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HYDRAULIC FRACTURING - MANAGING THE RISK OF PRODUCED WATER

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While promising to make huge quantities of oil and gas available from already existing shale reservoirs, hydraulic fracturing produces very high volumes of saline water as a by-product. What questions should operators be asking to address economic risk caused by varying formation geochemistry, regulatory uncertainty, and the complexity of wastewater treatment options?

INTRODUCTION

The United States has entered a new 'Golden Era' of energy exploration and production. According to the International Energy Association (IEA) studies, the U.S. will overtake Russia as the world's top gas producer by 2015, and will surpass Saudi Arabia as the global oil producer by 2017 (IEA, 2012). A primary driver of these projections is the development of unconventional, onshore natural oil and gas reserves located in deep shales.

Huge reserves available. Hydrocarbon resources, or fossil fuels, are trapped in tight geologic formations known as shales, stratified sedimentary rock formed from sediment, clay, or consolidated mud over huge time periods and located deep within the earth, often one to two miles beneath the ground surface. The amount of fossil fuel in the form of oil and gas trapped in these formations varies significantly, and is highly location dependent. The Monterey shale located in the San Joaquin Valley in California, for example, is estimated to contain 15.4 billion barrels of oil. The Marcellus shale spanning New York, Pennsylvania, Ohio, Maryland, Virginia, and West Virginia is estimated to hold recoverable natural gas in quantities nearing 500 trillion cubic feet. With crude oil prices of roughly $100 per barrel and natural gas unit prices of $3.60 per thousand cubic feet in January 2013, the economics of extraction are highly favorable to the producer and consumer.

Significant volume of produced water. The USGS estimates that about 14 billion barrels[1] of water per year are produced to extract hydrocarbon energy resources across the United States. In addition, high volumes of water are required to conduct hydraulic fracturing (fracking). The amount of water needed to frack one well varies according to drilling method and formation geology; estimates range from just under one to 6.5 million gallons of water per well.

In general, fresh water is used to stimulate the source[2] . Because fresh water is a constrained and valuable resource, the need to manage these high volumes of water in an environmentally sustainable manner is paramount. The produced water returned to the surface contains various salts, trace elements, fracking chemicals and organic geochemistry unique to the formation.

The water used to frack, whether from a fresh source or mixed with previously produced water, includes additives for increasing water viscosity and inhibiting bacterial growth and biocorrosion. In addition, small solid structures, such as sand or ceramics, are added to the mixture to maintain the integrity of fractured openings in the formation. These fracking chemicals and proppants comprise generally less than 10% of the total volume introduced under high pressure, and are highly dependent on the formation geochemistry and geology (GWPC and ALL Consulting, 2009). Large portions of the additives are recovered in the produced water that is returned to the surface during the initial hydraulic fracturing process with additional recovery once the well is brought into full hydrocarbon production (EPA 2010a).

Consequent salinity. The water returned to the surface during hydrocarbon production is highly saline. Salinity levels vary with formation geochemistry, but generally exceed acceptable freshwater or agricultural grade salinity requirements for reuse or disposal, as shown in Chart 1. The salinity levels in produced well water are significant, often comparable to seawater and as high as the saline levels in the Great Salt Lake or the Dead Sea. The service life of a well depends upon

[1] 1 barrel = 42 gallons

[2] Some operations include recycled water in the fracking liquid, and thus require a lower percentage of fresh water (Clark and Veil, 2009)

