Summary of Input on Oil and Gas Extraction Wastewater Management Practices Under the Clean Water Act

EPA-821-S19-001

U.S. Environmental Protection Agency

Engineering and Analysis Division

Office of Water

1200 Pennsylvania Avenue, NW

Washington, D.C. 20460

Final May 2020

DISCLAIMER

This document is not a regulation, nor is it guidance on how to comply with regulations. Thus, this document does not impose legally binding requirements on the U.S. Environmental Protection Agency, states, tribes, or the regulated community, and the general description provided here may not apply to a particular situation based upon the circumstances. This document does not confer legal rights or impose legal obligations upon any member of the public.

CONTENTS

LIST OF TABLES

Page

LIST OF FIGURES

Page

1. EXECUTIVE SUMMARY

Large volumes of wastewater are generated in the oil and gas industry, and projections show that these volumes are likely to increase. Currently, the majority of produced water is managed via reuse within the oil field for practices such as enhanced oil recovery, or by disposing of it using a practice known as underground injection where that water can no longer be accessed or used. The limits of injection are evident in some areas, and new approaches are becoming necessary. Some states and stakeholders are asking whether it makes sense to continue to waste this water, particularly in water scarce areas of the country, and what steps would be necessary to treat and renew it for other purposes.

As a result, the U.S. Environmental Protection Agency (EPA) conducted a study evaluating management of produced waters[1] from onshore oil and gas extraction activities. The EPA wanted to better understand produced water generation, management, and disposal options at the regional, state and local levels for both conventional and unconventional[2] onshore oil and gas extraction. While the EPA looked at a variety of alternatives for reuse of produced water, ultimately, the EPA's study goal was to evaluate approaches to manage oil and gas extraction wastewaters generated at onshore facilities. EPA had previously studied facilities that treat and discharge oil and gas extraction wastewaters to surface waters that are regulated under the Clean Water Act (CWA) (for purposes of this report, "surface waters"[3]) in the Centralized Waste Treatment Study (U.S. EPA, 2018). A second goal was to better understand any potential need for, and any concerns over, additional discharge options under the CWA for onshore oil and gas wastewater.

During the EPA's outreach activities, stakeholders raised several concerns regarding additional discharge options for treated produced waters. The main concerns were related to the amount of available data on the chemistry of produced waters and the performance of treatment technologies. A related concern was the availability of analytical methods for measuring the constituents in produced water, and the potential toxicity of these constituents. Stakeholders were also concerned about potential impacts to downstream users, such as impacts to drinking water utilities. These are considerations that are

[1] For purposes of this study, EPA is using the definition of *produced water* found at 40 CFR Part 435 which is: "the water (brine) brought up from the hydrocarbon-bearing strata during the extraction of oil and gas, and can include formation water, injection water, and any chemicals added downhole or during the oil/water separation process."

[2] EPA defines unconventional oil and gas at 40 CFR 435.33(a)(2)(i) as "crude oil and natural gas produced by a well drilled into a shale and/or tight formation (including, but not limited to, shale gas, shale oil, tight gas, tight oil)."

[3]Only waters that meet the definition of "waters of the United States" are regulated under the CWA 33 U.S.C. 1362(7). Therefore, the term "surface waters" as used in this report refers to "waters of the United States."

important as the EPA considers next steps for its CWA programs related to produced water management.

The EPA currently regulates discharges of oil and gas wastewater under the oil and gas extraction effluent limitations guidelines and pretreatment standards (ELGs) found at 40 CFR part 435. For onshore oil and gas producers, except stripper wells[4] and coalbed methane wells,[5] and producer facilities west of the 98th meridian,[6] discharges of pollutants from produced water to surface waters are prohibited. In addition, discharges from centralized waste treatment (CWT) facilities that accept produced water are regulated under ELGs found at 40 CFR part 437. 40 CFR part 437 provides for discharge to surface waters and contains numerical limitations for such discharges.

The characteristics, quantity and quality of the wastes generated during oil and gas exploration and production (E&P) activities depend upon factors such as the characteristics of the formation, the type of drilling employed, the depth of the well and the type and quantity of chemical additives used during drilling, production and well maintenance and stimulation activities. Solid wastes such as drill cuttings are typically managed through landfilling or on-site disposal. Some produced water is reused within the oil field for enhanced oil recovery or for hydraulic fracturing. Produced water that is not reused has historically been managed as a waste via Class I and II underground injection control (UIC) disposal wells under the Safe Drinking Water Act (SDWA) or disposal in on-site evaporation or seepage pits. While management via UIC disposal wells continues to be the predominant management approach for disposal of produced water in the United States, produced water is increasingly being recycled and reused within the oil and gas field for hydraulic fracturing activities. While opportunities exist to recycle/reuse produced water outside of the oilfield, this management approach is rare. Some produced water is currently used for irrigation of crops. Road spreading of produced water for dust and ice control is also occurring in some states. Off-site CWT facilities are also used to manage these wastewaters. In addition, some produced water is managed at publicly-owned treatment works (POTWs[7]).

Currently, discharge of oil and gas extraction wastewaters to surface waters is occurring in limited geographic areas of the country. Discharges west of the 98th meridian for agriculture and wildlife propagation are occurring primarily in Wyoming; these produced waters generally receive limited treatment in most cases, consisting primarily of settling and/or skimming. Indirect discharge via POTWs is primarily occurring in Pennsylvania; these produced waters receive limited or no treatment prior to transfer to

[4] See 40 CFR 435 Subpart F

[5] See 40 CFR 435 Subpart H

[6] See 40 CFR 435 Subpart E (44 FR 22075).

[7] The discharge of pollutants from *unconventional* oil and gas extraction activities to POTWs is prohibited (40 CFR Part 435.33 and 435.34).

the POTW. Discharge via CWT facilities are occurring primarily in the Marcellus and Utica shale areas of Pennsylvania, Ohio and West Virginia; these wastewaters receive varying levels of treatment, ranging from simple physical/chemical treatment to advanced treatment utilizing membranes or distillation.

Representatives of state agencies that the EPA engaged for this study generally supported increasing opportunities for management of oil and gas wastewaters including discharge of oil and gas extraction and production wastewater. Reasons include providing additional flexibility for producers, opportunities to address water scarcity concerns and to provide additional water for agriculture. Representatives of some agencies raised concerns regarding the treatability of produced waters and the unknown human health and ecological risks that might occur. Such risk is primarily a function of the unknown chemistry of many produced waters. In addition, management of treatment residuals, particularly the salts and radioactive material that would be generated, were identified as concerns.

Representatives of tribes generally expressed concern about increasing opportunities for discharge, however some tribal representatives supported discharge to address water scarcity and to allow for continued resource development on tribal lands. Those who expressed concern raised issues about the unknown chemistry of produced waters and the impacts to surface waters which have important cultural uses.

Nationally, there is broad support amongst the oil and natural gas industry and its service providers for additional wastewater management options including to treat and discharge produced waters more broadly. However, support is not universal as some oil and natural gas companies are satisfied with the current regulatory structure and others perceive potential liability concerns associated with alternatives such as discharge. While discharge west of the 98th meridian is currently an option for oil and natural gas producers, use of the beneficial reuse provision under Subpart E outside of the State of Wyoming is rare. Based on information provided in this study, this is primarily due to the availability of other wastewater management options that are lower cost, such as reuse within the oil and gas field or disposal in Class II UIC wells, as well as the cost associated with treating produced waters to a level suitable for discharge. Industry indicated that unless the produced water has total dissolved solids concentrations generally of less than a few thousand milligrams per liter, treatment using membranes (e.g., reverse osmosis) or distillation would be necessary to generate water that is suitable for agricultural uses or for discharge to surface waters. The cost of such treatment is not currently competitive where other wastewater management options are available. However, treatment for discharge may be cost-competitive where other options are limited. For example, producers indicated that in some areas of Pennsylvania treatment for discharge would currently be cost-competitive with other available wastewater management options. This is primarily driven by the cost for trucking produced water to other management or disposal options.

Some environmental NGOs expressed opposition to, and raised concerns about, expanding options for discharge of produced waters. They also expressed concern about current available options for discharge. Concerns raised relate to the unknown nature of produced water chemistry, documented problems from discharges that are currently occurring or that have occurred in the past, the current limited treatment for some current discharges of produced water and the toxicity of produced water and its constituents. Other NGOs (and associations of state regulators) see potential benefits related to water availability associated with increased opportunities for discharge of treated produced waters. In addition, some are supportive of additional discharge options, seeing opportunities to generate revenue from the treated produced water and to facilitate growth in oil and gas extraction.

Those in academia that the EPA engaged identified concerns related to the unknown chemistry of produced waters and the limited amount of data regarding treatability of produced waters. These concerns include the risk to human health or environmental implications of discharge. Some in academia stressed the need for additional research into these topics, noting that some studies are currently underway. Some also saw the potential for reducing the cost and improving the performance of treatment technologies that could make treatment for discharge more cost-competitive with other management options.

