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Technical Development Document for the Effluent Limitations Guidelines and Standards for the Oil and Gas Extraction Point Source Category

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U.S. Environmental Protection Agency
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ABBREVIATIONS

AO	Administrative Order
API	American Petroleum Institute
Bcf	billion cubic feet
BDL	below method detection limit
BOD_5	biochemical oxygen demand
BPD	barrels per day
BPT	best practicable control technology currently available
$CaCO_3$	calcium carbonate
CBM	coalbed methane
Ci	curie
CIU	categorical industrial user
COD	chemical oxygen demand
COG	conventional oil and gas
CWA	Clean Water Act
CWT	centralized waste treatment
DBP	disinfection byproduct
DMR	discharge monitoring report
DOE	Department of Energy
EIA	Energy Information Administration
ELGs	Effluent Limitations Guidelines and Standards
EPA	U.S. Environmental Protection Agency
EUR	estimated ultimate recovery
gpd	gallons per day
IU	industrial user
LTPW	long-term produced water
MG	million gallons
MGD	million gallons per day
mg/L	milligrams per liter
MI DEQ	Michigan Department of Environmental Quality
NORM	naturally occurring radioactive material
NPDES	National Pollutant Discharge Elimination System
OH DNR	Ohio Department of Natural Resources
ORD	Office of Research and Development
PA DEP	Pennsylvania Department of Environmental Protection
pCi	picocurie
PESA	Petroleum Equipment Suppliers Association
POTW	publicly owned treatment works
SIU	significant industrial user
SRB	sulfate-reducing bacteria
TDD	technical development document
TDS	total dissolved solids
TENORM	technologically-enhanced naturally occurring radioactive material
THM	trihalomethane
TOC	total organic carbon
TRR	technically recoverable resource

ABBREVIATIONS (Continued)

UIC	underground injection control
UOG	unconventional oil and gas
USGS	U.S. Geological Survey
UV	ultraviolet
WV DEP	West Virginia Department of Environmental Protection

GLOSSARY[1]

Biochemical oxygen demand (BOD_5)	The amount of oxygen consumed by biodegradation processes during a standardized test. The test usually involves degradation of organic matter in a discarded waste or an effluent. Standard Method 5210 B-2001, USGS I-1578-78, and an AOAC method.
Centralized waste treatment (CWT) facility	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 offsite.
Chemical oxygen demand (COD)	The amount of oxygen needed to oxidize reactive chemicals in a water system, typically determined by a standardized test procedure. Standard Method 5220 (B-D)-1997, ASTM D1252-06 (A), EPA Method 410.3 (Rev. 1978), USGS I-3560-85, and an AOAC method.
Class II UIC disposal well	A well that injects brines and other fluids associated with the production of oil and natural gas or natural gas storage operations. Class II disposal wells can only be used to dispose of fluids associated with oil and gas production.
Class II UIC enhanced recovery well	A well that injects produced water, brine, salt water, water, steam, polymers, or carbon dioxide into oil-bearing formations to recover residual oil and—in some limited applications—natural gas.[2]
Conventional oil and gas (COG) resources	Crude oil[3] and natural gas[4] that is produced by a well drilled into a geologic formation in which the reservoir and fluid characteristics permit the oil and natural gas to readily flow to the wellbore.
Drill cuttings	The particles generated by drilling into subsurface geologic formations and carried out from the wellbore with the drilling mud.
Drilling mud	The circulating fluid (mud) used in the rotary drilling of wells to clean and condition the hole and to counterbalance formation pressure.
Drilling wastewater	The liquid waste stream separated from recovered drilling mud (fluid) and drill cuttings during the drilling process.

[1] The definitions of terms in the Glossary are only meant to apply to the terms as used throughout the *Technical Development Document for the Effluent Limitations Guidelines and Standards for the Oil and Gas Extraction Point Source Category (TDD)* and the TDD supporting documentation.

[2] The injection of fluids for hydraulic fracturing is also a form of enhanced recovery. See *Legal Environmental Assistance Foundation v. EPA*, 276 F.3d 1253 (11th Cir. 2001). However, Congress amended the Safe Drinking Water Act to exempt hydraulic fracturing (except where diesel fuels are used) from regulation under the UIC program (SDWA Section 1421(d)(1)). Because there are currently no Class II permits for hydraulic fracturing activities, EPA did not consider wells that have been hydraulically fractured within the context of this TDD.

[3] Crude oil includes “lease condensates,” components that are liquid at ambient temperature and pressure.

[4] Natural gas can include “natural gas liquids,” components that are liquid at ambient temperature and pressure.

GLOSSARY (Continued)

Flowback	The produced water generated in the initial period after hydraulic fracturing prior to production (i.e., fracturing fluid, injection water, any chemicals added downhole, and varying amounts of formation water). See long-term produced water.
Formation water	Water that occurs naturally within the pores of rock.
Hydraulic fracturing	Fracturing of rock at depth with fluid pressure. Hydraulic fracturing at depth may be accomplished by pumping water or other liquid or gaseous fluid into a well at high pressures.
Hydraulic fracturing base fluid	The primary component of fracturing fluid to which proppant (sand) and chemicals are added. Hydraulic fracturing base fluids are typically water-based; however there are cases of non-aqueous fracturing fluids (e.g., compressed nitrogen, propane, carbon dioxide). Water-based fluid may consist of only fresh water or a mixture of fresh water, brackish water and/or reused/recycled wastewater.
Hydraulic fracturing fluid	The fluid, consisting of a base fluid and chemical additives, used to fracture rock in the hydraulic fracturing process. Hydraulic fracturing fluids are used to initiate and/or expand fractures, as well as to transport proppant into fractures. See hydraulic fracturing base fluid.
Long-term produced water (LTPW)	The produced water generated during the production phase of the well, after the initial flowback process, which can include increasing amounts of formation water.
Naturally occurring radioactive material (NORM)	Material that contains radionuclides at concentrations found in nature. See also technologically-enhanced radioactive material (TENORM).
Non-TDS removal technologies	Technologies that remove non-dissolved constituents from wastewater, including suspended solids, oil and grease and bacteria, or remove and/or exchange certain ions that can cause scale to form on equipment and interfere with fracturing chemical additives. These technologies are not designed to reduce the levels of dissolved constituents, which are the majority of compounds that contribute to TDS in UOG extraction wastewater.
Produced sand	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 (brine)	The fluid (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 the oil/water separation process.
Proppant	A granular substance (e.g., sand grains, aluminum pellets) that is carried in suspension by the fracturing fluid and that serves to keep the cracks open when fracturing fluid is withdrawn after a fracture treatment.

GLOSSARY (Continued)

Publicly owned treatment works (POTW)	Any device and system used in the storage, treatment, recycling and reclamation of municipal sewage or industrial wastes of a liquid nature that is owned by a state or municipality. This definition includes sewers, pipes, or other conveyances only if they convey wastewater to a POTW providing treatment.
Source water	Water used to make up base fluid in hydraulic fracturing operations. Examples include surface water (e.g., ponds, rivers, lakes), ground water, reused/recycled oil and gas extraction wastewater, and treated industrial and municipal wastewater.
TDS removal technologies	Technologies capable of removing dissolved constituents that contribute to TDS (e.g., sodium, chloride, calcium) as well as the constituents removed by non-TDS removal technologies. Treatment systems with these treatment technologies typically include non-TDS removal technologies for pretreatment (e.g., TSS, oil and grease).
Technologically-enhanced naturally occurring radioactive material (TENORM)	Naturally occurring radionuclides that human activity has concentrated or exposed to the environment.
Total dissolved solids (TDS)	A measure of the matter, including salts (e.g., sodium, chloride, nitrate), organic matter, and minerals dissolved in water. Standard Method 2540C-1997, ASTM D5907-03, and USGS I-1750-85.
Total organic carbon (TOC)	The concentration of organic material in a sample as represented by the weight percent of organic carbon. Standard Method 5310 (B-D)-2000, ASTM D7573-09 and D4839-03, an AOAC method, and a USGS method.
Total suspended solids (TSS)	The matter that remains as residue upon evaporation. Suspended solids include the settable solids that will settle to the bottom of a cone-shaped container in a 60-minute period. Standard Method 2540 D-1997, ASTM D5907-03, and USGS I-3765-85.
Unconventional oil and gas (UOG)	Crude oil[5] and natural gas[6] 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). For the purpose of the rule, the definition of UOG does not include CBM.
UOG extraction wastewater	Wastewater sources associated with production, field exploration, drilling, well completion, or well treatment for unconventional oil and gas extraction (including, but not limited to, drilling muds, drill cuttings, produced sand, produced water).

[5] Crude oil includes “lease condensates,” components that are liquid at ambient temperature and pressure.
[6] Natural gas can include “natural gas liquids,” components that are liquid at ambient temperature and pressure.

Chapter A. INTRODUCTION AND BACKGROUND

1 INTRODUCTION

1.1 Purpose and Summary of the Rule

The EPA is publishing a final Clean Water Act (CWA) regulation that better protects human health and the environment and protects the operational integrity of publicly owned treatment works (POTWs) by establishing pretreatment standards that prevent the discharge of pollutants in wastewater from onshore unconventional oil and gas (UOG) extraction facilities to POTWs (also called municipal wastewater treatment plants). UOG extraction wastewater can be generated in large quantities and has constituents that are potentially harmful to human health and the environment. Because these constituents are not typical of POTW influent wastewater, some UOG extraction wastewater constituents can be discharged, untreated, from the POTW to the receiving stream; can disrupt the operation of the POTW (e.g., by inhibiting biological treatment); can accumulate in biosolids (sewage sludge), limiting its use; and can facilitate the formation of harmful disinfection byproducts (DBPs).

Based on the information collected by the EPA, the requirements in this final rule reflect current industry practices for onshore UOG extraction facilities. Therefore, the EPA does not project that the final rule will impose any costs or lead to pollutant removals: rather, it will ensure that such current industry best practice is maintained over time.

1.2 How to Use This Document

This document supports the EPA's development of pretreatment standards for UOG extraction wastewater. The remainder of Chapter A describes the regulatory background for this rulemaking and related federal regulations. Subsequent chapters provide further detail on what "unconventional oil and gas" means in the context of this rulemaking, then further detail on UOG resources, extraction processes, and wastewater generation. The subsequent chapters also describe the quantity and quality of wastewater generated and the practices industry uses to manage and/or dispose of UOG extraction wastewater.

The pretreatment standards for UOG extraction wastewater are based on data generated or obtained in accordance with the EPA's Quality Policy and Information Quality Guidelines. The EPA's quality assurance (QA) and quality control (QC) activities for this rulemaking include the development, approval, and implementation of Quality Assurance Project Plans for the use of environmental data generated or collected from sampling and analyses, existing databases, and literature searches.

References cited in this document are listed in Chapter E and are identified in the body of the document by reference ID numbers (e.g., 73) and document control numbers (DCNs) (e.g., DCN SGE00586). Information presented in this document was taken from existing data sources, including state and federal agency databases, journal articles and technical papers, technical references, vendor websites, and industry/vendor telephone calls, meetings, and site visits. The EPA classified the quality of the data sources with a "data source quality flag," assigning ratings from "A" for peer-reviewed journal articles and documents prepared by or for a government agency to "D" for documents prepared by a source that could not be verified and that do not include citation information, such as some newspaper articles and conference presentations. For each source cited in this document, the reference list in Chapter E includes the reference ID number, DCN, source citation, and data source quality flag.

Appendix F includes two tables with information about where to find more data about certain topics, tables, and/or figures contained in the TDD. Table F-1 lists supporting memoranda along with their associated DCNs and a brief description of the type of information covered in the memoranda. Each supporting memorandum includes a section about QC activities related to the data and/or analyses it discusses. Table F-1 also lists the relevant TDD sections associated with each memorandum. Table F-2 contains further information about each table and figure in the TDD, including the original source(s) of information for the data presented in the table or figure and the relevant memorandum and attachments, where applicable.

2 REGULATORY BACKGROUND

Wastewater discharges from crude oil[7] and natural gas[8] extraction facilities are subject to federal regulation. Section A.2.1 describes effluent limitations guidelines and standards (ELGs), which are federal regulations that control pollutants in industrial wastewater discharges to waters of the United States and POTWs, respectively. Section A.2.2 discusses the national pretreatment program (40 CFR part 403). Section A.2.3 describes ELGs specifically for the Oil and Gas Extraction point source category (40 CFR part 435).

2.1 Background on Effluent Limitations Guidelines and Pretreatment Standards

Congress passed the Federal Water Pollution Control Act Amendments of 1972, also known as the CWA, to "restore and maintain the chemical, physical, and biological integrity of the Nation's waters" (33 U.S.C. 1251(a)). The CWA establishes a comprehensive program for protecting our nation's waters. Among its core provisions, it prohibits the discharge of pollutants from a point source to waters of the United States, except as authorized under the CWA. Under its Section 402, discharges may be authorized through a National Pollutant Discharge Elimination System (NPDES) permit. The CWA establishes a two-pronged approach for these permits, technology-based controls that establish the floor of performance for all dischargers, and water-quality-based limits where the technology-based limits are insufficient for the discharge to meet applicable water quality standards. To serve as the basis for the technology-based controls, the CWA authorizes the EPA to establish national technology-based effluent limitations guidelines and new source performance standards (NSPS) for discharges from different categories of point sources, such as industrial, commercial, and public sources, that discharge directly into waters of the United States.

Direct dischargers (those discharging directly to surface waters) must comply with effluent limitations in NPDES permits. Technology-based effluent limitations in NPDES permits for direct dischargers are derived from effluent limitations guidelines (CWA Sections 301 and 304) and NSPS (CWA Section 306) promulgated by the EPA, or based on best professional judgment where the EPA has not promulgated an applicable effluent guideline or NSPS (CWA

[7] Crude oil includes "lease condensates," components that are liquid at ambient temperature and pressure.

[8] Natural gas can include "natural gas liquids," components that are liquid at ambient temperature and pressure.

Section 402(a)(1)(B) and 40 CFR 125.3). The effluent guidelines and NSPS established by regulation for categories of industrial dischargers are based on the degree of control that can be achieved using various levels of pollution control technology, as specified in the Act.

The EPA promulgates national effluent guidelines and NSPS for major industrial categories for three classes of pollutants:

- Conventional pollutants (total suspended solids, oil and grease, biochemical oxygen demand [BOD_5], fecal coliform, and pH), as outlined in CWA Section 304(a)(4) and 40 CFR 401.16
- Toxic pollutants (e.g., metals such as arsenic, mercury, selenium, and chromium; and organic pollutants such as benzene, benzo-a-pyrene, phenol, and naphthalene), as outlined in Section 307(a) of the Act, 40 CFR 401.15, and 40 CFR part 423, Appendix A
- Nonconventional pollutants, which are those pollutants that are not categorized as conventional or toxic (e.g., ammonia-N, phosphorus, and TDS)

The CWA also authorizes the EPA to promulgate nationally applicable pretreatment standards that restrict pollutant discharges from facilities that discharge pollutants indirectly, by sending wastewater to POTWs, as outlined in Sections 307(b) and (c) and 33 U.S.C. 1317(b) and (c). Specifically, the CWA authorizes the EPA to establish pretreatment standards for those pollutants in wastewater from indirect dischargers that the EPA determines are not susceptible to treatment by a POTW or which would interfere with POTW operations. Pretreatment standards must be established to prevent the discharge of any pollutant that can pass through, interfere with, or is otherwise incompatible with POTW operations (CWA Sections 307(b) and (c)).

There are four types of standards applicable to direct dischargers (facilities that discharge directly to surface waters), and two types of standards applicable to indirect dischargers (facilities that discharge to POTWs), described in detail below. Subsections 1 through 4 describe standards for direct discharges and subsection 5 describes standards for indirect discharges.

2.1.1 Best Practicable Control Technology Currently Available (BPT)

Traditionally, the EPA defines BPT effluent limitations based on the average of the best performances of facilities within the industry, grouped to reflect various ages, sizes, processes, or other common characteristics. BPT effluent limitations control conventional, toxic, and nonconventional pollutants. In specifying BPT, the EPA looks at a number of factors. The EPA first considers the cost of achieving effluent reductions in relation to the effluent reduction benefits. The Agency also considers the age of equipment and facilities, the processes employed, engineering aspects of the control technologies, any required process changes, non-water-quality environmental impacts (including energy requirements), and such other factors as the Administrator deems appropriate. See CWA Section 304(b)(1)(B). If existing performance is uniformly inadequate, however, the EPA can establish limitations based on higher levels of control than what is currently in place in an industrial category, if it determines that the technology is available in another category or subcategory and can be practically applied.

2.1.2 Best Conventional Pollutant Control Technology (BCT)

The 1977 amendments to the CWA require the EPA to identify additional levels of effluent reduction for conventional pollutants associated with BCT technology for discharges from existing industrial point sources. In addition to other factors specified in Section 304(b)(4)(B), the CWA requires that the EPA establish BCT limitations after consideration of a two-part "cost reasonableness" test. The EPA explained its methodology for the development of BCT limitations on July 9, 1986 (51 Fed. Reg. 24974). Section 304(a)(4) designates the following as conventional pollutants: BOD_5, total suspended solids (TSS), fecal coliform, pH, and any additional pollutants defined by the Administrator as conventional. The Administrator designated oil and grease as an additional conventional pollutant on July 30, 1979 (44 Fed. Reg. 44501; 40 CFR 401.16).

2.1.3 Best Available Technology Economically Achievable (BAT)

BAT represents the second level of stringency for controlling direct discharge of toxic and nonconventional pollutants. In general, BAT-based effluent guidelines and NSPS represent the best available economically achievable performance of facilities in the industrial subcategory or category. Following the statutory language, the EPA considers the technological availability and the economic achievability in determining what level of control represents BAT (CWA Section 301(b)(2)(A)). Other statutory factors that the EPA considers in assessing BAT are the cost of achieving BAT effluent reductions, the age of equipment and facilities involved, the process employed, potential process changes, and non-water-quality environmental impacts, including energy requirements and such other factors as the Administrator deems appropriate (CWA Section 304(b)(2)(B)). The Agency retains considerable discretion in assigning the weight to be accorded these factors (*Weyerhaeuser Co. v. Costle*, 590 F.2d 1011, 1045, D.C. Cir. 1978).

2.1.4 Best Available Demonstrated Control Technology (BADCT)/New Source Performance Standards (NSPS)

NSPS reflect effluent reductions that are achievable based on the best available demonstrated control technology (BADCT). Owners of new facilities have the opportunity to install the best and most efficient production processes and wastewater treatment technologies. As a result, NSPS should represent the most stringent controls attainable through the application of the BADCT for all pollutants (that is, conventional, nonconventional, and toxic pollutants). In establishing NSPS, the EPA is directed to take into consideration the cost of achieving the effluent reduction and any non-water quality environmental impacts and energy requirements (CWA section 306(b)(1)(B)).

2.1.5 Pretreatment Standards for Existing Sources (PSES) and New Sources (PSNS)

As discussed above, Section 307(b) of the Act calls for the EPA to issue pretreatment standards for discharges of pollutants from existing sources to POTWs. Section 307(c) of the Act calls for the EPA to promulgate PSNS. Both standards are designed to prevent the discharge of pollutants that pass through, interfere with, or are otherwise incompatible with the operation of POTWs. Categorical pretreatment standards for existing sources are technology-based and are analogous to BPT and BAT effluent limitations guidelines, and thus the Agency typically considers the same factors in promulgating PSES as it considers in promulgating BAT. See *Natural Resources Defense Council v. EPA*, 790 F.2d 289, 292 (3rd Cir. 1986). Similarly, in establishing pretreatment standards for new sources, the Agency typically considers the same factors in promulgating PSNS as it considers in promulgating NSPS (BADCT).

2.2 The National Pretreatment Program (40 CFR part 403)

To implement the National Pretreatment Program, the EPA developed the General Pretreatment Regulations to protect POTW operations. As described in Chapter 2 of the EPA's introduction to the program (19 DCN SGE00249), these regulations apply to all non-domestic sources that introduce pollutants into a POTW. Non-domestic sources are referred to as industrial users (IUs). To distinguish small, simple IUs (e.g., coin-operated laundries, commercial car washes) from larger, more complex IUs (e.g., crude oil refineries, steel mills), the EPA established a category called significant IUs (SIUs). The General Pretreatment Regulations apply to all nondomestic sources that introduce pollutants into a POTW and are intended to protect POTW operations from "pass-through" and "interference." See the textbox for a list of prohibited pollutant discharges, as defined by 40 CFR part 403.

Pretreatment Program Implementation

Control authorities implement and enforce the National Pretreatment Program. The Control Authority refers to the POTW if the POTW has an approved Pretreatment Program, or the state or the EPA if the POTW does not have an approved Program. Most of the responsibility for implementing the National Pretreatment Program rests on local municipalities. For example, 40 CFR 403.8(a) requires that POTWs designed to treat more than 5 million gallons per day (MGD) of wastewater and receiving pollutants from IUs that pass through or interfere with the POTW's operation must establish a local pretreatment program.[9] The POTW's NPDES permit will include requirements for developing a local pretreatment program that will control the wastewater discharged to the POTW by IUs.

The National Pretreatment Program regulations identify specific requirements

40 CFR 403.5(b) notes eight categories of pollutant discharge prohibitions:

1. Pollutants that create a fire or explosion hazard in the POTW
2. Pollutants that will cause corrosive structural damage to the POTW
3. Solid or viscous pollutants in amounts that will obstruct the flow in the POTW, resulting in interference
4. Any pollutant, including oxygen-demanding pollutants (e.g., BOD), released in a discharge at a flow rate and/or pollutant concentration that will interfere with the POTW
5. Heat in amounts that will inhibit biological activity in the POTW, resulting in interference
6. Petroleum oil, nonbiodegradable cutting oil, or products of mineral oil origin in amounts that will cause interference or pass-through
7. Pollutants that result in the presence of toxic gases, vapors, or fumes within the POTW in a quantity that may cause acute worker health and safety problems
8. Any trucked or hauled pollutants, except at discharge points designated by the POTW

[9] POTWs designed to treat less than 5 MGD may be required by their Approval Authority to develop a local pretreatment program if the nature or volume of the industrial influent, treatment process upsets, violations of POTW effluent limitations, contamination of municipal sludge, or other circumstances warrant one to prevent interference with the POTW or pass through.

that apply to IUs, additional requirements that apply to all SIUs, and certain requirements that apply only to categorical industrial users (CIUs). There are three types of national pretreatment requirements:

- Prohibited discharge standards that include general and specific prohibition on discharges
- Categorical pretreatment standards
- Local limits

Prohibited discharge standards. The prohibited discharge standards are not technology-based and are intended to prevent the POTW from receiving pollutants(s) that may cause pass through or interference. All IUs—regardless of whether they are subject to any other national, state, or local pretreatment requirements—are subject to the general and specific prohibitions identified in 40 CFR 403.5(a) and (b), respectively.

- General prohibitions forbid the discharge of substances that pass through the POTW or interfere with its operation. Note that under the definition of "pass-through," only pollutants that are limited in the POTW's NPDES permit are prohibited from pass-through by the general prohibitions.
- Specific prohibitions in 40 CFR 403.5(b) forbid eight categories of pollutant discharges that will harm POTW workers or the POTW, including the collection system. Pollutant discharges outside these defined categories are not specifically prohibited.

Categorical pretreatment standards. As discussed in Section A.2.1, the CWA authorizes the EPA to promulgate national categorical pretreatment standards for industrial sources that discharge to POTWs. Developed by the EPA on an industry-specific basis, categorical pretreatment standards set regulatory requirements based on the performance of technology. These requirements typically limit discharges of toxic and nonconventional pollutants that could cause pass-through or interference.[10] Categorical pretreatment standards represent a baseline level of control that every IU in the category must meet, without regard to the individual POTW to which it discharges. IUs subject to categorical pretreatment standards are known as CIUs. The EPA establishes two types of categorical pretreatment standards for CIUs: PSES and PSNS.

Local limits. Developed by individual POTWs, local limits address the specific needs and concerns of the POTW, its sludge, and its receiving waters. Typically, POTWs develop local limits for discharges from all SIUs, not just CIUs. To evaluate the need for local limits, the POTW will survey the IUs subject to the pretreatment program, determine the pollutants discharged and whether they present a reasonable potential for pass through or interference, evaluate the capability of the POTW system to address pollutants received by all users (IUs and

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[10] In determining whether a pollutant would pass through POTWs for categorical pretreatment standards, the EPA generally compares the percentage of a pollutant removed by well-operated POTWs performing secondary treatment to the percentage removed by a candidate technology basis. A pollutant is determined to pass through POTWs when the median percentage removed nationwide by well-operated POTWs is less than the median percentage removed by the candidate technology basis.

residential sources), and implement a system to control industrial discharges. Additional information can be found in the EPA's 2004 *Local Limits Development Guidance* (80 DCN SGE00602*)*.

Responsibilities of Control Authorities and IUs

The Control Authority (POTW, state, or EPA) controls the discharges from the IU through an individual control mechanism, often called an IU permit. The Control Authority may also issue general permits under certain conditions if it has adequate legal authority and approval. POTWs with approved local pretreatment programs must have procedures for:

- Identifying all possible IUs, and the character and volume of pollutants from IUs introduced to the POTW
- Communicating applicable standards and requirements to IUs
- Receiving and analyzing reports
- Inspecting IUs, including annual inspections of SIUs
- Sampling in certain cases
- Investigating noncompliance with pretreatment standards and requirements
- Reporting to the Approval Authority (i.e., state or regional pretreatment program)

Each IU of a POTW is responsible for compliance with applicable federal, state, and local pretreatment standards and requirements.

Approval Authority

POTWs establish local pretreatment programs to control discharges from non-domestic sources. These programs must be approved by the Approval Authority, which is also responsible for overseeing implementation and enforcement of the programs (19 DCN SGE00249). The Approval Authority is the director in a NPDES authorized state with an approved state pretreatment program, or the appropriate EPA regional administrator in a non-NPDES authorized state or NPDES state without an approved state pretreatment program. A state may have a NPDES permit program but lack a state pretreatment program. One example is Pennsylvania, which the EPA has authorized for the NPDES program but not for the pretreatment program. EPA Region 3 is the Approval Authority for POTW pretreatment programs in Pennsylvania.

Hauled Wastewater

As discussed in the EPA's *Introduction to the National Pretreatment Program* (19 DCN SGE00249), in addition to receiving wastewater through the collection system, many POTWs accept trucked wastewater. An IU may truck its wastewater to a POTW when it is outside the POTW's service area (e.g., in a rural area) and is not connected to the collection system. Just like wastewater received through the collection system, trucked wastewater is subject to the General Pretreatment Regulations and is also subject to applicable categorical pretreatment standards. Therefore, the POTW must regulate hauled wastewater from CIUs or hauled wastewater that otherwise qualifies the discharger as an IU in accordance with the requirements of the General Pretreatment Regulations and any applicable categorical pretreatment standards, including any applicable requirements for permitting and inspecting the facility that generates the wastewater.

Section 403.5(b)(8) of the General Pretreatment Regulations specifically prohibits the introduction of any trucked or hauled pollutants to the POTW, except at discharge points designated by the POTW. As explained in *Introduction to the National Pretreatment Program* (19 DCN SGE00249), Section 403.5(b)(8) of the General Pretreatment Regulations is the only pretreatment requirement specifically addressing hauled wastewater. POTWs are not required to have waste hauler control programs. However, POTWs that accept any hazardous waste by truck, rail, or dedicated piping at the POTW facility are considered treatment, storage, and disposal facilities (TSDFs) subject to management requirements under the Resource Conservation and Recovery Act (RCRA). Consequently, a POTW should not accept industrial hauled waste without considering the implications of its acceptance (see 40 CFR part 260).

2.3 Oil and Gas Extraction ELG Rulemaking History

The EPA first promulgated the Oil and Gas Extraction ELGs (40 CFR part 435) in 1979, and substantially amended the regulation in 1993 (Offshore), 1996 (Coastal), and 2001 (Synthetic-Based Drilling Fluids). The Oil and Gas Extraction industrial category is subcategorized[11] in 40 CFR part 435 as follows:

- Subpart A: Offshore
- Subpart C: Onshore
- Subpart D: Coastal
- Subpart E: Agricultural and Wildlife Water Use
- Subpart F: Stripper Wells

The existing subpart C and subpart E regulations cover wastewater discharges from field exploration, drilling, production, well treatment, and well completion activities in the onshore oil and gas industry. The limitations for direct dischargers in the Onshore Subcategory represent Best Practicable Control Technology Currently Available (BPT). Based on the availability and economic practicability of underground injection technologies, the BPT-based limitations for direct dischargers require zero discharge of pollutants to waters of the United States. However, there are currently no requirements in subpart C that apply to onshore oil and gas extraction facilities that are “indirect dischargers,” i.e., those that send their discharges to POTWs. Although oil and gas resources occur in unconventional formations in offshore and coastal regions, recent development of UOG resources in the United States has occurred primarily onshore in regions where the regulations in subpart C (Onshore) and subpart E (Agricultural and Wildlife Water Use) apply; thus, the gap in onshore regulations is the focus of this final rule. For this reason, only the regulations that apply to onshore oil and gas extraction are described in more detail here.

Note that facilities that accept oil and gas extraction wastewater from offsite may be subject to requirements in 40 CFR part 437, the Centralized Waste Treatment category (see Section D.4 for more information).

[11] Subpart B is reserved.

Subpart C: Onshore Subcategory

Applicability. As set forth in 40 CFR 435.30, subpart C applies to facilities engaged in production, field exploration, drilling, well completion, and well treatment in the oil and gas extraction industry, located landward of the inner boundary of the territorial seas—and not included in the definition of other subparts, including subpart D (Coastal) at 40 CFR 435.40.

Direct discharge requirements. The regulations at 40 CFR 435.32 specify the following for BPT:

> *…there shall be no discharge of waste water pollutants into navigable waters from any source associated with production, field exploration, drilling, well completion, or well treatment (i.e., produced water, drilling muds, drill cuttings, and produced sand).*

Subpart E: Agricultural and Wildlife Use Subcategory

Applicability. As set forth in 40 CFR 435.50, subpart E applies to 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 of the United States. Definitions in 40 CFR 435.51(c) explain that the term "use in agricultural or wildlife propagation" means that two things are true:

- The produced water is of good enough quality to be used for wildlife or livestock watering or other agricultural uses.
- The produced water is actually put to such use during periods of discharge.

Direct discharge requirements. Subpart E prohibits the discharge of waste pollutants into navigable waters from any source (other than produced water) associated with production, field exploration, drilling, well completion, or well treatment (i.e., drilling muds, drill cuttings, produced sands). Therefore, the only allowable discharge under this subpart is produced water[12] that meets the "good enough quality" and actual use requirements described above, with an oil and grease concentration not exceeding 35 mg/L.

3 STATE PRETREATMENT REQUIREMENTS

In addition to applicable federal requirements, some states regulate the management, storage, and disposal of oil and gas extraction wastewater, including regulations concerning pollutant discharges to POTWs from oil and gas extraction facilities. In addition to pretreatment requirements, some states have indirectly addressed the issue of pollutant discharges to POTWs by limiting the management and disposal options available to operators. Table A-1 summarizes state regulations and/or guidance related to UOG extraction wastewater discharges to POTWs.

[12] Produced water is not defined in subpart C (onshore) or subpart E (agricultural and wildlife use). For subparts A (offshore) and D (coastal), produced water is defined as "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."

Table A-1. Summary of State Regulations/Guidance

State	State Authority(s)	State Code (Source DCN)	State's Relevant Regulations or Guidance
PA	EPA Region 3; PA DEP	25 PA Code Ch. 95.10 (14 SGE00187; 148 SGE00982; 63 SGE00545)	The Pennsylvania Code, amended in 2010, states that waters of Pennsylvania will not exceed a threshold of 500 mg/L of TDS. In addition, the standard is applied specifically to the natural gas sector, which PA DEP based on several factors. Discharge loads of TDS authorized by PA DEP are exempt from the regulation until the net load is to be increased. It is important to note that only an increase in net TDS load is considered to be a new or expanding discharge loading. Further (according to PA Bulletin, Doc. No. 10-1572, 14 DCN SGE00187), the pretreatment requirements are "that POTWs may accept these wastewaters only if the wastes are first treated at a CWT facility and meet the end-of-pipe effluent standards imposed by the rule. In effect, the final rule regulates these indirect discharges in a manner consistent with direct discharges of these wastes."
OH	OH EPA; OH DNR	OH R.C. Title 15, Chapter 1509, part 22(C)(1) (149 SGE00983)	The Ohio Revised Code includes a provision that describes the acceptable disposal of brine:[13] injection into an underground formation, surface application, enhanced recovery, or in any other manner that is approved by a permit. This provision applies to any well except an exempt Mississippian well.[14]
WV	WV DEP	(129 SGE00766; 130 SGE00767)	A WV DEP guidance document "discourages POTWs from accepting wastewater from oil and gas operations." This document groups coalbed methane and Marcellus Shale wastewaters together. WV DEP discourages this practice "because these wastewaters essentially pass through sewage treatment plants and can cause inhibition and interference with treatment plant operations" (130 DCN SGE00767).
MI	MI DEQ	MI Oil and Gas Regulations, part 324.703 (20 SGE00254)	Michigan's Oil and Gas Regulations discuss the well permittee's responsibility for handling waste. The regulations dictate that oil and gas waste must be injected into an underground well such that there is no additional wastewater stream.

Abbreviations: PA DEP—Pennsylvania Department of Environmental Protect; OH EPA—Ohio Environmental Protection Agency; OH DNR—Ohio Department of Natural Resources; R.C.—Revised Code; WVDEP—West Virginia Department of Environmental Protection; MI DEQ—Michigan Department of Environmental Quality

[13] The Ohio EPA defines brine as "all saline geological formation water resulting from, obtained from, or produced in connection with the exploration, drilling, or production of oil or gas, including saline water resulting from, obtained from, or produced in connection with well stimulation or plugging of a well."

[14] OH R.C. Section 1509.01 defines an "exempt Mississippian well" as a well that (1) was drilled and completed before January 1, 1980; (2) is in an unglaciated part of the state; (3) was completed in a reservoir no deeper than the Mississippian Big Injun sandstone in areas underlain by Pennsylvanian or Permian stratigraphy, or the Mississippian Berea sandstone in areas directly overlain by Permian stratigraphy; and (4) is used primarily to provide oil or gas for domestic use.

The Groundwater Protection Council's (GWPC's) 2014 report *Regulations Designed to Protect State Oil and Gas Water Resources* (162 DCN SGE01077) describes a survey of 27 oil-and-gas-producing states[15]

> *regarding the use of POTWs for discharging production fluids including flowback water. Of the states responding, three indicated this practice was banned by regulation, five states did not have a regulation covering this disposal method but would not allow it as a matter of policy, and nine indicated it was either regulated by another state agency or would otherwise be allowed under certain circumstances.…[A]s of 2013, six state oil and gas agencies had permitting requirements for POTWs accepting this waste.*

In 2015, State Review of Oil & Gas Environmental Regulations, Inc. (STRONGER)[16] published voluntary guidelines to help states develop effective oil and gas regulatory programs for production wastes (197 DCN SGE01208).

4 Related Federal Requirements

As required by the Safe Drinking Water Act, Section 1421, the EPA has promulgated regulations to protect underground sources of drinking water through underground injection control (UIC) programs that regulate the injection of fluids underground. These regulations are found at 40 CFR parts 144 through 148, and specifically prohibit any underground injection not authorized by UIC permit (40 CFR 144.11). They classify underground injection into six classes; wells that inject fluids brought to the surface in connection with oil and gas production are classified as Class II UIC wells (see Section D.2 for more information). Thus, an onshore oil and gas extraction facility that seeks to meet zero discharge requirements through underground injection of wastewater must dispose of the wastewater in a well with a Class II disposal well permit.

[15] Alabama, Alaska, Arkansas, California, Colorado, Florida, Illinois, Indiana, Kansas, Kentucky, Louisiana, Michigan, Mississippi, Montana, Nebraska, New Mexico, New York, North Dakota, Ohio, Oklahoma, Pennsylvania, South Dakota, Texas, Utah, Virginia, West Virginia, and Wyoming.

[16] STRONGER's mission is to assist states in documenting the environmental regulations associated with the exploration, development, and production of crude oil and natural gas (214 DCN SGE01331).

Chapter B. SCOPE AND INDUSTRY DESCRIPTION

As described in Chapter A, this document provides background information and data considered in the development of the revised ELGs for the Oil and Gas Extraction point source category to address discharges from UOG extraction facilities to POTWs. To provide context for discussions of UOG extraction wastewater volumes and characteristics (Chapter C) and management and disposal practices (Chapter D), this chapter contains:

- An overview of UOG and the scope of this rulemaking
- A discussion of the UOG well development process, with a focus on the processes that generate UOG extraction wastewater
- A description of the industry, including historical and current UOG drilling and completion activity and total UOG resource potential

Relevant national economic information about the UOG industry is included in a separate document in the record, titled *Profile of the Unconventional Oil and Gas Industry*, (212 DCN SGE01277).

1 UNCONVENTIONAL OIL AND GAS

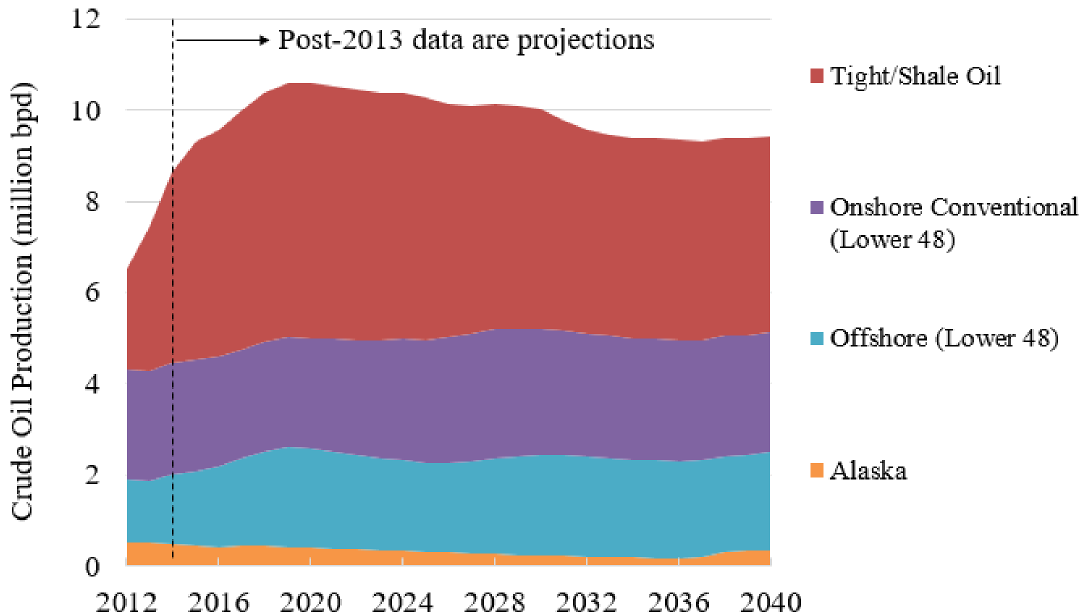
1.1 Overview of Oil and Gas Resources

The United States has developed oil and gas resources since 1821 (1 DCN SGE00010). Beginning around 2000, advances in technologies such as horizontal drilling and advances in hydraulic fracturing made it possible to more economically produce oil and natural gas from tight and shale resources (164 DCN SGE01095). The Energy Information Administration (EIA)'s Annual Energy Outlook (AEO), which publishes historical and projected future oil and gas production by resource type, shows the increasingly large role of UOG. The EIA's 2015 AEO projects that, in the next 30 years, the majority of the country's crude oil[17] and natural gas[18] will come from unconventional resources (194 DCN SGE01192). Figure B-1 and Figure B-2 show the historical and future profiles of conventional oil and gas (COG) and UOG production in the United States by resource type according to the EIA.[19] Coalbed methane (CBM) and COG are included in some of the figures in this chapter, but are identified separately within each figure.

[17] Crude oil includes "lease condensates," components that are liquid at ambient temperature and pressure.

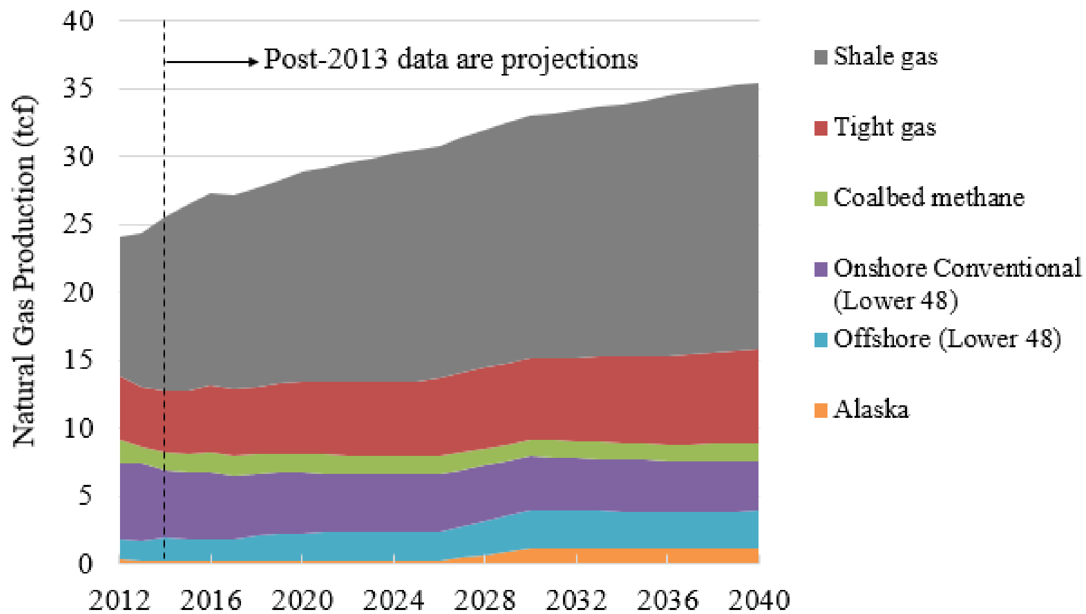
[18] Natural gas can include "natural gas liquids," components that are liquid at ambient temperature and pressure.

[19] In Figure B-1, the EIA refers to all types of unconventional oil including shale as "tight oil." As explained in Section B.1, this TDD differentiates between shale and tight oil.



Source: Created by the EPA using data from the EIA's 2015 AEO (194 DCN SGE01192)

Figure B-1. Historical and Projected Crude Oil Production by Resource Type[20]



Source: Created by the EPA using data from the EIA's 2015 AEO (194 DCN SGE01192)

Figure B-2. Historical and Projected Natural Gas Production by Resource Type[21]

[20] The EIA reported these data as "tight oil" production but stated that they include production from both shale oil formations (e.g., Bakken, Eagle Ford) and tight oil formations (e.g., Austin Chalk). Condensates are included in crude oil production. Alaska includes conventional onshore and offshore production in Figure B-1.

[21] Alaska includes conventional onshore and offshore production in Figure B-2.

1.2 Scope of This Rulemaking

The scope of this final rule is specific to pretreatment standards for onshore oil and gas extraction facilities (subpart C) of 40 CFR part 435. The EPA did not propose to reopen the regulatory requirements applicable to any other subpart or to the requirements for direct dischargers in subpart C. Rather, the scope of the final rule amends subpart C only to add requirements for indirect dischargers where there currently are none. Further, the final rule establishes requirements for wastewater discharges from UOG extraction facilities to POTWs. It does not establish requirements for wastewater discharges from COG or CBM extraction facilities. EPA reserves such standards for a future rulemaking, if appropriate. Section B.1.2.1 describes publicly available information defining onshore UOG extraction facilities, Section B.1.2.2 describes EPA's record of UOG operators' understanding of the names and types of formations from which they extract, and Section B.1.2.3 shows how EPA used this information to define the scope of this rule.

1.2.1 Description of UOG Resources in Publicly Available Sources

Onshore UOG extraction facilities make up the universe that would be subject to this final rule. For purposes of the final rule, the EPA is defining "unconventional oil and gas" 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)." This definition is generally consistent with those in other readily available sources, but—as indicated above—for purposes of this final rule, it does not extend to CBM. The following list presents examples of similar definitions from publicly available sources:

- A report by the Energy Water Initiative (EWI)[22] titled *U.S. Onshore Unconventional Exploration and Production Water Management Case Studies* defines unconventional as "Oil and natural gas production from shale and tight (low permeability) formations—a relatively new method of production—as compared to traditional oil and gas well drilling and production that tapped underground reserves with greater permeability" (224 DCN SGE01344).
- The 2014 Federal Multi-Agency Collaboration on Unconventional Oil and Gas Research states "Unconventional oil and gas (UOG) refers to resources such as shale gas, shale oil, tight gas, and tight oil that cannot be produced economically through standard drilling practices" (214 DCN SGE01330).
- The U.S. Geological Survey (USGS) has described UOG resources as including shale and tight resources in several published documents.
  — USGS's 2014 report titled *U.S. Geological Survey Assessments of Continuous (Unconventional)*[23] *Oil and Gas Resources, 2000 to 2011*, categorizes resources into four distinct reservoir categories: "shale gas, coalbed gas, tight gas, and continuous oil" (211 DCN SGE01275).

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[22] EWI is a collaborative effort among participating members of the U.S. oil and natural gas industry including Anadarko Petroleum, Apache Corporation, BP America Production Company, Chesapeake Energy Corporation, ConocoPhillips, Devon Energy, Marathon Oil, Newfield Exploration Company, Pioneer Natural Resources USA, Inc., QEP Resources, Inc., Southwestern Energy, Talisman Energy USA Inc.

[23] USGS sometimes refers to unconventional resources as "continuous" resources.

  - USGS's 2015 report titled *Trends in Hydraulic Fracturing…in the United States from 1947 through 2010—Data Analysis and Comparison to the Literature* states that "…development of unconventional, continuous accumulations of oil, gas, and natural gas liquids, including tight oil and gas, coalbed methane, and shale gas..." (164 DCN SGE01095).
- Papers published by the Society of Petroleum Engineers (SPE) have described UOG as including shale and tight oil and gas. For example, SPE's 2012 paper titled *Comparisons and Contrasts of Shale Gas and Tight Gas Developments, North American Experience and Trends* includes the phrases "The more recent growth in natural gas production from unconventional tight and especially shale reservoirs is a result of technological advances (hydraulic fracturing and horizontal wells" and "…unconventional gas resources, including CBM, Shale Gas, and Tight Gas" (57 DCN SGE00527).
- A survey by the American Petroleum Institute (API) and the American Natural Gas Alliance states, "…unconventional wells are considered to be shale gas wells, coal bed wells, and tight sand wells which must be fractured to produce economically" (28 DCN SGE00291).
- IHS, Inc.'s 2012 report titled *America's New Energy Future: The Unconventional Oil and Gas Revolution and the US Economy* (111 DCN SGE00728) states, "Today, unconventional natural gas—which includes shale gas, as well as natural gas from tight sands formations and coal bed methane—accounts for nearly 65% of US natural gas production" and "…'tight oil' or 'unconventional'—crude oil and condensate production from sources such as shale and other low permeability rocks…"
- Scientific journal articles often indicate the names of formations that are considered to be unconventional formations. For example, Warner et al., 2014, use the phrase "The development of several unconventional formations (e.g., Marcellus, Barnett, and Fayetteville)…" (173 DCN SGE01166). Similarly, Lewis, 2012, identifies "…unconventional gas exploration in the Marcellus shale…" (35 DCN SGE00345).

The EPA also looked at available state definitions, finding that four states have defined "unconventional oil and gas" in their regulations. As expected, many of these definitions are specific to resources and formations within those states. Table B-1 summarizes these states' definitions.

Table B-1. Summary of State Regulatory Definitions

State	Code, Chapter, or Section	Regulatory Definition	DCN
AK	AS 38.05.965(14)	"Nonconventional gas" means coalbed methane, gas contained in shales, or gas hydrates.	204 SGE01250
AR	Rule B-43	(a) For purposes of this rule, unconventional sources of supply shall mean those common sources of supply that are identified as the Fayetteville Shale, the Moorefield Shale, and the Chattanooga Shale Formations, or their stratigraphic shale equivalents, as described in published stratigraphic nomenclature recognized by the Arkansas Geological Survey or the United States Geological Survey. (b) For purposes of this rule, conventional sources of supply shall mean all common sources of supply that are not defined as unconventional sources of supply in section (a) above.	205 SGE01251
OK	165:10-3-28.(b)(20)	"Unconventional reservoir" shall mean a common source of supply that is a shale or a coalbed. "Unconventional reservoir" shall also mean any other common source of supply designated as such by Commission order or rule. "Conventional reservoir" shall mean a common source of supply that is not an unconventional reservoir.	206 SGE01252
PA	PA Code, Chapter 78. Oil and Gas Wells	Unconventional formation—A geological shale formation existing below the base of the Elk Sandstone or its geologic equivalent stratigraphic interval where natural gas generally cannot be produced at economic flow rates or in economic volumes except by vertical or horizontal well bores stimulated by hydraulic fracture treatments or by using multilateral well bores or other techniques to expose more of the formation to the well bore. Unconventional well—A bore hole drilled or being drilled for the purpose of or to be used for the production of natural gas from an unconventional formation. Conventional formation—A formation that is not an unconventional formation.	207 SGE01253

1.2.2 UOG Operators' Understanding of UOG Resources and Formations

Oil and gas industry representatives are aware of the names and types of formations from which they are producing natural gas or crude oil. The EPA conducted several calls and site visits with industry representatives; the documentation from these calls and site visits shows that operators know both the names of the formations in which they are active and whether the formations are shale or tight (e.g., tight sands, carbonates). The following list presents some examples of operators' knowledge on these subjects:

- On February 29, 2012, the EPA met with members of the oil and gas industry to discuss economic and engineering topics for this rulemaking. Two applicable excerpts from the meeting notes (54 DCN SGE00521) are:
  - "Apache is looking at potential closed loop fracturing projects in the Eagle Ford and Barnett shale plays of Texas."

  - "…[H]ydraulic fracturing in tight sands and shale is very similar. However, a few minor differences include: tight sands fracturing fluids may require more clay control additives than shale fracturing fluids; tight sands fracturing fluids may not need the same viscosity as shale fracturing fluids."
- The Petroleum Equipment Suppliers Association (PESA) surveyed 206 oil and gas operators regarding the outlook for domestic unconventional resources. Some of the results of the survey, including a graph of "Frac Jobs Targeting Selected Formations in North America," indicate tight gas, shales, CBM, etc. (70 DCN SGE00575).
- In a conference call with the EPA, North Star Disposal specified that it receives water from shale gas operations. Figure 1 of the North Star conference call notes shows all the "Pennsylvania Marcellus *Shale* Gas Wells" that sent wastewater to North Star in 2011, indicating that North Star knows which gas wells are in shale formations. North Star is a drilling and operating company; as of July 2, 2012 (the date of the conference call), it owned seven underground injection wells (23 DCN SGE00279).
- After a site visit with Anadarko Petroleum on June 26, 2012, the EPA was given information about the company's active operations. Anadarko specified its active operation in formations categorized as shale gas, shale oil, and tight gas. Table 3-1 in the Anadarko site visit report lists Anadarko's active U.S. formations by name (e.g., Eagle Ford) and type (e.g., shale oil) (24 DCN SGE00280).
- In a conference call with the EPA, BLX, Inc., indicated that it knows which wells are conventional versus unconventional, as well as which formation it is drilling into. For example, the call notes state that "BLX…has drilled conventional wells since 1986 and decided to drill their first Marcellus well in 2006." The conference call took place on May 15, 2012 (25 DCN SGE00283).
- EPA conducted a site visit with Citrus Energy on June 19, 2012, and the operator indicated that they know which basin and/or formation they are drilling into. During the site visit, Citrus Energy representatives listed two specific basins/formations in which it was (or had been) active: "Prior to drilling in the Marcellus region, Citrus was active in the Anadarko basin in Oklahoma and Barnett Shale in Texas" (21 DCN SGE00275).
- In a conference call with the EPA, ConocoPhillips provided a count of its shale wells by formation; it also mentioned "an on-going recycling pilot project for produced water from a conventional formation." The conference call took place on November 5, 2012 (100 DCN SGE00695).
- During the 2012 Tight Oil Water Management Summit Conference in Denver, Colorado, the EPA attended a presentation by Katherine Fredriksen from Consol Energy. Consol specified that the water discussed in the presentation was "produced water from [its] shale operations" (33 DCN SGE00305.A10).
- During the 2014 Produced Water Reuse Initiative Conference in Denver, Colorado, the EPA attended a presentation by Erik Anglund from Anadarko Petroleum. The presentation showed Anadarko's operations throughout the country and categorized them as either "shale play," "natural gas," or "oil and natural gas" (160 DCN SGE01017.A05).

Operators must complete and submit a well completion report to their governing state oil and gas agency after completing each new oil and gas well. All states require operators to submit information on the geologic formation name (e.g., Bakken, Marcellus)[24] in which the well is completed, and all states except Florida require information about the well completion method (e.g., hydraulic fracturing, acidization). The fact that well completion reports require the formation name demonstrates that operators will have that information. These well completion reports are further discussed in Section B.2.3 and in a separate memorandum to the record, titled *Well Completion Reports Memorandum* (210 DCN SGE01263).

Information from the well completion reports is ultimately reported, along with other reports,[25] into a national database of wells called Drillinginfo (DI) Desktop® (176 DCN SGE01170). DI is an oil and gas research firm in Austin, Texas. The DI Desktop® database contains a record (i.e., row) for each oil and gas well drilled in the United States.[26] Basic well data contained in DI Desktop® for each well include the API number,[27] state, basin, formation, operator, and well trajectory.[28] For much of the underlying data that support this TDD, the EPA relied on analysis of the DI Desktop® well database described in a separate memorandum titled *Analysis of DI Desktop®* (182 DCN SGE01180).

1.2.3 Rule Applicability

The final rule establishes requirements for wastewater discharges from UOG extraction facilities to POTWs. Based on the definition of unconventional oil and gas: 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), the EPA was able to identify shale and tight formations in the United States using publicly-available sources. The list of shale and/or tight formations is published by the U.S. Energy Information Administration (EIA), and the name of the formation into which a well is drilled is reported in well completion reports required by all States and compiled into the national database owned by DI (see section above).

The U.S. EIA publishes summary maps of natural gas in the Lower 48 States and North America and the maps are separated into the following: Conventional Fields, Shale Gas and Oil Plays (193 DCN SGE01191), Major Tight Gas Plays, which includes tight gas and tight oil[29] (11

[24] Well completion reports sometimes refer to the formation as the “reservoir” or “pool.”

[25] Operators must submit other types of reports to state oil and gas agencies in addition to well completion reports. Examples include production reports (crude oil, natural gas, and produced water), well integrity reports, well closure reports, etc.

[26] The database is subject to restrictions on its use and dissemination. Based on the license agreement for the version of the database used to support these rulemaking analyses, access to the raw data in the database is limited to ERG (EPA’s contractor) and EPA personnel only, although summary data developed using queries may be disseminated more widely. Wholesale “data dumps” may not be disseminated electronically. All disseminations of such summary data, however, should cite Drillinginfo as the source of the information.

[27] An API number is a unique identifier assigned to each well drilled for oil and gas in the United States.

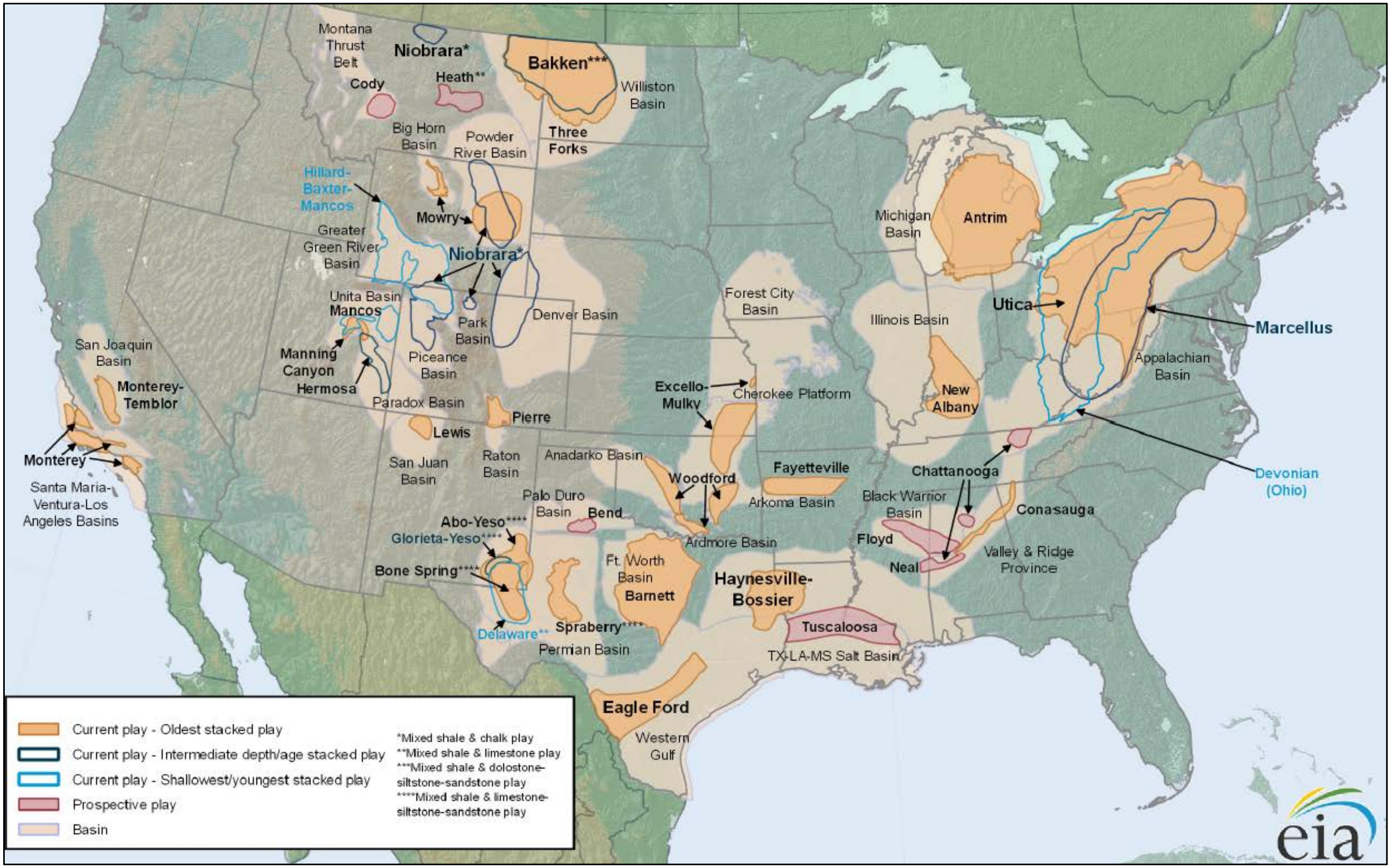
[28] DI Desktop® includes more technical information about each well such as depth, completion date, spud date, annual crude oil, natural gas, and produced water production per well.

[29] For example, the tight gas map (11 DCN SGE00155) shows the Austin Chalk formation in the West Gulf Coast Basin. In its *Assumptions to the 2015 Annual Energy Outlook* report, the EIA shows that about half of the technically recoverable resource in the Austin Chalk is crude oil.

DCN SGE00155), Coalbed Methane Fields, and Offshore Fields (208 DCN SGE01255). Figure B-3 and Figure B-4 show the UOG resources, respectively, in the lower 48 states.[30] The EIA also periodically publishes a list of all known UOG formation names in its AEO reports. The most recent list can be found in Table 9.3 of the EIA's *Assumptions to the 2015 Annual Energy Outlook* report (192 DCN SGE01190). Appendix F (Table F-3 and Table F-4) provides an updated and more thorough list of UOG formations than what is shown in the EIA maps below (i.e., Figure B-3 and Figure B-4).

