U.S. Produced Water Volumes and Management Practices in 2017

Prepared for the Ground Water Research and Education Foundation

GROUNDWATER
RESEARCH & EDUCATION FOUNDATION

by
John Veil
Veil Environmental, LLC

February 2020

Table of Contents

Executive Summary

Background

Produced water is water from the same formations as oil and gas. When oil and gas flow to the surface, the produced water is brought to the surface with the hydrocarbons. Produced water contains some of the chemical characteristics of the formation from which it was produced and from the associated hydrocarbons. Produced water may originate as natural water in the formations holding oil and gas or can be water that was previously injected into those formations through activities designed to increase oil production from the formations such as water flooding or steam flooding operations. In some situations, additional water from other formations adjacent to the hydrocarbon-bearing layers may become part of the produced water that comes to the surface.

Most wells in unconventional oil and gas formations (e.g., shale, coal bed methane, tight gas sands) are stimulated using hydraulic fracturing, through which water is injected under pressure into the formation to create pathways allowing the oil or gas to be recovered in a cost-effective manner. Immediately following hydraulic fracturing (a frac job), some of the injected water returns to the surface as part of the "flowback process". After a few weeks, the volume of water returning from a fractured well may be greatly reduced. All water returning to the surface from oil and gas wells is reported as produced water for the sake of this report.

This report focuses solely on produced water volumes and the types of water management practices that are used. It does not look at source water, the types of treatment used, storage practices, or transportation practices. These are very important for the industry, but are outside the scope of this report.

Data Collection and Approach

The data were collected by contacting state oil and gas agencies in the 32 states with active oil and gas production and several federal agencies that have jurisdiction over federal onshore and offshore lands and tribal lands to obtain detailed information on produced water volumes and management. A questionnaire was sent to each state agency (the wording of the questionnaire is shown in Chapter 3 of this report, and the replies from the states are shown in Chapter 5). Not all states had readily available precise produced water volume figures. In a few states, the agencies had very complete data records easily obtainable from online sources. Other states had summary-level volume data without much detail or had data available only in in-house data repositories. Where complete data were not available, it was necessary to estimate volumes using assumptions, alternate data, calculations, and extrapolations. Chapter 5 of the report provides state-by-state descriptions of how data were collected, estimated, and compiled.

Produced Water Volume

This report is the third in a series of similar reports that evaluates produced water volume and how it is managed. Previous studies were conducted by the author looking at the 2007 and 2012 calendar years. This current study looks at the 2017 year and attempts to estimate the total volume of produced water from the approximately 1 million operating oil and gas wells in the United States.

Clark and Veil (2009) made a national produced water volume estimate for the 2007 calendar year of 21 billion barrels (barrel is abbreviated as bbl; 1 bbl = 42 U.S. gallons) for the entire United States. Veil (2015) estimated the total volume of produced water for 2012 at about 21.2 billion bbl.

This current report estimates that in 2017, the total volume of produced water was 24.4 billion bbl[1] – an increase of 15.2% over the 2012 volume. However, the volumes of oil (50.4%) and gas (17.7%) also increased over the same period, but at a faster rate.

Figures ES-1, ES-2, and ES-3 show the water, oil, and gas volumes for each of the three target years. When the entire ten-year period (2007-2017) is considered, the numbers are even more extreme. U.S. oil production increased by 94.6%, and U.S. gas production increased by 43.6% during those years. U.S. water production increased by 16.2% between 2007 and 2017.

The important take-away message is that water production increased at a slower rate than oil and gas production during that ten-year period. This means that for every bbl of oil and Mmcf (million cubic feet) of gas produced in 2017, less produced water was generated than in 2007 and 2012.

In 2017, onshore wells (both oil and gas wells) generated 23,816,000,000 bbl of produced water. Offshore wells (both oil and gas wells) contributed another 576,000,000 bbl for a total U.S. volume of 24,392,000,000 bbl of produced water in 2017.

Several states dominated the 2017 total produced water volume estimates. Texas, with nearly 10 billion bbl, represented 41% of the national total. Other states with produced water volumes exceeding 1 billion bbl included California (13%), Oklahoma (12%), Wyoming (7%), and Kansas (5%). Texas produced the highest volumes of water, oil, and gas. But the other top water-producing states were not necessarily in the highest rankings for oil and gas production.

---

[1] This volume equals just over 1 trillion gallons for the full year, 69 million bbl/day, or 2.8 billion gallons/day.

Figure ES-1 — Volume of Water Produced in 2007, 2012, and 2017

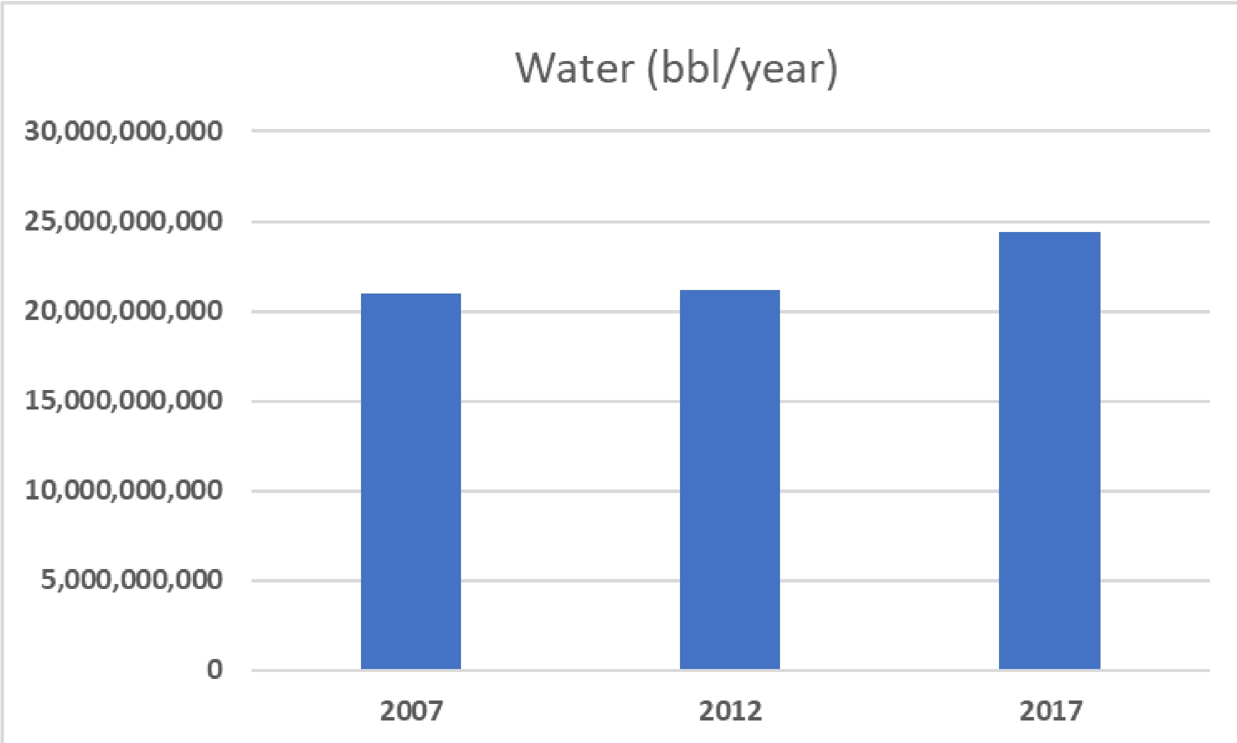


Figure ES-2 — Volume of Oil Produced in 2007, 2012, and 2017

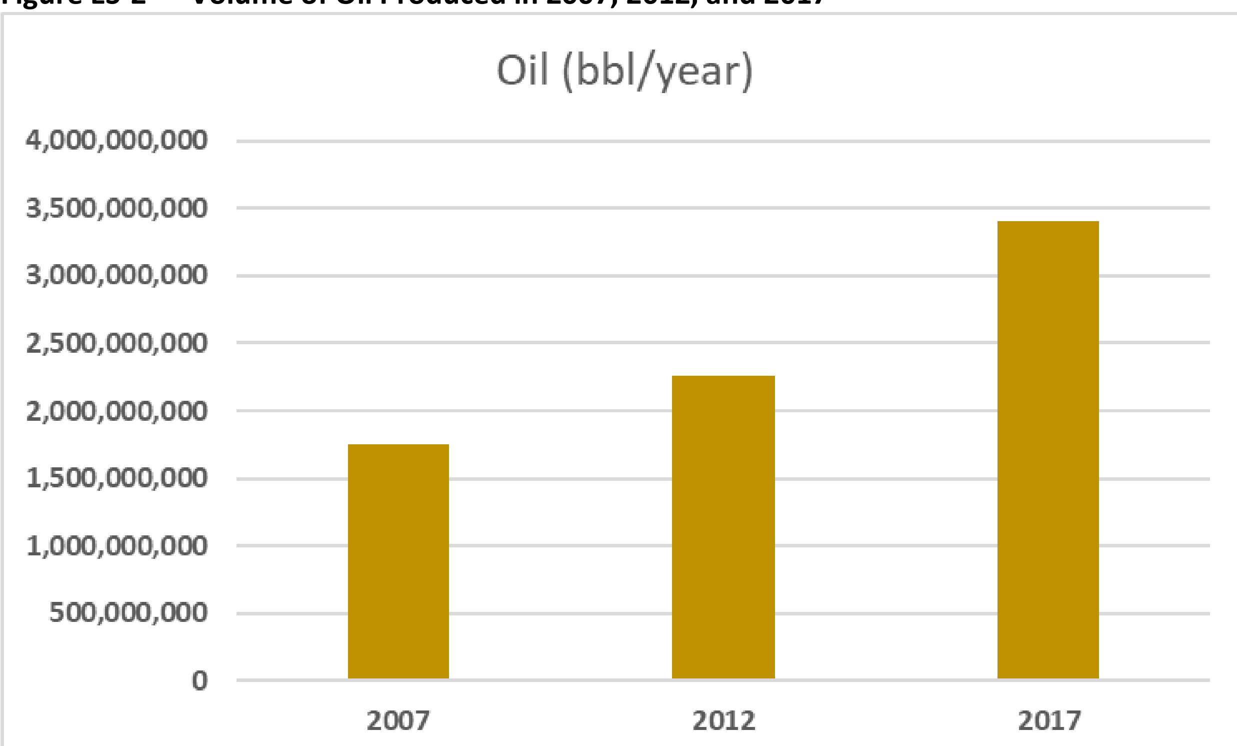
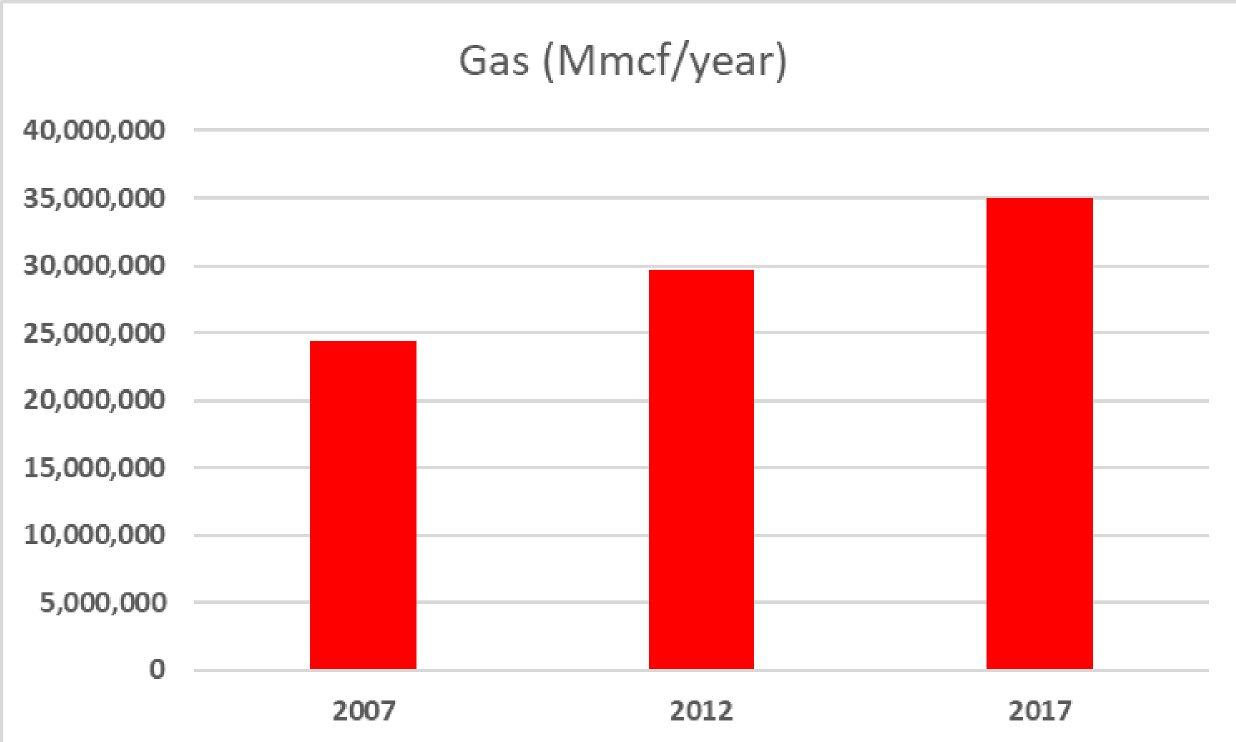


Figure ES-3 — Volume of Gas Produced in 2007, 2012, and 2017



Readers unfamiliar with the oil and gas industry may wonder why the data show that oil and gas volumes have increased at a faster rate than water volumes. One explanation involves the types of wells and formations that are used to produce hydrocarbon. In 2007, much of the U.S. production came from wells in conventional formations. Wells in conventional formations tend to generate a small initial volume of water that gradually increases over time. The total lifetime water production from each well can be high.

Between 2007 and 2012, the United States experienced a large increase in the number of wells drilled in unconventional formations, like shales and coal seams. These wells recover a relatively large amount of produced water initially during the flowback period, but the volume drops off, leading to a low lifetime water production from each well. During this five-year period, many older conventional wells (with high water cuts) were taken out of service. The new wells generated more hydrocarbon for each unit of water than the older wells they replaced. The same trend in well inventory continued through 2017.

The data questionnaire asked the agencies to provide oil, gas, and water volumes separately for conventional and unconventional production. Only a few states were able to provide data at that level of detail. For the most part, few of the highest water volume states were part of this list. Although water-to-oil and water-to-gas ratios are calculated in Chapter 4 using the limited set of data, readers are cautioned not to treat those values as accurate national values.

Produced Water Management

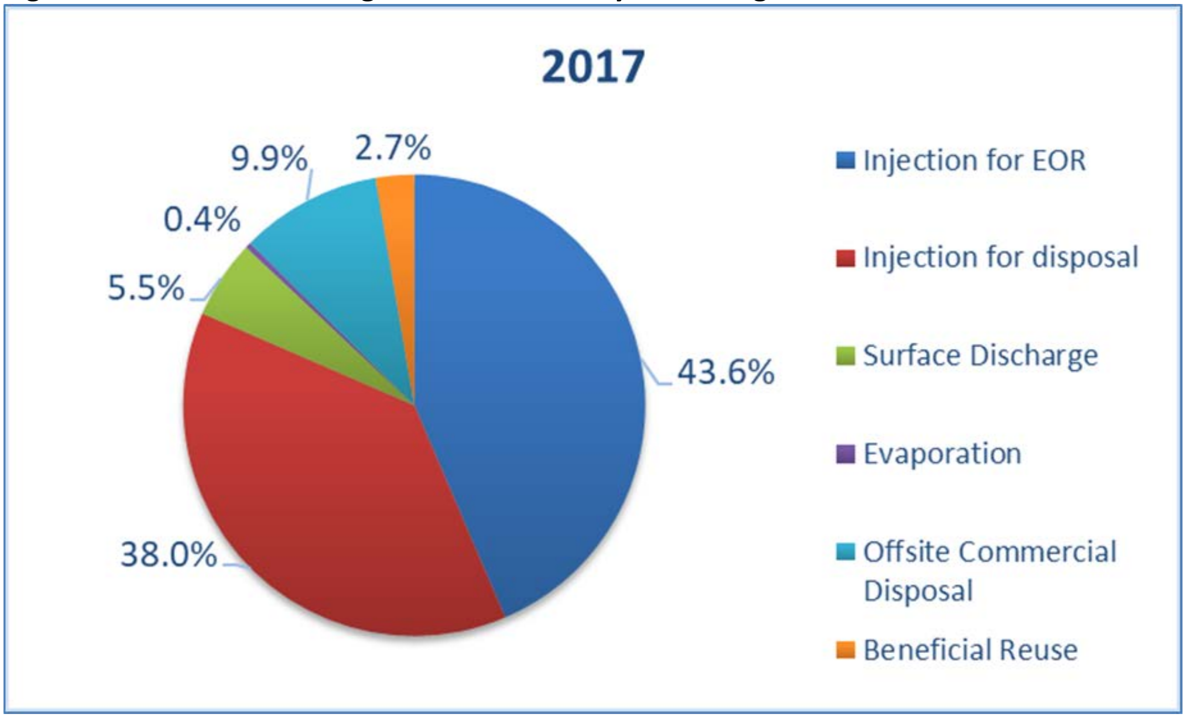
Produced water is generated from most of the nearly 1 million actively producing oil and gas wells in the United States. Produced water is the largest volume byproduct associated with oil and gas exploration and production. The cost of managing such a large volume of water is a key consideration to oil and gas producers. A second focus of this report was to compile national-level information on how the large volume of produced water was managed by the oil and gas companies.

Chapter 4 includes a full-page table showing how produced water was managed in each state and in federal waters. The summary of that table shows:

- 91.5% of the produced water was injected. 43.6% was injected for enhanced oil recovery (EOR), and 38.0% was injected at non-commercial disposal wells. An additional 9.9% was injected at offsite commercial disposal facilities -- these are third-party businesses that charge a fee to receive incoming produced water and other oil and gas wastes. Water was treated and processed in various ways. Nearly all of these commercial disposal facilities managed water by injection into disposal wells. A small percentage of the commercial facilities utilize evaporation ponds – water managed at those facilities is counted under the evaporation category.
- 5.5% was discharged to surface water.
- 0.4% was evaporated, primarily in several arid western states, from onsite ponds and pits and at several commercial disposal facilities.
- 1.4% was reused within the oil and gas industry for purposes other than injection for enhanced recovery (which is also a reuse of produced water for a beneficial value). The actual percentage was probably higher than this, but it was not quantified for most states during 2017. Much of the reuse was done by recycling produced water to use as drilling fluids and frac fluids for new wells in the same fields.
- 1.3% was reused in applications outside of the oil and gas industry. Examples include irrigation (when the water has low salinity) and for dust and ice control on roads.

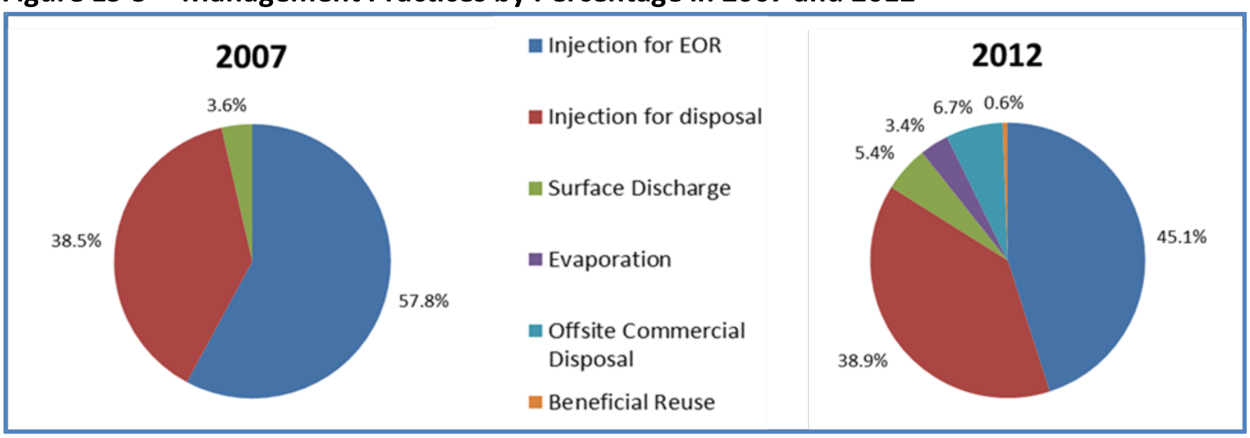
The 2017 water management information is shown graphically in Figure ES-4.

Figure ES-4 — Water Management Practices by Percentage in 2017



For the sake of comparison to the previous studies, Figure ES-5 shows similar charts for 2007 and 2012. Note that in the 2007 study, fewer management options were surveyed.

Figure ES-5 -- Management Practices by Percentage in 2007 and 2012



It is interesting to examine the percentage of produced water injected over time. Table ES-1 shows that the percentage of water injected has remained over 90% during the ten-year period, and is very similar between 2012 and 2017. Differences between the years may represent different reporting by the states and/or different assumptions made when compiling the data. Rather than focusing on the exact percentage, it is more important to recognize that injection has dominated produced water management in the past and continues to dominate today.

Table ES-1 — Produced Water Managed by Injection over a Ten-Year Period

Year	% Injected into Disposal Wells	% Injected for EOR	% Injected by Offsite Commercial Disposal Companies	Total % Injected
2017	**43.6**	**38.0**	**9.9**	**91.5**
2012	**38.9**	**45.1**	**6.7**	**90.7**
2007	**38.5**	**57.8**	**no data**	**96.3**

The continued decrease in EOR percentage during this ten-year period is primarily attributed to the decommissioning of conventional waterflood operations over time. In any case, underground injection is the predominant way in which produced water is managed from onshore wells. However, at offshore wells, nearly all produced water is treated then discharged to the ocean under the terms of EPA-issued discharge permits.

Data Availability and Quality

The following observations were also made during the two previous studies. Little has changed over the ten-year period (2007 to 2017) concerning ease of data collection to create national-level estimates.

Readily available and precise data on produced water volumes were difficult to obtain. It took half a year to compile the data needed to prepare the national total estimates in this report. The author is grateful to the state agencies for taking the time out of their busy schedules to provide much of this data. Where data were not available through the state agencies, additional efforts were made to estimate water volumes and management practices. The assumptions, data sets, and analyses used to develop the estimates are described separately for each state in Chapter 5.

There are institutional factors affecting the accuracy of the raw data and the chain of custody from field to agency to database. Nonetheless, this report represents the most complete and current effort to estimate U.S. produced water volumes and management practices for 2017 or any other recent year.

Chapter 1 — Introduction

This report estimates the volume of produced water generated from all U.S. oil and gas wells in the year 2017. It also provides estimates of how that water was managed. Data and discussion about produced water are provided for more than 30 states and several federal agencies.

Five years earlier, the author wrote a similar report that used 2012 as the target year (Veil 2015). Very little has changed concerning background and characteristics of produced water. The methods used to collect data are the same as were used in the previous study. The availability and quality of the data collected for 2017 was variable – very much like the data from the previous study. But the volumes of oil, gas, and produced water for 2017 are different. Details are provided in the following chapters.

This report focuses on the 2017 data collected from individual states and federal agencies. Chapter 4 provides two summary tables that allows comparison between jurisdictions and provides some analysis and interpretation of the data.

The heart of this report is found in Chapters 5 (states) and 6 (federal agencies). For each state, Chapter 5 provides a discussion of how data were obtained, how those data were analyzed and augmented, and the assumptions that were made. Each section contains the same two tables – one shows volumes of oil, gas, and produced water, and the other shows how the water was managed in that state. Chapter 6 provides a similar discussion for wells on onshore and offshore federal lands.

1.1 What Is Produced Water?

Produced water is water from underground formations that is brought to the surface during oil and gas production. Because the water has been in contact with hydrocarbon-bearing formations, it contains some of the chemical characteristics of the formations and the hydrocarbons. It may include water from the oil and gas formation, water previously injected into the formation, and residuals of those chemicals added during the production processes. The physical and chemical properties of produced water vary considerably depending on the geographic location of the field, the geologic formation, and the type of hydrocarbon product being produced. Produced water properties and the volume of water brought to the surface also vary throughout the lifetime of a reservoir. More discussion of produced water characteristics is provided in Chapter 2.

1.2 Produced Water Volume

The combined volume of produced water generated from nearly 1 million U.S. oil and gas wells[2] in a year is very large. Two previous national produced water volume estimates were made by the author using an approach similar to this report.

- Clark and Veil (2009) estimated that about 21 billion barrels (bbl) of produced water were generated in the year 2007.
- Veil (2015) estimated that about 21.2 billion bbl of produced water were generated in the year 2012.

One oil field bbl = 42 gallons. Those volumes are equivalent to just under 900 billion gallons per year or about 2.4 billion gallons per day.

One of the most anticipated outcomes of this report was to see if the produced water volume in 2017 was larger than the volumes in 2007 and 2012 (these two years had almost identical produced water volumes), and if so, how much larger. To the extent that more produced water was generated in 2017, how does that correspond to the volumes of oil and gas produced during the year?

1.3 Produced Water Management

This report also provides information on how the produced water is managed after it comes to the surface and is separated from the oil and gas. Nearly all produced water is managed in one of the following ways:

- Injection to a hydrocarbon-bearing formation to help produce more hydrocarbon (enhanced recovery)
- Injection to a non-hydrocarbon-bearing formation for disposal
- Discharge to surface water bodies
- Evaporation
- Paying a commercial disposal company to take the water and manage it
- Reuse for oil and gas operations (e.g., drilling fluids, frac fluids)
- Reuse for other purposes.

Some states track produced water management closely, but most states do not have much information on how the water is handled and managed other than injection volumes.

---

[2] The U.S. Department of Energy's Energy Information Administration (EIA) estimated that in 2017, there were 435,460 oil wells and 555,217 gas wells for a total of 990,677. This number is constant changing, with older wells getting closed in and new wells being drilled. These data were taken from https://www.eia.gov/petroleum/wells/. Visited October 6, 2019.

1.4 Why Is Produced Water Important?

What is it about produced water that makes it so important to many companies, decision makers, and researchers? First of all, it is water. Many parts of the United States experience drought conditions at times. Existing freshwater sources become in high demand. There may be opportunities to put produced water to some other use, thereby conserving freshwater resources for drinking, agriculture, and domestic use.

A great deal of produced water is being reused within the oil and gas industry to make up new drilling fluids, in hydraulic fracturing operations, and in water floods conducted to bring more oil out of formations. Opportunities to use produced water in applications outside the oil and gas industry are not as readily available, but may make sense in certain circumstances. Most produced water contains large amounts of salt (often expressed as total dissolved solids or TDS) and cannot be used for applications requiring freshwater without some degree of treatment. Further, produced water may contain many other chemical constituents. Knowing the constituents of produced water and the type of treatment required to make the treated water fit for its end use are important steps in evaluating reuse projects.

Second, produced water is a byproduct of oil and gas production. The volume of water is huge and is scattered throughout more than 30 states at nearly a million sites. As long as companies produce oil and gas, the need to figure out ways to manage the water in an environmentally responsible way at an affordable cost will be vital. Reports such as this can help in sharing information about current water management practices.

The flip side of the cost to the oil and gas companies of managing produced water is that the money spent on services, equipment, transportation, treatment, and other items contribute assets to the local and regional economy and provide job opportunities. The vast amount of produced water requiring management can involve significant amounts of money that help support other businesses.

Produced water has been important since the inception of the oil and gas industry and will remain important as the industry moves into the future.

Chapter 2 — Produced Water

This chapter provides information about produced water and produced water management.

2.1 Definition of Produced Water

Produced water is water brought to the surface along with oil and gas. Produced water is found in the same formations as oil and gas. It can also be referred to as “brine” or “saltwater”. Produced water may originate as natural ground water in the formations holding oil and gas or can be water that was previously injected into those formations through activities designed to increase oil production from the formations such as water flooding or steam flooding operations. In some situations, additional water from other formations adjacent to the hydrocarbon-bearing layers may become part of the produced water that comes to the surface. The key point is that the water is produced to the surface along with oil and gas and not where the water originated.

