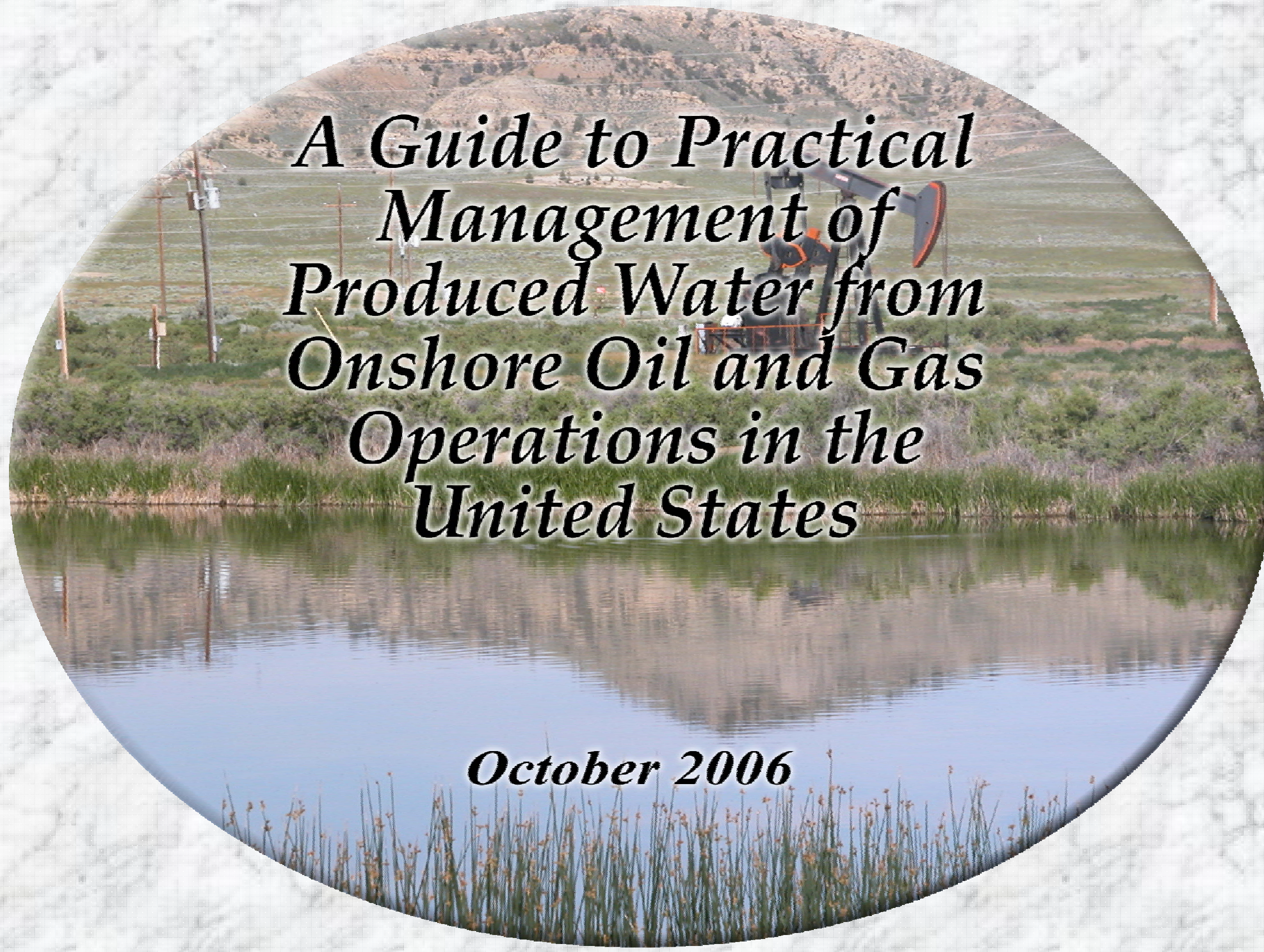
A Guide to Practical Management of Produced Water from Onshore Oil and Gas Operations in the United States



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DISCLAIMER

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ACRONYM LIST

AC	Alternating Current
API	American Petroleum Institute
ARI	Advanced Resource International
ASR	Aquifer Storage and Recovery
Ba	Barium
BAT	Best Available Technology
BCT	Best Conventional Pollutant Control Technology
BER	Board of Environmental Review
BLM	Bureau of Land Management
BOPD	Barrels of Oil Per Day
BPT	Best Practicable Control Technology
BTEX	Benzene, Tolulene, Ethylbenzene, Xylene
Ca	Calcium
CaCO3	Calcium Carbonate
CAFO	Concentrated Animal Feeding Operations
CBNG	Coal Bed Natural Gas
CDT	Capacitive Deionization Technology
Cl	Chloride
COOH	Carboxylic Acid
CWA	Clean Water Act
DC	Direct Current
DOE	Department of Energy
DOWS	Downhole Oil/Water Separation Technology
ECA	Electrochemical Activiation
ED	Electrodialysis
EDI	Electro-deionization
EDR	Électrodialysis Reversal
EIA	United States Energy Information Administration
ESPs	Electric Submersible Pumps
FTE®	Freeze Thaw Evaporation
GAC	Granular Activated Carbon
GTI	Gas Technology Institute
GWPC	Ground Water Protection Council
H+	Hydronium
HCO3	Bicarbonate
HEED™	High Efficiency Electodialysis
HERO™	High Efficiency Reverse Osmosis
HSWA	Hazardous & Solid Waste Amendments
HUC	Hydrologic Unit Code
HTC	Hydrotalcite
IID	Class II Injection Disposal Wells
IIR	Class II Injection Recovery Wells
IOGCC	Interstate Oil and Gas Compact Commission
kg/m2h	kilograms per meters squared-hour
KSU	Kansas State University
MBOGC	Montana Board of Oil and Gas Conservation

MCF	Thousand Cubic Feet
MMCF	Million Cubic Feet
MDEQ	Montana Department of Environmental Quality
MF	Microfiltration
Mg	Magnesium
MPDES	Montana Pollutant Discharge Elimination System
MWCO	Molecular Weight Cutoff
Na	Sodium
NaCl	Sodium Chloride
NaOH	Concentrated Sodium Hydroxide
NETL	National Energy Technology Laboratory
NF	Nanofiltration
NO3	Nitrate
NORM	Naturally Occurring Radioactive Materials
NPDES	National Pollutant Discharge Elimination System
NPR-3	Naval Petroleum Reserve No. 3
NRCS	National Resource Conservation Service
NSPS	New Source Performance Standards
PAC	Project Advisory Council
PCPs	Progressive Cavity Pumps
POD	Project Plan of Development
POTWs	Publicly Owned Treatment Works
PRRC	Petroleum Recovery and Research Center
ppm	Parts Per Million
psi	Pounds Per Square Inch
RCCD	Reverse Circulation Center Discharge
RCRA	Resource Conservation and Recovery Act
RO	Reverse Osmosis
RMOTC	Rocky Mountain Oilfield Testing Center
RSE	Rapid Spray Evaporation™
SAC	Strong Acid Cation
SAR	Sodium Absorption Radio
SDI	Subsurface Drip Irrigation
SDWA	Safe Drinking Water Act
SEO	State Engineer's Office
SNL	Sandia National Laboratory
SO3H	Sufonic Acid Group
TCEQ	Texas Commission of Environmental Quality
TCF	trillion cubic feet
TDS	Total Dissolved Solids
TMDL	Total Maximum Daily Load
TPH	Total Petroleum Hydrocarbons
UBD	Underbalanced Drilling
UF	Ultrafiltration
UIC	Underground Injection Control
USDW	Underground Sources of Drinking Water
USEPA	United States Environmental Protection Agency
USGS	United States Geological Survey

VSEP	Vibratory Shear Enhanced Processing
WAC	Weak Acid Cation
WDEQ	Wyoming Department of Environmental Quality
WGR	Water to Gas Ratios
WGS	Wyoming Geological Survey
WOGCC	Wyoming Oil and Gas Conservation Commission
WOR	Water to Oil Ratios
WWQRR	Wyoming Water Quality Rules and Regulations

SECTION 1.0 INTRODUCTION

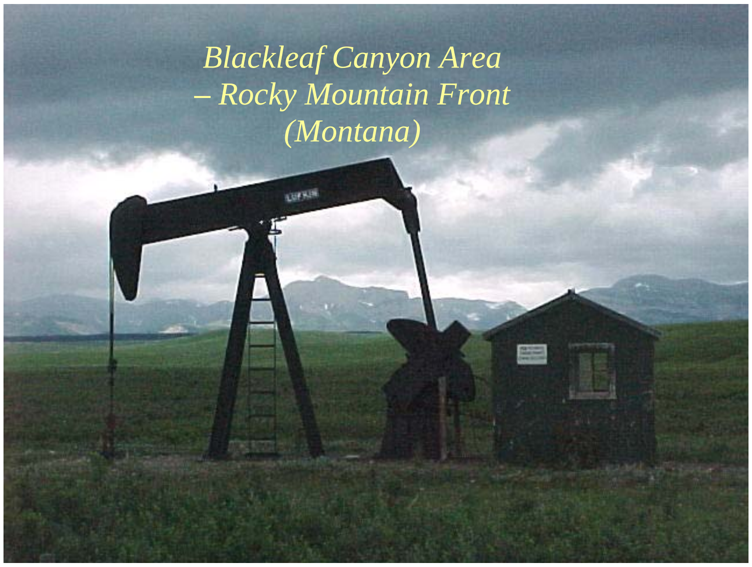
The make-up of the oil and gas industry in the United States today is different than it was 25 years ago. The domestic oil and gas sector is no longer dominated by large oil and gas companies. Currently, 65 percent of the natural gas and 40 percent of the oil produced in the United States is produced by small independent oil and gas companies which typically employ no more than 10 full-time employees (DOE, 2006 and API, 2006). This core of independent producers might not have the financial aptitude to conduct the research required to make the technological advances necessary to continue to economically produce domestic energy resources, but the domestic oil and gas industry cannot sustain itself without the critical development of new technologies. This is a major concern that is addressed by the United States Department of Energy (DOE) National Energy Technology Laboratory (NETL) through research grants targeted to fill this void.

Along with Congress, President George W. Bush set forth an Energy Bill in 2005 that focuses on increasing our nation's ability to be more reliant on domestic sources of energy and less reliant on foreign oil and gas. President Bush stated the following in an address to the Sandia National Laboratory in Albuquerque, NM:

> *"Meeting the needs of our growing economy also means expanding our domestic production of oil and natural gas, which are vital fuels for transportation and electricity and manufacturing."*

To meet the goals of the President, NETL has focused research funding to develop oil and natural gas technologies and technology transfer projects to enhance the ability of domestic producers to extract energy resources while continuing to protect the environment (DOE, 2006). Produced water management is widely recognized as a core issue that may be a barrier to continued economical and environmentally sensitive oil and gas development in the United States. Figure 1.1 is a map of the United States showing the distribution of oil and natural gas producing regions across the country. The distribution of producing areas is not uniform across the United States, as there are distinct regions where oil and gas production occurs. These regions include, but are not limited to: the Mid-Continent, Gulf Coast, the Rocky Mountain Region, Appalachian Mountain Region, California, and Alaska. The increased demand for energy resources in the United States has caused increases in oil and gas prices, which have led to a renewed interest in previously uneconomical or marginally economic areas. These once marginal, or high risk, plays include tertiary recovery projects, continuous reservoirs and other conventional and unconventional oil and gas plays that often have high water to oil ratios (WOR) and/or high water to gas ratios (WGR). Many of these new unconventional plays are under development and have resulted in a broad spectrum of new produced water management challenges.

Various technological advances such as improved water reduction procedures that lower the WOR and/or WGR at the wellhead and cutting edge produced water management alternatives that can treat large volumes of marginal quality water to beneficial use standards are constantly being developed. The benefit of these technological advances typically results in extending the productive life of a well, or in some cases an entire field. The benefits are not likely to be attained, however, if the technological advances are not widely available to the public and industry via technology transfer.

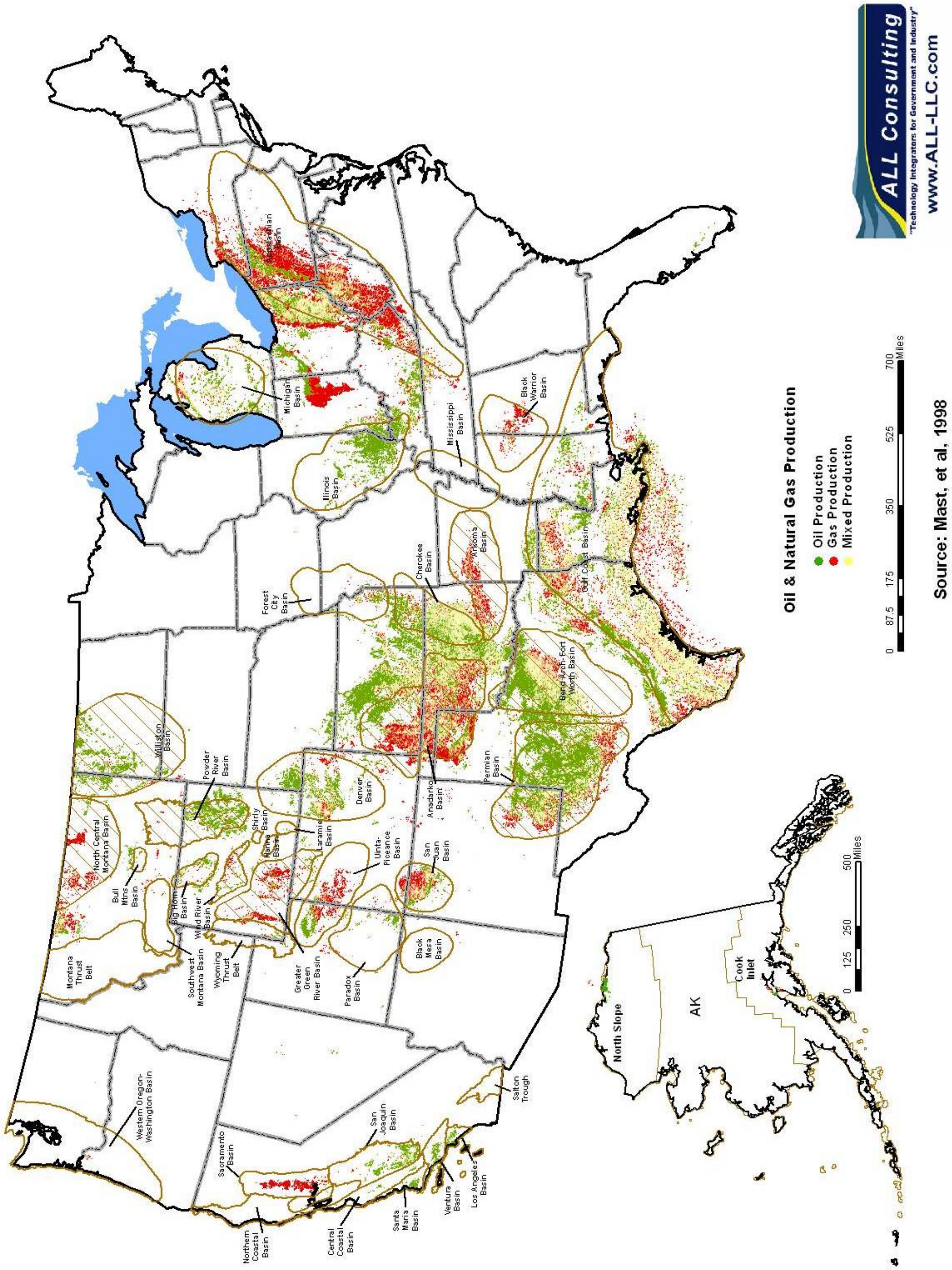


Blackleaf Canyon Area – Rocky Mountain Front (Montana)

Advanced technology also might allow development of resources that were not previously economically viable, such as unconventional natural gas (e.g., coal bed natural gas, oil shales, tight sands, regionally extensive-highly permeable reservoirs) and mature oil and gas fields ("stripper" wells). More than 75 percent (423,000 out of 555,000) of our nation's oil wells are classified as "stripper" wells, or wells that produce less than 10 barrels per day (BOPD), or 60 million cubic feet (MMCF) of gas per day (IOGCC, 2005). On average, these stripper wells produce about 2 BOPD, but collectively, they account for nearly 15 percent of domestic oil production (API, 2006). The WOR on stripper wells can be as high as 40 barrels of water to 1 barrel of oil produced (API, 2006). The economic and environmental benefit to lowering the WOR on stripper wells is wide reaching and can affect the industry on a nationwide basis.

Water produced during oil and gas operations constitutes the industry's most prolific product. By volume, water production represents approximately 98 percent of the non-energy related fluids produced from oil and gas operations, yielding approximately 14 billion barrels of water annually (Veil, 2004). When compared to the annual oil (1.9 billion barrels, EIA, 2006) and gas (23.9 TCF, EIA, 2006) production across the United States, the argument could be made that the oil and gas produced would be more appropriately identified as a byproduct to production of water.

Figure 1.1 Oil and Natural Gas Production in the United States



Source: Mast, et al, 1998 and ALL Consulting, 2006

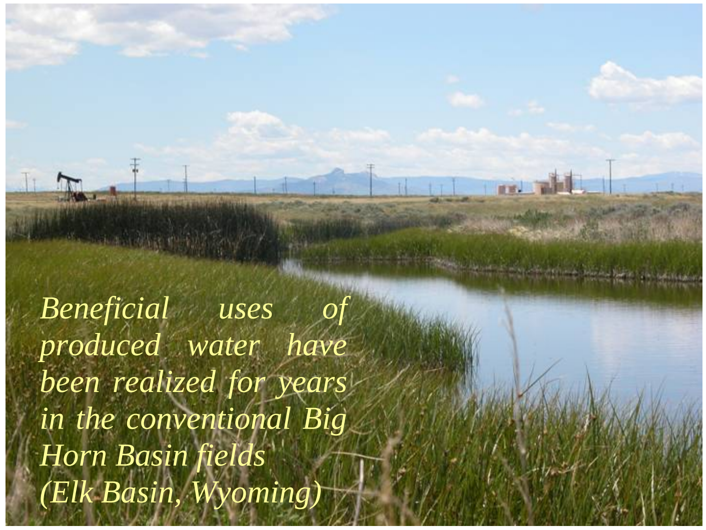
In recent years, the oil and gas industry's view on water production has changed dramatically. Produced water has historically been viewed by most as a waste stream that must simply be disposed of in the most cost efficient and environmentally sound manner possible. This outdated viewpoint has and is continuing to evolve in the upstream energy industry and in the eyes of many other stakeholders (e.g., landowners, government regulatory agencies, and non-governmental organizations). The evolving view on produced water has stemmed from many issues the industry and our nation have faced, including lengthy droughts in areas of the western United States; water shortages for power generation; and many other environmental challenges facing our nation. This evolving viewpoint has led some to the belief that produced water is not a waste stream at all, rather it has created a desire to beneficially use the water opposed to simply disposing of it as a waste (ALL, 2006).

Adding gypsum to produced water prior to discharge to meet discharge permit criteria (PRB, Wyoming)

The large volumes of high quality water produced today have resulted in operators looking for alternative means of managing this water in a cost-effective and environmentally safe manner. A common misconception is that there is one produced water management practice that will work throughout the United States. Quite the opposite is true. In fact, produced water management practices vary widely across the United States and in some instances across a single oil and gas field. A few examples of produced water management practices currently in use are:

- **Water Treatment**: Water treatment (purification or composition adjustment) technologies are advancing and expanding into oilfield use in many areas. The area that has led the drive to implement water treatment technologies is the coal bed natural gas development in the Powder River Basin located in northeastern Wyoming and southeastern Montana. Other areas have expanded the use of water treatment technologies for temperature correction, solids removal, oil and grease removal, and purification to facilitate drilling and stimulation.
- **Enhanced Recovery**: Produced water has long been used for enhanced oil recovery or even for pressure maintenance through waterflooding. The majority of injection wells used in the United States in association with the energy industry are used for enhanced recovery.
- **Deep Well Injection**: In some cases, oilfield wastes do not meet the criteria to be injected into a Class II injection well and must be disposed of via a Class I industrial or hazardous waste disposal well. For instance, reject water from some water treatment facilities is disposed of in Class I injection wells.
- **Sustainable Development Practices**: In some areas of the country, water is difficult to obtain and operators are forced to make the best overall use of the water produced. In these areas, operators store and save produced water for drilling activities, dust suppression, stimulation, clean-up, and other uses to avoid acquiring water from substantial distances.

- **Water Reduction**: Technology continues to play a tremendous role in natural gas and oil development. In some reservoirs, water production poses tremendous problems for economic production of hydrocarbons. Many alternatives have been and are continuing to be used more prolifically. Water reduction alternatives such as downhole oil/water separation technology (DOWS) have a great potential to save money and reduce the environmental impacts of managing produced water at the surface (Veil, et al. 1999).
- **Beneficial Uses**: High quality water with a total dissolved solids (TDS) concentration of less than 10,000 parts per million (ppm) may be employed for an assortment of beneficial uses, providing recreational opportunities, drinking water for stock and wildlife, irrigation water in arid regions, and a supplemental source for municipal water supplies. In some basins, such as the Big Horn, in north-central Wyoming and south-central Montana, landowners have come to depend on the produced water for farming and ranching.


Beneficial uses of produced water have been realized for years in the conventional Big Horn Basin fields (Elk Basin, Wyoming)

The above mentioned practices are discussed in more detail in Section 4, along with several other practices and water treatment alternatives that are currently being tested, researched, and implemented on pilot scale studies to further the potential for beneficial use of produced water that normally would be considered as marginal to poor quality.

Section 1.1 Purpose and Need

Industry operators and state regulators share two goals: to effectively and efficiently manage produced water while 1) remaining protective of the environment and 2) continuing to economically develop domestic energy resources. This document aids in achieving these goals by compiling various sources of data and providing an analysis for how the data can be used to create innovative produced water management solutions. The data include:

- **Produced Water Management Practices:** A catalogue of water management practices, treatment technologies, and water reduction techniques is presented for use as a reference of water management practices currently available to operators. Leading edge technologies that have not yet been widely applied are also identified and discussed. Operational parameters of each water management practice are identified as well.
- **Produced Water Quality**: The quality of produced water from various onshore oil and gas producing basins of the United States is presented in terms of TDS. TDS is a good indicator of salinity, which can be used to determine appropriate produced water management practices, because many practices might become uneconomical or impractical based on the salinity of the water. Case studies of water management

practices currently used to handle a wide range of water qualities in various basins are presented to provide examples of success stories and lessons learned.

- **Socio-economic Setting and Climate:** The ability to beneficially use water can be dependant on the socio-economic setting and the weather trends of the area from which it is produced. Arid areas with a high population density or areas highly dependant on agricultural activities to sustain their population are most likely to be interested in utilizing the produced water. Water quality data are geospatially presented along with average rainfall, evapotranspiration, and population density. The result is identification of areas of the United States where water management is considered of utmost importance because any beneficial use might improve the sustainability of that area.
- **Availability of Injection Zones:** The ability to economically inject produced water may dictate the feasibility of marginal wells with extremely high salinity water that has no redeemable beneficial use other than enhanced recovery. A statistical analysis of permitted injection wells and their disposal rates is presented on a state-by-state basis to identify areas where injection is most common.

The analyses of these datasets include technology transfer recommendations by matching the applicable water management practices to relevant basins of the United States that meet or exceed the critical operational parameters. While each state is responsible for regulating the produced water management techniques implemented in their state, this analysis may prove to be instrumental to state and federal regulators' decision-making process in regards to produced water regulations that are protective of the environment while avoiding economic impacts caused by the disruption of domestic oil and natural gas supply and delivery.

This Guidebook may be utilized by operators during the planning phase for determining produced water management options as they move into areas of the United States that might be unfamiliar to them. Operators also can take advantage of the technology transfer recommendations by evaluating alternative options for water management as they seek to maintain economic production from older fields that have progressed to higher WORs and WGRs. This Guidebook also provides operators with a valuable reference to lead them as they pursue unconventional oil and gas plays that can involve large volumes of produced water and unusually high WOR and/or WGRs.

Section 1.2 Overview of Research

This document contains the results of research conducted to provide an overview of current issues as they relate to produced water and produced water management. This research focused on developing inter-basin technology transfer recommendations based on the findings. The following list presents the topics researched and presented in this document:

- **Current and Emerging Trends:** Where available, researchers compiled production data from the 37 oil and gas producing states. Nationwide production trends associated with produced water were noted and documented to support the growing concern that annual domestic produced water volumes continue to rise as annual domestic oil and gas production volumes decline.
- **Existing and Emerging Regulations:** Researchers examined the applicable and relevant regulatory literature as it applies to produced water management of onshore oil and gas exploration and production sites. To expedite the process, the research team interviewed various state agencies that govern produced water issues of the oil and gas industry. Industry personnel also were interviewed in various states to determine what issues, if any, are relevant and germane to industry in terms of impacting the economic viability of oil and gas production. The Project Advisory Council (PAC) described in Section 1.3 was instrumental in identifying various regulatory issues and challenges that warranted further research.
- **Produced Water Management Alternatives:** Researchers examined various produced water management practices, water treatment technologies, and water reduction techniques to identify the operational requirements of each. Operational requirements may include water quality and quantity, environmental impacts, operational costs, applicability per resource type, regional setting, and basin statistics, among others. Strengths and weaknesses of the various management alternatives analyzed were noted and categorized for ease of technology transfer between regions of the United States.
- **Case Studies:** Several case studies were performed to gain further insight into produced water management alternatives in various basins. Industry personnel were interviewed as a part of the case study process, and the research team documented success stories and lessons learned.
- **Watershed Based Permitting:** Watershed based permitting is a relatively new concept intended to protect the environment while maintaining reasonable discharge limits based on the assimilative capacity of the watershed as a whole. The Wyoming Department of Environmental Quality (WDEQ) began implementation of a watershed based permitting program in the Powder River Basin in 2005. Members of the research team followed the progress of the WDEQ and attended various public meetings to gain input from various stakeholders. As part of the research phase of the project, the results of these meetings and the pending outcomes are documented in this report.

Section 1.3 Project Advisory Council

The research herein was conducted under the direction of the Interstate Oil and Gas Compact Commission, with oversight and direction from the PAC. The PAC is comprised of a diverse group with interests related to produced water management associated with oil and gas development that includes: oil and gas agency directors, state and federal agency representatives, industry representatives, and other stakeholders. Because the PAC includes such a diverse group, input actively was sought at various stages of the research to provide direction and to help identify issues that are relevant to the success of the research. The diversity of the PAC has resulted in the research obtaining rare perspectives into the produced water management issues associated with oil and gas development.

SECTION 2.0 CURRENT INDUSTRY TRENDS

Water production within the domestic oil and gas industry has increased with the industry's efforts to increase production from existing fields (such as the de-watering projects in the Anadarko Basin) and from non-conventional fields (such as the Barnett shales in Northern Texas and the coal bed natural gas (CBNG) plays in various basins of the western United States). Furthermore, the past few years have seen a drastic increase in the price of crude oil and natural gas while demand for these resources has continued to rise. Operators in the United States have attempted to alleviate the shortage by increasing domestic production. Although production statistics typically lag a few years on a nationwide scale, indicators present in state data such as that from the Montana Board of Oil and Gas Conservation's records show that oil production is increasing (as a result of the expansive development of the non-conventional Bakken shale oil fields), while other aging fields in Montana are producing less oil and more water (MBOGC, 2006). In general, this trend is correlative to the oil and gas industry across the United States. As a result, to increase daily oil and gas production, operators of these older fields also must increase daily water production. This ultimately leads to an increase in the production ratios of water to oil (WOR) and/or water to gas (WGR).

In addition to the common aging trend, technological advances have allowed the oil and gas industry to focus on several new non-conventional plays that have intrinsically higher water production rates to facilitate the yield of oil and gas:

- **CBNG** often requires de-pressurization of the producing coal seam by pumping large volumes of high quality water (<10,000 mg/L TDS) to facilitate the production of natural gas.
- **Shales and diatomites** such as the Barnett Formation of north-central Texas require high-volume hydraulic fracture treatments that produce water back to wells for a long period of time. This water can be fairly high quality but because of state and federal regulations, the water must be managed as an oil and gas waste.
- **Dewatering** of old reservoirs aims to drain the water from competing permeability systems to allow oil into the borehole. These projects require pumping of prodigious amounts of water as evidenced by the high rate disposal permits obtained in recent years within mid-continent fields in Oklahoma, Texas, and Kansas.

The quality and quantity of produced water varies across the United States. Section 2.1 explains how the water quality varies from region to region; introduces a scientific theory that explains why these differences may have come to be; and presents oil, gas, and water production trends across the United States that show how the average WOR and WGR have been increasing over the last few years.

The production trends noted in Section 2.1 are representative of the WOR and WGR of the nation on average. This is useful information, but it does not necessarily explain what is impacting the increase in these ratios. Section 2.2 looks closer at individual state production trends, permitting activity, and completion activity to determine the key aspects that are impacting water production volumes, energy prices, and new technologies.

Section 2.1 Domestic United States Overview

As previously mentioned, the quality and quantity of produced water varies across the United States. Section 2.1.1 provides an illustration of how the quality of produced water varies and Section 2.1.2 provides a discussion that explains why these differences may have come to be. Section 2.1.3 demonstrates the nationwide impact of produced water quantities in terms of WOR and WGR.

Section 2.1.1 Produced Water Quality Trends Across the United States

Produced water quality data on a national level are available from the DOE-USGS Produced Water Database (USGS, 2002) and state-specific data are collected by some of the oil and gas producing states and stored in the producing states' databases for oil and gas production. Figure 2.1 presents a summary map of the data from the USGS produced water database. The colored data points shown in Figure 2.1 represent a range of salinity (as represented by TDS) values collected from the produced water from oil and gas boreholes. TDS ranges are indicated by color, with the data ranges indicated in the legend of Figure 2.1.

This database consists of approximately 53,000 individual produced water samples from 35 states. Water quality information comes from the analysis of water taken from the boreholes during oil and gas production, from production tests, and from drill-stem tests. Data quality may vary across the sample set due to evaporation from surface tanks and contamination from rainwater or mud filtrate. The DOE-USGS database contains descriptors of sample type. Water chemistry data in the database vary from sample to sample with many samples consisting only of TDS while other samples include detailed cation and anion concentrations. Although individual ions may affect beneficial use, suitability for most beneficial uses can be ascertained by total salinity (as represented by TDS). The water quality from this database is analyzed in more detail for various basins in the United States in Section 6.

Section 2.1.2 Understanding the Science of Produced Water Quality

Water may be produced from oil and gas reservoirs as a part of routine operations. In the subsurface, water exists in the pores or other openings of the reservoir. Reservoir rocks can contain predominantly hydrocarbons, predominantly water, or a mixture of the two, but in each case the water is a part of the dynamic rock-fluid system. After sediments are laid down, subsequent movement of water and other fluids is largely lateral, driven by hydraulic pressure differences. However, net movement of water is consistently towards the surface, driven by induration, compaction, and maturation of the rock frame. As vertical movement continues, filter-pressing through shales rich in chemically active clay minerals can retard the passage of dissolved constituents, thereby increasing the salinity of the water in deeper reservoirs. The phenomenon of natural filter-pressing by shales is analogous to nano-filtration desalination (Cohen, et. al., 2001). If upward migrating water has reduced salinity, the pore water left behind will have higher salinity. In this way, the vertical flux of migrating water will give rise to a salinity gradient within the sedimentary column from shallow strata with pore water much like sea water (approximately 32,000 mg/L) to very strong brines (up to a saturated solution of approximately 350,000 to 400,000 mg/L) at depth. This, in general, is what is seen in many sedimentary basins, where the oldest sedimentary rocks have pore water that is nearly saturated and the younger, shallow strata contain water of lesser salinity. A diagram depicting this process of water movement is shown on the right-hand side of Figure 2.2.

Figure 2.1 Total Dissolved Solids from the USGS Produced Water Database in the United States

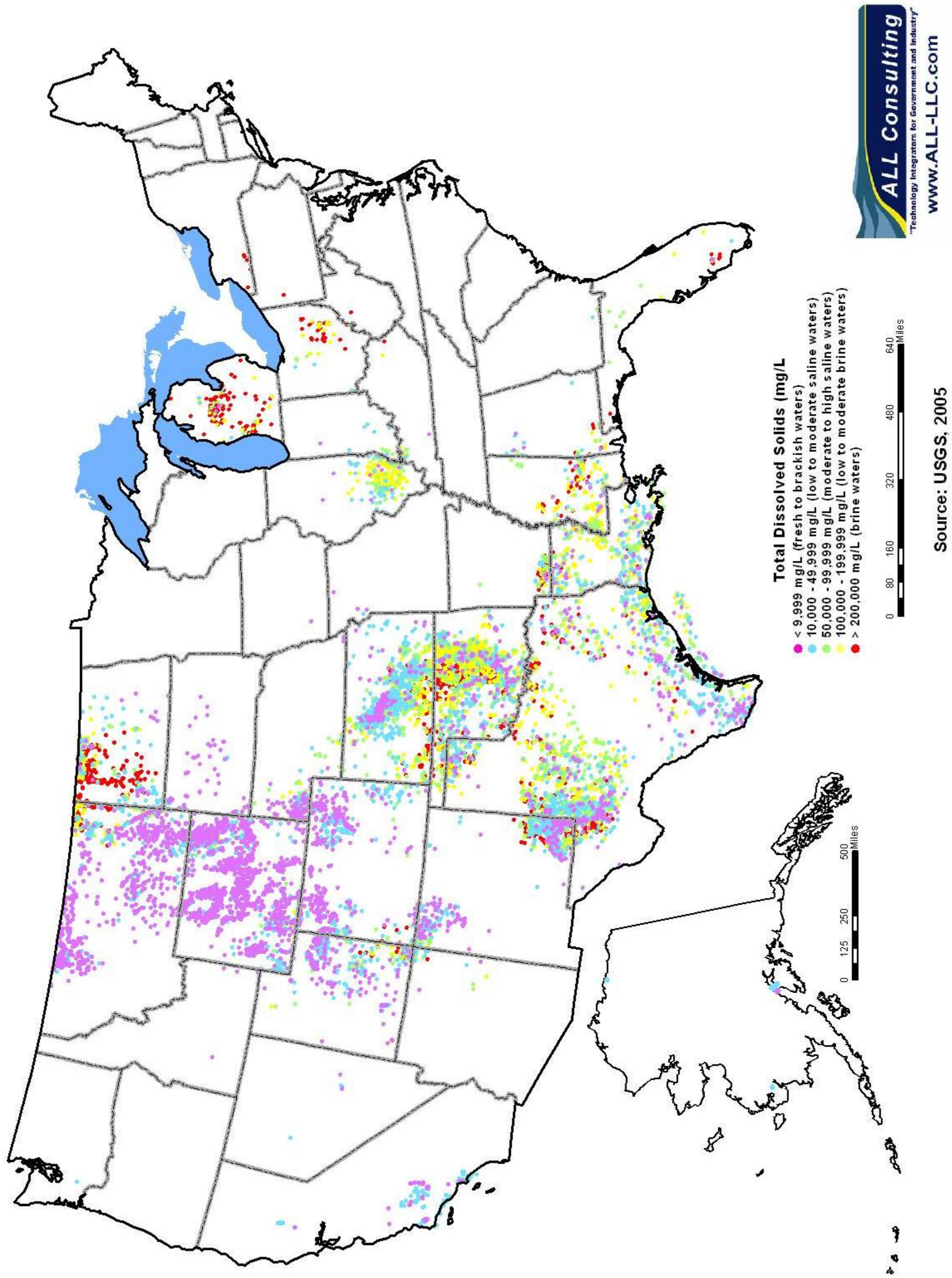
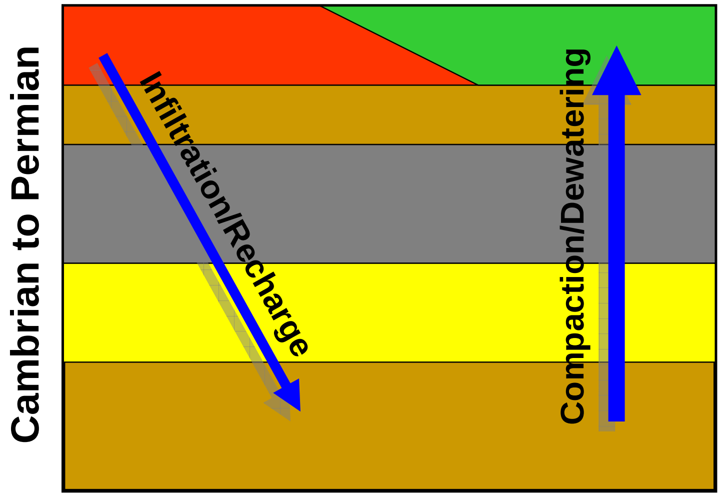


Figure 2.2 Natural Water Progression in Basins Such as the Anadarko or Permian Basin



The general trend of increasing salinity can be modified by several more or less local processes including long-range, dip-wise migration of fresh water from the outcrop, driven by surface recharge. Surface recharge can be occurring at the present time in those areas near the outcrop belt on uplifted areas, or historical recharge could have occurred during times of uplift and deep erosion. It is unknown how far recharge with meteoric water can extend, but Tertiary-aged recharge of Mississippian Madison Formation under the Great Plains of Wyoming and Montana extends many miles down-dip from the outcrop. Recharge is driven by hydraulic pressure generated by elevation of the outcropping recharge area, causing downward flow of the lighter meteoric water column. Meteoric water begins at the surface as high quality rain water, but over time the comparatively fresh water infiltrates and obtains added salinity from soluble minerals within the strata overlying the reservoir rock. The downward progression of recharge water is depicted on the left-hand side of Figure 2.2.

