Paper #2-17

MANAGEMENT OF PRODUCED WATER FROM OIL AND GAS WELLS

Prepared by the Technology Subgroup
of the
Operations & Environment Task Group

On September 15, 2011, The National Petroleum Council (NPC) in approving its report, *Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources*, also approved the making available of certain materials used in the study process, including detailed, specific subject matter papers prepared or used by the study's Task Groups and/or Subgroups. These Topic and White Papers were working documents that were part of the analyses that led to development of the summary results presented in the report's Executive Summary and Chapters.

These Topic and White Papers represent the views and conclusions of the authors. The National Petroleum Council has not endorsed or approved the statements and conclusions contained in these documents, but approved the publication of these materials as part of the study process.

The NPC believes that these papers will be of interest to the readers of the report and will help them better understand the results. These materials are being made available in the interest of transparency.

The attached paper is one of 57 such working documents used in the study analyses. Also included is a roster of the Subgroup that developed or submitted this paper. Appendix C of the final NPC report provides a complete list of the 57 Topic and White Papers and an abstract for each. The full papers can be viewed and downloaded from the report section of the NPC website (www.npc.org).

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Table of Contents

ABSTRACT

Produced water is water that is returned to the surface through an oil or gas well. It is made up of natural formation water as well as the uphole return of water injected into the formation (flowback water) that was sent downhole as part of a fracture stimulation (frac) process or an enhanced recovery operation. Produced water is typically generated for the lifespan of a well.

Although produced water varies significantly among wells and fields, several groups of constituents are present in most types of produced water. The major constituents of concern in produced water are: Salt content (expressed as salinity, total dissolved solids, or electrical conductivity); Oil and grease (identified by an analytical test that measures the presence of families of organic chemical compounds); Various natural inorganic and organic compounds (e.g., chemicals that cause hardness and scaling such as calcium, magnesium, sulfates, and barium); Chemical additives used in drilling, fracturing, and operating the well that may have some toxic properties (e.g., biocides, corrosion inhibitors); Naturally occurring radioactive material (NORM).

Technologies and strategies applied to produced water comprise a three-tiered water hierarchy: (1) Minimization; (2) Recycle / Re-use; and (3) Disposal. Techniques to minimize produced-water volumes are tailored as is feasible for individual locations but diposal must ultimately be addressed. Most onshore produced water is re-injected to underground formations, either to provide additional oil and gas recovery or for disposal, under permits issued by state agencies or regional offices of the US Environmental Protection Agency (EPA). Most offshore produced water is diposed as discharge to the ocean following treatment according to requirements of the National Pollutant Discharges Elimination System (NPDES) as permitted EPA regional offices. Techniques to minimize produced-water volumes are tailored as is feasible for individual locations. Recycling or re-use of produced water is an ongoing area of focused research and development that has equipped the oil and gas industries with numerous technological solutions which can be tailored for individual applications.

Produced water is an inescapable fact of life for oil and gas production that offers both opportunities and challenges for sustainable recovery of hydrocarbon resources. Based on a review of current practices and future outlooks, key finding are:

- For most forms of oil and gas production, produced water is by far the largest byproduct stream (estimated at 21 billion barrels per year in the United States in 2007) and has given rise to numerous technologies that treat different components of produced water to allow discharge, injection, or beneficial re-use.

- Flowback water tends to be very salty and can contain high concentrations of various chemical constituents. Flowback water is often injected into commercial disposal wells where they are available, although over the past few years, the gas industry has utilized various approaches to collect the flowback, treat it, and re-use the water for future frac operations.

- Many companies have developed technologies to treat produced water and flowback water, in part because this sector has great potential for business growth. Treatment performance has increased and costs have become more competitive.

- Two of the most important emerging and future opportunities for management or produced water through re-use are: (1) Treatment and re-use as a water supply for towns, agriculture, and industry; and (2) Secondary industrial processes such as extraction of minerals from produced water or re-purposing as the working fluid into geothermal energy production.

- Future water management technologies are likely to focus on: (1) Reduced treatment costs; (2) Reduced air emissions, including CO2; (3) Minimizing transportation; (4) Minimizing energy inputs; (5) Capturing secondary value from the re-purposed water.

THE ROLE OF WATER IN OIL AND GAS PRODUCTION

Water is needed for drilling, hydraulic fracturing, and for enhanced recovery operations. Water used for those purposes can come from surface water or groundwater sources, municipal water supplies, or from water recycled or re-used from some other source. Much of the water sent downhole for drilling and well completion also returns to the surface and must be handled as a waste stream. The waste stream also can include water released from underground geologic formations as a result of drilling, fracturing or completion operations.

A. Produced Water

Produced water is water that is returned to the surface through an oil or gas well. It is made up of natural formation water as well as water injected into the formation as part of a fracture stimulation process or an enhanced recovery operation. Produced water is typically generated for the lifespan of a well. The annual volume of produced water generated in the United States is about 21 billion bbl/yr (Clark and Veil, 2009).

Another important water category is known as flowback water[1]. It is water that was a large component of fluids injected into a well at high pressure as part of a hydraulic fracturing (frac) operation. Within a few hours to a few weeks after the frac job is completed, a portion of the water returns to the surface. It typically contains much higher levels of chemical constituents, including dissolved salts, than did the original frac fluid.

As noted above, water is an important substance for conducting certain aspects of oil and gas development. However, this paper focuses only on management of produced water (including some limited discussion of flowback water) and not on how water supplies are obtained for production purposes. This paper describes some of the many possible options or technologies that can be used for managing produced water.

Because the produced water has been in contact with the hydrocarbon-bearing formation for centuries, it contains some of the chemical characteristics of the formation and the hydrocarbon itself. It may include water from the reservoir, water injected into the formation, and any chemicals added during the production and treatment processes. Produced water is not a single commodity. The physical and chemical properties of produced water vary considerably depending on the geographic location of the field, the geological host formation, and the type of hydrocarbon product being produced. Produced water properties and volume can even vary throughout the lifetime of a reservoir.

[1] Some companies and organizations consider flowback to be a process rather than a fluid stream. They use the term "flowback" to describe the process of excess fluids and sand returning through the borehole to the surface. They further consider all the water produced during flowback operations to be produced water. However, most sources distinguish between: a) the fluids returning to the surface in the first few hours to several days following a frac job (flowback water), which consists primarily of the water that was injected as a component of the frac fluids, and b) the lower volume of ongoing, long-term water flow to the surface (produced water). While acknowledging these different points of view, this paper follows the convention of describing flowback as a fluid stream different from produced water.