2. STUDY SCOPE AND GOALS

Recent advances in oil and gas drilling and production techniques have resulted in dramatic increases in the number of oil and gas wells drilled in the United States. For example, the number of hydraulically fractured wells increased from approximately 36,000 in 2010 to over 300,000 in 2015 (U.S. DOE, 2016). Production from shale gas and tight oil resource areas is projected to grow through 2050 because of the large size of the associated resources, according to the U.S. Energy Information Administration's Annual Energy Outlook 2018 (U.S. DOE, 2018). The rise in the number of oil and gas wells has also led to the generation of large volumes of produced water. As an example, in 2017, oil and natural gas production in New Mexico produced 37.8 billion gallons of produced water according to the New Mexico Energy, Minerals and Natural Resources Department. Nationally, the Ground Water Protection Council estimates in their 2019 *Produced Water Report* that produced water generation in 2012 was 890 billion gallons. In some areas, produced water generation is increasing. Data in the report *Sustainable Produced Water Policy, Regulatory Framework, and Management in the Texas Oil and Natural Gas Industry: 2019 and Beyond* (Texas Alliance of Energy Producers and IPAA) estimates that in 2017 the total volume of produced water generated in Texas was more than 357 billion gallons, and estimates that volume increasing to over 630 billion gallons per year by 2023. As explained in the Executive Summary, currently most of this wastewater is managed by disposing of it in a practice known as deep underground injection, where that wastewater can generally no longer be accessed or reused. Representatives of some states and stakeholders are asking whether it makes sense to continue to treat produced water as a waste or rather look at the produced water as a potential resource. This may be particularly important as forty out of fifty State water managers expect freshwater shortages to occur in their states in the next ten years.[8]

In spring of 2018, the EPA embarked on this study to better understand produced water generation, management, and disposal options at the regional, state and local levels for both conventional and unconventional onshore oil and gas extraction. The EPA's study goal was to evaluate approaches to manage oil and gas extraction wastewaters generated at onshore facilities, including but not limited to an assessment of technologies for facilities that treat and discharge oil and gas extraction wastewaters to surface waters. A second goal was to understand any potential need for, and any concerns over, additional discharge options for onshore oil and gas wastewater. To do so, as described in Section 4, the EPA engaged with representatives of state agencies that are responsible for oil and gas permitting and water and waste management, tribes, industry, academia, environmental groups, and other stakeholders to solicit information from their individual perspectives on topics surrounding produced water management.

---

[8] Government Accountability Office (GAO) 2014. Freshwater: Supply Concerns Continue and Uncertainties Complicate Planning. GAO-14-430.

This report details the information obtained during the EPA's outreach to stakeholders on these topics. The information in this report will help the EPA determine whether any future actions by EPA are appropriate to further address oil and gas extraction wastewater.

3. BACKGROUND

3.1 Produced Water Characteristics

Oil and gas exploration and production (E&P) activities generate a variety of waste materials requiring management. These waste materials include produced waters, spent drilling fluids, used drilling muds and drill cuttings. Produced water is the largest wastewater source by volume generated during oil and gas extraction. Produced water is the fluid (often called brine) brought up from the hydrocarbon-bearing strata during the extraction of oil and gas and includes, where present, formation water, injection water, and any chemicals added downhole or during drilling, production or maintenance processes. The ratio of produced water to hydrocarbon recovered in oil and gas extraction in the U.S. can vary greatly across different formations. For example, stakeholders reported ratios of produced water to oil ranging from less than 1:1 to more than 100:1. Naturally occurring constituents include, but are not limited to, bromide, calcium, chloride, magnesium, sulfate, and radioactive materials. Materials added downhole include hydraulic fracturing chemicals, well stimulation chemicals and well maintenance chemicals. Over time, the characteristics and volume of produced water generated for a well can change. In addition, periodic well maintenance and stimulation activities can affect produced water characteristics and generation rates.

The purpose, quantity and characteristics of materials utilized during well development, stimulation and maintenance are diverse. For example, the EPA identified some 692 unique ingredients reported for additives, base fluids and proppants contained in more than 39,000 FracFocus[9] disclosures provided by the Ground Water Protection Council (GWPC) (U.S. EPA, 2015). Table 3-1 describes the types and purposes of some additives used in well development, stimulation and well maintenance activities.

There are many sources of produced water characterization data available. A source that the EPA identified is the USGS National Produced Waters Geochemical Database (USGS database), containing geochemical data for produced water and other deep formation waters from wells in the United States (USGS, 2014). The USGS database is periodically updated (for example, Version 2.1 includes data for almost 60,000 wells in 36 states, sampled between 1900 and 2012). Data for select parameters from Version 2.2 of the USGS database are shown in Figure 3-1 as box and whisker plots, showing the minimum (excluding non-detect values), 25th percentile, median, 75th percentile and maximum values for each parameter.[10] As illustrated in Figure 3-1, the concentration of these select

[9] FracFocus is a publicly accessible website managed by GWPC and the Interstate Oil and Gas Compact Commission (IOGCC) where oil and gas production well operations can disclose information about ingredients used in hydraulic fracturing fluids at individual wells.

[10] These plots were generated by extracting all data from the database for conventional hydrocarbon, shale gas, tight gas and tight oil well types. Zero values and entries listed as unknown were excluded from the counts and statistics.

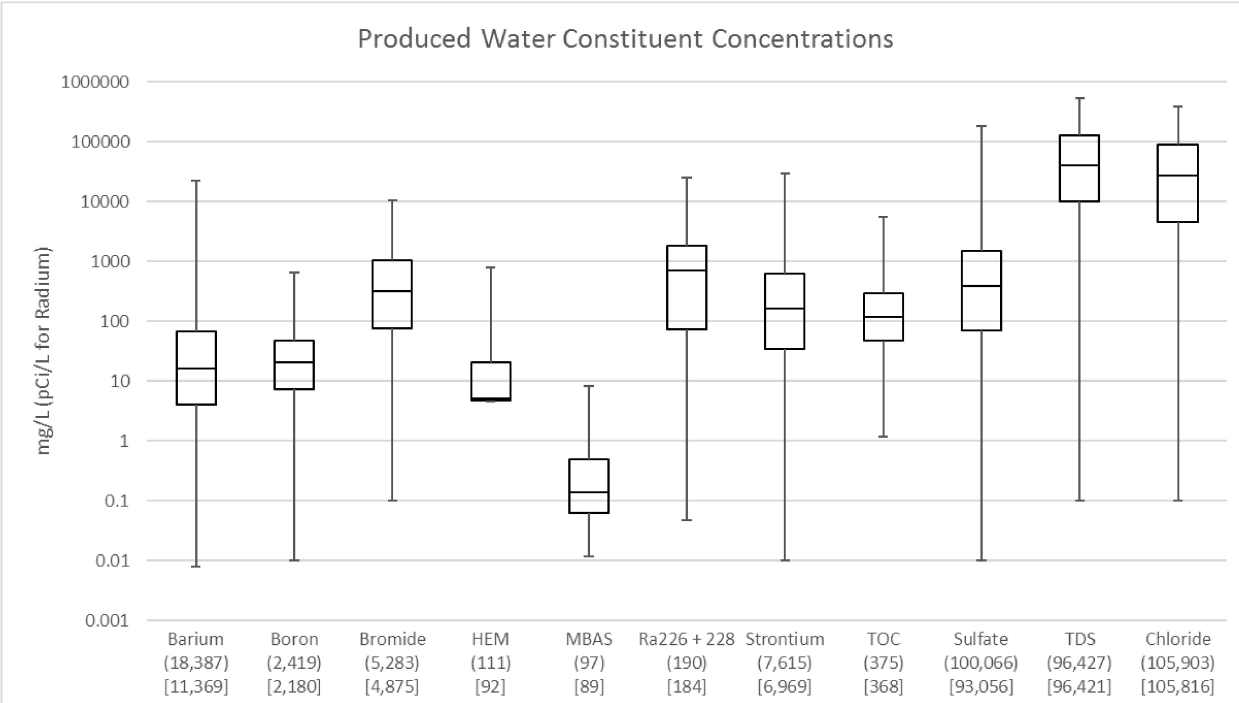
parameters varies greatly. Another source of data and information is the June 2019 GWPC *Produced Water Report*, that examines current regulations, practices, and research needed to expand the use of produced water as a resource. A more complete discussion of produced water characteristics can be found in U.S. EPA, 2016; U.S. EPA, 2016b; and U.S. EPA, 2018.

Table 3-1. Type and Purpose of Additives used in Well Development, Stimulation and Maintenance

Category of Additive [a]	Example Constituents [b]	Purpose
Acid	Hydrochloric acid; muriatic acid	Removes cement and drilling fluid from casing perforations prior to fracturing fluid injection.
Biocide	Glutaraldehyde; 2,2-dibromo-3-nitrilopropionamide	Inhibits growth of organisms that could produce gases (particularly hydrogen sulfide) that could contaminate methane gas; prevents the growth of bacteria that can reduce the ability of the fluid to carry proppant into the fractures by breaking down the gelling agent.
Breaker	Peroxydisulfate salts	Reduces the viscosity of the fluid by breaking down the gelling agents to release proppant into fractures and enhance the recovery of the fracturing fluid.
Clay Stabilizer	Potassium chloride	Creates a brine carrier fluid that prohibits fluid interaction (e.g., swelling) with formation clays; interaction between fracturing fluid and formation clays could block pore spaces and reduce permeability.
Corrosion Inhibitor	Acetaldehyde; formic acid	Reduces rust formation on steel tubing, well casings, tools, and tanks.
Crosslinker	Borate salts; potassium hydroxide	Increases fluid viscosity to allow the fluid to carry more proppant into the fractures.
Friction Reducer	Polyacrylamide	Minimizes friction, allowing fracturing fluids to be injected at optimum rates and pressures.
Gel	Guar gum; hydroxyethyl cellulose	Increases fracturing fluid viscosity, allowing the fluid to carry more proppant into the fractures.
Iron Control	Citric acid	Sequestering agent that prevents precipitation of metal oxides, which could plug the formation.
pH Adjusting Agent	Acetic acid; potassium or sodium carbonate; sodium hydroxide	Adjusts and controls the pH of the fluid to maximize the effectiveness of other additives such as crosslinkers.
Proppant	Quartz; sand; silica	Used to hold open the fractures created in the formation, allowing the natural gas or crude oil to flow to the production well.
Scale Inhibitor	Methylene phosphonic acid, polyacrylate	Prevents the precipitation of carbonate and sulfate scales (e.g., calcium carbonate, calcium sulfate, barium sulfate) in pipes and in the formation.
Surfactant	Ethoxylated glycols; alcohol ethoxylates	Reduces the surface tension of the fracturing fluids to improve fluid recovery from the well after fracture is completed.

