U.S. Produced Water Volumes and Management Practices in 2012

Prepared for the Ground Water Protection Council

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Table of Contents

List of Tables

List of Figures

Executive Summary

Background

Produced water is water found in the same formations as oil and gas. When the 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 in the well (a frac job), some of the injected water returns to the surface and is known as flowback water. After a few weeks, the volume of water returning from a fractured well is greatly reduced. At this point, any remaining water coming to the surface from the well is called produced water. This study does not distinguish between volumes of flowback water and produced water generated from unconventional wells – all water returning to the surface from oil and gas wells is counted as produced water for the sake of volume estimates.

Produced Water Volume

A 2009 report[1] made a national produced water volume estimate for the 2007 calendar year of 21 billion barrels (bbl; 1 bbl = 42 U.S. gallons) per year for the entire United States. This is equivalent to a volume of 2.4 billion gallons per day. This new report updates and expands the 2009 report to provide a current estimate for the volume of produced water generated from all onshore and offshore oil and gas production in the United States during the 2012 calendar year. The volume estimate represents a compilation of data obtained from state oil and gas and environmental agencies as well as from several federal agencies. The total volume of produced water estimated for 2012 is about 21.2 billion bbl.

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[1] 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.

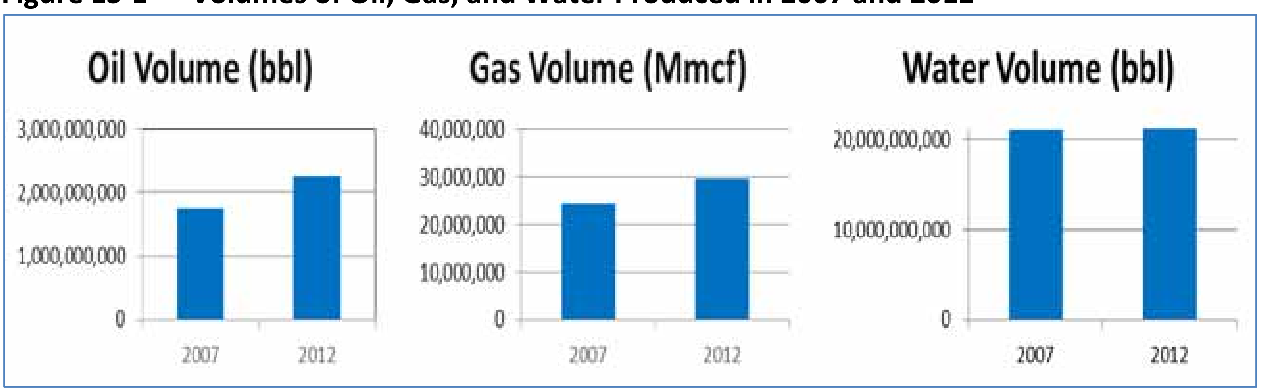
The data were collected by contacting state oil and gas agencies in the 31 states with active oil and gas production and several federal agencies that have jurisdiction over federal onshore and offshore lands and tribal lands to obtain detailed information on produced water volumes and management. A questionnaire was sent to each state agency. 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.

In 2012, onshore wells in the 31 states and on federal lands and tribal lands generated 20,555,884,000 bbl of produced water. Offshore wells contributed another 624,762,000 bbl for **a *total U.S. volume of 21,180,646,000 bbl of produced water in 2012***.

Several states dominated the total produced water volume estimates. Texas, with more than 7.4 billion bbl, represented 35% of the national total. Other states with produced water volumes exceeding 1 billion bbl included California (15%), Oklahoma (11%), Wyoming (11%), 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.

Many organizations with an interest in water have assumed that with the large increase in unconventional oil and gas production between 2007 and 2012, the total volume of produced water generated would climb significantly. However, the data from this report do not bear out that assumption. ***U.S. oil production increased by 29% between 2007 and 2012, and U.S. gas production increased by 22% during those years. However, during the same period, U.S. water production increased by less than 1%.*** Figure ES-1 shows the volumes of oil, gas, and water in both 2007 and 2012.

Figure ES-1 — Volumes of Oil, Gas, and Water Produced in 2007 and 2012



It was not possible using these data to make a clear national distinction between water produced from conventional wells vs. unconventional wells. Some evidence was available from states like Arkansas, North Dakota, and Pennsylvania, each of which had tremendous growth in unconventional oil and gas production between 2007 and 2012. In each state, the increase in either oil (North Dakota) or gas (Arkansas and Pennsylvania) was far greater than the increase in water. ***This suggests that, at least in those three states, unconventional wells may generate less produced water per unit of hydrocarbon output than conventional wells.***

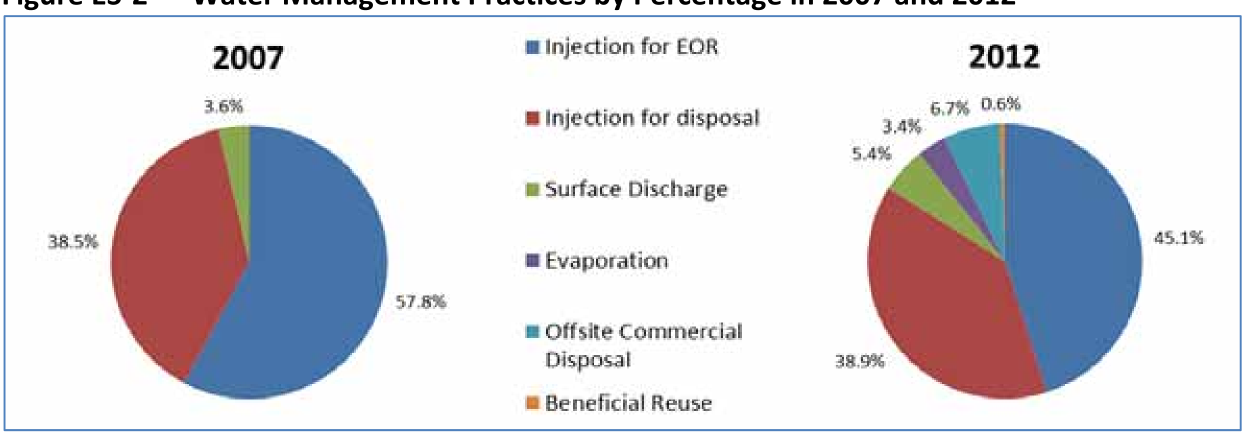
Some of the states provided separate water volume data for their oil wells and their gas wells. This allowed calculation of the amount of water generated for each unit of oil (bbl) or gas (Mmcf – million cubic feet). ***The national weighted average water-to-oil ratio (WOR) was 9.2 bbl of water/bbl of oil, and the national weighted average water-to-gas ratio (WGR) was 97 bbl of water/Mmcf of gas. Because several states with large numbers of older oil wells that produce high proportions of water (e.g., Texas and Oklahoma) were unable to provide data that allowed calculation of WORs, the true value for the national weighted average WOR is likely to be at least 10 bbl of water/bbl of oil, and probably somewhat higher. The range of state values for the WGRs was so large that a weighted average WGR is probably not a meaningful number.***

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 by-product or waste stream 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.

