SECTION 5.0 PRODUCED WATER REDUCTION TECHNIQUES

A white paper studying the applicability of various water reduction techniques to the coalbed natural gas development of the Powder River Basin in Montana and Wyoming was prepared as part of a research project funded by the National Energy Technology Laboratory (NETL) of the DOE. This section presents a summary of the findings of this research as they may apply to various basins across the United States. The title of the white paper is: *Reducing Produced Water Volumes from Coal Bed Natural Gas in the Powder River Basin* (ALL, 2005).

Across the CBNG industry, the following were identified as the more promising technologies for minimizing produced water on the surface:

1) Downhole Water Separation and Injection – avoids producing the groundwater to the surface as it separates water from gas downhole and injects the water into underground disposal/injection zones.
2) Advanced Production and Completion Techniques – controls unconfined fracture propagation and reduces hydraulic connectivity between water bearing formations other than the resource bearing formation near the producing well.
3) Horizontal Drilling – improves resource recovery (often without stimulation) per barrel of produced water and appears to be a way to reduce net water production.

The technologies listed above are commonly used in the development of oil and gas reservoirs but are not applicable to every field. Each technology has geotechnical limitations and operational pros and cons that are described in Section 5.1 for downhole water separation and injection; Section 5.2 for advanced production and completion techniques; and Section 5.3 for horizontal drilling.

Section 5.1 Downhole Water Separation and Injection

Downhole separators separate water from oil or gas within the well bore; oil or gas with little or no water is then produced to the surface. Significant amounts of water are disposed into a non-producing formation above or below the oil or gas producing formation using injection tools within the well bore. The performance of downhole separators is influenced by the geology of disposal zone. The small amount of water produced to the surface along with oil or gas requires appropriate handling or treatment, or disposal in accordance with the existing regulations. The downhole separator assembly comprises a number of various compact elements installed within the actual well bore.

1) Separation Tool – Separates water from incoming fluids from the reservoir. The tool is not a necessity for a gas producing wells, but is required for oil producing wells.
2) Pump – Pressurizes large amounts of water from the separator and injects the water into the disposal zone. Sucker rod pumps, plunger pumps, progressive cavity pumps (PCPs) or electric submersible pumps (ESPs) are utilized depending on the requirements of injection pressure and volume.

3) Motor – Heavy duty compact motor-modules are required to perform desired pumping duty.
4) Miscellaneous – Downhole monitoring equipment, cables, surface controls, etc. may also be required for better controlled operations.

The evaluation of both engineering and economic feasibility varies significantly by operator and location. Some of the technical issues of concern for downhole separation are the following:

Producing and Receiving Formation Suitability

Selection of a suitable injection zone/area within the producing formation may depend upon several criteria, including reservoir characteristics, depth, relative location to producing wells, and possible contamination of underground sources of drinking water (USDW). To be a suitable candidate for downhole separation, the productive zone would have to produce very few fines that could plug the receiving zone.

Zonal Isolation

The receiving formation must be vertically and laterally separated or otherwise confined from producing formations and other USDWs. Suitability analyses also would require the examination of local fracturing and faulting as the fractures may be able to hydraulically connect injection and producing zones; this could cause recycling of produced water in the vicinity of the well bore.

Porosity

Injection formation must have sufficient porosity to adequately hold the injected formation fluids.

Permeability

A productive reservoir or an attractive injection zone will have sufficiently high permeability to allow sufficient fluid movement. Confining zones should have very low permeability in order to act as seals rather than zones that will allow fluid movement.

Storativity

The storage capacity of a geologic unit can be estimated using a simplistic approach by estimating the pore volume of the entire injection zone. For instance, a permeable unit that has 10% porosity, is 20 feet thick, and is homogenous and regionally extensive would have a storage capacity of 2 million barrels if the injectate front extended for ¼ mile. Higher storativity is desired and contributes to the success of injection.

Injection Pressure

Reservoir pressure may limit the rate at which fluids can be injected and/or may limit the injectivity. Injection pressures may be so high that fracture-propagation could be initiated and augmented; fractures within and outside the injection zone could cause real problems at the injection site leading to injected fluids moving out of the zone into a nearby producing zone or USDW.

Fractures

Natural fracture or fractures created during injection can be helpful if they are confined to the injection zone and do not create conduits for flow across the confining zones. Fractures can reduce the impacts of near well bore damage and improve injectivity. However, unconfined vertical fractures extending from the producing formation to an USDW can cause problems.

Water Quality

The chemical compatibility of the injectate fluids also plays a part in the feasibility assessment of the injection plan. If the injected water is incompatible with the underground water of the injection zone it can cause scaling problems (from the precipitation of minerals) that could damage or reduce the hydraulic conductivity of the formation.

Injectivity Loss

Water being separated downhole and injected is not filtered in the same manner that water brought to the surface and then re-injected is filtered. Clogging of pores of the injection formation by sand or fine solid particles, scale, biological slimes, and precipitates can reduce the rate a formation can receive injectate. The processes that cause injectivity loss can reduce the success of the downhole water separation installation more than any other effect, especially if a large volume of water is being injected every day. The build-up of fines across the perforations can act as a cement. For example, if the injectate contains as little as 50 mg/L suspended fines, injecting 1000 bpd will result in approximately 70 lbs of fines being forced into the formation opposite the perforations every day of operation. Over a very short time, plugging can lead to irreparable damage to an injection zone.

Section 5.2 Advanced Production and Completion Techniques

Improvements to production and completion techniques are being attempted by operators to reduce the production of water to the surface during the production of oil and gas resources. Some of the new techniques that operators are trying to utilize are described below.

Section 5.2.1 Reverse Circulation Center Discharge

A recent innovation is a unique drilling program developed by Calgary-based K2 Energy Corp (Evergreen, 2002). The process is called “reverse circulation center discharge” (RCCD). The company, in conjunction with Midnight Sun Drilling of Whitehorse, Yukon, has recently completed nine shallow gas wells in northern Montana. RCCD creates minimum drilling damage to the formation, thus allowing shallow, low pressure gas to flow to the surface during drilling operations. RCCD drilling consists of three basic components: double-wall drillpipe, an air hammer, and a downhole blowout prevention system. The drillpipe has 4.5-inch outer and 2.875-inch inner diameter tubulars. Air circulates between the two strings, drives the air hammer, and at the same time reverse circulates the formation cuttings back up the inner pipe to the surface. K2 reports that the well bore is perfectly straight from top to bottom, with no fill at the bottom of the well. The well can flow gas as it is drilled.

Section 5.2.2 Cavitation

As a stimulation or clean-up treatment, the cavitation process uses dynamic pressure changes to break apart the rock face and to widen the effective borehole across the producing zone. Air or foam is pumped into the well to increase the pressure in the reservoir followed by a sudden release that blows out the air/gas along with rock fragments (Oil and Gas Accountability, 2004).

This action is sometimes referred to as "surging," and it is accompanied by a jet engine-like noise that can last up to 15 minutes. The rock fragments, foam, water, and gas that escape from the well are directed at an earthen berm to prevent the materials from entering the greater environment. Some of the loose rock material remains in the well. It is cleaned out by circulating water or foam in the well and pumping the material into the recovery pit or steel tank.

Cavitation Inc. developed a new cavitation and cleaning tool specifically for CBNG completion. The cavitation and cleaning tool is engineered and designed for enlarging hole size, completion, and work over uses. The cavitation and cleaning tool can be used with air, water, and drilling foam, or just water and foam. An air compressor can be sized to the depth of a well. For example, a 950 cfm and 350 psi air compressor can be used on a well as deep as 1,200 feet, according to how much water the well makes. The tool can be adjusted to depth and hole size. The advantages of this technology include enlargement and cleaning of the well bore in one run and replacement of “water enhancement” activities that could create unconfined fractures responsible for higher water production. Limitations of cavitation may include shortening the production life of the CBNG well.

Section 5.2.3 Well Stimulation

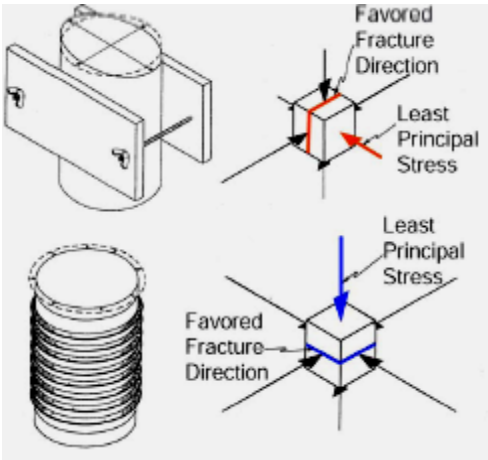
After the producing well is completed either in one open hole zone or one or more zones opened by perforations through casing, the well is often stimulated by the injection of a fluid under pressure. Stimulation is achieved by one of several technologies – hydraulic fracturing, propellant fracturing, and various other techniques.

Hydraulic Fracturing:

One option for the operator is to complete producing wells with high pressure hydraulic fracture stimulation. Hydraulic fracturing is often avoided to prevent fracturing the confining formations adjacent to the producing zones, which can significantly increase water production. If the fracture is confined within the producing zone, for example, horizontal fractures in a vertical well within the zone contribute to increased gas production. If the fracture extends in vertical direction it can possibly contact the overlying or underlying water bearing formations or even extend into those aquifers. The vertical fractures then have the possibility of increasing the volume of produced water because water will be drawn not only from the productive zone but also from the water saturated sands around it. Typically, operators are aware of this possibility and go to great lengths to avoid this scenario so as to protect valuable water resources and to preserve the economics of their development.

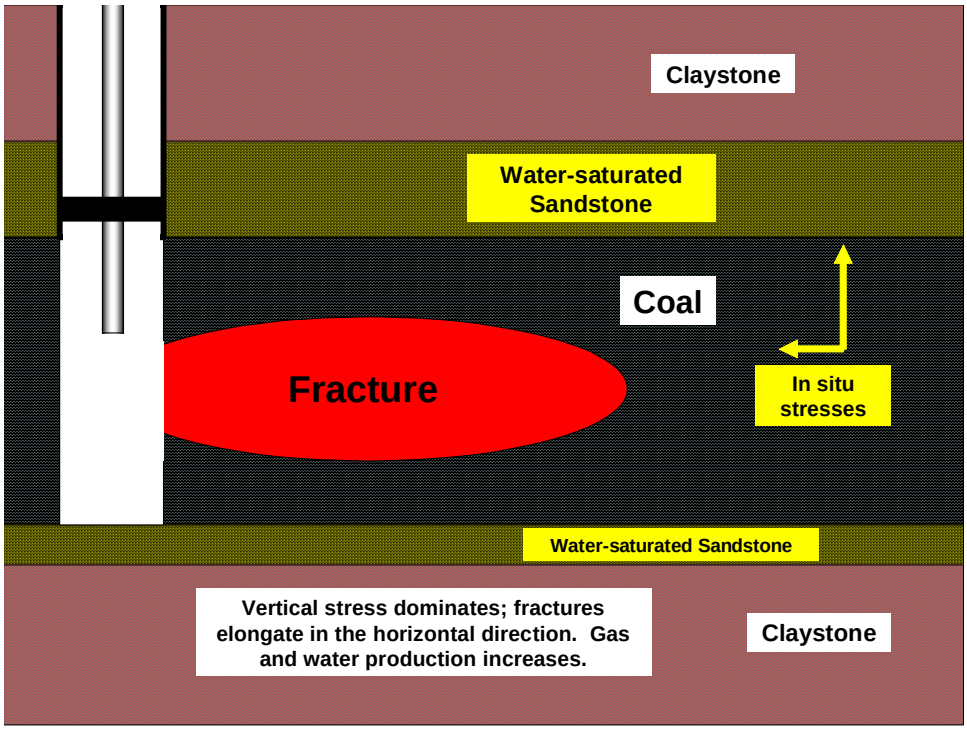
Research related to the stress analysis of earthen materials has determined that an individual fracture extends or propagates perpendicular to the least principal stress. If the least principal stress is vertical or overburden then the hydraulic fractures propagate in the horizontal direction. If the least principal stress is horizontal, then fractures propagate in vertical direction (perpendicular to minimum of all horizontal stresses). This is illustrated in Figure 5.1, which shows the application of principal stresses to a cone of earthen material, the directions of least principal stress and the favored fracture development direction for the two previously discussed scenarios.

Figure 5.1 A fracture propagates perpendicular to the minimum principal stress.



An additional concern for hydraulic fracturing practices is unconfined fracture propagation. Figure 5.2 illustrates an example of the possible results from fracturing a coal under a vertically-dominated stress field. This example holds true for conventional oil/gas hydraulic fracturing as well. In this case, if fractures are initiated and enlarged, they would tend to elongate in the horizontal direction; that is, stay within the producing coal seam. This may augment both natural gas and water production from the well. Although gas production may increase, water production rates may increase also, and the water to gas ratios may change as a result of the fracturing.

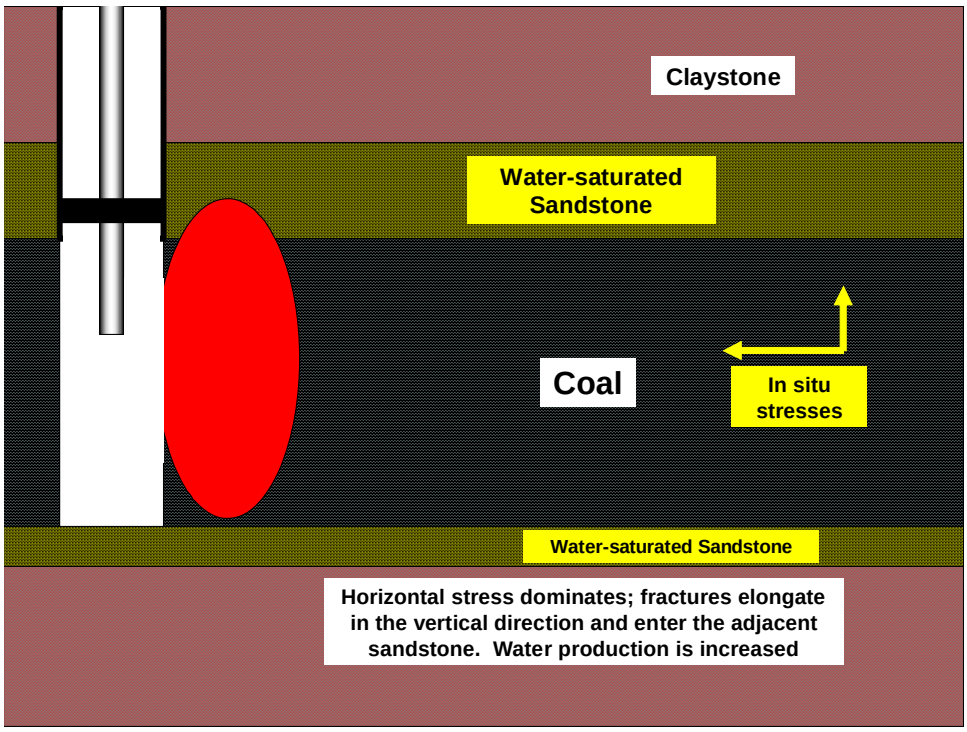
Figure 5.2 Hydro-fracturing a CBNG well. Possible results under conditions of a vertical-dominated stress field; horizontal fractures can be formed.



If the horizontal stresses predominate in an area, fracture treatment of the coal may result in fractures elongated in a vertical direction (Figure 5.3) moving toward the overlying water-saturated sandstone reservoirs. Depending upon the relative fracture gradients of the coal and the sandstone, the vertical fractures may extend up to the contact with the sandstone or may actually enter the sandstone bed. In either case, the borehole may be opened to the adjacent sandstones that contain only water. If these fractures are created, water production may be increased while not increasing natural gas production rates. Natural fractures might exist locally in the coals but can be difficult to detect. These fractures might be oriented in the same directions as the local cleat or may be at different orientations. These natural fractures may be vertical and might already connect some coal seams to adjacent sands; therefore, this may be a factor as to why some coals produce more water than others. If natural fractures exist in a CBNG development zone, they may be augmented by hydro-fracturing treatments.

Real time fracture height measurement can help in mapping fractures. Hydraulic fracturing models can be calibrated with real-time data to optimize treatment designs and to prevent undesired propagation of vertical fractures that could increase water production. Several diagnostic technologies are commercially available to map hydraulic fracture growth. Surface tilt meters can be used to measure fracture orientation, but there can be surface access issues.

Figure 5.3 Hydro-fracturing a CBNG well. Possible results under conditions of a horizontal-dominated stress field; vertical fractures can be formed.



Various downhole tilt meter instruments are run into the well bore prior to beginning the treatment (Stutz and Fisher, 2004). The tools are coupled to the well bore with magnetic decentralizers. Pumping begins, and induced tilt is measured at each tool allowing fracture height to be measured in real time. Fracture geometry is directly measured as a function of actual treatment parameters. The result is a calibrated fracture model that enables optimized fracturing treatment design. The accurate treatment designing helps to avoid uncontrollable fracture propagation, which can cause higher water production volumes.

Hydraulic Fracturing – Case Study

Anadarko's CBNG production at Copper Ridge field in the PRB of Wyoming is a good example of real time fracture mapping used to optimize the fracture treatment design while avoiding excessive water production. The coals are present in 2-foot to 12-foot stringers spread over 100–foot to 300-foot gross intervals at depths ranging from 2,600 to 3,000 feet. The most prolific seams are perforated and fracture stimulated using cross-linked gel with a combination of 16/30 and 20/40 sands as proppant. The Ericsson sand zone, used for water disposal, underlies the coal sections while higher permeability water sands overlay the sections.

Fracture mapping occurred on six wells, and fracture engineering and modeling were performed. Where fractures were mapped, growth was measured in real time. The measured fracture growth was then incorporated into the software program, FracproPT, along with pressures, volumes, and injection rates. This allowed on-site adjustments to prevent fracturing into the adjacent water sands. The fracturing model was quickly optimized and used on all subsequent wells.

The objectives that led Anadarko to obtain real time data and use them to model the fracture treatment were to:

- Stay out of overlying and underlying water zones;
- Minimize the number of stages while still achieving complete interval stimulation;
- Create long fractures with adequate conductivity.

Tilt meter data were obtained in real time while the proppant was being pumped. Previously, data had been gathered only during proppant-free stages, such as with mini-fracturing, acid fracturing, and water-only fracturing. Safe operating bounds for pumping rate, viscosity, sand concentration, and job duration, within which the tools and wire-line can be safely operated, were determined during pilot treatment.

This treatment showed some tendency for upward fracture growth toward the overlying water sands. The proppant ramp was adjusted, accordingly, to be more aggressive early in the treatment. This ensured adequate conductivity if the treatment needed to be halted early due to the fracture top getting too close to the water sands. The propped treatment was pumped to completion while monitoring fracture height in real time. Treatment avoided growth into the overlying water sand.

Fracturing treatments were optimized to avoid propagation into permeable water sands. Savings from reduced water production were $1.3 million in the first year. Research into such carefully monitored fracture jobs should include costs for the treatments as well as water management costs over time.

Propellant Fracturing:
Propellant fracturing (ARI, 1994) is a controlled pulse fracturing, tailored pulse loading, or high energy gas fracturing that involves the use of a wire-line run, electrically ignited propellant (similar to solid rocket fuel) placed across the formation to create a high pressure pulse. This pulse of gas creates multiple short (5 foot to 20 foot) radial fractures in the formation that connect to the well bore and are confined close to the zone stimulated. In addition, propellant fracturing avoids the resulting well bore damage often associated with explosive fracturing.

In addition to minimizing near-well bore damage, propellant fracturing also controls vertical fracture growth. Fracture cracks are restricted to about one-half the horizontal length of the fracture. This is because the fracture growth is gas-dynamic, and there is not time nor energy available for the unrestricted height growth that can occur with a large hydraulic fracture. Therefore, knowing the distance to the reservoir cap, a propellant treatment can be designed to virtually guarantee that breakthrough will not occur. With recent concerns over the possibility that hydraulic fracturing could contaminate aquifers, this technique could be used to ensure that the fracture does not communicate with the overlying aquifers.

By restricting or avoiding fracture propagation into the over- or under-lying water bearing formations, this technique can control excessive water production.

One of the disadvantages of propellant technology is that the created fractures are left unpropped, and hence are susceptible to closure and plugging. It can be applied as an effective near-well bore damage removal technique.

Miscellaneous:
Utilization of coil tube fracturing, multi-zone completions (DOE-NETL, 2003), hydraulic fracturing with high performance slurry, etc. improves gas recovery by means of improved accuracy in fracturing, reducing near-well-bore damage, improved connectivity, and other factors that contribute to enhance fracturing results in terms of gas production. However, on the basis of this literature search it is not clear that these techniques can reduce excessive water production during operations.

Section 5.3 Horizontal Drilling

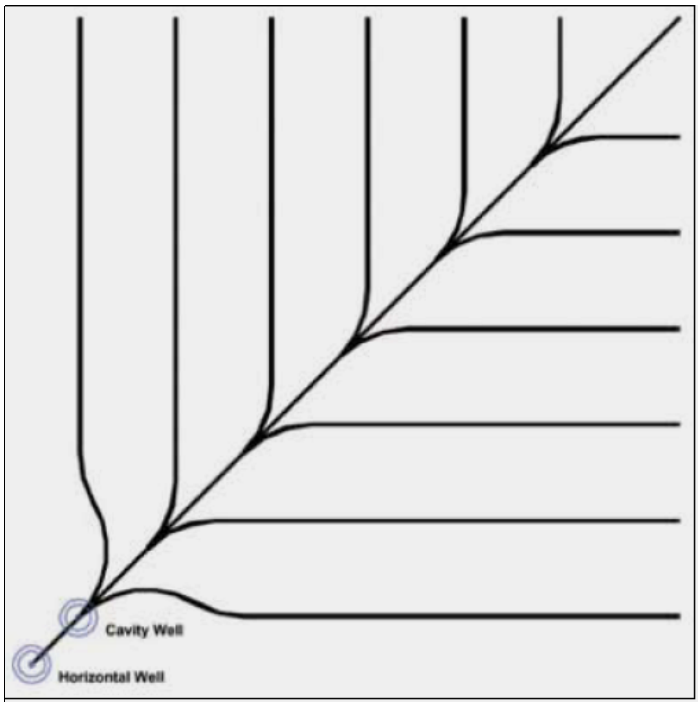
The advantages of horizontal drilling typically are noted as higher recovery at accelerated rates and more uniform reservoir drainage.

The Dallas-based company, CDX, has developed and demonstrated a Z-pinnate horizontal drilling and completion system as illustrated in Figure 5.4. Using horizontal laterals, CDX can access up to 1,200 acres from a single well site, significantly reducing surface impacts. (Vertical CBNG wells are often drilled on 80-, 40- or even 20-acre spacing.) CDX's pinnate drilling pattern accelerates gas recovery allowing as much as 85% of the gas in place to be produced within 36 months.

The first step of pinnate drilling involves drilling a vertical well to the target producing zone. If producing zones are stacked, it is possible to extend the vertical well downward to pierce multiple zones. A cavity is reamed in the vertical well at each zone to create an accumulation chamber, or sump, for water collection. Next, a directional well is drilled nearby and steered to

intersect the cavity horizontally, then continuing to pierce the producing zone laterally. Laterals totaling as much as 25,000 feet are drilled off the main lateral to procure a roughly square drainage pattern. Subsequently, as many as three additional pinnates can be drilled from a single surface location in a "quad-pinnate" pattern. This provides 360° of drainage, optimizing production. Comparing a 500 MMcf horizontal pinnate well with a 500 MMcf fracture stimulated well, the pinnate well produces at a high initial rate and depletes in approximately 6 years; whereas, the conventional well will deplete at a lower rate in approximately 15 years. A one-mile radius drainage pattern from each well can cover up to 1,200 acres from a single drilling location. In CBNG fields, maximal reservoir contact, as would be realized in a horizontal well, speeds up the depressurizing process meaning that first production is achieved more quickly and at greater rates.

Figure 5.4 A schematic of Z-pinnate drilling



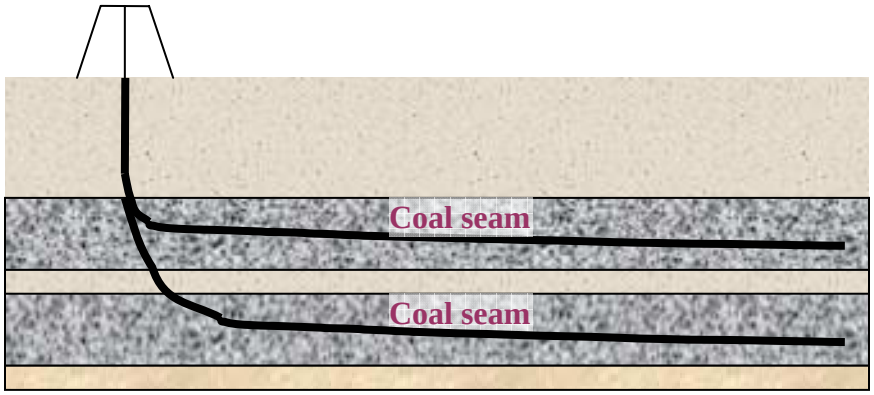
Source: CDX technology

The pinnate drilling program is not without problems. Its applicability to each field and the economics of drilling such an expensive well need to be evaluated against the cost of conventional completions.

The typical well bore construction for a horizontal well involves going from vertical to horizontal mode in two phases. The first portion of the curve is achieved above the uppermost portion of the producing zone. Typically, the well is drilled out vertically below surface casing to a kickoff point, depending on the proximity of the uppermost zone. Then directional tools are conveyed into the well bore, and a curve is built with a 6°/100-foot to 8°/100-foot build rate so as not to create too severe a dogleg. A dogleg is a particularly crooked place in a well bore where the trajectory of the well bore in three-dimensional space changes rapidly. Minimizing the dogleg is important because artificial lift equipment may need to be run through this section. When the

well bore reaches a tangent angle between 60° and 75°, that tangent is held constant and laterally drilled through the entire producing zone, extending approximately 150 feet beneath the deepest zone to be completed. This drilling geometry for a CBNG project is illustrated in Figure 5.5.

Figure 5.5 Multi horizontal wells penetrate through multiple coal seams



Improved ultimate gas recovery, higher gas production rates, greater effective drainage, and less surface disturbance are the major advantages of horizontal drilling. The chief limitation to using horizontal laterals in any field is to find suitable formations that will have sufficient drillability and borehole stability. Additional research is required to understand and evaluate the effects on water production and WGRs from horizontal wells. Success of horizontal drilling in eastern and central hard coal basins has been reported. Fracturing may not be needed with horizontal wells, even at later stages of production. This factor alone could reduce the chances for uncontrolled vertical fracture propagation and, hence, reduce the chances for unnecessary, higher water production.

Weatherford International offers an underbalanced drilling (UBD) technique for creation of horizontal wells. UBD provides a non-damaging alternative for horizontal drilling within producing zones. UBD requires that the circulating bottom-hole pressure remain below reservoir pore pressure while, at the same time, the hole be cleaned as it is drilled. For soft formations it is possible to drill, even horizontally, at a rate higher than the cuttings can be cleaned from the well bore (Saikat and Heinz, 2004). This requires controlled drilling to keep the hole clean, and also to monitor and maintain the circulating pressure environment to continue to drill in an underbalanced fashion.

Well bore stability remains the greatest barrier to horizontal drilling in many fields. For example, the Tertiary-age Fort Union Formation low-rank coals of the PRB are notoriously low in strength and have a tendency to slough into the borehole even in vertical wells. Only limited horizontal drilling has been attempted in the PRB, but those attempts have been failures because of sloughing. Horizontal boreholes in weak producing zones may not be able to stay open without a liner and may not even be drillable. This question is very important when considering horizontal drilling and completions. If the producing zone cannot be successfully drilled, then this water reduction technique is not applicable. Horizontal drilling innovations could eventually increase the drillability of soft formations. Currently, two innovative products

may supply much needed information – designer mud systems forming a “stress-cage” within the borehole and borehole stability modeling.

Stress-cage designer muds have been demonstrated on low-strength materials (Aston, 2004). The mud is designed to be an ultra low fluid loss system that builds and maintains a bridge across the fractures in the borehole allowing the hole to stay open until a screen or liner can be installed. The stress-cage muds would then be dispersed prior to production. Economics of this horizontal technique are unknown at present time.

STABView (McLelland and Hawkes, 2002) is a commercial well bore modeling program designed to use wire-line and core information to model borehole stability in low-strength rocks. The model uses log derived data, core analyses, and borehole stress measurements to predict borehole deformation and collapse. Work on Canadian coals suggests that results are depth sensitive and that mapping borehole deformation in vertical holes can predict stability in deflected holes and horizontal laterals. Borehole stability models could have application in selecting potential candidates in weak producing zones and predicting favorable depth ranges for horizontal drilling.

THIS PAGE INTENTIONALLY LEFT BLANK

SECTION 6.0 ANALYSIS OF SELECT OIL & GAS BASINS

In early years of oil and gas production, oily water was pumped into shallow ponds so that crude oil could be skimmed off and sold. The brine water in the ponds often seeped into the subsoil, causing salt scars that proved difficult to remediate. Around this same time, the oil and gas industry discovered a beneficial use for high-salinity produced water – secondary oil recovery via subsurface water floods. Individual states began to pass laws prohibiting pollution in general and the release of deleterious materials to air, water, and soil. Oil and gas producing states set up rules and regulatory agencies to control the production of crude oil, natural gas, and salt water by the petroleum industry. The regulatory process is designed to safeguard the physical environment, prevent the waste of the hydrocarbon resource, and protect correlative property rights on the land surface and in the subsurface.

Oil and gas environmental regulation became a federal issue with the passage of the Safe Drinking Water Act in 1974 that included nationwide underground injection regulations. The federal regulations established a number of classes of injection wells with construction and operating requirements relevant to the various classes of wells. Most oil and gas injection and disposal wells fall under the Class II regulations.