While it is not possible to describe produced water using a single set of chemical properties and concentrations, several groups of constituents are present in most types of produced water. The major constituents of concern in produced water are:

- Salt content (expressed as salinity, total dissolved solids, or electrical conductivity).
- Oil and grease (identified by an analytical test that measures the presence of families of organic chemical compounds).
- Various natural inorganic and organic compounds (e.g., chemicals that cause hardness and scaling such as calcium, magnesium, sulfates, and barium).
- Chemical additives used in drilling, fracturing, and operating the well that may have some toxic properties (e.g., biocides, corrosion inhibitors) – typically at very concentrations.
- Naturally occurring radioactive material (NORM).

B. Technologies and Options for Managing Produced Water

The characteristics of produced water vary from location to location and over time. Different locales have different climates, regulatory/legal structures, and degree of existing infrastructure. As a result, no single treatment technology is used at all locations. Many different technology options are available that can be employed at specific locations. Selection of a management option for produced water at a particular site varies based on:

- Chemical and physical properties of the water.
- Volumes, duration, and flow rate of water generated.
- Desired end use or disposition of the water.
- Treatment and disposal options allowed by the state and federal regulations.
- Technical and economic feasibility of any particular option, including transportation and logistics.
- Availability of suitable infrastructure for disposal.
- Willingness of companies to employ a particular technology or management option, including their concerns about potential liability.
- Cost involved with meeting the requirements and restrictions set by the regulatory agency.

Much of the information for this paper is derived from the Produced Water Management Information System (PWMIS) website, developed by Argonne National Laboratory for DOE. PWMIS currently is housed as part of the website for DOE's National Energy Technology Laboratory (NETL) (http://www.netl.doe.gov/technologies/PWMIS/).

Water management technologies and strategies can be organized into a three-tiered water management or pollution prevention hierarchy (i.e., minimization, recycle/re-use, and disposal). Examples of technologies and practices for each group are shown in Tables 1-5. Where technologies and practices are likely to be different for frac flowback water than for produced water, they are listed separately.

Tier 1 – Minimization. In the water minimization tier, processes are modified, technologies are adapted, or products are substituted so that less water is generated (Table 1). When feasible, water minimization can often save money for operators and results in greater protection of the environment.

Table 1. Water Minimization Technologies.

Approach	Technology	Pros	Cons
		Produced Water	
Reduce the volume of water entering the wells	Mechanical blocking devices (e.g., packers, plugs, cement jobs)	These should be used in new construction. They can be added later on to fix some problems.	May not be easy to fix pre-existing problems.
	Water shut-off chemicals (e.g., polymer gels)	Can be very effective in selected instances.	Need the right type of formation in order to achieve cost-effective results.
Reduce the volume of water managed at the surface by remote separation	Dual completion wells (downhole water sink)	Can be very effective in selected instances.	Limited prior use. Makes wells more complex.
	Sea floor separation modules	May be a good future technology.	Cost is very high. Only two of these have ever been installed through 2009.
		Flowback Water	
Use less water in frac fluids	Substitute other materials, like CO_2 or nitrogen in place of water as main ingredient in frac fluids.	Avoids water availability concerns and minimizes the volume of water requiring management.	May not be as effective. May be far more costly.
	Consider using gelled frac fluids instead of "slickwater" fluids.	Gels reduce the volume of water needed (compared to slickwater fracs) to deliver large volumes of proppant.	Gelled fluids are much more likely to damage the formation. Also gels require the use of different types and larger volumes of chemicals due to the need for gel breakers, and pH buffers.

Tier 2 – Recycle / Re-use. For water that cannot be managed through water minimization approaches, operators can move next to the second tier, in which produced water is re-used or recycled (Table 2). The most common way to re-use produced water is to re-inject it into a producing formation to enhance production. Re-injection for enhanced recovery occurs in tens of thousands of injection wells throughout the United States and elsewhere.

Water is a scarce commodity in many parts of the world. Substantial efforts are ongoing to develop economic methods to treat produced water, most of which is quite salty, and put it to a new use. Some produced water, particularly the water associated with coalbed methane (CBM) production in the Rocky Mountain region of the United States, has low salinity. That water may be suitable for re-use without any treatment. However, it may be counterproductive to expend high amounts of energy to treat very salty produced water, when a smaller amount of energy could be used to treat more efficiently an alternative water source (i.e., treated municipal wastewater, brackish groundwater, and maybe even seawater depending on the quality of the produced water).

Table 2. Water Re-Use and Recycle Management Options.

Management Option	Specific Use	Pros	Cons
Produced Water			
Re-injection for enhanced recovery	Water flood; steam flood; SAGD (steam assisted gravity drainage) for oil sands	Common use of produced water for onshore wells. Usually has low cost.	Need to ensure chemical compatibility with receiving formation.
Injection for future water use	Aquifer storage and recovery	Great option when possible. Only one actual example (Wellington, Colorado).	Need to ensure that water meets drinking water standards before injecting it into a shallow aquifer. May encounter public opposition.
Injection for hydrological purposes	Subsidence control	Can help solve a local problem (e.g., Long Beach, CA).	Need to ensure chemical compatibility with receiving formation.
Agricultural use	Irrigation; subsurface drip irrigation.	Can be a great benefit to arid areas.	May need to treat the water before applying it to the soil or add soil supplements.
	Livestock and wildlife watering	Can provide a source of water for animals.	Need to ensure that water is clean enough to avoid illness or other impacts to animals.
	Managed/constructed wetlands	Provides a “natural” form of treatment. Creates a good habitat for wildlife.	Large space requirements. Needs extensive oversight and management.
Industrial use	Oil and gas industry applications	Can substitute for fresh water supplies in making new drilling fluids or frac fluids.	May need treatment in order to meet operational specifications.
	Power plants	May be able to supplement cooling water sources	Will require treatment. The large volumes needed result in collection and transportation costs.