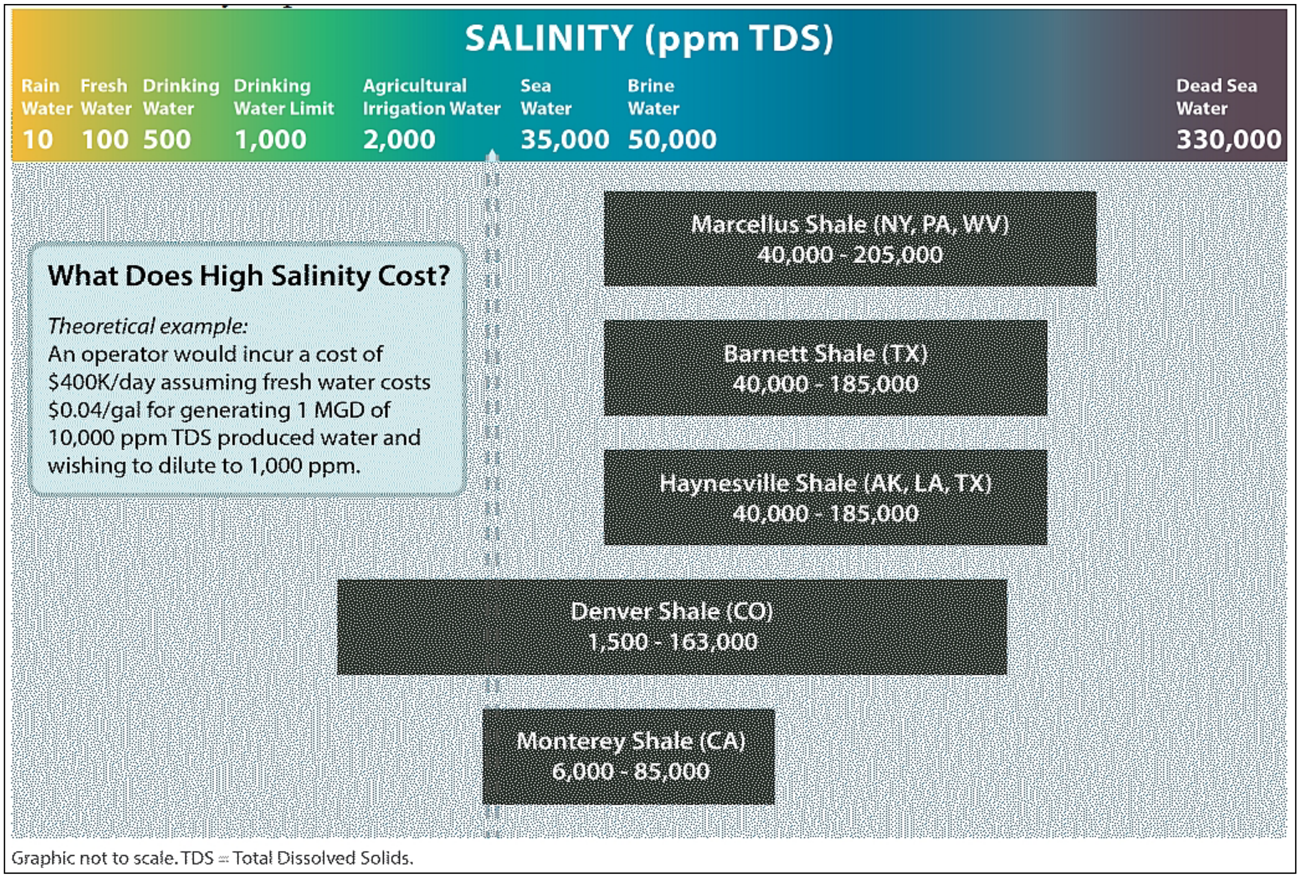

Chart 1. Salinity of produced water.

the formation yield, and wells can remain active for decades, although peak yields typically occur over a few years (EIA, 2001). If produced water is released into the environment without adequate treatment, exposure to its pollutants can be harmful to human health and ecosystems (EPA, 2010b).

Complex and evolving environmental regulation. Federal, state, and local regulatory authorities often control water management options available to operators. Federal laws govern environmental aspects of oil and gas development such as, the Clean Air Act, the Clean Water Act, the Safe Drinking Water Act and the National Environmental Policy Act. Most of these federal laws allow for granting 'Primacy' to oil and gas producing state agencies to implement environmental protection programs with federal oversight. Often, multiple state-level regulatory agencies have jurisdiction over the various aspects of development from establishing regulations to permitting and enforcement (GWPC, 2009). State rules and regulations govern well permitting, design and construction, plugging and abandonment, as well as water acquisition, management, treatment, injection and disposal (API, 2010). Hence, the choice of acquisition and disposal option determines the type and number of authorities an operator works with.