The produced water data presented in this report was assessed relative to Total Dissolved Solids (a representation of the produced waters salinity) to illustrate the range and distribution of the produced water salinities for each of the basins. Produced water quality data is also presented in two ways – numerically and geographically. The water classifications presented in the bar graphs for the individual basins use ranges based on classifications of groundwater quality and salinity expressed as TDS and were modified to reflect the relative management options for the waters. The ranges are 0 mg/L to 9,999 mg/L TDS (fresh to brackish waters in USGS classification), 10,000 mg/L to 49,999 mg/L TDS (low to moderate saline waters), 50,000 mg/L to 99,999 mg/L TDS (moderate to high saline waters), 100,000 mg/L to 199,999 mg/L TDS (low to moderate brine waters), and 200,000 mg/L to 460,000 mg/L TDS (brine waters).

Basic statistics are listed in the bar graphs to show the distribution of produced water quality samples collected within the individual basins for each of the classification groups listed above. While these statistics are calculated from the various reservoirs sampled within the basins, it is assumed for this report that these statistics approximate the distribution of salinities within the basin and within the total water volume produced each year, unless otherwise noted. Median TDS (salinity) as well as the lowest and highest TDS samples are presented for each chart to provide additional information of the variability of water salinity for each basin. The data is also plotted on maps to provide spatial analysis of the produced water quality distribution within the basins.

Section 6.1 Alaska North Slope and Cook Inlet

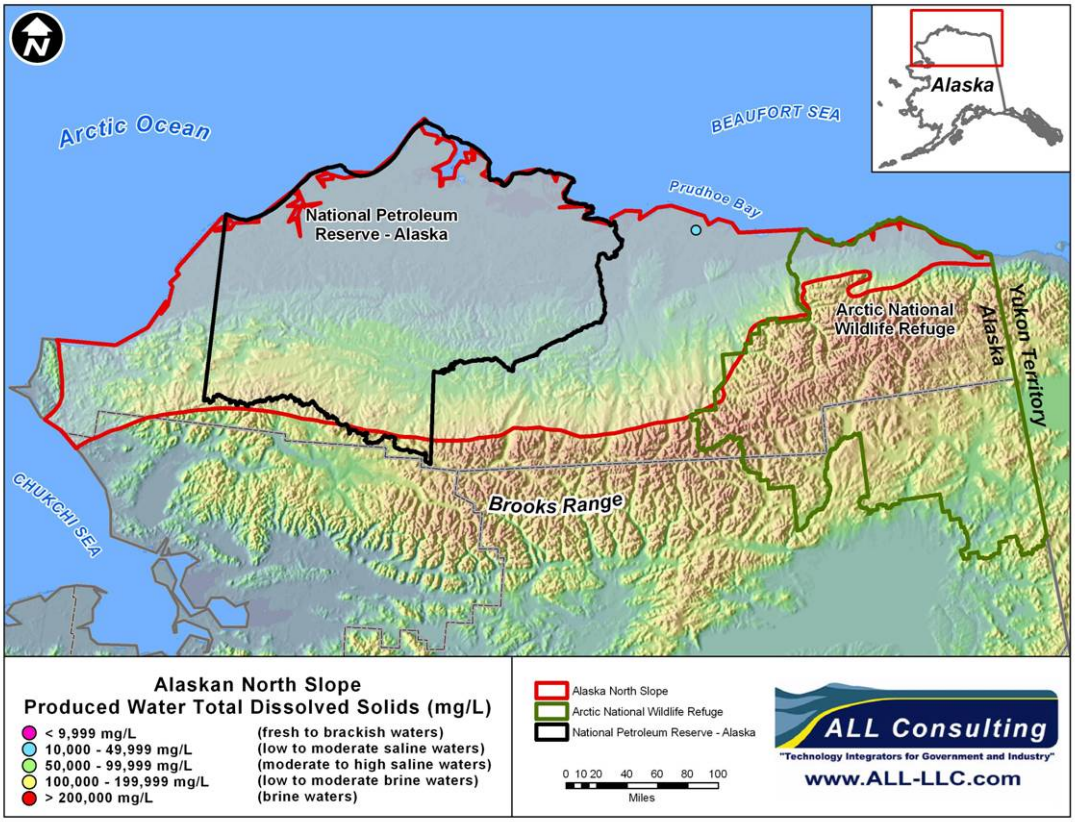
North Slope

The Alaska North Slope, which covers approximately 88,000 square miles, is the region of Alaska located on the northern slope of the Brooks Range foothills to the coast of the Arctic Ocean. The region contains the major petroleum reserves of Alaska, including Prudhoe Bay, which is North America's largest oil and gas field. The region also contains the Arctic National

Wildlife Refuge. Prudhoe Bay is a coastal feature of the Beaufort Sea approximately 250 miles north of the Arctic Circle and 1,300 miles south of the North Pole (Alyeska Pipeline, 2006). Prudhoe Bay includes 3,898 exploratory wells, 170 drilling pads, 500 miles of road, 1,100 miles of pipeline, 5 docks, and 25 production, processing, sea-water treatment, and power plants.

The state of Alaska receives about 85% of its revenues from oil and gas activity. Most of these revenues come from the 1.5 million bpd production of the Prudhoe Bay field on the North Slope. Figure 6-1 depicts the location of the Alaska North Slope (red line) and defines the National Petroleum Reserve in Alaska (black line) and the Arctic National Wildlife Reserve (ANWR) as the green line; the water quality data presented on Figure 6.1 is from the Prudhoe Bay field which is located east of the National Petroleum Reserve and west of ANWR.

Figure 6.1 Geologic Setting and Produced Water Quality Distribution of the Alaska North Slope



(Source: USGS, 2005)

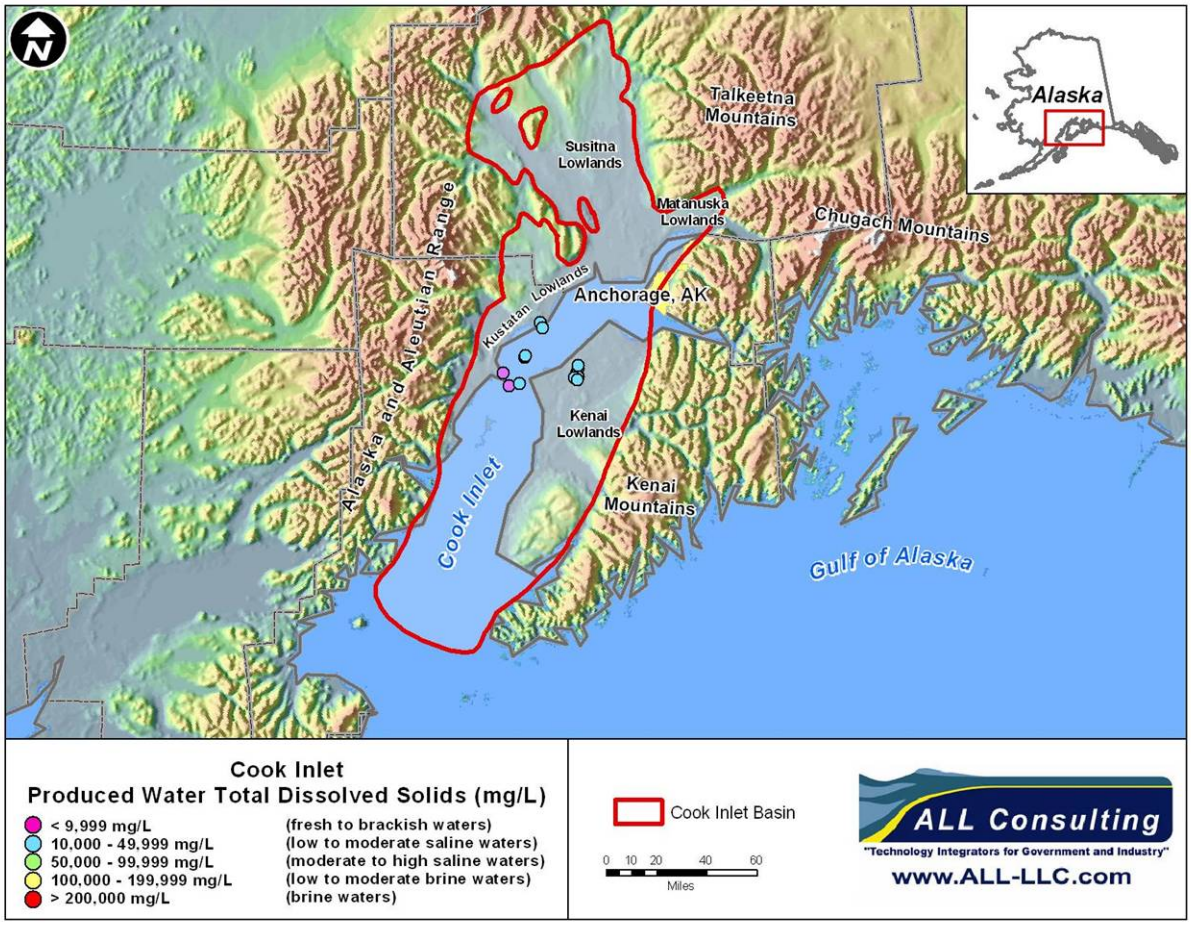
Cook Inlet

The Cook Inlet basin is about 380 km long and about 80 km wide and is bordered to the west and north by the Alaska and Aleutian Ranges and to the northeast and east by the Talkeetna, Chugach, and Kenai Mountains. Cook Inlet and its extensions, Turnagain Arm and Knik Arm, form a major marine re-entrant of the south-central Alaska coastline and subdivide the Cook Inlet Lowland into several natural subunits (Alaska Department of Natural Resources, 2003). These include the Kenai Lowland, which fronts the Kenai Mountains to the east; the Kustatan Lowland, a narrow coastal shelf fronting the Aleutian and Alaskan Ranges to the west; the

Susitna Lowland, a broad lowland between the Alaska Range and the Talkeetna Mountains that is drained by the Susitna River, which in turn flows into Cook Inlet from the north; and the lower Matanuska Lowland, drained by Knik Arm, which lies between the Talkeetna and Chugach Mountains to the northeast (Alaska Department of Natural Resources, 2003).

The origins of the Alaska oil and gas industry began in Cook Inlet with the discovery of Alaska's first commercially viable oil find in the Swanson River field in 1957. After the Swanson River finding, additional wells were developed in Cook Inlet and more leases were approved throughout the basin. By 1959, 187,000 barrels of crude oil were produced annually in Cook Inlet (Alaska Department of Natural Resources, 2004). The Cook Inlet or Kenai Peninsula watershed is located in south-central Alaska and is approximately 47,000 square miles in size, lying generally below an elevation of 1,000 feet (Alaska Department of Natural Resources, 2003). Figure 6.2 defines the boundary and geologic setting of the Cook Inlet Basin.

Figure 6.2 Geologic Setting and Produced Water Quality Distribution of the Alaska Cook Inlet Basin/ Kenai Peninsula



(Source: USGS, 2005)

SIGNIFICANT GEOLOGIC FEATURES

North Slope

The North Slope of Alaska is a major hydrocarbon-producing region of North America, but its geologic setting is still not completely understood (Alyeska Pipeline, 2006). This is in part due to the tectonic history of northern Alaska, where there is a complex interplay between the formation of the Brooks Range collisional orogen and the development of the nearby north Alaska rifted continental margin (Wallace and Hanks, 2005).

In general, the North Slope consists of the Carboniferous Lisburne Group, a thick, heterogeneous and highly fractured sequence of carbonate rocks that acts as the reservoir horizon for some oilfields located in the North Slope (Wallace and Hanks, 2005). The Lisburne Group also is widely exposed throughout northern Alaska as an important element of the Brooks Range fold-and-thrust belt. The Lisburne Group was recognized as a potential reservoir horizon very early during petroleum exploration of northern Alaska and was considered by many to be the primary exploration target during the early phases of drilling on the North Slope (Wallace and Hanks, 2005). As in many carbonate reservoirs, naturally occurring fractures in the Lisburne Group play a major role in hydrocarbon production by providing both porosity and permeability. However, the distribution, density, and character of fractures within the Lisburne are highly variable and difficult to predict, and may depend on the lithology of the host rock, the structural setting of the reservoir, and/or other unidentified factors (Wallace and Hanks, 2005).

Cook Inlet

The present topography of Cook Inlet and adjoining areas is primarily the product of at least five major Pleistocene glaciations and two minor post-Pleistocene glacial advances (Karlstrom, 1964). These are recorded by the distribution of moraines and ice scoured landforms, by discordant drainage relations, and by stratigraphic evidence of multiple drift sheets separated by major unconformities and weathering profiles (Karlstrom, 1964). The Cook Inlet basin occupies a structural trough, is underlain at variable depths by rocks of Middle Jurassic through early Cretaceous sediments (2,700 m), 4,300 m of Early and Late Cretaceous flysch, and up to 6,500 m of Tertiary fluvial sediment (Alaska Department of Natural Resources, 2004).

Semi-consolidated coal-bearing formations of Tertiary age crop out at the surface or occur at relatively shallow depth at the southwest end of the Kenai Lowland and along the flank of the Alaska Range between Tyonek and Peters Creek (Alaska Department of Natural Resources, 2003).

OIL AND GAS PRODUCTION

North Slope

Petroleum reserves in Prudhoe Bay were discovered in 1968 with initial recoverable reserves estimated at 9.6 billion barrels of oil and 26 trillion cubic feet of gas (Alaska Department of Natural Resources, 2004). Production was initially restricted to small quantities used to fuel field operations until the Trans Alaska Pipeline System (TAPS) was completed in July 1977. Until this, operators injected surplus crude and residual oil back into the Prudhoe Bay reservoir.

North Slope gas production began near Barrow in the mid-1940s. Gross gas production on the North Slope in 2000 was 3.2 trillion cubic feet (8.7 billion cubic feet (BCF)) per day, but 93% of this volume was injected into oil producing reservoirs (Alaska Department of Natural Resources, 2004). The remaining net gas production, equal to 297 BCF in 2003, is consumed locally on the North Slope to fuel oilfield equipment, operations, and pipelines. North Slope industrial yearly gas consumption is approximately equal to annual gas produced in Cook Inlet (Alaska Department of Natural Resources, 2004).

From the beginning of Prudhoe Bay production, dissolved gas and water were separated from the crude oil and injected back into the reservoir. Over time the proportion of both produced gas and water to oil increased. Eventually, oil production was constrained by the rate at which the separating plants could process gas and water. The North Slope has produced 14.4 billion barrels of oil and natural gas liquids (NGLs) by the end of 2003; nearly all from the large Prudhoe Bay and Kuparuk fields (Alaska Department of Natural Resources, 2004). NGLs produced on the North Slope are blended with oil and shipped down TAPS or used to make miscible injectant for enhanced oil recovery projects. Today, incremental oil production from new fields brought on-line since 1995 account for about 27% of total yearly Alaska North Slope production. Oil production in the bay has slowed considerably and at the present time an average of 680,000 barrels per day is produced (Alaska Department of Natural Resources, 2004).

Cook Inlet

The Cook Inlet watershed contains more than 225 miles of active oil pipelines and more than 690 miles of active natural gas pipelines, approximately 100 miles of active oil and natural gas gathering lines in several onshore production fields, and numerous miles of active natural gas distribution pipelines, particularly in the Anchorage area. First commercial production from an Alaska oilfield began at Swanson River, Cook Inlet in 1959. Five other Cook Inlet fields began production between 1965 and 1972. Most recently, West McArthur River began production in 1993 and Redoubt in 2002. All Cook Inlet oil is currently shipped to the Tesoro refinery at Nikiski on the Kenai Peninsula. Oil from fields on the west side of Cook Inlet is transported by pipeline to the Drift River terminal, and then transported to Nikiski (Alaska Department of Natural Resources, 2004). Oil from the eastside fields is shipped by pipeline directly to the refinery. By year-end 2003, the Cook Inlet had produced almost 1.3 billion barrels of oil, including 10 million barrels of NGLs (Alaska Department of Natural Resources, 2004).

Cook Inlet gas production began in 1959 as a by-product of Swanson River oil development. As more oil and gas fields were discovered, nearby markets for the gas were developed in Anchorage and Kenai to supply space heat and electricity generation. In 1968 Unocal started up the ammonia-urea plant at Nikiski to take advantage of the abundance of cheap stranded natural gas (Alaska Department of Natural Resources, 2004). In recent years, NGL exports to Japan accounted for about 33% of total Cook Inlet gas production. Industrial use of Cook Inlet gas has remained fairly constant since 1983; production has increased in step with the growing residential and commercial demand for space heating and electric power generation (Alaska Department of Natural Resources, 2004). By 1984, net annual natural gas production reached 305 BCF per year and peaked at 311.5 BCF in 1990. Cook Inlet natural gas production has remained relatively stable at an average of 217 BCF per year from 1998 to 2005.

PRODUCED WATER MANAGEMENT

North Slope

The numerical distribution of produced water quality for the Alaskan North Slope area is shown in Figure 6.3. The USGS produced water database contains 22 individual samples of produced water quality for the Alaskan North Slope; the Alaska Oil and Gas Conservation Commission also had two individual water quality samples from the area. Produced water salinity in the Alaskan North Slope included only two produced water quality ranges identified for analysis in this study; from 0 mg/L to 9,999 mg/L and 10,000 mg/L to 49,999 mg/L TDS. Median produced water salinity for the Alaskan North Slope was 28,230 mg/L TDS (saline). The range of salinity values for the Alaskan North Slope ranged from 786 mg/L to 45,640 mg/L with a median of 28,320 mg/L (Figure 6-3). From the small sample set (24 total samples), the majority of samples (92%) indicate TDS results that fall within the 10,000 mg/L to 49,999 mg/L group; the remaining 8% of the samples fall in the group 0 to 9,999 mg/L. Additionally, no collected samples indicate results greater than 49,999 mg/L.

Figure 6.3 Produced Water Quality from the Alaska North Slope

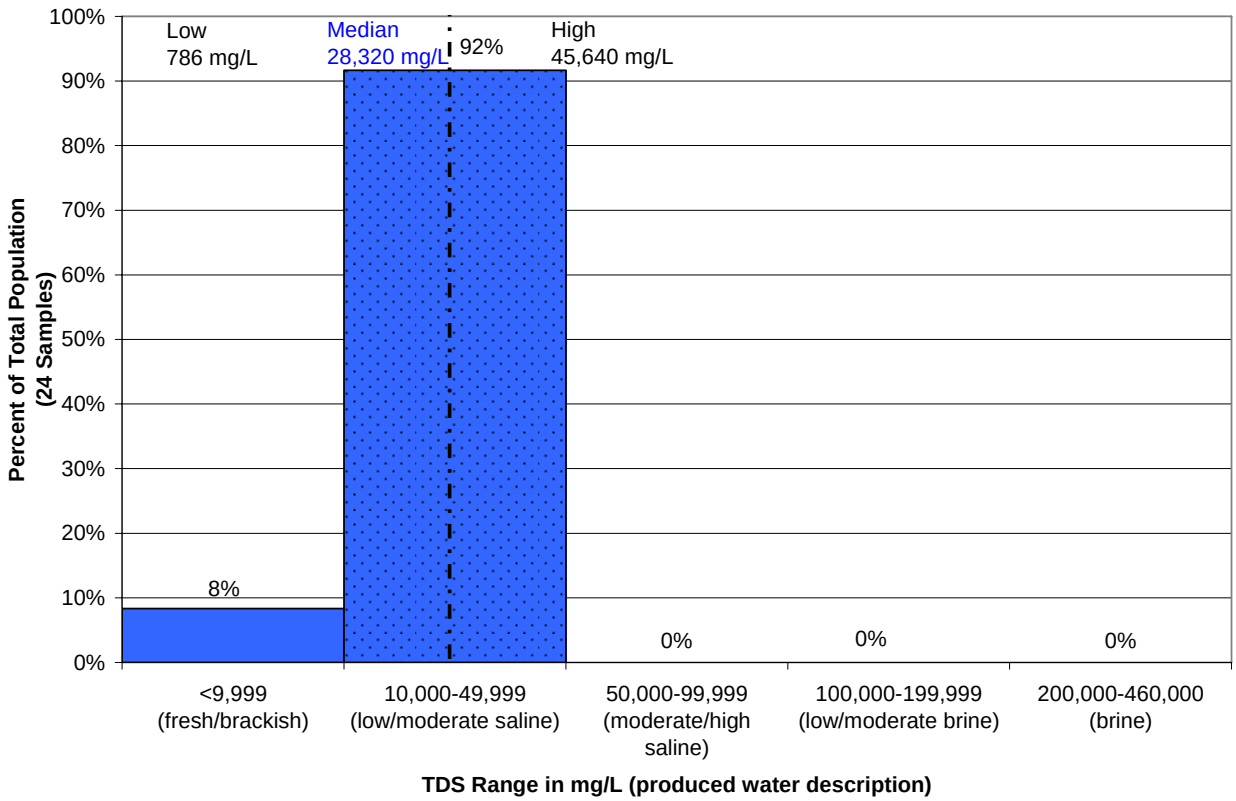


Figure 6.1 documents the spatial distribution of the water quality samples from the USGS produced water database across the Alaskan North Slope showing that the produced water samples were all located in a single area, Prudhoe Bay. While Figure 6.1 graphically delineates the location of the 22 samples as all falling in a single production area, assessment of produced water quality in other regions cannot assume all produced water quality for the Alaskan North Slope would be of the same quality. Produced water from the Alaskan North Slope area is

either injected into the producing reservoirs for pressure maintenance and secondary recovery or into Cretaceous formations for injection disposal (ConocoPhillips, 2006). Secondary recovery and pressure maintenance is also being supplemented by make-up water collected by pumping sea water into the reservoir (Alyeska Pipeline, 2006).

Cook Inlet

The numerical distribution of produced water quality for the Cook Inlet Basin is depicted in Figure 6.4. The USGS produced water database contains 37 individual samples of produced water quality for the Cook Inlet Basin; the Alaska Oil and Gas Conservation Commission also had 38 individual water quality samples from the area. Produced water salinity in the Cook Inlet Basin included three produced water quality ranges identified for analysis in this study; from 0 mg/L to 9,999 mg/L, 10,000 mg/L to 49,999 mg/L, and 50,000 mg/L to 99,999 mg/L TDS. Median produced water salinity for the Alaskan North Slope was 9,605 mg/L TDS (brackish). The range of salinity values for the Cook Inlet Basin ranged from 178 mg/L to 75,717 mg/L (Figure 6.4). Nearly all of the produced water quality samples from the Cook Inlet Basin (99%) have TDS concentrations below 50,000 mg/L (Figure 6.4). Fifty-one percent and 48% of the produced water from this basin fall within TDS results of 0 to 9,999 mg/L or 10,000 to 49,999 mg/L, respectively. Additionally, 1% of the produced water is described within the 50,000 to 99,999 mg/L TDS group.

Figure 6.4 Produced Water Quality from the Alaska Kenai Peninsula/Cook Inlet

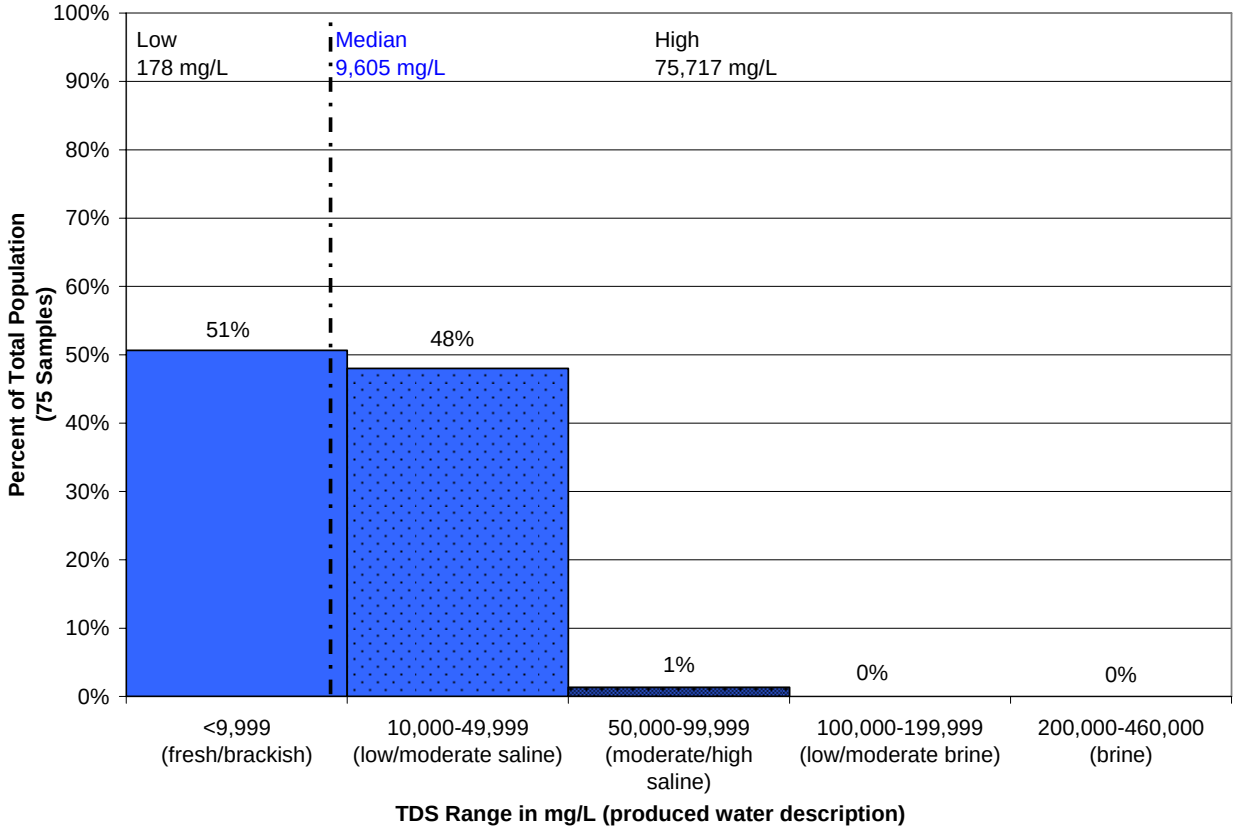


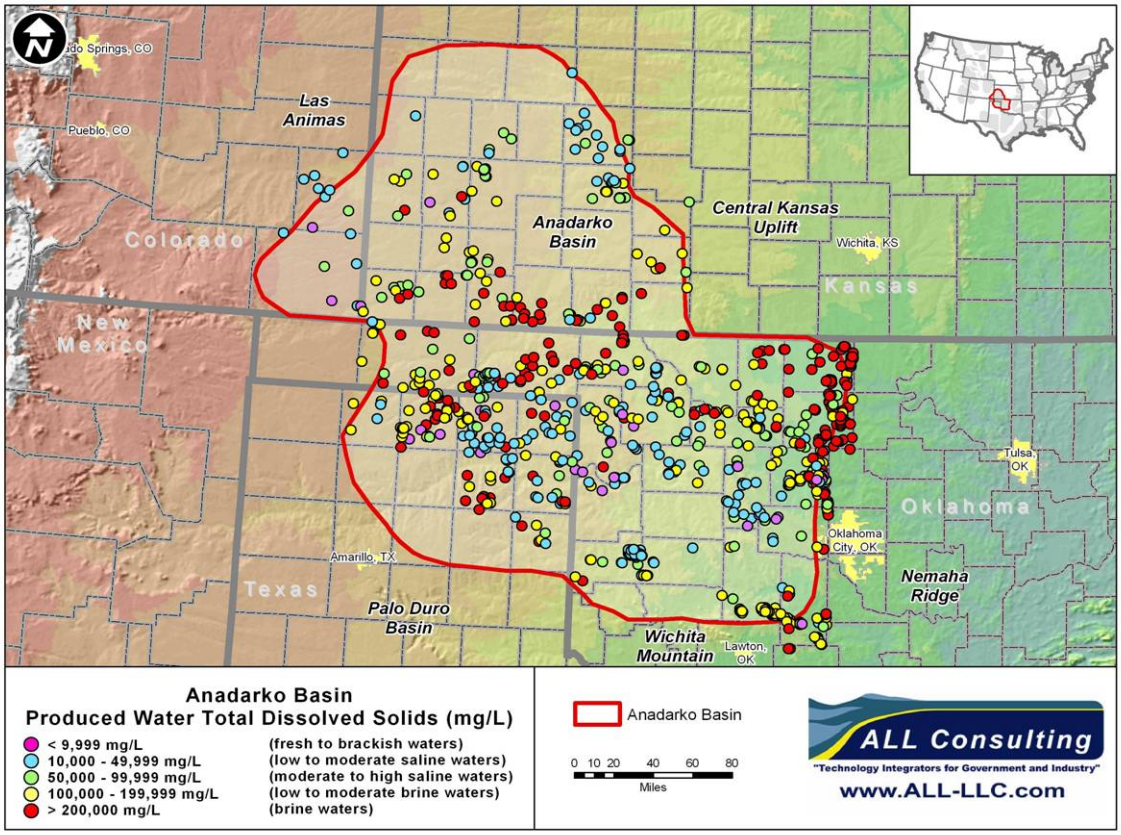
Figure 6.2 documents the spatial distribution of the water quality samples from the USGS produced water database across the Cook Inlet Basin showing that the produced water samples

were concentrated in only a few areas. While Figure 6.2 graphically delineates the location of the 37 samples as all falling in a few production areas, assessment of produced water quality in other regions of this basin cannot assume all produced water quality for the Cook Inlet Basin would be of the same quality. In general, produced water from onshore oil and gas facilities in Cook Inlet Basin is disposed of via Class II disposal wells or is used for enhanced recovery. Since 1968, the produced water volume in the Swanson River Field has consistently fluctuated near 0.2 bbls/day, with a spike in volume between 1972 and 1973.

Section 6.2 Anadarko Basin

The Anadarko Basin covers a large portion of the Southern Great Plains; the majority of the basin is located in western Oklahoma and the basin extends into the northeastern Texas panhandle, southeastern Colorado, and southwestern Kansas (Henry and Hester, 1995). Figure 6.5 shows the approximate extents of the basin, lying in a northwest to southeast orientation, with the Wichita Mountains to the south; the axis and deepest portion of the basin lying just north of the mountains. The basin is further bounded by the Palo Duro Basin to the southwest, Las Animas Arch to the northwest, the Central Kansas Uplift to the northeast, and Nemaha Ridge to the southeast. The Anadarko Basin covers an area of approximately 50,000 square miles (Henry and Hester, 1995).