Management Option	Specific Use	Pros	Cons
Produced Water			
	Other (e.g, vehicle wash, fire-fighting, dust control on gravel roads)	Can be a good supplemental water supply in arid areas.	Will need storage facilities and possibly treatment.
Treat to drinking water quality	Use for drinking water and other domestic uses	Can help supply water to communities in arid areas.	Cost to treat may be high. Need good quality control. May encounter public opposition. Concern over liability. It may be more cost-effective and energy-conserving to treat other water sources like saline groundwater rather than treating produced water.
Flowback Water			
Use flowback water for future frac fluids	Use after settling, filtration, or other basic treatment step.	Several Marcellus Shale operators began doing this in 2009-2010. Saves disposal fees, transportation costs, and requires less new water for next frac job. It also offers social benefits through fewer truck trips to haul water and less demand on local water supplies.	Must have a new well waiting to be fracked so long-term water storage is avoided. Limited data are available about lifetime productivity of wells fracked with these fluids, but initial results look excellent.
	Use after more advanced treatment steps	Several types of thermal distillation and evaporation systems have been used to treat flowback with high TDS levels, especially in the Barnett Shale of Texas. Byproducts include clean water and concentrated brine. In some cases, the brine can be used in drilling operations. Waste heat from nearby natural gas compressor stations or gas directly from the wellhead can be used to power these systems.	Cost and energy requirements are high for thermal treatment. Many operational challenges with scale buildup. Management of brine can be an issue.

Tier 3 –Disposal. When water cannot be managed through minimization, re-use, or recycle, operators must dispose of it (Table 3).

Table 3. Water Disposal Technologies.

Technology	Pros	Cons
Discharge	Very common for offshore facilities. Offers moderate cost and acceptable environmental impact, where permitted.	Not approved for most onshore wells. Where allowed, requires treatment unless the water is high quality, such as some CBM effluent. Different treatment requirements for discharges into different types of water bodies.
Underground injection (other than for enhanced recovery)	Very common onshore practice. Tends to have low cost. EPA and state agencies recognize this as a safe, widely used, proven, and effective method for disposing of produced water.	Requires presence of an underground formation with suitable porosity, permeability, and storage capacity. May require treatment to ensure that injectate does not plug formation. UIC permitting in two key Marcellus Shale states that do not have delegated authority to administer the UIC program (PA and NY) can be very time-consuming. For these states, the EPA Region III office issues UIC permits.
Evaporation	In arid climates, takes advantage of natural conditions of humidity, sun, and wind.	Not practicable in humid climates. May create air quality and salt deposition problems.
Offsite Commercial disposal	Provides service to oil and gas community by accepting and disposing water for a fee. Removes water management burden from the operator.	Requires infrastructure (disposal facilities and transportation network to move water to disposal site). Can be costly. Potential for Superfund liability.

Prior to disposing of or re-using water, operators may need to employ different treatment processes and technologies. The final disposition of the water determines the type and extent of treatment. For example, if water is discharged, the parameter of greatest concern can be related to either the organic content (oil and grease) or the salt content (salinity, conductivity). The salinity of produced water discharged to the ocean is not a parameter of concern, but the oil and grease concentration is regulated. Onshore discharges must remove salinity in addition to oil and grease.

Treatment technologies can be divided into two general categories, depending on which types of pollutants are removed. Table 4 lists treatment technologies designed to remove salt and other inorganic materials from produced water. Table 5 lists treatment technologies designed to remove oil and grease and other organic materials from produced water.

Table 4. Water Technologies for Removing Salt Content.

Technology	Subcategory	Pros	Cons
Membrane processes	Microfiltration, ultrafiltration, and nanofiltration	They are good pretreatment steps for more advanced processes like reverse osmosis (RO). They operate at lower pressure and lower cost than RO.	These levels of filtration cannot remove most salinity. Potential for membrane fouling. Sensitivity to fluctuating water quality.
	Reverse osmosis (RO)	RO can remove salinity (up to about 50,000 mg/L TDS.	Requires pretreatment and regular membrane cleaning. Not suitable for high-salinity flowback water. Potential for membrane fouling. Sensitivity to fluctuating water quality.
	Other (e.g., electrodialysis, forward osmosis)	May offer future treatment opportunities.	Have not been used in full-scale oilfield treatment systems yet. Potential for membrane fouling. Sensitivity to fluctuating water quality.
Thermal Treatment	Distillation	Can process high-salinity waters like flowback. Generate very clean water as one product (can be re-used).	High energy usage and cost. Generates concentrated brine stream that requires separate disposal. Potential for scaling.
	Evaporation / Crystallization	Can treat to a zero liquid discharge standard.	High energy usage and cost. Limited usage in oilfield applications. Potential for scaling. Challenges in disposing of salt residue.
Ion exchange	N / A	Successfully treat low to medium salinity water (e.g., Powder River Basin).	Large acid usage. Resins can foul. Challenges in disposing of rinse water and spent media (resin). Also ineffective on high salinity produced waters.
Capacitive deionization	N / A	Low energy cost.	Limited to treating low salinity waters. Limited usage in oilfield applications.

Table 5—Water Technologies for Removing Oil and Grease Content.

Technology	Subcategory	Pros	Cons
Physical separation	Advanced separators (e.g., inclined plate, corrugated plate)	Provide enhanced oil capture compared to basic oil/water separators	Work well for free oil, but not as effective on dispersed and soluble oil. Performance can be improved by adding flocculants.
	Hydrocyclone	No moving parts results in good reliability. Separates free oil very well.	Does not work well on dispersed and soluble oil.
	Filtration	Different types of filter media and filter operations provide a good range of oil and grease removal.	Requires regular back-flushing. Does not treat soluble oil.
	Centrifuge	Provides good separation of free and dispersed oil.	More expensive than other technologies in this group.
Coalescence	N/A	Collects small oil droplets and forms larger droplets that can be more easily removed by the other technologies.	Limited value for dispersed or soluble oil.
Flotation	Dissolved air flotation, induced gas flotation	Removes free and dispersed oil.	Does not remove soluble oil.
Combined physical and extraction processes	EPCON, C-Tour	Can treat to very low oil and grease levels.	Not used currently in U.S. because its low level of oil and grease is not needed to meet U.S. regulatory standards. Probably is very costly.
Solvent extraction	Macro-porous polymer extraction	Can treat to very low oil and grease levels.	Not used currently in U.S. because its low level of oil and grease is not needed to meet U.S. regulatory standards. Probably is very costly.
Adsorption	Organoclay, activated carbon, zeolites.	Does a good job at removing oil and grease. Used primarily for polishing.	Media cannot be re-used or regenerated – results in large volume of solid waste.

