MODULE 2: Produced Water Reuse in Unconventional Oil and Gas Operations

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MODULE 2

Produced Water Reuse in Unconventional Oil and Gas Operations

MODULE SUMMARY

Reuse varies by region.
Substantial differences in reuse of produced water exist based on a variety of factors both above and below the surface. For this report, data from 18 producing companies were collected on water reuse, produced water, and source water by basin. The data was aggregated by basin, or region, to determine an indicative water reuse percentage as shown in Figure 2-1. The weighted average national reuse was 10 percent but varied from 0 to 67 percent across the seven basins considered.

Cost is the key driver of water management and reuse.
In most of the regional discussions conducted for this report, cost was the dominant driver for water reuse, although by no means the only factor companies consider. Most companies interviewed are publicly traded and have a legal obligation to conduct operations in a cost-effective way that delivers value to their stockholders. Costs were particularly emphasized with the downturn in the prices of oil and natural gas starting in 2015. Transportation costs are also a significant factor in produced water reuse evaluations.

Water management and water reuse are evolving.
Water management and water reuse are continuing to evolve in most regions. As the market demands that companies maximize efficiencies in their operations, an increasing number of companies are building pipelines for source water, pipelines to connect to disposal wells, or to other water facilities for treatment and reuse. Water management practices are also evolving in areas where local demand for source water and disposal are driving up water costs. When sourcing and disposal costs rise, reuse becomes more economically attractive and cost competitive.
Companies weigh risks in water management and reuse.

Increasing water reuse can reduce company exposure to some risks but increase risk in other areas. The qualitative assessment of risks is weighed against tangible cost considerations to make water reuse plans.

**Water midstream solutions are emerging.**

Water midstream is a recent development involving the gathering and distribution of source water for hydraulic fracturing as well as the gathering and disposal of produced water. Although there are both positive and negative drivers for water midstream development, increasingly, third-party midstream solutions are emerging. Water midstream companies have acquired water systems and developed new projects over the last couple of years. While water midstream is generally provided by an independent company for multiple producing companies, producers are also exchanging produced water in certain situations.

**Data on reuse volumes is not widely available.**

Neither federal regulators nor most states require reporting of the source of water used for completions, or hydraulic fracturing. Companies often report on their websites if they are reusing produced water in a specific region, but volumes are usually not reported. The *Journal of Petroleum Technology* concluded that “Improved reporting is needed to guide the industry and regulators as they look for solutions and figure out how to manage scarce resources, particularly the limited capacity of subsurface formations used for water injection.”29

**State regulation variations impact reuse practices.**

Most producers and state regulators agree that states are better able to craft regulations that address regional conditions instead of applying a blanket federal regulatory framework on operations. The corollary of states having varying rules is that companies must understand all the variations for the states where they operate. If state regulators consider water reuse in crafting new and updating existing regulations, they can encourage reuse. Statutes and regulations that optimize and balance both flexibility and environmental protection will encourage reuse.

Operators should also be aware of any relevant local land use restrictions or permitting processes that may impact their ability to reuse water. This may occur at the town or county level, depending on the state.

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**Background**

Managing produced water is a normal cost of doing business for oil and gas producing companies. While produced water is most commonly disposed of into permitted salt water disposal (SWD) wells within deep saline underground formations, it is also frequently reinjected into conventional reservoirs for enhanced oil recovery (EOR) operations. Additional opportunity for managing produced water is reusing it in unconventional oil and gas plays, particularly in hydraulic fracturing of wells or other well completion operations. Currently, use of produced water in unconventional plays is limited, primarily by cost and logistical barriers.

This module focuses on the potential for increasing the rates of produced water reuse in unconventional oil and gas operations. It addresses the evolution of produced water management and reuse practices in unconventional operations; available data on water volumes and produced water quality; operational and environmental challenges related to produced water reuse; and opportunities to facilitate water reuse through new business models as well as legislative, regulatory, policy, and research initiatives. The module also characterizes top-producing unconventional basins or regions and the similarities and differences among these basins/regions that may impact water management practices. Case studies illustrating trends in water management and reuse in the unconventional oil and gas industry are provided in Appendix 2-A.

Information for this module was gathered from public sources as well as from stakeholders specifically for this report. Research methodologies included analysis of public data and company web sites; regional discussions with groups of producing companies about water management practices; discussions with regulators, industry groups, and other non-governmental organizations; data requests to producing companies relayed through the American Petroleum Institute; and special requests to IHS Energy Group, which provides industry data on produced water and the cost of source water. Notes from discussions are included in Appendix 2-B.

Water management practices, including produced water reuse, vary substantially from region to region. All told, data on water management was gathered for this report from 18 producing companies, with operations summarized for seven of the major unconventional regions, shown in Figure 2-3. It is important to consider that, while this data set is the best available, it still represents a very small subset of the overall industry. As an indication of sample size, the 18 producing companies contributing data for this report accounted for 29 percent of the total water sourced in the seven basins in 2017.
**Water Management in Unconventional Oil and Gas Operations**

This section examines the changing dynamics of water management in unconventional oil and gas operations, the potential for increasing the rate of produced water reuse in hydraulic fracturing or other well completion operations, and how this potential varies across major producing regions.

**Overview of Water Management**

The water lifecycle for unconventional oil and gas operations can be complex because water management practices vary widely across the United States. Figure I-5 in the Introduction charts the possible pathways for water in normal operations. The water lifecycle graphic could apply to a wellpad, an entire county, or a region. If transportation is available, the system can balance produced water with the water needed for completions more effectively. As drilling and completions move from area to area within a county or region, an integrated water system would facilitate water reuse. However, once drilling and completions activities slow down or are discontinued in a region, reuse becomes more difficult due to the distance between the location of the producing wells and the nearest completion activity.

Figure 2-4 is a simplified comparison of the infrastructure requirements for produced water disposal and reuse. The reuse graphic shows how water reuse changes the water lifecycle.

![Figure 2-4: Simplified Flow Diagrams for Water Reuse vs. Disposal](http://investors.pxd.com/static-files/5aebb0b7-50e1-4c75-a10b-711ce71422c4)

Source: Pioneer Natural Resources
The active unconventional producing regions of the United States have substantially different water management characteristics. This variability is discussed in detail in *Water Management and Produced Water Reuse by Region*. Some areas have significant surface water available for sourcing for completions, while other areas are more arid. Water injection disposal capacity varies based on the availability of adequate geologic formations and disposal wells. When either source water or disposal capacities are limited, produced water reuse becomes more economically viable and operationally practical. The volume of water produced from an oil or gas well also varies by region and formation. These variables affect water management practices and the potential to reuse produced water.

Importantly, the reuse system must have enough storage, transportation, treatment capacity, and ongoing needs for source water, to ensure higher levels of water reuse. The logistics of transferring water from the production site to where it can be reused in another completion are critical. Often, the cost to transport water by truck can exceed the treatment and storage costs. It is usually not practical to transport water long distances by truck due to the high transport cost. Storage is often needed for reuse since water production may be at a steady lower rate, but the volumes needed during hydraulic fracturing are comparatively high and intermittent. Treatment of produced water, when necessary to make it suitable for reuse, may also create residual liquids and solids that must be disposed of properly.

While it is possible to reuse produced water outside of oil and gas operations, this practice is currently limited due to the cost of treating produced water for other applications, environmental risks, regulatory restrictions, and operational factors. Produced water typically has TDS levels that are very high compared to state water quality standards for surface water bodies. If produced water discharges are allowed under an NPDES permit, the discharge will be required to meet applicable state and federal standards. In most cases, treatment would be required to meet the constituent limits. Further, most potential reuse opportunities for produced water outside the oil and gas industry would require extensive treatment to lower salt content of the water. Most, though not all, produced water has at least as much salinity as seawater and commonly may have three to eight times the salinity of seawater. There are a few fields from which the produced water has a low TDS content. For example, in Texas, there are numerous fields that produce from formations with sufficiently low TDS content that the produced water can be discharged under an NPDES permit. In addition, produced water from coalbed methane (CBM) formations can be an exception to the high TDS norm. There are instances where CBM operations discharge produced water after minimal treatment due to the low salinity of the water. Produced water reuse outside of the oil and gas operations is the subject of Module 3 of this report.

Waterfloods and enhanced oil recovery (EOR) projects use produced water differently from unconventional oil and gas developments. Waterfloods have historically been performed exclusively in conventional formations, with fewer starting up in recent years. It is only in the initial years of the waterflood that makeup water is needed. Most waterfloods in the United States have reached a maturity where the produced water is reinjected back into the formation in a steady state. Figure 2-5 shows the typical water flow paths in waterfloods or EOR projects. The GWPC estimated that 45 percent of all produced water in 2012 (conventional and unconventional) was reused for EOR or waterflooding. Therefore, waterfloods are independent of unconventional water management and are not likely to factor into produced water reuse for unconventional development.

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Evolution of Water Management in Unconventional Oil and Gas Regions

Horizontal well and hydraulic fracturing technologies have had an unparalleled impact on the growth of U.S. oil and natural gas production, making it economically feasible to produce shale oil and gas resources. The multi-stage hydraulic fracturing of a single horizontal shale gas well can use an average of about 12 million gallons of water. Sourcing and managing the large quantities of water used in unconventional production is a central challenge for operators. Currently, produced water reuse in unconventional oil and gas operations is relatively uncommon, representing about 10 percent of produced water volumes overall. However, the rate of produced water reuse and the potential for increasing it vary significantly from region to region, depending largely on the economics of reuse compared to alternatives for water sourcing and disposal.

Produced water reuse, where feasible, can play a role to meaningfully reduce the use of fresh or brackish water for unconventional oil and gas operations and reduce the need for deep injection of produced water. Reuse represents an opportunity to improve the balance of water in specific areas of the United States and to support the sustainable, economic development of important U.S. energy resources. Achieving significant levels of produced water use in unconventional producing regions will require capital investment in storage, transportation, and treatment capacity; a predictable supply of produced water; ongoing demand for source water for nearby production operations; and a supportive regulatory framework.

Figure 2-5: Secondary Recovery Process


In some cases, especially in the Permian Basin and Oklahoma, conventional produced water may be available in the same region as unconventional operations. In these non-waterflood fields, it may be possible to reuse the conventional produced water as a source for hydraulic fracturing of unconventional formations.
Unconventional shale development started in the Barnett Shale in the 1980s; however, significant drilling activity did not begin until gas prices increased in the late 1990s. Devon Energy acquired Mitchell Energy in 2002 and established itself as the leading producer from the Barnett Shale.*

*Texas Railroad Commission
A Decade of Change

Just as large-scale unconventional oil and gas development is relatively new, so are the practices of water planning and management within shale plays. In the early days, unconventional development required widespread, highly dispersed, and rapidly changing drilling schedules, and the priority for operators was to prove a new area would produce effectively. Water planning was challenged by the limited scale of production and uncertainty over long-term drilling plans. Typically, water was sourced locally from groundwater or surface sources and, because water volumes were small compared to those used in today’s hydraulic fracturing operations, there was little or no impact on local resources.

In the past decade, producing companies successfully demonstrated the technical and economic viability of hydraulic fracturing in horizontal wells. This led to a dramatic increase in unconventional production, with the U.S. horizontal rig count climbing above 900 for the first time in 2010. The growing volumes of sourced and produced water required in these operations raised sustainability concerns in unconventional regions, prompting greater emphasis on long-term water planning. Stakeholders from Pennsylvania to Texas were increasingly concerned about potential groundwater contamination or use of source water for hydraulic fracturing. At the mandate from Congress, the Environmental Protection Agency (EPA) announced in March 2010 that it would conduct a research study investigating the potential impacts of hydraulic fracturing on drinking water resources. In 2011 and 2012, both Texas and Oklahoma experienced extreme drought. State officials and stakeholders were concerned that water use by oil and gas operations was depleting critical resources. The investor organization, Ceres, published a report in 2014 mapping unconventional development in water-stressed areas.

Over time, producers began practicing water reuse in some unconventional regions to help address sourcing and disposal challenges. Some successful efforts to manage water more effectively are documented in the Energy Water Initiative Case Studies report from 2015. Technology developments were important in driving down costs and making such produced water reuse more feasible. Advances in hydraulic fracturing chemistry allowed operators to use produced water with minimal treatment, compared to early reuse projects. In addition, drilling multiple wells from a single pad allowed water managers to better optimize water transportation infrastructure. However, the high costs of transporting produced water, particularly in areas lacking an established water pipeline infrastructure, remained a significant barrier to water reuse in most regions.

Recent Trends in Water Management and Reuse

Water management and reuse are continuing to evolve in most regions. In recent years, both the Permian Basin and Oklahoma have had rising water source and disposal costs, making reuse more economically attractive and cost competitive. Self-reporting by companies in the Permian Basin suggests that reuse has increased there in the last two years, and several producers in Oklahoma also recently announced new reuse projects. In addition, operators in the Marcellus Shale in Pennsylvania and West Virginia have pioneered large-scale water recycling technologies.

Another factor driving interest in water reuse has been induced seismicity, often defined as earthquakes triggered by human activity. Induced seismicity is a concern in parts of Ohio, Arkansas, Texas, Oklahoma, and Kansas. While each situation was unique, regulators and other experts linked deep well injection of...
produced water as the potential cause. Regulatory authorities have taken a variety of risk-mitigation actions to lessen or prevent potential seismic impacts. Examples have included establishing seismic monitoring networks, installing instruments to monitor surface particle motion, suspending well operations, requiring modifications to well construction or operational parameters, requiring well tests, reducing injection pressure, or reducing water injection volumes. These actions can have the effect of increasing disposal costs and making water reuse a more economically attractive alternative.

Transportation costs have remained a major limitation on reuse in most regions. Additionally, volatility in oil and natural gas prices has constrained the ability of producers to invest in capital-intensive water systems that allow reuse. In the second half of 2014, oil prices fell from more than $100 per barrel to about $30 per barrel, slowing unconventional drilling activities and reducing producing companies’ overall capital budgets. However, as oil prices recovered in 2017 and 2018, companies became more confident in planning and building water projects in order to maximize their operational efficiencies. An increasing number of companies are building temporary or permanent pipelines to transport sourced water, to connect to disposal wells, or to connect to facilities for water treatment and reuse. Such large infrastructure investments are possible due to large, contiguous acreage positions.