Unconventional oil and gas development generates wastewater following a hydraulic fracturing treatment (frac job). During a frac job, a large volume of water, often millions of gallons, is injected into the well at very high pressures to create a network of fractures (tiny cracks) in the source rock of the formation. These fractures allow the oil and gas to move from the formation into a well where they can be produced. After the fractures are created, the pressure is lowered, and a portion of the injected water returns to the surface. This process is known as the flowback process. Although in some previous reports, this water was called “flowback water”, for the purposes of this report, all the water that flows following a frac job is considered to be produced water. Nearly all of the water that comes from a well during the first few days following a frac job is water that was injected during the frac job.

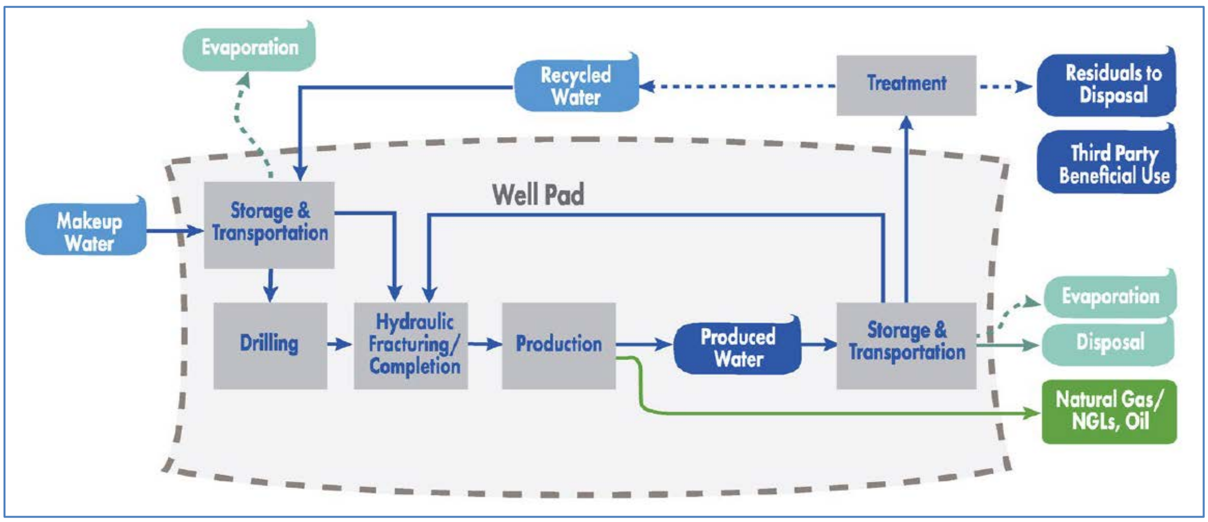
2.2 Water Plays a Role in Oil and Gas Production

Water plays an important role in oil and gas production, not only as a byproduct on the produced water portion of the water cycle, but also as a necessary element to support drilling and fracturing and to promote additional production in many formations. Figure 2-1 shows a water life cycle for unconventional oil and gas production. The box on the left called Makeup Water includes different types of source water, such as ground water, surface water, municipal water, or other. Companies need to plan well in advance to obtain a sufficient volume of source water to meet the needs and schedules of the drilling and hydraulic fracturing activities. The source water must be stored and transported to the well site.

Water is used to make up drilling fluids, frac fluids, and for general clean up during these processes. Following a frac job, produced water flows to the surface. It must be separated from the oil and gas, stored, and managed. Some forms of produced water management require treatment ranging from simple to complex, depending on whether the water is disposed or reused. In other cases, water may be taken directly to injection wells or evaporated. When treatment is required, the treatment process generates cleaner water and sludges, brines, or other residuals that must be managed.

Some produced water is intended for reuse within the oil and gas process (the Recycled Water box on the figure). It may be treated as needed then blended with other water sources to be used for a subsequent well.

Figure 2-1. Water Lifecycle for Unconventional Oil and Gas Production



Source: This figure is based on a graphic prepared by the Energy Water Initiative, a collaborative group of U.S. oil and gas companies. The figure was previously published in the Ground Water Protection Council (GWPC) 2019 Produced Water Report (GWPC 2019), a report focusing on produced water and the opportunities for reusing it.

This report focuses solely on produced water volumes and the types of water management practices that are used. It does not look at source water, the types of treatment used, storage practices, or transportation practices. These are very important for the industry, but are outside the scope of this report.

2.3 Characteristics of Produced Water

Ideally, all produced water would have similar physical and chemical characteristics, but that is not always the case. The physical and chemical properties of produced water vary considerably depending on the geographic location of the field, the geologic formation from which the water was produced, and the type of hydrocarbon product being produced. For those sites where waterflooding is conducted, the properties and volumes of the produced water may vary dramatically due to the injection of additional water into the formation to increase hydrocarbon production. Considering that nearly 1 million oil and gas wells operated in the United States during 2017, it is not surprising that there is a great deal of variation.

The major constituents of concern are:

- *salt content* (often expressed as salinity, conductivity, or total dissolved solids [TDS]),
- *oil and grease* (not a single chemical; the analytical method measures various organic compounds associated with hydrocarbons in the formation),
- inorganic and organic *toxic compounds* introduced as chemical additives to improve drilling and production operations or that leached into the produced water from the formation rock or the hydrocarbon, and
- *naturally occurring radioactive material (NORM)* that leaches into the produced water from some formations.

No single report can realistically characterize all produced water. And even those studies that do try to evaluate a known list of chemical constituents may overlook other chemicals that are part of the additives used in frac fluids or their chemical byproducts resulting from interactions between the fluids and the formation.

Here are several references that have useful information about selected groups of produced water. Readers are referred to these, but are cautioned to remember that none of those sets of data are representative of all U.S. produced water.

1. GWPC's 2019 Produced Water Report. GWPC published a report that evaluates the opportunities for reusing produced water (GWPC 2019). Module 3 of that report focused on how produced water might be used for purposes outside of the oil and gas industry. One of the concerns of the authors of that module was that there may be chemicals that are not well characterized in produced water, and that efforts to understand their presence and concentration is necessary before reuse projects are undertaken. To support this idea, Module 3 included an extensive literature search on produced water. Some of those references include lists of chemicals found in produced water and their concentrations in specific formations.

2. EPA's 2016 Report on the Impact of Hydraulic Fracturing on Drinking Water. EPA devoted a great deal of effort to publish a major report on the impact of hydraulic fracturing on U.S. drinking water supplies (EPA 2016). They catalogued chemicals identified in hydraulic fracturing fluids and/or produced water in Appendix H to the report. This is probably the most comprehensive effort to identify chemicals that may be found in at least some produced water samples.

3. The FracFocus program. In 2011, GWPC and the Interstate Oil and Gas Compact Commission (IOGCC) introduced an online chemical registry that later came to be embraced by many of the oil and gas producing states. FracFocus[3] provides a mechanism for operators to list each chemical ingredient in all the additives used to

---

[3] https://fracfocus.org/. Visited on October 6, 2019.

make up frac fluids. The data are entered for each well and included chemical names, CAS numbers, and the amount used in the well. FracFocus does not provide any direct measurements or data on the produced water that returns to the surface following a frac job. But knowing the chemicals and quantities of chemical that are injected into the ground as part of a frac job may help in learning more about initial produced water from those wells.

4. USGS Produced Water Database. The U.S. Geological Survey's National Produced Waters Geochemical Database[4] is an updated compilation of geochemical and related information for water from oil and gas wells in the United States. The latest version of the database is v2.3. It includes identification and location information, well descriptions, dates, rock properties, physical properties of the water, inorganic chemistry, organic chemistry, and isotopes. The list of parameters reported for each sample varies.

5. EPA Study of Oil and Gas Extraction Wastewater Management Under the Clean Water Act. EPA conducted a study evaluating management of produced water from onshore oil and gas extraction activities (EPA 2019). The EPA wanted to better understand produced water generation, management, and disposal options at the regional, state and local levels for both conventional and unconventional onshore oil and gas extraction. As of October 2019, this report is currently available only as a draft.

6. Produced Water in the Western United States. Researchers from the Colorado School of Mines published a study of produced water in the western United States (Benko and Drewes 2008). They found the oil and grease content to range from 40 mg/L to 2,000 mg/L. Another important constituent of concern in onshore operations is the salt content of produced water. Most produced waters are more saline than seawater. Benko and Drewes (2008) found the TDS concentration of produced water in the western United States to vary between 1,000 mg/L and 400,000 mg/L, although the median TDS concentration from most formations was less than 100,000 mg/L.

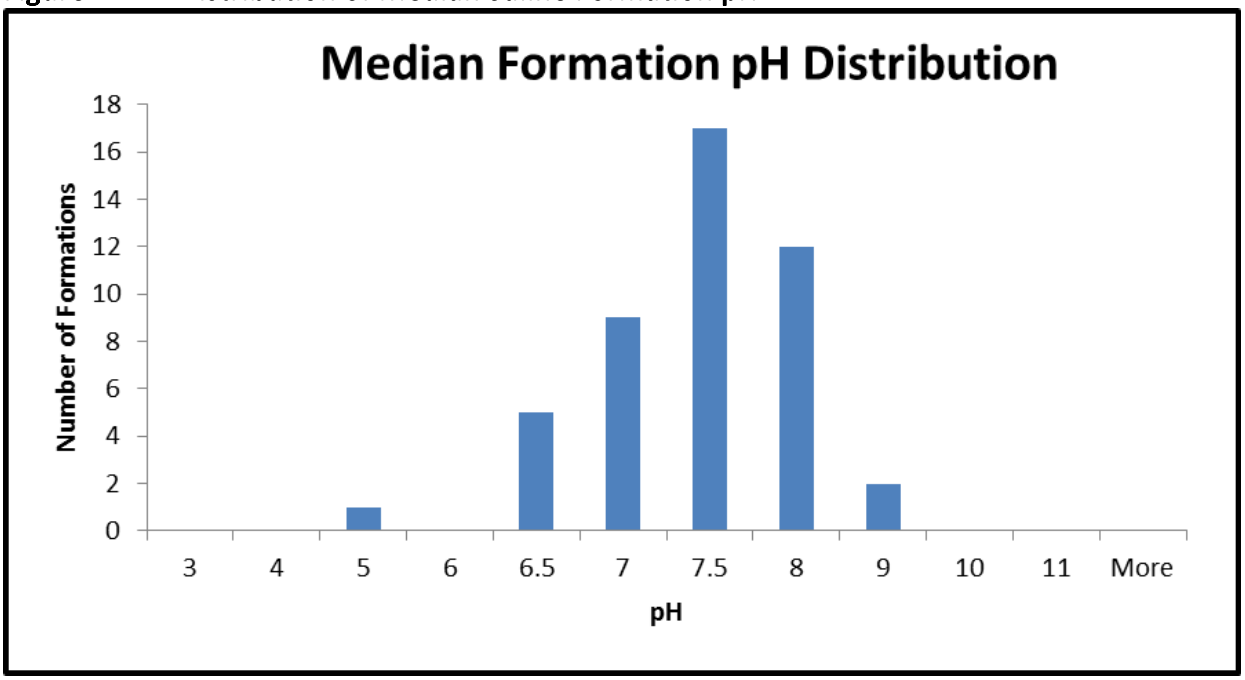
7. Produced Water Discharged to the Gulf of Mexico and its Impact on the Hypoxic Zone. Veil et al. (2005) includes the results of produced water sampling at 50 offshore platforms in the Gulf of Mexico. The focus of this study was on identifying concentrations of substances that affected the oxygen demand of produced water after it entered the Gulf of Mexico. The data were collected using a strict QA/QC protocol and were used by EPA to make a regulatory determination for a general discharge permit.

[4] https://www.sciencebase.gov/catalog/item/59d25d63e4b05fe04cc235f9. Visited on October 6, 2019.

An earlier version of the USGS produced water database was used by Harto and Veil (2011) to evaluate deep saline formations that might be candidates for carbon sequestration. A search was performed to obtain data on the chemical composition of saline brines (many of the samples are produced water samples) from these formations.

The data were reviewed and analyzed to help understand the typical conditions that may be encountered in deep saline formations used for carbon sequestration. Harto and Veil (2011) provided summaries of brine characteristics, with data on pH, total dissolved solids (TDS), and concentrations of several other individual chemical constituents. Figures 2-1 and 2-2 represent the distribution of the median pH and TDS across different formations. Figure 2-1 shows that pH was roughly normally distributed around a mean between 7 and 7.5.

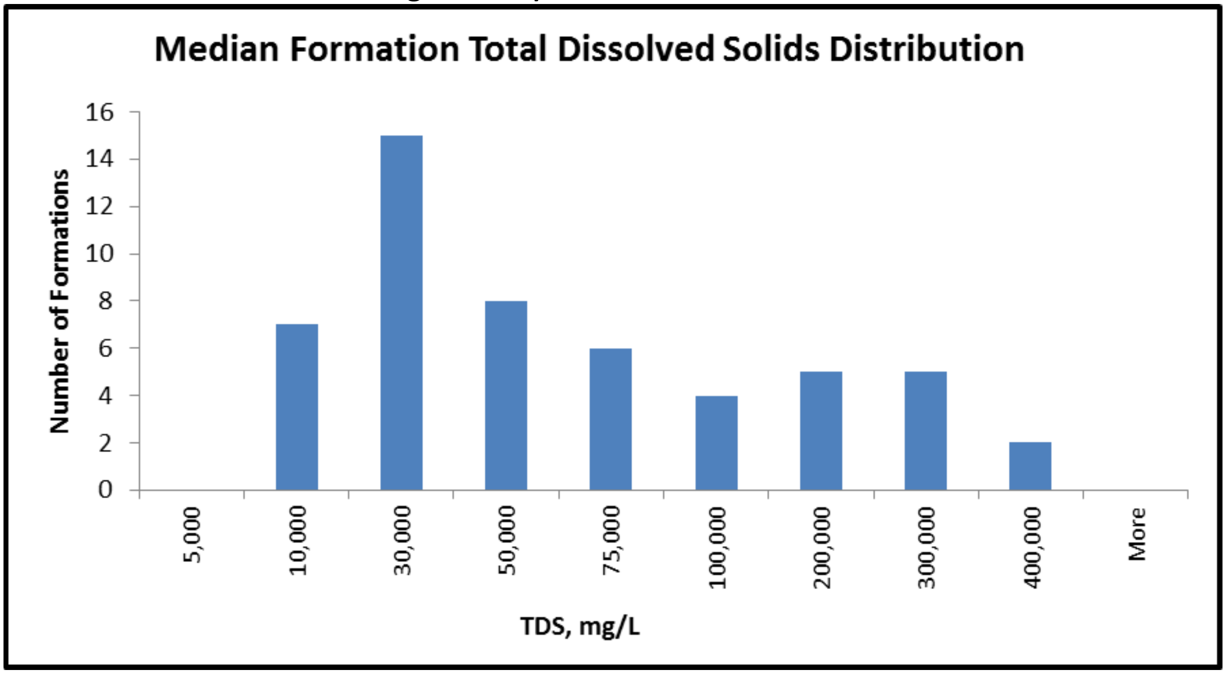
Figure 2-1 — Distribution of Median Saline Formation pH



Source: Harto and Veil (2011)

The distribution of median TDS from many formations shows a wider range of values in Figure 2-2.

Figure 2-2 — Distribution of Median Formation Total Dissolved Solids (Note that the scale on the axis is neither linear nor logarithmic)



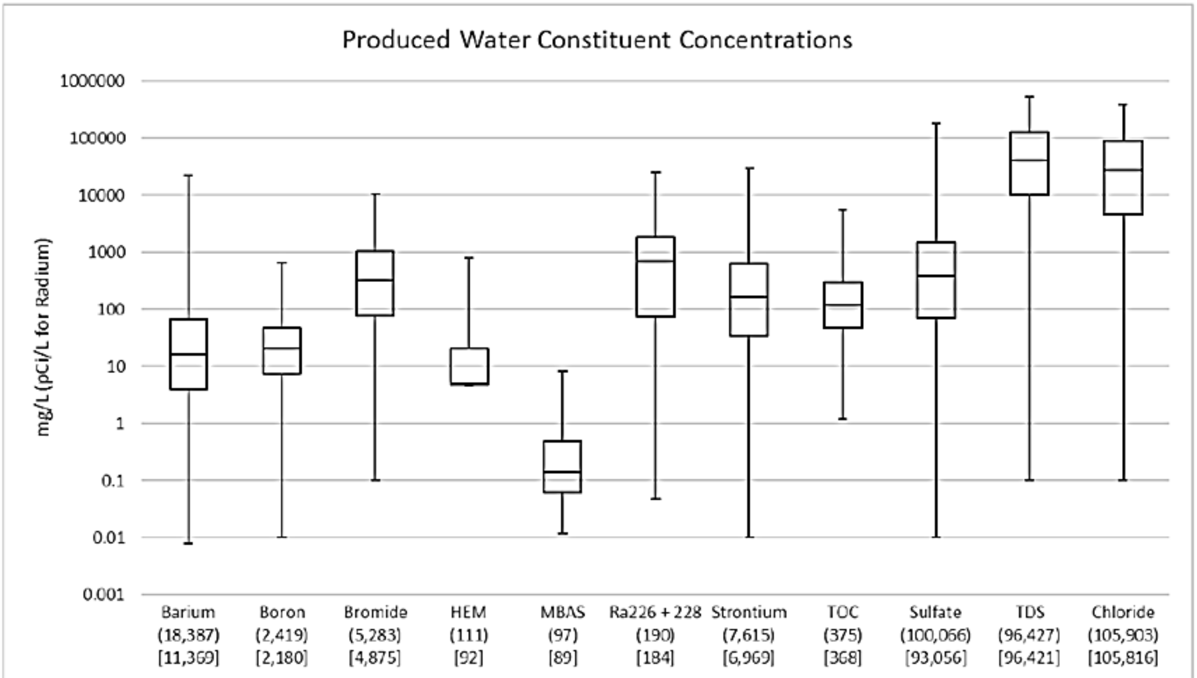
Source: Harto and Veil (2011)

EPA (2019) included a figure that shows values for select produced water constituents. That figure is reproduced here as Figure 2-3. EPA used data from Version 2.2 of the USGS produced water database. Results are displayed as box and whisker plots, showing the minimum (excluding non-detect values), 25th percentile, median, 75th percentile and maximum values for each parameter.

In addition to the chemical constituents naturally found in produced water, other chemicals can become part of the produced water and can affect its overall toxicity. Chemical additives such as corrosion and scale inhibitors, emulsion breakers, coagulants, and solvents may be used in drilling operations, production operations, and separations processing to combat scaling and maintain production efficiency.

All of the data shown in this section and the references listed above point out that produced water physical and chemical characteristics are quite variable from place to place.

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



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

Source: This figure was taken from EPA (2019).

2.4 Produced Water Management

As noted above, the characteristics of produced water vary from one geographical play to another and also over time. Different locales have different climates, regulatory/legal structures, and degrees of existing infrastructure. As a result, no single water management technology is used at all locations. Many different technology options are available that can be employed at specific locations.

2.4.1 Injection for Enhanced Recovery

For more than a century, oil companies realized that they could extract additional oil from conventional formations by pumping water back into the formation in a controlled manner. This technique is often called water flooding, secondary recovery, or more generically "enhanced oil recovery". A large percentage of produced water is injected for this purpose. A few U.S. fields produce heavy oil that benefits from injection of steam to help the oil flow from the formation. The water used to make steam is often produced water that is further treated to make up highly purified boiler feed water.

Unconventional formations do not benefit from water flooding to the extent that conventional formations do, since most of the unconventional formations have low permeability. As the percentage of U.S. wells completed in unconventional formations has increased over the past 10-15 years, the volume of oil produced per unit of water injected has increased.

2.4.2 Injection for Disposal

In most U.S. oil and gas fields, the least expensive method of managing produced water (other than what is needed for enhanced recovery) is to inject the water into a Class II disposal well. There are tens of thousands of Class II disposal wells in the United States. Regulators are comfortable with injection, and its track record has proven to be safe for disposal of produced water.

During the past decade, concern has risen over cases of seismic activity (earthquakes) that could be felt at the surface. While most disposal wells are very safe, in some locations, evidence is strong that the seismic activity was triggered by injection of large volumes of fluids into disposal wells over time. Changes in state regulations and operating practices have mitigated the number of seismic events. Disposal wells remain a major management practice for many states.

2.4.3 Surface Discharge

The EPA regulations for produced water generated by the oil and gas industry allow discharges in some circumstances but not in others. Onshore wells located east of the 98th meridian (a line roughly from east Texas north to the border between Minnesota and the Dakotas) are not permitted to discharge produced water. Onshore wells west of the 98th meridian can discharge produced water to surface waters as long as the treated water meets limits in a National Pollutant Discharge Elimination System (NPDES) permit and is put to a beneficial use for agricultural or wildlife watering purposes. Some of the western states do issue NPDES permits for produced water discharge.

One exception to this practice is the coal bed methane wells located in the Black Warrior Basin in Alabama. Companies operating in this area petitioned EPA suggesting that their wastewater from dewatering coal seams was more like wastewater from the coal mining industry than from other types of oil and gas production. The EPA gave them a limited waiver from the prohibition on discharging produced water east of the 98th meridian. Many of the companies in the Black Warrior Basin do discharge treated produced water to surface waters.

EPA allows offshore platforms to discharge produced water to the ocean after appropriate treatment. Nearly all offshore produced water is managed this way.

2.4.4 Evaporation

In a few of the arid western states, produced water is intentionally placed in large ponds or basins and allowed to evaporate either passively or through mechanical spraying.

2.4.5 Offsite Commercial Disposal

In cases where companies elect not to manage their own produced water, they can pay a third-party company to accept and manage the water. Although there are a few commercial evaporation operations, nearly all of the offsite commercial disposal companies in the United States utilize injection into disposal wells.

2.4.6 Reuse

Produced water has potential value to be used for some other purpose, either within the industry or elsewhere. The enhanced recovery described in 2.4.1 is an example of reuse, but since it has been going on so long and is a large-scale operation, it is almost always considered separately.

Over the past decade, more operators are capturing their produced water, treating it, and reusing it as source water to make up new drilling and frac fluids.

There are only a few examples of cases in which produced water is put to reuse in applications outside of the oil and gas industry. GWPC (2019) provides a detailed review and discussion of reuse examples both within and outside of the oil and gas industry.

Veil (2015) contains several tables that describe treatment technologies that are typically used to remove different groups of contaminants, and the pros and cons of each technology. GWPC (2019) contains an extensive discussion of produced water treatment technologies, as well as several theoretical treatment trains that might achieve desired water quality.

Chapter 3 — Approach and Methods

During preparation of Veil (2015) the author contacted state oil and gas agencies in the 31 states with active oil and gas production in 2012 to obtain detailed information on produced water volumes and management. State agencies were selected due to their long-term direct experience with oil and gas activities in the specific state and the data management systems that most states employ for tracking production data.

3.1 Initial Data Collection

The 2017 study effort attempted to follow the same methodology. Data collection began during May 2019. Requests for assistance were sent by email to oil and gas directors or other senior managers in each of 35 states believed to have production during 2017 (3 states subsequently replied that they had minimal or no oil and gas production during 2017). Those emails included a questionnaire with two tables and instructions for completing the tables. A copy of the questionnaire is shown below. Similar versions were sent to federal land management agencies.

> *Two previous studies have estimated the total volume of produced water generated in the United States in a full year and characterized the ways in which that water was managed. The previous studies looked at the 2007 and 2012 calendar years. The Groundwater Research & Education Foundation (GWREF) recently provided funding to the author of the two previous studies (John Veil of Veil Environmental, LLC) to update the study to look at 2017 as the target year. This questionnaire serves as the primary mechanism to collect information on produced water from each of the oil and gas producing states*
>
> *In this study we consider produced water to include water brought to the surface along with oil and gas production. This includes water that flows back to the surface from wells that were recently fractured as well as any ongoing water production from the wells over time. It includes natural groundwater in formations that produce oil and gas as well as any water that has been injected into those formations to aid in producing more oil and gas. The key point is that the water comes to the surface along with oil and gas.*
>
> *Over the past 15 years, the U.S. oil and gas production has evolved from nearly all wells producing from conventional formations to an increasing number of wells producing from unconventional formations. Water production profiles often are quite different in conventional and unconventional formations.*
>
> *The U.S. Department of Energy's Energy Information Administration defines unconventional oil and natural gas production as: "an umbrella term for oil and natural gas that is produced by means that do not meet the criteria for conventional production." EIA defines conventional oil and natural gas production as: "crude oil and natural gas 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." The boundaries between conventional and unconventional production have changed over time and may differ among users of the terms. However, production of the following types of hydrocarbon resources are generally considered to be unconventional (coal bed methane, shale gas, shale oil, tight oil, tight gas sands). Other hydrocarbon types less common in the United States also can be considered as unconventional production (oil shale, oil/tar sands, gas hydrates).

Table 1 below seeks oil, water, and gas production information separately for conventional vs. unconventional formations. We recognize that some states do not track production separately by formation type. To the extent possible, with your agency's geological knowledge of the formations that produce in your state, please try to provide information separately for conventional and unconventional production. If you are unable to make that distinction, we greatly appreciate any relevant produced water data you can provide.

Part I – Produced Water Volume

1. Please provide information on the volume of produced water generated in your state for calendar year 2017. If you do not have fully compiled data for 2017, please provide data from the next most recent year for which you do have full data. These data should be entered into Table 1, or you can indicate how we can access your state's electronic data management system. Even if you don't have information on the volume generated, but you do have information on the volume reinjected (assuming that most produced water from your state is reinjected), that is valuable information too, and should be entered in Table 1 with a notation that the figure represents injected volumes. To the extent possible, we would like to see the produced water volume estimates broken down by the type of hydrocarbon produced by the well as shown in Table 1. This helps in calculating water/oil and water/gas ratios. If you do not have quantitative information on the volume of produced water generated, please give us your educated "best estimate" of the volume either in absolute volume or in percentages.

2. Please provide information on the annual volume of each type of hydrocarbon produced in your state for 2017 or the next most recent year. This information should be entered into the last column of Table 1. Please express natural gas production in Mmcf (million cubic feet) per year. Crude oil and water should be expressed in bbl (barrels) per year.

3. If your state does not keep track of water volumes, please let us know that so we can find another way to estimate produced water volumes for your state.

Table 1 – Produced Water Volume Information

Type of Hydrocarbon	***# Wells Producing Primarily That Type of Hydrocarbon***	***Total Volume of Produced Water Brought to Surface (bbl/year)***	***Volume of Hydrocarbon Produced (bbl/year or Mmcf/year)***
Crude oil from conventional formations			
Natural gas from conventional formations			
Crude oil from unconventional formations			
Natural gas from unconventional formations			
Total			

Part II – Produced Water Management

4. Please provide information on how produced water was disposed of or otherwise managed in your state for calendar year 2017 or the next most recent year. This information should be entered into Table 2. If you do not have quantitative information on produced water management practices, please give us your educated "best estimate" of the percentage of produced water that is handled by each management practice.

In the 2012 data set, less than 1% of all produced water was reported as being beneficially reused (note that this does not include water injected into producing formations to augment production – that is tallied separately). In many cases, this low percentage resulted from the fact that companies were not typically required to report on water reuse, and therefore while agencies suspected produced water was being reused, they had no quantitative data to characterize those practices. We believe that more produced water was reused in 2017 than in 2012, and request that you provide as much information as you can (quantitative or qualitative). In the new report, we make no distinction in terminology between recycle, use, or reuse. When using those terms, we are referring to managing produced water that has come to the surface by putting it to a secondary use (e.g., makeup water for drilling and frac jobs, cooling water, irrigation water, and others). Please describe, to the best of your knowledge, the ways in which produced water is being reused in your state.

Table 2 – Produced Water Management Practices

Management Practice	***Total Volume of Produced Water Managed by That Practice (bbl/year)***	***Percentage of Produced Water Managed by That Practice***
Injection for enhanced recovery		
Injection for disposal		
Surface discharge		
Evaporation		
Offsite commercial disposal (pay another company to manage your produced water)		
Reuse within the oil and gas industry		
Reuse in ways other than in the oil and gas industry (please specify, e.g. irrigation, cooling water, etc.)		
Other		

5. If your state has significant hydrocarbon production in more than one of the categories shown in Table 1, and you believe that the produced water from one production type is managed differently from another production type, please complete separate versions of Table 2 for each of those production types.