In addition to general upward flux of subsurface water and recharge from outcrops, reservoir rocks are subject to water variations caused by original water chemistry and fluid invasion from maturing, transforming shale masses (Hunt, 1979). As temperatures increase due to increasing burial, shales can expel water and entrained hydrocarbons. Simple compaction of the shale will drive out native pore water as the shales' porosity decreases from an original 80%. At some point, however, clay minerals within the shale begin to change, driving out water of crystallization, which can have a very different chemical composition from the pore water. Near the same point (in terms of temperature), organic material within the shale begins to give off large volumes of hydrocarbons. This charge of fluids can migrate throughout the sedimentary basin, depending upon permeability connections.

As an example, the Silurian-Devonian Hunton Formation is a prolific reservoir in the Anadarko Basin. Hunton oils found in Oklahoma fields have been geochemically correlated with overlying Woodford shales (Comer, 1992). On the other hand, thick, over-pressured Springer/Chester shales of the deep basin may be in connection with deep Hunton reservoirs by way of major regional faults, changing the water chemistry. It would be difficult to predict the salinity and chemistry of expelled water from the Woodford or Springer/Chester shales; that water would likely be a combination of pore water squeezed physically out of the shales and water of crystallization displaced by clay mineralogy changes.

Reservoir water chemistry in ancient sediments can be a product of original water chemistry. Some sediments, such as the Tertiary coals of the Powder River Basin, appear to have been laid down in fresh water, not sea water; this may be one of the reasons that the coals produce high quality, low TDS water. Other sediments such as the Permian Aged formations of the Anadarko Basin contain inter-bedded evaporates suggesting that deposition was in hypersaline environments resulting in reservoir waters that are very high in TDS.

A comprehensive paper (Bein and Dutton, 1993) describes interpreted formation waters in the southern Mid-Continent from the Delaware Basin to the Anadarko Basin, throughout the Paleozoic section. With the help of detailed chemical analyses, including stable isotopes, the authors saw the presence of several migrating brines that have modified the characteristics of formation waters. The authors saw the influence of meteoric water reacting with strata containing halite, gypsum, clays and other minerals. Downward leaching gave rise to saturated brines and low salinity brines, depending upon the local intervening strata. The authors observed high salinity brines in reservoirs adjacent to the Wichita Uplift, presumed to be caused by meteoric waters leaching through thick Permian evaporites. The complex geological history of these basins has produced complex varieties of produced water that often can be resolved only on a local basis.

Section 2.1.3 Nationwide Trends in Produced Water Quantities

The IOGCC consists of 30 member states and seven associate member states representing the regions of domestic oil and gas production of the United States. Available data were collected from each state and then aggregated to determine the United States domestic production trends (oil, gas, and produced water) as a whole. Trends may vary on a state-by-state basis, but the overwhelming tendency for the nation is shown to be increasing volumes of water, while oil and gas production is decreasing. As a result, industry has been experiencing higher WOR and WGR than in recent history. Figure 2.3 presents the water and oil production and the WOR since 2000, and Figure 2.4 presents the water and gas production and the WGR since 2000. The WOR has an upward trend with a high at around 9.8 barrels of water per 1 barrel of oil produced in 2005. The WGR also has an upward trend from 2000-2005; the high in 2005 was approximately 1 barrel of water produced per 1.0 MCF of natural gas.

Please note that if a state's production data were not available for any of the three components (oil, gas or water), all data for that state were not included in the analysis. States not included as a result of these data gaps were: Missouri, New York, Nevada, West Virginia, Virginia, Tennessee, Texas, and Utah. Furthermore, some states did not have data available for 2004 and/or 2005 (Arkansas, Mississippi, New Mexico, North Dakota, Ohio, and Pennsylvania), and the states that did have data for 2005 or only had partially complete datasets (Alaska, California, Colorado, Florida, Michigan, Montana, Nebraska, South Dakota, and Wyoming). Although this skews the total 2004 and 2005 production volumes of the oil, gas, and water produced, the oil/water and oil/gas ratios are believed to be representative of a complete dataset, which stresses the importance of the WOR and WGR versus actual production volumes when performing the comparative analysis. In general, the data support the notion that over time operators have had to produce more water to get the same amount (or less) of oil and gas production from a reservoir.

Figure 2.3 Water and Oil Production Volumes in the United States Since 2000

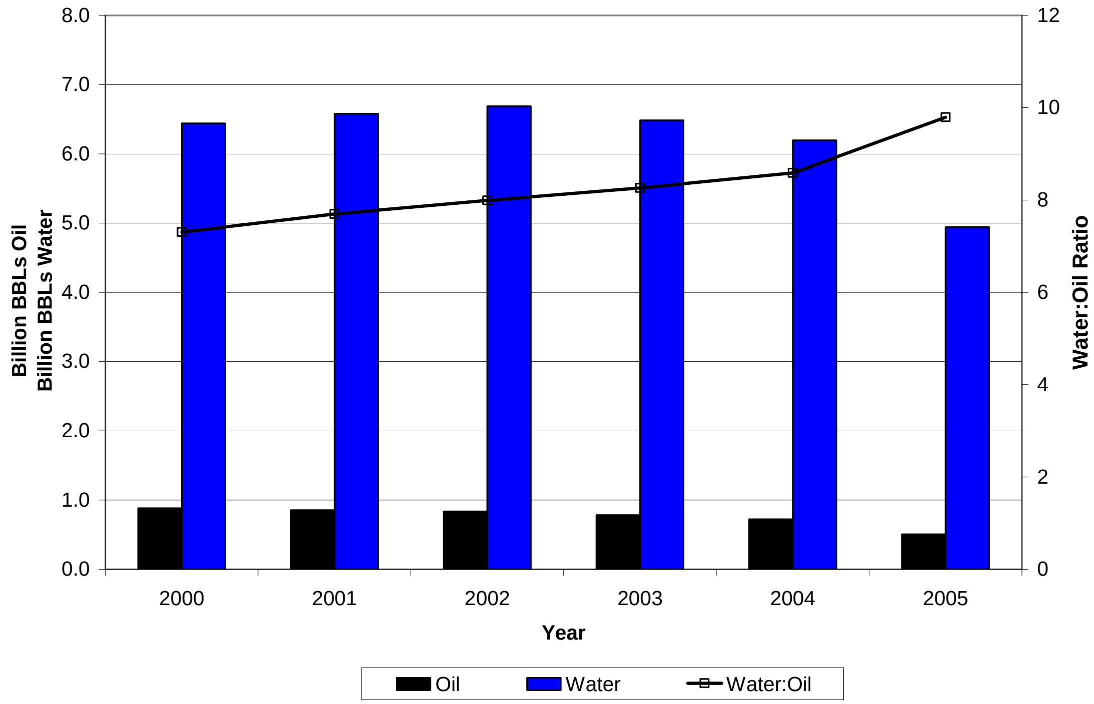
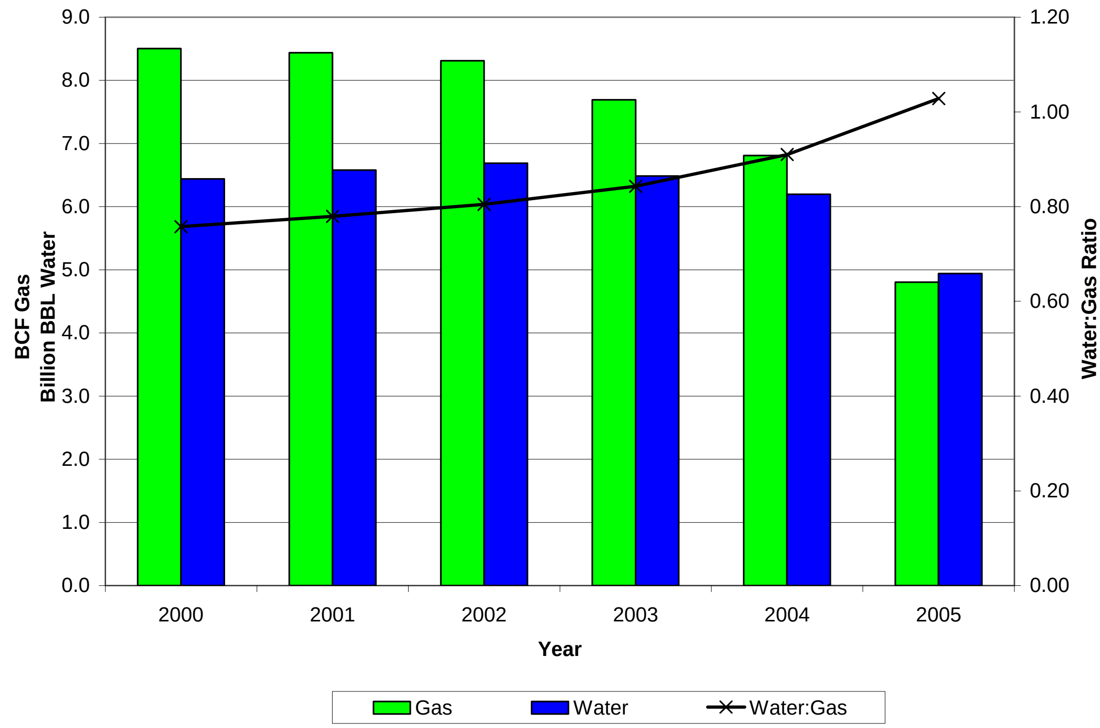


Figure 2.4 Water and Gas Production Volumes in the United States Since 2000



Note: Data for Figures 2.3 and 2.4 were compiled from the following state agencies:

2000 - 2003 – AK, AR, CA, CO, FL, MI, MS, MT, NM, ND, NE, OH, PA, SD, and WY
2004 – AK, AR, CA, CO, FL, MI, MS, MT, ND, NE, SD, and WY
(partial) 2005 – AK, CA, CO, FL, MI, MT, NE, SD, and WY

Section 2.2 Production Trends in Select States

Oil, gas and produced water databases were analyzed from Montana, Wyoming, Alaska, and Kansas to identify and evaluate production trends and the driving forces behind those trends (i.e. hot play exploited within the state, new technologies incorporated, and energy price fluctuations). The primary driver that impacts domestic oil and gas production trends is the market price of oil and gas, which is driven by a number of factors, one of which is demand. Over the last few years domestic energy demands have reached new heights and as a result, oil and gas prices have continued to rise. Section 2.2.1 discusses how the rise in oil and gas prices has lead to a push for domestic oil and gas exploration and production to increase to lessen the need for foreign imports. Section 2.2.2 shows how the push for increased domestic oil and gas production has lead to unprecedented advances in the use of new technologies, such as horizontal drilling and horizontal re-completions. The end result is a net increase in produced water across much of the nation. However, the new technologies employed are not necessarily responsible for an increase in WOR and WGRs. Section 2.2.3 provides discussion of how new drilling technologies increase water production while also decreasing the WOR. With rising energy prices, this example of employing new technologies might now prove to be economical because the increased revenue from oil and gas production might offset or exceed the incremental increase in capital drilling costs and operational water management costs.

Section 2.2.1 Energy Prices Impact Trends

The price of oil and gas either can stimulate or chill domestic oil and gas exploration and production. Figures 2.5, 2.7, 2.9, and 2.11 illustrate the effect of pricing on permit activity in Montana, Wyoming, Alaska, and Kansas respectively. Likewise, Figures 2.6, 2.8, 2.10, and 2.12 illustrate the effect of pricing on well completion activity in Montana, Wyoming, Alaska, and Kansas respectively. The data presented is for oil and gas wells in the representative state compared to the average oil and gas prices for the United States on an annual basis. The figures generally show that there is a positive correlation between oil and gas prices, permits issued, and well completion activity from 1990 to 2005. Alaska is the one state that does not appear to follow this trend directly, as can be seen in Figures 2.9 and 2.10.

As oil prices declined and gas prices remained steady in the early 1990s the well permit activity in Montana, Wyoming, and Kansas declined, from nearly 400 permits in 1990 to a little over 200 permits by 1993 in Montana, from over 1100 permits in 1990 to about 1000 permits in 1993 in Wyoming, and from almost 4000 permits in 1990 to less than 1500 permits in 1995 in Kansas. As energy prices have increased over the last 10 – 12 years, well permit activity also has increased for these three states. As oil and gas prices reached new highs in 2005, permit activity in Montana and Wyoming also reached new highs, with more than 1,300 well permits approved in Montana in 2005 and around 10,000 permits approved in Wyoming that same year. Kansas was also up in permits in 2005 with over 3500 permits approved. Figures 2.5, 2.7, and 2.11 show the permit application data in terms of the primary energy resource extracted from the well from Montana, Wyoming, and Kansas respectively, while Figures 2.6, 2.8, and 2.12 show the well completion data broken down in the same manner for these three states. The data presented in these figures show how new technologies (advances in horizontal well borings) and new developments (CBNG and the Bakken play) are impacting production of oil and gas resources in these states.

Figure 2.5 Well Permitting Activity in Montana, by Resource Compared to Average Oil and Gas Prices 1990 - 2005

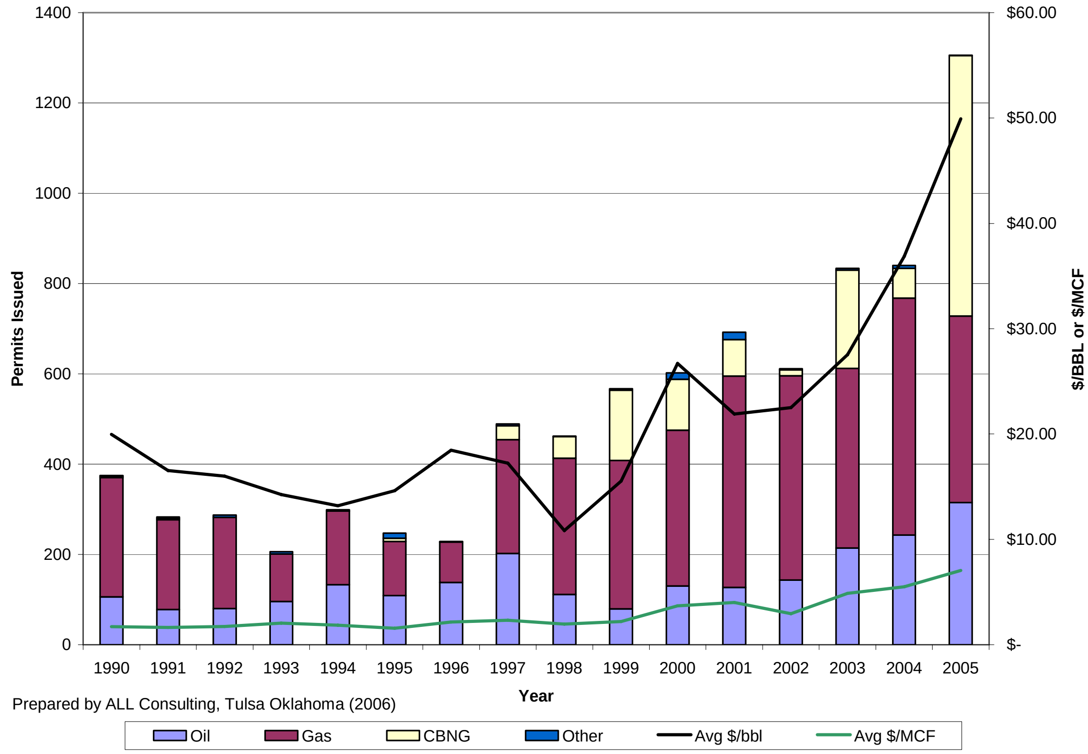


Figure 2.6 Well Completion Activity in Montana, by Resource Compared to Average Oil and Gas Prices 1990 - 2005

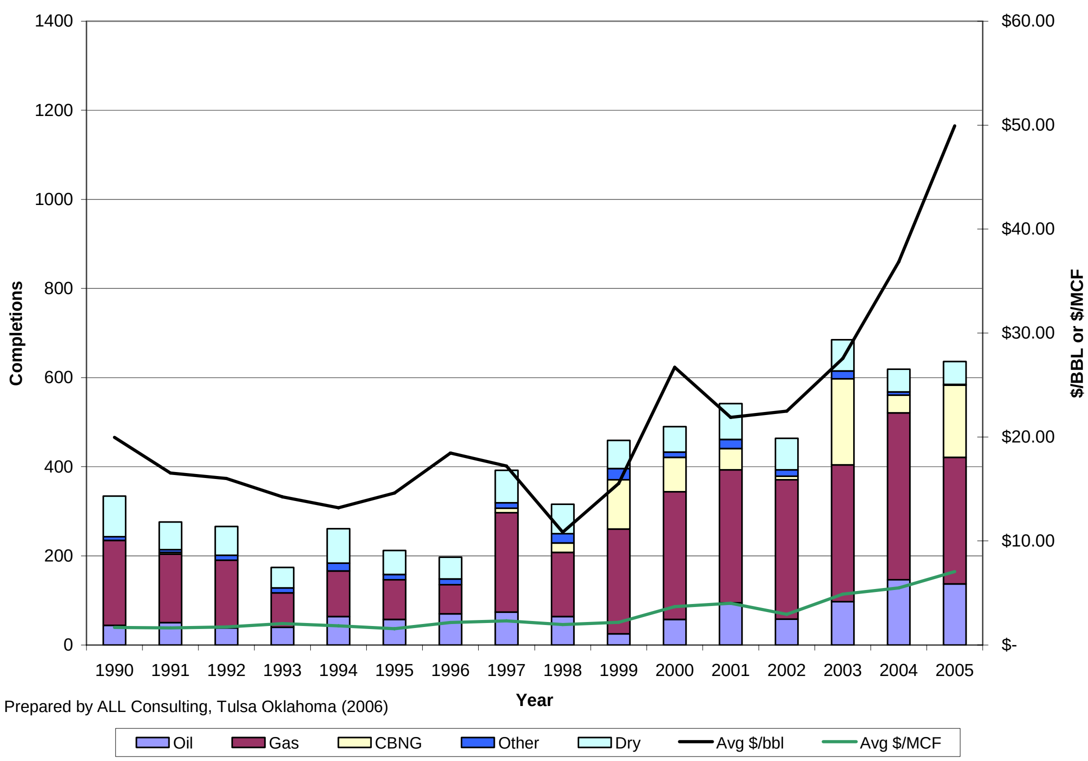


Figure 2.7 Well Permitting Activity in Wyoming, by Resource Compared to Average Oil and Gas Prices 1990 - 2005

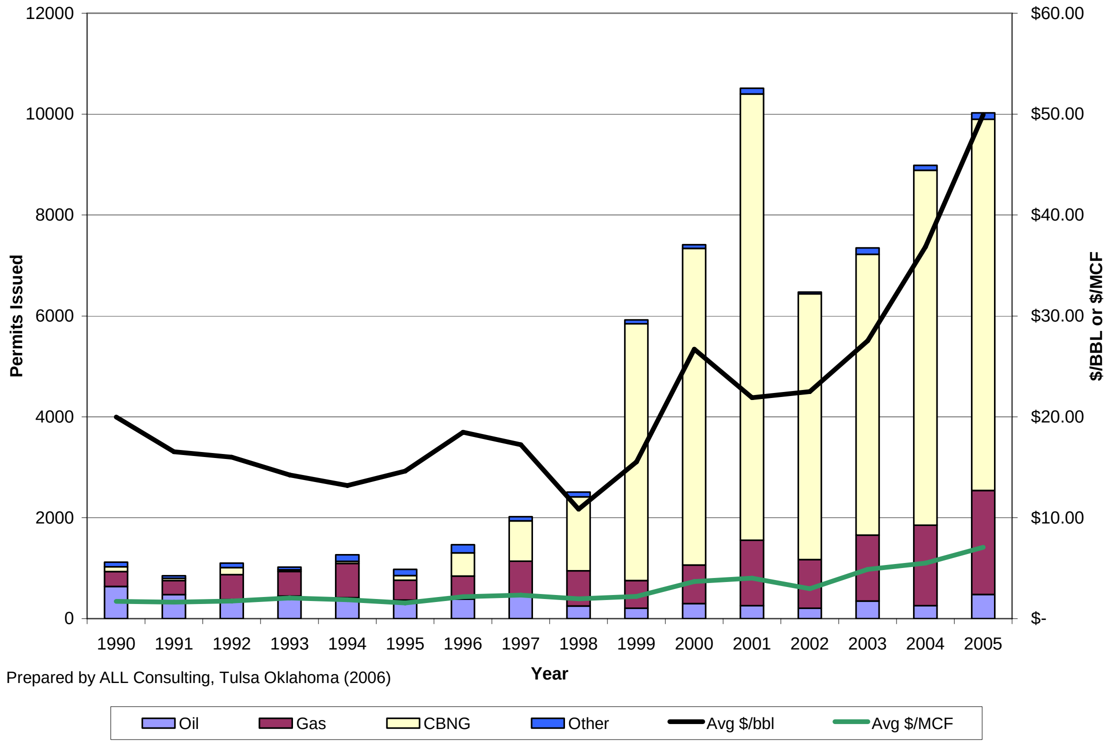


Figure 2.8 Well Completion Activity in Wyoming, by Resource Compared to Average Oil and Gas Prices 1990 - 2005

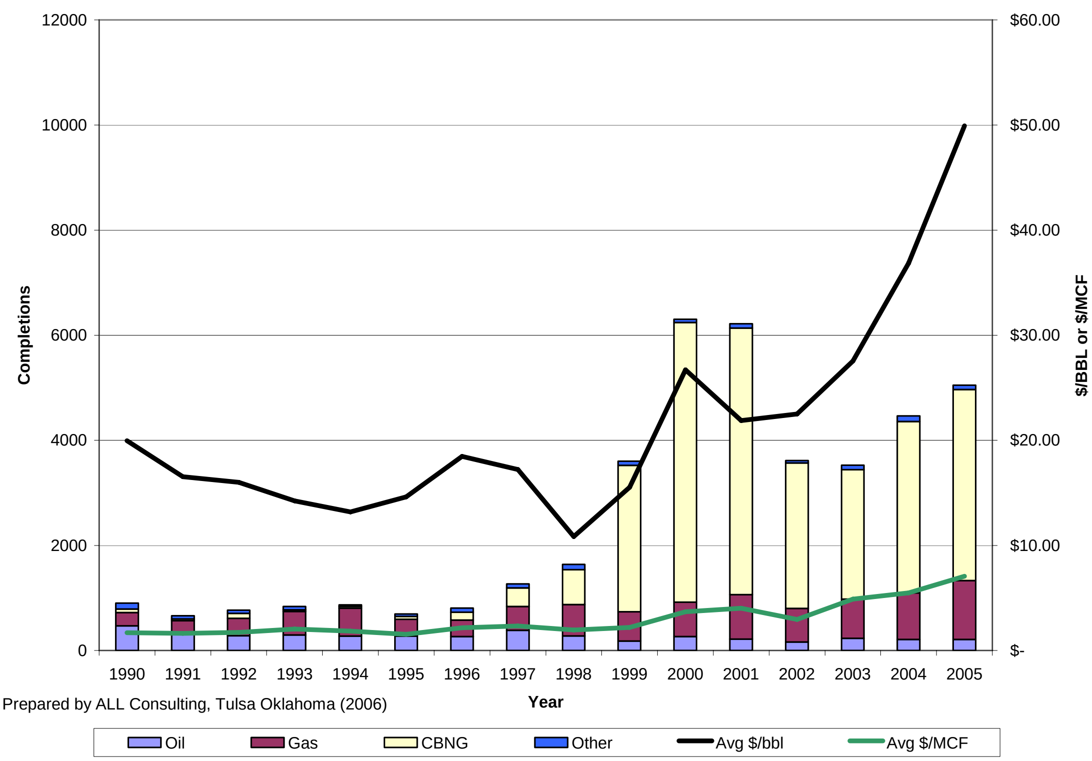


Figure 2.9 Well Permitting Activity in Alaska, by Resource Compared to Average Oil and Gas Prices 1990 - 2005

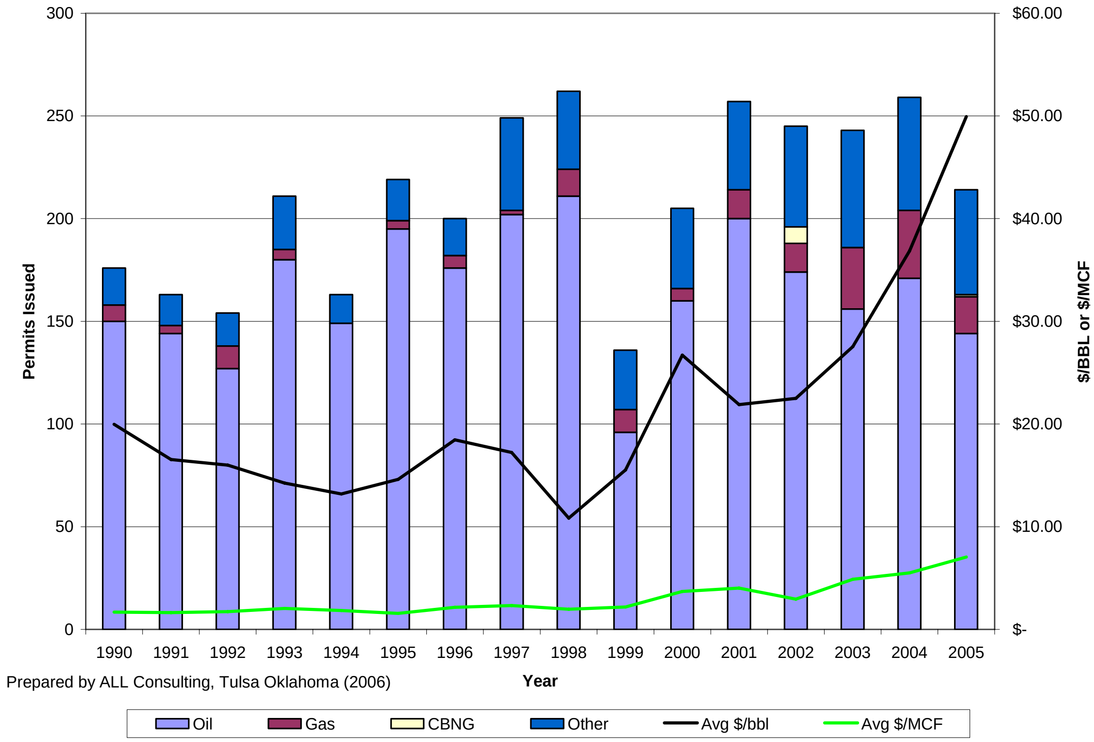


Figure 2.10 Well Completion Activity in Alaska, by Resource Compared to Average Oil and Gas Prices 1990 - 2005

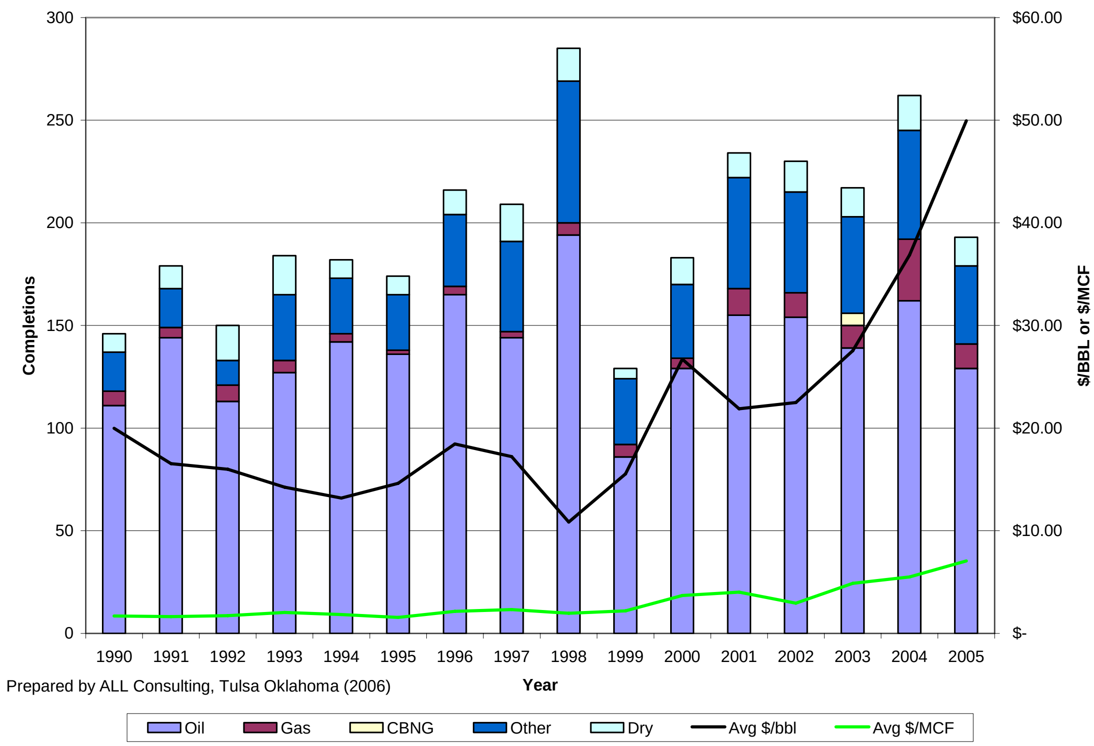


Figure 2.11 Well Permitting Activity in Kansas, by Resource Compared to Average Oil and Gas Prices 1990 - 2005

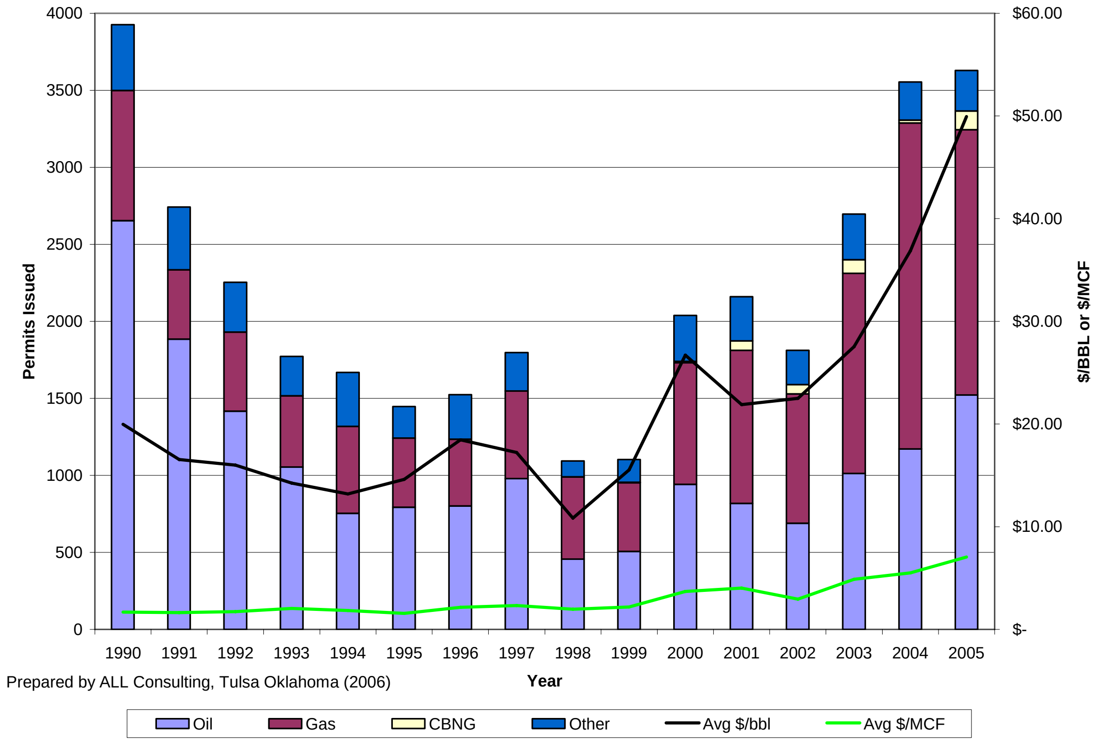
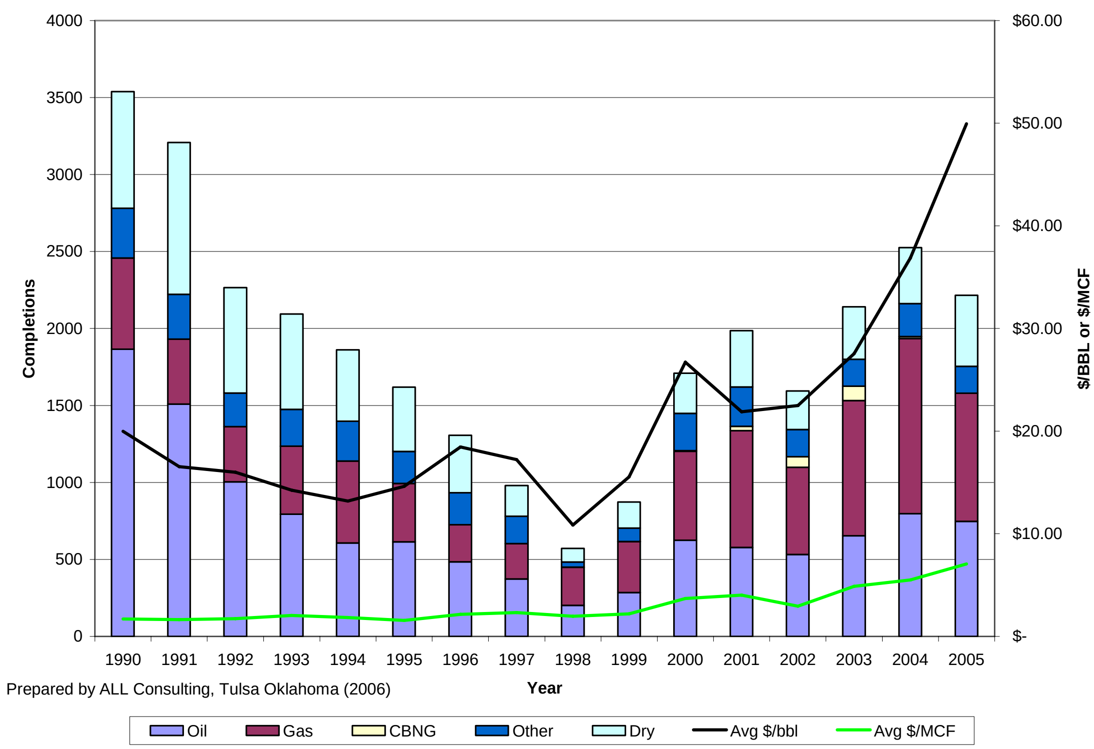


Figure 2.12 Well Completion Activity in Kansas, by Resource Compared to Average Oil and Gas Prices 1990 - 2005

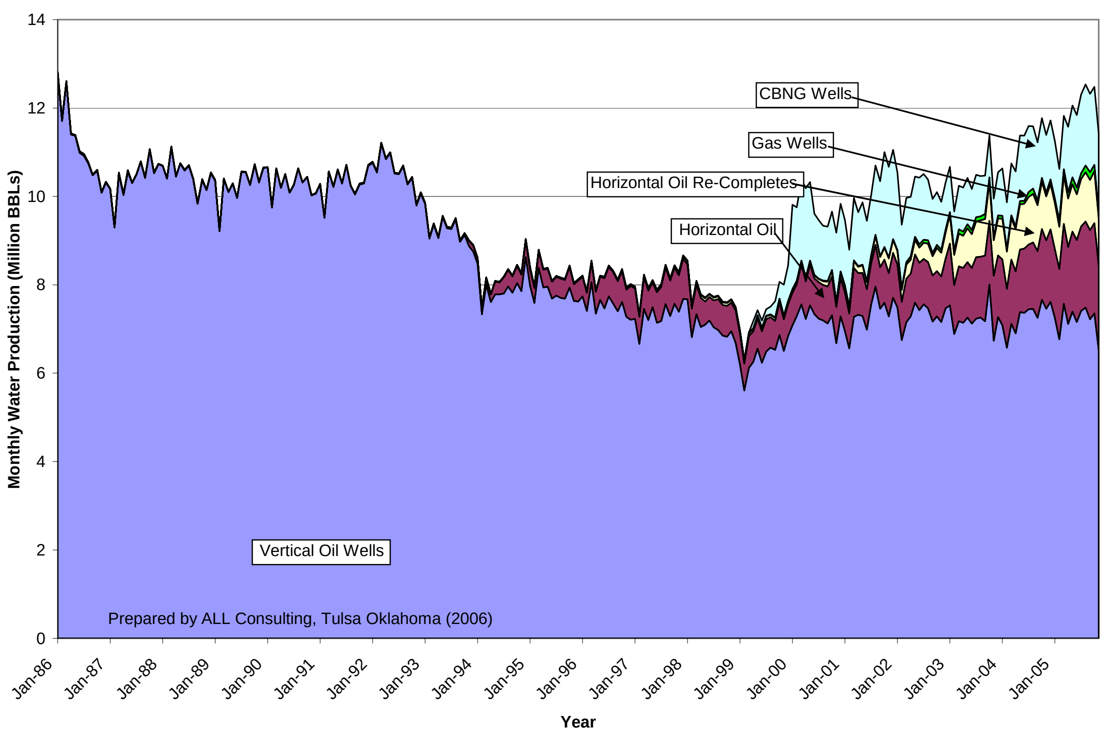


Section 2.2.2 New Technologies Impact Trends

As previously mentioned, increases in domestic and worldwide energy demand has driven up the price of oil and gas, which has stimulated domestic exploration and production programs. Higher prices can allow operators to explore the use of experimental and new technologies, which can increase domestic exploration and production and allow for the development of new plays that previously might have been uneconomical or technologically unattainable. Figures 2.6 and 2.8 document the affect the rise in energy prices had on the onset and increases in CBNG development, which was once considered uneconomical.