Navigating the regulatory landscape is a complex and evolving endeavor. New state and federal requirements that could significantly alter water management strategies for producers are anticipated in the coming years. As an example, some states are presently altering requirements that can prohibit Publicly Owned Treatment Works (POTWs) from accepting fracking operation produced water. Producers who had planned on this disposition option for their produced water will now have to develop alternative treatment and disposal options and understand their economic impact.

Developing produced water treatment strategies. Surface storage of produced water does not constitute a treatment as such, and only delays wastewater[3] treatment. The disposal option chosen by the producer will include some form of water treatment today or in the future. The level and complexity of treatment can vary from minimal conditioning of wastewater prior to injection into a deep subsurface reservoir to maximal treatment returning the produced water to drinking water standards. The challenge to meet treatment objectives in a cost-effective manner has spurred the wastewater treatment industry to re-engineer existing technologies and develop novel ones, adding another layer of decision complexity for oil and gas producers.

ALTERNATIVES FOR PRODUCED WATER TREATMENT

The water balance necessary for producing hydrocarbon resources via fracking is complicated, as shown in Chart 2. Millions of gallons of water are introduced per well, a percentage of which will return to the surface as produced water - a mix of fracking fluid and groundwater - throughout the life of the well. It should be noted that some portion of the fracking fluid may remain in the formation, and groundwater associated with the formation may be removed with production; hence, the water balance is not a closed loop, and the total water introduced will not necessarily equal to the total water output (Clark and Veil, 2009). The options available to operators for managing the produced water generated include recycle and reuse for continued stimulation and hydrocarbon production, temporary storage in surface ponds or tanks, treatment on-site or in close proximity to well production activities, or transportation for off-site treatment, with ultimate disposal either in injection wells, surface water bodies, or sanitary sewers for disposal to a POTW or for beneficial reuse.