Figure ES-2 shows how produced water was managed by percentage in both 2007 and 2012. Note that the 2007 report did not include any data on evaporation, offsite commercial disposal, or beneficial reuse. Those water management practices were used in 2007, but data were not collected for them. The percentages of the produced water management practices shifted slightly since 2007, but the major trends remain the same.

Figure ES-2 — Water Management Practices by Percentage in 2007 and 2012



During 2012, most U.S. produced water was injected. About 93% of produced water from onshore wells and about 91% of the produced water from all wells was injected underground (this included water injected for enhanced recovery, water injected for disposal, and water sent to offsite commercial disposal). Slightly more than half of that was injected into producing formations for enhanced recovery. Slightly less than half of the injected produced water was injected to non-commercial and commercial disposal wells.

About 80% of the produced water from offshore wells was treated on the platform and discharged to the ocean. Only about 3% of onshore produced water was discharged. ***The percentage discharged from all wells (onshore and offshore combined) was about 5.6%.***

The 2012 data described in this report show that nearly ***7% of produced water was managed by sending it to an offsite commercial facility, where the water was treated and disposed***. 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. Most of these facilities managed water by injection into disposal wells.

About 3.6% of all produced water in 2012 was evaporated. In some arid western states, produced water was managed through evaporation from onsite ponds and pits. Several commercial facilities managed water by evaporation from large ponds.

At least 0.6% of the produced water and flowback water in 2012 was put to a beneficial reuse – it is likely that a higher percentage was reused, but data were not available to quantify the amount. Much of the reuse was done by recycling flowback water and produced water to make drilling fluids and frac fluids for new wells in the same fields. Other portions of produced water may have been used for irrigation (when the water has low salinity) or for dust and ice control on roads.

Data Availability and Quality

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. We are 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 2012 or any other recent year.

It is apparent that there is no easy way to obtain national estimates of produced water volumes. No federal regulatory program or data collection effort requires agencies to track produced water volume, and many states have not required submittal of produced water information by oil and gas companies. Consequently, when regulatory and data management resources are limited, some states do not collect or maintain produced water information.

Chapter 1 — Introduction

Produced water is water from underground formations that is brought to the surface during oil or 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 reservoir, 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 volume also vary throughout the lifetime of a reservoir.

1.1 Produced Water Volume

The volume of produced water generated from oil and gas wells is very large. Previous national produced water volume estimates are in the range of 15 to 21 billion barrels[2] (= 630 to 882 billion gallons) per year in the United States (API 1988, 2000; Veil et al. 2004; Clark and Veil 2009). The first three of those reports did not collect data separately from all states and used extensive extrapolation. However Clark and Veil (2009) collected data in a much more intensive manner and were able to make a more detailed and reliable estimate (~21 billion bbl in the year 2007 or about 2.4 billion gallons per day during that year). To put this volume in perspective, the U.S. Geological Survey's most recent compilation of water usage in the United States estimated that water use of all types in the United States in 2010 was estimated to be about 355 billion gallons per day (Maupin et al. 2014). Water use for mining purposes, which includes oil and gas production, was about 5.3 billion gallons per day.

The volume of produced water 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.

This report estimates the volumes of produced water generated in each state as well as on federal lands, including offshore wells in federal waters. The methods used to collect the information, any assumptions and analyses used to fill in gaps where necessary, and the persons who helped by supplying data are identified in the following pages.

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[2] 1 barrel (bbl) = 42 U.S. gallons. In this report, oil and water volumes are expressed in bbl. Gas volumes are expressed in million cubic feet (Mmcf).

1.2 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 the following ways:

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

Some states track produce water management closely (e.g., Pennsylvania), but most states do not have much information other than injection volumes.

1.3 Purpose of Report

The last comprehensive study of U.S. produced water volumes and management practices was published in 2009. It reflected conditions during the 2007 calendar year. The current report revisits the same subjects but for the 2012 calendar year. The results and findings from this report represent the newest national level information on produced water available.

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 found in the same formations as oil and gas. When the oil and gas are produced to the surface, the produced water is brought to the surface, too. It can also be referred to as “brine” or “saltwater”. 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.

Unconventional oil and gas development (particularly those wells drilled in shale formations) generates a similar type of water stream referred to as “flowback water”. During a hydraulic fracturing operation (often called a frac job), a large volume of water, often several million gallons, is injected into the well at very high pressures to create a network of cracks in the source rock. These cracks allow the oil and gas to move from the formation into a well where they can be produced. After the cracks 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, and the water that flows initially following a frac job is often called flowback water. Flowback water comes to the surface from a well in the first few days to weeks following hydraulic fracturing in the well (a frac job). Nearly all of the water classified as flowback water is water that was injected during the frac job.

After a few weeks, the volume of water returning to the surface from an unconventional well diminishes and levels off at a considerably lower daily flow rate. However, this lower-flow volume of water can continue for many months. This type of water from unconventional wells is also known as “produced water.” It may contain some of the original water from the frac fluids and may also contain some formation water.[3]

Within this study when calculating volume estimates, no distinction was made between volumes of flowback water and produced water generated from unconventional wells – all water returning to the surface from oil and gas wells was counted as produced water. One

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[3] Some industry groups prefer to call all water returning to the surface from unconventional oil and gas wells “produced water”. They believe that “flowback” refers to a process (flowing water back to the surface) and not to the water itself. However, most authors use the two different terms – flowback water and produced water.

exception to this policy of describing flowback water as produced water is found in Section 5.24. The Pennsylvania oil and gas agency posts separate data about both flowback water and produced water management on its website, thereby allowing more detailed analysis of the volumes and management practices in that section.