Figure 2.13 presents the volume of water produced in the state of Montana per month from 1986 through 2005 for different well classifications. Figure 2.13 shows the impact of new technologies such as horizontal wells on water production presenting the total Montana water production by month for horizontal oil, horizontal re-completed oil, vertical oil, conventional gas, and CBNG wells. Water production from conventional gas wells appears to be a minor percentage in relationship to the other well types. Furthermore, Figure 2.13 breaks down the water production for oil wells using different completion technologies, showing the decline in water production from conventional vertical oil wells, while horizontal oil and horizontal oil re-completion wells are all showing increasing volumes of water production. Horizontal oil wells allow for increased areas of the reservoir to be exposed to production, which results in increased oil and water output.

Figure 2.13 Water Produced in Montana from Oil and Gas Wells by Type, 1986 - 2005



CBNG is not the only new play in Montana. The Bakken oil shale play in Richland County also has received attention due to the new horizontal development technologies applied as a result of the high oil and gas prices. When Figure 2.13 is compared to Figure 2.14 and Figure 2.15,

Figure 2.14 Impact of New Technologies on Oil Production in Montana

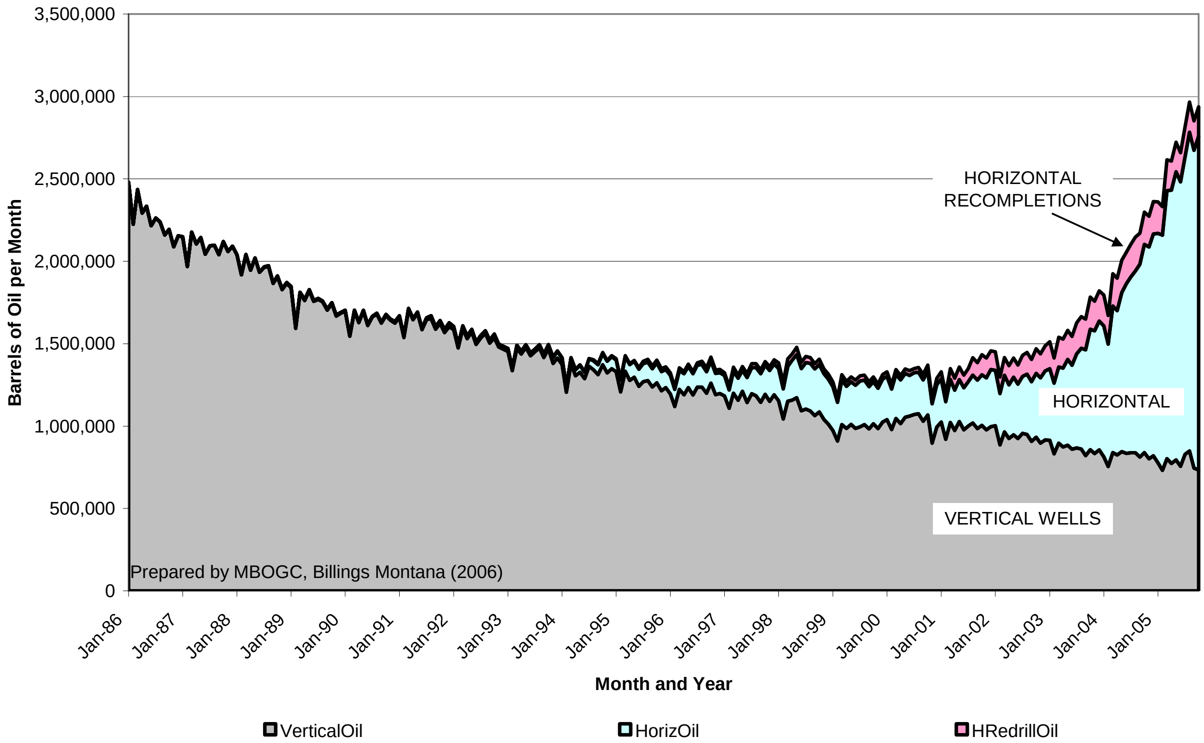
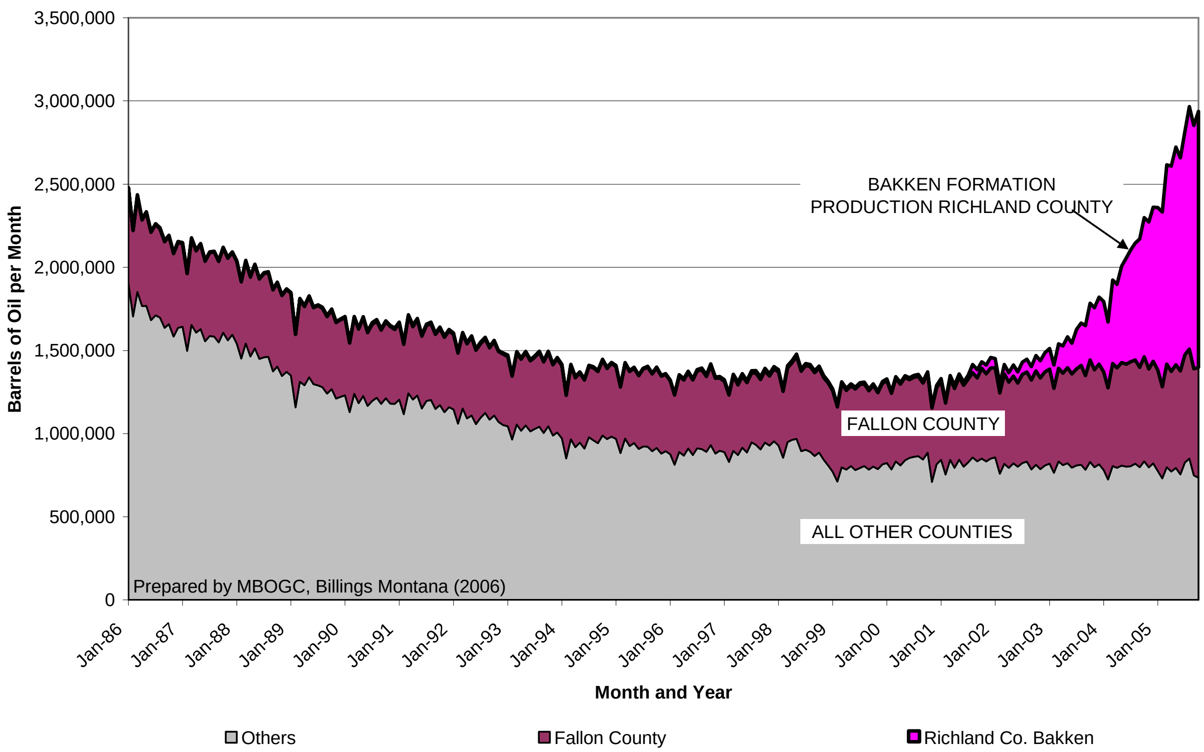


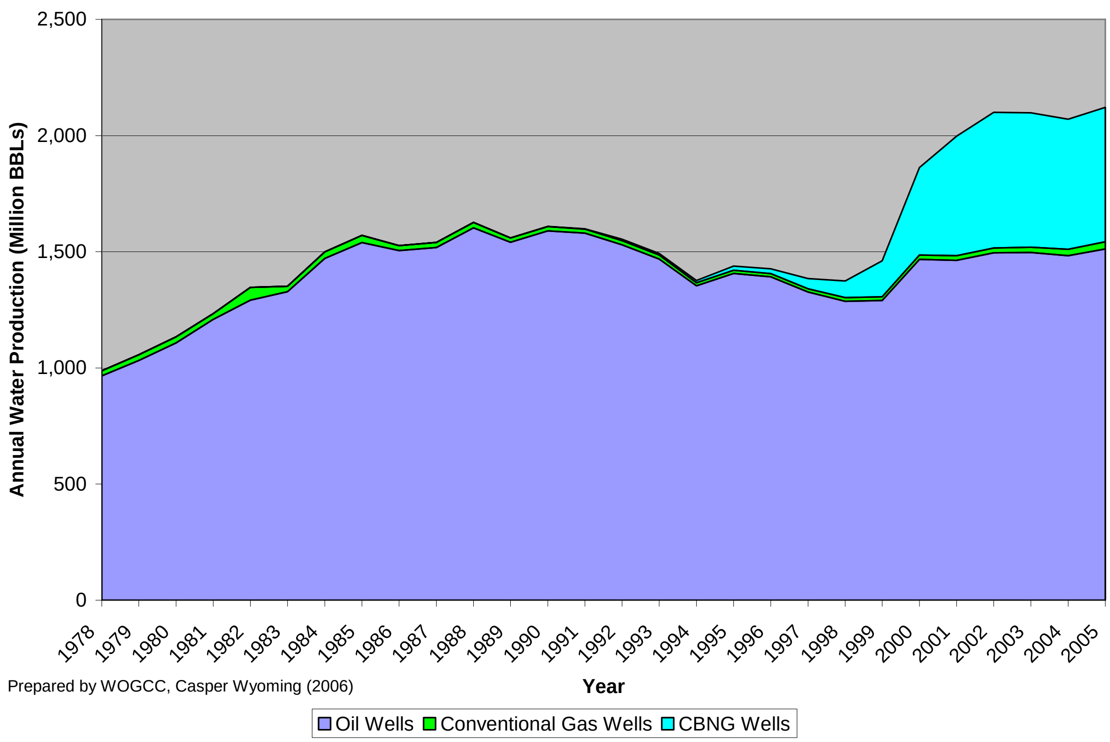
Figure 2.15 The Impact of the Recent Development of the Bakken Formation on Oil Production in Montana



the economic impact to the state of Montana from the new technology is evident as the horizontal completions in the Bakken play and the horizontal completions and re-completions in the Cedar Creek Anticline of Fallon County have led to a 20-year peak in annual oil production in Montana. The evidence that this peak has occurred as a result of these technological advances can be seen in Figure 2.14 and 2.11 where despite the fact that oil production from the rest of the state (as shown by vertical well completions in Figure 2.14 and by the other counties' line in Figure 2.15) has shown a decline for the last 20 years.

Figure 2.16 presents the volume of water produced in the state of Wyoming per year from 1978 through 2005 for oil, gas, and CBNG wells. Figure 2.16 shows the impact of new CBNG production since 1998. Water production from conventional gas wells appears to be a minor percentage in relationship to oil and CBNG.

Figure 2.16 Water Produced in Wyoming from Oil, Gas, and CBNG Wells, 1978 - 2005

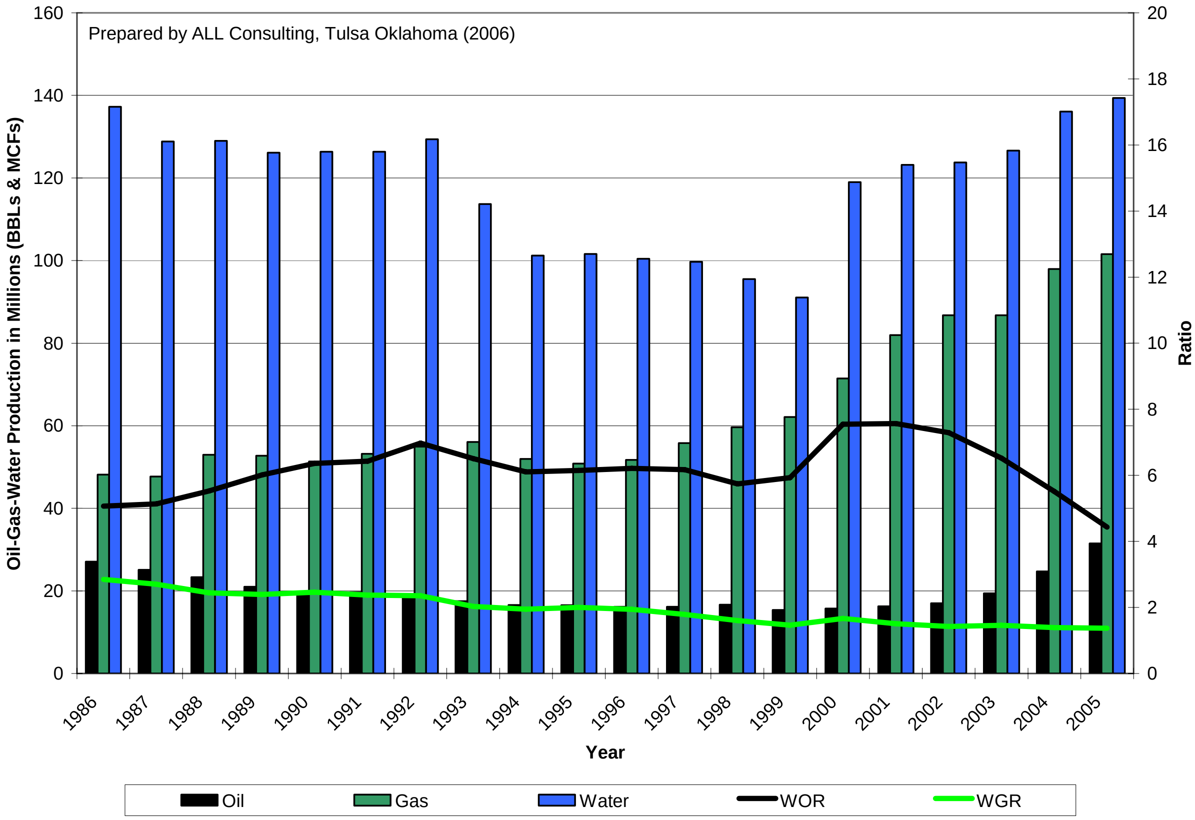


Section 2.2.3 How Trends Impact Produced Water Management

As development evolves with the introduction of new technologies and increased production from new oil and gas plays, produced water management also must evolve to meet the needs of the volumes of water being produced. This section provides some analysis of observed trends in oil and gas produced water and how they affect management of it. The first example documents produced water management within the state of Montana and provides analysis related to the trends of the last 20 years of reported production data. The data analyzed in this section look at the gross production numbers for oil, gas and produced water as well as the WORs and WGRs.

Figure 2.17 presents the gross production for oil, gas and water in Montana from 1986 through partial year data for 2005. Figure 2.17 also presents the WORs and WGRs over the same period of time. Analysis of the gross production trends for water in the state shows that water production had been on the decline from 1986 through 1999 with totals dropping from approximately 137 million barrels in 1986 to approximately 90 million barrels in 1999 (Figure 2.17). Since 1999, water production in Montana has been increasing with output in 2005 approaching 140 million barrels --- a volume greater than production in 1986 (Figure 2.17). Analysis of the gross oil production trends in the state of Montana shows a similar trend to the gross water production, with a decline in oil production from 1986 to 1999 from approximately 28 million barrels to approximately 15 million (Figure 2.17). Since 1999, oil production has increased to greater than 30 million barrels in 2005 (Figure 2.17). Analysis of the gross production trends for gas shows that production has been increasing steadily from 1986 through 2005 with total annual production rising from approximately 48 MMCF to greater than 100 MMCF.

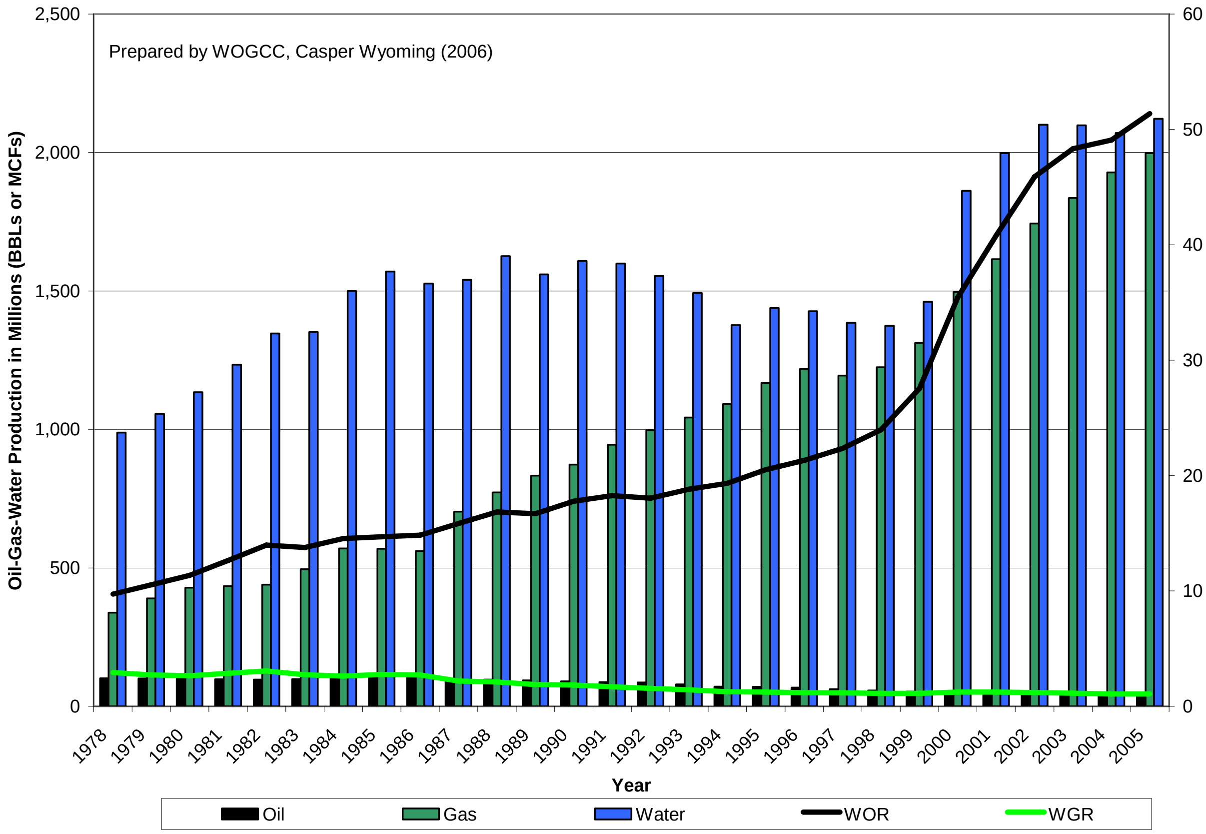
Figure 2.17 Oil, Gas, and Water Production Trends for Montana from 1986 to 2005



Analysis of WOR and WGR for the 1986 to 2005 time frame for Montana is also shown in Figure 2.17. While the WGR shows a relatively steady decline from 1986 to 2005, the WOR shows several fluctuations from 1986 to 2005. WOR rose during two intervals --- from 1986 to 1992, and from 1998 to 2000 --- while there was a leveling off and slight decrease from 1993 to 1998. Data from 2001 to 2005 show the WOR to be declining.

Figure 2.18 presents the gross production for oil, gas and water in Wyoming from 1978 through 2005. Figure 2.18 also presents the WORs and WGRs over the same period of time. Analysis of the gross production trends for water in the state shows that water production had been on the decline from 1990 through 1998 with totals dropping from approximately 1.6 billion barrels in 1990 to approximately 1.4 billion barrels in 1998 (Figure 2.18). Since 1998, water production in Wyoming has been increasing with output in 2005 over 2.1 billion barrels --- a volume greater than production in any year since 1978 (Figure 2.18). Analysis of the gross oil production trends in the state of Wyoming shows a decline in oil production from 1978 from approximately 101 million barrels to approximately 41 million barrels in 2005 (Figure 2.18). Analysis of the gross production trends for gas shows that production has been increasing steadily from 1978 through 2005 with total annual production rising from approximately 338 MMCF to almost 2 BCF.

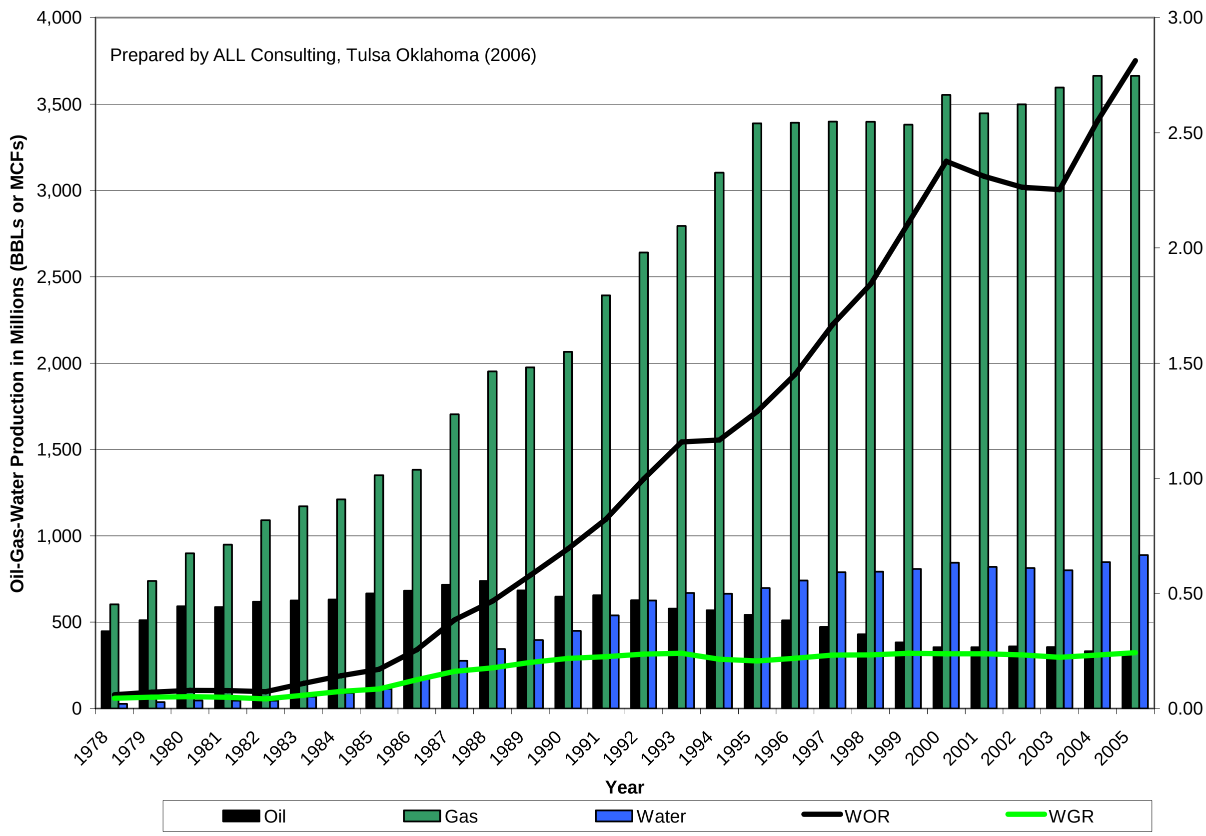
Figure 2.18 Oil, Gas, and Water Production Trends for Wyoming from 1978 to 2005



Analysis of WOR and WGR for the 1978 to 2005 time frame for Wyoming is also shown in Figure 2.18. While the WGR shows a relatively steady decline from 1978 to 2005, the WOR shows a steady climb from 1978 to 1998, and then a sharp increase from 1998 to 2003 while stabilizing somewhat from 2003 to 2005.

Figure 2.19 presents the gross production for oil, gas and water in Alaska from 1978 through 2005. Figure 2.19 also presents the WORs and WGRs over the same period of time. Analysis of the gross production trends for water in the state shows that water production has been on the steady incline from 1978 through 1998 with totals coming up from approximately 26 million barrels in 1978 to approximately 800 million barrels in 1998 (Figure 2.19). Since 1998, water production in Alaska has been increasing slightly with output in 2005 just over 880 million barrels --- a volume greater than production in any year since 1978 (Figure 2.19). Analysis of the gross oil production trends in the state of Alaska shows a rise in oil production from 1978 to 1988 from approximately 450 million barrels to approximately 740 million barrels in 1988, and then a steady decline to 2005 where totals are approximately 315 million barrels (Figure 2.19). Analysis of the gross production trends for gas shows that production has been increasing steadily from 1978 through 1995 with total annual production rising from approximately 600 MMCF to over 3.3 BCF in 1995, and then a slight incline to 2005 where totals are approximately 3.6 BCF (Figure 2.19). .

Figure 2.19 Oil, Gas, and Water Production Trends for Alaska from 1978 to 2005



Analysis of WOR and WGR for the 1978 to 2005 time frame for Alaska is also shown in Figure 2.19. While the WGR shows a relatively steady incline from 1978 to 1991 at which point it stabilizes to 2005, the WOR shows a steady climb from 1978 to 2000, and then a slight dip from 2000 to 2003, and then a sharp increase from 2003 to 2005.

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SECTION 3.0 CURRENT REGULATORY CHALLENGES

Water produced in association with oil and natural gas production comprises 80 percent of the oil and gas industry's residual waste requiring management and disposal. It contributes to the overall cost of energy production (GTI, 2002). Management costs associated with produced water can impact the economics of oil and natural gas developments; thus, newly promulgated regulations and policies that have the potential to limit water management options possibly could halt some existing production operations that are marginally profitable. Approximately 60% of produced water is managed via deep injection disposal wells at costs ranging from $0.50 to $1.75/bbl in wells that cost $400,000 to $3 million to install (Argonne National Laboratory, 2002). Other methods of management, such as beneficial use and discharge to surface waters, cost considerably less but may be limited by proposed regulations. Due to an increase in future expenses and disposal limitations resulting from proposed regulations, some existing water management options might become economically impractical.

Management of produced water from the oil and gas industry is regulated under rules enacted federally by the Clean Water Act (CWA) and the Safe Drinking Water Act (SDWA). Recent research related to how produced water is regulated and managed has covered a wide range of topics such as how new natural gas developments are impacted by existing regulation as well as identifying alternative means (typically beneficial uses) of managing the water (ALL Consulting, 2003; ALL Consulting and MBOGC, 2004; Argonne National Laboratory, 2002; Jackson and Meyer, 2002; Jackson and Meyer, 2003; Reynolds, 2003; Veil, 1997). This section discusses how existing and proposed regulations are affecting the management of water produced from conventional production activities. Furthermore, the intent of this section is not to describe various state produced water regulations, or the history of their promulgation, but to focus on evolving regulatory challenges that could have long-reaching impacts on how produced water is managed.

The prolific development of coal bed natural gas and other continuous reservoirs has prompted regulators to reconsider produced water management rules and policies to the point that the rules soon might be affecting conventional oil and gas operations. The proposed rule and policy changes are making it increasingly difficult to manage the produced water through traditional procedures at the same time policy is moving toward limiting the potential for many beneficial uses of this valuable resource. Beneficial use of produced water has become the mantra of many local, state, and federal agencies to avoid what these agencies consider to be wasting a valuable resource. These agencies are demanding that produced water of any redeemable quality be used beneficially and that uses such as irrigation, stock water, and wetlands maintenance be incorporated into all oil and gas operations where water quality is appropriate. At the same time, what could be one of the largest beneficial uses, discharge to downstream water users, is becoming more difficult for operators to get permitted.

Section 3.1 Regulatory Synopsis

The United States Environmental Protection Agency's (EPA) regional offices typically initiate policy and the direction of enforcement actions under the Clean Water Act and Safe Drinking Water Act in an effort to protect human health and the environment. These two federal regulations are the basis for other federal and state regulatory programs that control the management of water produced during oil and gas development. The federal government has established several regulatory water classifications and standards. In some regulatory programs, federal classifications and/or standards may be adopted by applicable state regulatory agencies. Water can be classified according to its characteristics, use, source, location, and other criteria. Water classifications generally take into consideration the use and value of water for public supplies; protection and propagation of aquatic wildlife; recreation in and on the water; and other potential uses (e.g., agricultural, industrial, municipal). Standards also might be established to maintain the quality of water as well as current and potential beneficial uses. In addition to federal programs, individual states also can have classifications and standards to account for local or regional environmental issues.

Although the EPA acts at the federal level to set national standards, states and tribal governments can acquire primacy for Underground Injection Control (UIC) and National Pollutant Discharge Elimination System (NPDES) by meeting the EPA's primacy requirements. A state that meets the primacy requirements is allowed to set more stringent state specific standards for these programs. Since individual states can acquire primacy over their respective programs, it is not uncommon to have varying requirements for these programs from state to state. This variation can affect how the oil and gas industry manages produced water within a basin that crosses between two states.

Section 3.1.1 Clean Water Act and NPDES

The Clean Water Act was established to protect water quality, which includes regulation of the NPDES permitting process. NPDES establishes, through a permit, pollutant limits on the discharge of produced water that generally include a volume (quantity) and concentration (quality) (U.S. EPA, 2004). Pollutants under the NPDES program fall into one of three categories: conventional, toxic, and non-conventional. There are two types of permits under the NPDES program that allow for the discharge of pollutants from point sources, individual permits, which are specific to an individual facility, and general permits, which cover multiple facilities within a specific permit category.

There are two controls which are the basis for NPDES permit limit: 1) the EPA effluent limitation guidelines for a particular industry (which are technology based and vary by industry), and 2) water quality based limits (U.S. EPA, 2004). Effluent limitation guidelines developed by the EPA under the Clean Water Act include three guidelines for existing discharges and one for new discharges:

- Best conventional pollutant control technology (BCT) for conventional pollutants and applicable to existing discharges.
- Best practicable control technology currently available (BPT) for conventional, toxic, and non-conventional pollutants and applicable to existing discharges.
- Best available technology economically achievable (BAT) for toxic and non-conventional pollutants and applicable to existing discharges.
- New source performance standards (NSPS) for conventional pollutants and applicable to new sources.

In addition to the controls on pollutant discharge established by the effluent limitation guidelines, the Clean Water Act has additional controls on pollutant discharges to water bodies that have been identified as currently being impaired because these waters do not meet water quality standards. The Total Maximum Daily Load (TMDL) program specifies the maximum amount of a pollutant that can be discharged to a body of water without exceeding established water quality standards and provides an allocation of the pollutant among the existing point and non-point sources of the pollutant (U.S. EPA 2005a).

Section 3.1.2 Safe Drinking Water Act and Underground Injection Control

The Safe Drinking Water Act was established to protect public health by regulating public drinking water supplies and to protect sources of drinking water. Through the Safe Drinking Water Act, the Underground Injection Control (UIC) Program was established to protect underground sources of drinking water from potential contamination from injection wells. Injection is responsible for approximately 60% of the produced water management activities for the oil and gas industry. The EPA's classification of UIC wells defines a separate well class (Class II) for oil and gas brine injection wells, which includes disposal and enhanced recovery wells used in conventional oil and gas production (U.S. EPA, 2005b). Historically, Class I injection wells also have been used for disposal of oil and gas produced water.

Class I injection wells typically are technologically sophisticated deep injection wells isolated by a confining zone from underground sources of drinking water; the injection formations typically are below the lowest underground source of drinking water (U.S. EPA, 2005b). Class I injection is sometimes identified as "deep" disposal injection when discussed relative to the oil and gas industry because the formations used for Class I injection are typically thousands of feet below the land surface and the injection of the fluids do not result in enhanced oil or gas recovery. The number of Class I injection wells in the United States is small relative to the number of Class II and Class V injection wells.

Not all oil and gas produced water management injection wells are Class I and II wells. Recent activities associated with the management of produced water have started to utilize Class V wells. The Class V injection well category was created to categorize all the injection wells that did not fit into the more easily defined categories of Class I through Class IV. Class V wells can range from technologically simple septic systems to technologically advanced injection well systems. Simply put, the EPA defines Class V injection wells as any shallow well that is a bored, drilled, driven, or dug hole that is deeper than its width at its widest point. Class V wells typically are shallow wells which are used to place non-hazardous fluids below the land surface (U.S. EPA, 2005b).

Section 3.2 Beneficial Use of Produced Water

The beneficial use of produced water has become a popular water management alternative for regulators, operators, and landowners alike. Beneficial use in western states is considered a priority to prevent the potential wasting of a groundwater resource, and in many cases, oil and gas operators find beneficial uses to be a cost effective water management alternative. Additionally, the western United States' climate is arid, and therefore water quality impacts and water wasting issues are a great concern. As a result, developers and resource managers are requested to find beneficial uses for produced water while minimizing potential impacts to the environment.

Oil and gas operators are feeling pressure from both regulators and activist groups to find beneficial uses for the water produced with conventional oil and gas development activities. In general, some produced water is suitable for livestock and wildlife watering, agriculture, and other industrial uses. Beneficial uses of produced water have expanded in recent years with the invention of new treatment technologies. This has allowed more flexible management options for regulators to meet regional or local water needs. Examples of treatment technologies already in use are included in Section 4, and a discussion of cutting edge technologies currently being considered by the oil and gas industry is included in Section 5.

Conventional oil and gas produced water can be of varying quality with lower quality produced water having TDS concentrations >200,000 mg/l, where some of the produced water from shallower oil and gas development can range from 100's mg/l to 10,000's mg/l TDS. A discussion of the water quality in various domestic oil and gas basins is included in Section 4.

Higher TDS water typically will have more limited beneficial uses and treatment becomes more difficult and more expensive as TDS increases. Typically, water treatment technologies are limited to treating specific constituent types concentrated in water, e.g., dissolved solids, organics, conductive ions, etc. Depending on the eventual use of the water and the desired constituent concentrations, treatment processes are often coupled to achieve required water use objectives. For this reason, an integral aspect of the treatment process is the performance of water analysis to ascertain the presence of specific constituents for any given water source. This step provides various entities such as government agencies, oil and gas companies, or landowners the ability to choose a treatment technology (or technologies) best suited to achieve the necessary water quality objectives for beneficial use.