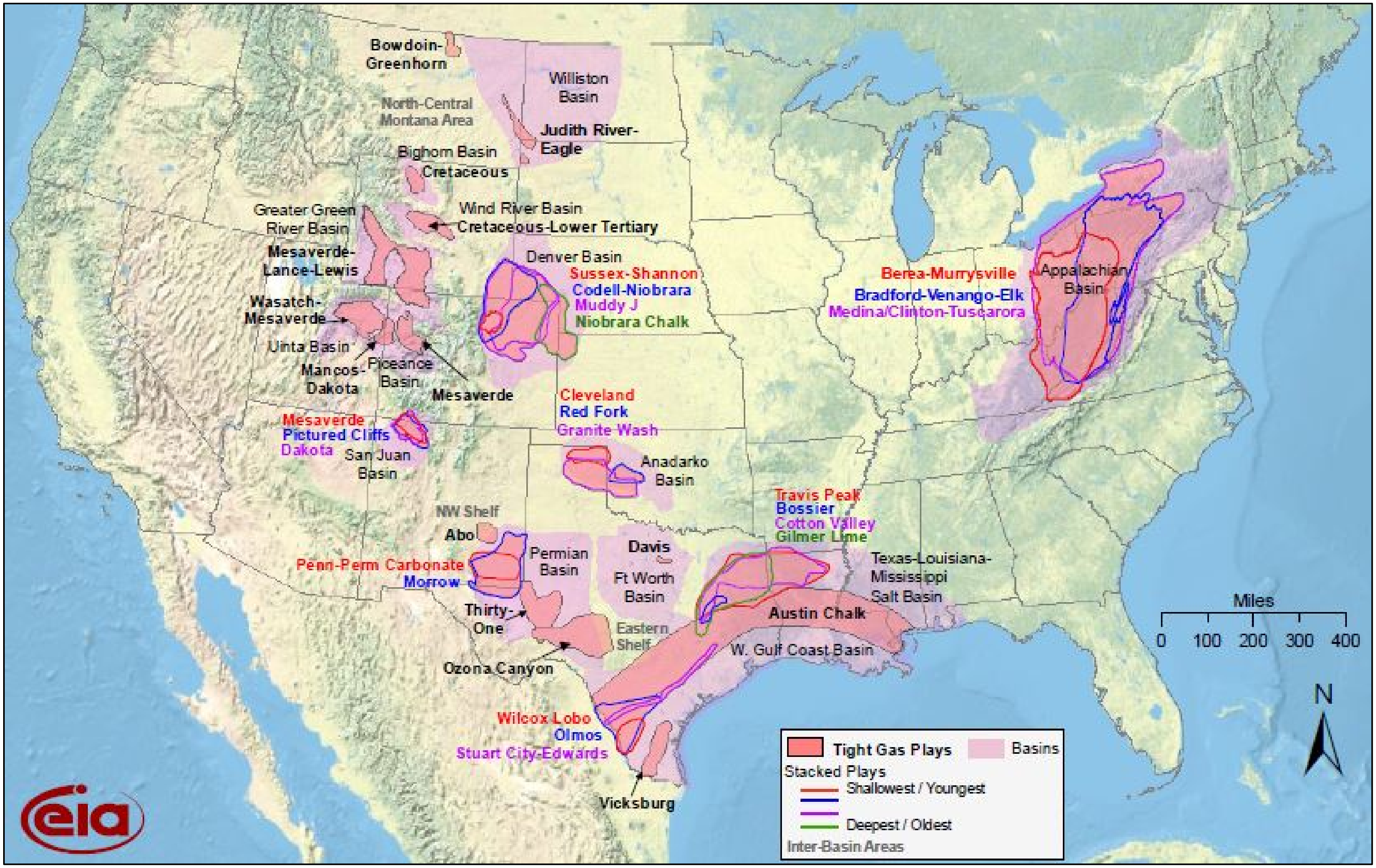
The EPA was able to identify UOG wells using the basin and formation name in DI Desktop® in combination with a list of known UOG formations published in Table 9.3 of the EIA's *Assumptions to the 2015 Annual Energy Outlook* report (192 DCN SGE01190). Formation names are also reported with the well completion reports as explained in Section B.2.3 (210 DCN SGE01263). This list of known UOG formations generally matches the formations shown in the EIA's shale and tight plays maps provided in Figure B-3 (193 DCN SGE01191) and Figure B-4 (11 DCN SGE00155). EPA used the combination of the formation names listed in DI Desktop®, the EIA list of the known UOG formations, and the EIA shale and tight plays maps to distinguish between shale and tight formations.

[30] The EIA uses the term "play" to describe subsets of UOG resources in Figure B-3 and Figure B-4, which are similar to the term "formation" as used in this TDD.



Source: 193 DCN SGE01191

Figure B-3. Major U.S. Shale Plays (Updated April 13, 2015)



Source: 11 DCN SGE00155

Figure B-4. Major U.S. Tight Plays (Updated June 6, 2010)

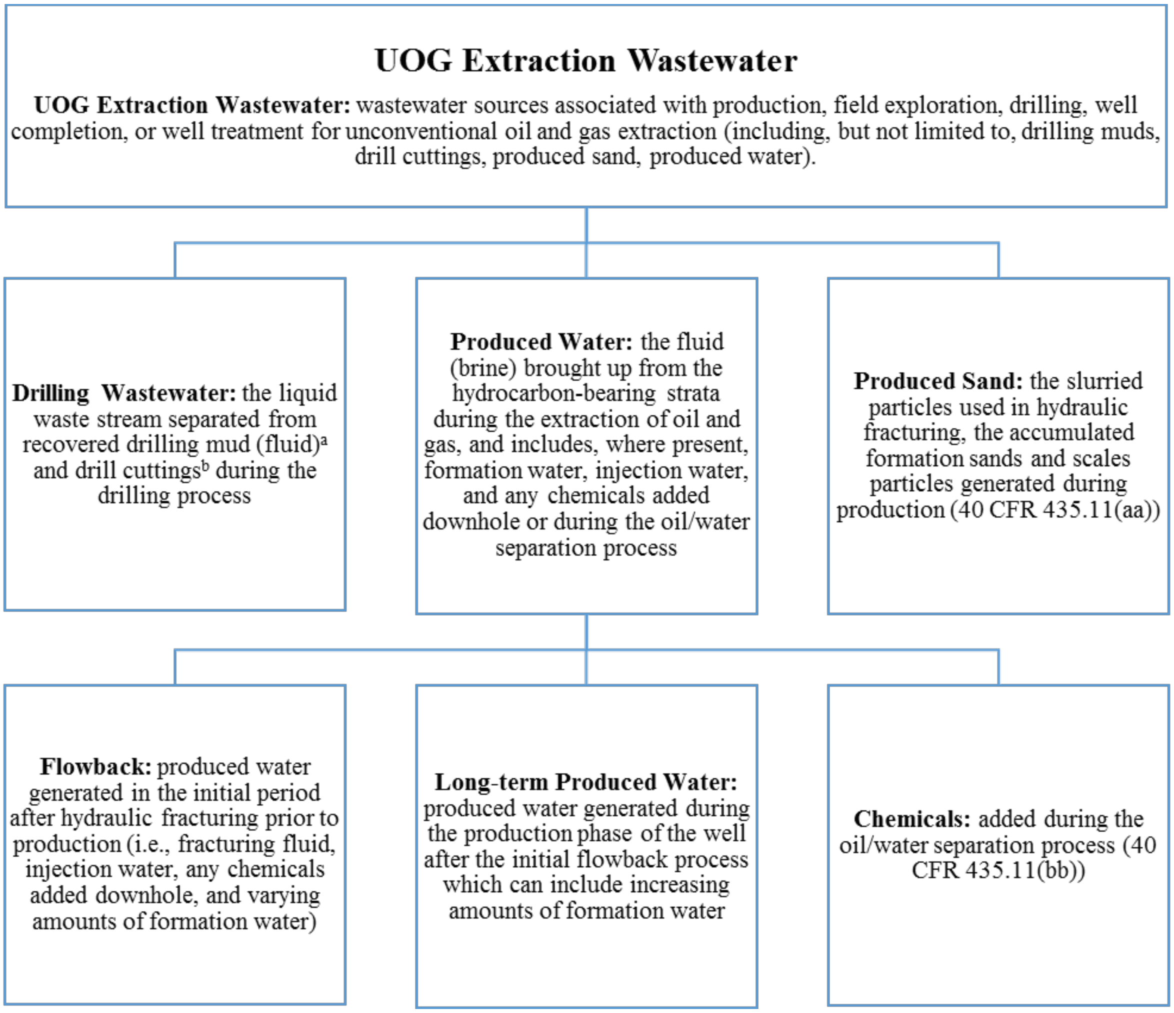
2 INDUSTRY DESCRIPTION: UOG WELL DEVELOPMENT PROCESS

UOG well development includes the following processes: exploration, well pad construction, well drilling and construction, well treatment and completion (e.g., stimulation)[31], and production. Before UOG well development, operators must obtain surface use agreements, mineral leases, and permits. These steps can take a few months to several years to complete. When they are completed, operators begin the well development process, as described in the following subsections.

Throughout the well development process, many materials are transported to the well pad. These materials include well casing and tubing; fuel (e.g., diesel, liquefied natural gas); and base fluid, sand, and chemicals for hydraulic fracturing. Sand, chemicals, and construction materials are typically transported to the well pad by truck, but fracturing base fluid (e.g., fresh water, recycled UOG produced water) may be transported via truck or temporary piping (92 DCN SGE00625; 95 DCN SGE00635; 21 DCN SGE00275).

The largest volumes of UOG extraction wastewater generated during well development are flowback, which is generated during the well completion process, and long-term produced water, which is generated during production (see Section C.2 for characteristics of each). UOG well drilling also generates wastewater, referred to in this document as drilling wastewater. As shown in Figure B-5, produced water, drilling wastewater, and produced sand are collectively referred to as UOG extraction wastewater.

[31] Well treatment is a generic term that describes actions performed to a well such as well cleaning, stimulation, and isolation, which are generally performed during well completion, the process of bringing a wellbore into production after well drilling.



a—Drilling mud is the circulating fluid (mud) used in the rotary drilling of wells to clean and condition the hole and to counterbalance formation pressure.
b—Drilling cuttings are the particles generated by drilling into subsurface geologic formations and carried out from the wellbore with the drilling mud.

Figure B-5. UOG Extraction Wastewater

Operators must also transport UOG extraction wastewater from the well to the ultimate wastewater management or disposal location—e.g., a centralized waste treatment (CWT) facility, an underground injection well for disposal, or another well for reuse. UOG extraction wastewater is transported via truck or temporary piping (92 DCN SGE00625; 95 DCN SGE00635; 21 DCN SGE00275).

2.1 UOG Exploration

Before well construction, a UOG operator conducts exploration—either before or after obtaining a lease, depending on the site-specific circumstances. During exploration, UOG operators use geological data (e.g., formation depth, formation thickness, formation slope, permeability, porosity) to target the most favorable UOG formation from which to produce crude oil and/or natural gas (22 DCN SGE00276). Operators can obtain geological data using some of the following methods (22 DCN SGE00276):

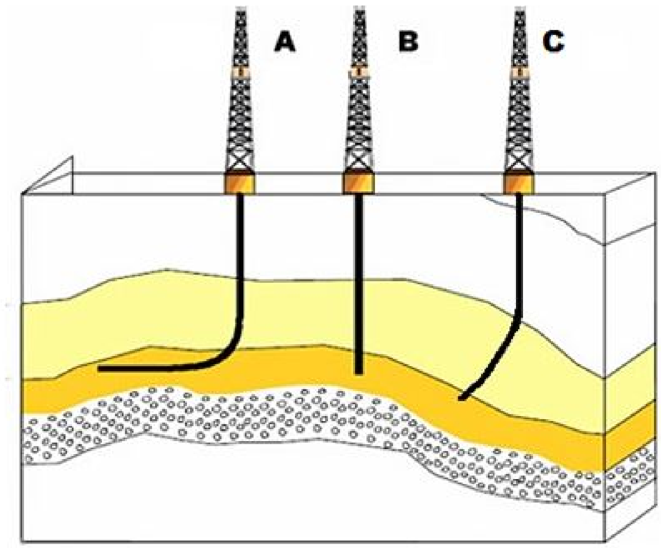
- **Offset production data**—analysis of existing production data from nearby wells.
- **Existing drilling data logs**—analysis of data logs from drilling existing wells.
- **Seismic data**—analysis of data collected using specially equipped trucks that send and receive sound waves through the ground. Special service providers convert the received sound waves into 2D or 3D images of the formation.

Geologists analyze the geological data and recommend well locations based on the areas with the highest production potential. It is not always possible to drill in the exact location recommended by a geologist due to several factors such as topography, environmentally sensitive habitats, water availability, state restrictions for siting, or surface access restrictions from land owners. In these situations, operators find the closest possible drilling location that will still allow for the effective production of crude oil and/or natural gas from the well (95 DCN SGE00635).

2.2 UOG Well Drilling and Construction

Drilling occurs in two phases: exploration and development. Exploration involves the drilling of wells to locate hydrocarbon-bearing formations and to determine the size and production potential of hydrocarbon reserves (explained in Section B.2.1). Development involves drilling production wells once a hydrocarbon reserve has been discovered and delineated. After the well pad is constructed, operators drill and construct the well. Operators use one of the three drilling trajectories below to drill for UOG (see Figure B-6). See Table B-3 for a breakdown of active UOG wells by well trajectory as of 2014.

- **Vertical drilling** is the drilling of a wellbore straight down into the ground. In UOG well drilling, vertical well drilling is more commonly used for tight wells than for shale wells (57 DCN SGE00527). For shale wells, vertical drilling is typically used by operators during the exploration phase of well development (95 DCN SGE00635), in shallow formations (e.g., Antrim shale), or by small entity operators who may be unable to make large investments in horizontal wells (25 DCN SGE00283). Vertical drilling has historically been used for COG wells.
- **Directional drilling** is the drilling of a wellbore at an angle off the vertical to reach an end location not directly below the well pad. Directional drilling is used when a well pad cannot be constructed directly above the resource (e.g., in rough terrain). Directional drilling is common in conventional and unconventional tight formations that occur as accumulations as illustrated in Section B.1.
- **Horizontal drilling,** the most advanced drilling technique, allows operators to drill vertically down to a desired depth, about 500 feet above the target formation (called the “kickoff point”), and then gradually turn the drill 90 degrees to continue drilling laterally. Horizontal drilling exposes the producing formation via a long horizontal lateral, which typically can vary in length between 1,000 and 5,000 feet (76 DCN SGE00593; 91 DCN SGE00623). Horizontal drilling is the most common method for continuous UOG formations (37 DCN SGE00354; 1 DCN SGE00010).



Source: 76 DCN SGE00593 (edited by the EPA)

Figure B-6. Horizontal (A), Vertical (B), and Directional (C) Drilling Schematic

Because shale reservoirs occur in continuous accumulations over large geographic areas, operators drilling in these resources typically drill multiple horizontal wells on each well pad (92 DCN SGE00625; 95 DCN SGE00635; 21 DCN SGE00275). However, tight reservoirs occur in both continuous and non-continuous accumulations; therefore, operators may drill multiple horizontal wells or a single directional or vertical well on a well pad, depending on the location and accumulation type of the tight reservoir. Directional and horizontal well configurations give operators access to more of the producing formation and reduce surface disturbance (37 DCN SGE00354; 2 DCN SGE00011). Operators may drill one or two horizontal wells on a well pad initially and move on to the next pad. When this happens, the operator typically comes back to drill the remaining wells on the pad after the initial wells show favorable economic conditions[32] and production (95 DCN SGE00635).

Drilling for crude oil and natural gas is generally performed by rotary drilling, in which a rotating drill bit grinds through the earth's crust as it descends. Well drilling and construction is an iterative process that includes several sequences of drilling, installing casing, and cementing succeeding sections of the well (95 DCN SGE00635). During drilling, operators inject drilling fluids down the wellbore to cool the drill bit, to circulate fragments of rock (i.e., drill cuttings) back to the surface so they do not clog the wellbore, and to control downhole pressure. Operators use one of the following types of drilling fluids depending on which portion of the well they are drilling (183 DCN SGE01181):

- **Compressed gases.** During the beginning phase of drilling a UOG well (i.e., the initial drilling close to the surface), compressed gases may be used to minimize costs. This category includes dry air, nitrogen gas, mist, foam, and aerated fluids.

[32] Favorable conditions include sufficient oil and/or gas prices, available drilling rigs, available fracturing crews, and permits.

- **Water-based.** At several thousand feet deep, operators typically use water-based drilling fluids (i.e., drilling mud), which provide more robust fluid properties at these depths than compressed gases. Water-based drilling fluids may contain salts,[33] barite, polymers, lime, and gels as additives.
- **Oil-based.** For drilling at deep depths and/or the horizontal laterals of wells, operators may use oil-based mud to maintain more consistent fluid properties at the higher temperatures and pressures that are associated with deeper depths. Oil-based drilling fluids may use diesel oil and/or mineral oils and contain emulsifiers, barite, and gels as additives.
- **Synthetic-oil-based.** For drilling at deep depths and/or the horizontal laterals of wells, operators may also use synthetic-oil-based fluids. These are similar to oil-based fluids; instead of using diesel oil and/or mineral oils, though, they use organic fluids (e.g., esters, polyolefins, acetal, ether, and linear alkyl benzenes) with similar fluid properties as diesel and mineral oils. Synthetic-oil-based fluids have been referred to as more environmentally friendly[34] than oil-based fluids but are also more expensive (157 DCN SGE01006; 158 DCN SGE01009).

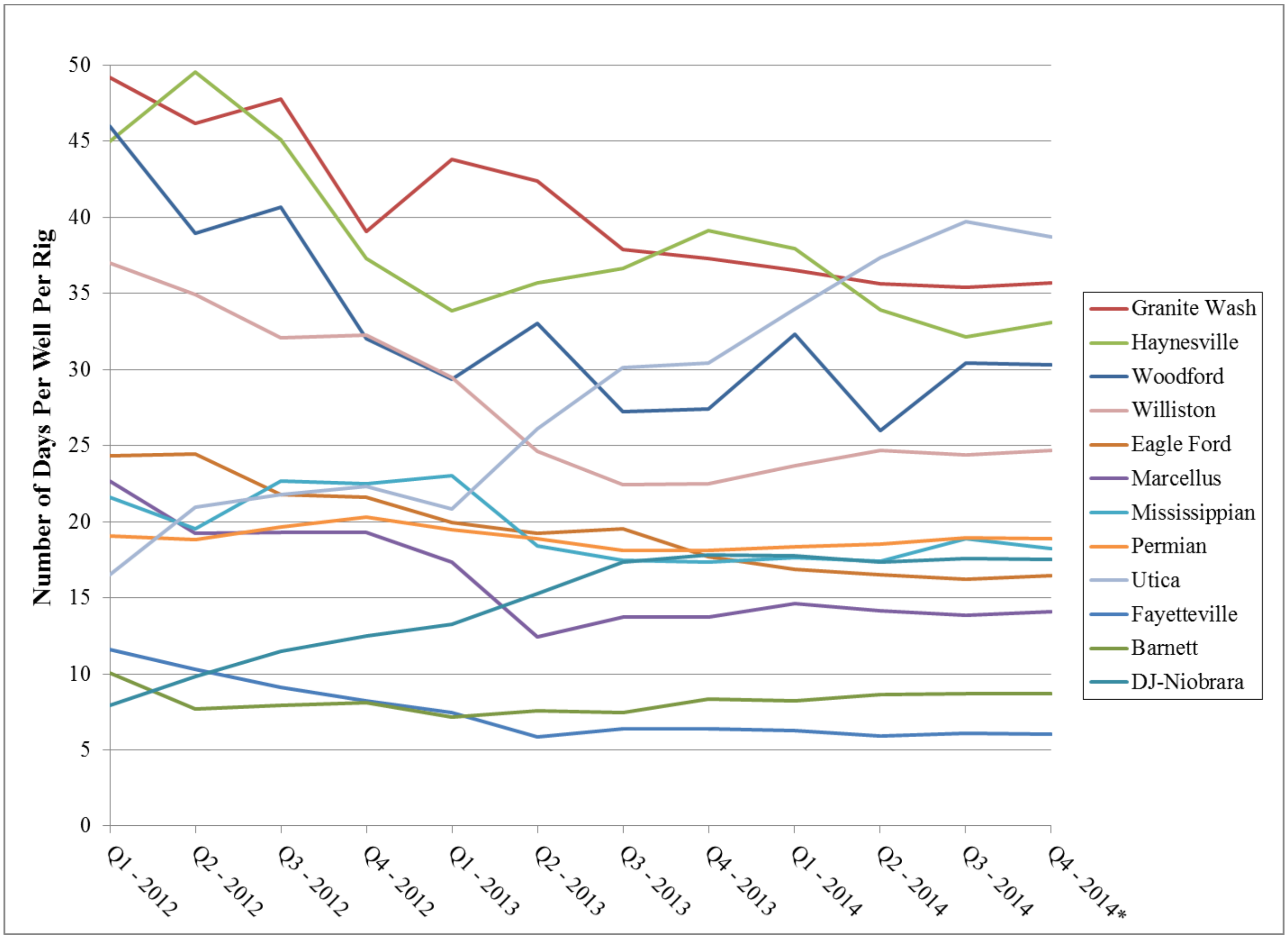
When returned to the surface, drill cuttings (solids) are removed from the drilling fluids using shakers, desilters, and centrifuges. This results in drill cuttings and a liquid waste stream, referred to as drilling wastewater. Typically, drilling wastewater is immediately reused/recycled for drilling the same well through a closed loop process. After well drilling is complete or when the drilling wastewater can no longer be reused/recycled,[35] operators manage it through other methods (e.g., reuse/recycle for drilling another well, transfer to a CWT facility, injection for disposal) (169 DCN SGE01125; 95 DCN SGE00635).

Well drilling and construction typically lasts between five days and two months, depending on well depth and how familiar operators are with the specific formation. Figure B-7 shows that drilling time generally decreases as UOG operators become more familiar and efficient at drilling in a UOG formation (201 DCN SGE01234; 95 DCN SGE00635; 52 DCN SGE00516). Figure B-7 also compares drilling phase durations among UOG formations (e.g., Granite Wash requires 30 to 50 days for drilling while Barnett requires 10 or fewer days).

[33] The UOG industry may refer to water-based drilling fluids that contain salts as “salt mud.”

[34] Using synthetic-oil-based drilling fluids results in a lower volume of wastewater that must be disposed. They also have lower toxicities, lower concentrations of certain priority pollutants, lower bioaccumulation potential, and faster biodegradation rates than oil-based drilling fluid.

[35] At the stage when the drilling mud (fluids) can no longer be reused/recycled they are sometimes referred to as “spent” or “spent drilling fluids.”



Source: 179 DCN SGE01179

*The most recent quarter of well count data is preliminary and is subject to revision.

Figure B-7. Length of Time to Drill a Well in Various UOG Formations (2012 through 2014)

2.3 UOG Well Completion

After the well is drilled and constructed, the well completion process begins. “Well completion” is a general term used to describe the process of bringing a wellbore into production once drilling and well construction is completed (150 DCN SGE00984). The UOG well completion process involves many steps, including cleaning the well to remove drilling fluids and debris, perforating the casing that lines the producing formation,[36] inserting production tubing to transport the hydrocarbon fluids to the surface, installing the surface wellhead, stimulating the well (e.g., hydraulic fracturing), setting plugs in each stage, and eventually drilling the plugs out of the well. It also includes the flowback process, in which fluids injected during well stimulation return to the surface.

[36] In some instances, open-hole completions may be used, where the well is drilled into the top of the target formation and casing is set from the top of the formation to the surface. Open-hole well completions leave the bottom of the wellbore uncased.

After operators complete a new oil and gas well for production, they must submit a well completion report to the governing state oil and gas agency. All states require that the well completion reports contain the following information (210 DCN SGE01263):

- Well API number
- Well completion technique (e.g., hydraulic fracturing, acidization)
- Formation, pool, or reservoir name in which the well is completed (e.g., Marcellus)

These well completion reports are documented in a separate memorandum to the record, titled *Memorandum to the Record Discussing Well Completion Reports* (210 DCN SGE01263). The following two subsections describe the well stimulation and flowback processes of well completion that are commonly part of UOG well development.

2.3.1 UOG Well Completion: Well Stimulation

UOG well stimulation techniques include but are not limited to hydraulic fracturing, acidization, or a combination of fracturing and acidization (146 DCN SGE00966; 225 DCN SGE01345). The most common well stimulation technique for UOG wells is hydraulic fracturing, discussed in the rest of this subsection (also refer to Section B.1) (1 DCN SGE00010). Hydraulic fracturing of COG wells is also becoming more common, but traditionally COG wells have been completed with open-hole techniques that allow the oil and/or gas resources to flow naturally (35 DCN SGE00345; 61 DCN SGE00533).

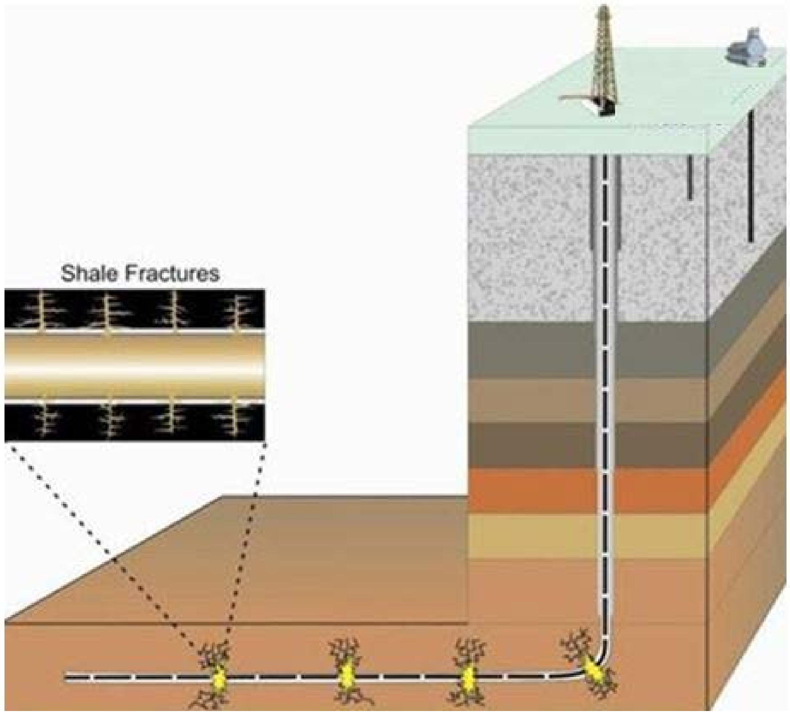
Operators typically fracture UOG wells in multiple stages to achieve the high pressures necessary to fracture the reservoir rock. Stages are fractured starting with the stage at the end of the wellbore and working back toward the wellhead. The number of stages depends on lateral length. Because horizontal laterals are 1,000 to 5,000 feet long, operators may use between eight and 23 stages for horizontal wells (22 DCN SGE00276). Vertical wells are typically only fractured with one stage (1 DCN SGE00010). A fracturing crew can typically fracture two to three stages per day when operating 12 hours per day or four to five stages per day when operating 24 hours per day.[37] Consequently, a typical well may take two to seven days to complete (15 DCN SGE00239; 169 DCN SGE01125). The following processes are performed for each stage:

- **Perforation.** Operators lower a perforation gun into the stage using a line wire. The perforation gun releases an explosive charge to create holes that penetrate about 1 foot into the formation rock in a radial fashion. These perforations create a starting point for the hydraulic fractures.
- **Hydraulic fracturing.** Operators inject fracturing fluids (e.g., water, sand, and other additives) down the wellbore to highly pressurize the formation to the point where small fractures are created in the rock (see Figure B-8).[38] See Section C.1 for information about fracturing fluid volumes and characteristics.

[37] The hours per day depends on the operator, local ordinances, and weather.

[38] The first stage is fractured with what is known as the pad fracture. The pad is the injection of high-pressure water and chemical additives without proppant (i.e., solid material designed to keep fractures open to allow gas to flow

- **Stage plugging.** Once the stage is hydraulically fractured, a stage plug is inserted down the wellbore, separating it from additional stages until all stages are completed.



Source: 82 DCN SGE00604

Figure B-8. Hydraulic Fracturing Schematic

The components of fracturing fluid (i.e., base fluid, sand, chemical additives) are typically stored on the well pad before hydraulic fracturing begins. (See Section C.1 for a more detailed description of the fracturing fluid composition.) Operators may store fresh water in storage impoundments (see Figure B-9) or fracturing tanks that typically range from 10,500 to 21,000 gallons (250 to 500 barrels) in size (see Figure B-11) (24 DCN SGE00280; 21 DCN SGE00275; 22 DCN SGE00276). Operators that reuse/recycle UOG produced water in subsequent fracturing jobs typically store the reused/recycled wastewater in fracturing tanks and/or pits (24 DCN SGE00280; 195 DCN SGE01206). Operators typically have sand trucks and pump trucks onsite during the hydraulic fracturing process. The sand trucks contain the sand prior to mixing in the fracturing fluid and the pump trucks pump the fracturing fluid down the wellbore during each stage of fracturing.

from the producing formation) to create the initial fractures into the formation. After the pad is pumped downhole, proppant is introduced to the fracturing fluid for the additional stages.

Source: 21 DCN SGE00275

Figure B-9. Freshwater Impoundment

2.3.2 UOG Well Completion: Flowback Process

After all of the stages of a well have been hydraulically fractured, the stage plugs are drilled out of the wellbore and the pressure at the wellhead is released. Releasing the pressure allows a portion of produced water to return to the wellhead; this waste stream is often referred to as “flowback.” Industry commonly refers to this as the flowback process (95 DCN SGE00635). The flowback consists of a portion of the fluid injected into the wellbore and can be combined with formation water. At the wellhead, a combination of flowback water, sand, and product (crude oil, condensates, and/or natural gas) is routed through phase separators, which separate products from wastes. Industry uses different types of separators depending on a number of factors such as the type of production (i.e., crude oil, natural gas, condensate). Figure B-10 shows an example of a separator used for dry gas production (i.e., only requires gas and water separation because there is no crude oil or condensate production).

Higher volumes of flowback water are generated in the beginning of the flowback process and flowback rates decrease as the well goes into the production phase. Operators typically store flowback in fracturing tanks onsite before treatment or transport offsite.[39] In addition to flowback, small quantities of crude oil, condensates, and/or natural gas may be produced during the initial flowback process. The small quantities of produced gas may be flared

[39] Fracturing tanks cannot be transported from one site to another when they contain wastewater. Wastewater is typically transported via trucks with capacities of about 4,200 to 5,000 gallons (100 to 120 barrel) or via pipe (95 DCN SGE00635).

or if the operator is using "green completions," the gas may instead be captured.[40] If oil is produced, oil/water separators may be used[41] or the oil may be recovered from the flowback water after it is transported offsite.

Source: 92 DCN SGE00625

Figure B-10. Vertical Gas and Water Separator

Flowback typically lasts from a few days to a few weeks (1 DCN SGE00010; 2 DCN SGE00011; 90 DCN SGE00622; 75 DCN SGE00592; 27 DCN SGE00286). At some wells, the majority of fracturing fluid may be recovered within a few hours (1 DCN SGE00010; 2 DCN SGE00011; 90 DCN SGE00622; 75 DCN SGE00592; 27 DCN SGE00286). A 2009 report published by the Ground Water Protection Council and ALL Consulting stated that operators recover between 10 and 70 percent of the fracturing fluid that they inject down the wellbore (1 DCN SGE00010; 75 DCN SGE00592; 27 DCN SGE00286). Section C.3.1 provides more details on flowback generation rates over time and fracturing fluid recovery percentages for specific UOG formations.

[40] On April 17, 2012, the U.S. EPA issued regulations, required by the Clean Air Act, requiring the natural gas industry to reduce air pollution by using green completions, or reduced emission completions. The EPA identified a transition period until January 1, 2015, to allow operators to locate and install green completion equipment (40 CFR parts 60 and 63).

[41] Operators sometimes use chemicals during the oil/water phase separation process.

Source: 92 DCN SGE00625

Figure B-11. Fracturing Tanks

2.4 UOG Production

After the flowback process, the well enters the production phase. During this phase, UOG wells produce crude oil, condensates, and/or natural gas and water. This water, called “long-term produced water” in this TDD, consists primarily of formation water and continues to be produced throughout the lifetime of the well, though typically at much lower rates than flowback (75 DCN SGE00592). Long-term produced water rates range from less than a barrel up to 4,200 gallons (100 barrels) per day and gradually decrease over the life of the well.[42] The rates vary with each well because they are dependent on formation characteristics and the completion success of the given well (see Chapter C for information about flowback and long-term produced water volumes and characteristics).

When the well enters the production phase, operators typically remove the fracturing tanks that were used to collect water during flowback. Produced water that is separated from the product (crude oil, condensates, and/or natural gas) is stored in permanent above-ground storage tanks referred to as produced water tanks with capacities that range from 4,200 to 33,600 gallons (100 to 800 barrels) (see Figure B-12) (24 DCN SGE00280; 21 DCN SGE00275; 96 DCN SGE00636). The number of produced water tanks depends on the number of wells that are producing on the well pad and the volume of water produced by each well. Most operators configure water piping on the well pad so that each well has a designated produced water tank (95 DCN SGE00635; 22 DCN SGE00276).

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[42] The life of an UOG well varies significantly by well. Some wells are expected to produce up to 40 years without further stimulation, while others may only produce economically for 10 years (27 DCN SGE00286).

Source: 21 DCN SGE00275

Figure B-12. Produced Water Storage Tanks

3 INDUSTRY DESCRIPTION: UOG WELL DRILLING AND COMPLETION ACTIVITY

The following subsections describe historical, current, and projections of future UOG drilling activity, including:

- Historical and current UOG well drilling activity
- Total estimated UOG resource potential
- Current and projections of future UOG well completions

3.1 Historical and Current UOG Drilling Activity

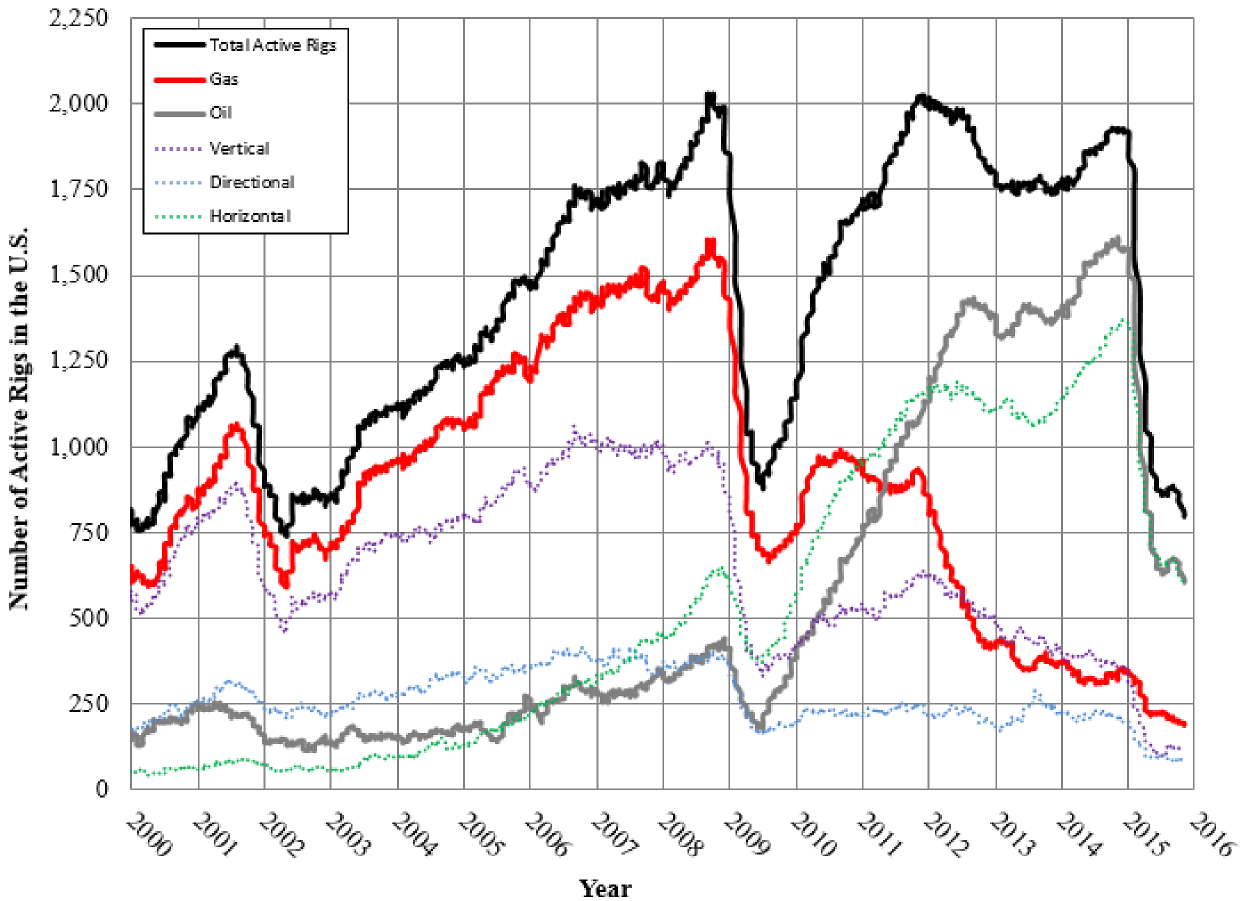
Since 2000, hydraulic fracturing coupled with drilling directional and horizontal wellbores in unconventional formations has increased (164 DCN SGE01095). More recently, drilling has also increased in liquid-rich formations.[43] Baker Hughes, one of the world's largest oilfield services companies, periodically publishes location and other data for active U.S. rigs.[44]

[43] Liquid-rich formations are those that either primarily produce crude oil or primarily co-produce natural gas with gas condensates (i.e., hydrocarbons such as ethanes, propanes, and butanes). When gas condensates are depressurized at the wellhead, they condense into a liquid phase.

[44] Baker Hughes obtains data in part from RigData, a company that sells rig and well data. Rig data Baker Hughes publishes are reported in major newspapers and journals (e.g., *Oil and Gas Journal*) and are used by the industry as an indicator for demand of oil and gas equipment.

Figure B-13 shows Baker Hughes' estimates of total number of active drilling rigs in the United States between January 2000 and October 2015 and shows drilling trajectory (i.e., directional, horizontal, vertical) and product type (i.e., crude oil, natural gas). While these counts include rigs that are drilling for CBM and COG, drilling for UOG surpassed drilling in CBM and COG by the late 2000's (194 DCN SGE01192). Both horizontal drilling and oil well drilling have increased since 2000. As of October 9, 2015, 79 percent of rigs were drilling horizontal wells compared to 6 percent in January 2000.[45] In 2009, horizontal well drilling surpassed vertical well drilling for the first time in the United States. Shortly after, in 2011, oil well drilling surpassed gas for the first time since 1993 (202 DCN SGE01235). In 2014, approximately 1,800 active rigs drilled over 37,000 wells (201 DCN SGE01234). Baker Hughes has not yet released the drilled well count for 2015. As footnoted on Figure B-13, the number of active rigs drilling new wells decreased significantly after 2014 likely due to low natural gas and crude oil prices (194 DCN SGE01192).

[45] Another seven percent of rigs were drilling directional wells in the United States as of October 9, 2015.



Source: 179 DCN SGE01179

Figure B-13. Number of Active U.S. Onshore Rigs by Trajectory and Product Type over Time[46]

Table B-2 shows the active drilling rigs in the United States by formation or basin, broken down by well trajectory and resource type, as of October 2015. Based on data reported by Baker Hughes and rig counts reported in other literature, the majority of rigs were drilling into unconventional formations at this time (200 DCN SGE01233; 76 DCN SGE00595). Where Baker Hughes did not specify the formation being drilled into, counts may include a mixture of rigs that are drilling for UOG, CBM, and COG. Note that the number of active rigs has continued to decline and the March 4, 2016, count was 463 active rigs in the United States (217 DCN SGE01335).

[46] The sharp decreases in active drilling rigs observed in 2009 and 2015 are likely attributed to the sudden drop in natural gas and crude oil prices experienced in those years (194 DCN SGE01192).

Table B-2. Active Onshore Oil and Gas Drilling Rigs by Well Trajectory and Product Type (as of October 9, 2015)

Basin[a]	Formation[a]	Resource Type[a]	Gas Rigs by Well Trajectory				Oil Rigs by Well Trajectory[b]				Total Rigs
			Directional	Horizontal	Vertical	Total Gas	Directional	Horizontal	Vertical	Total Oil	
Permian	—[c]	Mix	0	5	0	5	4	182	44	230	235
Other[d]	—[c]	Mix	25	20	11	56	19	66	41	126	182
Western Gulf	Eagle Ford	Shale	0	12	0	12	0	65	3	68	80
Williston	—[c,e]	Mostly shale[e]	0	0	0	0	2	62	1	65	65
Appalachian	Marcellus	Shale	0	45	1	46	0	0	0	0	46
Anadarko	Mississippian	Tight	0	0	0	0	0	11	2	13	13
Anadarko	Granite Wash	Tight	0	5	0	5	0	6	0	6	11
Denver	Niobrara	Shale	0	5	0	5	0	19	3	22	27
Anadarko	Woodford[f]	Shale	0	6	0	6	1	40	0	41	47
TX-LA-MS Salt	Haynesville	Shale	0	23	0	23	0	0	1	1	24
Fort Worth	Barnett	Shale	0	3	0	3	0	0	3	3	6
Appalachian	Utica	Shale	0	15	0	15	1	3	1	5	20
Arkoma	Fayetteville	Shale	0	4	0	4	0	0	0	0	4
Total			**25**	**143**	**12**	**180**	**27**	**454**	**99**	**580**	**760**

Sources: 179 DCN SGE01179

a—Baker Hughes (200 DCN SGE01233) reported a mixture of basins and formations. The EPA classified them by resource type (i.e., shale, tight) when specific formations were reported. When formations were not reported, the EPA classified the resource type as a "mix" of resources (conventional, tight, shale).

b—Oil rigs include six "miscellaneous" rigs reported by Baker Hughes (200 DCN SGE01233).

c—Baker Hughes reported basin as opposed to formation for these areas. Therefore, these areas may include rigs drilling in conventional and unconventional formations.

d—The majority of the rigs in the "Other" category were drilling in Texas, Louisiana, Wyoming, California, Utah, and Colorado. The remaining rigs in the "Other" category were distributed evenly throughout the United States.

e—The majority of these rigs are expected to have been drilling in the Bakken shale formation based on rig counts reported by the EIA (76 DCN SGE00595).

f—This formation includes the Woodford-Cana, Arkoma Woodford, and Ardmore Woodford formations.

3.2 UOG Resource Potential

This section quantifies how many new UOG wells may be drilled in the future (i.e., new well potential), using USGS and EIA assessments, to estimate the potential number of new UOG extraction wastewater sources. Assessments by the USGS and the EIA show substantial potential for new UOG wells. The EIA also calculates new UOG well potential in its AEO, but because it is only for several sub-formations,[47] the EPA calculated new well potential for all UOG formations.[48] This analysis is the same as the EIA methodology and is documented in a separate memorandum titled *Data Compilation Memorandum for the Technical Development Document for Effluent Limitations Guidelines and Standards for Oil and Gas Extraction (TDD)* (179 DCN SGE01179; 180 DCN SGE01179.A02).

The two EIA-reported parameters that the EPA used to calculate new well potential are:

- **Estimated ultimate recovery per well (EUR).** EUR is the quantity of crude oil and/or natural gas that is produced by a single well over its life.
- **Technically recoverable resources (TRR).** The TRR is the quantity of crude oil and/or natural gas producible from a geological formation using current drilling and completion technology. The EIA's TRR estimates are functions of total formation geographic area (square miles), the portion of formation land area that can be developed for oil and gas extraction, average well spacing assuming that the formation is fully developed, and EUR per well. TRR is the sum of proven reserves and unproven resources.[49]

EIA published these parameters for all known UOG formations in Table 9.3 of the EIA's *Assumptions to the 2015 Annual Energy Outlook* report (192 DCN SGE01190). The EIA's estimates of these parameters are primarily based on geological characteristics published by the USGS, which in turn rely on historical production data from existing wells and the technology deployed at the time of assessment. However, the EIA adjusts these estimates annually to account for the ongoing changes in drilling and completion practices and to account for formations not yet assessed by the USGS (192 DCN SGE01190).

To evaluate new well potential, the EPA calculated new well potential for each formation or sub-formation by dividing the TRR by the EUR. Appendix F provides EUR and TRR on a formation basis based on this analysis. To calculate total TRR and new well potential by resource

[47] For example, the *Assumptions to the 2015 Annual Energy Outlook* reported new well potential for several, but not all, Bakken sub-formations: 13,045 wells (192 DCN SGE01190, Table 9.5, Bakken Central). The EPA estimated approximately 13,072 new Bakken wells for the same Bakken sub formations (180 DCN SGE01179.A02). Differences between EIA and EPA new well potential are due to rounding.

[48] These estimates do not factor in future changes to TRR estimates by the EIA, advances in drilling technology, or economic conditions that ultimately affect how many wells UOG operators drill over time (192 DCN SGE01190; 194 DCN SGE01192).

[49] Proven reserves are resources that are currently developed commercially or have been demonstrated with reasonable certainty to be recoverable in future years under existing economic conditions and current technologies. Unproven resources are resources that have been confirmed by exploratory drilling but are not yet commercially developed.

type, the EPA summed the TRR and the new well potential for all formations in each resource type shown in Table F-2 and Table F-3. Table B-3 summarizes the total new well potential the EPA calculated for the four UOG resource types.[50]

Table B-3. UOG Potential by Resource Type as of January 1, 2013

Resource Type	Weighted Average[a] Oil EUR (MMbls per well)	Weighted Average[a] Gas EUR (Bcf per well)	Total Oil TRR (MMbls)	Total Gas TRR (Bcf)[b]	Total New Well Potential (Beginning in 2013)	Active 2014 UOG Well Count[c]
Shale gas	0.008	0.534	7,300	515,900	967,000	H: 56, 801 D: 1,836 V: 15,877 U: 17,755
Shale oil	0.096	0.146	43,900	66,800	456,000	
Tight gas	0.016	0.447	12,000	339,100	758,000	H: 11,175 D: 12,565 V: 82,954 U: 36,208
Tight oil	0.095	0.124	21,200	27,700	224,000	
All UOG	0.035	0.395	84,400	949,500	2,405,000	H: 67,976 D: 14,401 V: 98,831 U: 53,963

Sources: 179 DCN SGE01179

a—Weighted averages are based on total oil or gas TRR (i.e., formations with more TRR were given more weight than formations with less TRR).

b—Gas production from shale and tight oil resources is associated gas that is produced simultaneously with oil.
c—Well counts are based on ERG's DI Desktop® data analysis explained in the *Analysis of DI Desktop®* memorandum (182 DCN SGE01180). They may not be all-inclusive.

Abbreviations: MMbls—million barrels; Bcf—billion cubic feet of gas; EUR—estimated ultimate recovery (per well); TRR—technically recoverable resources; H—horizontal; D—directional; V—vertical; U—trajectory unknown

The results presented in Table B-3 show that the UOG new well potential is much greater than the active well count. The EPA estimates that approximately 2.4 million potential new UOG wells—with associated extraction wastewater—may be drilled in the future. Table B-3 also shows the approximate number of active UOG wells in 2014, broken out by well trajectory and resource type, based on the EPA's analysis of the DI Desktop® well database (176 DCN SGE001170; 182 DCN SGE01180).

3.3 <u>Current and Projections of Future UOG Well Completions</u>

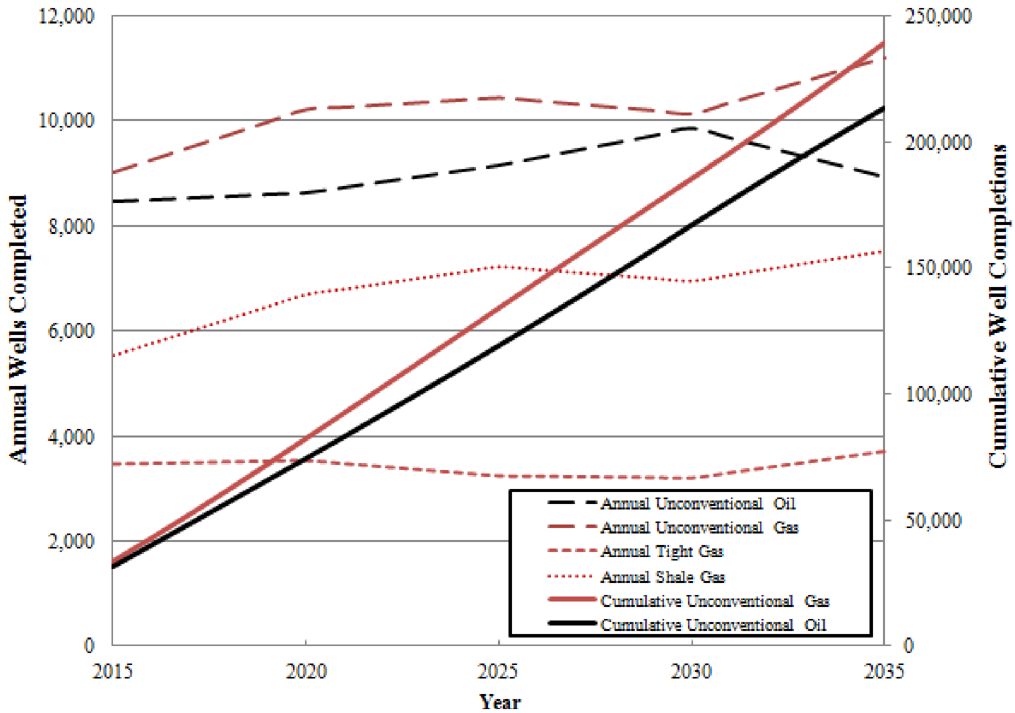
In 2013 and 2014 alone, more than 27,000[51] oil and gas wells were hydraulically fractured nationwide each year (175 DCN SGE01169). As previously explained, hydraulic fracturing is currently the most popular well stimulation technique for UOG wells. A survey

[50] These estimates only include shale and tight oil and gas resources. They do not include CBM or COG.

[51] This is based on EPA's analysis of FracFocus (186 DCN SGE01184). The actual number of wells fractured is likely greater because some states where fracturing is common (e.g., Michigan) did not yet require reporting to FracFocus during these years.

conducted by the API and the American Natural Gas Alliance shows that, as of 2010, nearly all unconventional wells were being completed using hydraulic fracturing (28 DCN SGE00291).[52] Operators may also refracture existing oil and gas wells. Based on a national database maintained by IHS, Inc., 0.13 to 0.35 percent of well completions involving hydraulic fracturing from 2000 to 2010 were reported as refracturing of existing oil and gas wells (165 DCN SGE01095.A09). A more recent survey of 205 UOG operators conducted by PESA[53] shows that in 2012 and 2013 about 10 percent of well completions involving hydraulic fracturing were refracturing of existing oil and gas wells (70 DCN SGE00575).

In 2012, HIS, Inc. estimated the total number of UOG wells that UOG operators may complete through 2035 (111 DCN SGE00728). The EPA generated Figure B-14 using data published by HIS, Inc. (179 DCN SGE01179). The figure shows the projected number of UOG wells completed annually and cumulatively. Unconventional gas is further broken down into tight gas and shale gas. The projections estimated by HIS, Inc., show a gradual increase in annual UOG well completions through 2035.



Source: 179 DCN SGE01179

Figure B-14. Projections of UOG Well Completions

[52] This survey included well completion information for 5,307 well completions in 2010, consisting of a mixture of conventional and unconventional wells. The survey results showed that more than 96 percent of tight gas wells and 99 percent of shale gas wells surveyed were hydraulically fractured. The survey also showed that 69 percent of conventional wells were hydraulically fractured.

[53] PESA represents the energy industry's manufacturers and oilfield service and supply companies. Its mission is to promote and advocate for policies that will support the oilfield service sector's continued job creation, technological innovation, and economic stability.

Chapter C. UNCONVENTIONAL OIL AND GAS EXTRACTION WASTEWATER VOLUMES AND CHARACTERISTICS

Since 2000, horizontal drilling and hydraulic fracturing of UOG resources has increased dramatically (164 DCN SGE01095). The EIA, in its 2015 AEO, projects that, within the next 30 years, the majority of the country's crude oil[54] and natural gas[55] will come from unconventional resources (194 DCN SGE01192). Consequently, industry experts expect UOG produced water volumes to continue to increase (103 DCN SGE00708; 46 DCN SGE00479; 107 DCN SGE00722; 131 DCN SGE00768.A01; 132 DCN SGE00768.A25).

This chapter discusses UOG extraction wastewater volumes and characteristics. This includes the following sources (see Figure B-5 above):

- **Produced water—**the fluid (brine) brought up from the hydrocarbon-bearing strata during the extraction of crude oil and natural gas, and includes, where present, formation water, injection water, and any chemicals added downhole or during the oil/water separation process. Based on the type of oil and gas extraction method, produced water can be further broken down into the following components:
  - **Flowback—**the produced water generated in the initial period after hydraulic fracturing prior to production (i.e., fracturing fluid, injection water, any chemicals added downhole, and varying amounts of formation water). After the hydraulic fracturing procedure is completed and pressure is released, the direction of fluid flow reverses, and the fluid flows up through the wellbore to the surface. The water that returns to the surface is commonly referred to as "flowback."
  - **Long-term produced water—**the produced water generated during the production phase of the well after the initial flowback process which can include increasing amounts of formation water. Long-term produced water continues to be produced throughout the lifetime of the well.
- **Drilling wastewater—**the liquid waste stream separated from recovered drilling mud[56] (fluid) and drill cuttings[57] during the drilling process.
- **Produced sand—**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, as well as blowdown of the water phase from the produced water treatment system.

The EPA identified drilling wastewater and produced water as the major sources of wastewater pollutants associated with UOG extraction, so these wastewaters are described

[54] Crude oil includes "lease condensates," components that are liquid at ambient temperature and pressure.

[55] Natural gas can include "natural gas liquids," components that are liquid at ambient temperature and pressure.

[56] Drilling mud is the circulating fluid (mud) used in the rotary drilling of wells to clean and condition the hole and to counterbalance formation pressure.

[57] Drill cuttings are the particles generated by drilling into subsurface geologic formations and carried out from the wellbore with the drilling mud.

further below. The following subsections discuss volumes and chemical constituents found in fracturing fluid typically used by UOG operators and volumes and characteristics of drilling wastewater, flowback, and long-term produced water generated by UOG operations. The EPA identified this information from existing data sources, including state and federal agency databases, journal articles and technical papers/reports, academic papers/reports, technical references, industry/vendor telephone calls, industry site visits, and meetings with industry. The EPA reported the data exactly as reported in existing literature throughout Chapter C. In some instances, the EPA compiled the existing data into a separate document to compile and analyze the data. These separate memoranda, referenced throughout Chapter C, are titled *Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation* (186 DCN SGE01184) and *Data Compilation Memorandum for the Technical Development Document (TDD) for Effluent Limitations Guidelines and Standards for Oil and Gas Extraction* (179 DCN SGE01179).

Section C.1 discusses the characteristics of fracturing fluid,[58] Section C.2 discusses typical volumes of UOG extraction wastewater, and Section C.3 presents constituents that are typically found in UOG extraction wastewater. Section C.3 extensively discusses TDS, a parameter that is often used to characterize UOG extraction wastewater because it provides a measure of dissolved matter including salts (e.g., sodium, chloride, nitrate), metals, minerals, and organic material (3 DCN SGE00046). Data in Section C.3 show that sodium and chloride make up the majority of TDS in UOG produced water. The data also show that chloride contributes heavily to the makeup of TDS in UOG drilling wastewater. TDS is not a specific chemical, but is defined as the portion of solids that pass through a filter with a nominal pore size of 2.0 µm or less as specified by Standard Method 2540C-1997.[59] Because TDS in UOG produced water primarily consists of inorganic salts and other ionic species, conductivity measurements may also be used to estimate TDS.[60] High measurements of specific conductivity are indicative of high TDS concentrations.

TDS and chloride are potential concerns in the management of UOG extraction wastewater because of the high concentrations of these parameters in the wastewater. UOG produced water can have TDS concentrations up to 400,000 mg/L, which is over 10 times the concentration of TDS typically found in seawater (i.e., 35,000 mg/L). Chapter D discusses UOG extraction wastewater management and disposal practices.

1 FRACTURING FLUID CHARACTERISTICS

As discussed in Section B.2.3, most UOG resources (e.g., tight oil, shale gas) are stimulated using hydraulic fracturing. Hydraulic fracturing of UOG resources typically requires high volumes of fracturing fluid, consisting of a base fluid mixed with proppant (e.g., sand) and chemicals. The quantity of each fracturing fluid component varies by operator, basin, formation,

[58] The type of fracturing fluid and total fracturing fluid volume may influence the characteristics of UOG produced water and are therefore described in this chapter.

[59] 40 CFR part 136 lists Standard Method 2540C as an approved test method for TDS.

[60] The electrical conductivity of water is directly related to the concentration of dissolved ionized solids in the water.

and resource type. The remainder of this subsection discusses the sources used for base fluid, concentrations of chemical additives, and observed constituents in fracturing fluids.

1.1 Base Fluid Composition

The primary component of fracturing fluid is the base fluid to which proppant (sand) and chemicals are added. Fracturing fluids are typically water-based, though cases of non-aqueous fracturing fluids are documented in the literature (e.g., compressed nitrogen, propane) (164 DCN SGE01095). Base fluid typically consists of only fresh water (surface, groundwater, or municipal water) or a mixture of fresh water, reused/recycled UOG produced water, and/or other sources (e.g., treated municipal wastewater, groundwater) (97 DCN SGE00639; 70 DCN SGE00575). PESA reports the following percentages of UOG operators using each water source as fracturing fluid in the United States (70 DCN SGE00575):

- Surface water (e.g., rivers, lakes) (40 percent)
- Groundwater (36 percent)
- City/ municipal water[61] (16 percent)
- Recycled UOG produced water (7 percent)[62]
- Industrial wastewater (1 percent)

Table C-1 shows the composition of base fluid for basins and/or formations with available data. Fresh water sources are those generally characterized by having low concentrations of dissolved salts and other TDS (e.g., ponds, lakes, rivers, certain underground aquifers). Brackish sources are those with more salinity than freshwater, but not as much as seawater (e.g., other industrial wastewater, certain groundwater aquifers). Fresh water is the most common source of base fluid across all basins. As shown in Table C-1, brackish sources are used more often in arid regions (e.g., the Permian and Gulf Coast basins in Texas and New Mexico). For basins/formations where the EPA identified projected data in addition to historic data, the projected values for the year 2020 are reported parenthetically in Table C-1.

In general, the fraction of base fluid that can be composed of UOG produced water is limited by two factors (66 DCN SGE00556; 105 DCN SGE00710):

- **Produced water volume.** When large volumes of flowback and long-term produced water are generated by other UOG wells in the area, reuse/recycle wastewater can make up a larger portion of base fluid water on average.
- **Produced water quality.** When the concentration of TDS in UOG produced water rapidly increases after fracturing, it may have less potential for reuse/recycle as a source of base fluid to fracture another well (105 DCN SGE00710).

[61] PESA does not specify whether this water source is potable drinking water or treated municipal effluent (70 DCN SGE00575).

[62] The amount of UOG wastewater that is reused/recycled in fracturing fluid varies significantly by UOG formation. See Section D.2 for more information about UOG wastewater reuse/recycle.

Table C-1. Sources for Base Fluid in Hydraulic Fracturing

Basin	UOG Formation	Resource Type	Percentage of Total Base Fluid Used for Hydraulic Fracturing[a] Fresh Water[b]	Brackish Water[b]	Reused/Recycled UOG Produced Water
All CA basins	All formations	Shale and tight	96	0	4
Appalachian	Marcellus (PA)	Shale	82 to 90	0	10 to 18
	Marcellus (WV)	Shale	77 to 83[c,d]	—[c]	6 to 10
Anadarko	All formations	Shale and tight	50 (40)	30 (30)	20 (30)
Arkoma	Fayetteville	Shale	70	0	30
Fort Worth	Barnett	Shale	92 (75)	3 (15)	5 (10)
Gulf Coast	Eagle Ford	Shale	80 (50)	20 (40)	0 (10)
Permian (Far West)	All formations	Shale and tight	20 (20)	80 (30)	0 (50)
Permian (Midland)	All formations	Shale and tight	68 (35)	30 (40)	2 (25)
TX-LA-MS	All formations	Shale and tight	95 (90)	0 (0)	5 (10)
Nationwide	All formations	Shale and tight	40	53	7

Sources: 179 DCN SGE01179

a—Parentheses contain projected data for the year 2020, reported as the “most likely” scenario by Nicot et al. 2012 (97 DCN SGE00639).

b—Fresh water is naturally occurring water on the Earth’s surface. Examples include ponds, lakes, rivers and streams, and certain underground aquifers. Fresh water is generally characterized by having low concentrations of dissolved salts. Brackish water is water that has more salinity than fresh water, but not as much as seawater. Example brackish water sources include certain underground aquifers, effluent from publicly owned treatment plants (POTWs), and wastewater from other industries.

c—In addition to the 77 to 83 percent fresh water reported for the Marcellus shale in WV, 6 to 17 percent of base fluid was reported as “purchased water” and 1 to 3 percent was reported as groundwater both of which could be fresh or brackish. Neither of these values are included in this table.

d—Hansen et al. 2013 (60 DCN SGE00532) reported this data as “surface water.”

“—” indicates no data.

1.2 Additives

In addition to base fluid, operators add proppant and chemicals to adjust the fracturing fluid properties. Proppant generally makes up 10 percent or less of the total fracturing fluid by mass. Chemical additives in total typically make up less than 0.5 percent of the total fracturing fluid by mass (1 DCN SGE00010). The additives and the quantity of additives used in fracturing fluid depend on the formation geology, base fluid characteristics, and UOG operator (106 DCN SGE00721; 4 DCN SGE00070; 136 DCN SGE00780; 137 DCN SGE00781). Fracturing fluid additives are constantly evolving as UOG operators determine the most efficient composition to use for each fracture job. There are two general types of water-based fracturing fluids:

- **Slickwater fracturing** fluids consist of small quantities of friction reducer, biocides, scale inhibitors, surfactants, and propping agents. Operators generally use slickwater designs to fracture dry natural gas producing formations (105 DCN SGE00710; 101 DCN SGE00705).

- **Gel fracturing** fluids include higher quantities of gels to increase fluid viscosity that enables the fluid to carry higher concentrations of propping agents into the formation. Using gel fracturing fluids requires less total base fluid volume than using slickwater fracturing fluids, but gel fracturing fluids contain more additives and proppant. Consequently, gel fracturing fluids are more complex than slickwater fracturing fluids and are more sensitive to the quality of base fluid (105 DCN SGE00710; 101 DCN SGE00705). Operators generally use gel fracturing fluids to fracture liquid-rich formations[43] (101 DCN SGE00705).

In 2015, the EPA's Office of Research and Development (ORD) released a report summarizing additives used by operators based on public disclosures to FracFocus[63] (106 DCN SGE00721). In addition, several sources have published information regarding fracturing fluid additives and their uses in hydraulic fracturing (4 DCN SGE00070; 136 DCN SGE00780; 137 DCN SGE00781; 146 DCN SGE00966). Table C-2 shows specific additives used by operators categorized by purpose. Many additives can have multiple purposes depending on the exact design of the fracturing fluid. Table C-3 and Table C-4 show the medians and ranges (5^{th} to 95^{th} percentile) of the maximum possible fluid concentrations reported by operators of the most frequently reported ingredients in the FracFocus public disclosures, summarized in the EPA ORD report, for hydraulically fractured gas and oil wells. Ingredients in Table C-3 and Table C-4 are sorted from highest to lowest median of the maximum concentrations.

Table C-2. Fracturing Fluid Additives, Common Compounds, and Common Uses

Additive Type[a]	Common Compound(s)[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	Peroxydisulfates; salts	Reduces the viscosity of the fluid by "breaking down" the gelling agents in order 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	Ammonium bisulfite; methanol	Reduces rust formation on steel tubing, well casings, tools, and tanks (used only in fracturing fluids that contain acid).
Crosslinker	Borate salts; potassium hydroxide	Increases fluid viscosity to allow the fluid to carry more proppant into the fractures.