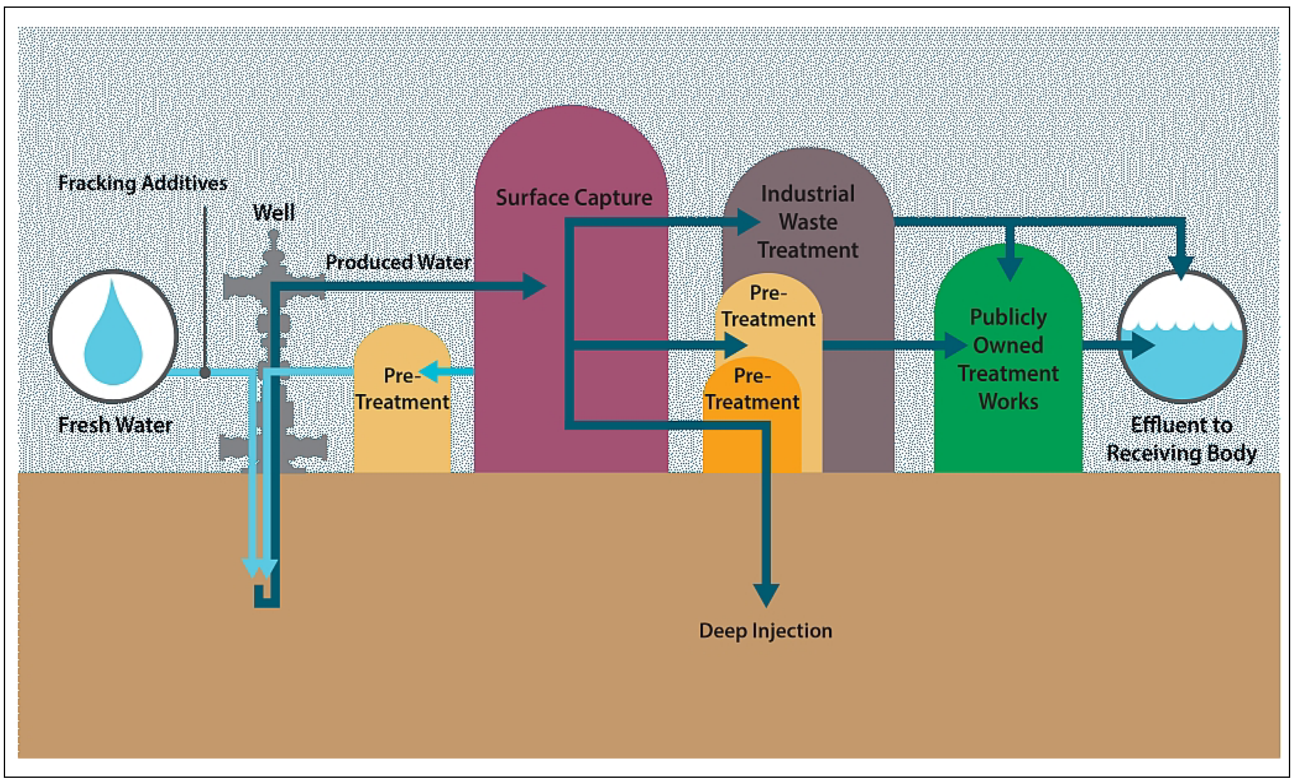

Chart 2. Produced water balance.

[3] Throughout this paper, the term 'produced water' refers without distinction to both to the initial flowback and to subsequent production phase water. A more generic term, 'wastewater', also refers to both types without distinction.

Ponding. On-site storage of produced water in lined or unlined ponds or tanks are a temporary solution, except when used as a thermal desalination treatment technique in arid environments in which evaporation exceeds precipitation. Any form of water storage that will ultimately require treatment is an environmental liability for any operator.

Reuse for well stimulation. Preparing wastewater for subsequent reuse in further formation stimulation or for injection into disposal wells requires, at a minimum, conditioning the water to prevent fouling or clogging of mechanical features, as well as removing hydrocarbon by-products resulting from production.

Deep well injection. A primary management option for produced waters in the United States is deep well reinjection; this option requires suitable subsurface conditions with porous sedimentary rock. Conditions for deep well injection are more favorable in the western United States and less favorable in the east. Pre-treatment to remove oil and suspended solids is required prior to reinjection to meet Class II discharge standards (EPA, 2002) and to prevent well plugging and formation clogging due to microbial growth and scale-forming chemicals. In addition to environmental quality concerns, deep well injection has also raised concerns about seismicity and the potential for hydraulic connectivity between subsurface reservoirs that could yield transport of disposed produced waters into areas unintended for such waste.

Publicly Owned Wastewater Treatment Plant. POTWs are designed to handle municipal wastewater that contains suspended solids, dissolved organic compounds that cause oxygen demand in receiving waters, and nutrients such as ammonia or nitrate. POTWs are not designed to remove salts or high loads of dissolved inorganic chemicals, and, as such, will allow these constituents to pass through the facility and into receiving water bodies. Because POTWs have a heavy biological treatment component, high concentrations of salts can severely cripple biological communities that need large amounts of time to recover. In addition, high salinity can result in clogging and damage to mechanical features throughout the plant, thereby impacting overall operations. For these reasons, then, pre-treatment in the form of desalination is necessary prior to introducing produced water to a POTW.

On-site Treatment. Treatment of produced water can be performed near the wellhead and truck-mounted or site-specific treatment alternatives are available, but cost and efficacy play a major role. The level of salinity in produced water will vary over the life of the well and well field, with salinity levels generally rising over time. As such, treatment methodology at or near the wellhead may need to change over time. One solution often will not 'fit all', instead requiring strategies that offer flexibility and diversity.