Although states typically will define what they consider a beneficial use (generally incorporating the EPA's beneficial use definition of livestock watering, wildlife watering, agricultural uses, and wetlands enhancement), other beneficial uses can include:

- **Agriculture** (impoundment stock water, irrigation, wildlife and waterfowl habitat, fish hatcheries, water leased)
- **Municipal** (domestic, fire protection, recreation uses)
- **Industrial/Commercial** (power, geothermal, mining, sediment control, erosion control, pollution abatement, navigation)

In most cases, state regulations do not require that produced water be used for beneficial use, but instead mandate water quality standards specific to state water classification schemes that must be satisfied prior to the water's beneficial use. The EPA, under 40 CFR Part 435, subpart E, provides the beneficial use exception rule to no discharge of produced water from oil and gas activities. This rule applies to the continental United States west of the 98th meridian, and allows for discharges of produced water if the produced water is clean enough to be used for wildlife and livestock watering or other agricultural use. Subpart E allows produced water of "good enough quality to be used for wildlife or livestock watering or other agricultural uses" but the water "must actually be put to such use during periods of discharge" (40 CFR Part 435, subpart E). However, Subpart E does not require beneficial use of good quality water nor does it require treatment of produced waters to meet the beneficial use options defined in Subpart E.

Section 3.3 NPDES Discharge Challenges

The evolution of CBNG development and other continuous type reservoirs has resulted in the need to manage large quantities of produced water that are considered to be of high quality. One of the most economical means of managing high quality produced water is through direct discharge to surface waters, which also provides benefit to downstream users.

Section 3.3.1 Challenges in Wyoming

As the number of direct discharge outfalls from CBNG increases in the Wyoming portion of the Powder River Basin, Wyoming regulatory agencies and the EPA have begun to scrutinize Wyoming's surface water quality and discharge regulations. Wyoming has primacy over their NPDES discharges, including produced water from both CBNG and conventional oil and gas operations. Currently, most of the discharges from conventional oil and gas development occur in watersheds that are Class 4, as defined by the Wyoming Chapter 1 surface water quality rules. Generally, Class 4 waters are those not designated as Class 1, where it has been determined that aquatic life uses are not attainable pursuant to the reclassification and site-specific criteria provisions (WDEQ, 2001). Some of the surface waters in which conventional oil and gas produced water is being discharged have developed into perennial streams, which could result in their ability to support some species of fish. Conventional oil and gas operators have developed concerns that such a scenario is occurring. As a result, the EPA might reclassify these surface waters to Class 3 or better, which would prevent continued discharge of produced water (WOGCC Staff Personal Communication, 2005). This would negatively impact the ability to discharge, which could affect the ability of downstream users to beneficially use the water and damage the stream's ability to support fish that have become acclimated to it.

Personnel with the oil and gas operators in the Bighorn Basin have expressed concerns that a reclassification of waters from Class 4 to Class 3 or higher would require discharges of produced water to meet the Chapter 1 Water Quality Criteria for Priority Pollutants of Aquatic Life. Oil and gas operators believe the produced water being discharged from the actively permitted outfalls would not be capable of meeting the Chapter 1 standards without treatment.

Draft changes currently available on the WDEQ Water Quality Division website for the Chapter 1 Surface Water Standards might be the cause of some of the concerns that operators are having specific to the Priority Pollutant - chloride. The draft Chapter 1 regulation changes have in part been created to address concerns from the high salinity discharges from CBNG that have resulted in the development of Acute Aquatic Life Criteria for chloride of 230 ppm and Chronic Aquatic Life Criteria of 860 ppm. These changes, if applied to the current Chapter 1 water classifications, would be applicable to Class 3 surface waters in Wyoming, and thus could affect existing discharges to surface waters. However, the changes that are proposed in the draft version of the Chapter 1 standards for chloride currently are applicable only to certain surface water classifications. The proposed chloride standards are for surface waters in Class 1, 2AB, 2B and 2C (WDEQ, 2005a). Therefore, the adoption of the draft three version of the Chapter 1 Surface Water Standards, even if accompanied by a lowering of classification of the surface waters to which oil and gas operators in the Bighorn Basin are discharging into, would not result in an implementation of the chloride standard unless those waters change from Class 4 waters to a Class 1, 2AB, 2B or 2C classification.

Section 3.3.2 Inter-State Challenges between Wyoming and Montana

Further complicating the management of CBNG produced water in the PRB is the fact that many of the significant watersheds in the basin flow in a northerly direction from Wyoming into Montana. This is the case with some of the major watersheds where CBNG development is occurring, including the Tongue and Powder River watersheds. In fact, much of the production from one of the thickest producing coal seams in the Wyoming portion of the basin, the Big George Coal, falls mainly within the Powder River Watershed.

In an effort to limit impacts to watersheds flowing into Montana, Wyoming and Montana are working together and have generally agreed to manage CBNG produced water in such a fashion to avoid any changes in quality and quantity of the various applicable watersheds. More recently, Montana has proposed new rules presently being considered by the Montana Department of Environmental Quality's (MDEQ's) Board of Environmental Review (BER) to further restrict discharges of CBNG produced water. These proposed rules would change the way water would be managed throughout the entire PRB. Two of the more significant proposed amendments include Rules II and VIII.

Proposed Rule II is a "zero discharge" requirement applicable to the Montana Pollutant Discharge Elimination System (MPDES) program. This proposed new rule requires that "*(1) except as provided in [New Rules III through IX], point-sources of methane wastewater shall achieve zero discharge of pollutants, which represents the minimum technology-based requirement. Zero discharge shall be accomplished by reinjection [sic] of methane wastewater into suitable geologic formations in the project area in compliance with all other applicable federal and state laws and regulations*." The rule does provide a means to obtain an exemption from the injection requirement, but timeframes to obtain an exemption may be greater than 12 months as the rule is currently proposed.

Proposed Rule VIII establishes "*treatment-based effluent limitations*" for CBNG produced water. The proposed rule requires that "*(1) If the department grants a waiver from the zero discharge requirement for all or a portion of the wastewater pursuant to [New Rules II and III], the amount of wastewater that obtains the waiver shall achieve the following minimum technology-based effluent limitations at the end of the pipe prior to discharge*:

- *(a) calcium average concentration between 0.1 mg/L and 0.2 mg/L;*
- *(b) magnesium average concentration between 0.1 mg/L and 0.6 mg/L;*
- *(c) sodium average concentration of 10 mg/L;*
- *(d) bicarbonate average concentration of 30 mg/L and instantaneous maximum concentration of 115 mg/L;*
- *(e) sodium adsorption ratio instantaneous maximum of 0.5;*
- *(f) electrical conductivity average concentration of 233 µmhos/cm;*
- *(g) total dissolved solids average concentration of 170 mg/L;*
- *(h) ammonia average concentration of 0.1 mg/L and instantaneous maximum concentration of 0.3 mg/L; and*
- *(i) arsenic concentration of <0.0001 mg/L.*"

Evaluation of the proposed amendments suggests that implementation of the new rules would significantly impede and/or likely cause the cessation of current and future CBNG development in the Wyoming portion of the PRB. Implementing a zero discharge requirement likely would reduce production by 25 percent immediately upon enforcement of the rule. Within one year of implementation, production rates are expected to decrease by as much as 50 percent. Within five years, production likely would decline by 90 percent, eliminating much (if not all) of the potential production in the region.

Section 3.4 UIC Program Challenges

UIC wells for the management of produced water from conventional oil and gas activities are typically EPA Class II injection wells. Increasingly, however, produced water is being managed by way of Class V and Class I wells.

Section 3.4.1 The Evolution of Class V Wells

As oil and gas development expands into continuous reservoirs, the quality of water produced with the resources increases. As a result, water management options increasingly have begun to include the use of Class V injection wells. Class V injection wells have been used for aquifer recharge and aquifer storage and recovery in parts of the Rocky Mountain West as a means to beneficially manage produced water for future uses, including public water supply and as irrigation water. Class V wells are being used to manage large volumes of produced water from oil and gas production, something Class V was never meant to do. Class V wells that inject large volumes of produced water could be regulated as Class II wells by Class II agencies. If water is not being directly injected into active USDWs, the Class II agency has the background and regulatory framework to oversee wells that manage high volumes of low-toxicity wastes.

Another question that has been raised by industry is whether subsurface irrigation could be considered to be a Class V injection activity. Subsurface irrigation facilities have the ability to manage large volumes of produced water, enabling ranchers and farmers to grow large amounts of hay and grain. The facilities share construction details with infiltration trenches that do not require Class V permits. Permitting subsurface irrigation in a reasonable manner will be a challenge for UIC regulators in the near future. Steps recently have been taken in Texas to allow for an authorization by rule; thus Class V approvals for subsurface drip irrigation have been streamlined to take no longer than 60 days (TCEQ, 2006). Similar steps can be taken in other states as well, as appropriate.

Section 3.4.2 Classification of Brine

Water produced with oil and gas can be treated to beneficial use standards. In the process of treatment, concentrated brine often is generated as a by-product. In respect to regulatory concerns, the brine is no longer considered as oil and gas production waste, and therefore does not qualify for the oil and gas exemption provided in the federal Resource Conservation and Recovery Act (RCRA). The brine can represent as little as 1% of the produced water volume, or as much as 70% of the produced water volume, depending on the quality of the produced water and the treatment process; however, it is considered an industrial process waste once the produced water has been treated. Currently, this brine can be determined to be either a Class I or Class II industrial process waste, and different states might have different criteria for making this determination. Classification of the brine appears to be sensitive to a number of things such as the physical arrangement of the treatment plant, the corrosiveness of the brine, and the use of the treated water. The classification may need to be standardized across the country to prevent the brine from being classified differently in the same basin, based on in which state the brine is generated.

Section 3.5 Watershed Based Permitting

The primary objectives of watershed based permitting are to develop an improved permitting process for surface discharges, improve environmental protection, and provide for more informed permitting decisions within a watershed by the governing regulatory agency. The approach is intended to: 1) provide a clear understanding of the limits and constraints of discharging produced waters; 2) provide equitable distribution of finite assimilative capacity; and 3) improve the mechanism to hear and address concerns of the stakeholders and understand the competing interests involved with the discharge of produced water. The holistic approach of looking at the impacts to an entire watershed allows the governing regulatory agency to make more informed decisions with regard to permitting discharges into the watershed.

Until recently, watershed based permitting had not been attempted. However, in 2005 the WDEQ implemented a watershed based approach to permitting discharge of CBNG produced waters into the Powder River watershed. Therefore, the steps the WDEQ has taken to implement watershed based permitting are included in Section 3.5.1 as a template for other state agencies to use in determining whether or not watershed based permitting would benefit their state. Advantages and disadvantages of watershed based permitting are discussed in Section 3.5.2.

WDEQ's approach was intended to address concerns over the increasing quantities and decreasing quality of produced water from CBNG development. A heightened concern by stakeholders over the cumulative impacts also spurred the process. These stakeholders include the landowners in Wyoming and downstream states of Montana and South Dakota, regulatory agencies in these states, and environmental interest groups.

Parallel to the watershed based permitting process, the WDEQ developed an assimilative capacity allocation and control process for the Powder River mainstem to further preserve and protect the Powder River. The assimilative capacity control process has not been implemented at this time, but is expected to be in place soon. The Program Policy was issued for public comment and was presented in a September 2005 meeting of the Wyoming Water and Wastewater Advisory Board. The assimilative capacity control process will control the amount of TDS and sodium that can be discharged by CBNG produced water by using the calculated assimilative capacity of the Powder River and 'credits' calculated from coal volumes under an operator's leased acreage. A description of the policy is included in Section 3.5.3 along with the implications of the calculated credits.

Section 3.5.1 The Process

The watershed based permitting process is a holistic approach that looks at surface water uses and processes within an entire watershed. The process can first be initiated by identifying all the stakeholders within a pre-defined watershed. These stakeholders may include government agencies, operators, landowners and users, and environmental interest groups. An initial public meeting can be held to discuss the watershed based permitting process.

The next step can be collection of information about the surface water uses within the watershed. This information may be collected from sources that include the operators, landowners, USGS, EPA, BLM, Wyoming State Engineer's Office (SEO), WDEQ, WOGCC, Wyoming Game and Fish Department, and the conservation districts. The data collected might include information on seasonal stream flow quantity and quality, irrigation use, channel capacity, topography, erosion, and produced water quality and quantity. These data can be analyzed and summarized to identify water quality objectives. Water quality objectives may include:

- Target flow volume limit, determined for each watershed.
- Target concentrations of constituents of concern, determined for each watershed.
- Potential water users.

Based on these water quality objectives, discharge options can be evaluated, selected, and discussed with all area stakeholders at a public meeting. Current discharge options may include irrigation, on- and off-channel storage, direct discharge, treatment and discharge, re-injection, and consolidation of outfalls.

Monitoring locations can be established within the watershed and a monitoring plan can be developed. The monitoring plan may address the constituents of concern, sampling and reporting frequency, responsibilities, and contingencies. Permitees can be held responsible for monitoring and reporting, and can conduct these activities independently, or they can collaborate with other permit holders within the watershed.

The governing agency might then develop permit conditions and draft the permit. It is up to the area stakeholders involved whether a general permit will be issued for the watershed or if individual permits will be required. If a general permit is issued, a notice to the public may be published and the permit made available for public review and comment. The governing agency can respond to public comments, if any, and then issue the permit. The general permit can define TDS and sodium limits within the watershed at the monitoring points. The permit can also establish cumulative discharge limits for all the discharge points above the monitoring points. These discharge limits may be year-round limits or vary month-by-month, but are not to be exceeded.

Any operator wishing to discharge under a general permit must submit a notice of intent to discharge to the governing agency prior to discharge. The notice of intent will specify the location of discharge points and the maximum discharge volume. The notice of intent also will supply analyses of the proposed discharge water to demonstrate its similarity to prevailing produced water quality standards.

If stakeholders require individual permits, then a permit application must be filed by the operator and reviewed by the governing agency. The agency would then draft an individual permit, issue it for public review and comment, and then prepare a final permit after the comment period.

Currently, the watershed based permitting process is underway for the undeveloped hydrologic unit code (HUC) 10 watersheds within the Powder River Drainage. As existing WPDES discharge permits for CBNG produced water expire, they will be rolled into a watershed based permit, either general or individual, based on the preference of the watershed stakeholders. CBNG produced water discharges within the Tongue and the Belle Fourche drainages in Wyoming will be subject to watershed based permitting in the future (WDEQ, 2005b).

Section 3.5.2 Advantages and Disadvantages

The primary advantage of watershed based permitting is the involvement of all stakeholders and management of assimilative capacity within the watershed. Each stakeholder is given the opportunity to voice concerns and be included in decision making during the permitting process. As such, one disadvantage is the process may be exhaustive and can prolong the permitting process.

Section 3.5.3 Assimilative Capacity Allocation and Control System

Parallel with the watershed based permitting process, the WDEQ has developed an Assimilative Capacity Allocation and Control System for protecting and managing the surface water quality of the Powder River consistent with both Wyoming and Montana conditions while providing for the development of the CBNG resources of Wyoming. A draft Program Policy was developed and issued for public comment. The WDEQ worked toward implementation of the policy, and believed it would be in effect in early 2006 (WDEQ, 2005b). Implementation of the assimilative capacity and control system on the Powder River mainstem involves five principle parts:

1) **Determine the assimilative capacity of the Powder River mainstem.** The WDEQ will use ambient water quality data collected at the USGS gauging station near Moorehead, Montana, in predictive models to assess the assimilative capacity of the Powder River. The available load will be calculated in pounds per day for each month and will be reduced by 5 percent to allow a reasonable margin of safety.
2) **Establish credits for assimilative capacity.** The modeled assimilative capacity will be divided into credits representing 10 pounds of total dissolved solids or sodium. The credits will be calculated from the CBNG operator's share of mineral lease acreage multiplied by the calculated coal volume under the lease. Each credit is valid only for the month in which it is calculated and issued. Historical monthly flows of the Powder River are used for monthly allocation of credits.
3) **Regulate credits through issuance of a general permit.** A general permit will be the vehicle used to regulate and allocate the calculated available mass loading of TDS and sodium for discharges of CBNG produced water in the entire Powder River mainstem watershed. The WDEQ will issue this permit after public notice and comment.
4) **Establish a Credit Registration procedure.** The Wyoming Geological Survey (WGS) will act as the Registrar and will implement the registration procedures. The WGS will issue a map and list calculated coal thicknesses, by section, of the Powder River watershed. For the purposes of the assimilative capacity allocation and control policy, it will be assumed that all coal seams will produce the same volume of water per measured unit of thickness.
5) **Establish a Credit Tracking Mechanism, or credit bank.** Permitted discharges based on appropriated credits will be debited from the appropriate CBNG operator's credit bank account, which will be managed by the WDEQ. Individual and/or watershed permits will continue to regulate limits required by Chapter 1 and Chapter 2 (WWQRR) and as necessary to protect local and watershed conditions in addition to TDS and sodium for the Powder River mainstem.

GENERAL POWDER RIVER MAINSTEM PERMIT AND CREDITS

All CBNG produced water discharging into the Powder River mainstem, tributaries, and on-channel reservoirs will require an applicable general, individual, or watershed permit in accordance with the Chapter 2, WWQRR. Upon implementation of the Assimilative Capacity Policy, new and renewed CBNG produced water discharge permits will be issued in conformance with available credits authorized by the Powder River Mainstem General Permit. Dischargers will continue to comply with their existing permit until reopened, renewed, or a major modification is made, at which time the individual permit will be brought into conformity with the Assimilative Capacity Policy.

Upon application for a new permit, a major modification to an existing permit, or a permit renewal, the permittee must submit a water management plan that describes how the produced water will be discharged/managed through the use of credits, treatment, impoundment, or other means. The WDEQ will then verify through the credit bank that the applicant has sufficient credits or facilities to implement its water management plan.

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SECTION 4.0 PRODUCED WATER MANAGEMENT PRACTICES

It is paramount that produced water be managed in innovative ways that will both reduce the operational cost to produce oil and gas reserves as well as be protective of the environment. A common misconception is that there is one management practice that will work throughout the United States to manage the produced water in a responsible way. Quite the opposite is true. In fact, produced water management practices vary widely across the United States, and in some instances across a single oil and gas field. Produced water management falls under two broad categories: underground injection and surface management. Water treatment is also a produced water management practice, but the end result of a water treatment facility is 1) a higher quality stream of water that must be managed at the surface, and 2) a concentrated stream of wastewater that must be disposed through underground injection. Therefore, water treatment is discussed at the end of this section as a means of transforming the water quality to make best use of the water as a resource, and not as a "management practice".

Underground Injection encompasses a wide range of water management practices. The EPA classifies five different injection well categories, and three of them are applicable in one way or another to the management of produced water from oil and gas development. In general, oil and gas produced water is an exempt waste and therefore can be injected in Class II or Class V injection wells. Operators of Class II wells inject fluids associated with oil and natural gas production (EPA, 2005). Class II injection wells can either be classified as disposal wells (IID) or as enhanced recovery wells (IIR). The process wastewater that is the result of produced water treatment, however, does not carry the same exemption; therefore it must be disposed of in a Class I injection well. The EPA defines Class I wells as technologically sophisticated wells that inject hazardous and non-hazardous wastes below the lowermost underground source of drinking water (USDW). Injection occurs into deep, isolated rock formations that are separated from the lowermost USDW by layers of impermeable clay and rock (EPA, 2005). Class V wells (i.e. shallow injection, subsurface drip irrigation) are injection wells that are not included in the other classes, and generally their simple construction provides little or no protection against possible groundwater contamination; therefore, it is important to control what goes into them (EPA, 2005).

Surface Management includes all water management practices where the water (whether it be raw produced water, or treated produced water) is managed at the surface by either discharging directly into a water course, into an impoundment, or to the land for some beneficial use. Once the water has been brought to the surface, a number of techniques, processes, approaches, and/or beneficial uses can be applied to enhance the management of the water and lower the associated costs for the operator. These include, but are not limited to, surface impoundments (i.e. stock watering/irrigation storage ponds, evaporation ponds, enhanced evaporation/aeration ponds, recreational ponds, constructed wetlands) and industrial uses (i.e. cooling tower water, dust suppression, truck wash station, oil and gas completion activities).

As noted above, there is a wide range of water management practices and alternatives that fall under these two categories. This section provides a more detailed description of these water management practices and alternatives. Class I wells are discussed in terms of the applicability and constraints for managing the process wastewater from water treatment processes. Class II wells, Class V wells, and the various surface management practices are discussed in terms of their applicability and their constraints for managing produced water.

Section 4.1 Class I Injection

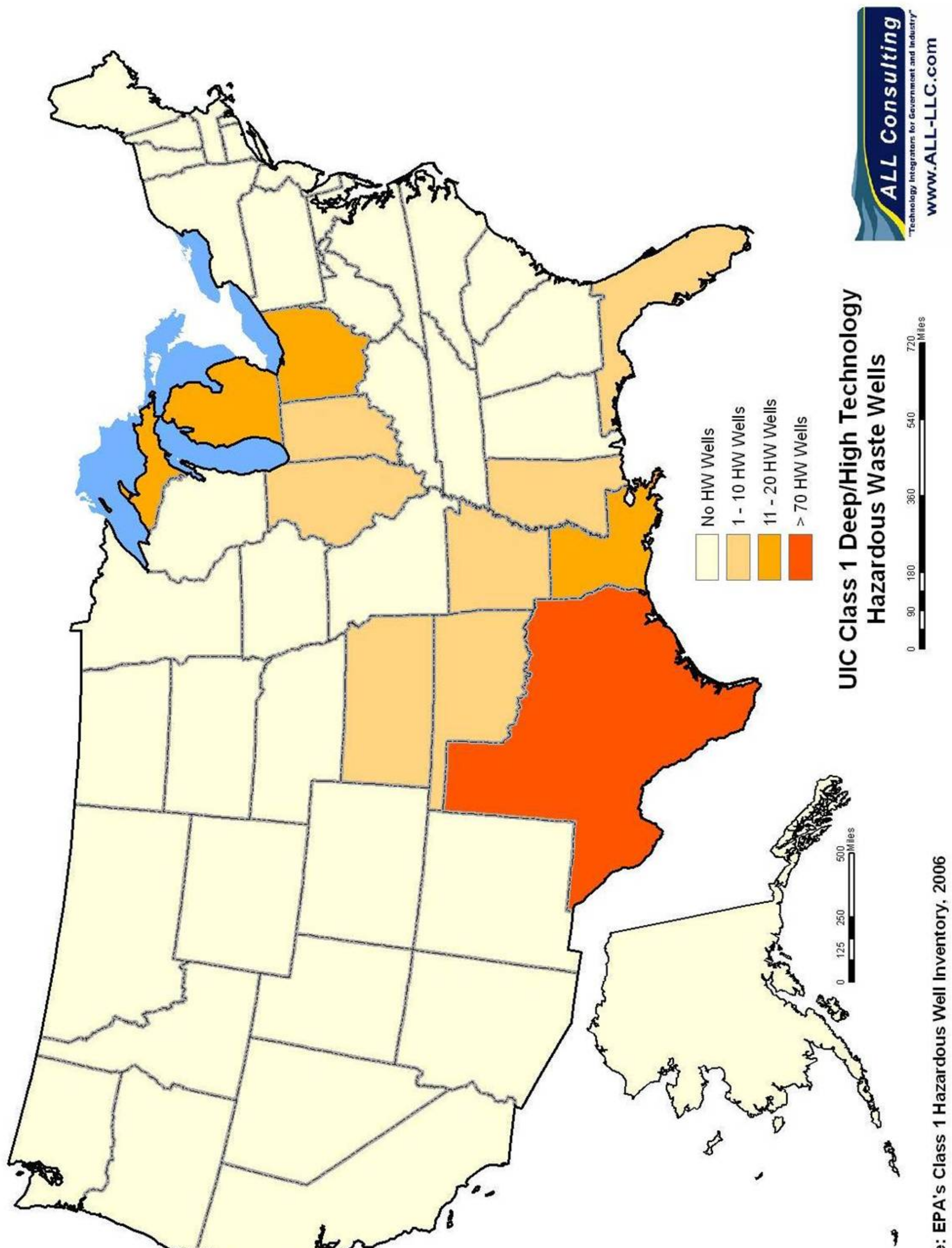
Class I injection wells are technologically sophisticated wells that inject large volumes of industrial hazardous or non-hazardous wastes into deep, isolated rock formations that are separated from the lower most USDW by layers of impermeable clay and rock. Although most hazardous waste fluids are treated and released to surface waters, Class I wells account for 89 percent of the hazardous waste fluids disposed of on land (GWPC, 2006). Class I wells are classified as hazardous or non-hazardous, depending on the characteristics of the wastewaters injected. For instance, municipal waste is classified as non-hazardous. The EPA regulates Class I underground injection wells under the Safe Drinking Water Act (SDWA) and the Hazardous and Solid Waste Amendments of the Resource Conservation and Recovery Act (RCRA). These regulations establish siting, design, construction, and monitoring requirements for these injection wells to ensure protection of USDWs from injected wastewater (EPA, 2001a).

Underground injection of wastewater began in the 1930s when oil companies began disposing of oilfield brines and other oil and gas waste products into depleted reservoirs. Most of the early injection wells were oil production wells converted for wastewater disposal. In the 1950s, injection of hazardous chemical and steel industry wastes began. At that time, four Class I wells were reported; by 1963, there were 30 wells. In the mid 1960s and 1970s, Class I injection began to increase sharply, growing at a rate of more than 20 wells per year (EPA, 2001a).

Currently, under the UIC Program, the EPA and the states regulate more than 400,000 injection wells. Class I wells comprise less than 1% of the injection wells in the U.S. (GWPC, 2006). There are 272 active Class I injection facilities nationwide. Of these, 51 are hazardous and 221 are non-hazardous. These 272 facilities maintain approximately 529 Class I injection wells that are scattered throughout the U.S. in 19 states (EPA, 2006). The 51 hazardous injection facilities are composed of 163 Class I hazardous waste injection wells, most of which are located in Texas (78) and Louisiana (18) (see Figure 4.1). Eleven of the facilities are commercial hazardous waste injection facilities. These are the only facilities that can accept hazardous waste generated offsite for injection. Ten of them are located in the Gulf Coast region while one is located in the Great Lakes region. There are 366 Class I non-hazardous injection wells nationwide. While these wells are scattered through 19 states, most of them are found in the states of Florida (112) and Texas (110) (EPA, 2006).

Class I wells are used mainly in the petroleum refining, metal production, chemical production, pharmaceutical production, commercial disposal, and municipal disposal industries (EPA, 2006). However, almost half of the fluids injected into non-hazardous and municipal waste injection wells are manufacturing wastes; municipal effluent accounts for approximately 28% of the Class I non-hazardous wastes (GWPC, 2006).

Figure 4.1 Approximate Class I Well Count in Each State



Applicability

The use of Class I injection wells for produced water management has limited applicability to the oil and gas industry. However, certain circumstances may arise that will require or dictate disposal via Class I injection. If produced water is used for industrial purposes, then the disposal of the water could be required by use of a Class I injection well (ALL and MBOGC, 2002). Additionally, concentrated produced water waste streams generated as a byproduct from certain treatment technologies (e.g., reverse osmosis, ion exchange, distillation, etc.) could require disposal using Class I injection wells.

Constraints

Class I wells must be sited so that wastewaters are injected into a formation that is below the lowermost formation containing, within one-quarter mile of the well, a USDW (EPA, 2001a). Typically, Class I fluids are injected deep into geologic formations thousands of feet below the land surface composed of brine-saturated formations or non-freshwater zones. In the Great Lakes region, for example, injection well depths typically range from 1,700 to 6,000 feet; in the Gulf Coast, depths range from 2,200 to 12,000 feet or more (EPA, 2001a). Fluids at these depths move very slowly, on the order of a few feet per hundred or even thousand years, meaning that fluids injected into the deep subsurface are likely to remain confined for a long time (EPA, 2001a).

EPA requires that Class I wells be located in geologically stable areas that are free of transmissive fractures or faults through which injected fluids could travel to drinking water sources (EPA, 2001a). Well operators must also show that there are no wells or other artificial pathways between the injection zone and USDWs through which fluids can travel. Extensive pre-siting geological tests can be used to confirm that the injection zone is of sufficient lateral extent and thickness, as well as sufficiently porous and permeable, so that the fluids injected through the well can enter the rock formation without an excessive build-up of pressure and possible displacement of injected fluids outside of the intended zone (EPA, 2001a). In addition this "injection zone" should be overlain by one or more layers of relatively impermeable rock that will hold injected fluids in place and not allow them to move vertically toward a USDW (confining zone)(EPA, 2001a).

In 1984, Congress enacted the Hazardous and Solid Waste Amendments (HSWA) to RCRA that banned the land disposal of hazardous waste, unless the hazardous waste is treated to meet specific standards. EPA amended the UIC regulations in 1988 to address the Hazardous and Solid Waste Amendments. Operators of Class I wells are exempt from the ban if they demonstrate that the hazardous constituents of the wastewater will not migrate from the disposal site for 10,000 years or as long as the wastewater remains hazardous. This demonstration is known as a no-migration petition (EPA, 2001a and EPA, 2006).

Section 4.2 Class II Injection

Injection wells used for disposal or enhanced recovery below any USDW are classified by the EPA as Class II wells, and they commonly are used for managing produced water in conventional oil and gas operations. Class II wells have to follow strict construction and conversion standards except when historical practices in the state and geology allow for different standards. A Class II well that follows EPA federal standards is built very much the same as a Class I well. There are approximately 167,000 oil and gas injection wells in the United States, most of which are used for the secondary recovery of oil. The majority of the oil and gas injection wells are located in the Southwest, with Texas having the largest number (53,000) and California, Oklahoma, and Kansas following some distance behind with 25,000, 22,000, and 15,000 wells, respectively. Figure 4.2 shows the approximate count for Class II injection wells in each state.

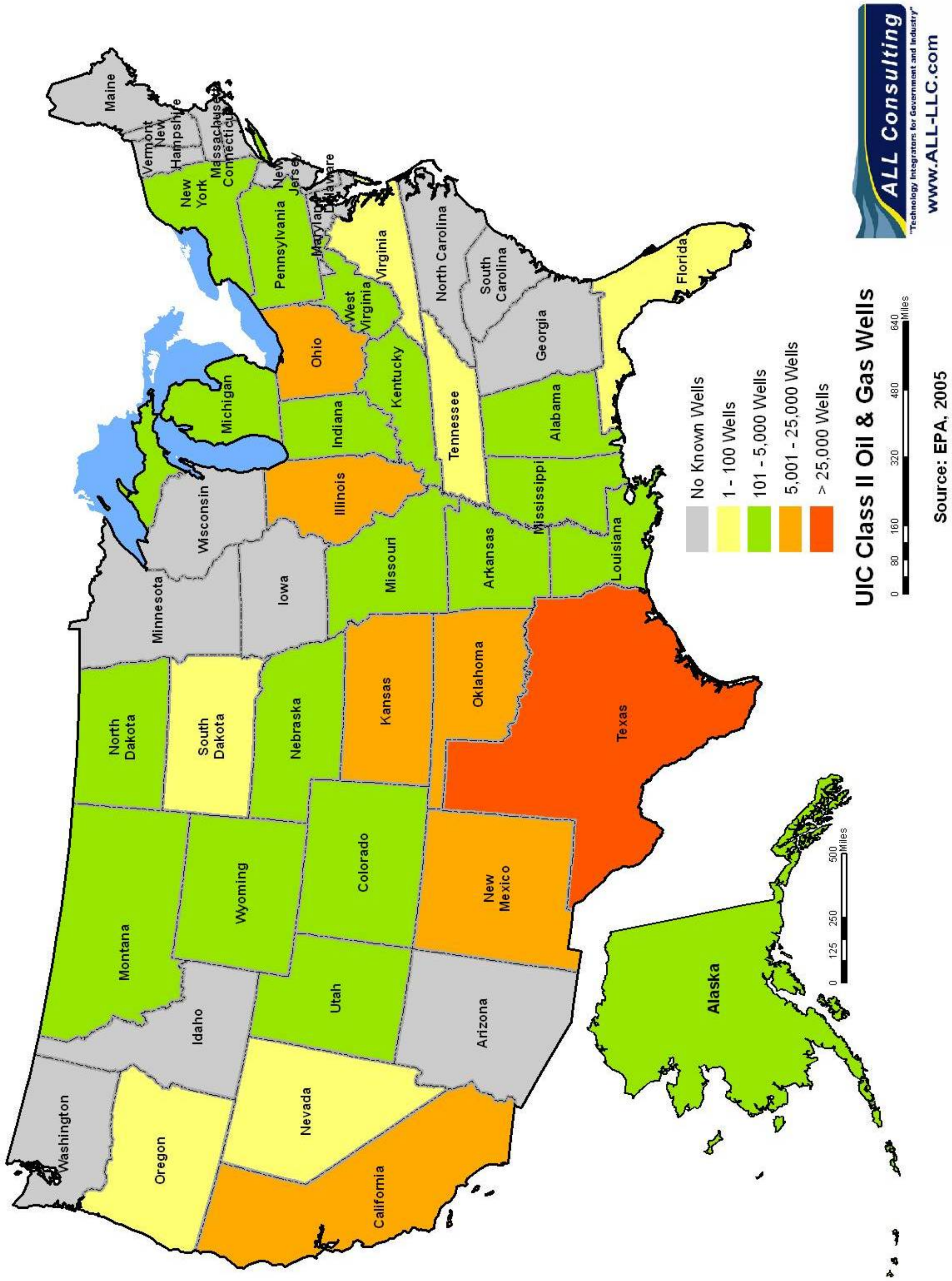
Class II injection wells are subdivided as either IID (for disposal) or IIR (for secondary oil recovery). Over 2 billion gallons of produced water are injected daily into Class II injection wells in the United States (EPA, 2005). The largest portion of the water is injected into Class IIR wells. In a common configuration, one injection well is surrounded by four or more extraction wells. The recovered fluid is sent to a phase separator where the oil, gas, and water can be separated. In Class IID wells, excess water from production and some other activities directly related to the production process are injected solely for the purpose of disposal.

Applicability

Class II injection is applicable for a wide range of produced water quality in terms of TDS; however, for produced water that is of high quality (i.e. TDS less than 10,000 mg/L) Class II may not be a reasonable option as the water resource may be wasted through injection into a lower quality aquifer. Successful Class II wells may be able to accept more than 50,000 barrels of water per day while unsuccessful wells will take little or no water.

Class IIR injection is applicable in many conventional oil fields. Waterfloods consist of a number of injection wells in a particular field that are coordinated to move the oil that remains in the target reservoir toward the producing wells in the subject field. A waterflood project can consist of less than a dozen wells or several hundred wells. Each of the operating waterfloods uses injection wells to inject water back into the oil reservoir to maintain reservoir energy and drive more oil toward the producing wells. The injected water can be water produced from the field being waterflooded, or it can be “make-up” water obtained from another source. In some cases the original field wells do not produce enough water with the oil to support a flood project and in those cases the operator will either postpone the flood project or will find make-up water from nearby production, surface water, or groundwater produced through water supply wells. As the waterflood continues, the reservoir fills up and eventually the injected water and additional oil will be seen at the producing wells. As production continues, the water produced in the oil wells replaces make-up water and the flood becomes more or less self-sustaining so no outside water is needed.

Figure 4.2 Approximate Class II Well Count in Each State



Class IID injection is applicable into underground reservoirs that are greater than 10,000 mg/L TDS or are identified as an exempted aquifer. Deep aquifers that could be suitable for injection may contain less than 10,000 mg/L TDS and would require an aquifer exemption in order to receive injectate. Aquifer exemptions are written in federal EPA regulations and are meant to avoid giving full protection to aquifers that will never be used for public water supply because of the cost of producing and treating the water. It would be risky to put a depth limit or water quality limit on an aquifer before it might qualify for an aquifer exemption; if the aquifer is deeper than 10,000 feet, it is unlikely that it would be an economic source of drinking water for a public water supply. These deep Class IID wells are generally expected to be able to inject large volumes of water in an environmentally safe and unobtrusive manner. These injection zones can be very deep and isolated by thick, impermeable confining zones safely confining the injectate away from drinking water aquifers. Wells will be inherently safe, thus providing minimal environmental concerns.

Technological advances in the use of Class II wells has lead to the development of horizontal disposal and enhanced recovery wells that have opened up new fronts in once marginal fields. In the Oklahoma City field of the Arkoma Basin, once thought depleted, a process known as "de-watering" has proven to be effective in recovering oil and gas along with high volumes of water. The process is economical due to the efficient water management system that runs the water through a high volume phase separator prior to injection of the water in a horizontal disposal well capable of handling 60,000 barrels of water per day.