Sources: U.S. EPA, 2015; Acharya, 2011; FracFocus, 2014; CCST, 2014; ExxonMobil Corporation, 2014.
[a] Operators do not use all of the chemical additives in hydraulic fracturing fluid for a single well: they decide which additives to use on a well-by-well basis.
[b] The specific compounds used in a given fracturing operation will vary depending on company preference, base fluid quality, and site-specific characteristics of the target formation.

Figure 3-1. Concentration of Select Constituents in Oil and Gas Produced Water (USGS National Produced Waters Geochemical Database, V2.2)



Note: For each constituent, the total number of samples are shown in parentheses and the number of samples with values greater than the detection limit are shown in brackets (for example, there were 18,387 samples for barium, 11,369 of which were greater than the detection limit).

3.2 Management of Produced Waters

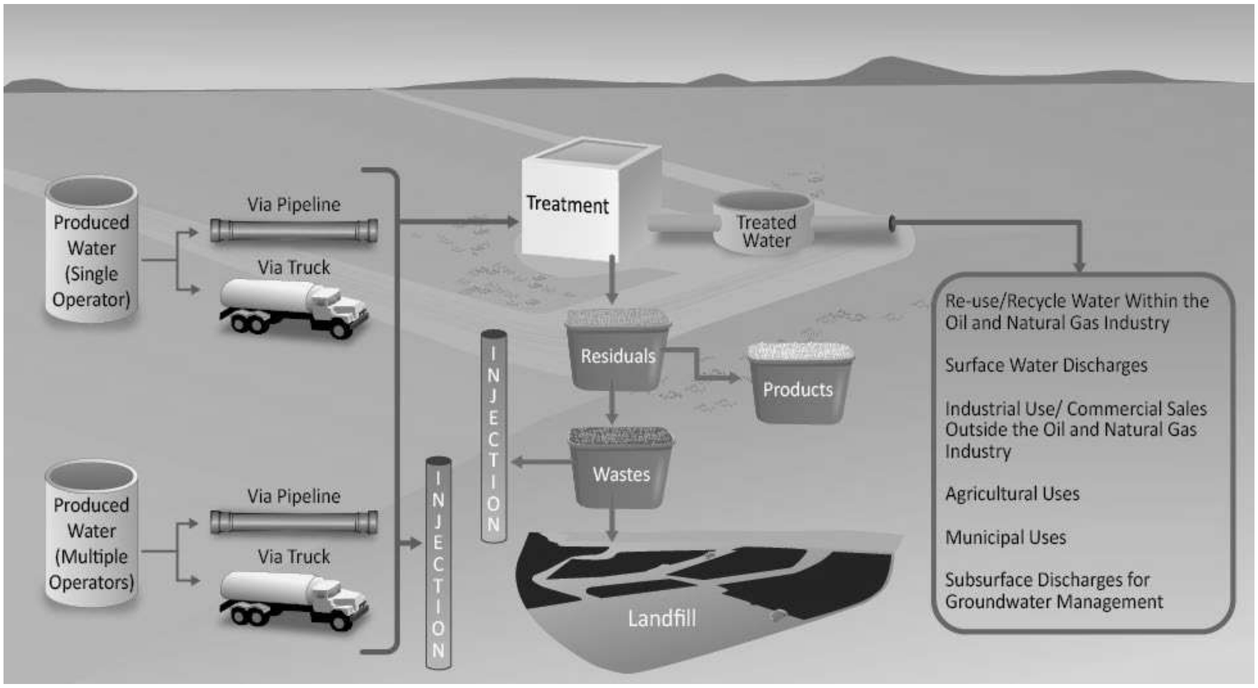
Figure 3-2 depicts produced water management options. The predominant disposal option for produced waters is use of Class II UIC wells (identified as injection in Figure 3-2). These wells are regulated under the Safe Drinking Water Act (SDWA). Disposal wells are prevalent in most oil and gas producing areas of the country. Some produced waters are also used for practices such as enhanced oil recovery[11] or to recharge aquifers, which is generally also subject to UIC regulation under the SDWA.

Some produced waters are managed on-site or within the oil and gas field using evaporation ponds or seepage pits. Recycling and reuse of produced waters for exploration and production operations within the oil and gas field is another primary means of produced water management. Some treatment may be required to render the water suitable for reuse in hydraulic fracturing. Another management strategy is the use of produced water for dust suppression and deicing, though some states are looking more closely at this practice and restricting or removing this as an option. These management

[11] Enhanced oil recovery is generally subject to Class II UIC regulation (40 CFR 144.6(b)(2). However, the injection of fluids for hydraulic fracturing is exempt from regulation under the SDWA, except where diesel fuels are used. SDWA section 1421(d)(1)(B)(ii).

approaches are not subject to CWA NPDES permitting requirements if they do not discharge to surface waters.[12]

Figure 3-2. Produced Water Management Options



Currently in limited instances produced waters are used for irrigation of crops. This practice currently occurs primarily in California, although limited use has occurred in other states. In California, produced waters are used for irrigation of a variety of crops, including those for human consumption. Use in agriculture that does not involve discharge to surface waters does not require a CWA NPDES permit.

Discharge of produced waters to surface waters is currently allowed west of the 98th meridian under Subpart E of 40 CFR 435, and this is occurring primarily in Wyoming. Also, discharges from stripper wells and coalbed methane extraction under Subpart F and Subpart H of 40 CFR part 435, respectively, are allowed, with requirements for these discharges developed on a case by case basis by the permitting authority.[13] Subpart E, F and H discharges to surface waters require NPDES permits (see additional information below). In addition, producers can transfer produced water from some types of wells to

[12] The U.S. EPA authorities discussed in this paper are not the only statutory and regulatory authorities that may be implicated when produced water is re-used, recycled, treated or discharged. For example, the disposal of RCRA non-hazardous waste is generally subject to EPA RCRA standards in 40 CFR 257 or 258. In addition to federal regulations many state laws and regulations may apply.

[13] Discharges of wastewater from coalbed methane and stripper wells are not within the scope of this study.

POTWs for management and subsequent discharge. However, discharge of pollutants from unconventional wells to POTWs is prohibited (40 CFR part 435.33 and 435.34).

Another option for management of produced waters is transfer off-site for management. Options include transfer to another industry or municipality for use (for example, for cooling water) or transfer to off-site CWT facilities. While transfer off-site for other uses is currently not widespread, the practice of transferring produced waters off-site to a CWT facility does commonly occur in the Marcellus Shale producing areas including Pennsylvania, Ohio and West Virginia. CWT facilities that discharge to surface water are subject to EPA's CWT ELGs in 40 CFR part 437.

3.3 The EPA's Clean Water Act Regulations for Produced Water

The CWA establishes the basic structure for regulating discharges into surface waters. Under the CWA, it is unlawful to discharge any pollutant from a point source into surface waters except as authorized by a NPDES permit (*see* CWA sections 301 and 402) or by certain other specified statutory provisions. The NPDES program aims to protect and restore the quality of water bodies (e.g., rivers, lakes and coastal waters) through permit requirements by monitoring and controlling pollutants discharged from point sources. The EPA's NPDES permit regulations require permittees to report compliance with NPDES permit limits via periodic Discharge Monitoring Reports (DMR) submitted to the permitting authority. A NPDES permit must include any applicable technology-based effluent limitations (TBELS) and, if there is a reasonable potential to cause or contribute to an instream excursion above applicable water quality standards, additional water quality-based effluent limitations (WQBELS). Currently forty-seven states are authorized to issue NPDES permits; however as of December 2018, the EPA issues NPDES permits for onshore oil and gas extraction activities in six states (Idaho, Massachusetts, New Hampshire, New Mexico, Oklahoma and Texas) as well as certain territories and tribal lands.

3.3.1 Technology-Based Effluent Limitations

ELGs are generally the source of technology-based effluent limitations. ELGs are national wastewater discharge standards that are developed by the EPA on an industry-by-industry basis. These are technology-based regulations and are intended to represent the greatest pollutant reductions that are economically achievable for an industry. The standards for ***direct dischargers*** are incorporated into NPDES permits issued by states and the EPA regional offices, and standards for ***indirect dischargers*** directly apply and may be incorporated into permits or other control mechanisms issued by pretreatment authorities. Where the EPA has not established ELGs for direct dischargers in a particular industry, permitting authorities develop permit-

> ***Direct Discharger***
> A point source that discharges pollutants to waters of the United States.
>
> ***Indirect Discharger***
> A facility that discharges pollutants to a publicly-owned treatment works (municipal sewage treatment plant).

specific technology-based requirements according to their best professional judgement (BPJ).