2.2 Water Plays a Role in Oil and Gas Production

Water plays an important role in oil and gas production both as a necessary element to support drilling and fracturing and to promote additional production in many formations. Produced water is generated from all types of oil and gas wells, although the volume, characteristics, and flow rate profile varies quite a bit depending on how the oil and gas are produced. Table 2-1 shows examples of water needs and produced water generation for each major type of oil and gas production.

Table 2-1 — Comparison of Water Needs and Produced Water Generation

Type of Oil and Gas Production	Water Needs for Production	Produced Water Generated
Conventional Oil and Gas	- Modest needs for drilling, and additional need for some wells that use hydraulic fracturing - Typically much water is needed for enhanced recovery as a field matures	- Low volume initially - Increased volume over time - High lifetime produced water production
Coalbed Methane	- Modest needs for hydraulic fracturing	- High produced water volume initially - Decreases over time
Shale Oil and Gas	- Large needs for hydraulic fracturing	- Initial flowback rate is high, but quickly drops to very low - Low lifetime flowback and produced water production
Heavy Crude	- Steam flood to help move heavy oil to production wells - Steam production requires very clean water for boiler feed	- Much of the wastewater results from the injected steam used in steam flooding
Oil Sands	- Steam (or water) injection used in large volumes	- For in-situ production methods, some water is formation water, but much is from the injected steam - Oil sand mining production methods and subsequent processing steps also generate wastewater

2.3 Previous Produced Water Volume Estimates

While one of the purposes of this report is to present a current estimate of produced water volumes, it is useful to know previous estimates and the assumptions used in arriving at those estimates. Few worldwide estimates have been published. Khatib and Verbeek (2003) estimated a global average of 210 million bbl of water produced each day, which resulted in an annual estimate for 1999 of 77 billion bbl of produced water. It is not clear how those authors derived their estimate.

Several other reports (typically market analysis reports prepared by consulting firms) include estimates of global produced water volumes that are considerably higher than those suggested by Khatib and Verbeek, but they do not include any information explaining how they derived their estimates.

Collecting and compiling accurate produced water data within a single country is a challenging task, and most nations do not track and compile produced water volumes. Water volumes must be estimated through various extrapolations and assumptions. Consequently, international estimates must be taken as rough approximations.

U.S. onshore produced water volumes from oil and gas activities were estimated at 21 billion bbl in 1985 and 18 billion bbl in 1995 by the American Petroleum Institute (API 1988, 2000) and 14 billion bbl in 2002 by Veil et al. (2004). Significant additional volumes of produced water are generated at U.S. offshore wells. Although those estimates span a wide range, it is likely that the different values reflect the methodologies used to create the estimates rather than dramatic shifts in actual water volumes. And as is discussed in Chapter 4, the raw data on produced water volumes is not precise, nor are the estimation and extrapolation procedures used to generate total volumes.

The most recent previous U.S. estimate (Clark and Veil 2009) used a more detailed and methodical approach to collecting produced water data. Those authors[4] contacted each state oil and gas agency (about 30 states have oil and gas production) and representatives of federal land management agencies to get the best volume estimate possible. The agency responses ranged from precise water volumes to partial information that required some extrapolation to no data at all. In the latter cases, volumes were estimated using different approaches based on hydrocarbon production. The final tally for the 2007 calendar year was nearly 21 billion bbl for all U.S. oil and gas production.

Several companies or organizations specializing in market analysis for water and wastewater have made future projections of produced water volumes associated with the oil and gas industry. The estimates, while differing from one group to another, all predict a steadily increasing volume of produced water through 2020. The absolute values of the projected volumes are less important than the tendency of the volume to increase over time.

[4] The author of the current report was a co-author of the 2009 report.

2.3.1 Industry Changes Since 2007 That May Influence Produced Water Volume

Clark and Veil (2009) used 2007 as the baseline year for their produced water volume estimate. During 2007, shale oil and gas development was in the early years of growth as the unconventional oil and gas sector expanded from the Barnett Shale in Texas to other active plays around the country. Unconventional growth grew dramatically between 2007 and 2012 (the baseline year for the current study). Tens of thousands of new wells were drilled and fractured resulting in substantial volumes of flowback water and ongoing produced water. Oil and gas opponents and the media called attention to these water volumes and often made questionable claims of their magnitude without having specific valid data to support their claims.

Without doubt, the rapid increase in unconventional oil and gas development has contributed considerable water to the national produced water total. What has not been well documented in the literature is how much produced water each unconventional well contributes compared to each conventional well, and whether new unconventional wells have supplanted older conventional wells.

2.4 Characteristics of Produced Water

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. The major constituents of concern are:

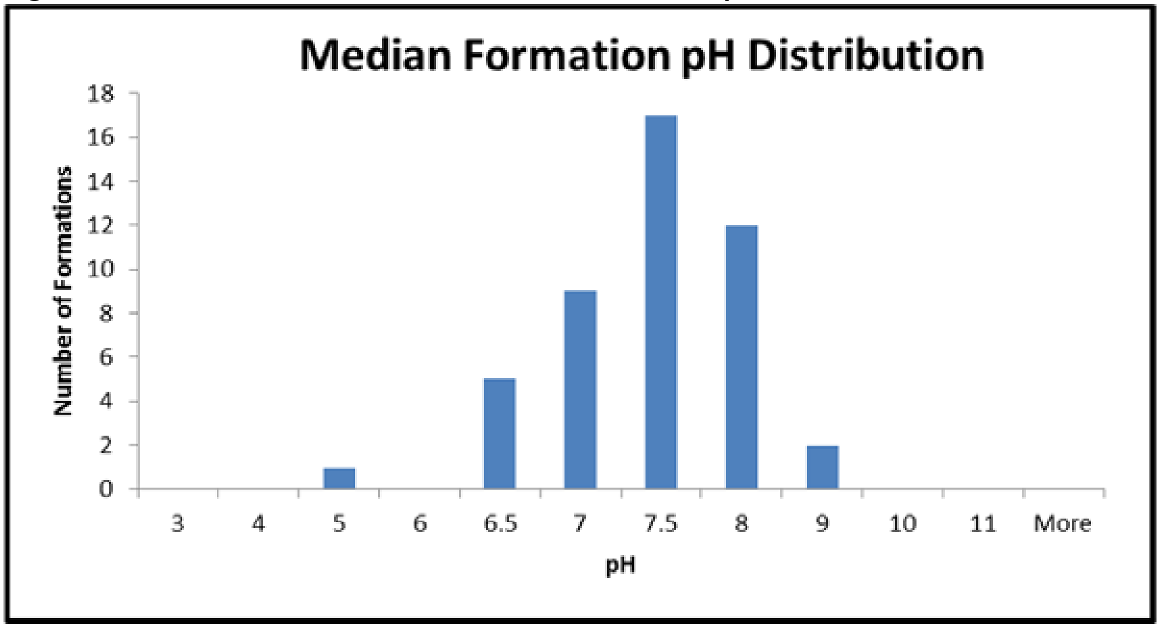
- *salt content* (often expressed as salinity, conductivity, or total dissolved solids [TDS]),
- *oil and grease* (not a single chemical; the analytical method measures various organic compounds associated with hydrocarbons in the formation),
- inorganic and organic *toxic compounds* introduced as chemical 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.