Centralized Industrial Waste Treatment. Some operators treat the produced water at dedicated Industrial Waste Treatment (IWT) facilities. The treatment technologies used in these facilities are similar to POTWs, but are designed to handle highly saline wastewaters. Following desalination treatment at an IWT facility, water can be discharged to surface water bodies or sewers for subsequent transport to a POTW, depending upon the removal efficiencies. Scale matters, as some treatment technologies are only relevant and applicable for large volumes at industrial-scale levels. IWT facilities generally receive produced water from multiple generators or large production areas, and may be situated in close proximity to energy or heat resources to enhance their cost profile. As an example, biogas generated from a POTW could fuel thermal evaporation or distillation processes.

Treatment, whether conducted on-site or at an IWT, includes removing three primary constituents: suspended solids, organics such as oil and grease, and dissolved solids such as salts. In areas in which Naturally Occurring Radioactive Material (NORM) is present[4] , treatments that target the aforementioned constituents will generally remove NORM though its presence can impact solids disposal strategies. Suspended solids are typically removed by filtration or gravity in settling tanks or holding ponds. Organics such as oil and grease can be removed via a number of processes, including filtration, hydroclones, centrifuge, dissolved air flotation, solvent extraction, and adsorption (Hammer and VanBriesen, 2012). Treatments for removing suspended solids and organics will rarely affect dissolved solids or salts.

For targeted salt removal, desalination treatment options include thermal methods such as, distillation, evaporation and crystallization and non-thermal options such as, reverse osmosis (RO) with or without vibratory shear-enhanced processing (VSEP), ion exchange (IX), capacitive deionization (CDI), forward osmosis (FO) and electrodialysis.

Selecting an appropriate treatment strategy depends on four key factors: influent salinity concentration and reduction requirements, proximity of treatment to extraction location and volume of water to be treated, cost considerations in the form of capital and Operation & Maintenance (O&M), and the maturity of the treatment technology.

Constraints on salinity treatment and concentration over time

Salinity levels for produced waters vary significantly based on the formation and the life of the well. As indicated in Chart 1, the salinity levels to be expected from the formation can vary from slightly brine to levels far exceeding seawater concentrations. As shown in Chart 3, the applicable technologies that can treat increasing salinity also vary. It is not uncommon for the salinity levels at the wellhead to increase over the life of the well, and to rise from low to moderately brackish water to fully brackish water. This local change can have a significant impact on the applicable treatment technology, the integrity of the physical plant, and the subsequent removal efficiency. Operators must understand the variability of salinity levels and the associated treatment options available.

Extraction location and volume of water to be treated

Whether treatment is performed near the wellhead or produced waters are transported to a treatment facility depends on feasibility and cost. Transportation of produced water via truck can be logistically challenging for highly remote fracking locations, and the resulting increase in traffic and road wear-and-tear can result in complaints from local communities. Piped conveyance systems are costly, require critical mass and coordination amongst producers, as well as a long time horizon to make them economically viable.

Treatment volumes impact technology choices, since low volume flow rates make some treatment options highly undesirable. For example, thermal technologies such as multi stage flash (MSF) distillation, multi effect distillation (MED), and vapor compression distillation (VCD) are excellent for high salinity produced water treatment, yet require centralized design and construction of large-scale plants, and thus would not be appropriate for wellhead treatment. Smaller, more modular treatment options are ideal for wellhead and field applications, but may be constrained as to the level of salinity they can handle. Using land for large footprint surface treatment (such as engineered evaporation ponds or freeze thaw applications) typically requires low flow rates.

[4] Radionuclides in produced water can include radium-226, radium-228, radon-222, and lead-210 (Smith, 1992).