When developing ELGs, the EPA identifies the best available technology that is economically achievable for that industry and sets regulatory requirements based on the performance of that technology. The ELGs do not require facilities to install the specific technology identified by the EPA; however, the regulations do require facilities to achieve the same level of pollutant reductions. ELGs can apply to both existing dischargers and new dischargers. ELGs also establish different levels of control for specific classes of pollutants (***priority pollutants***, ***conventional pollutants*** and ***nonconventional pollutants***).

> ***Priority Pollutants***
> A list of 126 toxic pollutants, last modified in 1981, that are frequently found in water samples, produced in significant quantities and have approved EPA methods for detection.
>
> ***Conventional Pollutants***
> Biochemical oxygen demand, total suspended solids, fecal coliform, pH and oil and grease.
>
> ***Nonconventional Pollutants***
> All other pollutants not considered priority or conventional pollutants.

The direct discharge pollution control guidelines that are developed by the EPA in ELGs include: best practicable control technology currently available (BPT), best conventional pollutant control technology (BCT), best available technology economically achievable (BAT), and best available demonstrated control technology for new sources, or new source performance standards (NSPS). The analogous indirect discharge pollution control standards that are developed by the EPA in ELGs are pretreatment standards for existing sources (PSES) and pretreatment standards for new sources (PSNS). Table 3-2 illustrates the types of dischargers and the different levels of control in ELGs and Table 3-3 illustrates the classes of pollutants addressed by different levels of control in ELGs.

Table 3-2. Applicability of Effluent Guidelines Levels of Control to Types of Discharger

Type of Discharger Regulated	BPT	BCT	BAT	NSPS	PSES	PSNS
Existing Direct Dischargers	●	●	●			
New Direct Dischargers				●		
Existing Indirect Dischargers					●	
New Indirect Dischargers						●

Table 3-3. Pollutant Classes Regulated by Effluent Guidelines Levels of Control

Pollutants Regulated	BPT	BCT	BAT	NSPS	PSES	PSNS
Priority Pollutants	●		●	●	●	●
Conventional Pollutants	●	●		●		
Nonconventional Pollutants	●		●	●	●	●

Discharges from oil and gas extraction facilities are subject to ELGs at 40 CFR Part 435. These regulations are subcategorized (e.g., onshore, offshore and in coastal areas), and the levels of control vary for each subpart. Table 3-4 shows the levels of control that are contained in the oil and gas extraction ELGs. These regulations address wastewater discharges from activities such as field exploration, drilling, production, well treatment and well completion activities.

Table 3-4. Levels of Control by Subcategory in the Oil and Gas Extraction Effluent Guidelines

Type of Discharger Regulated	BPT	BCT	BAT	NSPS	PSES	PSNS
Offshore Subcategory	●	●	●	●		
Onshore Subcategory [a]	●				●	●
Coastal Subcategory	●	●	●	●	●	●

[a] PSES and PSNS for the onshore category were promulgated in June 2016 for unconventional oil and gas extraction activities. Pretreatment standards currently do not exist for onshore conventional extraction activities.

Waste streams addressed by the guidelines for 40 CFR Part 435 for the onshore category include:

- Drill cuttings, which are the particles generated by drilling into subsurface geologic formations and carried out from the wellbore with the drilling fluid.
- Drilling fluid or mud, which are the circulating fluid used in the rotary drilling of wells to clean and condition the hole and to counterbalance formation pressure.
- Produced sand, which are the slurried particles used in hydraulic fracturing, the accumulated formation sands, and scales particles generated during production. Produced sand also includes desander discharge from the produced water waste stream, and blowdown of the water phase from the produced water treating system.
- Produced water, which are the fluids brought up from the hydrocarbon-bearing strata during the extraction of oil and gas, and includes, where present, formation water, injection water, and any chemicals added downhole or during the oil/water separation process.

The oil and gas extraction effluent guidelines also contain several subparts, applicable to production activities in different locations and/or to different types of wells. Table 3-5 provides additional details on the applicability and limitations contained in these subparts. Offshore and coastal facilities are not part of the scope of this study.

The onshore category under Subpart C prohibits the direct discharge of pollutants from oil and gas extraction facilities and prohibits the indirect discharge of pollutants from unconventional wells to POTWs. This is called a *zero discharge of pollutants* standard. However, onshore producers can currently discharge produced water under Subpart E for facilities located west of the 98th meridian (see Figure 3-3). In addition, there are currently no national pretreatment standards for discharges to POTWs for wells that do not meet the EPA's definition of unconventional (see 40 CFR 435.33 and 435.34).

Table 3-5. Subparts of 40 CFR Part 435 and their Applicability and Limitations

Subpart	Title	Applicability	Description
A	Offshore Subcategory[14]	Facilities located in waters that are seaward of the inner boundary of the territorial seas as defined in 502(g) of the CWA.	BPT, BAT, BCT and NSPS regulations require numeric limits for some wastestreams in certain locations. For other wastestreams in certain locations, the rule requires zero discharge.
C	Onshore Subcategory	Facilities located landward of the inner boundary of the territorial seas as defined in 40 CFR 125.1(gg) and which are not included within subparts D, E, or F	BPT regulations require zero discharge of produced water for direct dischargers. PSES and PSNS regulations require zero discharge for unconventional oil and gas extraction facilities.
D	Coastal[15] Subcategory	Facilities located in or on a water of the United States landward of the inner boundary of the territorial seas (40 CFR 435.40(a), or as defined at 40 CFR 435.40(b)(1)	BAT regulations require zero discharge (except for Cook Inlet) and PSES regulations require zero discharge.
E	Agricultural and Wildlife Water Use Subcategory	Onshore facilities located in the continental United States and west of the 98th meridian for which the produced water has a use in agriculture or wildlife propagation when discharged into navigable waters.	Requires no discharge of wastewater pollutants into navigable waters from any source other than produced water. Produced water discharges have a daily maximum limitation of 35 mg/L for oil and grease by the application of the BPT, and must be "of good enough quality" for wildlife or agricultural use.
F	Stripper[16] Subcategory	Onshore facilities which produce 10 barrels per well per calendar day or less of crude oil and which are operating at the maximum feasible rate of production and in accordance with recognized conservation practices.	Contains no ELG-based limitations. Technology-based limitations are developed on a case-by-case basis in an individual or in a state-wide general permit using BPJ.
H	Coalbed Methane[17] Subcategory	Facilities engaged on extraction of Coalbed Methane	Contains no ELG-based limitations. Technology-based limitations are developed on a case-by-case basis in an individual or in a state-wide general permit using BPJ.

Note: Subpart B is reserved. Subpart G requirements prevent moving effluent produced in one subcategory to another subcategory for disposal under less stringent requirements.

14 Not included in the scope of this study.

15 Not included in the scope of this study.

16 Not included in the scope of this study

17 Not included in the scope of this study

Figure 3-3. Map of 98th Meridian*

*Onshore oil and gas extraction activities may discharge produced water west of the 98th meridian if it is of good enough quality for agriculture or wildlife uses and is actually put to such use during the period of discharge.

Producers can also discharge produced water under Subpart F and H, as applicable. The regulation does not specify discharge requirements so TBELs must be developed by the permitting authority on a case by case basis using BPJ based on the factors specified in 40 CFR 125.3(c)(2).

Produced water may also be managed by off-site CWT facilities. Discharges from both direct discharging and indirect discharging CWT facilities are regulated under 40 CFR part 437. CWT facilities accept waste, wastewater, or used materials from off-site for disposal, recovery or recycling. The EPA defines off-site as “outside the boundaries of a facility” (40 CFR 437.2(n)).

> 40 CFR part 437 defines a CWT facility as: *“any facility that treats (for disposal, recycling or recovery of material) any hazardous or nonhazardous industrial wastes, hazardous or non-hazardous industrial wastewater, and/or used material received from off-site.”*

The guidelines at 40 CFR part 437 categorize CWT facilities into four subparts:

- Subpart A: Metals Treatment and Recovery
- Subpart B: Oils Treatment and Recovery
- Subpart C: Organics Treatment and Recovery
- Subpart D: Multiple Wastestreams

A key question that arises with respect to oil and gas extraction activities and CWT facilities is how to determine if a facility is located off-site. The EPA defines *site* at 40 CFR 122.2 as "the land or water area where any 'facility or activity' is physically located or conducted, including adjacent land used in connection with the facility or activity." *Facility or activity* means any NPDES "point source" or any other facility or activity (including land or appurtenances thereto) that is subject to regulation under the NPDES program."

The EPA issued a compliance guide and associated frequently asked questions (FAQs) to explain, among other things, the relationship between the CWT ELGs and the oil and gas extraction ELGs for natural gas drilling in the Marcellus shale (U.S. EPA, 2011c, 2011d). In the FAQs, the EPA indicates that for gas drilling activities:

> *(T)he land identified in the drilling permit; including the locations of wells, access roads, lease areas, and any lands where the facility is conducting its exploratory, development or production activities, or adjacent lands used in connection with the facility or activity, would constitute the site. Land that is outside the boundaries of that area is considered to be "off-site."*

While these FAQs are not legally binding, they provide information that may be useful to permitting authorities to help inform decisions on what constitutes off-site in the context of Marcellus shale gas extraction activities.