A study of produced water in the western United States found the oil and grease content to range from 40 mg/L to 2,000 mg/L (Benko and Drewes 2008). 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.

Another source of information on produced water characteristics is a USGS produced water database (http://energy.cr.usgs.gov/prov/prodwat/data2.htm). A version of that 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, 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

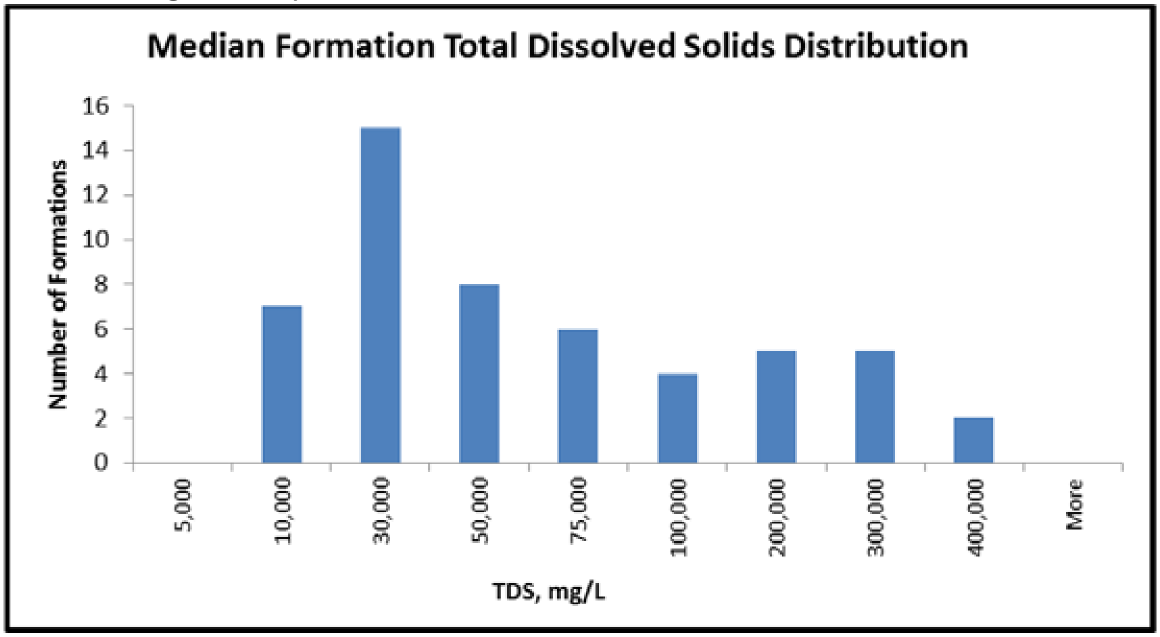


Source: Harto and Veil (2011)

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

Produced water from oil production activities often contains constituents in addition to those that are naturally found within the formation. Additional water is often needed to maintain sufficient pressure in a reservoir for oil production. Produced water may be reused for this purpose, but the water may also be supplied from additional sources including groundwater and seawater. These additional water sources may contain solids, microorganisms, and other constituents that could lead to formation plugging or other damage.

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



Source: Harto and Veil (2011)

To combat scaling and maintain production efficiency, chemical additives such as corrosion and scale inhibitors, emulsion breakers, coagulants, and solvents may be used in drilling operations, production operations, and separations processing. These additives can become part of the produced water and can affect its overall toxicity.

2.4.1 Produced Water Characteristics from Unconventional Wells

The Department of Energy's Energy Information Administration (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."* EIA 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."* Unconventional production or well types are often described in somewhat vague terms like those. Functionally, unconventional production includes tight oil, tight gas sands, coal bed methane (CBM), and shale gas, among others. For the purposes of this report, each state was given the freedom to determine which of its wells produced in a conventional or unconventional manner.

Produced water from CBM production differs from produced water from conventional wells. Oil and grease are less of a concern from CBM water than other produced waters. To recover the methane in CBM reservoirs, a well is drilled into a coal seam. Water is pumped out rapidly to dewater the coal seam and change the hydrostatic pressure. Initially produced water comes to the surface at a high rate, but later the flow rate decreases. When the hydrostatic pressure becomes sufficiently low, methane releases from the coal cleats and is produced to the surface through the well.

Characteristics of CBM water that may affect reuse are salinity, sodicity, and to a lesser extent iron, manganese, and boron (ALL 2003). Some coal formations from which CBM is produced contain water with very low TDS (e.g., Powder River Basin). Some of the Powder River Basin water is used for crop irrigation or is discharged to local rivers. Other CBM formations contain water with higher TDS (e.g., San Juan Basin) – this water is usually injected to disposal wells.

Shale gas water (including both flowback and produced water) starts out with moderate to high TDS, and the TDS increases as time goes along. Each major shale formation has its own range of TDS values. Few data have been published on the chemical characteristics of flowback and produced water from shale gas wells, especially data that show trends in concentrations over time. One interesting reference that shows such data is Hayes (2009). Table 2-2 shows data from five Marcellus Shale wells (excerpted from Hayes 2009). It shows the increase in TDS at 1, 5, 14, and 90 days after each of five wells has been fractured. The column labeled Day 0 represents the fluid concentration before it is injected into the well.