HISTORY OF PRODUCED-WATER MANAGEMENT

A. The Early Years: Onshore Production

In the early days of oil and gas production, little care was taken in managing produced water. In some cases it was released to surface water bodies without much treatment, was spilled onto the ground, or was placed in pits where it evaporated and soaked into the ground.

Early in the history of oil and gas production, petroleum engineers realized that injecting water into hydrocarbon-producing reservoirs could increase production. This process, known as waterflooding, began as early as 1865 in Pennsylvania. Waterflooding moved from Pennsylvania to Oklahoma and Texas in the 1930s, but did not have widespread use until the 1950s (Thakur and Satter, 1998). It is not known whether produced water or local surface water was used as the source of water for the early waterfloods. At some point in time, particularly in areas with arid climates where large volumes of surface water were not available, companies began re-injecting produced water into formations for waterflooding.

Initially, a well may produce nearly all oil and gas (some will produce all oil, others all gas, and still others a mixture). However, as production continues the produced fluids will begin to contain formation water (in addition to oil and gas), the proportion of which increases over time. Logically, the earliest efforts at water management were those steps taken to separate water from oil and gas by gravity separation. The first step in managing the produced fluids is to separate them into three phases (oil, gas, and water) using gravity separation in a free-water knockout tank. Gravity separation removes most oil and gas from the water and also collects some solids through settling.

In the early years of using produced water for waterflooding, gravity separation was most likely the only preparation or treatment that was done. However, there can be problems with long-term injectivity if the water contains substances that block the pores of the receiving formation. Frequently, operators will remove additional oil and solids through filtration or other steps. In many cases, various control chemicals may be added to the produced water stream (e.g., biocides, corrosion inhibitors, scale preventers).

In cases where more produced water was generated than was needed for waterflooding, companies injected the excess produced water into other, non-hydrocarbon-producing formations solely for disposal. Injection (either for waterflooding or for disposal) has been the dominant method for managing onshore produced water for many years. Data from national E&P waste management surveys conducted by the American Petroleum Institute in 1985, and again in 1995, showed that injection was used to manage 92% of produced water (API, 2000). A more recent national study reported that in 2007, about 98% of produced water was injected (Clark and Veil, 2009). Table 6 compares the results.

Table 6. Percentage of Produced Water Injected.

Year	% Injected for Waterflooding	% Injected for Disposal	Total % Injected
1985	62	30	92
1995	71	21	92
2007	59	39	98

The practice of injection was formally regulated at the federal level through the Safe Drinking Water Act's Underground Injection Control (UIC) Program in the 1970s, although states had established their own injection regulatory programs prior to that time.

B. Offshore Production Leads to New Produced-Water Technologies

The first well drilled from a fixed platform offshore and out-of-sight of land was completed in 1947. By 1949, 11 fields were found in the Gulf of Mexico with 44 exploratory wells. The standard practice for managing offshore produced water was to discharge it to the ocean after the initial separation of oil and water. Gravity separation often left behind sufficient oil in the produced water to create a sheen when the water was discharged. This gave industry an impetus to remove a higher percentage of the oil before discharge.

It is not possible to develop an accurate timeline of the early history of offshore produced-water management. About the earliest federal regulatory approach to produced water discharges began in 1974 with an Environmental Protection Agency (EPA) study of oil and gas platforms operating in the estuarine, coastal and Outer Continental Shelf (OCS) areas. It took note of the distinction between treatment in offshore areas and on land-based platforms. In onshore areas, the discharge of salty produced water was forbidden because the receiving waters are fresh.

Later in 1974, EPA published a "Draft Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Oil and Gas Extraction Point Source Category" that selected the treatment systems that constituted BPT (Best Practicable Control Technology Currently Available – an interim level of performance specified by the Clean Water Act) and then proposed appropriate effluent limitations. For onshore areas, BPT allowed for no discharge of produced water. Offshore, a platform could discharge produced water providing it installed treatment systems to remove oil and grease (an analytical test that measured the presence of various families of organic compounds) from the water before discharging it overboard. The selected BPT limits (48 mg/L average and 72 mg/L maximum for oil and grease) reflected the capability and performance of the operating platforms in the early 1970s. Technologies such as separators, filtration, skim piles, and gas flotation were used to remove additional oil and grease. The final BPT discharge regulations (known as effluent limitations guidelines) were adopted in 1979.

A more advanced level of performance for existing facilities, BAT (Best Available Technology Economically Achievable) was not adopted until 1993. The BAT limits for oil and grease (29 mg/L average and 42 mg/L maximum) were based on a statistical analysis of the actual performance of offshore facilities during the early 1980s. Additional technologies that were used to reach the more stringent BAT level of performance included improved gas flotation, granular filtration, membrane filtration, hydrocyclones, and centrifuges.

C. Other Onshore Options

As part of the 1979 effluent limitations guidelines, EPA allowed limited onshore discharges of produced water in locations west of the 98th meridian where the water is actually used for agriculture or wildlife propagation. The 98th meridian extends from near the eastern edge of the Dakotas through central Nebraska, Kansas, Oklahoma, and Texas. This provision is relevant only for produced water that contains low salinity.

Coalbed methane (CBM) producers in Alabama could not take advantage of this provision because they were located to the east of the 98th meridian. They petitioned EPA to allow them to discharge and noted that the studies conducted to develop the national effluent limitations guidelines were conducted at a time prior to CBM development. They further noted that CBM produced water was water withdrawn from a coal seam. It was more like coal mining effluent than oil and gas produced water. EPA agreed that the Alabama CBM producers would be allowed to discharge (Veil, 2002). EPA is currently studying the CBM sector to determine if national effluent limitations guidelines are needed.

Produced water has the potential to be recycled or re-used for many other purposes. Depending on the quality of the untreated produced water and the quality of the water needed for the end use, many different treatment technologies or combinations of technologies can be used. In some formations (e.g., Powder River Basin) CBM produced water is relatively fresh. Following treatment for total dissolved solids (TDS) and/or sodium adsorption ratio, the water can be re-used. This led to the adaptation of reverse osmosis, ion exchange, and thermal treatment technologies for use in the oil and gas community during the late 1990s and the early 2000s.

Shale gas development and oil production in tight formations (low porosity and permeability) relies on hydraulic fracturing at each well. Following completion of the frac job, some of the injected water returns to the surface. It usually contains very high concentrations of TDS and other constituents. In many parts of the country, this flowback water is re-injected. However, in the Marcellus Shale region (particularly in Pennsylvania and New York), very few injection wells are available.