For example:

- **Pioneer Natural Resources** is building a pipeline network that will span 100 miles north to south and about 60 miles east to west over many of the counties in the heart of the Midland Basin (Figure 2-8). The largest water system for shale plays in the United States, the system will have line sizes up to 30- to 36-inch diameter and will distribute effluent water from municipal sources, brackish water, and treated produced water for reuse. The company was expected to spend $135 million in capital in 2018 for the Midland wastewater treatment plant upgrade, additional subsystems, produced water ponds, and produced water reuse. Pioneer is several years into the system development.

![Figure 2-8: Simplified Diagram of Pioneer Water System Components](Source: Pioneer Natural Resources)

Pioneer Natural Resources is constructing the largest water system for shale plays in the United States. The system will distribute effluent water from municipal sources, brackish water, and treated produced water for reuse.

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• **Antero Resources** has the largest desalination plant for produced water reuse in the industry. The 60,000 barrels per day capacity plant in West Virginia cost approximately $500 million. The company has a water system to gather produced water and distribute the treated water for reuse (Figure 2-9).

![Map Showing Antero, Inc. Water Systems](source: Antero, Inc.)

This map shows the water system of Antero Resources, which operates the largest desalination plant for produced water reuse in the industry.

• **Anadarko** implemented a water recycling and closed-loop water-on-demand (WOD) system in Colorado, consisting of more than 150 miles of pipeline (Figure 2-10). The WOD system uses automation and consolidates equipment to conserve water, reduce traffic by more than 2,000 vehicles per day, and reduce greenhouse gas emissions. The system transports about 98 percent of this water via these pipelines. The WOD system has the added benefit of reducing the number of water storage tanks needed onsite, which further reduces surface impacts. Anadarko also partnered with **Western Gas**, which has a 90,000 barrels per day water system in Loving and Reeves Counties in the Delaware Basin of west Texas to enable large scale reuse of produced water.43,44

• In the Midland Basin, **Concho** built a 90-mile pipeline that transports more than 90 percent of its water via pipelines. The pipeline, which includes water storage facilities and can accommodate up to 125,000 barrels/day, transports treated effluent to Concho’s areas of operation in the Midland Basin.

The emergence of water midstream solutions is a recent development involving efforts to coordinate water sourcing for completion operations with produced water reuse across multiple producing companies. While water midstream solutions generally are provided by an independent third-party company, producers themselves are also directly involved in exchanging produced water in certain situations. Sharing produced water among producing companies is most common in the Marcellus and Utica plays of Pennsylvania and West Virginia where operations are far from disposal wells. It has also been reported in Colorado and Oklahoma. Produced water may be transferred from a company that lacks sufficient disposal options to another nearby company that reuses the water in its completion operations. Agreements to exchange water can potentially reduce costs for both companies, while reducing truck miles driven and reducing disposal. However, if sharing of produced water triggers a commercial designation and requires additional permitting, it can be a deterrent to reuse.

Considerations for Operators

Today, most mid and larger sized producing companies have corporate goals to reduce sourcing from fresh water, leaving more fresh water for agriculture, human consumption, aquatic life, and other industries. All 10 of the larger companies surveyed for this report had stated efforts to decrease fresh water use. (These efforts are discussed on websites for ExxonMobil, Shell, Chevron, BP, ConocoPhillips, EOG, Oxy, Anadarko, Pioneer, and Concho.) Discussions with producers’ water managers confirmed this priority and identified the most commonly used non-fresh water sources as brackish surface or groundwater, produced water, and municipal wastewater effluent. In some regions, especially the Permian and Eagle Ford, brackish water is preferentially used over fresh water by many companies. Other companies in Texas and Oklahoma are sourcing brackish water when available. Areas with abundant fresh water may not be sourcing brackish water to the same extent.

Economic considerations—as outlined in the following section, Evaluating the Economics of Produced Water Reuse—are paramount in decisions made by operators in weighing reuse potential. In addition, companies weigh other relative risks and benefits of investing in produced water reuse.

Increasing water reuse can reduce company exposure to the following risks:

• Water disposal limitations caused by localized induced seismicity or over-pressuring of the disposal formation, or lack of appropriate geologic formations for disposal
• Restrictions to normal sourced water due to drought or other reasons
• Increased cost for source water and disposal capacity
• Increased trucking costs for water sourcing and disposal and other transportation restrictions
• Regulatory or stakeholder initiatives
• Reputation risks from external perceptions that the company does not support water conservation
• Missing an opportunity to shape how reuse infrastructure, technologies, and regulations develop.

Risks associated with increased water reuse may include:

• Spills associated with the additional transport and storage if required

* Upstream” refers to operations involved with the drilling, completion, and production of oil and gas wells, while “downstream” operations include refineries and gas stations. “Midstream” includes the processes of treating natural gas for sale, gas pipelines, and oil pipelines to the refineries.
Recent Developments in Multi-Company Sharing and Water Midstream

Sharing produced water among producing companies is most common in the Marcellus and Utica plays of Pennsylvania and West Virginia where operations are often far from disposal wells. It has also been reported in Oklahoma. In these cases, water may be transferred from one company without enough nearby completion operations to another company needing produced water for reuse. Agreements to exchange water can potentially reduce costs for both companies, while reducing truck miles driven and water disposal. In other areas with more available disposal capacity, produced water transfers are less common. Concerns have arisen in some states about whether surface owners may make a monetary claim on water transferred among operators. A second concern is whether the liability for spills is fully passed to the receiving company. Despite these concerns, water sharing among producers has the effect of smoothing out the peaks and valleys of individual company water demands.

Another more substantial method of sharing water is the trend for midstream companies to own and operate a water system for multiple operators. The midstream ownership concept in oil and gas was developed decades ago as midstream companies developed oil pipelines and gas plants to allow the
Figure 2-11: Trends in Water Management

Source: Jacobs Engineering

Figure 2-11 summarizes key trends in water management, as derived from discussions with operators for this report, and may not be accurate for all U.S. regions. Red downward arrows indicate activities that have decreased in recent years and green upward arrows indicate activities that have increased. A horizontal line indicates no clear trend.

**Sourcing.** Many operators have expressed a commitment to reduce fresh water sourcing. They have identified the most commonly used non-fresh water sources as brackish surface or groundwater, produced water, and municipal wastewater effluent.

**Treatment.** It is now widely recognized that companies do not need to remove total dissolved solids (TDS) to reuse water in oil and gas operations. Most water treatment for reuse in completions removes limited solids or a few specific constituents such as iron or scale forming cations. (In contrast, for produced water to be used outside of the oil and gas operations, most TDS must be removed, along with other constituents of concern.) The trend of using poorer quality water has reduced the level of treatment needed for produced water reuse. Most areas are using a combination of mobile treatment units and permanent plants, depending on the forecast for additional drilling and amount of the produced water to be treated.

**Storage.** Several states (Texas, New Mexico and Oklahoma) have been moving towards the use of larger impoundments as the scale of water operations has increased. In some cases, state regulations are more restrictive for impoundments, reducing their applicability.

**Transport.** Pipeline transportation of water has grown in many areas, most notably in the Permian Basin, resulting in reduced truck traffic. However, lack of a critical volume of produced water or difficult terrain reduce the feasibility of permanent water piping in some basins. For example, the Appalachian Basin has little piping of produced water, but there have been projects to install permanent piping for sourcing water. Often, temporary “layflat hose” is used to convey the water the last mile or so to the well site, where it is not usually practical to run permanent lines.

**Disposal.** Reuse has grown as an option to disposal in SWD wells in many areas. However, as drilling activity remains high in many areas like the Permian, it is possible that water disposal in SWD wells could continue to increase, even while reuse of produced water increases.*

Nationwide total withdrawals of water in the mining category, which includes oil and gas use, were about 1 percent of total withdrawals in 2015.** Texas’ water withdrawals in the mining category (including oil and gas) are estimated to be 1 percent of total withdrawals in 2016, the most recent data available.† In three states that track state-wide water use data—Colorado, New Mexico, and Wyoming—oil and natural gas activities use less than 1 percent of the total water in the state. However, the percentage of water use by oil and gas operations in some individual counties will be much higher than the state-wide average.‡

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‡ Western Energy Alliance, Oil and Natural Gas Exploration and Production Water Sources and Demand Study: Colorado, Montana, New Mexico, North Dakota, Utah and Wyoming (July 14, 2014), https://www.westernenergyalliance.org/sites/default/files/WesternWaterUseStudy.pdf.
products to move to market. Natural gas is treated near the area of production at gas plants then put into regional sales lines. Water midstream is a relatively new industry, created since unconventional oil and gas development began in select plays. Only in the last few years has water midstream begun to have significant scale. Most water midstream development has been focused in the Permian, a relatively “wet” play that continues to produce water over time.

Water midstream companies may originate from producing companies forming subsidiaries or independent companies (e.g., Pioneer, EQT, Anadarko). In other cases, they are new startups specifically focused on water midstream (e.g., WaterBridge, H2O Midstream, Solaris). Other participants include companies providing salt water disposal solutions that build gathering pipelines to expand into water midstream (e.g., Oilfield Water Logistics, Goodnight Midstream), as well as oil and gas midstream companies or other water companies that expand into water midstream (e.g., Layne Christensen, Crestwood Midstream).

Recent publicly announced projects demonstrate that water midstream solutions are poised to grow.

- **WaterBridge Resources** announced a partnership with Fort Stockton, Texas to purchase water resources for oil and gas (July 2017); acquired Arkoma Water Resources LLC with 110 miles of water pipelines (October 2017); and acquired EnWater’s assets in Permian including 100 miles of pipelines and SWDs (August 2017).

- **Layne Christensen** built a 20-mile water pipeline system to water sources to deliver up to 200,000 barrels/day from their water storage facility (June 2017).

- **H2O Midstream** announced the first truck-less produced water hub in Permian with pipelines, storage, and disposal (June 2018), and acquired produced water assets from Encana Oil and Gas in Permian (June 2017).

- **Solaris Midstream** acquired Vision Resources water sources and its 200+ miles of water pipelines (June 2018) to complement Solaris nearby water reuse and disposal system in southeast New Mexico; it commenced operations on the new Pecos Star System reuse system in New Mexico (May 2018).

- **EQT** (Producer) spun off its midstream company that operates Appalachian assets, including water midstream (February 2018).

- **Oilfield Water Logistics** completed a 30-mile produced water pipeline with a capacity of 150,000 barrels/day (July 2016).

- **Goodnight Midstream** added 50 miles of produced water gathering and five additional SWDs to its North Dakota water system (March 2018), which now has 24 SWDs and 250 miles of water pipelines. The company announced it is planning a 200,000 barrels/day produced water system in Lea County, New Mexico (February 2018), and that is has formed a multi-year partnership to gather and dispose produced water for producer Callon Petroleum (September 2017).

- **Waterfield Midstream**, formed with a private equity commitment of $500 million, has a focus on the Permian Basin.

- **Lagoon Water Solutions** announced backing of $500 million from private equity (September 2018) and has a focus on Oklahoma.

Pipelines can reduce variable transportation cost sufficiently to enable large-scale reuse of produced water. Yet networks built by and for a single operator may suffer from the volatility of that producer’s completion schedule and produced water volumes. When larger systems are built for multiple companies, individual company’s needs can be balanced more effectively. The scale of water midstream will allow reuse to grow steadily, especially in the most active areas in the Permian, Appalachia, and Oklahoma.
Table 2-1: Water Midstream Drivers
Source: Jacobs Engineering

<table>
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<th>Water Midstream Drivers</th>
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<tbody>
<tr>
<td>Positives:</td>
</tr>
<tr>
<td>• Reduce overall costs with economics of scale</td>
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<tr>
<td>• Reduce upfront capital costs for producer</td>
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<tr>
<td>• Allow producers to focus on high return completions and production</td>
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<tr>
<td>• Allow a better overall water balance (supply and demand)</td>
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<tr>
<td>Negatives:</td>
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<tr>
<td>• Producer’s loss of absolute control of system</td>
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<tr>
<td>• Commitment needed to Midstream to build system</td>
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<tr>
<td>• Water mixing problems or different source quality criteria</td>
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<td>• Complexity of system allocation and working with other companies</td>
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Although there are both positive and negative drivers for water midstream development, third-party midstream solutions are increasingly emerging. Water midstream companies have acquired water systems and developed new projects in recent years.

Potential for Basin-to-Basin Produced Water Transfer
Since some formations and basins produce significantly more water than others, transferring produced water from basin to basin potentially could facilitate water reuse. For example, the Delaware Basin in Texas and New Mexico, probably the most prolific water-producing basin on a per well basis, is also one of the most active areas for drilling. This makes it more likely that Delaware Basin disposal could become restricted even if water reuse continues to grow. Meanwhile, the Midland Basin has substantial drilling and completion activity, but typically produces lower volumes of water over the life of the well than the Delaware Basin. Constructing a pipeline or series of pipelines to carry produced water from the Delaware Basin to the Midland Basin might be feasible if the Midland basin could reuse additional produced water.

A similar situation exists in Oklahoma, although at a smaller scale. The Mississippi Lime area of north central Oklahoma produces more water than can be reused and has been limited by water disposal capacity due to seismicity. The STACK play in central Oklahoma will likely need sourced water for a long time, even if it continues to ramp up water reuse. An evaluation of a 200,000 barrel per day transfer pipeline conducted as part of CH2M’s water study for the Oklahoma Water Resources Board (OWRB) suggested that a pipeline could potentially be economically feasible. In a second ongoing study, OWRB is making a more in-depth review of the pipeline potential, including non-economic factors. Several major uncertainties remain, including water quality differences that could increase completion costs or create formation damage in the hydraulically fractured well.

Evaluating the Economics of Produced Water Reuse
Unconventional oil and gas development is capital-intensive. An unconventional well is generally considerably more expensive to drill and complete than a conventional well due to technical factors such as the need for hydraulic fracturing. Sourcing water for the hydraulic fracturing of unconventional wells is a significant portion of the capital for drilling and completing a new well.

After the well is put on production, the management and disposal of the produced water is an operating cost that typically lasts for the life of the well. The “default” water management strategy is to source water as locally as possible and reuse it or dispose of it in nearby injection wells.

In most of the regional discussions conducted for this report, cost was the dominant driver for water reuse, although by no means the only factor companies consider. Most companies interviewed were publicly traded with a legal obligation to conduct operations in a cost-effective way that delivers value to their stockholders. Costs were particularly emphasized with the downturn in the prices of oil and natural gas starting in 2015. Within individual companies, U.S. regional operations constitute a business unit that must compete against other domestic and international business units. Not surprisingly, water managers and asset executives must demonstrate that water reuse competes economically with alternatives for that business unit.