Figure 6.5 Geologic Setting and Produced Water Quality Distribution of the Anadarko Basin



(Source: USGS, 2005)

Significant Geological Features

The Anadarko Basin contains strata of Cambrian through Permian age with a thin veneer of Tertiary continental sediments. Most of the basin-fill volume is taken up with the Ordovician through Permian sediments that accumulated in the ancient seaway. The sources of the older sediments were the Paleozoic outcroppings to the north and the ancestral Rocky Mountains to the west. The important strata in the basin include the Lower Ordovician Arbuckle Formation, which is the same age and similar in lithology to the massive Knox carbonates of the Appalachians and the Ellenberger of Texas. The Upper Ordovician through Mississippian section is present as thickened versions of thinner strata that blanketed most of the Mid-Continent. During the Pennsylvanian and Permian eras the Wichita Mountains to the south began to emerge from the seaway as the Anadarko basin began to vanish.

The result of this long history of sedimentation is the thick sedimentary column over 40,000 feet thick in some places that holds a variety of hydrocarbon-bearing reservoirs. In addition, the sedimentary column holds several zones that make thick, permeable injection zones that are able to serve as disposal reservoirs. Formations such as the Permian Red Cave and Ordovician Arbuckle can receive water at rates of thousands of barrels per day on a long-term basis.

Oil and Gas Production

Oil and gas has been produced from the basin's shallow, prolific oil pools and deep, high-pressured gas reservoirs. First production from the basin was in the 1890's with more than 2.3 billion barrels of oil (BBO) and more than 65.5 trillion cubic feet of gas (TCFG) having been produced to date. Since the conception of oil and gas activity in the Anadarko Basin, wells have produced low quality water, commonly referred to as brine.

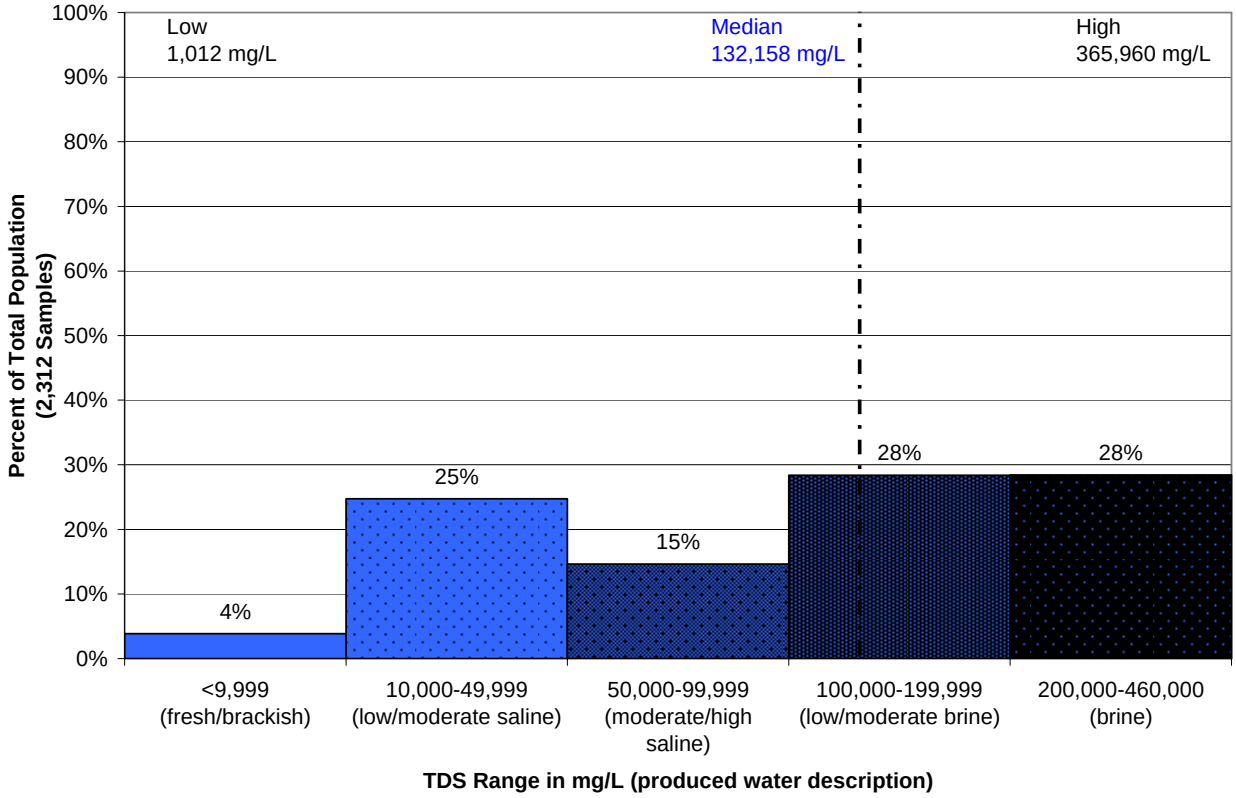
Earliest petroleum production was from shallow reservoirs that had prominent surface expression such as the Oklahoma City Field and Cement Field. As the technology progressed, deeper reservoirs could be exploited so that by the 1960's, exploratory wells were being drilled below 30,000 feet in the Anadarko Basin. Currently, production in the basin is on the decline although the number of feet of exploratory holes drilled each year remains high. Among the plays generating interest are deep reservoirs near the center of the basin, stratigraphic traps throughout the basin, existing continuous reservoirs in the Permian Hugoton Gas Field, and new unconventional, continuous reservoir accumulations in the Woodford-Chattanooga sequence. These plays have implications for produced water management in the Anadarko Basin.

Produced Water Management

Oil and gas operators in the Anadarko Basin have utilized several options for the management of produced water. Typically oil and gas production in the Anadarko Basin has utilized injection as the primary management practice for produced water. The presence of permeable disposal zones at readily drillable depths has helped the oil and gas industry in the Anadarko Basin to manage produced salt water volumes. Early in the production life of a field, operators are typically disposing of produced water in an injection zone not connected to the producing reservoir. As oil and gas fields in the basin age, production declines and operators have the option of initiating a water flood with their produced water.

Produced water quality data for this basin is presented in two ways – numerically and geographically. The numerical distribution of produced water quality is shown in Figure 6.6. The USGS produced water database contains 2,312 individual samples of produced water quality for the Anadarko Basin. Produced water salinity in the Anadarko Basin includes all of the ranges identified for analysis in this study, from <10,000 mg/L to >200,000 mg/L TDS. Median salinity expressed as TDS is relatively high at 132,158 mg/L (low to moderate brine waters). The range of salinity values for the Anadarko Basin ranged from 1,012 mg/L (slightly brackish) to 365,960 mg/L (brine) (Figure 6.6). More than half (56%) of the produced water samples collected from the Anadarko Basin had TDS concentrations greater than 100,000 mg/L, which would be classified as brines. Approximately 4% of the samples in the USGS produced water database had salinity values less than 10,000 mg/L (brackish waters). Produced water varies across the basin from saturated (approximately 350,000 mg/L) brines to waters less than 10,000 mg/L (Bein and Dutton, 1993). While most of this produced water is used in secondary oil recovery operations, some water is disposed of into scattered commercial disposal wells.

Figure 6.6 Produced Water Quality from the Anadarko Basin



(Source: USGS, 2002)

Figure 6.5 documents the geographical distribution of water quality samples across the basin showing that produced water quality varies randomly. This map indicates that the small amount of high quality produced water with TDS less than 10,000 mg/L is widely scattered from the deep basin to the Anadarko Shelf on the north side of the basin. Figure 6.5 shows that 4% of the water quality samples from the reservoirs held brackish quality water less than 10,000 mg/L TDS. Some of this high quality water is shallow, the result of fresh water that has

entered oil reservoirs from the surface; this water could have a beneficial use if the oil and grease content was appropriate or could be removed prior to beneficial use. Water less than 10,000 mg/L would appear to be of minor importance in the Anadarko Basin because of the relatively small percentage (4%) it represents of the produced water from the basin.

Figure 6.5 shows that 25% of the produced water in the Anadarko Basin falls in the water quality range from 10,000 to 49,999 mg/L TDS (low to moderate saline waters). Although for most surface beneficial uses this water is of insufficient quality, there are some options for the treatment of this water to enable it to be used. Figure 6.5 shows the distribution of the majority of the water produced (TDS >50,000 mg/L) in the basin is scattered across the basin. This produced water can be used for secondary recovery in water floods of local oil reservoirs. Many times the water is filtered and treated and pumped back into the reservoir it came from. Other water is transported to another water flood in the area that is in need of “make-up” water to begin or maintain a flood. Often at the initiation of a flood, insufficient water volume exists in the field and outside water will need to be supplied. Oil and gas operators ensure that the outside water is fully compatible with the water chemistry of the flooded reservoir and that the water is free of suspended sediment. Material either dissolved or suspended in the flood water injected into the reservoir can cause plugging either in the injection wells or within the reservoir itself, thereby reducing flow and production.

There are areas where water floods are not utilized, commonly in gas-producing areas; produced waters that are not able to be used for surface uses are disposed of by injection into saltwater-bearing reservoirs. Injection disposal is discussed in more detail in Section 4.

Many parts of the Anadarko Basin have only minor oil production and, therefore, the need for secondary recovery water flood injection is not great. One of these areas is the giant Hugoton gas field in parts of Kansas, Oklahoma, and Texas. This shallow, continuous gas field was initially developed in the 1940’s and has been in operation since then. As the wells increase in age, they could begin to produce more water. In the Hugoton, the primary option for produced water management is to use dedicated disposal wells, either owned by the oil and gas operator or commercial wells. The expense of managing the increasing volumes of produced water from these wells can be enough to cause early abandonment of the producing well. Some operators have installed disposal wells but with the wide spacing of wells in the field, the disposal wells may be long distances from the producing wells, requiring additional transportation costs.

A produced water reduction alternative is to use Downhole Gas/Water Separators (DGWS) and the injection of the produced water into a separate water-bearing zone perforated within a producing gas well. Produced water from nearby wells can also be accommodated in these wells if the receiving zone is capable of accepting the additional volume of water. Several gas wells have been equipped with DGWS in the Oklahoma and Kansas portions of the Hugoton. One of the benefits of DGWS technology is its hygiene; if water does not get to the surface for storage and filtering, it is less likely to pick up impurities, including sulfate-reducing bacteria. In parts of the Kansas portion of the Hugoton, H_2S is being produced where none had been produced historically. This apparently has been caused by operators introducing surface waters into the reservoir formations where they have proliferated to liberate enough H_2S gas to reduce the natural gas value and make it potentially harmful to livestock and humans. DGWS completions may have applicability in other gas fields as a way of efficiently managing produced water.

Similar completions have been used in water floods to rapidly achieve fill-up of the reservoir. "Dump-flood" wells can produce saltwater from a prolific, non-hydrocarbon bearing zone and pump it directly into the flood zone without drawing the water to the surface. Such wells must be carefully engineered to convey clean water to the flooded reservoir and avoid suspended material that may plug the reservoir. Such wells in Oklahoma can move thousands of barrels of produced water every day at very low costs.

Several "de-watering" projects are underway in Oklahoma and Kansas that utilize high rates of water production in a different setting. These projects produce large volumes of water from previously watered-out fields. Producing wells utilize large electric submersible pumps to produce high volumes of saltwater every day until oil begins to move to the wellbore. Produced water is disposed into injection wells utilizing thick, continuous injection zones such as the Arbuckle Formation.

Section 6.3 Arkoma Basin

The Arkoma Basin is a medium-sized interior basin located in southeastern Oklahoma and west-central Arkansas (Perry, 1995). Figure 6.7 shows the approximate extents of the basin. The Arkoma Basin is bisected by the Oklahoma-Arkansas border and lies in slight southwest to northeast orientation (Figure 6-10). The basin is bounded by the Ozark uplift to the northeast, the Cherokee Basin to the northwest, and the Ouachita Foldbelt to the south as shown in Figure 6.7. The Arkoma Basin covers an area of approximately 33,800 square miles (Perry, 1995).

Significant Geological Features

The Arkoma Basin is filled with Cambrian through Pennsylvanian sediments that have been folded, faulted, and heated to such an extent that the traps contain only dry gas. The basin contains nearly all of the early to middle Pennsylvanian section (Perry, 1995). The sedimentary rocks present in the basin range from 3,000 to 20,000 feet in thickness and are composed of pre-Mississippian carbonate shelf deposits, Mississippian marine shales and Pennsylvanian fluvial deposits (Perry, 1995).

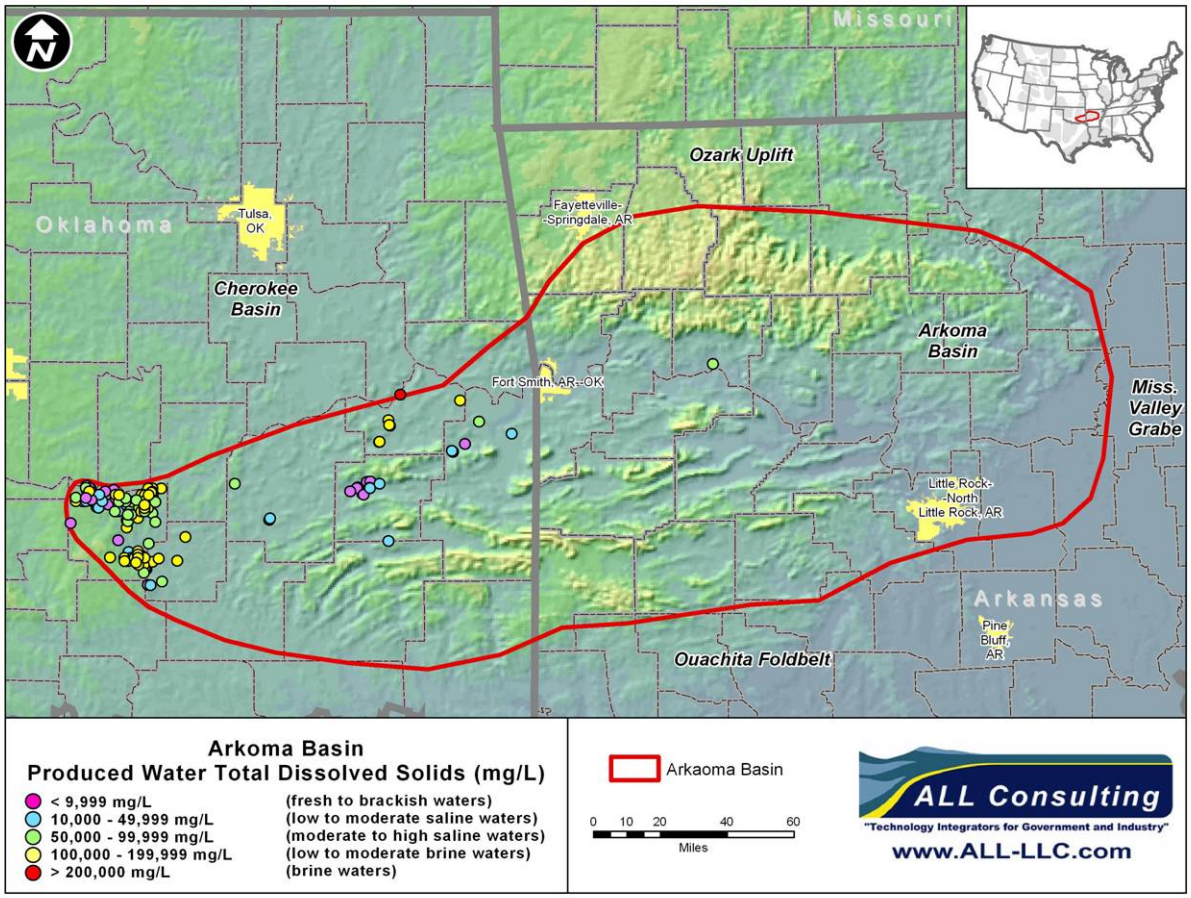
Heating that the area has undergone has driven out much of the pore water within the basin; only minor amounts of water are produced in conventional gas wells. Groundwater is present only in alluvium within the basin and any water wells will be sourced by this alluvium.

Oil and Gas Production

Natural gas has been produced in this basin since 1910 (Perry, 1995) and continues to the present. The geology of the basin indicates that little or no formation water is present in any of the oil and gas reservoirs. Gas is trapped in large structural reservoirs, in small- and medium-sized stratigraphic traps, and in coal bed natural gas accumulations. CBNG wells make only small amounts of formation water while conventional gas wells produce no formation water, but do produce small volumes of water that exist in the gas reservoir as water vapor entrained with the natural gas. When the natural gas is produced, the water vapor condenses at the surface. In high-flowing gas wells, the condensed vapor can represent a large volume. This water is typically very high quality and locally would have beneficial uses if the regulatory environment would allow its use.

At the present time, the Mississippian Fayetteville shale is being developed as a source of unconventional shale gas similar to the Barnett play in the Fort Worth Basin. Drilling and production of gas from the Fayetteville could become as important as the Barnett play. The Mississippian Fayetteville is a thick, highly bituminous shale that can produce natural gas as a continuous reservoir. To date, approximately 82 wells have been completed, 53 are producing gas, and others are drilling or are awaiting completion. Of the 82 completed wells, 31 are horizontal wells; 13 of these have been completed and have an average production off 2.5 mmcf per day. These wells are scattered over seven counties in Arkansas (Southwest Energy, 2006). Like the Barnett wells, the Fayetteville wells are fracture treated before the wells produce sizable gas volumes. Fracturing has been done using high pressure nitrogen, although some wells have used water and sand. It is possible that in the future these shale-gas wells will be similar to Barnett wells in that they may receive large water-fracs that could cause the wells to produce large volumes of water with the natural gas.

Figure 6.7 Geologic Setting and Produced Water Quality Distribution of the Arkoma Basin



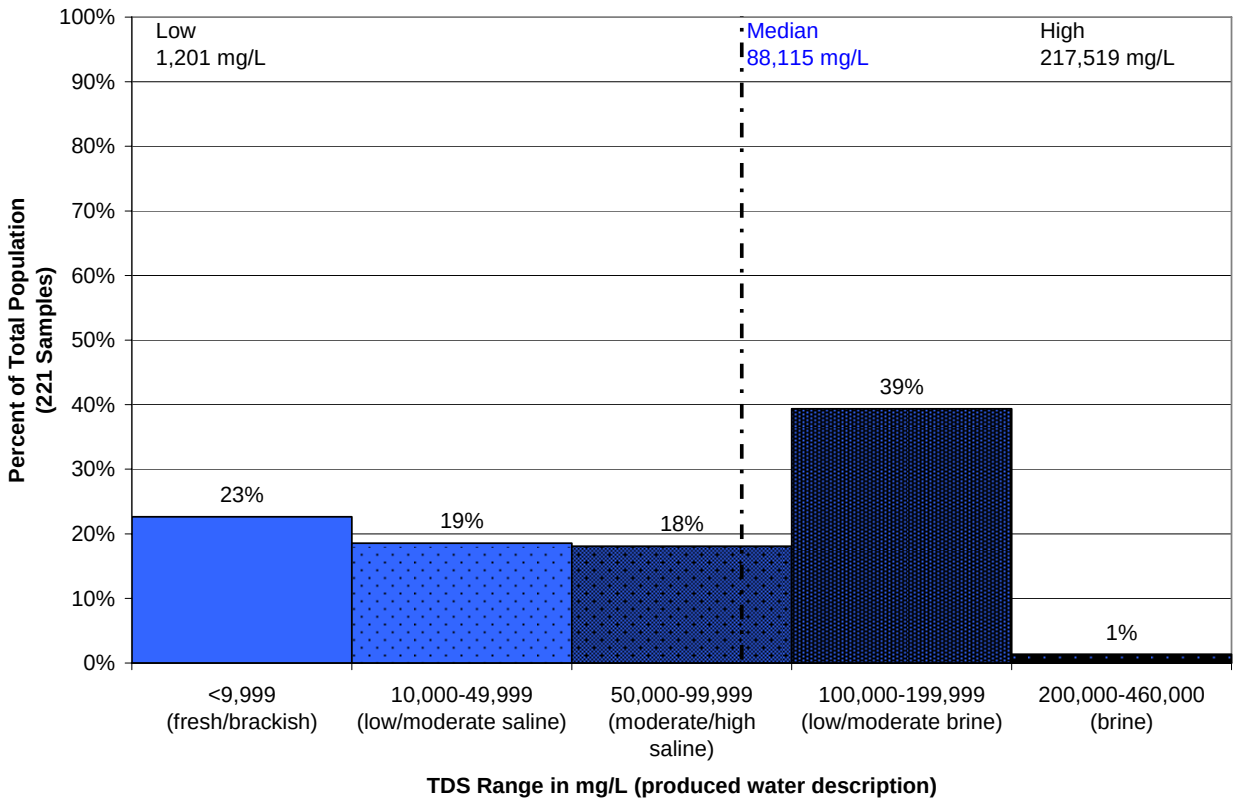
(Source: USGS, 2005)

Produced Water Management

The USGS produced water database lists 221 samples of produced water from the Arkoma Basin, and includes samples from a variety of formations and depths. Figure 6.8 documents the

quality of the produced water from the USGS produced water database for the Arkoma basin. The produced water from this basin appears to be relatively poor in quality with 1% of the samples having TDS concentrations greater than 200,000 mg/L (brine waters), 39% of the samples having TDS concentrations between 100,000 and 199,999 mg/L (low to moderate brine waters), and 18% of the samples having TDS concentrations between 50,000 and 99,999 mg/L (moderately saline to saline waters). The median produced water quality for the Arkoma Basin was saline water with a TDS of 88,115 mg/L. The salinity values for the basin range from a low of 1,201 mg/L (slightly brackish) to a high of 217,519 mg/L (moderate brine) (Figure 6.8). Approximately 23% of the samples in the USGS produced water database had a TDS less than 10,000 mg/L (brackish waters); this is water of sufficient quality that it may have some beneficial uses.

Figure 6.8 Produced Water Quality from the Arkoma Basin



(Source: USGS, 2002)

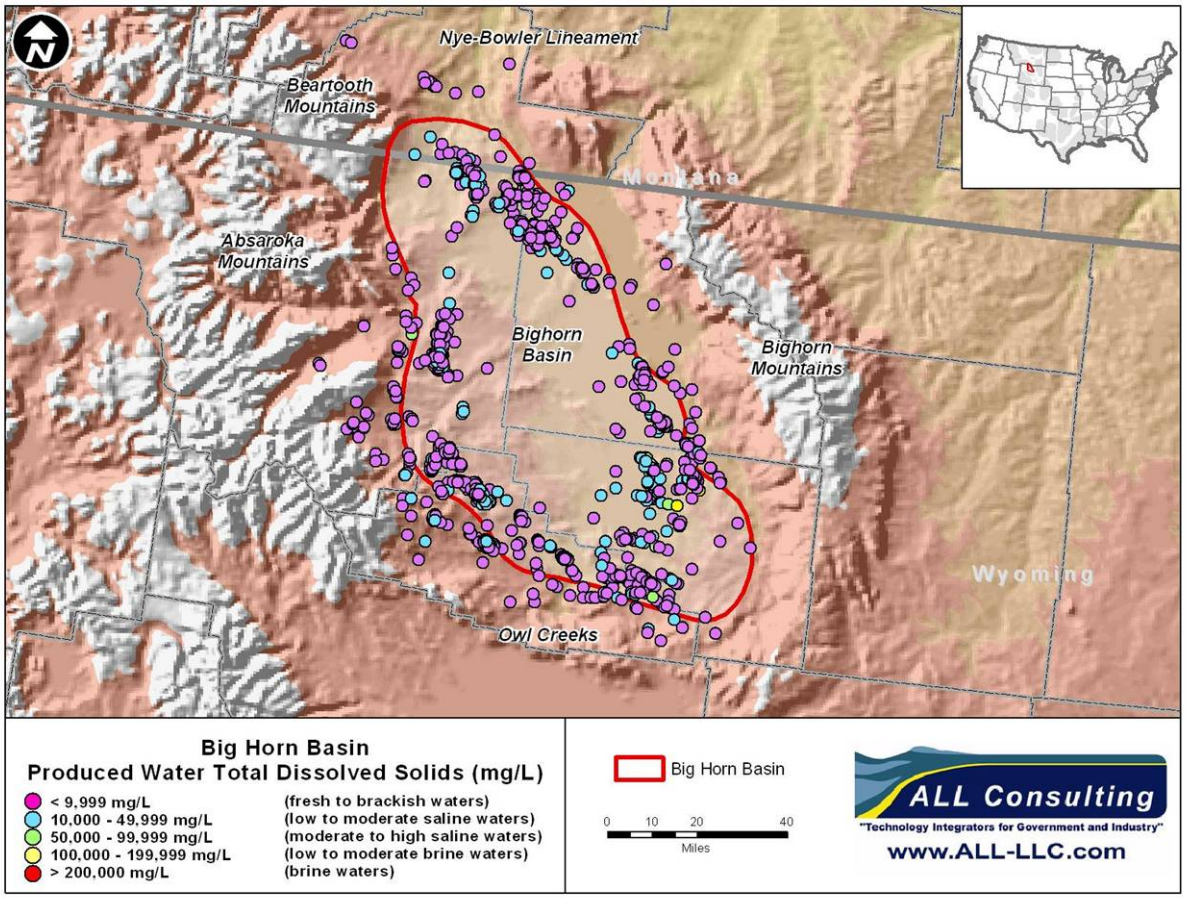
Figure 6.7 documents the distribution of USGS produced water quality samples across the Arkoma Basin showing the produced water quality distribution across the basin. The geographical distribution of water salinity as shown in Figure 6.7 indicates that the brackish quality produced water with TDS <10,000 mg/L (23% of the total) is scattered from the western edge of the basin to the center portion of the basin. Water volumes from conventional natural gas production are minor and scattered. Other brackish quality water is recovered from deep, high-flowing natural gas wells where the water comes to the surface as vapor entrained in the natural gas and condenses at the surface. Some of this water is produced in water-starved areas such as southeastern Oklahoma and could have important beneficial uses if the

regulatory framework would allow (Baker, 2005). Most of the produced water is not a viable beneficial use source except for localized uses, unless Fayetteville shale-gas development becomes as prolific as the Barnett play and large volumes of water are produced from these wells. Oil and gas operators in the Arkoma Basin have utilized several options for the management of produced water. Typically oil and gas producers in the Arkoma Basin have utilized injection as the primary management practice for produced water. The presence of permeable disposal zones at readily drillable depths has helped the oil and gas industry in the Arkoma Basin to manage produced saltwater volumes.

Section 6.4 Bighorn Basin

The Bighorn Basin covers north-central Wyoming extending into south-central Montana (Fox and Dolton, 1995a). Figure 6.9 shows the approximate extents of the asymmetric heart-shaped Bighorn Basin which lies in a northwest to southeast orientation located between the Bighorn Range and the Rocky Mountain Range. Surrounding the basin are the Bighorn Mountains to the east, the Beartooth and Absaroka Mountains to the west, the Nye-Bowler Lineament to the north, and the Owl Creeks to the south. The Bighorn Basin covers an area of approximately 13,200 square miles (Fox and Dolton, 1995a).

Figure 6.9 Geologic Setting and Produced Water Quality Distribution of the Bighorn Basin



(Source: USGS, 2005)

Significant Geological Features

The Bighorn Basin contains strata of Cambrian through Tertiary age. The sources of the sediment are the fault bounded Laramide uplifts that surround the basin (Fox and Dolton, 1995a). The important strata for oil and gas development in the basin are the Permian and Cretaceous source rocks and reservoirs, which include the Pennsylvanian Tensleep Sandstone, Permian Phosphoria, and Upper Cretaceous Frontier sandstones.

Oil and Gas Production

Oil and gas has been produced from the basin margin anticlinal structures since their discovery in 1906 and 1907 (Fox and Dolton, 1995a). Oil and gas production in the Bighorn Basin has occurred from formations ranging in age from Cambrian to Late Cretaceous.

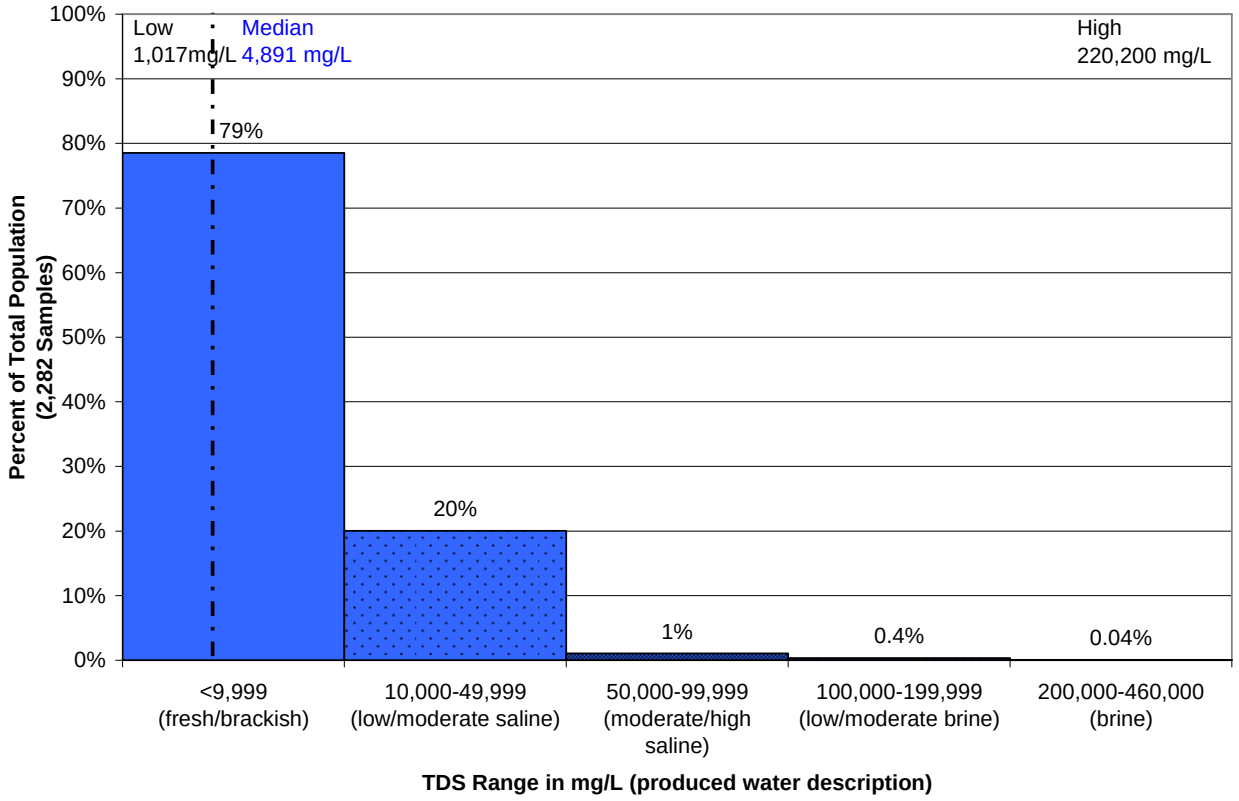
Produced Water Management

Oil and gas operators in the Bighorn Basin have utilized both enhanced recovery and agricultural beneficial use for the management of produced water. Typically, oil and gas production in the Bighorn Basin has utilized injection for enhanced oil recovery as the primary management practice for produced water.