If the companies that generate produced water are unable to discharge, inject, or re-use produced water, they can also look to evaporation and offsite commercial disposal to manage their water. This leads to development of commercial infrastructure in the parts of the country with high oil and gas production.

VARIATIONS BASED ON RESOURCE TYPE AND LOCATION

As noted before, produced water characteristics vary depending on the geographic location and depth of the well, the geology of the formation, the type of hydrocarbon produced, and other factors. This section of the paper describes the different types of hydrocarbon production and the features of the produced water associated with them.

A. Onshore Crude Oil and Conventional Natural Gas

This is the most typical case. The combined produced fluids come to the surface and are separated in a free water knockout unit. The produced water receives additional filtration if necessary, appropriate chemicals are added, the water is re-injected.

B. Offshore Crude Oil and Conventional Natural Gas

The combined produced fluids come to the surface and are separated in a free water knockout unit. The water may go to an additional settling unit, such as a corrugated plate or inclined plate separator. Coalescers may be used to make small oil droplets converge to form larger oil droplets. Some combination of hydrocyclones and media filters, membrane filters, and gas flotation units are generally employed. Other technologies, such as organoclay adsorbents or activated carbon can be used when the oil and grease is made up of a high percentage of dissolved oil that is not removed well by physical processes. Following treatment, the produced water is discharged.

The technologies mentioned above can nearly always meet the U.S. offshore discharge standards. Some other parts of the world may have more restrictive discharge standards that require even more treatment steps. Several other types of technology are available to achieve very low levels of oil and grease if needed. Examples include compact separators that utilize swirling action plus solvent addition, and organics removal with proprietary solvents.

C. Coalbed Methane (CBM)

The water from some CBM formations is salty (e.g., San Juan Basin). Most of that water is injected for disposal. Other CBM formations (e.g., Powder River Basin) yield low-salinity produced water. Some of this water is being applied to beneficial secondary uses following treatment. Examples of the beneficial uses are irrigation, stream flow augmentation, drinking water for livestock and wildlife, dust control on gravel roads, vehicle wash, and fire fighting. Different types of treatment have been employed depending on which constituent of the produced water must be treated. Ion exchange and membrane treatment (including reverse osmosis) processes are employed. In some instances, thermal treatment processes have also been used. When CBM water is used for irrigation, treatment may be needed to reduce the sodium adsorption ratio to avoid damaging the soil. Technologies employed are adding soil amendments, like gypsum, and subsurface drip irrigation.

Alabama CBM producers treat their water and discharge it to local surface water bodies. The treatment generally involves aeration, pH adjustment, flocculation, and settling.

A new online CBM produced water management tool, which was developed by researchers at the Colorado School of Mines, Argonne National Laboratory, and Kennedy-Jenks Consultants (http://aqwatec.mines.edu/produced_water/tools/index.htm), is available for open-access. The water quality module catalogs existing CBM water quality data from several CBM basins and allows users to enter their own data. A companion technology selection module was developed to help CBM producers choose one or more technologies that can treat the water to various end water qualities.

D. Shale Gas

The largest volume of water associated with shale gas production is the frac flowback water[2] that returns to the surface at the completion of a hydraulic fracturing job. The flowback water, often containing a high level of TDS, can represent a million gallons or more over the course of a few weeks. Typically, the flowback water is collected in frac tanks or lined pits, then is transported to injection wells, either operated as "in-house" wells by the gas producer, or as third-party commercial disposal wells.

However, for shale gas production in the Marcellus Shale (Pennsylvania, New York, and West Virginia) few disposal wells are available within the gas-producing areas. Some disposal wells are available in Ohio, often more than 100 miles distant. In addition to hauling water to Ohio, Marcellus Shale producers can transport their wastewater to commercial wastewater treatment facilities or to local sewage treatment plants, where permitted by the state environmental protection agency. Most of the existing commercial wastewater treatment facilities provide pH adjustment, flocculation, and settling. This removes metals, but does not treat the TDS. Recent regulations changes in Pennsylvania will result in any new discharges meeting strict limits for TDS and other parameters.

The feasibility of re-using shale gas produced depends on three major factors. First is the volume of the flowback and produced water generated. Wells that produce significant volumes of flowback water are preferred for re-use due to the logistics involved in storing and transporting the water for re-use. A continuous volume can keep tanks and trucks moving, increasing the economic efficiency of re-using the water from one well site to another. Long-term produced water production is also important because wells that yield substantial volumes of produced water over long periods of time will require a disposal or re-use option that is located in close proximity to the well site in order to retain the economic viability of the operation.

The second factor in produced water re-use is the quality of the produced water. The salt content (usually expressed as TDS), total suspended solids (TSS; the larger suspended particulates in water), and the scale-causing (hardness) compounds have a major effect on the feasibility of re-using produced water. TDS can be managed in the re-use process by blending with freshwater to reduce the TDS. TSS can be managed with relatively inexpensive filtration systems. Scale-causing compounds can also be managed with chemical treatments, but each additional treatment step reduces the economic efficiency of the process. The ideal produced water for re-use has low TDS, low TSS, and little to no scale causing compounds (Mantell, 2010).

Some of the Marcellus Shale producers are providing basic settling and filtration of their flowback and produced water. The filtered water is blended with fresh water to make up new frac fluids for the next well. They test the filtered water to ensure compatibility with fresh water and the frac fluid additives. This water quality monitoring is critical to allow sustainable re-use in the Marcellus Shale region. Without such information, scaling and microbial growth may occur in the formation.

The primary technology that can effectively treat water with TDS levels above 50,000 mg/L is thermal distillation. Other companies are treating flowback water with thermal distillation systems to create very clean water and concentrated brine. The clean water can be re-used or discharged. Two of the thermal distillation technologies currently used in the Marcellus Shale are described by Veil (2008). Thermal distillation technologies are also being applied in the Barnett Shale of Texas to recycle flowback water.

E. Oil Sands

The processes involved with oil sands production often require external water supplies for steam generation, washing, and other steps. While some oil sands processes generate produced water, others generate different types of industrial wastewater. Management and disposition of the wastewater presents challenges and costs for the operators. In addition to requiring water, production of oil from oil sands requires a substantial amount of energy for removing the oil from the ground, processing it, and transporting it off-site (Dusseault, 2001, 2008)

Oil sands production involves either mining large tracts of land, which results in surface disturbance, or drilling of numerous injection and recovery wells for in situ production. Both methods have the potential to cause impacts to ground and surface water resources. In addition, large-scale production of heavy oil resources will require local availability of large volumes of water to support the production process.