[63] Operators submit reports for individual wells to FracFocus. These reports include date of completion, well type (oil, gas), total fracturing fluid volume, well API number, well depth, location coordinates, and the concentrations of additives. These reports mostly represent wells completed in UOG formations but may also include some in conventional and CBM formations.

Table C-2. Fracturing Fluid Additives, Common Compounds, and Common Uses

Additive Type[a]	Common Compound(s)[b]	Purpose
Friction reducer	Petroleum distillates	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	Adjusts and controls the pH of the fluid in order to maximize the effectiveness of other additives such as crosslinkers.
Proppant	Quartz; sand; silica	Used to hold open the hydraulic fractures, allowing the natural gas or crude oil to flow to the production well.
Scale inhibitor	Ethylene glycol	Prevents the precipitation of carbonate and sulfate scales (e.g., calcium carbonate, calcium sulfate, barium sulfate) in pipes and in the formation.
Surfactant	Isopropanol; naphthalene	Reduces the surface tension of the fracturing fluids to improve fluid recovery from the well after fracture is completed.

Sources: 106 DCN SGE00721; 4 DCN SGE00070; 136 DCN SGE00780; 137 DCN SGE00781; 146 DCN SGE00966

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.

Table C-3. Most Frequently Reported Additive Ingredients Used in Fracturing Fluid in Gas Wells from FracFocus (2011–2013)

Specific Constituents	CAS Number	Maximum Concentration in Hydraulic Fracturing Fluid (% by Mass)[a]		
		Number of Reported Uses	Median Concentration	5th to 95th Percentile Concentration
Water	7732-18-5	7,998	0.18	0.000090–91
Guar gum	9000-30-0	3,586	0.1	0.00057–0.38
Hydrochloric acid	7647-01-0	12,351	0.078	0.0063–0.67
Distillates, petroleum, hydrotreated light	64742-47-8	11,897	0.017	0.0021–0.27
Sodium chloride	7647-14-5	3,608	0.0091	0–0.12
Glutaraldehyde	111-30-8	5,635	0.0084	0.00091–0.023
Ethylene glycol	107-21-1	5,493	0.0061	0.000080–0.24
Peroxydisulfuric acid, diammonium salt	7727-54-0	4,618	0.0045	0.000050–0.045
Solvent naphtha, petroleum, heavy arom.	64742-94-5	3,287	0.0044	0.000030–0.030
Sodium hydroxide	1310-73-2	4,656	0.0036	0.000020–0.088
2-Butoxyethanol	111-76-2	3,325	0.0035	0.000010–0.041
Acetic acid	64-19-7	3,563	0.0025	0–0.028
Quartz	14808-60-7	3,758	0.0024	0.000030–11
Ethanol	64-17-5	6,325	0.0023	0.00012–0.090
Methanol	67-56-1	12,269	0.002	0.000040–0.053
2,2-Dibromo-3-nitrilopropionamide	10222-01-2	3,668	0.0018	0.000070–0.022
Citric acid	77-92-9	4,832	0.0017	0.000050–0.011
Isopropanol	67-63-0	8,008	0.0016	0.000010–0.051
Naphthalene	91-20-3	3,294	0.0012	0.0000027–0.0050
Propargyl alcohol	107-19-7	5,811	0.00007	0.000010–0.0016

Source: 106 DCN SGE00721

a—Represents 17,035 FracFocus disclosures for gas wells.

Note: See Table 9 in the original source for further details about this data and how to interpret it (U.S. EPA. 2015. Analysis of Hydraulic Fracturing Fluid Data from the FracFocus Chemical Disclosure Registry 1.0. Office of Research and Development. 106 DCN SGE00721).

Table C-4. Most Frequently Reported Additive Ingredients Used in Fracturing Fluid in Oil Wells from FracFocus (2011–2013)

Specific Constituents	CAS Number	Maximum Concentration in Hydraulic Fracturing Fluid (% by Mass)[a]		
		Number of Reported Uses	Median Concentration	5th to 95th Percentile Concentration
Water	7732-18-5	8,538	1	0.0050–9.1
Hydrochloric acid	7647-01-0	10,029	0.29	0.013–1.8
Guar gum	9000-30-0	9,110	0.17	0.027–0.43

Table C-4. Most Frequently Reported Additive Ingredients Used in Fracturing Fluid in Oil Wells from FracFocus (2011–2013)

Specific Constituents	CAS Number	Maximum Concentration in Hydraulic Fracturing Fluid (% by Mass)[a]		
		Number of Reported Uses	Median Concentration	5th to 95th Percentile Concentration
Phenolic resin	9003-35-4	3,109	0.13	0.019–2.0
Distillates, petroleum, hydrotreated light	64742-47-8	10,566	0.087	0.00073–0.39
Ethanol	64-17-5	3,536	0.026	0.000020–0.16
Ethylene glycol	107-21-1	10,307	0.023	0.00086–0.098
Methanol	67-56-1	12,484	0.022	0.00064–0.16
Potassium hydroxide	1310-58-3	7,206	0.013	0.000010–0.052
Sodium hydroxide	1310-73-2	8,609	0.01	0.00005–0.075
Peroxydisulfuric acid, diammonium salt	7727-54-0	10,350	0.0076	0.00028–0.067
Sodium chloride	7647-14-5	3,692	0.0071	0–0.27
Glutaraldehyde	111-30-8	5,927	0.0065	0.00027–0.020
Isopropanol	67-63-0	8,031	0.0063	0.00007–0.22
Solvent naphtha, petroleum, heavy arom.	64742-94-5	3,821	0.006	0–0.038
2-Butoxyethanol	111-76-2	4,022	0.0053	0–0.17
Acetic acid	64-19-7	4,623	0.0047	0–0.047
Citric acid	77-92-9	3,310	0.0047	0.00016–0.024
Quartz	14808-60-7	8,577	0.0041	0.000040–12

Source: 106 DCN SGE00721

a—Represents 17,640 FracFocus disclosures for oil wells.

Note: See Table 8 in the original source for further details about this data and how to interpret it (U.S. EPA. 2015. Analysis of Hydraulic Fracturing Fluid Data from the FracFocus Chemical Disclosure Registry 1.0. Office of Research and Development. 106 DCN SGE00721).

1.3 Fracturing Fluids

Fracturing fluid is the final mixture of base fluid and additives. Its total volume depends on the well trajectory (i.e., vertical, directional, horizontal) and the type of fracturing fluid used (e.g., gel, slickwater) (164 DCN SGE01095). Operators fracture UOG wells using from 50,000 to over 10 million gallons (1,200 to over 238,000 barrels) of fracturing fluid per well with up to a million or more pounds of sand (i.e., proppant). Operators typically fracture horizontal wells in eight to 23 stages, using between 250,000 and 420,000 gallons (6,000 and 10,000 barrels) of fracturing fluid per stage (24 DCN SGE00280). Literature reports that tight oil and gas wells typically require less fracturing fluid than shale oil and gas wells (61 DCN SGE00533). Typical volumes of fracturing fluid vary by UOG formation, well trajectory, number of stages, and resource type and are provided in Section C.2.

The concentrations of TDS in fracturing fluid are often low (<20,000 mg/L) compared to levels found in UOG produced water, which suggests that the majority of the TDS in UOG produced water is contributed by the formation (see Section C.3) (6 DCN SGE00110, 44 DCN

SGE00414). Other constituents, such as total organic carbon (TOC) and biochemical oxygen demand (BOD_5), have been found at higher concentrations in fracturing fluid than in flowback and long-term produced water. For example, one study of Marcellus UOG produced water found median concentrations of BOD_5 in fracturing fluid of about 1,700[64] mg/L but BOD_5 in the corresponding flowback and long-term produced water of 300[65] mg/L or less on average (44 DCN SGE00414). As indicated in Table C-2, Table C-3, and Table C-4 organic materials (which contribute to BOD_5 and TOC) are typical chemical additives in fracturing fluid (44 DCN SGE00414).

2 UOG EXTRACTION WASTEWATER VOLUMES

As explained previously, UOG wells generate three main types of wastewater over the life of the well: drilling wastewater, flowback, and long-term produced water (the latter two are collectively referred to as produced water). These wastewater streams' flow rates and total volumes generated per well vary based on several factors, including:

- Time since flowback commenced
- Resource type (e.g., shale oil, tight gas)
- Specific geology properties
- Whether the producing formation is dry or contains formation water
- Well trajectory (i.e., horizontal, directional, vertical)

The following two subsections quantify wastewater volumes generated during the UOG well development process. Section C.2.1 summarizes general trends in UOG extraction wastewater volumes for each part of the well development process by resource type and well trajectory. Section C.2.2 provides detailed produced water volumes by UOG formation and well trajectory.[66]

2.1 <u>UOG Extraction Wastewater Volumes by Resource and Well Trajectory</u>

This section quantifies the volumes of UOG extraction wastewater generated, on a per well basis, for the following three wastewater components:

- Drilling wastewater
- Flowback
- Long-term produced water

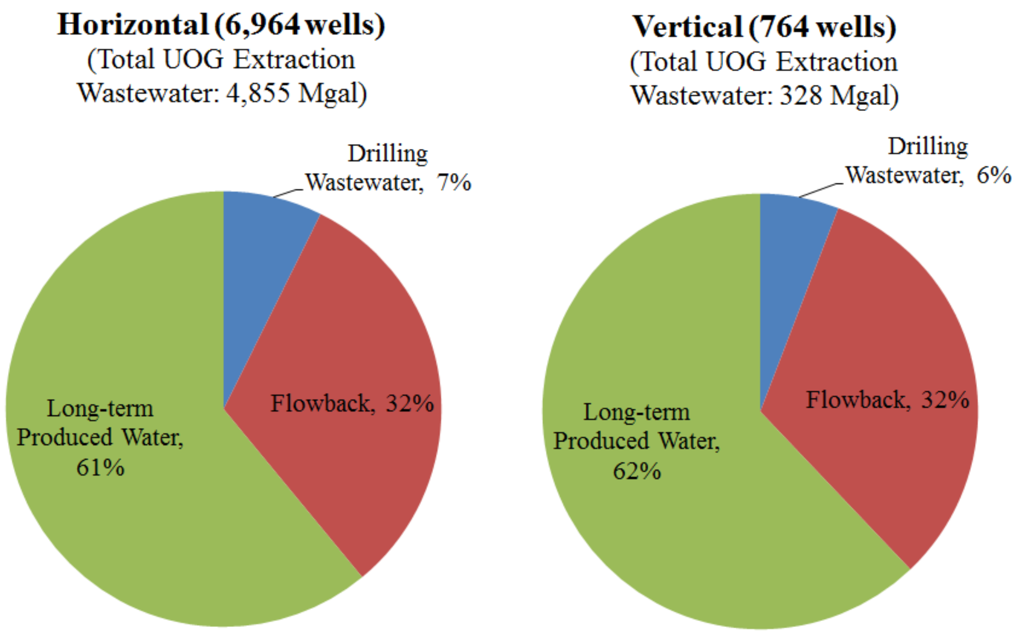
Flowback and long-term produced water are the largest volumes of UOG extraction wastewater. Figure C-1 shows a breakdown of UOG extraction wastewater volumes generated

[64] This study reported 1,700 mg/L as the median concentration based on 19 samples. The overall range of BOD was 4.3 to 47,400 mg/L.

[65] This study reported 330 mg/L as the median concentration based on 19 flowback samples. The overall range of BOD was 30 to 1,440 mg/L.

[66] Section C.2.2 does not include drilling wastewater volumes by well trajectory because EPA identified drilling wastewater volumes data without well trajectory information.

from Marcellus shale wells in Pennsylvania based on data from PA DEP's statewide waste production reports for all wells active between 2004 and 2014 (184 DCN SGE01182). This trend varies by formation and, sometimes, within formations. However, a general rule of thumb for all UOG formations is that the total volume of UOG produced water (i.e., flowback and long-term produced water) generated by a well over its lifetime is approximately 50 percent flowback and 50 percent long-term produced water—despite the fact that flowback is generated over a short period of time and long-term produced water is generated over the well life, which may be more than 10 years (111 DCN SGE00728).[67]



Sources: 184 DCN SGE01182

Figure C-1. UOG Extraction Wastewater Volumes for Marcellus Shale Wells in Pennsylvania (2004–2014)

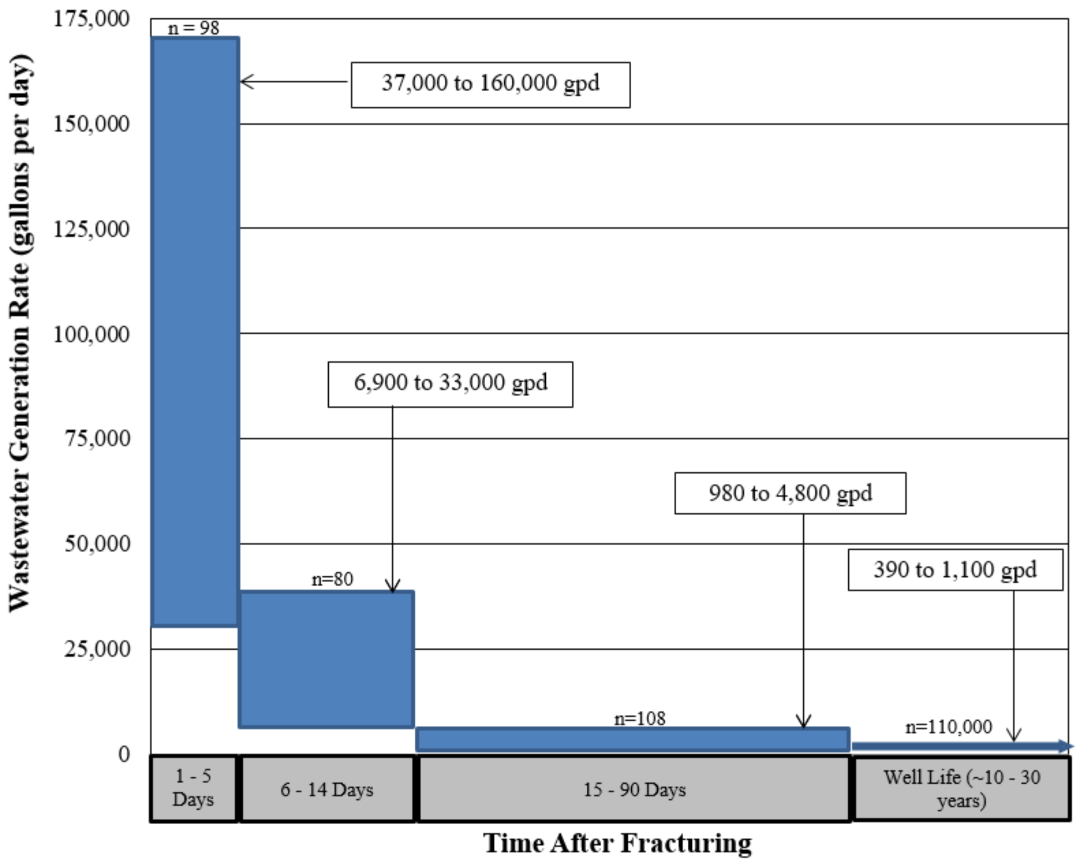
Figure C-2 shows the quantities of produced water (i.e., flowback and long-term produced water) generated from UOG wells from the time of well completion to the end of the well life. The produced water generation rates reflect aggregated data from multiple UOG formations;[68] "n" is the number of data points for each time period.[69] As shown in the figure, UOG produced water generation rates are highest immediately after well completion, when there

[67] Figure C-1 shows that long-term produced water is more than 50 percent of total UOG produced water for Marcellus shale wells likely because Marcellus wells generate relatively lower flowback volumes compared to other UOG formations (see Table C-9).

[68] As explained in Chapter B, the length of the flowback process is variable. Literature generally reports it as 30 days or less (60 DCN SGE00532). Other operators report it as only lasting five days (36 DCN SGE00350).

[69] Data for the first 90 days represent the Marcellus, Barnett, Woodford, Codell-Niobrara, Bakken, and Fayetteville UOG formations. Data beyond 90 days (long-term produced water) are from Table C-9.

is little or no crude oil and natural gas production (flowback). During the transition from the flowback process to production (within weeks of well completion), produced water generation rates decrease significantly and eventually level out. During production, produced water generation rates gradually decrease over the life of the well (long-term produced water).



Source: 186 DCN SGE01184

Figure C-2. Ranges of Typical Produced Water Generation Rates over Time After Fracturing

2.1.1 Drilling Wastewater

Volumes of drilling wastewater typically increase with the length of the wellbore. For example, a vertical well will typically produce a smaller volume of drilling wastewater than a horizontal well drilled into the same formation, because the latter requires additional drilling fluid to complete the horizontal lateral (184 DCN SGE01182). Table C-5 illustrates this trend for UOG wells drilled into the Marcellus formation in Pennsylvania.

Table C-5. Median Drilling Wastewater Volumes for UOG Horizontal and Vertical Wells in Pennsylvania

Well Trajectory	Median Drilling Wastewater Volume per Well(Gallons)	Range of Drilling Fluid Volume per Well (Gallons) [a]	Typical Total Measured Depth [b]	Number of Data Points
Horizontal	50,000	3,400–200,000	7,300–13,000	3,961
Vertical	35,000	5,000–190,000	6,000–7,000	230

Source: 184 DCN SGE01182

a— These ranges are based on the 10th and 90th percentile of volumes reported for individual wells.

b— Total measured depth is the true length of wellbore drilled (i.e., sum of the vertical and horizontal).

The EPA collected information on volumes of drilling wastewater generated per well. Table C-6 shows typical ranges of drilling wastewater generated by UOG wells by resource type and formation. Operators report that nearly all of the drilling fluid used per well is recovered as wastewater at the end of drilling.[70] Therefore, where it had information on drilling fluid volumes but not the resulting drilling wastewater volume, the EPA assumed the former is representative of the latter.

Table C-6. Drilling Wastewater Volumes Generated per Well by UOG Formation

Resource Type	Formation	Typical Drilling Wastewater Volume Range (Gallons per Well)	Typical Total Measured Depth[b] (Feet)	Number of Data Points
Shale	Haynesville	420,000–1,100,000	13,000–19,000	5
Tight	Anadarko Basin[b]	200,000–420,000	—[c]	2
Shale	Niobrara	300,000[a]	7,500–13,000	1
Shale	Barnett	170,000–500,000	8,500–14,000	6
Shale	Permian Basin[b]	84,000–420,000	—[c]	8
Tight	Granite Wash	200,000[a]	—[c]	1
Tight	Cleveland	200,000[a]	—[c]	1
Shale	Eagle Ford	130,000–420,000	6,000–16,000	7
Shale	Utica	100,000[a]	6,000–19,000	1
Tight	Mississippi Lime	100,000[a]	—[c]	1
Shale	Marcellus	3,400–200,000[d] (median: 50,000)	7,300–13,000	3,962

Source: 183 DCN SGE01181

a—Only one data point was identified for these formations. Therefore, there is no range to display.

b—Total measured depth is the true length of wellbore drilled (i.e., sum of the vertical and horizontal).

c—Information is unknown.

d—Due to the large number of volume data points for the Marcellus formation, the EPA calculated the 10th and 90th percentile values to represent the typical volume range and to eliminate outliers. The EPA was also able to calculate a median for the Marcellus due to the large number of data points. For all other formations, the EPA used the reported maximum and minimum volume range reported because of the limited number of data points.

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[70] Some drilling fluid volume may be lost downhole and/or to moisture in the cuttings, but these losses account for a relatively small percentage of the total volume (92 DCN SGE00625).

2.1.2 Produced Water: Flowback

As described above, for purposes of this document, produced water includes flowback in addition to long-term produced water. Table C-7 quantifies the portion of fracturing fluid returned as flowback.[71] Because the volume of fracturing fluid used during well stimulation affects flowback quantities, fracturing fluid volumes are also listed. Based on the data in Table C-7,[72] total flowback volumes typically range between 40,000 to 1,100,000 gallons (950 to 25,000 barrels) per well. On average, horizontal shale wells generate the highest volumes of flowback. In terms of wastewater management, operators must consider that the flowback process generates large volumes of wastewater in a short period of time (e.g., 30 days) compared to long-term produced water that is generated in small volumes over a long period of time.

Table C-7. UOG Well Flowback Recovery[73] by Resource Type and Well Trajectory

Resource Type	Trajectory	Fracturing Fluid (MG)[a]			Flowback Recovery (Percent of Fracturing Fluid Returned)[a]		
		Weighted Average[b]	Range	Number of Data Points	Weighted Average[b]	Range	Number of Data Points
Shale	H	4.2	0.091–24	80,388	7	0–580	7,377
	D	1.4	0.037–20	340	33	12–57	36
	V	1.1	0.015–19	5,197	96	2–581	57
Tight	H	3.4	0.069–12	7,301	12	0–60	75
	D	0.5	0.046–4	3,581	10	0–60	342
	V	1	0.016–4	10,852	4	0–60	130

Source: 186 DCN SGE01184

a—Most of the underlying fracturing fluid volume data and flowback recovery data were reported in different sources. To avoid representing the data incorrectly, the EPA did not calculate total flowback volume for Table C-7. Data are based on aggregated data from Table C-9, which contains volumes by formation.

b—The weighted averages are based on the number of data points (i.e., formation/trajectory combinations with more data points were given more weight than those based on fewer data points).

Abbreviations: MG—million gallons; H—horizontal well; D—directional well; v—vertical well

2.1.3 Produced Water: Long-Term Produced Water

Long-term produced water rates remain relatively constant[74] over the well life compared to flowback rates (95 DCN SGE00635). Table C-8 quantifies long-term produced water rates in

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[71] The EPA explains how it differentiated between flowback and long-term produced water volumes in literature in its memorandum *Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation* (186 DCN SGE01184).

[72] Approximate flowback volumes can be estimated by multiplying total fracturing volume by the percent of fracturing fluid returned during flowback. However, EPA does not show this calculation in Table C-7 because not all data sources report both fracturing fluid volume and percent of fracturing fluid recovered as flowback.

[73] Flowback recovery is the percent of total fracturing fluid injected during hydraulic fracturing that returns to the wellhead during the flowback process.

[74] Note that long-term produced water rates typically gradually decrease over the well life. However, the change is small relative to flowback.

gallons per day by UOG resource and well trajectory. Typical (i.e., weighted average values in Table C-8) long-term produced water rates range from about 390 to 1,100 gallons (9 to 26 barrels) per day. A comparison of median long-term produced water rates for shale formation wells, as listed in the table, shows that horizontal shale wells have higher rates than directional and vertical shale wells. Similarly, for tight formation wells in Table C-8, horizontal wells have the highest typical long-term produced water generation rates.

Table C-8. Long-Term Produced Water Generation Rates by Resource Type and Well Trajectory

Resource Type	Trajectory	Long-Term Produced Water Generation Rates (gpd per Well)[a]		
		Weighted Average[b]	Range	Number of Data Points
Shale	H	1,100	0–29,000	43,893
	D	820	0.83–12,000	1,493
	V	500	4.8–51,000	12,551
Tight	H	980	10–120,000	4,692
	D	390	15–8,200	10,784
	V	650	0.71–2,100	34,624

Sources: 186 DCN SGE01184

a—Data are based on aggregated data from Table C-9, which contains volumes by formation.

b—The weighted averages are based on the number of data points (i.e., formation/trajectory combinations with more data points were given more weight than those based on fewer data points).

Abbreviations: gpd—gallons per day; H—horizontal well; D—directional well; V—vertical well

2.2 UOG Produced Water Volumes by Formation

Table C-9 shows UOG produced water volumes by UOG formation and well trajectory; these data were used to generate the summary statistics in Section C.2.1. The data in Table C-9 are sorted alphabetically by basin. Because the EPA identified less data by formation for drilling wastewater, Table C-9 does not include drilling wastewater volumes.

Data in Table C-9 illustrate that volumes of flowback and flow rates of long-term produced water vary by formation. For example, horizontal UOG wells drilled into the Barnett shale formation in the Fort Worth basin generate 530 gallons (13 barrels) per day of long-term produced water compared to 1,900 gallons (45 barrels) per day for horizontal UOG wells drilled into the Eagle Ford shale formation in the Western Gulf basin (91 DCN SGE00623). In some cases, produced water even varies geographically within the same formation, which is not evident in Table C-9. For example, operators report that wells drilled in the northeast portion of the Marcellus shale formation (in Pennsylvania) generate less produced water than wells drilled in the southwest portion of the Marcellus shale formation (in West Virginia) (95 DCN SGE00635).

Table C-9. Produced Water Volume Generation by UOG Formation

Basin	UOG Formation	Resource Type	Well Trajectory	Fracturing Fluid (MG)			Flowback Recovery (% of Fracturing Fluid Returned)			Long-Term Produced Water Rates (gpd)		
				Weighted Average[a]	Range[b]	Number of Data Points[c]	Weighted Average[a]	Range[b]	Number of Data Points[c]	Weighted Average[a]	Range[b]	Number of Data Points[c]
Anadarko	Caney	Shale	H	8.1	4.4–12	11	—	—	0	—	—	0
	Cleveland	Tight	H	1.7	0.2–4	928	—	12–40	2	410	59–2,000	1,160
			V	0.18	0.033–3	15	50	50–50	1	66	56–400	130
	Granite Wash	Tight	H	4.9	0.2–8.3	924	—	6.5–22	2	980	10–2,400	762
			V	0.53	0.085–3	72	50	50–50	1	520	330–790	1,397
			D	—	—	0	—	—	0	480	160–940	83
	Mississippi Lime	Tight	H	2	1.3–5	3,301	50	50–50	1	—	37,000–120,000	4
			V	0.34	0.016–0.71	59	—	—	0	10	0.71–38	16
	Woodford	Shale	H	5.2	1–12	3,243	34	20–50	3	5,500	3,200–6,400	198
			V	0.36	0.015–1.6	11	—	—	0	—	—	0
			D	1.6	0.21–1.9	10	—	—	0	—	—	0
	Clinton-Medina	Tight	V	—	—	0	—	—	0	7.9	7.3–11	551
Appalachian	Devonian	Shale	V	—	—	0	—	—	0	13	4.8–19	197
	Marcellus	Shale	H	4.6	0.9–11	17,316	7.1	4–47	4,374	820	54–13,000	6,494
			V	0.25	0.11–5.4	116	40	21–60	7	200	94–1,000	741
			D	0.16	0.092–0.17	6	—	—	0	—	—	0
	Utica	Shale	H	6.8	1–13	1,108	2.5	0.66–27	684	800	420–1,700	764
Arkoma	Fayetteville	Shale	H	5	1.7–11	3,014	—	10–20	2	430	150–2,300	2,305
Denver J.	Codell	Tight	H	3.5	2.4–7.1	234	16	—	36	400	110–1,100	179
			V	0.23	0.11–0.46	97	0	0–4	13	59	47–120	158
			D	0.26	0.14–0.5	362	0	0–3	8	46	18–71	667

Table C-9. Produced Water Volume Generation by UOG Formation

Basin	UOG Formation	Resource Type	Well Trajectory	Fracturing Fluid (MG)			Flowback Recovery (% of Fracturing Fluid Returned)			Long-Term Produced Water Rates (gpd)		
				Weighted Average[a]	Range[b]	Number of Data Points[c]	Weighted Average[a]	Range[b]	Number of Data Points[c]	Weighted Average[a]	Range[b]	Number of Data Points[c]
	Codell-Niobrara	Tight	H	2.8	2.7–5.4	65	7.2	7.2–7.2	32	75	19–560	38
			V	0.3	0.15–0.4	490	2.8	—	21	33	13–65	2,113
			D	0.4	0.2–0.46	806	0	0–5	11	45	28–70	1,853
	Muddy J	Tight	H	1.4	0.44–2.6	6	—	—	0	860	220–1,100	6
			V	0.27	0.12–0.45	139	0.09	—	15	120	52–550	340
			D	0.42	0.17–0.62	758	0	0–0	11	63	39–110	1,106
	Niobrara	Shale	H	2.9	1.9–5.1	1,435	16	1.8–100	173	760	120–1,300	1,213
			V	0.24	0.015–0.31	455	33	1.6–90	29	330	15–600	5,808
			D	0.36	0.13–2.9	25	—	—	0	41	8.1–590	38
Fort Worth	Barnett	Shale	H	3.7	1–7.3	26,495	30	21–40	11	530	240–4,200	11,957
			V	1.3	0.38–1.9	3,773	—	—	0	230	140–390	2,416
			D	1.2	0.48–1.6	96	—	—	0	210	79–410	481
Green River	Hilliard-Baxter-Mancos	Shale	H	1.7	1–5.6	2	—	—	0	—	—	0
			D	—	—	0	—	—	0	35	14–56	10
	Lance	Tight	H	—	—	0	—	—	0	730	350–1,100	6
			V	1.5	0.82–3.9	37	3.3	0.88–50	38	610	410–840	61
			D	0.97	0.65–2.1	881	12	1.8–40	187	650	420–1,100	2,787
	Mancos	Shale	H	15	1.8–24	24	3.1	0.063–17	8	770	—	26
			D	5.4	0.12–20	10	—	—	0	140	0.83–1,400	36
	Mesaverde	Tight	H	—	—	0	—	—	0	220	130–480	5
			V	0.16	0.13–0.22	21	18	6.3–43	15	440	120–780	33
			D	0.19	0.11–0.3	448	9.3	0.7–36	94	380	150–610	856
Illinois	New Albany	Shale	H	—	—	0	—	—	0	2,940	2,940–2,940	1
Michigan	Antrim	Shale	V	0.05	0.05–0.05	1	—	25–75	2	1,300	530–4,600	7

Table C-9. Produced Water Volume Generation by UOG Formation

Basin	UOG Formation	Resource Type	Well Trajectory	Fracturing Fluid (MG)			Flowback Recovery (% of Fracturing Fluid Returned)			Long-Term Produced Water Rates (gpd)		
				Weighted Average[a]	Range[b]	Number of Data Points[c]	Weighted Average[a]	Range[b]	Number of Data Points[c]	Weighted Average[a]	Range[b]	Number of Data Points[c]
Permian	Avalon & Bone Spring	Shale	H	2.3	1.2–5.7	965	19	4.9–40	48	2,700	2,100–5,700	1,171
			V	0.4	0.07–1.3	21	—	—	0	2,000	1,000–4,800	68
			D	1.8	1.2–3.4	40	33	12–57	36	1,300	800–3,300	94
	Barnett-Woodford	Shale	H	2.1	0.5–4.5	2	—	—	0	—	—	0
	Delaware	Shale	H	1.3	0.42–3	85	79	9.7–230	20	9,400	5,000–29,000	232
			V	0.19	0.044–0.38	141	210	84–580	19	1,600	1,100–3,800	412
			D	0.26	0.15–0.4	47	—	—	0	4,500	2,400–5,700	90
	Devonian (TX)	Shale	H	0.47	0.091–5.5	43	—	—	0	1,700	630–2,700	325
			V	0.14	0.075–1	187	—	—	0	3,700	1,400–5,400	306
			D	0.11	0.037–0.13	11	—	—	0	2,400	250–12,000	40
	Morrow	Tight	V	—	—	0	—	—	0	130	41–290	7
			D	—	—	0	—	—	0	140	34–2,200	66
	Spraberry	Tight	H	1.3	0.069–6.5	29	—	—	0	1,000	420–3,800	41
			V	0.91	0.071–1.6	449	—	—	0	1,000	670–1,500	936
			D	1	0.06–1.5	16	—	—	0	1,200	660–2,500	42
	Trend Area	Tight	H	8.3	2.4–12	991	—	—	0	890	530–3,900	457
			V	1.1	0.58–1.9	8,733	—	—	0	780	690–920	15,494
			D	1	0.4–1.7	41	—	—	0	620	370–1,500	50
	Wolfcamp	Shale	H	6.7	1.4–12	1,775	16	12–23	12	3,500	450–15,000	1,237
			V	1.6	0.18–2.3	383	—	—	0	780	460–1,400	1,142
			D	1.8	0.17–3	12	—	—	0	1,700	750–3,600	170
Piceance & Uinta	Mesaverde	Tight	D	—	—	0	—	—	0	510	130–700	52
	Hermosa	Shale	D	—	—	0	—	—	0	47	27–260	21
Powder River	Mowry	Shale	H	2.5	0.76–7.4	15	15	4.3–580	14	450	61–2,100	16

Table C-9. Produced Water Volume Generation by UOG Formation

Basin	UOG Formation	Resource Type	Well Trajectory	Fracturing Fluid (MG)			Flowback Recovery (% of Fracturing Fluid Returned)			Long-Term Produced Water Rates (gpd)		
				Weighted Average[a]	Range[b]	Number of Data Points[c]	Weighted Average[a]	Range[b]	Number of Data Points[c]	Weighted Average[a]	Range[b]	Number of Data Points[c]
San Juan	Dakota	Tight	V	0.16	0.061–0.34	85	1.6	—	22	75	35–490	81
			D	0.12	0.063–0.32	136	4.1	1.1–60	29	230	53–950	511
	Mesaverde	Tight	V	—	—	0	—	—	0	43	14–560	5
			D	—	—	0	—	—	0	21	15–180	49
	Pictured Cliffs	Tight	H	—	—	0	—	—	0	370	190–720	7
			D	—	—	0	—	—	0	4,700	1,200–8,200	6
TX-LA-MS	Bossier	Shale	H	3.8	2.6–5.4	12	—	—	0	37	5.6–370	47
			V	0.61	0.22–1.7	82	—	—	0	230	4.8–480	1,143
			D	0.55	0.18–1.1	48	—	—	0	150	1.2–300	304
	Cotton Valley	Tight	H	4.4	0.25–8.5	433	60	60–60	1	710	410–2,600	689
			V	0.27	0.018–1.4	355	60	60–60	1	700	490–890	9,267
			D	0.45	0.046–4	79	60	60–60	1	620	240–980	1,912
	Haynesville	Shale	H	5.7	0.95–15	3,855	5.2	5.2–30	3	910	84–1,200	2,575
			V	0.9	0.2–2.5	2	—	—	0	330	210–560	230
			D	3.9	1.9–7.3	35	—	—	0	660	130–1,200	204
	Travis Peak	Tight	H	3	0.25–6	2	—	—	0	710	110–4,200	7
			V	0.17	0.032–4	36	—	—	0	630	270–930	1,046
			D	—	—	0	—	—	0	520	140–800	134
	Tuscaloosa	Shale	H	11	6.1–14	28	—	—	0	—	—	0
			V	13	4.7–19	11	—	—	0	7,400	220–51,000	64
Western Gulf	Austin Chalk	Tight	H	1.7	0.83–5.4	134	—	—	0	2,200	980–5,100	752
			V	—	—	0	—	—	0	97	21–1,500	51
	Eagle Ford	Shale	H	4.8	1–14	12,810	4.2	2.1–8.4	1,800	1,900	88–6,200	7,971
			V	0.94	0.23–2	8	—	—	0	1,200	510–2,300	12
			D	—	—	0	—	—	0	4,300	3,000–5,600	5
	Edwards	Tight	H	—	—	0	—	—	0	2,300	1,000–24,000	266

Table C-9. Produced Water Volume Generation by UOG Formation

Basin	UOG Formation	Resource Type	Well Trajectory	Fracturing Fluid (MG)			Flowback Recovery (% of Fracturing Fluid Returned)			Long-Term Produced Water Rates (gpd)		
				Weighted Average[a]	Range[b]	Number of Data Points[c]	Weighted Average[a]	Range[b]	Number of Data Points[c]	Weighted Average[a]	Range[b]	Number of Data Points[c]
			V	—	—	0	—	—	0	560	150–2,100	32
			D	—	—	0	—	—	0	160	69–290	6
	Olmos	Tight	H	1.9	0.37–6	246	—	—	0	180	13–700	229
			V	0.11	0.078–0.21	50	—	—	0	78	52–370	1,120
			D	—	—	0	—	—	0	51	15–470	16
	Pearsall	Shale	H	3.5	1.6–5.6	47	—	—	0	160	53–1,500	51
	Vicksburg	Tight	V	0.21	0.072–0.61	158	—	—	0	700	330–990	702
			D	0.23	0.11–0.63	40	—	—	0	830	390–1,400	193
	Wilcox Lobo	Tight	H	0.33	0.082–2.4	8	—	—	0	370	250–610	84
			V	0.1	0.042–0.6	56	—	—	0	650	400–940	1,084
			D	0.094	0.058–0.16	14	—	—	0	500	300–4,200	395
Williston	Bakken	Shale	H	2.4	0.35–10	8,103	19	5–47	225	910	500–3,800	7,309
			V	0.16	0.04–2.7	6	—	—	0	2,400	150–5,100	5

Sources: 186 DCN SGE01184

a—Weighted averages are based on the number of data points reported by each data source (i.e., data sources that reported volume data for a particular formation/trajectory combination based on a large number of data points were given more weight than those based on fewer data points).

b—For some formations, if only one data point was reported, the EPA reported it in the range column and did not report a weighted average value.

"—" indicates no data.

c—For some formations, the number of data points was not reported in the data source. In these instances, this table reports that number as 1, except if the source reported a range in which case this table reports the number of data points as 2.

Abbreviations: MG—million gallons; H—horizontal well; D—directional well; V—vertical well

3 UOG EXTRACTION WASTEWATER CHARACTERIZATION

As discussed in Chapter B, UOG operations generate wastewater that includes drilling wastewater, flowback, and long-term produced water. Drilling wastewater is generated during the initial drilling of the well and typically maintains the characteristics of the drilling fluid, but also contains additional solids (i.e., drill cuttings) that are generated during the well drilling process. Flowback may contain the specific fracturing fluid composition (e.g., chemical additives, base fluid) used by each UOG operator as well as chemical constituents present in the UOG formation (27 DCN SGE00286; 6 DCN SGE00110). Long-term produced water typically mimics the characteristics of the UOG formation, which often contributes, in part, to high concentrations of select naturally occurring ions (169 DCN SGE01125). The volumes and characteristics of UOG extraction wastewater may vary significantly between basins, between formations, and sometimes between wells within the same formation (see Section C.2 for a discussion of UOG extraction wastewater volumes) (75 DCN SGE00592). The following subsections describe the characteristics of UOG extraction wastewater.

3.1 Availability of Data for UOG Extraction Wastewater Characterization

The EPA identified concentration data for constituents commonly found in UOG extraction wastewater. These constituents include, primarily, total dissolved solids (TDS), anions/cations, metals, hardness, and radioactive constituents. The EPA presents summarized UOG extraction wastewater characterization data in the following subsections, which are organized into five constituent categories: classical and conventional,[75] organic, metal, radioactive, and other. For all of the constituent categories, there are fewer data available for drilling wastewater than for produced water generated at all UOG wells. The EPA presents available data in the following subsections.

3.2 UOG Extraction Wastewater Constituent Categories

The data in the following subsections are representative of UOG extraction wastewater characteristics as presented in the literature for the entire UOG industry.[76] The data show combined characterization data for shale and tight reservoirs as well as for oil and gas resources. Regarding UOG produced water, the EPA sometimes presents the data as flowback and long-

[75] Note that section 304(a)(4) of the Clean Water Act (CWA) designates the following as "conventional" pollutants: biochemical oxygen demand (BOD_5), total suspended solids (TSS), fecal coliform, pH, and any additional pollutants the EPA defines as conventional. The Agency designated "oil and grease" as an additional conventional pollutant on July 30, 1979 (see 44 FR 44501). The CWA does not define "classical pollutant." Rather, pollutants that are not designated as either conventional or toxic are considered nonconventional pollutants. An example would be TDS. In the discussion of pollutants in UOG wastewaters contained in Chapter C of the TDD, the EPA has organized the discussion according to the categories in Table C-9, which includes the category "Classical and conventional." In this context, "Classical and conventional" refers to a range of parameters that are determined via classical wet chemistry analytical methods, including some CWA 304(a)(4) conventional pollutants as well as other parameters such as nutrients, alkalinity, hardness, COD, etc.

[76] Note that the lack of data for select constituents may not necessarily imply that those constituents are not present in the wastewater, but rather that they were not measured and/or reported in the existing literature. Refer to 186 DCN SGE01184 for additional details on the parameters reported in the literature reviewed. The accompanying database (187 DCN SGE01184.A13) includes nondetect, below detection, or zero values that were reported in the literature reviewed.

term produced water individually. In other instances, the data are presented as UOG produced water, which includes both flowback and long-term produced water. Some data sources reported characterization data as an aggregate (i.e., produced water) and others specified data as representing flowback or long-term produced water. Given the uncertainty of which stage the aggregate data represents, EPA presented it as produced water. However, where the type of produced water was specified, EPA presents the specified data because some constituent concentrations vary between flowback and long-term produced water.

3.2.1 Classical and Conventional Constituents in UOG Extraction Wastewater

Table C-10 presents typical concentrations of select classical and conventional constituents that are present in UOG drilling wastewater.[77] According to one CWT facility operator, TSS is high in returned drilling fluid before cuttings are removed. Depending on how well the cuttings are removed by the operator, solids can be as high as 50 percent by mass in drilling wastewater (18 DCN SGE00245) (see Section B.2.1). The EPA identified the following limitations to the data presented in Table C-10:

- Fewer data points (i.e., less than 30 data points) were available for each parameter.
- Only data representing drilling wastewater from Marcellus shale formation wells were available.
- All of the data came from the Marcellus shale formation.

Table C-11 presents typical concentrations of select classical and conventional constituents that are present in UOG produced water. The EPA identified the following limitations to the data presented in Table C-11:

- Fewer data points (i.e., less than 30 data points) were available for ammonia and phosphate.
- The majority of data associated with alkalinity, BOD_5, chemical oxygen demand (COD), hardness as $CaCO_3$, oil and grease, specific conductivity, TOC, and TSS came from the Marcellus shale formation.

[77] Table C-10 presents the number of detects, which represents the number of data points underlying sources indicated were a detected value. This nomenclature is used throughout the TDD.

Table C-10. Concentrations of Select Classical and Conventional Constituents in UOG Drilling Wastewater from Marcellus Shale Formation Wells[78]

Parameter	Units	Range	Median	Number of Data Points	Number of Detects
Alkalinity	mg/L	110–42,000	1,600	11	11
Ammonia	mg/L	0.98–35	7	8	8
BOD_5	mg/L	80–1,100	390	8	8
Chloride	mg/L	160–23,000	12,000	12	12
COD	mg/L	150–9,300	1,800	8	8
Hardness as $CaCO_3$	mg/L	1,400–46,000	4,400	12	12
Oil and grease	mg/L	ND[a]–150	2.5	8	8
pH	SU	6.8–12	9.0	12	12
Phosphate	mg/L	—[b]	16	4	4
Specific conductivity	µS/cm	1,100–60,000	19,000	10	10
TDS	mg/L	560–80,000	31,000	14	14
TSS	mg/L	120–600,000	28,000	16	16

Source: 183 DCN SGE01181

a—Source did not report detection limit.

b—Source only reported median value.

Abbreviations: mg/L—milligrams per liter; ND—nondetect; SU—standard units; µS/cm—microsiemens per centimeter

[78] Drilling wastewater may contain differing amounts of drill cuttings depending on how the operator chooses to remove drill cuttings from drilling wastewater.

Table C-11. Concentrations of Select Classical and Conventional Constituents in UOG Produced Water

Parameter	Units	Range	Median	Number of Data Points[a]	Number of Detects	Formations Represented[a]
Alkalinity	mg/L	41–1,100	140	265	265	Barnett (29); Eagle Ford (1); Marcellus (232); Woodford-Cana-Caney (3)
Ammonia	mg/L	40–270	110	13	13	Marcellus (5); Niobrara (5); Woodford-Cana-Caney (3)
Bicarbonate	mg/L	130–2,000	700	10,206	7,274	Bakken (399); Barnett (6); Cleveland (11); Codell (9); Cody (38); Cotton Valley/Bossier (3); Dakota (35); Eagle Ford (2925); Frontier (224); Hilliard-Baxter-Mancos (32); Lance (1905); Lansing Kansas City (16); Lewis (54); Mancos (2); Marcellus (154); Mesaverde (461); Mesaverde/Lance (13); Mesaverde/Lance/Lewis (878); Morrow (1); Mowry (5); New Albany (1); Niobrara (189); Oswego (5); Pearsall (3); Spraberry (26); Woodford-Cana-Caney (2811)
BOD	mg/L	22–1,300	160	154	153	Barnett (28); Marcellus (122); Medina/Clinton-Tuscarora (1); Woodford-Cana-Caney (3)
Carbonate	mg/L	0–270	53	205	144	Bakken (20); Barnett (4); Codell (2); Cody (1); Cotton Valley/Bossier (2); Dakota (3); Eagle Ford (4); Frontier (16); Lance (23); Lewis (6); Mesaverde (51); Mesaverde/Lance/Lewis (39); Niobrara (8); Spraberry (26)
Chloride[b]	mg/L	9,900–130,000	70,000	5,228	2,190	Bakken (22); Barnett (144); Cleveland (11); Codell (9); Cody (17); Cotton Valley/Bossier (25); Dakota (3); Eagle Ford (1651); Granite Wash/Atoka (1); Hilliard-Baxter-Mancos (33); Lance (1843); Marcellus (287); Mesaverde/Lance (5); Mesaverde/Lance/Lewis (943); Mowry (5); New Albany (1); Niobrara (193); Pearsall (3); Spraberry (26); Utica (1); Woodford-Cana-Caney (5)
COD	mg/L	1,000–14,000	3,200	149	149	Barnett (23); Marcellus (122); Medina/Clinton-Tuscarora (1); Woodford-Cana-Caney (3)
Hardness as $CaCO_3$	mg/L	2,200–77,000	21,000	80	80	Barnett (15); Marcellus (65)
Oil and grease	mg/L	4.6–120	5.6	134	99	Barnett (23); Marcellus (108); Woodford-Cana-Caney (3)
pH	SU	5.7–8.1	7	9,154	6,147	Bakken (421); Barnett (31); Cleveland (4); Codell (9); Cody (41); Cotton Valley/Bossier (3); Dakota (35); Eagle Ford (1601); Fayetteville (2); Frontier (223); Hilliard-Baxter-Mancos (33); Lance (1933); Lansing Kansas City (16); Lewis (54); Mancos (2); Marcellus (301); Medina/Clinton-Tuscarora (3); Mesaverde (460); Mesaverde/Lance (13); Mesaverde/Lance/Lewis (917); Morrow (1); Mowry (5); Niobrara (189); Spraberry (26); Woodford-Cana-Caney (2831)
Phosphate	mg/L	12–77	31	4	4	Barnett (1); Marcellus (1); Woodford-Cana-Caney (2)

Table C-11. Concentrations of Select Classical and Conventional Constituents in UOG Produced Water

Parameter	Units	Range	Median	Number of Data Points[a]	Number of Detects	Formations Represented[a]
Specific conductivity	µS/cm	25,000–380,000	120,000	165	165	Bakken (9); Barnett (26); Dakota (3); Eagle Ford (1); Marcellus (104); Spraberry (19); Woodford-Cana-Caney (3)
TDS	mg/L	13,000–210,000	94,000	5,196	2,164	Bakken (11); Barnett (38); Bradford-Venango-Elk (5); Cleveland (11); Codell (9); Cody (17); Cotton Valley/Bossier (3); Dakota (3); Devonian (11); Eagle Ford (1647); Fayetteville (4); Green River (1); Haynesville/Bossier (2); Hilliard-Baxter-Mancos (33); Lance (1839); Marcellus (373); Mesaverde/Lance (5); Mesaverde/Lance/Lewis (942); Mississippi Lime (3); Mowry (5); New Albany (1); Niobrara (195); Pearsall (3); Spraberry (26); Utica (1); Woodford-Cana-Caney (8)
TOC	mg/L	9.7–610	82	132	127	Bakken (2); Barnett (29); Eagle Ford (1); Marcellus (97); Woodford-Cana-Caney (3)
TSS	mg/L	23–850	140	38	38	Bakken (2); Barnett (29); Eagle Ford (1); Marcellus (113); Woodford-Cana-Caney (5)

Source: 186 DCN SGE01184

a—In some instances the sum of the number of data points associated with individual formations does not equal the total number of data points. In these instances, there were data points reported in existing literature for which an associated shale or tight oil and gas formation was not identified.

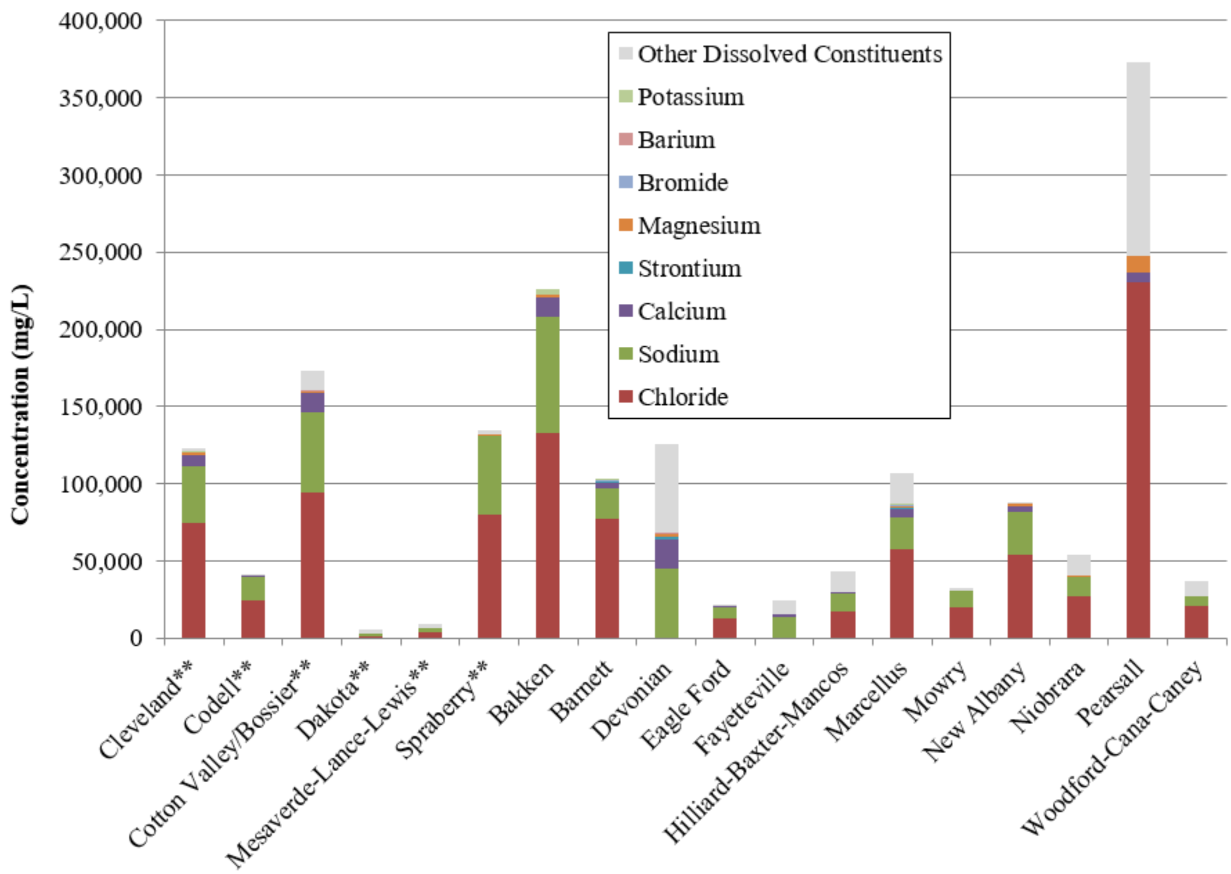
b—The EPA assumed values reported as "Cl" in the wastewater characterization data were meant to represent "chloride" values.

Abbreviations: mg/L—milligrams per liter; SU—standard units; µS/cm—microsiemens per centimeter

COD is a measure of the amount of oxygen needed to oxidize organic matter in wastewater using a strong chemical oxidant; therefore, it is an indicator of the presence of organic constituents in wastewater. As reported in Table C-11, the median COD concentration found in UOG produced water is 3,200 mg/L. However, researchers have shown that concentrations of COD may be influenced by chloride, bromide, alkaline earth metals (e.g., barium, calcium), and reduced inorganic constituents (e.g., sulfide, nitrite). As shown in Table C-13, the median concentrations of sulfide and nitrite in UOG produced water are less than 10 mg/L, indicating that they are not likely to have an influence on the COD concentrations. However, chloride, bromide, and alkaline earth metals are present at higher concentrations than reduced inorganic constituents in UOG produced water and may interfere with COD sample measurements (109 DCN SGE00725). In Table C-11, the relatively low median TOC concentration (82 mg/L) and BOD_5 concentration (160 mg/L) compared to the COD concentration likely indicates that some of the COD measurements reported in existing literature experienced interference from high concentrations of chloride, bromide, and group II alkaline earth metals. Therefore, reported COD concentrations may be higher than actual COD concentrations in UOG produced water.

TDS, which is regularly measured in UOG produced water, provides a measure of dissolved matter including salts (e.g., sodium, chloride, nitrate), metals, minerals, and organic material (3 DCN SGE00046). TDS is determined by measuring the portion of solids that pass through a filter with a nominal pore size of 2.0 µm or less (Standard Method 2540C-1997, ASTM D5907-03, and USGS I-1750-85). Salts, specifically sodium and chloride, are the majority (i.e., much greater than 50 percent) of TDS in UOG produced water (26 DCN SGE00284). Calcium and other group II alkaline earth metals (e.g., strontium, barium, magnesium) also contribute to the TDS in UOG produced water.

Figure C-3 shows the primary anions and cations that contribute to TDS in UOG produced water in various shale and tight oil and gas formations. The data presented in Figure C-3 represents approximately 26,000 samples. Data for all of the anions and cations contributing to TDS were not available for all formations. For example, the EPA did not identify any sodium concentration data in the Pearsall formation. Specifically, for this figure, the “other dissolved constituents” were captured by EPA by subtracting the sum of the listed parameters (e.g., sodium, chloride) from the total TDS concentration reported for the formation.

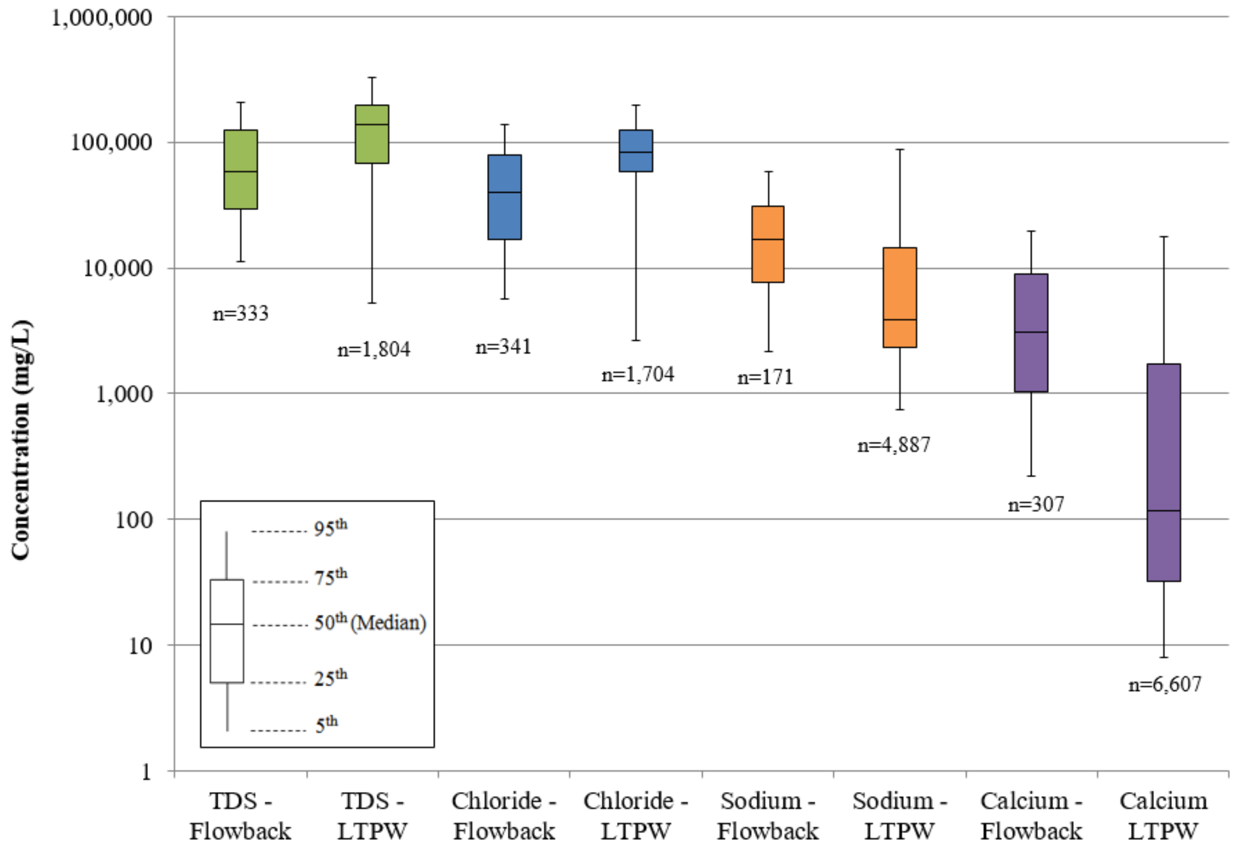


Source: 186 DCN SGE01184

Figure C-3. Anions and Cations Contributing to TDS Concentrations in Shale and Tight Oil and Gas Formations[79]

As shown in Figure C-3, of those constituents specifically identified as contributing to TDS, sodium, chloride, and calcium ions make up the majority of TDS in UOG produced water according to available data. Additional ions that may contribute to the TDS in UOG produced water include bromide, fluoride, nitrate, nitrite, phosphate, and sulfate. Figure C-4 contains box and whisker plots of TDS, chloride, sodium, and calcium data for UOG flowback and long-term produced water. The plots show the fifth percentile, first quartile, median, third quartile, and 95th percentile values of the data. The data used to create this figure include constituent concentration data from flowback or long-term produced water generated from UOG wells. The data show that concentrations of TDS and chloride are typically higher in long-term produced water than in flowback.

[79] In Figure C-3, the EPA indicates tight oil and gas formations by "**" after the formation name. The EPA assumed values reported as "Cl" in the wastewater characterization data were meant to represent "chloride" values and has reported them as such in Figure C-3.



Source: 186 DCN SGE01184

Figure C-4. Chloride, Sodium, and Calcium Concentrations in Flowback and Long-Term Produced Water (LTPW) from Shale and Tight Oil and Gas Formations[80]

Table C-12 presents typical concentrations of bromide and sulfate, which may contribute to TDS in drilling wastewater. The EPA identified the following limitations to the data presented in the table:

- Fewer data points (i.e., less than 30 data points) were available for these parameters.
- All of the data came from the Marcellus shale formation.

Table C-13 presents typical concentrations of additional constituents that may contribute to TDS in UOG produced water. The EPA identified the following limitations to the data presented in the table:

- Less data (i.e., less than 30 data points) were available for nitrite and phosphate.
- All of the available data for nitrite came from the Marcellus shale formation.

[80] The EPA assumed values reported as “Cl” in the wastewater characterization data were meant to represent “chloride” values and has reported them as such in Figure C-4.

- The majority of the data associated with nitrate came from the Bakken shale formation.
- The majority of the data associated with bromide, fluoride, and sulfide came from the Marcellus shale formation.

Table C-12. Concentrations of Bromide and Sulfate in UOG Drilling Wastewater from Marcellus Shale Formation Wells

Parameter	Units	Range	Median	Number of Data Points	Number of Detects	Formation Represented
Bromide	mg/L	23–210	110	5	5	Marcellus
Sulfate	mg/L	ND–1,600	220	13	10	Marcellus

Source: 183 DCN SGE01181

Abbreviation: mg/L—milligrams per liter

Table C-13. Concentrations of Select Anions and Cations Contributing to TDS in UOG Produced Water

Parameter	Units	Range	Median	Number of Data Points[a]	Number of Detects	Formations Represented (Number of Associated Data Points)[a]
Bromide	mg/L	81–1,200	510	111	111	Barnett (23); Marcellus (85); Woodford-Cana-Caney (3)
Fluoride	mg/L	0.5–5	2.5	99	97	Barnett (23); Marcellus (73); Woodford-Cana-Caney (3)
Nitrate	mg/L	0.3–190	0.3	110	110	Bakken (107); Marcellus (3)
Nitrite	mg/L	—[b]	5	2	2	Marcellus (2)
Phosphate	mg/L	12–77	31	4	4	Barnett (1); Marcellus (1); Woodford-Cana-Caney (2);
Sulfate	mg/L	8.9–700	110	8,203	5,451	Bakken (425); Barnett (31); Cleveland (9); Codell (1); Cody (27); Cotton Valley/Bossier (1); Dakota (28); Devonian (4); Eagle Ford (1166); Fayetteville (2); Frontier (123); Hilliard-Baxter-Mancos (28); Lance (1722); Lansing Kansas City (15); Lewis (52); Mancos (2); Marcellus (301); Medina/Clinton-Tuscarora (2); Mesaverde (438); Mesaverde/Lance (11); Mesaverde/Lance/Lewis (916); Morrow (1); Mowry (5); New Albany (1); Niobrara (133); Oswego (4); Pearsall (3); Spraberry (26); Woodford-Cana-Caney (2726)
Sulfide	mg/L	1.7–3.2	3	79	72	Barnett (1); Eagle Ford (1); Marcellus (77)

Source: 186 DCN SGE01184

a—In some instances the sum of the number of data points associated with individual formations does not equal the total number of data points. In these instances, there were data points reported in existing literature for which an associated shale or tight oil and gas formation was not identified.

b—Only two data points were identified for nitrite concentrations in UOG produced water and both data points reported the same value.

Abbreviation: mg/L—milligrams per liter

3.2.2 Organic Constituents in UOG Extraction Wastewater

Table C-14 presents concentration data from existing literature on organic constituents in UOG drilling wastewater. The EPA identified the following limitations to the data presented in the table:

- Fewer data points (i.e., less than 30) were available for each parameter.
- All of the data came from the Marcellus shale formation.