3.3.2 Water Quality-Based Effluent Limitations

WQBELS are the second main component of NPDES permits. When drafting a NPDES permit, a permit writer must consider the impact of the proposed discharge on the quality of the receiving water. Water quality goals for a waterbody are defined by state water quality standards. By analyzing the effect of a discharge on the receiving water, a permit writer could find that technology-based effluent limitations alone will not be sufficient to meet the applicable water quality standards. In such cases, the CWA and its implementing regulations require development of WQBELs. WQBELs help meet the CWA objective of restoring and maintaining the chemical, physical, and biological integrity of the nation's waters and help to ensure attainment of the designated uses of waters established by the state which include the protection and propagation of fish, shellfish and wildlife, and recreation in and on the water (*fishable/swimmable*).

WQBELs are designed to protect water quality by ensuring that water quality standards are met in the receiving water. When TBELS based on the requirements of 40 CFR 125.3(a) are not sufficient to meet water quality standards, additional or more stringent effluent limitations and conditions, such as WQBELs, are included in NPDES permits.

CWA section 301(b)(1)(C) requires that permits include any effluent limitations necessary to meet water quality standards. To satisfy that requirement, permit writers evaluate effluents to determine if pollutants in the effluent would cause, have the reasonable potential to cause, or contribute to the excursion of water quality criteria adopted in a state's water quality standards, even after attainment of a TBEL (40 CFR 122.44(d)(1)(i)). Where such "reasonable potential" is found, the permit writer must include a WQBEL for such pollutant(s). After completing that process, the permit writer determines the final effluent limitations, includes any compliance schedules and interim effluent limitations, as appropriate, and documents all his or her decisions and calculations in the fact sheet or statement of basis of the permit.

In the context of discharges of oil and gas extraction wastewaters, permit writers would consider the applicable TBELs contained in either the oil and gas extraction or CWT ELGs, or BPJ-based TBELS for subcategories not subject to limitations in the ELGs, and any applicable state or tribal water quality standards. Since the existing CWT ELGs and Subpart E Oil and Gas ELGs do not contain limitations for many pollutants that can be found in produced waters, additional or more-stringent WQBELs may apply to such discharges.

4. THE EPA'S OUTREACH TO STAKEHOLDERS

In support of the goal of the study, the EPA conducted outreach with a variety of stakeholders across the country to better understand produced water management practices and challenges. This outreach included in-person meetings, as well as conference calls and webinars. During these discussions, the EPA discussed with a wide range of stakeholders their experiences with produced water management. The goal of these discussions was to better understand produced water generation, management, and disposal options at the regional, state and local levels. Participants shared their individual perspectives on several topical areas, including:

- Produced water management – the pros and cons with the status quo.
- Produced water management alternative options such as treatment technologies, availability of alternatives and drivers for alternative management practices.
- Current or future produced water management barriers to alternatives.
- Concerns related to federal regulations that allow, in some instances, for the discharge of treated produced water to surface waters or to municipal wastewater treatment.
- Challenges to developing permit limits for facilities that treat and discharge produced waters.
- Appropriate level of treatment required for produced waters that would be discharged to surface waters or Publicly Owned Treatment Works (POTWs).
- Existing state regulations and requirements that conflict with a different federal approach to produced water management (e.g., water rights).

The EPA also held a public meeting on October 9, 2018 to report on what it had learned to date and provide stakeholders the opportunity to provide additional individual input.[18] The EPA engaged with the stakeholders identified in Table 4-1 during the study. A summary of the information gleaned from these discussions, organized by category of entity, follows. The summaries present the individual thoughts and opinions of the participants in the various meetings, and do not necessarily represent the official positions of the entities identified in Table 4-1. The EPA has not verified the accuracy of the information provided by stakeholders, nor has the Agency provided any interpretation or opinions regarding the information received.

[18] To view EPA's presentation, see: https://www.epa.gov/eg/oil-and-gas-extraction-wastewater-management-study-documents.

Table 4-1. List of Engagement Activities in 2018

Month	Calls/Meetings
April, 2018	New Mexico, Office of the State Engineer (4/24) New Mexico, Energy, Mineral and Natural Resources Dept. (4/24) New Mexico Environment Department (4/24) New Mexico Oil and Gas Association (4/25)
May, 2018	Interstate Oil and Gas Compact Commission (IOGCC) (5/8) Texas Commission on Environmental Quality (CEQ) (5/11) American Exploration and Production Council (5/15) American Petroleum Institute (API) Upstream Group and Independent Petroleum Association of America (5/15) Department of Energy (DOE), Office of Oil and Natural Gas (5/15) Louisiana Department of Environmental Quality (5/18) Ground Water Protection Council (GWPC) (5/18) Western States Land Commissioners Association (5/21) EPA Region 8 states, including Colorado, Wyoming, North Dakota state agencies (5/21) EPA Region 8 Academia – Colorado State University, Colorado School of Mines, Berkeley, University of Wyoming (5/21) Western Energy Alliance (5/22) EPA Region 8 Environmental NGO Stakeholders (5/22) Clean Water Action (5/23) Natural Resource Defense Council (5/23) Texas Water Board (5/24) California Water Boards (5/24)
June, 2018	National Tribal Water Council Meeting (6/6) Texas Oil and Gas Association (6/19) Environmental Defense Fund (6/19) Texas Independent Producers and Royalty Owners Association (6/19) Gulf Coast Authority (6/20) Environmental NGOs (6/20) Texas Water Development Board; Texas CEQ; Texas Railroad Commission (6/20) Environmental Council of States (6/20) Texas Alliance of Energy Producers (6/21) Texas Bureau of Economic Geology (6/21) Jicarilla Apache Nation (6/26) EPA Tribal Program Managers Update Call (6/28)
July, 2018	Western States Land Commissioners Association meeting in Duluth, MN (7/8-12) Region 1 Regional Tribal Operations Committee (Tribal) Call (7/11) National Tribal Water Council Update (Tribal) Call (7/11) Region 6 Regional Tribal Operations Committee (Tribal) Call (7/11) Texas General Land Office (7/17) Bureau of Land Management (7/18) PolyCera (7/18) Region 9 Regional Tribal Operations Committee (Tribal) Call (7/18) Tasman Geosciences (7/19) The Pacific Institute, Clean Water Action, Environmental Working Group (7/23) California Independent Petroleum Association (7/23) Western States Petroleum Association (7/23) California Water Quality Boards and California EPA (7/24) University of California Berkeley, and Lawrence Berkeley National Laboratory (7/24) California Division of Oil, Gas, and Geothermal Resources (7/25) Site Visits Chevron San Ardo, Sentinel Peak Arroyo Grande, Chevron Kern River (7/25 – 7/26)

Table 4-1. List of Engagement Activities in 2018

Month	Calls/Meetings
	Region 8 Regional Tribal Operations Committee (Tribal) Call (7/25) Albaron (7/30)
August, 2018	Region 4 Regional Tribal Operations Committee (Tribal) Call (8/01) University of New Mexico (8/2) Produced Water Society (8/6) Wilsa Holdings (8/8) National Tribal Water Council Update (Tribal) Call (8/8) SOURCEWATER (8/14) University of Oklahoma and Oklahoma State University (8/21) Oklahoma Oil and Gas Association, Oklahoma Independent Petroleum Association and Industry Stakeholders (8/21) Exxon Research and Development (8/22) Ground Water Protection Council, National Rural Water Association, OK Rural Water Association, State Review of Oil and Natural Gas Environmental Regulations (8/22) Interstate Oil and Gas Compact Commission (8/23) Oklahoma Water Resources Board, Corporation Commission, Department of Environmental Quality, Department of Agriculture, Food and Forestry (8/23) Region 7 Regional Tribal Operations Committee (Tribal) Call (8/23) Health Effects Institute (8/30)
September, 2018	TX Alliance of Energy Producers (9/4) Ground Water Protection Council – New Orleans (9/10-13) Exxon (9/21) Eureka Resources (9/21) Pennsylvania Academia (Penn State, University of Pittsburgh) (9/25) United States Department of Energy National Energy Technology Laboratory (9/25) Pennsylvania Department of Environmental Protection (9/26) Pennsylvania Grade Crude Oil Coalition, Pennsylvania Independent Petroleum Producers Association, Pennsylvania Independent Oil and Gas Association, Marcellus Shale Coalition (9/26) Pennsylvania Crude Development Advisory Council (9/27)
October, 2018	American Petroleum Institute (10/3) Utah Division of Water Quality (10/4) October 9 Public Meeting in DC United States Department of Energy and Sandia National Laboratories (10/15) Wind River (Northern Arapaho) Tribe (10/15) Wind River (Eastern Shoshone) Tribe (10/17)
November, 2018	NALCO (11/8)

4.1 Major Themes from State Agencies

Meetings with states included representatives from agencies responsible for NPDES permitting, oil and gas permitting, wastewater management, and other aspects of produced water management. The EPA also met with users of water, such as state agriculture departments. The EPA did not meet with agencies from every state, but instead focused efforts on those states with significant oil and gas E&P activities and produced water generation. Some states currently issue permits for produced water discharges (for example, west of the 98th meridian); others do not.