The numerical distribution of produced water quality for the Bighorn Basin is shown in Figure 6.10. The USGS produced water database contains 2,282 individual samples of produced water quality. Produced water salinity in the Bighorn Basin includes all of the ranges identified for analysis in this study, from <10,000 mg/L to >200,000 mg/L TDS. Median produced water salinity is relatively good at 4,891 mg/L (moderately brackish). The range of salinity values for the Bighorn Basin ranged from 1,017 mg/L (slightly brackish) to 220,200 mg/L (moderate brine) (Figure 6.10). Most of the produced water quality samples from the Bighorn Basin (79%) have TDS concentrations less than 10,000 mg/L, which would be classified as brackish waters with the potential for beneficial uses. The USGS produced water database also includes nearly 20% of the samples for the Bighorn Basin in the next highest water quality category from >10,000 mg/L to <50,000 mg/L TDS. The three remaining produced water quality distributions discussed in this report contained less than 1.5% of total number of samples in the USGS produced water database (Figure 6.10).

Figure 6.9 documents the spatial distribution of water quality samples across the Bighorn Basin indicating that the low TDS produced water is widely distributed. The higher salinity produced water (that produced water with TDS >100,000 mg/L) from the USGS produced water database is located in the southeastern portion of the basin in Washakie County, Wyoming (Figure 6.9). Some of the high quality water is from shallow reservoirs with fresh water recharging these zones from the surface, while the low quality water is from deeper reservoirs in the deeper portions of the basin. The Bighorn Basin contains a large portion of low salinity water that is widely distributed as shown in Figure 6.9. Once the oil and gas have been separated from the water, this low salinity water can have important beneficial uses in addition to enhanced recovery of resources; the water can be utilized by local landowners for livestock watering, irrigation, and other beneficial uses.

Figure 6.10 Produced Water Quality from the Wyoming and Montana Portions of the Bighorn Basin



Source: USGS, 2002

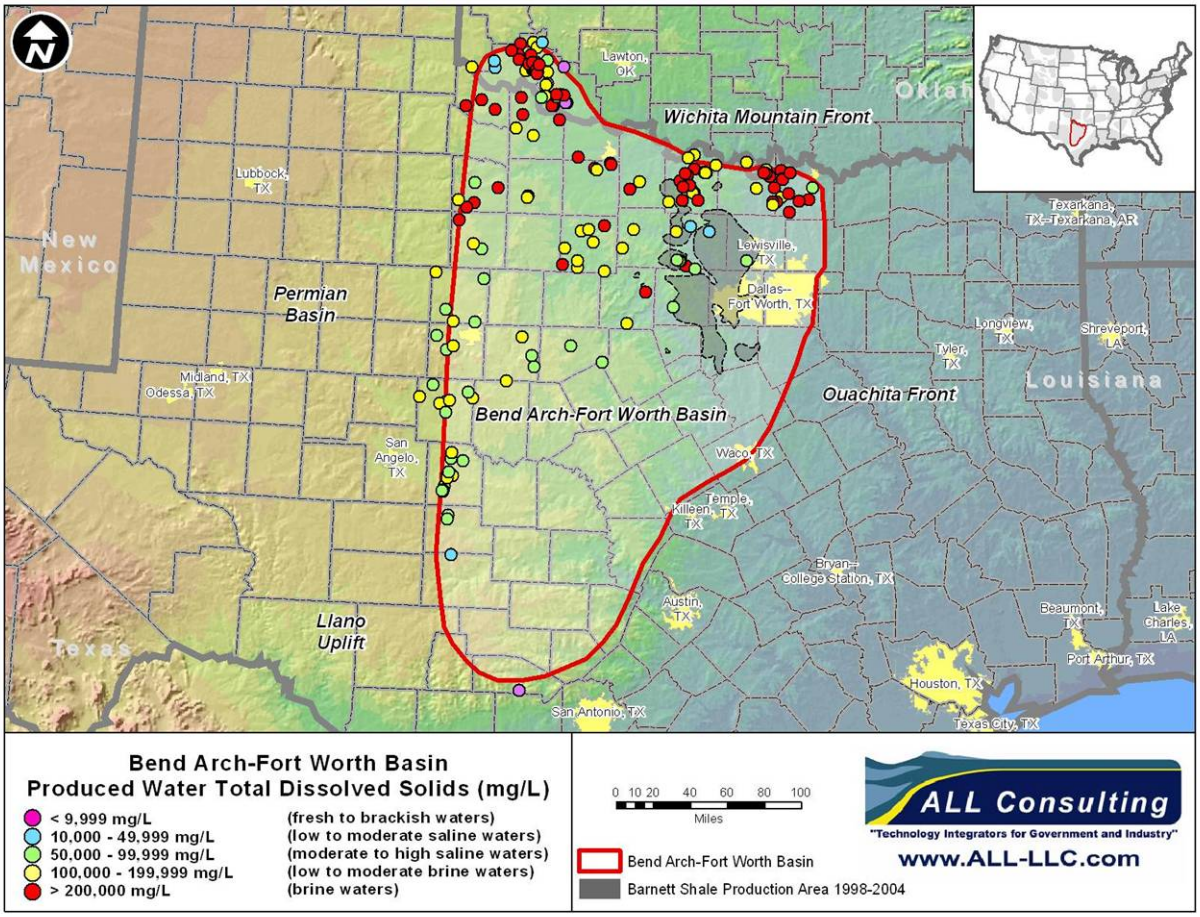
Within the Bighorn Basin, water quality varies by producing formation; typically produced water quality decreases with depth in a basin. Produced water quality for the Madison, Phosphoria, and Tensleep formations of the Bighorn Basin from the Wyoming Oil and Gas Conservation Commission (WOGCC) are presented below. Produced water from the WOGCC for the Madison Formation varies from less than 500 mg/L to 4,000 mg/L TDS (WOGCC, 2006). The Phosphoria Formation produces water ranging from less than 500 mg/L to more than 80,000 mg/L TDS. The Tensleep Formation produces water ranging from less than 2,000 to more than 4,000 mg/L TDS. The majority of produced water from this basin is used in secondary recovery operations while some volumes are used for agricultural purposes.

Section 6.5 Fort Worth Basin

The Fort Worth Basin covers a large portion of north-central Texas and small portion of southwestern Oklahoma. The basin is bounded by the Wichita Mountains to the north, the Ouachita Front to the east and south, the Permian Basin to the west, and the Llano Uplift to the south (Ball and Perry, 1995). Figure 6.11 shows the approximate extents of the basin. The Fort Worth Basin has a similar geological history to the Anadarko Basin to the north and the Permian Basin to the south. Figure 6.11 shows the basin to lie in a north to south orientation

along its western edge where it junctions with the Permian Basin (Ball and Perry, 1995). The Fort Worth Basin covers an area of approximately 54,000 square miles.

Figure 6.11 Geologic Setting and Produced Water Quality Distribution of the Fort Worth Basin



Source: USGS, 2005

Significant Geological Features

The sedimentary strata filling the Fort Worth Basin are mostly Paleozoic in age from Ordovician through Permian. A thin veneer of Cretaceous sediments hold the drinking water aquifers of the area and covers the older section containing oil, gas, and saltwater reservoirs. The total thickness of sediments in the Fort Worth Basin is approximately 12,000 feet or less. Some faulting is present on the edges of the basin. Conventional oil and gas development have taken place in the basin for a long time, but recently the development of unconventional gas in the Barnett shale has dominated the drilling in this basin. The Barnett gas play is currently the most active development in the United States.

Oil and Gas Production

The Fort Worth Basin has produced commercial quantities of oil and gas for most of the 20th Century. First production from the basin was in the early 1900's with more than 2.3 BBO and more than 65.5 TCFG having been produced to date. Productive reservoirs include the

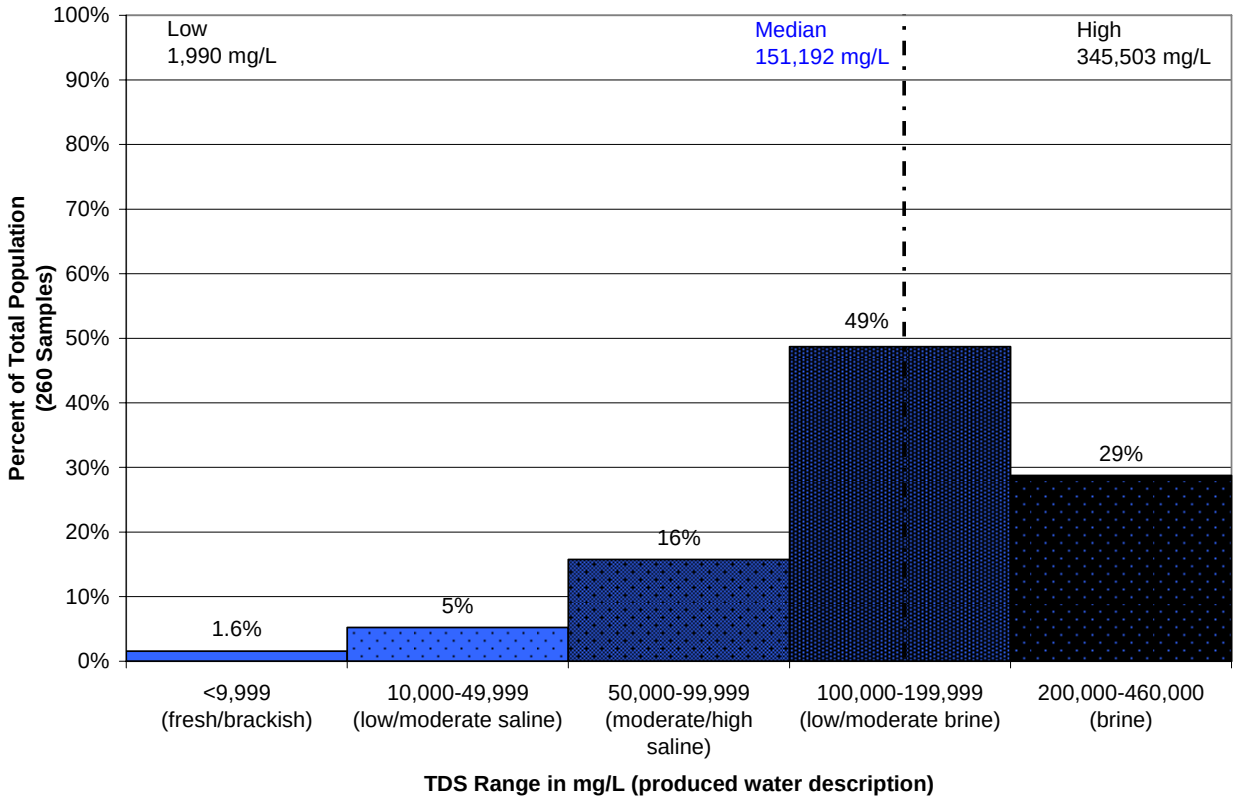
Ellenberger, Mississippian, and prolific Pennsylvanian/Permian sands. Fields developing these formations have been producing mostly oil since the 1960's. The biggest play at the present time is the Mississippian Barnett shale, a thick, highly organic, siliceous fine-grained rock laid down over most of the basin. The Barnett is a self-sourced reservoir that holds large quantities of dry natural gas that can be produced if the reservoir rock is fractured. Figure 6.11 shows the extent of the Barnett play in the basin. Horizontal wells have become prolific dry gas Barnett producers in the past few years. After drilling, the horizontal wells are fractured with huge volumes of water to open permeability in the fine-grained rock. Once natural gas production has been established, the water used to fracture the reservoir is produced back to the surface. Therefore, the Barnett wells produce large volumes of frac water that needs to be managed.

The Newark East Barnett field (noted on Figure 6.11 as the Barnett Shale production area from 1998 – 2004) is currently the largest gas field in Texas and the most active drilling area in the nation. Total production from the Barnett through October 2005 was 5.6 million barrels of oil and 1.6 TCFG. At the end of 2005 there were approximately 4,500 producing Barnett wells with total daily gas production rates of approximately 9.62 BCF and approximately 3,367 barrels of oil per day. There is an estimated 26 TCF of gas recoverable in the play (Rushworth, 2006).

Produced Water Management

Most oil and gas production has associated water production in the basin, but other than the frac water from the Barnett wells, the volumes are not large. Management historically has been by way of water floods or injection disposal wells. Figure 6.12 charts the numerical distribution of water quality across the basin from the USGS produced water database, which contains 768 individual samples of produced water quality for the Fort Worth Basin. Produced water salinity in the Fort Worth Basin includes the ranges from <10,000 mg/L to >200,000 mg/L TDS. Median salinity expressed as TDS is high at 151,192 mg/L (moderate brine). The range of salinity values for the basin ranged from 1,990 mg/L (brackish) to 345,503 mg/L (brine) (Figure 6.12). The distribution is quite similar to the Permian and Anadarko basins suggesting their similar geological history. Of the 768 produced water quality samples from the Fort Worth Basin, the largest portion of the produced water quality samples (49%) for the Fort Worth Basin were reported in the 100,000 mg/L to 199,999 mg/L range (Figure 6-18). The next largest distribution of produced water quality for the basin (29%) was the 200,000 mg/L to 460,000 mg/L TDS range (Figure 6-18). The large percentage (80%) of produced water in the brine quality ranges suggests that few beneficial uses exist for the produced water from this basin other than for water flood projects.

Figure 6.12 Water Quality Distribution in the Fort Worth Basin



(Source: USGS, 2002)

Figure 6.11 documents the distribution of water quality samples across the Fort Worth Basin showing how the produced water quality varies throughout the basin. The geographic distribution of water salinity shown in Figure 6.11 reflects higher TDS water is more prevalent in the northern and western portions of the basin, and the lower TDS water is present in the central and eastern portions of the basin. Produced water with greater than 100,000 mg/L TDS is more prevalent in the northern portion of the basin, near the Texas-Oklahoma border (Figure 6.11). The produced water quality samples with TDS less than 100,000 mg/L are more predominant in the central and eastern portions of the basin with some associated produced water samples of higher TDS present in this area (Figure 6-19).

Currently the Barnett production has taxed the water management options when the water used to fracture the well is produced to the surface. Few disposal wells existed in the basin before the hundreds of Barnet wells were drilled. Over most of the basin, the Pennsylvanian sands and the Ellenberger carbonates water-bearing permeable units traditionally have been used for disposal by Class II disposal wells. The Ellenberger has more capacity, consisting of thick carbonates that often are naturally fractured and cavernous. Pennsylvanian sands are present above the Barnett and are drilled through by each producing well. The Ellenberger, however, is situated beneath the Barnett shale and is not drilled by the Barnett field wells.

Produced water from the Barnett development is a challenge for operators in the basin. A fracture job on a horizontal well can utilize more than 2 million gallons of water that is then

produced back to the surface during the productive life of the well. Operators often use water from municipal water systems to be sure that the water is clean and contains no live bacteria that could be introduced into the formation. The fracture water that is brought back to the surface during production has picked up some oil and grease, dissolved salts, and may contain >100,000 mg/L TDS. Water of this quality could be treated to drinking water or irrigation quality, but to date the water has not been treated. However, some of this produced water is re-used by operators for fracturing other wells in the field. Most of the produced water is sent to disposal wells in the basin.

In January 2005, the Texas Railroad Commission approved a pilot project to be conducted by Fountain Quail Water Management to treat fracture-job flow-back water in the Barnett Shale trend on a lease held by Devon Energy in North Texas for the purposes of recycling the fluid. The approval given by the Commission allows the recycling operations to go forward without the need to obtain certain permits or additional financial assurance for the operation. A skid-mounted device located at the site of a Barnett well to be fracture stimulated is utilized to distill produced water brought in from off-site. The produced water is distilled through a series of heat exchangers yielding 2,000 barrels of distilled water for every 2,350 barrels of produced water put into the system. The remaining 350 barrels of saltwater and waste require off-site disposal at a conventional Class I injection facility. Once a sufficient volume of distilled water is produced, the water may be used for fracture stimulating a Barnett well on Devon's lease (Forbis, 2005).

In addition to using commercial injection wells, Class II (oil and gas) injection wells are also used for disposal of produced water in the Fort Worth Basin. Class II injection well permits can be difficult to obtain and the permit process can be delayed by citizen protests. One aspect of the Barnett play that is different from other oil and gas plays is the fact that oil and gas activity in the Barnett is centered on and around the city of Fort Worth, Texas, and its suburbs. Because the Barnett play is located near an urban area, development is often surrounded by residential homes with residents that may not be familiar with oil and gas production facilities. Because of the large urban population and their water needs, injection pressure gradients incorporated into disposal permits are curtailed in some areas for the shallow Pennsylvanian sands in order to prevent impact to overlying drinking water aquifers. At these lower injection pressures, Class II disposal wells completed into the Pennsylvanian sands often cannot inject enough water to make the wells economical to operate. One option is for operators to complete wells in the deeper Ellenberger zone where higher pressure gradients can be permitted to inject and large quantities of water can usually be injected. However, Barnett wells are completed at shallower depths than the Ellenberger zone; because of this, operators who wish to use an Ellenberger disposal well will need to drill a different well for this purpose. The necessity of drilling a separate disposal well to the Ellenberger adds considerably to the expense of the injection well installation.

Section 6.6 Greater Green River Basin

The Greater Green River Basin is located in the Rocky Mountain Foreland from western to south-central Wyoming and extends into northeastern Utah and northwestern Colorado (Law, 1995). Figure 6.13 shows the basin to lie in a northwest to southeast orientation located between the Uinta Uplift to the southwest and the Hanna and Wind River Basins to the northeast and east. The Greater Green River Basin is further bounded by the Medicine Bow and Park Range Uplifts to the south-southeast, Wyoming-Utah-Idaho Thrust Belt to the northwest, and the Absaroka Mountains to the north. The Greater Green River Basin covers an area of approximately 19,700 square miles (DeJarnett et. al., 1997).

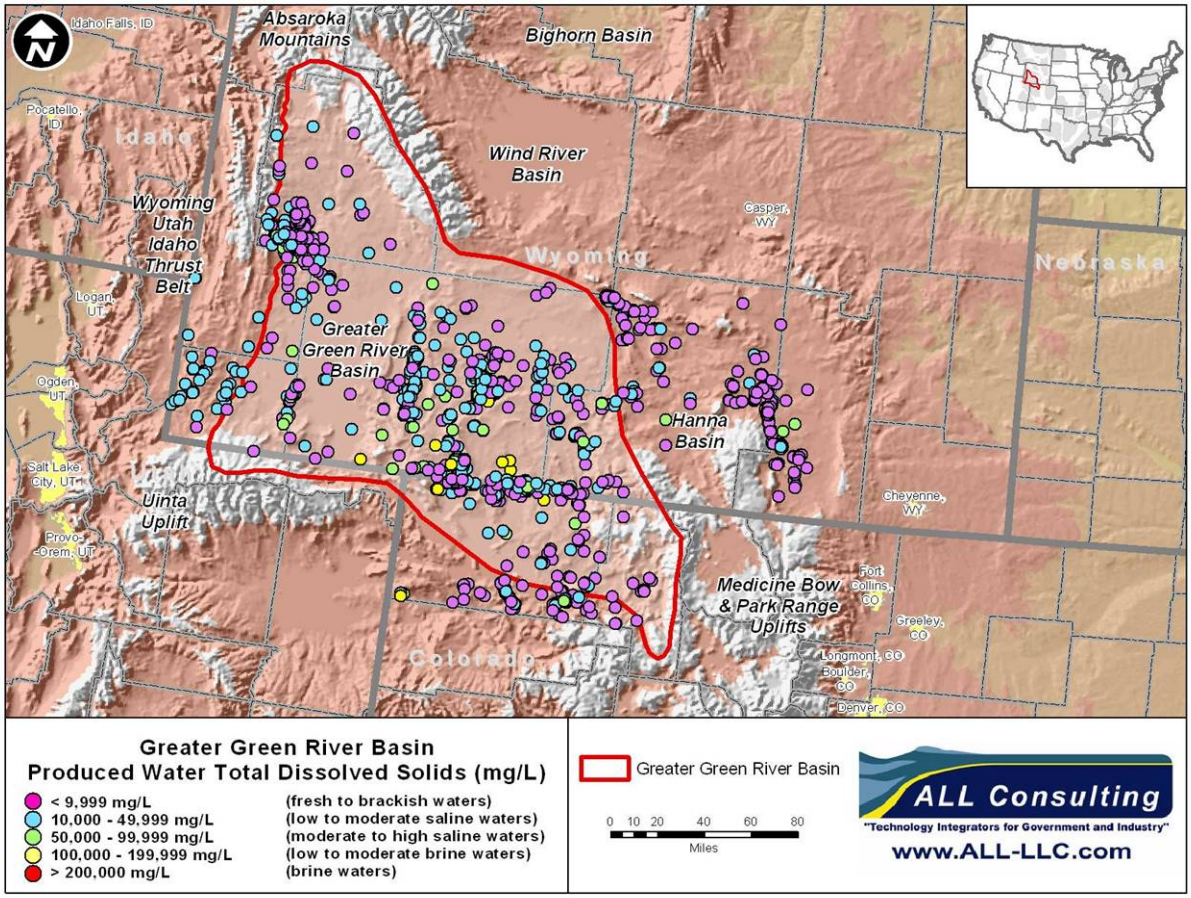
Significant Geological Features

The Greater Green River Basin contains strata of Cambrian through Tertiary age, which are believed to have been deposited in three stages (Law, 1995). The first stage of deposition is referred to as the shelf in which the area was inundated by shallow seaways from the Middle Cambrian to Middle Jurassic. The middle stage is the foreland stage in which sediments were supplied to the basin from uplift areas to the west (Idaho and Utah). The final stage is the inter-basin sedimentation stage in which sediments were derived from the uplift of local areas. The result of these three stages of deposition is an accumulated thickness of sediments in the northern part of the basin that approaches 32,000 feet (Law, 1995). The important strata for oil and gas development in the basin range from Paleozoic to Tertiary in age, with recent production focusing on tight sands of Cretaceous aged Almond and Frontier Formations (DeJarnett et. al., 1997).

Oil and Gas Production

Oil and gas production has been ongoing in the basin since discovery of the Lost Soldier field in 1916 with the first gas play discovery in 1922 on the Rock Springs Uplift (Law, 1995 and Gibson, 1997). To date, more than 0.17 BBO and more than 13.75 TCFG have been produced from the Greater Green River Basin (Gibson, 1997 and WOGCC, 2006). The basin has seen sporadic testing of CBNG resources since the mid 1980's into the early 1990's. Much of the gas production has been occurring in tight sandstone formations in the center of the basin, which have resulted in large volumes of produced water co-produced with the gas.

Figure 6.13 Geologic Setting and Produced Water Quality Distribution of the Greater Green River Basin

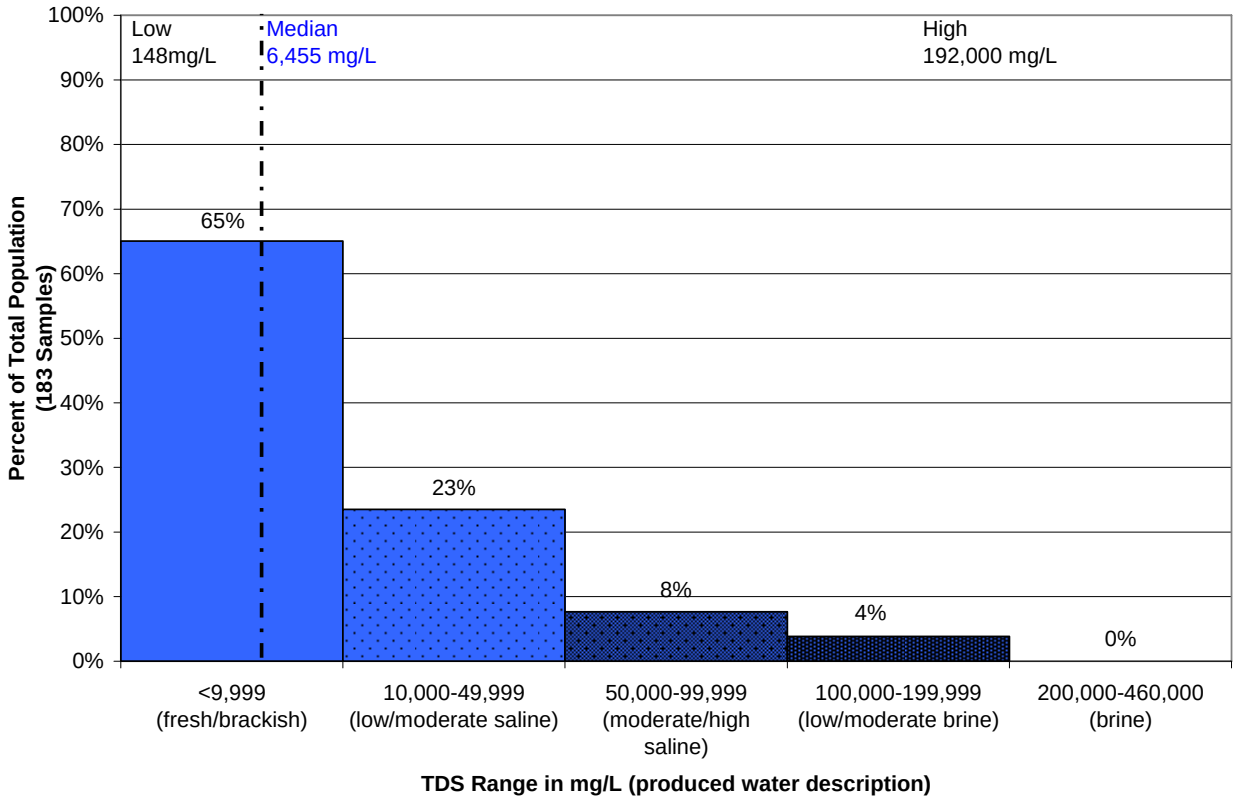


(Source: USGS, 2005)

Produced Water Management

The numerical distribution of produced water quality data from the USGS produced water database for the Greater Green River Basin is shown in Figure 6.14. The database contains 183 individual samples of produced water quality. Produced water salinity in the basin includes ranges from <10,000 mg/L to <200,000 mg/L TDS; there were no samples in the database for the 200,000 mg/L to 460,000 mg/L range (Figure 6-21). Median salinity expressed as TDS for the Greater Green River Basin was low at 6,455 mg/L (brackish water). The range of salinity values for the basin ranged from 148 mg/L (fresh water) to 192,000 mg/L (moderate brine). More than half of the produced water samples (65%) reported for the basin have TDS concentrations <10,000 mg/L. The next highest grouping of produced water quality samples (23%) was the 10,000 mg/L to 49,999 mg/L TDS (saline waters). The moderately saline (8%) to moderate brine (4%) categories contain the remaining 12% of the produced water quality samples. (Figure 6.14).

Figure 6.14 Water Quality Distribution in the Greater Green River Basin



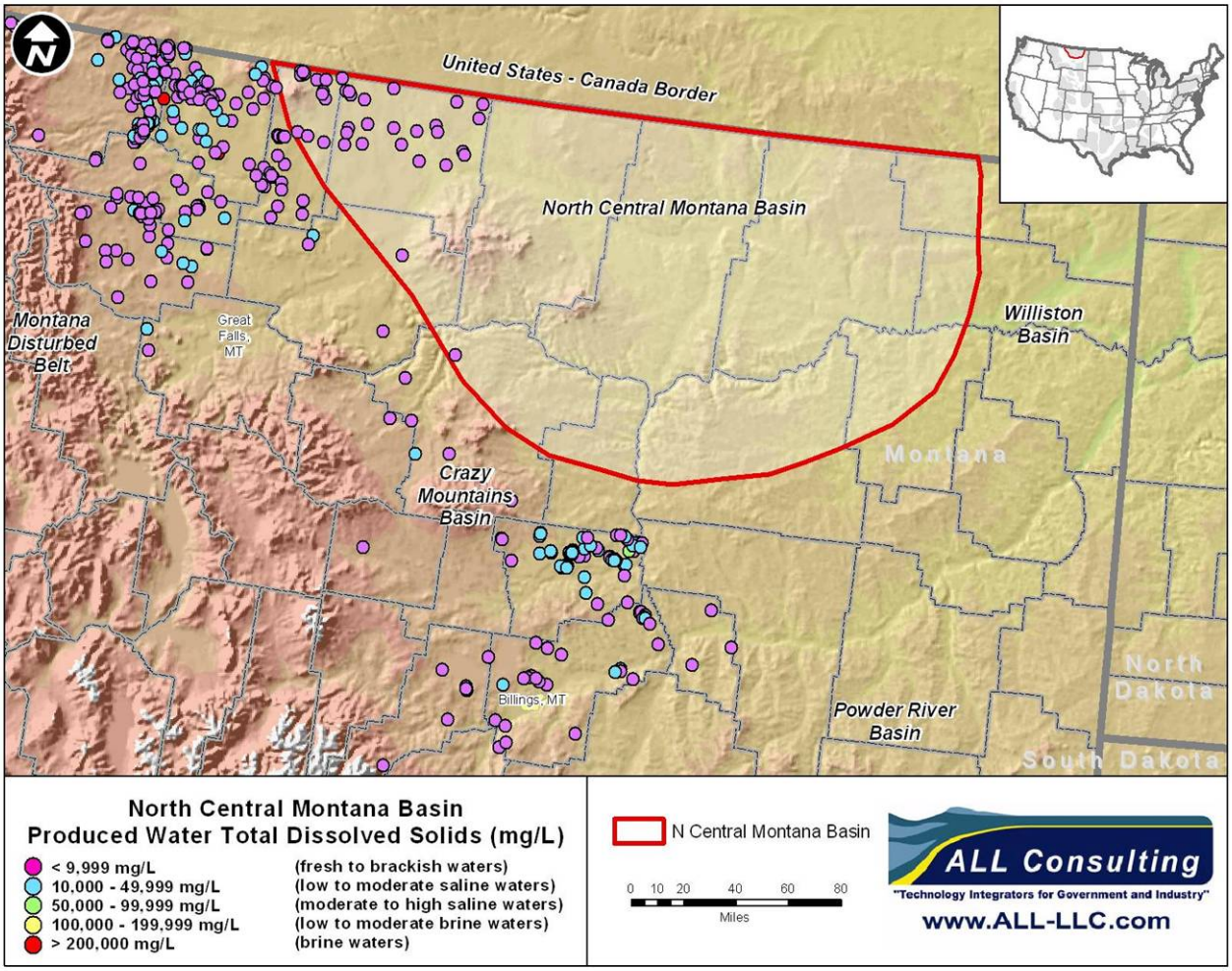
(Source: USGS, 2002)

Figure 6.13 documents the distribution of water quality samples across the Greater Green River Basin and shows that fresh to brackish quality produced water (TDS <10,000 mg/L) is scattered across the basin. Similarly, the two groupings of saline produced water (10,000 mg/L to 49,999 mg/L and 50,000 to 99,999 mg/L TDS) are also scattered across the basin (Figure 6.14). The one grouping of brine waters (100,000 mg/L to 199,999 mg/L TDS) identified for the basin from the USGS produced water database is present along the Wyoming-Colorado state line (Figure 6.13). This grouping is likely indicative of production occurring in a deeper portion of the basin in formations that are not receiving fresh water recharge from the surface.