Reusing produced water has the potential to reduce or eliminate the costs of sourcing water for well completion and of disposing of it in permitted SWD injection wells. However, decisions about water reuse involve complex determinations about both operating costs and capital investments. If low-cost

sourcing and disposal are available, water reuse is not likely to be a competitive option. In contrast, if sourcing and disposal are limited and expensive, reuse may be economically attractive, provided that any necessary capital investments in transportation, storage, and treatment infrastructure can be justified. The area where reuse is highest, Pennsylvania and West Virginia, and the area where reuse is growing fastest, the Permian Basin, are regions where disposal options have been limited and disposal costs have been high or are increasing. In addition, several of the top basins are in arid regions resulting in limited availability of sourced water.

Primary water lifecycle costs for unconventional oil and gas operations can be simplified, as shown below, when produced water is not reused.

When produced water is reused, the water lifecycle cost for unconventional oil and gas operations changes (Figure 2-13). Commonly, additional sourced water is blended with reused produced water in a hybrid of Figures 2-13 and 2-14.

Comparing Lifecycle Water Costs
In evaluating the potential for produced water reuse, most operators compare the total lifecycle water costs of sourcing and disposing locally to water reuse. Comparing costs on a per-barrel basis requires considering the costs of source water acquisition, sourced water transportation, produced water transportation, produced water treatment and storage, and produced water disposal. These water cost components vary by region and even down to the individual well.

- **Sourced water acquisition.** Water source costs vary with local water availability, local and regional market demand and commercial considerations, availability of water source permits (which is more important in some states than others), water quality (fresh water and brackish water may be valued differently), and volumes purchased (larger volume contracts usually have a lower price per barrel.) Several of the top unconventional basins are in arid regions with limited availability of sourced water.
• **Water transportation.** Transportation costs per barrel will differ significantly depending on whether produced water is moved by trucks or pipelines. Often the most expensive component of produced water reuse, transportation can be complicated by continual changes in well locations as the drilling rig moves from well to well, and by the changing volumes of produced water, which typically decline over time as wells mature. Due to the high cost, water is rarely transported over 50 miles, so most sourcing and disposal is performed locally, normally within 10 miles.

• **Produced water treatment.** With the technical advancements in hydraulic fracturing chemistry, minimal water treatment is required for reuse within the oil and gas operations. Treatment of produced water, when necessary to make it suitable for reuse, may also create residual liquids and solids that must be disposed of properly.

• **Produced water storage.** Storage is often needed for reuse since water production may be at a steady lower rate, while the volumes needed during hydraulic fracturing are comparatively high and intermittent. Storage cost per barrel can be low if the storage system is used for large volumes of water over time. Transportation and storage costs can be reduced using on-site water treatment.

• **Produced water disposal.** Disposal costs can vary significantly by region. Costs are largely determined by the availability or scarcity of appropriate geologic formations for water disposal through injection and the number of permitted SWD wells.

**Justifying Capital Investments**

Water infrastructure is built in a specific area with the expectation that intensive drilling and production will follow in that location. If companies decide to discontinue drilling in the area because a new area has better performance, oil price drops make production infeasible or for any other reason, the capital invested in water pipeline, storage, and treatment facilities will be underutilized and project economics will be negatively impacted.

Before investing in the pipelines, storage, and treatment infrastructure to support produced water reuse in an area, producers need to ensure that the supply of produced water and demand for sourced water merit the investment. Considerations include produced water volumes and longevity, the concentration of development activity in the area, and the existence of nearby ongoing drilling and completions in which to reuse produced water. Unless the producing company has acreage continuity from the point of water production to the sites of reuse, landowner permission must be obtained to cross the area. Obtaining such right-of-way access takes time and resources.

Decision making is complicated by uncertainties about oil and gas prices, drilling and hydraulic fracturing forecasts in the area of concern, technology changes in completion operations, changes in regulations related to water management, and changes in...
the availability of sourced water or disposal capacity and associated pricing. Typically, producing companies may only have specific well forecasts for 12 to 18 months, even if corporate financial models project drilling unspecified locations for multiple years.

Companies have indicated that a regulatory framework that reduces the cost of storage, transportation, and/or transfer costs (for example, by facilitating the use of on-site water treatment, and produced water sharing among companies operating in an area) supports increasing water reuse. Of course, all these items must be evaluated within the constraint of protecting public health and the environment.

**Evaluating Water Midstream Options**

The emergence of water midstream solutions may change the economics of produced water reuse for some producers. Producers may have better financial returns on producing wells than on water infrastructure, depending on the nature of the individual plays. By leveraging infrastructure investments made by midstream companies, these producers can focus their investments on producing wells and improve their cashflows. This option allows them to respond to pressure from energy investors who encourage upstream companies to limit borrowing.

Nevertheless, producers may be reluctant to commit to a midstream solution for several reasons. First, if producing companies own and operate their own water system, they may have more control over sourcing and disposal of water. Water midstream is a developing business and the relatively new producer water teams are still figuring out this new option. Second, companies may be concerned that long-term, volume-based, take-or-pay commitments to the midstream company may be required to allow the system to be built. Third, in peak times there may be complexity with allocation of the system capacity among producers. Fourth, water mixing problems and differing water quality needs for various water sources could be an issue. Finally, regulatory and other business risks may inhibit midstream growth.

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![Figure 2-15: Oil Prices Since 2000](image)

Volatile oil and gas prices have had a profound effect on unconventional drilling activity and, in turn, on water reuse investments. Leading up to the 2007 peak of oil prices, industry was just getting started with shale plays and unconventional development. The price crash of 2008 and 2009 during the great recession reminded a new generation how volatile oil prices can be. From 2010 to 2014, prices were remarkably stable, until another price collapse in 2015. In 2015 and 2016, market conditions forced numerous companies to reduce the size of their workforce and their capital budgets, which created uncertainty for longer-term planning and capital investment. As drilling levels declined in most basins, constraints on water sourcing and disposal eased, making capital investments in water projects difficult to justify.
Operational Challenges of Produced Water Management
Operational challenges related to produced water reuse include the logistics of moving water from source to well site for use; storing produced water for reuse; regulatory and permitting requirements relative to all aspects of reuse and sourcing; landowner agreements and permissions needed, including right-of-way; and water quality requirements for completion and the need to dilute produced water.

Transporting Water for Reuse
Produced water can be transported by permanent pipelines, temporary pipelines, or trucks, or by a combination of these modes. Transportation was named by water managers interviewed for this report as the top operational challenge affecting produced water reuse.

The operating cost of moving water by existing pipelines is substantially less than the cost of trucking the water, often the difference between cents per barrel and dollars per barrel. However, if permanent pipelines do not exist, installing them typically requires companies to commit to a multi-year capital investment plan that can only be justified by the need to transport large volumes of water over an extended period of time.

The Marcellus and Utica plays in Pennsylvania, Ohio, and West Virginia are the exception to building
pipelines to establish reuse. Due to regulations, hilly terrain, and the relatively small volumes of water, most water reused in Appalachia is trucked from the gathering points to the next completion site. The cost of trucking is highly dependent on the distance water must be transported, which may limit produced water reuse when the closest hydraulic fracturing site is farther away than the closest disposal well.

**Permanent and Temporary Pipelines**

Permanent pipelines are typically buried and are usually 18 inches or larger in diameter. Evaluations of when and where to install permanent lines to transport water must weigh uncertainties about oil and natural gas prices that impact drilling activity, capital investments, and water needs. The lead time to design, permit, and install buried water pipelines may be six to 18 months. This lag time from decision to operation is another complicating factor since drilling plans by companies are often revised monthly or even weekly.

Often, the location where the treated produced water is needed changes over time. In the simple “default” scenario, a single water line may connect a group of wells to a disposal well. However, for reuse, a complex network of water pipelines may be needed to move the water to within a few miles of the well site for reuse. Short transfers of water simplify logistics. Often, the sourced water can be conveyed with temporary surface lines while permanent water lines link produced water to disposal wells.

Designing a permanent pipeline infrastructure must take into account physical and operating conditions including normal operating pressures and flows, pipeline material, pump station spacing, and control and isolation valves. Special considerations must be given to rights of way, the crossing of roads, railroad tracks, water bodies, and environmentally sensitive areas which may require a permit. Equally important is construction oversight to ensure construction meets design specifications and addresses any required field modifications during construction. Once the pipelines are installed, monitoring of operating conditions incorporating leak detection and routine inspections is important.

Temporary pipelines are typically laid across the surface (such as “layflat pipe” or “layflat hose”) and may be smaller in diameter (4 to 12 inches) than permanent pipelines. These lines can be reliably deployed for short periods of time. Steel-reinforced (or similarly reinforced) flexible pipe is available for use as temporary pipelines. This piping is routinely available in long lengths of 600 feet or more in order to minimize connecting joints, which are a common source of pipeline leaks. Pressure ratings for temporary pipelines are well in excess of typical pipeline transfer operating pressures. More sophisticated leak detection systems are not designed for temporary pipelines. Therefore, more dependence is placed on flow and pressure monitoring and visual inspection during fluid transfer operations. In order to improve reliability of layflat hose and prevent against possible leaks, the American Petroleum Institute has a standards committee looking at this issue.
Permanent Pipelines for Water Reuse

Challenges

• High upfront capital cost
• Time required to obtain right-of-way access from landowner
• Hilly terrain and rocky soils making installation more complex and costly
• Uncertainties in oil and natural gas prices and drilling forecasts combined with the longer term payout of a water system
• Monitoring for leaks and spills and effectively responding when they occur
• Companies owning a low concentration of acreage which may lack a critical mass
• Automating pumping and storage systems where possible to ensure smooth operations and reduce labor costs
• Measuring and reporting water volumes for better transparency

Opportunities

• Lower costs to move water once the system is installed
• Potential to link storage, treatment, and disposal capacities into an efficient flexible system
• Dramatic reduction of truck traffic for water hauling and reduced accidents and road damage
• Enabling produced water reuse at a large scale
• Reducing fresh and brackish water sourcing and water disposal through increased reuse

Temporary (transfer) Pipelines for Water Reuse

Challenges

• Obtaining permits and right of way
• Infrastructure engineering and construction costs
• Monitoring and leak detection
• Routine inspection and maintenance costs
• Potential regulatory constraints

Opportunities

• Efficient movement of fluids while alleviating dependence on tracking
• Implementing robust leak detection and inspection procedures to reduce potential for leaks and spills
• Ability to quickly deploy and move the piping based on factors such as need, site conditions, etc.
**Trucking**
Legislators and regulators in key oil and gas producing states report hearing more complaints about truck traffic than all other industry issues. The impacts of trucking in oil and gas operations are documented in a report by The Academy of Medicine, Engineering and Science of Texas.\(^{46}\) In addition to wanting to reduce impacts on stakeholders, producing companies also often want to minimize trucking due to its high costs. Yet it is unlikely that trucking can be entirely eliminated for water transport. When produced water volumes are low or the terrain is difficult, it becomes impractical to install a water pipeline. In some basins where wells are widely spaced, or the volumes of water are small, trucking the produced water is the most common transport choice (Appalachia and Eagle Ford).

Some producing companies and service companies are using GPS to track truck locations and direct them in a more efficient process. This optimization can track where the water loads should be obtained, and which nearby salt water disposal wells have the shortest wait time. The same systems can also track vehicle speed for safety purposes. These systems have aided oil and gas companies in managing their water trucking operations. For example, Pioneer Natural Resources has a sophisticated control room for water trucking operations and other logistics.\(^{47}\)

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**Trucking Mileage Math**

Hydraulic fracturing operations at a well site may require approximately 50,000 barrels of water per day. Trucks typically have a capacity of 120 barrels. Thus, if a truck is making a 20-mile round trip to deliver 120 barrels of water and all of the water is delivered by truck, the trucks would drive about 8,300 miles per day.

If the loading, unloading, and roundtrip driving took two hours, the ongoing operations would require 35 trucks 24 hours per day.

For these reasons, sourced water for operations is largely provided by a series of permanent and/or temporary water pipelines.

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**Trucking Produced Water**

**Challenges**

- Minimizing trucking to reduce community impacts and costs
- Consistently maintaining safe trucking operations even when industry activity is at a crescendo
- Local road conditions and weight limits
- Producer responsibilities and liabilities associated with road maintenance and repairs
- Truck fleet availability and scheduling difficulties

**Opportunities**

- Using technology to improve the efficiency of trucking timing and routes
- Improving methods to record and track volumes of water trucked

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\(^{47}\) Pioneer Natural Resources, Operations.
**Produced Water Storage**

Produced water must be stored before it is reused. This intermediate storage is needed because water normally is produced at low flow rates compared to the high, variable flow rates used during fracturing operations (up to 75,000 barrels per day). Water storage systems used in operations include frac tanks, in-ground impoundments, and above-ground storage tanks. The type selected is based on how long storage will be needed, regulations, space available, terrain, and soil/rock conditions. Measures taken during design, construction, and operations to minimize leaks and spills from storage facilities include:

- Using qualified individuals and properly designing facilities to meet specific storage needs and siting conditions
- Conducting construction oversight to ensure construction meets design specifications, addressing any required field modifications during construction
- Using spill prevention and containment at fluid loading and off-loading points
- Using secondary containment around above-ground storage (frac tanks and ASTs) with enough volume to contain a release from a potential tank failure
- Insuring proper leak detection and prevention systems for in-ground impoundments are installed and monitored appropriately.

**Frac tanks**

Frac tanks typically have a small capacity (450 to 500 barrels) relative to the average need of wells (180,000 to 350,000 barrels). They are used for mixing of fluids before being pumped downhole but may also be used to store water before completion. Most commonly, multiple frac tanks (six to eight) are used as buffers to supply consistent flow rates during hydraulic fracturing. Regulations in some states have restricted impoundments or make them difficult to be permitted, thus encouraging the use of frac tanks. Some regions like the Marcellus/Utica use frac tanks almost exclusively.
**Impoundments**

Impoundments are the lowest cost option for storage over a period of years. New impoundments in the Permian and Oklahoma areas may have capacities up to 1,000,000 barrels, which is 2,000 times the capacity of an individual frac tank. Most states have regulations for the design and permitting of impoundments. One of the major risks to impoundments storage of produced water is potential leaks of the liners. Most in industry consider the dual lined impoundments with leak detection a reliable way to store treated produced water that is awaiting reuse. Permitting and construction of large impoundments can take from two to 12 months or more and may require additional permitting under other regulatory programs such as dam safety.