Table C-15 presents concentration data from existing literature on organic constituents in UOG produced water. The EPA identified the following limitations to the data presented in the table:

- All of the available data for carbon disulfide, ethanol, methanol, methyl chloride, and tetrachloroethylene came from the Marcellus shale formation.
- The majority of the data associated with each of the organic constituents presented in the table came from the Marcellus shale formation.

Table C-14. Concentrations of Select Organic Constituents in UOG Drilling Wastewater from Marcellus Shale Formation Wells

Parameter	Units	Range	Median	Number of Data Points	Number of Detects	Formation Represented
Benzene	µg/L	ND[a]–40	ND[a]	20	5	Marcellus
Ethylbenzene	µg/L	—[b]	9.6	4	4	Marcellus
Ethylene glycol	mg/L	—[b]	500	1	1	Marcellus
Toluene	µg/L	ND[a]–80	ND[a]	20	8	Marcellus
Xylene (m,p)	µg/L	—[b]	88	4	4	Marcellus
Xylene (o)	µg/L	—[b]	22	4	4	Marcellus

Source: 183 DCN SGE01181

a—Source did not report detection limit.

b—Source only reported median value.

Abbreviations: ND—nondetect; mg/L—milligrams per liter; µg/L—micrograms per liter

Table C-15. Concentrations of Select Organic Constituents in UOG Produced Water

Parameter	Units	Range	Median	Number of Data Points[a]	Number of Detects	Formations Represented (Number of Associated Data Points)[a]
1,2,4-Trimethylbenzene	µg/L	1.1–100	5	92	89	Barnett (25); Marcellus (67)
1,3,5-Trimethylbenzene	µg/L	3–130	5	85	81	Barnett (18); Marcellus (67)
Acetone	µg/L	12–1,100	40	96	86	Barnett (22); Marcellus (72)
Benzene	µg/L	4.8–3,700	8.5	144	122	Barnett (25); Marcellus (111); Niobrara (5); Woodford-Cana-Caney (3)
Carbon disulfide	µg/L	5–250	5	68	67	Marcellus (68)
Chlorobenzene	µg/L	0–100	5	72	70	Marcellus (69); Woodford-Cana-Caney (3)
Chloroform	µg/L	0–100	5	77	75	Barnett (5); Marcellus (69); Woodford-Cana-Caney (3)
Ethanol	µg/L	5,000–20,000	10,000	53	53	Marcellus (53)
Ethylbenzene	µg/L	3.4–130	5	130	104	Barnett (18); Marcellus (108); Medina/Clinton-Tuscarora (1); Woodford-Cana-Caney (3)
Isopropylbenzene	µg/L	5–100	5	83	69	Barnett (16); Marcellus (67)
Methanol	µg/L	5,000–180,000	10,000	55	55	Marcellus (55)
Methyl chloride	µg/L	5–100	5	95	69	Marcellus (95)
Naphthalene	µg/L	1.8–110	5	129	103	Barnett (39); Marcellus (90)
Phenol	µg/L	1.9–56	2	111	83	Barnett (17); Marcellus (91); Woodford-Cana-Caney (3)
Pyridine	µg/L	7.9–900	86	91	90	Barnett (24); Marcellus (67)
Tetrachloroethylene	µg/L	5–100	5	95	68	Marcellus (95)
Toluene	µg/L	2–2,900	6	149	125	Barnett (25); Marcellus (115); Medina/Clinton-Tuscarora (1); Niobrara (5); Woodford-Cana-Caney (3)
Xylenes	µg/L	5.2–850	15	136	111	Barnett (20); Marcellus (112); Medina/Clinton-Tuscarora (1); Woodford-Cana-Caney (3)

Source: 186 DCN SGE01184

a—In some instances the sum of the number of data points associated with individual formations does not equal the total number of data points. In these instances, there were data points reported in existing literature for which an associated shale or tight oil and gas formation was not identified.

Abbreviation: µg/L—micrograms per liter

Table C-3 indicates that ethanol, methanol, and naphthalene are commonly reported additives to fracturing fluid. This suggests that at least some portion of the concentrations of these constituents found in UOG produced water (see Table C-15) may have originated from the fracturing fluid. Methanol is typically used in fracturing fluid as a biocide, corrosion inhibitor, crosslinker, and surfactant; ethanol is also used as a biocide and surfactant (see Table C-2). Operators may also use methanol as an antifreezing agent at UOG operations in areas with seasonal temperature fluctuations. Methanol may be used at the wellhead to avoid freezing in the wellbore or at compressor stations to prevent equipment from freezing (95 DCN SGE00635).

The EPA did not identify any quantitative information about diesel-range organics or total petroleum hydrocarbons in UOG produced water. However, Table C-3 and Table C-4 show that petroleum distillates are typically used in fracturing fluid. The EPA ORD's 2015 *Analysis of Hydraulic Fracturing Fluid Data from the FracFocus Chemical Disclosure Registry 1.0* contains additional information about these constituents (106 DCN SGE00721).

3.2.3 Metals in UOG Extraction Wastewater

UOG extraction wastewater contains varying concentrations of numerous metals.

Table C-16 presents concentration data from existing literature for the metals most commonly detected in UOG drilling wastewater. The EPA identified the following limitations to the data presented in the table:

- Fewer data points (i.e., less than 30 data points) were available for each parameter.
- All of the data came from the Marcellus shale formation.

Table C-17 presents concentration data from existing literature for the metals most commonly detected in UOG produced water. The EPA identified the following limitations to the data presented in the table:

- The majority of the data associated with aluminum, antimony, arsenic, beryllium, boron, cadmium, cobalt, copper, lead, lithium, manganese, mercury, molybdenum, nickel, phosphorus, selenium, silver, strontium, thallium, tin, titanium, vanadium, and zinc came from the Marcellus shale formation.
- The majority of the data associated with iron came from the Lance tight formation.
- The majority of the data associated with chromium came from the Bakken shale formation.

Table C-16. Concentrations of Select Metal Constituents in UOG Drilling Wastewater from Marcellus Shale Formation Wells

Parameter	Units	Range	Median	Number of Data Points	Number of Detects
Aluminum	mg/L	1.7–6,900	38	12	12
Arsenic	mg/L	ND[a]–4.2	ND[a]	12	6
Barium	mg/L	2.6–2,000	13	14	14
Beryllium	mg/L	ND[a]–0.018	ND[a]	8	2

Table C-16. Concentrations of Select Metal Constituents in UOG Drilling Wastewater from Marcellus Shale Formation Wells

Parameter	Units	Range	Median	Number of Data Points	Number of Detects
Boron	mg/L	ND[a]–2.7	0.17	8	4
Cadmium	mg/L	ND[a]–0.0050	ND[a]	8	1
Calcium	mg/L	150–15,000	1,300	13	13
Chromium	mg/L	ND[a]–11	0.010	12	8
Cobalt	mg/L	ND[a]–1.8	ND[a]	8	3
Copper	mg/L	ND[a]–17	0.83	8	6
Iron	mg/L	4.2–18,000	86	12	12
Lead	mg/L	ND[a]–8.0	0.35	12	10
Lithium	mg/L	ND[a]–1.2	ND[a]	8	1
Magnesium	mg/L	ND[a]–3,600	290	12	11
Manganese	mg/L	ND[a]–350	4.3	12	11
Mercury	mg/L	ND[a]–0.029	ND[a]	8	2
Molybdenum	mg/L	—[b]	0.10	1	1
Nickel	mg/L	ND[a]–16	0.55	12	9
Potassium	mg/L	—[b]	8,800	4	4
Selenium	mg/L	ND[a]–0.11	ND[a]	8	3
Silver	mg/L	ND[a]–0.010	ND[a]	8	1
Sodium	mg/L	170–16,000	2,900	12	12
Strontium	mg/L	1.8–1,500	21	13	13
Zinc	mg/L	ND[a]–38	2.1	12	10

Source: 183 DCN SGE01181

a—Source did not report detection limit

b—Source only reported median value

Abbreviation: mg/L—milligrams per liter; ND—nondetect

Table C-17. Concentrations of Select Metal Constituents in UOG Produced Water

Parameter	Units	Range	Median	Number of Data Points[a]	Number of Detects	Formations Represented (Number of Associated Data Points)[a]
Aluminum	mg/L	0.13–2	0.48	206	175	Bakken (4); Barnett (31); Eagle Ford (5); Frontier (1); Lance (7); Marcellus (114); Mesaverde (37); Mesaverde/Lance (2); Woodford-Cana-Caney (3)
Antimony	mg/L	0.01–0.1	0.047	112	79	Barnett (9); Marcellus (103)
Arsenic	mg/L	0.014–0.11	0.06	135	99	Barnett (16); Eagle Ford (1); Marcellus (115); Woodford-Cana-Caney (3)
Barium	mg/L	2.1–790	18	1,191	1,190	Bakken (312); Barnett (39); Cotton Valley/Bossier (2); Dakota (3); Devonian (4); Eagle Ford (10); Fayetteville (2); Frontier (10); Lance (21); Lansing Kansas City (7); Marcellus (210); Medina/Clinton-Tuscarora (1); Mesaverde (38); Mesaverde/Lance (8); Morrow (1); Utica (1); Woodford-Cana-Caney (522)
Beryllium	mg/L	0.02–0.04	0.04	114	72	Barnett (2); Marcellus (112)
Boron	mg/L	3.1–67	14	151	137	Bakken (8); Barnett (33); Eagle Ford (2); Marcellus (103); Niobrara (5)
Cadmium	mg/L	0.0014–0.05	0.0086	134	92	Barnett (16); Marcellus (115); Woodford-Cana-Caney (3)
Calcium	mg/L	16–16,000	190	9,272	6,261	Bakken (427); Barnett (40); Cleveland (11); Codell (9); Cody (41); Cotton Valley/Bossier (3); Dakota (35); Devonian (4); Eagle Ford (1645); Fayetteville (2); Frontier (223); Hilliard-Baxter-Mancos (33); Lance (1942); Lansing Kansas City (15); Lewis (53); Mancos (2); Marcellus (343); Medina/Clinton-Tuscarora (2); Mesaverde (461); Mesaverde/Lance (13); Mesaverde/Lance/Lewis (917); Morrow (1); Mowry (5); New Albany (1); Niobrara (189); Oswego (5); Pearsall (3); Spraberry (26); Woodford-Cana-Caney (2821)
Chromium	mg/L	0.021–0.9	0.3	386	352	Bakken (234); Barnett (27); Eagle Ford (6); Marcellus (116); Woodford-Cana-Caney (3)
Cobalt	mg/L	0.013–5	0.5	124	92	Barnett (16); Eagle Ford (5); Marcellus (103)
Copper	mg/L	0.024–0.5	0.13	150	110	Bakken (2); Barnett (23); Eagle Ford (6); Marcellus (116); Woodford-Cana-Caney (3)
Iron	mg/L	4–170	38	3,070	383	Bakken (22); Barnett (36); Codell (8); Cody (6); Cotton Valley/Bossier (2); Dakota (3); Eagle Ford (11); Fayetteville (2); Hilliard-Baxter-Mancos (32); Lance (1767); Marcellus (301); Mesaverde/Lance/Lewis (772); Mowry (3); Niobrara (72); Spraberry (26); Utica (1); Woodford-Cana-Caney (6)
Lead	mg/L	0.013–0.42	0.03	133	96	Bakken (1); Barnett (15); Eagle Ford (1); Marcellus (113); Woodford-Cana-Caney (3)
Lithium	mg/L	4.6–150	44	155	132	Barnett (32); Eagle Ford (1); Hilliard-Baxter-Mancos (4); Lance (4); Lewis (1); Marcellus (90); Mesaverde (8); Mesaverde/Lance/Lewis (4); Niobrara (11)

Table C-17. Concentrations of Select Metal Constituents in UOG Produced Water

Parameter	Units	Range	Median	Number of Data Points[a]	Number of Detects	Formations Represented (Number of Associated Data Points)[a]
Magnesium	mg/L	3–1,300	40	7,116	4,374	Bakken (427); Barnett (40); Cleveland (11); Codell (9); Cody (39); Cotton Valley/Bossier (3); Dakota (28); Devonian (4); Eagle Ford (1622); Fayetteville (2); Frontier (213); Hilliard-Baxter-Mancos (33); Lance (1791); Lansing Kansas City (15); Lewis (52); Mancos (2); Marcellus (327); Medina/Clinton-Tuscarora (2); Mesaverde (391); Mesaverde/Lance (13); Mesaverde/Lance/Lewis (778); Morrow (1); Mowry (4); New Albany (1); Niobrara (188); Oswego (5); Pearsall (3); Spraberry (26); Woodford-Cana-Caney (1086)
Manganese	mg/L	0.47–9	1.7	238	224	Bakken (7); Barnett (38); Cotton Valley/Bossier (2); Dakota (3); Eagle Ford (8); Fayetteville (2); Marcellus (156); Spraberry (19); Woodford-Cana-Caney (3)
Mercury	mg/L	0.000029–0.00025	0.0002	118	88	Barnett (12); Eagle Ford (1); Marcellus (102); Woodford-Cana-Caney (3)
Molybdenum	mg/L	0.014–0.4	0.038	140	118	Bakken (1); Barnett (29); Eagle Ford (5); Marcellus (105)
Nickel	mg/L	0.019–2	0.14	154	124	Barnett (28); Eagle Ford (6); Marcellus (117); Woodford-Cana-Caney (3)
Phosphorus	mg/L	0.065–2.5	0.2	105	103	Bakken (6); Barnett (24); Eagle Ford (1); Marcellus (71); Woodford-Cana-Caney (3)
Potassium	mg/L	13–5,100	120	4,074	1,447	Bakken (382); Barnett (37); Cleveland (3); Cody (34); Cotton Valley/Bossier (3); Dakota (22); Eagle Ford (150); Frontier (163); Hilliard-Baxter-Mancos (26); Lance (1709); Lewis (39); Marcellus (137); Medina/Clinton-Tuscarora (2); Mesaverde (423); Mesaverde/Lance (9); Mesaverde/Lance/Lewis (818); Mowry (5); Niobrara (109); Woodford-Cana-Caney (3)
Selenium	mg/L	0.025–0.05	0.05	110	75	Barnett (7); Marcellus (103)
Silver	mg/L	0.0093–0.087	0.05	115	75	Marcellus (112); Woodford-Cana-Caney (3)
Sodium	mg/L	1,500–80,000	5,400	7,404	4,382	Bakken (427); Barnett (39); Cleveland (11); Codell (9); Cody (41); Cotton Valley/Bossier (3); Dakota (35); Devonian (4); Eagle Ford (1632); Fayetteville (2); Frontier (226); Hilliard-Baxter-Mancos (33); Lance (1938); Lansing Kansas City (16); Lewis (54); Mancos (2); Marcellus (203); Medina/Clinton-Tuscarora (2); Mesaverde (465); Mesaverde/Lance (13); Mesaverde/Lance/Lewis (933); Morrow (1); Mowry (5); New Albany (1); Niobrara (193); Oswego (5); Spraberry (26); Woodford-Cana-Caney (1085)
Strontium	mg/L	1.5–3,500	360	325	323	Bakken (10); Barnett (36); Cotton Valley/Bossier (2); Dakota (3); Devonian (4); Eagle Ford (9); Fayetteville (2); Frontier (2); Lance (21); Marcellus (184); Medina/Clinton-Tuscarora (2); Mesaverde (38); Mesaverde/Lance (8); Utica (1); Woodford-Cana-Caney (3)
Thallium	mg/L	0.017–0.5	0.1	120	83	Barnett (13); Marcellus (104); Woodford-Cana-Caney (3)

Table C-17. Concentrations of Select Metal Constituents in UOG Produced Water

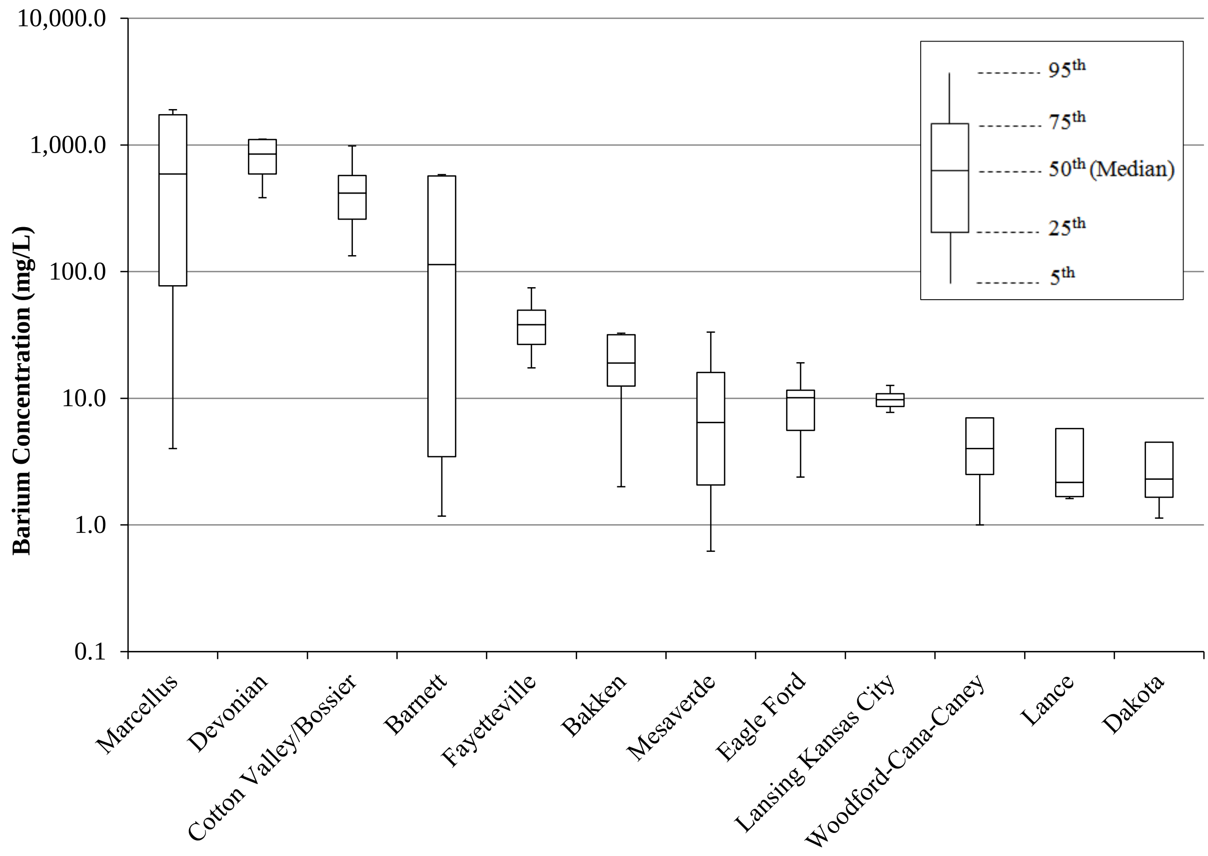
Parameter	Units	Range	Median	Number of Data Points[a]	Number of Detects	Formations Represented (Number of Associated Data Points)[a]
Tin	mg/L	0.021–2	1	86	84	Barnett (12); Eagle Ford (3); Marcellus (71)
Titanium	mg/L	0.024–0.5	0.19	114	83	Barnett (17); Eagle Ford (2); Marcellus (95)
Vanadium	mg/L	0.18–26	4.2	30	5	Barnett (1); Eagle Ford (2); Marcellus (27)
Zinc	mg/L	0.06–1.5	0.2	163	138	Bakken (2); Barnett (33); Eagle Ford (6); Fayetteville (2); Marcellus (117); Woodford-Cana-Caney (3)

Source: 186 DCN SGE01184

a—In some instances the sum of the number of data points associated with individual formations does not equal the total number of data points. In these instances, there were data points reported in existing literature for which an associated shale or tight oil and gas formation was not identified.

Abbreviation: mg/L—milligrams per liter

As discussed in Section C.3.2.1, sodium and calcium are two of the primary constituents that contribute to TDS in UOG produced water. Strontium, which is a group II alkaline earth metal, is another metal that contributes to TDS in UOG produced water, with a median concentration in the data evaluated by the EPA of 360 mg/L. Low-solubility salts of alkaline earth metals (e.g., barium sulfate) commonly precipitate in pipes and valves, forming scale (12 DCN SGE00167). Barium is commonly found in higher concentrations in produced water from the Marcellus and Devonian shale formations than in produced water from other UOG formations, according to data evaluated by the EPA. Figure C-5 shows box and whisker plots of the concentrations of barium in UOG produced water from various shale and tight oil and gas formations on a log scale. Median concentrations of heavy metals (e.g., chromium, copper, nickel, zinc, lead, mercury, arsenic) in UOG produced water are less than 1 mg/L, much lower than the concentrations of the alkaline earth metals.



Source: 186 DCN SGE01184

Figure C-5. Barium Concentrations in UOG Produced Water from Shale and Tight Oil and Gas Formations

3.2.4 Radioactive Constituents in UOG Extraction Wastewater

Oil and gas formations contain varying levels of naturally occurring radioactive material (NORM) resulting from uranium and thorium decay, which can be transferred to UOG produced water. Radioactive decay products typically include radium-226 and radium-228 (188 DCN

SGE01185). The EPA identified limited available data (primarily from the Marcellus Shale formation) on some radioactive constituents in UOG extraction wastewater, including radium-226, radium-228, gross alpha, and gross beta, and therefore focused the radioactive constituent discussion and data presentation on these parameters. ERG's *Radioactive Materials in the Unconventional Oil and Gas (UOG) Industry* memorandum (188 DCN SGE01185) contains a more detailed discussion of this topic.

The EPA identified limited radioactive constituent concentration data for UOG drilling wastewater. Table C-18 shows the available data from the Marcellus shale formation.

Table C-18. Concentrations of Select Radioactive Constituents in UOG Drilling Wastewater from Marcellus Shale Formation Wells

Parameter	Units	Range	Median	Number of Data Points	Number of Detects
Gross alpha	pCi/L	17–3,000	130	5	5
Gross beta	pCi/L	32–4,200	1,200	5	5

Sources: 183 DCN SGE01181
Abbreviation: pCi/L—picocuries per liter

Similarly, the EPA identified limited radioactive constituent concentration data for UOG produced water. As presented in Table C-19, most available data characterize produced water from the Marcellus formation; limited data were available from the Niobrara formation. Radium-226 and radium-228 are both found in UOG produced water, with radium-226 concentrations generally two to five times greater than radium-228 concentrations.

The EPA identified the following limitations to the data presented in the table:

- Limited or no radioactive constituent concentration data were available for the majority of shale and tight formations.
- Many EPA methods are known to experience interference from high TDS concentrations or the presence of Group II elements, which are typical of UOG extraction wastewater, and may result in an underestimation of reported values. ERG's *Radioactive Materials in the Unconventional Oil and Gas (UOG) Industry* memorandum (188 DCN SGE01185) discusses potential interference issues associated with various EPA methods and notes that the following methods may experience interference from some UOG extraction wastewater: 900.0, Gross Alpha and Gross Beta Radioactivity; 903.0, Alpha-Emitting Radium Isotopes; and 903.1, Radium-226, Radon Emanation Technique.

Table C-19. Concentrations of Select Radioactive Constituents in UOG Produced Water

Parameter	Formation	Method(s)	Range (pCi/L)	Median (pCi/L)	Number of Data Points	Number of Detects
Gross alpha	Marcellus	900.0	4.7–24,000	8,700	103	101
Gross alpha	Niobrara	900.0	300–820	1,800	3	3
Gross beta	Marcellus	900.0	0.66–1,700	1,600	94	92

Table C-19. Concentrations of Select Radioactive Constituents in UOG Produced Water

Parameter	Formation	Method(s)	Range (pCi/L)	Median (pCi/L)	Number of Data Points	Number of Detects
Gross beta	Niobrara	900.0	170–420	760	3	3
Radium-226	Marcellus	901.1 Mod., 903.0, 903.1, γ-spectrometry	10–88,000	1,700	74	74
Radium-226	Niobrara	901.1 Mod.	960–3,300	620	3	3
Radium-228	Marcellus	901.1, 903.0, 904.0, γ-spectrometry	15–16,000	470	73	72
Radium-228	Niobrara	901.1 Mod.	400–1,100	330	3	3

Sources: 186 DCN SGE01184

Abbreviation: pCi/L—picocuries per liter

As a point of comparison, Table C-20 includes data from a 2014 International Atomic Energy Agency report (134 DCN SGE00769) that included radium isotope concentrations in rivers, lakes, groundwater, and drinking water from public water systems. Data for radium-228 were limited, but the average of measured concentrations of radium-226 found in U.S. rivers and lakes was 0.56 pCi/L (21 millibecquerel per liter). The median concentrations of radium-226 and radium-228 in UOG produced water in the Marcellus and Niobrara formations presented in Table C-19 were above the maximum naturally occurring concentration in U.S. rivers, lakes, groundwater, or drinking water from public water systems presented in Table C-20. Radium in groundwater may originate from rocks, soil, and other naturally occurring materials, which are likely also the origins of a portion of the radium in UOG produced water.

Table C-20. Concentrations of Radioactive Constituents in Rivers, Lakes, Groundwater, and Drinking Water Sources Throughout the United States (pCi/L)

Parameter	Location Description	Minimum	Maximum	Average
Radium-226	Boise, Idaho—well water	—	—	0.10
	Florida—groundwater	ND	76	—
	Florida—well water	0.20	3.3	—
	Hudson River	—	—	0.032
	Illinois—well water	0.020	23	—
	Illinois Lake	0.059	1.3	—
	Iowa—well water	0.10	48	—
	Iowa—well water	1.8	25	—
	Joliet, Illinois—well water	—	—	6.5
	Lake Ontario	0.04	1.7	—
	Memphis, Tennessee—well water	—	—	0.21
	Miami, Florida—well water	—	—	0.48
	Mississippi River	0.010	1.1	—
	Ottawa County, OK—well water	0.10	15	—
	Sarasota, Florida—groundwater	1.5	24	—
	South Carolina—well water	2.7	27	—

Table C-20. Concentrations of Radioactive Constituents in Rivers, Lakes, Groundwater, and Drinking Water Sources Throughout the United States (pCi/L)

Parameter	Location Description	Minimum	Maximum	Average
	South Texas—groundwater	0.40	170	—
	Suwannee River	—	—	0.20
	U.S. drinking water from public water systems	0.011	4.9	—
	Utah—well water	1.0	20	—
	Wichita, Kansas—groundwater	—	—	0.23
Radium-228	Iowa—well water	0.60	6.3	—
	South Carolina—well water	4.7	12	—
	U.S. drinking water from public water systems	0	0.014	—

Source: 134 DCN SGE00769

"—"—Data were not reported.

Note: Data are presented as they were reported, either as a range (i.e., minimum, maximum) or as an average value.

Abbreviations: pCi/L—picocuries per liter; ND—nondetect

In January 2015, PA DEP announced the results of a study of radioactive elements in UOG extraction wastewater, sludge, and drill cuttings. Although PA DEP concluded "…[t]here is little potential for radiological exposure to workers and members of the public from handling and temporary storage of [flowback fluid and] produced water on natural gas well sites," it did conclude "…[t]here is a potential for radiological environmental impacts from spills of produced water [and flowback fluid] on natural gas well sites and from spills that could occur from the transportation and delivery of …[these] fluid[s]" (161 DCN SGE01028).

3.2.5 Other Constituents in UOG Extraction Wastewater

UOG produced water may also contain guar gum, which is a polymer that is commonly used in fracturing fluid to transport the proppant to the end of the wellbore (see Table C-2, Table C-3, and Table C-4). Guar gum may be found in UOG produced water at concentrations between 100 mg/L and 20,000 mg/L (88 DCN SGE00616). Guar gum treatment requires a breakdown of the polymer and is a consideration for UOG operators who are reusing/recycling wastewater for fracturing.

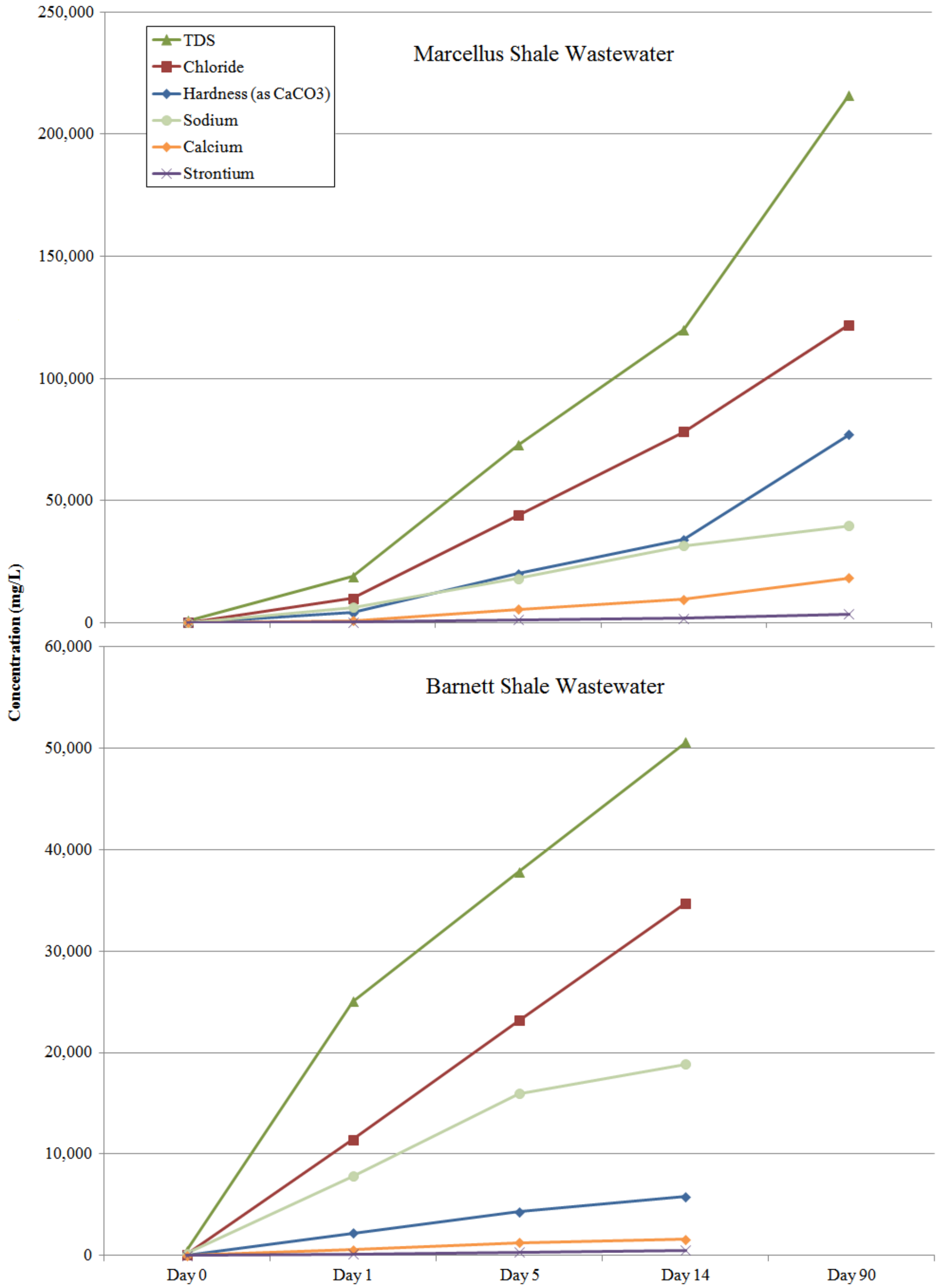
Microorganisms are also found in UOG drilling wastewater and produced water. Microorganisms may be present in concentrations as high as 1×10^9 organisms per 100 mL in UOG produced water (88 DCN SGE00616). Sulfate-reducing bacteria (SRB) are one classification of a naturally occurring microorganism that may be found in UOG produced water and drilling wastewater. SRB can cause problems during reuse/recycle of UOG produced water because they can reduce and/or precipitate metals and ions, potentially causing scale in the wellbore. They can also create hydrogen sulfide,[81] a potential human health concern that is also highly corrosive and can harm the well casing and wellbore (106 DCN SGE00721).

3.3 UOG Produced Water Characterization Changes over Time

Concentrations of TDS, radioactive elements, metals, and organic compounds vary across different formations and over time. However, for the vast majority of formations for which data are available, the data demonstrate that flowback and long-term produced water are both influenced by constituents present in the formation. For example, concentrations of select naturally occurring constituents commonly found in shale formations (e.g., bromide, magnesium) are found in elevated concentrations in flowback compared to hydraulic fracturing fluid. The elevated concentrations indicate that the formation is contributing concentrations of these constituents to the flowback. Similarly, concentrations of TDS and TDS-contributing constituents (e.g., sodium, chloride, calcium) increase over time as formation water and the dissolution of constituents out of the formation contribute to long-term produced water.

RPSEA's 2012 Characterization of Flowback Waters from the Marcellus and the Barnett Shale Regions (44 DCN SGE00414) presents sampling data from 19 sites in the Marcellus shale and five sites in the Barnett shale. The sampled constituents include a wide array of classical, conventional and organic parameters and metals. Where possible, these constituents were sampled at day 0, day 1, day 5, day 14, and day 90. Figure C-6 presents median data for select constituents as reported in the RPSEA report. Figure F-1 in the appendices presents median data for additional constituents as reported in the RPSEA report.

[81] Exposure to low concentrations of hydrogen sulfide may cause difficulty breathing and/or irritation to the eyes, nose, or throat. Exposure to high concentrations of hydrogen sulfide may cause headaches, poor memory, unconsciousness, and death (108 DCN SGE00723).



Source: The EPA generated this figure using data from 44 DCN SGE00414.

Figure C-6. Constituent Concentrations over Time in UOG Produced Water from the Marcellus and Barnett Shale Formations

Chapter D. UOG EXTRACTION WASTEWATER MANAGEMENT AND DISPOSAL PRACTICES

During the lifetime of a well, UOG extraction generates large volumes of UOG extraction wastewater that contain constituents potentially harmful to human health and the environment. This creates a need for appropriate wastewater management infrastructure and disposal practices. Except in limited circumstances,[82] the existing effluent guidelines for oil and gas extraction prohibit the onsite direct discharge of wastewater into waters of the United States. Historically, operators primarily managed their wastewater via underground injection using Class II enhanced recovery and disposal wells, where available. In fact, in 2010, the EPA and industry stakeholders estimated that over 90 percent of oil and gas produced water (conventional and unconventional) was disposed of via Class II enhanced recovery and disposal wells (91 DCN SGE00623). This section discusses the methods used by UOG operators to manage and dispose of UOG extraction wastewater.

1 OVERVIEW OF UOG EXTRACTION WASTEWATER MANAGEMENT AND DISPOSAL PRACTICES

UOG operators primarily use three methods for management of UOG produced water (86 DCN SGE00613; 22 DCN SGE00276; 58 DCN SGE00528):

- Dispose of wastewater via Class II disposal wells ("disposal wells")
- Reuse/recycle wastewater in subsequent fracturing jobs
- Transfer wastewater to a CWT facility

UOG operators primarily use the following methods for management of drilling wastewater, which includes drill cuttings and drilling fluids[83] (183 DCN SGE01181):

- Disposal via disposal wells
- Reuse/recycle in subsequent drilling and/or fracturing jobs
- Transfer to a CWT facility
- Onsite burial[84]
- Disposal via landfill
- Land application

[82] While the existing oil and gas extraction ELG allows onshore oil and gas extraction wastewater generated west of the 98th meridian to be permitted for discharge when the water is of good enough quality for agricultural and wildlife uses (see 40 CFR part 435 subpart E), EPA has not found that these types of permits are typically written for UOG extraction wastewater as defined for in this document for the final rule.

[83] As discussed in Chapter B, drilling muds (fluids) are reused/recycled until they are considered "spent," i.e., they can no longer be reused/recycled, at this stage they are sometimes referred to as "spent drilling fluids."

[84] Onsite burial involves temporary fluid storage in onsite open earthen or lined pits with burial of residual solids after fluids are solidified, removed from the top, or evaporated.

Figure D-1 and Figure D-2 illustrate the primary management methods for UOG produced water and drilling wastewater, respectively. In select areas, UOG operators also use evaporation ponds for disposal of UOG produced water and drilling wastewater. However, there are certain requirements for using evaporation ponds, including very dry climates, which mainly occur in the western United States (105 DCN SGE00710). Evaporation ponds also require a large, flat site, and they perform best only during select months of the year (e.g., May through October) (135 DCN SGE00779.A24).

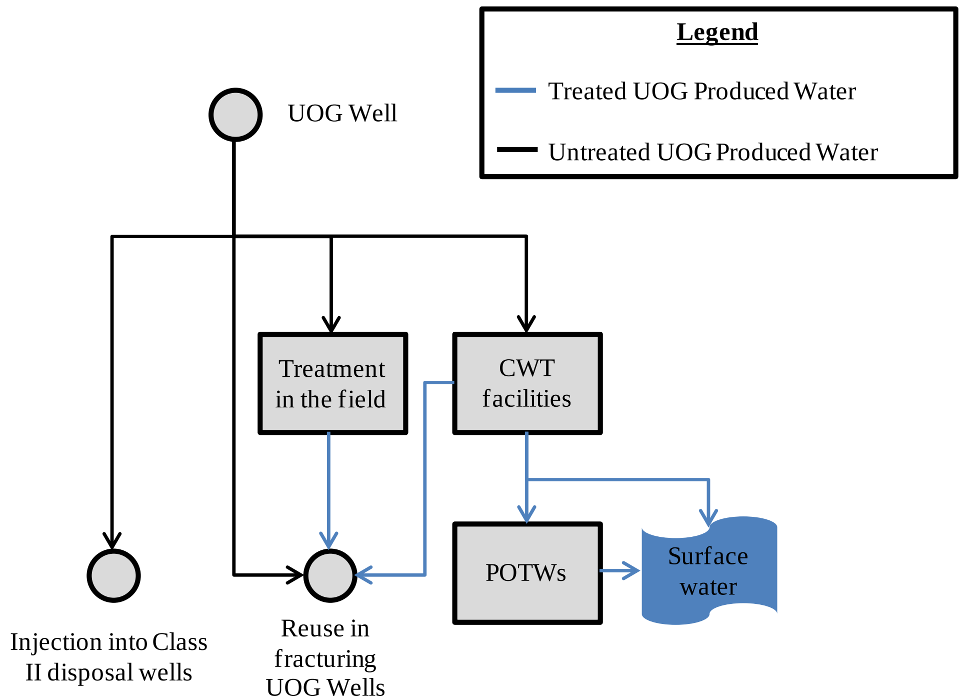


Figure D-1. UOG Produced Water Management Methods

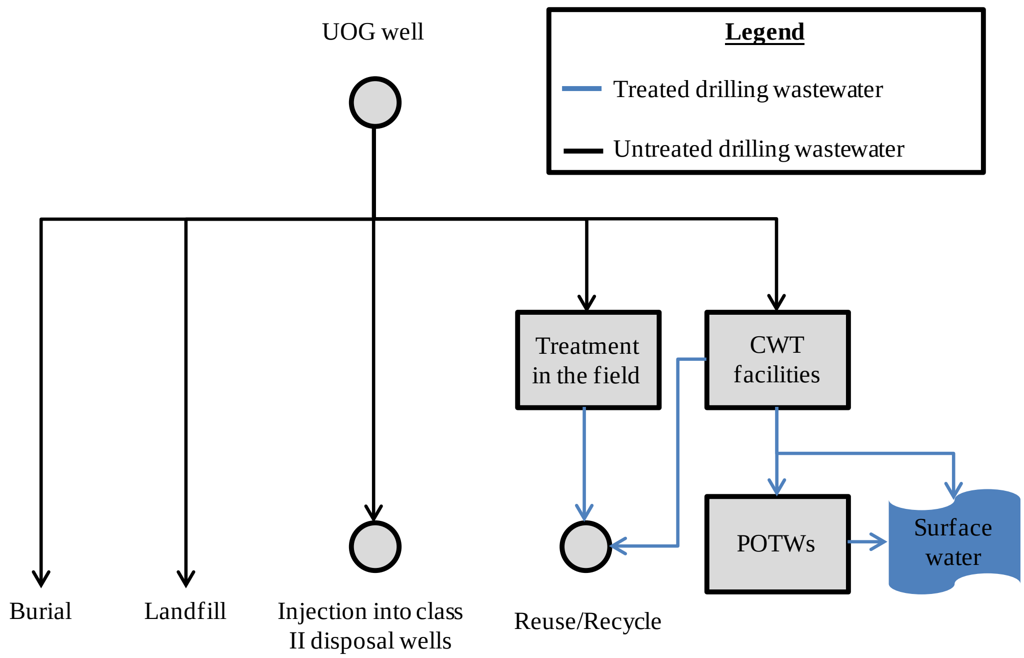


Figure D-2. UOG Drilling Wastewater Management Methods

UOG operators' frequency of use of each of the aforementioned UOG extraction wastewater management options varies by operator, by formation, and sometimes within each region of the formation (71 DCN SGE00579; 22 DCN SGE00276; 95 DCN SGE00635; 37 DCN SGE00354; 105 DCN SGE00710). Table D-1 describes how UOG operators manage produced water specifically in basins containing major UOG formations, which varies by basin and formation. As detailed above, historically, the oil and gas industry has most commonly managed produced water by underground injection (171 DCN SGE01128), but the industry is increasingly turning to reuse/recycle and, in some geographic areas, transferring to CWT facilities to manage growing volumes of wastewater (see Section D.3 and Section D.4) (178 DCN SGE01178; 102 DCN SGE00707; 103 DCN SGE00708). Although cost is the primary factor, operators also consider other factors for wastewater management decisions such as proximity to management options (e.g., CWT facilities, Class II injection wells), climate, federal or state regulatory requirements, wastewater quality and volume, and operator-specific risk management policies (91 DCN SGE00623). In some areas of the U.S., there may be additional considerations that drive change from traditional use of Class II injection wells to other wastewater management practices.[85]

The literature does not contain the same level of detailed information about drilling wastewater management practices as is provided for produced water management in Table D-1. However, the EPA did identify comprehensive data for management of drilling wastewater

[85] For example, some studies suggest that Class II UIC wells have been associated with nearby seismic activity (198 DCN SGE01216; 226 DCN SGE01351; 227 DCN SGE01352) and in some cases the use of those wells have been restricted (227 DCN SGE01352). If use of a particular Class II UIC well becomes restricted, operators may utilize other options such as transfer to a different Class II UIC well, reuse/recycle and transfer to a CWT.

generated by Marcellus shale wells located in Pennsylvania. Figure D-3 shows management practices used by UOG operators in Pennsylvania for managing their UOG drilling wastewater from 2008 to 2014. In recent years (2010 to 2014), transfer to CWT facilities, reuse/recycle in drilling or fracturing, and injection for disposal—in that order—were the most common practices for UOG drilling wastewater management in Pennsylvania (184 DCN SGE01182). In addition to this detailed information about drilling wastewater management in Pennsylvania, the EPA obtained information from the fifth largest U.S. oil and gas operator regarding its Fayetteville shale operations. This operator reported that it reuses/recycles the majority of its drilling wastewater in drilling subsequent wells and the remainder is disposed of via disposal wells (92 DCN SGE00625).

To illustrate how management practices used by UOG operators vary geographically, the EPA mapped the locations of known CWT facilities and disposal wells in the Appalachian basin (containing the Utica and Marcellus shale formations).[86] Figure D-4 compares the east and west portions of the basin, thus illustrating basin and formation differences in wastewater management practices. The east side of the basin contains very few underground disposal wells, but contains a high density of CWT facilities that have accepted or plan to accept UOG produced water from operators. In contrast, the west side has an abundance of disposal wells and injection for disposal is the primary wastewater management practice.

The remaining subsections in Chapter D describe UOG produced water management practices: how disposal in disposal wells is the most common practice, how reuse/recycle in fracturing fluid is increasing, and how increasing numbers of CWT facilities are accepting UOG produced water and drilling wastewater where disposal wells are limited. Although operators have discharged UOG extraction wastewater to POTWs in the past, information available to EPA indicates that these discharges were discontinued in 2011 (184 DCN SGE01182; 27 DCN SGE00286; 35 DCN SGE00345; 71 DCN SGE00579). After describing the three management alternatives that the UOG industry uses (i.e., injection into disposal wells, reuse/recycle in fracturing, transfer to CWT facility), Chapter D ends with a discussion of POTWs and how they cannot remove some of the constituents in UOG extraction wastewater. The end of Chapter D also presents EPA-collected data indicating that POTWs have not received any UOG extraction wastewater between 2011 and the end of 2014. EPA received no data during the public comment period on the proposed rule to indicate that this is still not the case.

[86] The EPA obtained information about CWT facilities accepting UOG extraction wastewater from publicly available sources. Therefore, the list of CWT facilities the EPA identified may not be complete.

Table D-1. UOG Produced Water Management Practices

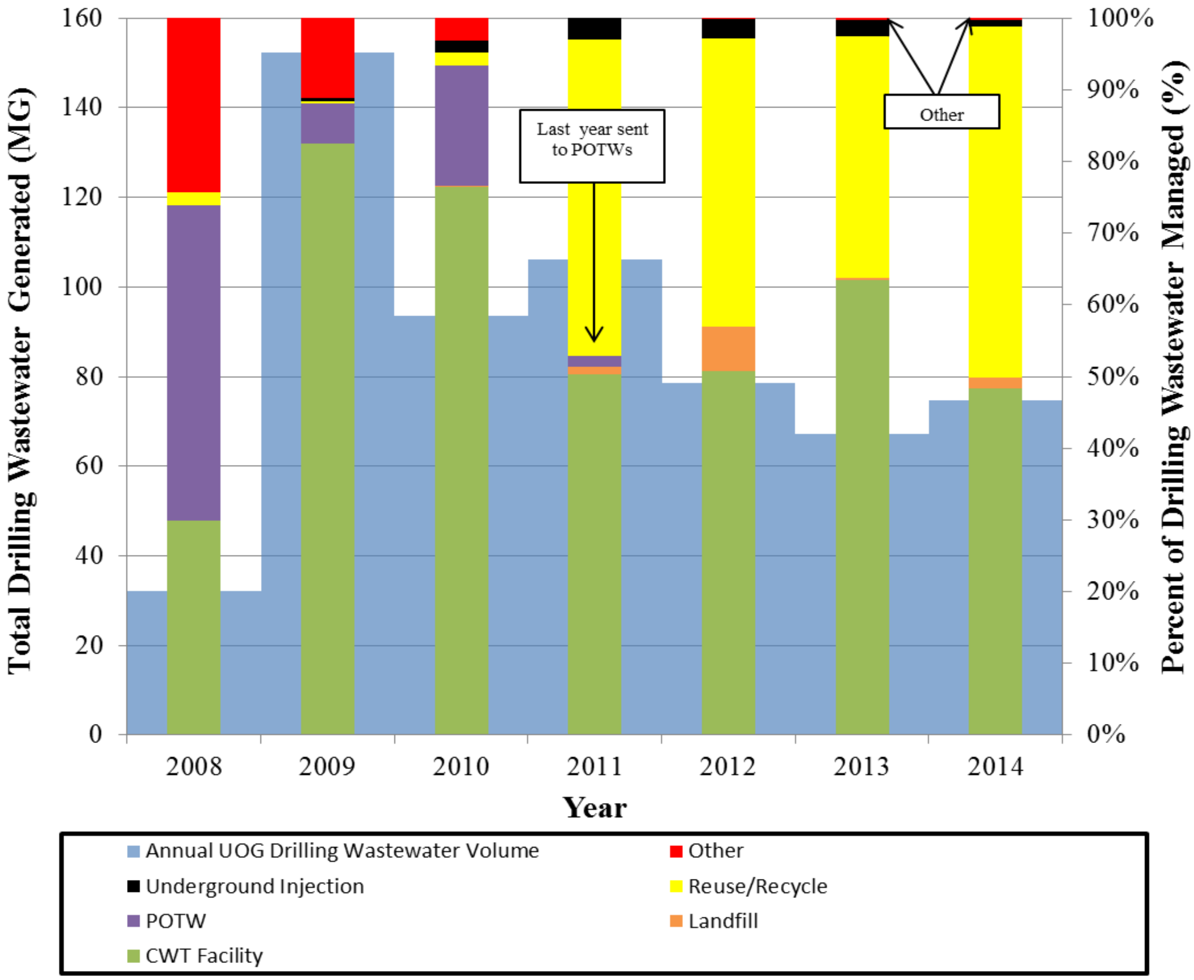
Basin	UOG Formation	Resource Type	Reuse or Recycle	Injection for Disposal	CWT Facilities	Notes	Available Data[b]
Michigan	Antrim	Shale gas		XXX			Qualitative
Appalachian	Marcellus/Utica (PA)	Shale gas	XXX	XX	XX	Limited disposal wells in east	Quantitative
	Marcellus/Utica (WV)	Shale gas/oil	XXX	XX	X		Quantitative
	Marcellus/Utica (OH)	Shale gas/oil	XX	XXX	X		Mixed
Anadarko	Granite Wash	Tight gas	XX	XXX	X[a]		Mixed
	Mississippi Lime	Tight oil	X	XXX		Reuse/recycling limited but is being evaluated	Qualitative
	Woodford, Cana, Caney	Shale gas/oil	X	XXX	X[a]		Qualitative
Arkoma	Fayetteville	Shale gas	XX	XX	X[a]	Few existing disposal wells; new CWT facilities are under construction	Mixed
Fort Worth	Barnett	Shale gas	X	XXX	X[a]	Reuse/recycle not typically used due to high TDS early in flowback and abundance of disposal wells	Mixed
Permian	Avalon/Bone Springs, Wolfcamp, Spraberry	Shale/tight oil/gas	X	XXX	X[a]		Mixed
TX-LA-MS Salt	Haynesville	Tight gas	X	XXX		Reuse/recycle not typically used due to high TDS early in flowback and abundance of disposal wells	Mixed
West Gulf	Eagle Ford, Pearsall	Shale gas/oil	X	XXX	X		Mixed
Denver Julesburg	Niobrara	Shale gas/oil	X	XXX	X		Mixed
Piceance; Green River	Mesaverde/Lance	Tight gas	X	XX	X	Also managed through evaporation to atmosphere in ponds in this region	Qualitative
Williston	Bakken	Shale oil	X	XXX		Reuse/recycling limited but is being evaluated	Mixed

Sources: 179 DCN SGE01179

a—CWT facilities identified in these formations are all operator-owned.

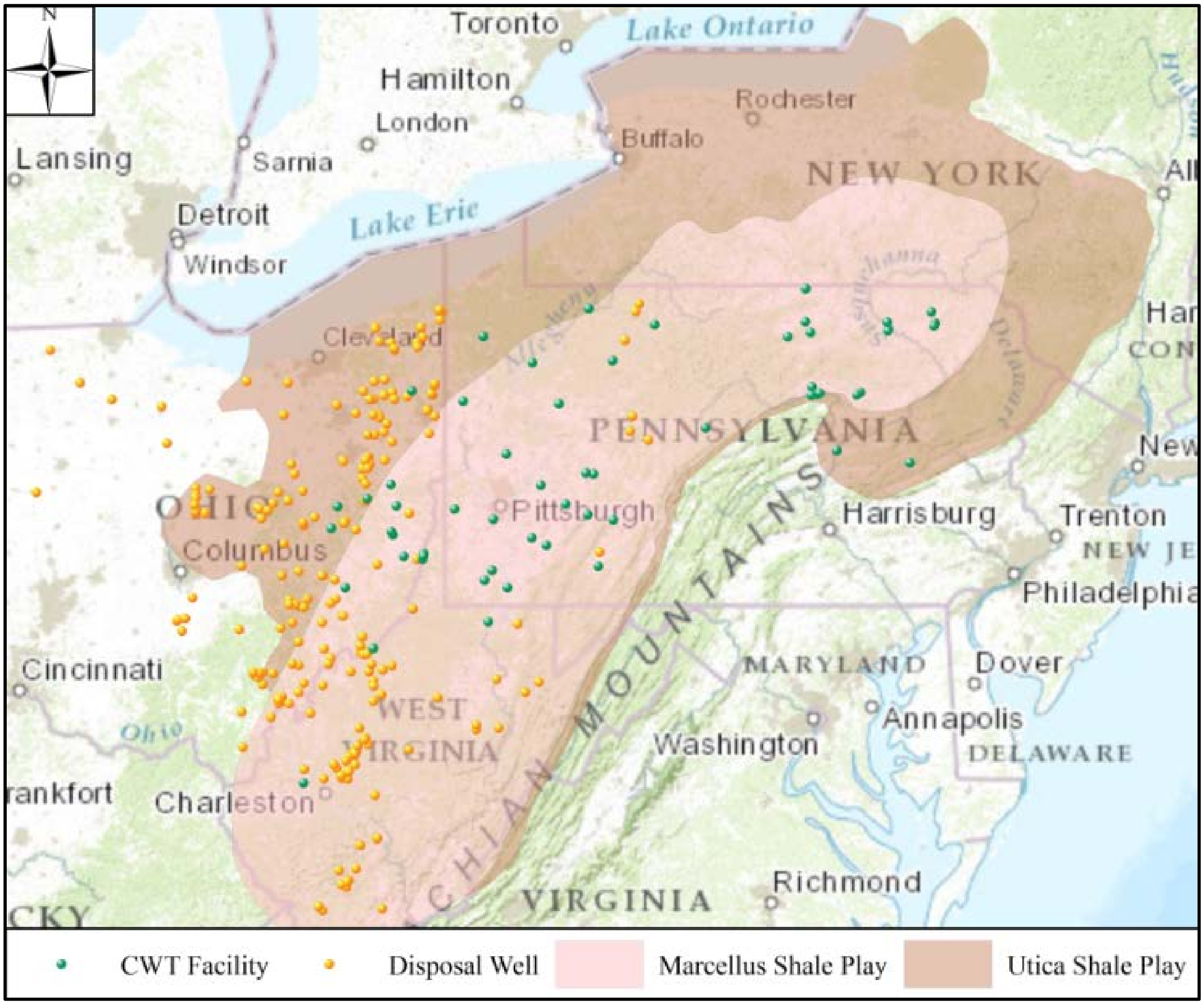
b—This column indicates the type of data the EPA based the number of Xs on. In most cases, the EPA used a mixture of qualitative and quantitative data sources along with engineering judgment to determine the number of Xs.

XXX—The majority (≥50%) of wastewater is managed with this management practice; XX—A moderate portion (≥10% and <50%) of wastewater is managed with this management practice; X—This management practice has been documented in this location, but for a small (<10%) or unknown percent of wastewater. Blanks indicate the management practices has not been documented in the given location.



Sources: 184 DCN SGE01182

Figure D-3. Management of UOG Drilling Wastewater Generated by UOG Wells in Pennsylvania (2008–2014)



Sources: Generated by the EPA using data from 178 DCN SGE01178 and 190 DCN SGE01187

Figure D-4. Active Disposal Wells and CWT Facilities Identified in the Appalachian Basin[87]

2 INJECTION INTO DISPOSAL WELLS

Historically, underground injection has been the most common wastewater management method among UOG operators. In 2010, the EPA and industry stakeholders estimated that over 90 percent of oil and gas produced water (conventional and unconventional) was disposed of via Class II enhanced recovery and disposal wells (91 DCN SGE00623). Underground injection involves pumping wastes into an underground formation with a confining layer of impermeable rock. The formation must also be porous enough to accept the wastewater. In its underground

[87] The active disposal wells data were last updated in December 2013 for Pennsylvania. The last update for the active disposal wells data in Ohio and West Virginia is unknown. The EPA accessed the Ohio data in February 2013 and the West Virginia data in December 2013. The CWT facility data were last updated at the end of 2014, based on publicly available information.

injection well control program codified in 40 CFR parts 144 to 148, the EPA established six classes of underground injection wells (8 DCN SGE00132):

- Class I industrial and municipal waste disposal wells
- Class II oil and gas related injection wells
- Class III mining wells
- Class IV shallow hazardous and radioactive injection wells (banned)
- Class V any not covered in Class I through IV (e.g., leach fields)
- Class VI carbon dioxide storage or sequestration

Class II injection wells serve three major purposes:

- Injection of hydrocarbons for storage
- Injection of fluids for disposal (i.e., disposal wells)
- Injection of fluids for enhanced recovery (i.e., enhanced recovery wells)

Approximately 20 percent of Class II injection wells in the United States are Class II disposal wells; the remaining 80 percent are mostly Class II enhanced recovery wells (8 DCN SGE00132). Injection into Class II disposal wells typically involves injecting wastewater into a porous and non-oil-and-gas-containing reservoir. Industry does not use Class II enhanced recovery wells for disposing of UOG extraction wastewater because most enhanced recovery projects consist of a closed-loop system with two or more wells: at least one producing well and at least one enhanced recovery well. Operators of enhanced recovery projects typically route the wastewater generated by the producing well directly back to the adjacent enhanced recovery well (91 DCN SGE00623; 8 DCN SGE00132; 86 DCN SGE00613). Available literature and communication with industry indicates that industry only hauls UOG extraction wastewater to Class II disposal wells and does not use Class II enhanced recovery wells. In fact, the leading method of UOG extraction wastewater management throughout the United States is injection into a Class II disposal well (181 DCN SGE01179.A03). However, all types of oil and gas extraction wastewater (e.g., conventional, CBM, UOG) may be disposed of in Class II disposal wells.

2.1 Regulatory Framework for Underground Injection

The EPA's regulations on underground injection wells are described in Chapter A. States, territories, and tribes have the option of requesting primacy, or primary enforcement authority, from the EPA for the Class II wells within their boundaries. In order to receive primacy, the state underground injection program must meet the EPA's regulatory requirements or have a program determined to be effective to prevent underground injection that endangers drinking water sources. Currently, the EPA has delegated Class II primacy to 39 states, three territories, and two tribes. The EPA has authority over the Class II UIC programs in the remaining 11 states, two territories and all other tribes (84 DCN SGE00611).

2.2 Active Disposal Wells and Volumes

The availability of underground injection for disposal varies by state. Some states have a large number of Class II injection wells (e.g., Texas, Oklahoma, Kansas) while others have few (e.g., Virginia, South Dakota). The EPA tabulated active Class II disposal wells using data from state agencies and EPA direct implementation programs. More information about how the EPA compiled data from state agencies is documented in a separate memorandum titled *Analysis of Active Underground Injection for Disposal Wells* (190 DCN SGE01187; 191 DCN SGE01187.A01).

Table D-2 presents the number of active Class II disposal wells by state (190 DCN SGE01187; 191 DCN SGE01187.A01). Only states with active disposal wells are listed; all other states have zero active disposal wells. Table D-2 also includes total state disposal rate on a million gallon per day basis for each state. Lastly, Table D-2 presents average disposal rates on a gallon per day per well basis for each state based on the active number of disposal wells and total state disposal rate. Average disposal rates of individual wells vary significantly, reflecting the geology of the underlying formation (23 DCN SGE00279). States are first sorted by geographic region, then by the total state disposal rate. States with no disposal volume and rate data are sorted by highest to lowest count of active Class II disposal wells.

The average disposal rate per well estimates in Table D-2 are not exact but rather are general approximations based on a number of assumptions, listed below and described in more detail in a separate memorandum, *Analysis of Active Underground Injection for Disposal Wells* (190 DCN SGE01187).

- **Calculation of the average disposal rate per well (gpd/well).** The EPA included all wells identified as active even if some of these wells reported zero injection volume. This assumption may decrease the average disposal rate per well but only affects states where the EPA used state databases as the source for injection volumes (NM, AK, and OK). However, the EPA excluded wells that were identified as just being drilled because they could not have injected any wastewater.
- **Calculation of the state disposal rate (MGD).** The EPA included the number of disposal wells identified as currently being drilled (e.g., under construction) in the active number of disposal wells. This assumption may increase the current state injection rates but was intended to capture wells that will inevitably come online in the near future. However, the EPA excluded wells from all calculations that were only permitted or proposed new well projects because these wells may be terminated even after they are permitted or proposed (i.e., may never come online).
- **Missing volume data.** The EPA was unable to identify injected volumes for Illinois, which has a substantial number of active disposal wells. Therefore, the total volume of produced water injected into disposal wells in the nation estimated by this analysis may be an underestimate. Also, there is no available injection volume data for wells on tribal lands.
- **Number of active disposal wells on tribal lands.** It was unclear if the underlying data sources EPA used to generate Table D-2 included Class II disposal wells on tribal lands. Therefore, Table D-3 presents the number of active Class II disposal wells on tribal lands reported by the EPA's Office of Ground Water and Drinking Water (OGWDW) (159 DCN SGE01012; 190 DCN SGE01187; 191 DCN SGE01187.A01). Table D-3 includes over 800 active Class II disposal wells located on tribal lands in eight different states. Tribes are first sorted by geographic region,

then by the number of active Class II disposal wells. No disposal volumes or rate data were available for Class II disposal wells on tribal lands.