6. Please provide the name and contact information for a person representing your agency or another agency in your state if produced water data management is not part of your agency. We may need to contact that person to clarify the data submittal or ask additional questions.

Responses should be sent by email to John Veil at john@veilenvironmental.com. If you have any questions on how to answer the questions, or would prefer to provide information in a different format, please contact Mr. Veil at 410-212-0950.

We recognize that state agencies are very busy and often under-staffed. Nevertheless, we request that you provide us with your responses within three weeks. This is a very important GWREF initiative, and we hope to complete the project in a timely manner. If you are unable to provide all the requested information, please provide as much of it as possible. Thank you in advance for your assistance.

3.2 Additional Data Collection Efforts

The information requested through the questionnaire represented the desired "wish list." For most of the submitted questionnaires, some data were missing, inconsistent, or unclear. In those cases, it was necessary to contact the person who submitted the questionnaire to get clarification.

In some cases, states did not have or were unable to provide the data. In a few states, the agencies did not respond to repeated requests for data. In those cases, other methods were used. Where possible, other published data on oil and gas agency websites or other reports were reviewed to extract relevant data. Chapter 5 includes the specific details of data collection for each state. Chapter 6 provides similar information for federal lands.

3.3 Data Collection for Wells on Federal Lands

In the previous study (Veil 2015), several Department of the Interior agencies (Office of Natural Resources Revenue - ONRR, Bureau of Safety and Environmental Enforcement – BSEE, and the Bureau of Ocean Energy Management, Regulation and Enforcement - BOEMRE) were contacted for information. In the current study, the websites for those agencies contained most of the information needed for oil, gas, and water production volumes, such that direct inquiries to the agencies were not necessary.

A key missing piece of information was how much produced water was discharged from the offshore platforms into the ocean. Several EPA regions and EPA headquarters were contacted to provide information on which platforms actually discharged produced water during 2017. The EPA contacts provided lists of platforms that discharged during 2017. Most of the data were subsequently extracted from EPA's online ECHO database (Enforcement Compliance History Online).[5]

The oil and gas production estimates from these federal resources as well as the responses from state agencies were compared with available production data from the EIA to identify any major inconsistencies – none were found.

3.4 Distribution of Production between State and Federal Categories

Although oil and gas volume estimates were obtained for onshore federal lands and for tribal lands, evidence suggested that these volumes were already being counted through the state totals.

Since the onshore component of federal and tribal lands was accounted for through the state totals, the remaining federal component to quantify was the offshore production from federal waters. A few states have some offshore production in state waters (i.e., inshore from the Outer Continental Shelf). These production volumes were already included within the state

[5] https://echo.epa.gov/. Visited numerous times during 2019.

totals. To simplify accounting, all onshore production volumes (regardless of the ownership of the lands where the wells were located) were considered to be state totals, and all offshore production volumes were considered to be federal totals. This is not an exact distribution, but it does account for all production and is a practical representation of the data.

Chapter 4 — Analysis and Results

4.1 Response to Questionnaire

The produced water questionnaire for 2017 data was sent to 35 state oil and gas agencies. Most of the states returned a questionnaire with at least some of the boxes completed. Three states (Maryland, North Carolina, and South Carolina) wrote back indicating that there had been either no oil and gas production or minimal production during 2017.

For those states that did not directly provide the requested information, efforts were made to extract available data from accessible reports from oil and gas agency websites. Additional inquiries were made to federal land management agencies, the EPA, and several state environmental protection agencies to fill in the information gaps. Details on the sources and types of information obtained for each state and for federal agencies are included in Chapters 5 and 6.

4.2 Data Availability and Completeness

The volume of produced water from oil and gas wells is not documented regularly or consistently in the United States or elsewhere in the world. In the United States, the responsibility for managing and regulating most aspects of oil and gas development is assigned to individual states, rather than to the federal government. Since more than 30 states have oil and gas production within their borders, there are more than 30 different sets of regulations, rules, and requirements for monitoring and reporting oil, gas, and water volumes from producing wells. These different sets of requirements range from reporting of detailed water information for each well to no water reporting at all.

The previous study (Veil 2015) noted that data on produced water volumes and management practices were not available from all states to the same extent. That report pointed out some of the reasons why data were not more available or complete. It also offered some comments on data quality. This current study experienced the same types of issues. For that reason, much of the text in 4.2 and 4.3 is repeated from Veil (2015) with updating and edits as appropriate.

Perhaps the greatest challenge for this study was getting useful and representative data for each state that could be combined in a consistent manner to develop national estimates. Some states had complete data on water production and management. Other states had information on water production but did know how much water was injected or otherwise managed. The reverse of this was found in quite a few states – the state knew the volume injected into Class II wells, but did not have any information on the volume of produced water generated. In most of these cases, the assumption was made that total injected volume was the same as the volume generated. Other states had little or no information at all on water production or management.

The amount of information available and how readily it can be extracted from agency databases depend on various factors. First is the requirement to collect the data. While there may be general interest from the public, researchers, and the media in how much water is generated from oil and gas wells, the state legislatures and agencies may not believe that water generation information is a necessity. Requirements to collect and submit information generally must be supported by language in a state law or regulation specifying the type and frequency of data collection. Oil and gas volumes are measured and reported because the states collect taxes and royalties for each bbl or Mmcf of hydrocarbon produced. No such fees are charged for water production – as a result, there is less reason for the state agency to require companies to monitor the volumes. Further, requiring water volume data collection could be perceived as a regulatory burden on the industry. At the federal level, the EIA collects a great deal of information about oil and gas production, but does not collect comprehensive data on produced water volumes.

A second factor is what data elements are included in the submitted data. Companies will only submit data that are requested by the states and generally use the forms that the agencies have created for that purpose. If those forms do not have boxes for certain data elements, those data are not provided. For example, some states are able to provide the volume of water injected for enhanced recovery separately from the volume injected for disposal. Other states could provide only the total injected volume, without specifying the way in which the water was injected.

A third factor is that the state reporting forms may require entries into specified water management categories that make sense under that state's regulations, but do not easily match the categories requested for this study. For example, both Colorado and California require detailed reporting on produced water volumes from each well and how that water is managed. But their reporting system calls for data to be assigned to various management categories that did not match up easily with the management options specified by the questionnaire for this report.

A related issue is determining which agency receives and maintains the desired data. In many states, the oil and gas agencies manage most or all of the activities related to oil and gas production. However, states may administer some of the Underground Injection Control (UIC) program well classes (injection wells), the National Pollutant Discharge Elimination System (NPDES) program (discharges to surface water bodies), or waste recycling and reuse programs in an environmental protection agency rather than the oil and gas agency. The initial contacts for this study were made to the oil and gas agencies. When it became apparent that some relevant data were outside those agencies' jurisdiction, inquiries to additional agencies (including several EPA regional offices) were made.

A fourth factor is learning how the data are stored and can be accessed. Most states have large, sophisticated databases that contain hundreds of data elements in addition to oil, gas, and water volumes for each well. GWPC has aided the states in this regard by its development and strong support of the Risk-Based Data Management System (RBDMS) for oil and gas data that is used by many states. Trained IT personnel will know how to query the databases to get subsets of information, but oil and gas regulatory staff may not have that knowledge. A few states make much of their production data available on public websites. Some states publish annual reports that contain information on oil, gas, and water production. These were used for several states.

This study planned to provide consistent data showing differences between water generation and management from conventional oil and gas production vs. unconventional production. Some states were able to share this type of information, but many of the larger oil and gas producing states were unable to split the generated water volume by production type. Without the contribution of the largest states, a national perspective is not possible.

4.3 Data Accuracy and Quality

The produced water volume information in this report relies on the data received from many different agency sources. Those agencies, in turn, rely on data that has been submitted to them by operators. When collecting information from thousands of operators who own and operate nearly one million wells, then compiling them into large databases, there is some likelihood that the data will not be completely accurate.

Much of the potential inaccuracy arises from how the raw water volume data are measured or estimated, how frequently the volumes are measured, and what types of quality control measures are employed as data moves from field measurement to entry on a form to transcription of the form data into a database.

Commodities with some economic value (e.g., oil and gas), may be measured with a calibrated flow meter. Water volume, on the other hand, is typically measured in a less rigorous manner. Water volume can be measured by comparing relative heights in a tank, by pump capacity and running time, or by counting the number of truckloads of water moved offsite, among other methods. These methods give results that have some relationship to true volume, but are not precise. As noted above, unless a regulatory agency sees a need to quantify water volumes with high accuracy, the data will remain as approximations.

In most onshore oil field applications, water volume is not monitored continuously. Estimates are made based on intermittent readings and are combined to generate a composite estimate. When flows are consistent and ongoing, those estimates should be more accurate than when flows are irregular and variable in volume.

Field water volume estimates must be entered onto log sheets then later summed and transferred to agency forms. There are opportunities for typos at this stage, as well as in the agencies, when the forms are transcribed into the agencies' databases. It is also possible to find inconsistent usage of units (gallons, bbl, mcf,[6] Mmcf). More agencies are moving to electronic submittal of forms, which can eliminate at least one level of manual transcription.

The data provided by the state agencies (as described in Chapter 5) usually showed volumes expressed to the individual bbl or Mmcf. Accuracy at this level could not be validated for this report. The volumes estimated in Chapter 5 are shown in Table 4-1, but in a separate row at the bottom of Table 4-1, the total oil and water volumes are rounded to the nearest million bbl, and total gas is rounded to the nearest thousand Mmcf. Likewise, the volumes in Table 4-2 for each management practice are the exact numbers from the state summaries in Chapter 5. Those are rounded in the bottom row of Table 4-2. *The rounded totals are the national totals that should be used and cited.*

When the agency personnel extract data from their databases, they need to use certain filters to form their queries. Those personnel tried to provide data that matched the questionnaire requests as closely as possible, but may have inadvertently included additional information or omitted relevant information. There is no way of knowing how those queries were made, so in most cases, the data were accepted at face value.

For many of the states, it was necessary to start with the data from their questionnaires and extrapolate or otherwise modify or supplement the agency data. Every time those processes were used, the author applied certain assumptions about the data and made calculations, which are described in the state-by-state summaries in Chapter 5. Hopefully those assumptions and calculations were done adequately, but the end result does reflect the author's own choices – another author may have chosen different assumptions and made different analyses.

In a few states, the volume of water managed greatly exceeded the volume of water generated. Much of that incremental volume was attributable to additional sources of makeup water used for enhanced recovery operations. Where it was possible to separate out the makeup water, this report does that.

All of the factors described in sections 4.2 and 4.3 contribute to the magnitude and precision of the final data used in this report. Inevitably the values shown in the following tables are estimates with some degree of error or uncertainty surrounding them. Error bars or standard deviations were not calculated for the data using formal statistical analysis. The inherent imprecision of the data sources does not allow that sort of detailed comparison. However, despite that imprecision, the data do provide a useful snapshot of water generation and management in 2017. No other published material offers such a complete description of produced water in 2017.

[6] The unit mcf represents thousand cubic feet. Some of the data submitted by the agencies used units of mcf. Every effort was made to convert those volumes to Mmcf for consistency.

4.4 Results of Produced Water Volume Analysis

In 2017, U.S. onshore and offshore oil and gas production activities generated 24,392,000,000 bbl of produced water along with 3,406,000,000 bbl of oil (includes condensate) and 35,001,000 Mmcf of gas. Table 4-1 provides oil, gas, and water production information for each state and for federal lands (the contribution from offshore wells located in federal waters) for 2017. The comparable data for 2012 (Veil 2015) are also shown in the table. As noted in section 3.4, production from federal onshore wells and tribal wells was included in the state totals. Any offshore production from wells in state waters was included within the state totals.

4.4.1 Comparison to 2012 Volumes

U.S. oil production increased by 50.4% between 2012 and 2017, and U.S. gas production increased by 17.7% during the same period. U.S. water production increased by 15.2% between 2012 and 2017. In other words, particularly the oil, and to some extent the gas increased at a higher rate than the water during that five-year period.

The data from Table 4-1 can be used to calculate increases or decreases on a state-by-state basis. Using Texas as an example, since it is the highest producing state for oil, gas, and water, the percentage changes of those commodities from 2012 to 2017 are: oil → 209% increase, gas → 0.2% decrease, and water → 33% increase. The massive increase in oil production was considerably larger than the increase in water production.

Table 4-1 — Production Summaries for 2017 and 2012

State	Oil 2017 (bbl/year)	Oil 2012 (bbl/year)	Gas 2017 (Mmcf/year)	Gas 2012 (Mmcf/year)	Water 2017 (bbl/year)	Water 2012 (bbl/year)
Alabama	6,827,900	11,310,000	150,857	216,000	63,870,227	106,619,000
Alaska	180,546,058	192,368,000	3,268,520	3,182,000	828,067,983	769,153,000
Arizona	12,829	51,900	342	116	38,786	81,000
Arkansas	5,288,375	6,568,000	692,469	1,137,000	315,958,569	184,867,000
California	172,293,268	197,749,000	189,444	174,000	3,134,503,023	3,074,585,000
Colorado	132,846,403	49,361,000	2,174,415	1,709,000	310,650,278	358,389,000
Florida	1,923,238	2,171,000	23,132	19,000	58,673,032	62,641,000
Idaho	0	0	3,789	0	91,566	0
Illinois	8,314,000	8,908,000	2,131	2,100	282,599,989	99,142,000
Indiana	1,780,016	2,350,000	5,914	8,800	50,797,713	57,566,000
Kansas	35,822,288	43,743,000	241,845	299,000	1,205,091,949	1,061,019,000
Kentucky	2,477,000	3,198,000	88,715	106,000	13,913,894	19,689,000
Louisiana	52,282,199	82,781,000	3,306,864	3,347,000	998,519,062	927,635,000
Michigan	5,800,000	7,400,000	97,500	130,000	80,500,000	117,000,000
Mississippi	17,037,830	24,146,000	52,275	437,000	171,145,175	231,236,000
Missouri	116,808	175,000	0	12,000	2,763,613	2,103,000
Montana	20,707,078	26,495,000	27,529	67,000	141,733,134	182,833,000
Nebraska	2,092,816	2,514,000	456	1,200	50,069,495	58,641,000
Nevada	284,954	368,000	3	4	6,510,029	5,865,000
New Mexico	172,587,378	85,340,000	1,296,990	1,252,000	879,740,841	775,930,000
New York	214,821	360,000	11,800	27,000	189,746	510,000
North Dakota	390,730,886	243,272,000	688,605	259,000	505,828,554	291,147,000
Ohio	19,802,406	5,063,000	1,770,454	86,000	24,142,988	5,542,000
Oklahoma	159,207,164	92,988,000	2,350,071	2,023,000	2,844,485,617	2,325,153,000
Pennsylvania	6,454,010	4,300,000	5,464,661	2,260,000	55,321,026	34,089,000
South Dakota	1,304,321	1,754,000	260	15,000	6,924,285	5,296,000
Tennessee	275,316	372,000	3,038	6,000	44,163	1,480,000
Texas	1,271,143,548	608,213,000	8,124,096	8,137,000	9,895,084,619	7,435,659,000
Utah	34,438,271	30,195,000	315,143	491,000	155,047,940	166,945,000
Virginia	795	9,700	115,492	146,000	2,156,931	3,232,000
West Virginia	7,570,204	2,561,000	1,611,100	539,000	26,650,935	13,772,000
Wyoming	75,717,834	45,382,000	1,808,429	2,079,000	1,705,309,511	2,178,065,000
State Total	2,785,900,014	1,781,466,600	33,886,339	28,167,220	23,816,424,673	20,555,884,000
Federal Total	619,697,287	482,774,000	1,114,880	1,563,000	575,926,287	624,762,000
U.S. Total	3,405,597,301	2,264,240,600	35,001,219	29,730,220	24,392,350,960	21,180,646,000
Rounded U.S. Total	**3,406,000,000**	**2,264,000,000**	**35,001,000**	**29,730,000**	**24,392,000,000**	**21,181,000,000**

4.4.2 Top Producing States

Oil, gas, and water have never been uniformly generated among the oil and gas producing states. Table 4-2 shows the ten states (or as appropriate, the federal offshore portion) with highest production of water. The table also shows how those states ranked in the 2012 year.

Table 4-2 — Top Ten States in Terms of Water Production in 2017

Ranking 2017	Ranking 2012	State	2017 Volume	% of Total Water
1	1	Texas	9,895,084,619	41
2	2	California	3,134,503,023	13
3	3	Oklahoma	2,844,485,617	12
4	4	Wyoming	1,705,309,511	7
5	5	Kansas	1,205,091,949	5
6	6	Louisiana	998,519,062	4
7	7	New Mexico	879,740,841	4
8	8	Alaska	828,067,983	3
9	9	Federal offshore	575,926,287	2
10	11	North Dakota	505,828,554	2

Tables 4-3 and 4-4 show the same rankings for oil and for gas.

Table 4-3 — Top Ten States in Terms of Oil Production in 2017

Ranking 2017	Ranking 2012	State	2017 Volume	% of Total Oil
1	1	Texas	1,271,143,548	37
2	2	Federal Offshore	619,697,287	18
3	3	North Dakota	390,730,886	11
4	5	Alaska	180,546,058	5
5	7	New Mexico	172,587,378	5
6	4	California	172,293,268	5
7	6	Oklahoma	159,207,164	5
8	9	Colorado	132,846,403	4
9	10	Wyoming	75,717,834	2
10	8	Louisiana	52,282,199	2

Table 4-4 — Top Ten States in Terms of Gas Production in 2017

Ranking 2017	Ranking 2012	State	2017 Volume	% of Total Gas
1	1	Texas	8,124,096	23
2	4	Pennsylvania	5,464,661	16
3	3	Louisiana	3,306,864	9
4	6	Alaska	3,268,520	9
5	7	Oklahoma	2,350,071	7
6	2	Colorado	2,174,415	6
7	5	Wyoming	1,808,429	5
8	21	Ohio	1,770,454	5
9	11	West Virginia	1,611,100	5
10	9	New Mexico	1,296,990	4

Texas was the largest producer of all three fluids. It generated 41% of all the U.S. produced water, and produced about 37% of all U.S. oil and 23% of all U.S. gas. No other entity approached those high percentages, with the possible exception of the federal offshore oil production (18% of national total) and Pennsylvania gas production (16% of national total).

The sum of the top five states in each category made up well over half of the total U.S. volume (77% for water, 77% for oil, and 64% for gas). No state other than Texas ranked in the top five in all three categories.

The 2017 top ten states for water production were nearly identical to 2012. The top ten oil states in 2017 were the same ten states as in 2012, but some of the states changed ranking order. The 2017 top ten gas states added two new members – Ohio and West Virginia, and Pennsylvania vaulted to the second ranking position.

4.4.3 Ratio of Water to Hydrocarbon

In addition to total volumes produced, it is interesting to consider the water-to-oil ratios (WORs) and water-to-gas ratios (WGRs) from production activities. The WORs and WGRs calculated here represent the ratio of water and hydrocarbons in the fluids produced to the surface and do not necessarily represent fluid proportions remaining in the reservoir.

Many of the states were unable to provide water volumes from oil wells separately from water volumes from gas wells, making calculation of WORs and WGRs impossible. Tables 4-5 and 4-6 show water-to-hydrocarbon ratios from those states where produced water data could be provided according to the predominant hydrocarbon produced at a specific location. The bottom row of each table shows a calculated weighted average WOR or WGR that takes each state's actual production volumes into account.

Table 4-5 — WORs for States in which Data Allows their Calculation

State	Oil (bbl)	Water from Oil Wells (bbl)	WOR
Alabama	6,827,900	29,335,000	4.3
Arizona	12,829	36,186	2.8
Arkansas	5,288,375	305,273,682	57.7
Michigan	5,800,000	18,500,000	3.2
Mississippi	17,037,830	167,565,806	9.8
Missouri	116,808	2,763,613	23.7
Montana	20,707,078	139,816,906	6.8
Nebraska	2,092,816	47,566,021	23
Nevada	284,954	6,510,029	23
New York	214,821	113,292	0.5
North Dakota	390,730,886	505,820,717	1.3
Ohio	19,802,406	5,073,914	0.25
South Dakota	1,304,321	6,923,943	5.3
Utah	34,438,271	125,739,740	3.7
Wyoming	75,717,834	1,432,993,542	18.9
Total	580,377,129	2,794,032,391	
Weighted Average WOR			4.8

Suitable data were available for just 15 states. The WORs ranged from 0.5 bbl/bbl for New York to 57.7 bbl/bbl for Arkansas. The weighted average for those states with suitable data sets was 4.8 bbl/bbl. Readers are advised not to cite this WOR value as being representative of the entire United States. The total water represented by these states is just a small fraction of all the produced water generated in the country.

Of the top ten states in water production, only Wyoming and North Dakota are represented on this list. Many of the states with large numbers of older conventional wells in mature fields (for example, Texas, Kansas, Louisiana, and Oklahoma) typically have very high WORs, but were unable to distinguish the water generated from oil wells vs. water coming from gas wells. It is very likely that if the wells from those states were averaged in with the wells from the other states in Table 4-5, the national weighted average WOR would be higher. Unfortunately, the data provided by the states does not allow a more precise estimate of WOR.

Table 4-6 show the 14 states that had suitable data to calculate WGRs. The WGRs ranged from 6.5 bbl/Mmcf for New York to 5,490 bbl/Mmcf for Nebraska – a very broad range. The weighted averages for those states with suitable data sets was 76.4 bbl/Mmcf. As noted above for WOR, the total water accounted for in Table 4-6 is just a small fraction of the total produced water for the whole country. As a result, the weighted average WGR calculated here is not really representative.

Table 4-6 — WGRs for States in which Data Allows their Calculation

State	Gas (Mmcf)	Water from Gas Wells (bbl)	WGR (bbl/Mmcf)
Alabama	150,857	34,535,000	229
Arizona	342	2,600	7.6
Arkansas	692,469	10,684,887	15.4
Michigan	97,500	62,000,000	775
Mississippi	52,275	3,579,369	68
Montana	27,529	1,916,226	70
Nebraska	456	2,503,474	5,490
New York	11,800	76,464	6.5
North Dakota	688,605	7,837	n/a
Ohio	1,770,454	19,069,074	10.8
South Dakota	260	342	n/a
Utah	315,143	29,308,200	93
Virginia	115,492	2,156,931	18.7
Wyoming	1,808,429	272,315,969	151
Total	5,731,611	438,156,373	
Weighted Average WGR			76.4

With the limited availability of data to estimate national WOR and WGR values, one other way to express the relationship between water and hydrocarbon is to convert natural gas volumes to barrels of oil equivalent (BOE), then add the oil volume and the BOE (from gas volume). Conversion factors are available on the EIA website.[7] On an energy equivalence basis, 1 Mmcf of gas has the same megajoule value as 181.59 bbl of oil.

For 2017, the national total natural gas volume of 35,001,219 Mmcf equals 6,355,871,358 BOE. The total hydrocarbon (oil + BOE) = 9,761,468,659 BOE. The total water volume is 24,392,350,960 bbl. The value of water-to-BOE ratio is roughly 2.5. For the sake of comparison, the water-to-BOE ratio for 2012 was 2.76. For 2007, the same ratio was 3.40. The decline in the water-to-BOE ratio over ten years supports the overall trend that less water is being generated per unit of hydrocarbon.

4.5 Results of Produced Water Management Analysis

Efforts were made to obtain detailed data on how produced water was managed for each state and in the federal offshore areas in 2017. Some states provided complete data, others

[7] https://www.eia.gov/energyexplained/units-and-calculators/energy-conversion-calculators.php. Visited on October 6, 2019.

provided partial data, and a few were unable to share any information on how produced water was managed.

The total volume of produced water managed in 2017 is estimated to be 24,483,000,000 bbl. This matches closely with the volume of produced water generated. This is not surprising, since the state summaries for many of the states show that generated volumes exactly match managed volumes.

Table 4-7 shows a state-by-state breakout of how water was managed and the volumes managed in each category. The details behind these summary data can be found in the individual state summaries in Chapter 5.

Table 4-7 — Produced Water Management Practices and Volumes for 2017 (bbl/year)

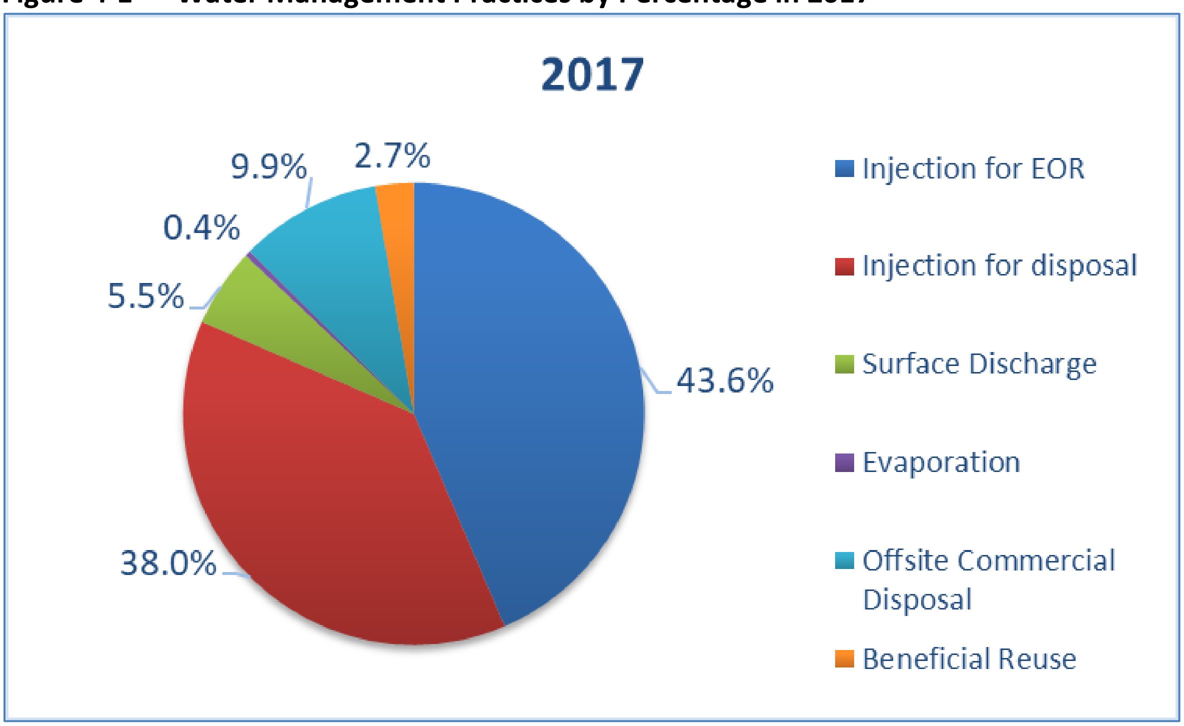
State	Injection EOR	Injection for Disposal	Surface Discharge	Evaporation	Offsite Commercial Disposal	Beneficial Reuse in Oil Field	Beneficial Reuse outside Oil Field	Total Prod Water Managed
Alabama	861,000	29,980,000	32,858,000	0	171,000	0	0	63,870,000
Alaska	772,433,217	84,966,098	37,222	0	0	0	0	857,436,537
Arizona	0	47,208	0	0	0	0	0	47,208
Arkansas	44,270,037	266,347,907	0	0	5,340,625	0	0	315,958,569
California	1,841,612,368	694,302,395	13,809,445	28,752,996	56,144,945	159,535,576	311,107,975	3,105,265,700
Colorado	108,207,977	157,040,690	18,217,065	20,084,676	0	29,728,976	0	333,279,384
Florida	48,636,117	10,249,420	0	0	0	0	0	58,885,537
Idaho	0	0	0	91,566	0	0	0	91,566
Illinois	193,261,188	89,338,801	0	0	0	0	0	282,599,989
Indiana	36,296,729	14,450,187	50,797	0	0	0	0	50,797,713
Kansas	298,991,227	906,098,487	0	0	2,235	0	0	1,205,091,949
Kentucky	12,789,124	1,124,770	0	0	0	0	0	13,913,894
Louisiana	70,739,593	877,374,282	0	0	50,405,187	0	0	998,519,062
Michigan	14,500,000	64,500,000	0	0	1,500,000	0	0	80,500,000
Mississippi	41,391,526	156,763,266	0	0	0	0	0	198,154,792
Missouri	2,586,948	176,665	0	0	0	0	0	2,763,613
Montana	73,571,587	58,893,204	6,576,855	2,691,488	0	0	0	141,733,134
Nebraska	23,515,265	24,694,793	319,812	1,009,932	409,674	0	120,019	50,069,495
Nevada	0	6,528,730	0	0	0	0	0	6,528,730
New Mexico	351,201,250	443,893,992	0	0	0	79,176,676	0	874,271,918
New York	2,238	17,510	19,088	523	87,151	33,323	29,913	189,746
North Dakota	40,833,265	266,459,626	0	0	198,535,663	0	0	505,828,554
Ohio	554,565	37,886,014	0	0	0	3,837,053	85,384	42,363,016
Oklahoma	1,276,853,948	1,185,687,061	0	0	381,944,608	0	0	2,844,485,617
Pennsylvania	0	566,870	893,870	0	0	50,767,765	198,556	52,427,061
South Dakota	4,179,533	2,743,752	0	1,000	0	0	0	6,924,285
Tennessee	27,887	1,170	0	15,106	0	0	0	44,163
Texas	4,557,819,641	3,586,674,633	34,279,995	0	1,716,310,350	0	0	9,895,084,619
Utah	61,800,708	76,439,156	7,103,047	9,705,029	0	0	0	155,047,940
Virginia	0	2,156,931	0	0	0	0	0	2,156,931
West Virginia	3,660,000	15,000,000	195,650	0	0	7,795,285	0	26,650,935
Wyoming	802,309,212	243,010,765	648,126,190	40,000,000	2,450,183	0	0	1,735,896,350
State Total	10,682,906,150	9,303,414,383	762,487,036	102,352,316	2,413,301,621	330,874,654	311,541,847	23,906,878,007
Federal Offshore	0	0	575,926,287	0	0	0	0	575,926,287
U.S. Total	10,682,906,150	9,303,414,383	1,338,413,323	102,352,316	2,413,301,621	330,874,654	311,541,847	24,482,804,294
Rounded U.S. Total	**10,683,000,000**	**9,303,000,000**	**1,338,000,000**	**102,400,000**	**2,413,000,000**	**331,000,000**	**311,500,000**	**24,483,000,000**

Produced water management by category in 2017 was as follows:

- 91.5% of the produced water was injected. 43.6% was injected for enhanced recovery and 38.0% was injected at non-commercial disposal wells. An additional 9.9% was injected at offsite commercial disposal facilities -- these are third-party businesses that charge a fee to receive incoming produced water and other oil and gas wastes. Water was treated and processed in various ways. Nearly all of these facilities managed water by injection into disposal wells. A small percentage of the commercial facilities utilize evaporation ponds – water managed at those facilities is counted under the evaporation category.
- 5.5% was discharged to surface water.
- 0.4% was evaporated, primarily in several arid western states, from onsite ponds and pits and at several commercial disposal facilities.
- 1.4% was reused within the oil and gas industry for purposes other than injection for enhanced recovery (which is a reuse of produced water for a beneficial value). The actual percentage was probably higher than this, but it was not quantified for most states during 2017. Much of the reuse was done by recycling produced water to use as drilling fluids and frac fluids for new wells in the same fields.
- 1.3% was reused in applications outside of the oil and gas industry. Examples include irrigation (when the water has low salinity) and for dust and ice control on roads.