![Figure 2-19: A Pioneer Drilling Rig Behind the Lined Containment Berm of a Water Storage Pond](image1)

*Source: Pioneer Natural Resources*

Impoundments to store produced water are usually dual-lined with leak detection. The height of the berm, the earthen wall, may commonly be 12 feet.

**Above-ground storage tanks**

Above-ground storage tanks (ASTs) are often rented for short and medium time frames (months vs. years) because they can be set up quickly and easily moved to a new site. These tanks can range from 4,500 to 62,000 barrels in capacity. They are often 10 feet tall, with steel or plastic sides and open tops, and are lined with polyethylene liners to prevent leaks. ASTs have a reduced footprint compared to frac tanks for the same water volume.

![Figure 2-20: Muscle Wall Above-Ground Storage Tank in Permian](image2)

*Photo courtesy of Muscle Wall Holdings, LLC*

Above-ground storage tanks have a reduced footprint compared to frac tanks for the same water volume.

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Water Storage for Reuse

Challenges

- Permitting, bonding, and closure of impoundments
- Longer lead time for constructing impoundments
- Solids buildup including normally occurring radioactive material (NORM)
- Keeping costs low enough to compete against local disposal of produced water
- Preventing leaks and maintaining monitoring standards of produced water
- Preventing air emissions, especially volatile organic compounds (VOCs)

Opportunities

- Regulations that allow all types of water storage, including impoundments, as well as an effective permitting process and timeline (Example: A change in Texas impoundments rules by the Texas Railroad commission in 2013 greatly improved the adoption of large impoundments that led to additional water reuse.)*
- Reducing the difficulty for operators to share produced water and store in impoundments, whether by facilitating commercial permits or some other regulatory change


Water Disposal in Injection Wells

Water disposal in injection wells has proven to be a reliable method for disposal of waste water from oil and gas operations since the 1930s. Disposal wells are typically regulated by the states under delegated authority from the EPA. Wells are designed with multiple strings of steel casing separated by cement layers to ensure that the wellbore fluids do not contaminate groundwater. Typically, produced water is injected into saline formations that were more saline than ocean water before the process started. Approximately 80 percent of the Class II injection wells are for enhanced oil recovery and the remainder are for disposal.
Discussions with water managers from producing companies indicate that having disposal capacity is a bigger concern in the Permian, Oklahoma, Haynesville, and Bakken basins/regions than in other areas. While reuse of produced water within the industry is important where possible in order to save fresh water resources, having an option to dispose is also important.

### Deep Well Disposal of Produced Water

**Challenges**
- Having appropriate permeable formations that allow sufficient injection rates
- Knowing whether disposal in a particular area could create induced seismicity
- Increasingly difficult and complex permitting in some states and regions
- Loss of a potentially valuable water resource

**Opportunities**
- Complementing water reuse systems when produced water volume exceeds what is reusable
- Allowing an outlet for produced water when reuse is impractical
- Reducing disposal to increase reuse and reduce fresh water use
- Potentially recharging pressures in depleted formations, allowing water intended for disposal to be used for enhanced oil recovery

### Treatment of Produced Water for Reuse in Hydraulic Fracturing

Prior to about 2010 or 2011, most reused produced water for hydraulic fracturing was treated to reduce total dissolved solids (TDS) to a fresh level. This desalination was necessary because hydraulic fracture chemistries in use at the time required high quality water to create a highly viscous gel to carry the sand to formation. In 2004, Devon Energy established the first commercial reuse in the Barnett Shale using desalinated produced water.\(^{50,51}\)

The Energy Water Initiative report in 2015 documented a trend toward more robust hydraulic fracturing chemistry allowing the use of lower quality water with high salinity.\(^{52}\) Today, most reused produced water is minimally treated due to these advances in fracture fluid chemistry. This minimal approach—which treats only a few specific constituents to create “clean brine”—is significantly less costly than desalination. The most common items treated are bacteria, total suspended solids, iron, and a few other constituents. In some cases, only bacteria are treated.

### Desalination

In limited cases, desalination is still done to provide an option that could meet discharge water quality requirements or reduce the potential risk from a spill. Companies using this treatment include Antero, Eureka, and Fairmont. Southwestern Energy had a desalination facility in its Fayetteville Shale operations, but that site is not currently treating produced water. Desalination of high salinity produced water tends to be very expensive and creates substantial solid waste that requires disposal. For example, a 20,000 barrel per day desalination plant processing 150,000 mg/L TDS brine could produce approximately 350 tons per day of solids.

The technology and operational efficiency of water treatment in oil and gas operations has improved markedly over the last 10 years. These improvements have helped facilitate the economic reuse of produced water in more situations by reducing costs for a variety of clean brine and desalination treatments.

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A related trend has been the development of permanent plants to sell some of the separated solids such as salt, calcium chloride, and iodine. The revenue from selling separated material has also helped offset treatment costs.53,54

One of the challenges to water treatment costs has been the lack of consistently available large volumes of water. Smaller volumes of water, less than 5,000 to 10,000 barrels per day, have fewer barrels over which to spread the fixed costs. The economies of large-scale systems that transport and treat large volumes of water (perhaps 50,000 barrels per day and up) offer lower costs per barrel. As the water pipeline infrastructure projects grow larger, the economies of scale should continue to reduce treatment costs.

### Desalination Treatment of Produced Water

**Challenges**

- Reducing water treatment costs for smaller volumes of water
- Finding methods to dramatically reduce costs as pipeline systems aggregate larger volumes of water
- Determining the optimal blend of permanent plants and mobile treatment facilities to meet changing water volumes and pace of activity
- Developing sustainable water agreements to align with typical pace and changes in operational activity (i.e., ability to commit to plants without having committed water volumes)
- Managing treatment solids and residuals, including potential NORM and TENORM constituents, that pose regulatory and disposal challenges
- Regulatory constraints or prohibitions on discharge of treated produced water
- Ambiguous ownership of produced water in some states

**Opportunities**

- Reducing energy requirements to operate treatment facilities
- Improving separation of saleable solids such as salts and calcium chloride
- Finding effective methods to treat scale and other challenges associated with mixing different quality water sources
- Optimizing water quality for reuse
- Demonstrating that commercially viable treatment technologies can treat to discharge standards
- Resource preservation

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Enhanced evaporation
As an alternative to water reuse or SWD disposal, natural evaporation has been used to reduce produced water volumes in limited cases. The method is most widely reported in Wyoming (seven companies), followed by Colorado (four companies), Utah (four companies), and New Mexico (three companies). Disposal costs using enhanced evaporation ranged from $0.40 to $3.95 per barrel.\(^{55}\) Using natural evaporation to reduce produced water disposal has generally not been effective because the rate of evaporation from a large impoundment is small compared to the amount of produced water. Natural evaporation is more cost effective in arid to semi-arid conditions. Ponds should be kept shallow as evaporation occurs only at the surface.

Some treatment companies offer enhanced evaporation as an alternative to desalination and discharge. A 2017 survey found costs to be 39 to 54 percent of desalination costs.\(^{56}\) Enhanced evaporation may be most feasible when disposal and reuse are already fully employed. If the choice is between desalination and evaporation, evaporation may have more positives in some situations.

Enhanced Evaporation of Produced Water

**Challenges**
- Typically more costly than disposal if available
- Disposing of significant volumes of solids (unless evaporation is done simply to concentrate brine for disposal)
- Minimizing the risk of salt in evaporated steam (critical to local soil conditions)
- Need for quick startup (in months) when rigs and completions are restricted due to oil or gas price pullback
- Air emissions and emission control processes
- Lack of direct reuse opportunity

**Opportunities**
- Competitive costs (may be roughly half cost of desalination)
- Less rigorous permitting criteria and no water quality criteria for discharge
- Potential for new efficiencies as technologies and operations progress with more regular operations
- Reduced disposal volumes

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55 National Energy Technology Laboratory, Fact Sheet–Offsite Commercial Disposal, [https://netl.doe.gov/node/3179](https://netl.doe.gov/node/3179).

Environmental Challenges of Produced Water Management

The production, transport, storage, reuse, and disposal of produced water involves environmental risk. Because of its high saline content and other constituents, produced water can create numerous potential environmental impacts if it contacts soil or water bodies, including impacts on ecosystems and wildlife. In comparison to disposal options, reuse requires storing produced water in greater volumes for longer periods of time and transporting it from points of generation to the well site and in some instances to treatment facilities between the two. As water transfers increase, so do the risks of spills. Other potential environmental impacts can result from mismanagement of residuals generated from produced water treatment as well as air emissions.

Upstream oil and gas operations are typically regulated by several federal and state agencies, including state departments of environmental quality or natural resources or, in cases of federal or tribal lands, the Bureau of Land Management.

Managing the environmental challenges of produced water management requires minimizing and remediating spills and leaks, managing residuals, controlling air emissions, and taking actions to protect wildlife.

Minimizing Spills and Leaks

Surface spills and well casing leaks near the surface are the most likely pathways for oil and gas activities to contaminate drinking water sources and cause environmental damage. The depth separation between oil-bearing zones and drinking water-bearing zones in many areas makes direct fracturing into drinking water zones unlikely.

Methods of minimizing leaks and spills vary by the types of storage and transportation used.

- **Storage.** Key elements for surface impoundments may include double lining with leak detection and freeboard requirements, while for ASTs they are secondary containment, leak detection and overfill control, and fluid loading and off-loading operations to catch and retain potential spills.

- **Permanent pipeline infrastructure.** Permanent pipelines require appropriate design, considering physical and operating conditions including normal operating pressures and flows, pipeline material, pump station spacing, and control and isolation valves. Special considerations must be given to the crossing of roads, water courses, and environmentally sensitive areas. Equally important is construction oversight to ensure that construction meets design specifications and addresses any required field modifications during construction. Isolation valves are recommended on either end of a water or road crossing and at the boundaries of environmentally sensitive areas to allow the isolation and depressurization of these pipe segments in the event of a leak. Additionally, isolation valves should be located at defined distances along pipe segments. Leak detection for pipelines can be accomplished in many ways. A reliable standard method involves monitoring of pressure and flow and comparing the results to a system model of what pressures should be. Routine visual inspection of the pipeline route and right-of-way are likely to catch small leaks that the system monitoring may not find. In addition, continuous monitoring leak detection systems provide relatively quick and accurate identification of a leak and its location. These systems include negative pressure wave, real-time transient model, and statistical corrected volume balance.  

- **Temporary pipeline infrastructure.** The primary method of minimizing leaks and spills is routine inspection of the lines.

The design and construction of an impoundment, tank, or pipeline is a project encompassing not just design by qualified individuals but oversight and quality assurance during construction. Design plans and specifications should be developed and may need to be sealed by a professional engineer. However, that is not where the involvement of design personnel ends. Construction oversight by qualified individuals must also occur during construction.
This oversight will include documenting all field modifications to address conditions encountered that were not accounted for during design, checking field modifications against design parameters and getting sign-off by the designer if needed, verifying field quality control requirements are met, and developing final as-built plans documenting the facility as it was constructed.

An effective way to ensure proper construction oversight is by developing and implementing a Construction Quality Assurance (CQA) plan. A formal CQA establishes procedures to document that construction is in accordance with the approved engineering plans and specifications and meets appropriate regulatory requirements. It also provides a paper trail to verify that specified activities are properly completed. Verification is achieved through a CQA report documenting the extent to which construction was performed in compliance with design drawings and specifications.

Ongoing inspection and maintenance are required throughout the course of operating impoundments, tanks, or pipelines. Elements include routine inspection, the use of remote sensing technology, and a program to correct identified issues and verify repairs are completed properly. A checklist is an effective tool in both conducting and documenting this effort. For in-ground impoundments, inspections of the berms and liners are important. For steel tanks, corrosion monitoring is appropriate.

At the end of a facility’s service life, any impacts from operation must be addressed (starting with identification and followed by remediation and verification of completeness of any response action). Tools and programs will be different but typically include a level of financial assurance to provide for future closure/decommissioning costs.

**Remediating Spills**

Oil and gas produced water is often much saltier than sea water and can damage soil if large amounts spill or leak during storage or transport. In fact, a produced water spill can cause much more long-term damage to land than an oil spill. Various studies of reported spills of produced water indicate that the majority are small spills. The typical small spill may have limited impact and can be remediated a variety of ways. These small spills can however persist for decades and rarely naturally remediate, primarily as a result of the high salinity that impacts both vegetation and soil structure. Remediation of the brine impacts typically includes flushing of the soil to reduce the salt content in the plant root zone and rebuild the soil structure (addressing the cation and anion imbalance), and revegetation to re-establish the ecosystem and counter erosion. Revegetation can take multiple years, depending on severity of the spill.

Beyond salt, produced water can contain many chemicals that are either present in formation water or known to be used in the well completion or maintenance processes. Chemicals may range from ethylene glycol (antifreeze) to hydrochloric acid and could include radionuclides (from NORM). Regulator-approved chemical detection methods only exist for about a quarter of the potential chemicals.

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### Minimizing and Remediating Spills

**Challenges**

- Minimizing large and small spills in all aspects of water management and reuse
- Developing cleanup standards and remediation techniques for various environmental media (surface water, ground water, drinking water, soil, pad materials, wetlands and other environments) for a variety of spill types including produced water

**Opportunities**

- Limit risk and impact of water spills using automation and leak detection technologies
- Limit risk and impact of water spills using proper design and operating practices in containment and transport

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Residuals Management
The most common residuals with minimally treated produced water are suspended solids that may be separated in the treatment process or settle in the water storage impoundments or tanks. These solids must be disposed of according to state regulations. Often the solids will be sent to landfills. If the solids contain NORM that is concentrated through industrial processes, they may be classified as “technologically enhanced naturally occurring radioactive material” (TENORM) and must be disposed of in hazardous waste landfills designed for such materials. Management of the solids creates an additional cost to the reuse process and may introduce separate risks.

Typically, the residuals may contain salts that will potentially create risks to groundwater if they leak from the landfill. Transporting any elevated concentrations of NORM or TENORM from the treatment site to the special landfill also introduces potential risks. In some cases, residual solids may have a marketable value that can help offset the costs of treatment. However, it sometimes is not clear who owns these saleable solids.

In some treatment processes, a residual concentrated brine may be produced. This brine would normally be disposed in a disposal well. The disposal of concentrated brine can reduce the volume of solids needing disposal.