Table 2-2 — Total Dissolved Solids Data (mg/L) over Time for Flowback Water from Selected Marcellus Shale Wells

Day 0	Day 1	Day 5	Day 14	Day 90
990	15,400	54,800	105,000	216,000
27,800	22,400	87,800	112,000	194,000
719	24,700	61,900	110,000	267,000
1,410	9,020	40,700	no data	155,000
7,080	19,200	150,000	206,000	345,000

Source of data: Hayes (2009)

This suggests that the frac fluid water that does not initially return to the surface remains in contact with new rock surfaces created through the fracturing process and is able to dissolve certain constituents from the interstitial pores containing highly saline brine (Balashov et al. 2015). The longer the water remains in contact with the pore spaces, the higher the dissolved constituents are likely to be up to some saturation or equilibrium point. For the most extreme example from this dataset, look at the 90-day value for the last of the wells. At 345,000 mg/L (essentially 345,000 parts per million), more than one-third of that water sample was made up of TDS. This approaches the limits of solubility. Other constituents of flowback and produced water also show a trend of increasing concentration over time. This makes treatment of the later wastewater (produced water) more challenging than treatment of the early flowback water.

Acharya et al. (2011) provide flowback characteristic data over time from wells in the Woodford Shale. The authors sampled for TDS, total suspended solids, total organic carbon, hardness, alkalinity, barium, strontium, sulfate, iron, manganese, boron, and silica. Samples were taken frequently during the first two weeks of flowback and again a few weeks later. Some constituents increased over time, while others decreased over time – the concentrations are plotted on charts in Acharya et al. (2011).

2.5 Produced Water Management

The characteristics of produced water vary from location to location and 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.

2.5.1 Overview of Produced Water Technologies and Management Practices

Water management technologies and strategies can be organized into a three-tiered water management or pollution prevention hierarchy (i.e., minimization, recycle/reuse, and disposal). Examples of technologies and practices for each group are shown in the tables in the following sections with comments on the pros and cons of each.

Much of the information in this section was initially compiled as part of a detailed white paper on produced water (Veil et al. 2004). A few years later the information was converted into the Produced Water Management Information System (PWMIS) website, developed by Argonne National Laboratory[5] for the U.S. Department of Energy (DOE) in 2007. PWMIS currently is housed as part of the website for DOE's National Energy Technology Laboratory (NETL). It was moved several times from its initial web location. As of November 2014, fact sheets on many produced water management technologies can be found at http://www.netl.doe.gov/research/coal/crosscutting/pwmis/tech-desc.

A more recent written version of produced water technologies can be found in Veil (2011).

2.5.1.1 Tier 1 – Minimization

While not directly a produced water management approach, minimizing the volume of produced water that is generated to the surface is a way to simplify water management operations and costs. In the water minimization tier, processes are modified, technologies are adapted, or products are substituted so that less water is generated. When feasible, water minimization can often save money for operators and may result in greater protection of the environment. Examples of water minimization approaches and technologies are shown in Table 2-3.

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[5] The author of this report was the project manager and lead technology content developer for the PWMIS website while he was employed at Argonne National Laboratory.

Table 2-3 — Produced Water Minimization Technologies

Approach	Technology	Pros	Cons
Reduce the volume of water entering the wells	Mechanical blocking devices (e.g., packers, plugs, good cement jobs)	These should be used in new construction. They can be added later on to fix some problems.	May not be easy to fix pre-existing problems.
	Water shut-off chemicals (e.g., polymer gels)	Can be very effective in selected instances, primarily in sandstone and limestone formations.	Need the right type of formation in order to achieve cost-effective results.
Reduce the volume of water managed at the surface by remote separation	Dual completion wells (downhole water sink)	Can be very effective in selected instances.	Limited prior use. Makes wells more complex.
	Downhole oil/water separation	May be a good future technology.	Earlier trials were inconsistent and the technology went out of favor. New designs and good candidate wells are needed to bring back this technology.
	Sea floor separation modules	May be a good future technology.	Cost is very high. Only a few of these have ever been installed.

2.5.1.2 Tier 2 – Recycle/Reuse: For water that cannot be managed through water minimization approaches, companies can move next to the second tier, in which produced water is reused or recycled. The most common way to reuse produced water is to reinject it into a producing formation to enhance production. Reinjection for enhanced recovery occurs in tens of thousands of injection wells throughout the United States and elsewhere. Examples of water reuse and recycle management options and some of the specific uses are shown in Table 2-4.

Table 2-4 — Produced Water Reuse and Recycle Management Option

Management Option	Specific Use	Pros	Cons
Reinjection for enhanced recovery	Water flood; steam flood	Common use of produced water for onshore conventional formations. Usually has low cost.	Need to ensure chemical compatibility with receiving formation.

Management Option	**Specific Use**	**Pros**	**Cons**
Injection for future water use	Aquifer storage and recovery	Can augment public water supplies.	Need to ensure that water meets drinking water standards before injecting it into a shallow aquifer. May encounter public opposition. Oil and gas companies may not choose this option due to fear of future liability.
Injection for hydrological purposes	Subsidence control	Can help solve a local problem (e.g., Wilmington Oil Field, Long Beach, CA).	Need to ensure chemical compatibility with receiving formation.
Agricultural use	Irrigation; subsurface drip irrigation	Can be a great benefit to arid areas.	May need to treat the water before applying it to the soil or add soil supplements. May need to choose salt-tolerant plant species.
	Livestock and wildlife watering	Can provide a source of water for animals.	Need to ensure that water is clean enough to avoid illness or other impacts to animals.
	Managed/con-structed wetlands	Provides a "natural" form of treatment. Creates a good habitat for wildlife.	Large space requirements. Needs extensive oversight and management. Typically limited to water with low to moderate salinity.
Industrial use	Oil and gas industry applications (e.g., drilling fluids, frac fluids)	Can substitute for fresh water supplies in making new drilling or stimulation fluids.	May need treatment in order to meet operational specifications.
	Power plants	May be able to supplement cooling water sources	Will require treatment. The large volumes needed result in collection and transportation costs.
	Other (e.g., vehicle wash, fire-fighting, dust control on gravel roads; road deicing)	Can be a good supplemental water supply in arid areas.	Will need storage facilities and possibly treatment. Concerns about water quality impacts from runoff after application or inappropriate application.

Management Option	Specific Use	Pros	Cons
Treat to drinking water quality	Use for drinking water and other domestic uses	Can help supply water to communities in arid areas.	Cost to treat may be high. Need good quality control. May encounter public opposition and face concern over liability. It may be more cost-effective and energy-conserving to treat other water sources like saline groundwater rather than treating produced water.

2.5.1.3 Tier 3 - Disposal

When water cannot be managed through minimization, reuse, or recycle, operators must dispose of it. Table 2-5 lists water disposal methods.