Section 6.7 North Central Montana Basin

The North Central Montana Basin covers a large portion of the center of the state of Montana (Figure 6-23). The U.S. portion of the basin is bounded by the United States-Canadian border to the north, the Williston Basin to the east, the Powder River Basin to the southeast, the Crazy Mountain Basin to the southwest, and the Montana Disturbed Belt to the west (Figure 6.15). Several geological features are present in the basin, including: Sweetgrass Arch, Kevin-Sunburst and Bowdoin Domes, Bearpaw Uplift, and Central Montana Trough (Dyman, 1995). The North Central Montana Basin is approximately 250 miles long and 250 miles wide and covers an area of approximately 60,000 square miles (Dyman, 1995).

Figure 6.15 Geologic Setting and Produced Water Quality Distribution of the North Central Montana Basin



(Source: USGS, 2005)

Significant Geological Features

The North Central Montana Basin contains strata of Cambrian through Tertiary age, which are present both at the outcrop and in the subsurface throughout the basin (Dyman, 1995). Much of the active oil and gas production in the basin comes from the Cretaceous sandstones from the Kootenai Formation and the Madison Group carbonates. Other formations with potential plays include the Cambro-Ordivician and Jurassic-Cretaceous sandstones, carbonates of the Devonian-Mississippian, and shallow Cretaceous biogenic gas (Dyman, 1995). Recent activity includes the Bakken Shale play, which extends from the Williston Basin into the North Central Montana Basin.

Oil and Gas Production

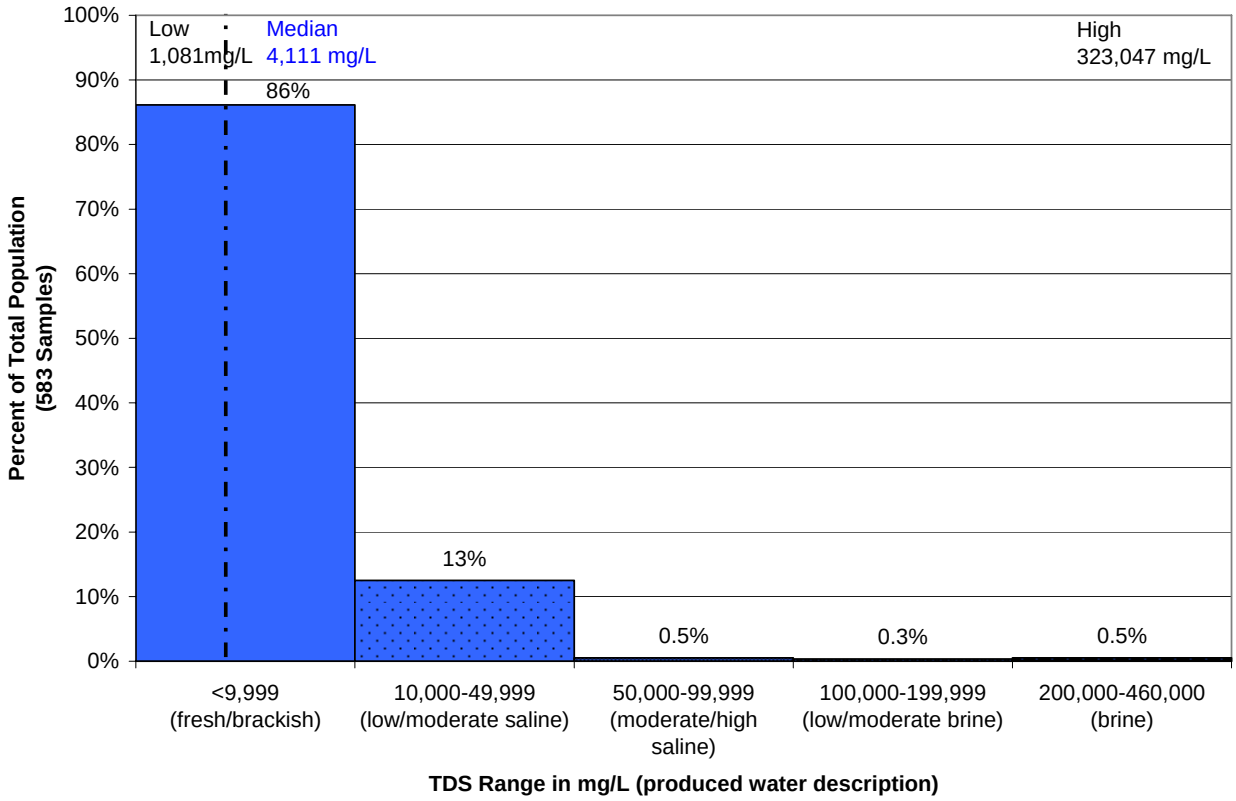
Oil and gas production in the North Central Montana Basin has been ongoing since the early 1900's from the Bowdoin Field and the Cutbank oil field (Dyman, 1995). Both crude oil and natural gas are produced from Cretaceous through Devonian aged reservoirs across the North Central Montana Basin, with more than 0.46 BBO and more than 1.67 TCFG having been produced from the basin to date (Dyman, 1995 and MBOGC, 2006).

Produced Water Management

The numerical distribution of produced water quality samples from the USGS produced water database for the North Central Montana Basin is shown in Figure 6.16. The USGS produced water database contains 583 individual samples of produced water quality for the North Central Montana Basin. Produced water salinity includes all ranges identified for analysis in this study from <10,000 mg/L to >200,000 mg/L TDS. Median salinity expressed as TDS is low at 4,111 mg/L (brackish). The range of salinity values for the basin ranged from 1,081 mg/L (slightly brackish) to 323,047 mg/L (brine) (Figure 6.16). Produced water from this basin is very high quality with 86% of the samples in the USGS database having less than 10,000 mg/L TDS. Another 13% of the produced water samples were reported in the range from 10,000 mg/L to 49,999 mg/L TDS. The remaining percentage (approximately 1.3%) were relatively evenly distributed through the remaining three water quality groupings analyzed in this report (Figure 6.16).

Figure 6.15 documents the distribution of water quality samples across the basin showing that the high quality produced water is distributed across the producing regions. Since there is such a small percentage of low quality produced water (>50,000 mg/L TDS) it is difficult to assess the distribution of these samples within the basin. While the low quality water (<10,000 mg/L TDS) appears to be focused along several features close to the Montana-Canadian border, some scattered production reaches into the central part of Montana (Figure 6.15). The low salinity water might have beneficial uses that include enhanced recovery of oil and gas resources and agricultural. The majority of these low salinity samples are from production wells at depths less than 5,000 feet below the surface where fresh surface waters are recharging these zones. Many of the low TDS produced water quality samples were taken from the Mississippian aged Madison Formation, although many other formations were sampled.

Figure 6.16 Water Quality Distribution of the North Central Montana Basin



(Source: USGS, 2002)

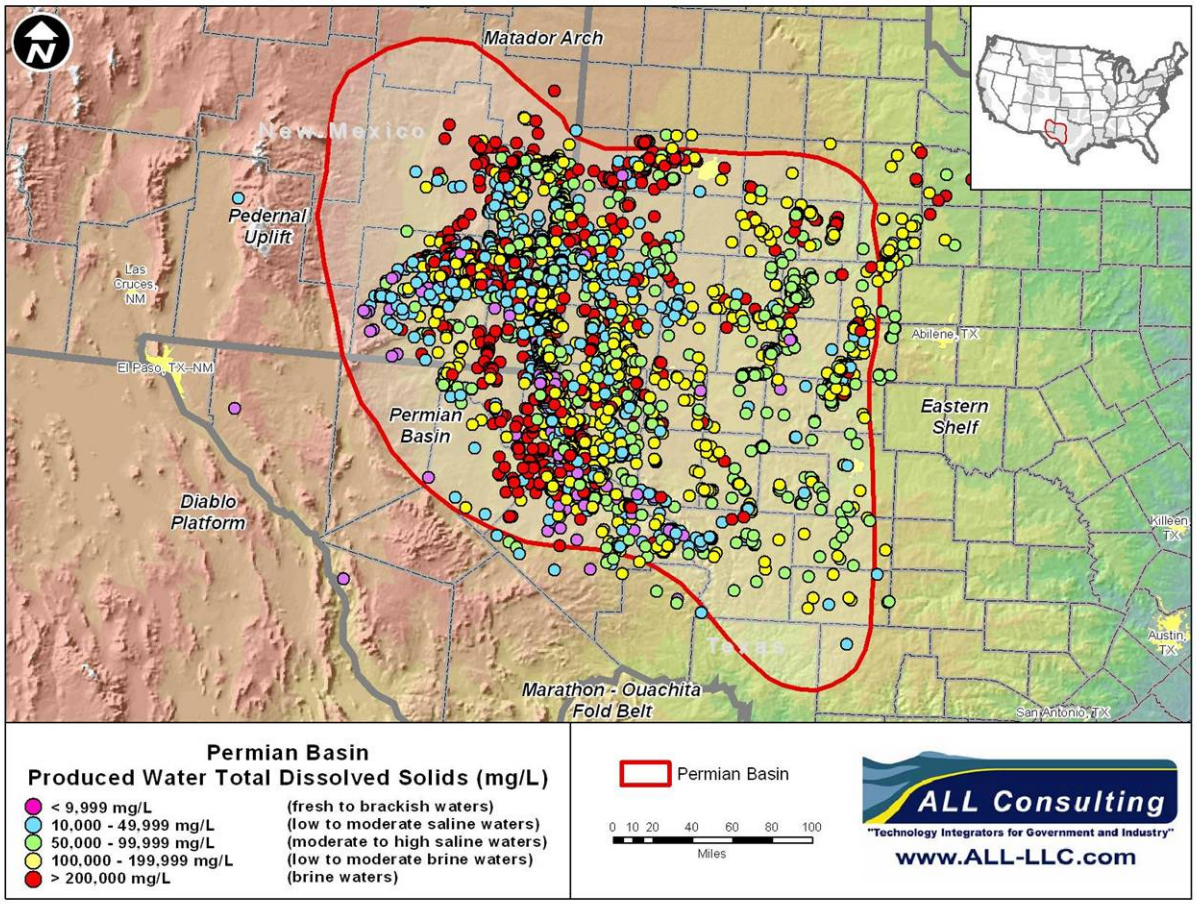
Section 6.8 Permian Basin

The Permian Basin covers a large portion of western Texas and southeastern New Mexico. The majority of the basin is located in western Texas as seen in Figure 6.17. The basin contains a variety of hydrocarbon reservoirs that also produce water (Steuber, 1998). Figure 6.17 shows the Permian Basin to lie in a north to south orientation, with the Matador Arch to the north, the Eastern Shelf of the Midland Basin to the east, the Marathon-Ouachita Fold Belt to the south, and the Pedernal Uplift and Diablo Platform to the west (Ball, 1995). The Permian Basin is approximately 260 miles by 300 miles with a total surface area exceeding 86,000 square miles.

Significant Geological Features

The Permian Basin contains strata of predominantly Paleozoic in age with thinner extent of younger sediments; the basin's current structural features developed from the Late Mississippian to Early Pennsylvania time (Dutton et. al., 2004). Most of the basin-fill volume is taken up with the Paleozoic strata with oil and gas production from rocks ranging from the Cambrian through Cretaceous age sediments. The important strata in the basin include the Ordovician Ellenburger carbonates, which are the same age and similar in lithology to the massive Knox carbonates of the Appalachians and the Arbuckle Formation of the Anadarko Basin. The stratigraphy of the Permian Basin includes a thick sequence of Paleozoic age rocks, which can be greater than 25,000 feet in thickness (Ball, 1995).

Figure 6.17 Geologic Setting and Produced Water Quality Distribution of the Permian Basin



(Source: USGS, 2005)

Oil and Gas Production

The Permian Basin continues to be one of most prolific and largest oil production basins in the United States. As of 2002, the Permian Basin production was 17% of the total United States oil production (BEG, 2002). Oil and gas production occurs in rocks dating from the Cambrian to the Cretaceous with most production coming from reservoirs of Paleozoic age (Ball, 1995). More than 35 BBO, 5.5 BBNGL, and 90.7 TCFG had been produced from the basin as of the early 1990's (Ball, 1995).

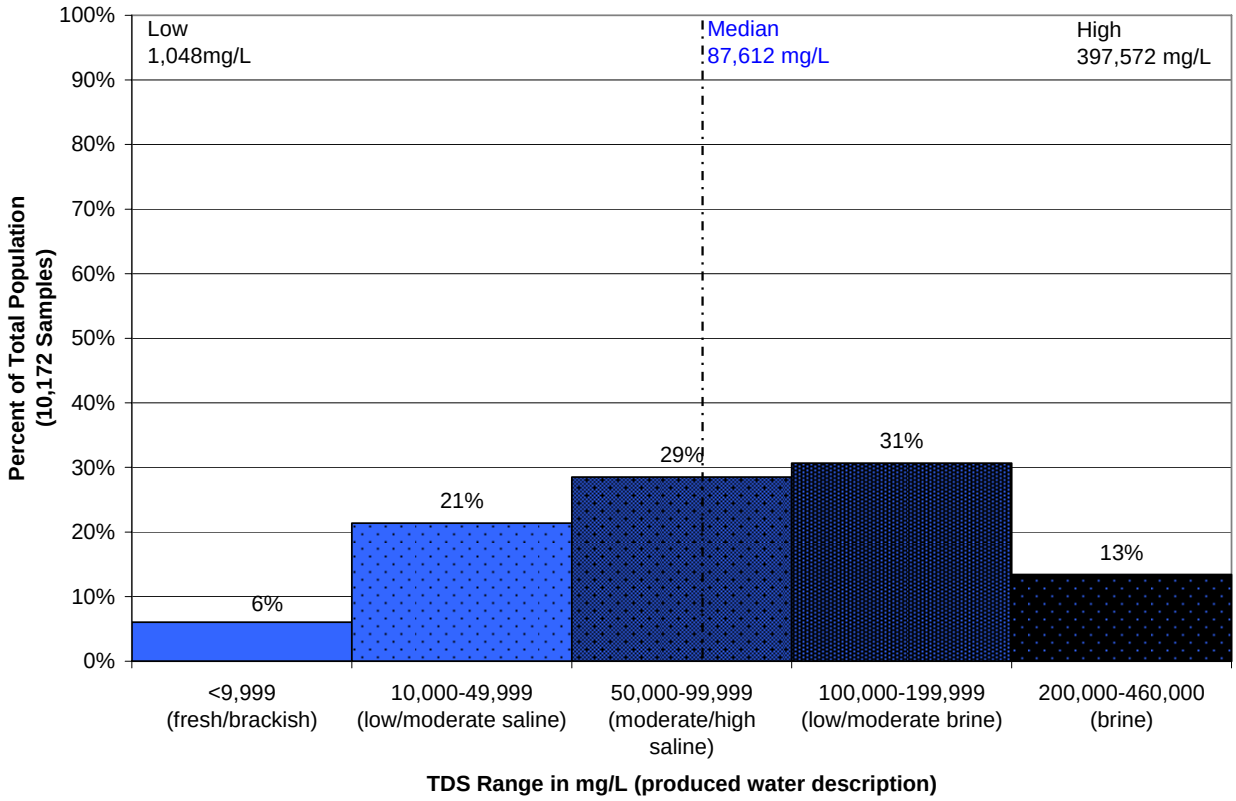
Produced Water Management

The numerical distribution of produced water for the Permian Basin is presented in Figure 6.18. The USGS produced water database contains more than 10,000 individual samples for the Permian Basin. Produced water salinity in the basin includes all ranges identified for analysis in this study from <10,000 mg/L to >200,000 mg/L TDS (Figure 6-27). Median salinity expressed as TDS was 87,612 mg/L with the range of salinity values ranging from 1,048 mg/L (slightly brackish) to 397,572 mg/L (brine). Approximately 6 percent of the water samples in the database were below 10,000 mg/L TDS and could have local beneficial uses; this high quality water is reported from shallow aquifers that do not produce hydrocarbons (USGS, 2002), but scattered wells have sampled productive formations that locally contain high quality water.

Depths of those samples less than 10,000 mg/L range from 25 feet to more than 19,000 feet. Most of these low salinity water samples were taken less than 4,000 feet deep. Water this deep probably cannot be economically exploited by wells drilled expressly for water, but could be exploited as a by-product of oil and gas production.

The largest grouping of produced water for the Permian Basin (31%) was reported in the 100,000 mg/L to 199,999 mg/L TDS grouping, with slightly fewer samples (29%) in the 50,000 mg/L to 99,999 mg/L TDS category (Figure 6.18). Figure 6.17 shows the distribution of produced water salinity values, showing that produced water quality varies randomly throughout the basin. The geographic distribution of the produced water salinity values show the high quality water samples (TDS <10,000 mg/L) to be located along the western boundary of the basin (Figure 6.17). This water may be able to satisfy some uses in its raw state without treatment while uses such as industrial and municipal water supply may require treatment. The other classifications of produced water appear to be much more evenly distributed with most of the produced water currently utilized for extensive secondary recovery operations in the basin's oil fields.

Figure 6.18 Water Quality Distribution in the Texas and New Mexico Portions of the Permian Basin

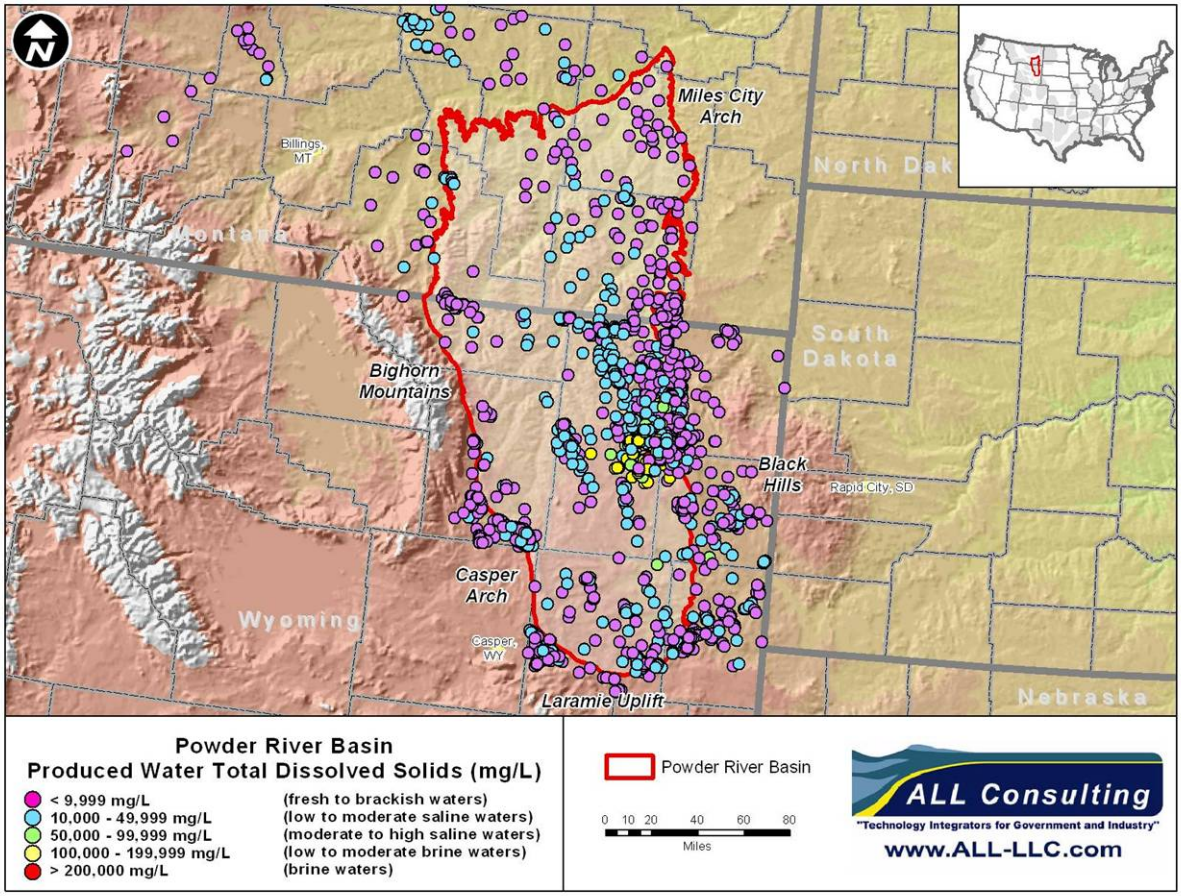


Source: USGS, 2002

Section 6.9 Powder River Basin

The Powder River Basin forms part of the Unglaciated Missouri Plateau section of the Great Plains province. It extends from northeastern Wyoming into southeastern Montana and contains strata of Cambian to Tertiary age (Figure 6.19). On the surface of the basin, there are several watersheds while outcropping formations are primarily Tertiary in age. Figure 6.19 shows the Powder River Basin to lie in a northwest to southeast orientation that is bound by the Miles City Arch to the north, the Black Hills to the east, the Laramie Uplift and Casper Arch to the south, and the Bighorn Mountains to the west (Dolton and Fox, 1995). The Powder River Basin covers an area of approximately 34,000 square miles (Dolton and Fox, 1995).

Figure 6.19 Geologic Setting and Produced Water Quality Distribution of the Powder River Basin



(Source: USGS, 2005)

Significant Geological Features

The basin is filled with a thick sequence of sediments from the Cambrian to Tertiary in age. The sediments result from accumulations of Paleozoic shelf carbonates, sandstones, and shales, overlain by a thick sequence of Mesozoic to Tertiary sediments that accumulated during the time of the Western interior seaway, with recent sediments for local uplifted areas (Dolton and Fox, 1995). Formations within the Powder River Basin important to oil and gas development

range from the shallow Tertiary coal beds to conventional oil and gas reservoirs from the Mississippian to lower Cretaceous. The stratigraphy of the basin includes a thick sequence of Phanerozoic strata, which can be greater than 18,000 feet in thickness near the basin's axis (Dolton and Fox, 1995).

Oil and Gas Production

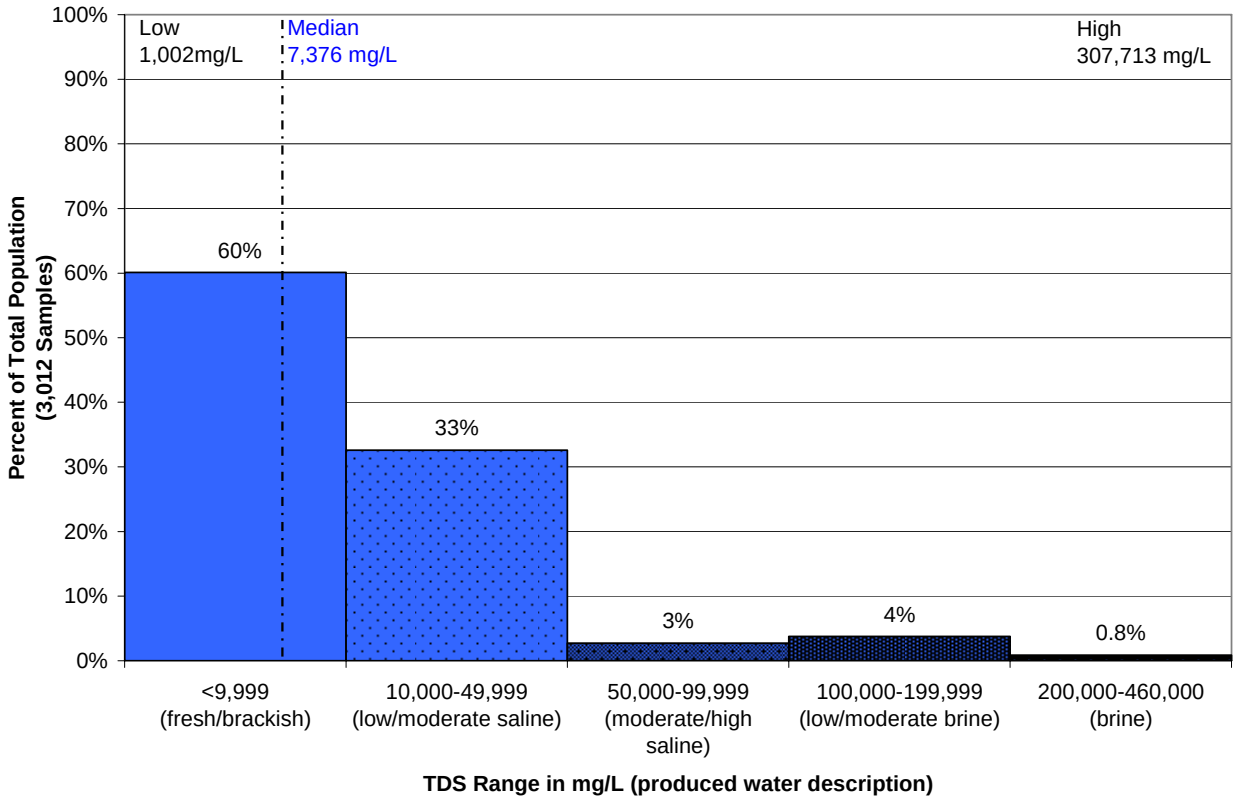
Oil and gas has been developed in the Powder River Basin since the discovery of the Salt Creek field in 1908 (Dolton and Fox, 1995). Since this initial discovery, recoverable resources have been estimated at 2.7 BBO and 2.3 TCFG within the basin (Dolton and Fox, 1995). Conventional oil and gas exploration has been declining in the Montana portion, with considerable decreases in oil production since 1986; natural gas production had been declining in the Powder River Basin until the start of CBNG production in 1990's. Since then, the basin increasingly has become a larger source of natural gas revenues for Montana and Wyoming, with production of CBNG contributing to the majority of the increase in production.

Produced Water Management

The numerical distribution of produced water quality for the Powder River Basin is presented in Figure 6.20. The USGS produced water database contains 3,012 individual samples for the Powder River Basin. Produced water salinity in the basin includes all ranges identified for analysis in this study from <10,000 mg/L to >200,000 mg/L TDS. Median salinity expressed as TDS is moderately brackish at 7,376 mg/L (Figure 6-30) with a range of salinity values from 1,002 mg/L (slightly brackish) to 307,713 mg/L (brine). More than half the produced water quality samples (60%) in the USGS database for the basin have TDS concentrations of less than 10,000 mg/L. Another 33% of the produced water samples were reported in the range from 10,000 mg/L to 49,999 mg/L TDS. The majority of the remaining percentage (approximately 7%) was distributed between the 50,000 mg/L to 99,999 mg/L (3%) and the 100,000 mg/L to 199,999 mg/L (4%) groupings. Less than one percent (0.8%) of the produced water quality samples were reported in the highest salinity grouping from 200,000 mg/L to 460,000 mg/L (Figure 6.20). Formation water varies from strong brines in deep reservoirs, higher quality water trapped in Tertiary and Cretaceous reservoirs, and fresh meteoric water that has entered some of the aquifers at their outcrop and migrated into the basin.

Figure 6.19 documents the distribution of water quality samples across the Powder River Basin showing how the produced water quality varies across the basin. The geographical distribution of water salinity as shown in Figure 6.19 indicates that the water quality reflects the geometry of the basin. Produced water of the fresh to brackish quality (0 mg/L to 9,999 mg/L TDS) is located along the basin margins with some scattering of this higher quality water into the center of the basin. The produced water quality of low-to-moderate salinity (10,000 mg/L to 49,999 mg/L TDS) are predominately located toward the center of the basin inside the area of the fresh to brackish quality samples (Figure 6.19). The lower quality produced water samples (>50,000 mg/L TDS) are located toward the deeper portion of the basin as shown in Figure 6.19.