High Volume Phase Separator Used in a "De-watering" Project (Oklahoma)

Constraints

Feasibility of underground injection as a tool for managing produced water involves several technical considerations including geologic, economic, and engineering questions. These may vary significantly by operator and location. There are, however, a common set of questions that must be answered for any proposed injection well (ALL, 2006), including:

- **Formation Suitability**: Selection of a suitable injection zone potentially might include reservoir characteristics; depth; relative location to producing wells and locally important aquifers; significance of local fracturing and faulting; condition of active and abandoned wells within the area; as well as other artificial penetrations.

- **Isolation**: The receiving formation must be vertically and laterally separated or otherwise confined from other USDWs. The well must also be equipped to isolate the receiving zone from other porous zones in the well to avoid unauthorized fluid movement into zones that are not permitted for injection.

- **Porosity**: Porosity is the percentage of void spaces or openings in a consolidated or unconsolidated material (EPA, 1999). Reservoir rocks are typically high in porosity, while confining zone rocks range from high to very low porosity.

- **Permeability**: Permeability is defined as a measure of the relative ease with which a porous medium can transmit a liquid under a potential gradient (EPA, 1999). A reservoir rock will have sufficiently high permeability to allow fluid movement. Confining zone rocks will have very low permeability and will act as seals rather than zones of fluid movement. Often porosity and permeability are not correlative; highly porous sands can have very low permeability while low porosity sands can be highly permeable due to natural fractures.

- **Storage Capacity**: The storage capacity of a geologic unit can be estimated using a simplistic approach by estimating the pore volume of the entire injection zone.

- **Reservoir Pressure**: The reservoir pressure is the static pressure within the receiving formation expressed either as pound per square inch or fluid head. Reservoir pressure may limit the rate at which fluids can be injected and/or may limit the total volume of fluid that can be injected.

- **Water Quality**: The quality and chemistry of water of the injectate and water within the receiving formation will determine the type of injection well to be used. The chemical compatibility of their fluids will also play a part in the feasibility assessment of the injection plan. Compatibility tests can be run prior to installing necessary pipelines to deliver the water. In order to be reliable, the test will require sidewall or full-hole cores of the reservoir; these are usually obtained when an oil operator is beginning to exploit a new field. Important aspects of a compatibility test will be pore-throat size range to determine the filter system and the presence of clays and other mineral grains that can react, swell, or become mobile when exposed to the injected water. If incompatibility is discovered, the testing contractor will be able to recommend a chemical additive that may prevent the reaction.

Technically feasible injection requires that the injection rate is sufficient for the operator's needs without exceeding the fracture pressure of the confining zone. The operator can test the injection zone to verify fracture pressure and injectivity – the injection rate as it is related to the injection pressure. Injection pressure can exceed the fracture pressure in the injection zone but cannot exceed the fracture pressure of the confining zone. This is best determined by step-rate tests. Prior to use, the injection zone may need to be stimulated by way of acidization or fracturing. This might involve pumping small amounts of weak acid or large volumes of fluid with sand to prop open the fractures in the injection zone (ALL, 2006).

Class IID deep wells must be demonstrated to be safe and protective of the environment. Mechanical and engineering integrity must be shown prior to the well being used; the injection zone must be isolated from other aquifers and USDWs. The operator must show that the deep injection zone is isolated from other permeable zones away from the borehole and the injection perforations are isolated from the long-string casing in the well. The former – stratigraphic isolation – can be demonstrated by wire-line log cross-sections through the proposed injection well and nearby wells; stratigraphy can illustrate local and regional isolation. At the same time, integrity of the injection tubing and packer on top of the injection perforations can be tested by pressuring up on the long-string casing to check for leaks.

Section 4.3 Class V Injection

Class V injection wells are defined by the EPA as any well that does not fit under the other four classes (I, II, III, and IV). Typically, Class V injection wells are shallow "wells," such as septic systems and drywells, used to place non-hazardous fluids directly below the land surface. The minimum requirements for a Class V injection well have been set by Volume 40 of the Code of Federal Regulations (40 CFR) Sections 144-147, as well as within state promulgated Rules and Regulations. The EPA estimates there are more than 650,000 Class V wells in the United States (EPA, 2001b). Examples of Class V injection wells used to manage produced water include:

> **Subsurface Drip Irrigation (SDI)** supplies water to crops by a system of hoses and pipes buried in a network of trenches under the field within the root zone of the crops. SDI allows enhanced crop production without negative environmental impacts associated with leaching or runoff. Water can be applied year-round instead of just during the typical growing season of most crops, allowing for more water to be beneficially used, and reducing or eliminating the need to store produced water during winter months. SDI application of water during non-growing months may not represent irrigation but may be seen as a beneficial use in the aid of the soil and subsoil, flushing the salts below the root zone. An added benefit is an increase in crop production for the surface landowner.
>
> **Aquifer Storage and Recovery (ASR)** is the process of injecting water into an aquifer for storage and subsequent recovery for beneficial use using the same well. Beneficial uses include, but are not limited to, public drinking water, agricultural uses, future recharge, and industrial uses. The storage aquifers may be the primary drinking water source for a region, a secondary drinking water source, or may be used for agricultural or industrial purposes. ASR is regularly used in areas with no drinking water source, areas undergoing seasonal depletions, and in areas where salt water is intruding into the fresh water aquifer (EPA, 1999). When injection is considered using Class V type wells for beneficial uses, pre-treatment of the produced water may be required before it is injected into an aquifer for either recharge or ASR. For example, treatment of water may be required to prevent the injection of bacteria contaminated water when the water has been temporarily stored in an impoundment.

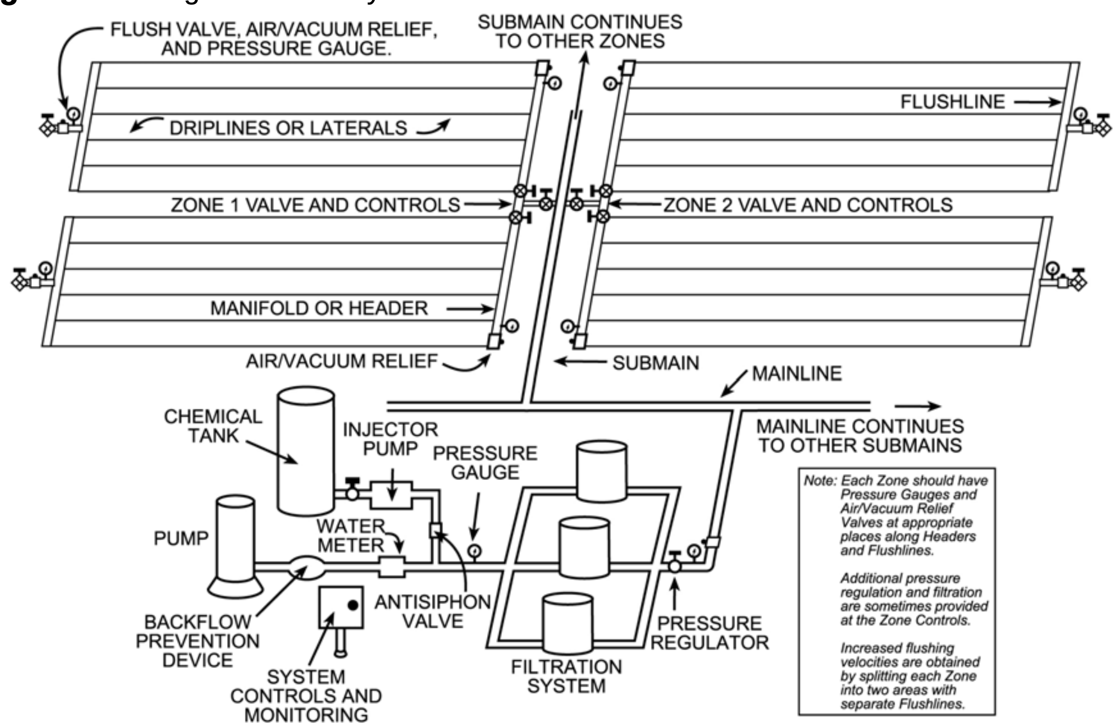
Section 4.3.1 Subsurface Drip Irrigation (SDI)

Irrigation is a common and proven beneficial use of produced water when the water quality is sufficient and compatible with soil conditions. In arid regions, good sources of water for irrigation are not abundant except near rivers and reservoirs; therefore, good sources of usable water are desirable for farmers and ranchers for irrigation use. Some of the problems associated with typical surface irrigation include soil crusting on the surface, dispersion, and salt accumulation in the root zone. SDI supplies water to crops by a system of hoses and pipes buried in a network of trenches under the field. The water enters the soil below the soil surface avoiding these problems. Subsurface drip irrigation has long been used in Israel and Australia with high quality and saline water (KSU, 2005). Figure 4.3 illustrates a typical SDI system.

Applicability

SDI appears to be a well suited type of irrigation available for use with produced water as it avoids some of the drawbacks of surface irrigation. There is increased flexibility in matching field shape and field size, and SDI's pressure compensating systems are not as limited as surface irrigation in regard to the slope. Furthermore, since the SDI process applies irrigation water to the subsurface, operators might be able to pump water year round; field operations can occur during irrigation; less irrigation equipment is exposed to vehicular damage; there is no surface soil crusting; any salt accumulation is below the root zone; there is less or no runoff into streams; and reduced weather-related application constraints (especially high winds and freezing temperatures). Other advantages include decreased energy costs as compared to other irrigation systems; improved in-field uniformities, resulting in better control of the water, nutrients and salts; and the SDI system can be easily and economically sized to the available water supply.

Figure 4.3 Diagram of SDI System



Source: KSU, 2005

Crop selection is also important with the use of SDI. Optimum plant species will vary with different regions of the United States. Perennial crops are the most suited for SDI, with alfalfa and refined grasses as some of the better candidates. Alfalfa, a forage crop, has high crop water needs and, thus, can benefit from highly efficient irrigation systems such as SDI. In some regions, the water allocation is limited by physical or institutional constraints, so SDI can effectively increase alfalfa production by increasing the crop transpiration while reducing or eliminating soil evaporation. Since alfalfa is such a high-water user and has a very long growing season, irrigation labor requirements with SDI can be reduced relative to less efficient alternative irrigation systems that would require more irrigation events. Currently, SDI is used to irrigate a number of alfalfa fields in the Powder River Basin of Wyoming, and it is estimated that about 60 inches of water can be applied annually, with the crop using 40 inches of that water through evapotranspiration (Zupancic, 2005). Continuation of irrigation reduces the amount of water stress on the alfalfa and, thus, can increase forage production that is generally linearly related to transpiration. Salt tolerant or moderately tolerant grass species such as halophytes or mixes of grass should be chosen for use with SDI.

Constraints

Constraints that may limit the attractiveness of utilizing a SDI system include, but are not limited to:

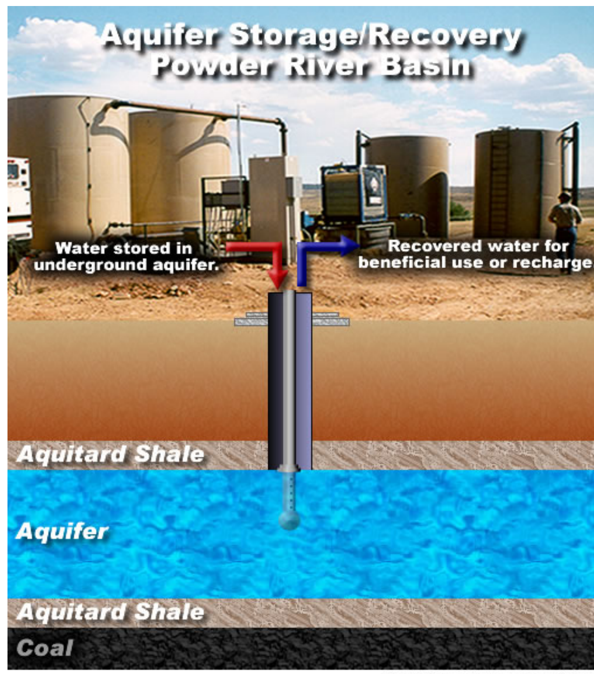
- **Regulatory -** Permits vary from state to state. The permitting process can add to the time required before the operator can start using SDI irrigation with oil and gas produced water and can add to the cost of implementation.
- **Water Pre-Treatment –** Proper leaching leads to flushing salts below the root zone by applying more water than the plant needs. There is a potential for salt accumulation to occur above the root zone if appropriate leaching is not performed during irrigation. Often this leaching process can be facilitated by natural rainfall. However, gypsum, or other amendments, might need to be used to help reduce SAR in the soil.
- **Operational Challenges –** Various operational issues exist that may cause constraints to the installation of a SDI system. Examples include limitations to soil tillage options, lack of ability to visually inspect the system to troubleshoot malfunctions leading to more difficult subsurface repairs, and root intrusion into drip lines.
- **Groundwater Impacts –** If the groundwater in alluvial aquifers is shallow, there could be a possibility that saline water could affect the aquifer. For groundwater to be impacted by SDI systems, saturated flow must exist through the soil/unsaturated zone to the point where water is moving in a continuous wetting front under gravity to the groundwater table. If produced water is applied in accordance with crop needs, soil water holding capacities, climatic characteristics, soil infiltration rates, and leaching requirements, the aquifer should not be affected. It may be necessary to perform modeling to avoid this situation, especially if the water is applied on a continual basis throughout the year.

Section 4.3.2 Aquifer Storage Recovery Wells

Underground injection into shallow aquifers offers a potential means for managing water produced from oil and gas wells. This type of injection uses boreholes drilled into shallow formations, such as sands, that are classified as USDWs, and then involves the pumping of the produced water into those formations to replenish depleted aquifers that might have experienced several years of pumping for domestic or municipal supply.

Applicability

The use of ASR wells for produced water management is applicable in areas where the quality of the produced water is of a useable nature, or can be easily treated to a useable level. Furthermore, this management practice is most likely to be applicable in arid regions where the water supply can be heavily impacted by droughts. Existing non-productive wells may be nearby and available to the operator at low cost with minimal pipeline costs, making this type of water management practice even more practical. Applicability further depends on the ability of the formation to accept water at a rate commensurate with the cost to implement this management practice.



SOURCE: ***ALL Consulting***

Perhaps the most prominent example of an ASR project was where the City of Gillette, Wyoming's well field had been locally depleted. The well field was completed in Lower Fort Union sands at a depth of approximately 1,500 feet. These sands had been pumped for a number of years to supply water for public use and consumption. Over time, water levels in the city's wells had decreased considerably. The city coordinated with a CBNG operator to install Class V aquifer recharge wells that were sufficient to manage all of the produced water from a small, CBNG producing project. In this example, the best injection well averaged more than 1 million barrels per year for more than three years (Olson, 2005). Although this example is unique, it does illustrate the potential capability of ASR Class V shallow injection wells.

Constraints

The most serious constraint for ASR Class V wells appears to be the loss of permeability over time. Permeability losses could be caused by plugging of reservoir pores with fines suspended in the water or by clay swelling (Olson, 2005). These problems are common to all types of injection wells that require careful pre-injection tests to determine the vulnerability of the aquifer's rock-frame to plugging by fines and to chemical effects. Injection testing might involve either full-hole or sidewall cores through the aquifer and lab tests of pore-throat sizes and water-rock compatibility analysis. Tests might be necessary on each injection well due to aquifer variations and other issues that have the potential to negatively impact placing water underground.

Permeability constraints may be overcome by injecting at higher pressures. In Class V wells, this might mean pressures over the local fracture pressure. High pressure injection can be difficult to permit but might allow the disposal of large volumes of produced water.

Water also might need to be treated before injection to insure that it meets water quality constraints that can be part of state permit requirements, or otherwise required by a water user. Treatment of the water is dependant upon the quality of the water, the proposed use of the water, and the storage history of the water, if any.

Section 4.4 Surface Discharge

Surface discharge involves release of produced water onto the earth's surface, either to surface water or to a watercourse. Surface discharge is a water management option that allows water to augment stream water flow. Increasing stream water flow can enhance riparian areas and provide additional water resources to support agriculture. Releases to surface water resources must be carefully managed, however, to maintain state specified water quality standards and to avoid excessive riparian erosion. The specific amount of water that can be managed by surface discharge will depend upon the existing characteristics of the stream and the quality of the produced water.

Applicability

Surface discharges are applicable in a variety of instances, such as:

- Direct discharge to surface waters. In this situation, water is delivered to a stream by pipeline or dry drainage where it mixes with existing stream flow.
- Discharge to surface impoundments with possible infiltration into the subsurface and surface water. This is further discussed in Section 4.5.
- Discharge to surface soil with possible runoff to surface water. This involves the release and management of water through different irrigation techniques. Specific management and site conditions will determine the rate of water that can be discharged to the surface, as well as the possibility of any runoff and subsequent discharge to surface water. If irrigation and runoff rates are high, significant volumes of water can enter and mix with surface water. This is further discussed in Section 4.6.

Surface discharges can be managed through evaporation and infiltration into subsoil and bedrock aquifers. When water enters a shallow aquifer, the water could migrate to surface water. Management of this water allows operators to discharge significant volumes of water that can be available for beneficial use with minimal impact on the environment. Additionally, the discharge of produced water can bolster seasonal flows of local rivers and accommodate more beneficial uses. Various discharge scenarios can be considered based on the quantity and quality of the produced water and the receiving water. Discharges directly to surface waters, such as streams and rivers, can be accomplished by the use of pipelines. The pipeline method avoids erosion and the incorporation of suspended sediments, which can impact stream water quality. Pipeline use prevents interaction of produced water with local soil and bedrock.

Water has successfully been managed through this technique for several years in the Big Horn Basin of Wyoming and Montana, as well as in the Belle Creek Field in the Powder River Basin of Montana. Prior to discharge the water is separated from fugitive oil and grease, but the quality of the water in many instances is such that it provides a tremendous source of beneficial uses to downstream water users.

Constraints

The quality of the produced water is a major constraint on the ability to discharge to the surface. If the quality of the produced water is such that it negatively impacts the receiving water quality, then surface discharge is not an option without treating the water to an acceptable quality.

The flow rate of the produced water stream in relation to the receiving stream may also limit the ability to discharge to the surface. If the produced water stream flow rate is considerably high relative to the receiving stream, then erosion may be a serious cause for concern as the additional flow may cause the side slopes and bed of the stream to be transported downstream, causing sedimentation issues at downstream reservoirs and low energy points along the stream.

Section 4.5 Surface Impoundments

A surface impoundment is an excavation or diked area that is typically used for the treatment, storage, or disposal of liquids (EPA, 1991) and can vary from less than one acre in size to several hundred acres. Impoundments are usually constructed in low permeable soils, with the possible exception of recharge ponds, to prevent or decrease raw water loss due to subsurface infiltration or percolation. Based upon an EPA national impoundment survey that characterized more than 180,000 impoundments, the oil and gas industry is considered one of the largest users of this technology. A breakdown of applied impoundment uses by this industry includes storage (29%), disposal (67%), and treatment (4%) (EPA, 1991).

The impoundment of produced water from oil and gas production can be an option utilized by operators as part of their water management practices. In some producing basins, impoundments play a large role in water management practices, while in other basins impoundments might be used only during drilling operations.

The impoundment of produced water is the placement of water produced during operations at the surface in a pit or pond. There are a variety of ways in which operators can impound produced water at the surface. Impoundments can be constructed on- or off-channel, and the regulatory authority in some states varies based on whether the impoundments are on- or off-channel.

Impoundments can be used for a variety of water management options, including disposal by evaporation and/or infiltration; storage prior to other water management options such as injection or irrigation; or for beneficial use such as a fishpond, livestock and wildlife watering ponds, or a recreational pond. The impoundment of water can be performed in any area where there is sufficient construction space. Impoundments can be constructed to provide a single management option, or a combination of management options that include livestock and wildlife watering from wetlands, fisheries and recreational ponds, recharge and evaporation ponds, or other combinations.

The purpose of the discussion in this section is to provide a brief overview for the management of produced water via impoundments. Operators, landowners, or other entities interested in the use of impoundments to receive produced water should contact their appropriate state authority, including Departments of Environmental Quality, State Engineer's Office, Oil and Gas Commission, and Fish and Wildlife, for additional information, pertinent statutes, or clarification of the information provided within.

Section 4.5.1 Evaporation and Aeration

Evaporation ponds are usually off-channel constructed impoundments designed to store water at the surface so that natural evaporative processes can move the water from the land surface into the atmosphere. As evaporation occurs, pure water is removed from the pond, resulting in an increase in the TDS for the remaining water. Over time, as more water is lost to the atmosphere, the water remaining in the pond may become concentrated brine.

Applicability

Evaporation and aeration (enhanced evaporation) is applicable in arid regions where the average annual rainfall is relatively low and the average annual evaporation is relatively high. If the evaporation pond is constructed solely for evaporative loss (no infiltration), the ponds are generally designed to be broad shallow pools that maximize the surface area allowing for increased evaporation rates. Additional consideration is given to exposure; areas with high winds and few natural windbreaks could provide additional evaporative potential, which would include finding areas with low-level vegetation.

In the Battle Creek Field of Montana a zero-discharge system of managing produced water has been developed by utilizing enhanced evaporation ponds through aeration coupled with recycling the produced water for oilfield uses (such as well completions and dust prevention).


Enhanced Evaporation in the Battle Creek Field (Montana)

Constraints

Climate conditions may provide constraints that interfere with the effectiveness of evaporation. In colder regions evaporation might be effective for only short periods throughout the year, making it an ineffective year round water management practice. In wet regions there may be more water provided to the pond via rainfall than can be managed via evaporation.

Water quality and geological setting also can impact the ability to use evaporation as a water management practice. Depending on the quality of the water and the soil at the bottom of the evaporation pond, the bottom and toe areas may need to be lined to prevent infiltration and migration of the water. Lining the evaporation pond may make this an uneconomical water management option; however, it has proven to be cost effective in the Bowdoin Field in Montana by master planning the phased construction of several lined ponds adjacent to each other to ensure capacity while not over-designing the water management system.

In geologic settings where a suitable material is available to prevent infiltration, the ponds may be placed on natural confining layers such as bentonite rich clay soils, or exposed shales that prevent the downward migration of the groundwater.

Section 4.5.2 Wildlife and Stock Watering

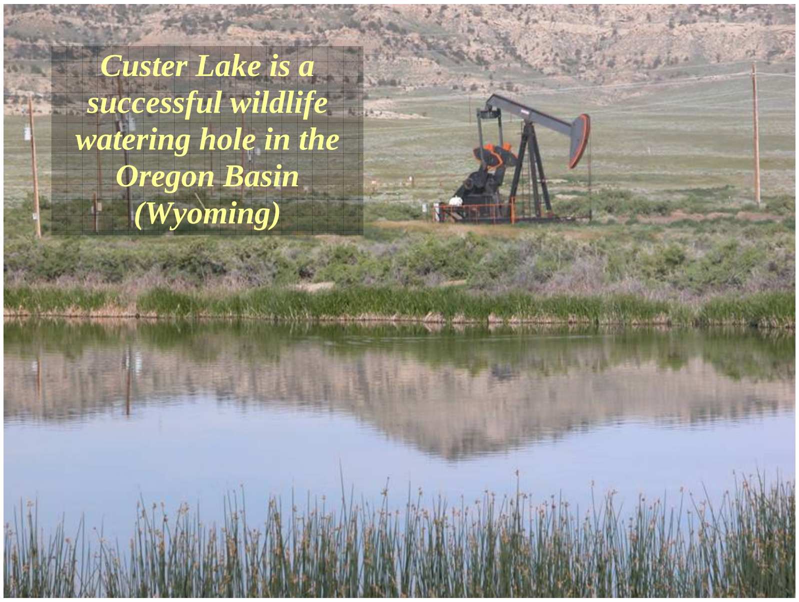
Wildlife watering ponds are typically small off-channel reservoirs that are used to help supplement wildlife or livestock water demands in semi-arid to arid regions. There are many types of watering facility designs available and choosing the correct one depends on proper evaluation of the situation to ensure landowner needs are satisfied.

The Natural Resource Conservation Service (NRCS) provides nationwide standards and technical guidelines for wildlife watering facilities (NRCS, 1982) to help facilitate the decision process and assure proper recommendations are presented to landowners. State NRCS offices in some cases have customized these standards to meet the demands or requirements for their particular region.

Applicability

Where water quality allows, wildlife watering ponds function to improve, or enhance watering places and systems for wildlife, to provide adequate drinking water during drought periods, to create or expand suitable habitat for wildlife, and, in some cases, to improve water quality. Wildlife watering ponds are commonly constructed in areas of the western United States to enhance habitat limited by water supplies. In some areas, watering ponds provide wintering areas for migrating waterfowl, neotropical birds, or other transient species. In severe drought conditions, watering ponds are used to provide water to mule deer, coyotes, bobcats, badgers, and other wildlife (U.S. Fish and Wildlife, 2002).

Watering ponds should be located in habitats that can provide food and shelter for as many wildlife species as possible and should include water level control devices or a means for escape to prevent drowning (ALL, 2003). Other important considerations include aesthetics, accessibility for periodic maintenance, and the control of noxious weeds. In some cases, natural watering areas can be improved to function in the same manner as constructed watering ponds. Natural watering areas are often found where run-off water accumulates in depressions. These areas can be improved by deepening the catchments, by trenching run-off waters to the basin, or developing the springs and seeps (ALL, 2003).


Custer Lake is a successful wildlife watering hole in the Oregon Basin (Wyoming)

In general, surface impoundments for wildlife should have gentle slopes to reduce erosion and suspended solids (Rumble, 1989). The surface area and depth of the pond would depend on the climate and the species expected to utilize it. Ponds expected to sustain waterfowl populations should have a surface area of 0.4 to 4.0 ha (1 to 10 ac) (Proctor et. al., 1983) and at least 25% of the pond should have a depth of 3 meters (10 ft) (Rumble, 1989). Watering ponds of this size and depth could also be used to sustain populations of shore and upland birds and fish. Ponds with a surface area less than 0.4 ha (1 ac) would likely not be able to support fish populations without management (Marriage and Davison, 1971).

A successful wildlife watering pond known as Custer Lake is located in the Oregon Basin of Wyoming. Approximately 30,000 barrels of water per day are discharged to what would normally be a seasonal playa lake. Wildlife such as waterfowl and big game flourish in the area as a result.

Constraints

As with many beneficial uses, the quality of the produced water can prove to disallow the use of this water management practice. Typically water with TDS above 10,000 ppm is not of sufficient quality for wildlife consumption. Water quantity can also be a concern if this water management practice is employed, and it is likely that additional water management practices such as enhanced recovery would need to be used in conjuncture with this practice to manage all of the water produced.

Section 4.6 Managed Irrigation and Land Application

This management option involves either the discharge of raw produced water directly to the land surface, or pre-treating the water with amendments just prior to applying the water to the land surface by way of irrigation methods. The common methods of irrigation include center-pivots, side-rolls, and fixed or mobile water-guns.


Surface Irrigation in the Hamilton Dome (Wyoming)

Applicability

The direct discharge of water to the land surface can be a viable practice for operators, depending upon site-specific conditions. Under this management strategy, water can be discharged to fields and pastures in order to support plant growth, and disposed of through evaporation, transpiration by way of plant tissue, and infiltration into the soil. However, factors such as the quality of produced water, existing land uses, landowner's future plans for use, soil type, vegetative cover, and other factors all affect the land's ability to accept surface discharge produced water. Although it should be assumed that this management option could lead to runoff that reaches surface water, depending upon local conditions, many control or mitigation practices exist to minimize this effect.

Constraints

As mentioned before, the quality of the produced water can prove to disallow the use of this water management practice. Typically water with high salinity and/or high SAR values can damage plant life and make soil unusable in the future. In this instance, water quality can be improved by adding amendments either to the soil or to the water prior to application of the water to the soil. The required amendments would be site specific depending on the soil, water, and plant that the water would be irrigated with.

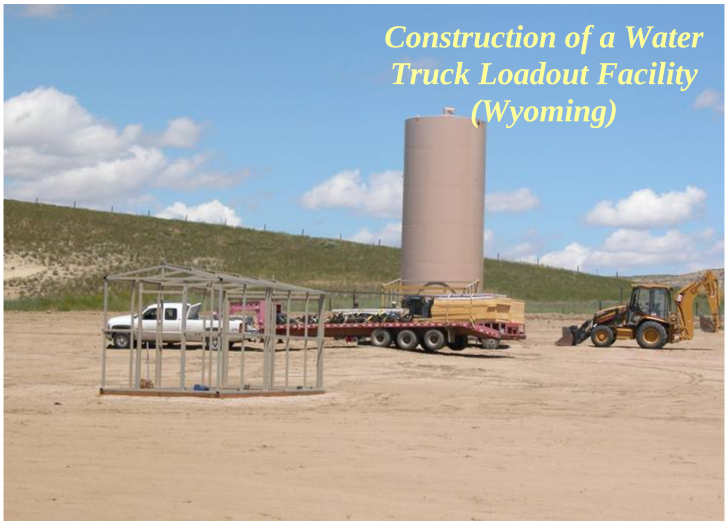
Water quantity can also be a concern if this water management practice is employed, and it is likely that additional water management practices such as enhanced recovery would need to be used in conjuncture with this practice to manage all of the water produced.

Section 4.7 Industrial Uses

There are various beneficial industrial uses that may be applicable for produced water management depending on site-specific conditions and economics. Some examples discussed here include the use of the water in oil and gas operations (i.e. truck wash station, well completions, fracturing), use of the produced water for the cooling needs of a power plant, and dust suppression (i.e. at coal mines or on unpaved county roads). The applicability and constraints of these industrial uses are discussed here, along with examples of where these practices have already been employed.

Section 4.7.1 Oil and Gas Operations

Water is used for various things in the day-to-day operations of the oil and gas industry. Some uses such as truck washing, well completions, and fracture water may not require the water to be of high quality. Therefore produced water generated from oil and gas development can be used for these activities with little to no regard for the quality of the water. By utilizing produced water in this fashion, operators not only lower the cost to dispose of the produced water, but eliminate the cost to acquire the water necessary for operations.


Construction of a Water Truck Loadout Facility (Wyoming)

Applicability

The use of produced water in oil and gas operations is applicable in several regions under various scenarios. One example in the PRB of Wyoming is a water truck load-out facility that utilizes produced water to supply oil and gas activity with the water necessary for operations, thus taking some pressure off the local water supply to meet this demand.

In the Barnett Shale play in Texas as much as 2 million of gallons of make-up water is required for a fracture job. This water is subsequently produced back to the surface in the early stages of development. To reduce the cost of fracturing wells, efforts are being made to reclaim and recycle this water as it is produced by utilizing it to fracture the next well.

Another example previously discussed is in the Battle Creek Field of Montana. A zero-discharge system has been developed to manage produced water through enhanced evaporation ponds coupled with recycling the produced water for operational uses (such as well completions and dust prevention). The central evaporation ponds are used as a water supply source. Water trucks haul water from these ponds to the site where water is required.

Constraints

The main constraint to using produced water for oil and gas operations is the fact that the volume of water used may be nominal when compared to the total volume of water produced, and therefore it may be uneconomical to put practices in place solely to recycle the produced water for operational uses. This can be overcome by applying a portfolio of water management practices, such as in the Battle Creek Field example, where the water is readily available when needed for operations, but operations is not the sole source of managing the water.

Section 4.7.2 Power Plant Cooling Water

Electric generating power plants can have a considerable need for water for cooling. Nationally, water availability has been a limiting factor in the development of new power plants. With the current and projected over-abundance of produced water from development when combined with existing and potential future power plants in the United States, consideration of using produced water for cooling at power plants is reasonable.

Applicability

In general, power plants have the capacity to individually generate between 80 and 2,110 Megawatts (MW). As an integral part of the power generating process, these power facilities must employ water, air, mist, or a combination of these for cooling. Produced water could be used for cooling at power plants in several states, thus avoiding the need for costly air cooling, potentially reducing overall power generation costs. Further, the presence of a water surplus could be used to attract power generating facilities for exporting power.

Water usage volumes can vary widely among power plants, with ranges from approximately 20,000 bpd to more than 400,000 bpd (Schultz, 2005). As an example, Basin Electric operates a large power facility near Wheatland, Wyoming. Designed as a water-cooled facility, this plant has a capacity of 1,650 MW and requires approximately 400,000 bpd of water for cooling. Currently, its water comes from the Grey Rocks Reservoir on the North Platte watershed. This reservoir does not have an adequate supply of water to support its cool water fishery. Further, the entire watershed lacks sufficient water to support irrigation and to fulfill commitments to the Platte River Compact (Lawson, 2005).

Constraints

Several technical constraints may exist for supplying produced water to power plants. These include water quality, water quantity, consistency of water quality and quantity, water treatment issues, distance from the producing area to the usage area, water transportation issues, and the length of time the water would be available.

Plants are generally designed to accommodate cooling water of a relatively high and consistent quality. These issues are of particular concern with respect to produced water since considerable variations exist in both produced water quality and consistency of quality and volume across the nation. These issues would need to be considered and addressed when further pursuing the use of produced water for cooling at power plants.

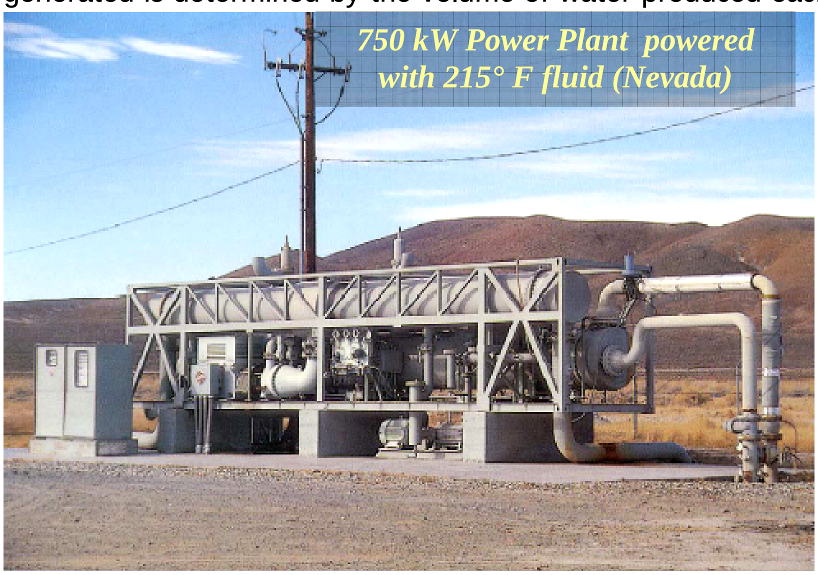
The issue of a single operator being able to commit to long-term supply needs of a power plant has been challenging (Cline, 2005). Furthermore, the costs of this water management strategy would include significant up-front capital costs and long-term operational costs for the water transportation pipelines. Therefore, to economically meet the short- and long-term water supply needs of a power plant, it is likely that a consortium of operators would need to cooperate for this management practice to be feasible.

There has been some small-scale usage of produced water for cooling by power plants. This usage has been short-lived and minor from the standpoint of the power plants (Stafford, 2005). In all of the historical cases where produced water has been used, the usage point was very close to the production area, thus minimizing transportation costs (ALL, 2006). Unfortunately, due to rapid water production declines, the cases evaluated were unable to meet plant quantity requirements for an extended time, thus forcing the plant to seek cooling water from alternative sources.

Water rights issues may provide additional constraints through public perception and outcry in the event that produced water is transported long distances over state and basin boundaries. Inter-basin transfer of water can involve complex water ownership issues that could delay or restrict the implementation of oil and gas projects.

Section 4.7.3 Geothermal Power Generation

Produced water that is at/above a temperature of approximately 215°F can be utilized for the economic generation of electric power (Blackwell, 2004). The electric power generated can 1) be used by the operator to supply the operational needs of the development, 2) be sold either to local end-users or to the local utility company. The amount of potential electric power generated is determined by the volume of water produced each day and the temperature of the water as it reaches the surface. The geothermal generation process does not interfere with the other management options discussed elsewhere in this chapter. For example, after running through the generator, the water may be put to further beneficial use if the water is of high quality, the water may subsequently be re-injected into the subsurface into a disposal zone, or into the original subsurface reservoir to maintain reservoir pressure and enhance oil production.



Applicability

Given the right conditions, electrical power can be generated as part of an oil or natural gas development. Efficient and cost effective power generation requires high volumes of water production and high water temperatures. Current state-of-the-art technology generators require at least 15,000 barrels of water per day with a minimum temperature of 215°F (Blackwell, 2004). This volume of water is frequently exceeded by medium and large oil and gas fields in the United States where 100 producing wells may average 200 to 500 barrels of water per day each. Further, water of the required temperature can be found in many deep fields in the United States as shown in Figures 4.4 and 4.5. Figure 4.4 is a map of the United States showing estimated temperatures at a depth of approximately 9,800 feet (3 km), and Figure 4.5 depicts estimated temperatures at a depth of approximately 16,400 feet (5 km).