<table>
<thead>
<tr>
<th>Challenges</th>
<th>Opportunities</th>
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<tbody>
<tr>
<td>• Designing processes that limit solid waste</td>
<td>• Selling marketable products from residuals when possible to offset treatment costs</td>
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<tr>
<td>• Handling solids appropriately and preventing environmental impacts from residuals</td>
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<tr>
<td>• Being particularly cautious with NORM and TENORM management and disposal, which is becoming an increasingly regulated aspect of oil and gas operations</td>
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</table>
Managing Air Emissions
Air emissions from produced water in tons per year would vary depending on what type of storage is being used and the throughput that storage can accommodate. Some produced water could be transported to a large impoundment in volumes that result in permit/notice triggering levels of volatile organic compounds (VOCs) being released. Emissions must be managed in accordance with state and federal regulations. For example, methanol is a common additive in hydraulic fracturing and production operations. It is considered a VOC. Methanol emissions from water impoundments have been an issue infrequently. One conclusion of a whitepaper examining the use of methanol in hydraulic fracturing was that “Because of methanol’s low tendency to volatilize out of water and into air, methanol will practically not volatize from flowback ponds.” However, since methanol has a boiling point much lower than water, thermally enhanced evaporation or distillation processes will allow methanol to volatize before water vapor, which may require that it be trapped or scrubbed from the emissions.

Water treatment, especially desalination, may involve heating produced water with natural gas. The burned natural gas will increase CO₂ emissions and may increase emissions of other gasses such as sulfur dioxide (SOx) and nitrogen dioxide (NOx), which may change permitting criteria for a facility.

Hydrogen sulfide (H₂S) is naturally present in some producing formations or can be a byproduct from bacteria growth in stored produced water, especially during hotter months. The amount generated from an impoundment is typically low, but H₂S is a potential safety and health concern if concentrated. Low levels of H₂S can create a bad smell and a nuisance. Most producing companies have established operations to prevent H₂S growth in impoundments, including relatively simple methods of circulating the water and aerating the ponds. Additionally, there are mechanical and chemical methods available to remove higher levels of H₂S from water.

Air Emissions Management

<table>
<thead>
<tr>
<th>Challenges</th>
<th>Opportunity</th>
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<tr>
<td>• Preventing VOCs, H₂S or other air emissions that could create any risk to health or safety</td>
<td>• Establishing water reuse operations and systems that minimize air emissions and keep overall emissions from upstream energy operations as low as possible</td>
</tr>
<tr>
<td>• Effectively monitoring air emissions from water reuse operations</td>
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</table>

Preventing Potential Impacts to Wildlife
State and federal regulations apply to protect wildlife around oil and gas operations. Federal statutes, such as the Migratory Bird Treaty Act, provide substantial penalties for the death of many species of birds that could occur from contact with oil in an open top tank or impoundment. Some states require bird abatement for produced water storage. Common forms of prevention may involve netting or a sound source to prevent birds from landing. Netting is not typically practical for large impoundments.

It is important to keep animals from being trapped in an impoundment due to a slippery liner. Often, fences around the impoundment secure the area and protect walking wildlife. Companies also want to prevent deer and cattle from walking on the liner, since their hooves may puncture the liner and trigger the leak detection system.

Figure 2-23: Netting over Impoundment
*Photo courtesy of American Netting, LLC*

Netting can be used over open tanks or impoundments to prevent birds from landing.

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### Protecting Wildlife

**Challenges**
- Preventing any occurrence of wildlife impact over the long life of an oil and gas development
- Deterring birds from produced water impoundments and tanks, which may be attractive to them as water sources
- Preventing trucking hazards to deer and other wildlife

**Opportunities**
- Building water pipeline systems that can have less impact on wildlife than trucking
- Protecting and enjoying wildlife

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Regulatory and Legal Challenges and Opportunities

Management of produced water is subject to a complex set of federal, state, and sometimes local regulations that may address a wide range of topics (permitting, siting criteria, bonding, water acquisition, temporary storage alternatives, facility construction, facility operations, liabilities for misuse, discharge reporting and response, environmental monitoring transport, infrastructure, land disturbance, reclamation, treatment technologies, beneficial use, recycling, reporting site closure, and decommissioning). The purpose of state and federal regulations is to allow for orderly and efficient development of resources while ensuring protection of the environment, public health, and safety.

Regulations evolve over time in response to such factors as emerging practices, new technologies, and identified risks that are not adequately addressed by existing regulations. In the case of produced water management, the emergence of unconventional resource development has led to new midstream approaches to water gathering, storage, treatment, and distribution for use. These midstream operations are often outside of traditional state regulatory frameworks and require state authorization and oversight for activities that are neither associated with permitted oil and gas operations, nor facilities at Class II underground injection operations. For example, the surface storage of produced water may entail the use of impoundments, which may be regulated by a state agency other than the state oil and gas agency. Determining how these impoundments would be regulated and by which state agency or agencies will require a thorough review of current statutes and authorities. State laws typically establish broad performance objectives and empower one or more state agencies to promulgate more specific regulatory standards, with authority to enter properties and enforce state standards. This process will need to be repeated with respect to midstream water management companies and will take time. In the meantime, rapid growth of such companies could lead to potential problems for which no or only a limited regulatory response is available.

In response to the emergence of a midstream produced water industry, some state legislative bodies have passed laws to authorize these emerging practices. For example, in 2014, the Ohio General Assembly enacted Am. Substitute House Bill 59, authorizing the Ohio Division of Oil and Gas Resources Management to develop new rules to establish requirements for permitting and operating new facilities that will temporarily store, recycle, treat, and/or process produced water not associated with sites permitted for drilling and completion of oil and gas wells or Class II injection wells. By law, Ohio now authorizes new facilities by permit until such time that rules are enacted.

In recent years, some states have enacted rules that address specific components of the challenges posed by emerging practices. For example, prior to 2013, Texas producers were having difficulty obtaining permits for impoundments to store produced water to facilitate reuse. The issue was often just the difference in time to obtain a permit as compared to the fast-changing drilling plans. The Railroad Commission of Texas changed the requirements for permitting to allow permits by rule under certain conditions. The revised Statewide Rule 8 (16 Tex. Admin. Code §3.8) allowed companies to implement water reuse impoundments in a timelier fashion and reuse has grown over time.

The Ground Water Protection Council and Interstate Oil and Gas Compact Commission can facilitate the exchange of applied research, emerging standards, and continually improving regulations to assist states in developing and implementing effective regulatory frameworks. The State Oil and Gas Regulatory Exchange program provides a process for the exchange of ideas as state regulations evolve.
The Oklahoma Corporation Commission (OCC) has revised bonding requirements associated with storage impoundments to support produced water reuse. This bonding provides the state with the funds necessary to close any water impoundments left behind in the event of a bankruptcy. In this regard, the Oklahoma Corporation Commission (OCC) requires bonding on a per barrel of water storage capacity at a water treatment facility. The trend in water storage is to construct impoundments to accommodate the larger hydraulic fracturing completions being performed. Typically, multiple impoundments will be necessary to effectively reuse produced water in a service area of a recycling facility, potentially leading to multi-millions of dollars of bonding requirements in a relatively small play area. This bonding requirement has been identified by producing companies as a potential deterrent to produced water reuse. The OCC has been working cooperatively with industry on this issue so as not to discourage recycling of produced water, while at the same time remaining environmentally protective. The OCC will review new application bonding requirements on a case-by-case basis with an eye toward potential use of blanket bonding for multiple recycling facilities by producers.

Most producers and state regulators agree that states are better able to craft regulations that address regional conditions instead of applying a blanket federal regulatory framework on operations. The corollary of states having varying rules is that companies must understand all the variations for the states where they operate. Statutes and regulations that optimize and balance both flexibility and environmental protection will encourage reuse. Where reuse of produced water is important to an individual state, evaluating the differences between its laws and regulations with those of similarly situated states might result in changes that could encourage reuse.

The Case for Improved Reporting
Neither federal regulators nor most states require reporting of the source of the water used for completions or hydraulic fracturing. Companies often report on their websites if they are reusing produced water in a specific region. Most states require that operators report water volumes and chemicals used during hydraulic fracturing in their FracFocus® reports by well. It is not a requirement to report the source or the quality of the water used, which may be surface water, groundwater, treated wastewater effluent or produced water (reuse).

State regulators continually balance the need for data to evaluate compliance with the risk of increasing operating costs and potentially reducing economic activity. The lack of full information about reuse frequency and produced water availability will limit policymakers’ understanding of the issue when it may become more important. For example, in the event of a drought or disposal problem, regulators may have a limited ability to determine how important reuse could be in helping with a potential solution.

Produced water reuse is a relatively new priority in this fast developing and changing industry. The Journal of Petroleum Technology concluded that “Improved reporting is needed to guide the industry and regulators as they look for solutions and figure out how to manage scarce resources, particularly the limited capacity of subsurface formations used for water injection.”

Research Needed to Facilitate Produced Water Reuse

Most producing companies interviewed for this report do not see significant research needs or opportunities related to water reuse within oil and gas operations. Breakthroughs in water transport, a major operational and cost barrier to reuse, are viewed as unlikely, since pipelines and pumps for produced water are mature technologies. However, the interviews identified the following areas as potentially valuable.

- **Leak detection.** Optimization of leak detection is potentially promising. Monitoring systems for real-time detection of leaks in saltwater pipelines flag pressure changes that are inconsistent with the rate of pumping. This technology for large high-rate saltwater systems is immature and research may help improve operational efficiencies. More sophistication with controls from the impoundments and pumping may also be beneficial.

- **Addressing specific water treatment challenges.** Some producing companies identified water treatment as an area where technology improvements could potentially be very beneficial. They noted that, while service providers have already substantially reduced water treatment costs in recent years, technical challenges are periodically encountered due to unique water quality or mixing. Problems may relate to scale buildup or a specific analyte such as barium, sulfate, iron, or some other component. Research by universities and water treatment companies to improve solutions for specific treatment problems could help reduce costs for reuse and increase reuse volumes.

- **Improvement in enhanced evaporation or desalination.** Advances in enhanced evaporation technologies could be beneficial in reducing the risk of salt carry over into the steam or spray. Also, enhanced evaporation or desalination that concentrates the brine to near saturation without creating solids would reduce the potential impact of managing large amounts of solids in landfills.

- **Automation in treatment systems.** Research on treatment systems that can be operated remotely with little or no human intervention offer the potential for labor cost savings.

- **Separation of saleable products during treatment.** Water treatment costs can be partially offset when treatment companies separate out saleable products. Analytes such as iodine or lithium may be separated when in higher concentrations, even without full desalination of the produced water. For example, Iofina—a company involved in the exploration and production of iodine, iodine specialty chemical derivatives, and produced water and natural gas—is separating iodine found in higher-than-normal concentrations in the produced water of one Oklahoma operator. Research could further the separation of saleable products by determining the best saleable products, and processes to create the products.

- **Water treatment research needs.** Companies also touched on water treatment research needed to facilitate water reuse outside the oil and gas industry through discharge or use in another industry. To date, the discharge of produced water has been rare, hindered by the high costs of required desalination and other treatments. Yet, from an operational perspective, some producers contend that discharge may need to be integrated into long-term water management strategies, especially in plays with limited disposal compared to the volume of produced water (e.g., the Marcellus in Pennsylvania, the STACK in Oklahoma, and the Delaware Basin in New Mexico and Texas). Discharge also might be built into water planning for periods when drilling and completion activities drop. In those periods, the same water network that normally moves water to where it is needed for reuse within the oil and gas industry could transport it to a desalination treatment facility that allows the water to be used in another industry or discharged. Research into automation, low energy treatment options, and low-cost capital facilities will be important.
Another potential route to offsetting costs is the separation of saleable products during treatment processes. Separation of products has even more potential when treating for discharge rather than for reuse in the oil and gas industry, since desalination is involved. Research is needed to determine what useful products can be created and which processes are best to create the materials. Module 3 discusses this further.

- **Regulatory changes needed to facilitate discharge.** Enabling the surface discharge of appropriately treated produced water will require regulatory changes, which may include modifications to storage requirements, NPDES discharge permitting, transportation requirements, and others.

**REGULATORY UPDATE NEEDS**

Enabling the surface discharge of appropriately treated produced water will require regulatory changes, which may include modifications to storage requirements, NPDES discharge permitting, transportation requirements, and others.

**Policy Initiatives to Facilitate Reuse**

Producers interviewed for this report raised several consistent themes when discussing how state and local policies may support or inhibit increased water reuse.

- **Tracking water transfers.** Regulators in some areas of the Marcellus/Utica region could facilitate reuse by reducing requirements to track produced water moved from site to site by actual barrels. The barrels cannot be definitively tracked when they are mixed together in storage.

- **Commercial designation.** In some states, water management requirements for non-commercial reuse are more flexible than for commercial reuse. While the commercial regulations usually set a higher standard, sometimes they prevent companies from working together efficiently to reuse produced water. With the trend toward larger reuse systems and water sharing, regulations should be reviewed to assure they strike the right balance between resource protection and reuse.

- **Storage.** Companies want the flexibility to use the best operational option for the situation. In some cases, states limit or prohibit impoundments for storing treated produced water. In many situations, the alternate produced water storage options are substantially more expensive and deter reuse.

- **Temporary layflat lines.** If temporary layflat hose is not permitted to transport produced water the last mile or two to the well site, the alternatives are less feasible. Trucking water for the last short run or running permanent pipe to every well site may increase costs dramatically and increase the impacts related to truck traffic.

- **Right-of-way on county roads.** Right-of-way on county roads can enable water transport via permanent or temporary pipelines. Water reuse is hampered in counties that prohibit this possibility.

- **Timely permitting.** If operators encounter lengthy permit approval times for reuse operations, they will tend to default to local sourcing and disposal to meet completion schedules. Speeding up approval times will support greater water reuse. Some companies have been critical of the historically slow process of obtaining an NPDES permit to discharge produced water, reporting that in some cases it can take two years, which is much longer than the companies’ well planning cycle. It should be noted that there are many reasons why the permitting process may take longer than expected including insufficient program funding, problems with the application, communication and response time-lags, and others. Also, Bureau of Land Management (BLM) water-related permitting processes are reportedly much slower than state processes.

- **Clarity of regulations.** Companies mentioned that variation of rules from state to state can complicate their efforts to understand and comply with the intentions of the regulations.
Incentives. Some companies mentioned that incentives such as state or federal tax deductions for water reuse would be helpful. However, any incentives should consider possible unintended consequences and the associated administrative effort to implement the plan.