Figure 6.20 Water Quality Distribution of the Entire Powder River Basin of Montana and Wyoming



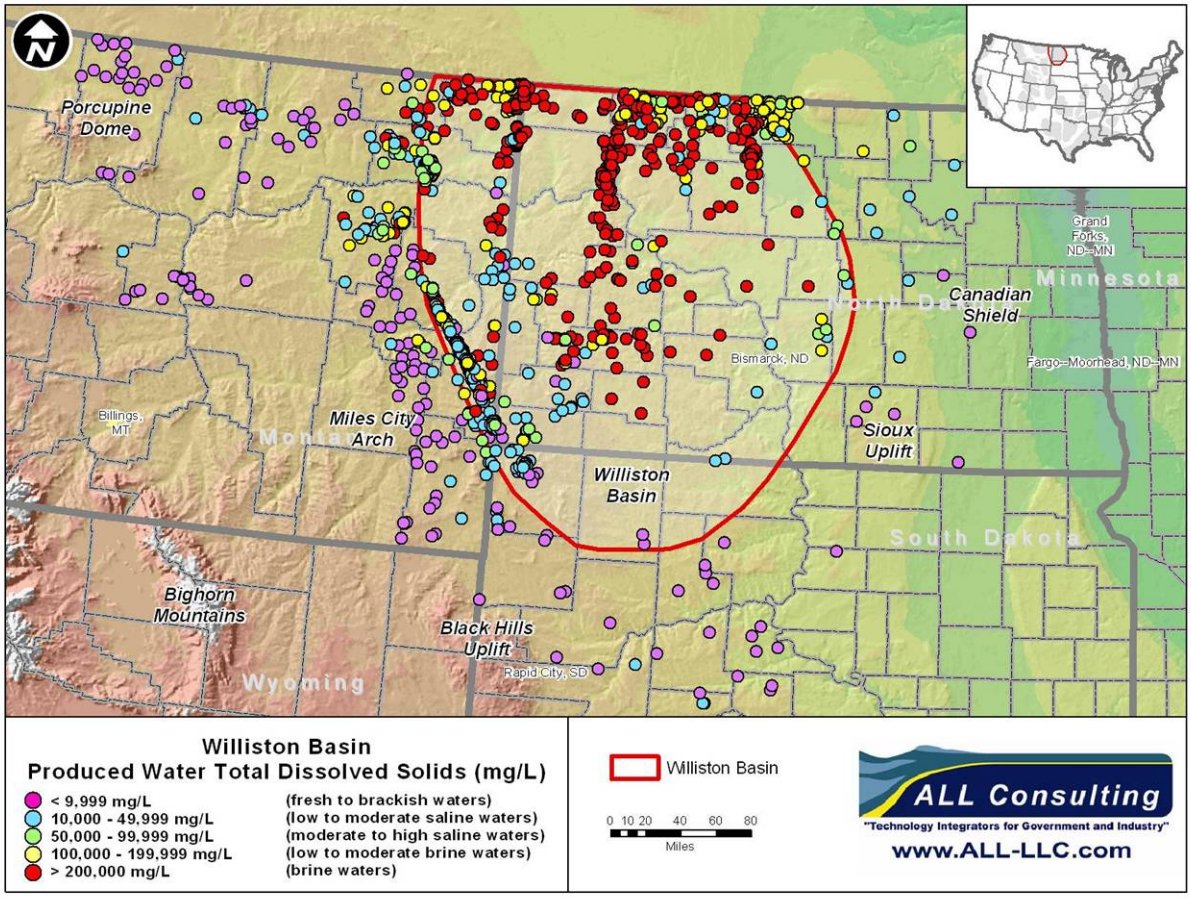
(Source: USGS, 2002)

Within the Powder River Basin, produced water varies by reservoir type and depth. CBNG produced water typically has a TDS between approximately 1,000 mg/L and 4,000 mg/L. CBNG fields are prodigious water producers and account for approximately 50% of all produced water in the basin (WOGCC, 2006). Water from the Muddy/Newcastle Formations varies from less than 2,000 mg/L to more than 50,000 mg/L; water from the Nugget Formation ranges from 50,000 mg/L to 70,000 mg/L; water from the Madison Formation varies from less than 1,000 mg/L to 8,000 mg/L; Dakota Formation water ranges between 2,000 mg/L to 8,000 mg/L; and the Minnelusa Formation contains water in excess of 150,000 mg/L TDS.

Section 6.10 Williston Basin

The Williston Basin is located at the northern end of the Great Plains and covers approximately 143,000 square miles within the United States, including parts of eastern Montana and North and South Dakota (Figure 6.21). The Williston Basin is bound in the east by the Canadian Shield, the southeast by the Sioux Uplift, to the southwest by the Black Hills Uplift, and to the west by the Miles City Arch and Porcupine Dome (Peterson, 1995). The Williston Basin is the result of subsidence, which is believed to have started as early as the Ordovician Period and continues today (Heck et al. 2002). The Williston Basin contains a nearly complete rock record reflecting the numerous transgressive/regressive sequences that have occurred in the basin (Heck et al. 2002).

Figure 6.21 Geologic Setting and Produced Water Quality Distribution of the Williston Basin



(Source: USGS, 2005)

Significant Geological Features

The sediments within the basin range from the Cambrian through Tertiary strata, with the maximum thickness of Phanerozois rocks being greater than 16,000 feet in the North Dakota portion of the basin (Peterson, 1995). Outcrops within the Williston Basin consist primarily of the Tertiary sediments from the Fort Union Formation, Cretaceous sediments from the Hell Creek Formation, and Quaternary Alluvium along the various river valleys. Oil and gas have been developed from Cretaceous, Mississippian, Devonian, Silurian, and Ordovician reservoirs within the basin (MBOGC, 2005). The Tertiary deposits contain sediments including various coals and lignites which to date have been sporadically tested for only CBNG in North Dakota. The Williston Basin contains several significant geologic features relative to oil and gas development, including the Cedar Creek Anticline, Nesson Anticline, the Poplar Dome, and the Bakken Formation.

Oil and Gas Production

Oil and gas has been produced from the Williston Basin since the 1910's with production of shallow gas resources from the Cretaceous Eagle Sandstone on the Cedar Creek Anticline in Montana, and major oil production on the Nesson Anticline in North Dakota starting after World

War II (Peterson, 1995). Much of current activity in the Williston basin is focused on the Cedar Creek Anticline, which is currently experiencing exploration and production in the Siluro-Ordovician with recent horizontal water-floods getting the most attention in the basin. Other recent oil and gas development in the Williston Basin has been focused on the continuous Bakken play of east central Montana and west central North Dakota.

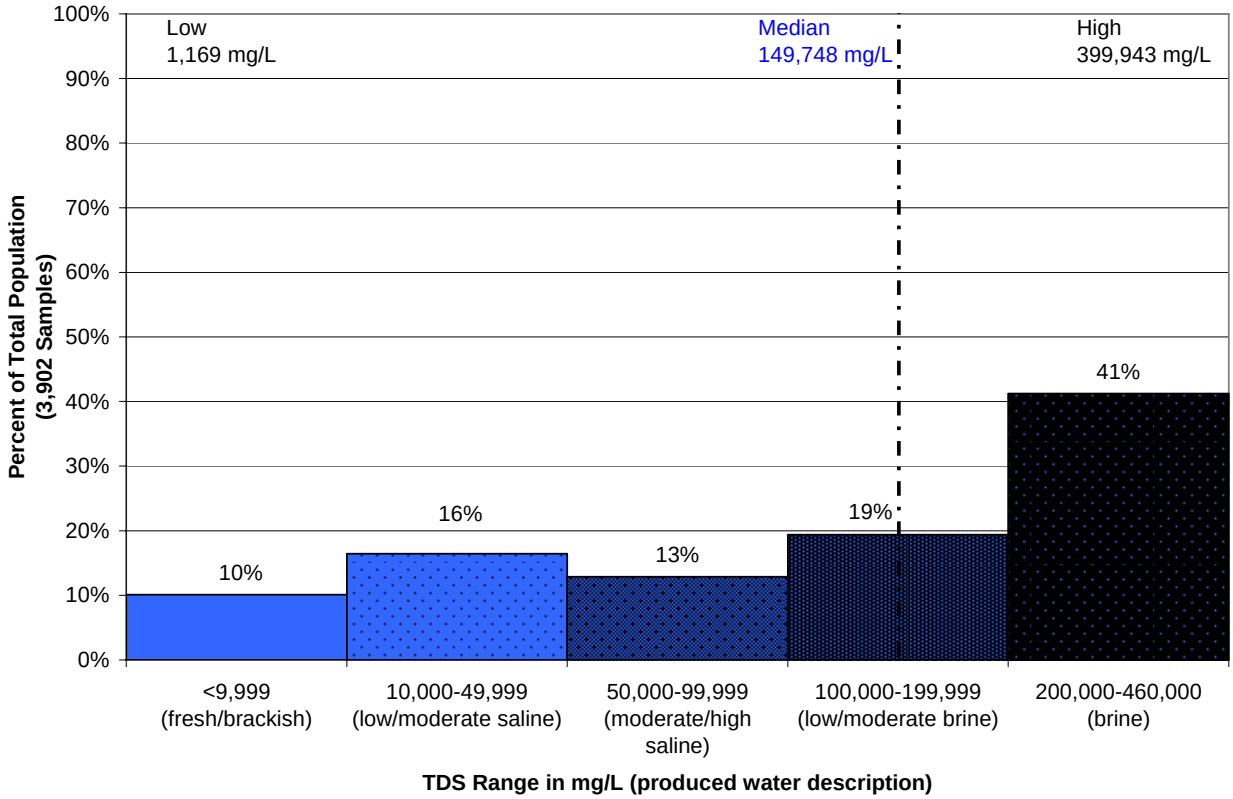
Produced Water Management

The numerical distribution of produced water quality for the Williston Basin is shown in Figure 6.22. The USGS produced water database contains 3,902 individual samples for the Williston Basin. Produced water salinity for the Williston Basin includes all ranges identified for analysis in this study from <10,000 mg/L to >200,000 mg/L TDS. Median salinity expressed as TDS for the basin is relatively high at 149,748 mg/L (moderate brine waters) as shown in Figure 6.22. The range of salinity values for the Williston Basin ranged from 1,169 mg/L (slightly brackish) to 399,943 (brine). The largest percentage (41%) of the water quality samples from the USGS produced water database for the Williston Basin had TDS concentrations between 200,000 mg/L and 460,000 mg/L. The next highest distribution percentage (19%) was the 100,000 mg/L to 199,999 mg/L range. The remaining 39% are distributed between the 50,000 mg/L to 99,999 mg/L (13%), the 10,000 mg/L to 49,999 mg/L (16%), and the <10,000 mg/L (10%) ranges.

Figure 6.21 documents the distribution of water quality samples across the Williston Basin, showing how the produced water quality varies geographically. The distribution of water salinity as shown in Figure 6.21 indicates that the water quality reflects the geometry of the basin. Produced water of the fresh to brackish quality (0 mg/L to 9,999 mg/L TDS) is located along the basin margin with most of the higher quality water located along the southwestern edge of the basin. The low-to-moderate saline waters (10,000 mg/L to 49,999 mg/L) are predominately located inside of the fresh to brackish quality samples. The lower quality produced water samples (>50,000 mg/L) are located toward the deeper central portion of the basin as shown in Figure 6.21.

Because most of this water is not of beneficial use quality (<10,000 mg/L TDS), the majority is utilized in secondary oil recovery operations or disposed of commercially. Almost 90% of the produced water from the Williston Basin is high in TDS and lacks any other use. Some reservoirs (Tertiary aged) within the Williston Basin do produce water low enough in TDS to support some uses, but at the present time no water is being produced from lignite coalbeds in the Tertiary Fort Union Formation. If these lignites ever prove productive of CBNG, this water may be of sufficient quality and quantity to sustain beneficial uses such as irrigation, cattle, or support of coal mining and power generation operations as is seen in the Powder River Basin.

Figure 6.22 Water Quality Distribution in the United States Portion of the Williston Basin



(Source: USGS, 2002)

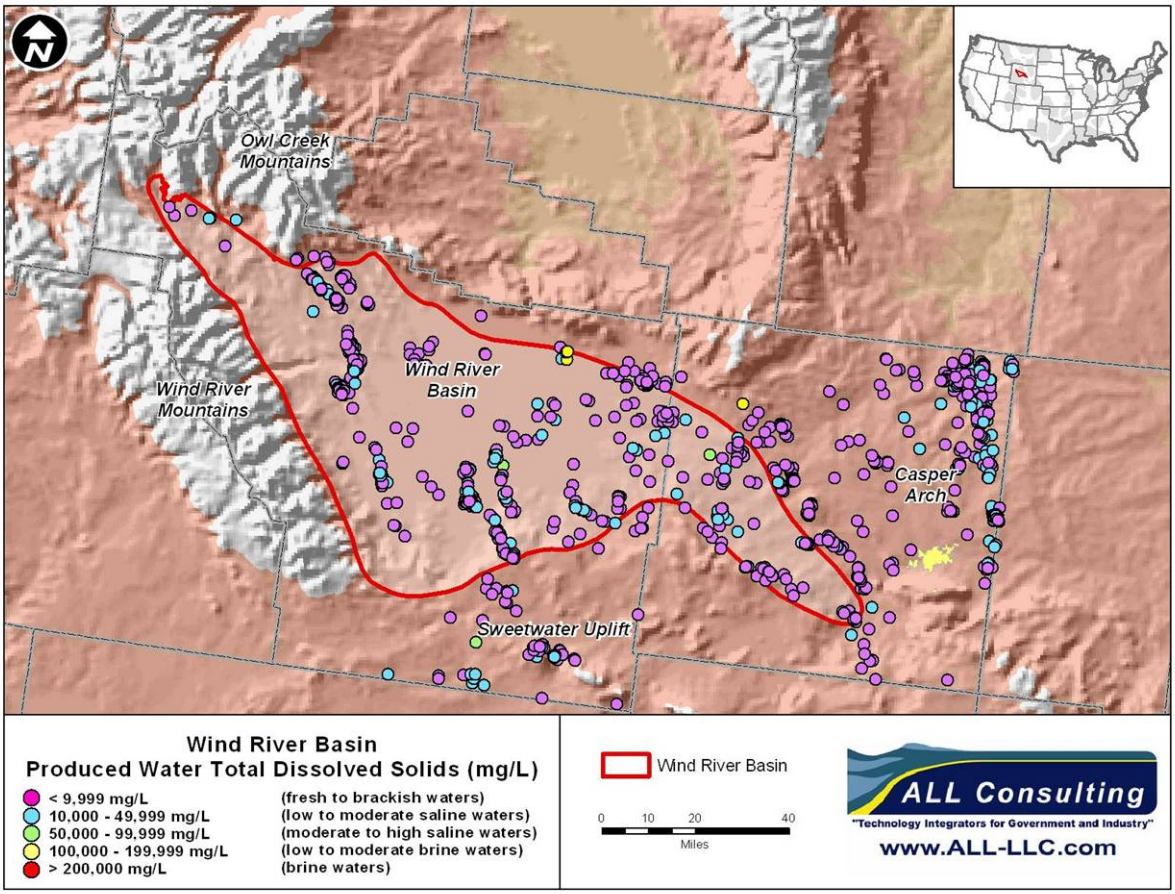
Section 6.11 Wind River Basin

The Wind River Basin is a major foreland basin in the Wyoming Rockies located in central Wyoming, south of the Bighorn Basin. The Wind River Basin is an asymmetric basin with a southeast-northwest orientation and contains major structures related to the bounding structural uplifts (Figure 6.23). The basin is bound by the Sweetwater Uplift to the south, the Wind River Mountains to the west, the Owl Creek Mountains to the north, and the Casper Arch to the east as shown in Figure 6.23 (Fox and Dolton, 1995b). The Wind River Basin covers an area of approximately 11,700 square miles (Fox and Dolton, 1995b).

Significant Geological Features

The basin has produced oil and gas since 1884 when Wyoming's first oil well was completed in the Wind River Basin. The basin is split between oil and gas production with oil dominating production until the 1950's when natural gas became more important. The basin is currently one of the most important natural gas producing areas in the state. Both crude oil and natural gas are produced from Cretaceous through Devonian aged reservoirs across the North Central Montana Basin, with more than 0.59 BBO and more than 4.73 TCFG having been produced from the basin to date (Fox and Dolton, 1995b and WOGCC, 2006).

Figure 6.23 Geologic Setting and Produced Water Quality Distribution of the Wind River Basin



(Source: USGS, 2005)

In 2005, the Wind River Basin produced 3.95 million bbls of oil, 245.8 BCF of gas, and 209 million bbls of water (WOGCC, 2006). No CBNG is currently produced in the basin.

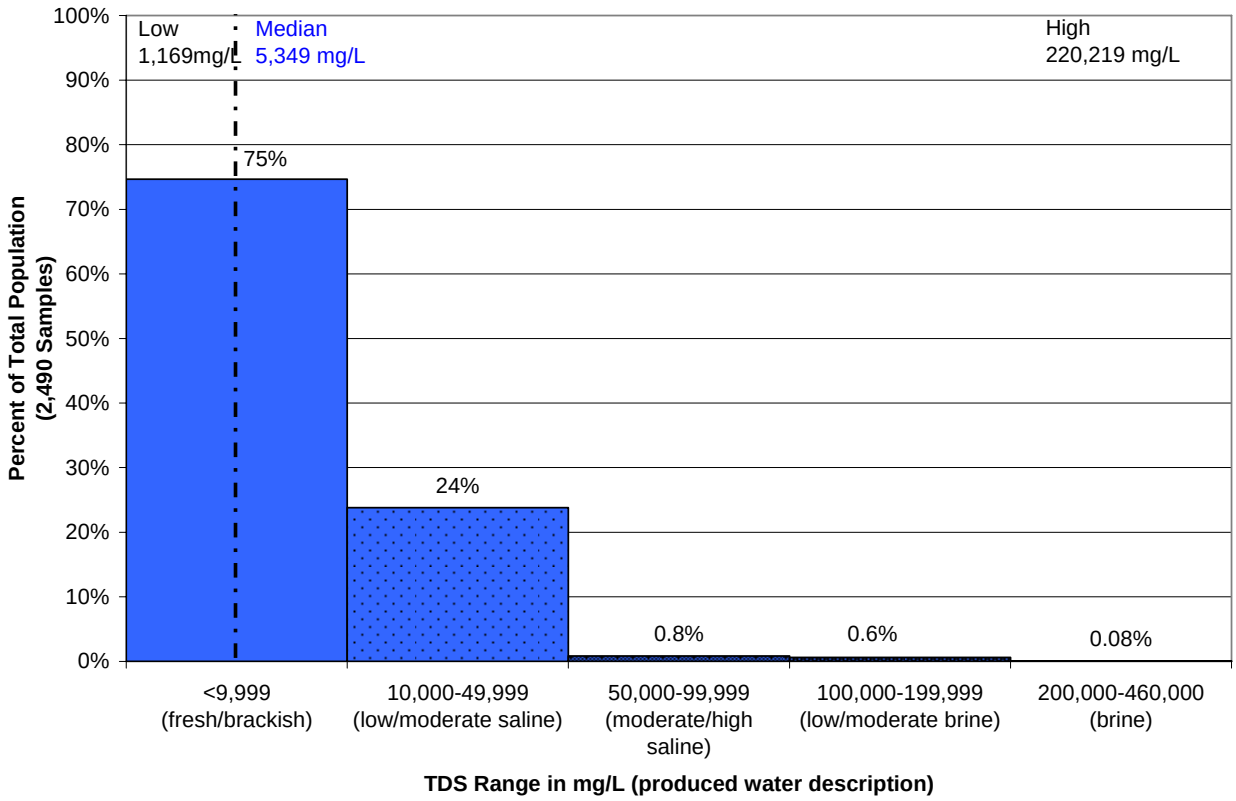
Produced Water Management

The numerical distribution of produced water quality for the Wind River Basin is shown in Figure 6.24. The USGS produced water database contains 2,490 individual samples for the Wind River Basin. Produced water salinity in the basin includes all of the ranges identified for analysis in this study from <10,000 mg/L to >200,000 mg/L TDS. Median salinity expressed as TDS was low at 5,349 mg/L (brackish water) (Figure 6.24). Salinity values for the Wind River Basin ranged from 1,169 mg/L (slightly brackish) to 220,219 (brine). The largest percentage (75%) of the water quality samples have TDS concentrations <10,000 mg/L. The next highest distribution percentage (24%) was the 10,000 mg/L to 49,999 mg/L range. The remaining 1.5% was distributed between the 50,000 mg/L to 99,999 mg/L (0.8%) range, the 100,000 mg/L to 199,999 mg/L (0.6%) range, and the 200,000 mg/L to 460,000 mg/L (0.08%) range.

Figure 6.23 documents the distribution of water quality samples across the Wind River Basin showing how the produced water quality varies. The geographical distribution of water salinity indicates that the highest produced water quality samples are distributed all across the basin. Produced water of the fresh to brackish quality (0 mg/L to 9,999 mg/L TDS) is located

throughout the basin with most of this higher quality water likely located in shallow formations receiving recharge from the surface (Figure 6.23). Much of this water could have local beneficial uses. The produced water quality of low-to-moderate saline waters (10,000 mg/L to 49,999 mg/L) similarly are distributed across the basin and are likely produced from the deeper formations. The lower quality produced water samples (>50,000 mg/L) are located toward the north-central portion of the basin, but represent only a small percentage of the total samples (<2%).

Figure 6.24 Water Quality Distribution in the Wind River Basin



(Source: USGS, 2002)

The large volumes of water are of varying quality ranging from less than 300 mg/L to much stronger brines. Deep gas reservoirs typically produce very high quality water that likely represents condensed water present as vapor in the subsurface; this water could have local beneficial uses for agriculture and livestock watering. Oil reservoirs produce water at rates up to 100 times the rate of crude oil production; this water is most often injected back into the oil reservoirs to support oil production.

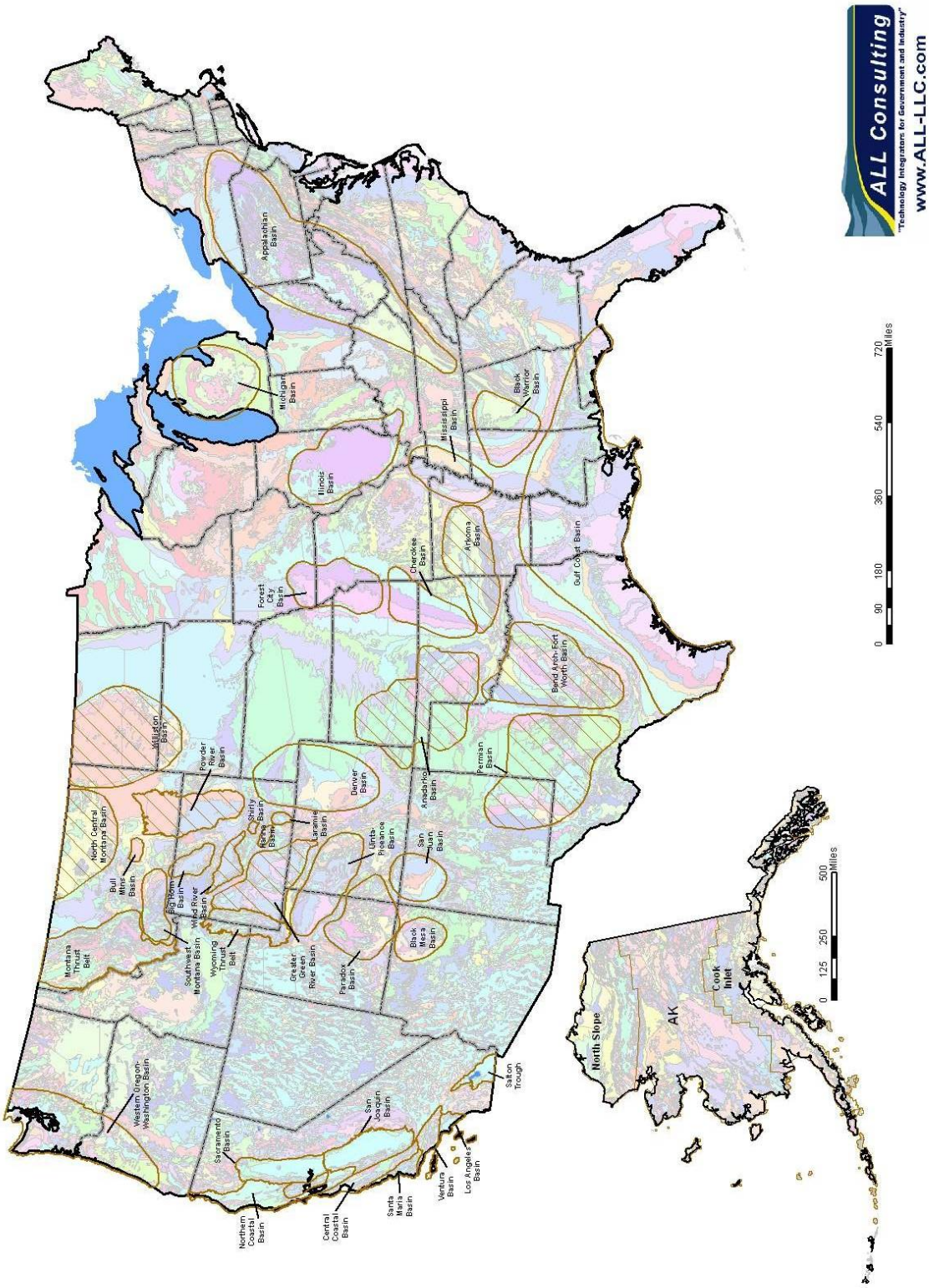
THIS PAGE INTENTIONALLY LEFT BLANK

SECTION 7.0 REGIONAL IMPLICATIONS TO PRODUCED WATER MANAGEMENT IN THE UNITED STATES

Section 6 presents a detailed analysis of several hydrocarbon producing basins located primarily in Alaska, Montana, Wyoming, Kansas, Oklahoma, and Texas. Several other major basins exist in the United States, as shown in Figure 7.1. The basins discussed in Section 6 provide a varied cross section of produced water issues sufficient to document the majority of proven water management practices utilized across the United States in the other basins shown in Figure 7.1. These issues include, but are not limited to:

- **Produced Water Characteristics –** The range in water quality is extreme across the United States. Produced water with TDS less than 10,000 mg/L may have significant beneficial uses for industrial and agricultural activities while water with a TDS greater than 50,000 mg/l has limited use other than enhanced recovery and will likely require injection disposal for proper management. Water quantity is difficult to predict because it is likely to change from well to well over time. Conventional wells typically yield more water as production progresses, while non-conventional plays, such as CBNG, may yield less water as production progresses. Regardless, understanding the water quality and quantity of a site is important when determining an appropriate water management practice.
- **Socio-economic and Political Setting –** Socio-economic setting can be quantified by population density and industrial activity. Areas with a higher population density will typically yield more complicated water management issues than areas of low population density, and areas with a high level of industrial activity might have use for water that is low in quality, or water demand may be high enough to offset the cost to treat the water to a usable level. Political setting is a concept that is best considered qualitatively; however, it can be noted that regions where split estate is common, (i.e. surface ownership has been severed from mineral ownership) the political setting can be detrimental for oil and gas development as the produced water management options may be limited by legal issues.
- **Climate Zones –** Annual rainfall and evapotranspiration (ET) are two elements of the weather that may play a role in the effectiveness of different produced water management practices. In areas where the average rainfall is close to, or less than, the average ET, produced water beneficial use (for produced water less than 10,000 mg/L TDS) can help to sustain farmers and ranchers through irrigation and water supply for livestock. Furthermore, these areas might be able to capitalize on marginal produced water (with a TDS less than 50,000 mg/L) by treating the water for beneficial use and disposing of the lower quantity waste stream.

Figure 7.1 Major Hydrocarbon Producing Basins of the United States



The culmination of these issues often dictates regional-specific problems and solutions that are not always shared outside that region. However, various regions can benefit from sharing problems experienced in other regions, and how operators have met with success (and failure) when solutions to these problems are employed in the field. This section attempts to close the information gap between hydrocarbon producing regions by identifying and sharing applicable produced water management practices that may have implications outside of their current region. Furthermore, in light of recent concerns that produced water can and should be treated as a resource rather than as a waste, this section provides a forward looking discussion in terms of treating and beneficially using produced water of marginal quality (i.e. with a TDS value greater than 10,000 mg/l, but less than 50,000 mg/l) versus wholesale disposal of this resource.

Section 7.1 Water Quality and Quantity

The range in water quality across the United States is great, as shown in Figure 7.2, which suggests that produced water has many possible origins, as described in Section 2. For example, large areas within the arid Great Plains and adjacent to recharge areas in the Rocky Mountains contain water that is low in TDS and has potential beneficial uses. The low TDS produced water often represents infiltrated meteoric water that enters porous strata at the outcrops on the edge of large basins.

Water quality may be the single most important factor when considering the water management practice selected. Table 7.1 illustrates a numerical summary of the water quality statistical analyses in the oil and gas basins discussed in Section 6. Produced water less than 10,000 mg/L might have significant beneficial uses for industrial and agricultural activities, and produced water less than 50,000 mg/L may have the potential to be treated and beneficially used in the same manner. Figure 7.3 is a graphical representation of the same data that shows how the basins compare to one another in terms of water quality. In Figure 7.3 the basins are ranked by percent of produced water that is either usable in the raw form (less than 10,000 mg/L) or marginal quality water that is treatable (less than 50,000 mg/L).

Of the basins analyzed, the following basins had a high percentage of high to marginal quality produced water that may be used or treated for beneficial uses: Alaska North Slope (100%), North Central Montana (99%), Bighorn (99%), Wind River (99%), Alaska Cook Inlet (99%), Powder River (93%), and Greater Green River (88%). The Arkoma Basin has a moderate percentage of usable or treatable water (42%). In many instances, the water from these basins is already being put to beneficial uses such as irrigation, stock and wildlife watering, supplemental public water supply, and fish hatcheries, to name a few. However, the actual implementation of these beneficial uses might not be realized to the fullest extent possible for a number of reasons (i.e. regulatory barriers, public outcry, economic barriers). It is important for produced water that is fresh or marginal in quality be recognized and utilized as a resource across the entire United States, especially in arid regions where water is not always in abundance.

Water with salinity above 50,000 mg/L is either cost prohibitive or technologically incapable of being treated for traditional beneficial uses. However, this water can be used for enhanced recovery water injection projects or recycled for multiple hydraulic fracturing jobs. As discussed in Section 6, this is a common practice is most basins, and more notably so in older fields that have been exploited for many years.