Table D-2. Distribution of Active Class II Disposal Wells Across the United States (Primarily 2012 and 2013 Data)

Geographic Region (from the EIA)	State	Number of Active Disposal Wells[a]	Average Disposal Rate per Well (gpd/Well)[b]	State Disposal Rate (MGD)
Alaska	Alaska	45	182,000	8.2
East	Illinois	1,054	—[c]	—[c]
	Michigan	772	16,200	13
	Florida	14	246,000	3.4
	Indiana	208	7,950	1.7
	Ohio	190	8,570	1.6
	West Virginia	64	6,970	0.45
	Kentucky	58	4,650	0.27
	Virginia	12	17,500	0.21
	Pennsylvania	9	6,380	0.057
	New York	10[d]	33.7	0.00034
Gulf Coast/Southwest	Texas	7,876	52,100	410
	Louisiana	2,448	40,300	99
	New Mexico	736	48,600	36
	Mississippi	499	24,200	12
	Alabama	85	53,300	4.5
Mid-Continent	Kansas	5,516	25,600	140
	Oklahoma	3,837	35,900	140
	Arkansas	640[e]	25,400	16
	Nebraska	113	19,100	2.2
	Missouri	11	2,270	0.025
	Iowa	3	—[c]	—[c]
Northern Great Plains	North Dakota	395	53,300	21
	Montana	199	32,700	6.5
	South Dakota	15	17,400	0.26
Rocky Mountains	Wyoming	335	107,000	36
	Colorado	292	48,800	14
	Utah	118	83,400	9.8
West Coast	California	826	86,800	72
	Nevada	10	54,600	0.55
	Oregon	9	—[c]	—[c]
	Washington	1	—[c]	—[c]
Total		**26,400**	**41,300**	**1,050**

Source: 190 DCN SGE01187

a—Number of active disposal wells is based primarily on data from 2012 to 2013.

b—Typical injection volumes per well are based on historical annual volumes for injection for disposal divided by the number of active disposal wells during the same year (primarily 2012 to 2013 data). These approximations are based on a number of assumptions, detailed in a separate memorandum, *Analysis of Active Underground Injection for Disposal Wells* (190 DCN SGE01187).
c—Disposal rates and volumes are unknown.

d—These wells are not currently permitted to accept UOG extraction wastewater (source: 110 DCN SGE00726).

e—Only 24 of the 640 active disposal wells in Arkansas are in the northern half of the state, close to the Fayetteville formation (50 DCN SGE00499).

Abbreviations: gpd—gallons per day; MGD—million gallons per day

Table D-3. Distribution of Active Class II Disposal Wells on Tribal Lands (2014 Data)

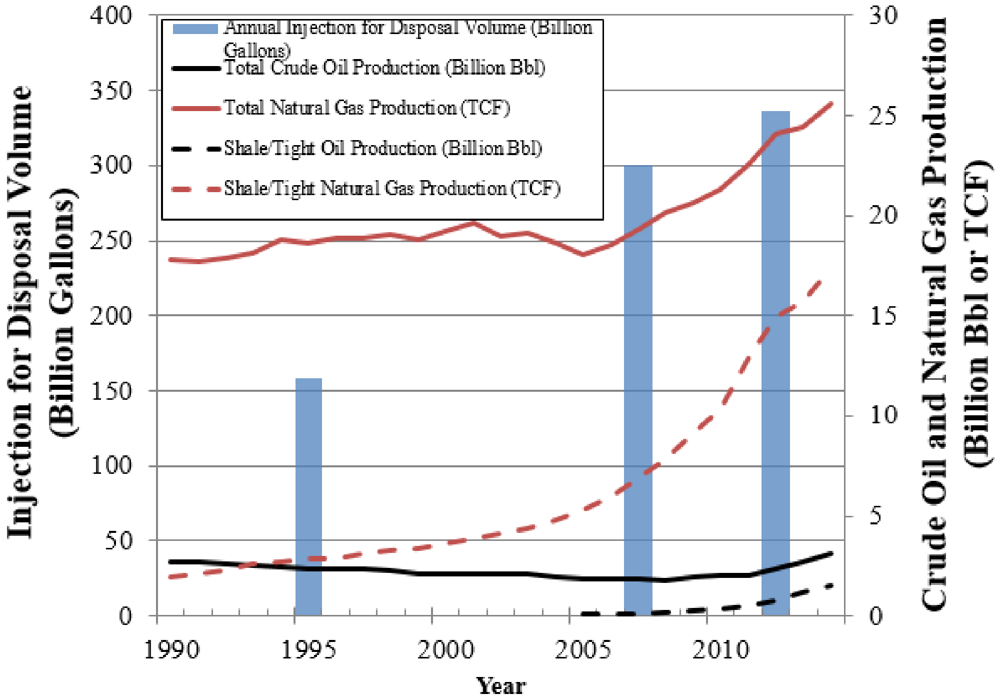
Geographic Region (from the EIA)	Tribe ID	Tribe Name	Associated State	Number of Active Disposal Wells
East	472	Saginaw Chippewa Indian Tribe	MI	7
Gulf Coast/Southwest	701	Jicarilla Apache Nation	NM	1
	751	Ute Mountain Tribe of the Ute Mountain Reservation	NM	2
Mid Continent	930	Osage Nation	OK	775
	812	Pawnee Nation	OK	5
	809	Apache Tribe	OK	2
	824	Sac & Fox Nation	OK	2
	808	Comanche Nation	OK	1
Northern Great Plains	201	Blackfeet Tribe of the Blackfeet Indian Reservation	MT	6
	301	Three Affiliated Tribes of the Fort Berthold Reservation	ND	5
Rocky Mountains	687	Ute Indian Tribe of the Uintah & Ouray Reservation	UT	48
	750	Southern Ute Indian Tribe of the Southern Ute Reservation	CO	31
	281	Arapahoe Tribe of the Wind River Reservation	WY	4
Total				**889**

Source: 190 DCN SGE01187

2.3 Underground Injection of UOG Wastewaters

Nationally, injection for disposal volumes have increased as crude oil and natural gas production has increased. Figure D-5 shows the trend over time of injection for disposal volumes (blue bars), total crude oil and natural gas production (solid lines), and UOG production in the United States (dotted lines). The annual injection for disposal volume increased from 1995 to 2012 as UOG production ramped up significantly over the same period. The EPA observed a similar trend in the Bakken shale formation in North Dakota. Figure D-6 shows the trend over time of injection for disposal volumes in North Dakota (blue bars), total crude oil production in North Dakota (solid black line), and Bakken shale crude oil production in North Dakota (dotted black line). The annual injection for disposal volume increased from 1998 to 2013 as crude oil production ramped up significantly over the same period. Figure D-7 further demonstrates how additional disposal wells were drilled over the same time period in North Dakota to meet the increased disposal demand.

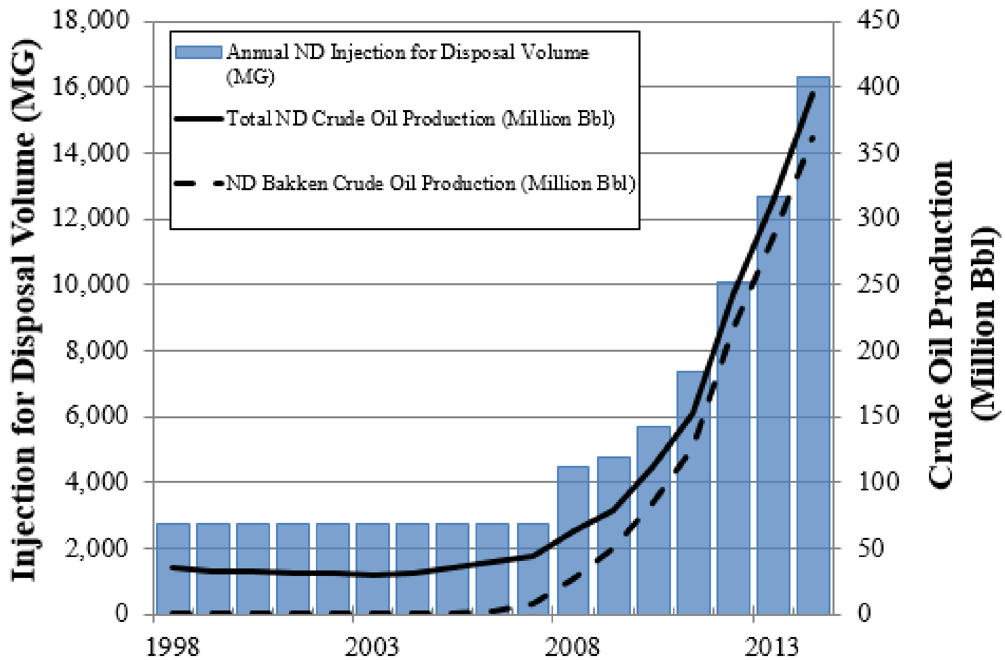
The EPA anticipates that in many parts of the United States, additional injection for disposal capacity will become available as demand increases with increased UOG production. However, as illustrated above in Table D-2, underground injection for disposal capacity in close proximity to producing wells is much less available in certain portions of the United States.



Source: 171 DCN SGE01128; 194 DCN SGE01192; 213 DCN SGE01322; 220 DCN SGE01339; 221 DCN SGE01340

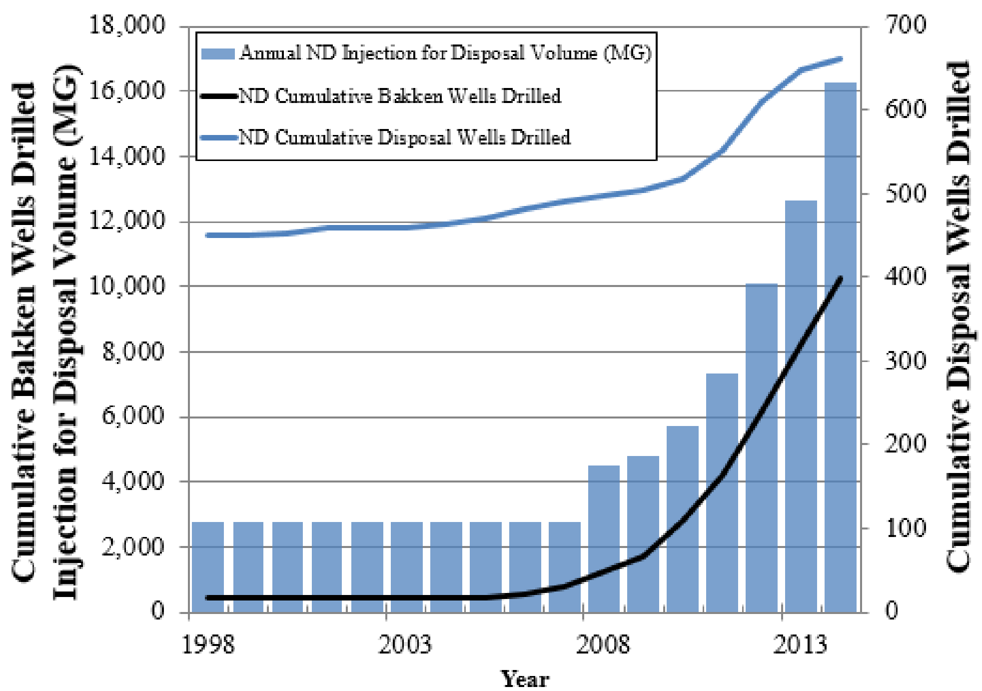
Figure D-5. U.S. Injection for Disposal Volume and UOG Production over Time[88]

[88] Total crude oil and natural gas production includes lease condensates, CBM, onshore conventional, offshore, conventional onshore Alaska, and offshore Alaska. Unconventional crude oil production also includes lease condensates.



Source: 218 DCN SGE01336; 219 DCN SGE01337; 13 DCN SGE00182; 171 DCN SGE01128; 221 DCN SGE01340

Figure D-6. Injection for Disposal Volume and Crude Oil Production over Time in North Dakota



Source: 67 DCN SGE00557; 13 DCN SGE00182; 171 DCN SGE01128; 221 DCN SGE01340

Figure D-7. Injection for Disposal Volume, Cumulative Bakken Wells Drilled, and Cumulative Disposal Wells Drilled in North Dakota

Operators of commercial injection wells for disposal may impose a surcharge to dispose of flowback (23 DCN SGE00279). Injection well operators impose the surcharge because flowback has a lower density than long-term produced water. Injection of high-density wastewater requires less power (i.e., pumping) than the injection of less-dense wastewater,[89] and the injection rate (i.e., barrels per day per well) is inversely proportional to the injection pressure due to technical and permit limitations. As a result, disposal well operators must inject lower-density flowback at a lower flow rate and typically use more power.

3 REUSE/RECYCLE IN FRACTURING

Many operators evaluate reusing/recycling UOG extraction wastewater before deciding to manage it via another method (i.e., disposal well or CWT facility) (86 DCN SGE00613; 54 DCN SGE00521; 22 DCN SGE00276). Reuse/recycle involves mixing flowback and/or long-term produced water from previously fractured wells with other source water[90] to create the base fluid[91] used in a subsequent well fracture (3 DCN SGE00046). Operators typically transport the wastewater, by truck or pipe, from storage to the fracturing site just before and during hydraulic fracturing. Operators typically store the wastewater in 10,500- to 21,000-gallon (250- to 500-barrel) fracturing tanks onsite until they are ready to blend it with other source water during the hydraulic fracture. When hydraulic fracturing begins, they pump the stored UOG produced water for reuse and other source water to a blender to form the base fluid. The blending usually occurs upstream of other steps such as fracturing chemical addition or pressurization by the pump trucks (92 DCN SGE00625).

Since the late 2000s, UOG operators have increased wastewater reuse/recycle (86 DCN SGE00613; 172 DCN SGE01143; 199 DCN SGE01231). In the early development of UOG (i.e., the early to mid-2000s), most operators believed that reuse/recycle was not technically feasible because high TDS concentrations in UOG extraction wastewater adversely affected fracturing chemical additives and/or formation geology (86 DCN SGE00613). As a result, operators used only fresh water as base fluid for fracturing. One of the changes that contributed to more widespread reuse of wastewater as a base fluid is that fracturing service providers were able to design fracturing additives to tolerate base fluids with higher concentrations of TDS (99 DCN SGE00691; 54 DCN SGE00521; 86 DCN SGE00613; 5 DCN SGE00095).

To date, slickwater fracturing fluid designs (defined in Section C.1) are the most accommodating for using base fluid that contains the high end of the TDS criteria ranges (see Table D-5 in Section D.3.2 for these ranges) (86 DCN SGE00613; 101 DCN SGE00705; 88 DCN SGE00616). Gel fracturing fluid designs (defined in Section C.1), which are typically used to fracture liquid rich plays (e.g., Bakken), are more complex and industry currently finds them to be less compatible with high concentrations of TDS than slickwater designs (101 DCN SGE00705; 86 DCN SGE00613; 88 DCN SGE00616). As a result, at present, gel designs require

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[89] The density of flowback is typically close to that of fresh water (8 pounds per gallon), while the density of produced water can be greater than 10 pounds per gallon (23 DCN SGE00279).

[90] Source water is any fluid that makes up fracturing base fluid. See Section C.1.1.

[91] Base fluid is the primary component of fracturing fluid to which proppant and chemicals are added. See Section C.1.1.

base fluid that meets the low end of the TDS criteria ranges (see Table D-5 in Section D.3.2 for these ranges). This is primarily because TDS interferes with the properties of the cross-linked gels inherent to gel fracturing fluid designs. Industry also reports that boron is a constituent of concern for reuse/recycle when using gel recipes because it interferes with the intended delayed activation of cross-linked gels (88 DCN SGE00616; 101 DCN SGE00705). This may be changing: industry has demonstrated the use of higher-TDS base fluid in 2013 to 2014 for gel fracturing as new chemical additives are becoming available for gel designs that tolerate higher TDS concentrations[92] (98 DCN SGE00667; 101 DCN SGE00705).

PESA surveyed 205 UOG operators about their wastewater management practices in 2012 (70 DCN SGE00575).[93] Table D-4 presents the survey results. Nationally, UOG operators reported reusing/recycling 23 percent of total produced water generated. The results also showed that most operators anticipate reusing/recycling higher percentages of their produced water in the two to three years following the survey. Other research firms that gather data on UOG extraction wastewater management report similar findings (103 DCN SGE00708; 104 DCN SGE00709). For example, IHS, Inc., estimates that in 2013 operators reused/recycled 16 percent of UOG produced water nationwide and expects this number to double by 2022 (103 DCN SGE00708). The EPA participated in several site visits and conference calls with operators in several formations that have been able to reuse/recycle 100 percent of their produced water under certain circumstances (95 DCN SGE00635; 21 DCN SGE00275; 92 DCN SGE00625; 96 DCN SGE00636).

[92] One vendor reported that testing of new additives for gel designs that allow the use of high-TDS base fluid is underway. This vendor expected the cost for these chemicals to initially be high (101 DCN SGE00705).

[93] Out of the 205 respondents, 143 represented operators active in major U.S. UOG plays.

Table D-4. Reuse/Recycle Practices in 2012 as a Percentage of Total Produced Water Generated as Reported by Respondents to 2012 Survey

Basin	UOG Formation	Resource Type	Percent of Wastewater Reused/Recycled for Fracturing	Percent of Wastewater Managed Using Other Methods[a]	Percent of Respondents Planning to Increase Reuse/Recycle
Appalachian	Marcellus/Utica	Shale gas/oil	74	26	50
TX-LA-MS Salt	Haynesville	Shale gas	30	70	67
Arkoma	Fayetteville	Shale gas	30	70	67
Western Gulf	Eagle Ford	Shale gas/oil	16	84	60
Fort Worth	Barnett	Shale gas	13	87	86
Permian	Avalon; Barnett-Woodford	Shale gas/oil	7	93	67
Williston	Bakken	Shale oil	5	95	56
Gulf Coast (Austin Chalk, Cotton Valley, Vicksburg)[b]		Unknown	10	90	100
Mid-Continent (Woodford, Cana, Caney, Granite Wash)[b]		Unknown	25	75	68
Rockies (Niobrara, Mancos)[b]		Unknown	14	86	100
Total sample (as reported by PESA)			23	77	55

Source: 70 DCN SGE00575

a—PESA (70 DCN SGE00575) reported this as “disposal” but did not clearly describe what it means.

b—PESA (70 DCN SGE00575) did not specify basin or formation for these areas. The EPA provided formation names that are present in these areas if not already previously listed above.

3.1 Reuse/Recycle Strategies

Operators can reuse/recycle UOG extraction wastewater for fracturing through different strategies (174 DCN SGE01168). An operator’s choice of strategy depends on many factors, which Section D.3.2 describes in detail. The following subsections discuss direct reuse/recycle without treatment and reuse/recycle after treatment.

3.1.1 Direct Reuse/Recycle for Fracturing Without Treatment

Many operators reuse/recycle their wastewater for fracturing without any treatment (i.e., only blending with fresh water) or with minimal treatment such as sedimentation or filtration to remove suspended solids. The primary purpose of the blending is to control TDS concentrations (88 DCN SGE00616; 99 DCN SGE00691). When using this strategy, operators either transport UOG extraction wastewater directly to the next well they are fracturing or transport it to a temporary storage area offsite until they are ready to fracture the next well.

Reuse/recycle without treatment accounts for a large portion of all wastewater that industry reuses/recycles. In PESA’s 2012 survey (70 DCN SGE00575), UOG operators reported that 54 percent of produced water reused/recycled by the UOG industry in 2012 for fracturing requires minimal or no treatment. In addition, the EPA conducted several site visits and conference calls with operators that have increasingly reused/recycled wastewater with no treatment (95 DCN SGE00635; 21 DCN SGE00275; 92 DCN SGE00625; 96 DCN SGE00636; 22 DCN SGE00276).

3.1.2 Reuse/Recycle in Fracturing After Treatment

Operators also reuse/recycle UOG extraction wastewater after some type of treatment. Where treatment is employed, the UOG industry typically uses one of two levels of treatment:

- **Non-TDS removal technologies—**technologies that remove non-dissolved[94] constituents from wastewater, including suspended solids, oil and grease and bacteria, or remove and/or exchange certain ions that can cause scale to form on equipment and interfere with fracturing chemical additives. These technologies are not designed to reduce the levels of dissolved constituents, which are the majority of compounds that contribute to TDS in UOG extraction wastewater.
- **TDS removal technologies—**technologies capable of removing dissolved constituents that contribute to TDS (e.g., sodium, chloride, calcium) as well as the constituents removed by non-TDS removal technologies. Treatment systems with these treatment technologies typically include non-TDS removal technologies for pretreatment (e.g., TSS, oil and grease).

Each of these levels of treatment is described in more detail below. Also see the EPA's report titled *Unconventional Oil and Gas (UOG) Extraction Wastewater Treatment Technologies* (189 DCN SGE01186), which discusses treatment technologies used to treat UOG produced water.

<u>Non-TDS Removal Technologies</u>

As discussed in Section D.3, there are constituents in UOG extraction wastewater other than TDS that operators may need to remove or destabilize before reuse/recycle. In particular, they may need to reduce constituents that may cause scale, formation damage, and/or interference between chemical additives and the formation geology (189 DCN SGE01186). These constituents include suspended solids, oil and grease, bacteria, and certain ions (e.g., iron, calcium, magnesium, and barium). Non-TDS removal technologies used to treat UOG extraction wastewater for reuse/recycle include (86 DCN SGE00613; 5 DCN SGE00095):

- Solids removal (e.g., sedimentation, filtration, dissolved air flotation)
- Chemical precipitation
- Electrocoagulation
- Advanced oxidation precipitation
- Disinfection

[94] The EPA has categorized treatment technologies into two categories in this document: those that are designed to remove dissolved constituents and those that are not designed to remove dissolved constituents. However, it should be noted that some of the technologies in the non-TDS removal category do in fact remove some dissolved constituents. For example, chemical precipitation or ion exchange may be used to remove certain metals or compounds that can cause scaling. However, these technologies typically will not remove salts and hardness, which are the primary components of TDS in UOG extraction wastewater.

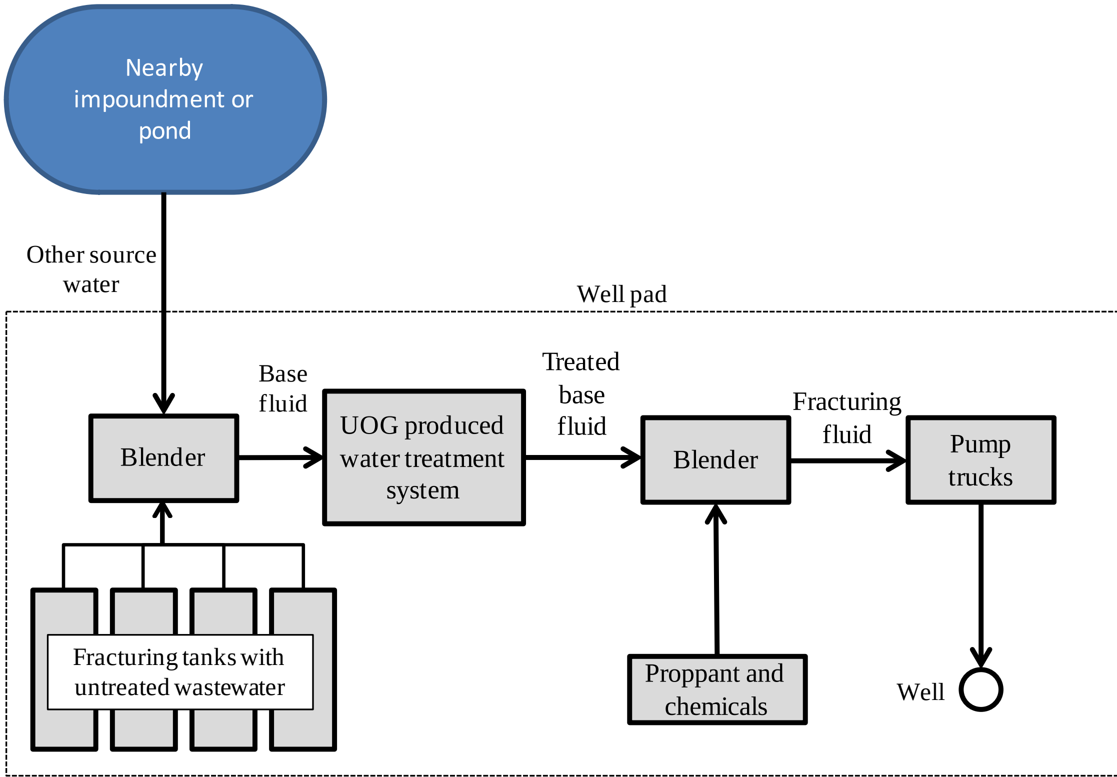
Industry often uses non-TDS removal technologies to remove or destabilize the aforementioned constituents. This treatment may be done in the field at the well site or offsite at a CWT facility. One method used in the field to treat UOG extraction wastewater is referred to as "on the fly" treatment, where the wastewater is treated as fluids are mixed for hydraulic fracturing.

Figure D-8 shows a simplified flow diagram of on-the-fly treatment of UOG produced water for reuse/recycle. In this practice, the operator treats the mixture of UOG produced water and other source water concurrently with the hydraulic fracturing process. Therefore, wastewater treatment occurs at relatively high flow rates equivalent to the rate of hydraulic fracturing.[95] Other than the treatment unit, there is no additional equipment required in this setup that is not already required for hydraulic fracturing (e.g., additional storage typically required for treated wastewater). This eliminates or reduces the following (34 DCN SGE00331):[96]

- Transporting wastewater for reuse/recycle to a CWT facility and then transporting it again to the next well for fracturing
- Procuring the services of a CWT facility
- Purchasing or renting storage containers, and renting space on which to keep the storage containers, for treated wastewater

[95] Operators typically hydraulically fracture wells at rates of 2,520 to 5,040 gallons (60 to 120 barrels) per minute. On-the-fly treatment technologies must be capable of treating wastewater at the same rate (189 DCN SGE01186).

[96] The most common technology for on-the-fly treatment is advanced oxidation. This technology eliminates the need to add biocide to the fracturing fluid to prevent bacteria growth.



Source: Generated by EPA using 34 SGE00331.

Figure D-8. Flow Diagram of On-the-Fly UOG Produced Water Treatment for Reuse/Recycle

TDS Removal Technologies

In general, TDS removal technologies convert influent wastewater into two streams: concentrated brine and low-TDS water (i.e., distillate or permeate). As discussed in the introduction to Section D.3, operators have learned that low-TDS base fluid is not necessarily required for fracturing. However, some operators may still use TDS removal technologies to treat wastewater for reuse/recycle in fracturing. TDS removal technologies that UOG operators have used to treat UOG extraction wastewater for reuse/recycle include reverse osmosis (when TDS is less than approximately 50,000 mg/L) and evaporation/condensation and crystallization (86 DCN SGE00613; 5 DCN SGE00095; 189 DCN SGE01186). Some vendors currently offer skid-mounted mobile TDS removal units for reuse/recycle in the field (189 DCN SGE01186). The EPA also identified several CWT facilities that treat UOG extraction wastewater that use TDS removal technologies (e.g., evaporation/condensation) (26 DCN SGE00284).

3.2 Reuse/Recycle Drivers

The reuse/recycle strategy operators choose depends on many different factors. The following subsections describe the two biggest drivers (105 DCN SGE00710):

- Pollutant concentrations in UOG extraction wastewater compared to maximum acceptable pollutant concentrations for base fluid (described in more detail in Section D.3.2.1)

- Volume of UOG extraction wastewater available for reuse/recycle compared to total volume of base fluid required for fracturing a new well (described in more detail in Section D.3.2.2)

These factors vary by formation and operator; therefore, the potential for reusing/recycling UOG extraction wastewater for fracturing also varies by formation and operator. These two drivers ultimately affect the level of treatment required, if any, and the total cost for reuse/recycle. Operators always consider the total cost per barrel for reuse/recycle as compared to other management alternatives.

3.2.1 Pollutant Concentrations in Available UOG Extraction Wastewater for Reuse/Recycle

Operators typically consider TDS when they evaluate whether they can reuse/recycle their wastewater and, if so, what level of treatment is required prior to reuse/recycle (105 DCN SGE00710). Operators are more likely to reuse/recycle UOG extraction wastewater with low TDS and high volumes to avoid TDS treatment and/or minimize freshwater usage. As explained in Section C.3.2.1 and shown in Figure C-6, TDS concentrations increase over time as the flow rate decreases after fracturing (105 DCN SGE00710, 44 DCN SGE00414, 38 DCN SGE00357, 36 DCN SGE00350, 92 DCN SGE00625). Therefore, operators are more likely to reuse/recycle flowback than long-term produced water because concentrations of TDS in flowback, on average, are lower than concentrations in long-term produced water (see Section C.3.2.1) (105 DCN SGE00710).

Some operators are able to reuse/recycle long-term produced water with no or minimal TDS treatment, as observed by the EPA in the Marcellus and Fayetteville shale formations (96 DCN SGE00636; 95 DCN SGE00635; 92 DCN SGE00625). However, this may not be possible in all UOG formations. As shown in Chapter C, the maximum concentration of TDS and the rate at which that concentration is reached are functions of the underlying geology. This means that, in some basins, the TDS concentrations for long-term produced water may be lower than the TDS concentrations for flowback in other basins. For example, in the Bakken formation, TDS concentrations in flowback increase rapidly to levels as high as 200,000 mg/L (within five days after fracturing), which may limit the volume of this wastewater capable of being used for reuse/recycle (36 DCN SGE00350).[97] On the other hand, data indicates that long-term produced water in the Fayetteville shale formation has less than 40,000 mg/L TDS (92 DCN SGE00625).[98]

If operators reuse/recycle UOG extraction wastewater that contains too much of certain constituents, the fracturing fluid, well, and/or formation may undergo one or more of the following problems (4 DCN SGE00070):

- Fluid instability (change in fluid properties)
- Well plugging (restriction of flow)
- Well bacteria growth (buildup of bacteria on casing)

[97] Data available to EPA indicates that only the initial five percent of the injected fracturing fluid volume that returns to the surface contains TDS less than 60,000 mg/L in the Bakken. This is based on sampling data for 62 wells.

[98] This operator reported that it is able to reuse all of its UOG wastewater due to low TDS concentrations.

- Well scaling (accumulation of precipitated solids)
- Formation damage (restriction of flow in the reservoir)

Table D-5 shows ranges of observed or recommended constituent concentration criteria for the fracturing base fluid and the associated effect that the fluid or well may experience with concentrations in excess of the criteria. These ranges represent general values that industry reports, not values specific to one UOG formation. The exact criteria an operator uses depend on operator preference, geology, and the fracturing fluid chemistry (e.g., slickwater, gel), but the selected criteria typically fall within the ranges shown in Table D-5.

Table D-5. Reported Reuse/Recycle Criteria

Constituent	Reasons for Limiting Concentrations	Recommended or Observed Base Fluid Target Concentrations (mg/L,[a] After Blending)
TDS	Fluid stability	500–70,000
Chloride	Fluid stability	2,000–90,000
Sodium	Fluid stability	2,000–5,000
Metals		
Iron	Scaling	1–15
Strontium	Scaling	1
Barium	Scaling	2–38
Silica	Scaling	20
Calcium	Scaling	50–4,200
Magnesium	Scaling	10–1,000
Sulfate	Scaling	124–1,000
Potassium	Scaling	100–500
Scale formers[b]	Scaling	2,500
Phosphate	Not reported	10
Other		
TSS	Plugging	50–1,500
Oil	Fluid stability	5–25
Boron	Fluid stability	0–10
pH (SU)	Fluid stability	6.5–8.1
Bacteria (counts/mL)	Bacterial growth	0–10,000

Sources: 179 DCN SGE01179

a—Unless otherwise noted.

b—Includes total of barium, calcium, manganese, and strontium.

Abbreviations: mg/L—milligrams per liter; SU—standard units; mL—milliliter

3.2.2 Base Fluid Demand for Fracturing

The amount of wastewater used in fracturing fluid make up depends not just on wastewater pollutants and concentrations but also on wastewater quantity compared to the amount of water required for the base fluid.

Water Demand at the Well Level

The volume of fracturing fluid required per well for fracturing may also influence the level of treatment or blending ratio necessary to meet the base fluid pollutant criteria in Table D-5. The blending ratio is the volume of reused/recycled wastewater as a percent of the total base fluid volume used to fracture a specific well. The blending ratio depends on the wastewater pollutants and concentrations as well as on the volume of UOG extraction wastewater available and the total volume of base fluid required. Operators consider how much wastewater is generated by nearby wells with respect to how much fracturing fluid is required to fracture a subsequent well. In areas where produced water volume generation is high and/or the required total base fluid volume for fracturing is low, operators may use a high blending ratio. As explained above, this high ratio may require more treatment depending on TDS and other constituent concentrations. On the other hand, in formations where produced water volume generation is low and total base fluid fracturing volume is high, operators may use a low blending ratio. A low blending ratio can typically be used with little to no treatment (21 DCN SGE00275; 95 DCN SGE00635; 86 DCN SGE00613). Table D-6 shows observed blending ratios for various formations. This table also includes theoretical upper end blending ratios as presented in literature, based on the typical fracturing fluid volume and produced water volume generated per well[99] for each formation (93 DCN SGE00627; 97 DCN SGE00639; 99 DCN SGE00691).

Table D-6. Reported Reuse/Recycle Practices as a Percentage of Total Fracturing Volume

Basin	Formation	Resource Type	Observed Blending Ratio[a] (%)	Estimated Maximum Potential Blending Ratio[b] (%)
Anadarko	Cleveland	Tight	—	10–40
	Granite Wash	Tight	—	10–40
	Mississippi Lime	Tight	—	50
Appalachian	Marcellus	Shale	10–12	10–40
	Utica	Shale	—	10–40
Arkoma	Fayetteville	Shale	6–30	—
Denver J.	Niobrara	Shale	—	10–40
Fort Worth	Barnett	Shale	4–6	10–40
Permian	—[c]	Shale/tight	2–40	50
TX-LA-MS Salt	Haynesville	Shale	5	5–10
	Tuscaloosa Marine	Shale	25	—
Western Gulf	Eagle Ford	Shale	—	10–40

Sources: 179 DCN SGE01179

Note: Data years represented range from 2009 to 2013.

a— Actual observed volumes of reused/recycled UOG extraction wastewater as a percentage of fracturing fluid volume.

b— Estimated maximum blending ratio based on typical flowback volume per well compared to typical fracturing volume per well as presented in 93 DCN SGE00627; 97 DCN SGE00639; and 99 DCN SGE00691.

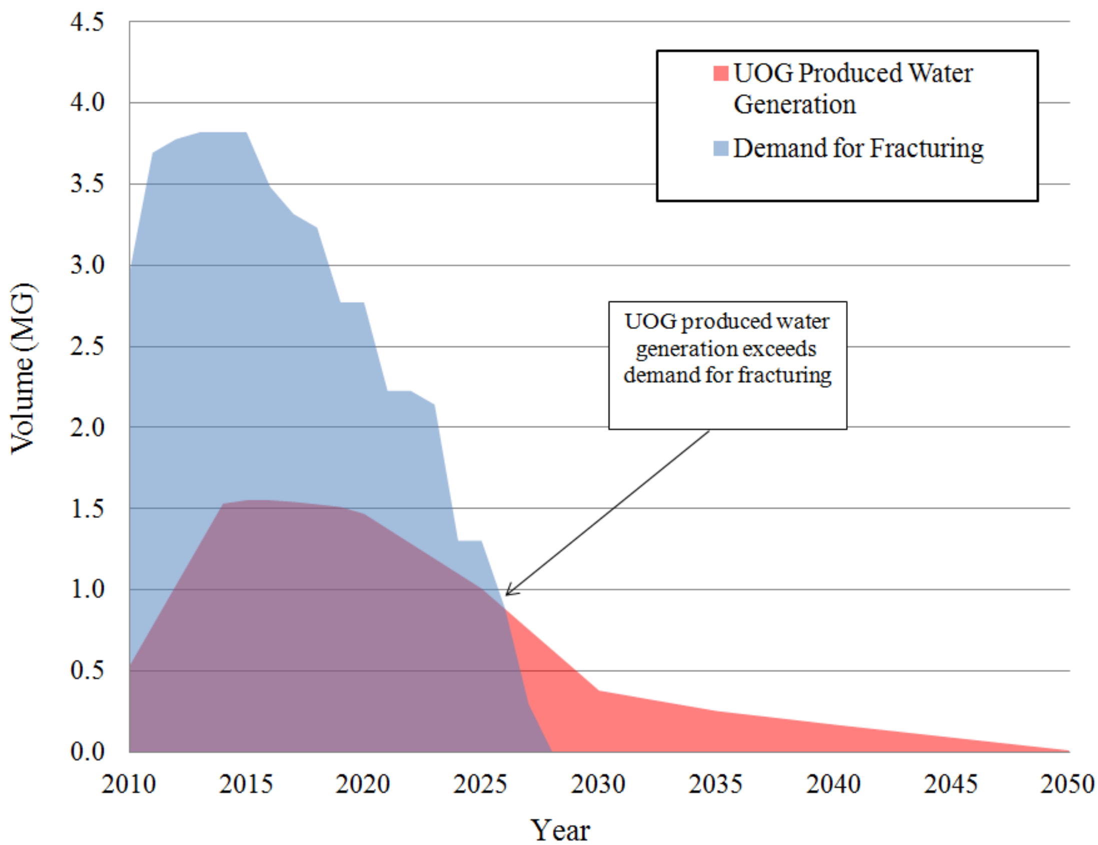
c— References do not specify a specific formation.

[99] This theoretical value reported in literature is irrespective of constituent concentrations.

"—" indicates no data.

Water Demand at the Formation Level

Although reuse/recycle has become popular as a way to manage UOG extraction wastewater, it is anticipated to become less attractive as a formation matures and the operator drills and fractures fewer wells (105 DCN SGE00710). As a formation matures, the volume of base fluid needed to fracture new wells may be less than the volume of produced water generated by producing wells in the area (92 DCN SGE00625). Figure D-9 illustrates this concept[100] with a hypothetical situation for an operator in a single formation as reported by an operator (32 DCN SGE00305.A03). During early years of development, the base fluid demand for fracturing wells always exceeds the volume of produced water generated. This provides favorable conditions for reuse/recycle. As drilling decreases, the volume of base fluid needed decreases below the volume of produced wastewater generated. Consequently, the operator must find an alternative to dispose of at least some portion of the produced water such as injection in disposal wells or transfer the wastewater to CWT facilities.



Source: 179 DCN SGE01179 (Generated by the EPA based on figure in 32 DCN SGE00305.A03)

Figure D-9. Hypothetical UOG Produced Water Generation and Base Fracturing Fluid Demand over Time

[100] This concept assumes that operators do not typically share wastewater for reuse in fracturing.

3.3 Other Considerations for Reuse/Recycle

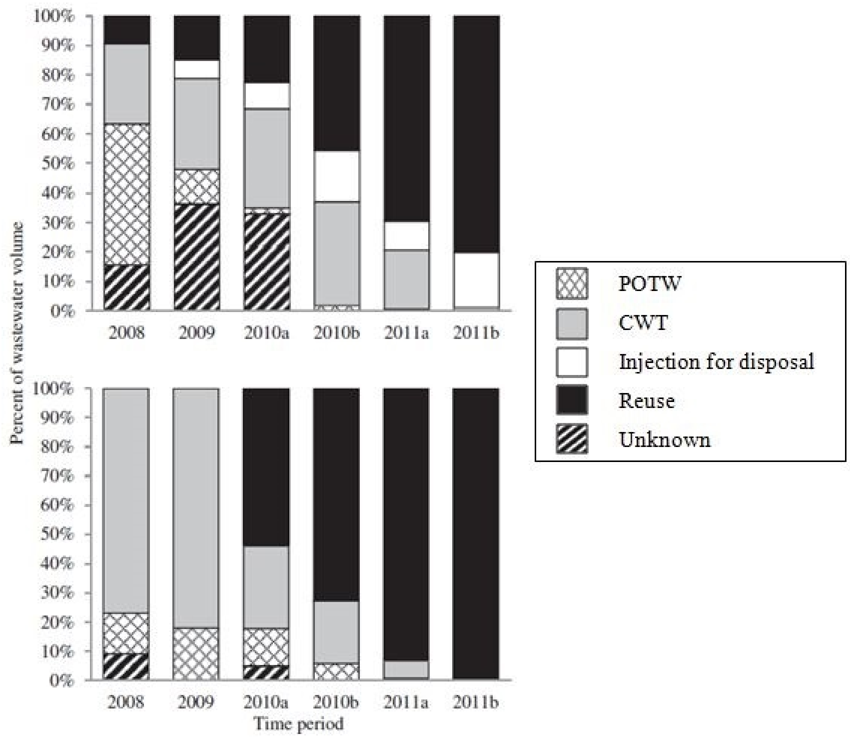
In addition to the level of treatment required for reuse/recycle, operators consider the following as they decide whether to reuse/recycle their wastewater:

- Wastewater transportation
- Wastewater storage
- Source water availability and cost

3.3.1 Transportation

Transportation requirements affect the wastewater reuse/recycle potential in a specific area. While not explicitly stated above, the location of the producing well(s) relative to the location of disposal well(s), CWT facilities, and/or a subsequent well(s) to be drilled is also a consideration. Operators must determine and compare the cost (dollars per barrel) to transport the wastewater for all management scenarios.

Further, when a UOG well generating wastewater is far from management approaches such as a disposal well or CWT facility, reuse/recycle may also be more economical. The distance between disposal wells and CWT facilities from the UOG well generating the wastewater can vary by formation and even within formations. For example, Figure D-10 shows how operators in the northeast region of the Marcellus reused/recycled a higher percentage of wastewater than in the southwestern region between 2008 and 2011 (71 DCN SGE00579). This is due to the fact that Marcellus wells in the southwestern part of Pennsylvania are closer to disposal wells in Ohio, whereas Marcellus wells in the northeast portion of Pennsylvania are more than 200 miles from disposal wells in Ohio. As a result, it is typically less expensive per barrel to reuse/recycle the wastewater in the northeast than to transport it to a disposal well in Ohio because transportation alone can cost as much as $13 per barrel (31 DCN SGE00300).



Source: Graphic reprinted with permission from Brian Rahm **(**71 DCN SGE00579).
Note: "a" and "b" for 2010 and 2011 represent the first and second half of the year, respectively.

Figure D-10. UOG Extraction Wastewater Management Practices Used in the Marcellus Shale (Top: Southwestern Region; Bottom: Northeastern Region)

3.3.2 Storage

Storage requirements and the number of wells the operator is drilling per unit time under its drilling program may also dictate when operators can reuse/recycle wastewater. In general, the effective storage cost to the operator increases the longer UOG extraction wastewater is stored before reuse in a subsequent well[101] (21 DCN SGE00275). For example, an operator that is considering reusing/recycling extraction wastewater for fracturing and fractures 12 wells per year in an area may need to store wastewater an average of one month between fracturing jobs. In comparison, an operator that fractures 50 wells per year in an area may only need to store wastewater an average of one week before being able to reuse/recycle it in the next fracturing job (25 DCN SGE00283). Section B.2 explains UOG extraction wastewater storage options in more detail.

3.3.3 Source Water Availability

Operators that successfully reuse/recycle their wastewater can reduce the total volume of other types of source water they need to use for base fluids, creating an offset in costs associated

[101] This is primarily because many operators rent fracturing tanks on a per-tank-per-day basis. Even if operators purchase fracturing tanks instead, the effective cost to the operator still increases as storage time increases.

with source water (5 DCN SGE00095). Fresh water from rivers and streams is relatively abundant and inexpensive in some areas, but in others it can be a stressed resource. Seasonal droughts can cause a high demand for resources and operators can experience inflated acquisition costs. Reuse/recycle is more likely to be driven by these reasons for operators in arid or drought-prone regions than for operators in regions where freshwater and groundwater resources are abundant and inexpensive (72 DCN SGE00583; 105 DCN SGE00710; 196 DCN SGE01207). This is because as the cost of fresh water and groundwater increases, the offset in costs from reusing/recycling wastewater to replace other source water also increases.[102] Examples of such areas include California, the Denver Julesburg and Permian basins, and the Eagle Ford shale formation (105 DCN SGE00710). In addition, as mentioned above, a lack of disposal wells in some areas may be another driver behind wastewater reuse/recycle activity in some areas (e.g., Marcellus shale).

4 TRANSFER TO CWT FACILITIES

Some operators manage UOG extraction wastewater by transporting it to CWT facilities. Treated UOG extraction wastewater at CWT facilities is either discharged[103] or returned to the operator for reuse/recycle in fracturing. Operators may choose to use CWT facilities primarily when other wastewater management options (e.g., disposal wells) are not available where they are operating (105 DCN SGE00710; 10 DCN SGE00139).

This section provides a general overview of the types of CWT facilities that exist and that UOG operators may use for wastewater management, typical CWT facility treatment processes, CWT facilities that EPA is aware of that have in the past or currently accept UOG extraction wastewater, and considerations for using CWT facilities to manage UOG extraction wastewater.

4.1 Types of CWT Facilities

A CWT facility is 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 offsite (40 CFR 437.2(c)). CWT facilities that accept UOG extraction wastewater are sometimes run by the UOG operator and are sometimes run by an entity not engaged in the oil and gas extraction business. Since UOG development ramped up in the late 2000s, new CWT facilities that accept extraction wastewater from operators have become available (178 DCN SGE01178), mostly in areas with less underground injection capacity. In addition, many UOG operators have vertically integrated their companies by purchasing or constructing their own CWT facilities (see Section D.2.3) (178 DCN SGE01178). Some CWT facilities accept only oil and gas wastewater while others accept a variety of industrial wastewater. They follow different discharge practices:

- Zero discharge (treated wastewater is typically reused in fracturing or disposed of in a Class II disposal well)
- Discharge (to surface waters or POTWs)

[102] Transportation distances may also affect costs.

[103] Discharge includes both indirect discharge (to a POTW) and direct discharge (to surface water).

- Multiple discharge options (a mix of discharge and zero discharge)

Pollutant discharges to surface waters or to POTWs from CWT facilities may not be subject to the Oil and Gas Extraction ELGs (40 CFR part 435). Rather, they may be subject to the CWT ELGs promulgated in 40 CFR part 437. Unlike the Oil and Gas Extraction ELGs, 40 CFR part 437 includes limitations and standards for both direct and indirect dischargers.

The level of treatment CWT facilities accepting UOG wastewaters use depends on factors such as the fate of the treated wastewater. The two primary types of treatment technologies are non-TDS removal technologies[104] and TDS removal technologies,[105] defined in Section D.3. In general, CWT facilities typically accepting UOG wastewaters use non-TDS removal technologies for treatment before reuse/recycle. Direct and indirect discharging CWT facilities accepting UOG wastewaters currently use a mix of TDS and non-TDS removal technologies.[106]

4.1.1 Zero Discharge CWT Facilities

After treatment, a zero discharge CWT facility does not discharge the wastewater to surface water or a POTW. Instead, it typically returns the wastewater to UOG operators for reuse/recycle in fracturing.[107] CWT facilities that accept UOG extraction wastewater from operators and fall into this category typically allow them to unload a truckload of wastewater for treatment and take a load of treated wastewater on a cost-per-barrel basis (18 DCN SGE00245). Others may allow an operator to unload a truckload of wastewater for a surcharge without taking a load of treated wastewater, as long as other operators need additional treated wastewater. Most of these CWT facilities provide minimal (i.e., non-TDS removal) treatment, but some also use TDS-removal technologies.

4.1.2 Discharging CWT Facilities

Some CWT facilities discharge treated wastewater either indirectly to a POTW or directly to surface waters. As discussed in Section A.2, discharges from the CWT facility to the POTW are controlled by an Industrial User Agreement that must incorporate the pretreatment standards set out in 40 CFR part 437 and requirements set out in 40 CFR part 403. Surface water discharges from CWT facilities are controlled by NDPES permits that include pollutant discharge limitations based on water-quality-based limitations and the technology-based limitations set out in 40 CFR part 437. The level of treatment typically depends on the requirements in the NPDES permit, which may or may not include restrictions on TDS. Direct-discharging CWT facilities use a mixture of TDS and non-TDS removal technologies. However,

[104] Examples of CWT facilities using this level of treatment are described in 92 DCN SGE00625; 95 DCN SGE00635, 18 DCN SGE00245, 47 DCN SGE00481, and 43 DCN SGE00379.

[105] Examples of CWT facilities using this level of treatment are described in 45 DCN SGE00476, 39 DCN SGE00366, 40 DCN SGE00367, and 42 DCN SGE00374.

[106] EPA is currently aware of several discharging CWT facilities accepting oil and gas wastes that, as of early 2016, do not utilize TDS removal technologies. See 178 DCN SGE01178 for a list of known CWT facilities accepting UOG wastewater and the discharge status and the level of treatment utilized at these facilities.

[107] Zero discharge CWT facilities may also evaporate the wastewater or send it to underground injection wells (42 DCN SGE00374).

new state regulations in Pennsylvania, for example, have led direct-discharging CWT facilities to use more TDS removal technologies (178 DCN SGE01178).

4.1.3 CWT Facilities with Multiple Discharge Options

Some discharging[108] CWT facilities may also recycle a portion of the treated wastewater. Consequently, these types of CWT facilities may employ both non-TDS and TDS removal technologies. One such facility is Eureka Resources in Williamsport, Pennsylvania. The Eureka CWT facility holds a General Permit (WMGR123NC005)[109] from PA DEP that includes limits[110] for TDS (500 mg/L), chloride (25 mg/L), and radium-226 + radium-228 (5 pCi/L), among others. The Eureka CWT facility uses a non-TDS removal technology (chemical treatment) followed by a TDS removal technology (evaporation/condensation) (31 DCN SGE00300). Operators may take a load of treated wastewater for reuse/recycle that the facility treated using the non-TDS removal technology train or using the entire treatment train (both non-TDS and TDS removal technologies). There are no NPDES permit limits that must be met for wastewater that is treated for reuse. The level of treatment is based on the operators' specifications.

4.2 Active CWT Facilities Accepting UOG Extraction Wastewater

To date, the EPA has identified 74 CWT facilities that have accepted or plan to accept UOG extraction wastewater. Most of them accept only oil and gas wastewater, not wastewater from other industries. Table D-7 shows the total number of CWT facilities, by state, that have accepted or plan to accept UOG extraction wastewater. The table includes a breakdown by treatment level and facility discharge type (described in Section D.4.1). The majority of these facilities can treat between 87,000 and 1,200,000 gallons (2,100 and 29,000 barrels) per day (178 DCN SGE01178).[111]

To generate Table D-7, the EPA used information from state agencies (e.g., PA DEP statewide waste reports), CWT facility websites, and news articles. The collected information is documented in a separate memorandum titled *Analysis of Centralized Waste Treatment (CWT) Facilities Accepting UOG Extraction Wastewater* (178 DCN SGE01178), which lists known CWT facilities along with information such as permit number, location, treatment capacity, and treatment level when available. Because few states keep comprehensive lists of CWT facilities,

[108] Discharge includes both indirect discharge (to a POTW) and direct discharge (to surface water).

[109] More information available online at: http://files.dep.state.pa.us/Waste/Bureau%20of%20Waste%20Management/WasteMgtPortalFiles/SolidWaste/Residual_Waste/GP/WMGR123.pdf.

[110] In addition to setting discharge limitations to the nearby POTW, Eureka's General Permit allows it to treat wastewater for reuse purposes only, in which case there are no actual limits.

[111] To exclude outliers, the EPA presents the 10th and 90th percentiles of reported treatment capacities at CWT facilities.

Table D-7 likely underestimates the number of CWT facilities accepting UOG extraction wastewater.[112]

Table D-7. Number of CWT Facilities That Have Accepted or Plan to Accept UOG Extraction Wastewater, by State

State	UOG Formation(s) Served	Zero Discharge CWT Facilities[a]		CWT Facilities That Discharge to a Surface Water or POTW[a]		CWT Facilities with Multiple Discharge Options[a]		Total Known Facilities
		Non-TDS Removal	TDS Removal	Non-TDS Removal	TDS Removal	Non-TDS Removal	TDS Removal	
AR	Fayetteville	2	0	0	0	0	1	**3**
CO	Niobrara, Piceance Basin	3(1)	0	0	0	0	0	**3**
ND	Bakken	0	1 (1)	0	0	0	0	**1**
OH	Utica, Marcellus	10 (7)	0	1	0	0	0	**11**
OK	Woodford	2	0	0	0	0	0	**2**
PA	Utica, Marcellus	22	7(3)	8	0	0	3 (1)	**40**
TX	Eagle Ford, Barnett, Granite Wash	1	3	0	0	0	0	**4**
WV	Marcellus, Utica	4 (2)	0	0	0	1	1	**6**
WY	Mesaverde and Lance	0	2	0	0	0	2	**4**
Total		**44**	**13**	**9**	**0**	**1**	**7**	**74**

Sources: 178 DCN SGE01178

a—Information is current as of 2014; it is possible that since 2014 some listed CWT facilities have closed and/or new CWT facilities not listed have begun operation. Number of facilities includes facilities that have not yet opened but are under construction, pending permit approval, or are in the planning stages. Facilities that are not accepting UOG extraction wastewater but plan to in the future are noted parenthetically and not included in the sum of total known facilities.

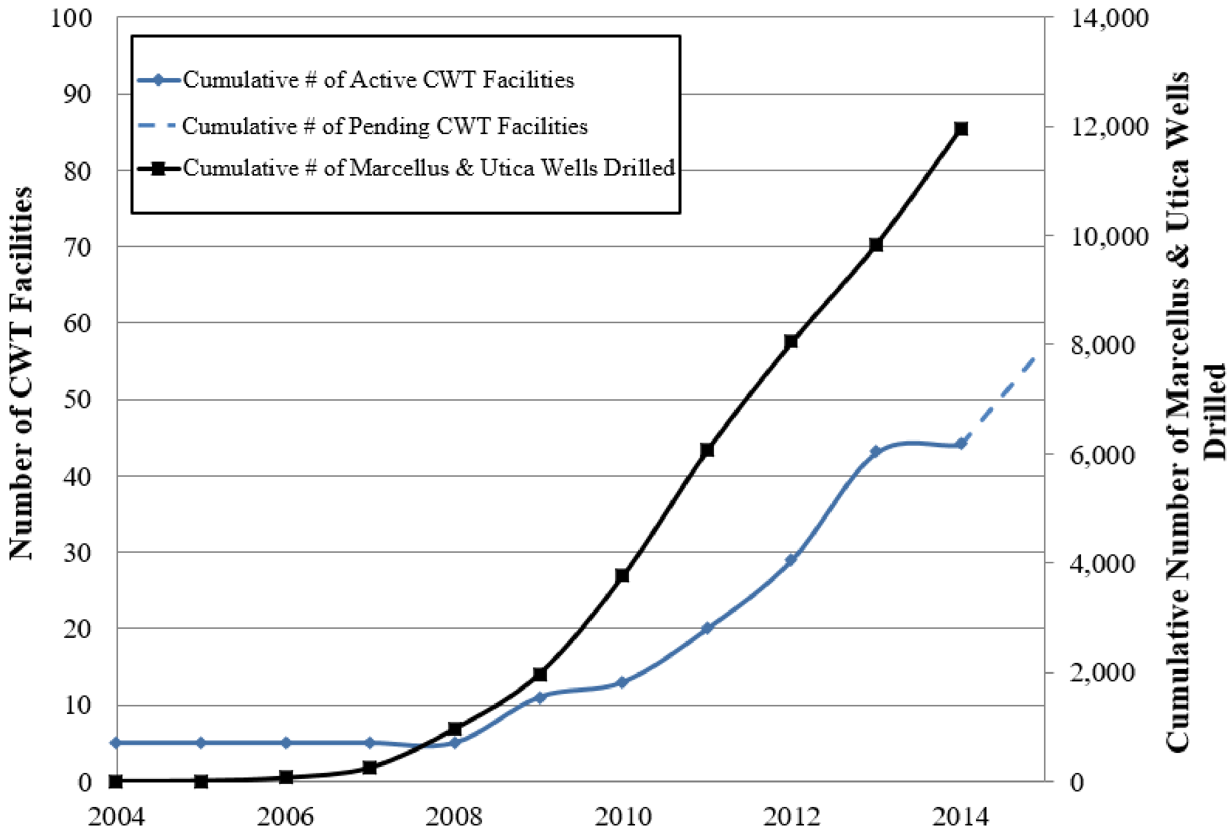
This information shows that CWT facilities have developed in regions of increasing oil and gas production, especially in areas where capacities for other management practices are less available (10 DCN SGE00139). To illustrate this, the EPA analyzed the number of active CWT facilities available to Marcellus shale and Utica shale operators where there are few disposal wells in some parts of the region.[113] Figure D-4 illustrates how the eastern half of the Appalachian basin contains many CWT facilities and few disposal wells and the western half contains many disposal wells and few CWT facilities. Figure D-11 shows the trend over time of active CWT facilities available to operators in the Marcellus and Utica shales,[114] along with the number of UOG wells drilled. The number of CWT facilities available to operators in the Marcellus and Utica shales has increased with the number of wells drilled. The EPA observed a similar trend in the Fayetteville shale formation in Arkansas. Although Arkansas has several

[112]The information in Table D-7 is current as of 2014; it is possible that since 2014 some listed CWT facilities have closed and/or some CWT facilities not listed have begun operation.

[113] This analysis included Pennsylvania, West Virginia, and Ohio.

[114] The Marcellus and Utica shale formations are in the Appalachian basin.

hundred active disposal wells, only 24 wells are located in the northern half of the state in close proximity to Fayetteville shale wells (190 DCN SGE01187). As a result, the largest active operator in the Fayetteville shale has constructed three CWT facilities. The EPA anticipates that more CWT facilities will become available near UOG formations where access to disposal wells is limited as additional UOG wells are drilled.



Sources: 178 DCN SGE01178

Figure D-11. Number of Known Active CWT Facilities over Time in the Marcellus and Utica Shale Formations

5 DISCHARGE TO POTWS

In locations where disposal wells and CWT facilities are limited or transportation distances are a factor, operators have, in the past, managed UOG extraction wastewater by discharge to POTWs. This practice can be problematic because POTWs do not use technologies that can remove some UOG extraction wastewater constituents (e.g., TDS). Also, constituents in UOG extraction wastewater such as TDS may interfere with POTW operations and may increase pollutant loads in receiving streams to the detriment of receiving water quality and biota and affect downstream water use (27 DCN SGE00286; 35 DCN SGE00345; 71 DCN SGE00579; 59 DCN SGE00531; 94 DCN SGE00633; 162 DCN SGE01077).[115]

This section provides an overview of typical treatment processes used at POTWs, a discussion of how constituents commonly found in UOG extraction wastewater interact with POTWs (including examples of POTWs that have been used to manage UOG extraction wastewater), a review of POTWs that have accepted UOG extraction wastewater, and the current status of UOG extraction wastewater discharges to POTWs.

5.1 POTW Background and Treatment Levels

40 CFR 403.3(q) defines a POTW as "a treatment works as defined by section 212 of the [Clean Water] Act,[116] which is owned by a State or municipality." POTWs are designed to treat residential, commercial, and industrial wastewater, focusing on the removal of suspended solids and dissolved organic constituents. Table D-8 presents concentrations of weak, moderate, and strong domestic wastewater as would be typically experienced by a POTW (i.e., influent).

Table D-8. Typical Composition of Untreated Domestic Wastewater

Constituent	Concentrations (mg/L)		
	Weak	Moderate	Strong
TDS	270	500	860
COD	250	430	800
TSS	120	210	400
BOD_5	110	190	350
TOC	80	140	260
Oil and grease	50	90	100
Chlorides	30	50	90
Nitrogen, total	20	40	70
Sulfate	20	30	50
Phosphorus, total	4	7	12
Nitrates	0	0	0
Nitrites	0	0	0

Source: 12 DCN SGE00167

Abbreviation: mg/L—milligrams per liter

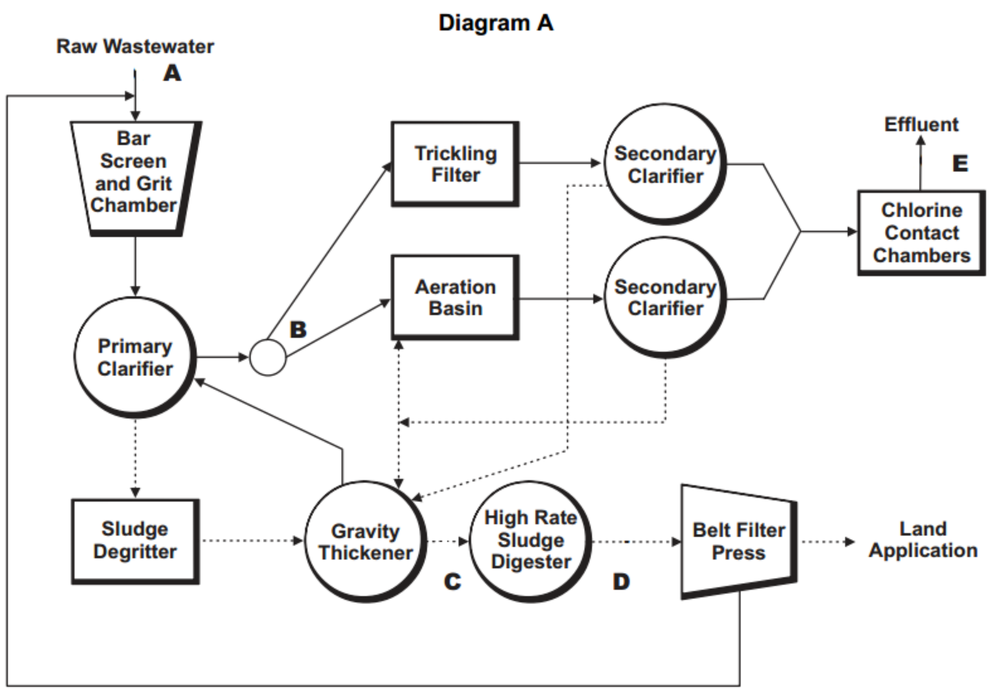
Typical treatment processes used at POTWs are categorized into the following levels:

115 GWPC, 2014 (162 DCN SGE01077) states, "For a POTW to accept a waste stream for treatment, the facility must show that the accepted waste will not interfere with the treatment process or pass through the facility untreated. Since POTWs are typically not designed to treat fluids with constituents found in produced water (e.g., high TDS concentrations, hydrocarbons, etc.), problems have occurred as a result of produced water being sent to POTWs including impacts to the treatment process or the discharge of constituents at levels detrimental to the receiving water body."

116 Section 212 of the CWA defines the term "treatment works" as "any devices and systems used in the storage, treatment, recycling, and reclamation of municipal sewage or industrial wastes of a liquid nature."

- **Primary treatment,** capable of removing some suspended solids and organic matter from influent wastewater using unit operations such as screening and clarification.
- **Secondary treatment,** capable of removing additional suspended solids and biodegradable organic matter from influent wastewater using biological treatment processes, such as activated sludge and trickling filters. Secondary treatment is sometimes followed by chlorination or ultraviolet (UV) disinfection to reduce microbial pathogens.
- **Tertiary (advanced) treatment,** capable of removing other pollutants, such as nutrients, not removed in secondary treatment using processes such as nitrification/denitrification and activated carbon adsorption (12 DCN SGE00167).