Produced water ownership. Companies cite ambiguity related to produced water ownership as a potential impediment to produced water sharing and reuse. In some states, they report it is not clear that the producer can sell or transfer water to another producer. In most basins, produced water does not have any value if one tries to sell it. If it has value, it is often less than the cost to treat and transfer the water. In some instances, surface owners may claim a right to a royalty to any water that is treated and sold.

Water Management and Produced Water Reuse by Region

Water management practices, including produced water reuse, vary substantially from region to region. This section focuses on the top seven basins/regions based on oil and gas production and current drilling activity: the Permian, Appalachian, Bakken, Niobrara, Anadarko, Haynesville, and Eagle Ford basins/regions, shown in Figure 2-24. In this report, the Permian is sometimes referred to as its component Midland and Delaware sub-basins, and the Appalachia as the Marcellus/Utica play. Central Oklahoma is a sub-basin in the Anadarko.

Overview of Regional Differences

Significant variables affect water management across these regions. Some have appropriate geology for water disposal and wide availability of permitted underground injection control (UIC) wells, while others have very limited access to disposal. Some areas have abundant supplies of surface water or groundwater, while others are relatively arid. Some are primarily rural regions, others more urban. The amount of produced water from a typical well varies by region, as does the quality of the produced water. Differences in topography determine the feasibility and cost effectiveness of developing water pipeline systems. Applicable state and local regulations vary by region, as do landowner and mineral lease requirements relating to the use of water. Some regions are affected by potential seismicity concerns associated with disposal well injection into specific formations.

Currently, the Appalachia basin with its Marcellus and Utica formations of Pennsylvania and West Virginia has the highest rate of produced water reuse. Primary drivers for the Appalachian region’s reuse have been the extremely limited number of regionally available disposal wells and the high costs of transporting water to these distant wells. Pennsylvania has less than 10 permitted disposal wells for produced water; in comparison, Texas has over 8,000 permitted and operating disposal wells.63,64

The second highest level of reuse is occurring in the Permian Basin of west Texas and New Mexico. Despite its large disposal capacity, the Permian Basin has had significant increases in reuse projects over the last two years, driven by rising costs for other source water and increasing costs for disposal injection wells due to high demand.

Figures 2-25 to 2-41 highlight the relative production of the top basins and contrast differences in their water use and management.

The top seven basins/regions based on oil and gas production and current drilling activity are the Permian, Appalachian, Bakken, Niobrara, Anadarko (includes Central Oklahoma), Haynesville, and Eagle Ford.

Produced water reuse is highest in the Appalachia and Permian Basins. This figure is based on data collected for this report from 18 producing companies and aggregated by basin/region with help from the American Petroleum Institute. The weighted average reuse was 10 percent but varied from 0 to 67 percent across the seven basins considered. The reuse volume was divided by the lower of the water sourced or water produced in the basin. The sourced water was higher than the produced water in four of seven basins. The 18 producing companies contributing data for this report accounted for 29 percent of the total water sourced in the seven basins in 2017.
The Permian is the leading onshore oil-producing basin, followed by Eagle Ford and Bakken.

In natural gas production, the Appalachia is the leading basin, followed by Permian and Haynesville. Generally, the higher the oil or gas production, the more drilling and well completions have occurred. Higher activity will correlate to higher water source demands and, to some extent, to produced water production rates. Higher activity may also correlate to higher produced water reuse opportunities.
Well completion activity and oil production growth rates have varied over time based on changing technical understandings of the economic viability of the basins. Oil production in the Permian was high in 2007 from conventional production. The Bakken grew faster than the other areas from 2007 to 2011. The Eagle Ford production grew dramatically from 2011 to 2015. The Permian Basin is the only oil producing basin that continued to grow when oil prices fell in late 2014 and early 2015. Production dipped in the other basins, then resumed a growth trend around January 2017 as oil prices recovered.

Natural gas production has grown dramatically in Appalachia, driven by high-rate well production and proximity to the East Coast gas market. The other basins resumed their increasing production trend starting around January 2017. The Appalachia and Haynesville areas are the only pure gas plays. The others are primarily oil plays with associated gas that is produced with the oil.
The Permian basin had just over half of the U.S. onshore rigs in December 2018. High rig count is an indicator of a region’s having economically viable wells and foretells potential production growth. Higher rig counts increase demand for sourced water for hydraulic fracturing which, in turn, will eventually lead to higher water production.

The Permian, Eagle Ford, and Appalachia regions accounted for 70 percent of the water used for hydraulic fracturing in 2017 across the key basins. The Permian (Delaware and Midland sub-basins) accounted for the greatest volumes, using 40 percent of the total across the key basins.
Water Disposal by County (Based on Available Data)

Figure 2-32: Injected Produced Water by County (bbl.) in 2017
Source: IHS Energy Group

Counties with high water disposal volumes—a proxy for high water production—are highlighted in red, orange, and yellow and are mostly concentrated in Texas and Oklahoma. This figure shows the estimated volume of injected produced water in barrels generated at a county level in 2017, where available. These volumes are a proxy for water production, but do not account for reuse or water crossing county lines.

Water Use for Hydraulic Fracturing per Well

Figure 2-33: Water Use per Well in Hydraulic Fracturing for Key Basins/Regions in 2017
Source: After FracFocus*, http://www.fracfocus.org

The Haynesville and Marcellus natural gas-producing formations and the oil-producing Midland Basin used the highest water volumes per well in 2017. Per-well water use for hydraulic fracturing varies by formation properties and the length of the horizontal. Larger volumes of water needed and produced can provide the economics of scale to make reuse more viable. The multi-year trend has been for wells to use more water in their completion than previously required.
Typical Water Production by Well

Figure 2-34: Typical Water Production by Well
Source: Energy Water Initiative 2015 Case Studies Report

While water production generally increases over time in conventional wells, it usually declines in unconventional wells in line with the well’s oil and gas production. Declining water production can make single sourcing of reused water challenging or less viable.

Ratios of Produced Water to Sourced Water by Basin

Figure 2-35: Produced Water to Sourced Water Ratio by Region for 2017
Source: After FracFocus®, http://www.fracfocus.org and IHS Energy Group

Haynesville, Permian, and Oklahoma have much more produced water than sourced water in 2017.*
Produced water volumes in some regions far exceed the water volumes sourced for hydraulically fracturing of wells. Other regions, in contrast, produce less water than water sourced for hydraulic fracturing. The average amount of produced water over the life of a well varies from basin to basin and is influenced by the development maturity of an area, coupled with the number of wells drilled historically. The Haynesville area produced roughly 18 times as much water as was used in hydraulic fracturing in the area. Haynesville has conventional production that has substantial produced water and its water needs for hydraulic fracturing are relatively small. Comparing water volumes needed for hydraulic fracturing to the volume of produced water illuminates the potential balance of water for reuse.

* The produced water data is from IHS Energy Group, a company specializing in business information, and the sourced water data from FracFocus®. Counties with less than 100,000 barrels of sourced water in 2017 were excluded. Importantly, the produced water includes water from conventional production and enhanced oil recovery.
Ratios of Produced Water to Sourced Water by County

Figure 2-36: Ratio of Produced Water Divided by the Amount of Water Sourced for Completions by County for 2017
Sources: IHS Energy Group and FracFocus®

Water balance (supply divided by potential demand) varies significantly by county. Many areas in North Dakota, Ohio, Pennsylvania, West Virginia, and south Texas (counties shown in blue) are areas where produced water volumes were less than the sourced water needed. Based on the current production and completion activity, additional source water will always be needed in these areas even if all produced water is reused. In contrast, areas shown in red and orange have more produced water than the water needed for new completions.

Estimated Lifetime Ratios of Produced Water to Frac Volume by Basin

Figure 2-37: Ratio of Expected Lifetime Produced Water Divided by the Amount of Water Sourced for Completions
Source: Interviews with producers

In the long run of continuous drilling, the Delaware basin is expected to have far more produced water than can be reused in subsequent hydraulic fracturing. The Midland and Bakken areas are second and third in this ratio. These ratios are based on estimates provided by operators (typically five to ten operators per basin) when asked what amount of produced water will result over the life of the well compared to the amount used to hydraulically fracture the well. The ratio of four to six times produced water to fracture volume for the Delaware stands out among the basins.
Basins vary greatly in the amount of produced water transported to SWDs via pipelines. These estimated percentages are based on interviews with producers. Having interconnected salt water disposal pipelines facilitates the gathering of produced water and its potential reuse. The pipelines provide economies of scale for reuse and reduce trucking. Capacity of pipeline infrastructure is also dependent on when unconventional development of a particular field began. It takes time for buildout. Therefore, more is trucked in the first year or longer. The buildout of pipelines to move produced water to disposal wells is ongoing where it is economically feasible, usually when higher volumes of water justify the pipeline capital cost.
Permian Basin (Delaware and Midland Sub-Basins)

The Permian Basin in West Texas and the adjoining area of southeastern New Mexico underlies an area approximately 250 miles wide and 300 miles long. The first commercial oil well in the Permian Basin was completed in 1921. As the largest petroleum-producing basin in the United States, the Permian has produced a cumulative 28.9 billion barrels of oil and 75 trillion cubic feet of gas to date. The Energy Information Administration (EIA) has estimated that the remaining reserves are 43 billion barrels of oil and 18 trillion cubic feet of gas. However, some experts claim the content is much larger, half a trillion barrels or even 2 trillion barrels. The switch to hydraulically fractured horizontal wells and unconventional formations began in 2011. Production in the Permian increased from about 1 million barrels per day in 2011 to about 3.3 million barrels per day in 2018 (Figure 2-24). Company spending increased, direct and indirect employment increased, and state and federal tax receipts increased.

As of December 2018, the Permian Basin had 485 active drilling rigs, which was 45 percent of the U.S. total and 23 percent of the worldwide rigs in operation.* Permian’s oil production of 3.8 million barrels per day was over 45 percent of the U.S. oil production and more than 3.2 percent of world production. The Permian is the highest oil producing region in the United States and, if it were a country, would rank as the world’s 10th highest producer.**


The Permian Basin is the highest oil producing region in the United States and, if it were a country, would rank as the world’s 10th highest producer.

The level of activity in west Texas and southeastern New Mexico strains water sourcing but offers opportunities for efficiencies in water management strategies. The demand for sourced water correlates to the rig count and the need for water disposal or reuse. New unconventional wells normally flow much higher water rates than older unconventional wells. Water sourcing is among several operational bottlenecks that have emerged in the Permian Basin. Such bottlenecks are normal for intense activity in an emerging market. Unconventional development often entails concentrated activity, which allows the building of water infrastructure and facilitates more produced water reuse than in areas with dispersed activity. All nine of the largest companies by market capitalization operating in Permian report reusing produced water in the region, representing a substantial increase in reuse compared to only a few years ago, when very few companies reported reusing water in the Permian. Historical information on the volume of reuse is not collected by any regulatory agency in Texas, nor are the reuse volumes typically reported elsewhere.

Many companies are building water networks to move the produced water by pipeline rather than by truck. This is a major investment toward reuse capability and results in reduced vehicle emissions and community disturbance. Based on industry news and company press releases, the Permian has more water projects (pipelines and reuse projects) ongoing than any other basin. The weighted average for water reuse in the Permian Basin was approximately 12 percent.

The Permian has more ongoing pipelines and reuse projects than any other basin. (Industry news and company press releases)

In the Delaware Basin, a sub-basin in the western part of the Permian Basin, an unusually high amount of water is produced over the life of a typical well. The produced water to completion volume is typically 400 to 600 percent. This large volume of produced water may put pressure on disposal capacity but may also provide a steady stream for reuse.

Discussions with Delaware Basin producers suggest that five to 30 percent of the produced water is transported by pipeline to salt water disposal wells or reuse treatment facilities. The water piped, as opposed to trucked, to disposal or reuse facilities is likely to grow over time.
Figure 2-41: Produced Water Production for Selected Counties in Permian Basin
Source: IHS
This figure plots monthly water disposal for some key counties in the Permian Basin. Both Reeves and Loving Counties had greater than 100 percent increases in water disposal from January 2017 to April 2018.

Figure 2-42: West Texas Seismicity Events per Month Above M 2.5
Source: BEG TexNet
West Texas has observed seismicity since at least the 1930s. Seismicity has recently increased in and near Reeves County, which is currently the most seismically active area in Texas. Unlike the plays in Oklahoma, the relationship between water disposal and seismicity remains more uncertain in West Texas. West Texas seismicity in the 1970s and 1980s was attributed to a mixture of natural pressure, inducement from production, and potential inducement from disposal/EOR. The geology is complex in west Texas and disposal is generally not into the deep formations close to basement rock, which can be more problematic. The TexNet seismic monitoring grid was initially installed in early 2017, and additional monitoring stations have been added. The addition of seismic monitoring stations result in a denser—and more sensitive—monitoring network, which may partially account for some of the increase in events. Research by both companies and universities is being done to better understand the seismicity issues. While seismicity is currently low in magnitude in a relatively sparsely populated area, it could be a concern if the trend continues and magnitudes of the quakes increase.
Drought is also a risk to communities and industry in the arid climate of Permian. In the drought year of 2011, Midland-Odessa, the unofficial capital of the Permian Basin, received only 5.5 inches of rain, instead of its normal 15-inch average. The drought put pressure on producing companies and spurred commitments to limit fresh water use. In 2013, Barnhart, Texas made national news when its one water supply well ran out of water and water had to be trucked in until a new well could be drilled.

The following are examples of water initiatives undertaken by oil and gas companies.

- Shell has taken steps to improve water recycling in one area of the Permian. Previously, groundwater used for hydraulic fracturing was transported through a 13-mile pipeline due to limited local water supply in this area. Since late 2016, the company replaced about 40 percent of this water by recycling produced water near a new development area.

- Apache’s hydraulic fracturing water usage in some of its projects in the Midland Basin. The company’s goal in 2018 is to raise that total closer to 50 percent where recycling is possible.

- Pioneer Natural Resources is acquiring non-fresh water from three main sources: reuse of produced water after treatment, brackish groundwater sources, and treated industrial and municipal wastewater sources.

- SM Energy is building a water pipeline infrastructure in Howard County, Texas, as shown in Figure 2-43. The company moves 95 percent of the sourced water via pipelines. It will also connect produced water directly to disposal wells to reduce truck traffic.