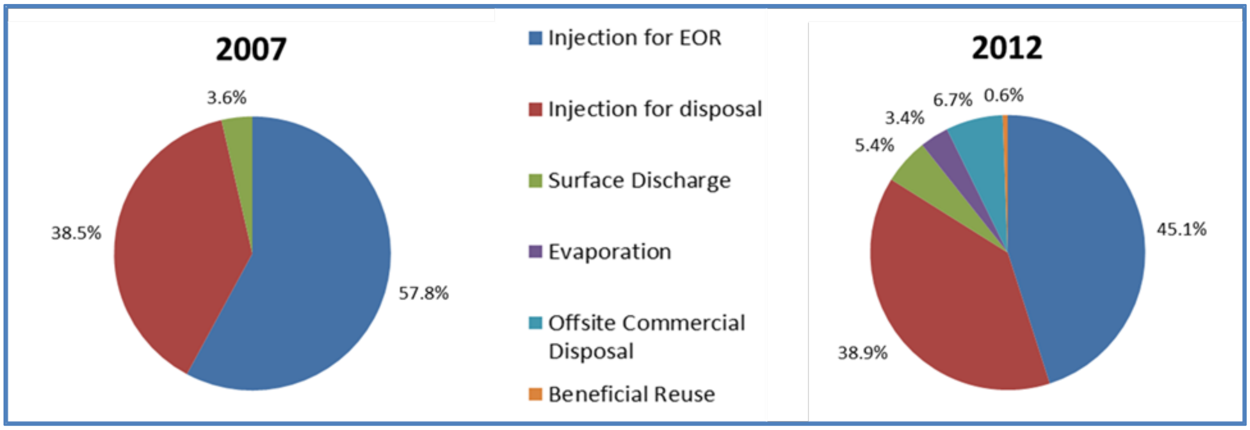
The 2017 water management information is shown graphically in Figure 4-1.

Figure 4-1 — Water Management Practices by Percentage in 2017



For the sake of comparison to the previous studies, Figure 4-2 shows similar graphs for 2007 and 2012. Note that in the 2007 study, fewer management options were surveyed.

Figure 4-2 -- Management Practices by Percentage in 2007 and 2012



It is interesting to examine the percentage of produced water injected over time. Figure 4-3 shows that the percentage of water injected has remained over 90% during the ten-year period, and is very similar between 2012 and 2017. Differences between the years may represent different reporting by the states and/or different assumptions made when compiling the data. Rather than focusing on the exact percentage, it is more important to recognize that injection has dominated produced water management in the past and continues to dominate today.

Figure 4-3 — Produced Water Managed by Injection over a Ten-Year Period

Year	% Injected into Disposal Wells	% Injected for EOR	% Injected by Offsite Commercial Disposal Companies	Total % Injected
2017	43.6	38.0	9.9	91.5
2012	38.9	45.1	6.7	90.7
2007	38.5	57.8	no data	96.3

The continued decrease in EOR percentage during this ten-year period is primarily attributed to the decommissioning of conventional waterflood operations over time. In any case, underground injection is the predominant way in which produced water is managed from onshore wells. However, at offshore wells, nearly all produced water is treated then discharged to the ocean under the terms of EPA-issued discharge permits.

4.5.1 Comments and Caveats on Water Management

Data concerning the most common management practice (injection) was available from most states, since the oil and gas agencies typically managed the Class II UIC programs. Many states were able to provide separate volume estimates for the water injected for enhanced recovery vs. the water injected to disposal wells. Unfortunately, some of the states were unable to distinguish between the volumes injected for enhanced recovery and disposal. To make the data set as complete as possible, it was necessary to use some assumptions and analyses to allocate water to the two types of injection.

In some situations, water generated in one state may have been subsequently managed in another state. One good example is that a large volume of flowback and produced water generated from wells in Pennsylvania and West Virginia was transported to disposal wells in Ohio. The Ohio volume for water managed greatly exceeded the volume of produced water generated in the state. This situation is discussed in Chapter 5 for each of those states.

Some states reported a large volume of water injected for enhanced recovery. They acknowledged that the total water consisted of some produced water and some makeup water from other sources. Where it was possible to segregate these water types, the data were adjusted accordingly.

Chapter 5 — State-by-State Summary

This chapter provides a summary of the data received for each state, including the agency that provided it and when it was received. For those states that submitted completed questionnaires, copies of Tables 1 and 2 from the questionnaire are shown. In some instances, modifications were made to the states' numbers – those are described in each state summary. For those states that did not submit questionnaires, the same two tables are shown with descriptions of the method used to estimate produced water volume and management practices.

The use of the term "conventional oil" means the same thing as "oil from conventional formations." The same phrasing applies to the terms "unconventional oil," "conventional gas," and "unconventional gas."

Some states reported a production of condensate separately from crude oil. For making the state and national oil production totals, condensate production was combined with crude oil production to estimate oil production.

Pages on the EIA website provide estimates of the volume of oil and gas generated by each state for 2017:

- Oil - http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_a.htm
- Gas - http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_a.htm.

These estimates were compared to the estimates provided by the state agencies. State agency estimates were used when available.

The Interstate Oil and Gas Compact Commission (IOGCC) asks states to provide them with data on oil and gas production each year, as well as the volume of water injected for enhanced recovery and injected for disposal. The IOGCC compiles this information into a spreadsheet. The IOGCC provided the author with a copy of this spreadsheet.[8] It was used for those states that did not provide completed questionnaires. Where the IOGCC spreadsheet data were used, the state summaries note that source of information.

In some states the total volume of water injected greatly exceeded the total volume of water generated. This was often a result of enhanced recovery operations requiring more water for injection than was available from the generated produced water supply. The total water injected for enhanced recovery included produced water plus makeup water from some other source. For most states that showed a large differential between injected water and generated water, the total water injected for enhanced recovery was reduced in the tables so that the

---

[8] Email from IOGCC to John Veil on June 25, 2019.

overall volume of produced water generated matched the overall volume managed. In the few cases where an alternate procedure was followed, the state summary gives an explanation.

Data had been collected from all states by the end of August 2019. The author made a presentation of the preliminary findings at the GWPC Annual Forum in September 2019. Following that presentation, copies of the draft state summaries were sent to each state for their review. This was an effort to make sure that states were satisfied with the language used to describe their produced water situation. Several states replied indicating they were satisfied with the draft summaries. Several other states offered some edits or revised data. About half of the states did not respond at all.

5.1 Alabama

The State Oil and Gas Board of Alabama provided produced water generation and management data.[9] Tables 5-1 and 5-2 show the replies to the questionnaire. At the end of 2017, Alabama had 6,462 wells producing hydrocarbons, with the majority of these wells producing CBM (5,628 wells). The remaining wells produced conventional oil (541 wells), conventional gas (253 wells), and condensate (39 wells).

The statewide total produced water volume for 2017 was 63,870,227 bbl – considerably lower than the 2012 water volume of 106,619,000 bbl. CBM production generated about 51% of that total, and conventional oil contributed another 46%.

Using the hydrocarbon and water production data, the following ratios were determined: WOR of 4.3 bbl/bbl, WGR of 19 bbl/Mmcf for conventional gas, and WGR of 533 bbl/Mmcf for CBM. The combined WGR for gas wells was 229 bbl/Mmcf.

Table 5-1 — 2017 Production for Alabama

Type of Hydrocarbon	# Wells Producing Primarily That Type of Hydrocarbon	Total Volume of Produced Water Brought to Surface (bbl/year)	Volume of Hydrocarbon Produced (bbl/year or Mmcf/year)
Crude oil from conventional formations	541	29,335,167	5,791,028 bbl; 11,961 Mmcf associated gas
Natural gas from conventional formations	253 gas; 39 gas condensate	1,676,931	77,288 Mmcf; 1,036,872 bbl gas condensate
Crude oil from unconventional formations	0	0	0
Natural gas from unconventional formations	5,628 coal bed methane; 1 shale gas	32,858,129	61,608 Mmcf
Total	6,462	63,870,227	6,827,900 bbl; 150,857 Mmcf

Unlike most other states, roughly half of produced water in Alabama was managed through discharge to surface water bodies. The U.S. EPA national effluent limitations guidelines (discharge standards) for the oil and gas industry specify zero discharge of produced water for most onshore wells in the eastern half of the United States. However, several decades ago, the CBM producers in Alabama petitioned EPA for an exception to those provisions, suggesting that

[9] Emails from the State Oil and Gas Board of Alabama to John Veil on June 11, 2019.

water in contact with coal seams was more like coal mining water and less like oil and gas produced water. EPA agreed, allowing many discharges of treated CBM water to the Black Warrior River under the auspices of NPDES permits (Veil 2002). The Alabama Department of Environmental Management (ADEM) administers the NPDES permit program.

Permitted surface discharge accounted for 51% of produced water management in Alabama. Injection for disposal managed 47% of produced water, about 1.4% was injected for enhanced recovery. The remaining small percentage of produced water was managed through offsite commercial disposal. There was no reported beneficial reuse of produced water in Alabama.

Table 5-2 — 2017 Produced Water Management Practices for Alabama

Management Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	861,136	1.4%
Injection for disposal	29,980,234	46.9%
Surface discharge (CBM wells)	32,858,082	51.4%
Evaporation	0	0
Offsite commercial disposal (pay another company to manage your produced water)	170,775	0.3%
Reuse within the oil and gas industry	0	0
Reuse in ways other than in the oil and gas industry	0	0
Total	63,870,227	100%

5.2 Alaska

The Alaska Oil and Gas Conservation Commission (AOGCC) provided produced water generation and management data.[10] Additional information regarding produced water management was provided by the Alaska Department of Environmental Conservation (ADEC).[11] Tables 5-3 and 5-4 show the replies to the questionnaire. In 2017, Alaska had 2,450 wells with the majority of these wells producing conventional oil (2,250 wells) along with a large volume of associated gas. The remaining 200 wells produced conventional gas. No unconventional production was reported.

The statewide total produced water volume for 2017 was 828,067,983 bbl. Conventional oil production generated more than 99% of that total with conventional gas wells contributing a fraction of one percent of the produced water volume. The numbers shown in Table 5-3 include offshore hydrocarbon and water production from wells located within State waters.

In their data submittal, the AOGCC reported 13 dedicated water source wells. The majority of the water produced from those water wells (33,102,993 bbl in 2017) was reinjected into producing formations for enhanced recovery. Alaska also utilized water from seawater sources. Those volumes are not recorded in the AOGCC produced water totals in Table 5-3 since they represented water unrelated to oil and gas production wells.

Table 5-3 — 2017 Production for Alaska

Type of Hydrocarbon	# Wells Producing Primarily That Type of Hydrocarbon	Total Volume of Produced Water Brought to Surface (bbl/year)	Volume of Hydrocarbon Produced (bbl/year or Mmcf/year)
Crude oil from conventional formations	~2,250	826,805,079	180,546,058 bbl; 3,173,622 Mmcf
Natural gas from conventional formations	~200	1,262,904	94,898 Mmcf
Crude oil from unconventional formations	0	0	0
Natural gas from unconventional formations	0	0	0
Total	~2,450	828,067,983	180,546,058 bbl; 3,268,520 Mmcf

[10] Email from AOGCC to John Veil on June 13, 2019.

[11] Email from ADEC to John Veil on July 18, 2019.

The AOGCC reported that a volume of 1,113,144,016 bbl of water was injected for EOR purposes in 2017. Of that volume, 772,433,217 bbl was believed to be produced water. The difference between these two numbers is the amount of supplemental EOR water being sourced from seawater treatment plants and from dedicated water wells.

An additional 84,966,098 bbl of fluids was injected into disposal wells. The AOGCC reported that 59,671,332 bbl was produced water injected into UIC Class II disposal wells, and the ADEC reported that 25,294,766 bbl of wastewater (produced water with workover and completion fluids) was injected into UIC Class I disposal wells.

ADEC reported that 37,222 bbl of produced water was discharged to state-controlled surface waters during 2017. During the 2012 year studied in the previous report (Veil 2015), discharges to Cook Inlet were regulated by EPA Region 10. Since 2012, primacy for the NPDES permit program was transferred to Alaska and is now administered by the ADEC.

Both ADEC and AOGCC are aware of some limited disposal at an offsite commercial company that operates disposal wells, but neither agency had any quantitative information on the volume of produced water involved. The agencies noted that the volume would have been included with either the Class I or Class II volumes in the Injection for Disposal row.

Table 5-4 — 2017 Produced Water Management Practices for Alaska

Management Practice	**Total Volume of Produced Water Managed by That Practice (bbl/year)**	**Percentage of Produced Water Managed by That Practice**
Injection for enhanced recovery	772,433,217 bbl (produced water portion); 1,113,144,016 bbl overall	90%
Injection for disposal	84,966,098	10%
Surface discharge	37,222	<0.1%
Evaporation	0	
Offsite commercial disposal (pay another company to manage your produced water)	0	0
Reuse within the oil and gas industry	0	0
Reuse in ways other than in the oil and gas industry	0	0
Total	857,436,537	100%

Neither the AOGCC or the ADEC is aware of any beneficial reuse of produced waters either within the industry or in other applications.

The total volume of water managed (857,436,537 bbl) exceeds the volume generated (828,067,983 bbl). No information is available on that differential.

5.3 Arizona

The questionnaire was sent to the Arizona Oil and Gas Conservation Commission (AZOGCC). The AZOGCC replied that they did not have compiled data to complete the questionnaire and suggested that the author contact the Arizona Department of Environmental Quality (ADEQ) Records Management Center.[12] The AZOGCC noted that Arizona's only hydrocarbon production, albeit small, is from the Four Corners region on the Navajo Reservation.

The ADEQ Records Management Center provided electronic copies of the Form 16 (Monthly Producer's Report) that had been submitted by operators for the 2017 year.[13] These forms provided information on the volume of oil, gas, and water brought to the surface. They also provided copies of Form 14 (Report of Injection Project), which provided the volume of water injected.

The data from these numerous individual reports were combined in a spreadsheet and then summarized in Table 5-5. No information was provided by the AZOGCC regarding whether the oil and gas production was from conventional or unconventional wells. In the data provided by Arizona agencies for the 2012 report, all wells were reported as being conventional wells. This convention is used again for the 2017 report.

In 2017, Arizona had 42 wells that reported to the AZOGCC on Form 16s. However, 18 of those wells had no production during the year. 17 wells produced mainly oil, and 7 wells produced gas. The total volume of oil was 12,829 bbl. The total volume of gas was 342 Mmcf. These produced water volumes resulted in a WOR of 2.8 bbl/bbl of crude oil and WGR of 7.6 bbl/Mmcf of conventional gas.

The AZOGCC was unable to provide information on how produced water was managed. The 2012 report noted that "all produced water in Arizona was managed by injection into 2 disposal wells". The 2017 report follows that same convention (Figure 5-6). The annual injected volume of 47,208 bbl was slightly higher than the annual produced water volume of 38,786 bbl. This suggests that either produced water from another state was brought to the disposal well in Arizona or fluids other than produced water were injected into the disposal well.

[12] Email from AZOGCC to John Veil, May 9, 2019.

[13] Email from ADEQ to John Veil, May 14, 2019.

Table 5-5 — 2017 Production for Arizona

Type of Hydrocarbon	# Wells Producing Primarily That Type of Hydrocarbon	Total Volume of Produced Water Brought to Surface (bbl/year)	Volume of Hydrocarbon Produced (bbl/year or Mmcf/year)
Crude oil from conventional formations	29	36,186	12,829 bbl
Natural gas from conventional formations	13	2,600	342 Mmcf
Crude oil from unconventional formations	0	0	0
Natural gas from unconventional formations	0	0	0
Total	42	38,786	12,829 bbl; 342 Mmcf

Table 5-6 — 2017 Produced Water Management Practices for Arizona

Management Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	0	0
Injection for disposal	47,208	100%
Surface discharge	0	0
Evaporation	0	0
Offsite commercial disposal (pay another company to manage your produced water)	0	0
Reuse within the oil and gas industry	0	0
Reuse in ways other than in the oil and gas industry	0	0
Total	47,208	100%

5.4 Arkansas

The Arkansas Oil and Gas Commission provided produced water generation and management data.[14] Tables 5-7 and 5-8 show the replies to the questionnaire. In 2017, Arkansas had 17,901 oil and gas wells with 7,661 of them producing conventional oil. 4,438 wells produced conventional gas. Arkansas had significant unconventional gas production from the Fayetteville Shale – this included 5,802 wells in 2017.

The statewide total produced water volume for 2017 was 315,958,569 bbl. Conventional oil production generated about 97% of that total. These produced water volumes resulted in a WOR of 57.7 bbl/bbl of crude oil, a WGR of 5.9 bbl/Mmcf of conventional gas, and a WGR of 16.5 bbl/Mmcf of unconventional gas. The overall WGR for all gas production was 15.4 bbl/Mmcf.

Table 5-7 — 2017 Production for Arkansas

Type of Hydrocarbon	# Wells Producing Primarily That Type of Hydrocarbon	Total Volume of Produced Water Brought to Surface (bbl/year)	Volume of Hydrocarbon Produced (bbl/year or Mmcf/year)
Crude oil from conventional formations	7,661	305,273,682	5,288,375 bbl
Natural gas from conventional formations	4,438	418,984	71,143 Mmcf
Crude oil from unconventional formations	0	0	0
Natural gas from unconventional formations	5,802	10,265,903	621,326 Mmcf
Total	17,901	315,958,569	5,288,375 bbl; 692,469 Mmcf

The Oil and Gas Commission reported that produced water was managed primarily by injection in Arkansas during 2017. About 14% of the water was injected for enhanced oil recovery. Another 84% was injected into operator-owned disposal wells. 1.7% of the produced water was sent to offsite commercial saltwater disposal (SWD) wells.

In the previous report (Veil 2015), the Oil and Gas Commission estimated that about 2 million bbl of the water generated was flowback (produced) water from Fayetteville Shale wells that was reused to make up new frac fluids for fracturing other Fayetteville Shale wells. In the Commission's submittal for the 2017 report, they did not estimate an actual volume of water

[14] Email from Arkansas Oil and Gas Commission to John Veil on July 24, 2019.

that was reused. However, they suggested that the volume was minimal, as a result of the reduced drilling activity in 2017.

Table 5-8 — 2017 Produced Water Management Practices for Arkansas

Management Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	44,270,037	14.0%
Injection for disposal	266,347,907	84.3%
Surface discharge	0	0%
Evaporation	0	0%
Offsite commercial disposal (pay another company to manage your produced water)	5,340,625	1.7%
Reuse within the oil and gas industry	??	??
Reuse in ways other than in the oil and gas industry	0	0%
Total	315,958,569	100%

5.5 California

The California Department of Conservation (CDOC) Division of Oil, Gas, and Geothermal Resources (DOGGR) provided produced water generation data and links to extract data on water management.[15] Table 5-9 shows the oil, gas, and water volumes for 2017. In 2017, California had 50,296 active oil and gas wells with 98% of them producing both conventional oil and conventional gas or being operated as cyclic steam wells for heavy oil production. Another 2% of the wells produced only conventional gas. Several platforms produced oil and gas in offshore California waters. Information on these platforms is provided in Chapter 6.

The statewide total produced water volume for 2017 was 3,134,503,023 bbl. According to a CDOC annual report of 2017 data (CDOC 2018), offshore wells in state waters accounted for about 16% of the statewide total of produced water, about 6% of the oil, and about 2% of the gas.

Table 5-9 — 2017 Production for California

Type of Hydrocarbon	# Wells Producing Primarily That Type of Hydrocarbon	Total Volume of Produced Water Brought to Surface (bbl/year)	Volume of Hydrocarbon Produced (bbl/year or Mmcf/year)
Crude oil from conventional formations	49,228	3,133,764,429	172,293,628 bbl; 169,394 Mmcf
Natural gas from conventional formations	1,068	738,594	20,049 Mmcf
Crude oil from unconventional formations	0	0	0
Natural gas from unconventional formations	0	0	0
Total	50,296	3,134,503,023	172,293,268 bbl; 189,444 Mmcf

Much of the gas production came from oil wells. The water production could not be allocated to oil and gas production. Therefore, it was not possible to calculate the WOR or WGR for California.

[15] Emails from DOGGR to John Veil on June 24, 2019.

In 2014, the California legislature passed Senate Bill 1281. It required oil and gas operators to submit detailed information about the volume of produced water generated from their wells and how that water was managed. Twelve categories of water management are specified in the instructions. These categories are listed below showing the code and the method.

- 01 - Sump (unlined) – evaporation and percolation (infiltration and evaporation)
- 02 - Sump (lined) – evaporation
- 03 - Surface water discharge – ocean, lake, pond, etc.
- 04 - Domestic sewer system
- 05 - Subsurface injection – in oil field by operator
- 06 - Other – commercial disposal, industrial use, etc.
- 07 - Sale/Transfer – to other operator or oil field
- 08 - Surface discharge – land application
- 09 - Operator's facilities within oil field
- 10 - Well stimulation treatment
- 11 - Sale/Transfer – domestic use
- 12 - Drilling, well work, and well abandonments.

In order to match these 12 categories to the water management categories used in this report, the following groupings are followed:

- Injection for enhanced recovery - 05
- Injection for disposal - 05
- Surface discharge - 03
- Evaporation – 01, 02
- Offsite commercial disposal - 06
- Reuse within the oil and gas industry – 07, 08, 09, 10, 12
- Reuse in ways other than in the oil and gas industry - 11
- Other – 04

Data on the volume of produced water managed in each of these ways can be found on the CDOC website.[16] Compiled reports are available for the first and second quarters of 2017, but for the third and fourth quarters, data must be extracted from large databases that can be downloaded from that website.

Table 5-10 shows the produced water management volumes from the SB 1281 data for 2017. Note that the total produced water volume for Q4 is considerably lower than for the first three quarters. As an additional supporting factor, the SB 1281 produced water management spreadsheet for Q3 has over 78,000 rows, whereas the similar spreadsheet for Q3 has only

[16] https://www.conservation.ca.gov/dog/SB%201281/Pages/SB_1281DataAndReports.aspx; accessed July 4, 2019.

30,000 rows, suggesting that operators did not fully report during Q4. To account for this shortfall, a revised Q4 volume was calculated and used in deriving the Total column. It is calculated as the average (mean) of the Q1, Q2, and Q3 volumes. This gives a total managed produced water volume of 3,105,279,036 bbl. This is close to the produced water volume shown in Table 5-10.

Table 5-10 – 2017 Produced Water Management Volumes for California from SB 1281 Data

Category	Q1 (bbl)	Q2 (bbl)	Q3 (bbl)	Q4 reported (bbl)	Q4 revised (bbl)[a]	Total[b]
01	5,562,744	11,800,466	3,858,579	178,812	7,073,930	28,295,719
02	116,375	116,375	110,208	115,978	114,319	457,277
03	1,210,304	1,194,787	1,093,221	1,116,783	1,166,104	4,664,416
04	2,560,259	2,265,441	2,033,072	1,248,542	2,286,257	9,145,029
05	645,821,403	634,579,539	621,535,130	340,398,008	633,978,691	2,535,914,763
06	14,810,709	13,569,372	13,728,628	10,902,537	14,036,236	56,144,945
07	25,982,748	26,378,424	27,983,244	20,516,533	26,781,472	107,125,888
08	962,037	946,520	886,709	833,898	931,755	3,727,021
09	1,978,382	2,397,333	1,946,366	335,034	2,107,360	8,429,441
10	10,551,370	7,975,594	8,542,366	7,502,507	9,023,110	36,092,440
11	74,294,055	78,568,912	80,468,014	35,729,480	77,776,994	311,107,975
12	892,211	1,101,687	1,126,691	975,056	1,040,196	4,160,785
Total	**784,742,597**	**780,894,451**	**763,322,229**	**419,853,168**	**776,319,759**	**3,105,279,036**

[a] Q4 revised is calculated as the average of Q1, Q2, and Q3.

[b] The Total column is the sum of Q1, Q2, Q3, and Q4 revised.

SB 1281 category 05 refers to water that is injected into the subsurface of the same oil field and operator from which it was produced. That information does not distinguish between water injected for enhanced recovery or water injected for disposal. Nor does it distinguish between produced water or some other type of water injected for enhanced recovery. The amount of water needed for water flooding and steam flooding exceeded the amount of available produced water. As a result, other sources of water were used to supplement the produced water. California is one of the few places in the United States that utilizes large steam flooding operations. In order to generate steam, water must be treated and purified to meet boiler feed standards. Removing salinity from water is expensive – operators may be seeking lower salinity water sources than produced water to meet their boiler feed requirements. To estimate values to include in Table 5-11, the following assumptions and calculations were used:

a. Total water injected = 2,843,012,050 bbl (from CDOC 2018)
b. Total water injected for disposal (assume all is produced water) = 694,302,395 bbl (from CDOC 2018)
c. Total water (from all sources) injected for EOR (water and steam injection) = 2,148,709,655 bbl (from CDOC 2018)
d. Total produced water injected (includes disposal and EOR) = 2,535,914,763 bbl (from Table 5-11)

e. Total produced water injected for EOR = (d) – (b) = 1,841,612,368 bbl
f. Total water from other sources injected for EOR = (c) – (e) = 307,097,287 bbl

California oil and gas companies managed produced water in many ways, which reflects the wide range of the state's oil and gas fields in different geographic settings. Table 5-11 shows that nearly 60% of the produced water was managed by injection for enhanced recovery in water flooding and steam flooding operations. Injection for disposal accounted for 22% of produced water, surface discharge for 0.2%, evaporation for 0.9%, disposal at offsite commercial facilities for 1.8%, and release to the municipal sewer system (shown as Other category) for 0.3%.