Table 2-5 — Produced Water Disposal Methods

Technology	Pros	Cons
Discharge	Very common for offshore facilities. Offers moderate cost and acceptable environmental impact, where permitted.	Not approved for most onshore wells. Where allowed, requires treatment unless the water is high quality, such as some CBM effluent. Different treatment requirements for discharges into different types of water bodies.
Underground injection (other than for enhanced recovery)	Very common onshore practice. Tends to have low cost. EPA and state agencies recognize this as a safe, widely used, proven, and effective method for disposing of produced water.	Requires presence of an underground formation with suitable porosity, permeability, and storage capacity. May require treatment to ensure that injectate does not plug formation. A small subset of disposal wells has been linked to felt earthquake activity – this is an active area of research. Transportation costs can be significant.
Evaporation	In arid climates, takes advantage of natural conditions of humidity, sun, and wind.	Not practicable in humid climates. May create air quality and salt deposition problems.
Offsite Commercial disposal	Companies providing services to oil and gas community by accepting and disposing water for a fee. Removes water treatment burden from the operator.	Requires infrastructure (disposal facilities and transportation network to move water to disposal site). Can be costly. Potential for Superfund liability.

2.5.1.4 Produced Water Treatment Technologies

Prior to disposing of or reusing water, companies may need to employ different treatment processes and technologies. The final disposition of the water determines the type and extent of treatment. For example, if water is discharged, the parameter of greatest concern can be related to either the organic content or the salt content. Onshore discharges must remove salinity in addition to oil and grease and other parameters limited by permitting agencies.

Treatment technologies can be divided into two general categories, depending on which types of pollutants are removed. Table 2-6 lists treatment technologies designed to remove salt and other inorganics from produced water.

Table 2-6 — Produced Water Technologies for Removing Inorganic Chemicals and Salt Content

Technology	Subcategory	Pros	Cons
pH adjustment, flocculation, and clarification	N/A	This is a common pretreatment step to remove metals. The cost is modest.	This process removes metals but does not treat chlorides or TDS. The process generates sludge that requires disposal.
Membrane processes	Microfiltration, ultrafiltration, and nanofiltration	They are good pretreatment steps for more advanced processes like RO. They operate at lower pressure and lower cost than RO.	These levels of filtration cannot remove most salinity. Potential for membrane fouling. Sensitivity to fluctuating water quality.
	Reverse osmosis (RO)	RO can remove salinity (up to about 40,000 mg/L TDS.	Requires pretreatment and regular membrane cleaning. Not suitable for high-salinity water. Potential for membrane fouling. Sensitivity to fluctuating water quality. Moderate to high energy usage and cost.
	Other (e.g., electrodialysis, forward osmosis)	May offer future treatment opportunities.	Have not been used extensively in full-scale oil field treatment systems yet. Potential for membrane fouling. Sensitivity to fluctuating water quality.
Thermal Treatment	Distillation	Can process high-salinity waters like flowback. Generate very clean water (can be reused).	High energy usage and cost. Generates concentrated brine stream that requires separate disposal. Potential for scaling. May require remineralization before release or beneficial reuse.

Technology	Subcategory	Pros	Cons
	Evaporation/ Crystallization	Can treat to a zero liquid discharge standard.	High energy usage and cost. Limited usage in oil field applications. Potential for scaling. Challenges in disposing of salt residue.
Ion exchange	N/A	Successfully treats low to medium salinity water (e.g., Powder River Basin).	Large acid usage. Resins can foul. Challenges in disposing of rinse water and spent media (resin). Also ineffective on high salinity produced waters.
Capacitive deionization	N/A	Low energy cost.	Limited to treating low salinity waters. Limited usage in oil field applications.

Table 2-7 lists treatment technologies designed to remove oil and grease and other organics from produced water.

Table 2-7 — Produced Water Technologies for Removing Oil and Grease Content

Technology	Subcategory	Pros	Cons
Physical separation	Advanced separators (e.g., inclined plate, corrugated plate)	Provide enhanced oil capture compared to basic oil/water separators	Work well for free oil, but not as effective on dispersed and soluble oil. Performance can be improved by adding flocculants.
	Hydrocyclone	No moving parts results in good reliability. Separates free oil very well.	Does not work well on dispersed and soluble oil.
	Filtration	Different types of filter media and filter operations provide a good range of oil and grease removal.	Requires regular back-flushing. Does not treat most soluble oil.
	Centrifuge	Provides good separation of free and dispersed oil.	More expensive than other technologies in this group.
Coalescence	N/A	Collects small oil droplets and forms larger droplets that can be more easily removed by the other technologies.	Limited value for dispersed or soluble oil.
Flotation	Dissolved air flotation, induced gas flotation	Removes free and dispersed oil.	Does not remove soluble oil.
Combined physical and extraction processes	Compact separators and other units.	Can treat to very low oil and grease levels.	Not used currently in U.S. because its low level of oil and grease is not needed to meet U.S. regulatory standards.

Technology	Subcategory	Pros	Cons
Solvent extraction	Macro-porous polymer extraction	Can treat to very low oil and grease levels.	Not used currently in U.S. because its low level of oil and grease is not needed to meet U.S. regulatory standards. Probably is very costly.
Adsorption	Organoclay, activated carbon, zeolites, specialized polymers, swelling glass.	Does a good job at removing oil and grease. Used primarily for polishing.	Most types of media cannot be reused or regenerated – results in large volume of solid waste.
Oxidation	Advanced processes using combinations of ozonation, cavitation, and electrochemical decomposition	Creates nearly sterile brine	Has high energy input. Limited use to date.

New produced water technologies and products are being introduced to the marketplace each month. Some of them will be adopted by the industry and gain acceptance, while others will not. This section provides a sense of the major technology categories in use through 2014, but cannot be fully inclusive of every product.

Chapter 3 — Approach

During preparation of Clark and Veil (2009) the authors contacted state oil and gas agencies in the 31 states with active oil and gas production 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 2014 study effort attempted to follow the same methodology. Data collection began during July 2014. Requests for assistance were sent by email to oil and gas directors or other senior managers in each of the 31 states. 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.

> *The Ground Water Protection Council (GWPC) is working with John Veil of Veil Environmental, LLC to update an often-cited 2009 report that summarized the volume of produced water generated by all producers in the United States and described the primary ways in which produced water was managed during the 2007 year.*
>
> *We plan to rely heavily on state agency data resources as we undertake the study. GWPC and Veil Environmental request your assistance in providing information on produced water or pointing us to existing data management resources that you already use. The following sections describe the types of information we hope to get from each state.*
>
> *In this study we consider produced water to include water brought to the surface along with oil and gas production. This includes flowback water from wells that were recently fractured as well as any ongoing water production from the wells over time.*
>
> ***Part I – Produced Water Volume***
>
> *1. Please provide information on the volume of produced water generated in your state for calendar year 2012. If you do not have fully compiled data for 2012, 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. 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. 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 2012 or the next most recent year. This information should be entered into the last column of Table 1.