Figure 7.2 Total Dissolved Solids of Produced Water in the United States

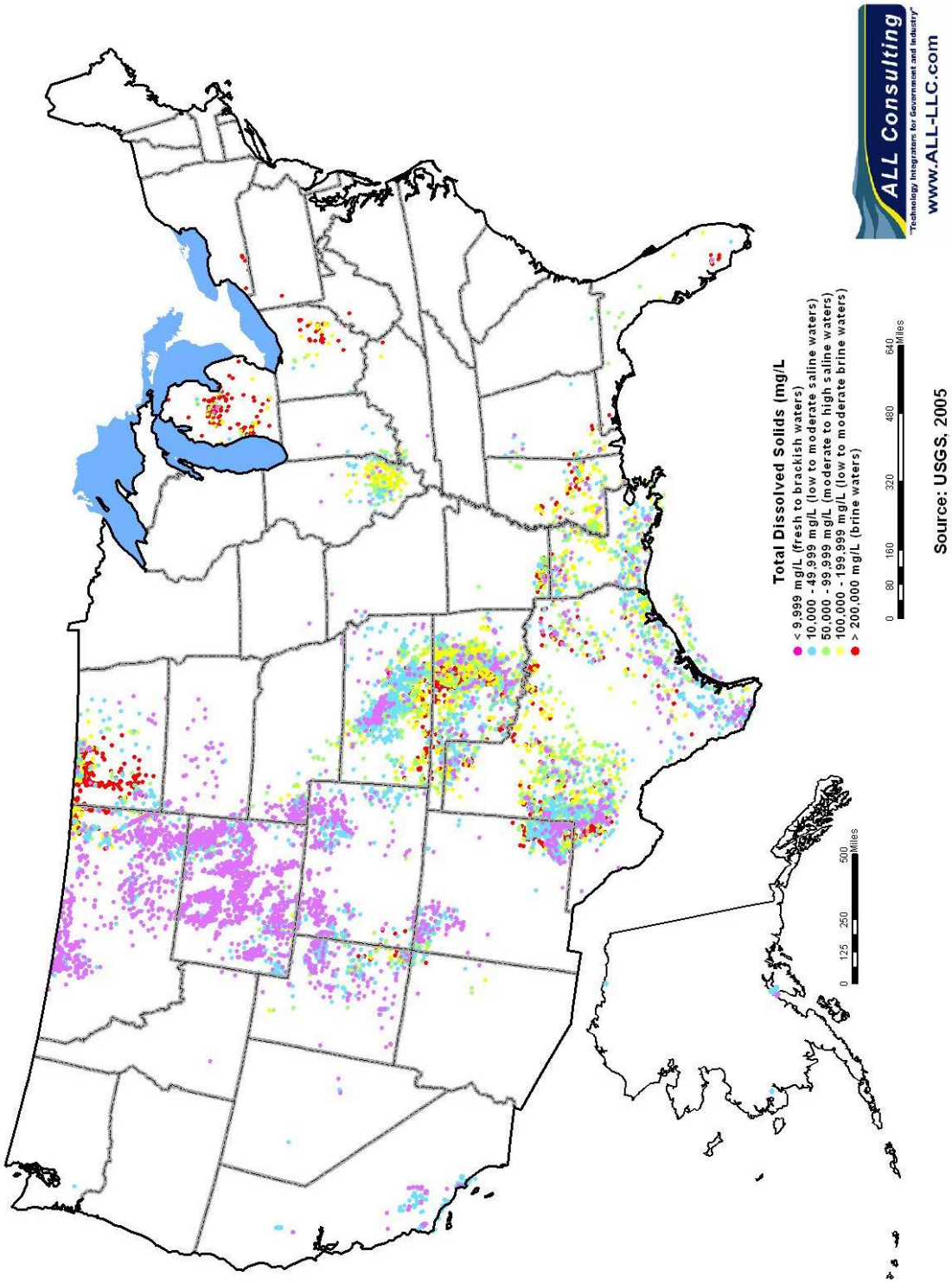
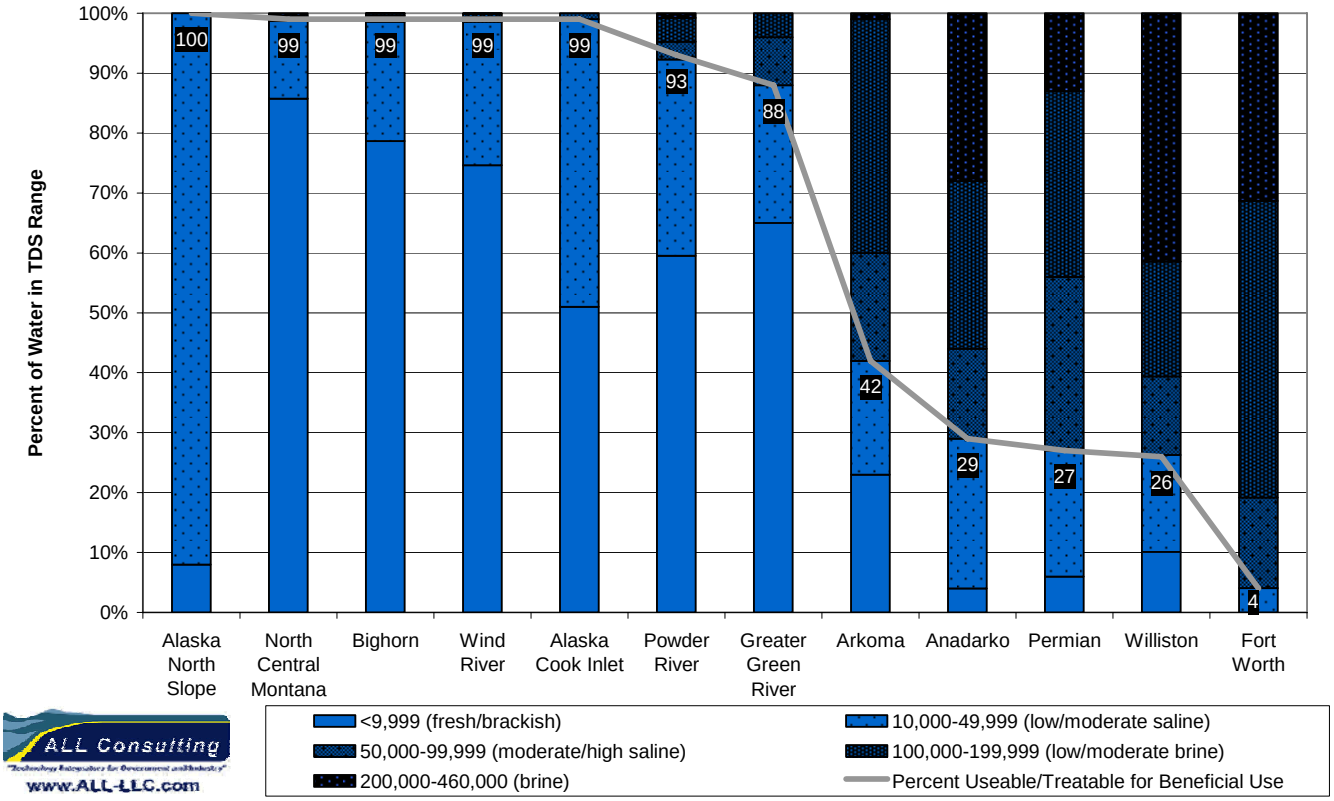


Table 7.1 Summary of Produced Water Quality Statistics

Basin Name	Produced Water Quality Percentage for Ranges (mg/L TDS)				
	0 – 9,999	**10,000 – 49,999**	**50,000 – 99,999**	**100,000 – 199,999**	**200,000 – 460,000**
Alaska North Slope	8	92	0	0	0
Alaska Cook Inlet	51	48	1	0	0
Anadarko Basin	4	25	15	28	28
Arkoma Basin	23	19	18	39	1
Bighorn Basin	79	20	1	0.4	0.04
Fort Worth Basin	0	4	15	49	31
Greater Green River	65	23	8	4	0
North Central Montana	86	13	0.5	0.3	0.5
Permian Basin	6	21	29	31	13
Powder River Basin	60	33	3	4	0.8
Williston Basin	10	16	13	19	41
Wind River Basin	75	24	0.8	0.6	0.08

Figure 7.3 Water Quality Statistical Analysis of Select Oil and Gas Basins



ALL Consulting
www.ALL-LLC.com

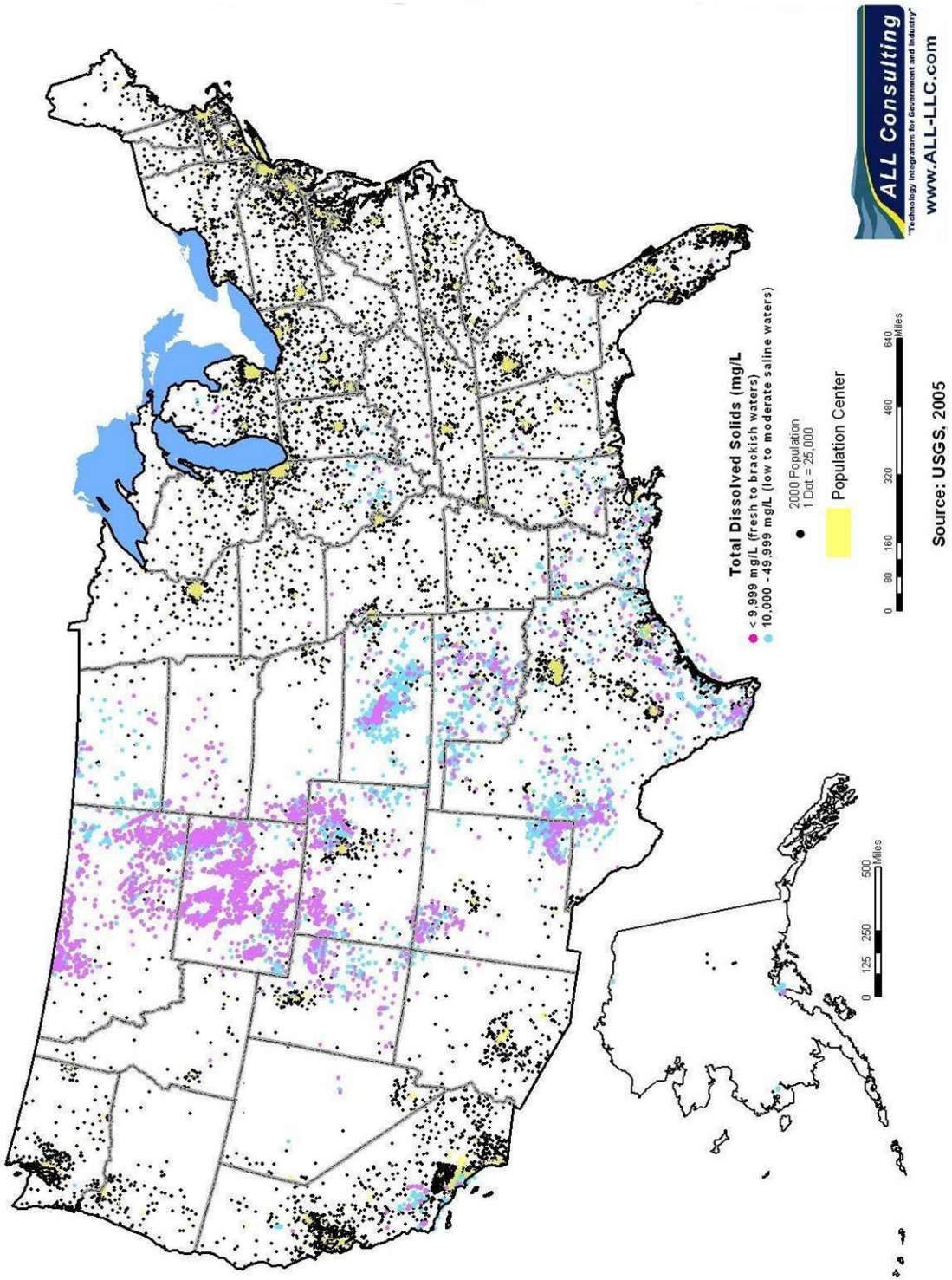
Water quantity also can play a role in deciding how best to manage produced waters. Some potential industrial applications of produced water, such as cooling water for a power generation facility, need a reliable source of water in terms of daily quantity, longevity, and quality. Some industrial sites would prefer to pay for a reliable source of water that they know will be available to them rather than rely on a free source of water that may diminish or be cut off over time. This stems from the fact that water quantities are highly variable from field to field; therefore making broad generalizations about water quantities for different basins is not recommended. Furthermore, the dynamics of produced water quantities can vary as the field is developed. Conventional fields typically yield more water as production progresses, while non-conventional plays such as CBNG might yield less water as production progresses. However, operators can develop a site-specific understanding of their projected water quantities by tracking the water they produce, and therefore instill a better understanding of their water management options that can utilize the water in a beneficial manner and be more economical in the future.

Section 7.2 Socio-Economic Setting

The socio-economic setting of a region can influence the options for how produced water is managed in that region. For purposes of exploring this idea further, socio-economic setting is quantified by population density and potential industrial uses. Areas with a higher population density typically will yield more complicated water management issues than areas of lower population density; however, the high population density areas may have a greater demand for water supply. Figure 7.4 provides a geographical distribution of water that is generally considered treatable (TDS < 50,000 mg/L) and population density across the contiguous United States. Areas can be identified from this map that might provide suitable water management solutions in high population areas. For example, the city of Denver is located near sources of usable and treatable produced water.

The impact of socio-economic setting is also evident when dealing with low quality water in areas such as the de-watering project in the Oklahoma City field of the Anadarko basin and the Barnett Shale play in and around Fort Worth, Texas. Surface use of the land in these densely populated areas precludes the drilling of wells at several well pad sites. Rather, multiple horizontal wells can be drilled from one well pad in various horizontal directions, which in turn can raise the costs of drilling when compared to similar projects in rural Oklahoma and Texas. In the Anadarko Basin the water is either re-injected for enhanced recovery, or it is injected into a horizontal disposal well capable of handling more than 60,000 barrels of water per day. In the Barnett Shale play the water may be recycled for use on fracturing additional wells in the area, thus saving the operator money on the cost of water for the fracture job, and saving local residents the burden on their local water supply.

Figure 7.4 Oil and Gas Basins compared to Population Density of the Contiguous United States



Another factor that population density can be a predictor of is qualified and available work force. In general, highly populated areas have a larger pool of potential workers, and therefore it can be easier to find a suitable labor force. Rural areas may not have immediate work force available, which in turn can raise the cost of a drilling program if the work crew is transported in from another region. This does not necessarily impact the water management options available, but it can impact the overall cost of the drilling program, which indirectly can impact the ability to economically treat and beneficially use produced water of marginal quality.

In regions where split estate is a common occurrence, (i.e. surface ownership has been severed from mineral ownership) the political setting might be unfavorable for oil and gas development because the produced water management options might be limited by legal issues between surface and mineral owners. This has been an issue with the CBNG resources in the Powder River Basin of Montana where federal mineral ownership is a common occurrence.

Section 7.3 Annual Rainfall and Evapotranspiration

Annual rainfall and evapotranspiration (ET) are two elements of the weather that can play a role in the effectiveness of different produced water management practices. Figures 7.5 and 7.6 provide estimates for the annual average rainfall and annual average lake evaporation rates, and Figure 7.7 provides a state-by-state estimate of the water available for ET in the United States. The water available for ET was calculated on a state-by-state basis by examining statewide water budgets:

Precip. + Surf. In-flow – Surf. Out-flow –Consumption = Water Available for ET

These figures can be used together to identify areas with a net zero or negative supply of water. For example, in the Big Horn and Powder River Basins the annual lake evaporation is between 40 and 50 inches per year (Figure 7.6); however, there is less than 10 inches per year available for ET (Figure 7.7). Therefore, the region in general is in need of water for irrigation as the evaporation rate is 4 to 5 times greater than the water available for ET.

If the produced water in these water starved areas is sufficient in quality for beneficial use (TDS less than 10,000 mg/L) the water can help to sustain farmers and ranchers through irrigation and water supply for livestock. Furthermore, these areas also might have the ability to use produced water that is marginal in quality (TDS less than 50,000 mg/L) by treating the water for beneficial use and disposing of a lower quantity waste stream.

Figure 7.5 Annual Average Rainfall in the Contiguous United States and Alaska

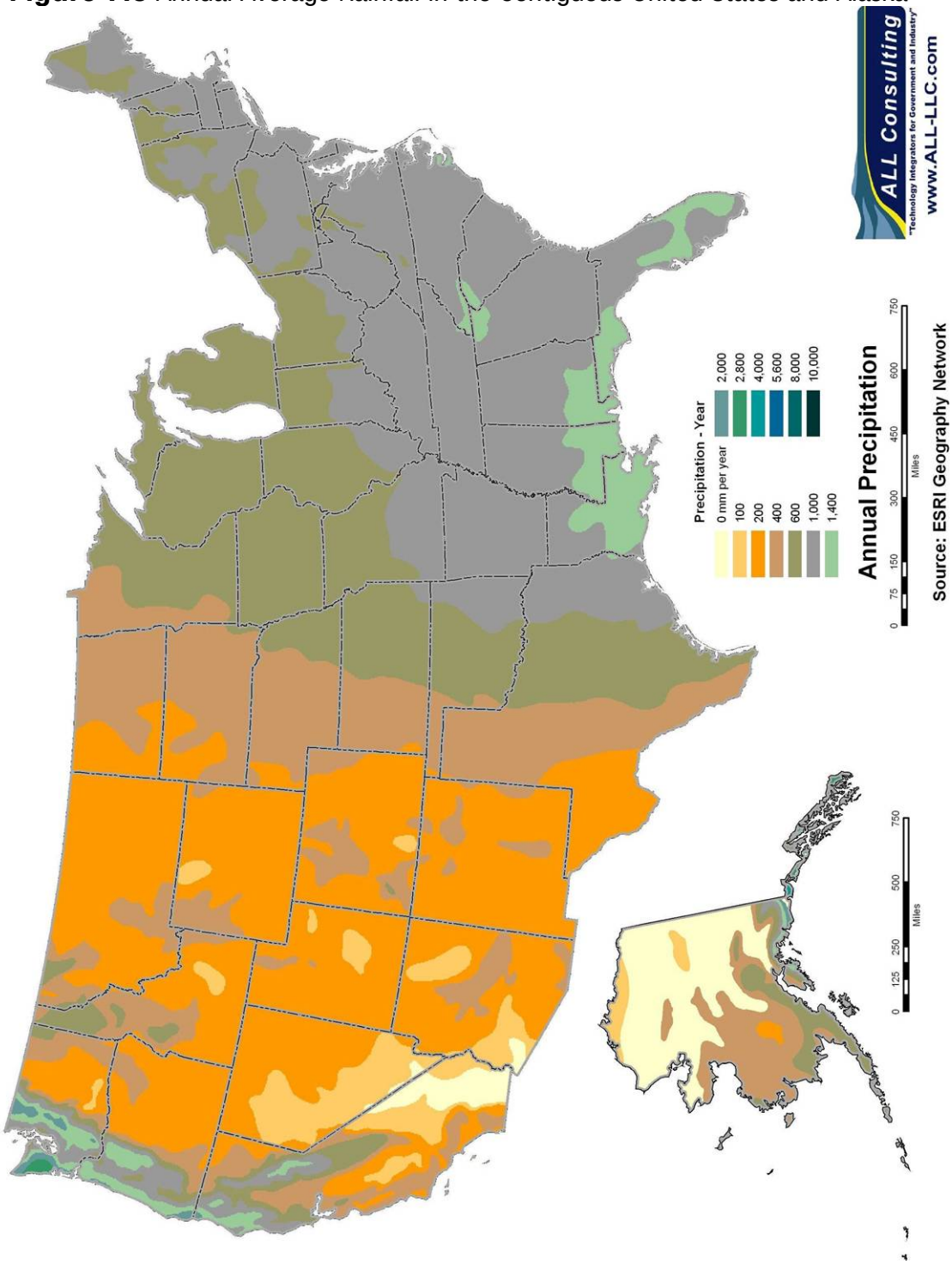


Figure 7.6 Annual Average Lake Evaporation in the United States

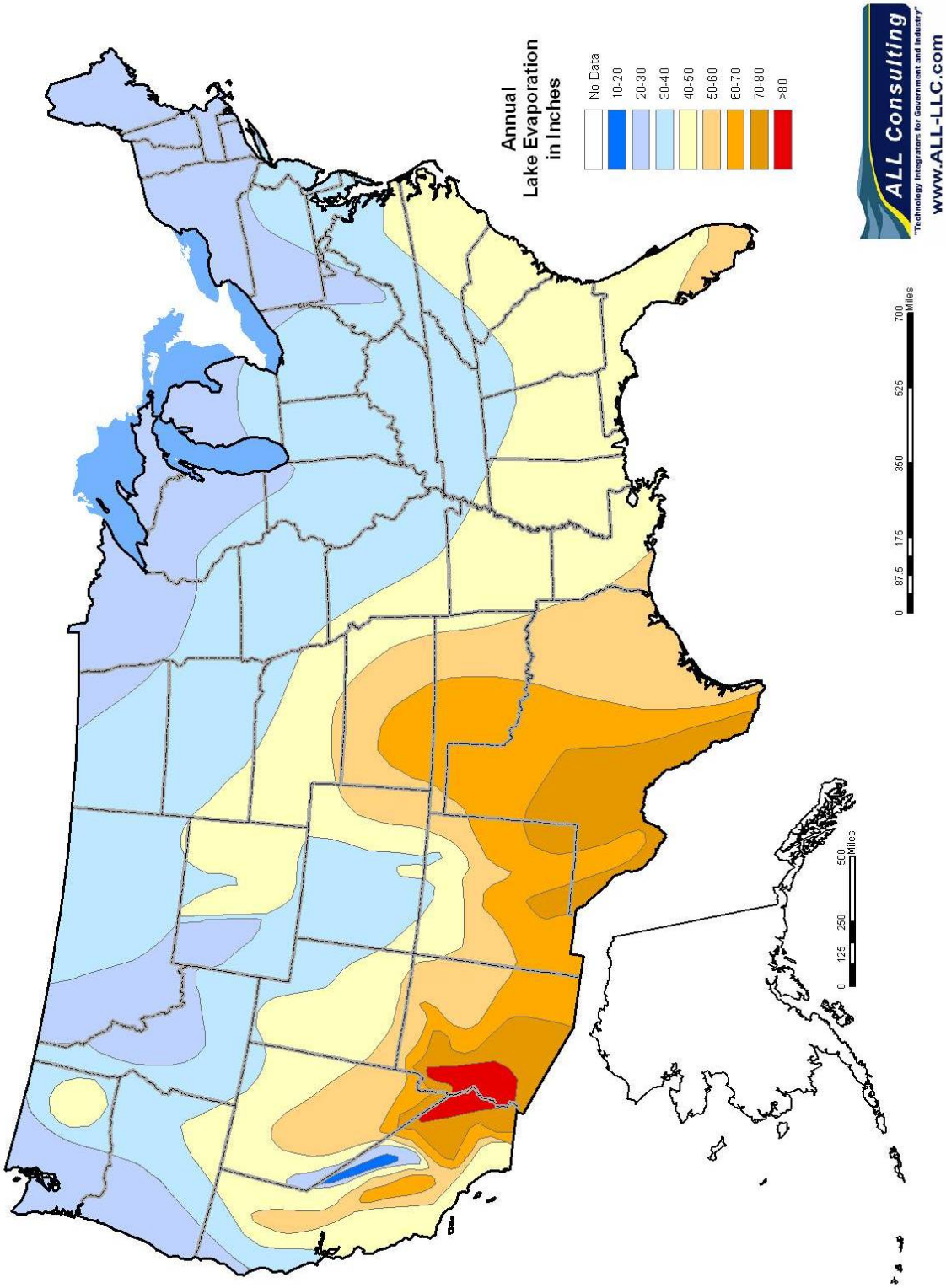
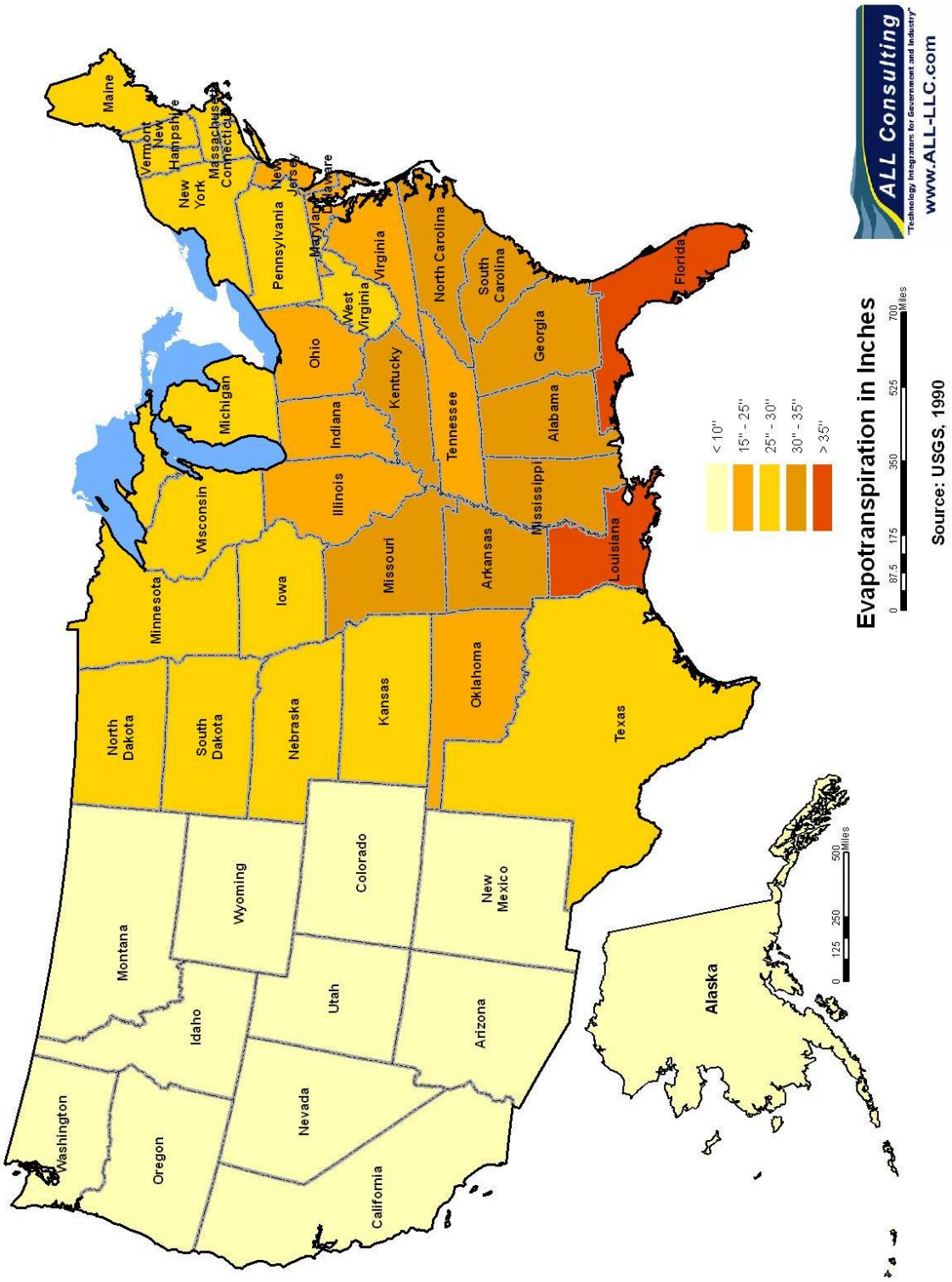


Figure 7.7 Annual Average Water Available for Evapotranspiration in the United States



The arid Western states provide several other examples where evaporation rates far exceed the water available for ET. In general, the water available for ET in these states is less than 10 inches per year; however, several basins intersect areas where evaporation is as high as 60 inches per year and rainfall is not more than 20 inches per year. These include several basins where beneficial uses of the water are common, and have been for several years, such as the Big Horn Basin, the North Central Montana Basin, the Powder River Basin, and the San Joaquin Basin in California. Other areas that might not be as obvious include the Arkoma Basin of Arkansas and Oklahoma. The water available for ET (25-35 inches per year) is relatively high, but when compared to the average annual lake evaporation (between 40 and 60 inches per year) a potential need for irrigation water can be identified because the evaporation rate can be as much as twice the amount available for ET. Furthermore, the water quality in some portions of the Arkoma Basin is of sufficient quality for beneficial uses such as flood irrigation and livestock watering; however, a large percentage of this high quality water is being disposed of in commercial disposal wells. BP has initiated a pilot program to use this water beneficially in coordination with the Oklahoma Corporation Commission and the local landowners in the Red Oak field. Similar programs may be feasible in the basin where water can be economically managed while providing an asset to landowners.

Historic annual precipitation and evapotranspiration ratios have changed in the past few years with a widespread drought in the upper Great Plains (Handwerk, 2005). This drought has lowered average annual precipitation and could be a cyclic phenomenon or a manifestation of Global Climate Change (Linden, 2006). Over the last century, the average temperature in Laramie, Wyoming, has increased 1.5°F. Precipitation has decreased by up to 20% in many parts of the state. Over the 21st Century, climate in the Great Plains may change even more due to the increases in greenhouse gases. By 2100, for example, temperatures in Wyoming could increase by 4°F in spring and fall, 5°F in summer, and 6°F in the winter. If temperatures and evaporation increase as forecast and the drought continues, surface water resources could be reduced drastically across the Great Plains. This could lead to severe competition for groundwater resources, including lesser quality groundwater that may require pre-use treatment.

If this drought is a long-term climatic development for the Great Plains and adjacent areas, potential beneficial uses for produced water gain importance. If precipitation is indeed to be lower throughout the future, produced water may become valuable for augmenting base-flow in streams and supplying water to cities and towns. Competition for scarce water resources might lead to increased value for higher quality produced water and may lead to large scale treatment of lower quality water prior to its use. Important uses might include protection of habitat within the riparian zone, supplement to irrigation and animal husbandry, or supplement to drinking water systems in towns and cities of the Great Plains. If global climate change is occurring, beneficial use of the water produced with oil and gas will become more important.

Section 7.4 Potential for New and Innovative Beneficial Uses

As previously mentioned, the culmination of water quality, quantity, socio-economic setting, and climatic conditions often lead to the development of regional-specific produced water management solutions. The potential exists for implementing new and/or innovative management solutions for produced water by identifying and sharing applicable produced water management practices that may have implications outside of their current region. The purpose of this document is to serve as a tool for achieving this goal.