One positive outcome of the more detailed produced water management reporting resulting from SB 1821 is that there is now quantified data relating to produced water reuse. This was not available during the previous produced water study that looked at the 2012 year (Veil 2015). Reuse within the oil and gas industry represents about 5% of all produced water. Reuse in applications outside the oil and gas industry involves about 10% of California's produced water – a very significant volume.

Table 5-11 — 2017 Produced Water Management Practices for California

Management Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	1,841,612,368 (produced water portion); 2,148,709,655 overall	59.3%
Injection for disposal	694,302,395	22.4%
Surface discharge	4,664,416[a]	0.2%
Evaporation	28,752,996	0.9%
Offsite commercial disposal (pay another company to manage your produced water)	56,144,945	1.8%
Reuse within the oil and gas industry	159,535,576	5.1%
Reuse in ways other than in the oil and gas industry	311,107,975	10.0%
Other	9,145,029[a]	0.3%
Total	3,105,279,036	100%

[a] In Table 5-11, the volume in the Other category is shown as a separate row. In the national summary table in Chapter 4, the Other volume is combined with the Surface Discharge Volume.

Several well-documented projects treat produced water for beneficial reuse. For example, in the San Ardo field some of the produced water was treated and reused for cooling tower makeup water. The remaining water undergoes further treatment to create water suitable to recharge a shallow aquifer that was used in the area for crop irrigation. GWPC (2019) provides some description of the extensive use of treated produced water for irrigating fruit, vegetable, and nut crops in California.

The total produced water generated volume shown in Table 5-9 (3,134,503,023 bbl) is slightly larger than the total produced water managed volume in Table 5-11 (3,105,279,036 bbl). The difference between the two volumes is less than 1%. Given the very large number of wells and the assumptions described above, this differential is not an issue for concern.

5.6 Colorado

Data for Colorado were provided by the Colorado Oil and Gas Conservation Commission (COGCC). The author was assisted in analyzing and interpreting the data by Thom Kerr, a consultant who formerly worked as a manager at COGCC, where he had familiarity with the agency's data management systems.[17] Data on oil, gas, and water volumes are shown in Table 5-12.

Colorado had over 52,000 producing oil and gas wells in 2017. 65% of these produced natural gas from conventional formations. Another 23% of the wells produced oil from conventional formations. 11% produced oil from unconventional formations, and a few other wells produced gas from unconventional formations.

82% of the oil production came from unconventional formations, and 70% of the natural gas production came from unconventional formations.

The COGCC reported 310,650,278 bbl of produced water for 2017. They were unable to break out water volumes by hydrocarbon type or by formation type. Therefore, no WOR or WGR was calculated.

Table 5-12 — 2017 Production for Colorado

Type of Hydrocarbon	# Wells Producing Primarily That Type of Hydrocarbon	Total Volume of Produced Water Brought to Surface (bbl/year)	Volume of Hydrocarbon Produced (bbl/year or Mmcf/year)
Crude oil from conventional formations	12,179	310,650,278	23,259,295 bbl
Natural gas from conventional formations	34,207		1,521,125 Mmcf
Crude oil from unconventional formations	5,606		109,587,108 bbl
Natural gas from unconventional formations	245		653,290 Mmcf
Total	52,237	310,650,278	132,846,403 bbl; 2,174,415 Mmcf

The process for estimating how the produced water was managed was quite complex. The COGCC collects data from operators on water volumes and how the water is managed. But

[17] Email from COGCC to Thom Kerr LLC, on August 5, 2019. Email forwarded to John Veil on August 14, 2019.

that information does not easily mesh with the data categories used in this report. The following paragraphs explain how the COGCC data were evaluated and reallocated to complete Table 5-14.

The COGCC receives monthly reports of operations from the oil and gas operators. The reports must indicate how much produced water was generated and how it was managed in one of these five categories:

- Commercial disposal facility (These are third-party facilities that receive water for management by disposal wells or in pits).
- Onsite pit (Most of the water evaporates, or the excess water was hauled to disposal wells).
- Central disposal (These are central pits or disposal well facilities operated by a single producer or cooperatively among several operators. Water from multiple wells was collected and managed in a centralized location. Some water was recycled, but much was injected into disposal wells).
- Injected (This water was injected into wells under the COGCC's UIC authority).
- Surface discharge (This water was either fresh or treated to acceptable standards and discharged to a surface water body).

Table 5-13 shows the data provided by COGCC in these categories.

Table 5-13 — 2017 Produced Water Management Data from COGCC Database

Disposal method	Volume (bbl/yr)
Onsite Pit	20,084,676
Surface Discharge	18,217,065
Commercial Disposal Facility	58,262,519
Injected	154,628,067
Central Disposal	59,457,951
Total	310,650,278

These COGCC water management categories partially match up with the water management categories used in this report, but for the other categories, despite the similarity in names, there is no easy way to allocate the volumes provided by COGCC to the categories here. The following discussion highlights some of the challenges faced in analyzing the COGCC data, and the assumptions made by the author to adjust them to a format that is compatible with water data from the other states. This assumed allocation system does not provide a fully accurate estimation of the actual water management practices in Colorado, but is an attempt to do the best possible with the data available.

The Surface Discharge volume from Table 5-13 is assigned to the Surface Discharge category in Table 5-14. The Onsite Pit volume from Table 5-13 is assigned to the Evaporation category in

Table 5-14, even though not all water in the pits will be evaporated. Some water held in pits in the Central Disposal and Commercial Disposal Facility categories is evaporated too, but cannot be quantified.

Assigning the volumes in the other categories was not nearly as straightforward. Although Table 5-13 shows a volume in the Injected category, the COGCC also provided separate estimates of the volume of water injected into Class II UIC wells (either by the producers themselves or at commercial disposal wells). For the 2017 calendar year, 157,040,690 bbl were injected for disposal, and 108,207,977 bbl were injected for enhanced recovery. These numbers were used in Table 5-14 for the two injection categories.

The volumes from the Class II injection well reports exceeded the total reported Injected volume from Table 5-13. The operators of enhanced recovery projects augmented produced water supplies with water from other sources, such as fresh water. There is no way of telling how much makeup water was included in the reported volumes for enhanced recovery. Therefore, the entire volume reported as injected for enhanced recovery is used in the Injection for Enhanced Recovery category in Table 5-14.

Portions of the Commercial Disposal Facility and the Central Disposal volumes from Table 5-13 are already counted under one of the two injection categories in Table 5-14. Some portion of the Central Disposal category represents flowback water that is reused in the oil and gas fields, and some of the water in the Commercial Disposal Facility category may be reused too. GWPC (2019) provides several examples of produced water reuse projects in Colorado.

The COGCC also has an independent estimate of the volume of produced water that is reused. The COGCC requires that water volumes used in hydraulic fracturing treatments be reported on well completion reports. The volume of reused water in these treatments for 2017 was reported as 154,628,067 bbl. This water is reused and treated with some of the effluent discarded and disposed of in injection wells. According to Mr. Kerr, some or most of this is not included in the total produced water volume generated (310,650,278 bbl).[18] Therefore, this reused volume does not make a good estimate for Table 5-14. To create an estimate of the volume reused in the oil and gas industry, 50% of the volume reported under Central Disposal was assigned to the Reuse within the Oil and Gas category in Table 5-14.

There was almost no other type of beneficial use of produced water except that which has been discharged to surface water for agricultural or wildlife purposes under NPDES permits.

The final results in Table 5-14 show that about 80% of the produced water was injected, with smaller amounts discharged to surface water and evaporated. There is active reuse of produced water in the oil and gas fields in Colorado. Given the assumptions stated above, about 9% of the produced water is reused. With all the uncertainties and assumptions in

[18] Email and phone conversation between Thom Kerr LLC, and John Veil on August 23, 2019.

reassigning data from Table 5-13 to 5-14, the volumes in Table 5-14 are imperfect estimates but do serve to represent Colorado's produced water management in the overall report.

Table 5-14 — 2017 Produced Water Management Practices for Colorado

Management Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	108,207,977	32.5%
Injection for disposal	157,040,690	47.1%
Surface discharge	18,217,065	5.5%
Evaporation	20,084,676	6.0%
Offsite commercial disposal (pay another company to manage your produced water)	Included in the volumes reported in other categories	0
Reuse within the oil and gas industry	29,728,976	8.9%
Reuse in ways other than in the oil and gas industry	0	
Total	333,279,384	100%

5.7 Florida

The Florida Department of Environmental Protection (FDEP) Oil and Gas Program did not submit a completed questionnaire.[19] However, the agency contact advised that the requested data could be found on the FDEP Oil and Gas Program website.[20] The author populated Tables 5-15 and 5-16 using data from the agency's websites.

Florida's oil and gas fields are located in two sections of the state. All wells were permitted as oil-producing wells. The 46 wells in the Northwest Florida fields produced 1,424,199 bbl of oil, 23,060 Mmcf of gas, and 46,584,255 bbl or water. The 17 wells in the South Florida fields produced 499,039 bbl of oil, 72 Mmcf of gas, and 12,088,777 bbl of water.

All of the gas production came from oil wells. The water production could not be allocated to oil and gas production. Therefore, it was not possible to calculate the WOR or WGR for Florida.

Table 5-15 — 2017 Production for Florida

Type of Hydrocarbon	# Wells Producing Primarily That Type of Hydrocarbon	Total Volume of Produced Water Brought to Surface (bbl/year)	Volume of Hydrocarbon Produced (bbl/year or Mmcf/year)
Crude oil from conventional formations	63	58,673,032	1,923,238 bbl; 23,132 Mmcf
Natural gas from conventional formations	0	0	0
Crude oil from unconventional formations	0	0	0
Natural gas from unconventional formations	0	0	0
Total	63	58,673,032	1,923,238 bbl; 23,132 Mmcf

In the South Florida fields, all produced water (10,249,420 bbl) was sent to disposal wells that inject to the boulder zone. In the Northwest Florida fields, all produced water (48,636,117 bbl) was injected back into the producing formations. Data on injection volumes was obtained by

[19] Email from FDEP to John Veil on June 14, 2019.

[20] https://floridadep.gov/water/oil-gas/documents/state-production-data; accessed July 1, 2019.

extracting data from the FDEP's Electronic Document Management System (OCULUS)[21] for each of the operating fields in the state. Data were found on monthly Form 10A reports.

The total volume of water injected (58,885,537 bbl) slightly exceeds the volume of produced water brought to the surface (58,673,032 bbl). The person responding from the FDEP Oil and Gas Program noted that additional water may be injected in the Jay Field.

Table 5-16 — 2017 Produced Water Management Practices for Florida

Management Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	48,636,117	82.5%
Injection for disposal	10,249,420	17.5%
Surface discharge	0	0
Evaporation	0	0
Offsite commercial disposal (pay another company to manage your produced water)	0	0
Reuse within the oil and gas industry	0	0
Reuse in ways other than in the oil and gas industry	0	0
Total	58,885,537	100%

[21] https://depedms.dep.state.fl.us/Oculus/servlet/login; accessed July 1, 2019.

5.8 Idaho

The Idaho Department of Lands, Oil and Gas Division, provided data on produced water volumes and how it was managed.[22] This information is shown in Tables 5-17 and 5-18. In 2017, Idaho had 8 conventional gas wells producing 3,789 Mmcf of gas. Those gas wells generated 91,566 bbl of produced water.

Table 5-17 — 2017 Production for Idaho

Type of Hydrocarbon	# Wells Producing Primarily That Type of Hydrocarbon	Total Volume of Produced Water Brought to Surface (bbl/year)	Volume of Hydrocarbon Produced (bbl/year or Mmcf/year)
Crude oil from conventional formations	0	0	0
Natural gas from conventional formations	8	91,566	3,789 Mmcf
Crude oil from unconventional formations	0	0	0
Natural gas from unconventional formations	0	0	0
Total	8	91,566	3,789 Mmcf

All produced water was sent to offsite commercial disposal facilities that evaporated the produced water. Because most offsite commercial disposal facilities inject water into disposal wells, Table 5-18 shows the produced water volume in the evaporation row.

[22] Email from Idaho Department of Lands, to John Veil on May 24, 2019.

Table 5-18 — 2017 Produced Water Management Practices for Idaho

Management Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	0	0
Injection for disposal	0	0
Surface discharge	0	0
Evaporation	91,566	100%
Offsite commercial disposal (pay another company to manage your produced water)	Volume is shown on the evaporation row.	0
Reuse within the oil and gas industry	0	0
Reuse in ways other than in the oil and gas industry	0	0
Total	91,566	100%

5.9 Illinois

The Illinois Department of Natural Resources, Office of Oil and Gas Resource Management (OOGRM) did not submit a questionnaire. Information on oil and gas production in Illinois was obtained from a spreadsheet of state oil and gas data provided to the author by the IOGCC. That data had been submitted to the IOGCC by staff at the OOGRM in 2018 and in subsequent years. OOGRM staff was asked to verify that the data on that spreadsheet were accurate. They replied with revised water injection information,[23] which is used here.

Tables 5-19 and 5-20 show information extracted from the IOGCC spreadsheet (as revised by the OOGRM staff). In 2017, Illinois had 19,904 conventional oil wells producing 8,314,000 bbl of oil and 429 conventional gas wells producing 2,131 Mmcf of gas.

Table 5-19 — 2017 Production for Illinois

Type of Hydrocarbon	# Wells Producing Primarily That Type of Hydrocarbon	Total Volume of Produced Water Brought to Surface (bbl/year)	Volume of Hydrocarbon Produced (bbl/year or Mmcf/year)
Crude oil from conventional formations	19,904	??	8,314,000 bbl
Natural gas from conventional formations	429	??	2,131 Mmcf
Crude oil from unconventional formations	0	0	0
Natural gas from unconventional formations	0	0	0
Total	20,333	282,599,989	8,314,000 bbl; 2,131 Mmcf

The IOGCC spreadsheet did not provide any estimate of the total volume of produced water brought to the surface along with the oil and gas. It did provide estimates of the water injected for enhanced recovery and for disposal. Those two volumes were combined to give an estimate of total produced water generated (282,599,989 bbl). This assumes that all water injected for enhanced recovery was produced water. No information was available about the other methods of produced water management.

Water production is not broken out for oil wells and gas wells separately. Therefore, it was not possible to calculate the WOR or WGR for Illinois.

[23] Email from Illinois Office of Oil and Gas Resource Management to John Veil on July 8, 2019.

Table 5-20 — 2017 Produced Water Management Practices for Illinois

Management Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	193,261,188	68%
Injection for disposal	89,338,801	32%
Surface discharge	0	0
Evaporation	0	0
Offsite commercial disposal (pay another company to manage your produced water)	0	0
Reuse within the oil and gas industry	0	0
Reuse in ways other than in the oil and gas industry	0	0
Total	282,599,989	100%

5.10 Indiana

Produced water data were provided by the Division of Oil and Gas of the Indiana Department of Natural Resources (IDNR).[24] Tables 5-21 and 5-22 show the replies to the questionnaire. In 2017, Indiana had 5,317 active oil and gas wells, with 81% of them producing oil from conventional formations. 12% of the wells produced gas from conventional formations, and 6% produced gas from unconventional formations.

The statewide total produced water volume for 2017 was 50,797,713 bbl and was based on the total volume of produced water managed. The IDNR was not able to allocate produced water to different oil and gas production categories. Therefore, no WOR or WGR can be calculated.

Table 5-21 — 2017 Production for Indiana

Type of Hydrocarbon	# Wells Producing Primarily That Type of Hydrocarbon	Total Volume of Produced Water Brought to Surface (bbl/year)	Volume of Hydrocarbon Produced (bbl/year or Mmcf/year)
Crude oil from conventional formations	4,325	??	1,780,016 bbl
Natural gas from conventional formations	668	??	5,914 Mmcf
Crude oil from unconventional formations	0	0	0
Natural gas from unconventional formations	324	??	Included with gas from conventional formations
Total	5,317	50,797,713	1,780,016 bbl 5,914 Mmcf

Nearly all produced water in Indiana was injected. 71% was injected for enhanced recovery, and 28% was injected for disposal. A small fraction of produced water (0.1%) was managed through surface discharge. According to Veil (2015), this water comes from CBM operations and has low salinity. NPDES permits were issued to authorize those discharges.

---

[24] Email from IDNR to John Veil, on August 13, 2019.

Table 5-22 — 2017 Produced Water Management Practices for Indiana

Management Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	36,296,729	71.4%
Injection for disposal	14,450,187	28.5%
Surface discharge	50,797	0.1%
Evaporation	0	0
Offsite commercial disposal (pay another company to manage your produced water)	0	0
Reuse within the oil and gas industry	0	0
Reuse in ways other than in the oil and gas industry	0	0
Total	50,797,713	100%

5.11 Kansas

Information on oil, gas, and produced water was provided by the Kansas Corporation Commission (KCC).[25] Tables 5-23 and 5-24 show the replies to the questionnaire.

In 2017, Kansas had 75,479 active oil and gas wells, with 70% of them producing conventional oil. Another 25% of the wells produced conventional gas. Kansas had a small number of unconventional gas wells too.

The KCC did not provide a total volume for produced water brought to the surface. They did, however, provide a volume for total water managed of 1,205,091,949 bbl. In the absence of other data, this volume is used to represent the total volume brought to the surface.

Because produced water volume was not provided separately for oil wells and gas wells, it was not possible to calculate the WOR or WGR for Kansas.

Table 5-23 — 2017 Production for Kansas

Type of Hydrocarbon	# Wells Producing Primarily That Type of Hydrocarbon	Total Volume of Produced Water Brought to Surface (bbl/year)	Volume of Hydrocarbon Produced (bbl/year or Mmcf/year)
Crude oil from conventional formations	52,743	??	35,822,288 bbl
Natural gas from conventional formations	19,018	??	220,815 Mmcf
Crude oil from unconventional formations	0	0	0
Natural gas from unconventional formations	3,718	??	21,030 Mmcf
Total	75,479	1,205,091,949	35,822,288 bbl; 241,845 Mmcf

All produced water was managed by injection wells in Kansas in 2017. About three quarters of the produced water was injected to disposal wells. The remaining 25% of the produced water was injected for enhanced recovery. The KCC noted that their agency does not permit "commercial" disposal wells as a class. The 2,235 bbl reported as being managed by commercial disposal represents produced water hauled out of state to a disposal well.

[25] Emails from the KCC Conservation Division to John Veil on May 29 and June 18, 2019.

The KCC indicated that they did not have information about the beneficial reuse of produced water.

Table 5-24 — 2017 Produced Water Management Practices for Kansas

Management Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	298,991,227	25%
Injection for disposal	906,098,487	75%
Surface discharge	0	0
Evaporation	0	0
Offsite commercial disposal (pay another company to manage your produced water)	2,235	miniscule
Reuse within the oil and gas industry	Unknown	??
Reuse in ways other than in the oil and gas industry	Unknown	??
Total	1,205,091,949	100%

5.12 Kentucky

The Kentucky Department of Natural Resources, Division of Oil and Gas submitted a partial questionnaire, which included volumes of water injected for enhanced recovery and for disposal. They did not provide production data.

Table 5-25 shows production figures taken from several sources. Information on oil and gas wells in Kentucky was obtained from a spreadsheet of state oil and gas data provided to the author by the IOGCC. There were 26,372 oil wells and 20,484 gas wells in Kentucky in 2017. Information on oil and gas volumes came from EIA websites for oil and gas. In 2017, Kentucky produced 2,477,000 bbl of oil and 88,715 Mmcf of gas. No distinction was made in these sources of data on whether production was from conventional or unconventional formations.

The Division of Oil and Gas noted that it did not have regulatory authority to monitor produced water and therefore could not provide any estimate on the volume of produced water brought to the surface. The total estimated produced water volume for Kentucky was 13,913,894 bbl, which equaled the volume of produced water injected into Class II wells during 2017. This assumes that all water injected for enhanced recovery was produced water.

Water production is not broken out for oil wells and gas wells separately. Therefore, it was not possible to calculate the WOR or WGR for Kentucky.

Table 5-25 — 2017 Production for Kentucky

Type of Hydrocarbon	# Wells Producing Primarily That Type of Hydrocarbon	Total Volume of Produced Water Brought to Surface (bbl/year)	Volume of Hydrocarbon Produced (bbl/year or Mmcf/year)
Crude oil from conventional and unconventional formations	26,372	??	2,477,000 bbl
Natural gas from conventional and unconventional formations	20,484	??	88,715 Mmcf
Total	46,856	13,913,894	2,477,000 bbl; 88,715 Mmcf

The Oil and Gas Division reported that all produced water from Kentucky oil and gas wells was reinjected into Class II wells. In the previous report (Veil 2015), data on volumes injected into Class II wells in Kentucky were obtained from EPA's Region 4 office. In 2017, EPA awarded primacy to administer the UIC Class II program to Kentucky. Therefore, for this study, the Oil and Gas Division was able to provide data on injected volumes.[26]

Table 5-26 shows that about 92% of the produced water is injected for enhanced recovery, and 8% is injected for disposal. Some of the disposal wells are third-party commercial wells, but the Oil and Gas Division does not separately track disposal wells used by oil and gas companies from those operated as third-party commercial businesses.

The Oil and Gas Division does not track produced water that is reused. They were unable to provide and data on that practice.

Table 5-26 — 2017 Produced Water Management Practices for Kentucky

Management Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	12,789,124	91.9%
Injection for disposal	1,124,770	8.1%
Surface discharge	0	0
Evaporation	0	0
Offsite commercial disposal (pay another company to manage your produced water)	Not broken out separately	0
Reuse within the oil and gas industry	Do not track	??
Reuse in ways other than in the oil and gas industry	Do not track	??
Total	13,913,894	100%

[26] Email from Kentucky Oil and Gas Division to John Veil on July 8, 2019.

5.13 Louisiana

The Louisiana Department of Natural Resources, Office of Conservation provided links to online databases for oil and gas volume and provided a spreadsheet for injection volume.[27] Tables 5-27 and 5-28 show the replies to the questionnaire.

The oil and gas volumes and number of wells were taken from the Yearly Production by Parish webpage.[28] Total oil plus condensate was 52,282,199 bbl, and total gas was 3,306,864 Mmcf. Louisiana had 39,594 operating oil and gas wells in 2017, but that webpage did not distinguish between oil wells and gas wells.

The Office of Conservation does not track the volume of produced water generated from each well, but it does have good estimates of the volume of water injected. Assuming the volume of water injected equals the volume generated (not an exact match but a reasonably close assumption), the injection data provided by the Office of Conservation can serve as an estimate of produced water volume. Using this approach, an estimated 998,519,062 bbl of produced water were generated in 2017. It was not possible to distinguish between water from oil wells and gas wells, nor was it possible to tell whether water came from conventional or unconventional production. As a result, it was not possible to calculate WORs and WGRs for Louisiana.

Table 5-27 — 2017 Production for Louisiana

Type of Hydrocarbon	# Wells Producing Primarily That Type of Hydrocarbon	Total Volume of Produced Water Brought to Surface (bbl/year)	Volume of Hydrocarbon Produced (bbl/year or Mmcf/year)
Crude oil from conventional and unconventional formations		??	52,282,199 bbl
Natural gas from conventional and unconventional formations		??	3,306,864 Mmcf
Total	39,594	998,519,062	52,282,199 bbl; 3,306,864 Mmcf

All produced water generated in Louisiana during 2017 was injected. About 88% of the produced water was injected into disposal wells. About 5% of water was injected for disposal at offsite commercial disposal facilities. The remaining 7% of produced water was reinjected for enhanced recovery.

[27] Emails from the Louisiana Office of Conservation to John Veil on September 3, 2019.

[28] http://sonlite.dnr.state.la.us/sundown/cart_prod/cart_con_yearprod2. Accessed September 3, 2019.

The Office of Conservation reported that there was no evaporation, surface discharge, or reuse during 2017.

Table 5-28 — 2017 Produced Water Management Practices for Louisiana

Management Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	70,739,593	7.1%
Injection for disposal	877,374,282	87.9 %
Surface discharge	0	0
Evaporation	0	0
Offsite commercial disposal (pay another company to manage your produced water)	50,405,187	5.0%
Reuse within the oil and gas industry	0	0
Reuse in ways other than in the oil and gas industry	0	0
Total	998,519,062	100%

5.14 Michigan

The Michigan Department of Environment, Great Lakes, and Energy's Office of Oil, Gas, and Minerals provided produced water generation and management information.[29] Tables 5-29 and 5-30 show the replies to the questionnaire.

In 2017, Michigan had 14,345 active oil and gas wells, with 70% of them producing unconventional gas. Another 26% of the wells produced conventional oil, and 3.4% produced conventional gas.

The statewide total produced water volume for 2017 was 80,500,000 bbl. Unconventional gas production generated about 77% of that total. Conventional oil wells contributed the remaining 21% of the total produced water volume.

The water production data were split between oil production and gas production. The resulting WOR was 3.2 bbl/bbl for oil and the WGR was 775 bbl/Mmcf for gas.

Table 5-29 — 2017 Production for Michigan

Type of Hydrocarbon	# Wells Producing Primarily That Type of Hydrocarbon	Total Volume of Produced Water Brought to Surface (bbl/year)	Volume of Hydrocarbon Produced (bbl/year or Mmcf/year)
Crude oil from conventional formations	3,750	18,500,000	5,8000,000 bbl
Natural gas from conventional formations	495	??	17,500 Mmcf
Crude oil from unconventional formations	0	??	0
Natural gas from unconventional formations	10,100	62,000,000	80,000 Mmcf
Total	14,345	80,500,000	5,800,000 bbl; 97,500 Mmcf

Nearly all of the produced water in Michigan was managed through underground injection. The large majority of produced water (80%) was injected into disposal wells, while 18% was injected for enhanced recovery. The Office of Oil, Gas, and Minerals noted that about 2% of the produced water was sent to offsite commercial disposal facilities where it was commingled with other exploration and production wastes prior to management.

---

[29] Email from Michigan Department of Environment, Great Lakes, and Energy, to John Veil on August 14, 2019.

Some produced water was beneficially used for ice and dust control and soil and road stabilization under a groundwater discharge permit issued by the Department's Water Resources Division. Permit holders are required to maintain a log of the produced water they apply, but were not required to submit data to the Department on a regular basis. Therefore, the Department had no way of quantifying the volume actually applied.

Table 5-30 — 2017 Produced Water Management Practices for Michigan

Management Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	14,500,000	18%
Injection for disposal	64,500,000	80%
Surface discharge	0	0
Evaporation	0	0
Offsite commercial disposal (pay another company to manage your produced water)	1,500,000	2%
Reuse within the oil and gas industry	0	0
Reuse in ways other than in the oil and gas industry	Some is applied to roads for ice and dust control. No information is available on volume.	??
Total	80,500,000	100%

5.15 Mississippi

The Mississippi State Oil and Gas Board provided produced water generation and management information.[30] Tables 5-31 and 5-32 show the replies to the questionnaire.

In 2017, Mississippi had 3,240 active oil and gas wells. 54% of them produced conventional oil and 44% produced conventional gas. About 2% produced unconventional oil, and a single well produced unconventional gas.

Table 5-31 — 2017 Production for Mississippi

Type of Hydrocarbon	# Wells Producing Primarily That Type of Hydrocarbon	Total Volume of Produced Water Brought to Surface (bbl/year)	Volume of Hydrocarbon Produced (bbl/year or Mmcf/year)
Crude oil from conventional formations	1,754	166,357,935	15,904,499 bbl
Natural gas from conventional formations	1,426	3,579,007	52,249 Mmcf
Crude oil from unconventional formations	59	1,207,871	1,133,331 bbl
Natural gas from unconventional formations	1	362	26 Mmcf
Total	3,240	171,145,175	17,037,830 bbl; 52,275 Mmcf

The statewide total produced water volume for 2017 was 171,145,175 bbl. Conventional oil production generated about 97% of that total. The water production data were split between oil production and gas production. The resulting WOR was 9.8 bbl/bbl and the WGR was 68 bbl/Mmcf.