Some state agency representatives were supportive of additional discharge options for treated produced water. The reasons identified were varied. One primary theme was that treated produced water could be an additional source of water to augment surface and groundwater supplies. Some states with significant oil and gas extraction activity are also arid or semi-arid where water scarcity is a current and growing problem. If produced water could be treated to a level suitable for discharge, these state agency representatives see this as a benefit. Potential downstream users of the water that were identified include agriculture, municipalities and industry. In addition to providing water to downstream users, state agency representatives indicated that discharge of treated produced water could help meet downstream water allocations and interstate water compacts. The concept of re-branding produced water from a waste product requiring management to a potential valuable resource was a common theme.

Some state agency representatives noted that the oil and gas industry can be a significant user of fresh water in certain areas, given that water is often required for drilling and hydraulic fracturing activities. In many cases, industry relies on withdrawal from surface water or groundwater supplies to obtain needed water. After use in E&P activities, this water may be reused within the oil and gas field, but in many cases, is ultimately disposed of in Class II UIC wells where it is no longer part of the water cycle. State agency representatives indicated that treating this water for discharge and reintroduction to the water cycle would help to preserve or augment freshwater supplies. On a related note, representatives of one state agency indicated that there has been discussion of recovering water injected into Class II UIC disposal wells for reuse within oil and gas operations; this could reduce freshwater imports into the oil and gas sector.

State agency representatives also indicated that allowing producers to treat and discharge produced water closer to where it is generated would reduce the need for transport via trucks or pipelines. Transport of produced water can be costly and brings with it the risks of spills or illicit discharge. In addition, truck traffic can damage roads and increase the risk of traffic accidents and associated injuries and fatalities. Also, truck traffic can be disruptive to those located along trucking routes. State agency representatives indicated that reducing trucking could provide benefits to air quality as well due to reduced emissions.

In states where water rights and water allocation law are established, there were questions about who would own produced water that is treated for discharge. Representatives of some state agencies indicated that there has been or is ongoing work to clarify ownership and water rights for discharged produced water, while others indicated that this question has yet to be addressed. Regardless of ownership, selling or obtaining royalties from discharge of treated produced water was identified as another potential benefit, as someone (either the state, a landowner, industry or some other entity) would own the water and therefore could benefit financially from selling the water and any mineral co-products extracted from the water.

Representatives of some state agencies indicated that there are existing and emerging constraints on Class II UIC disposal well capacity due to over-pressurization of receiving formations which can lead to induced seismicity. This was particularly of note in areas of the Permian basin in New Mexico and Texas. Also, in discussions with some state agencies induced seismicity was identified as a constraint. However, these concerns were not limited to just those states. Representatives of some state agencies were keenly concerned about the capacity of formations being used for disposal to meet the future demand, particularly when factoring in projected increases in E&P activities. They noted that where formation disposal capacity is insufficient to meet demand, other, perhaps more costly, options would be needed. They were concerned that this could impact the ability of producers to continue producing in certain areas, or at a minimum would increase their costs which may reduce E&P activity. Implications to state royalty revenue, as well as employment impacts, were identified as potential consequences. They indicated that providing additional options for discharge of treated produced water could help to reduce injection disposal capacity concerns in those areas, although potentially the costs could be higher.

Some state agency representatives indicated that as existing disposal options become more constrained, and as the cost of disposal increases, producers could abandon wells. Identifying and plugging these wells could be a significant cost for the state. In addition, they indicated that increasing disposal costs could increase the occurrence of illegal dumping. Therefore, according to them, it would be desirable to maintain existing management options, as well as to provide additional options.

Some state agency representatives were not supportive of providing additional discharge options for treated produced waters. One reason identified was that existing management options are sufficient. These options, including reuse within the oil and gas field or disposal in Class II UIC disposal wells, were identified as widely available and preferable to surface discharge. Also, representatives of one state agency indicated that they did not support changes to the existing Subpart E beneficial reuse provisions but were not opposed to expanding discharge options.

Some state agency representatives were concerned about the potential human health and ecological implications of broader surface discharge and identified many unknowns around produced water composition and treatability as primary reasons for this concern. They indicated that little is known about produced water composition, due to the variety of chemicals used by industry in fracturing, stimulation and well maintenance activities. While producers are required to disclose the chemicals used in hydraulic fracturing in some cases, some state agency representatives reported that these disclosures are often incomplete due to the proprietary nature of formulations. They indicated that many of these compounds have not been evaluated for human health and aquatic toxicity, and treatability has not been determined. Also, downhole reactions and transformations have not been assessed. In addition, formation water and E&P practices vary across production areas and basins, further confounding evaluation of produced water characteristics.

Some state agency representatives identified several impediments to additional discharge of treated produced waters. A primary impediment identified was that the cost of treatment could be significantly greater than other management options. They noted that in most areas, the nature of produced water would require extensive treatment to remove constituents such as barium, technologically enhanced naturally occuring radioactive material (TENORM), hardness, organics, and dissolved solids such as chlorides. Treatment consisting of technologies including chemical precipitation, reverse osmosis, and thermal evaporation were identified as necessary to generate discharge-quality water. Also, treatment residuals such as concentrated brines, crystallized salts and sludges would require management, which would add to costs. Management of TENORM-containing sludges was identified as a particular challenge. Where produced waters contain radium, it was described that treatment will concentrate radioactivity in sludges or other residuals. Depending on the radioactivity of these materials, management options were identified as being limited and costly. In addition, they noted the potential for release to the environment through spills or through landfill leachate. Given the extensive treatment that may be appropriate, as well as residuals management concerns, doubts were raised as to whether treatment for discharge would be cost-competitive with other options such as reuse within the oil and gas field or disposal in Class II UIC disposal wells. However, states agency representatives did indicate that recovering valuable co-products, such as lithium or rare-earth metals from the treatment residuals, could improve the economics of treatment for discharge. They noted that this might spur growth of other industries that can utilize these co-products, such as battery manufacturing.

Some state agency representatives reported that they lack technical expertise in permitting discharges under the NPDES program and would look to the EPA to provide this expertise. NPDES permits include both technology-based and water quality-based effluent limitations, and they indicated that determining the water quality limitations could be challenging since standards and criteria do not exist for many constituents in produced water. In addition, they noted that production may occur in areas where receiving waters are high quality and therefore it could be difficult for dischargers to meet stringent water quality standards. In particular, meeting standards for chlorides in receiving waters was identified as a potential challenge. Also, some state agency representatives indicated that there are no surface waters in the vicinity of much E&P activities, so discharge to surface waters would not be a viable option even if regulations allowed for it. They also indicated that there would be a public perception challenge associated with allowing discharge to surface waters.

Many state agency representatives indicated that the timeline required to obtain NPDES permits could be an impediment to broader discharge. They indicated that producers may desire the ability to discharge for a short-duration as the need arises, perhaps at multiple locations within their operations. This is different than typical NPDES dischargers which tend to be established facilities discharging long-term. Given the many steps involved in issuing permits, they observed that producers may not be able to obtain permits in the timeframe desired. They indicated that a general permit might be a good option for this industry to address concerns over the time required to issue permits. Another option would be for producers to utilize fixed CWT facilities that manage produced waters from multiple production operations. This could be a commercial facility that accepts produced waters from multiple operators, or a facility owned and operated exclusively by one producer for just their wells. State agency representatives indicated that some producers are currently installing water management infrastructure to centralize their water recycling operations, and that this may lead to construction of treatment plants for discharge in the future. While issuing a permit to such a fixed facility may still require considerable time, they indicated that such an option may be feasible. However, there were questions about how to permit CWT facilities and what the governing ELGs would be, particularly if such a facility treats only oil and gas extraction wastewater. There were requests for the EPA to clarify this, and to revisit the definitions in the CWT ELGs to provide more flexibility for oil and gas operations such as to allow a CWT facility to accept oil and gas wastewater via pipeline. In some states, the EPA issues NPDES permits which means the state has less control of the permit issuance process. State agency representatives acknowledged that obtaining authorization from the EPA for the NPDES program, where they do not already have it, would be an option, however they identified barriers to delegation such as staffing and funding.

While state agency representatives indicated that reuse of produced water within the oil and gas field is desirable, there are some existing state laws or regulations that can interfere with reuse, particularly sharing water between producers. As a result, there is less recycling occurring than could potentially occur. According to these state agency representatives, changes to state legislation would be necessary to remove these barriers. They also indicated that in some cases, land owners require producers to purchase freshwater from them as part of the lease. If freshwater must be purchased, then there is less incentive to reuse produced waters for E&P activities. Consequently, additional produced water is generated that would subsequently require disposal. They indicated that as the total volume of wastewater requiring disposal increases, additional management options including discharge may be desirable.

Some state agency representatives indicated that better data on produced water generation, reuse and injection well utilization could help manage disposal well capacity concerns. For example, they indicated that if some areas are becoming over-pressurized, then remedial actions such as limiting the volumes that specific injection disposal wells can accept could be implemented. They indicated that requiring injection disposal well operators to report volumes of water accepted or well pressures at a greater frequency could help with management of those wells. Additionally, requiring more reporting from producers on produced water disposition was identified as an aid for management of injection disposal wells.