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			
Other			
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 2012 or the next most recent year. This information should be entered into Table 2. Where available, please enter the number of wells that manage produced water by each of the management practices. If you do not have quantitative information on produced water management practices, please give us your educated "best estimate" of the percentage of wells following each management practice.

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.

Table 2 — Produced Water Management Practices

Management Practice	*# Wells Using That 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			
Beneficial reuse			
Other			

6. For any produced water entered under the beneficial reuse or other categories, please provide, to the extent possible, more details on the actual methods employed.

7. 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.

Contacts: *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 or Mike Nickolaus of GWPC at mnickolaus@gwpc.org or 682-936-2822.*

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 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.

3.3 Data Collection for Wells on Federal Lands

In order to account for produced water generated from wells outside of the scope of state oil and gas agencies, efforts to obtain production information at the federal level were also undertaken. For onshore production activities, the questionnaire described above was sent to Department of the Interior's (DOI's) Office of Natural Resources Revenue (ONRR). This agency is the successor to the Minerals Revenue Management Program, which was the relevant agency at the time the 2009 report was prepared.

For offshore data, the DOI's Bureau of Safety and Environmental Enforcement (BSEE) and the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) were contacted. These agencies are the successors to the Minerals Management Service (MMS), which was the relevant agency at the time the 2009 report was prepared.

Discharge data from offshore platforms was obtained from the U.S. Environmental Protection Agency (EPA) Region 9 (California offshore) and Region 10 (Alaska offshore and Cook Inlet).

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 inconsistencies.

3.4 Distribution of Production between State and Federal Categories

Although oil, gas, and water 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. For example, production on federal land areas within Montana was reported through the Montana state total. Likewise, production from tribal areas within the boundaries of Oklahoma was reported through the Oklahoma total.

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 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 was sent to 31 state oil and gas agencies. Most of the states returned a questionnaire with at least some of the boxes completed. 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 Chapter 5.

4.2 Data Availability and Completeness

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, or vice versa. 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 large 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 (at least that was the case in the past). 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. In other cases, the forms require entries into specified water management categories that may make sense under that state's regulations, but do not easily match the categories requested for this study (e.g., Colorado's system for determining how water is managed).

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 relevant data were outside those agencies' jurisdiction, inquiries to additional agencies (including several EPA regional offices) were made.

A third 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. 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 most of the large 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. Chapter 5 provides separate profiles for three states that experienced a major increase in unconventional activity between 2007 and 2012. These include Fayetteville Shale activity in Arkansas, Bakken Shale activity in North Dakota, and Marcellus Shale activity in Pennsylvania.

4.3 Data Accuracy and Quality

The quality of the data sources used for this report result from various factors. Much of the inaccuracy arises from how the raw water volume data are measured, how frequently they 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 bucket and stopwatch, 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 rough 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. Rounding, as is done in the tables in this chapter, also adds a small degree of error. The impact of small percentage differences is described with actual data in the state summary for Texas in Chapter 5.

When the agency personnel extract data from their databases, they need to use certain assumptions to form their queries. Those personnel tried to provide data that matched the questionnaires 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. During a final review period, several states revised their initial volume estimates with major changes in the numbers. Apparently the initial estimates were incomplete or had used inaccurate assumptions or queries to the state databases.

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 and made calculations, which are described in the state-by-state summaries in Chapter 5. Hopefully those assumptions and calculations were done wisely, 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. In at least two states (New York and Wyoming), the opposite situation occurred – the volume of water generated greatly exceeded the volume managed. This situation can arise when the oil and gas agency does not have responsibility for all types of water management practices used in that state and does not have any knowledge of how large portions of the water are actually managed.

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[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.

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 2012.

4.4 Results of Produced Water Volume Analysis

In 2012, U.S. onshore and offshore oil and gas production activities generated 21,180,646,000 bbl of produced water along with 2,264,241,000 bbl of oil (includes condensate) and 29,730,000 Mmcf of gas. Table 4-1 provides oil, gas, and water production information for each state and for federal offshore wells for 2012. The comparable data for 2007 (from Clark and Veil 2009) are also shown in the columns on the right side of the table. As noted in section 3.4, production from federal onshore wells and tribal wells was included in the state totals. In 2007, tribal water production was estimated separately. However, for 2012, this report assumes that tribal oil, gas, and water production were included in the totals for the states in which the tribal lands are located. Any state offshore production was included within the state totals.

4.4.1 Comparison to 2007 Volumes

U.S. oil production increased by 29% between 2007 and 2012, and U.S. gas production increased by 22% during the same period. However, U.S. water production increased by less than 1% between 2007 and 2012. Keeping in mind the caveats expressed in the previous sections, the 2012 water volume was not measurably different from the 2007 volume.

These observations are quite important in light of the huge proliferation of oil and gas production from unconventional wells (particularly from shale plays) that have transformed the U.S. oil and gas market over the past decade. Much of that growth occurred during the period of 2007 to 2012. Many persons in the media and those outside the oil and gas industry assumed that the large increases in oil and gas production would lead to great increases in water production. *However, the data collected for this study do not support that premise.*

4.4.2 Top Producing States

Oil, gas, and water were not uniformly generated in all oil and gas producing states during 2012. Table 4-2 shows the ten states (or as appropriate, the federal offshore portion) with highest production of water.