In 2017 all of the produced water in Mississippi was managed through underground injection. 21% of produced water was injected for enhanced recovery, while 79% was injected into disposal wells. The Oil and Gas Board noted three caveats relating to the injection volumes they submitted. These in part explain why the total volume of produced water managed (198,154,792 bbl) is higher than the volume of produced water generated (171,145,175 bbl).

- Injection for Enhanced Recovery - Operators in Mississippi can use water source wells that produce only water (no oil or gas) that will be injected into enhanced recovery wells as makeup water. The amount of water that comes out of those wells does not

[30] Emails from Mississippi State Oil and Gas Board to John Veil on July 19 and 22, 2019.

have to be reported to the Oil and Gas Board, so it is not included in the produced water total in Table 5-29. When water from those water source wells is injected into an enhanced recovery well, it does have to be reported to the Board on an injection form. This causes the enhanced recovery injection totals in Table 5-30 to be higher than just the amount of produced water.

- Injection for Disposal - In addition to the volume of produced water, this number can contain salt brine water that is derived from the leaching process used to create gas storage caverns in salt formations. That water originally comes from a fresh water source, so it is not included in the produced water volume in Table 5-29. The resulting brine is disposed of in a disposal well, and is reported to the Board on an injection form that will cause the disposal well total in Table 5-30 to be higher than just for produced water.

- Offsite Commercial Disposal – The Oil and Gas Board reported that injection from offsite commercial disposal facilities is not tracked separately from non-commercial disposal wells. Therefore, any water injected at an offsite commercial disposal facility is shown in the Injection for Disposal row of Table 5-30.

Table 5-32 — 2017 Produced Water Management Practices for Mississippi

Management Practice	**Total Volume of Produced Water Managed by That Practice (bbl/year)**	**Percentage of Produced Water Managed by That Practice**
Injection for enhanced recovery	41,391,526	21%
Injection for disposal	156,763,266	79%
Surface discharge	0	0
Evaporation	0	0
Offsite commercial disposal (pay another company to manage your produced water)	0	0
Reuse within the oil and gas industry	0	0
Reuse in ways other than in the oil and gas industry	0	0
Total	198,154,792	100%

5.16 Missouri

The Missouri Geological Survey (MGS) provided produced water generation and management information.[31] The information is shown in Tables 5-33 and 5-34.

Missouri had 440 active oil wells during 2017. 87% of those wells produced oil from unconventional formations. The other 13% of the wells produced oil from conventional formations. No gas wells were reported by the MGS for 2017.

These oil wells generated 116,808 bbl of oil and 2,763,613 bbl of produced water. The WOR for all oil wells was 23.7 bbl/bbl. Looking at WOR separately by production type, the WOR for conventional wells was 8.9, and the WOR for unconventional wells was 25.9.

Table 5-33 — 2017 Production for Missouri

Type of Hydrocarbon	# Wells Producing Primarily That Type of Hydrocarbon	Total Volume of Produced Water Brought to Surface (bbl/year)	Volume of Hydrocarbon Produced (bbl/year or Mmcf/year)
Crude oil from conventional formations	59	139,502	15,683 bbl
Natural gas from conventional formations	0	0	0
Crude oil from unconventional formations	381	2,624,111	101,125 bbl
Natural gas from unconventional formations	0	0	0
Total	440	2,763,613	116,808 bbl

All produced water in 2017 was managed by injection. 93.6% of the produced water was injected for enhanced recovery, and 6.4% was injected into disposal wells.

[31] Email from Missouri Geological Survey to John Veil on June 20, 2019.

Table 5-34 — 2017 Produced Water Management Practices for Missouri

Management Practice	**Total Volume of Produced Water Managed by That Practice (bbl/year)**	**Percentage of Produced Water Managed by That Practice**
Injection for enhanced recovery	2,586,948	93.6%
Injection for disposal	176,665	6.4%
Surface discharge	0	0
Evaporation	0	0
Offsite commercial disposal (pay another company to manage your produced water)		
Reuse within the oil and gas industry	0	0
Reuse in ways other than in the oil and gas industry	0	0
Total	2,763,613	100%

5.17 Montana

The Montana Board of Oil and Gas Conservation (BOGC) provided produced water generation and management information.[32] Tables 5-35 and 5-36 show this information. Montana had more than 10,000 active oil and gas wells in 2017. Most of those wells produced oil (34%) and gas (53%) from conventional formations. About 12% of the wells produced oil from unconventional formations, and a few wells produced gas from unconventional formations.

These wells generated 20,707,078 bbl of oil and 27,529 Mmcf of gas during 2017. Montana wells generated 141,733,134 bbl of produced water in 2017. The conventional oil wells generated about 92% of the water.

The WOR for conventional oil was 13.5 bbl/bbl and for unconventional oil, the WOR was 0.9. The WOR for all oil combined was 6.8. The WGR for gas from conventional formations was 27. The WGR for all gas combined was 70.

Table 5-35 — 2017 Production for Montana

Type of Hydrocarbon	# Wells Producing Primarily That Type of Hydrocarbon	Total Volume of Produced Water Brought to Surface (bbl/year)	Volume of Hydrocarbon Produced (bbl/year or Mmcf/year)
Crude oil from conventional formations	3,453	130,182,002	9,628,587 bbl
Natural gas from conventional formations	5,352	739,280	27,308 Mmcf
Crude oil from unconventional formations	1,172	9,634,906	11,078,491 bbl
Natural gas from unconventional formations	55	1,176,946	221 Mmcf
Total	10,032	141,733,134	20,707,078 bbl 27,529 Mmcf

The water management data provided by the BOGC showed that 80,148,442 bbl were injected for enhanced recovery. 58,893,204 bbl were injected to disposal wells. BOGC also report that 2,691,488 bbl were managed by evaporation. BOGC was unable to provide any estimate of the volume sent to offsite commercial disposal or managed through reuse.

The total water volume managed in 2017 was 148,309,989 bbl. This exceeded the volume of water generated (141,733,134 bbl). Presumably the difference represented water sources other

[32] Email from Montana BOGC to John Veil on June 17, 2019.

than produced water that were injected for enhanced recovery. The actual enhanced recovery water volume provided by the BOGC was 80,148,442 bbl. It also includes an estimated 6,576,855 bbl of makeup water. The number shown in Table 5-36 for enhanced recovery reflects the actual produced water contribution to the total injected for enhanced recovery.

Table 5-36 — 2017 Produced Water Management Practices for Montana

Management Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	73,571,587 bbl (produced water portion) 80,148,442 bbl total	52%
Injection for disposal	58,893,204	41%
Surface discharge	6,576,855	5%
Evaporation	2,691,488	2%
Offsite commercial disposal (pay another company to manage your produced water)	unknown	??
Reuse within the oil and gas industry	unknown	??
Reuse in ways other than in the oil and gas industry	unknown	??
Total	141,733,134	100%

Produced water discharges are regulated by the Montana Department of Environmental Quality (MDEQ). The MDEQ has issued a general discharge permit for produced water discharges as well as several individual NPDES permits for produced water discharges. Those permits require that companies operating under the permits must submit discharge flow rate data. The 24 facilities covered under the general permit report produced water flow rate twice per year in gallons per minute. The three facilities covered by individual permits report flow monthly in million gallons per day.

For the current report, EPA's ECHO database was used to obtain reported 2017 flow rates for the permitted facilities.[33] The total composite flow from the facilities covered by the general discharge permit was 391.5 gallons per minute (gpm). No additional information was available concerning the duration of those discharges (24/7 vs. intermittent). For the sake of this report, the flows were assumed to be continuous flows on a 24/7 basis. Following that assumption, the flow volume equaled 4,899,593 bbl/yr.

---

[33] https://echo.epa.gov/; accessed July 13, 2019.

The total flow rate from the facilities having individual discharge permits was 0.193 million gallons per day. As above, the flows were assumed to be continuous flows on a 24/7 basis. Following that assumption, the flow volume equaled 1,677,262 bbl/yr. Combining the flows from both groups of dischargers gave a total surface discharge volume of 6,576,855 bbl/yr. This volume was added to Table 5-36.

5.18 Nebraska

The Nebraska Oil and Gas Conservation Commission provided both water production and management information.[34] The information is shown in Tables 5-37 and 5-38. In 2017, there were 1,500 active wells, with 90% of those wells producing 2,092,816 bbl of conventional oil. The remaining 10% of the wells produced 456 Mmcf of conventional gas.

Those wells generated 50,069,495 bbl of produced water. About 95% of the water came from the oil wells. The WOR was 23 bbl/bbl, and the WGR was 5,490 bbl/Mmcf.

Table 5-37 — 2017 Production for Nebraska

Type of Hydrocarbon	# Wells Producing Primarily That Type of Hydrocarbon	Total Volume of Produced Water Brought to Surface (bbl/year)	Volume of Hydrocarbon Produced (bbl/year or Mmcf/year)
Crude oil from conventional formations	1,353	47,566,021	2,092,816 bbl
Natural gas from conventional formations	147	2,503,474	456 Mmcf
Crude oil from unconventional formations	0	0	0
Natural gas from unconventional formations	0	0	0
Total	1,500	50,069,495	2,092,816 bbl; 456 Mmcf

The Nebraska Oil and Gas Conservation Commission data showed that 47% of produced water was injected for enhanced recovery and 49% was injected into disposal wells. 2% was evaporated, and less that 1% was managed by surface discharge and by offsite commercial disposal.

The Commission also reported that about 120,000 bbl of produced water was reused for road spreading. The county road superintendents have the authority to request produced water to be spread on the roads for different purposes including building new roads and dust control. This practice serves to save drinking water that would be used for those purposes in the absence of the produced water.

[34] Email from Nebraska Oil and Gas Conservation Commission to John Veil on June 18, 2019.

Table 5-38 — 2017 Produced Water Management Practices for Nebraska

Management Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	23,515,265	47.0%
Injection for disposal	24,694,793	49.3%
Surface discharge	319,812	0.6%
Evaporation	1,009,932	2.0%
Offsite commercial disposal (pay another company to manage your produced water)	409,674	0.8%
Reuse within the oil and gas industry	0	0
Reuse in ways other than in the oil and gas industry (road building)	120,019	0.2%
Total	50,069,476	100%

5.19 Nevada

The Nevada Division of Minerals supplied water production and management data.[35] The information is shown in Tables 5-39 and 5-40. In 2017, there were 61 active wells producing 284,954 bbl of conventional oil and 3 Mmcf of associated gas.

Those wells generated 6,510,029 bbl of produced water. The WOR was 23 bbl/bbl.

Table 5-39 — 2017 Production for Nevada

Type of Hydrocarbon	# Wells Producing Primarily That Type of Hydrocarbon	Total Volume of Produced Water Brought to Surface (bbl/year)	Volume of Hydrocarbon Produced (bbl/year or Mmcf/year)
Crude oil from conventional formations	61	6,510,029	284,954 bbl 3 Mmcf
Natural gas from conventional formations	0	0	0
Crude oil from unconventional formations	0	0	0
Natural gas from unconventional formations	0	0	0
Total	61	6,510,029	284,954 bbl 3 Mmcf

The Division of Minerals reported that all produced water was injected into 10 disposal wells. The volume of injected water (6,528,730 bbl) represents the initial reported injected volume plus water from several additional wells not initially reported.[36] Although this volume does not match the volume of produced water generated, it is quite close.

[35] Email from Nevada Division of Minerals to John Veil on June 13, 2019.

[36] Emails from Nevada Division of Minerals to John Veil on July 15 and 18, 2019

Table 5-40 — 2017 Produced Water Management Practices for Nevada

Management Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	0	0
Injection for disposal	6,528,730	100%
Surface discharge	0	0
Evaporation	0	0
Offsite commercial disposal (pay another company to manage your produced water)	0	0
Reuse within the oil and gas industry	0	0
Reuse in ways other than in the oil and gas industry	0	0
Total	6,528,730	100%

5.20 New Mexico

The Oil Conservation Division (OCD) of the New Mexico Energy, Minerals, and Natural Resources Department provided information on produced water volume and management.[37] This information is shown in Tables 5-41 and 5-42. The oil, gas, and water volumes are based on information taken from the document "Statewide Natural Gas and Oil Production Summary Including Produced Water and Injection by Month (1970 to 2019)" that can be found on the OCD's website.[38]

In 2017, New Mexico wells generated 172,587,378 bbl of oil, 1,296,990 Mmcf of natural gas, and 879,740,841 bbl of produced water.

Table 5-41 — 2017 Production for New Mexico

Type of Hydrocarbon	# Wells Producing Primarily That Type of Hydrocarbon	Total Volume of Produced Water Brought to Surface (bbl/year)	Volume of Hydrocarbon Produced (bbl/year or Mmcf/year)
Crude oil from conventional and unconventional formations	??	??	172,587,378 bbl
Natural gas from conventional and unconventional formations	??	??	1,296,990 Mmcf
Total	??	879,740,841	172,587,378 bbl; 1,296,990 Mmcf

The OCD reported that in 2017, the volume of produced water injected for enhanced recovery is 341,201,250 bbl. The volume injected for disposal is 443,893,992 bbl.

There are no permitted surface water discharges in New Mexico. The OCD does note that there may be some unintentional releases such as leaks and spills or intentional illegal releases (presumably these are relatively low in volume). None of the other states reported any volumes for these categories, even though there are likely to be small volume releases in each state. Therefore, a zero volume is shown for surface discharge.

The OCD acknowledges that there is some produced water evaporation due to the arid climate in New Mexico. Quantitative information on the amount of water that is evaporated is not readily available.

---

[37] Email from NM OCD to John Veil, on October 31, 2019. This was supplemented by a phone conversation on November 1, 2019 to clarify several points.

[38] http://www.emnrd.state.nm.us/OCD/statistics.html. Accessed July 26, 2019

Water sent to offsite commercial disposal facilities located within New Mexico would already be included under the injected volumes. Some produced water is sent to offsite commercial disposal facilities located in Texas. The OCD did not have readily available information on those volumes. It is likely that this water would show up in the total water managed in the Texas state summary.

With the rapid growth of production in the Permian Basin, some of the operators are reusing their own produced water in their operations. The OCD does not regularly track the volume of produced water that is reused by the oil and gas industry. Based on the experience of OCD staff, they estimate that about 8% to 10% of the produced water is reused that way. A value of 9% of the produced water generated in Table 5-41 is shown in Table 5-42.

A recent report on produced water reuse (GWPC 2019) provides several examples of oil and gas companies that have collected their produced water and reused that water within the Permian Basin region. Much of that reuse activity occurs in the Texas portion of the Permian, but some is also likely to occur in the New Mexico portion.

Table 5-42 — 2017 Produced Water Management Practices for New Mexico

Management Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	351,201,250	40.2%
Injection for disposal	443,893,992	50.8%
Surface discharge	0	0
Evaporation	??	??
Offsite commercial disposal (pay another company to manage your produced water)	??	??
Reuse within the oil and gas industry	79,176,676	9.0%
Reuse in ways other than in the oil and gas industry	0	0
Total	874,271,918	100%

The volume of produced water generated is slightly larger than the volume managed. The OCD noted that the modest difference can be explained by a combination of factors such as unquantified evaporation, unintended releases, the actual percentage reused by the industry, math errors, and unquantified water being conveyed into Texas for management.

5.21 New York

The New York State Department of Environmental Conservation (NYDEC) Division of Mineral Resources provided oil, gas, and water production information.[39] The NYDEC data are shown in Tables 5-43 and 5-44. New York had 10,423 active oil and gas wells in 2017, with 36% of the wells producing 214,821 bbl of oil and 64% producing 11,800 Mmcf of gas.[40]

Those wells generated 189,746 bbl of produced water. Oil wells generated about 60% of the water with gas wells generating the remaining 40%. The WOR from these data was 0.5 bbl/bbl. The WGR for gas was 6.5 bbl/Mmcf.

Table 5-43 — 2017 Production for New York

Type of Hydrocarbon	# Wells Producing Primarily That Type of Hydrocarbon	Total Volume of Produced Water Brought to Surface (bbl/year)	Volume of Hydrocarbon Produced (bbl/year or Mmcf/year)
Crude oil from conventional formations	3,775	113,292	214,821 bbl
Natural gas from conventional formations	6,648	76,464	11,800 Mmcf
Crude oil from unconventional formations	0	0	0
Natural gas from unconventional formations	0	0	0
Total	10,423	189,746	214,821 bbl; 11,800 Mmcf

The NYDEC provided detailed information on how the produced water was managed – many different management practices were followed. Nearly half of the produced water was sent to offsite commercial disposal companies. About one third of the water was reused – 17.6% was reused within the oil and gas industry and another 15.8% was reused for road spreading and dust control. About 10% was discharged to surface waters, 9% was injected into disposal wells, 1.2% was injected for enhanced recovery, and less than 1% was evaporated.

[39] Email from Division of Mineral Resources, NYDEC to John Veil on May 24, 2019.

[40] The NYDEC reported 11.8 Mmcf. When comparing to other sources of gas production like EIA and IOGCC, the correct number was a bit higher than 11,000. For consistency, the 11.8 value was multiplied by 1,000.

Table 5-44 — 2017 Produced Water Management Practices for New York

Management Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	2,238	1.2%
Injection for disposal	17,510	9.2%
Surface discharge	19,088	10.1%
Evaporation	523	0.3%
Offsite commercial disposal (pay another company to manage your produced water)	87,151	45.8%
Reuse within the oil and gas industry	33,323	17.6%
Reuse in ways other than in the oil and gas industry (road spreading and dust control)	29,913	15.8%
Total	189,746	100%

5.22 North Dakota

The North Dakota Industrial Commission (NDIC) Oil and Gas Division provided information about oil, gas, and water production as well as water management practices.[41] The data are shown in Tables 5-45 and 5-46. North Dakota had 15,164 active oil and gas wells in 2017, with 82% of the wells producing from the unconventional Bakken Shale. Another 17% of the wells produced conventional oil, and the remaining 1% produced conventional gas. Most of the gas produced was associated gas from the unconventional oil wells. The volume of associated gas was not provided by the NDIC. It was estimated by taking the total volume of gas produced by North Dakota from the EIA website and subtracting the volume of gas from gas wells.

North Dakota generated 505,828,554 bbl of produced water in 2072. The unconventional oil wells generated 73% of the water, the conventional oil wells generated 27%, and the conventional gas wells generated a small volume. The WOR for conventional oil was 8.8 bbl/bbl. The WOR for unconventional oil was just 1.0 bbl/bbl. The combined WOR for oil was 1.3 bbl/bbl.

Table 5-45 — 2017 Production for North Dakota

Type of Hydrocarbon	# Wells Producing Primarily That Type of Hydrocarbon	Total Volume of Produced Water Brought to Surface (bbl/year)	Volume of Hydrocarbon Produced (bbl/year or Mmcf/year)
Crude oil from conventional formations	2,627	137,918,002	15,572,345 bbl
Natural gas from conventional formations	157	7,837	15,507 Mmcf
Crude oil from unconventional formations	12,380	367,902,715	375,158,541 bbl; 673,098 Mmcf (associated gas)
Natural gas from unconventional formations	0	0	0
Total	15,164	505,828,554	390,730,886 bbl; 688,605 Mmcf

All of the produced water in North Dakota in 2017 was managed by injection. 53% of the water was injected into disposal wells by the producers. Another 39% was sent offsite for commercial disposal – most of which goes into large disposal wells. The remaining 8% was managed through injection into enhanced recovery wells.

---

[41] Emails from the NDIC to John Veil on July 12, 2019.

However, the total water volume injected for enhanced recovery was considerably larger than the 40,833,265 bbl shown in the table. The actual enhanced recovery water volume provided by the NDIC was 114,699,636 bbl. This also included an estimated 73,866,371 bbl of makeup water.

Table 5-46 — 2017 Produced Water Management Practices for North Dakota

Management Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	40,833,265 bbl (produced water portion) 114,699,636 bbl (total injected – includes makeup water)	8%
Injection for disposal	266,459,626	53%
Surface discharge	0	0
Evaporation	0	0
Offsite commercial disposal (pay another company to manage your produced water)	198,535,663	39%
Reuse within the oil and gas industry	0	0
Reuse in ways other than in the oil and gas industry	0	0
Total	505,828,554	100%

5.23 Ohio

The Ohio Department of Natural Resources, Division of Oil and Gas Resources Management (DOGRM) provided oil, gas, and water production information and produced water management information.[42] The data are shown in Tables 5-47 and 5-48.

Ohio had 47,312 active oil and gas wells in 2017 – nearly all of them produced from conventional formations. DOGRM noted that one-third of the wells reporting both oil and gas were allocated to the oil category, and two-thirds were allocated to the gas category. Additionally, there were 660 conventional wells that did not report oil and gas production but did report produced water. These were added to the conventional oil numbers.

About 1,900 unconventional wells produced during 2017, mostly from the Utica Shale formation. Although these unconventional wells represent only 4% of Ohio's wells, they had a disproportionate share of the hydrocarbon production. Those wells accounted for 84% of the total oil and 97% of the total gas produced during the year.

Ohio generated 24,142,988 bbl of produced water in 2017. The unconventional wells generated 94% of the water. The WOR for conventional oil was 0.7, and for unconventional oil was 0.2. The WOR for all oil combined was 0.25. The WGR for conventional gas was 34, and for unconventional gas was 10. The WGR for all gas combined was 10.8.

Table 5-47 — 2017 Production for Ohio

Type of Hydrocarbon	No. Wells Producing Primarily That Type of Hydrocarbon	Total Volume of Produced Water Brought to Surface (bbl/year)	Volume of Hydrocarbon Produced (bbl/year or Mmcf/year)
Crude oil from conventional formations	12,357	2,329,495	3,266,598 bbl
Natural gas from conventional formations	33,051	1,534,582	44,958 Mmcf
Crude oil from unconventional formations	456	2,744,419	16,535,808 bbl
Natural gas from unconventional formations	1,448	17,534,492	1,725,496 Mmcf
Total	47,312	24,142,988	19,802,406 bbl 1,770,454 Mmcf

[42] Emails from DOGRM to John Veil on June 24 and 25, 2019.

Nearly all produced water in Ohio in 2017 was managed through underground injection, with 89% of produced water being injected into disposal wells. The DOGRM does not make a distinction between commercial and non-commercial disposal wells during the Class II UIC permitting process. As a result, the agency's database does not include separate volumes for commercial and non-commercial disposal wells. Therefore, no data were entered on the offsite commercial disposal row of the table – whatever volume would otherwise be on that line is included in the injection for disposal row.

Ohio is unique among the states in that it has a network of commercial disposal facilities that accept a large volume of produced water from wells located in other states – primarily from the neighboring states of Pennsylvania and West Virginia. The total volume of produced water managed by disposal wells is 37,886,0145 bbl. 48% of that volume is water brought to Ohio from other states.

554,565 bbl of produced water were injected for enhanced recovery. Another 85,384 bbl of produced water were used for deicing and dust control on roads (a beneficial reuse activity).

The DOGRM is aware that Ohio operators are reusing some of their produced water within the oil and gas fields, but the agency does not require companies to submit data on the reused volumes, and therefore does not have quantitative data. In its submittal of 2017 data, the DOGRM did not include any number in the reuse within the oil and gas industry row.

Table 5-48 — 2017 Produced Water Management Practices for Ohio

Management Practice	**Total Volume of Produced Water Managed by That Practice (bbl/year)**	**Percentage of Produced Water Managed by That Practice**
Injection for enhanced recovery	554,565	1.3%
Injection for disposal (water comes from Ohio wells)	19,665,986	46.4%
Injection for disposal (water comes from out-of-state wells)	18,220,028	43.0%
Surface discharge	0	0
Evaporation	0	0
Offsite commercial disposal (pay another company to manage your produced water)	Included in injection for disposal	??
Reuse within the oil and gas industry	3,837,053[a]	9.1%
Re-use in ways other than in the oil and gas industry (deicing and dust control on roads)	85,384	0.2%
Total	42,363,016	100%

[a] The DOGRM did not initially provide a volume for reuse within the industry. This volume was assumed to be the amount reused by the industry in their operations.

The total produced water managed in Ohio greatly exceeds the volume generated in the state. Much of that is explained by the produced water brought to Ohio from neighboring states for disposal. However, even when the out-of-state volume is subtracted, the total in-state water managed excluding any allocation for reuse within the industry (20,305,935 bbl) is considerably lower than the volume of produced water generated (24,142,988 bbl). The OGRM did not have a definite explanation for that difference, but suggested that the extra water may be produced water that is reused by the companies in field operations. For the sake of making the water volumes balance, the 3,837,053 bbl differential was assigned to the reuse within the oil and gas industry row of the table.

5.24 Oklahoma

The Oklahoma Corporation Commission (OCC) provided produced oil and gas production information and produced water management information.[43] The data are shown in Tables 5-49 and Table 5-50.

In 2017, Oklahoma had about 177,000 oil and gas wells producing from conventional formations. 64% of those wells produced primarily oil (159,207,164 bbl), and 36% produced primarily gas (2,350,071 Mmcf). The OCC does not receive data from operators on the volume of produced water generated, and therefore was unable to provide a quantitative volume for produced water generated in 2017. The volume of produced water shown in Table 5-49 is the same as the volume of water managed (Table 5-50). While this assumption is not completely accurate, there is no other available mechanism to estimate produced water volume.

Produced water volume was not subdivided into water from oil wells and water from gas wells. Therefore, it was not possible to determine WORs or WGRs. However, many of the oil wells were older wells that have high water production. Presumably the overall WOR for Oklahoma wells would be equal to or higher than the values from most other states.

Table 5-49 — 2017 Production for Oklahoma

Type of Hydrocarbon	# Wells Producing Primarily That Type of Hydrocarbon	Total Volume of Produced Water Brought to Surface (bbl/year)	Volume of Hydrocarbon Produced (bbl/year or Mmcf/year)
Crude oil from conventional formations	114,000	??	159,207,164 bbl
Natural gas from conventional formations	63,000	??	2,350,071 Mmcf
Crude oil from unconventional formations	0	0	0
Natural gas from unconventional formations	0	0	0
Total	177,000	2,844,485,617	159,207,164 bbl; 2,350,071 Mmcf

All of the produced water management reported by the OCC was through injection. About 45% of the water was injected for enhanced recovery. About 13% was taken to commercial disposal well facilities. Another 42% was injected for disposal at wells operated by the oil and gas

[43] Email from OCC to John Veil on June 17, 2019.

companies. Within that latter category, the OCC reported that 1,184,820,135 bbl were injected into disposal wells. In addition, 866,926 bbl of water were injected for disposal by simultaneous injection wells. These wells are designed to separate water from oil and gas downhole, rather than at the surface. The separated water is injected directly to a different formation and is never brought to the surface. The volume from the simultaneous wells was added to the volume injected for disposal.

The OCC does not track reuse of produced water within the oil and gas industry. They believe that some reuse is occurring, but cannot quantify the volume. The OCC noted that Oklahoma has 19,000,000 barrels of storage available for this practice.

Table 5-50 — 2017 Produced Water Management Practices for Oklahoma

Management Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	1,276,853,948	44.9%
Injection for disposal	1,185,687,061	41.7%
Surface discharge	0	0%
Evaporation	0	0%
Offsite commercial disposal (pay another company to manage your produced water)	381,944,608	13.4%
Reuse within the oil and gas industry	??	??
Reuse in ways other than in the oil and gas industry	0	0%
Total	2,844,485,617 bbl	100%

5.25 Pennsylvania

The Pennsylvania Department of Environment Protection (PADEP) provided information on produced water volume and management. The data provided by the PADEP are used in this section.[44]

The PADEP provided the following discussion of active well counts. A well inventory report generated in 2017 shows 129,462 wells with active status, including 118,904 conventional and 10,558 unconventional. A well inventory report for 2017 generated in October 2019 shows 128,622 active wells, including 116,906 conventional and 11,716 unconventional. However, the production reports show 92,655 wells with "active" status reported production or a non-production comment in 2017, including 83,021 conventional wells and 9,634 unconventional wells. Counting only the wells that reported production for 2017, there were 81,784 in total, including 73,381 conventional and 8,402 unconventional. The conventional wells produced nearly all the crude oil. The unconventional Marcellus Shale wells produced nearly all the gas and condensate. Condensate was added to the crude oil volume to represent total oil.