4.2 Major Themes from Tribes

Some tribes were supportive of additional discharge options as this would allow for continued development of oil and gas resources on tribal lands. However, they would want the discharges to meet water quality standards and be protective of the environment. Some tribes currently have discharges of produced water to water bodies located within tribal lands, consistent with the beneficial reuse provisions of 40 CFR 435 Subpart E. Continued discharge of this water is important for both economical as well as ecological and wildlife considerations. Tribes would also be interested in identifying additional uses for treated produced water outside of agriculture and wildlife propagation, including direct use by the tribe to supplement water supplies. However, they indicated that additional information on the performance of treatment technologies, as well as financial assistance, would be needed.

Other tribes were not supportive of additional discharge options for produced water. These tribes indicated that they were concerned about the environmental and human health implications of discharge. In addition, many surface waters have important tribal uses such as fishing or ceremonial practices, and these tribes were concerned about potential impacts to water quality that may affect those uses. There were also questions about which specific water bodies would potentially be affected.

4.3 Major Themes from Oil and Gas Industry Members

Most in industry were supportive of additional discharge options for treated produced water. The exception were some producers who were currently discharging under the Subpart E beneficial reuse provisions, who did not see the need for additional discharge options and did not support regulatory changes. Industry indicated that while reuse of produced water within the oil and gas field is their preferred management option, this is not feasible in some cases. Examples include when demand for reuse decreases as drilling activity decreases or when produced water transportation costs make reuse not cost-competitive with other water sources. Where reuse is not feasible, and where injection disposal well capacity is limited, treatment followed by surface discharge may be viable if it were a more widely available option. This includes treatment and discharge by CWT facilities or discharge by industry themselves if regulations were changed to allow discharge. Some in industry also indicated that indirect discharge via POTWs should continue to be an available option and would prefer that the EPA establish non-zero numerical pretreatment standards.

A common theme among discussions with industry representatives is that options for produced water should be expanded. Those in the oil and gas extraction industry pointed to other industries that are permitted to discharge wastewater and would like there to be equity in this respect. An example given was petroleum refineries, which can discharge wastewater yet the oil and gas extraction industry that supplies petroleum to the refineries has limited discharge options. Some indicated that the technology is available to treat produced water to a level that meets water quality standards designed to protect the designated use. Industry representatives noted that this may not have been the case when the oil and gas extraction ELGs were written, but treatment technology has changed since then. They believe that the EPA can determine what technology is necessary to treat produced water to be suitable for discharge, pointing to the EPA's 2018 CWT study.

Industry representatives indicated that technology on the production side has also changed since the oil and gas extraction ELGs were written. An example is the continued advances in horizontal and directional drilling. The volume of water used in drilling and fracturing these wells is much greater than was previously used. Therefore, more produced water is generated which presents management challenges. Also, some formations produce much greater quantities of water as compared to oil and gas. While drilling and well development activities are taking place, there is a demand for reuse of produced water within the oil and gas field. However, once resource areas become more developed the water demand for E&P activities decreases. When this occurs, the amount of produced water requiring disposal may increase. This may increase disposal costs, particularly if insufficient injection disposal well capacity exists. Industry representatives indicated that treating and discharging produced water should be an available option in these cases and that treatment for discharge may be cost-competitive with other management options. Also, there may be short-term or long-term slowdowns in drilling activity if commodity prices decrease. The associated decrease in water demand could present water management challenges that could be addressed via a surface water discharge option.

Industry representatives indicated that currently reuse within the oil and gas field and disposal in Class II UIC wells are generally the least-cost methods of managing produced water. In the near-term industry does not see this changing on a national scale. Reuse is the preferred method of management and is utilized where possible. One major operator stated that they would not support the use of treated produced water outside the oilfield due to a lack of science around treatment efficacy and associated liability risks. There are some impediments to reuse, including perceived liability as well as business competition. In addition, existing state regulations were identified as barriers to reuse in some areas. Where reuse is not available, disposal in Class II UIC disposal wells is frequently utilized. Costs for injection disposal were reported to generally be less than $1 per barrel of produced water. In addition, disposal wells were reported to be plentiful in most areas such that trucking or piping costs to these wells is low. As a comparison, treatment for discharge may cost several dollars per barrel, and may be $10 or more per barrel depending on the market and the level of treatment needed. According to industry, even when considering potential reductions in transportation costs, treatment for discharge would still cost more than injection disposal in most cases. However, industry indicated that there are currently specific areas of the country where reuse and disposal options are limited, and that treatment and discharge would be utilized if more discharge options were available. A primary driver is the distances that produced water must be transported to disposal options. Industry also indicated that there are specific areas of the country (an example is the Permian Basin) where disposal at some injection wells is limited, for example due to concerns over induced seismicity. In these cases, operators have had to transport produced water greater distances for disposal. Industry is concerned that as the quantity of produced water increases as production of oil and gas increases, that injection disposal well capacity will be insufficient to meet demand. Also, industry noted that regulatory agencies are reevaluating the suitability of some currently used injection zones and may limit or prohibit injection in those areas in the future. Industry indicated that as injection capacity decreases, other produced water management options would be needed.

While use of CWT facilities is currently limited as they exist only in certain areas of the country, producers indicated that they would use commercial facilities if they were available and cost-competitive with other disposal options. Producers indicated that they have discussed increasing CWT availability with vendors and water service companies.

However, these companies frequently want long-term contracts with producers before investing in treatment plants. Producers generally are reluctant to engage in such contracts due to the potential for unknown market factors. Producers indicated that they would prefer to have the ability to bring mobile treatment systems to the well sites when needed, which would be less costly than trucking or piping wastewater to centralized treatment facilities.

Industry representatives noted that treatment for discharge has benefits for addressing water scarcity, since much oil and gas E&P activity occurs in arid or semi-arid areas of the country. In these areas, surface water supplies can be sparse and treated produced water could help augment these supplies. This water would also be available for subsequent downstream uses, including by the oil and gas industry. Using receiving streams as conveyance for treated produced water could reduce trucking or piping costs.

Industry representatives also indicated that discharging treated produced water could be a potential revenue source, as downstream users may pay for the water. However, this would depend on water rights and ownership of the water. Industry indicated that ownership of the treated produced water is something that lacks clear definition in some states. Industry also noted that there is the potential to recover valuable co-products from treating produced water. As with water rights, ownership of the minerals that might be extracted from produced waters is something that industry noted lacks clarity in some states. There is the potential that royalties may need to be paid to the landowners for any co-products extracted from treated produced water, but this is an issue that would be settled under state law.

Industry representatives are concerned that the ability to economically manage produced water may affect the economics of extracting oil and gas resources in some areas. If the costs and regulatory burden for managing produced water are too high, certain areas may not be developed. In addition, areas that are currently producing resources may need to be prematurely shut-in if produced water management costs significantly increase. Expanding the option for surface discharge could help the economics of such projects.

Like states, industry representatives identified the time required to obtain NPDES permits as a potential impediment to broader surface water discharge. The timeline for deciding whether or not to proceed with a given oil and gas extraction project, they pointed out, is typically much shorter than the time it historically takes to develop, propose and finalize an NPDES permit. Industry indicated that some states have experience writing NPDES permits for oil and gas extraction facilities under 40 CFR 435 Subpart E, while other states have not written permits for oil and gas extraction wastewater discharges. Also, some states do not have delegation of all or part of the NPDES program. Industry indicated that they would like to have the option to treat and discharge produced water at or near the well site as the need arises and obtain authorization to discharge on a prompt timeline. Given that NPDES permits may contain both technology-based and water quality-based effluent limitations, there was concern over the ability to meet water quality standards in certain areas where surface waters are of high quality. In addition, there was concern that permits would not be obtained in a timely manner given that the need to discharge may be periodic and of short duration. Industry indicated that a general permit would be a potential solution as this was viewed as being more flexible and perhaps coverage under a general permit could be obtained more quickly than an individual permit. Industry also indicated that were the EPA to revise its regulations to allow for broader surface discharge, there are potential barriers at the state level to issuing NPDES permits that may be difficult to overcome in some cases. Examples given were meeting water quality-based effluent limitations and antidegradation requirements.

With respect to produced water characterization, producers noted that they disclose much of the constituents used in hydraulic fracturing. While noting that some constituents are proprietary, they indicated that in many cases it is the provider of the additive that claims confidentially and not the producer. Thus, they can provide the name of the additive but not the actual composition of the additive. They also noted that many of these proprietary constituents are non-toxic and would not pose a risk to the environment if discharged. However, they did note that some constituents can exhibit aquatic toxicity and they work with service companies to reduce the toxicity of constituents they use. They also indicated that treatment technologies are effective in removing the range of constituents present in produced waters and that the level of treatment can be adjusted based on the intended use of the treated produced waters.

4.4 Major Themes from Members of NGOs

The primary concern raised by NGO representatives was the potential toxicity and human health and ecological implications of discharges of produced waters. This is due to the large number of chemical compounds used in hydraulic fracturing, well maintenance and other E&P activities. There are also constituents naturally present in producing formations that are contained in the resulting produced water. NGO representatives observed that many chemicals have little data on toxicity. In addition, they noted that disclosure requirements may be incomplete and much of the data that is disclosed is proprietary, further complicating assessment of toxicity and risk. They further noted that the chemistry of produced water is constantly changing as new chemical formulations enter the market and as advances in hydraulic fracturing occur, and that activities such as well maintenance and stimulation may use different chemistries. Another concern was the transformation of chemical constituents into other chemical compounds due to the high temperature and pressures that may occur within the well. NGO representatives indicated that little is known about these transformations and the toxicity of the transformation products that may occur.