![Figure 2-43: Water Pipeline in Howard County, Texas](https://s22.q4cdn.com/545644856/files/doc_presentations/2018/06/060118-June-Investor-Presentation.pdf)

SM Energy is building a water pipeline infrastructure in Howard County, Texas, to move source water and transport produced water to disposal wells.


68 “Water,” Pioneer Natural Resources.
• **Fasken Oil and Ranch** is reusing produced water for hydraulic fracturing. Any water need not met by reuse is brackish water. Fasken had recycled over 5.5 million barrels of water as of 2016.\(^{69}\)

• **Matador Resources** reported sourcing 26 percent of its 11.6 million barrels of water needed in 2017 from reused produced water in the Delaware Basin. As of May 2018, the company reported recycling more than 9 million barrels of water since its operations began in May 2015. Matador Resources operates water recycling facilities in the Delaware Basin, in Loving County, Texas, and in Eddy County, New Mexico. The facilities are capable of recycling about 160,000 barrels per day and will be expanded to 220,000 barrels per day. Prior to April 2017, 13 wells were stimulated with 100 percent recycled water. The company plans to expand its recycling efforts in other areas of the Permian Basin through 2018.\(^{70,71}\)

• **Marathon Oil** took action to reduce waste and minimize freshwater use in the Permian Basin, including building a 300,000 barrel produced water storage and recycling facility within six months of their basin entry. The facility was treating and reusing produced water in stimulation jobs within three months of Marathon’s acquisition and working to make produced water an economic supply source during droughts.

• More than 95 percent of the water used in **Chevron’s** well completions in the Permian Basin is from brackish water sources.\(^{72}\)

• **Solaris Midstream** has completed more than 50 miles of 12-inch and 16-inch produced water pipelines in Eddy and Lea Counties. It plans to build out 300 miles of high-capacity water lines through 2018.\(^{73}\) In June 2018, Solaris acquired a private water supply company, adding more than 15 million barrels of industrial water per year, as well as access to significant sources of water, freshwater storage ponds, and more than 200 miles of water supply pipelines of varying sizes and associated rights-of-way.\(^{74}\)

Permian case studies for Shell and XTO/ExxonMobil are described in Appendix 2-A.

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71 “Investor Presentation August 2018,” Matador Resources Company.


Appalachia (Marcellus and Utica Formations)
The Appalachia basin extends across southwestern New York, northern and western Pennsylvania, eastern Ohio, and all of West Virginia. Appalachia was the heart of the global oil industry in the 1860s and 1870s. Almost as quickly as it began, the boom in Appalachia ended, as regions in California and Texas became the new centers of the domestic industry. Oil production in the Appalachian region peaked around 1900. Over 100 years later, horizontal drilling combined with hydraulic fracturing of the Marcellus and Utica formations in Appalachia took off in 2010. The impact on natural gas production has been dramatic, increasing more than 20 times from early 2007 to December 2018 (Figure 2-45).

![Figure 2-45: Appalachian Basin Oil and Natural Gas Production](Image)

Source: EIA

The Appalachian formations of the Marcellus and Utica produced approximately 31 billion cubic feet (BCF) of natural gas in December 2018. This made Appalachia the highest producing natural gas region in the United States.

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Figure 2-46 shows water sourced for individual completions in 2017 based on data from FracFocus®. Data includes the Marcellus and Utica activity in Ohio, Pennsylvania, and West Virginia. Surface water is often used as a supplement to reused produced water in these areas, due to the plentiful sources of surface water.

One factor affecting water management in the Appalachian Basin is the potential for induced seismicity associated with injection. In 2011, a series of earthquakes near Youngstown, Ohio, with magnitudes ranging from 2.1 to 4.0 were linked to a produced water disposal well nearby. Concerns about seismicity in Ohio led to a temporary moratorium on new injection well permits following the seismic events at the Northstar well near Youngstown until emergency rules were enacted. Pennsylvania already had limited disposal wells based on factors such as minimal appropriate geology for disposal and the time required to obtain federal UIC permits.

Faced with limited disposal options and high disposal cost, Marcellus and Utica operators in Pennsylvania became early adopters of produced water reuse. When the alternative is to truck water for significant distances for disposal, reuse offers lower cost when it can be coordinated operationally. The extremely limited disposal in Pennsylvania and, to a lesser extent, West Virginia, sets the Appalachian area apart from other major regions that typically had adequate disposal capacity predating hydraulic fracturing development.

As noted in a report by the American Geosciences Institute, “The Marcellus shale in the northern Appalachians produces very little water compared to other major oil- and gas-producing regions. Almost all of the produced water is reused in hydraulic fracturing operations, but the small amount of water produced compared to the amount used means that produced water can provide only a small fraction of the water needed for hydraulic fracturing in this area.” The small amount of water produced is normally highly diluted with additional fresh water to makeup the necessary volumes, thus reducing the need for treatment of the produced water for reuse in hydraulic fracturing.

According to the Pennsylvania Department of Environmental Protection, reuse of produced water was approximately 90 percent with the other 10 percent being disposed in disposal wells in 2013.

Ohio currently has 217 active injection wells that have been used by Ohio producers to successfully manage nearly all produced water in the area. Prior to the increase in water injection from shale development, approximately 6 million barrels of water were injected annually in Ohio. In 2017, 37.8 million barrels of water were injected with 48 percent coming from Pennsylvania, West Virginia, and New York.

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Company web sites report various reuse water initiatives in Appalachia.

- **Chevron** in the Appalachian region reused 97 percent of its produced water in 2014 and 2015. Chevron Appalachia has created water-sharing agreements with select local operators that facilitate reuse of Chevron’s produced water by other operators for their drilling and hydraulic fracturing activities. This practice has multifaceted benefits, including maximizing water recycling to offset freshwater demands and limiting disposal to injection wells. Since the execution of agreements in March 2017, Chevron Appalachia has shared approximately 500,000 barrels of water.78

- **Antero Resources**, in partnership with the water treatment company **Veolia North America**, is developing a 60,000 barrel per day water treatment plant in Doddridge County, West Virginia for nearly $500 million. The complex, shown in Figure 2-47, allows Antero to treat and reuse flowback and produced water rather than permanently dispose of the water in injection wells.79 Although the treated produced water is primarily intended to be reused in new wells, the desalination advanced treatment creates low TDS water and reduces the risk from any spills during water transfers.

**Figure 2-47: Antero Water Treatment Plant in West Virginia**

*Photo courtesy of Antero Resources*

Antero Resources developed this water treatment facility in partnership with Veolia North America.

- **In Range Resources Corp’s** core operating area, the Marcellus Shale, “Range uses treated water from Pennsylvania-permitted treatment facilities that originated from other Exploration & Production (E&P) operators within the area. This contributes to a play-wide recycling and reuse program. Range recycles nearly 100 percent of its produced/process water from its E&P operations. This represents a significant percentage of our total water usage.”80

- In 2017, **Southwestern Energy** started a water infrastructure project throughout its West Virginia Panhandle acreage in southwestern Appalachia. The pipeline system will source water from the Ohio River and distribute it to wellpads. The project will be built out in phases to provide fresh water for the company’s wellpads and hydraulic fracturing operations. The system will have the potential to later be expanded to carry wastewater away from the wellpads for reuse.


• **Southwest Energy** shares its produced water in West Virginia and Pennsylvania with other companies. Southwest’s teams built relationships with the adjacent operators, worked out water-sharing agreements for both fresh and reuse water, and planned efficient transportation routes. As a result, in 2016 more than 708,000 barrels of produced water, which would otherwise have been disposed, was instead used by other operators for hydraulic fracturing.  

The Marcellus and Utica region has led other basins in the development of commercial water treatment plants. The commercial plants, some starting operations as early as 2010, will typically take water from multiple producers. The plants treat and may store the water until it is needed for reuse.

• **Eureka Resources** has three commercial water treatment plants in Pennsylvania. Although two of the plants have a permit to discharge treated water to the Susquehanna River, most of the water is reused for other oil and gas operations. The plants have a treatment capacity of 10,000 barrels per day. In addition to treating the water, one plant is also removing methanol from the water and reselling it for natural gas operations in the area. A different Eureka plant recovers sodium chloride (salt) and calcium chloride for industrial sales.

• **Fairmont Brine Processing** has a permit to discharge treated produced water from its commercial plant in Marion County, West Virginia. The plant has a capacity of 5,000 barrels per day. In addition to treating the water, the plant recovers and sells salt and calcium chloride. The company reports that treatment costs are about $4/barrel for the existing plant, but a second plant that is to be constructed at three times the size of their first plant would have treatment fees around $2.50/barrel, based on economies of scale.

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The EPA released a report in May 2018 that included a listing of facilities that have permits to discharge treated produced water. All but one of the facilities are in the Pennsylvania, West Virginia, and Ohio region of the Marcellus/Utica plays (see Table 2-3). However, not all discharge permits are issued by USEPA. Some are issued by state agencies.

Other commercial water treatment facilities may treat produced water for reuse and may not have discharge permits. This includes Hydro Recovery’s three plants in Pennsylvania, Fluid Recovery Services’ three plants in Pennsylvania, and RES Water’s two plants in Pennsylvania.

Table 2-3: Summary of In-Scope Discharging CWT Facilities Treating Oil and Gas Extraction Wastes

<table>
<thead>
<tr>
<th>Facility Name</th>
<th>City</th>
<th>State</th>
<th>Discharge Type</th>
<th>Facility Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Byrd/Judsonia Water Reuse/Recycle Facility</td>
<td>Judsonia</td>
<td>AR</td>
<td>Direct</td>
<td>Facility is permitted for discharge but operates almost exclusively as a recycle facility and discharges infrequently.</td>
</tr>
<tr>
<td>Clarion Altela Environmental Services (CAES)</td>
<td>Clarion</td>
<td>PA</td>
<td>Direct</td>
<td>Facility is permitted for discharge, but as of late 2016 facility was not accepting wastewater for discharge.</td>
</tr>
<tr>
<td>Eureka Resources, Standing Stone Facility</td>
<td>Wysox</td>
<td>PA</td>
<td>Direct</td>
<td></td>
</tr>
<tr>
<td>Eureka Resources, Williamsport 2nd Street Plant</td>
<td>Williamsport</td>
<td>PA</td>
<td>Indirect</td>
<td></td>
</tr>
<tr>
<td>Fairmont Brine Processing, LLC</td>
<td>Fairmont</td>
<td>WV</td>
<td>Direct</td>
<td>Facility is not currently permitted under part 437, but revised permit expected to contain part 437 limitations.</td>
</tr>
<tr>
<td>Fluid Recovery Services: Frankling Facility (Aquatech)</td>
<td>Franklin</td>
<td>PA</td>
<td>Direct</td>
<td>Facility is not currently permitted under part 437, but revised permit expected to contain part 437 limitations.</td>
</tr>
<tr>
<td>Fluid Recovery Services: Creekside Facility (Aquatech)</td>
<td>Josephine</td>
<td>PA</td>
<td>Direct</td>
<td>Facility is not currently permitted under part 437, but revised permit expected to contain part 437 limitations.</td>
</tr>
<tr>
<td>Max Environmental Technologies, Inc – Yukon Facility</td>
<td>Yukon</td>
<td>PA</td>
<td>Direct</td>
<td>Accepts drilling muds and cuttings for stabilization and solidification along with other industrial wastes. Facility is permitted for discharge of CWT wastes.</td>
</tr>
<tr>
<td>Patriot Water Treatment, LLC</td>
<td>Warren</td>
<td>OH</td>
<td>Indirect</td>
<td></td>
</tr>
<tr>
<td>Waste Treatment Corporation</td>
<td>Warren</td>
<td>PA</td>
<td>Direct</td>
<td></td>
</tr>
</tbody>
</table>

Note: EPA identified one additional facility, the CARES McKean facility in Pennsylvania, that was previously permitted under Part 437. However, the most recent permit for this facility issued in 2016 no longer includes the CWT ELGs, indicating that this facility no longer discharges process wastewater from Part 437-regulated activities.

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**Eagle Ford (South Texas)**

South Texas oil and gas production dates back more than 100 years. Several formations were actively developed in the 1980s and 1990s. Production from the formation via hydraulically fractured horizontal wells increased dramatically starting about 2010. The Eagle Ford formation is the second highest producing oil basin and natural gas liquids region in the United States, producing approximately 1.4 million barrels per day in December 2018, according to the EIA (Figure 2-50).

Produced water reuse is economically challenging in Eagle Ford. Over its life, a typical Eagle Ford well may produce only 20 to 30 percent of the water used in completion (fracture treatment). These relatively small volumes of produced water are more costly to aggregate and distribute for reuse on a per barrel basis than the larger water volumes found in other regions. Additionally, the lower volumes of produced water have not driven up water disposal costs. Some companies are reusing limited volumes of produced water, but it is usually a special situation warranting the reuse. Many companies in Eagle Ford have sourced brackish water as a way to limit fresh water use. For example, Marathon Oil reports using 92 percent non-fresh water in 2017 in Eagle Ford, primarily brackish water.

Figure 2-50: Eagle Ford Oil and Gas Production
*Source: EIA*

Oil and gas production in Eagle Ford have risen sharply since the start of unconventional operations.
Oklahoma
Oil was first discovered in Oklahoma, by accident, in 1859, near Salina, in a well that had been drilled for salt. In 1907, before Oklahoma became a state, it produced more oil than any other state or territory in the United States. From 1907 to 1930, Oklahoma and California traded the title of number one U.S. oil producer several times. Oklahoma oil production peaked in 1927, at 762,000 barrels per day.\(^3\)

From January 2007 to December 2018, Oklahoma oil production increased by 355 percent and natural gas production increased by 88 percent based on data from the EIA as shown in Figure 2-51. The increase came from hydraulic fracturing of multiple formations in the central part of the state.

Oklahoma measured an increase in earthquakes over a magnitude 3 from 41 in 2010 to a peak of 903 in 2015. The number of events decreased to 304 in 2017. The Oklahoma Geological Survey has determined that the majority of recent earthquakes in central and north-central Oklahoma are very likely induced by the injection of produced water into deep disposal wells. A regulator and producer group has initiated projects to track and study the state’s seismicity. The Oklahoma Corporation Commission (OCC), regulator of produced water injection wells, implemented approximately 11 mitigation plans between 2015 and 2017. Many of the actions involved restricting produced water disposal in areas adjacent to the seismic activity.\(^4\) The reduction of magnitude 2.5 or greater earthquakes over the last two years in Oklahoma appears to demonstrate that problems with induced seismicity can be effectively managed with appropriate action (see Figure 2-52). In fact, a recent model by Stanford University predicts that the probability of a magnitude 5.0 or above is expected to fall from 32 percent in 2018 to 19 percent in 2020.\(^5\)


\(^{84}\) “What We Know,” Earthquakes in Oklahoma, Website of the Office of the Oklahoma Secretary of Energy and the Environment, https://earthquakes.ok.gov/what-we-know/.