The oil sands industry requires water for many non-process purposes that are applicable to nearly all production methods. Some of the uses directly support human needs, such as drinking water supply, toilets, showers, and laundries. Some of this water is needed at the job site, while other water is needed to support the living accommodations for the employees, presumably at an off-site but nearby location. Water is also needed to provide support and safety functions, such as dust control and fire protection. If reclamation of the land surface is undertaken following the end of production, irrigation water may be necessary. To the extent that oil sands production requires power generation from on-site or nearby facilities, large volumes of water may be needed to support the power plant. A new power plant or increased capacity at an existing plant would require water for steam generation, scrubber operations, cooling systems, and dust control (Veil, 2008).

When oil is produced from oil sands via in situ processes, steam is often used to lower the viscosity of the bitumen. Water may also be needed for fracturing the formation to promote better fluid movement. Water is needed for steam production for steam flooding, cyclic steam stimulation, and steam-assisted gravity drainage (SAGD). Other water may be used for water flooding and for water-alternating-gas (WAG) processes. Water also may be necessary to cool machinery used at the surface.

ENVIRONMENTAL BENEFITS

The vast volume of produced water generated each year presents an environmental challenge to the industry. If the water was managed carelessly, such as discharging to local surface water bodies without treatment or letting it soak into the ground, extensive environmental degradation would be found. However, the industry is following responsible courses of actions. Through decades of experience and regulatory evolution, conscientious oil and gas operators in North America are using practices that provide environmental protection while still allowing cost-effective oil and gas production.

As noted in the previously, the level of performance of the technologies commonly used has improved over time. Most offshore water is managed by discharge to the ocean following treatment. Offshore facilities have employed additional water treatment technologies to meet the requirements of the NPDES (National Pollutant Discharges Elimination System) permits issued by EPA regional offices in Regions 4, 6, 9, and 10. Each permit renewal contains more comprehensive requirements and limits, including toxicity testing using live organisms to ensure safe discharges. The industry modifies operational practices and enhances treatment performance as necessary to remain in compliance.

Most onshore water is re-injected to underground formations, either to provide additional oil and gas recovery or for disposal. Permits for injection are made by state agencies and EPA regional offices (where states do not have suitable authority) through the UIC program. Hundreds of thousands of injection wells operate each day to manage produced water and flowback in an environmentally safe manner. The use of produced water for enhanced recovery is a valuable benefit, as it avoids the use of a comparable volume of surface or ground water.

In limited cases, onshore produced water has been treated and re-used. Where re-use is practical, authorized by regulatory agencies and cost-effective, it represents a beneficial use of what would otherwise be a waste product.

Every water management technology can be viewed as a tradeoff. All of them offer some benefits, yet all have some down sides when viewed in a cross-media, holistic light. For example, offshore discharges, even when well treated, do have some impact, albeit modest, including reduced oxygen and elevated contaminant levels in the near field. For most open water situations, the amount of local dilution and the currents that promote dispersion reduce potential impacts very quickly. In near-shore settings (e.g., shallow water, over marsh lands), discharges from offshore platforms could have a substantial impact, and EPA usually requires zero discharge in these areas. However, if some other water management practice were employed, it might have a lower water impact but could have a greater air or energy use impact.

For example, if EPA adopted a zero discharge requirement for produced water at all offshore platforms, companies would probably inject the water underground. This would involve powerful pumps and motors that would consume fuel to operate and would generate air emissions. In that environment, the modest water impacts are preferable to larger air and fuel usage impacts that would be associated with an alternate practice.

ECONOMIC IMPACTS (POSITIVE AND NEGATIVE)

The costs of managing produced water vary greatly. For many well-developed onshore fields that have existing injection wells available, the cost for water management can be $0.01/bbl or less. Where new facilities must be constructed or where injection is not readily available, the cost quickly rises to more than $1/bbl, especially if the water must be treated for TDS removal. In some situations, particularly those where water must be transported long distances for disposal, the cost can approach $10/bbl or get even higher. The magnitude of costs can affect the economic viability of continuing operations or initiation of new projects.

Different technologies are selected based on a variety of factors, as described previously. Cost is an important factor, but is certainly not the only factor that must be considered by oil and gas operators. Even within the general category of costs, there are numerous components that contribute to the overall cost. These include:

- Site preparation
- Pumping
- Electricity
- Treatment equipment
- Storage equipment
- Management of residuals removed or generated during treatment
- Piping
- Maintenance
- Chemicals
- In-house personnel and outside consultants
- Permitting
- Injection
- Monitoring and reporting

- Transportation
- Down time due to component failure or repair
- Clean up of spills
- Other long-term liability.

In most cases, water management technologies or practices (other than injection for enhanced recovery) do not directly aid or speed recovery of additional oil and gas. However, without suitable and affordable practices, oil and gas development can readily be hindered.

One interesting example of how new technology directly allowed increased production comes from the PanCanadian Petroleum operations in the Alliance field in east-central Alberta (Matthews et al., 1996). At one of their locations, the water-handling facilities were sized to handle the anticipated volume of produced water. As production proceeded, the water-to-oil ratio increased substantially, such that the volume of water generated exceeded the capacity of the facilities. At some point, the company was unable to operate its wells at full capacity because too much water was being generated. The company evaluated two options: a) add more surface water handling capacity; or b) test downhole oil/water separation technology. They proceeded with the second option. Installation of the new downhole separation technology worked very well at that location. It not only improved the oil output of the wells on which it was installed, but it also freed up water-handling capacity for the field, so that other wells could be returned to full production rate.

INNOVATION AND FUTURE USE

Historically, the technologies used to manage produced water originated in the oilfield or were adapted from other applications by companies working in the oil field. Over the past few years, as awareness of the importance of water management for the industry has grown, many new companies have entered the produced water management business. Some of the new companies have developed or modified innovative technologies that have niche applications. More and more, large international companies that sell a broad spectrum of wastewater treatment equipment to many industrial and municipal clients have turned their focus on produced water management. This increased emphasis and competition helps to promote innovation and keep costs from rising rapidly.