Some NGO representatives were also concerned that analytical methods do not exist for many of the chemical compounds used in E&P activities. In addition, they indicated that the high salinity of many produced waters can interfere with certain analytical approaches, complicating quantification of constituents in produced water. They were concerned that analytical shortcomings can complicate assessment of the human health and ecological risk associated with discharges of produced water.

Another concern was that only limited treatment technology performance data exists for many compounds present in produced water. They were concerned that it would be difficult to determine the appropriate treatment technologies, and to assess whether those treatment technologies are adequately removing constituents in produced water, given these data gaps. Given the data uncertainty, NGO representatives expressed concern that increased opportunities for discharge would result in human health and ecological impacts.

Some NGO representatives were also concerned that states lack sufficient water quality criteria for many of the constituents present in produced water. As a result, they were concerned that NPDES permits may not be protective of water quality. They also noted that there is little data about the synergistic effects that may occur due to the presence of multiple constituents in produced water discharges. NGO representatives were also concern that since much E&P activities occur in arid and semi-arid areas, discharges will occur primarily to intermittent and ephemeral streams. According to these NGO representatives, discharging water to such streams may alter the hydraulic and hydrologic regime of the stream, causing concerns such as erosion. They stated that such discharges may also alter the vegetation or biota present in and adjacent to the stream. Further, they stated that discharges to such streams receive little or no dilution by the receiving water, increasing the risk of adverse effects from discharges, and noted that any upsets to treatment systems discharging to such stream, or spills into such stream, could magnify adverse effects.

Some NGO representatives were opposed to the EPA revising ELGs to allow for broader discharge of produced water, stating that it is not the EPA's responsibility to solve industry's water management problem. They identified the increasing volume of water used for well completions as a primary driver for constraints on management of produced water and suggested that industry moderate the pace of drilling activities. They were concerned that changes to ELGs to allow for broader discharge options would be a weakening of existing regulations. They also stated that a zero discharge of pollutants standard remains available to the industry, that this is the goal of the CWA, and therefore the EPA should not revise this standard.

Some NGO representatives saw potential benefit from produced water discharges due to water scarcity concerns. While acknowledging discharges of treated produced water could be used for agriculture, water supply and other uses, they indicated that they would want such discharges to be protective of the receiving water quality and downstream uses. In addition, selling treated produced water could generate additional revenue in some cases. Also, some NGOs indicated that providing additional options for industry can help to promote continued oil and gas development, which has an economic benefit for communities, states and landowners.

4.5 Major Themes from Members of Academia

Those in the academic community that were engaged highlighted knowledge gaps regarding produced water that complicates assessment of the need for and the implications of discharge of treated produced water from many production areas. For example, they indicated that there is little available data regarding the chemical composition of produced water. Produced water characteristics vary considerably between formations and are influenced not only by the production method but also by the chemical formulations used in hydraulic fracturing, well maintenance and well stimulation. In addition, possible transformations inside the well of constituents can complicate characterization of produced water. Academia representatives also indicated that analytical methods for monitoring of constituents in produced water are lacking.

Some in academia indicated that, due to the lack of data, it is difficult to determine what treatment technologies are needed to treat produced water to a level that is suitable for discharge. Limited data also makes it difficult to assess the toxicity of produced water, and the possible environmental implications of discharge. Academia is currently researching additional approaches for assessing the toxicity of produced water, such as bioassays. In addition, they indicated that some research done to date shows potential environmental implications, such as radium accumulating in sediments downstream of discharge sources and accumulating in aquatic organisms and possible toxic effects from some constituents in produced waters.

In addition to data gaps for produced water composition, toxicity, and treatability, there are gaps in information on produced water generation and disposition. According to academia, there are few requirements for tracking of where produced water is generated and in what quantities, and where it is transported for subsequent management. There is little data available on how much produced water is managed in injection disposal wells, and what the pressures are in those wells. Given the lack of data, academia indicated that it is difficult to determine where injection pressures may be increasing and where problems such as induced seismicity may occur. In addition, academia noted that there is little data on the fate of produced water injected into some formations due to complex geology and the lack of monitoring data. Academia further noted that in cases where data does exist, its availability may be delayed such that timely assessment of implications and adjustments (such as reducing injection volumes) may be difficult.

Those academics engaged noted that while there are existing technologies available for treating produced waters for discharge, the cost is still high compared to other management options. Research is ongoing into lower cost treatment technologies, such as advanced membranes. In addition, they indicated that use of waste heat for thermal distillation could significantly reduce treatment costs. One source of waste heat that was identified are natural gas compressor stations. In addition, natural gas that is currently flared could instead be used to drive thermal distillation systems or converted into electricity for powering membrane treatment systems. Academia identified several issues with treatment for discharge, including increased air emissions from treatment systems and residuals management. With respect to residuals, managing the large quantities of salts that would be produced from widespread adoption of distillation/crystallization as well as TENORM containing sludges were identified as particular challenges.

4.6 Major Themes from Other Entities

In addition to people from states, tribes, the oil and gas extraction industry, NGOs and academia, the EPA met with other stakeholders such as POTWs, technology vendors and service providers. These stakeholders provided additional input to the EPA from their individual perspectives.

Generally, the EPA heard from associations that represent POTWs that these facilities do not want to accept produced water because the treatment technology they employ will not treat produced waters. A primary constituent of concern is TDS and chlorides which are not removed by the treatment technologies in place at the vast majority of POTWs. However, at least one POTW would like to build plants specifically designed to treat produced water for discharge and would like the EPA to revise its regulations to allow POTWs to accept these wastewaters. This POTW indicated that produced water management options are limited in some areas and that building plants suitable for treating and discharging produced water could address capacity limitations.

There are many vendors, service providers and water treatment companies currently offering produced water management options for producers and the EPA met with some of them. Several indicated that they are actively exploring treatment technologies to reduce the cost of produced water treatment. They indicated that the cost of treatment that includes desalination is much higher than the cost to reuse produced water in the oil and gas field or to inject into disposal wells. They indicated that recovering and selling co-products is necessary to offset treatment costs and be profitable. One company indicated that it may be difficult to recover these co-products with mobile treatment systems given that extensive pretreatment prior to desalinization is needed to remove contaminants that may otherwise partition into the co-products. Also, establishing markets for co-products can be difficult due to the lack of standard specifications and varying state requirements. It was also stated that it is not easy to treat produced water in some cases due to the high TDS and mineral content which can degrade and damage treatment equipment. Also, residuals management such as TENORM-containing sludges can be a substantial cost.

5. Summary and Next Steps

The EPA obtained input from a variety of states, tribes and stakeholders concerning produced water management under the CWA and that input is described herein. While some entities were supportive of expanding discharge opportunities which would increase flexibility while reducing costs and increase available water supplies, others were not supportive due to concerns such as potential environmental or human health implications. Expressions of support and concern were reinforced by input letters received by the EPA during the public input period of the draft report[19] (the EPA accepted public input during May and June of 2019). The EPA has considered the information obtained during the outreach activities, as well as during the public input period, in preparing this final report. The Agency intends to announce next steps for produced water management under the CWA in subsequent communications.

[19] The public input letters are available at Regulations.gov under Docket ID No. EPA–HQ–OW–2018–0618.

6. REFERENCES

1. Acharya, Harish R. 2011. Cost Effective Recovery of Low-TDS Frac Flowback Water for Reuse. GE Global Research. U.S. DOE NETL.
2. CCST. 2014. Advanced Well Stimulation Technologies in California: An Independent Review of Scientific and Technical Information.
3. ExxonMobil Corporation. 2014. Hydraulic Fracturing Fluid. XTO Energy.
4. FracFocus. 2014. What Chemicals Are Used?
5. Government Accountability Office (GAO) 2014. Freshwater: Supply Concerns Continue and Uncertainties Complicate Planning. GAO-14-430.
6. GWPC, 2019. Produced Water Report: Regulations, Current Practices, And Research Needs. Ground Water Protection Council, Oklahoma City, OK. June, 2019
7. U.S. DOE. 2016. United States Energy Information Administration (EIA). Today in Energy: Hydraulically fractured wells provide two-thirds of U.S. natural gas production. United States Department of Energy. 5 May 2016.
8. U.S. DOE. 2018. United States Energy Information Administration (EIA). Annual Energy Outlook 2018. United States Department of Energy. 6 February 2018.
9. U.S. EPA. 2015. Analysis of Hydraulic Fracturing Fluid Data from the FracFocus Chemical Disclosure Registry 1.0. EPA/601/R-14/003.
10. U.S. EPA. 2016. Hydraulic Fracturing for Oil and Gas: Impacts from the Hydraulic Fracturing Water Cycle on Drinking Water Resources in the United States (Final Report). U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-16/236F.
11. U.S. EPA. 2016b. Technical Development Document for the Effluent Limitations Guidelines and Standards for the Oil and Gas Extraction Point Source Category. U.S. Environmental Protection Agency, Washington, DC, EPA-820-R-16-003.
12. U.S. EPA. 2018. Detailed Study of the Centralized Waste Treatment Point Source Category for Facilities Managing Oil and Gas Extraction Wastes. U.S. Environmental Protection Agency, Washington, DC, EPA 821-R-18-004.
13. USGS. 2014. National Produced Waters Geochemical Database v2.1 (Provisional) - Documentation. U.S. Geological Survey.