Figure 2-51: Central Oklahoma Oil and Gas Production
Source: EIA
Increases in Oklahoma’s oil and gas production have resulted from hydraulic fracturing of multiple formations in the central part of the state.
The Ground Water Protection Council published a primer on seismicity in 2015 that has a summary of aspects of Oklahoma’s seismicity. A second edition of the primer was published in 2017.\textsuperscript{86}

In December 2015 Oklahoma Governor Mary Fallin established a fact-finding work group to look at ways that water produced in oil and natural gas operations may be recycled or reused instead of being injected into underground disposal wells. The Water for 2060 Produced Water Working Group has been charged with identifying regulatory, technical, and economic barriers to produced water reuse as well as looking at opportunities and challenges associated with treating produced water for beneficial uses, such as industrial use or crop irrigation. The April 2017 report on produced water in Oklahoma is available at \url{https://www.owrb.ok.gov/2060/PWWG/pwwgfinalreport.pdf}. The report included the following conclusions:

- Produced water reuse by the oil and gas industry is the most viable cost-effective alternative due to minimal water treatment needs and thus low treatment costs.

- The specific desalination cases evaluated for the study for reuse outside of oil and gas operations were significantly more costly than current operations or reuse for oil and gas operations.

- An evaluation case to transfer produced water from an area of excess to an area of need was somewhat encouraging.

- Enhanced evaporation was lower cost and more economically viable than the desalination cases.

The transfer pipeline and enhanced evaporation are the subjects of an ongoing study by the Oklahoma Water Resources Board.

Figure 2-40 shows water sourced for individual completions in 2017 in Oklahoma based on data from FracFocus\textsuperscript{®}. Data includes Texas, Oklahoma, New Mexico, and Louisiana.

Oklahoma has a few specific water-related characteristics. For example, Oklahoma surface ownership is more fractionated than most other areas in the west. This makes obtaining right-of-way more difficult and magnifies landowner challenges. Additionally, central Oklahoma unconventional plays do not produce large amounts of produced water and the volumes quickly decline, reducing the economies of scale for reuse. Finally, brackish groundwater aquifers are undergoing research in some areas but are not extensively detailed in many locations; therefore, they are not widely utilized. Operators rely on surface and fresh groundwater sources.

In spite of the challenges unique to Oklahoma, several producing companies have taken action to reduce disposal by reusing produced water. For example:

- **Continental Resources** operates four recycling facilities in the SCOOP and STACK plays in central Oklahoma, which can recycle over 95,000 barrels of water per day (with a peaking capacity of 250,000 barrels per day) total at these facilities. Continental’s ultimate goal is to reduce its fresh water use by approximately 50 percent within the service areas of its recycling facilities. Additionally, Continental works with the Oklahoma Corporation Commission and other producers to make available its recycling facilities when capacity is available, further reducing the industry's fresh water footprint.

- **Newfield** built a 30,000-barrels-per-day water treatment facility to facilitate reuse in Kingfisher County in 2017. From 2010 to 2017, Newfield constructed a 144-mile infrastructure system across its Oklahoma operating areas, with the majority of pipeline located in the SCOOP and STACK development areas. The pipeline infrastructure has reduced truck traffic on average by more than 60,000 round trips per year, taking more than 160 trucks off the road per day.87 A more detailed case study of Newfield’s Oklahoma operations is found in Appendix 2-A of this module.

- In the STACK play in west-central Oklahoma, **Devon** built a pipeline network connecting well sites to a central water reuse facility. This conserved millions of barrels of water during a drought.88
Niobrara/DJ Basin
The Niobrara Shale stretches through most of northern Colorado and eastern Wyoming, as well as into parts of Kansas and Nebraska. The two major oil and gas basins in the region are the Powder River Basin in northeast Wyoming and the Denver-Julesburg, or DJ Basin, in northeast Colorado and southwest Wyoming. The DJ Basin has the richest petroleum history of the two, dating to a 1901 oil discovery in Boulder County, Colorado. Today, the DJ Basin is known for the Wattenberg gas field, one of the largest natural gas deposits in the country. While the Powder River Basin is known more for coal production than for oil and gas, the application of horizontal drilling and hydraulic fracturing is driving oil production growth from that region’s stacked shale plays (Figure 2-55). Figure 2-56 shows water sourced for individual completions in 2017 based on data from FracFocus®. Data includes the DJ Basin and Niobrara activity in Colorado and Wyoming.

Figure 2-55: Niobrara/DJ Oil and Gas Production
Source: EIA
In the Powder River Basin, use of horizontal drilling and hydraulic fracturing is driving oil production growth from stacked shale plays.

Figure 2-56: Water Source Plot for Individual Completion in Colorado and Wyoming in 2017
Source: FracFocus®
This figure shows water sourced for individual completions in 2017 based on data from FracFocus®.

Following are examples of water management initiatives by producing companies in the Niobara/DJ Basin:

- **Anadarko Petroleum** has implemented water reuse programs and closed loop water management systems in the DJ basin. Its underground piping system eliminated approximately 8 million truck-miles in 2017.90

- In its Rockies plays, **EOG** has drilled water wells and installed water gathering and distribution infrastructure. This infrastructure allows water to be transported directly to EOG’s well sites, decreasing EOG’s need for trucking services. EOG has also invested in produced water gathering, recycling, and disposal infrastructure in the Rockies.91

- **Laramie Energy** has built a one-million-barrel lined treated water pond for produced water reuse in western Colorado. The system includes a significant amount of water lines and two pump stations for long distance delivery and reuse.92

A 5,000-well Powder River Basin project is being planned by five major companies in Wyoming. The BLM environmental study in January 2018 moved this project forward. It would be one of the largest single projects Wyoming has had go through the federal permitting process. However, a landowners advocacy group is concerned about the scale of drilling, including having enough sourced water and disposal capacity. The Converse county commissioner said water was also a local concern, but he believes the water issue can be solved.93,94

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92 Fifth Creek Energy, ENERCOM The Oil & Gas Conference, 2017.


Bakken
Oil was first discovered within the Bakken in North Dakota in 1951, but past production efforts faced technical difficulties. The application of hydraulic fracturing and horizontal drilling technologies has caused a boom in Bakken oil production since 2000. The Bakken was first major commercial shale oil play in the U.S. and its production using hydraulic fracturing of horizontal wells broke new ground. In January 2011, Bakken oil production was already about 354,000 barrels per day, while Eagle Ford production was only 142,000 during the same period. In early 2011, very few hydraulically fractured horizontal wells had been completed in the Permian, cementing Bakken’s claim to be the first unconventional oil play.

Bakken production peaked in late 2014 before dipping in 2015 and 2016 during a period of extremely low crude oil prices. Figure 2-57 shows that current production in the Bakken is at an historic high.

Figure 2-58 shows water sourced for individual completions in 2017 based on data from FracFocus®. Data includes the Bakken formation of the Williston Basin activity in North Dakota.

A report by the American Geosciences Institute observed that “In the Bakken area of North Dakota only about 5 percent of the wells drilled in 2014 used produced water in their fracturing fluid. This is partly
due to state regulations that prohibit storage of salty
produced water in open-air pits and partly because
the extreme salinity of produced water in this area
makes treatment and reuse difficult and expensive."

Examples of water management projects by produc-
ing companies in the Bakken include the following:

- **EOG** has a water reuse facility in the Bakken
  that began operating in 2012. The company
  also built a water pipeline system, consisting
  of more than 40 miles of dual 8-inch and
  12-inch pipelines that carry water used in the
  completion process directly to the wellpads.
  This system reduces EOG’s well completion
  costs and decreases water transportation by
  truck in Bakken-area communities.

- **Hess** is using produced water in place of fresh
  water for production maintenance, which
  includes well workovers and well mainte-
  nance. In 2017, Hess reused approximately
  2,000,000 barrels of produced water for this
  purpose instead of using fresh water.

- **Goodnight Midstream** operates 22 saltwa-
  ter disposal wells (SWDs), including water
  pipeline infrastructure, in the Bakken. Where
  the pipe system connects to operator tank
  batteries, it eliminates the need to truck water
  to SWD wells. The interconnected produced
  water system could potentially be used for
  reuse if it becomes technically and economi-
  cally feasible. A future increase in either
  sourced water costs or disposal costs could
  tip the balance and make reuse viable using
  this pipeline system.

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Haynesville

Geologists had long known that the Haynesville Formation in northern Louisiana and eastern Texas contained vast quantities of natural gas. However, because of its low permeability, the Haynesville was originally considered only a source rock rather than a gas reservoir. In 2008, the successful application of horizontal drilling and hydraulic fracturing forever changed the Haynesville (Figure 2-60). The Haynesville Shale is now considered the second largest natural gas field in the United States, trailing only the Marcellus Shale. At its peak in 2010, nearly 190 drilling rigs were operating in the play. However, the success of this and other natural gas shale plays around the country pushed natural gas prices down to a level that substantially reduced rig count in the region until 2017. However, even at a reduced rig count overall, production has risen to an all-time high due to more productive wells.

Figure 2-40 shows water sourced for individual completions in 2017 in the Haynesville based on data from FracFocus®. Data includes Texas, Oklahoma, New Mexico, and Louisiana.

The Sabine River and the region’s many lakes provide surface water for sourcing in the Haynesville Play. However, the US Corps of Engineers and the rules of the states of Texas and Louisiana all come into play in this region. Companies are working with the river authorities on multi-year take-or-pay contracts. Typical costs for fresh water may range from $0.05 to $0.30 per barrel. Trucking costs may range from $0.75 to $1.50 per barrel.

Third party disposal costs average about $1 per barrel. Occasionally, operators will share a water source with another producer. Some of the producers are concerned about disposal wells beginning to increase disposal formation pressure, although there has not been significant seismicity in the area.

The companies interviewed were not reusing produced water, but were aware of one producer that was reusing produced water. Because the Haynesville is still in the early delineation phase where wells are drilled in a more scattered fashion, the aggregation of water is difficult. An estimated 98 percent of water is trucked to SWDs. There is one small commercial reuse facility in northern Louisiana.

Figure 2-60: Haynesville Oil and Gas Production
Source: EIA

The Haynesville Shale is now considered the second largest natural gas field in the United States, trailing only the Marcellus Shale.

Water quality data from 18 producing companies was gathered for this report. The American Petroleum Institute (API) helped with the gathering and compiling of the data. The companies reported the high and average values by basin for seven parameters. An average of the individual company’s high numbers and average numbers are plotted in Figure 2-61 and Figure 2-62. The figures indicate that the produced water quality varies by a factor of four among the basins for a variety of components. The age of a well also influences its water quality; an individual well usually has an increasing TDS in the first weeks and months of production. Table 2-4 shows the data used in Figures 2-61 and 2-62.

### Table 2-4: Summary of Water Analysis Data from Producing Areas

*Source: 18 producing companies*

<table>
<thead>
<tr>
<th></th>
<th>pH</th>
<th>TDS (mg/l)</th>
<th>Calcium (mg/l)</th>
<th>Magnesium (mg/l)</th>
<th>Bicarbonates (mg/l)</th>
<th>Sulfates (mg/l)</th>
<th>Chlorides (mg/l)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>High</td>
<td>Average</td>
<td>High</td>
<td>Average</td>
<td>High</td>
<td>Average</td>
<td>High</td>
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<tr>
<td>Bakken</td>
<td>7.2</td>
<td>5.9</td>
<td>317,040</td>
<td>270,743</td>
<td>28,184</td>
<td>15,886</td>
<td>2,198</td>
</tr>
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<td>Central OK</td>
<td>7.4</td>
<td>6.6</td>
<td>162,884</td>
<td>70,547</td>
<td>12,431</td>
<td>3,376</td>
<td>1,955</td>
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<td>Delaware</td>
<td>7.7</td>
<td>6.7</td>
<td>216,319</td>
<td>129,354</td>
<td>17,078</td>
<td>5,892</td>
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<tr>
<td>DJ/Niobrara</td>
<td>8.3</td>
<td>7.0</td>
<td>74,340</td>
<td>28,238</td>
<td>4,298</td>
<td>574</td>
<td>766</td>
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<td>Eagle Ford</td>
<td>7.6</td>
<td>6.5</td>
<td>82,669</td>
<td>41,999</td>
<td>5,607</td>
<td>2,300</td>
<td>769</td>
</tr>
<tr>
<td>Haynesville</td>
<td>7.1</td>
<td>5.5</td>
<td>206,835</td>
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<td>21,121</td>
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<td>Marcellus</td>
<td>7.2</td>
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<td>288,318</td>
<td>226,590</td>
<td>36,374</td>
<td>26,874</td>
<td>3,398</td>
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</tbody>
</table>

Figure 2-61: Water Quality Variation by Basin (TDS and Chlorides)
*Source: 18 Producing Companies*

Figures on Y axis represent Mg/L. Many basins have average TDS content ranging up to several times that of seawater.

Figure 2-62: Water Quality Variation by Basin (Calcium, Magnesium, Bicarbonates, Sulfates)
*Source: 18 Producing Companies*
PRODUCED WATER QUALITY BASED ON USGS DATA

The EPA characterized produced water in a recent study using the USGS produced water database. Figure 2-63 indicates some of the constituents and variation in TDS. Data for select parameters from the USGS database Version 2.2 are the minimum (excluding non-detect values), 25th percentile, median, 75th percentile, and maximum values for each parameter. For each constituent, the total number of samples and the number of samples with values greater than the detection limit are shown in parentheses (for example, there were 18,387 samples containing barium, 11,369 of which were greater than the detection limit). As illustrated in Figure 5-1, the concentration of these select parameters varies greatly across the country. An example is TDS, which can vary significantly by basin. Figure 5-2 shows the box and whisker plots with TDS concentration data for the 10 basins with the greatest number of samples contained in Version 2.2 of the USGS database (TDS values below 10 mg/L are not shown in this plot). As illustrated by these data, TDS concentrations for samples contained in the database vary greatly, both within a specific basin and across different basins.*