The PADEP provided updated oil and gas volumes for 2017. These are shown in Table 5-51. Oil from conventional wells was reported as 1,118,658 bbl, and condensate was 52,356 bbl. Oil from unconventional wells was reported as 7,586 bbl, and condensate was 5,275,410 bbl. The volume of gas from conventional wells was 100,852 Mmcf, and the volume from unconventional wells was 5,363,809 Mmcf.

The PADEP production data do not show the actual produced water generation volume. The volume was estimated by assuming that the total volume of produced water managed was equal to the volume of water generated (55,321,026 bbl). Conventional wells generated 4,742,840 bbl of water. Unconventional wells generated 50,578,186 bbl of water. It was not possible to calculate the WORs and WGRs for Pennsylvania.

[44] Email from PADEP to John Veil on October 9, 2019.

Table 5-51 — 2017 Production for Pennsylvania

Type of Hydrocarbon	# Wells Producing Primarily That Type of Hydrocarbon	Total Volume of Produced Water Brought to Surface (bbl/year)	Volume of Hydrocarbon Produced (bbl/year or Mmcf/year)
Crude oil from conventional formations	73,381	4,742,840	1,118,658 bbl + 52,356 bbl condensate
Natural gas from conventional formations			100,852 Mmcf
Crude oil from unconventional formations	8,402	50,578,186	7,586 bbl + 5,275,410 bbl condensate
Natural gas from unconventional formations			5,363,809 Mmcf
Total	81,784	55,321,026	6,454,010 bbl; 5,464,661 Mmcf

The water management database for Pennsylvania was detailed – water management volume and practice were shown separately for each of the tens of thousands of wells. By sorting and combining the rows and columns in the databases, totals were derived.

Table 5-52 provides the full distribution of water management data. Table 5-53 combines the data into the same tabular format used for other states. The water management categories in Table 5-52 are described below, with a discussion of how each category is reorganized to fit into the categories of Table 5-53:

- Centralized treatment plant – the water was trucked to a centralized plant where it was treated. Water could then be discharged (if the facility had an NPDES permit) or is returned to the field for reuse. The discharged water is shown in the surface discharge category in Table 5-53. The reused water is added to the reuse within the industry category in Table 5-53.
- Injection disposal well – Pennsylvania has very few disposal wells. Most of the water managed in this way was trucked to disposal wells in neighboring states (nearly all went to Ohio). The water sent to Ohio disposal wells is shown in Table 5-51, but is not shown in Table 5-53, since it is already accounted for in the Ohio state summary. The water sent to Pennsylvania disposal wells is shown in the disposal for injection category in Table 5-53.
- Onsite encapsulation/pits/landfill – small volumes of produced water were managed by various land application methods. These are shown in the Other category in Table 5-53.
- Public sewage treatment – some of the produced water from the conventional wells was sent to a local municipal wastewater treatment plant. Unconventional produced

water is not allowed to be sent there. This volume is shown in the surface discharge category of Table 5-53.

- Residual waste processing – The PADEP issued a general permit allowing residual waste (including produced water) to be recycled. This is shown in the reuse within the industry category for Table 5-53.
- Reuse – The PADEP had several categories of reuse – all are combined here. Most of this wastewater was given some degree of treatment in the field and was then reused in other wells. This is shown in the reuse within the industry category for Table 5-53.
- Roadspreading – A small portion of the conventional produced water was applied to roads in winter months for deicing. This is shown in the reuse outside of the industry category in Table 5-53.
- Storage pending disposal or reuse. This category covers water accumulated in tanks or pits that was awaiting some form of water management at the time the report was filed by the operator. For the sake of this report, this is shown in the reuse within the industry category for Table 5-53.
- Surface impoundment. This is similar to the storage category above. For the sake of this report, this is shown in the reuse within the industry category for Table 5-53.

Some of the produced fluids were reported in units of tons (2,000 lb). Salty water is more dense than fresh water. The PADEP suggested using a conversion factor of 1.2 g/cm^3 (equal to 4.752 bbl/ton). The values reported in tons were multiplied by 4.752 and then added to the values reported in bbl.

Table 5-52 — Detailed Water Management Data for Pennsylvania

Management Method	Unconventional (bbl)	Unconventional (tons)	Convert tons to bbl	Total Unconventional (bbl)	Conventional	Conventional (tons)	Convert tons to bbl	Total Conventional (bbl)	Total (bbl)
Centralized Waste Treat + discharge	16,882	182	865	17,747	489,134			489,134	506,881
Centralized Waste Treat + Recycle	94,925			94,925	2,090			2,090	97,015
Disposal well (PA)	139,487			139,487	427,383			427,383	566,870
Disposal well (other state)	2,793,742	70	333	2,794,075	99,890			99,890	2,893,965
Landfill/pit	13,234	4,354	20,690	33,924	5,659			5,659	39,583
Public sewage treatment	77		0	77	345,238	440	2,091	347,329	347,406
Residual waste processing	16,874,462	18,474	87,788	16,962,250	537,075	575	2,732	539,807	17,502,058
Reuse	25,951,185	2,216	10,530	25,961,715	2,451,831		0	2,451,831	28,413,546
Roadspreading	0			0	198,461	20	95	198,556	198,556
Storage	145,441			145,441	382			382	145,823
Surface Impoundment	4,428,544			4,428,544	180,779			180,779	4,609,323
Total Volume (bbl)				50,578,186				4,742,840	55,321,026

Pennsylvania shows a far higher percentage of beneficial reuse than any other state. This was driven primarily by the comparative economics of each of the available water management methods. The cost to provide modest treatment followed by reuse was typically lower than the cost of all other management options. As a result, the companies chose to follow that management practice at most wells to manage about 97% of the water in that way.
Disposal wells within Pennsylvania manage about 1% of the total produced water. However, when the produced water injected in disposal wells in neighboring states is considered, the total volume of produced water injected into disposal wells is about 6%.

Although Table 5-53 shows a separate volume for other (land applications), when the values are transferred to the summary table in Chapter 4, the land application volume is combined with the surface discharge volume.

Table 5-53 — 2017 Produced Water Management Practices for Pennsylvania

Management Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	0	0%
Injection for disposal	566,870 bbl injected in PA disposal wells; (3,460,835 bbl total injected for disposal in PA, OH, and WV)	1.1%
Surface discharge	854,287	1.6%
Evaporation	0	0%
Offsite commercial disposal (pay another company to manage your produced water)	PA does utilize some offsite commercial disposal, but unlike other states, it is rarely disposal wells. Therefore, the volumes sent to offsite commercial disposal in PA are shown under the ways in which those facilities manage the water.	0%
Reuse within the oil and gas industry	50,767,765	96.8%
Reuse in ways other than in the oil and gas industry (road spreading)	198,556	0.4%
Other (land application)[a]	39,583	<0.1%
Total	52,427,061	100%

[a] This volume is added to the surface discharge volume on the master table in Chapter 4.

5.26 South Dakota

The South Dakota Department of Environment and Natural Resources (DENR), Minerals and Mining Program provided information on production and management of produced water related to oil and gas activities.[45] The data are shown in Tables 5-54 and 5-55.

South Dakota had 196 active oil and gas wells in 2017, with all wells producing from conventional formations. 78% of the wells produced oil (1,304,321 bbl), and 22% produced gas (260 Mmcf).

During 2017, South Dakota wells generated 6,924,285 bbl of produced water. Nearly all the water came from the oil wells. The WOR was 5.3 bbl/bbl. The volume of water from gas wells was so small (342 bbl) that calculation of a WGR was not meaningful.

Table 5-54 – 2017 Production for South Dakota

Type of Hydrocarbon	# Wells Producing Primarily That Type of Hydrocarbon	Total Volume of Produced Water Brought to Surface (bbl/year)	Volume of Hydrocarbon Produced (bbl/year or Mmcf/year)
Crude oil from conventional formations	152	6,923,943	1,304,321 bbl
Natural gas from conventional formations	44	342	260 Mmcf
Crude oil from unconventional formations	0	0	0
Natural gas from unconventional formations	0	0	0
Total	196	6,924,285	1,304,321 bbl; 260 Mmcf

According to the DENR, nearly all produced water was injected. 60% of the water was injected for enhanced recovery, and 40% was injected for disposal. The DENR noted that an estimated 1,000 bbl of produced water was evaporated.

[45] Emails from South Dakota DENR to Mike Nickolaus, GWPC, on May 13, 2019, and to John Veil on May 23, 2019 and October 1, 2019.

Table 5-55 — 2017 Produced Water Management Practices for South Dakota

Management Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	4,179,533	60%
Injection for disposal	2,743,752	40%
Surface discharge	0	0
Evaporation	1,000	<0.1%
Offsite commercial disposal (pay another company to manage your produced water)	0	0
Reuse within the oil and gas industry	0	0
Reuse in ways other than in the oil and gas industry	0	0
Total	6,924,285	100%

5.27 Tennessee

The Tennessee Oil and Gas Program in the Department of Environment and Conservation provided information about oil and gas production.[46] This information is shown in Table 5-56. Tennessee had 2,060 active oil and gas wells in 2017.

Table 5-56 — 2017 Production for Tennessee

Type of Hydrocarbon	# Wells Producing Primarily That Type of Hydrocarbon	Total Volume of Produced Water Brought to Surface (bbl/year)	Volume of Hydrocarbon Produced (bbl/year or Mmcf/year)
Crude oil from conventional formations	1,086	??	275,316 bbl
Natural gas from conventional formations	974	??	3,038 Mmcf
Crude oil from unconventional formations	0	0	0
Natural gas from unconventional formations	0	0	0
Total	2,060	44,163 bbl	275,316 bbl; 3,038 Mmcf

The Tennessee Oil and Gas Program does not currently track the small volume of produced water generated and managed in their state. An inquiry was made to the Tennessee Oil and Gas Association (TOGA) for more information on volumes and how the water is managed. TOGA responded that the oil formations in Tennessee produce very little water and offered more specific information on water generation and management.[47]

According to TOGA, almost all oil and gas produced in Tennessee comes from an 8-county area located on the Cumberland Plateau.

- Wells in Scott, Morgan, Anderson, Campbell, and Claiborne counties do not generate produced water.
- Wells in Fentress County do produce small amounts of water as the wells age. Water production ranges from 3 to 4 bbl of water a week per well. These small volumes of water are drained off into lined pits and allowed to evaporate.
- Most wells in Pickett County generate no water at all with the oil. If a well does produce some water, it is trucked to one of eight water injection wells in the area. When the cost of hauling water exceeds the income from a particular well, it is plugged.

---

[46] Email from Tennessee Oil and Gas Program to John Veil on June 20 and October 16, 2019.

[47] Letter from TOGA, to John Veil on October 2, 2019.

With that background from TOGA, the following assumptions were made to estimate volumes for Table 5-57. The total volume of water from that table was then assumed to be the total volume generated. This volume is shown in Table 5-56.

The Tennessee Division of Water Resources in the Department of Environment and Conservation provided the injection volume for several Class II wells. Three of these wells injected produced water for enhanced recovery (27,887 bbl), and the fourth one injected produced water for disposal (1,170 bbl).[48]

To estimate the volume of water evaporated in lined pits, the author examined the oil and gas permit database available on the TDEC website.[49] During the years of 2012 through 2017, 83 wells were permitted in Fentress County (these years were chosen to represent those wells that might actually be producing in 2017). Assuming the TOGA estimate of 3.5 bbl/week x 52 weeks x 83 wells, the total volume evaporated in lined pits is estimated to be 15,106 bbl. Admittedly this volume is only a rough estimate. But it is useful as a placeholder in Table 5-57.

Tennessee's total produced water volume is miniscule when viewed from a nationwide volume perspective but is reported here nonetheless.

Table 5-57 — 2017 Produced Water Management Practices for Tennessee

Management Practice	**Total Volume of Produced Water Managed by That Practice (bbl/year)**	**Percentage of Produced Water Managed by That Practice**
Injection for enhanced recovery	27,887	63%
Injection for disposal	1,170	3%
Surface discharge	0	0
Evaporation	15,106	34%
Offsite commercial disposal (pay another company to manage your produced water)	0	0
Reuse within the oil and gas industry	0	0
Reuse in ways other than in the oil and gas industry	0	0
Total	44,163	100%

[48] Email from Division of Water Resources to John Veil on July 9, 2019.

[49] https://www.tn.gov/content/tn/environment/permit-permits/redirect---other-permits/oil-and-gas-well-permit.html, visited October 21, 2019.

5.28 Texas

The Railroad Commission of Texas (RRC) provided information on produced water and hydrocarbon production.[50] The data are shown in Tables 5-58 and 5-59. Oil and gas activity in Texas is far larger than in any other state. The RRC reported 273,149 active oil and gas wells in Texas during 2017. Oil wells made up 66% of the total wells. The oil and gas production data and well counts did not distinguish between conventional and unconventional production.

The RRC does not require operators to submit data on the volume of water brought to the surface. In order to estimate the total water production, the RRC assumed that the volume of water managed was equal to the volume of water injected and discharged (they do have data on those activities). Although this is not an exact match, it represents a good estimate for the produced water volume.

For 2017, the RRC estimated a produced water volume of 9,895,084,619 bbl. The RRC was unable to provide a breakout of water production from oil wells vs. gas wells or from conventional vs. unconventional wells. As a result, it was not possible to calculated WORs or WGRs.

Table 5-58 — 2017 Production for Texas

Type of Hydrocarbon	# Wells Producing Primarily That Type of Hydrocarbon	Total Volume of Produced Water Brought to Surface (bbl/year)	Volume of Hydrocarbon Produced (bbl/year or Mmcf/year)
Crude oil from conventional and unconventional formations	180,860	??	1,271,143,548 bbl
Natural gas from conventional and unconventional formations	92,289	??	8,124,096 Mmcf
Total	273,149	9,895,084,619	1,271,143,548 bbl; 8,124,096 Mmcf

In its data submittal to the author for the previous report (Veil 2015), the RRC provided a total volume of water injected during 2012 (7,435,659,156 bbl), but was unable to break out the volume of water injected for enhanced recovery and the volume injected for disposal in non-commercial wells. In that report, the author followed the assumption that 50% of the produced water was managed by enhanced recovery and 50% was sent to disposal wells.

[50] Email from RRC to John Veil on July 22, 2019.

In its data submittal for the 2017-year report, the RRC was able to provide separate estimates of the volume injected for enhanced recovery (4,557,819,641 bbl) and the volume injected into non-commercial disposal wells (3,586,674,633 bbl). Texas has a large network of commercial disposal wells too. The RRC reported that commercial disposal well facilities injected 1,716,310,350 bbl of water during 2017. Adding the volume injected by non-commercial and commercial disposal well facilities gives 5,302,984,983 bbl. This represents 54% of the injected water. The volume injected for enhanced recovered represents about 46% of the injected water. This 46%/54% split is relatively similar to the 50%/50% split used in the previous study.

Although over 99% of the produced water in Texas was managed by injection, over 34 million bbl of produced water was managed by discharge to surface water bodies (state waters). A large volume of produced water is discharged from offshore platforms in the Gulf of Mexico Outer Continental Shelf – that volume is considered in Chapter 6 under federal lands.

The RRC recognizes that a significant volume of produced water is reused by oil and gas companies in their own operations. The RRC does not track this activity, and cannot give a quantitative estimate of the volume of produced water that is reused. GWPC (2019) provides several examples of oil and gas companies that have collected their produced water and reused that water within the fields (see Appendix 2-A of that report for two detailed case studies; other short examples are given within Module 2 of that report).

Since the volume of produced water in Table 5-59 is based on the volume injected plus the volume discharged, it is an estimated number. That volume does not account for the volume of produced water that is reused by the industry. Although it is not possible to assign a numerical value to the amount of reuse in Texas, produced water reuse is happening. Therefore, the actual volume of produced water generated by oil and gas wells within Texas is likely to be somewhat larger than the 9,895,084,619 bbl shown in this report. How much larger is unknown.

Table 5-59 — 2017 Produced Water Management Practices for Texas

Management Practice7	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	4,557,819,641	46.1%
Injection for disposal	3,586,674,633	36.2%
Surface discharge	34,279,995	0.3%
Evaporation	N/A	0
Offsite commercial disposal (pay another company to manage your produced water)	1,716,310,350	17.3%
Reuse within the oil and gas industry	Definitely happening, but volume is unknown	??
Reuse in ways other than in the oil and gas industry	??	??
Total	9,895,084,619	100%

5.29 Utah

The Utah Department of Natural Resources Division of Oil, Gas, and Mining (DOGM) provided data on oil, gas, and water production and on how the produced water was managed.[51] The data are shown in Tables 5-60 and 5-61.

Utah had 11,765 active wells during 2017. 60% of the wells produced gas, and 40% produced oil. During 2017, these wells generated 155,047,940 bbl of produced water. The DOGM did not differentiate between conventional and unconventional production.

The WOR was 3.7 bbl/bbl. The WGR was 93 bbl/Mmcf.

Table 5-60 — 2017 Production for Utah

Type of Hydrocarbon	# Wells Producing Primarily That Type of Hydrocarbon	Total Volume of Produced Water Brought to Surface (bbl/year)	Volume of Hydrocarbon Produced (bbl/year or Mmcf/year)
Crude oil from conventional and unconventional formations	4,735	125,739,740	34,438,271 bbl
Natural gas from conventional and unconventional formations	7,030	29,308,200	315,143 Mmcf
Total	11,765	155,047,940	34,438,271 bbl; 315,143 Mmcf

Utah managed 155,047,940 bbl of produced water during 2017. 49.3% of the water was injected for disposal, and 39.8% was injected for enhanced recovery. The DOGM provided the total volume for enhanced recovery – this includes produced water and makeup water. The makeup water was not counted in the total water managed.

Another 4.6% of the produced water was discharged to surface waters. According to Veil (2015), the water from the Ashley Valley field has low salinity and can be used for irrigation and later discharged. Utah producers sent 6.3% of the state's produced water to offsite commercial disposal facilities that employ large evaporation ponds. This volume is shown in the evaporation category in Table 5-61.

The DOGM does not presently track reuse of produced water. Both Veil (2015) and Clark and Veil (2009) note that some produced water has been reused within the industry in the past.

---

[51] Email from Utah DOGM to John Veil on August 9, 2019.

The use of the Ashley Valley water for irrigation was also a beneficial reuse as well as a surface discharge.

Table 5-61 — 2017 Produced Water Management Practices for Utah

Management Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	61,800,708 bbl (produced water portion); 77,807,413 bbl (total injected – includes makeup water)	39.8%
Injection for disposal	76,439,156	49.3%
Surface discharge	7,103,047	4.6%
Evaporation	9,705,029	6.3%
Offsite commercial disposal (pay another company to manage your produced water)	Shown under evaporation category	0
Reuse within the oil and gas industry	??	??
Reuse in ways other than in the oil and gas industry	??	??
Total	155,047,940	100%

5.30 Virginia

The Virginia Department of Mines, Minerals, and Energy (DMME) provided oil, gas, and water production information as well as produced water management information.[52] The information is shown in Tables 5-62 and 5-63. Virginia had 8,257 active oil and gas wells during 2017. 77% of the wells produced CBM (unconventional gas), and 23% produced conventional gas. Just two wells produced conventional oil.

Virginia wells generated 2,156,931 bbl of produced water during 2017. 99% of the water came from the CBM wells. The conventional gas wells generated less than 1% of produced water. No produced water was associated with the 2 conventional oil wells. Therefore, no WOR could be calculated. The WGR for CBM wells was 21.5 bbl/Mmcf. The WGR for conventional gas wells was 0.9 bbl/Mmcf. The WGR for combined gas was 18.7 bbl/Mmcf.

Table 5-62 — 2017 Production for Virginia

Type of Hydrocarbon	# Wells Producing Primarily That Type of Hydrocarbon	Total Volume of Produced Water Brought to Surface (bbl/year)	Volume of Hydrocarbon Produced (bbl/year or Mmcf/year)
Crude oil from conventional formations	2	0	795 bbl
Natural gas from conventional formations	1,857	13,769	15,937 Mmcf
Crude oil from unconventional formations	0	0	0
Natural gas from unconventional formations	6,398	2,143,162	99,555 Mmcf
Total	8,257	2,156,931	795 bbl; 115,492 Mmcf gas

The DMME reported that all produced water was injected into disposal wells. The total produced water injected was 2,050,822 bbl – slightly less than the volume generated (the differential is 106,109 bbl). The DMME also noted that Virginia operators injected into disposal wells 216,295 bbl of drilling fluids and other water that had been contained in pits. The operators also land spread 109,564 bbl of drilling fluids and flowback water that had been contained in pits. Presumably the liquid portion of the pit contents that was produced water from the flowback process makes up the difference between the volume of water generated and the volume injected. For the purposes of this report, it is assumed that the solid

[52] Emails from Virginia DMME to John Veil on May 22 and 23, 2019.

component of the pit contents was land spread, and the liquid component of the pit contents was injected. It is also assumed that 106,109 bbl of the pit contents was injected into disposal wells, making the total injected volume 2,156,931 bbl.

Table 5-63 — 2017 Produced Water Management Practices for Virginia

Management Practice	**Total Volume of Produced Water Managed by That Practice (bbl/year)**	**Percentage of Produced Water Managed by That Practice**
Injection for enhanced recovery	0	0
Injection for disposal	2,156,931	100%
Surface discharge	0	0
Evaporation	0	0
Offsite commercial disposal (pay another company to manage your produced water)	0	0
Reuse within the oil and gas industry	0	0
Reuse in ways other than in the oil and gas industry	0	0
Total	2,156,931	100%

5.31 West Virginia

The West Virginia Department of Environmental Protection (WVDEP) Office of Oil and Gas provided information on production activities and produced water management, the quantities of which are reported to the agency as mandated by various regulations.[53] They clarified the information submitted noting that West Virginia regulations do not require the reporting of all produced water quantities and the disposal fate of all produced water streams. Rather they collect produced water data as applicable to various programs. All oil and gas operators are required to dispose of produced water in accordance to these regulations, the records of which are subject to audit by the agency.

The data are shown in Tables 5-64 and 5-65. The data provided by the WVDEP showed 64,826 oil and gas wells. Of the total number of wells, 94% produced gas from conventional formations. The remaining wells produced from unconventional formations (4% from Marcellus and Utica shale wells, and 1.5% from CBM wells). However, the unconventional wells showed considerably higher production rates. The 3,687 unconventional wells produced over 90% of all West Virginia's gas and 87% of West Virginia's oil in 2017.

The WVDEP regulations do not require operators to submit data on all types of produced water generation volumes for conventional production and from CBM (except for those wells which use a general discharge permit for land application of water, as discussed below). It does however, as of 2016, collect data on produced water from the horizontal wells in the unconventional Marcellus and Utica shale formations. In 2017, those wells generated 20,707,722 bbl of produced water.

To estimate the volume of water associated with the other types of production, the WOR and WGR values from neighboring states were used to multiply conventional oil and gas volumes and coalbed methane volumes from West Virginia. In Ohio, the conventional WOR is 0.7 bbl/bbl, and the conventional WGR is 34 bbl/Mmcf. Multiplying the conventional oil and gas volumes in Table 5-64 by the WOR and WGR gives 681,563 bbl of water from oil production and 5,066,000 bbl of water from gas production.

The WGR for CBM wells in Virginia is 21.5 bbl/Mmcf. This is multiplied by the CBM gas volume in Table 5-64 to give 195,650 bbl of water. The total estimated produced water volume for 2017 is 26,650,935 bbl.

[53] Emails from WVDEP to John Veil on June 19 and October 15, 2019.

Table 5-64 — 2017 Production for West Virginia

Type of Hydrocarbon	# Wells Producing Primarily That Type of Hydrocarbon	Total Volume of Produced Water Brought to Surface (bbl/year)	Volume of Hydrocarbon Produced (bbl/year or Mmcf/year)
Crude oil and natural gas from conventional formations	60,974	681,563 (from oil); 5,066,000 (from gas)	973,662 bbl; 149,000 Mmcf
Crude oil and natural gas from unconventional formations	2,700	20,707,722 bbl	6,596,542 bbl; 1,453,000 Mmcf
Other – Coal Bed Methane	987	195,650	9,100 Mmcf
Total	64,826	26,650,935	7,570,204 bbl; 1,611,100 Mmcf

The WVDEP estimated that 15,000,000 bbl of produced water is injected into disposal wells by operators to manage their own produced water. For all other methods of water management, estimates were made as described below.

The WVDEP noted that West Virginia has 11 secondary recovery (water flood) fields. The quantities of produced water from these operations are reported to the state, but the totals are not currently tabulated. Produced water in secondary recovery fields is generated and recycled back for injection in a cyclic pattern, with additional freshwater added as needed. In the previous produced water volume and management report for 2012 (Veil 2015), an estimated 3,660,000 bbl were assumed to be injected for enhanced recovery. In the absence of any different numbers for 2017, it is assumed that the same volume is injected for enhanced recovery.

As noted in the Ohio state summary (section 5-22), 18,220,028 bbl of produced water originating from other states are sent to Ohio disposal wells. Much of West Virginia's production is along the border with Ohio, and a large volume of injectable fluid goes there. Data from Pennsylvania shows that 2,893,843 bbl of Pennsylvania produced water is sent to Ohio disposal wells. That leaves 15,326,185 bbl of produced water assumed to have come from West Virginia wells.[54] However, since that water is moved out of West Virginia for disposal, it is not added to the total water managed in West Virginia. It has already been counted in Ohio.

[54] The WVDEP felt that the estimated volume of produced water going to Ohio disposal wells was high, but was unable to provide any alternate estimate. Therefore, the estimate shown here is left in the report.

The Antero Clearwater Facility is an advanced wastewater treatment plant in West Virginia that was designed to take produced water (including flowback from shale wells) and treat it to make fresh water, which can be reused for use in the oil and gas fields. The salt that is removed is sent to a nearby landfill. The design capacity for the Clearwater facility is to receive 60,000 bbl/day of salty water and make 41,000 bbl/day of fresh water. Although this had potential to be an important facility for West Virginia's oil and gas industry, it began operating in late 2017 or early 2018. The volume of produced water actually managed there in 2017 was very small or zero. Therefore, it is not shown on Table 5-65. Further, the WVDEP reported that as of September 2019, the Antero facility was no longer operating.[55]

Produced water from some CBM wells is managed by land application, which allows produced water of a certain quality to be dispersed on the ground under authority of a water pollution control permit (https://dep.wv.gov/oil-and-gas/Documents/GP-WV-1-07%20CBM%20Land%20Application%20Permit_FINAL_Signed_%202015.08.01.pdf). The use of this permit is dictated by the regional water quality found in coal seams. Quantities of produced water using this disposal method are reported to WVDEP, the quantities of which are not currently tabulated in databases, but are available for review. Although Table 5-65 shows a separate volume for other (land applications), when the values are transferred to the summary table in Chapter 4, the land application volume is reported under the surface discharge volume.

The WVDEP is aware that much of the produced water from unconventional production is reused for other frac jobs. There are currently no regulatory requirements for the reporting of all quantities of produced water. Operators' records of disposal are auditable by the WVDEP. To account for this important activity, and to help balance the produced water generated volume with the produced water managed volume, a volume for reuse within the industry is calculated as the remaining volume not otherwise accounted for. The sum of injection for enhanced recovery, injection for disposal, and other is 18,855,650 bbl. Subtracting this from the 26,650,935 bbl of water generated gives 7,795,285 bbl that are assigned to reuse within the industry.

[55] Email from the WVDEP to John Veil on October 15, 2019.

Table 5-65 — 2017 Produced Water Management Practices for West Virginia

Management Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	3,660,000	14%
Injection for disposal	15,000,000	56%
Surface discharge	0	0
Evaporation	0	0
Offsite commercial disposal (pay another company to manage your produced water)	15,326,185 (sent to Ohio; not counted toward the West Virginia total water managed volume)	n/a
Reuse within the oil and gas industry	7,795,285	29%
Reuse in ways other than in the oil and gas industry	0	0
Other (land spreading)[a]	195,650	1%
Total	26,650,935	100%

[a] This volume is shown under surface discharge volume in the master table in Chapter 4.

5.32 Wyoming

The Wyoming Oil and Gas Conservation Commission (WOGCC)[56] and the Wyoming Department of Environmental Quality (WDEQ)[57] provided information on production activities and produced water management. The data are shown in Tables 5-66 and 5-67. Wyoming had 33,572 active oil and gas wells in 2017. About 46% of the wells produced conventional gas, and another 27% produced conventional oil. 20% of the wells produced unconventional gas, and 7% produced unconventional oil.