Technologies are already available to treat and remove virtually any contaminant from water. We are not lacking in the availability of technologies – rather we may be lacking technologies that can remove the pollutants of concern at a cost that allows profitable oil and gas production. Another consideration associated with cost is the amount of energy required to operate a treatment technology. Energy consumption relates to both cost and environmental impact.

A treatment technology's robustness is also an important consideration for oil and gas operations. Some of the more exotic technologies may not be suitable for all-weather field applications or may have other infrastructure requirements that keep them from being fully applicable.

Industry continues to lead the innovation of new and revised water management technologies. Service companies, equipment vendors, and even the oil and gas companies themselves are constantly innovating and advancing technology. Targeted government funding support has played an important role in allowing research at universities, national laboratories, and small businesses to continue. The US Department of Energy (DOE) has offered funding opportunities for produced water and flowback water research several times over the past decade. The relatively new Research Partnership to Secure Energy for America (RPSEA) has provided and continues to provide funding for water management projects. The government's Small Business Innovation Research (SBIR) program provides opportunities for small companies to test high-risk, high-reward projects. Some of these have explored unique approaches to water management.

Much of the industry's focus in the past year or two has been on finding technology solutions for the very high-TDS flowback water found in the Marcellus Shale and other shale gas plays. Most of the technologies in this niche rely on thermal distillation and evaporation. Other entrepreneurs continue to come up with new ideas that have varying degrees of merit.

The key considerations for a technology are:

- How does it work?
- What inputs are needed (e.g., energy, chemicals)?
- What byproducts are generated, and how can they be managed/disposed?
- What is the cost?
- What are the limitations on raw water quality that it can handle?
- Will it work in a real-world field application and is it dependable over the long term?

Since the industry already has workable water-management solutions, any new technologies that hope to carve out a niche must offer better performance, lower cost, lower environmental impact/risk, or all of the above.

Two of the most important emerging and future opportunities for water management are:

- Treatment and re-use of produced water as a water supply for towns, agriculture, and industry. This is discussed in more detail in the Barriers and Opportunities Section.

Utilization of produced water that has already been brought to the surface for other secondary applications (e.g., extraction of minerals from produced water; use of warm or hot produced water for geothermal energy production).

BARRIERS AND OPPORTUNITIES

A. General Considerations

Many water-management technologies are already available to the oil and gas industry. Depending on the unique features of a site and the relevant regulatory requirements, different practices or combinations of technologies may make sense. Treatment technologies do not generally face regulatory barriers. Instead they face potential cost and industry-acceptance barriers.

The previous section mentioned two emerging and future opportunities. The first of these, re-use of treated produced water for alternate water supplies, represents a great opportunity to turn a byproduct into a valuable resource. Much of the Nation's produced water and flowback water is very salty and would require treatment before it could be put to beneficial re-use. The cost of the salt-removal treatment has been a barrier in the past, but technological innovations continue to lower the cost. At the same time, the available fresh water supplies from surface and ground water sources are often fully allocated or over-allocated. This drives the cost for each new unit of water upward. In addition, as population continues to rise, competition for water sources will increase between the municipal, agricultural, industrial, and energy sectors. At some point, entities desiring new water will be willing to pay the higher costs needed to support salty water desalination. Before embarking on a program to treat salty produced water for re-use, potential users should look for other available sources of water that have lower levels of salinity or other undesirable constituents. Treatment of moderately saline groundwater, for example, is likely to be less costly than treatment of salty produced water.

Another consideration is the proximity of a produced water supply to the end user. Water is heavy (8.33 lb/gal) and requires a significant amount of energy to pump or haul it. One advantage to desalinating produced water that has been generated near a potential end user in a water-poor region is that transportation of any treated water can be minimized.

B. Barriers

To counter the obvious advantages of large-scale treatment and re-use of produced water are two lurking political/policy barriers that must be addressed before moving ahead. In October 2007, one of the co-authors of this paper had the opportunity to testify to the House Committee on Science and Technology, Subcommittee on Energy and Environment (Veil, 2007). His testimony described two very real barriers.

One barrier to re-use is potential liability to the oil or gas company. If an oil or gas company treats its produced water, then gives or sells the water to an end user (e.g., a municipality or a rancher), the company may later be sued by the end user if a person or a farm animal suffers ill effects. Corporate legal staffs have been reluctant to approve some beneficial re-use projects because of the concern for litigation.

A second potential barrier is the interplay of water rights with ownership or control of the produced water before and after treatment. As long as produced water is perceived as a waste or a byproduct, there is little demand for it. However, after the water has been treated so that it has a value, there may be competing demands for the water, potentially creating disincentives for treating the water.

Another potential future opportunity for deriving value from produced water is to use the material for purposes other than just as water. Two ways in which produced water can be used again are for geothermal power generation and as a feedstock for desirable mineral products.

C. Future Opportunity: Water for Geothermal Power

Geothermal energy is a renewable source of energy that utilizes heat generated within the Earth and which can be delivered for use in heating buildings or for producing electricity.

Geothermal power plants typically use hot ground water (300°F to 700°F) that is used as direct steam or through a heat exchange process to create steam. The steam spins a turbine connected to a generator. Traditionally, geothermal energy developers seek out high-temperature formations and construct new high-volume extraction wells to withdraw the hot ground water. However, in recent years, interest has shifted to finding existing sources of ground water for which the wells are already drilled. If the cost of constructing a well has already been paid for by another user, like an oil and gas producer, the geothermal power producer can use water of a lower temperature and still produce electricity economically. With this in mind, attention has shifted to evaluating operating oil and gas wells as geothermal source wells.

The first actual example in which geothermal power was generated from a producing oil and gas well was a test conducted at DOE's Rocky Mountain Oilfield Technology Center (RMOTC) in Wyoming. The test unit was a 250-kW Organic Rankine Cycle (ORC) power plant designed to use 40,000 bpd of 170 °F produced water from the field's Tensleep formation to vaporize the working fluid, isopentane. The projected gross power from the unit was 180 kW (net of 132 kW). Because of the lack of sufficient cooling water for the system, an air-cooled unit was designed.

The unit was put into service in September 2008 and operated until February 2009 when the unit was shut down because of operational problems. During this period, the unit produced 586 MW-hr of power. The operational problems, caused by operating in excess of the unit capacity, resulted in changes in the control system and repairs to the generator/turbine system. The unit was restarted in September 2009. Between September 2009 and the end of February 2010, the unit produced 478 MW-hr of power at a more consistent rate than before the extended shut down (Johnson and Walker, 2010).