Figure D-12 shows a typical process flow diagram for a POTW. The processes shown include primary treatment (screen, grit chamber, primary clarifier), secondary treatment (trickling filter, aeration, secondary clarifier), and disinfection (chlorine). The diagram also shows sludge treatment (gravity thickening, digestion, filter press) before use/disposal (e.g., land application).



Source: 80 DCN SGE00602

Figure D-12. Typical Process Flow Diagram at a POTW

In general, the average POTW in the United States has primary and secondary treatment. In addition to treated wastewater, POTW treatment processes produce residual solids (sludge), including biosolids generated during biological treatment and other suspended material removed in clarifiers. Most POTWs apply additional treatment to the sludge, typically gravity thickening followed by stabilization (e.g., anaerobic digestion) and dewatering (e.g., filter press). After this additional treatment, most sludge is either put to a beneficial use (e.g., land application, soil enrichment) or disposed of in a landfill or incinerator (78 DCN SGE00599).

Table D-9 shows typical removal percentages for various constituents. As discussed, removal rates for suspended solids are high (90 percent for TSS) and removal rates for metals and salts are low (6 percent for cobalt, 8 percent for TDS).

Table D-9. Typical Percent Removal Capabilities from POTWs with Secondary Treatment

Constituent	POTW Percent Removal (%)	Constituent	POTW Percent Removal (%)
Aluminum	91	Mercury	72
Ammonia as nitrogen	39	Molybdenum	19
Antimony	67	Naphthalene	95
Arsenic	66	Nickel	51
Barium	16	Oil and grease (as HEM)	86
Beryllium	72	Phenol	95
BOD_5	89	Phenolics, total recoverable	57
Boron	30	Phosphorus, total	57
Cadmium	90	Pyridine	95
Calcium	9	Selenium	34
Carbon disulfide	84	Silver	88
Chloride	57	Sodium	3
Chlorobenzene	96	Sulfate	85
Chloroform	73	Sulfide	57
Chromium	80	TDS	8
Cobalt	6	Thallium	72
COD	81	Tin	42
Copper	84	Titanium	92
Cyanide	70	TOC	70
Ethylbenzene	94	Toluene	96
Fluoride	61	Total petroleum hydrocarbons	57
Iron	82	TSS	90
Lead	77	Vanadium	10
Magnesium	14	Xylenes (m+p, m, o+p, o)	65 to 95
Manganese	36	Zinc	79

Source: 79 DCN SGE00600

Note: 79 DCN SGE00600 references data from the November 5, 1999, updated 50-POTW study and the RREL database compiled for the CWT effluent guidelines.

Table D-10 shows the breakdown of U.S. POTWs categorized according to their level of treatment. As of 2008, secondary treatment was the most common level of treatment at POTWs.

Table D-10. U.S. POTWs by Treatment Level in 2012

Treatment Level	Percent of Facilities (%)[a]	Number of Facilities[a]	Combined Design Capacity (MGD)[a]
Less than secondary (e.g., primary)	0.2	34	546
Secondary	50.0	7,374	17,765
Greater than secondary (e.g., tertiary, advanced)	34.1	5,036	23,710
No discharge	15.5	2,281	2,557
Partial treatment[b]	0.2	23	287
Total	**100.0**	**14,748**	**44,866**

Sources: 81 DCN SGE00603; 216 DCN SGE01332

a—The percent of facilities and number of facilities were taken from the 2012 Clean Watersheds Needs Survey (CWNS) (published in 2016, containing 2012 data), but the 2012 CWNS did not report design capacities, so they were taken from the 2008 CWNS.

b—These facilities provide some treatment to wastewater and discharge their effluent to other wastewater facilities for further treatment and discharge.

Abbreviation: MGD—million gallons per day

5.2 History of POTW Acceptance of UOG Extraction Wastewater

As operators began extracting oil and gas from unconventional formations, UOG operators discharged wastewater to POTWs in some cases (27 DCN SGE00286; 35 DCN SGE00345; 71 DCN SGE00579).[117] The EPA located the most comprehensive data about this practice in Pennsylvania. Therefore, this subsection primarily discusses data from PA DEP, though it also includes discussions about a few POTWs in West Virginia and New York. The PA DEP data indicate that the majority of UOG operators in Pennsylvania who decided to discharge to POTWs did so by 2008[118] (203 DCN SGE01245). To identify POTWs that accepted wastewater from UOG operations,[119] the EPA reviewed the following sources:

- Notes from calls with regional and state pretreatment program coordinators (113 DCN SGE00742, 114 DCN SGE00743)
- Notes from an EPA-state implementation pilot project with the Environmental Council of the States in coordination with the Association of Clean Water Administrators (128 DCN SGE00762)
- EPA Region 3's website (41 DCN SGE00368)

[117] EPA acknowledges that COG operators are still using POTWs as a viable option for disposal of COG wastewater.

[118] EPA did not identify any information indicating when POTWs in New York began accepting of UOG extraction wastewater. EPA also could not definitely determine when UOG operators in Pennsylvania began discharging UOG extraction wastewater at POTWs because the 2007 PA DEP Waste Report data are incomplete.

[119] EPA could not determine the date when POTWs began accepting UOG wastewater in all instances. The EPA has documentation that all POTWs in Pennsylvania stopped accepting UOG extraction wastewater by the end of 2011.

- Site visits, conference calls, and meetings with industry representatives (86 DCN SGE00613; 54 DCN SGE00521), UOG operators (92 DCN SGE00625; 95 DCN SGE00635; 21 DCN SGE00275; 24 DCN SGE00280), CWT facilities (30 DCN SGE00299; 31 DCN SGE00300; 18 DCN SGE00245; 17 DCN SGE00244), and Native American tribal groups (138 DCN SGE00785)
- PA DEP's statewide waste report data[120] (203 DCN SGE01245; 184 DCN SGE01182)
- The U.S. DOE's 2010 *Water Management Technologies Used by Marcellus Shale Gas Producers* report (2 DCN SGE00011)
- Publicly available data sources identified through Internet searches

The EPA compiled and analyzed much of these existing data in a separate document, *Publicly Owned Treatment Works (POTW) Memorandum for the Technical Development Document (TDD)* (185 DCN SGE01183). This memorandum is referenced throughout Section D.5.

The EPA identified POTWs that, at one time, accepted wastewater from UOG operators generated by Marcellus shale wells. Table D-11 presents information about POTWs that have accepted UOG extraction wastewater directly from onshore UOG operators.

[120] PA DEP's waste report data provide wastewater volumes by well over time and management/disposal information as it was reported by the oil and gas well operator to PA DEP. ERG's memorandum titled *Analysis of Pennsylvania Department of Environmental Protection's (PA DEP) Oil and Gas Waste Reports* provides more detail (184 DCN SGE01182).

Table D-11. POTWs That Accepted UOG Extraction Wastewater Directly from Onshore UOG Operators

Facility Name	NPDES Permit No.	City	State	POTW Currently Accepting UOG Wastewater from UOG Operator?	Year POTW Stopped Accepting UOG Wastewater from UOG Operator
Allegheny Valley Joint Sewer Authority	PA0026255	Cheswick	PA	No	2008
Altoona Water Authority—Easterly WWTP	PA0027014	Altoona	PA	No	2011
Belle Vernon Borough	PA0092355	Belle Vernon	PA	No	2009
Borough of Jersey Shore	PA0028665	Jersey Shore	PA	No	2010
Brownsville Municipal Authority	PA0022306	Brownsville	PA	No	2008
California Borough	PA0022241	California	PA	No	2009
Charleroi Borough	PA0026891	Charleroi	PA	No	2008
City of Auburn	NY0021903	Auburn	NY	No	2008
City of Johnstown Redevelopment Authority—Dornick Point	PA0026034	Johnstown	PA	No	2010
City of McKeesport	PA0026913	McKeesport	PA	No	2011
City of Watertown	SPDES NY 002 5984	Watertown	NY	No	2010
Clairton Municipal Authority	PA0026824	Clairton	PA	No	2011
Clearfield Municipal Authority	PA0026310	Clearfield	PA	No	2009
Dravosburg	PA0028401	Dravosburg	PA	No	2008
Lock Haven City STP	PA0025933	Lock Haven	PA	No	2008
Mon Valley Sewage Authority	PA0026158	Donora	PA	No	2008
Moshannon Valley Authority STP	PA0037966	Rush Township	PA	No	2009
Reynoldsville Sewer Authority	PA0028207	Reynoldsville	PA	No	2011
Ridgway Borough	PA0023213	Ridgway	PA	No	2011
Waynesburg Borough Water System	PA0020613	Waynesburg	PA	No	2008

Source: 185 DCN SGE01183

Based on data collected through January 2016, the EPA concluded that none of the POTWs listed in Table D-11 currently accept wastewater directly from UOG operations. That is, no UOG extraction wastewater is currently being managed by discharging to any of the POTWs in this table. This is, in large part, a result of UOG operators' compliance with PA DEP's April 2011 request that they stop discharging UOG extraction wastewater to POTWs (see Section A.0). PA DEP data indicate that UOG operators in Pennsylvania stopped sending their waste to POTWs in 2011 (203 DCN SGE01245). Furthermore, the EPA has not been able to identify any POTW in any state that is currently accepting UOG extraction wastewater directly from an operator. In addition, the EPA collected data about UOG operations on tribal reservations, UOG operators that are affiliated with Indian tribes, and POTWs owned or operated by tribes that may accept industrial wastewater (138 DCN SGE00785). According to this information, there are no tribes currently operating UOG wells that discharge wastewater to POTWs, nor are there any tribes that own or operate POTWs that accept UOG extraction wastewater. EPA solicited additional data and information on current industry practice as well as its preliminary finding that no UOG facilities currently discharge to POTWs in the proposal. EPA did not receive data since proposal to contradict this finding.

The EPA is aware of a few cases where UOG operators discharge wastewater to CWT facilities for treatment and those CWT facilities discharge to POTWs. As explained in Section A.2.3, such discharges may not be subject to the ELGs for the oil and gas extraction category which is the subject of the rule. Rather, discharges to POTWs from CWT facilities accepting UOG wastewaters may be subject to ELGs for the Centralized Waste Treatment Category (40 CFR part 437).

The EPA reviewed PA DEP statewide waste reports (184 DCN SGE01182) and discharge monitoring report (DMR) data (83 DCN SGE00608) to identify the total volumes of UOG extraction wastewater and average total influent wastewater for each POTW. Using these data sources, the EPA calculated the maximum annual average daily[121] percentage of UOG extraction wastewater accepted by the POTW as shown in Table D-12. The EPA found that discharges of UOG extraction wastewater from UOG operators to POTWs peaked in 2008 and the last known discharge was in 2011.

Table D-12 also presents the year in which the highest average daily flow occurred and the corresponding UOG extraction wastewater volume being accepted by the POTW during that year. The contribution of UOG extraction wastewater out of the total volume of wastewater treated at the POTW is typically a small percentage (less than 1 percent). However, based on the data presented in Table D-12, the contribution of UOG extraction wastewater was much higher (e.g., up to 21 percent) for some POTWs for some years.

[121] PA DEP waste reports provided the total volume of UOG extraction wastewater delivered to the POTW each year. The EPA divided the annual volume by 365 to calculate the annual average daily flow of UOG extraction wastewater accepted at the POTW. Therefore, it is possible that UOG extraction wastewater was discharged to the POTWs intermittently such that actual peak daily flow of UOG extraction wastewater to the POTWs in Table D-12 was higher than the daily average.

Table D-12. Percentage of Total POTW Influent Wastewater Composed of UOG Extraction Wastewater at POTWs Accepting Wastewater from UOG Operators

POTW Name	NPDES Permit No.	Maximum Annual Average Daily UOG Extraction Wastewater Flow (god)	Corresponding Total Annual Average Daily Influent Flow to POTW (MGD)[a]	Maximum Annual Average Daily UOG Extraction Wastewater Percent of POTW Influent (%)	Year of Maximum Average Daily UOG Extraction Wastewater Flow
Belle Vernon Borough	PA0092355	93,000	0.44	21[b]	2008
California Borough	PA0022241	84,000	0.60	14	2008
Charleroi Borough	PA0026891	180,000	1.74	10	2008
Waynesburg Borough Water System	PA0020613	56,000	0.58	9.7	2008
Mon Valley Sewage Authority	PA0026158	67,000	3.47	1.9	2008
City of Johnstown Redevelopment Authority—Dornick Point	PA0026034	130,000	9.47	1.4	2008
City of Auburn	NY0021903	1,800	0.20	0.91	2008
Brownsville Municipal Authority	PA0022306	9,400	0.88	1.1	2008
Borough of Jersey Shore	PA0028665	6,000	0.69	0.88	2008
Allegheny Valley Joint Sewer Authority	PA0026255	30,000	4.30	0.69	2008
Ridgway Borough	PA0023213	6,300	0.97	0.65	2010
Clairton Municipal Authority	PA0026824	12,000	4.15	0.30	2009
Moshannon Valley Authority STP	PA0037966	3,400	2.29	0.15	2008
Dravosburg	PA0028401	1,300	0.33	0.39	2008
City of McKeesport	PA0026913	11,000	16.25	0.07	2009
Reynoldsville Sewer Authority	PA0028207	1,280	0.80	0.16	2010
Bellefonte Water Treatment Plant	PA0020486	1,400	1.99	0.07	2008
Lock Haven City STP	PA0025933	1,800	2.84	0.06	2008
Altoona Water Authority	PA0027014	2,500	6.86	0.04	2011

Source: 185 DCN SGE01183

a—This is the total influent wastewater flow to the POTW (domestic sewage and UOG extraction wastewater) in the year associated with the maximum UOG extraction wastewater volume received by the POTW.

b—The average total flow through the POTW (MGD) in 2008 was calculated using the average of four months of available data (September 2008 through December 2008).

Abbreviations: gpd—gallons per day; MGD—million gallons per day

5.3 How UOG Extraction Wastewater Constituents Interact with POTWs

POTWs are likely effective in treating only some of the pollutants in UOG extraction wastewater. Most POTWs are designed to primarily treat domestic wastewater. They typically provide at least secondary-level treatment and, thus, are designed to remove suspended solids and organic material. However, secondary treatment technologies are not designed to remove the TDS, radioactive constituents, metals, chlorides, sulfates, and other dissolved inorganic constituents found in UOG extraction wastewater.[122] In addition, the performance of the treatment technologies utilized at POTWs can be adversely affected by high concentrations of constituents found in UOG extraction wastewaters. Because they are not typical of POTW influent wastewater, UOG extraction wastewater constituents:

- May be discharged, untreated, from the POTW to the receiving stream
- May disrupt the operation of the POTW (which may lead to exceeding permit limits for BOD_5 or TSS in discharges or inhibiting sludge settling, for example)
- May accumulate in sludge, limiting its use
- May facilitate the formation of disinfection byproducts (DBPs)

Where available, the EPA reviewed the following information related to POTWs that have accepted UOG extraction wastewater:

- Local limit evaluations completed by POTWs' pretreatment program coordinators
- Technical evaluations of the impact of oil and gas wastewater pollutants on POTW unit processes completed in response to Administrative Orders (AOs)[123] issued to a number of POTWs by PA DEP
- Pass through analyses completed by POTWs
- DMR data from times when POTWs accepted UOG extraction wastewater

In many cases, POTWs that accepted UOG extraction wastewater also accepted COG extraction wastewater. Because the UOG extraction wastewater constituents that are discussed in this chapter are also present in COG extraction wastewater (209 DCN SGE01260; 146 DCN SGE00966), information and studies on the treatability of these constituents by POTWs (or their impacts on POTWs) are similarly relevant when those POTWs are accepting only COG extraction wastewater and/or a combination of COG and UOG extraction wastewater. In most of the case studies presented in this chapter, the POTWs that were accepting UOG extraction wastewater were also accepting COG wastewater.

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[122] Some POTWs provide tertiary treatment, which removes additional nutrients as well as constituents targeted for removal using secondary treatment. Similar to secondary treatment, tertiary treatment processes are not designed to remove TDS, radioactive constituents, metals, chlorides, sulfates, and other dissolved inorganic constituents found in UOG extraction wastewater and their performance may be adversely affected by the high concentrations of these pollutants.

[123] PA DEP issued AOs to many POTWs in Pennsylvania that were accepting or suspected to begin accepting wastewater from UOG operations.

The EPA also reviewed common textbooks on wastewater treatment technology effectiveness. These textbooks indicated that POTWs would likely be ineffective for treatment of certain pollutants in UOG extraction wastewater, such as TDS and many pollutants that contribute to TDS (79 DCN SGE00600). The EPA used all of this information to evaluate treatment effectiveness at POTWs, primarily for TDS.

In addition to information about POTWs accepting oil and gas extraction wastewater, the EPA collected available information about other discharges to POTWs from industrial sources containing pollutants found in UOG extraction wastewater. The case studies presented in Sections D.5.3.1.2 and D.5.3.2.2 involve discharges to POTWs from CWT facilities that accepted oil and gas extraction wastewater. To the extent that a CWT facility discharges to a POTW and also lacks technologies that remove some oil and gas extraction pollutants (e.g., TDS), information on resulting POTW effluent concentrations (and/or inhibition) can be used as a proxy for UOG extraction operator discharges to a POTW.

Table D-13 summarizes the POTW studies and analyses that are presented in Section D.5.3.1 and Section D.5.3.2. Section D.5.3.1 discusses the potential for UOG pollutants to be discharged, untreated, from POTWs. Section D.5.3.2 discusses the potential for UOG wastewater pollutants to cause or contribute to inhibition and disruption at POTWs.

Table D-13. Summary of Studies About POTWs Receiving Oil and Gas Extraction Wastewater Pollutants

POTW	Summary of Study Findings
POTWs Accepting Wastewater from Oil and Gas Operators	
Clairton, PA, POTW	Treatment system influent and effluent samples show minimal or no TDS and chloride removals. See Section D.5.3.1.1.
McKeesport, PA, POTW	Treatment system influent and effluent samples show less than 10% removal of TDS, chloride, sulfate, and magnesium at the POTW. See Section D.5.3.1.1.
Ridgway, PA, POTW	TDS and chloride concentrations in effluent from the POTW were highest when the POTW was accepting the greatest volume of oil and gas extraction wastewater (including UOG extraction wastewater). Local limits analysis assumed zero percent removal of TDS, chloride, and sulfate at the POTW. See Section D.5.3.1.1.
Charleroi, PA, POTW	Treatment system influent and effluent samples show minimal or no TDS removal. The POTW rejects influent oil and gas wastewater with TDS greater than 30,000 mg/L and/or chloride greater than 15,000 mg/L. See Section D.5.3.1.1. Higher concentrations of TSS and BOD_5 in POTW effluent when the POTW was accepting UOG extraction wastewater. See Section D.5.3.2.1.
Clarksburg, WV, POTW	The POTW accepted UOG extraction wastewater, but chlorides were not removed, merely diluted. It also exceeded the desired effluent chloride concentrations during dry weather flows. See Section D.5.3.1.1.
Johnstown, PA, POTW	Higher concentrations of TSS and BOD_5 in POTW effluent, including 52 permit limit exceedances, when the POTW was accepting UOG extraction wastewater. See Section D.5.3.2.1.
California, PA, POTW	Higher concentrations of TSS and BOD_5 in POTW effluent, including four permit limit exceedances, when the POTW was accepting UOG extraction wastewater. See Section D.5.3.2.1.

Table D-13. Summary of Studies About POTWs Receiving Oil and Gas Extraction Wastewater Pollutants

POTW	Summary of Study Findings
Waynesburg, PA, POTW	High-salinity UOG produced water impacted biological growth in trickling filter. See Section D.5.3.2.1.
POTWs Accepting Wastewater Containing UOG Extraction Wastewater Pollutants from Other Industrial Sources (e.g., CWT Facilities)	
Franklin, PA, POTW	The Franklin POTW received industrial discharges from the Tri-County CWT facility (which received oil and gas extraction wastewater). The CWT facility targeted removal of TSS and oil and grease by filtration, flocculation, and skimming. TDS and chloride concentrations in effluent from the POTW were higher when the POTW was accepting industrial wastewater from the Tri-County CWT facility and decreased after it stopped accepting wastewater from this CWT facility. See Section D.5.3.1.2.
Wheeling, WV, POTW	The Wheeling POTW received oil and gas extraction wastewater from operators as well as industrial wastewater discharges from the Liquid Asset Disposal (LAD) CWT facility. The LAD CWT facility uses ultra-filtration, ozonation, and reverse osmosis to target the removal of chlorides prior to discharge to the Wheeling POTW. The POTW experienced higher concentrations of chloride in POTW effluent while accepting UOG extraction wastewater from UOG operators and from the LAD CWT facility (which receives oil and gas extraction wastewater). See Section D.5.3.1.2. The POTW experienced interference with biological treatment from accepting UOG extraction wastewater pollutants via the LAD CWT facility's industrial discharge. The POTW also experienced an upset that required the introduction of a "seed" sludge to maintain microbial activity in treatment processes. See Section D.5.3.2.2.
Warren, OH, POTW	The Warren POTW receives industrial wastewater discharges from the Patriot CWT facility. The Patriot CWT facility uses primary treatment processes (e.g., settlement tanks, clarifier tanks) and chemical precipitation to target the removal of suspended solids and metals from UOG extraction wastewater before discharge to the Warren POTW. Influent and effluent TDS and chloride concentrations at the Warren POTW show minimal or no TDS or chloride removals. See Section D.5.3.1.2.
Brockway, PA, POTW	The Brockway POTW received natural-gas-related wastewater treated by the Dannic Energy Corporation CWT facility.[124] The POTW experienced higher concentrations of TDS in POTW effluent while accepting industrial discharges from the CWT facility containing oil and gas extraction wastewater pollutants. See Section D.5.3.1.2. The POTW experienced scum formation on clarifiers as well as increased sludge generation and high concentrations of barium in the sludge, while treating industrial discharges from the CWT facility. See Section D.5.3.2.2.

[124] EPA could not find information about the treatment processes used by the Dannic Energy Corporation CWT facility.

Table D-13. Summary of Studies About POTWs Receiving Oil and Gas Extraction Wastewater Pollutants

POTW	Summary of Study Findings
New Castle, PA, POTW	The New Castle POTW received industrial wastewater from the Advanced Waste Services CWT facility (which treats oil and gas wastewater). The CWT facility uses the following treatment processes: solids settling, surface oil skimming, pH adjustment, and (occasional) flocculation. The POTW experienced numerous effluent TSS permit limit exceedances while accepting industrial discharges from the CWT facility. The CWT facility discharge was associated with adverse impacts on sludge settling in final clarifiers at the POTW. See Section D.5.3.2.2.

5.3.1 UOG Extraction Wastewater Constituents Discharged Untreated from POTWs

As described in Section D.5.3, the EPA reviewed studies and analyses relevant to POTWs accepting wastewater containing pollutants found in UOG extraction wastewater. Consistent with wastewater treatment literature, the POTWs described in these studies demonstrated that some UOG extraction wastewater pollutants are not removed by POTWs and are discharged untreated to receiving streams.

5.3.1.1 Case Studies of POTWs Accepting Oil and Gas Extraction Wastewater

Clairton, PA, POTW

The Clairton POTW discharges to Peters Creek, which flows into the Monongahela River and treats influent wastewater using screening and grit removal, comminutors (i.e., grinders),[125] aeration basins, clarifiers, activated sludge, aerobic digestion, and chlorine disinfection. The Clairton POTW is permitted to treat a maximum of 6 MGD (126 DCN SGE00758).

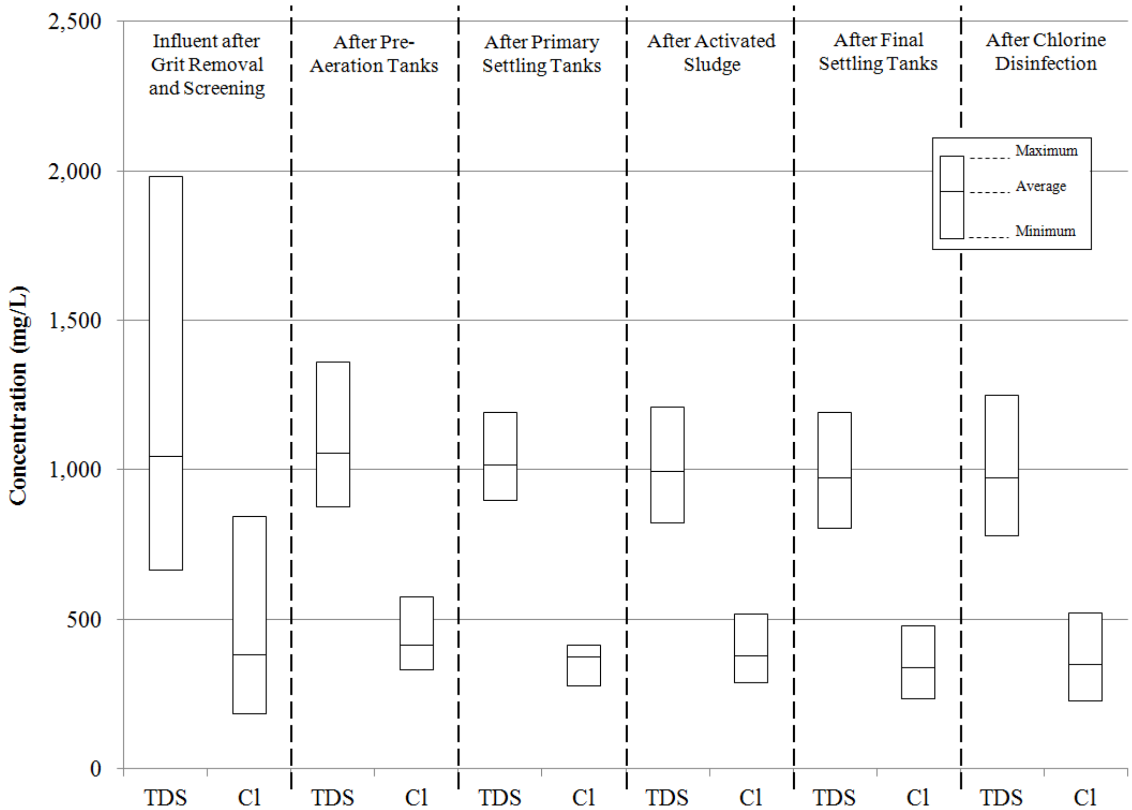
On October 23, 2008, PA DEP issued an AO to the Clairton POTW that established requirements for its acceptance of oil and gas wastewater. The AO required the Clairton POTW to restrict the volume of oil and gas wastewater it accepts to a flow rate no greater than 1 percent of the average daily flow. The AO also required the POTW to evaluate the potential impacts of oil and gas production wastewater on its treatment processes. The technical evaluation noted (126 DCN SGE00758):

> *The results of the samples taken and analyzed through the CMA [Clairton Municipal Authority] WWTP indicate that there is little to no reduction in concentration of TDS and chlorides through the plant processes. This is not unexpected as conventional sewage treatment facilities are not designed to remove dissolved constituents such as TDS and chlorides.*

Figure D-13 shows the results from the 24-hour composite sampling that occurred over five days in December 2008. According to PA DEP data (184 DCN SGE01182), in 2008, the Clairton POTW was accepting oil and gas wastewater amounting to an average of 0.05 percent

[125] A comminutor is a machine that reduces the particle size of wastewater solids using a cutting device.

of the POTW flow. Looking at the average measured concentrations, the results indicate little or no removal of TDS or chloride.



Source: 185 DCN SGE01183

Note: The data presented in this figure are based on five 24-hour composite samples taken from December 8, 2008, through December 12, 2008.

Figure D-13. Clairton POTW: Technical Evaluation of Treatment Processes' Ability to Remove Chlorides and TDS

Clairton POTW's consultant completed a pass through analysis in August 2009 (117 DCN SGE00748). Having collected two sets of influent concentration data from two different oil and gas wells, the consultant stated that the O&G Well No. 2 wastewater "was not characteristic of the oil and gas wastewater routinely accepted by the CMA POTW." Therefore, the EPA only included the wastewater characteristic data for O&G Well No. 1, as reported in the pass through analysis (see Table D-14). The pass through analysis assumes zero percent removal of TDS at the POTW and concludes that (117 DCN SGE00748):

> *The result of the mass balance analyses clearly indicates that TDS is untreated resulting in a "pass-through" to receiving waters…The hypothetical mass balance review…indicates that if higher concentrations of TDS are introduced into the POTW, the concentration and loading of TDS to the receiving waters increases proportionally.*

Table D-14. Clairton Influent Oil and Gas Extraction Wastewater Characteristics

Parameter	Wastewater Concentrations (mg/L)
	O&G Well No. 1
Barium	294
Calcium	3,060
Chloride	44,700
Magnesium	1,210
Sodium	84,500
TDS	76,000
TSS	1,600

Source: 117 DCN SGE00748

Abbreviation: mg/L—milligrams per liter

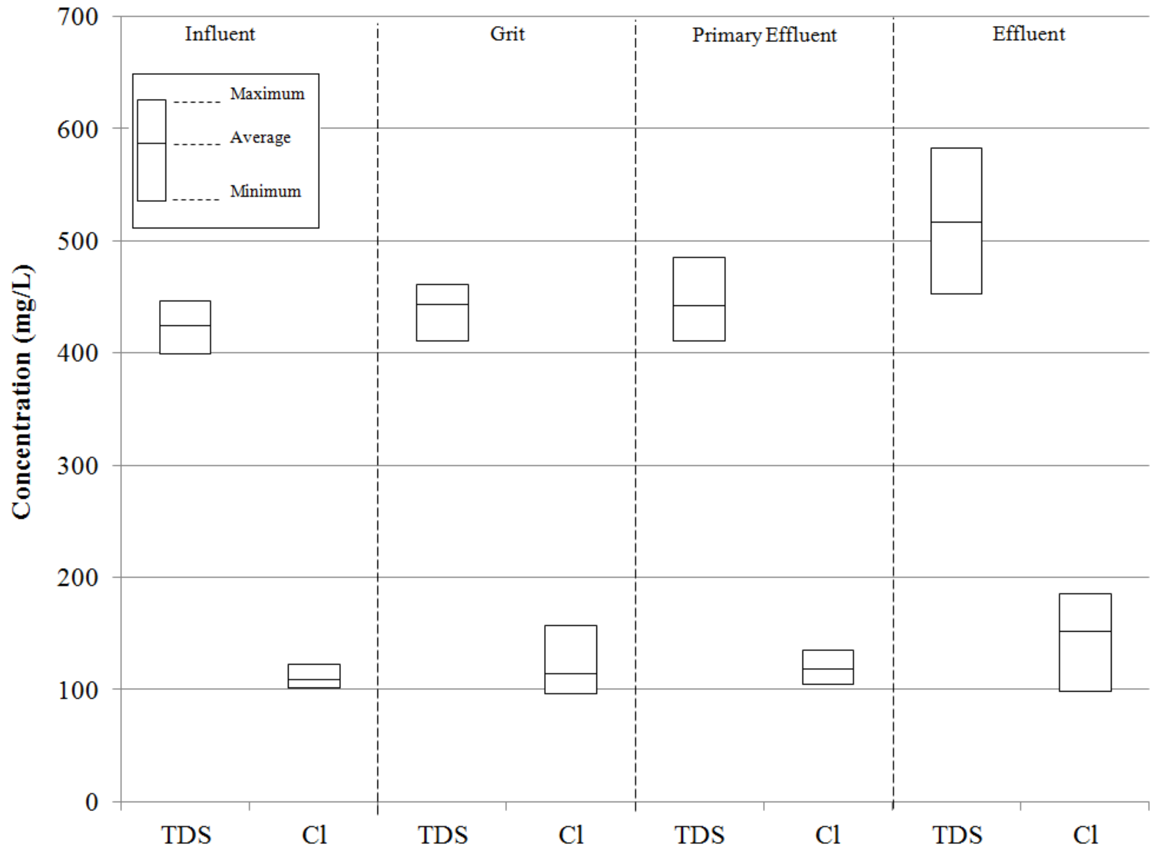
McKeesport, PA, POTW

The McKeesport POTW discharges to the Monongahela River and treats wastewater using screening and grit removal, aeration, clarification, activated sludge, aerobic digestion, and chlorine disinfection (115 DCN SGE00745). The McKeesport POTW began accepting COG wastewater in 2008 and UOG extraction wastewater in 2009. The POTW stopped accepting both COG and UOG extraction wastewater in December 2011 (184 DCN SGE01182).

On October 23, 2008, PA DEP issued an AO to the McKeesport POTW that allowed it to accept oil and gas wastewater in amounts no greater than 1 percent of its average daily flow, among other requirements. The AO also required the POTW to evaluate the potential impacts of oil and gas production wastewater on its treatment processes. The POTW conducted this technical evaluation in November 2008. According to PA DEP data (184 DCN SGE01182), in 2008, the McKeesport POTW was accepting only COG wastewater. The evaluation (125 DCN SGE00757) noted:

> *The results of the samples taken and analyzed through the MACM [Municipal Authority of the City of McKeesport] WWTP indicate that there is no reduction in concentration of TDS and chlorides through the plant processes. This is not unexpected as conventional sewage treatment facilities are not designed to remove dissolved constituents such as TDS and chlorides.*

Figure D-14 shows the results from 24-hour composite sampling over seven days in November 2008. The results indicate no removal of TDS or chloride. According to the manifests included in the technical evaluation (125 DCN SGE00757), McKeesport treated trucked wastewater from conventional wells during the seven-day sampling period. These wastewater sources are summarized in Table D-15, below.



Source: 185 DCN SGE01183

Note: The data presented in this figure are based on seven 24-hour composite samples taken from November 1, 2008, through November 7, 2008.

Figure D-14. McKeesport POTW: Technical Evaluation of Treatment Processes' Ability to Remove Chlorides and TDS

Table D-15. Trucked COG Extraction Wastewater Treated at McKeesport POTW from November 1 Through 7, 2008

Date	Waste Type[a]	Volume (gallons)	Chlorides (mg/L)	Chlorides (lbs)
November 3, 2008	Brine	3,780	155,000	4,886
November 4, 2008	Flowback	3,780	145,000	4,571
November 6, 2008	Flowback	3,780	155,000	4,886
November 6, 2008	Frac	4,620	20,000	771
November 7, 2008	Frac	4,620	20,000	771

Source: 115 DCN SGE00745

a—According to data from the technical evaluation, some waste streams were referred to as "frac" and "flowback," indicating that the conventional wells were hydraulically fractured.

Abbreviations: mg/L—milligrams per liter; lbs—pounds

McKeesport POTW's consultant completed a headworks loading analysis in March 2011 (115 DCN SGE00745). As part of the analysis, the consultant completed monthly sampling of the influent and effluent of the POTW from February 2010 through January 2011 and determined the average removal percentages based on the sampling results. During the time of sampling, a combination of UOG and COG wastewater contributed no more than 1 percent of the average daily flow and municipal wastewater made up the remaining influent to the McKeesport POTW. Table D-16 presents the percent removals calculated during this analysis and shows that the POTW removed less than 7 percent of the influent TDS and less than 5 percent of the influent chloride. Effluent TDS concentrations ranged from 600 to 1,500 mg/L while the facility accepted both UOG and COG wastewater during the sampling period (115 DCN SGE00745).

Table D-16. McKeesport POTW Removal Rates Calculated for Local Limits Analysis

Parameter	Removal Rates (%)
Sulfate	3.94
Chloride	4.44
TDS	6.43
Magnesium	6.62
Strontium	18.47
Bromide	26.99
Barium	71.64

Source: 115 DCN SGE00745

Note: The data presented in this table are based on timed composite samples obtained once a month for 12 months from February 2010 through January 2011.

A 2013 study by Ferrar et al. (56 DCN SGE00525) analyzed constituents in effluent wastewater discharged from two POTWs in Pennsylvania, first while the POTWs accepted industrial discharges containing UOG extraction wastewater pollutants (either from a CWT facility or from a UOG operator) and again after the POTWs stopped accepting those industrial discharges. The study included effluent sampling at the McKeesport POTW in 2010 while the POTW was accepting UOG extraction wastewater. The study specifically reported that the facility was accepting UOG extraction wastewater during the sampling but did not mention COG wastewater. Based on PA DEP data, the EPA is aware that the POTW accepted both UOG and COG wastewater in 2010; however, details were not available concerning whether COG wastewater was accepted on the specific days of the sampling. The UOG extraction wastewater, received from operators via tanker trucks, was stored in holding tanks, then mixed with municipal wastewater in the primary clarifier. The study sampled POTW effluent in October 2010, when the POTW was accepting UOG extraction wastewater and again in December 2011, after the POTW had stopped accepting COG and UOG extraction wastewater.[126] The study also collected one sample in November 2010 of UOG extraction wastewater before it was mixed with the municipal influent[127] (see Table D-17).

[126] The PA DEP waste reports data (183 DCN SGE01182) show that the McKeesport POTW stopped accepted COG and UOG wastewater after 2011.

[127] Note that the one-time sample of influent UOG extraction wastewater was not collected at the same time as either of the effluent sampling events.

On October 19, 2010, when Ferrar et al. collected their POTW effluent sample, they reported that the McKeesport POTW treated 13,020 gallons of UOG extraction wastewater, and the average daily flow of the POTW was 9.6 MGD, indicating that the UOG extraction wastewater accounted for 0.14 percent of the total influent.[128] The remaining influent wastewater consisted of municipal wastewater typically treated by the POTW (see Table D-8 for typical constituent concentrations in municipal wastewater).

Table D-18 shows the range and mean effluent concentrations, as measured by Ferrar et al., at the McKeesport POTW while they were accepting UOG extraction wastewater and after they had stopped accepting UOG extraction wastewater. As noted above, the study reported that the McKeesport POTW accepted an average daily flow of 9.6 MGD during the October 2010 sampling event. However, they did not report the average daily flow during the December 2011 sampling event. Although they reported that the facility was accepting UOG extraction wastewater on the first effluent sampling date (October 19, 2010), sampling data for that influent UOG extraction wastewater (like the data presented in Table D-17) were not available. Therefore, it is not possible to know whether the data presented in Table D-17 are representative of the UOG extraction wastewater influent on the date of the effluent sampling presented in Table D-18. As discussed in Section C.3, UOG extraction wastewater characteristics vary over time and from well to well.

Table D-17. Constituent Concentrations in UOG Extraction Wastewater Treated at the McKeesport POTW Before Mixing with Other Influent Wastewater

Analyte[a]	Concentrations in UOG Extraction Wastewater Treated at McKeesport POTW (mg/L)[b]
Barium	106
Calcium	1,690
Magnesium	203
Strontium	324
Bromide	151
Chloride	17,000
Sulfate	53.1
TDS	24,200

Source: 56 DCN SGE00525

a—Organic analytes were not detected in samples.

b—Sample date: 11/10/2010. Reported values are based on only one sample taken for each analyte. Samples were collected from a UOG extraction wastewater holding tank before mixture and dilution with influent municipal wastewater.

Abbreviation: mg/L—milligrams per liter

[128] Ferrar et al. (56 DCN SGE00525) noted that since the total volume of UOG wastewater was released at one time, the actual dilution might have been 0.81 percent UOG wastewater in the effluent when it was discharged (8–12 hours later).

Table D-18. McKeesport POTW Effluent Concentrations With and Without UOG Extraction Wastewater

Analyte[a]	Effluent Concentrations Measured While POTW Was Accepting UOG Extraction Wastewater (mg/L)[b]		Effluent Concentrations Measured After POTW Had Stopped Accepting UOG Extraction Wastewater (mg/L)[c]	
	Mean	Range	Mean	Range
Barium	0.55	0.21–0.81	0.036	0.034–0.039
Calcium[d]	50.3	42.4–55.9	58.8	56.6–63.4
Magnesium[d]	10.3	8.96–11.2	13.61	13.2–14.4
Strontium	1.63	0.924–2.26	0.228	0.219–0.237
Bromide	0.600	0.231–0.944	0.119	0.08–0.43
Chloride	228.7	150–377	136.8	133–142
Sulfate	98.1	81.2–139	65.9	64.4–67.2
TDS	562.2	466–648	494.2	464–524

Source: 56 DCN SGE00525

a—Organic analytes were not detected in samples.

b—Sample date: 10/19/2010. Reported values are based on the mean, minimum, and maximum of 24 samples taken for each analyte taken over 24 hours. Effluent samples were collected just before mixing with surface water.

c—Sample date: 12/1/2011. Reported values are based on the mean, minimum, and maximum of nine samples taken for each analyte taken over 24 hours. Effluent samples were collected just before mixing with surface water.

d—The effluent concentrations of calcium and magnesium increased after the POTW had stopped accepting UOG extraction wastewater. Ferrar et al. (56 DCN SGE00525) suggest that the increased concentrations of these ions may be from high influent calcium and magnesium concentrations in other wastewater treated by the McKeesport POTW (e.g., COG wastewater).

Abbreviation: mg/L—milligrams per liter

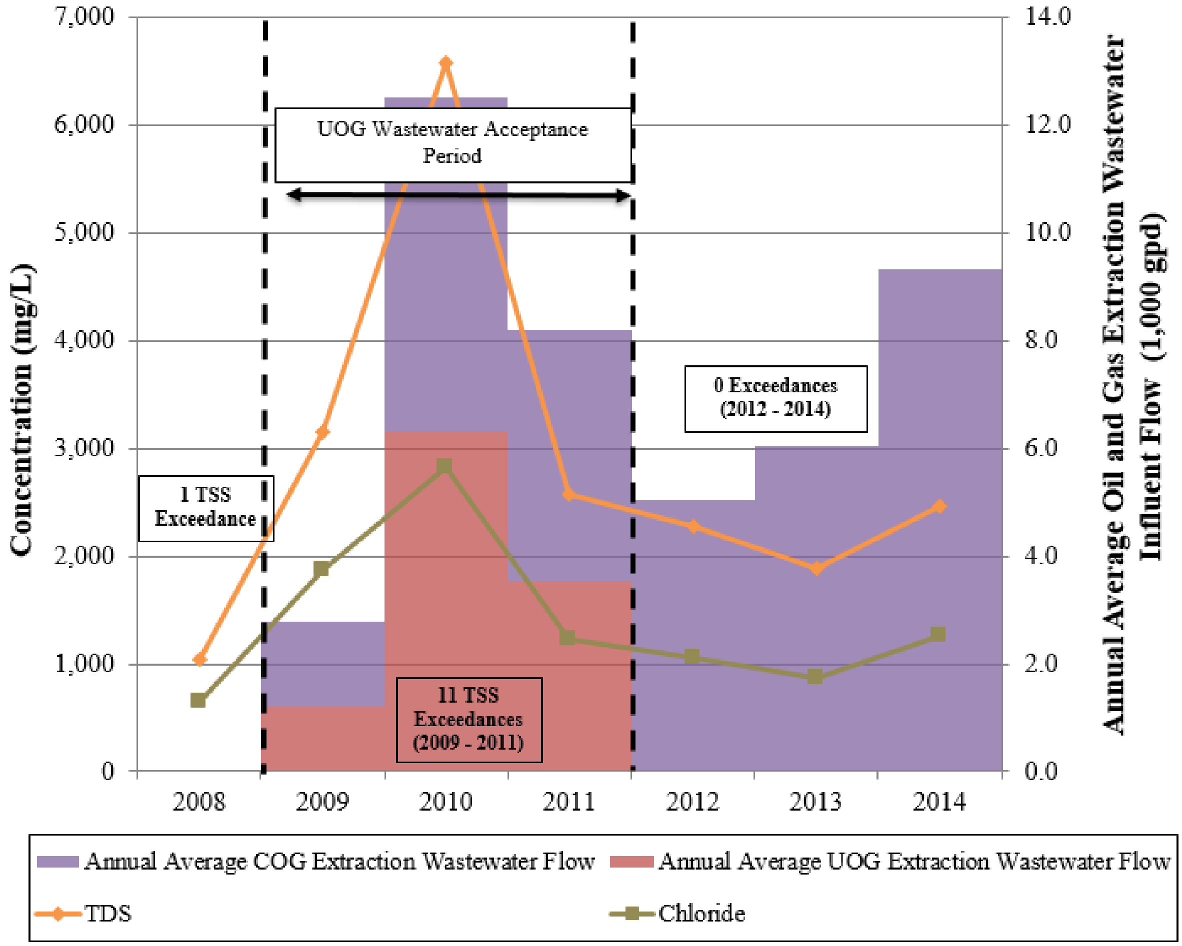
Ridgway, PA, POTW

Ridgway Borough operates a POTW that discharges to the Clarion River and has a maximum monthly average design rate of 2.2 MGD. The Ridgway POTW uses screening and grit removal, an equalization tank, aeration tanks, clarifiers, a chlorination feed system, a chlorine contact tank, aerobic digesters, and a belt filter press. This POTW began accepting both COG and UOG extraction wastewater in 2009. It stopped accepting UOG extraction wastewater in 2011 but continued accepting COG wastewater, and still was as of the end of 2014.[129] The total oil and gas wastewater volume accounted for less than 2 percent of the total POTW influent volume during 2009 through 2011 on average (184 DCN SGE01182). The POTW's total annual average daily flow rate ranges between 0.8 and 1.5 MGD, based on 2008 to 2014 DMR data (83 DCN SGE00608).

The EPA created Figure D-15 using the sampling data submitted in the EPA's DMR Loading Tool (83 DCN SGE00608) and PA DEP waste reports data (184 DCN SGE01182).

[129] Ridgway's October 2011 NPDES permit (123 DCN SGE00755) notes that "no more than 20,000 gallons/day of natural gas wastewater from shallow well operations shall be treated at the facility. The acceptance of wastewater generated from shale oil extraction activities is prohibited."

Each effluent concentration data point represents the average of 12 monthly average data points as calculated and reported by the DMR Loading Tool. PA DEP waste reports provided the total volume of UOG and COG wastewater delivered to the POTW each year. The EPA divided the annual volume by 365 to calculate the annual average daily flow. As shown in Figure D-15, in 2010, the Ridgway POTW experienced effluent TDS concentrations greater than 6,000 mg/L on average and effluent chloride concentrations greater than 2,500 mg/L on average while it was accepting the greatest volume of oil and gas wastewater, including that from UOG operators. As a point of comparison, in 2008, before accepting any oil and gas wastewater, the POTW experienced effluent TDS and chloride concentrations around 1,000 mg/L.



Source: 185 DCN SGE01183

Note: The annual average extraction wastewater flows for COG and UOG are presented as stacked bars in order to represent the total annual average oil and gas extraction wastewater influent flow.

Figure D-15. Ridgway POTW: Annual Average Daily Effluent Concentrations and POTW Flows

To comply with the requirements of the Ridgway Borough Pretreatment Program, the Ridgway POTW completed a local limits analysis in January 2014 that included paired POTW influent and effluent data. The samples were collected for 10 consecutive days in October and November 2013 after the POTW stopped accepting UOG extraction wastewater but was still accepting COG wastewater. Of particular interest is the fact that Ridgway POTW's contractor estimated zero percent removals for TDS, chloride, and sulfate. All three of these constituents are found in UOG extraction wastewater (124 DCN SGE00756).

Charleroi, PA, POTW

The Charleroi POTW uses an equalization tank, screening and grit removal, sedimentation, activated sludge, and chlorine disinfection. It began accepting both COG and UOG extraction wastewater in January 2005 and stopped accepting it in 2008 (120 DCN SGE00751; 184 DCN SGE01182). The total oil and gas wastewater accounted for up to 32 percent of the total POTW influent volume during 2008, on average. UOG extraction wastewater accounted for 10 percent of total POTW influent during 2008 on average (184 DCN SGE01182). The POTW's average annual flow rate ranges between 1.4 and 1.9 MGD based on 2008 through 2014 DMR data (83 DCN SGE00608). The EPA identified case studies showing potential for both pass-through (Section D.5.3.1.1) and inhibition/disruption (Section D.5.3.2.1) at the Charleroi POTW.

In 2008, PA DEP issued an AO requiring the Charleroi POTW to evaluate how accepting oil and gas production wastewater affects its treatment processes, among other things (120 DCN SGE00751). Charleroi's technical evaluation noted that the POTW typically rejects influent oil and gas wastewater with TDS concentrations greater than 30,000 mg/L or chloride concentrations greater than 15,000 mg/L. As part of the technical evaluation, Charleroi sampled influent wastewater (including UOG extraction wastewater) and effluent wastewater over a 24-hour period. The total oil and gas wastewater treated during this period was 150,650 gallons (3,587 barrels) and the total wastewater treated was 1,559,000 gallons (37,120 barrels). Therefore, the oil and gas wastewater accounted for 9.7 percent of the total influent to the plant during the sampling period (120 DCN SGE00751). Table D-19 shows the results of the sampling and the calculated removal rates. The data show that TDS is not removed by the Charleroi POTW treatment processes.

Table D-19. Charleroi POTW Paired Influent/Effluent Data and Calculated Removal Rates

Parameter	Influent Concentration (mg/L)	Effluent Concentration (mg/L)	Removal Rate (%)
Aluminum	2.34	0.656	72
Ammonia, as N	14.4	4.52	68.6
Barium	0.177	0.171	3.4
BOD_5	84	1.00	98.8
Hardness, as $CaCO_3$	265	260	1.9
Oil and grease	29	5	82.8
Phosphorus	0.49	0.3	38.8
TDS	1,020	1,030	0
TSS	116	21	81.9

Source: 120 DCN SGE00751

Abbreviation: mg/L—milligrams per liter

Clarksburg, WV, POTW

The Clarksburg POTW has a maximum capacity of 8 MGD and uses screening, a cyclone hydrogritter, clarifiers, aeration basins, and chlorine disinfection. The Clarksburg POTW started accepting "gas well wastewater" (i.e., brine) in July 2008 on a trial basis and continued through at least March 2009. Three frac tanks were set up on the treatment plant site and the brine (i.e., oil and gas extraction wastewater) was metered into the POTW's pump station wet well at a constant continuous flow rate. Total POTW flow was at least 5 MGD. The amount of brine metered to the POTW was gradually increased to evaluate the effect it would have on the POTW performance. Clarksburg provided the following non-comprehensive data about the quantity and chloride concentration of the brine metered to the POTW:

- July 2008, week 1: 10,000 gpd @ 50,000 mg/L chloride
- July 2008, week 2: 15,000 gpd @ 50,000 mg/L chloride
- July 2008, week 3: 17, 280 gpd @ 50,000 mg/L chloride
- July 2008, week 4: 25,000 gpd @ 50,000 mg/L chloride
- November 2008: 50,000 gpd @ 18,500 mg/L chloride

During the initial trial period in July 2008, the Clarksburg POTW superintendent noted that effluent chloride concentrations "exceeded the desired quantity of 235 mg/L a couple of times due to dry weather flows being below 5 MGD." He also noted that they would need to adjust the volume of brine in the influent to the POTW during low flow conditions, and that "Chlorides are not removed at the facility, merely diluted to acceptable levels." This statement further supports the concept that TDS, of which the primary contributing ions in UOG extraction wastewater are chloride and sodium, passes through POTWs untreated.

After the trial period, Clarksburg contacted the WV DEP about modifying its NPDES permit to allow acceptance of gas wastewater. The DEP told the Clarksburg POTW that it could continue accepting the gas wastewater as long as it was not violating its existing effluent limitations (118 DCN SGE00749; 64 DCN SGE00552). In July 2009, WV DEP sent a letter to the Clarksburg Sanitary Board with a list of requirements that would be imposed if it decided to accept oil-and-gas-related wastewater (166 DCN SGE01113). The letter also stated that

> *…WVDEP discourages POTWs from accepting wastewater from oil and gas operations such as…Marcellus shale wastewaters because these wastewaters essentially pass through sewage treatment plants and can cause inhibition and interference with treatment plant operations. The wastewaters from these types of operations contain high levels of chloride, dissolved solid, sulfate, and other pollutants. POTWs provide little to no treatment of these pollutants and could potentially lead to water quality issues in the receiving stream.*

In April 2013, WV DEP verified that no POTWs in WV were accepting UOG extraction wastewater (128 DCN SGE00762; 129 DCN SGE00766).

5.3.1.2 Case Studies About POTWs Accepting Wastewater from Other Industrial Sources Containing UOG Pollutants

Franklin Township, PA, POTW

The Franklin Township POTW discharges to the lower fork of Ten Mile Creek, a tributary to the Monongahela River, and treats influent wastewater using aeration, rotating biological contactors, clarification, filtration, and chlorination (116 DCN SGE00746). The Franklin Township POTW accepted industrial wastewater from the Tri-County Wastewater CWT facility until March 2011. During that time, the Tri-County CWT facility was accepting oil and gas extraction wastewater. The CWT facility targeted removal of TSS and oil and grease by filtration, flocculation, and skimming, but certain pollutants in the UOG extraction wastewater such as TDS remained in the treated effluent from the CWT facility. The industrial wastewater received from Tri-County Wastewater accounted for approximately 5.4 percent of the Franklin POTW's 0.982 MGD effluent by volume in November 2010 (56 DCN SGE00525).

On December 4, 2008, the Franklin POTW entered into a Consent Order and Agreement with PA DEP[130] regarding effluent discharges containing elevated levels of TDS. Paragraph G of the order notes that

> *Neither the STP [Franklin POTW] nor the Pretreatment Facility [Tri-County CWT Facility] currently has treatment facilities for the removal of Total Dissolved Solids.*

Ferrar et al. (56 DCN SGE00525) analyzed constituents in effluent wastewater discharged from the Franklin Township POTW during the period before and after it accepted industrial wastewater from the Tri-County Wastewater CWT facility. Table D-20 shows the mean and range of effluent concentrations at the Franklin Township POTW during the period when it accepted industrial wastewater from the CWT facility and after it stopped. Ferrar et al. analyzed pollutants typically found in UOG extraction wastewater; they report a mean effluent TDS concentration of 3,860 mg/L from the Franklin Township POTW while it was accepting wastewater from the Tri-County CWT facility and a mean effluent TDS concentration of 398 mg/L from the POTW after it stopped. The mean effluent concentrations for all pollutants presented in Table D-20 were higher when the POTW was accepting the industrial discharge from the Tri-County CWT facility, suggesting that pollutants were discharged from the POTW without treatment. Based on the treatment technologies currently in place at the Franklin Township POTW, one would expect little to no treatment of the common constituents in UOG extraction wastewater. Ferrar et al. concluded:

> *This research provides preliminary evidence that these and similar WWTPs may not be able to provide sufficient treatment for this wastewater stream, and more thorough monitoring is recommended.*

[130] PA DEP had issued an AO to the Franklin POTW in October 2008, but the Consent Order and Agreement superseded that order.

Table D-20. Franklin Township POTW Effluent Concentrations With and Without Industrial Discharges from the Tri-County CWT Facility

Analyte[a]	Effluent Concentrations from Franklin Township POTW Measured While POTW Was Accepting Wastewater from CWT Facility (mg/L)[b]		Effluent Concentrations from Franklin Township POTW Measured After POTW Had Stopped Accepting Wastewater from CWT Facility (mg/L)[c]	
	Mean	Range	Mean	Range
Barium	5.99	4.27–7.72	0.141	0.124–0.156
Calcium	231	207–268	40.6	38.8–43.5
Magnesium	32.6	29.1–36.6	8.63	8.04–9.11
Manganese	0.228	0.204–0.249	0.112	0.102–0.144
Strontium	48.3	41.8–56.1	0.236	0.226–0.249
Bromide	20.9	14.3–28.0	<0.016	<0.016
Chloride	2,210	1,940–2,490	61.9	57.5–64.6
Sulfate	137	117–267	65.6	60.0–75.0
TDS	3,860	3,350–4,440	398	376–450

Source: 56 DCN SGE00525

a—Organic analytes were not detected in samples.

b—Sample date: 11/10/2010. Reported values are based on the mean, minimum, and maximum of 24 samples taken for each analyte taken over 24 hours. Effluent samples were collected just before mixing with surface water.

c—Sample date: 11/7/2011. Reported values are based on the mean, minimum, and maximum of nine samples taken for each analyte taken over 24 hours. Effluent samples were collected just before mixing with surface water.

Abbreviation: mg/L—milligrams per liter

Wheeling, WV, POTW

The Wheeling POTW has primary and secondary treatment operations, including primary clarification, solids and floatable materials removal, and disinfection (155 DCN SGE00999). The Wheeling POTW accepted industrial wastewater from the Liquid Asset Disposal (LAD) CWT facility through August 2009[131] and wastewater directly from UOG operators in 2008.[132] The LAD CWT facility accepted a variety of wastewater from the following sources: sewage facilities, storm water from an international airport, and gas well development and production wastewater, among others. The LAD CWT facility is a SIU and was authorized to discharge into the Wheeling, WV, POTW (SIU Permit No. 0014) (48 DCN SGE00485). The LAD CWT facility uses ultra-filtration, ozonation, and reverse osmosis to target the removal of chlorides prior to discharges to the Wheeling POTW (152 DCN SGE00996).

The EPA analyzed sampling data submitted in its DMR Loading Tool (83 DCN SGE00608) and PA DEP waste reports data (184 DCN SGE01182) and found that the effluent concentrations of chloride experienced by the Wheeling POTW in 2008 were higher when it was

[131] EPA did not identify the date on which the Wheeling POTW began accepting wastewater from the LAD CWT facility. However, the LAD CWT SIU Permit No. 0014 was issued in August 2004 (156 DCN SGE01000).

[132] The Wheeling POTW may have accepted UOG extraction wastewater directly from operators in years other than 2008, but EPA only identified acceptance directly from operators in 2008 (202 DCN SGE01245).

accepting UOG extraction wastewater and industrial discharges from the LAD CWT facility than after it stopped. In 2008, the POTW accepted an average of 5,400 gallons/day of UOG extraction wastewater and had an average effluent chloride concentration of 650 mg/L. Comparatively, in 2011, the POTW did not accept any UOG extraction wastewater and had an average effluent chloride concentration of 130 mg/L.[133] Data from an August 2009 letter from WV DEP to the City of Wheeling states (167 DCN SGE01114)

> *The agency has determined that the following pollutants are of concern associated with oil and gas related wastewaters and may have a potential for inhibition, interference, and pass through: total dissolved solids (TDS), sulfate, chloride…zinc…copper…barium …total suspended solids, iron…benzene…strontium…gross alpha radiation, gross beta radiation, and radium 226 + radium 228. In addition to the potential for inhibition, interference, and pass through, these pollutants may also have an impact on sludge disposal requirements.*

Additional data from a 2011 Consent Order from WV DEP to the Wheeling POTW indicates that the LAD CWT facility exceeded its 9,000-pound daily chloride limitation, in violation of its SIU permit, 50 times between January 8, 2009, and February 4, 2010 (48 DCN SGE00485). Therefore, the UOG extraction wastewater and the industrial wastewater accepted by the Wheeling POTW from the LAD CWT facility likely contributed to the elevated effluent chloride concentrations.

Warren, OH, POTW

The city of Warren operates a 16 MGD POTW that discharges to the Mahoning River. The POTW employs screening and grit removal, primary settling, activated sludge aeration, final clarification, chlorination, dechlorination, and post-aeration treatment processes. Solid residuals are thickened by dissolved air flotation, dewatered using a belt filter press, stabilized with lime, and disposed of by land application or by distribution and marketing of usable end products.

In May 2009, the Warren POTW and its customer, the Patriot Water Treatment CWT facility,[134] began discussions with the Ohio EPA about accepting UOG produced water. Patriot planned to accept UOG produced water from shale gas operations, treat the wastewater to remove heavy metals and other constituents, and discharge the treated industrial wastewater to the Warren POTW. In preparation for acceptance of treated industrial wastewater from the CWT facility that would contain pollutants found in UOG produced water, the Warren POTW undertook a pilot study to show that accepting wastewater containing pollutants found in UOG produced water would not cause any problems with Mahoning River water quality. Patriot's treatment of UOG produced water includes reduction in heavy metal concentration, but not TDS

[133] The data about quantities of UOG extraction wastewater accepted by the Wheeling POTW are from the PA DEP waste report data and are reflective of volumes of UOG extraction wastewater accepted from UOG operators in Pennsylvania. The Wheeling POTW may be accepting additional UOG extraction wastewater from UOG operators in West Virginia or other nearby states; these volumes of wastewater are not captured in this discussion.

[134] The Patriot CWT facility uses primary treatment processes (e.g., settlement tanks, clarifier tanks) and chemical precipitation to target the removal of suspended solids and metals prior to discharge.

or chloride. The Ohio EPA worked with Patriot and the Warren POTW to develop a pilot treatment study that evaluated the effects of pretreated UOG produced water on the POTW. The study also evaluated the receiving stream (Mahoning River) water quality, upstream and downstream of the POTW discharge **(**55 DCN SGE00522).

The pilot study began on February 9, 2010, and ran for eight weeks. It focused on collecting data from the Warren POTW and did not include sampling at the Patriot CWT facility. The summarized TDS and chloride data from the study are presented in Table D-21. The Warren POTW reported typical flow rates of 13.38 MGD and accepted the following volumes of wastewater from the Patriot CWT facility over the eight weeks (percentage of total POTW flow accounted for by Patriot CWT facility's industrial wastewater is noted parenthetically)[135] (88 DCN SGE00616):

- Week 1: 5 days @ 20,000 gallons (0.15 percent)
- Week 2: 5 days @ 40,000 gallons (0.30 percent)
- Week 3: 5 days @ 60,000 gallons (0.45 percent)
- Week 4: 5 days @ 80,000 gallons (0.60 percent)
- Week 5: 5 days @ 100,000 gallons (0.75 percent)
- Week 6: 5 days @ 100,000 gallons (0.75 percent)
- Week 7: 5 days @ 100,000 gallons (0.75 percent)
- Week 8: 5 days @ 100,000 gallons (0.75 percent)

Table D-21 shows the average paired influent and effluent TDS concentrations measured prior to start up and during the pilot study. Baseline samples were collected when the POTW was not accepting wastewater from the Patriot CWT facility. The pilot study description states that the influent samples (baseline and pilot study) include only municipal influent and do not include any wastewater from the Patriot CWT facility.[136] The data show that TDS and chloride concentrations increased in the influent and effluent samples over time both during the baseline sampling and after the Warren POTW accepted wastewater from the Patriot CWT facility. The effluent concentrations of TDS and chloride increased at higher percentages over the influent concentration during the pilot study, when the POTW was accepting wastewater from the Patriot CWT facility (88 DCN SGE00616), suggesting that TDS and chloride were not removed by the POTW.