Figure 4.4 Temperature (°F) at 3 km (~9,800 ft) for the Continental United States

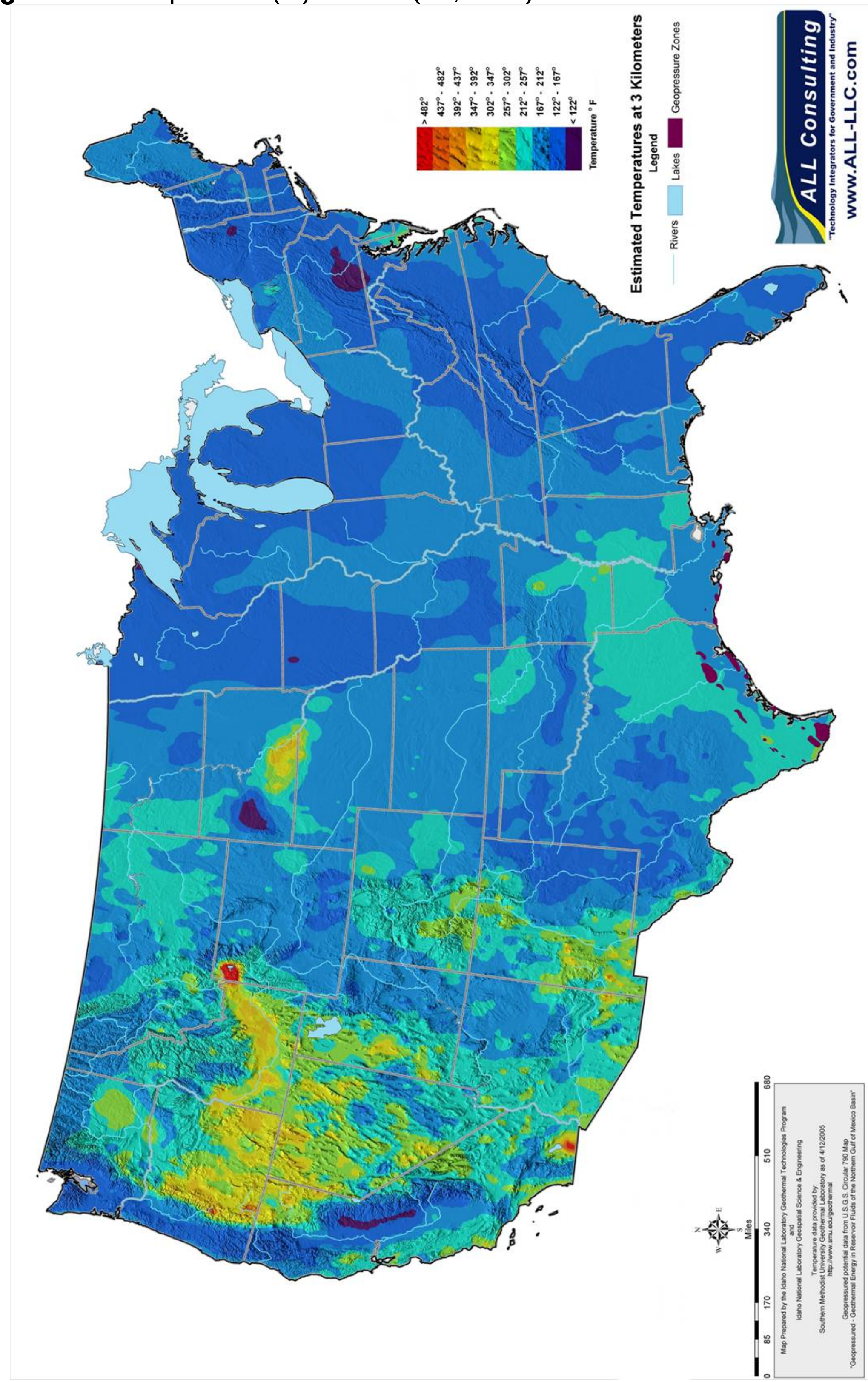


Figure 4.5 Temperature (^{o}F) at 5 km (~16,400 ft) for the Continental United States

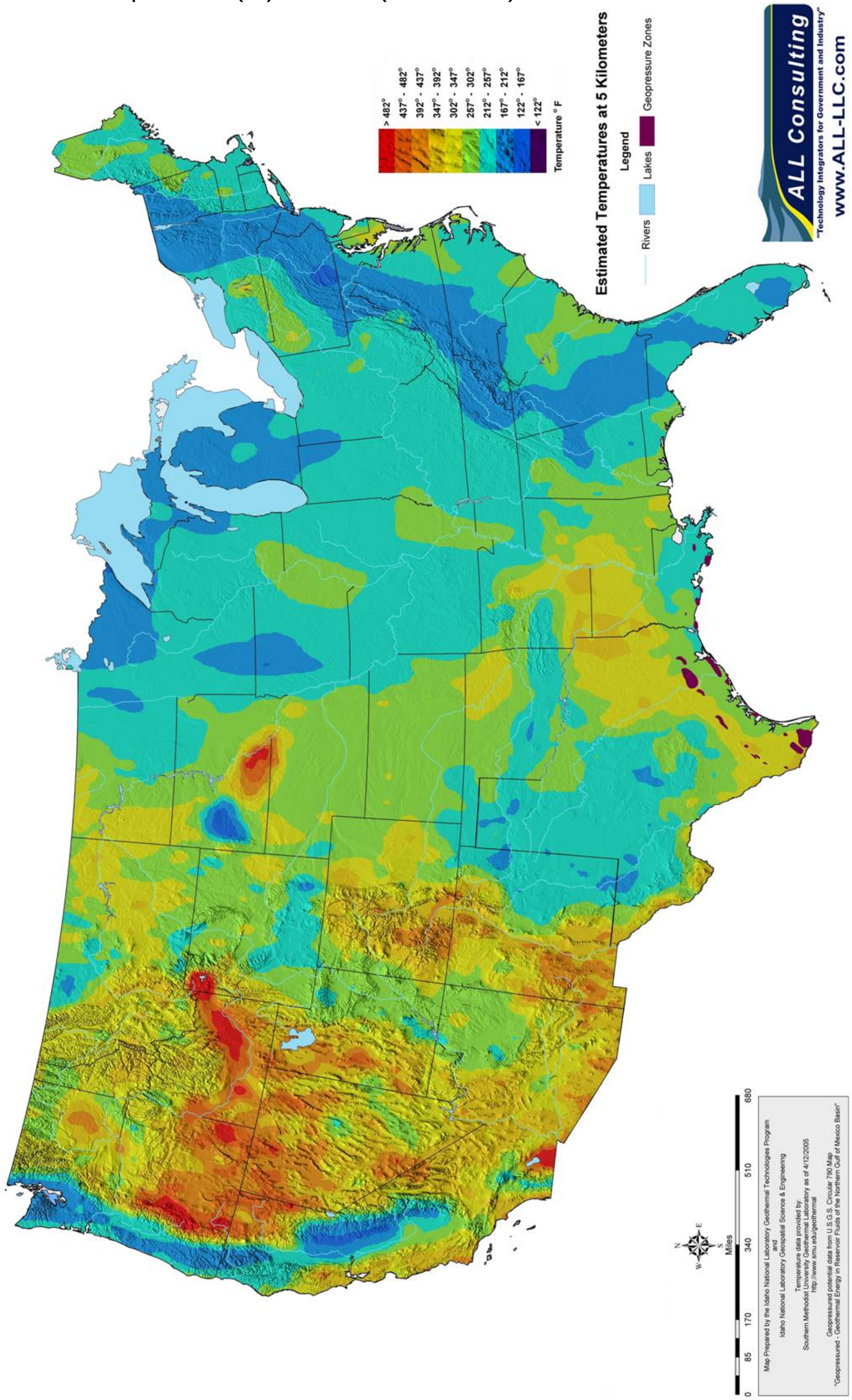


Figure 4.4 shows promising areas in East Texas and some spots in the Rocky Mountains at a depth of 9,800 feet (3 km). At deeper depths, a large percentage of the area shown in Figure 4.5 is underlain by strata in excess of 212°F at a depth of 16,400 feet (5 km), the approximate point of economic geothermal power generation.

Several manufacturers can supply generators on an on-the-shelf basis. The 750 kW Nevada facility shown in this section can be assembled in a short time and moved to another location if production characteristics change. A facility like this may be located on the grounds of a water plant at a large producing field between separators and the water injection plant (Thomsen, 2006). The generator shown requires a flow of 500 gpm (approximately 17,000 bpd) of water at 215°F to generate 750 kW. The power for this specific facility is sold to Sierra Pacific Power under a long term agreement.

Constraints

The biggest constraint on the development of geothermal power generation at traditional oil and gas sites is the temperature of the produced water as it reaches the surface. Given that the minimum temperature for efficient and economic power generation is 215°F, and that the geothermal gradient throughout the petroleum basins of the United States ranges between 1.0 and 1.2°F/100 feet, then the requisite temperature would be available at depths between 12,100 feet (70°F surface temperature and 1.2°F/100 feet) and 16,500 feet (50°F surface temperature and 1.0°F/100 feet) below the surface. These depths are attainable in many states, however, oil and gas wells are more commonly produced from depths shallower with associated waters less than the required 215°F. Temperature constraints may change in the future as the technology of geothermal power generation continues to advance.

Another serious constraint on the feasibility of generating efficient and economic power is the tendency of strata to lose porosity and permeability with increasing depth. When depth and pressures increase, both matrix porosity and fractures tend to close. Unless extraordinary forces keep pathways open, either by the action of local tectonic stresses or abnormally high fluid pressures, reservoir rocks at great depths will have limited ability to deliver the necessary volume of water to the power plant. Downhole permeability can be accurately measured by examining reservoir performance from oil, gas, and water production records. An operator with an interest in utilizing geothermal generators may be able to use historical production data to assess the feasibility.

The presence of secondary or tertiary recovery facilities will not constrain the operator’s ability to install geothermal generation. The space requirements are small and water production is in no way hampered (Thomsen, 2006). Scaling can develop within the generator from some produced water chemistries; which will be similar to the scaling experienced by the operator in existing water handling facilities. Scaling can be controlled by existing chemical treatments.

Section 4.7.4 Dust Suppression

Fugitive dust impacts to local or regional air quality are important issues (ALL, 2006). Some industrial sites, such as coal mines, constantly need to control fugitive dust. Some areas are facing dust levels that may require curtailment of mining and other industrial activity. Truck traffic in coal mine operations can be heavy, depending on the number of active pits, and they can travel as much as 15 miles on gravel roads for each pit (mine) (Hutchinson, 2005). As this is done, loaded trains leave for power plants while empty trains arrive at loading docks. All of this activity goes on continually year-round and almost all of this activity generates copious amounts of fugitive dust. The demand for water for dust suppression at mines is site-specific and dependant on the season; therefore, it can range anywhere from 2,400 bpd to 100,000 bpd (Murphree, 2005 and Hutchinson, 2005). Depending on the availability and cost of the water used to control the dust, produced water from oil and gas operations could be a viable option to supply this water. Produced water also can be used for washing trucks and other large equipment.

Applicability

Coal mines require more water for dust control during the dry periods of the summer and fall. During other times, water can be stored on-site in pits and settling ponds. A typical large coal mine can have storage approaching 5.0 million bbls (Murphree, 2005). Helping area coal mines control dust by supplementing their water sources for dust control can benefit the mining sector, help all industrial interests in the basin, and improve air quality issues. In addition, reducing dust with supplemental produced water can give operators a low-cost, year-round option for managing the water.

Several operators supply water to numerous coal mines, especially in Wyoming and Montana. The Spring Creek mine near Decker, Montana, receives between 200 and 800 gpm from the CX Ranch CBNG field in the area (Williams, 2005) and several mines near Gillette have previously received small amounts of water from adjacent CBNG fields (Stearns, 2005).

Constraints

Technical constraints of this option involve water quality requirements that may limit usage. However, there are differing impressions of the quality limits for dust control water applied to roads. Some operators are concerned about the buildup of salt at the side of coal mine roads and have a self-imposed limit of 10 SAR (Murphree, 2005) while other companies have a corporate policy about using high quality water for dust control and emphasize the use of poor quality water (Stearns, 2005). Some operators add Magnesium Chloride (MgCl) to dust control water and, thus, are unconcerned about water quality for dust control (Hutchinson, 2005).

The proximity of oil and gas operations to an industrial area where dust suppression is required is also a potential constraint from an economic standpoint. The cost to haul the water to the industrial site may preclude this as a viable option, and the capital cost required to construct a water pipeline would make it difficult for any operator to justify. As mentioned before, this option may become more viable if multiple operators collaborate in establishing the infrastructure necessary to transport the water from the wellhead to the site where it can be used for dust suppression.

Section 4.7.5 Concentrated Animal Feeding Operations (CAFO)

Livestock watering is one of the most common and proven beneficial uses of produced water. Most range and pasture used for livestock watering would require relatively minute quantities compared to the amounts of water produced; therefore, to support a concentrated animal feeding operation (CAFO) where large numbers of animals are confined and fed would manage a larger volume of produced water. The water needs of a CAFO could include animal consumption, irrigation of forage crops, and waste management. Current feedlot operators will already have sources of water; therefore, water would have to be provided at a very low cost for this to be economically feasible for them. Costs associated with the beneficial use of produced water for feedlots mainly would include transporting the water to the feedlot facility.

Applicability

Finishing cattle consume from 8 to 20 gallons of water per day, depending on the time of year and outdoor temperature (Guyer, 1977). For a larger feedlot handling 5,000 head, this would require a maximum volume of about 100,000 gallons, or 2,380 bpd of drinking water. The average size feedlot in the Great Plains is about 500 head (Davies and Widawsky, 1995); therefore, water use for livestock drinking would be about 240 bpd for an average size feedlot. Water requirements for waste management would increase this amount slightly. If produced water were to also supply irrigation for hay and grain adjacent to the feedlot, much more water would be required.

Table 4.1 shows the acceptable quality of water for livestock. Water with a TDS below 10,000 mg/L (EC <16 mmhos/cm) is generally considered acceptable.

Table 4.1 Water Quality Guide for Livestock Use

TDS (mg/L)*	Livestock Watering Comments
Less than 1,000 (EC < 1.5 mmhos/cm)	Excellent for all classes of livestock.
1,000 to 2,999 (EC = 1.5-5 mmhos/cm)	Very satisfactory for all classes of livestock. May cause temporary and mild diarrhea in livestock not accustomed to them.
3,000 to 4,999 (EC = 5-8 mmhos/cm)	Satisfactory for livestock, but may cause temporary diarrhea or be refused at first by animals not accustomed to them.
5,000 to 6,999 (EC = 8-11 mmhos/cm)	Can be used with reasonable safety for dairy and beef cattle, sheep, swine, and horses. Avoid use for pregnant or lactating animals.
7,000 to 10,000 (EC = 11-16 mmhos/cm)	Considerable risk in using for pregnant or lactating cows, horses or sheep, or for the young of these species. In general, use should be avoided although older ruminants, horses, poultry, and swine may subsist on them under certain conditions.
Over 10.000 (EC > 16 mmhos/cm)	This water is considered unsatisfactory for all classes of livestock.

(Source: NAS, 1974)
Note: Electrical conductivity (EC) expressed in micromhos per centimeter at 25°C can be substituted for total dissolved solids without introducing a great error in interpretation.

Constraints

The quality of the produced water most likely would present the biggest constraint for use of this water management practice. As stated above, water with a TDS of 10,000 is considered unsatisfactory for animal consumption. Furthermore, transporting the water from the producing areas to the CAFO would be another difficult aspect of this water management practice. Either trucking the water or building pipelines would be the most feasible solutions, but cost may be prohibitive, depending on the distances.

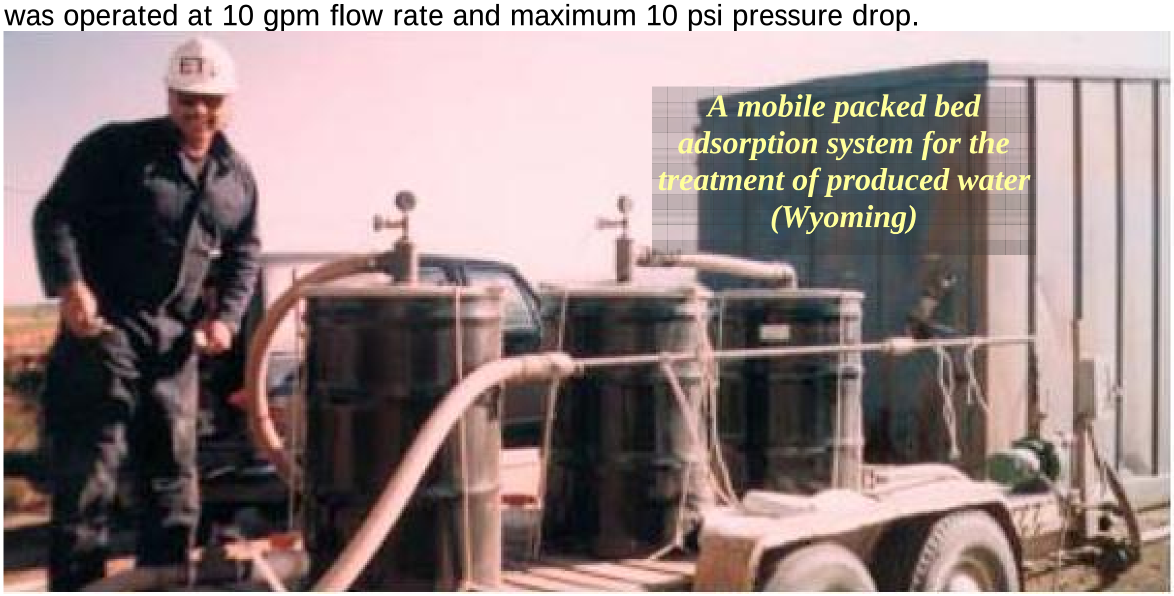
The issue of a single operator being able to commit to long-term supply needs of feedlot could be challenging. Therefore, to meet short- and long-term water supply demands, it is likely that a consortium of operators would need to cooperate to make this a viable produced water management option.

Section 4.8 Water Treatment Technologies

Various water treatment technologies are available to the oil and gas industry. The options can differ in their inherent facility requirements, capital costs, operating expense, and waste streams; all three factors can be important to the oil and gas operator. Some technologies may have large space requirements that may not be possible in some oil and gas installations. Some technologies may be commercially available as small, skid-mounted units that easily can be relocated as production conditions change. Equipment costs are obviously important in some installations where a large amount of dedicated equipment must be purchased just for managing produced water. Higher power costs and chemical expenses could be unsupportable early in the life of an oil and gas development. Treatment wastes derived from produced water might no longer be classified as oil and gas wastes and might be more difficult and more expensive to manage. This section discusses various produced water technologies along with examples of how they are being implemented in the field.

Section 4.8.1 Packed Bed Adsorption

ET Ventures, L.L.C., South Carolina, field tested its new ET #1 produced water treatment system at Rocky Mountain Oilfield Testing Center (RMOTC) in July 1996 to determine its effectiveness in adsorbing hydrocarbons from produced water (Doyle, et al., 1997). Water produced from the Tensleep formation was atmospherically cooled (to 90°F) and flowed through a three-stage packed bed adsorption treatment system. Higher temperature affects the removal efficiency of the adsorbent. The first two stages contained ET #1, a sodium bentonite modified organoclay adsorbent. The final stage contained granular activated carbon (GAC). The picture below shows a mobile treatment trailer used for the operation. The system was operated at 10 gpm flow rate and maximum 10 psi pressure drop.



The samples of inlet feed, effluent from ET #1 columns, and effluent from the GAC column were analyzed by a standard EPA (EPA 1664-A) analytical testing method. Table 4.2 shows the results obtained for one of the trials during the treatment. ET #1 treatment was sufficient to remove Total Petroleum Hydrocarbons (TPH) below detectable limits. Oil and grease values were below detectable levels after ET #1 adsorption treatment. Benzene, toluene, ethylbenzene, and xylene (BTEX) were removed to below detectable levels after GAC adsorption treatment.

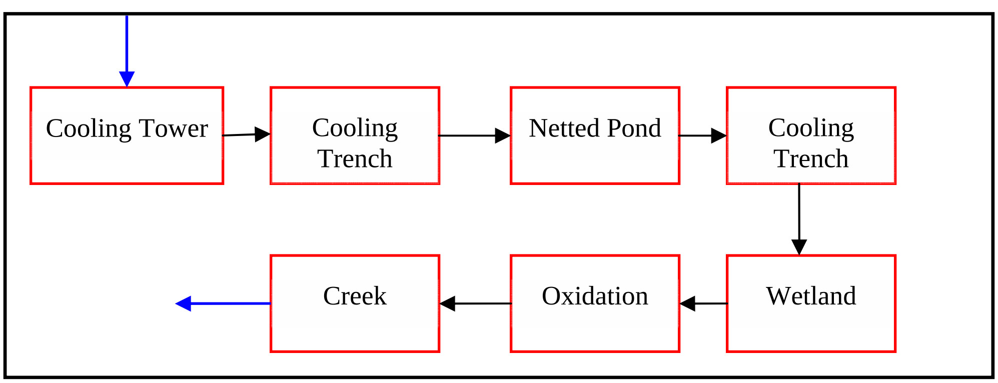
Table 4.2 Results from ET Venture's mobile produced water treatment system

Contents	**Before Treatment (ppm)**	**After Treatment (ppm)**
TPH	148	1.1
Oil and Grease	151	1.2
Benzene	3.14	<0.5
Toluene	4.97	<0.5
Ethylbenzene	4.95	<0.5
Xylene	29.7	<1

Section 4.8.2 Decomposition in Constructed Wetland

The DOE's Naval Petroleum Reserve No. 3 (NPR-3) bio-treatment facility with average throughput of 35,000 bpd of water is located in Natrona County in east-central Wyoming (Myers, et al., 2001). The wetlands treatment facility started in January 1996 to provide a cheaper alternative to reinjection and to benefit local wildlife by way of water discharge. Wetlands are thin film bioreactors that utilize various species of plants and microbes along with sands that oxidize contaminants present in the water. A schematic of treatment process is shown in Figure 4.6.

Figure 4.6 DOE Naval Petroleum Reserve's bio-treatment process



The process undergoes the following steps:

1. Cooling tower followed by a shallow cooling trench to reduce the temperature of produced water from 180 – 200°F to below 100°F. Higher temperatures reduce the performance of plants in the subsequent wetlands pond.

2. Netted pond or skimming pond further cools the water and also removes suspended solid and oil under gravity effects. Dispersed oil on the top surface is skimmed off.
3. Specially developed flora and fauna, including hydrocarbon decomposing bacteria, sulfate reducing bacteria, nitrifying and denitrifying bacteria, iron related bacteria, algae, etc. biodegrade various contaminants present in produced water.
4. Microorganisms in wetlands degrade most of the hydrocarbons and the remaining traces of hydrocarbons are removed in an oxidation process.

The produced water from the Tensleep formation was blended with the produced water from other formations before the treatment. The blending process reduced the level of some of the contaminants and also lowered the temperature. While TDS was not affected, certain persistent contaminants such as organics, alkalinity, and ammonia were greatly attenuated. Table 4.3 shows the result obtained using the bio-treatment facility.

Table 4.3 Summary of the performance of NPR-3 Bio-treatment facility which included wetland treatment

Constituents	Before treatment (ppm)	After treatment (ppm)	Overall removal (%)
NH_3	2.03	0.54	73
NO_3	<0.1	<0.1	-
Phosphorus	1.83	0.46	75
BOD	28	2.3	92
COD	48	29	40
TOC	32.7	3.6	90
TPH	112	5.8	95
Oil & Grease	71.9	4.2	94
Benzene	0.143	<0.001	100
Toluene	0.135	<0.001	100
Ethlybenzene	0.035	<0.001	100
Xylene	0.162	<0.001	100
Turbidity	45.4	4.76	90
TDS	4380	4010	9
Alkalinity	713	190	73

Section 4.8.3 Ion Exchange

The ion exchange process effectively removes arsenic, heavy metals, nitrates, radium, salts, uranium, and other elements from the produced water. Ion exchange is a reversible chemical reaction wherein positively or negatively charged ions present in the water are replaced by similarly charged ions present within the resin. The resins immersed in the water are either naturally occurring inorganic zeolites or synthetically produced organic resins. When the replacement ions on the resin are exhausted, the resin is recharged with more replacement ions.

Ion Exchange Resins

Ion exchange resins are classified as cation exchangers, which exchange positively charged ions, and anion exchangers, which exchange negatively charged ions. The resins are further classified as:

Strong Acid Cation (SAC) Resins:

The hydrogen or sodium forms of the cation resins are highly dissociated and H^+ or Na^+ ions are readily exchangeable over the entire pH range. Equation 1 shows an example of salt removal with SAC.

$$2(R-SO_3H)+NiCl_2 \rightarrow (R-SO_4)Ni+2HCl \qquad ..(1)$$

Equation 2 shows an example of Ca^+ softening with SAC.

$$2(R-SO_3H)+Ca^+ \rightarrow (R-SO_3)^2Ca+2H^+ \qquad ..(2)$$

These resins would be used in the hydrogen form for complete deionization (Na, Ca, Mg, Ba, etc. removal); they are used in the sodium form for water softening (Ca and Mg removal). After exhaustion, the resin is regenerated to the hydrogen form by contact with a strong acid solution, or to the sodium form with a sodium chloride solution.

Weak Acid Cation (WAC) Resins:

Weak acid resin has carboxylic acid (COOH) group as opposed to the sulfonic acid group (SO_3H) used in strong acid resins. These resins behave similarly to organic acids that are weakly dissociated. WAC has high affinity for divalent salts. Equation 3 shows an example of Ca^+ softening with WAC. Alkalinity present in bicarbonate form also can be removed by WAC.

$$2(R-COOH)+Ca^+ \rightarrow (R-COO)_2Ca+2H^+ \qquad ..(3)$$

Free H^+ ions can react with bicarbonate (present as hardness, $Ca(HCO_3)_2$) to form carbonic acid. The carbonic acid decomposes in carbon dioxide as shown in equation 4. Removal of carbon dioxide or decarbonation (Moftak, 2002) is necessary during the water treatment process.

$$HCO_3^- + H^+ \rightarrow H_2CO_3 \rightarrow CO_2 + H_2O \qquad ..(4)$$

Weak acid resins exhibit a much higher affinity for hydrogen ions compared to strong acid resins. This characteristic allows regeneration to the hydrogen form with significantly less acid than is required for strong acid resins. Almost complete regeneration can be accomplished with stoichiometric amounts of acid. The degree of dissociation of a WAC is strongly influenced by the solution pH. Consequently, resin capacity depends in part on solution pH.

Strong Base Anion Resins:

Strong base resins are highly ionized and can be used over the entire pH range. These resins are used in the hydroxide (OH^-) form for water deionization. They will react with anions in solution and can convert an acid solution to nearly pure water. Equation 5 shows the reaction involved in an anion exchange step.

$$(R-NH_3OH)+HCl \rightarrow (R-NH_3Cl)+HOH \qquad ..(5)$$

Regeneration with concentrated sodium hydroxide (NaOH) converts the exhausted resin to the hydroxide form.

Weak Base Anion Resins:

Weak base resins exhibit minimum exchange capacity above a pH of 7. The weak base anion resins sorbs anions associated with weak acid.

Applications

Ion exchange has several applications in water treatment processes such as hardness removal, desalination, alkalinity removal, radioactive waste removal, ammonia removal, and heavy metal removal. Since divalent ions (Ca, Mg, etc.) are favored over monovalent (Na, etc.) ions by the resin for replacement, secondary treatment for SAR (sodicity) is required.

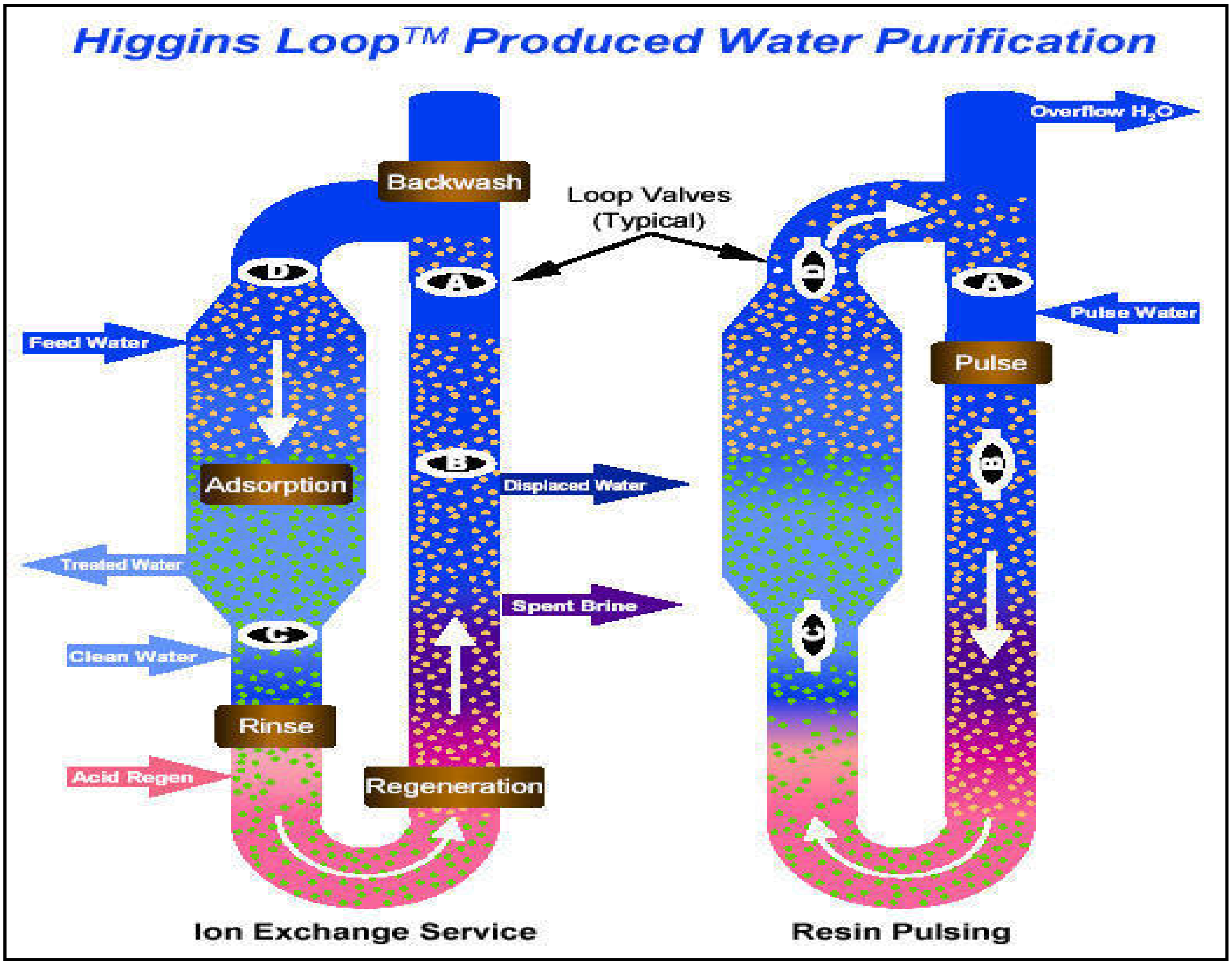
Powder River Gas, LLC

In 2002 Powder River Gas, LLC proposed a Project Plan of Development (POD) (Bopst and Reid, 2002) to drill and test for CBNG in eight federal and eight fee wells at eight locations (two wells per location) in an area northeast of the Tongue River Reservoir, Big Horn County of southeastern Montana.

Higgins Loop in operation (Montana)

Part of their *NO FEDERAL ACTION* alternative is to treat water produced from the wells using a Higgins Loop (continuous counter-current ion exchange) treatment facility prior to discharging to the Tongue River. The stationary Higgins Loop facility was constructed along with a series of impoundments and chemical storage tanks. All chemical storage tanks are surrounded by a shallow spill containment berm to prevent any accidental chemical spills.

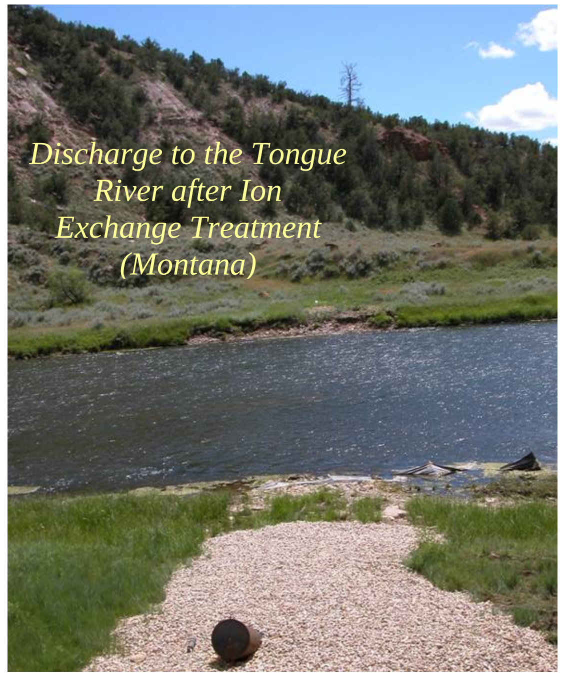
Figure 4.7 Higgins Loop schematic (Source: Seven Trent Services)



Produced water from CBNG wells is to be treated stepwise within the treatment facility. Settling of suspended sediments and releasing of residual gas will be within the impoundment. Na^+, barium and other heavy metals from produced water will be removed using SAC resins in the Higgins Loop. Removal of CO_2 produced during the ion exchange process and adjustment of pH will be achieved by adding calcium hydroxide. CO_2 can be removed by air-stripping or membrane degasification. The physical law governing this process is the equilibrium between the gas phase and the concentration of the solute gas in the liquid phase.

The schematic is shown in Figure 4.7. The Higgins Loop is a vertical cylindrical loop containing a packed bed of strong acid ion exchange resin that is separated into four operating zones by butterfly (loop) valves. These operating zones (Adsorption, Regeneration, Backwashing and Pulsing) function like four separate vessels.

The Higgins Loop treats liquids in the adsorption zone with resin while the ions are being removed from loaded resin in the regeneration zone simultaneously. Intermittently, a small portion of resin is removed from the respective zone and replaced with regenerated or loaded resin at the opposite end of that zone. This is accomplished hydraulically by pulsing of the resin through the loop. The result is continuous and countercurrent contacting of liquid and resin. The cations (Ca^+, Na^+ etc.) are replaced by hydronium (H^+) ions from resin beads. The hydronium ions are released in the treated water, which lowers the pH of the water. Cations are stripped from the resin in the regeneration zone concurrent with ion exchange in the adsorption zone. Dilute hydrochloric acid is injected into the loop and moves counter-current to the resin and the spent brine discharge, leaving the resin restored to the hydronium form.



Concentrated brine volumes average approximately 1.0% of the total loop feed volume, depending on the cation loading that is removed from the treated water. Excess brine that is not recycled to other beneficial uses is proposed to be transported offsite by truck for disposal by injection into a permitted Class I, deep disposal well located in Wyoming. The waste stream from the treatment process, at maximum flow, will generate approximately 60 barrels of brine or reject water per day. The treatment unit would discharge a total of 250 gpm of treated water.

EMIT Water Discharge Technology, LLC

EMIT Water Discharge Technology, LLC (Dow, 2003) developed a new treatment process that uses DOWEX G-26 (strong acid cation exchange resin manufactured by DOW Chemical Company). G-26 resin has a sulfonic acid (SO_3H^+) group that exchanges Na^+, Ba^+, Ca^{2+}, and $Mg2^+$ ions with H^+ ion. The ion exchange process is accomplished in a Higgins Loop. The Higgins Loop operation is followed by calcium addition to adjust pH, balance SAR, and increase calcium concentration. Table 4.4 shows the results of a field trial for the treatment of produced water from Powder River Basin, Wyoming. The process focused on the removal of sodium ions and reduction of SAR using a combination of Higgins loop and calcium addition.