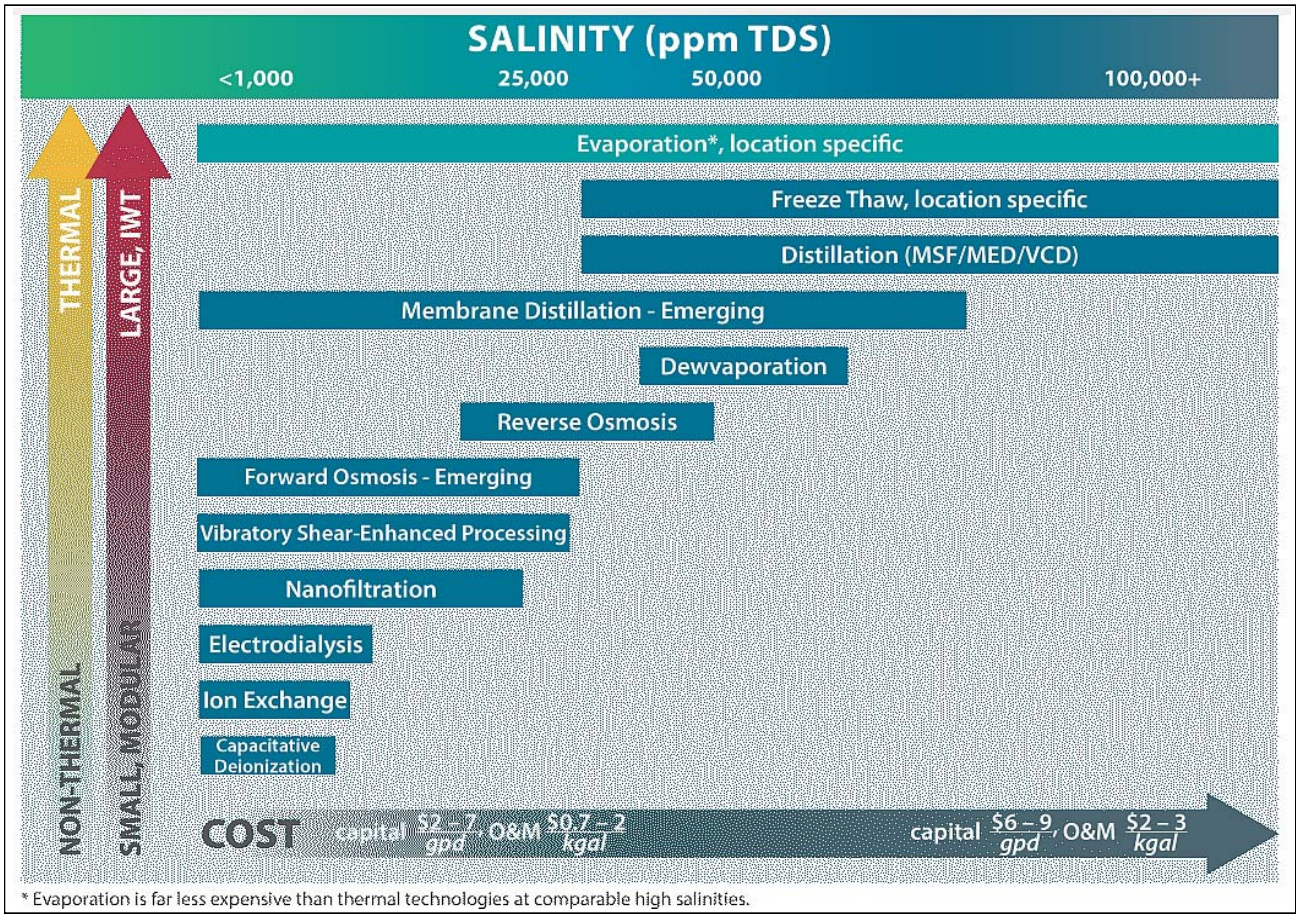

Chart 3. Saline water treatment technologies (source: RPSEA, 2009).

However, these solutions are highly site and climate specific applications that are only relevant to certain situations.

Capital and O&M cost

Treating highly saline waters is technically challenging and costly in comparison to treating non-saline wastewater. Thermal separation technologies are generally constructed in areas in which waste heat from other industrial processes is readily available, and in areas in which the cost of energy is lower because of the high-energy requirement of these methods. Membrane separation technologies require comparatively less energy, lower capital cost, and a smaller physical footprint, but are generally only applicable for salinity levels up to 45,000ppm TDS (Total Dissolved Solids), levels below many shale produced water limits. In addition to comparatively low salinity constraints, these technologies require a high level of pre-treatment, regular monitoring and maintenance, and their processes are limited in terms of percent recovery, resulting in the need for treatment trains that employ multiple technologies in order to reach desired removal efficiencies (RPSEA, 2009). As indicated in Chart 3, the capital and O&M cost for treatment generally increases with increasing salinity, with larger capital investments required for highly brackish produced waters. The cost of hydrocarbon recovery must be carefully evaluated in concert with the cost for produced water treatment.