[135] All flows were introduced into the Warren POTW over an eight-hour period.

[136] The Warren POTW pilot study description states that "Raw [influent] does not have any Patriot influence or plant return flows." The report author also noted increases in the TDS and chloride concentrations over the period of the study and suggested that "these increases are most likely due to seasonal fluctuations within the collection system as a result of user operations or seasonal runoff from spring rains" (88 DCN SGE00616).

Table D-21. TDS Concentrations in Baseline and Pilot Study Wastewater Samples at Warren POTW

Sample Type	Influent Concentration (mg/L)	Effluent Concentration (mg/L)	Percent Increase (%)
Baseline Samples			
TDS	584	599	2.6
Chloride	143	157	9.8
Eight-Week Pilot Study Samples			
TDS	679	885	30.3
Chloride	239	348	45.6

Source: 88 DCN SGE00616

Abbreviation: mg/L—milligrams per liter

From September 12 through 16, 2011, EPA Region 5 inspected and collected wastewater samples at the Warren POTW and noted that (88 DCN SGE00616)

the POTW had not experienced any of the following conditions since accepting the brine waste water from the Patriot CWT facility:

- *Diminished or inhibited performance of the biological treatment processes*
- *Adverse impacts to the downstream water quality*
- *Adverse impacts to the quality of the facility's biosolids*

The compliance inspection indicated that the Warren POTW was in compliance with all of its NPDES permit limitations. Table D-22 shows the results of EPA Region 5's wastewater sample analyses conducted during their September 2011 inspection. The compliance inspection data show minimal to no TDS removals by the POTW and minimal chloride removals.

Table D-22. EPA Region 5 Compliance Inspection Sampling Data

Pollutant	Warren POTW Influent Concentration (mg/L)[a]		Warren POTW Effluent Concentration (mg/L)[a]	
	Average	Range	Average	Range
TDS	726	686–748	726	648–778
Chloride	361	345–374	213	191–252
Sulfate	250	243–256	77	68–84
TSS	95.0	67.0–112	<4	NA[b]
BOD_5	33.3	27.7–39.0	<2	NA[b]
Bromide	5.25	5.01–5.43	1.57	1.40–1.89
Fluoride	3.62	3.36–4.13	1.83	1.40–2.14

Source: 88 DCN SGE00616

a—Samples were taken on four days (9/12/2013, 9/13/2013, 9/14/2013, and 9/15/2013).

b—All four samples were reported as below the detection limit.

Abbreviation: mg/L—milligrams per liter

As of March 2015, the Warren POTW was still accepting wastewater from the Patriot CWT facility (139 DCN SGE00786). Its NPDES permit allows it to accept a maximum of 100,000 gallons of "wastewater from a regulated CWT facility that is tributary to the City's collection system" per day (0.67 percent of its maximum total daily flow) at a maximum TDS concentration of 50,000 mg/L (29 DCN SGE00295).

Brockway, PA, POTW

The Brockway POTW treats industrial and domestic wastewater using screens, aerated basins, oxidation ditches, clarifiers, aerobic sludge digestion, UV disinfection, and post-aeration. Its NPDES permit (issued on July 3, 2012, and expiring on July 31, 2017) allows it to accept up to 14,000 gpd of "natural gas related wastewater," none of which may be from "Shale Gas Extraction related activities" (143 DCN SGE00931). As of June 2014, the Brockway POTW was still accepting natural-gas-related wastewater treated by the Dannic Energy Corporation CWT facility. The Brockway POTW is sampling and reporting the required parameters on PA DEP's electronic DMR system (eDMR) (143 DCN SGE00931). The permit includes limits for pH, carbonaceous BOD_5, TSS, fecal coliform, ammonia-nitrogen, TDS, and osmotic pressure. The permit also included reporting requirements for flow, barium, strontium, uranium, chloride, bromide, gross alpha, and radium-226/228.

The Brockway POTW saw increases in the effluent concentrations of TDS, which were below 400 mg/L before the acceptance of COG wastewater and increased to between 2,500 and 3,000 mg/L during the acceptance of COG wastewater. Typical COG wastewater accepted by the Brockway POTW may have TDS concentrations over 200,000 mg/L (121 DCN SGE00753).

5.3.2 UOG Extraction Wastewater Constituents and POTW Inhibition and Disruption

In addition to the discharge of pollutants not treated by a POTW, the presence of certain pollutants in industrial wastewater discharges can have the following effects on the receiving POTW:

- Inhibition or disruption of the POTW's treatment processes and/or operations
- Inhibition or disruption of the POTW's sludge processes, including sludge disposal processes
- Harm to POTW workers

The EPA investigated how pollutants in industrial wastewater discharges, which may contain constituents found in UOG extraction wastewater, might inhibit the performance of typical POTW treatment processes. Table D-23 presents inhibition threshold levels for activated sludge and nitrification, two treatment processes commonly used at POTWs, for select UOG constituents identified in Section C.3.[137] The EPA recognizes that POTW treatment processes will not be exposed to UOG constituents at the concentrations they are found in UOG produced water (i.e., flowback, long-term produced water).

[137] EPA also presents specific inhibition thresholds for anaerobic digestion and trickling filters, but the UOG constituent concentrations are not as likely to exceed the thresholds, so they were not included in Table D-23.

As discussed in Section A.2.2, POTWs establish local limits to control pollutant discharges that present a reasonable potential for pass through or interference with POTW operations. The inhibition levels presented in the EPA's 2004 *Local Limits Development Guidance* (80 DCN SGE00602) represent concentrations that would reduce the effectiveness or otherwise interfere with the treatment operations for treatment commonly used at POTWs. Inhibition of activated sludge processes at a POTW could impair BOD_5 removal and TSS removal (particularly if sludge settling is affected). Inhibition of nitrification, a process that some POTWs use to convert ammonia to nitrate/nitrite (which may be part of the activated sludge process or a separate biological treatment stage), may impair the POTW's ability to remove ammonia and nutrients in the wastewater.

Table D-23. Inhibition Threshold Levels for Various Treatment Processes

Pollutant	Reported Range of Activated Sludge Inhibition Threshold Levels (mg/L)[a]	Reported Range of Nitrification Inhibition Threshold Levels (mg/L)[a]
Ammonia	480	NA
Arsenic	0.1	1.5
Benzene	100–500, 125–500	NA
Cadmium	1–10	5.2
Chloride	NA	180
Chloroform	NA	10
Chromium, total	1–100	0.25–1.9, 1–100 (trickling filter)
Copper	1	0.05–0.48
Ethylbenzene	200	NA
Lead	1–5, 10–100	0.5
Mercury	0.1–1, 2.5 as Hg(II)	NA
Naphthalene	500, 500, 500	NA
Nickel	1–2.5, 5	0.25–0.5, 5
Phenol	50–200, 200, 200	4, 4–10
Sulfide	25–30	NA
Toluene	200	NA
Zinc	0.3–5, 5–10	0.08–0.5

Source: 80 DCN SGE00602

a—Where multiple values are listed (divided by commas), the data were reported individually in 80 DCN SGE00602 by different sources.

Abbreviations: mg/L—milligrams per liter; NA—not available

Because all POTWs are required to control TSS and BOD_5, they are designed for the effective removal of these two parameters. Elevated concentrations of TSS and BOD_5 in POTW discharges suggest inhibition/disruption of treatment processes. As some of the studies described in the following sections indicate, POTWs have linked TSS and/or BOD_5 permit limit exceedances with the acceptance of oil and gas extraction wastewater.

The following subsections present case studies that discuss inhibition/disruption at POTWs that accepted wastewater containing pollutants found in UOG extraction wastewater.

The purpose of these subsections is to identify instances of inhibition/disruption, or potential inhibition/disruption, at POTWs associated with the acceptance of UOG extraction wastewater pollutants.

5.3.2.1 Case Studies About POTWs Accepting Wastewater from Oil and Gas Extraction Facilities

Johnstown, PA, POTW

The Johnstown POTW uses screening, grit removal, high-purity oxygen activated sludge aeration with integrated fixed-film activated sludge, final clarification, and chlorination (142 DCN SGE00930). The Johnstown POTW accepted both UOG and COG wastewater before 2008 and stopped accepting both in 2011 (184 DCN SGE01182). The total oil and gas wastewater accounted for less than 3 percent of the total POTW influent volume during the acceptance period on average. The POTW's annual average daily flow rate ranges between 7.9 and 17.1 MGD based on 2008 through 2014 DMR data (83 DCN SGE00608).

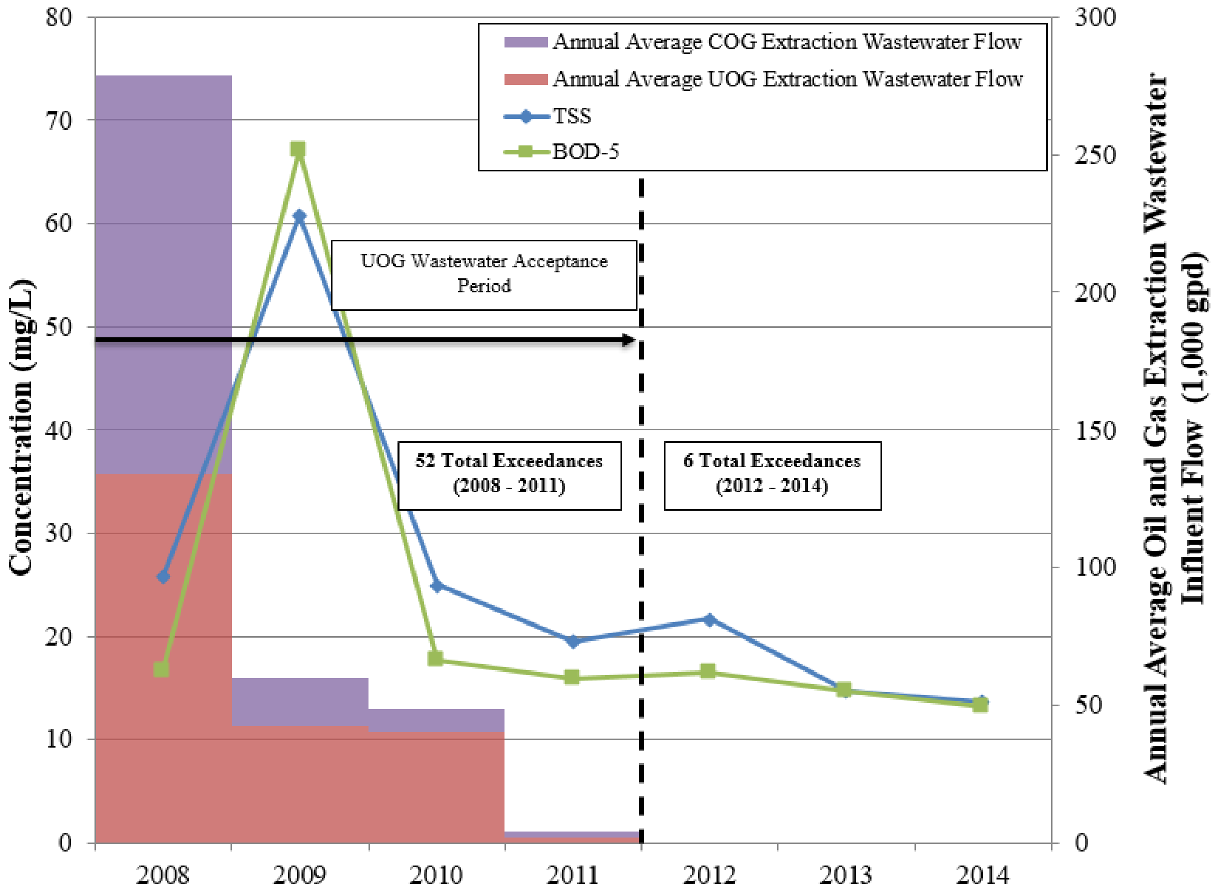
The EPA created Figure D-16 using the sampling data submitted in its DMR Loading Tool (83 DCN SGE00608) and PA DEP waste reports data (184 DCN SGE01182). Each effluent concentration data point represents the average of 12 monthly average data points as calculated and reported by the Loading Tool. PA DEP waste reports provided the total volume of UOG and COG wastewater delivered to the POTW each year. The EPA divided the annual volume by 365 to calculate the annual average daily flow. As shown in Figure D-16, the Johnstown POTW experienced a much larger number of permit limit exceedances during the period when they were accepting the greatest volume of oil and gas extraction wastewater. In a December 2012 letter regarding the 2011 annual pretreatment report, Johnstown's pretreatment coordinator stated,

> *[We] know that the treatment plant no longer accepts gas drilling waste,*[138] *and we anticipate that the number of violations will decrease.*

Further, Section C.3.2.1 presents data showing that TSS concentrations in drilling wastewater may be higher than TSS concentrations in UOG produced water.[139] The PA DEP waste reports data show that the Johnstown POTW accepted more drilling wastewater than any other POTW in Pennsylvania from 2008 through 2011. The POTW accepted the largest volume of drilling wastewater in 2009 and 2010, which totaled over 15 million gallons and accounted for over 40 percent of the total influent oil and gas wastewater accepted by the POTW. In total, the Johnstown POTW experienced 27 TSS permit limit exceedances from 2008 through 2011, 18 of which were in 2009 and 2010. The POTW also experienced elevated effluent TSS concentrations in 2009 (61 mg/L).

[138] The EPA assumes that this phrase refers to both COG wastewater and UOG extraction wastewater.

[139] Drilling wastewater initially includes cuttings (i.e., solids) that are partially removed by the operator before management or disposal. Any cuttings that remain may contribute to elevated TSS concentrations.



Source: 185 DCN SGE01183

Note: The annual average extraction wastewater flows for COG and UOG are presented as stacked bars in order to represent the total annual average oil and gas extraction wastewater influent flow.

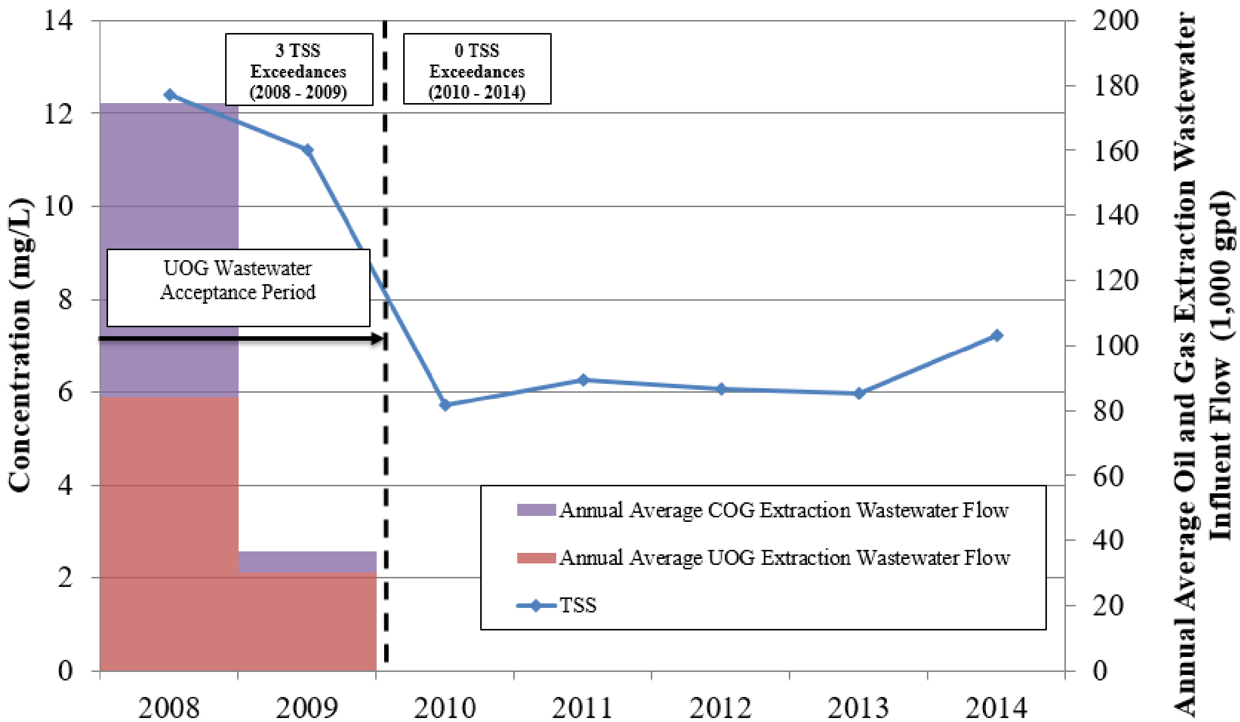
Figure D-16. Johnstown POTW: Annual Average Daily Effluent Concentrations and POTW Flows

California, PA, POTW

The California POTW uses a contact stabilization[140] process to treat influent wastewater (140 DCN SGE00787). In 2008 and 2009, the California POTW accepted both UOG and COG wastewater. The total oil and gas wastewater accounted for up to 33 percent of the total POTW influent volume during 2008, on average. UOG extraction wastewater accounted for 14 percent of total POTW influent during 2008, on average (184 DCN SGE01182). The POTW's average annual daily flow rate ranges between 0.5 and 0.8 MGD based on 2008 through 2014 DMR data (83 DCN SGE00608).

[140] Contact stabilization is a two-stage activated sludge process, consisting of a 30- to 60-minute absorptive phase followed by a one- to two-hour oxidation phase. Aeration volume requirements are half of those for conventional activated sludge (12 DCN SGE00167).

The EPA created Figure D-17 using the sampling data submitted in its DMR Loading Tool (83 DCN SGE00608) and PA DEP waste reports data (184 DCN SGE01182). Each effluent concentration data point represents the average of 12 monthly average data points as calculated and reported by the DMR Loading Tool. PA DEP waste reports provided the total volume of UOG and COG wastewater delivered to the POTW each year. The EPA divided the annual volume by 365 to calculate the annual average daily flow. As shown in Figure D-17, the California POTW experienced elevated concentrations of TSS while accepting oil and gas wastewater. Figure D-17 also shows that the California POTW experienced three exceedances of its TSS permit limits.[141]



Source: 185 DCN SGE01183

Note: The annual average extraction wastewater flows for COG and UOG are presented as stacked bars in order to represent the total annual average oil and gas extraction wastewater influent flow.

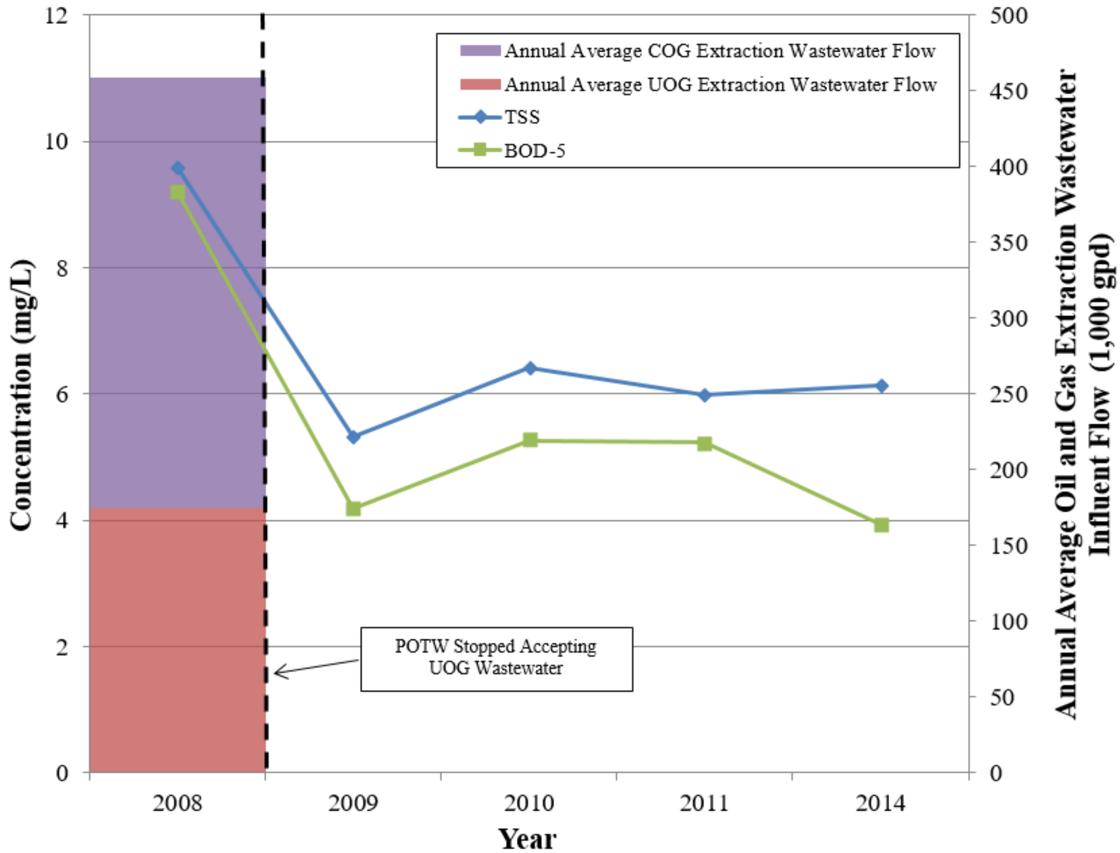
Figure D-17. California POTW: Annual Average Daily Effluent Concentrations and POTW Flows

<u>Charleroi, PA, POTW</u>

The Charleroi POTW was introduced and described in more detail in Section D.5.3.1 of this TDD.

[141] The California POTW had a monthly average TSS limit of 30 mg/L and a daily maximum TSS limit of 45 mg/L from 2008 through 2013.

The EPA created Figure D-18 using the sampling data submitted in its DMR Loading Tool (83 DCN SGE00608) and PA DEP waste reports data (184 DCN SGE01182). Each effluent concentration data point represents the average of 12 monthly average data points as calculated and reported by the Loading Tool. PA DEP waste reports provided the total volume of UOG and COG wastewater delivered to the POTW each year. The EPA divided the annual volume by 365 to calculate the annual average daily flow. As shown in Figure D-18, the Charleroi POTW experienced elevated concentrations of TSS and BOD_5 while accepting UOG extraction wastewater.



Source: 185 DCN SGE01183

Note: The annual average extraction wastewater flows for COG and UOG are presented as stacked bars in order to represent the total annual average oil and gas extraction wastewater influent flow.

Figure D-18. Charleroi POTW: Annual Average Daily Effluent Concentrations and POTW Flows[142]

[142] Figure D-18 shows data for 2008 through 2014, excluding 2012 and 2013 because there is no PA DEP waste report data or DMR Loading Tool data for the Charleroi POTW for 2012 or 2013.

Waynesburg, PA, POTW

The Borough of Waynesburg POTW accepted gas-exploration-related wastewater, hauled directly from operators, from June 2006 to November 2008. Gas well wastewater made up about 2 percent of total inflow in 2006. The percentage increased to 8.1 percent in 2007 and 9.5 percent in 2008. The Waynesburg POTW's average annual daily flow rate ranged between 0.37 and 0.62 MGD over those three years. The treatment process at Waynesburg POTW is as follows: two primary clarifiers, a trickling filter, a bio-tower, a final clarifier, and chlorine disinfection (153 DCN SGE00997, 154 DCN SGE00997.A01).

The Waynesburg POTW received a CWA §308 Request for Information from EPA Region 3 in February 2009. In March 2009, the Waynesburg POTW responded with a "Process Impact Evaluation" (119 DCN SGE00750), which stated that:

> *The amount of well water that was being accepted to the treatment facility has had no adverse effects on the trickling filter and the bio-tower except on one occasion in 2007. A hauler delivered a batch of well water that impacted the biological growth within the trickling filter. The water was believed to be frac water which possesses a high salinity which in turn impacted the biological growth in the trickling filter.*

5.3.2.2 Case Studies About POTWs Accepting Wastewater from Other Industrial Sources Containing UOG Pollutants (e.g., CWT Facilities)

New Castle, PA, POTW

The New Castle POTW accepted industrial wastewater from the Advanced Waste Services CWT facility, which treats oil and gas wastewater. Advanced Waste Services CWT facility treats "pretreated brine" (industrial wastewater) using solids settling, surface oil skimming, and pH adjustment. If influent wastewater does not meet Advanced Waste Services' pretreatment permit requirements, the facility applies additional treatment with flocculants (65 DCN SGE00554).

In its 2009 annual report to EPA Region 3, the New Castle POTW identified numerous violations of its NPDES permit limits for discharges of TSS. It also identified significant increases in the volume of industrial wastewater that it was receiving (see Table D-24) from Advanced Waste Services. New Castle's 2009 annual report does not include the total volume of wastewater it treated, but its 2013 NPDES permit indicates that all permit limits were based on an effluent discharge rate of 17 MGD (65 DCN SGE00554; 69 DCN SGE00573).

Table D-24. Industrial Wastewater Volumes Received by New Castle POTW (2007–2009)

Year	Industrial Wastewater Volume (gpd)	Percent of Total Volume Treated by POTW[a]
2007	74,278	0.44%
2008	130,608	0.77%
2009	331,381	1.95%

Source: 65 DCN SGE00554

a—Assuming 17 MGD is the total volume treated.

The 2009 annual report (65 DCN SGE00554) states that:

It is believed that pretreated brine wastewater from the developing oil & gas industry is adversely affecting the ability of the final clarifiers to separate solids via gravity settling. This has resulted in higher sludge blanket levels that are more easily upset and washed out during rainfall-induced high flow events. The Authority has begun using polymer flocculation to enhance settling with some success. However, there were numerous effluent TSS violations in 2009.

As noted in the annual report, instability in sludge blanket levels can cause increased washouts during large rain events, which may cause interference with biological treatment. New Castle reported 19 violations of its NPDES permit limits for TSS, believed to be caused by the acceptance of UOG extraction wastewater via the Advanced Waste Services CWT facility's industrial discharge (65 DCN SGE00554). The EPA compared the violations in 2009 to the violations that occurred in 2011, after the New Castle POTW stopped accepting industrial discharges from the CWT facility (i.e., violations between May and December 2011). The EPA identified two TSS violations during this nine-month time frame. Table D-25 shows detailed information about the violations in 2009 and 2011, including when they occurred, the measured values, and the percentage over the NPDES permit limit. The decrease in the number of TSS violations from 2009 to 2011, after the POTW stopped accepting industrial discharges from the Advanced Waste Services CWT facility, suggests that the UOG extraction wastewater pollutants were a contributing cause of the violations. However, the two violations in 2011 indicate that the UOG extraction wastewater was likely not the sole cause of interference with treatment processes at the POTW.

Table D-25. NPDES Permit Limit Violations from Outfall 001 of the New Castle POTW (NPDES Permit Number PA0027511)

Month, Year	Parameter	Sample Type	NPDES Permit Limit (mg/L)	Measured Value (mg/L)	Percentage Over Permit Limit (%)
March 2009	TSS	Weekly maximum	45	58	29
March 2009	TSS	Monthly average	30	37	23
May 2009	TSS	Monthly average	30	34	13
June 2009	TSS	Monthly average	30	38	27
July 2009	TSS	Weekly maximum	45	64	42
July 2009	TSS	Monthly average	30	45	50
August 2009	TSS	Weekly maximum	45	61	36
August 2009	TSS	Monthly average	30	50	67
September 2009	TSS	Monthly average	30	37	23
October 2009	TSS	Weekly maximum	45	46	2
October 2009	TSS	Monthly average	30	31	3
January 2010	TSS	Weekly maximum	45	60	33
January 2010	TSS	Monthly average	30	40	33
February 2010	TSS	Monthly average	30	33	10
March 2010	TSS	Monthly average	30	38	27

Table D-25. NPDES Permit Limit Violations from Outfall 001 of the New Castle POTW (NPDES Permit Number PA0027511)

Month, Year	Parameter	Sample Type	NPDES Permit Limit (mg/L)	Measured Value (mg/L)	Percentage Over Permit Limit (%)
March 2010	TSS	Weekly maximum	45	55	22
November 2010	TSS	Monthly average	30	34	13
November 2010	TSS	Weekly maximum	45	55	22
December 2010	TSS	Weekly maximum	45	56	24
November 2011	TSS	Monthly average	30	35	17
November 2011	TSS	Weekly maximum	45	64	42

Sources: 89 DCN SGE00620; 85 DCN SGE00612
Abbreviation: mg/L—milligrams per liter

<u>Wheeling, WV, POTW</u>

The Wheeling POTW, introduced in Section D.5.3.1, accepted industrial wastewater from the LAD CWT facility, which treats oil and gas wastewater.[143] A 2011 Consent Order issued to the Wheeling POTW by the WV DEP indicates that the POTW experienced interference with biological treatment from accepting UOG extraction wastewater via the CWT facility's industrial discharge. The Order describes the following timeline of events (48 DCN SGE00485):

- **July 21, 2009—**the Wheeling POTW experienced an upset that required several weeks of "vigilant action to recover" and included the introduction of a "seed" sludge from a nearby POTW. Plant upset conditions occurred during periods when the POTW exceeded discharge limits for fecal coliform and TSS.
- **August 21, 2009—**Meeting minutes from a meeting between Wheeling POTW and LAD CWT facility stated that Wheeling was accepting oil and gas wastewater "well above the 1% that is allowed." The minutes also said that Wheeling was concerned about the lack of diversity in microorganisms and that the wastewater from LAD was the cause of the lack of microbial diversity.
- **November 17, 2009—**WVDEP inspected Wheeling POTW and noted that "[t]he discharge from Wheeling was slightly turbid and causing a crispy white foam in the receiving stream." In addition, the Wheeling POTW experienced operational interference, inefficiency, or possible upset indicated by several factors including an increased chlorine demand, loss in effluent clarity, UV disinfection failures, and suspicious odors.
- **May 6, 2010—**Wheeling POTW representatives met with WV DEP representatives to discuss the draft Consent Order. The Order included numerous requirements including one that stated, "Upon entry of this Order, Wheeling shall continue to cease and desist acceptance of all oil and gas wastewater."

[143] As described in Section D.5.3.1, the Wheeling POTW accepted industrial wastewater from the LAD CWT facility through August 2009 and wastewater directly from UOG operators in 2008.

Brockway, PA, POTW

The Brockway POTW, introduced in Section D.5.3.1, was still accepting natural-gas-related wastewater treated by the Dannic Energy Corporation CWT facility as of June 2014. Before accepting COG wastewater, Brockway POTW installed an oil/solids separator and aerated equalization tank. The POTW began accepting COG wastewater starting in November 2008 and noticed an increase in sludge generation.[144] The POTW operators noticed a scum layer forming on the clarifiers because of a combination of calcium in the oil and gas wastewater and soaps/fats in the typical POTW influent wastewater. In addition to the scum layer on the clarifiers, the POTW experienced increased sludge generation and high concentrations of barium in the sludge (sludge barium content = 1,490 mg/kg). However, the POTW ran a hazardous waste determination and found that the barium content was below the hazardous waste classification threshold (121 DCN SGE00753).

5.3.2.3 POTW Sludge and Scale Formation

UOG extraction wastewater is also a concern in the disruption of POTW sludge processes, including sludge disposal, and the disruption of POTW operations as a result of excessive scale formation. For example, POTWs that accept and treat wastewater high in heavy metals (e.g., nickel, copper, zinc) face the potential for heavy metals accumulation in sludge. A POTW accepting wastewater with high metals concentrations may no longer be able to land-apply its sludge because it may violate sludge disposal rules.

While UOG extraction wastewater does not typically contain concentrations of heavy metals at levels that would likely prohibit the POTW from land-applying its sludge (see Table C-17), the EPA has identified the potential for elevated concentrations of radium-226 and -228 in sludge (9 DCN SGE00136; 161 DCN SGE01028). State and federal regulations for the transport and disposal of radioactive waste may limit the POTW's options for managing sludge contaminated with radium and other radioactive materials derived from UOG extraction wastewater. POTWs with sludge containing radioactive materials may resort to underground injection in a Class I well,[145] disposal at a hazardous waste landfill,[146] or disposal at a low-level radioactive waste landfill[147] (87 DCN SGE00615).

In addition to inhibiting the performance of treatment operations, UOG extraction wastewater may disrupt POTW operations as a result of excessive scale formation. Scale typically accumulates on valves, pipes, and fittings and, therefore, may interfere with POTW operation (e.g., restrict flow to unit processes). Scale is produced from deposits of divalent cations (e.g., barium, calcium, magnesium) that precipitate out of wastewater. Figure D-19

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[144] The EPA is not aware of any time when the Brockway POTW accepted UOG extraction wastewater.

[145] Class I underground injection wells are used to inject hazardous wastes, industrial non-hazardous liquids, or municipal wastewater beneath the lowermost underground source of drinking water.

[146] Hazardous waste landfills are regulated under RCRA Subtitle C. Some hazardous waste landfills are permitted to accept TENORM waste, while others have to request state approval before accepting TENORM waste.

[147] Low-level radioactive waste landfills are licensed by the U.S. Nuclear Regulatory Commission or by a state under agreement with the Commission. These landfills provide a disposal option for wastes with radionuclide concentrations that are unable to be disposed of at municipal, industrial, or hazardous waste landfills.

shows an example of barium sulfate scaling in an oil and gas pipe in the Haynesville shale formation.

Source: 133 DCN SGE00768.A26

Figure D-19. Barium Sulfate Scaling in Haynesville Shale Pipe

Table C-17 shows typical concentrations of barium, calcium, and strontium in UOG extraction wastewater, which suggest that UOG extraction wastewater may cause scale accumulation at POTWs. Because radium[148] behaves like other divalent cations, it may also accumulate in scale and form TENORM: technologically enhanced naturally occurring radioactive material, defined as naturally occurring radioactive materials that have been concentrated or exposed to the accessible environment as a result of human activities (147 DCN SGE00978) such as manufacturing, mineral extraction, or water processing (e.g., in treatment processes at a POTW). PA DEP's 2015 study report[149] (161 DCN SGE01028) provides the following examples of solids that may contain TENORM: drill cuttings, filter sock residuals, impoundment sludge, tank bottom sludge, pipe scale, wastewater treatment plant sludge, and soils.[150] The PA DEP TENORM study report concludes that "There is little potential for radiological exposure to workers and members of the public from handling and temporary storage of filter cake at POTWs. However, there is a potential for radiological environmental impacts from spills and the long-term disposal of POTW filter cake." The PA DEP TENORM study report includes the following recommendations for future action:

[148] Radium is a naturally occurring radioactive element that ionizes in water to a divalent cation with chemical properties similar to barium, calcium, and strontium.

[149] PA DEP initiated a study to collect data related to TENORM associated with oil and gas operations in Pennsylvania, including assessment of potential worker and public radiation exposure, TENORM disposal, and other environmental impacts.

[150] PA DEP's 2015 TENORM study sampled the following types of solids: surface soil impacted by sediments, filter cakes, soils, sludge, drill cuttings, drilling muds, proppant sand, and filter socks. PA DEP identified pipe scale as a source of TENORM, but did not sample for pipe scale in their 2015 TENORM study.

- "Perform routine survey assessment of areas impacted with surface radioactivity to determine personal protective equipment (PPE) use and monitoring during future activity that may cause surface alpha and beta radioactivity to become airborne."
- "Conduct additional radiological sampling and analyses and radiological surveys at all WWTPs accepting wastewater from O&G operations to determine if there are areas of contamination that require remediation; if it is necessary to establish radiological effluent discharge limitations; and if the development and implementation of a spill policy is necessary."

The Marcellus shale formation is known to contain radium and, therefore, is of particular concern for TENORM generation (9 DCN SGE00136; 53 DCN SGE00519; 74 DCN SGE00587).

Rowan et al. (16 DCN SGE00241) report a positive correlation between TDS concentrations and radium activity based on data for produced water from the Marcellus shale and conventional formations in the Appalachian basin. Therefore, UOG formations containing higher concentrations of TDS will likely also contain higher radium activity and, therefore, a higher chance for TENORM accumulation in sludge. However, the existing literature contains limited sampling data measuring radioactive constituents in UOG extraction wastewater (see Table C-19). Therefore, the potential for TENORM accumulation in scale from UOG extraction wastewater and the subsequent health risks to worker safety at POTWs are not fully known.

The 2015 PA DEP TENORM Study (161 DCN SGE01028) also looked into potential worker exposure, TENORM disposal options, and environmental impacts. PA DEP analyzed liquid and solid samples for alpha, beta, and gamma radiation and gas samples for radon. PA DEP sampled the following types of facilities, among others, as part of their study:

- **Well sites**—PA DEP sampled 38 well sites (4 conventional wells and 34 unconventional wells) from June 2013 through July 2014
- **Wastewater treatment plants**—PA DEP sampled 29 wastewater treatment plants (10 POTWs, 10 CWT facilities, and 9 zero liquid discharge (ZLDs) facilities)

PA DEP presents sample data of filter cakes from POTWs receiving oil and gas wastewater that showed "Ra-226 and Ra-228 present above typical background concentrations in soil. The average Ra-226 result was 20.1 pCi/g with a large variance in the distribution, and the maximum result was 55.6 pCi/g. The average Ra-228 result was 8.32 pCi/g, and the maximum result was 32.0 pCi/g Ra-228" (161 DCN SGE01028).

PADEP concluded, "…[t]here is little potential for radiological exposure to workers and members of the public from handling and temporary storage of filter cake at POTW-I's.[151] However, there is a potential for radiological environmental impacts from spills and the long-term disposal of POTW-I filter cake" (161 DCN SGE01028). ERG's *Radioactive Materials in*

[151] PA DEP defines a "POTW-I" as a POTW that was considered to be influenced by having received wastewater from the oil and gas industry.

the Unconventional Oil and Gas (UOG) Industry memorandum (188 DCN SGE01185) provides additional information and results from the PA DEP study.

5.3.3 Potential Impacts of DBP Precursors in UOG Extraction Wastewater

Disinfection, especially chlorination of drinking water and wastewater, is used to reduce outbreaks of waterborne disease. As well as killing pathogenic microbes, though, disinfection can produce a variety of toxic halo-organic compounds called DBPs. UOG extraction wastewater often contains elevated levels of bromide (see Table C-13) and chloride (see Table C-11), which are precursors of several toxic DBPs (51 DCN SGE00509; 122 DCN SGE00754). Brominated DBPs are reported to have greater health risks (e.g., higher risk of cancer) than chlorinated DBPs (141 DCN SGE00800). Additional information and discussion on DBPs and other human and ecological impacts can be found in other EPA resources (163 DCN SGE01093; 170 DCN SGE01126).

UOG extraction wastewater discharged to POTWs could be a potential source of DBPs in two scenarios:

- When UOG extraction wastewater is disinfected at a POTW (62 DCN SGE00535)
- When a POTW discharges wastewater including UOG extraction wastewater pollutants to a river that is used as a source water for a downstream drinking water treatment plant where disinfection is used (74 DCN SGE00587)

5.3.3.1 UOG Extraction Wastewater Disinfection at POTWs

DBPs can form within a POTW when disinfectants (e.g., chlorine, chloramine), natural organic matter, and bromide or iodide react. Because UOG extraction wastewater contains high concentrations of bromide (see Section C.2.2), treatment of UOG extraction wastewater at POTWs with disinfection processes can create DBPs. Hladik et al. investigated whether POTW treatment of wastewater from COG and UOG operations (hereafter referred to as “oil and gas wastewater”) could create DBPs, particularly brominated DBPs (62 DCN SGE00535).

Hladik et al. sampled effluent from three Pennsylvania POTWs, one POTW that did not accept oil and gas wastewater (POTW 1) and two that accepted oil and gas wastewater from oil and gas operators (POTW 2, POTW 3). The daily average discharge rates for the three POTWs were not reported. The total volume of oil and gas wastewater accepted at POTWs 2 and 3 was reported as ranging from 2.3 million gallons to 2.9 million gallons in 2012. Grab samples were collected in the river where the POTW effluent entered and were analyzed for 29 DBPs.

Table D-26 presents sampling results showing higher concentrations of DBPs in the majority of the effluent samples from POTWs that had accepted oil and gas wastewater from oil and gas operators. Hladik et al.’s results show that COG and UOG extraction wastewater may contribute to the formation of DBPs in chlorinated POTW effluent.

Table D-26. Concentrations of DBPs in Effluent Discharges at One POTW Not Accepting Oil and Gas Wastewater and at Two POTWs Accepting Oil and Gas Wastewater (µg/L)

Facility Identifier	POTW 1	POTW 1	POTW 2	POTW 3	MDL[a]
Sample Date	8/20/2012	11/28/2012	4/17/2013	4/17/2013	
Accepted Oil and Gas Wastewater	No	No	Yes	Yes	
Bromochloroiodomethane	ND	ND	0.10	0.12	0.02
Bromodichloromethane	BDL[b]	ND	BDL[b]	BDL[b]	0.10
Bromodiiodomethane	ND	ND	0.09	0.20	0.02
Bromoform	0.03	0.04	10.1	9.2	0.02
Chloroform	0.02	0.05	0.20	0.13	0.02
Dibromo-chloro-methane	0.05	0.05	0.83	0.51	0.02
Dibromoiodomethane	ND	ND	0.98	1.3	0.02
Dichloroiodomethane	ND	ND	BDL[b]	BDL[b]	0.04

Source: 62 DCN SGE00535

Note: The EPA presents data for eight DBPs in Table D-26. Hladik et al. (62 DCN SGE00535) collected data for 29 DBPs. The concentrations of DBPs in the effluent of POTWs that had accepted oil and gas wastewater were higher than the concentrations in POTWs that had not accepted oil and gas wastewater in all but three samples.

a—Method detection limits (MDLs) in surface water samples, as reported by Hladik et al. (62 DCN SGE00535).

b—Below method detection limit (BDL) indicates a value reported by Hladik et al. that was lower than the MDL. The EPA reported these values as BDL instead of reporting the values from Hladik et al. (62 DCN SGE00535).

Abbreviation: ND—nondetect; µg/L—micrograms per liter

5.3.3.2 Drinking Water Treatment Disinfection Downstream of POTWs

DBPs form when disinfectants (e.g., chlorine), natural organic matter, and bromide or iodide react. Therefore, they can form in drinking water treatment plants that use disinfection processes. Beginning in 2008, researchers in Pennsylvania detected high concentrations of bromide, a pollutant that facilitates the formation of toxic DBPs (e.g., brominated trihalomethanes), downstream of POTWs that accepted UOG extraction wastewater (68 DCN SGE00567; 74 DCN SGE00587).

Wilson and Van Briesen (94 DCN SGE00633) also investigated whether effluent discharges from POTWs were causing high TDS and bromide concentrations that would negatively impact drinking water treatment plants. They note that

> *Like TDS, bromide is not removed at drinking water treatment plants. Thus, produced water management that leads to increased concentrations of bromide in source waters for drinking water treatment plants can lead to increased concentrations of DBPs in drinking water.*

Wilson and Van Briesen later conclude that

> *Produced water management decisions should be informed by the potential contribution of this wastewater to the formation of disinfection by-products in downstream drinking water treatment plants.*

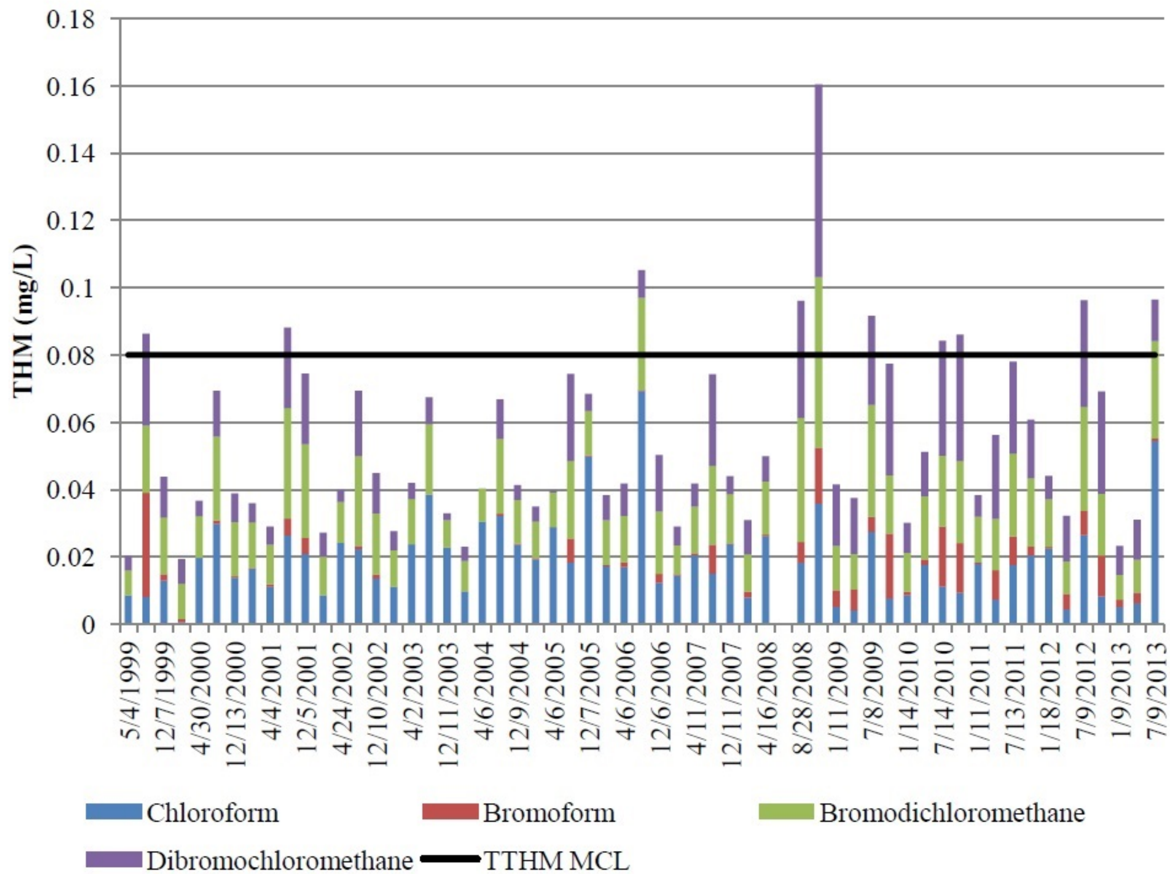
States et al. (74 DCN SGE00587) conducted a drinking water treatment plant survey and investigated bromide concentrations in the untreated river water intake and trihalomethanes (THMs) (i.e., chloroform, bromoform, dibromochloromethane, bromodicholoromethane) in the treated, "finished" drinking water. States et al. drew the following conclusions from their study:

- Elevated bromide concentrations in the influent to the studied drinking water treatment plant resulted in increased concentrations of certain DBPs, particularly brominated THMs, in the drinking water.
- Drinking water treatment plants cannot effectively remove bromide from intake water.
- POTWs discharging treated UOG extraction wastewater (specifically from the Marcellus shale formation) were major contributors to the increase in bromide in the drinking water treatment plant intake during the period of the study.

In February 2013, Eshelman and Elmore published a report for the Maryland Department of the Environment titled *Recommended Best Management Practices for Marcellus Shale Gas Development in Maryland* (112 DCN SGE00735). The report discussed POTW management of UOG extraction wastewater and specifically noted that this is not a best management practice. They further reported that the discharge of high-TDS loads into surface waters that could be drinking water treatment intakes should be prohibited. Eshelman and Elmore state that

> *Higher chloride levels cause taste and odor problems in finished water. High bromide levels lead to increased formation of carcinogenic disinfectant by-products that can persist in the water to the point of consumption. Treatment of produced water by POTWs and other conventional wastewater treatment methods that do not remove salts should be prohibited in Maryland.*

McTigue et al. published an article about the occurrence and consequences of bromide in drinking water sources (141 DCN SGE00800). They note that UOG extraction wastewater may contribute to recent increases in bromide-containing waste upstream of drinking water utilities, and thus to the increase in DBPs reported by the drinking water utilities. The authors provide an example of an unnamed water treatment plant (WTP E) that began experiencing influent water with high TDS concentrations in 2008, around the same time that UOG extraction operations began in the area. Figure D-20 shows the average quarterly total THM speciation from 1999 through 2013, which shows a decrease in chlorinated DBPs and an increase in brominated DBPs starting around 2008.



Abbreviations: TTHM MCL—total trihalomethane maximum contaminant level
Source: 141 DCN SGE00800.

Figure D-20. THM Speciation in a Water Treatment Plant (1999–2013)

Another example of concerns about DBP formation from oil and gas wastewater is shown in PA DEP's response to a comment on Ridgway POTW's NPDES permit renewal. The comment, from the University of Pittsburgh, stated that "bromide can create trihalomethane byproducts." PA DEP's response noted that trihalomethanes are made up of one of the following (followed parenthetically by measured effluent concentrations from the Ridgway POTW):

- Chloroform (nondetect)
- Bromodichloromethane (nondetect)
- Dibromochloromethane (nondetect)
- Bromoform (74 µg/L)

PA DEP noted that the effluent concentration of bromoform was low enough not to be of concern compared to water quality limits. However, it is studying the impact of bromides on surface waters. PA DEP recognizes that UOG extraction wastewater has the potential to contribute to the formation of DBPs.

In August 2013, EPA Region 3 issued a letter (144 DCN SGE00935) informing the NPDES permitting authorities in the Mid-Atlantic region that

> *…conventional and nonconventional pollutants, such as bromide, must be tested by existing dischargers as part of the permit application process if such pollutants are expected to be present in effluent.*

The letter goes on to state that EPA Region 3 has reason to believe that industrial discharges (including UOG extraction wastewater discharges) containing bromide contributed to elevated levels of bromide in rivers and streams that resulted in downstream impacts at drinking water treatment plants, including increased occurrence of DBPs. Therefore, if the parameter is not limited in an applicable ELG, NPDES permit applicants must either describe why the parameter is expected in their discharges or include quantitative data for the parameter. These requirements apply to the following parameters of interest in UOG extraction wastewater, among others (145 DCN SGE00935.A01):

- TDS
- Chloride
- Bromide
- Sulfate
- Fluoride
- Aluminum, total
- Barium, total
- Iron, total
- Manganese, total
- Radium-226/228
- Arsenic, total
- Selenium, total
- Benzene
- Bromoform
- Chlorobenzene
- Chloroform
- Ethylbenzene
- Toluene
- Phenol
- Naphthalene
- Alpha-BHC
- Beta-BHC

Parker et al. published an article in September 2014 (151 DCN SGE00985) that evaluated the minimum volume of UOG produced water from Marcellus shale and Fayetteville shale wells that, when diluted by fresh water, would generate and/or alter the formation and speciation of DBPs after chlorination, chloramination, and ozonation treatment.

Parker et al. suspect that, due to the increased salinity of UOG produced water, elevated bromide and iodide in UOG produced water may promote the formation of DBPs. The results show that UOG produced water dilution as low as 0.01 percent could result in altered speciation toward the formation of brominated and iodinated DBPs. The results also show that UOG produced water dilution as low as 0.03 percent increases the overall formation of DBPs. Parker et al. suggest either eliminating UOG produced water discharges or installing halide-specific removal techniques in CWT facilities and/or POTWs that are accepting UOG produced water for treatment.

Chapter E. REFERENCE FLAGS AND LIST

The EPA reviewed existing data sources, including state and federal agency databases, journal articles and technical papers, technical references, industry/vendor telephone queries, and vendor websites to gather information for the TDD. The EPA identified all of the information described in this TDD from these types of existing data sources, which are listed in Table E-1.

The EPA assigned one of the following data source quality flags to each of the sources referenced in this TDD:

- **Source quality flag "A"—**journal articles and documents prepared by or for a government agency (e.g., EPA site visit reports, industry meeting notes)
- **Source quality flag "B"—**documents prepared by a verified source that include citation information (e.g., operator reports, vendor documents, university publications)
- **Source quality flag "C"—**documents prepared by a verified source that do not include citation information (e.g., operator reports, vendor documents, conference presentations)
- **Source quality flag "D"—**documents prepared by a source that could not be verified and that do not include citation information

Table E-1. Source List

ID	DCN	Source Citation	Source Flag
1	SGE00010	GWPC and ALL Consulting. 2009. Modern Shale Development in the United States: A Primer. U.S. DOE. Office of Fossil Energy NETL. April 2009. Last accessed on May 17, 2016: http://www.netl.doe.gov/File%20Library/Research/Oil-Gas/Shale_Gas_Primer_2009.pdf	A
2	SGE00011	Veil, John A. 2010. Water Management Technologies Used by Marcellus Shale Gas Producers. Prepared by Argonne National Laboratory. Prepared for U.S. DOE NETL. (July). Last accessed on May 17, 2016: http://www.mde.state.md.us/programs/Land/mining/Marcellus/Documents/WaterMgmtinMarcellusfull.pdf	A
3	SGE00046	Abdalla, Charles W.; Drohan, Joy R.; Blunk, Kristen S.; Edson, Jessie. 2011. Marcellus Shale Wastewater Issues in Pennsylvania—Current and Emerging Treatment and Disposal Technologies. Penn State Cooperative Extension, College of Agricultural Sciences.	B
4	SGE00070	Acharya, Harish; Matis, Hope; Kommepalli, Hareesh; Moore, Brian; Wang, Hua. 2011. Cost Effective Recovery of Low-TDS Frac Flowback Water for Re-use. Prepared by GE Global Research. Prepared for US DOE NETL. Morgantown, WV. (June).	A
5	SGE00095	URS. 2011. Water-Related Issues Associated with Gas Production in the Marcellus Shale. (March 25).	B

Table E-1. Source List

ID	DCN	Source Citation	Source Flag
6	SGE00110	Bruff, Matthew. 2011. An Integrated Water Treatment Technology Solution for Sustainable Water Resource Management in the Marcellus Shale. Prepared by Altela, Inc., Argonne National Laboratory, BLX, Inc., and CWM Environmental, Inc. DE-FE0000833.	A
7	SGE001277	Abt Associates. 2016. Profile of the Oil and Gas Extraction (OGE) Sector, with Focus on Unconventional Oil and Gas (UOG) Extraction. (February 18).	A
8	SGE00132	U.S. EPA. 2011. Underground Injection Control Program: Class II Wells—Oil and Gas Related Injection Wells (Class II). Downloaded on 8/31/2011.	A
9	SGE00136	U.S. EPA. 2011. Oil and Gas Production Wastes. Last accessed on May 17, 2016: https://www.epa.gov/radiation/tenorm-oil-and-gas-production-wastes	A
10	SGE00139	Puder, M.G.; Veil, J.A. 2006. Argonne National Laboratory. Offsite Commercial Disposal of Oil and Gas Exploration and Production Waste: Availability, Options, and Costs. Prepared for U.S. DOE NETL. (August).	A
11	SGE00155	U.S. Energy Information Administration (EIA). 2010. Tight Sands Gas Plays, Lower 48 States. Prepared by EIA Office of Oil and Gas. (June).	A
12	SGE00167	Metcalf and Eddy, Inc. 2002. Wastewater Engineering: Treatment and Reuse. Fourth edition. McGraw-Hill, Inc.	B
13	SGE00182	Clark, C.E.; Veil, J.A. 2009. Produced Water Volumes and Management Practices in the United States. ANL/EVS/R-09/1. Argonne National Laboratory.	A
14	SGE00187	Pennsylvania Code. 2010. Title 25: Environmental Protection. Chapter 95: Wastewater Treatment Requirements. (August).	A
15	SGE00239	Hefley, William, et al. 2011. The Economic Impact of the Value Chain of a Marcellus Shale Well. University of Pittsburgh. (August).	B
16	SGE00241	Rowan, E.L., et al. 2011. Radium Content of Oil- and Gas-Field Produced Waters in the Northern Appalachian Basin (USA)—Summary and Discussion of Data. U.S. Geological Survey Scientific Investigations Report 2011–5135.	A
17	SGE00244	ERG. 2012. Camp, Meghan; Bicknell, Betsy; Ruminski, Brent. Notes on Conference Call with 212 Resources on 4 January 2012. (January 9).	A
18	SGE00245	ERG. 2012. Camp, Meghan; Bicknell, Betsy; Ruminski, Brent. Notes on Conference Call with Reserved Environmental Services, LLC on 5 January 2012. (February 1).	A
19	SGE00249	U.S. EPA. 2011. Introduction to the National Pretreatment Program. EPA 833-B-11-001. (June).	A
20	SGE00254	Michigan Department of Environmental Quality (MI DEQ). 2006. Michigan Oil and Gas Regulations: Natural Resources and Environmental Protection Act—Act No. 451 of the Public Acts of 1994, As Amended. Office of Geological Survey. (April).	A
21	SGE00275	U.S. EPA. 2012. Site Visit Report: Citrus Energy Corporation Marcellus Shale Gas Operations. (January 22).	A
22	SGE00276	U.S. EPA. 2012. Meeting with XTO Energy, Inc. about Unconventional Oil and Gas Sanitized.	A

Table E-1. Source List

ID	DCN	Source Citation	Source Flag
23	SGE00279	U.S. EPA. 2012. Meeting Summary: Conference Call with North Star Disposal, Inc Regarding Underground Injection Operations in Ohio. (July 2).	A
24	SGE00280	U.S. EPA. 2013. Site Visit Report: Anadarko Petroleum Corporation Marcellus Shale Gas Operations. (January 9).	A
25	SGE00283	ERG. 2012. Camp, Meghan; Ruminski, Brent. Notes on Conference Call with BLX, Inc on 15 May 2012. (June 11).	A
26	SGE00284	Hayes, Thomas et al. 2012. Barnett and Appalachian Shale Water Management and Reuse Technologies. Research Partnership to Secure Energy for America (RPSEA).	A
27	SGE00286	Hammer, R.; VanBriesen, J. 2012. In Fracking's Wake: New Rules Are Needed to Protect Our Health and Environment from Contaminated Wastewater. NRDC Document D:12-05-A. Natural Resources Defense Council. (May).	A
28	SGE00291	Shires, Terrie; Lev-on, Mairiam. 2012. Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production.	B
29	SGE00295	Warren Water Pollution Control Facility. 2011. Fact Sheet for NPDES Permit Renewal, Warren Water Pollution Control Facility, 2011–2012. City of Warren.	A
30	SGE00299	U.S. EPA. 2012. Site Visit Report: US Gas Field Fluids Management (formerly Clean Streams) Marcellus Shale Gas Operations. (October 9).	A
31	SGE00300	U.S. EPA. 2012. Site Visit Report: Eureka Resources, LLC Marcellus Shale Gas Operations. (February 25).	A
32	SGE00305.A03	Cheung, Timothy. 2012. Identifying the Recycling and Treatment Criteria That Must be Met to Avoid Scaling and Enable Successful Reuse. Shell.	C
33	SGE00305.A10	Fredriksen, K. 2012. How An Operator Is Developing A Systematic Sourcing Strategy To Guarantee Water Availability At Minimal Costs. Consol Energy.	C
34	SGE00331	Ely, John W.; Horn, Aaron; Cathey, Robbie; Fraim, Michael; Jakhete, Sanjeev. 2011. Game Changing Technology for Treating and Recycling Frac Water. Society of Petroleum Engineering. SP SPE-214545-PP.	A
35	SGE00345	Lewis, Aurana. 2012. Wastewater Generation and Disposal from Natural Gas Wells in Pennsylvania. Duke University.	B
36	SGE00350	Stepan, Daniel J.; Shockey, Richard E.; Kurz, Bethany A.; Kalenze, Nicholas S.; Cowan, Robert M.; Ziman, Joshua J.; Harju, John A. 2010. Bakken Water Opportunities Assessment—Phase 1. Energy & Environmental Research Center, University of North Dakota. Prepared for National Energy Technology Laboratory.	A
37	SGE00354	Clark, C.E.; Han, J.; Burnham, A.; Dunn, J.B.; Wang, M. 2011. Life-Cycle Analysis of Shale Gas and Natural Gas. Argonne National Laboratory. ANL/ESD/11-11.	A
38	SGE00357	Cramer, John. 2011. Post-frac Flowback Analysis and Reuse Implications. Superior Well Services.	B
39	SGE00366	Clarion Altela Environmental Services (CAES). n.d. CAES Overview. Downloaded on 1/28/2013.	C

Table E-1. Source List

ID	DCN	Source Citation	Source Flag
40	SGE00367	CARES. n.d. CARES McKean. Downloaded on 1/28/2013.	C
41	SGE00368	U.S. EPA. 2012. (Region 3). Key Documents About Mid-Atlantic Oil and Gas Extraction. (November 26). Last accessed on May 17, 2016: https://www.epa.gov/foia/oil-and-gas-extraction-mid-atlantic	A
42	SGE00374	Red Desert. n.d. What Makes Our Water Treatment & Reclamation Facility So Advanced? Downloaded on 1/28/2013.	C
43	SGE00379	Hill, David A. 2012. The Future Is NOW for Water Recycling in the Niobrara. Wyoming Energy News.	C
44	SGE00414	Hayes, Thomas; Severin, Blaine F. 2012. Characterization of Flowback Waters from the Marcellus and the Barnett Shale Regions Report No. 08122-05.09. Research Partnership to Secure Energy for America (RPSEA).	A
45	SGE00476	Hydro Recovery, LP. 2013. Company Info. Downloaded on 5/20/2013.	C
46	SGE00479	Kadramas, Lee & Jackson, Inc. 2012. Power Forecast 2012: Williston Basin Oil and Gas Related Electrical Load Growth Forecast.	B
47	SGE00481	McCutcheon Enterprises. 2013. Waste Reduction: A Greener Alternative for Treating Drilling Muds. (April).	C
48	SGE00485	West Virginia Department of Environmental Protection (WV DEP). 2011. Consent Order Issued Under the Water Pollution Control Act, West Virginia Code, Chapter 22, Article 11.	A
49	SGE00497	Angelo, Tom. 2013. From Pilot Study to Daily Processing: Warren, Ohio's Documentary to Hydraulic Fracturing Water Treatment. City of Warren, Ohio, Water Pollution Control Department. Presentation at EPA's Study of Hydraulic Fracturing and Its Potential Impact on Drinking Water Resources: Wastewater Treatment and Related Modeling Technical Workshop. April 18, 2013.	A
50	SGE00499	Arkansas Oil and Gas Commission (AOGC). 2013. Welcome to the Arkansas Oil and Gas Commission Online Production and Well Information. Accessed on 6/14/2013.	A
51	SGE00509	Brown, Daniel; Bridgeman, John; West, John R. 2011. Predicting Chlorine Decay and THM Formation in Water Supply Systems. Reviews in Environmental Science and Bio/Technology 10:79–99.	A
52	SGE00516	Cochener, John. 2010. Quantifying Drilling Efficiency. U.S. EIA, Office of Integrated Analysis and Forecasting. (June 28).	A
53	SGE00519	Davies, Peter J. n.d. Radioactivity. Cornell University.	B
54	SGE00521	ERG. 2012. Camp, Meghan; Ruminski, Brent. Notes for Shale Gas Industry Meeting Held on 29 February 2012. (April 20).	A
55	SGE00522	Environmental Review Appeals Commission, State of Ohio. 2012. Patriot Water Treatment, LLC, and City of Warren v. Chris Korleski, Director of Environmental Protection, and Scott Nally, Director of Environmental Protection: 2012 Decision.	A