The increment in calcium, chloride and sulfate levels were due to chemical addition during SAR adjustment. The field trial was conducted with throughput of 200 gpm. The treatment cost ranges from \$0.05 to \$0.20 per barrel of treated water depending on the influent composition, SAR, and availability of resources. The ion exchange treated water may then be discharged to the environment and the residue disposed of (ALL, 2003).

Table 4.4 Performance of Higgins Loop treatment for a field trial at Powder River Basin site

Constituents	Influent Produced Water	Treated Water	Removal %
Na, ppm	486	12	97.53
Ca, ppm	22.2	113	-409
Mg, ppm	13.2	<1	>93
K, ppm	13.5	<1	>93
Ba, ppm	0.72	ND	100
Carbonate, ppm	<1	<1	-
Bicarbonate, ppm	1430	311	78.52
Chloride, ppm	18	42	-133.33
Sulfate, ppm	1	1.1	-10
SAR	20.2	0.3	98.51
pH	8.1	6.5	19.75

Sandia Ion Exchange/Sorption Process

Sandia National Laboratory (SNL) reported use of Hydrotalcite (HTC) as anion exchanger and Permutite as cation exchanger (Sattler, et al., 2004). These ion exchangers are comprised of durable inorganic oxides that provide stability over a large range of pH. Based on the results of various experiments, SNL reported average ion exchange capacity of HTC and Permutite as 2.5 mEq/gram (measured with Na_2So_4), and 1.7-2.7 mEq/gram (measured with NaOH), respectively.

Anions in the inlet water are replaced by hydroxide ions (HTC anion exchange) and cations are replaced by hydrogen ions (Permutite cation exchange). Lime softening pretreatment is an optional stage.

Ion exchangers are regenerated after they are exhausted. In the regeneration process ion exchangers regain their ion exchange capacity. It might not be possible to regain 100% ion exchange capacity during the regeneration process. SNL attempted to determine effects of regeneration on the ion exchange capacity of above mentioned ion exchangers and concluded that Permutite can regain ion exchange capacity without significant loss. Regeneration of HTC at low temperatures was not promising, and at high temperatures regeneration became costly.

Section 4.8.4 Electrodialysis (ED) and Electrodialysis Reversal (EDR)

Electrodialysis (ED)

Most salts dissolved in water are ionic, being positively (cationic) or negatively (anionic) charged. These ions are attracted to electrodes with an opposite electric charge.

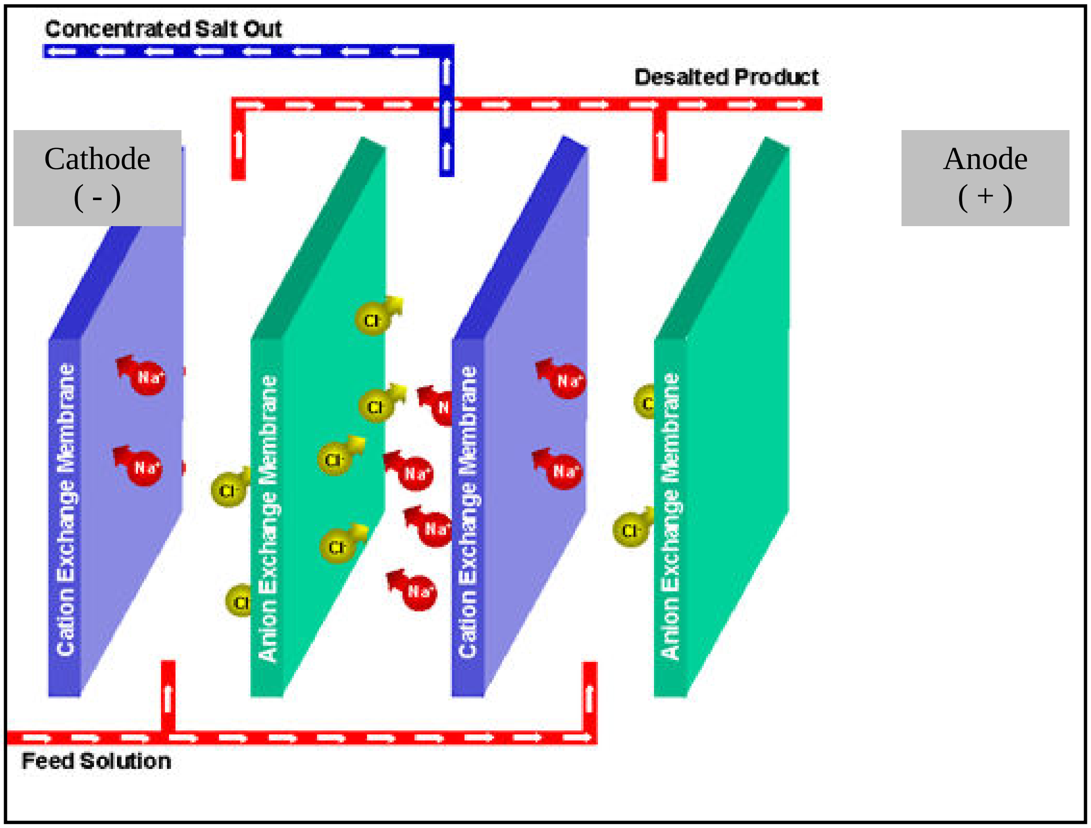
In ED, membranes that allow either cations or anions (but not both) to pass are placed between a pair of electrodes. These membranes are arranged alternately. A spacer sheet that permits feed water to flow along the face of the membrane is placed between each pair of membranes. Figure 4.8 shows an ED assembly with feed spacer and ion exchange membrane placed between oppositely charged electrodes. Positively charged ions (Na^+ etc) migrate to cathode and negatively charged ions (Cl^- etc) migrate to anode.

During migration the charged ions are rejected by similarly charged ion exchange membranes. As a result, water within the alternate compartment is concentrated leaving desalted water within the next compartment of the ED unit. The concentrate and desalted water are continuously removed from the unit. The basic electrodialysis unit consists of several hundred cell pairs bound together with electrodes on the outside and is referred to as a membrane stack.

Feed water passes simultaneously in parallel paths through all of the cells to provide a continuous flow of desalted water and brine to emerge from the stack. The feed water is circulated through the stack with a low-pressure pump with enough power to overcome the resistance of the water as it passes through the narrow passages. The raw feed water must be pretreated to remove materials that could harm the membranes or clog the narrow channels in the cells from entering the membrane stack. A rectifier is generally used to transform alternating current (AC) to the direct current (DC) supplied to the electrodes on the outside of the membrane stacks.

Post-treatment consists of stabilizing the water and preparing it for distribution. This post-treatment might consist of removing gases such as hydrogen sulfide and adjusting the pH.

Figure 4.8 An ED unit in operation (Source: Electrosynthesis Company, Inc)



Electrodialysis Reversal Process (EDR)

An EDR unit operates on the same general principle as a standard electrodialysis plant except that both the product and the brine channels are identical. At intervals of several times an hour, the polarity of the electrodes is reversed and the flows are simultaneously switched so that the brine channel becomes the product water channel and the product water channel becomes the brine channel.

The result is that the ions are attracted in the opposite direction across the membrane stack. Immediately following the reversal of polarity and flow, enough of the product water is dumped until the stack and lines are flushed out and the desired water quality is restored. This flush takes about 1 or 2 minutes, and then the unit can resume producing water. The reversal process is useful in breaking up and flushing scales, slimes, and other deposits in the cells before they can build up and create a problem. Flushing allows the unit to operate with fewer pretreatment chemicals minimizing membrane fouling. The charges of the electrodes are reversed by a motorized valve.

Applications

Electrodialysis is conducted at low pressure drops across the process (usually less than 25 psi). The pressure drop across the typical Reverse Osmosis (RO) membrane ranges from 400 – 1400 psi, which indicates higher energy consumption.

Wind River Basin, Lysite, Wyoming

The produced water from a conventional well in Wind River Basin of Wyoming (Hayes, 2004) contains H_2S, oil, acid, BTEX, dissolved solids, etc. About 93% of total TDS (8,300 to 10,000 ppm) is accounted for as sodium, chloride, calcium, and bicarbonates. Oil and grease content was about 65 ppm and BOD value was more than 330 ppm (contributed by acetates and volatile acids). The treatment trailer consists of the following units:

1. De-oiling via induced gas floatation unit.
2. Dissolved organics removal via two fluidized bed reactors. First was the anaerobic and nitrate consuming reactor for reducing large amounts of organics. The second was the aerobic reactor ensuring oxidation of dissolved organics.
3. Desalting/Demineralization using an ED unit.

ED provided economical demineralization in this case. The feed water had approximately 9,000 ppm TDS. As usual, the cost of the ED unit operation increases as the required TDS removal increases. Table 4.5 shows the overall removal of contaminants using different treatment technologies. The ED removed approximately 89% of TDS from the produced water.

Table 4.5 Produced water treatment performance at Wind River Basin, Wyoming

Parameter	Influent (ppm)	Effluent (ppm)	Overall Removal (%)
Oil and Grease	90	4	95.5
BOD	330	51	84.5
BTEX	11	0.1	99.1
TDS (using ED)	9,100	1,000	88.9

High Efficiency Electrodialysis (HEED^{TM}), Frac Water, Inc.

Frac Water, Inc. developed mobile ED treatment units for treating CBNG produced water and reusing it in fracturing treatment. Several case studies suggest that the mobile treatment units treat the produced water with TDS ranges from 11,400 to 27,000 ppm and sulphates from 4,000 to 14,000 ppm (Spitz, 2003). ED provides the following benefits over RO:

1. ED can sustain high temperature; in fact higher temperature of produced water from the wellhead (140°F) improved the conductivity and reduced resistance during the ED process, which leads to lesser voltage usage. Also, higher temperature reduces viscosity.
2. ED accepts feed water with Silt Density Index (SDI) value of 12 compare to SDI value of 3 for RO. Less SDI value indicates the necessity of pretreatment steps. The membranes are susceptible to fouling if feed water has high SDI.
3. Certain levels of fouling also occur in ED operations. ED membranes can be cleaned or regenerated using weak acid treatment.
4. Plate and frame configuration of the ED system enables easier maintenance and cleaning.

The picture below shows mobile ED treatment units from Frac Water, Inc. ED treatment primarily recovers 80 to 90% of brackish water. The patents-pending electrodialysis HEEDTM stack configuration with dual or multiple side-by-side ion exchange membrane cells and improved gasket design results in greater separation efficiencies and affords greater flexibility in unit design. The improved design requiring up to 40% less membrane area resulted in an increase in energy efficiency of more than 70%.


Mobile ED treatment trailer developed by Frac Water Inc (Wyoming)

Section 4.8.5 Capacitive Deionization Technology (CDT)

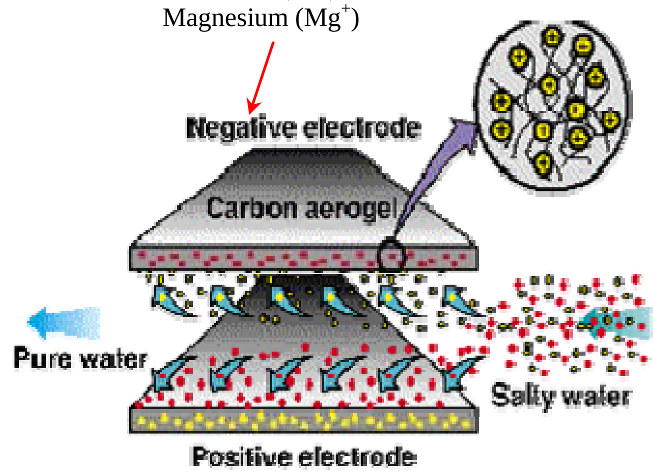
Capacitive deionization technology (CDT) is a new technology being developed for the purification of ocean and brackish groundwater. A constant voltage is applied and soluble salts are collected on the surface of porous carbon electrodes, thus purifying the water for human consumption or industrial processes. In CDT, a brackish water stream flows between pairs of high surface area carbon electrodes that are held at a potential difference of 1.2 V. The ions and other charged particles (such as microorganisms) are attracted to and held on the electrode of opposite charge. The negative electrode attracts positively charged ions (cations) such as calcium (Ca), magnesium (Mg), and sodium (Na) while the positively charged electrode attracts negative ions (anions) such as chloride (Cl) and nitrate (NO_3). Eventually, the electrodes become saturated with ions and must be regenerated. The applied potential is removed and the electrodes are flushed to release attached ions from the system producing the more concentrated brine stream.

The current carbon aero gel electrodes provide approximately 500 m^2/g surface area. They provide high electrical conductivity and high ion permeability. Carbon aero gel electrodes are expensive and their ion storage capacity is relatively low. The main problem is that the cost of the electrodes is high due the high cost of the resorcinol (Resorcinol Fluoride, RF) from which the electrodes are made. TDA Research, Inc. developed electrodes that provide higher surface area. CDT System, Inc. is developing an impregnate of carbon nanotubes on the RF resins.

Figure 4.9 shows a conceptual diagram of CDT. Exchange of ions does not occur; ions are adsorbed within the pores of charged electrodes under the effect of capacitance.

Figure 4.9 A conceptual diagram of an AquaCell during CDT operation

Negative electrode attracts positively charged ions (anions).
Sodium (Na^+)
Calcium (Ca^+)
Magnesium (Mg^+)



Positive electrode attracts negatively charged ions (anions).
Chloride (Cl^-)
Nitrate (NO_3^-)
Silica (SiO_2^-)

(Source: TDA Research, Inc.)

Applications

Desalination of produced water

Table 4.6 shows the result of the treatment of produced water from a CBNG well in Wyoming using CDT.

Table 4.6 Performance of CDT for the CBNG produced water treatment

Constituent	Before Treatment	After Treatment
Conductivity (micro s/m)	2,100	< 800
Sodium ions (ppm)	280	84
Bicarbonate ions (ppm)	520	144

CDT Mobile Systems also can be used to produce drinking water and water for agriculture purposes at a low cost. Table 4.7 shows the throughput capacity of a 28-foot mobile CDT unit that includes 30 AquaCells with the capability to be field expanded to 88 AquaCells. The expected quality of treated water is fixed at 500 ppm TDS for drinking water and 1000 ppm TDS for agriculture water.

Table 4.7 Treatment capacity of CDT unit

Feed Water TDS (ppm)	Capacity, Potable Water	Capacity, Agriculture Water
< 1,500	30,000 GPD	30,000 GPD
2,500	20,000 GPD	27,000 GPD
3,500	10,000 GPD	17,000 GPD
4,000	5,000 GPD	12,000 GPD

Source: CDT Inc, Dallas, TX

Section 4.8.6 Electrochemical Activation (ECA) Technology

Electrochemical Activation (ECA) technology is an innovative water disinfection technology that involves the exposure of water, and the natural salts, to a substantial electrical potential difference. As an anode (+) and a cathode (-) are placed in pure water and direct current is applied, electrolysis of water occurs at the poles leading to the breakdown of water into its constituent elements. If sodium chloride (NaCl), or table salt, is used as a solution, the dominant electrolysis end product is hypochlorite, a chlorine based reagent that is commonly used to disinfect water and kill microorganisms. This disinfection technology is currently used in series with the capacitive deionization technology in an activated water type of application. With this technology the natural water chemistry is used to produce highly effective disinfection agents that would destroy viruses and bacteria.

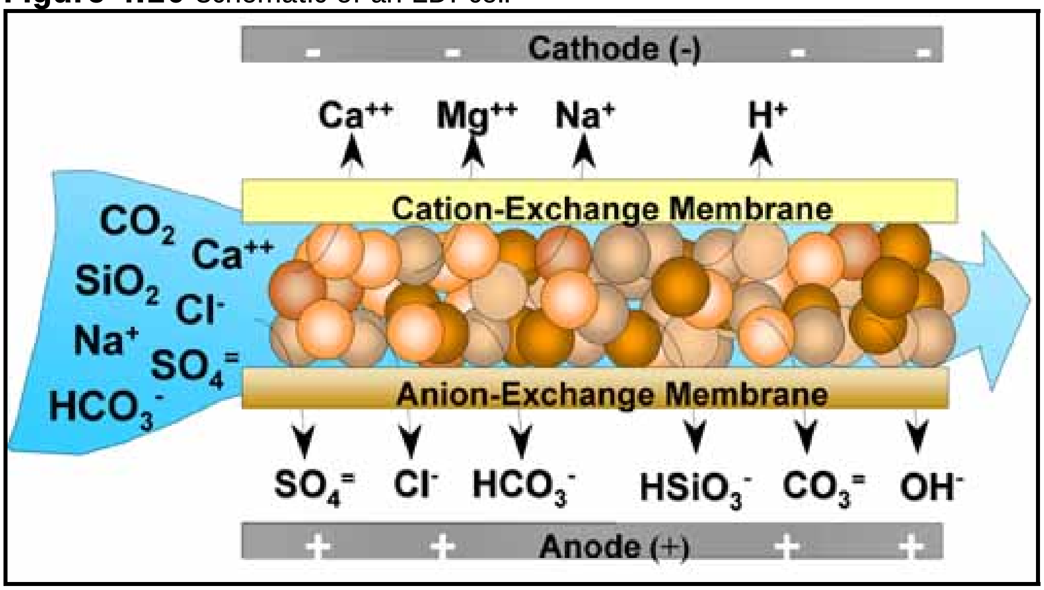
Typically, activated water would be dosed before and after the CDT AquaCells. Dosage before reduces the overall organic load into the AquaCells and also disinfects the feed stream, preventing biofouling. The dosage after the CDT AquaCells would then mainly serve as a final disinfection step specifically for potable water applications. Another benefit of the activated water technology is that the dosage before the AquaCells would also serve as a surfactant, thus reducing fouling - for example, membrane fouling by $CaCO_3$ (Calcium Carbonate) precipitation.

Section 4.8.7 Electro-deionization (EDI)

Weakly-ionized species such as carbon dioxide, boron, and ammonia are difficult to remove via such membrane processes as RO and EDR. EDI (Hernon, et al., 1999) is an electrically-driven membrane process. EDI combines ion-exchange resins, ion-exchange membranes, and a DC electrical field. In EDI, ionized species are removed much like conventional ED with the rate of ion removal greatly increased by the presence of the ion-exchange resins in the cell. In the cell, the DC electrical field splits water at the surface of the ion-exchange beads producing hydrogen and hydroxyl ions that act as continuous regenerants of the ion-exchange resins. This allows a portion of the resins in the EDI to always be in the fully regenerated state. Once ionized, these species are quickly removed under the influence of the DC electrical field. In effect, ionized species are removed in one area of an EDI stack, and weakly ionized species are removed in a second area.

Figure 4.10 shows the removal of ions as water travels through the EDI cell. Strongly ionized species are removed first in the flow path and weakly ionized species are removed as the water moves down the flow path. Removal of ionized species such as sodium, chloride, sulfate, and calcium by EDI is usually well over 99% and has been well documented previously. Removal of weakly ionized species is an area where a properly designed EDI can also achieve extremely high removal rates.

Figure 4.10 Schematic of an EDI cell



(Source: Ionics, Inc.)

Applications

Ionics, Inc. has installed EDI units in various power plants and semiconductor plants in the U.S. Table 4.8 shows the average removal of weakly ionized ions using EDI in such plants. The results are based on the EDI operation only and no pretreatment or post treatment results are included. For example, EDI was able to remove approximately 97% of boron from the RO permeate. In this case, RO was unable to effectively remove boron from the produced water.

Table 4.8 Average percentage removal of weakly ionized species using EDI

Treatment	Performance % removal (avg.)	Comments
Silica	> 99.2	
CO2	> 99.5	
Boron	> 97.0	Post RO treatment only
Ammonia	> 97.4	

The advantage of EDI is that it doesn't require addition of chemicals to remove weakly ionized species from the produced water.

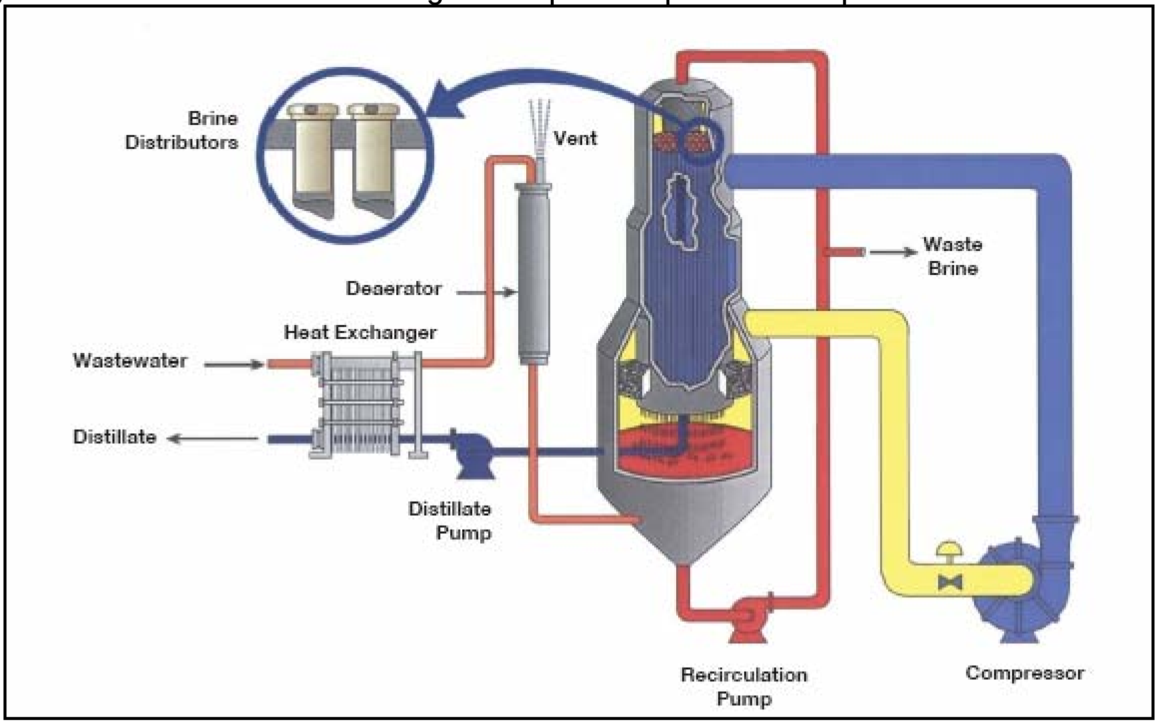
Section 4.8.8 Evaporation

Direct treatment of the produced water in an evaporation system eliminates majority of chemical/physical treatment. The principle of this technique is to provide latent heat to the feed water to generate vapor that can be condensed into pure water form. The remaining stream contains high concentrations of salts/solids.

Falling Film Vertical Tube Evaporators

Falling film vertical tube evaporators (Heinz and Peterson, 2003) have the highest heat transfer coefficient, which is required to save energy (see Figure 4.11). It also minimizes chances of fouling by keeping tubing surface wetted during operations. Produced water is de-oiled and the pH is adjusted. Next, a pre-heater increases the temperature of the produced water/brine. Hot brine goes to de-aerator, which removes non-condensable gases. Hot de-aerated brine enters the evaporator sump where it combines with the re-circulating brine slurry. The slurry is pumped to the top of a bundle of heat transfer tubes and flows down into each tube through a liquid distributor. As the brine flows down the tubes, a small portion evaporates and the rest falls into the sump to be re-circulated. The vapor travels down the tubes with the brine and goes to a compressor through mist eliminators. Compressed vapor flows to the outside of the heat transfer tubes where its latent heat is transferred to the cooler brine slurry falling inside. As a result, vapor gets condensed into pure water form that is pumped back through the heat exchanger where it gives up sensible heat to the incoming wastewater. A small amount of concentrated slurry from the evaporator sump is continuously discarded through a blowdown valve to maintain density of the slurry in the evaporator. The concentrated blowdown can be disposed through a class I injection well or can be converted into solid waste in a crystallizer.

Figure 4.11 A vertical tube falling film vapor compression evaporator



(Source: Ionics, Inc.)

Rapid Spray Evaporation (RSE)

AquaSonics International has developed a Rapid Spray Evaporation[TM] (RSE) system of ejecting contaminated water at high velocities through a specialized injector-nozzle into waste heat. The unit uses a heating element for a heat source across which air is blown into the evaporation chamber. As the heated air moves along the evaporation chamber, nebulized wastewater is injected into the evaporation chamber. The moving vapor and brine droplets pass through a mechanical filter that traps the brine droplets. The pure vapor phase then passes on to a condenser. The brine droplets are periodically flushed from the filter with the water being treated.

As the water vaporizes within milliseconds of ejection, the solids in the solution flash or separate out. The water vapor is condensed and collected while the precipitated solids form isolated crystalline particles that are collected through a vacuum process and sold as a byproduct. RSE ejects the salt water through a nozzle into a stream of heated air forming a mist of droplets that vaporize almost instantly. The minute flakes of solid salt left behind fall to the bottom of the evaporation chamber where they can be collected. The best success comes from developing nozzles that allow the process to work with hydraulic pressure.

Applications

Tests on the RSE system (Turner, 2002) carried out by Westwater Resources, Albuquerque, New Mexico, confirmed that it can process water containing up to 16% salt. The operating costs for RSE are about one-third of the cost of conventional desalination methods alone, producing 1,000 liters of fresh water for between 16 and 27 cents. AquaSonics claims to attain nearly 100% salt conversion of salt water into fresh water. Table 4.9 shows the results obtained during the testing phase.

Table 4.9 Rapid Spray Evaporation testing results (Source: WestWater Resources)

Solute	Untreated (ppm)	Treated (ppm)	Concentrate (ppm)
Calcium	79	1.6	20
Magnesium	490	1.7	600
Sodium	25,000	160	57,000
Potassium	610	1.9	1,100
Chloride	5,000	90	8,400
Sulfate	31,000	150	35,000
Bicarbonate	5,700	20	2,900
Phosphate	1,200	0	-
Carbon Dioxide	3,100	0	-
TDS	130,000	440	180,000

Freeze Thaw Evaporation (FTE)

Freeze thaw evaporation (FTE®) is a process whereby produced water is first stored in a holding pond until air temperatures drop below 0°C (32°F). The water is then removed from the pond using pumps and sprayed onto a separate freezing pad which consists of an elevated pipe grid with strategically placed sprinklers. These sprinklers can be raised as the ice builds up on the pipe grid. The unfrozen brine water drains from the ice grid and is separated using conductivity-controlled valves.

The concentrated brine water is then transported to separate storage ponds for either secondary treatment or for disposal. The picture below shows a Spray Freezing unit with sprinklers. The alternate to Spray Freezing process involves allowing the holding reservoir to freeze, and draining the brine that forms below the ice. The ice in the pond melts in the spring leaving fresh water.

Source: Hart Energy Publications

Applications

Crystal Solutions, LLC, a joint venture of Gas Technology and BC Technologies, utilized FTE (Lang, 2000) for produced water treatment at its first major commercial treatment facility near Wamsutter, Wyoming. The FTE uses naturally occurring ambient temperature swings to alternately freeze and thaw produced water, concentrating the dissolved solids and producing fresh water suitable for various beneficial uses.

During the 1999-2000 cycle, produced water with 14,000 ppm of TDS was converted to a concentrated brine of approximately 64,300 ppm TDS and the fresh water (melt from ice) having 924 ppm TDS. Roughly 55% of the feed was converted to melt water; about 30% is lost to evaporation and/or sublimation; and only about 15% of the original feed remains as concentrated brine. In this case, due to the concentrated brine having a potassium chloride concentration in excess of 2% it was a usable product for drilling applications.

Section 4.8.9 Pressure Driven Membrane Separation Technologies

Microfiltration (MF), Ultrafiltration (UF), Nanofiltration (NF) and Reverse Osmosis (RO) utilize high pressure across the membranes to accomplish filtration of contaminants from the produced water. These technologies are the most common techniques of water purification. The membranes also are continuously being upgraded or modified for superior performance. Various applications of the pressure driven membrane technologies are listed in Table 4.10. Molecular Weight Cutoff (MWCO) is the ability of a membrane to reject the species of certain molecular weight measured as Daltons.

Table 4.10 Applications of advanced membrane filtration technologies

Membrane Filtration	**Separation Specifications**	**Applications/Removal**
Microfiltration (MF)	>100,000 Daltons 10 - 0.1µm	bacteria, viruses, suspended solids etc
Ultrafiltration (UF)	10,000 to 100,000 Daltons 0.05 - 5 e-3 µm	proteins, starch, viruses, colloid silica, organics, dyes, fats, paint solids etc
Nanofiltration (NF)	1,000 to 100,000 Daltons 5 e-3 - 5 e-4 µm	starch, sugar, pesticides, herbicides, divalent ions, organics, BOD, COD, detergents etc
Reverse Osmosis (RO)	salts and lower MWCO 1 e-4 - 1 e-5 µm	metal ions, acids, sugars, aqueous salts, dyes, natural resins, monovalent salts, BOD, COD, ions etc
Gas Liquid Membrane	CO2, H2S	decarbonation, hydrogen sulfide removal

MF, UF and NF are based on the principle of rejection of species higher than the pore size of the membrane under pressure. RO uses the operating pressure higher than the osmotic pressure of salt present in the water to drive pure water through the membrane, thereby rejecting the salts. It is reversal of the osmosis process where water flows from the higher concentration solution to the lower concentration solution to attain natural equilibrium. The notion of these filtration technologies is discussed in the literature (“Membrane Filtration”, 1999).

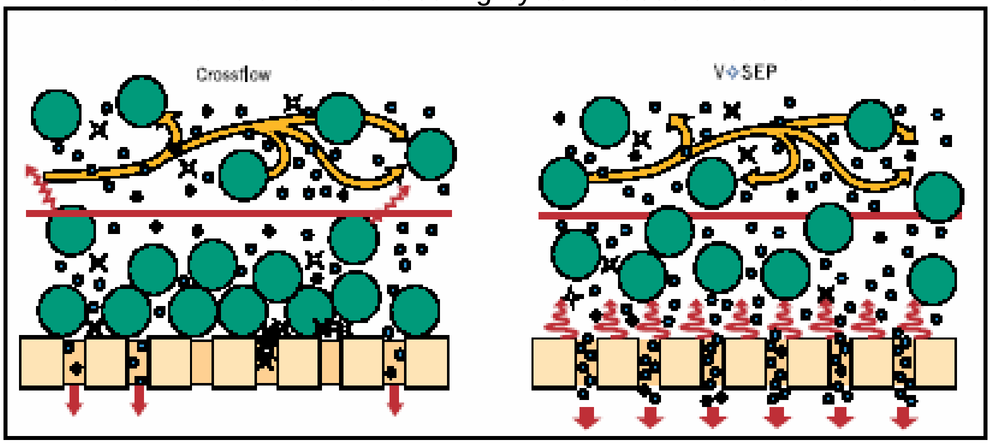
In gas-liquid separation, the pressure difference across a selective membrane is with pore size of about 0.03 micrometers (small enough to prevent water from leaking out, but large enough to allow CO_2 to pass through) is applied. Gas penetrates into the membrane at a rate that depends on diffusivity and solubility of molecules in order to attain the equilibrium between the gas phase and the solute gas in liquid. The pressure difference is created by either vacuum or gas sweep through the membrane.

Oil and gas operators exploit the clear advantages of using mobile produced water treatment units. GE Osmonics, one of the leading manufacturers of membranes focusing on produced water treatment applications, has been developing high performance compact membrane (such as spiral wound membrane) modules (GE, 2006). These membrane modules are easy to utilize in mobile systems. The spiral wound membrane offers the most efficient packing of membrane area to provide higher membrane contact area in limited space. The performance of these membranes is reduced by higher temperature; the upper limit for operating temperature is 113 to 122°F, but some of the spiral wound elements it can be used up to 194°F. Higher temperature operations require more pressure differential across the membranes and so more energy is required to achieve desired separation. However, higher temperature reduces the viscosity of the solution which somewhat offsets the temperature effect (Barrufet, et al., 2004).

The pH of the solution is also an important factor during the membrane filtration operations. High pH RO operation effectively removes boron if the membrane can sustain high pH.

Membrane fouling is a common problem in the various membrane filtration processes. Higher flow rate through the membrane module can produce enough shears near the membrane to avoid accumulation of oil and fouling agents. A hydrophilic membrane is less prone to oil fouling as it has a higher affinity for water and ability to reject oil and grease. New Logic Research developed a vibrating membrane mechanism to avoid membrane fouling caused by free oils and scaling agents (New Logic Research, 2003). The sinusoidal vibration of the membrane avoids the migration of colloids onto the membrane surface. The colloids are washed away with reject in the cross-flow configuration. The anionic membrane repels anions (monovalent, divalent, or multivalent) and associated cations (sodium, magnesium, copper, zinc, iron etc.). Figure 4.12 shows a conceptual picture of Vibratory Shear Enhanced Processing (VSEP) membrane.

Figure 4.12 A VSEP membrane avoids fouling by continuous sinusoidal vibration



(Source: New Logic Research Inc)

Petroleum recovery and research center (PRRC) of New Mexico Institute of Mining and Technology has developed inorganic membranes for the produced water treatment focusing on the treatment of high salinity produced water (> 50,000 ppm in San Juan and > 100,000 ppm in Permian basin). The inorganic membranes made up from zeolite provided higher flux, pH compatibility, and thermal and chemical stability. Table 4.11 shows the higher removal efficiency, even lower differential pressure, and higher flux operations. Each row is for different membranes.

Table 4.11 Performance of various zeolite membranes (Source: PRRC, NMIMT)

Membrane	Ions in feed	TDS (ppm)	Pressure (psi)	Flux ($kg/m^2.h$)	Rejection (%)
1	Na^+, K^+, Ca^{2+}, Mg^{2+}, NH_4^+, Cl^-	39,000	350	0.112	74.5
2	Na^+, Cl^-	5,500	300	0.135	89.2
3	Mg^{2+}, Cl^-	9,400	300	0.081	68.6
4	Ca^{2+}, Cl^-	11,000	300	0.096	57.6
5	Na^+, SO_4^-	14,200	300	0.097	57.4
6	Na^+, Cl^-	5,000	300	0.24	76.8

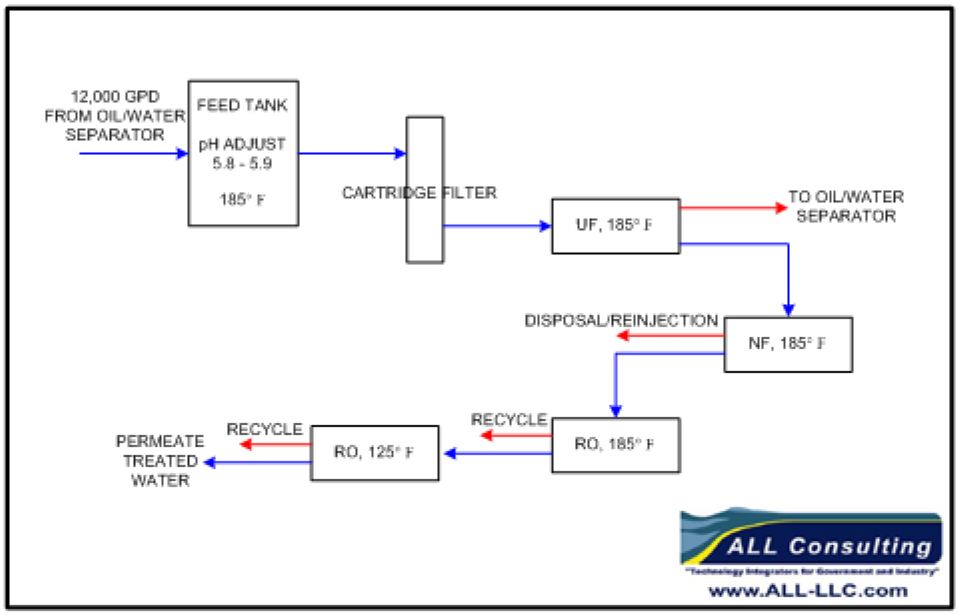
Applications

GE Pilot Study, California

In 2001, GE Osmonics performed a pilot study (GE, 2001) to evaluate feasibility of membrane filtration technologies for the treatment of produced water in California near Bakersfield. The produced water came to the surface at 185°F with approximately 10,000 ppm of salt, a high level of suspended solids, and free oil.

The three-step membrane separation combined with an ion exchange step proved to be sufficient to yield water suitable for irrigation (< 1,000 ppm TDS). The treated water contained 5 to 10 ppm boron, which is higher than the 0.75 ppm limit for irrigation water. Purification of treated water using ion exchange produced boron levels below the 0.75 ppm limit. The schematic of produced water treatment is shown in Figure 4.13.