Maturity of the treatment

The increase in fracking and the associated highly saline produced water has led to a market rich in new and emerging solutions for water treatment. Re-engineering of existing technologies, as well as developing wholly novel solutions has resulted in a landscape of emerging treatment solutions being pushed to market. A number of technologies are currently only available at the lab or pilot scale, and bringing these technologies to full scale is associated with significant risk for operators. Some recent innovations in corrosion control and process engineering have made thermal processes more attractive from a cost perspective for treating highly saline waters. These newer thermal separation technologies, such as freeze-thaw and dewvaporation, have been developed for treating produced water, and are picking up momentum in full field applications. Because of the need to reduce treatment costs and bring more viable solutions to operators, the U.S. Department of Energy has funded numerous studies leading to significant improvements in the alternatives available to operators (NETL, 2012). Risk-based decision-making must be taken into consideration when assessing immature or novel treatment technologies as part of an operator's water management plan.

SHAPING A COMPREHENSIVE WATER MANAGEMENT PLAN

The many diverse liabilities associated with fracking operations need to be identified and reduced by a systematic risk management approach. Successful water management programs have three factors in common: clearly understanding the magnitude and complexity of the future water remediation liabilities, proactively managing the regulatory landscape, and putting in place a risk-based strategy for treatment.

Assess produced water volumes and salinity levels early. The economic impact of treating produced water must be weighed against potential profits for oil and gas recovery. Baseline extraction levels determine the range of applicable treatment alternatives, and operators need to anticipate produced water quality and quantity characteristics before commencing full scale operations. Models need to be developed to predict a range of scenarios of the expected salinity concentration and produced water volume over the life of the well or field. Understanding that variability and its impact on the available treatment option space is critical. For example, operators may pursue an option of purchasing freshwater to dilute extracted wastewater to allow for consistent volume flow into a treatment system, as well as to maintain consistent salinity levels.

Work closely with regulators. In a sea of permanent changes in the regulatory landscape it is paramount that oil and gas producers work closely with local, state, and federal regulators when developing and implementing fracking operations. Acceptable water management practices today could be upturned in future years to come, resulting in significant remediation and clean-up requirements for producers. Anticipating potential changes and preparing backup option plans is essential for minimizing liabilities from past, present, and future production.

Increasingly, regulatory entities and the public want to understand the impact of fracking operations. This includes but is not limited to the amount of water produced, salinity levels, the presence of significant contaminants, and the treatment and disposal plans. Operators can demonstrate transparency and identify and proactively deal with issues by communicating their water management plan to regulators and the public early and often. For example, proactive communication with water planning agencies can help operators identify preferred water sources for fracking operations that do not constrain local resource requirements. Informing the broad array of interested parties helps clarify stakeholder issues and allows for proactive risk mitigation.

Put in place a comprehensive treatment plan. A comprehensive cost-benefit analysis that includes cradle-to-grave water management cost is essential. Prior to commencing fracking operations, oil and gas operators need to have a plan in place how to best manage produced water and bring it to acceptable discharge levels over the expected life of the operation. This master plan for treating produced water should consider all viable alternatives, including private or public partnerships with wastewater treatment operators, temporary ponding, or on-site treatment. Not only does the ultimate disposition of fracking waste have to be viable under current conditions and regulations, but backup options should also be developed, with a full understanding of their costs should they become necessary.

In the past, fracking operations were able to commence and proceed with little consideration of the required remediation of the highly saline produced water. In the future oil and gas companies involved with fracking will have to integrate environmental risk management into their standard business decision-making processes before, during, and after their exploration of these valuable resources. They will also have to develop new tools and approaches to minimize the costs of new and existing environmental liabilities.

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