In 2017, Wyoming wells generated 1,705,309,511 bbl of produced water. The conventional oil wells generated 65% of the total, with conventional gas wells producing 14% of the water. 19% of the water came from unconventional oil wells, with the remaining small portion coming from unconventional gas wells.

The Wyoming data allowed calculation of WORs and WGRs. The WOR for conventional oil was 39 bbl/bbl, and for unconventional oil it was 6.8 bbl/bbl. The WGR for conventional gas was 268 bbl/Mmcf, and for unconventional gas it was 42 bbl/Mmcf. If conventional and unconventional production volumes were combined, the overall WOR was 18.9 bbl/bbl, and the overall WGR was 151 bbl/Mmcf.

Table 5-66 — 2017 Production for Wyoming

Type of Hydrocarbon	# Wells Producing Primarily That Type of Hydrocarbon	Total Volume of Produced Water Brought to Surface (bbl/year)	Volume of Hydrocarbon Produced (bbl/year or Mmcf/year)
Crude oil from conventional formations	9,062	1,112,957,579	28,449,719
Natural gas from conventional formations	15,494	241,654,658	901,711
Crude oil from unconventional formations	2,308	320,035,963	47,268,115
Natural gas from unconventional formations	6,708	30,661,311	906,718
Total	33,572	1,705,309,511	75,717,834 bbl oil; 1,808,429 Mmcf gas

[56] Email from WOGCC to John Veil on July 2, 2017.

[57] Emails from WDEQ to John Veil on July 23 and 30, and October 16, 2019.

The WOGCC provided data on produced water injection. A total of 1,045,319,977 bbl of water was injected during 2017. 77% of the injected water was used for enhanced recovery. The remaining 22% was injected for disposal.

The WDEQ provided data on water discharged to surface waters under NPDES permits (648,126,190 bbl). Of this quantity, 179,345,238 bbl of produced water were generated by coalbed methane production and 468,780,952 bbl by other oil and gas production.

The WDEQ also provided data on water sent to offsite commercial evaporation facilities. The WDEQ did not require reporting of produced water volumes managed at these facilities, but they estimated that 40,000,000 bbl were evaporated at those facilities during 2017. Because the large volume of evaporated produced water is somewhat unique to Wyoming, the water evaporated at offsite commercial facilities is shown under the evaporation category in Table 5-67.

The WDEQ provided data on produced water injected into offsite commercial Class I disposal wells (2,450,183 bbl). This volume is shown under the offsite commercial disposal category in Table 5-67 (most offsite commercial disposal in the United States utilizes disposal wells).

Table 5-67 — 2017 Produced Water Management Practices for Wyoming

Management Practice	**Total Volume of Produced Water Managed by That Practice (bbl/year)**	**Percentage of Produced Water Managed by That Practice**
Injection for enhanced recovery	802,309,212	46%
Injection for disposal	243,010,765	14%
Surface discharge	648,126,190	37%
Evaporation	40,000,000	2%
Offsite commercial disposal (pay another company to manage your produced water)	2,450,183	<1%
Reuse within the oil and gas industry	??	
Reuse in ways other than in the oil and gas industry	??	
Total	1,735,896,350	100%

The WOGCC suggested that some of the produced water is reused in oil and gas operations but was unable to make any estimates of the volume reused. From prior experience studying coalbed methane activities in the Powder River Basin region of Wyoming, the author is aware that the coalbed methane water has low salinity allowing it to be discharged to surface water bodies or reused for irrigation or livestock watering. No information was available from either the WOGCC or the WDEQ about the extent of those activities.

The total volume of generated produced water in 2017 was less than the volume managed by about 31 million bbl. Some water was reused within the industry and outside the industry, but was not accounted for in Table 5-67. This makes that differential even larger.

5.33 Other States

Several other states were contacted as they had some potential for oil and gas production in 2017.

The North Carolina Geological Survey reported that: "the state of North Carolina anticipates the possibility of natural gas or oil production in the future, as of this date North Carolina has no commercially producing petroleum wells."[58]

The South Carolina Department of Health & Environmental Control reported: "South Carolina is a non-producing oil and/or natural gas state."[59]

The Maryland Department of the Environment (MDE) reported: "In 2017 there were 3 production wells and according to our database they produced 25,363 mcf"[60] (25 Mmcf). These were all gas wells – no oil wells are producing in Maryland. No information was available on water production or management, although the MDE contact suggested "it is very minimal, would be collected on site and then disposed of at an approved location." The volume of natural gas from Maryland wells is very small in comparison to the other states, and therefore is not included in the master summary in Chapter 4.

---

[58] Email from North Carolina Geological Survey to John Veil on June 13, 2019.
[59] Email from South Carolina Department of Health & Environmental Control to John Veil on June 14, 2019.
[60] Emails from Maryland Department of the Environment to John Veil on July 8, 2019.

Chapter 6 — Federal and Tribal Summary

This chapter provides information on produced water associated with production activities on federal lands (onshore), offshore production in federal waters, and tribal lands. Federal onshore mineral leasing activities are managed by the U.S. Department of the Interior (DOI) Bureau of Land Management (BLM) and the U.S. Department of Agriculture's Forest Service. DOI's Bureau of Ocean Energy Management (BOEM) manages the oil and gas leasing on the Outer Continental Shelf. Its sister agency, Bureau of Safety and Environmental Enforcement (BSSE), maintains production data from offshore leases.

The DOI Office of Natural Resources Revenue (ONRR) is responsible for management of all revenues associated with mineral leases on federal onshore, federal offshore, and tribal lands.

The oil, gas, and water volume information in this chapter were obtained from the ONRR and BSSE websites. Several regional offices of the EPA provided produced water management information. EPA Regions 4, 6, and 9 provided volumes of produced water discharged to the ocean from offshore wells. Region 10 noted that no produced water was discharged to surface waters in 2017.

6.1 Federal and Tribal Onshore Lands

Oil and gas production data for federal onshore lands was obtained from a DOI ONRR website.[61] The spreadsheet containing calendar year data for all commodities managed by the ONNR was downloaded and sorted to find those entries for onshore federal lands, 2017, and for oil and gas. In 2017, onshore oil production on federal lands was 191,184,056 bbl. Onshore gas production was 3,242,790 Mmcf. This spreadsheet did not include produced water volumes.

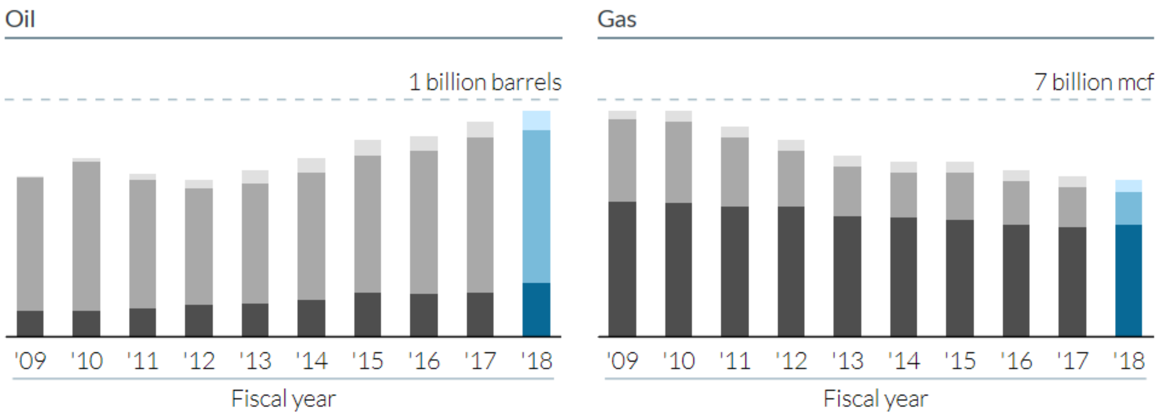
The same DOI ONRR website provided an estimate of tribal oil and gas production for 2018 (not 2017) – as for onshore production, no water values were available (see Figure 6-1). Presumably those 2018 values will be close enough to be representative of the 2017 volumes. In 2018, oil production on tribal lands was 81,094,848 bbl, and gas production was 349,153 Mmcf.

Onshore production on federal lands and production on tribal lands are assumed to be included in the total production volumes provided by the state agencies for those states in which the federal and tribal lands are located. These production volumes and the ways in which the produced water was managed were included in the state summaries in the previous chapter. Therefore, the volumes of oil and gas provided in this section were not included in the summary table in Chapter 4 to avoid double counting.

---

[61] https://revenuedata.doi.gov/downloads/federal-production/; accessed July 7, 2019

Figure 6-1 – DOI ONRR Data on Oil and Gas Production in 2018



Source	2018
Native American	81,094,848
Federal offshore	617,108,139
Federal onshore	214,144,945
Total	**912,347,931**

Source	2018
Native American	349,152,809
Federal offshore	989,788,992
Federal onshore	3,256,129,770
Total	**4,595,071,571**

Source: https://revenuedata.doi.gov/

6.2 Federal Offshore Production

Information on federal offshore oil, gas, and water production was obtained from the detailed databases available on the website for BSEE.[62] The 2017 oil, gas, and water volumes for Outer Continental Shelf activities are reported on several different databases available through that website. For this report, the volumes were taken from the OGOR-A Well Production Data database for the Pacific and Gulf of Mexico regions. The databases were downloaded in ASCII format and converted to Excel files. OGOR-A data were not available for the Alaska Region.

Figure 6-2 shows annual oil and gas production for the three OCS regions in tabular and graphic form. This figure can be found on the BSEE website as document "Outer Continental Shelf Oil and Gas Production". The oil and gas volumes from this chart are similar to but slightly different than the volumes obtained by using the OGOR-A data. In this report, the OGOR-A data for oil

---

[62] https://www.data.bsee.gov/Main/Production.aspx#pdf. Accessed on July 19, 2019 and August 21, 2019.

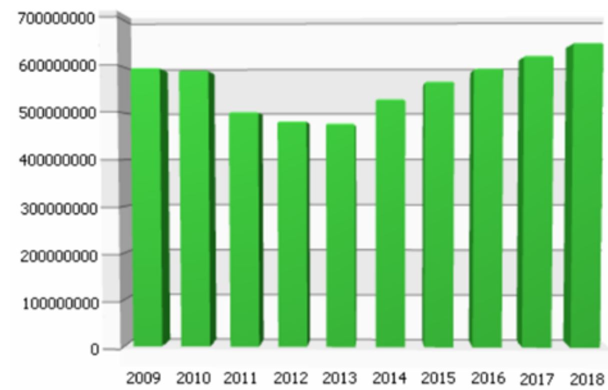
and gas are taken from the databases for the Gulf of Mexico and Pacific regions. The volume of oil and gas for the Alaska region is taken from the chart.

Figure 6-2 – DOI BSSE Data on Offshore Oil and Gas Production

Annual Oil and Gas Production

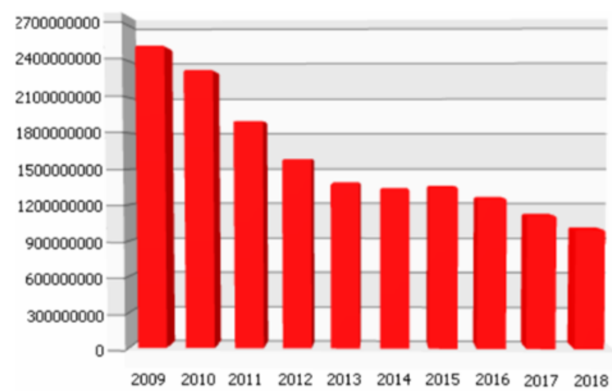
(Data obtained from Oil & Gas Operations Reports submitted by offshore operators to the Office of Natural Resources Revenue)

Oil (barrels)				
Year	**Alaska**	**Pacific**	**Gulf**	**Total**
2009	1,823,426	22,306,167	570,309,328	**594,438,921**
2010	1,337,999	21,707,342	566,628,383	**589,673,724**
2011	1,057,866	19,816,849	481,697,096	**502,571,811**
2012	627,108	17,678,493	464,786,485	**483,092,086**
2013	669,148	18,558,782	459,046,740	**478,274,670**
2014	625,303	18,481,821	510,467,459	**529,574,583**
2015	609,912	11,443,917	553,007,049	**565,060,878**
2016	548,343	6,142,614	585,354,172	**592,045,129**
2017	517,002	5,713,059	613,313,372	**619,543,433**
2018	498,216	4,873,812	641,218,109	**646,590,137**



Gas (MCF)*				
Year	**Alaska**	**Pacific**	**Gulf**	**Total**
2009	29,609,015	41,282,897	2,451,076,806	**2,521,968,718**
2010	29,659,633	41,238,691	2,250,426,803	**2,321,325,127**
2011	37,801,877	36,574,027	1,826,593,930	**1,900,969,834**
2012	21,960,989	27,261,910	1,535,897,665	**1,585,120,564**
2013	29,293,586	27,465,642	1,328,279,728	**1,385,038,956**
2014	31,264,462	28,244,946	1,276,676,600	**1,336,186,008**
2015	32,249,585	14,734,938	1,307,390,047	**1,354,374,570**
2016	31,705,685	4,499,110	1,221,161,389	**1,257,366,184**
2017	29,056,185	3,949,957	1,078,643,972	**1,111,650,114**
2018	3,211,259	3,426,874	992,713,448	**999,351,581**

*MCF = 1,000 cubic feet



Source: https://www.data.bsee.gov/Production/OCSProduction/Default.aspx.

For the combined OCS, oil production rose by 28% between 2012 and 2017. Oil production in the Alaska and Pacific regions fell between 2012 and 2017, but the rise in oil production from the Gulf of Mexico region was sufficiently high to make the combined total higher.

Gas production showed a different trend. Between 2012 and 2017, the gas volume for the entire OCS declined by about 30%. Gas volume for the Alaska region increased between 2012 and 2017, but in the Pacific and Gulf of Mexico regions it dropped.

Table 6-1 shows the oil and gas volumes combined for all three OCS regions. In 2017, wells in the OCS produced 619,697,287 bbl of oil and condensate, and 1,114,880 Mmcf of gas. Produced water volume data were available for just the Gulf of Mexico (504,418,661 bbl) and Pacific regions (71,507,626 bbl). The water from those two regions totaled 575,926,287 bbl.

Table 6-1 — 2017 Production for Offshore Areas in the Outer Continental Shelf

Type of Hydrocarbon	# Wells Producing Primarily That Type of Hydrocarbon	Total Volume of Produced Water Brought to Surface (bbl/year)	Volume of Hydrocarbon Produced (bbl/year or Mmcf/year)
Crude oil from conventional and unconventional formations	??		619,697,287 bbl
Natural gas from conventional and unconventional formations	??		1,114,880 Mmcf
Total	??	575,926,287	619,697,287 bbl; 1,114,880 Mmcf

To confirm how offshore produced water is managed at offshore platforms, three senior industry water experts, who formerly worked for major oil and gas companies and now are consultants, were asked their opinions.[63] All three indicated that nearly all offshore produced water is treated on the platform then discharged to the ocean under the authority of a general NPDES permit issued by an EPA regional office.

The BSSE OGOR-A data also show large volumes of injected water for the Gulf of Mexico (143,737,681 bbl) and Pacific (60,058,294 bbl) regions. No information was available to estimate the volume of produced water injected in the Alaska region, but it is assumed to be low to none. The experts noted that very little produced water is used for enhanced recovery operations in offshore fields because of concerns of hydrogen sulfide creation in the formation. When water flooding or pressure maintenance is used in offshore fields, the companies almost always use treated seawater (readily available in the offshore area) or water from a brine formation.

The experts also noted that very little offshore produced water is injected into disposal wells. One exception is older wells in shallow water that may send the water back to shore where it can be injected. However, many such wells may be located in state waters. Therefore, they would be counted in the state total, not the federal OCS total.

With that as background, additional efforts were made to quantify the volume of produced water discharged back to the ocean. These discharges are governed by NPDES general permits

[63] Emails from Lloyd Hetrick (LHH Engineering), Mike Parker (Parker Environmental and Consulting), and James Robinson (Oxidane Engineering), to John Veil on July 17, 2019.

issued by EPA Regions 4 (eastern Gulf of Mexico), 6 (western Gulf of Mexico), 9 (offshore California), and 10 (offshore Alaska).

EPA Region 4 provided produced water flow data for three platforms that reported a discharge during 2017.[64] The total flow was very low – 125,975 bbl for the full year.

The EPA Region 6 office was unable to provide any detailed estimate of discharged produced water in 2017. On August 21, 2019, EPA headquarters staff arranged a conference call between the author, Office of Water oil and gas specialists, an EPA data management specialist, and the Region 6 oil and gas permit contact to try to get better information. The data management specialist generated a spreadsheet that provided a list of permitted platforms. That spreadsheet contained data only for the fourth quarter of 2017. The Region 6 permit contact advised the group that the electronic discharge monitoring report software had been significantly modified during 2017. For part of the year, data could not be uploaded by the companies. Any information available to the region and the data management specialist was believed to be incomplete.

Using the list of permitted facilities on that spreadsheet, the author visited EPA's ECHO database. In a painstaking process, he searched for each platform individually and was able to download the four quarterly flow volume data points for several hundred platforms.[65] These data were provided in two different sets of flow units. The companies originally provided flow in bbl/day. The software automatically converted this to MGD (million gallons per day) for consistency with all other industry facilities include in the ECHO data system. Unfortunately, the conversion factor used in the software was incorrect and underestimated volume by about 33%. The author advised EPA of this error – hopefully it will be corrected. The final total produced water discharge volume estimated for Region 6 during 2017 (after the correct conversion was used) was 705,400,825 bbl.

The EPA Region 9 office[66] explained that the 2017 produced water discharge volumes from 7 operating offshore California platforms could be obtained through the ECHO database.[67] The total volume from the 7 platforms was 31,706 bbl/day or 11,572,690 bbl for all of 2017.

The EPA Region 10 office advised that no platforms in federal waters of Alaska had discharges during 2017.[68]

Combining the data from the four EPA regions, the total discharged volume for 2017 was 717,099,890 bbl. This is higher than the total offshore produced water reported by BSEE.

---

[64] Email from EPA Region 4 to John Veil on July 17, 2019

[65] https://echo.epa.gov/; accessed August 23-25, 2019

[66] Email from Region 9 to John Veil on June 24, 2019

[67] https://echo.epa.gov/; accessed June 27, 2019

[68] Emails from Region 10 to John Veil on June 25, 2019

Given the issues with the Region 6 electronic discharge monitoring report software during 2017, and the fact that water data were obtained from two different agencies with different data management systems, it is not surprising that the data are somewhat inconsistent. To provide values for Table 6-2, the following assumptions and calculations were used.

1) The total produced water managed volume is assumed to equal the total produced water generated (the BSEE estimate of 575,926,287 bbl). The EPA discharge estimate may have included discharges of other wastewater streams like stormwater runoff, deck drainage, or others.
2) Injection, evaporation, offsite commercial disposal, and reuse are assumed to be zero.

Table 6-2 — 2017 Produced Water Management Practices for Offshore Areas in the Outer Continental Shelf

Management Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	0	0
Injection for disposal	0	0
Surface discharge	575,926,287	100%
Evaporation	0	0
Offsite commercial disposal (pay another company to manage your produced water)	0	0
Reuse within the oil and gas industry	0	0
Reuse in ways other than in the oil and gas industry	0	0
Total	575,926,287	100%

Chapter 7 — Findings and Conclusions

7.1 Findings

7.1.1 Produced Water Volume

This report provides an estimate of the volume of produced water generated from oil and gas production in the United States during the 2017 calendar year. The volume estimate represents a compilation of data obtained from numerous state oil and gas agencies and several federal agencies. The total volume of produced water estimated for 2017 was about 24.4 billion bbl or just over 1 trillion gallons. This equals an average of 69 million bbl/day or 2.8 billion gallons/day. Produced water was generated from most of the nearly 1 million actively producing oil and gas wells in the United States.

Several states dominated the 2017 total produced water volume estimates. Texas, with nearly 10 billion bbl, represented 41% of the national total. Other states with produced water volumes exceeding 1 billion bbl included California (13%), Oklahoma (12%), Wyoming (7%), and Kansas (5%).

Texas produced the highest volumes of water, oil, and gas. But the other top water-producing states were not necessarily in the highest rankings for oil and gas production.

During the past ten years, the volume of oil, gas, and water produced in the United States has increased. For the interval of 2012 to 2017, U.S. oil production increased by 50.4%, and U.S. gas production increased by 17.7% during those years. U.S. water production increased by 15.2% between 2012 and 2017.

Looking at the entire ten-year period from 2007 to 2017, the numbers are even more extreme. U.S. oil production increased by 94.6%, and U.S. gas production increased by 43.6% during those years. U.S. water production increased by 16.2% between 2012 and 2017.

The important take-away message is that water production increased at a slower rate than oil and gas production.

7.1.2 Produced Water Management Practices

This report describes the practices used by oil and gas producers to manage produced water during 2017. As in 2007 and 2012, more than 90% of U.S. produced water was injected. In 2017, 91.5% of the produced water was injected. Of that amount, 43.6% was injected for enhanced recovery and 38.0% was injected at disposal wells operated by the oil and gas companies. An additional 9.9% was injected at offsite commercial disposal facilities.

5.5% of produced water was discharged to surface water. 0.4% was evaporated, primarily in several arid western states, from onsite ponds and pits and at several commercial disposal facilities.

1.4% was reused within the oil and gas industry other than injection for enhanced recovery (which is a legitimate way to reuse produced water for a beneficial value). The actual percentage was probably higher than this, but it was not quantified for most states during 2017. Much of the reuse was done by recycling produced water to make drilling fluids and frac fluids for new wells in the same fields. 1.3% was reused in applications outside of the oil and gas industry. Examples include irrigation (when the water has low salinity) and for dust and ice control on roads.

7.1.3 Data Availability and Quality

A few states had readily available precise produced water volume figures. In some states, the agencies had very complete data records easily obtainable from online sources. Other states had summary-level volume data without much detail or had data available only in in-house data repositories.

Where data were not available through the state agencies, additional efforts were made to estimate water volumes and management practices. The assumptions, data sets, and analyses used to develop the estimates are described separately for each state in Chapter 5.

Nearly all the water volume data received from the states gave volumes to the individual bbl. Since this level of data accuracy could not be validated, separate rows in the summary tables in Chapter 4 show rounded total volumes – these are the national totals that should be cited. There are institutional factors leading to imprecision and inaccuracy of the raw data (see discussion in Chapter 4).

7.2 Conclusions

This report provides the most detailed and current information on the volume of produced water generated in the United States and its management. It followed a similar procedure used in previous reports that looked at the 2007 and 2012 calendar years. Some procedures and estimation methods were revised and improved for the 2017 report.

The total volume of produced water generated in 2017 was 15.2% higher than the volume generated in 2012. This increase should be viewed in tandem with the even greater increases in oil (50.4%) and gas (17.7%) volumes from 2012 to 2017.

Why do the data show that oil and gas volumes have increased at a faster rate than water volumes? One explanation involves the types of wells and formations that are used to produce hydrocarbon. In 2007, much of the U.S. production came from wells in conventional formations. Wells in conventional formations tend to generate a small initial volume of water that gradually increases over time. The total lifetime water production from each well can be high.

Between 2007 and 2012, the United States experienced a large increase in the numbers of wells drilled in unconventional formations, like shales and coal seams. These wells generate a relatively large amount of produced water initially (the flowback period) but the volume drops off, leading to a low lifetime water production from each well. As many new unconventional wells were placed into service, many older conventional wells (with high water cuts) were taken out of service. The new wells generated more hydrocarbon for each unit of water than the older wells they replaced. The same trend of replacing conventional wells with unconventional wells continued through 2017.

Information on management practices has not changed significantly from the 2012 data. The large majority of onshore produced water was managed through injection, and most offshore produced water was treated and discharged to the ocean. The percentages of the management practices shifted slightly since 2012, but the major trends remain the same.

A final important conclusion of this study (this was also highlighted in the previous two studies) is that there is no easy way to obtain national estimates of produced water generation and management. The estimates presented in this report took months of investigation, numerous contacts with oil and gas agency staff members, and extensive follow-up. Some states had produced water information either published in reports or readily available through state databases. However, other states had only minimal information about produced water volumes or how the produced water was managed. No federal data collection effort (e.g., EIA forms) exists for tracking produced water volume. Consequently, when regulatory and data management resources are limited, some states do not maintain produced water information.

Acknowledgments

Preparation of this report involved extensive data collection from many states and several federal agencies. A comprehensive national data compilation such as this would not be possible without the support and efforts of state agency management and staff, and support from federal agencies too. The author greatly appreciates their efforts.

The author thanks the Ground Water Protection Council (GWPC) and its research arm, the Ground Water Research and Education Foundation (GWREF) for providing the opportunity and financial support for this project (funding for the project came from the GWREF). Without their interest and support, this effort probably would never have been undertaken, and the produced water community would not have the benefit of this information.

Special thanks are in order to Thom Kerr of Thom Kerr, LLC. Mr. Kerr formerly served as a manager in the Colorado Oil and Gas Conservation Commission before retiring. He was able to query the COGCC's data system to provide concise data sets for Colorado. Without his assistance, the Colorado state summary would not have been complete.

References

Benko, K., and J. Drewes, 2008, "Produced Water in the Western United States: Geographical Distribution, Occurrence, and Composition," *Environmental Engineering Science* 25(2):239–246. Available at https://www.researchgate.net/publication/245336675_Produced_Water_in_the_Western_United_States_Geographical_Distribution_Occurrence_and_Composition.

CDOC, 2018, "2017 Preliminary Report of California Oil and Gas Production Statistics," Publication No. PR03, prepared by California Department of Conservation, DOGGR, Available at ftp://ftp.consrv.ca.gov/pub/oil/annual_reports/2017/2017_Preliminary_Annual_Report.pdf.

Clark, C.E., and J.A. Veil, 2009, Produced Water Volumes and Management Practices in the United States, ANL/EVS/R-09/1, prepared for the U.S. Department of Energy, National Energy Technology Laboratory, September, 64 pp. Available at http://www.veilenvironmental.com/publications/pw/ANL_EVS__R09_produced_water_volume_report_2437.pdf.

EPA, 2019, "Study of Oil and Gas Extraction Wastewater Management Under the Clean Water Act," EPA- 821-R19-001, draft May. Available at https://www.epa.gov/sites/production/files/2019-05/documents/oil-and-gas-study_draft_05-2019.pdf.

EPA, 2016, "Hydraulic Fracturing for Oil and Gas: Impacts from the Hydraulic Fracturing Water Cycle on Drinking Water Resources in the United States," Office of Research and Development, Washington DC. EPA/600/R-16/236Fa. Available at https://cfpub.epa.gov/ncea/hfstudy/recordisplay.cfm?deid=332990.

GWPC (2019), "Produced Water Report – Regulations, Current Practices, and Research Needs," prepared by the Ground Water Protection Council, June, 311 pp. Available at http://www.gwpc.org/producedwater.

Harto, C.B., and J.A. Veil, 2011, "Management of Water Extracted from Carbon Sequestration Projects," ANL/EVS/R-11/1, prepared for the U.S. Department of Energy, National Energy Technology Laboratory, January, 50 pp. Available at http://www.osti.gov/scitech/biblio/1009368.

Veil, J., 2015, "U.S. Produced Water Volumes and Management Practices in 2012," prepared for the Ground Water Protection Council, April, 119 pp. Available at http://www.veilenvironmental.com/publications/pw/final_report_CO_note.pdf.

Veil, J.A., T.A. Kimmell, and A.C. Rechner, 2005, “Characteristics of Produced Water Discharged to the Gulf of Mexico Hypoxic Zone,” prepared for U.S. Department of Energy, National Energy Technology Laboratory, August, 74 pp. Available at http://www.veilenvironmental.com/publications/pw/ANL-hypoxia-report.pdf.

Veil, J., 2002, “Regulatory Issues Affecting Management of Produced Water from Coal Bed Methane Wells,” prepared for U.S. Department of Energy, Office of Fossil Energy. Available at http://www.veilenvironmental.com/publications/pw/cbm-prod-water-rev902.pdf.