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ID	DCN	Source Citation	Source Flag
56	SGE00525	Ferrar, Kyle J.; Michanowicz, Drew R.; Christen, Charles L.; Mulcahy, N.; Malone, Samantha L.; Sharma, Ravi K. 2013. Assessment of Effluent contaminants from Three Facilities Discharging Marcellus Shale Wastewater to Surface Waters in Pennsylvania. Environmental Science & Technology 47:3472–3481.	A
57	SGE00527	Kennedy, Robert L.; Knecht, William N.; Georgi, Daniel T. 2012. Comparisons and Contrasts of Shale Gas and Tight Gas Developments: North American Experience and Trends. SPE-SAS-245. Society of Petroleum Engineers.	B
58	SGE00528	Gilmer, Ellen. 2013. Data Show More Marcellus Wastewater, More Injections. E&E News. (February 22).	C
59	SGE00531	Hanlon, James. 2011. Natural Gas Drilling in the Marcellus Shale: NPDES Program Frequently Asked Questions. (March 16).	A
60	SGE00532	Hansen, Evan; Mulvaney, Dustin; Betcher, Meghan. 2013. Water Resource Reporting and Water Footprint from Marcellus Shale Development in West Virginia and Pennsylvania. (October 30).	B
61	SGE00533	Heffernan, Kevin. 2012. Unconventional Resource Development and Hydraulic Fracturing. Red Deer River Watershed Alliance. (October 25).	B
62	SGE00535	Hladik, Michelle; Focazio, Michael J.; Englae, Mark. 2014. Discharges of Produced Waters from Oil and Gas Extraction via Wastewater Treatment Plants Are Sources of Disinfection By-products to Receiving Streams. Science of the Total Environment 466–467:1085–1093.	A
63	SGE00545	Klaber, Kathryn. 2011. Letter to Michael Krancer, PA DEP. Marcellus Shale Coalition. (April 20).	C
64	SGE00552	Mon River Recreation and Commerce Committee. 2009. Minutes of Mon River Recreating & Commerce Committee Meeting 12 December 2008. Last access on May 17, 2016: http://www.monriversummit.org/MRRCC_archive/MRRCC_minutes/MRRCC-min-14Dec08.htm	C
65	SGE00554	Widmer Engineering, Inc. 2010. New Castle Sanitation Authority, New Castle, Lawerance County, Pennsylvania: Annual Pretreatment Report, 2009 Operating Year. Prepared for New Castle Sanitation Authority.	A
66	SGE00556	Nicot, Jean-Philippe, et al. 2011. Current and Projected Water Use in the Texas Mining and Oil and Gas Industry. University of Texas at Austin, Bureau of Economic Geology. Prepared for Texas Water Development Board.	A
67	SGE00557	NDIC. 2014. Basic Subscription Services—Well Index. Department of Mineral Resources, Oil and Gas Division. Last Accessed on 1/27/2014.	A
68	SGE00567	Handke, Paul. 2008. Trihalomethane Speciation and the Relationship to Elevated Total Dissolved Solid Concentrations Affecting Drinking Water Quality at Systems Utilizing the Monongahela River as a Primary Source During the 3rd and 4th Quarters of 2008. Pennsylvania Department of Environmental Protection.	A
69	SGE00573	Pennsylvania Department of Environmental Protection (PA DEP). 2013. NPDES Permit No. PA0027511 (New Castle Sanitation Authority). Effective date: March 1, 2013. Expiration date: February 28, 2018.	A

Table E-1. Source List

ID	DCN	Source Citation	Source Flag
70	SGE00575	Petroleum Equipment Suppliers Association (PESA). 2012. Outlook for Domestic Unconventional Resources. Presentation at PESA Annual Meeting.	B
71	SGE00579	Rahm, Brian, et al. 2013. Wastewater Management and Marcellus Shale Gas Development: Trends, Drivers, and Planning Implications. Journal of Environmental Management 120:105–113.	A
72	SGE00583	Romo, Carlos; Janoe, J. Scott. 2012. Regulatory Regimes for Recycling Produced and Frac Flowback Water. Paper 2012-A-453-AWMA.	A
73	SGE00586	State Review of Oil and Natural Gas Environmental Regulations (STRONGER). 2003. West Virginia Follow-Up and Supplemental Review. (January).	A
74	SGE00587	States, Stanley et al. 2013. Marcellus Shale Drilling and Brominated THMs in Pittsburgh, Pa., Drinking Water. Journal AWWA. (August).	A
75	SGE00592	U.S. Department of Energy (U.S. DOE). 2013. Water Issues Dominate Oil and Gas Production. E&P Focus. (Fall).	A
76	SGE00593	U.S. Energy Information Administration (EIA). 1993. Drilling Sideways—A Review of Horizontal Well Technology and Its Domestic Application. DOE/EIA-TR-0565, Distribution Category UC-950. (April).	A
77	SGE00595	U.S. Energy Information Administration (EIA). 2013. Drilling Productivity Report: For Key Tight Oil and Shale Gas Regions. (October).	A
78	SGE00599	U.S. EPA. 1999. Biosolids Generation, Use, and Disposal in the United States. EPA 530-R-99-009. (September).	A
79	SGE00600	U.S. EPA. 2003. Development Document for the Final Effluent Limitations Guidelines and Standards for the Metal Products and Machinery Point Source Category. EPA 821-B-03-001. (February).	A
80	SGE00602	U.S. EPA. 2004. Local Limits Development Guidance Appendices. EPA 833-R-04-002B. (July). Last accessed on May 17, 2016: http://www.epa.gov/npdes/pubs/final_local_limits_appendices.pdf	A
81	SGE00603	U.S. EPA. 2008. Clean Watersheds Needs Survey: 2008 Report to Congress. EPA 832-R-10-002.	A
82	SGE00604	U.S. EPA. 2010. Hydraulic Fracturing Research Study. EPA 600-F-10-002. (June).	A
83	SGE00608	U.S. EPA. 2012. Discharge Monitoring Report (DMR) Pollutant Loading Tool. Downloaded on 1/28/2013.	A
84	SGE00611	U.S. EPA. 2012. UIC Program Primacy. Downloaded on 10/24/2013.	A
85	SGE00612	U.S. EPA. 2013. DMR Loading Tool Download for New Castle POTW (NPDES No. PA0027511). Downloaded on 11/22/2013.	A
86	SGE00613	U.S. EPA. 2013. Meeting Summary: Meeting with Industry Representatives About the Unconventional Oil and Gas Effluent Guideline Rulemaking. (February 28).	A
87	SGE00615	U.S. EPA. 2013. Radionuclides in Drinking Water: Waste Disposal Options. (November 26).	A

Table E-1. Source List

ID	DCN	Source Citation	Source Flag
88	SGE00616	U.S. EPA. 2013. Summary of the Technical Workshop on Wastewater Treatment and Related Modeling. (April 18).	A
89	SGE00620	U.S. EPA. 2011. (Region 3) Administrative Order for Compliance and Request for Information, EPA Docket No. CWA-03-2011-0272DN. (September 28).	A
90	SGE00622	U.S. Geological Survey (USGS). 2013. Water Resources and Shale Gas/Oil Production in the Appalachian Basin—Critical Issues and Evolving Developments. (August). Last accessed on May 17, 2016: http://pubs.usgs.gov/of/2013/1137/pdf/ofr2013-1137.pdf	A
91	SGE00623	U.S. Government Accountability Office (GAO). 2012. Energy-Water-Nexus: Information on the Quantity, Quality, and Management of Water Produced During Oil and Gas Production. (January). GAO-12-156.	A
92	SGE00625	U.S. EPA. 2013. Site Visit Report: Southwestern Energy (SWN) Fayetteville Shale Gas Operations Sanitized.	A
93	SGE00627	Vidic, Radisav; Brantley, S.L.; Vandenbossche, J.M.; Yoxtheimer, D.; Abad, J.D. 2013. Impact of Shale Gas Development on Regional Water Quality. Science 340(6134).	B
94	SGE00633	Wilson, Jessica; Van Briesen, Jeanne. 2013. Oil and Gas Produced Water Management and Surface Drinking Water Sources in Pennsylvania. Environmental Practice 14(4):288–300.	A
95	SGE00635	U.S. EPA. 2012. Site Visit Report: Chesapeake Energy Corporation Marcellus Shale Gas Operations Sanitized.	A
96	SGE00636	U.S. EPA. 2012. Talisman Marcellus Operations Overview. (July 23).	A
97	SGE00639	Nicot, Jean-Philippe; Reedy, Robert C.; Costley, Ruth A.; Huang, Yun. 2012. Oil & Gas Water Use in Texas: Update to the 2011 Mining Water Use Report. University of Texas at Austin, Bureau of Economic Geology. (September).	A
98	SGE00667	Lord, R. LeBas; Luna, D.; Shahan, T. 2013. Development and Use of High-TDS Recycled Produced Water for Crosslinked-Gel-Based Hydraulic Fracturing. SPE 163824. Society of Petroleum Engineers.	B
99	SGE00691	U.S. EPA. 2013. Summary of the Technical Workshop on Water Acquisition Modeling: Assessing Impacts Through Modeling and Other Means. (September).	A
100	SGE00695	U.S. EPA. 2012. Conference Call with ConocoPhilips About Shale Gas Operations.	A
101	SGE00705	ERG. 2014. Ruminski, Brent. Notes on Call with Hydrozonix, LLC on 7 February 2014. (March 7).	A
102	SGE00707	Horn, Aaron; Patton, Mark; Hu, Jinxuan. 2013. Minimum Effective Dose: A Study of Flowback and Produced Fluid Treatment for Use as Hydraulic Fracturing Fluid. Hydrozonix, LLC. Presentation at American Association of Petroleum Geologists' Geosciences Technology Workshop. (March 18).	B
103	SGE00708	Environmental Leader. 2013. Unconventional E&P "$8 Billion of US Water Services Market." (November 11).	B

Table E-1. Source List

ID	DCN	Source Citation	Source Flag
104	SGE00709	Natural Gas Europe. 2012. Flowback Water Driving Flurry of Activity in Water Treatment (May 22).	B
105	SGE00710	Slutz, James; Anderson, Jeffrey; Broderick, Richard; Horner, Patrick. 2012. Key Shale Gas Water Management Strategies: An Economic Assessment Tool. SPE 157532. Society of Petroleum Engineers. (September 11).	B
106	SGE00721	U.S. EPA. 2015. Evaluation of Hydraulic Fracturing Fluid Data from the FracFocus Chemical Disclosure Registry 1.0. (March).	A
107	SGE00722	HIS. 2012. Water Management in Shale Gas Plays. (August).	B
108	SGE00723	Agency for Toxic Substances & Disease Registry (ATSDR). 2006. Hydrogen Sulfide ToxFAQs. (July).	A
109	SGE00725	Wolford, Robert. 2011. Characterization of Organics in the Marcellus Shale Flowback and Produced Waters. Pennsylvania State University. Master's Thesis. (August).	B
110	SGE00726	U.S. EPA. 2013. Email Chain between Jacqueline Rios, Frank Brock, and Lisa Biddle About UICs in NY Taking Oil and Gas Wastewater. (November 13).	A
111	SGE00728	HIS. 2012. America's New Energy Future: The Unconventional Oil and Gas Revolution and the US Economy. Volume 1: National Economic Contributions.	B
112	SGE00735	Eshelman, Keith N.; Elmore, Andrew. 2013. Recommended Best Management Practices for Marcellus Shale Gas Development in Maryland. University of Maryland Center for Environmental Science. Prepared for Maryland Department of the Environment. (February 18).	A
113	SGE00742	U.S. EPA. 2012. States Pretreatment Coordinators' Quarterly Conference Call: Summary. (August 8).	A
114	SGE00743	U.S. EPA. 2013. States Pretreatment Coordinators' Bi-monthly Conference Call. (August 14).	A
115	SGE00745	KLH Engineers. 2011. Municipal Authority of the City of McKeesport: Headworks Loading Analysis for Natural Gas Drilling Wastewater Pollutants. (March).	B
116	SGE00746	Franklin Township Sewer Authority. 2008. Franklin Township WWTP Fact Sheet/Statement of Basis (NPDES PA0046426). (June 2).	A
117	SGE00748	PG Environmental, LLC. 2009. Clairton Municipal Authority POTW Pass-Through Analysis Appendices. (August 19).	A
118	SGE00749	City of Clarksburg. 2009. Re: Clean Water Act Section 308 Request for Information. (March 2).	A
119	SGE00750	Borough of Waynesburg. 2009. Waynesburg Response to Clean Water Act Section 308 Request for Information. (March 31).	A
120	SGE00751	Borough of Charleroi. 2008. Re: Authority of the Borough of Charleroi Administrative Order. (November 21).	A
121	SGE00753	Keister, Timothy. 2010. Marcellus Hydrofracture Flowback and Production Wastewater Treatment, Recycle, and Disposal Technologies. Presentation at The Science of Marcellus Shale. (January 29).	B

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ID	DCN	Source Citation	Source Flag
122	SGE00754	Vengosh, A.; Jackson, Robert B.; Warner, N.; Darrah, Thomas H.; Kondash, A. 2014. A Critical Review of the Risks to Water Resources from Unconventional Shale Gas Development and Hydraulic Fracturing in the United States. Environmental Science & Technology 48(15):8334–8348.	A
123	SGE00755	Pennsylvania Department of Environmental Protection (PA DEP). 2011. NPDES Permit No. PA0023213 (Borough of Ridgway). (October).	A
124	SGE00756	Hill Engineering, Inc. 2014. Re: Local Limits Analysis for Ridgway Borough. (January 9).	A
125	SGE00757	KLH Engineers. 2008. Technical Evaluation of the Impact of Oil and Gas Well Wastewaters on the Municipal Authority of the City of McKeesport Wastewater Treatment Facility. (November).	A
126	SGE00758	KLH Engineers. 2009. Technical Evaluation of the Impact of Oil and Gas Well Wastewaters on the Clairton Municipal Authority Wastewater Treatment Facility. (February).	A
127	SGE00760	Freyman, Monika. 2014. Hydraulic Fracturing & Water Stress: Water Demand by the Numbers. Ceres. (February).	B
128	SGE00762	U.S. EPA. 2013. US EPA Technology Innovation Project: ECOS/ACWA Conference Call. (April 25).	A
129	SGE00766	U.S. EPA. 2014. Lockhart, John V. Email Correspondence between WV DEP and EPA. (June 3).	A
130	SGE00767	West Virginia Department of Environmental Protection (WV DEP). 2010. Letter to City of Follansbee Re: WV/NPDES Permit No. WV0020273 Accepting Oil and Gas Wastewater. (December 15).	A
131	SGE00768.A01	Robart, Alexander. 2014. E&P Infrastructure vs. Third-Party Services Regional Economic & Environmental Factors. PacWest Consulting Partners.	B
132	SGE00768.A25	Fletcher, Sarah. 2014. Water Management Infrastructure Investments: Decision Factors and Regional Economics. Sourcewater Cambridge Innovation Center at MIT.	B
133	SGE00768.A26	Tucker, Scott. 2014. Evaluating Characteristics of Source, Flowback, & Produced Water for Effective Water Treatment. (May 29).	B
134	SGE00769	International Atomic Energy Agency (IAEA). 2014. The Environmental Behaviour of Radium: Revised Edition. Technical Report Series No. 476. (March 1).	A
135	SGE00779.A24	Mastowski, Ryan. 2014. Disposal—Oil and Gas Environmental Compliance Conference. A&WMA Conference. (May 13-14).	B
136	SGE00780	ExxonMobile. 2014. Hydraulic Fracturing Fluid. XTO Energy. Downloaded on 6/13/2014.	C
137	SGE00781	FracFocus. 2014. What Chemicals Are Used?	B
138	SGE00785	U.S. EPA. 2015. Summary of EPA Outreach and Coordination with Indian Tribes for the Proposed Pretreatment Standards for UOG Extraction Wastewater.	A
139	SGE00786	U.S. EPA. 2014. UOG Workgroup—Warren, OH POTW Info Request. (June 19).	A

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ID	DCN	Source Citation	Source Flag
140	SGE00787	Borough of California. 2009. Borough of California Response to 308 Request for Information. (March 18).	A
141	SGE00800	McTigue, Nancy; Graf, Katherine; Brown, Richard. 2014. Occurrence and Consequences of Increased Bromide in Drinking Water Sources. Environmental Engineering & Technology, Inc.	A
142	SGE00930	Pennsylvania Department of Environmental Protection (PA DEP). 2012. Johnstown Redevelopment Authority (PA0026034)—Final Fact Sheet 2012.	A
143	SGE00931	Pennsylvania Department of Environmental Protection (PA DEP). 2012. Brockway Area Sewer Authority—PA0028428—Final Permit 2012.	A
144	SGE00935	U.S. EPA. 2013. Letter to Lee McDonnell, PA DEP, Informing NPDES Permitting Authorities of Testing as Part of the Permit Application Process. (August 28).	A
145	SGE00935.A01	U.S. EPA. 2013. Toxic Screening Analysis Spreadsheet.	A
146	SGE00966	California Council on Science and Technology (CCST). 2014. Advanced Well Stimulation Technologies in California: An Independent Review of Scientific and Technical Information. Sacramento, CA.	A
147	SGE00978	PA DEP. 2014. PA DEP TENORM Study—Update 2nd Quarter 2014 Update.	A
148	SGE00982	U.S. EPA. 2011. (Region 3) Letter to PA DEP regarding disposal of Marcellus Shale wastewater. (May 12).	A
149	SGE00983	Ohio Revised Code. 2012. Title 15, Chapter 1509: Division of Oil and Gas Resources Management—Oil and Gas. (September 10). Downloaded October 17, 2014.	A
150	SGE00984	Energy Information Administration (EIA). 2014. Glossary. Last accessed on May 17, 2016: http://www.eia.gov/tools/glossary	A
151	SGE00985	Parker, Kimberly M.; Zeng, Teng; Harkness, Jennifer; Vengosh, Avner; Mitch, William A. 2014. Enhanced Formation of Disinfection Byproducts in Shale Gas Wastewater-Impacted Drinking Water Supplies. Environmental Science & Technology 48(19):11161–11169.	A
152	SGE00996	Kicinski, J. 2007. Wheeling POTW Analysis 4.	A
153	SGE00997	Borough of Waynesburg. 2009. Clean Water Act Section 308 Request for Information.	A
154	SGE00997.A01	Borough of Waynesburg. 2009. Clean Water Act Section 308 Request for Information—Attachment 1: Acceptance Records.	A
155	SGE00999	McClung, L.A. 2008. Wheeling POTW Discharge Requirements.	A
156	SGE01000	City of Wheeling Water Pollution Control Division. 2007. Wheeling Effluent Data.	A
157	SGE01006	U.S. EPA. 2000. Development Document for Final Effluent Limitations Guidelines and Standards for Synthetic-Based Drilling Fluids and Other Non-Aqueous Drilling Fluids in the Oil and Gas Extraction Point Source Category. EPA-821-B-00-013. (December).	A

Table E-1. Source List

ID	DCN	Source Citation	Source Flag
158	SGE01009	Caen, R., Darley, H.C.H., and G. R. Gray. 2011. Composition and Properties of Drilling and Completion Fluids. 6th edition. Gulf Professional Publishing: Waltham, MA.	B
159	SGE01012	U.S. EPA. 2014. Class II Disposal Well Inventory Update. Office of Ground Water and Drinking Water. (July 29).	A
160	SGE01017.A05	Anglund, E. 2014. Rev Ops Strategies for Sourcing Large Volumes of Freshwater for Hydraulic Frac Ops in the Context of Competition from other Ind.	C
161	SGE01028	Pennsylvania Department of Environmental Protection. 2015. Technologically Enhanced Naturally Occurring Radioactive Materials (TENORM) Study Report.	A
162	SGE01077	Ground Water Protection Council (GWPC). 2014. Regulations Designed to Protect State Oil and Gas Water Resources. Last accessed on May 17, 2016: http://www.gwpc.org/sites/default/files/files/Oil%20and%20Gas%20Regulation%20Report%20Hyperlinked%20Version%20Final-rfs.pdf	A
163	SGE01093	Abt Associates. 2015. Final Annotated Bibliography for Sec XIV, Environmental Impacts, of the Preamble for “ELG and Standards for the O&G Extraction Point Source Cat; Prop Rule”	A
164	SGE01095	USGS. 2015. Trends in Hydraulic Fracturing Distributions & Trt Fluids, Additives, Proppants, & Water Volumes Applied to US Wells Drilled, 1947-2010.	A
165	SGE01095.A09	USGS. 2015. Trends in Hydraulic Fracturing Distributions & Trt Fluids, Additives, Proppants, & Water Volumes Applied to US Wells Drilled, 1947-2010: Attachment 9: Frac_Trtm_Type.xlsx.	A
166	SGE01113	West Virginia Department of Environmental Protection (WV DEP). 2009. WV/NPDES Permit No WV0023302 Clarksburg Sanitary Board Accepting Oil and Gas Wastewater.	A
167	SGE01114	West Virginia Department of Environmental Protection (WV DEP). 2009. WV/NPDES Permit No, WV0023230 City of Wheeling Accepting Oil and Gas Wastewater.	A
168	SGE01123	U.S. EPA. 2014. Tribal Unconventional Oil and Gas Operations and Wastewater Management Call Summary.	A
169	SGE01125	NYSDEC. 2015. Final Supplemental Generic Environmental Impact Statement on the Oil, Gas, and Solution Mining Regulatory Program.	A
170	SGE01126	U.S. EPA. 2015. Assessment of the Potential Impacts of Hydraulic Fracturing for Oil and Gas in Drinking Water Resources. ORD.	A
171	SGE01128	Veil, J. 2015. US Produced Water Volumes & Management Practices in 2012. Veil Environmental, LLC. Prepared for Ground Water Protection Council (GWPC).	A
172	SGE01143	Lyons, B. and Tintera, J.J. 2014. Sustainable Water Management in the Texas Oil and Gas Industry. Atlantic Council. Energy & Environment Program.	B
173	SGE01166	Warner, N.R., et al. 2014. New Tracers Identify Hydraulic Fracturing Fluids and Accidental Releases from Oil and Gas Operations.	A

Table E-1. Source List

ID	DCN	Source Citation	Source Flag
174	SGE01168	Myers, J.E. 2014. Chevron San Ardo Facility Unit (SAFU) Beneficial Produced Warer Reuse for Irrigation. Chevron. Society of Petroleum Engineers.	A
175	SGE01169	FracFocus. 2015. FracFocus Database Version 2.0. Accessed on July 22 2015.	A
176	SGE01170	DrillingInfo, Inc. 2015. DI Desktop® March 2015 Download_CBI.	B
177	SGE01177	ERG. 2016. Conventional Oil and Gas Memorandum for the Record.	A
178	SGE01178	ERG. 2016. Analysis of Centralized Waste Treatment Facilities (CWTs) Accepting UOG Extraction Wastewater.	A
179	SGE01179	ERG. 2016. Data Compilation Memorandum for the Technical Development Document (TDD).	A
180	SGE01179.A02	ERG. 2016. Data Compilation Memorandum for the Technical Development Document (TDD) Attachment 2: EIA UOG Resource Potential.	A
181	SGE01179.A03	ERG. 2016. Data Compilation Memorandum for the Technical Development Document (TDD) Attachment 3: TDD Data Compilation.	A
182	SGE01180	ERG. 2016. Analysis of DI Desktop® Memorandum.	A
183	SGE01181	ERG. 2016. Unconventional Oil and Gas (UOG) Drilling Wastewater Memorandum.	A
184	SGE01182	ERG. 2016. Analysis of Pennsylvania Department of Environmental Protection’s Oil and Gas Waste Reports.	A
185	SGE01183	ERG. 2016. Publicly Owned Treatment Works (POTW) Memorandum for the Technical Development Document (TDD).	A
186	SGE01184	ERG. 2016. Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation Memorandum.	A
187	SGE01184.A13	ERG. 2016. UOG Produced Water Volumes and Characterization Data Compilation—A13: UOG Wastewater Characterization Database.	A
188	SGE01185	ERG. 2016. Radioactive Elements in the Unconventional Oil and Gas (UOG) Industry.	A
189	SGE01186	U.S. EPA. 2016. Unconventional Oil & Gas Wastewater Treatment Technologies. U.S. EPA Office of Water, Engineering and Analysis Division.	A
190	SGE01187	ERG. 2016. Analysis of Active Underground Injection for Disposal Wells.	A
191	SGE01187.A01	ERG. 2016. Analysis of Active Underground Injection for Disposal Wells—Attachment 1: Injection for Disposal Well Data.	A
192	SGE01190	U.S. Energy Information Administration. 2015. Assumptions to the Annual Energy Outlook 2015.	A
193	SGE01191	U.S. Energy Information Administration. 2015. Lower 48 States Shale Plays. Prepared by EIA Office of Oil and Gas. (April).	A
194	SGE01192	U.S. Energy Information Administration. 2015. Annual Energy Outlook 2015 with Projections to 2040. DOE/EIA-0383 (2015). (April).	A

Table E-1. Source List

ID	DCN	Source Citation	Source Flag
195	SGE01206	Cart, J. 2015. Hundreds of illicit oil wastewater pits found in Kern County. LA Times.	D
196	SGE01207	US Govt Accountability Office. 2015. Water in the energy sector: Reducing freshwater use in hydraulic fracturing & thermoelectric power plant cooling.	A
197	SGE01208	State Review of Oil and Natural Gas Environmental Regulations, Inc. 2015. STRONGER: 2015 Guidelines.	A
198	SGE01216	Ellsworth, W.L. 2013. Injection-induced earthquakes. *Science* 341(6142). July 12, 2013. doi: 43 10.1126/science.1225942.	A
199	SGE01231	Maloney, K.O. and Yoxtheimer, D.A. 2012. Production and Disposal of Waste Materials from Gas and Oil Extraction from the Marcellus Shale Play in Pennsylvania. Environmental Practice.	A
200	SGE01233	Baker Hughes. 2015. North America Rotary Rig Count Pivot Table (Feb 2011–Current). (October 9). Downloaded on 10/12/2015.	B
201	SGE01234	Baker Hughes. 2015. U.S. Onshore Well Count. (January 9). Downloaded on 10/12/2015.	B
202	SGE01235	Baker Hughes. 2015. North America Rotary Rig Count (Jan 2000–Current). (October 9). Downloaded on 10/12/2015.	B
203	SGE01245	O'Connell, James, ERG. 2014. Pennsylvania Department of Environmental Protection's (PA DEP) Statewide Oil and Gas Waste Reports. (December).	A
204	SGE01250	The Alaska State Legislature. 2014. Alaska Statutes: Title 38 Chapter 5 Section 965.	A
205	SGE01251	Arkansas Oil and Gas Commission. 2015. General Rules and Regulations.	A
206	SGE01252	The State of Oklahoma. 2015. The Oklahoma Register: Title 165 Chapter 10.	A
207	SGE01253	The State of Pennsylvania. 1987. The Pennsylvania Code: Chapter 78.	A
208	SGE01255	US EIA. 2015. Maps: Exploration, Resources, Reserves, and Production. Last accessed on May 17, 2016: http://www.eia.gov/maps/maps.htm	A
209	SGE01260	U.S. Geological Survey (USGS). 2014. National Produced Waters Geochemical Database v2.1 (Provisional).	A
210	SGE01263	ERG. 2015. Memorandum to the Record Discussing Well Completion Reports.	A
211	SGE01275	USGS. 2015. U.S. Geological Survey Assessments of Continuous (Unconventional) Oil and Gas Resources, 2000 to 2011.	A
212	SGE01277	U.S. EPA. 2016. Profile of the Unconventional Oil and Gas Industry. EPA-821-R-16-003.	A
213	SGE01322	U.S. Department of Energy. 2015. US Tight Oil Production December 2015. U.S. Energy Information Administration (EIA).	A

Table E-1. Source List

ID	DCN	Source Citation	Source Flag
214	SGE01330	US DOE, US DOI, US EPA. 2014. Federal Multiagency Collaboration on Unconventional Oil and Gas Research: A Strategy for Research and Development. Last accessed on May 17, 2016: http://unconventional.energy.gov/pdf/Multiagency_UOG_Research_Strategy.pdf	A
215	SGE01331	STRONGER. 2016. Who We Are—STRONGER.	C
216	SGE01332	U.S. EPA. 2016. Clean Watersheds Needs Survey 2012 Report to Congress. EPA 830-R-15-005.	A
217	SGE01335	Baker Hughes. 2016. North American Rig Count Current Week Rig Count Summary.	C
218	SGE01336	North Dakota Industrial Commission. 2015. North Dakota Drilling and Production Statistics Annual Production Reports: 1998-2014 Oil.	A
219	SGE01337	North Dakota Industrial Commission. 2015. North Dakota Drilling and Production Statistics Annual Production Reports: 1998-2014 Gas.	A
220	SGE01339	U.S. Department of Energy. 2014. AEO 2014 Market Trends Figure MT 53 Data. U.S. Energy Information Administration (EIA).	A
221	SGE01340	U.S. Department of Energy. 2014. AEO 2014 Market Trends Figure MT 44 Data. U.S. Energy Information Administration (EIA).	A
222	SGE01341	North Dakota Industrial Commission. 2016. North Dakota Injection Data.	A
223	SGE01341.A01	Day, Ashleigh M. 2016. North Dakota Injection Data Copyright Clarification and Data Explanation. North Dakota Industrial Commission.	A
224	SGE01344	CH2MHill. 2015. U.S. Onshore Unconventional Exploration and Production Water Management Case Studies. Prepared for Energy Water Initiative.	B
225	SGE01345	Toxicity of acidization fluids used in California oil exploration DCN SGE01345	A
226	SGE01351	Weingartern, M., S. Ge, J.W., Godt, B.A. Bekins, and J.L. Rubinstein. 2015. High-rate injection 7 is associated with the increase in U.S. mid-continent seismicity. *Science* 348(6241), p. 1336-8 1340. June 19, 2015. doi: 10.1126/science.aab1345. Available online at: http://www.ourenergypolicy.org/wp-content/uploads/2015/06/Science-2015-Weingarten-1336-40.pdf	A
227	SGE01352	Ohio Department of Natural Resources. 2012. Preliminary Report on the Northstar 1 Class II Injection Well and the Seismic Events in the Youngstown, Ohio, Area. (March). Available online at: http://oilandgas.ohiodnr.gov/portals/oilgas/downloads/northstar/reports/northstar-executive_summary.pdf	A

Chapter F. APPENDICES

Table F-1. TDD Supporting Memoranda and Other Relevant Documents Available in FDMS

DCN	Title	Description	Relevant TDD Section(s)
SGE01178	Analysis of Centralized Waste Treatment (CWT) Facilities Accepting UOG Extraction Wastewater	Describes the various data sources used to identify CWT facilities that have accepted UOG wastewater and explains the different CWT facility analyses that are presented in Section D.4 of the TDD.	D.1, D.4
SGE01186	Unconventional Oil and Gas (UOG) Extraction Wastewater Treatment Technologies	Summarizes technologies that are currently used to treat UOG wastewater at full-scale operations and technologies not currently used to treat UOG extraction wastewater, but which may be applied in the future.	D.3
SGE01179	Data Compilation Memorandum for the Technical Development Document (TDD)	Explains various data analyses presented in Chapters B, C, and D of the TDD, involving well drilling and construction, historical and current drilling activity, UOG resource potential, fracturing fluid chemical additives, and reuse/recycle.	B.3, C.Intro, C.1, C.2, D.1, D.2, D.3
SGE01184	Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation	Describes the various data sources used to identify UOG wastewater volumes and characteristics data and explains the process that was used to standardize and summarize the data.	B.3, C.Intro, C.2, C.3
SGE01187	Analysis of Active Underground Injection for Disposal Wells	Explains the compilation of underground injection wells data from various sources.	D.1, D.2, D.4
SGE01182	Analysis of Pennsylvania Department of Environmental Protection's (PA DEP) Oil and Gas Waste Reports	Explains the PA DEP waste reports data and explains the processes that were used to analyze the data.	C.2, D.1, D.5
SGE01181	Unconventional Oil and Gas (UOG) Drilling Wastewater	Explains the well drilling process in more detail, with focus on drilling wastewater volumes and constituent concentrations.	B.2, C.2, C.3, D.1
SGE00785	Summary of Tribal Outreach Regarding Pretreatment Standards for Unconventional Oil and Gas (UOG) Extraction Wastewater	Summarizes the data collected as part of the tribal outreach efforts associated with the rule.	D.5

Table F-1. TDD Supporting Memoranda and Other Relevant Documents Available in FDMS

DCN	Title	Description	Relevant TDD Section(s)
SGE01183	Publicly Owned Treatment Works (POTW) Memorandum for the Technical Development Document (TDD)	Describes the various data sources used to identify POTWs that have accepted UOG wastewater and explains the different POTW analyses that are presented in Section D.5 of the TDD.	D.5
SGE01277	Profile of the Oil and Gas Extraction (OGE) Sector, with Focus on Unconventional Oil and Gas (UOG) Extraction	Provides economic background information about the oil and gas industry.	B. Intro
SGE01185	Radioactive Materials in the Unconventional Oil and Gas (UOG) Industry	Provides background information about radioactive elements in the UOG industry, with focus on radium-226 and radium-228.	C.3, D.5
SGE01180	Analysis of DI Desktop®	Summarizes the DI Desktop® data source and where it is cited throughout the rule analyses.	B.3.2
SGE01177	Conventional Oil and Gas (COG) Memorandum for the Record	Summarizes COG extraction wastewater characteristics and management and disposal practices used for COG extraction wastewater.	N/A

N/A—not applicable

Table F-2. Crosswalk Between TDD and Supporting Memoranda

TDD Table or Figure Number	TDD Table/Figure Title	In a Supporting Memo (Y/N)?[a]	Source or Supporting Memo DCN(s)	Supporting Memo Title(s)
Table A-1	Summary of State Regulations/Guidance	No	SGE00187, SGE00254, SGE00545, SGE00766, SGE00767, SGE00982, SGE00983	—
Figure B-1	Historical and Projected Crude Oil Production by Resource Type	No	SGE01192	—
Figure B-2	Historical and Projected Natural Gas Production by Resource Type	No	SGE01192	—
Figure B-3	Major U.S. Shale Plays (Updated April 13, 2015)	No	SGE01191	—
Figure B-4	Major U.S. Tight Plays (Updated June 6, 2010)	No	SGE00155	—
Figure B-5	UOG Extraction Wastewater	No (Created by the EPA)	—	—
Figure B-6	Horizontal (A), Vertical (B), and Directional (C) Drilling Schematic	No	SGE00593	—
Figure B-7	Length of Time to Drill a Well in Various UOG Formations	Yes	SGE01179	Data Compilation Memorandum for the Technical Development Document (TDD)
Figure B-8	Hydraulic Fracturing Schematic	No	SGE00604	—
Figure B-9	Freshwater Impoundment	No	SGE00275	—
Figure B-10	Vertical Gas and Water Separator	No	SGE00625	—
Figure B-11	Fracturing Tanks	No	SGE00625	—
Figure B-12	Produced Water Storage Tanks	No	SGE00275	—
Figure B-13	Number of Active U.S. Onshore Rigs by Trajectory and Product Type over Time	Yes	SGE01179	Data Compilation Memorandum for the Technical Development Document (TDD)
Figure B-14	Projections of UOG Well Completions	Yes	SGE01179	Data Compilation Memorandum for the Technical Development Document (TDD)

Table F-2. Crosswalk Between TDD and Supporting Memoranda

TDD Table or Figure Number	TDD Table/Figure Title	In a Supporting Memo (Y/N)?[a]	Source or Supporting Memo DCN(s)	Supporting Memo Title(s)
Table B-2	Active Onshore Oil and Gas Drilling Rigs by Well Trajectory and Product Type (as of October 9, 2015)	Yes	SGE01179	Data Compilation Memorandum for the Technical Development Document (TDD)
Table B-3	UOG Potential by Resource Type as of January 1,	Yes	SGE01179	Data Compilation Memorandum for the Technical Development Document (TDD)
Figure C-1	UOG Extraction Wastewater Volumes for Marcellus Shale Wells in Pennsylvania (2004–2014)	Yes	SGE01182	Analysis of Pennsylvania Department of Environmental Protection's (PA DEP) Oil and Gas Waste Reports
Figure C-2	Ranges of Typical Produced Water Generation Rates over Time After Fracturing	Yes	SGE01184	Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation
Figure C-3	Anions and Cations Contributing to TDS Concentrations in Shale and Tight Oil and Gas Formations	Yes	SGE01184	Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation
Figure C-4	Chloride, Sodium, and Calcium Concentrations in Flowback and Long-Term Produced Water (LTPW) from Shale and Tight Oil and Gas Formations	Yes	SGE01184	Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation
Figure C-5	Barium Concentrations in UOG Produced Water from Shale and Tight Oil and Gas Formations	Yes	SGE01184	Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation
Figure C-6	Constituent Concentrations over Time in UOG Produced Water from the Marcellus and Barnett Shale Formations	No	SGE00414	—
Table C-1	Sources for Base Fluid in Hydraulic Fracturing	Yes	SGE01179	Data Compilation Memorandum for the Technical Development Document (TDD)
Table C-2	Fracturing Fluid Additives, Common Compounds, and Common Uses	No	SGE00070, SGE00721, SGE00780, SGE00781, SGE00966	—

Table F-2. Crosswalk Between TDD and Supporting Memoranda

TDD Table or Figure Number	TDD Table/Figure Title	In a Supporting Memo (Y/N)?[a]	Source or Supporting Memo DCN(s)	Supporting Memo Title(s)
Table C-3	Most Frequently Reported Additive Ingredients Used in Fracturing Fluid in Gas Wells from FracFocus (2011–2013)	No	SGE00721	—
Table C-4	Most Frequently Reported Additive Ingredients Used in Fracturing Fluid in Oil Wells from FracFocus (2011–2013)	No	SGE00721	—
Table C-5	Median Drilling Wastewater Volumes for UOG Horizontal and Vertical Wells in Pennsylvania	Yes	SGE01182	Analysis of Pennsylvania Department of Environmental Protection’s (PA DEP) Oil and Gas Waste Reports
Table C-6	Drilling Wastewater Volumes Generated per Well by UOG Formation	Yes	SGE01181	Unconventional Oil and Gas (UOG) Drilling Wastewater Memorandum
Table C-7	UOG Well Flowback Recovery by Resource Type and Well Trajectory	Yes	SGE01184	Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation
Table C-8	Long-Term Produced Water Generation Rates by Resource Type and Well Trajectory	Yes	SGE01184	Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation
Table C-9	Produced Water Volume Generation by UOG Formation	Yes	SGE01184	Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation
Table C-10	Concentrations of Select Classical and Conventional Constituents in UOG Drilling Wastewater from Marcellus Shale Formation Wells	Yes	SGE01181	Unconventional Oil and Gas (UOG) Drilling Wastewater Memorandum
Table C-11	Concentrations of Select Classical and Conventional Constituents in UOG Produced Water	Yes	SGE01184	Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation
Table C-12	Concentrations of Bromide and Sulfate in UOG Drilling Wastewater from Marcellus Shale Formation Wells	Yes	SGE01181	Unconventional Oil and Gas (UOG) Drilling Wastewater Memorandum

Table F-2. Crosswalk Between TDD and Supporting Memoranda

TDD Table or Figure Number	TDD Table/Figure Title	In a Supporting Memo (Y/N)?[a]	Source or Supporting Memo DCN(s)	Supporting Memo Title(s)
Table C-13	Concentrations of Select Anions and Cations Contributing to TDS in UOG Produced Water	Yes	SGE01184	Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation
Table C-14	Concentrations of Select Organic Constituents in UOG Drilling Wastewater from Marcellus Shale Formation Wells	Yes	SGE01181	Unconventional Oil and Gas (UOG) Drilling Wastewater Memorandum
Table C-15	Concentrations of Select Organic Constituents in UOG Produced Water	Yes	SGE01184	Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation
Table C-16	Concentrations of Select Metal Constituents in UOG Produced Water	Yes	SGE01181	Unconventional Oil and Gas (UOG) Drilling Wastewater Memorandum
Table C-17	Concentrations of Select Metal Constituents in UOG Produced Water	Yes	SGE01184	Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation
Table C-18	Concentrations of Select Radioactive Constituents in UOG Drilling Wastewater from Marcellus Shale Formation Wells	Yes	SGE01181	Unconventional Oil and Gas (UOG) Drilling Wastewater Memorandum
Table C-19	Concentrations of Select Radioactive Constituents in UOG Produced Water	Yes	SGE01184	Unconventional Oil and Gas (UOG) Produced Water Volumes and Characterization Data Compilation
Table C-20	Concentrations of Radioactive Constituents in Rivers, Lakes, Groundwater, and Drinking Water Sources Throughout the United States (pCi/L)	No	SGE00769	—
Figure D-1	UOG Produced Water Management Methods	No (Created by the EPA)	—	—
Figure D-2	UOG Drilling Wastewater Management Methods	No (Created by the EPA)	—	—
Figure D-3	Management of UOG Drilling Wastewater Generated by UOG Wells in Pennsylvania (2008–2014)	Yes	SGE01182	Analysis of Pennsylvania Department of Environmental Protection's (PA DEP) Oil and Gas Waste Reports

Table F-2. Crosswalk Between TDD and Supporting Memoranda

TDD Table or Figure Number	TDD Table/Figure Title	In a Supporting Memo (Y/N)?[a]	Source or Supporting Memo DCN(s)	Supporting Memo Title(s)
Figure D-4	Active Disposal Wells and CWT Facilities Identified in the Appalachian Basin	No (Created by the EPA)	—	—
Figure D-5	U.S. Injection for Disposal Volume and UOG Production over Time	No	SGE01192; SGE01128; SGE01340; SGE01339 SGE01322	—
Figure D-6	Injection for Disposal Volume and Crude Oil Production over Time in North Dakota	No	SGE01337; SGE00182; SGE01128; SGE01340	—
Figure D-7	Injection for Disposal Volume, Cumulative Bakken Wells Drilled, and Cumulative Disposal Wells Drilled in North Dakota	No	SGE00557; SGE00182; SGE01128; SGE01340	—
Figure D-8	Flow Diagram of On-the-Fly UOG Produced Water Treatment for Reuse/Recycle	No	SGE00331	—
Figure D-9	Hypothetical UOG Produced Water Generation and Base Fracturing Fluid Demand over Time	Yes	SGE01179	Data Compilation Memorandum for the Technical Development Document (TDD)
Figure D-10	UOG Extraction Wastewater Management Practices Used in the Marcellus Shale (Top: Southwestern Region; Bottom: Northeastern Region)	No	SGE00579	—
Figure D-11	Number of Known Active CWT Facilities over Time in the Marcellus and Utica Shale Formation	Yes	SGE01178	Analysis of Centralized Waste Treatment (CWT) Facilities Accepting UOG Extraction Wastewater
Figure D-12	Typical Process Flow Diagram at a POTW	No	SGE00602	—
Figure D-13	Clairton POTW: Technical Evaluation of Treatment Processes' Ability to Remove Chlorides and TDS	Yes	SGE01183	Publicly Owned Treatment Works (POTW) Memorandum for the Technical Development Document (TDD)

Table F-2. Crosswalk Between TDD and Supporting Memoranda

TDD Table or Figure Number	TDD Table/Figure Title	In a Supporting Memo (Y/N)?[a]	Source or Supporting Memo DCN(s)	Supporting Memo Title(s)
Figure D-14	McKeesport POTW: Technical Evaluation of Treatment Processes' Ability to Remove Chlorides and TDS	Yes	SGE01183	Publicly Owned Treatment Works (POTW) Memorandum for the Technical Development Document (TDD)
Figure D-15	Ridgway POTW: Annual Average Daily Effluent Concentrations and POTW Flows	Yes	SGE01183	Publicly Owned Treatment Works (POTW) Memorandum for the Technical Development Document (TDD)
Figure D-16	Johnstown POTW: Annual Average Daily Effluent Concentrations and POTW Flows	Yes	SGE01183	Publicly Owned Treatment Works (POTW) Memorandum for the Technical Development Document (TDD)
Figure D-17	California POTW: Annual Average Daily Effluent Concentrations and POTW Flows	Yes	SGE01183	Publicly Owned Treatment Works (POTW) Memorandum for the Technical Development Document (TDD)
Figure D-18	Charleroi POTW: Annual Average Daily Effluent Concentrations and POTW Flows	Yes	SGE01183	Publicly Owned Treatment Works (POTW) Memorandum for the Technical Development Document (TDD)
Figure D-19	Barium Sulfate Scaling in Haynesville Shale Pipe	No	SGE00768.A26	—
Figure D-20	THM Speciation in a Water Treatment Plant (1999–2013)	No	SGE00800	—
Table D-1	UOG Produced Water Management Practices	Yes	SGE01179	Data Compilation Memorandum for the Technical Development Document (TDD)
Table D-2	Distribution of Active Class II Disposal Wells Across the United States	Yes	SGE01187	Analysis of Active Underground Injection for Disposal Wells
Table D-3	Distribution of Active Class II Disposal Wells on Tribal Lands	Yes	SGE01187	Analysis of Active Underground Injection for Disposal Wells
Table D-4	Reuse/Recycle Practices in 2012 as a Percentage of Total Produced Water Generated as Reported by Respondents to 2012 Survey	No	SGE00575	—
Table D-5	Reported Reuse/Recycle Criteria	Yes	SGE01179	Data Compilation Memorandum for the Technical Development Document (TDD)
Table D-6	Reported Reuse/Recycle Practices as a Percentage of Total Fracturing Volume	Yes	SGE01179	Data Compilation Memorandum for the Technical Development Document (TDD)

Table F-2. Crosswalk Between TDD and Supporting Memoranda

TDD Table or Figure Number	TDD Table/Figure Title	In a Supporting Memo (Y/N)?[a]	Source or Supporting Memo DCN(s)	Supporting Memo Title(s)
Table D-7	Number of CWT Facilities That Have Accepted or Plan to Accept UOG Extraction Wastewater	Yes	SGE01178	Analysis of Centralized Waste Treatment (CWT) Facilities Accepting UOG Extraction Wastewater
Table D-8	Typical Composition of Untreated Domestic Wastewater	No	SGE00167	—
Table D-9	Typical Percent Removal Capabilities from POTWs with Secondary Treatment	No	SGE00600	—
Table D-10	U.S. POTWs by Treatment Level in 20	No	SGE00603; SGE01332	—
Table D-11	POTWs That Accepted UOG Extraction Wastewater Directly from Onshore UOG Operators	Yes	SGE01183	Publicly Owned Treatment Works (POTW) Memorandum for the Technical Development Document (TDD)
Table D-12	Percentage of Total POTW Influent Wastewater Composed of UOG Extraction Wastewater at POTWs Accepting Wastewater from UOG Operators	Yes	SGE01183	Publicly Owned Treatment Works (POTW) Memorandum for the Technical Development Document (TDD)
Table D-13	Summary of Studies About POTWs Receiving Oil and Gas Extraction Wastewater Pollutants	No (Created by the EPA)	—	—
Table D-14	Clairton Influent Oil and Gas Extraction Wastewater Characteristics	No	SGE00748	—
Table D-15	Trucked COG Extraction Wastewater Treated at McKeesport POTW from November 1 Through 7, 2008	No	SGE00745	—
Table D-16	McKeesport POTW Removal Rates Calculated for Local Limits Analysis	No	SGE00745	—
Table D-17	Constituent Concentrations in UOG Extraction Wastewater Treated at the McKeesport POTW Before Mixing with Other Influent Wastewater	No	SGE00525	—
Table D-18	McKeesport POTW Effluent Concentrations With and Without UOG Extraction Wastewater	No	SGE00525	—

Table F-2. Crosswalk Between TDD and Supporting Memoranda

TDD Table or Figure Number	TDD Table/Figure Title	In a Supporting Memo (Y/N)?[a]	Source or Supporting Memo DCN(s)	Supporting Memo Title(s)
Table D-19	Charleroi POTW Paired Influent/Effluent Data and Calculated Removal Rates	No	SGE00751	—
Table D-20	Franklin Township POTW Effluent Concentrations With and Without Industrial Discharges from the Tri-County CWT Facility	No	SGE00525	—
Table D-21	TDS Concentrations in Baseline and Pilot Study Wastewater Samples at Warren POTW	No	SGE00616	—
Table D-22	EPA Region 5 Compliance Inspection Sampling Data	No	SGE00616	—
Table D-23	Inhibition Threshold Levels for Various Treatment Processes	No	SGE00602	—
Table D-24	Industrial Wastewater Volumes Received by New Castle POTW (2007–2009)	No	SGE00554	—
Table D-25	NPDES Permit Limit Violations from Outfall 001 of the New Castle POTW (NPDES Permit Number PA0027511)	No	SGE00612, SGE00620	—
Table D-26	Concentrations of DBPs in Effluent Discharges at One POTW Not Accepting Oil and Gas Wastewater and at Two POTWs Accepting Oil and Gas Wastewater (µg/L)	No	SGE00535	—
Figure F-1	Constituent Concentrations over Time in UOG Produced Water from the Marcellus and Barnett Shale Formations	No	SGE00414	—
Table F-1	TDD Supporting Memoranda and Other Relevant Documents Available in FDMS	No (Created by the EPA)	—	—
Table F-2	Crosswalk Between TDD and Supporting Memoranda	No (Created by the EPA)	—	—
Table F-3	UOG Resource Potential: Shale as of January 1, 2013	Yes	SGE01179	Data Compilation Memorandum for the Technical Development Document (TDD)
Table F-4	UOG Resource Potential: Tight as of January 1, 2013	Yes	SGE01179	Data Compilation Memorandum for the Technical Development Document (TDD)

a—Unless otherwise noted, figures and/or tables not included in a supporting memorandum were taken directly from a source without calculation or interpretation.

Table F-3. UOG Resource Potential: Shale as of January 1, 2013

EIA Region	EIA Basin	UOG Formation Name	Resource Type	Oil EUR (MMbls per well)	Gas EUR (Bcf per well)	Oil TRR (MMbls)	Gas TRR (Bcf)	New Well Potential
1—East	Appalachian	Devonian	Shale gas	0.000	0.061	0	23,700	388,500
		Marcellus	Shale gas	0.003	1.581	300	148,700	94,000
		Utica	Shale gas	0.002	0.470	200	53,100	112,900
			Shale oil	0.043	0.092	700	1,500	16,300
	Illinois	New Albany	Shale gas	0.000	1.188	0	29,100	24,500
	Michigan	Antrim	Shale gas	0.000	0.120	0	12,700	105,800
2—Gulf Coast	Black Warrior	Floyd-Neal/Conasauga	Shale gas	0.000	1.520	0	4,300	2,800
	TX-LA-MS Salt	Haynesville-Bossier	Shale gas	0.000	3.588	0	73,300	20,400
	Western Gulf	Eagle Ford	Shale gas	0.191	1.437	6,400	48,200	33,500
			Shale oil	0.123	0.227	3,900	7,200	31,700
		Pearsall	Shale gas	0.000	0.676	0	4,900	7,200
		Tuscaloosa	Shale oil	0.112	0.021	3,200	600	28,600
		Woodbine	Shale oil	0.122	0.061	600	300	4,900
3—Midcontinent	Anadarko	Cana Woodford	Shale gas	0.028	1.590	200	11,500	7,200
			Shale oil	0.036	0.961	100	2,700	2,800
	Arkoma	Caney	Shale gas	0.000	0.973	0	3,100	3,200
		Fayetteville	Shale gas	0.000	0.899	0	20,400	22,700
		Woodford	Shale gas	0.000	1.342	0	6,300	4,700
	Black Warrior	Chattanooga	Shale gas	0.000	0.968	0	1,600	1,700
4—Southwest	Fort Worth	Barnett	Shale gas	0.003	0.296	200	17,500	59,000
	Permian	Wolfcamp	Shale oil	0.085	0.347	6,100	24,900	71,800
		Barnett-Woodford	Shale gas	0.000	1.181	0	12,400	10,500
		Avalon/BoneSpring	Shale oil	0.118	0.367	2,900	9,000	24,500
5—Rocky Mountain	Denver	Niobrara	Shale oil	0.012	0.078	400	2,700	34,600
	Greater Green River	Hilliard-Baxter-Mancos	Shale gas	0.000	0.293	0	10,500	35,800
5—Rocky Mountain	Montana Thrust Belt	All tight oil plays	Shale oil	0.102	0.068	600	400	5,900

Table F-3. UOG Resource Potential: Shale as of January 1, 2013

EIA Region	EIA Basin	UOG Formation Name	Resource Type	Oil EUR (MMbls per well)	Gas EUR (Bcf per well)	Oil TRR (MMbls)	Gas TRR (Bcf)	New Well Potential
	Powder River	All tight oil plays	Shale oil	0.035	0.040	2,100	2,400	60,000
	San Juan	Lewis	Shale gas	0.000	2.200	0	9,800	4,500
	Uinta-Piceance	Mancos	Shale gas	0.000	0.752	0	9,300	12,400
	Williston	Gammon	Shale gas	0.000	0.433	0	3,300	7,600
		Bakken	Shale oil	0.147	0.078	22,700	12,100	154,800
6—West Coast	Columbia	Basin Centered	Shale gas	0.000	1.620	0	12,200	7,500
	San Joaquin/Los Angeles	Monterey/Santos	Shale oil	0.030	0.151	600	3,000	19,900

Sources: 179 DCN SGE01179

Abbreviations: EUR—estimated ultimate recovery (per well); MMbls—million barrels; Bcf—billion cubic feet of gas; TRR—technically recoverable resources

Table F-4. UOG Resource Potential: Tight as of January 1, 2013

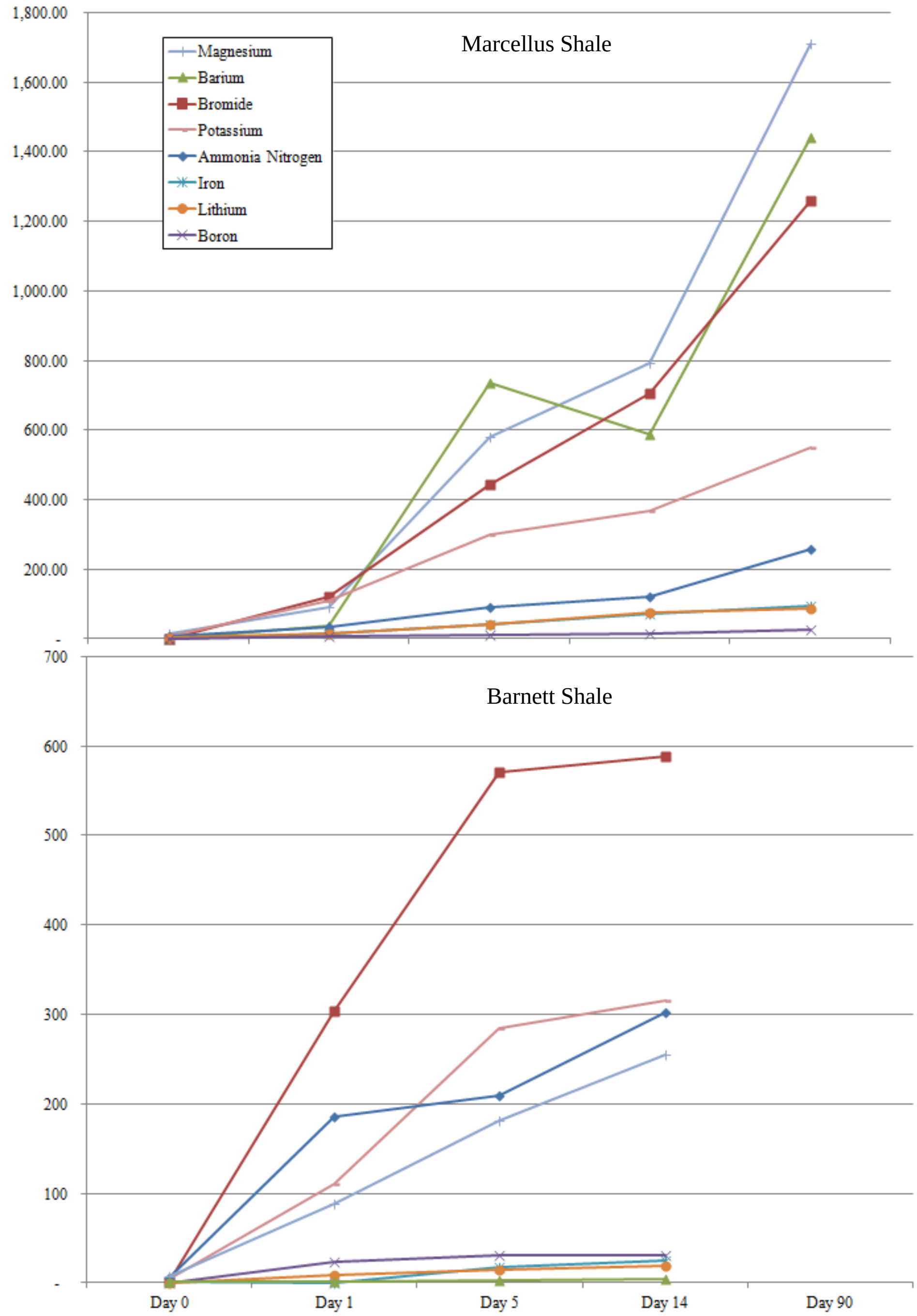
EIA Region	EIA Basin	UOG Formation Name	Resource Type	Oil EUR (MMbls per well)	Gas EUR (Bcf per well)	Oil TRR (MMbls)	Gas TRR (Bcf)	New Well Potential
1—East	Appalachian	Clinton-Medina	Tight gas	0.002	0.058	400	12,400	213,800
		Tuscarora	Tight gas	0.000	0.724	0	4,400	6,100
	Michigan	Berea Sand	Tight gas	0.000	0.110	0	6,600	60,000
2—Gulf Coast	TX-LA-MS Salt	Cotton Valley	Tight gas	0.008	1.323	800	139,300	105,300
	Western Gulf	Austin Chalk	Tight oil	0.061	0.116	5,500	10,400	89,700
		Buda	Tight oil	0.057	0.109	2,000	3,800	34,900
		Olmos	Tight gas	0.009	1.162	200	25,400	21,900
		Vicksburg	Tight gas	0.038	0.980	100	2,600	2,700
		Wilcox Lobo	Tight gas	0.000	1.403	0	12,800	9,100
3—Midcontinent	Anadarko	Cleveland	Tight gas	0.038	0.384	100	1,000	2,600
		Granite Wash	Tight gas	0.039	0.579	600	8,800	15,200
		Red Fork	Tight gas	0.000	0.459	0	900	2,000

Table F-4. UOG Resource Potential: Tight as of January 1, 2013

EIA Region	EIA Basin	UOG Formation Name	Resource Type	Oil EUR (MMbls per well)	Gas EUR (Bcf per well)	Oil TRR (MMbls)	Gas TRR (Bcf)	New Well Potential
4—Southwest	Permian	Abo	Tight gas	0.695	0.149	7,000	1,500	10,100
		Canyon	Tight gas	0.017	0.209	900	10,900	52,200
		Spraberry	Tight oil	0.131	0.152	10,600	12,300	80,900
5—Rocky Mountain	Denver	Muddy	Tight gas	0.002	0.180	100	11,500	63,900
	Greater Green River	All tight oil plays	Tight oil	0.126	0.014	900	100	7,100
	North Central Montana	Bowdoin-Greenhorn	Tight gas	0.000	0.078	0	100	1,300
	Paradox	Fractured Interbed	Tight oil	0.534	0.427	1,000	800	1,900
	San Juan	Dakota	Tight gas	0.000	0.258	0	3,800	14,700
		Mesaverde	Tight gas	0.000	0.548	0	6,800	12,400
		Pictured Cliffs	Tight gas	0.000	0.262	0	100	400
	SW Wyoming	Fort Union-Fox Hills	Tight gas	0.007	0.792	100	12,000	15,200
		Frontier	Tight gas	0.018	0.312	400	7,100	22,800
		Lance	Tight gas	0.022	1.152	400	21,200	18,400
		Lewis	Tight gas	0.006	0.312	200	9,700	31,100
		All tight oil plays	Tight oil	0.154	0.014	1,100	100	7,100
	Uinta-Piceance	Iles-Mesaverde	Tight gas	0.000	0.372	0	11,900	32,000
		Wasatch-Mesaverde	Tight gas	0.029	0.568	500	9,800	17,300
		Williams Fork	Tight gas	0.006	0.692	100	11,200	16,200
		All tight oil plays	Tight oil	0.053	0.105	100	200	1,900
	Williston	Judith River-Eagle	Tight gas	0.000	0.154	0	900	5,800
	Wind River	Mesaverde/Frontier Shallow	Tight gas	0.018	1.131	100	6,400	5,700

Sources: 179 DCN SGE01179

Abbreviations: EUR—estimated ultimate recovery (per well); MMbls—million barrels; Bcf—billion cubic feet of gas; TRR—technically recoverable resources



Source: The EPA generated this figure using data from 44 DCN SGE00414.

Figure F-1. Constituent Concentrations over Time in UOG Produced Water from the Marcellus and Barnett Shale Formations