Figure 4.13 GE produced water treatment system, California



The pH of the produced water from the oil separators was adjusted to 5.8 with sulfuric acid. The suspended solids were allowed to settle in a tank with a conical bottom. CO_2 and H_2S were degassed from the top of the tank and feed from the middle of the tank is discharged to a cartridge filter to remove smaller particles and oil. The effluent from the cartridge filter is passed through high temperature UF, NF and RO units followed by cooling operation and a low temperature RO unit. The overall system recovery was more than 80% considering the recycling of the UF concentrate and the use of the RO concentrate for various purposes. Table 4.12 shows the results of the produced water treatment system composed of membrane filtration units.

Table 4.12 GE pilot water treatment plant results

Constituent	Feed (ppm)	UF Permeate (ppm)	NF Permeate (ppm)	RO Permeate (ppm)
Sodium	9,610	9,610	5,250	144
Calcium	715	715	163	5
Magnesium	412	412	115	2
Potassium	174	174	77	2
Ammonium	110	110	68	2
Chloride	8,010	8,010	4,710	114
Sulfate	1,090	1,090	Non-detectable	Non-detectable
Oil	10 – 50	< 1	Non-detectable	Non-detectable
Recovery, %	-	90 – 95 %	90 – 95 %	80 – 90 %

Placerita Canyon Oil Field, California

The pilot water treatment unit at Placerita Canyon oilfield (Funston, et al., 2002) consisted of warm softening, coconut shell filtration, cooling (fin-fan), trickling filter, ion exchange, and reverse osmosis. The warm softening process removed approximately 95% hardness from the produced water. Silica levels in the softening effluent were 80 and 20 mg/l at a pH of 8.5 and 9.5, respectively. Silica level decreased to 3 mg/l when 400 mg/l of $MgCl_2$ were added. More than 95% of TDS was removed by RO. Approximately 90% removal of boron was achieved at a pH of 10.5 or above. Ammonia removal was 80% at a pH of 8.7 or below. The capital cost of the treatment varied from \$3.4 million to \$13.2 million. The annual estimated operation and maintenance cost varied from 6¢ to 27¢/barrel of water treated. Table 4.13 shows the summary of produced water treatment system. Figure 4.14 shows the schematic diagram of the produced water treatment system.

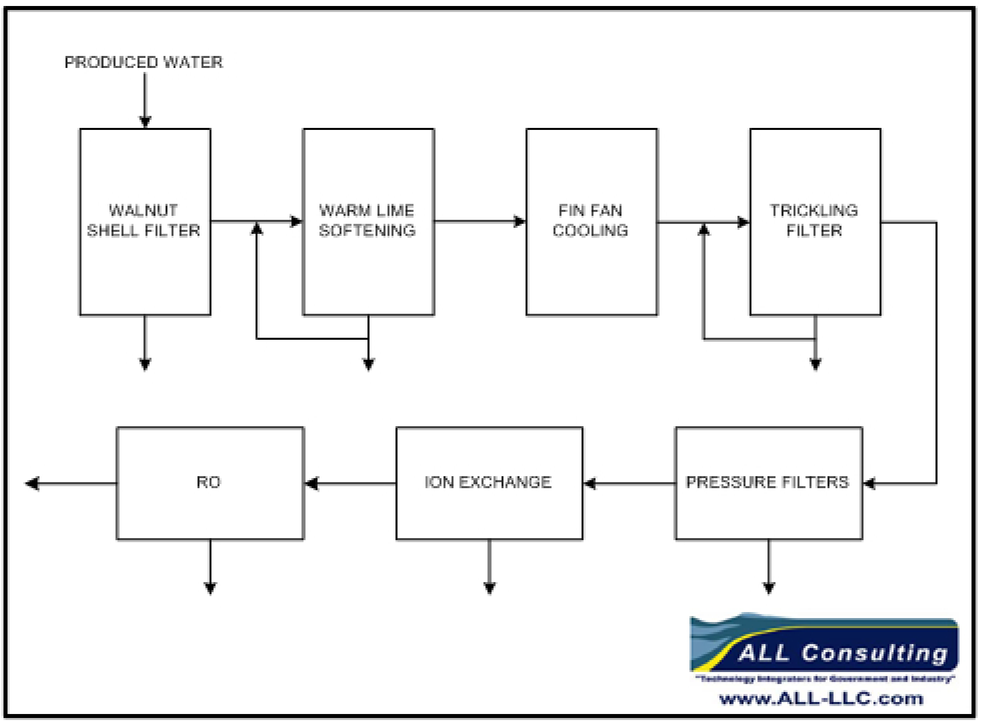
The first step was the Warm Softening process in which lime, $MgCl_2$ and ionic polymer were added to the produced water to precipitate calcium and magnesium hardness. Equation 6 shows the removal of bicarbonate hardness by addition of lime.

$$Ca(HCO_3)_2 + Ca(OH)_2 \rightarrow 2CaCO_3 + 2H_2O \qquad ..(6)$$

Table 4.13 A summary of utilized water treatment processes

Process	Specifications	Treatment	Comments
Warm Softening	100 gpm throughput with 10 gpm/ft2 precipitate rising rate	Hardness, Boron, Silica, Ammonia removal	sodium hydroxide/ polymer MgCl2 addition
Cooling	Fin-fan heat exchanger	cooling effluent from softening unit	necessary to prevent damage of the downstream units
Trickling Filter	400 ft3 of polypropylene packing 2.5 gpm/ft2 Hydraulic loading	Biological oxidation of organic carbon	effluent with < 2 ppm TOC
Ion Exchange	5 ft3 of Ionac C-249 resin with capacity of 25-30 grains/ft3	Pretreatment to RO stage residual hardness removal	cation exchange membranes
RO	4 X 40 spiral wound membrane	TDS, Boron, Silica removal	high pH for Boron removal
GAC Adsorber	activated carbon packing	organics removal	post trickling filter treatment

Figure 4.14 Schematic of produced water treatment process



Boron, silica, and ammonia were removed to some extent in the Lime Softening process. The effluent from the softening process was discharged to a fin-fan type heat exchanger to cool the water from more than 150°F to just above ambient air temperature as the units downstream of the softening unit were susceptible to damage at temperatures above 100°F.

The next step was the trickling filter for biological oxidation of organics (U.S. EPA, 2000). A trickling filter is a plastic or rock packed system with large diameter to depth ratio. Influent water is trickled through from the top in the presence of air (oxygen). The microorganisms in the produced water attach on the surface of packed media to form a biological film. Subsequently, the organic materials are degraded by the biological film. As the biological film thickens through microbial growth, oxygen penetration to the packed media is affected. Also, portions of the film lose their ability as they are used to degrade organics. This causes the used layer to fall off from the packed media, known as sloughing process. Next the sloughed solids are removed in pressure filters. During most stages of testing, the trickling filter was bypassed to allow the microbes produced to acclimate to the water organics. When bypassing the trickling filter, the water was sent directly from the heat exchanger.

Next, the processed water passed through the ion exchange softeners to remove any residual hardness. Finally, RO was used to remove TDS, boron, and additional organics. The RO permeate was sent to a 2,000-gallon polyethylene tank for storage and the concentrated reject stream was sent to the system drain. pH adjustment is the most important step in the treatment system because boron, silica, ammonia, and hardness removal depends on pH of the solution. The relationships among the constituents are not monotonous, which required careful pH adjustment during the process. For example, as the pH of the solution increases more silica gets ionized and that increases silica solubility, which may increase membrane leakage and deteriorates the silica removal. Opposite to that, as the silica solubility increases the chances of membrane fouling due to silica precipitation decreases, which improves RO membrane performance. As the pH of the solution increases ammonia solubility decreases, which diminishes ammonia removal by RO.

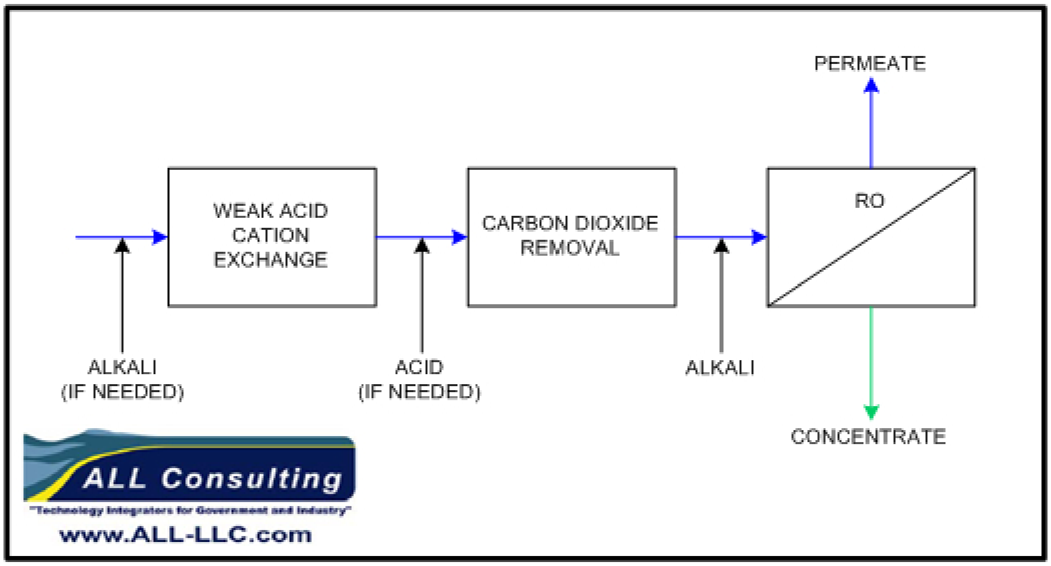
High Efficiency Reverse Osmosis (HERO^{TM})

GE Ionics developed HERO^{TM} (Hayter et al., 2004) to provide higher water recovery, higher quality permeate, higher operating flux, and lower overall cost than conventional RO treatment. The most important stage of HERO is pretreatment of the feed water before RO operation to raise the pH of feed water that enables higher efficiency. As discussed earlier, increase in pH improves boron removal and avoids membrane fouling.

As shown in Figure 4.15, HERO is a three step process.

1. *Hardness removal*: Calcium and Magnesium hardness can precipitate on RO membranes at high pH, which causes membrane fouling. Alkali is added to balance alkalinity and hardness which improves weak acid cation exchange (WAC) softening process efficiency. WAC resins exchange hardness from the produced water as discussed earlier. The H+ addition increases pH enabling conversion of bicarbonate alkalinity into carbon dioxide.
2. *Carbon dioxide removal*: As discussed in earlier sections, degasification using air stripping removes carbon dioxide from the water. The carbon dioxide removal further increases pH of the produced water.
3. *High pH RO*: High pH water increases solubility of silica and destroys biological organisms that cause membrane fouling. Dissolved solids are removed by the RO process.

Figure 4.15 A schematic of HERO system developed by GE Ionics



The biggest advantage of the HERO system is the reduced capital cost (~15%) at higher flux rate (50 GPM). Because of reduced fouling and scaling of the RO membrane, the operating and energy costs for HERO are also less than conventional RO. The increase in water recovery is obvious with HERO systems due to the high performance of membrane. The shortcomings of HERO are the treatment chemical requirements and the higher costs at lower flux operations.

GE Ionics tested a HERO system to upgrade the water purification plant of Sandia National Laboratories at Albuquerque, New Mexico. The system produced approximately 94% water recovery. The reported power usage was approximately 17 kWh per 1000 gallons of treated water. The reported operating cost was approximately $0.064 per gallon of treated water.

Oxidation Reactor

Newpark Environmental Services offers an innovative treatment system consisting of several components and is based on aggressive oxidation followed by precipitation of the contaminants present in the produced water (Lincz, 2004). Oxidation of contaminants is the most important part, which is accomplished in the Armel Reactor, a proprietary design of Newpark Environmental Services. The Armel Reactor is part of the chemical/physical treatment stage of this multi-stage technology. The chemical/physical stage is often adequate to achieve many water treatment requirements on its own. Dissolved contaminants such as monovalent salts are extremely resistant to oxidation/precipitation and may not be removed during the chemical/physical treatment stage. Such contaminants can be removed in the demineralization stage, which consists of MF, UF and/or RO units. The chemical/physical treatment stage before the demineralization stage removes contaminants that can plug the membrane and improves efficiency of the demineralization stage.

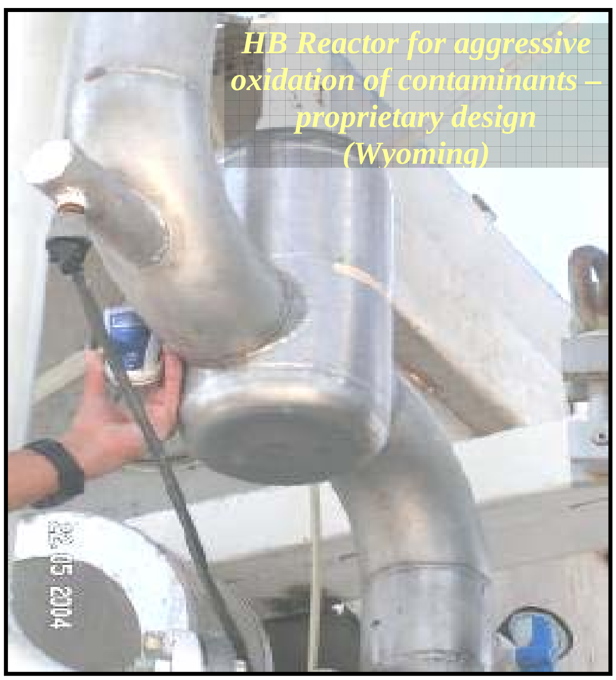
The Newpark system contains three separate stages that can be used separately or in tandem: the chemical/physical stage, the demineralization stage, and the waste disposal stage.

Chemical/Physical Stage

The chemical/physical stage consists of the following elements:

- *Degasification* – recovery of methane gas from produced water inflow from CBNG well and removal of CO2 from produced water.
- *Solids Removal* **–** water from degasification unit flows through patented Clasiker equipment that removes suspended solids ranging from debris to micro fines.
- *pH Adjustment* – pH of the water is adjusted to as neutral as possible, which would maximize the efficiency of oxidation reactor.
- *Liquid Ring Blower* – high volume, low pressure air is pumped into the water stream just prior to the HB.
- *Armel Reactor (sonic oxidation)* **–** the water/air mixture then flows through the reactor and is aggressively oxidized/energized. Water/air mixture then enters the reactor where millions of small micro-bubbles are generated from the entrained air by mechanical means (5 to 10 psi pressure drop). The micro-bubbles carry positive charge and repel other micro-bubbles, but attract negatively charged ions (these negatively charged ions are associated with positively charged ions) in the form of a contaminant (Ca+CO3-, Na2+SO4-2 etc.).

The charged micro-bubbles attract more oppositely charged contaminants and become thicker, which increases their surface tension. Due to ever increasing surface tension, the size of the micro-bubble decreases and the pressures and temperatures inside the bubble significantly increase, which creates points of highly localized temperature. Under the effects of increased pressure and temperature, contaminants attached to micro-bubbles are violently reacted with O_2 associated with atmospheric air inside the micro-bubble. The energy associated with this reaction results in ultrasonic wave and a very aggressive oxidation of contaminants. Those contaminants not oxidized are highly energized and in a very reactive state. The water (along with the oxidized and energized ions/contaminants) flows out of the reactor to the next stage.



HB Reactor for aggressive oxidation of contaminants – proprietary design (Wyoming)

- *Degasser* – at this stage all O_2 has been consumed but a significant amount of N_2 remains trapped in the water. Degasser removes the trapped N_2.
- *Coagulation/Flocculation* – a coagulant (lime) and flocculent (anionic polymer) is mixed into the water to precipitate out the treated contaminants in the form of flocculants.
- *Frictioning* – frictioner settles and removes the larger flocculants.
- *High Rate Clarification* – a series of tubes settles out and removes the smaller flocculants.
- *Sand/Activated Carbon Filtration* – the water is then filtered through a sand and activated carbon to remove the smallest flocculants. The water becomes clear through this process.

Demineralization Stage

Complete removal of dissolved contaminants can be achieved in the demineralization stage by further treatment of effluent water from the chemical/physical treatment system. The demineralization stage consists of the following elements:

- *MF Unit* – sub-micron size particles or contaminants are removed in MF unit. This ensures that undissolved sub-micron particles do not enter the RO system and plug the membranes.
- *RO Unit* – the water is then pumped at high pressure through a series of reverse osmosis membranes for the concentration and further removal of remaining dissolved contaminants.

Waste Disposal

Permeate from the RO unit can be utilized as a fresh water source with or without further treatment. Concentrate is generally hauled to the nearest disposal facility. Large volumes of concentrate, transportation costs, and limited capacity of disposal sites encourage further treatment of concentrate. Concentrate can be dried into a solid phase, which would be easier to handle.

- *Crystallizer and Evaporator* – Crystallizer further concentrates the RO concentrate stream by extracting water. Total volume of the concentrate is reduced while the associated TDS increases significantly. The water (extract phase) is re-circulated through the RO and concentrate (sludge-water) flows through evaporators. Water gets evaporated and the dissolved solids remain in sludge state. Handling and disposal of reduced volume of waste in sludge form is easier.

Figure 4.16 shows a schematic of produced water treatment system designed by Newpark Environmental Services. Newpark has tested this system for the treatment of produced water from various sources on the pilot scale.

Table 4.14 shows the performance of Newpark's system for the treatment of produced water from three facilities. The quality of effluent or treated water at the end of both the chemical/physical treatment stage and demineralization stage was supervised. The Pinedale and Gillette plants are company-owned facilities that process operators' water on a contract basis.

Section 4.8.10 NORM Treatment

Naturally occurring radioactive materials (NORM), such as radium, are mobilized from the oil or gas formations because of the solubility in the presence of chloride ions which are present in the water within formation (Tenorm Page, 2004). Low solubility of the sulfate species is a factor in redeposition of NORM. The low solubility precipitates scale containing high concentrations of radium in the form of barium sulfate or barite [Equation 7] under the effects of varying temperature and pressure during the production operations.

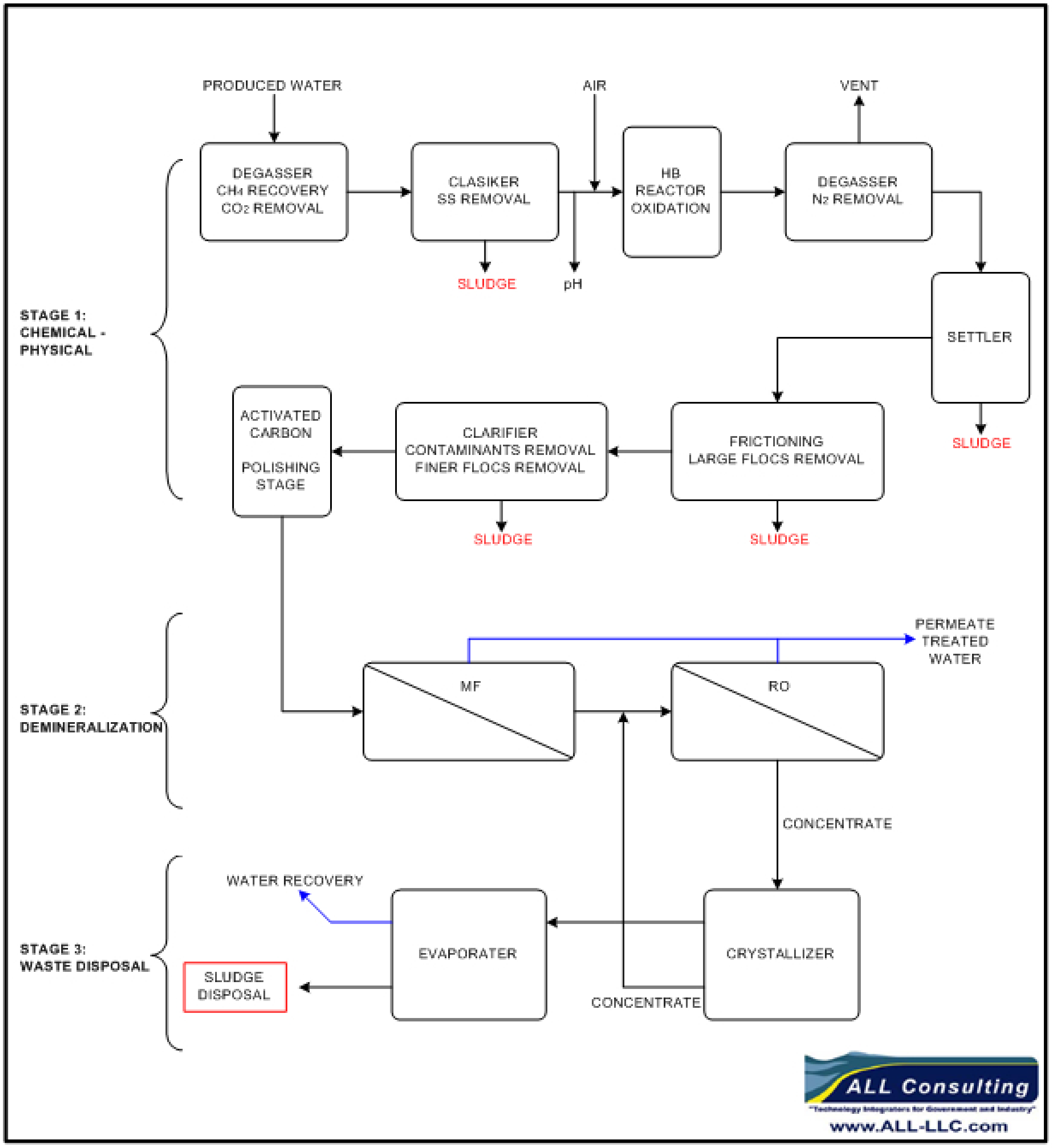
$$Ba^{+} + Ra^{+} + SO_4^{\ -} \rightarrow Ba[Ra]SO_4 \quad ..(7)$$

The handling and treatment of the precipitated sulfate deposits containing decaying radioactive materials is an absolute necessity because of the dangers of radioactivity. BPF Inc., Texas (Mickley, 2001), developed a mobile automated treatment system that includes separation of

NORM solids from other oilfield waste (produced water) containing less than 30 pCi/g (picocuries per gram, a measurement of radioactivity) radium and dissolving it into aqueous solutions. Extraction of radionuclides from the scale is done by dissolving the radioactive material in one or more aqueous solvents in the hydroclone, which separates solids with no NORM from the solution. The NORM containing solution is transported to class II injection sites and reinjected into the formation (Smith, et al., 1997).

Radioactive materials also occur in natural gas in the form of radon. One of the methods to treat the gas is packed bed adsorption of radon with activated charcoal. Monitoring of radioactivity is an essential part of NORM treatment, which is accomplished by in-situ radioassay capability.

Figure 4.16 Newpark Environmental Services produced water treatment system



(Source: Newpark Environmental Services)

Table 4.14 Results from field test with a produced water treatment system

	Pinedale, WY (Pinedale Field Produced Water)			Big Hills, TX (Conventional Oil and Gas Produced Water)			Gillette, WY (CBNG Water)		
Parameter mg/L or ppm	Influent	Effluent		Influent	Effluent		Influent	Effluent	
		Chemical/ Physical	After RO		Chemical/ Physical	After RO		Chemical/ Physical	After RO
Carbonate (CO_3)	< 1	-	-	< 1	< 1	< 1	< 1	-	< 1
Bicarbonate (HCO_3)	842	-	-	312	156	7.3	2,782	-	12.2
Calcium	68	-	-	2,388	303	0.96	43.67	-	1
Chloride	4,589	-	56.5	70,978	8,922	355	115	-	18
Magnesium	9	-	-	90	93	0.3	32.87	-	< 0.1
Sodium	3,324	-	36.6	49,590	5,140	217	1,076	-	21.5
Sulfates	1	-	-	6	280	< 1	< 1	-	<0.1
Alkalinity as $CaCO_3$	582	-	-	210	118	6	2,110	-	10
TDS	11,957	3,004	93	174,452	19,053	93.1	3,203	1,358	46
TPH	5	-	-	8	2	1	1	-	1

(Source: Newpark Environmental Services)

A summary table of the various treatment technologies included in here is presented in Table 4.15 for ease of use. The table describes advantages, disadvantages, and ranges of field applicability for each treatment technology evaluated. The table is segmented by treatment objective (for example “De-oiling”), and within each objective technologies can be compared in terms of their advantages, disadvantages, resulting waste stream, and applications to oil and gas fields. Advantages and disadvantages are described in comparative terms rather than absolute figures that are subject to change; the aim is to compare technological options for a given objective. Durability and cost are important factors that will depend on site-specific conditions and the specific commercial version picked by the operator. Comparisons of inherent durability can be made within each objective but these are only generalizations. No attempt was made to ascribe economic factors to these technologies since costs will vary from location to location and may be dependent upon commercial configurations and innovations.

Waste products are specific to each technology; for example desalinization can result in a residue consisting of 20% of the input stream or a residue made up of 1% of the input. The 1% residue will be a more concentrated brine than the 20% residue. However, both may no longer be classified as oil and gas wastes because they are a result of a treatment process. “Raw” produced water can be disposed of by way of an exemption from standard industrial waste regulations under the federal Resource Conservation and Recovery Act (RCRA) as described in Section 3. The oil and gas exemption means that “raw” produced water can be sent to deep disposal wells that inject the water back into deep, salt water bearing reservoirs with minimal regulatory requirements and cost. Industrial brines, however, are subject to increased regulatory compliance costs because the brines are a result of a treatment process. The challenges associated with the UIC process are discussed in more detail in Section 3, and the disposal options are discussed in Section 4.9.

Table 4.15 Advantages, Disadvantages, and Applicability of Produced Water Treatment Technologies

TREATMENT	DESCRIPTION	ADVANTAGES	DISADVANTAGES	WASTE STREAM	OIL AND GAS PRODUCED WATER APPLICATIONS
De-oiling					
Corrugated plate separator	separation of free oil from water under gravity effects enhanced by flocculation on the surface of corrugated plates	No energy required, cheaper, effective for bulk oil removal and suspended solid removal, with no moving parts, this technology is robust and resistant to breakdowns in the field.	inefficient for fine oil particles, requirement of high retention time, maintenance	suspended particles slurry at the bottom of the separator	Oil recovery from emulsions or water with high oil content prior to discharge. Produced water from water-drive reservoirs and water flood production are most likely feed-stocks. Water may contain oil & grease in excess of 1000 mg/L.
Centrifuge	separation of free oil from water under centrifugal force generated by spinning the centrifuge cylinder	efficient removal of smaller oil particles and suspended solids, lesser retention time-high throughput	energy requirement for spinning, high maintenance cost	suspended particles slurry as pre-treatment waste	
Hydroclone	free oil separation under centrifugal force generated by pressurized tangential input of influent stream	compact modules, higher efficiency and throughput for smaller oil particles	energy requirement to pressurize inlet, no solid separation, fouling, higher maintenance cost		
Gas floatation	oil particles attach to induced gas bubbles and float to the surface	no moving parts, higher efficiency due to coalescence, easy operation, robust and durable	generation of large amount of air, retention time for separation, skim volume	skim off volume, lumps of oil	
Extraction	removal of free or dissolved oil soluble in lighter hydrocarbon solvent	no energy required, easy operation, removes dissolved oil	use of solvent, extract handling, regeneration of solvent	solvent regeneration waste	Oil removal from water with low oil and grease content (< 1000 mg/L) or removal of trace quantities of oil and grease prior to membrane processing. Oil reservoirs and thermogenic natural gas reservoirs usually contain trace amounts of liquid hydrocarbons. Biogenic natural gas such as CBNG may contain no liquids in the reservoir but when pumped to the surface, the water takes up lubricating fluids from the pumps.
Ozone/hydrogen peroxide/oxygen	strong oxidizers oxidize soluble contaminant and remove them as precipitate	easy operation, efficient for primary treatment of soluble constituents	on-site supply of oxidizer, separation of precipitate, byproduct CO_2 etc.	solids precipitated in slurry form	
Adsorption	porous media adsorbs contaminants from the influent stream	compact packed bed modules, cheaper, efficient	high retention time, less efficient at higher feed concentration	used adsorbent media, regeneration waste	

TREATMENT	DESCRIPTION	ADVANTAGES	DISADVANTAGES	WASTE STREAM	OIL AND GAS PRODUCED WATER APPLICATIONS
Disinfection					
UV light/ozone	passing UV light or ozone produce hydroxyl ions that kills microbial	simple and clean operation, highly efficient disinfection	on-site supply of ozone, other contaminants reduce efficiency	small volumes of suspended particles at the end of the treatment	Microbes may exist in the subsurface reservoir or can be introduced during production or during water treatments. Disinfection may need to be done to protect potability or to or to prevent fouling of the reservoir, tubulars, and surface equipment.
Chlorination	chlorine reacts with water to produce hypochlorous acid which kills microbial	cheaper and the simplest method	does not remove all types of microbial		
Desalinization					
Lime softening	addition of lime to remove carbonate, bicarbonate etc. hardness	cheaper, accessible, can be modified	chemical addition, post treatment necessary	used chemical and precipitated waste	These technologies typically require less power and less pre-treatment than membrane technologies. Suitable produced waters will have TDS values between 10,000 and 1,000 mg/L. Some of the treatments remove oil and grease contaminants and some of them require oil and grease contaminants to be treated before these operations.
Ion exchange	dissolved salts or minerals are ionized and removed by exchanging ions with ion exchangers	low energy required, possible continuous regeneration of resin, efficient, mobile treatment possible	pre and post treatment require for high efficiency, produce effluent concentrate	regeneration chemicals	
Electrodialysis	ionized salts attract and approach to oppositely charged electrodes passing through ion exchange membranes	clean technology, no chemical addition, mobile treatment possible, less pretreatment	less efficient with high concentration influent, require membrane regeneration	regeneration waste	
Electro-deionization	Enhanced electrodialysis due to presence of ion exchange resins between ion exchange membranes	removes of weakly ionized species, high removal rate, mobile treatment possible	regeneration of ion exchange resins, pre/post treatment necessary	regeneration waste, filtrate waste from post-treatment stage	
Capacitive deionization	ionized salts are adsorbed by the oppositely charged electrodes	low energy required, higher throughput	expensive electrodes, fouling	regeneration waste	
Electrochemical Activation	ionized water reacts with ionized chloride ion to produce chlorite that kills microbial	simultaneously salt and microbial removal, reduce fouling	expensive electrodes	regeneration waste	
Rapid spray evaporation	injecting water at high velocity in heated air evaporates the water which can be condensed to obtained treated water	high quality treated water, higher conversion efficiency	high energy required for heating air, required handling of solids	waste in sludge form at the end of evaporation	

TREATMENT	DESCRIPTION	ADVANTAGES	DISADVANTAGES	WASTE STREAM	OIL AND GAS PRODUCED WATER APPLICATIONS
Freeze thaw evaporation	utilize natural temperature cycles to freeze water into crystals from contaminated water and thaw crystals to produce pure water	no energy required, natural process, cheaper	lower conversion efficiency, long operation cycle		
Membrane Treatment					
Microfiltration	membrane removes micro-particles from the water under the applied pressure	higher recovery of fresh water, compact modules	high energy required, less efficiency for divalent, monovalent salts, viruses etc.	concentrated waste from membrane backwash during membrane cleaning, concentrate stream from the filtration operation	Removal of trace oil and grease, microbial, soluble organics, divalent salts, acids, and trace solids. Contaminants can be targeted by the selection of the membrane. The size distribution of the removable species for membrane filtration technologies is shown in Table 4.10.
Ultrafiltration	membrane removes ultra-particles from the water under the applied pressure	higher recovery of fresh water, compact modules, viruses and organics etc. removal	high energy, membrane fouling, low MW organics, salts etc		
Nanofiltration	membrane separation technology removes species ranging between ultrafiltration and RO	low MW organics removal, hardness removal, divalent salts removal, compact module	high energy required, less efficient for monovalent salts and lower MW organics, membrane fouling		
Reverse Osmosis	pure water is squeezed from contaminated water under pressure differential	removes monovalent salts, dissolved contaminants etc., compact modules	high pressure requirements, even trace amounts of oil & grease can cause membrane fouling		Removal of sodium chloride, other monovalent salts, and other organics. Some organic species may require pre-treatment. While energy costs increase with higher TDS, RO is able to efficiently remove salts in excess of 10,000 mg/L.
Miscellaneous Treatment					
Trickling Filter	develops film of microbial on the surface of packed material to degrade contaminants within water	cheaper, simple and clean technology	oxygen requirement, large dimensions of the filter	sludge waste at the end of the treatment	Removal of suspended and trace solids, ammonia, boron, metals etc. Post-treatment is normally required to separate biomass, precipitated solids, dissolved gases etc.
Constructed wetland treatment	natural oxidation and decomposition of contaminants by flora and fauna	cheaper, efficient removal of dissolved and suspended contaminants	retention time requirement, maintenance, temperature and pH effects		
SAR adjustment	addition of Ca or Mg ions	cheaper option	chemical addition		Balance high SAR and very low TDS (higher percentage of sodium salts) after membrane processes.

TREATMENT	DESCRIPTION	ADVANTAGES	DISADVANTAGES	WASTE STREAM	OIL AND GAS PRODUCED WATER APPLICATIONS
NORM Treatment					
NORM treatment	extraction of radioactive material with aqueous solution	efficient for reducing radioactive waste volume	extracted radioactive materials need further treatment or disposal		Produced waters containing high levels of Uranium or Thorium. Unless treatment is accomplished, radioactive scale can form in surface equipment extensive remediation.
Natural Gas Recovery					
Air stripping	stripping of dissolved gas from water	concurrent or countercurrent operations, cheaper	post treatment, lower efficiency		

Source: ALL, 2005

Section 4.9 Handling of Water Treatment Waste/Concentrate

Produced water treatment technologies convert poor quality produced water into good quality water by removing contaminants and impurities. As discussed earlier, many such treatment technologies decontaminate inlet produced water producing a waste stream with higher concentration of contaminants and a treated water stream. For example, membrane systems separate influent water into cleaner product water and a more concentrated stream that is called concentrate in RO, NF, and EDR systems and backwash in UF and MF systems. Considering large scale of produced water treatment, the amount of concentrated waste volume needs to be considered when planning water treatment facilities.

The selection of concentrate disposal practice depends on several factors such as regional disposal availability (geology, geographical, climate, etc), local availability (existence of suitable disposal site, distance, compatibility, etc), volume of concentrate stream, applicable environmental regulations (NPDES, underground injection control regulations, and underground water resource regulations, etc. are imposed by local, state, or federal agencies), environmental impacts, public reception, cost, etc. Along with cost contributing factors such as transportation, treatment, development of disposal site, etc., environmental regulations also have major impacts on the feasibility of any particular concentrate disposal method.

Disposal to surface water:

Membrane wastes may be discharged to surface waters and ultimately reside within large receiving water bodies. Direct discharge to water bodies must have an NPDES permit (states' authority), which requires meeting CWA regulations for effluent limitations. Large volumes of concentrate waste and level of contaminants in it are some of the limiting factors for this practice.

Disposal to Publicly Owned Treatment Works (POTWs):

An NPDES permit is not required for the disposal into publicly owned treatment works (POTWs). However, POTWs may enforce pre-treatment before disposal according to federal regulations to control the level of wastewater pollutants entering the sewage system.

Disposal with injection well:

Injection of concentrated waste through a Class I injection well beneath the lowermost underground source of drinking water requires meeting UIC regulations according to state and federal standards. Research is being attempted to evaluate disposal of concentrate into depleted oil or gas fields through Class I wells (Nicot and Dutton, 2004). Formation damage, scaling, etc., are some of the concerns for using depleted oil or gas fields.

Evaporation ponds:

Evaporation ponds utilize solar energy to evaporate water into the atmosphere in vapor form leaving behind solids/salts in sludge form. This technology is limited to regions where solar irradiation is high. Permits may be required if a potential of leakage into surface water or drinking water aquifers exists.

Spray evaporation:

An NPDES permit may be required for spray evaporation if the potential of waste runoff to a receiving water body exists.

Zero liquid discharge:

The objective of zero liquid discharge is to eliminate any liquid waste at the end of the water treatment process. Evaporators or concentrators can be utilized to concentrate the waste stream. Conversion of concentrated sludge into solids/salts form can be accomplished by using a crystallizer. Disposal of solid waste from a crystallizer must avoid contamination of surface or groundwater.

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