In light of recent drought concerns and water shortages in many western states, produced water can be treated as a resource rather than as a waste product. In Section 7.2, basins were identified where a large portion of the produced water had quality that is currently deemed as "usable" (TDS values <10,000 mg/l) or "treatable" (TDS values >10,000 mg/l, but <50,000 mg/l) versus wholesale disposal of this resource. The identified basins include the Alaska North Slope, North Central Montana, Bighorn, Wind River, Alaska Cook Inlet, Powder River, Greater Green River, and the Arkoma. Basins identified as having a small percentage of beneficially usable or treatable water were the Anadarko, Permian, Williston, and Fort Worth, where the current practice of injection, whether it be for enhanced oil recovery, or strictly for disposal, seem to be the most practical options in these basins. Furthermore, of the basins with a large percentage of beneficially usable or treatable water, the socio-economic setting and climatic conditions were not favorable for taking advantage of the quality of the water in the two Alaskan basins (North Slope and Cook Inlet).

Marginal to Low Quality Water Basins

The Anadarko, Permian, Williston, and Fort Worth Basins fall within a scattering of population and industry ranging from large cities to strictly rural expanses. The precipitation regime of the basin is largely semiarid with an average rainfall between 15 and 30 inches per year (Figure 7.5), suggesting that surface water is a scarce commodity in these basins. There are a number of population centers as shown on Figure 7.4. Besides the historic petroleum industry, other forms of industry would include ranching and agriculture, which use copious amounts of water. The relatively low quality of the produced water of the basins, however, mitigates against its widespread use even for livestock watering. With low percentages of the reported produced water samples having less than 10,000 mg/L, it is unlikely that water in these basins would have industrial uses. A large percentage of the produced water quality samples from these basins was of poor quality with a TDS greater than 50,000 mg/L. If technologically possible, the costs of treating this water would be fairly high. Most industry users would prefer to use higher quality groundwater obtained locally if it can be attained economically.

Another use that may become more important if the current drought discussed in Section 7.4 continues is that produced water could be used for brush fire control. Brush fires have become more prevalent in the past several years across the United States. Depending upon their location, the large grass-fires and the need for water to control them may place undue stress on local reservoirs and aquifers that may have a higher use in support of agriculture or municipal water supply. High quality to marginal quality water produced through oil and gas operations could be used for fire suppression with minimal treatment. However, the means for transporting that water from the producing field where it is produced to the actual location of the fire may prove to be logistically complicated unless plans were made in advance to use the water in this manner.

High Quality Water Basins with Unfavorable Water Re-Use Conditions

As previously mentioned, the Alaskan North Slope and Cook Inlet have high percentages of beneficially usable and/or treatable quality water. However, these basins have other conditions that are unfavorable in regards to using the produced water. The low population density and the less than favorable annual climatic conditions lead to the conclusion that the current practice of injection, whether it be for enhanced oil recovery, or strictly for disposal, may be the most practical for Alaskan basins.

High Quality Water Basins with Favorable Water Re-Use Conditions

By considering water quality, socio-economic setting, and climatic conditions, the following basins have favorable characteristics for beneficially using produced water: North Central Montana, Bighorn, Wind River, Powder River, Greater Green River, and the Arkoma.

All of the basins in this category are almost predominantly rural with small cities dispersed throughout. They include some of the driest regions in the country with several locations averaging less than 5 inches of rain per year. In addition to the arid conditions, the basins in Montana and Wyoming have been in a prolonged drought since 1999 (NCDC, 2006) where precipitation has averaged only 84% of the historic annual value.

In the Bighorn Basin it is mostly agricultural users and local ranchers who have come to rely upon produced water for irrigation. The reliance is especially important during times of drought when rainfall can be very low. The basin appears to produce large volumes of high quality water that can be used for both stock watering and irrigation. The Bighorn Basin is similar in characteristics to other basins in Wyoming and Montana but unlike the others it has developed a system for utilizing produced water in the furtherance of agriculture. Therefore, the other basins in Montana and Wyoming have the potential for beneficially using the produced water in a way that can further the ability of farmers and ranchers.

The Arkoma Basin is spread across forested portions of eastern Oklahoma and western Arkansas. It is an area with small population centers and ample rainfall of 30 to 50 inches per year. Agriculture is the common industrial activity including confined animal feeding operations (CAFO). As discussed in Section 4, water requirements are greater at CAFO facilities when compared to range livestock; therefore, there might be a local demand for water that could be satisfied with produced water. The quality of the local produced water may mean that treatment is required and the demand for water might allow the user to pay for the treatment. Over 20% of the water tested from this basin is less than 10,000 mg/L and a smaller portion is high enough in quality to use for irrigation. These minor volumes of produced water have begun to play a local role in the Red Oak field, but due to the low volumes of the water produced it appears to have minimal affect on the economics of the region.

Population Centers Drive Water Demand

Southern California is a good example of how high density population centers can drive water demand to the point that new and innovative ways to treat and use water become a necessity. Municipal water district planners in Southern California predict that future water supply in the region will fall short of urban demand by 2020 without development of new water resources and increased conservation savings (UCR, 1999). Figure 7.4 shows that the produced water generated from nearby basins, such as the San Joaquin Basin, may be of suitable quality that it can either be treated for human consumption or it may continue to be used for irrigation purposes on orchards to offset the demand for treated water. Basins upstream of Southern California near the Colorado River (Unita-Piceance, San Juan, Paradox) also might be suitable to discharge water to the Colorado River system, thus providing additional water resources to downstream users in California. Other potential markets that might couple well with oil and gas producing basins include the Denver Basin with the Denver Metro Area, the Uinta-Piceance or the Greater Green River Basins with the Salt Lake City metro area, and the Forest City Basin with the Kansas City Metro area.

Section 8.0 References

AAPG, 1992. Geothermal Map of the United States.

AAPG, 2006: *Barnett Shale a Stimulating Play,* in AAPG Explorer, Feb 2006.

Alyeska Pipeline, 2006: Pipeline Facts: North Slope. accessed on March 7, 2006 @ http://www.alyeska-pipe.com/Pipelinefacts/North%20Slope.html.

Alaska Department of Natural Resources, 2003: Cook Inlet Oil & Gas. Department of Natural Resources. Division of Oil and Gas. Prepared by Tim Ryherd, Geologist, State of Alaska. July 29, 2003.

Alaska Department of Natural Resources, 2004: Oil and Gas Report. Division of Oil and Gas. accessed at: http://www.dog.dnr.state.ak.us/oil/products/publications/annual/2004_annual_report/Section1.pdf

Alaska Department of Natural Resources, 2006: Alaska Oil and Gas Activities. Division of Oil and Gas. Prepared by William Van Dyke, Acting Director, Alaska Department of Natural Resources. January 17, 2006. Advanced Resource International (ARI) for the U.S. EPA, 1994, 68-W-00-094. "Fracturing Technologies for Improving CMM/CBNG Production".

ALL Consulting (ALL) and Montana Board of Oil and Gas Conservation (MBOGC), 2002. Handbook on Best Management Practices and Mitigation Strategies for Coal Bed Methane in the Montana Portion of the Powder River Basin, prepared for United States Department of Energy – National Petroleum Technology Office, April 2002.

ALL Consulting (ALL), July 2003. Handbook on Coal Bed Methane Produced Water: Management and Beneficial Use Alternatives. Prepared For the Ground Water Protection Research Foundation, U.S. Department of Energy - National Petroleum Technology Office, Bureau of Land Management.

ALL Consulting (ALL), 2005. "Reducing Produced Water Volumes from Coal Bed Natural Gas in the Powder River Basin".

ALL Consulting (ALL), 2005. Technical Summary of Oil and Gas Produced Water Treatment Technologies.

ALL Consulting (ALL), 2006. "Feasibility Study of Expanded Coal Bed Natural Gas Produced Water Management Alternatives in the Wyoming Portion of the Powder River Basin: Phase I".

ALL Consulting (ALL), 2006. "Phase One: Feasibility Study of Expanded Coal Bed Natural Gas Produced Water Management Alternatives in the Wyoming Portion of the Powder River Basin".

ALL Consulting and MBOGC, 2004. Coal Bed Methane Primer: New Source of Natural Gas – Environmental Implications, Background and Development in the Rocky Mountain West, Prepared for: U.S. DOE National Petroleum Technology Office.

Argonne National Laboratory, 2002. Regulatory Issues Affecting Management of Produced Water from Coal Bed Methane Wells, Argonne National Laboratory, prepared for U.S. DOE Office of Fossil Energy.

American Petroleum Institute (API), 2006. "Where does the U.S. produce oil and natural gas?" Accessed online at: http://www.api.org

Aston, M.S., et al, SPE Paper 87130, March 2004. "Drilling Fluids for Well-bore Strengthening".

Barrufet M.A., Iglesias-Silva G., Petriciolet A., Patel C.V., and Burnett D., 2004. "A Modular Design And Implementation of A Brine Conversion Process: Oil Removal and Desalting Units," paper presented at the 11th IPEC, Albuquerque, NM.

Baker, Tim, 2005. Personal conversation between Dr. Langhus and Jake Crissup of ALL Consulting and Tim Baker of the Oklahoma Corporation Commission.

Ball, Mahlon, 1995. Permian Basin Province (044), in Gautier, D. L., Dolton, G.I., Takahashi, K.T., and Varnes, K.L., eds., 1995 National assessment of United States oil and gas resources--Results, methodology, and supporting data: U.S. Geological Survey Digital Data Series DDS-30.

Ball, M., and W. Perry, 1995. Bend Arch-Fort Worth Basin Province (045), in Gautier, D. L., Dolton, G.I., Takahashi, K.T., and Varnes, K.L., eds., 1995 National assessment of United States oil and gas resources--Results, methodology, and supporting data: U.S. Geological Survey Digital Data Series DDS-30.

Bein, A. and A. R. Dutton, 1993. Origin, distribution, and movement of brine in the Permian Basin: A model for displacement of connate brine. GSA Bull., vol. 105, pp. 695-707.

Blackwell, D. D., and M. C. Richards, 2004. Geothermal Map of North America, scale 1:5,000,000, AAPG, Map Code #423, April 2004.

Blackwell, D.D. et al, 2006. Geothermal Resources in Sedimentary Basins, 2006 SMU Geothermal Conference, Dallas, March 2006.

Bost A.L., and Reid T., 2004. "Powder River Gas L.L.C. Coal Creek CNBG POD – Hydrology Technical Report," BLM Montana (November 2004).

Bureau of Economic Geology, 2002. Play Analysis and Digital Portfolio of Major Oil Reservoirs in the Permian Basin: Application and Transfer of Advanced Geological and Engineering Technologies for Incremental Production Opportunities. Performed in cooperation with the New Mexico Bureau of Geology and Mineral Resources.

Cline, J., December 13, 2005. Personal conversation between Dr. Langhus and Jeff Cline of Anadarko Petroleum.

Cohen, Y., J. Glater, A. Tsao and R-W Lee, September 9-13, 2001. "Nanofiltration Membranes for Agricultural Drainage Water Reclamation," Paper published in the proceedings of the International Conference on Membrane Technology for Wastewater Reclamation and Reuse, Tel-Aviv, Israel.

Comer, J.B., 1992. Organic geochemistry and paleogeography of Upper Devonian formations in Oklahoma and northwestern Arkansas, in K.S. Johnson and B.J. Cardott, eds., Source rocks in the southern Mid-Continent, 1990 symposium: OGS Circular 93, p. 70-93.

Davies, S. and D. Widawsky, 1995. The Impact of the Changing Size of Feedlots on Corn Marketing in Colorado. Journal of the American Society of Farm Managers and Rural Appraisers, Volume 59, No. 1: Pg 120-127.

DeJarnett, B., F. Lim, and D. Calogero, 1997: Greater Green River Basin Production Improvement Project, prepared for the U.S. Department of Energy's Federal Energy Technology Center and Union Pacific Resources Company.

Dolton G., and J.E. Fox, 1995: Powder River Basin Province (033), in Gautier, D. L., Dolton, G.I., Takahashi, K.T., and Varnes, K.L., eds., 1995 National assessment of United States oil and gas resources--Results, methodology, and supporting data: U.S. Geological Survey Digital Data Series DDS-30.

The Dow Chemical Company (Dow), 2003. "A Low Cost Option to Reduce Sodium Levels in Coal Bed Methane Coproduced Wastewater using DOWEX G-26 Resin," DOWEX Ion Exchange Resins.

Doyle D.H., Daniel F., and Brown A.B., 1997. "Field Test of Produced Water Treatment with Polymer Modified Bentonite," paper SPE 38353 presented at the 1997 Rocky Mountain Regional Meeting, Casper, Wyoming.

Dutton, S., E. Kim, R. Broadhead, C. Breton, W. Raatz, S. Ruppel, and C. Kerans, 2004: Play Analysis and Digital Portfolio of Major Oil Reservoirs in the Permian Basin: Application and Transfer of Advanced Geological and Engineering

Technologies for Incremental Production Opportunities. Prepared by the Texas Bureau of Economic Geology and New Mexico Bureau of Geology and Mineral Resources.

Dyman, T.S., 1995: North-Central Montana Province (028), in Gautier, D. L., Dolton, G.I., Takahashi, K.T., and Varnes, K.L., eds., 1995 National assessment of United States oil and gas resources--Results, methodology, and supporting data: U.S. Geological Survey Digital Data Series DDS-30.

Evergreeen Resources Inc., CBM-1: A Supplement to the Oil & Gas Investor, December 2002. "Opportunities in CBNG".

Forbis, P., February 2006. *Agency Approves Fluid Recycling of Frac Fluids in Pilot Project,* in Texas Drilling Observer Newsletter, vol 7, Issue 4.

Fox, J.E., and G. Dolton, 1995a. Bighorn Basin Province (034), in Gautier, D. L., Dolton, G.I., Takahashi, K.T., and Varnes, K.L., eds., 1995 National assessment of United States oil and gas resources--Results, methodology, and supporting data: U.S. Geological Survey Digital Data Series DDS-30.

Fox, J.E., and G. Dolton, 1995b. Wind River Basin Province (035), in Gautier, D. L., Dolton, G.I., Takahashi, K.T., and Varnes, K.L., eds., 1995 National assessment of United States oil and gas resources--Results, methodology, and supporting data: U.S. Geological Survey Digital Data Series DDS-30.

Funston R., Ganesh R., and Leong Lawrence Y.C., 2002. "Evaluation of Technical and Economic Feasibility of Treating Oilfield Produced Water to Create a "New" Water Resource," paper presented at the 2002 Ground Water Protection Council (GWPC) meeting.

GE Infrastructure Water & Process Technologies (GE), 2006. "Membrane Filtration of Oil and Gas Field Produced Water".

GE Infrastructure Water & Process Technologies (GE), 2001. "Produced Water Pilot Study".

Groundwater Protection Council (GWPC), 2006. About Class I Injection Wells. accessed on March 2, 2006. http://www.gwpc.org/UIC/Well-Types/classi.htm

Gas Technology Institute (GTI), 2002. accessed at: http://www.gtionline.org/gti/main/main.cfm

Gibson, R.I., 1997. Greater Green River Basin: online at http://www.gravmag.com/grnriv.htm.

Guyer, P.Q. 1977. Water Requirements for Beef Cattle. University of Nebraska Cooperative Extension Service Bulletin G77-371-A.

Handwerk, B, June 14, 2005. Plains Drought Cycle Has Long History, Ominous Future, National Geographic News

Hayes T., 2004. "The Electodialysis Alternative for Produced Water Management," Gas Technology Institute (2004).

Hayter S., Tanner S., Urbatsch E., and Zuboy J., June 2004. "Saving Energy, Water, and Money with Efficient Water Treatment Technologies," DOE/EE-0294, A New Technology Demonstration Publication, Federal Energy Management Program.

Heck, Thomas J., R.D. LeFever, D.W. Fischer, and J. LeFever, 2002. Overview of the Petroleum Geology of the North Dakota Williston Basin, N.D. Geological Survey

Heins W., and Peterson D., June 2003. "Use of Evaporation for Heavy Oil Produced Water Treatment", a paper presented at the 4th Canadian International Petroleum Conference held in Calgary, Canada.

Henry, M. and T. Hester, 1995. Anadarko Basin Province (058), in Gautier, D. L., Dolton, G.I., Takahashi, K.T., and Varnes, K.L., eds., 1995 National assessment of United States oil and gas resources--Results, methodology, and supporting data: U.S. Geological Survey Digital Data Series DDS-30.

Hernon B., Zanapalidou H., Prato T., and Zhang L., 1999. "Removal of Weakly-Ionized Species by EDI," Ionics Inc.

Hutchinson, W., November 21, 2005. Personal conversation between Dr. Langhus and Wendy Hutchinson of Arch Coal Company.

Hunt, J. M., 1979. *Petroleum Geochemistry and Geology*: W. H. Freeman and Sons, San Francisco, 617.

Interstate Oil and Gas Compact Commission (IOGCC), 2005. "Marginal Oil and Natural Gas : American Energy for the American Dream"

Jackson, L., and J. Myers, October 16-17, 2002. "Alternative Use of Produced Water in Aquaculture and Hydroponic Systems at Naval Petroleum Reserve No. 3," presented at the 2002 Ground Water Protection Council Produced Water Conference, Colorado Springs, CO. (Paper available at http://www.gwpc.org/Meetings/PW2002/Papers-Abstracts.htm.)

Jackson, L.M., and J.E. Myers, October 2003. "Design and Construction of Pilot Wetlands for Produced Water Treatment," SPE 84587, presented at the SPE Annual Technical Conference and Exhibition, Denver, CO.

Kansas State University (KSU), November 2005. Kansas State University Research and Extension Department Website http://www.oznet.ksu.edu/sdi/Photos/Photos.htm.

Karlstrom, Thor N.V., 1964: Quaternary Geology of the Kenai Lowland and Glacial History of the Cook Inlet Region, Alaska. U.S. Department of the Interior. Geological Survey Professional Paper-443.

Lang K., 4th Quarter 2000. "Managing Produced Water", Hart Energy Publications Excerpts in Petroleum Technology Transfer Council Network News.

Law, Ben E., 1995, Southwestern Wyoming Province (037), in Gautier, D. L., Dolton, G.I., Takahashi, K.T., and Varnes, K.L., eds., 1995 National assessment of United States oil and gas resources--Results, methodology, and supporting data: U.S. Geological Survey Digital Data Series DDS-30.

Lawson, J., November 18, 2005. Personal conversation between Dr. Langhus and John Lawson of the United States Bureau of Reclamation.

Lincz R., December 2004. "Newpark's HB Reactor Water Treatment Technology Used for Anadarko Coal Bed Methane Produced Water Treatment for Discharge County Line Production Field", prepared by Newpark Environmental Services for DEQ-Water Quality Division.

Linden, E. 2006. *The Winds of Change*, Simon and Schuster, New York.

Marriage, L.D., Davison, V.E., 197.. Fish Ponds-Construction and Management. in: Teague, R.D., ed. A Manual of Wildlife Conservation. Washington D.C.. The Wildlife Society: 100-102.

"Membrane Filtration," Tech Brief, National Drinking Water Clearinghouse Fact Sheet (1999).

Mickley M., September 2001. "Membrane Concentrate Disposal: Practices and Regulation", prepared by Mickley & Associates for U.S. Department of The Interior under agreement no. 98-FC-81-0054, Desalination and Water Purification research and Development Program Report No. 69.

Moftah K., October 2002. "High pH RO for Wastewater Treatment," Pollution Engineering.

Murphree, P., 2005. Personal conversation between Dr. Langhus and Mr. Murphree of Peabody Coal Company.

Myers J.E., Jackson L.M., Bernier R.F., and Miles D.A., 2001. "An Evaluation of the Department of Energy Naval Petroleum Reserve No. 3 Produced Water Bio-Treatment Facility," paper SPE 66522 presented at the 2001 SPE/EPA/DOE Exploration and Production Environmental Conference, San Antonio, Texas.

Mast, R.F., Root, D.H., Williams, L.P., Beeman, W.R., and Barnett, D.L., 1998. Areas of historical oil and gas exploration and production in the conterminous United States: U.S. Geological Survey Geologic Investigations Series I-2582, one sheet.

McLelland, P. and Hawkes, C., October 2002. "Assessing Bore-hole Instability Risks for Horizontal Wells in Coals and Fractured Shales". 4th Annual Unconventional Gas and CBM Conference, Calgary

Montana Board of Oil and Gas (MBOGC), 2005. Montana Board of Oil and Gas Conservation online database, http://bogc.dnrc.state.mt.us/OnlineData.htm

Montana Board of Oil and Gas (MBOGC), 2006. Data compilation and analysis.

NCDC, March 2006. Climate of 2005 - June , Wyoming Division 4 Drought, National Climate Data Center website, http://www.ncdc.noaa.gov/oa/climate/research/2005/jun/st048dv04pcp200506.html

New Logic Research, 2003. "Using VSEP to Treat Produced Water – An effective and economical solution".

Nicot Jean-Philippe, and Dutton A.R., September 2004. "Please Pass the Salt: Using Oil Fields for the Disposal of Concentrate from Desalination Plants," a report presented to the U.S. Bureau of Reclamation.

Olson, J., November 8, 2005. Personal conversation between Dr. Langhus and Joe Olson of Williams Production.

Oil & Gas Accountability Project, April 2004. "Oil and Gas at Your Door – A Landowner's Guide to Oil and Gas Development".

Perry, William J., 1995. Arkoma Basin Province (062), in Gautier, D. L., Dolton, G.I., Takahashi, K.T., and Varnes, K.L., eds., 1995 National assessment of United States oil and gas resources--Results, methodology, and supporting data: U.S. Geological Survey Digital Data Series DDS-30.

Peterson, James A., 1995. Williston Basin Province (031), in Gautier, D. L., Dolton, G.I., Takahashi, K.T., and Varnes, K.L., eds., 1995 National assessment of United States oil and gas resources--Results, methodology, and supporting data: U.S. Geological Survey Digital Data Series DDS-30.

Proctor, B.R., Thompson, R.W., Bernin, J.E. et al, 1983. Practices for Protecting and Enhancing Fish and Wildlife on Coastal Surface Mined land in The Powder River-Ft. Union Region. United States Department of the Interior, Fish and Wildlife Service, FWS/OBS-83/10: 246.

Reynolds Rodney R., 2003. "Produced Water and Associated Issues," a manual for independent operator, *Petroleum Technology Transfer Council*.

Rumble, Mark, 1989. United States Department of Agriculture Forest Service, Surface Mine Impoundments as Wildlife and Fish Habitat.

Rushworth, S. and M. Manning, Decmeber 12, 2005. *Local Play Brings Business and New Technology*, in Fort Worth Business Press.

Saikat, Mazumder and Karl-Heinz, Wold A., Third Quarter, 2004. "A Different Direction for CBNG Wells". Weatherford W Magazine.

Stutz, Lloyd and Fisher, Kevin, PTTC Archive, June 2004. "Fracture mapping and modeling optimize CBNG fracture treatments".

Sattler A., Hightower M., Nenoff T., Pless J., Phillips M., Brister B., Arnold R., Cather M., and McPherson B., 2004. "Managing Coal Bed Methane Produced Water for Beneficial Uses, Initially Using The San Juan and Raton Basins as a Model", Interim Progress Report prepared for NETL, Sandia National Laboratory.

Shultz, J., December 9, 2005. Personal conversation between Dr. Langhus and John Shultz of Basin Electric Power Coop.

Smith K.P., Williams G.P., Blunt D.L., and Arnish J.J., 1997. "Radiological Dose Assessment of NORM Disposal in Class II Injection Wells," U.S. DOE contract W-31-109-Eng-38.

Southwest Energy Company, February 2006. Home Page/Operations/Fayetteville Shale Gas, http://www.swn.com/

Spitz L.R., 2003. "Advanced Mobile Water Treatment Systems for Treating Coal Bed Methane Produced Water," a paper presented at the 2003 Ground Water Protection Council meeting.

Stafford, B., December 9, 2005. Personal conversation between Dr. Langhus and Bill Stafford of Basin Electric Power Coop

Stearns, M., November 11, 2005. Personal conversation between Dr. Langhus and Marty Stearns of Kennecott Energy Company.

The Tenorm Page, 2004. "Mobilization and Redeposition of NORM".

Texas Commission of Environmental Quality (TCEQ), January 24, 2006. Personal communication between Jake Crissup of ALL Consulting and Bryan Smith of TCEQ.

Thomsen, Paul, A., 2006. New Technologies for Modular Geothermal Power Plants in Oil and Gas Settings, 2006 SMU Geothermal Conference, March 2006.

Turner W., 2002. "Report on Treatment of Power Plant Waste Water Using The Aquasonics Rapid Spray Desalination Process," WestWater Resources, NM.

United States Department of Agriculture and National Resource Conservation Service (NRCS), 1982. Agriculture Handbook Number 590, Ponds – Planning, Design, Construction. Revised 1997.

United States Department of Energy Office of Fossil Energy and National Energy Technology Laboratory-Strategic Center for Natural Gas, DOE/NETL-2003/1193, September 2003. "Multi-Seam Well Completion Technology: Implications for Powder River Basin Coalbed Methane Production".

United States Department of Energy (DOE), 2006. "Oil and Natural Gas Supply, Technology Transfer." Accessed online at: http://www.netl.doe.gov

United States Energy Information Administration (EIA), 2006. "United States Crude Oil and Natural Gas Supply & Disposition". Accessed online at: http://www.eia.doe.gov

United States Environmental Protection Agency (EPA), September 1988. Climate Change and Wyoming, EPA 236-F-98-007n.

United States Environmental Protection Agency (EPA), 1991. Industrial Surface Impoundment Study in the United States. EPA 530-R-01-005. Washington, DC.

United States Environmental Protection Agency (EPA), September 1999. "Class V Underground Injection Control Study", U.S. EPA/816-R-99-014.

United States Environmental Protection Agency (U.S. EPA), September 2000. "Wastewater Technology Fact Sheet – Trickling Filters," 832-F-00-014.

United States Environmental Protection Agency (EPA), March 2001a. Class I Underground Injection Control Program: Study of the Risks Associated with Class I Underground Injection Wells. EPA 816-R-01-007

United States Environmental Protection Agency (EPA), April 2001b. "EPA Proposes to Continue with its Existing Approach for Managing Class V Injection Wells". Accessed online at: http://www.epa.gov/safewater/uic/classvdetermination.html

United States Environmental Protection Agency (EPA), 2004. Water Permitting 101, NPDES Permit Program Basics, available on the U.S. EPA website at http://www.epa.gov/npdes/pubs/101pape.pdf

United States Environmental Protection Agency (EPA), 2005a, Overview of Current Total Maximum Daily Load- TMDL- Program and Regulations, available on the U.S. EPA website at http://www.epa.gov/owow/tmdl/overviewfs.html

United States Environmental Protection Agency (EPA), 2005b, Underground Injection Control Program, available on the U.S. EPA website at http://www.epa.gov/safewater/uic/index.html

United States Environmental Protection Agency (EPA), February 14, 2005. "Oil and Gas Injection Wells (Class II)". Accessed online at: http://www.epa.gov/safewater/uic/classii.html

United States Environmental Protection Agency (EPA), March 1, 2006. Underground Injection Control Program. Deep Wells (Class I). Accessed. http://www.epa.gov/OGWDW/uic/classi.html

United States Fish and Wildlife Service (U.S. Fish and Wildlife), October 2002. Buffalo Lake National Wildlife Refuge. http://southwest.fws.gov/refuges/texas/buffalo.html.

United States Geological Survey (USGS), December 2004. "A Tapestry of Time and terrain: The Union of Two Maps – Geology and Topography" http://tapestry.usgs.gov/physiogr/physio.html.

United States Geological Survey (USGS), April 2002. "Produced Waters Database" Accessed online at: http://energy.cr.usgs.gov/prov/prodwat/intro.htm

United States Geological Survey (USGS), May 2002. United States Geological Survey Produced Waters Database, compiled by George N. Breit, Provisional Release, online at: http://energy.cr.usgs.gov/prov/prodwat/index.htm

United States Geological Survey (USGS), December 2004. "A Tapestry of Time and terrain: The Union of Two Maps – Geology and Topography" http://tapestry.usgs.gov/physiogr/physio.html

United States Geological Survey (USGS), 2005. United State Geological Survey National Oil and Gas Assessment, online at: http://energy.cr.usgs.gov/oilgas/noga/

United States Geological Survey (USGS), 2005. United States Geological Survey National Oil and Gas Assessment Interactive Map Page, online at: 'http://certmapper.cr.usgs.gov/noga/servlet/MapWindowServ

University of California Riverside (UCR), August 1999. "California Water Demand Snapshot", UCRTRAC Newsletter

Veil, J. A., February 1997. Surface Water Discharge from Onshore Stripper Wells, Prepared for United States Department of Energy, Office of Fossil Energy.

Veil, J.A., Langhus, B.G., and Belieu, S., January 1999. "Feasibility Evaluation of Downhole Oil/Water Separation Technology," U.S. DOE Report.

Veil, J.A., Puder M.G., Elcock D., and Redweik R. Jr. J., January 2004. "A White Paper Describing Produced Water from Production of Crude Oil, Natural Gas, and Coal Bed Methane," USDOE, W-31-109-Eng-38.

Wallace, W. K., and C. L. Hanks, 2005. Structural Geology of the Brooks Range. University of Fairbanks. Department of Geology and Geophysics. Accessed at: http://www.uaf.edu/geology/Research/research/structure.html.

Williams, B., 2005. Personal conversation between Dr. Langhus and Bruce Williams of Fidelity.

Wyoming Department of Environmental Quality (WDEQ), 2001, Chapter 1 Wyoming Water Quality Rules and Regulations; Wyoming Surface Water Quality Standards, Wyoming Department of Environmental Quality-Water Quality Division.

Wyoming Department of Environmental Quality (WDEQ), 2005a, Chapter 1 Wyoming Surface Water Quality Standards, Draft Three of the proposed changes to the Chapter 1 Regulations.

Wyoming Department of Environmental Quality (WDEQ), December 2005b, Personal communication between Heidi Kaiser of ALL Consulting and Jason Thomas of WDEQ.

Wyoming Oil and Gas Conservation Commission (WOGCC), June 27, 2005. Personal communication between Jake Crissup of ALL Consulting and Craig Eggerman of WYOGCC.

Wyoming Oil and Gas Conservation Commission (WOGCC), 2006. Online Production Data available at: http://wogcc.state.wy.us/grouptrpMenu.cfm?Skip='Y'&oops=49.

Zupancic, J., October 31, 2005. Personal conversation between Dr. Langhus and John Zupancic of BeneTerra.

THIS PAGE INTENTIONALLY LEFT BLANK