In 2010, the Alberta Energy Research Institute provided grant funds for a geothermal power production plant to be operated at the Swan Hills oil and gas production facility in Alberta (Borealis Geopower, 2010). The power production plant will use geothermal waste heat from the facility to generate electricity to be used as an alternative or supplementary source of electricity at the facility. The oil, gas and water are pumped to the surface at approximately 163 - 170º F in very high volumes. The oil and gas are separated from the water, and the water is then pumped back into the formation. The project will utilize heat exchange technology to remove sufficient heat from the water before it is re-circulated to produce electricity.

Over the past year, the DOE Office of Energy Efficiency and Renewable Energy awarded several large grants relating to demonstration projects involving using produced water for geothermal power and in compiling bottomhole temperature data from oil and gas well records.

D. Future Opportunity: Extraction of Mineral Commodities

Some chemicals are produced through solution mining, a process which involves injection of water and other additives into a formation to dissolve soluble minerals. The mineral-laden water is then pumped back to the surface where the desired constituents are recovered. Solution mining is energy-intensive because of the need to inject and extract large volumes of liquid. If produced water from a particular formation contains sufficient concentrations of desirable compounds, it can be a cost-effective feedstock. The chemical producer would not have to pay for the cost of injecting water and extracting the solution – it would already be at the surface as a result of oil and gas production.

The concept of extracting saleable minerals is gaining interest. One element that has already attracted attention as a possible byproduct of produced water is lithium. Over the past year, the DOE Office of Energy Efficiency and Renewable Energy awarded a large grant to a company that will develop and validate improved lithium extraction technologies from geothermal brines of varying salinity. To the extent that such processes can be made economical, they can potentially be used on produced-water sources too.

LONG-TERM VISION

As described in the preceding sections, management of water from oil and gas production is accomplished through many different technologies and practices. It is challenging to envision the future of water management with so many different operational and environmental settings. One important prediction that can be made confidently is that re-injection of water from onshore wells will continue to be a predominant method for managing onshore produced water. America's mature oil and gas fields will require vast quantities of water for enhanced recovery operations for the foreseeable future.

Looking at the offshore sector, most produced water will be treated and discharged to the ocean in conformance with discharge permits. It is conceivable that future regulatory requirements will lead to stricter discharge limits, thereby requiring additional technologies or treatment steps before discharge. This is a clear example of regulation driving technology development. Operators can meet the existing discharge standards using conventional and existing technologies. Unless future regulations or permits include stricter discharge standards, it is unlikely that new technologies will be used by offshore operators unless they can provide comparable performance at a lower cost.

Where enhanced recovery is needed to improve production in offshore fields, most operators now use seawater as their water source. The seawater offers constant physical and chemical characteristics, is plentiful, and requires less pre-treatment than would a produced water source. However, if future regulatory requirements make treatment and discharge prohibitively expensive, operators may look to treat produced water on the platforms, then re-inject the water. Some North Sea operators have shifted their focus in this direction during the past decade. In some cases, they have experienced reservoir souring as a result of injecting produced water into a reservoir that has had years of seawater injection.

One area that is likely to see growth is beneficial re-use of produced water and flowback water from onshore wells. Table 2 describes many potential applications for water from oil and gas production. The primary obstacles to re-use are technical issues (e.g., the cost of treating to high enough quality to support end uses and transporting water from source to user) and policy issues (e.g., fear of liability and water rights). As fresh water supplies become less available and the cost of treating water declines, more opportunities to re-use water should become available.

New water-management and treatment technologies continue to be proposed and developed each year. SBIR programs allow testing for some of the outside-the-box ideas. Some new technologies will find a market niche, while others will prove to be unworkable or too costly. However, the research community will continue to be creative.

Future water management technologies are likely to focus on:

- Reduced treatment costs.
- Reduced air emissions, including CO2.
- Minimizing transportation.
- Minimizing energy inputs.
- Capturing secondary value from the water (extraction of minerals, power, or other factors).

FINDINGS

- Water is an integral part of oil and gas production both as a necessary ingredient and as a byproduct. Proper management of that water is critical to ensure both production and environmental protection.

- Sufficient volumes of water are needed to support enhanced recovery operations. At most onshore wells, produced water is re-injected for this purpose. When enhanced recovery is used offshore, typically seawater is chosen as a water source.

- Water is needed to support hydraulic fracturing, particularly in shale gas plays that typically use at least several million gallons of water for each new well. Finding and securing available and sustainable water supplies is a challenge for companies.

- For most forms of oil and gas production, produced water is by far the largest byproduct stream. Management of the vast volume of produced water generated by the industry (estimated at 21 billion barrels per year in the United States in 2007) can be expensive and challenging. This has given rise to numerous technologies that treat different components of produced water to allow some secondary process (discharge, injection, or beneficial re-use).

- Water that returns to the surface following hydraulic fracturing jobs (often referred to as "flowback water") tends to be very salty and can contain high concentrations of various chemical constituents. Flowback water is often injected into commercial disposal wells where they are available, although over the past few years, the gas industry has utilized various approaches to collect the flowback, treat it, and re-use the water for future frac operations.

- Many companies have developed technologies to treat produced water and flowback water, in part because this sector has great potential for business growth. Treatment performance has increased and costs have become more competitive.

- Two of the most important emerging and future opportunities for water management are:

    - <u>Treatment and re-use of produced water as a water supply for towns, agriculture, and industry</u>. This is most likely to occur when the salinity of the produced water is relatively low and when alternate sources of water are in low supply in that region. One barrier to re-use is potential liability to the oil or gas company. If an oil or gas company treats its produced water, then gives or sells the water to an end user (e.g., a municipality or a rancher), the company may later be sued by the end user if a person or a farm animal suffers ill effects. Corporate legal staffs have been reluctant to approve some beneficial re-use projects because of the concern for litigation. A second potential barrier is the interplay of water rights with ownership or control of the produced water before and after treatment. As long as produced water is perceived as a waste or a byproduct, there is little demand for it. However, after the water has been treated so that it has a value, there may be competing demands for the water, potentially creating disincentives for treating the water.

- Utilization of produced water that has already been brought to the surface for other secondary applications (e.g., extraction of minerals from produced water; use of warm or hot produced water for geothermal energy production).

- Future water management technologies are likely to focus on:
  - Reduced treatment costs.
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  - Minimizing transportation.
  - Minimizing energy inputs.
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