Table 4-1 — Production Summaries for 2012 and 2007

State	Oil 2012 (bbl/yr)	Gas 2012 (Mmcf/yr)	Water 2012 (bbl/yr)	Oil 2007 (bbl/yr)	Gas 2007 (Mmcf/yr)	Water 2007 (bbl/yr)
Alabama	11,310,000	216,000	106,619,000	5,028,000	285,000	119,004,000
Alaska	192,368,000	3,182,000	769,153,000	263,595,000	3,498,000	801,336,000
Arizona	51,900	116	81,000	43,000	1,000	68,000
Arkansas	6,568,000	1,137,000	184,867,000	6,103,000	272,000	166,011,000
California	197,749,000	174,000	3,074,585,000	244,000,000	312,000	2,552,194,000
Colorado	49,361,000	1,709,000	358,389,000	2,375,000	1,288,000	383,846,000
Florida	2,171,000	19,000	62,641,000	2,078,000	2,000	50,296,000
Illinois	8,908,000	2,100	99,142,000	3,202,000	no data	136,872,000
Indiana	2,350,000	8,800	57,566,000	1,727,000	4,000	40,200,000
Kansas	43,743,000	299,000	1,061,019,000	36,612,000	371,000	1,244,329,000
Kentucky	3,198,000	106,000	19,689,000	3,572,000	95,000	24,607,000
Louisiana	82,781,000	3,347,000	927,635,000	52,495,000	1,382,000	1,149,643,000
Michigan	7,400,000	130,000	117,000,000	5,180,000	168,000	114,580,000
Mississippi	24,146,000	437,000	231,236,000	20,027,000	97,000	330,730,000
Missouri	175,000	12,000	2,103,000	80,000	no data	1,613,000
Montana	26,495,000	67,000	182,833,000	34,749,000	95,000	182,266,000
Nebraska	2,514,000	1,200	58,641,000	2,335,000	1,000	49,312,000
Nevada	368,000	4	5,865,000	408,000	0	6,785,000
New Mexico	85,340,000	1,252,000	775,930,000	59,138,000	1,526,000	665,685,000
New York	360,000	27,000	510,000	378,000	55,000	649,000
North Dakota	243,272,000	259,000	291,147,000	44,543,000	71,000	134,991,000
Ohio	5,063,000	86,000	5,542,000	5,422,000	86,000	6,940,000
Oklahoma	92,988,000	2,023,000	2,325,153,000	60,760,000	1,643,000	2,195,180,000
Pennsylvania	4,300,000	2,260,000	34,089,000	1,537,000	172,000	3,912,000
South Dakota	1,754,000	15,000	5,296,000	1,665,000	12,000	4,186,000
Tennessee	372,000	6,000	1,480,000	350,000	1,000	2,263,000
Texas	608,213,000	8,137,000	7,435,659,000	342,087,000	6,878,000	7,376,913,000
Utah	30,195,000	491,000	166,945,000	19,520,000	385,000	148,579,000
Virginia	9,700	146,000	3,232,000	19,000	112,000	1,562,000
West Virginia	2,561,000	539,000	13,772,000	679,000	225,000	8,337,000
Wyoming	45,382,000	2,079,000	2,178,065,000	54,052,000	2,253,000	2,355,671,000
State Total	1,781,467,000	28,167,000	20,555,884,000	1,273,759,000	21,290,000	20,258,560,000
Federal Offshore	482,774,000	1,563,000	624,762,000	467,180,000	2,787,000	587,353,000
Tribal Lands	Included in state data			no data	no data	149,261,000
Federal Total	482,774,000	1,563,000	624,762,000	476,693,000	3,084,000	736,614,000
U.S. Total	2,264,241,000	29,730,000	21,180,646,000	1,750,452,000	24,374,000	20,995,174,000

Table 4-2 — Top Ten States in Terms of Water Production in 2012

Ranking	State	2012 Water (bbl/yr)	% of Total Water
1	Texas	7,435,659,000	35
2	California	3,074,585,000	15
3	Oklahoma	2,325,153,000	11
4	Wyoming	2,178,065,000	10
5	Kansas	1,061,019,000	5
6	Louisiana	927,635,000	4
7	New Mexico	769,153,000	4
8	Alaska	624,762,000	3
9	Federal Offshore	358,389,000	2
10	Colorado	320,191,000	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 2012

Ranking	State	2012 Oil (bbl/yr)	% of Total Oil
1	Texas	608,213,000	26.9
2	Federal Offshore	482,774,000	21.3
3	North Dakota	243,272,000	10.7
4	California	197,749,000	8.7
5	Alaska	192,368,000	8.5
6	Oklahoma	92,988,000	4.1
7	New Mexico	85,341,000	3.8
8	Louisiana	82,781,000	3.7
9	Colorado	49,361,000	2.2
10	Wyoming	45,382,000	2.0

Texas was the largest producer of all three fluids. It generated 35% of all the U.S. produced water, and produced about 27% of all U.S. oil and gas. It was the only state that ranked in the top five for all three fluids. No other state approached those high percentages, with the possible exception of the federal offshore wells that produced 21% of all U.S. oil.

The sum of the top five states in each category made up well over half of the total U.S. volume (76% for water, 76% for oil, and 64% for gas). No state ranked in the top five in all three categories other than Texas. Looking at the other top five water producing states:

- California was 2nd in water production, 4th in oil production, and not in the top ten for gas production.
- Oklahoma was 3rd in water production, 6th in oil production, and 6th in gas production.
- Wyoming was 4th in water production, 10th in oil production, and 5th in gas production.
- Kansas was 5th in water production, but was not in the top ten for oil or for gas production.

Table 4-4 — Top Ten States in Terms of Gas Production in 2012

Ranking	State	2012 Gas (bbl/yr)	% of Total Gas
1	Texas	8,137,000	27.4
2	Louisiana	3,347,000	11.3
3	Alaska	3,182,000	10.7
4	Pennsylvania	2,260,000	7.6
5	Wyoming	2,079,000	7.0
6	Oklahoma	2,023,000	6.8
7	Colorado	1,709,000	5.7
8	Federal Offshore	1,563,000	5.3
9	New Mexico	1,252,000	4.2
10	Arkansas	1,137,000	3.8

Clark and Veil (2009) found that the same five states made up the list of top five for water production. In 2007, those states contributed 75% of the national produced water volume. In 2012, those states contributed 76% of the total national produced water volume.

4.4.3 Ratio of Water to Hydrocarbon

In addition to total volumes produced, it is interesting to consider the water-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	Crude Oil (bbl/year)	Water from Oil (bbl/year)	WOR
Alabama	11,310,000	37,858,000	3.3
Alaska	192,368,000	768,133,000	4.0
Arizona	51,900	66,700	1.3
Arkansas	6,567,600	174,614,000	26.6
California	197,749,000	3,071,362,000	15.5
Illinois	8,908,000	105,268,000	11.8
Indiana	2,350,000	48,931,000	20.8
Kansas	43,743,000	971,009,000	22.2
Michigan	7,400,000	25,000,000	3.4
Mississippi	24,146,000	228,069,000	9.4
Missouri	175,000	2,103,000	12.0
Montana	26,495,000	179,085,000	6.8
Nebraska	2,514,000	57,873,000	23.0
Nevada	368,000	5,865,000	15.9
New Mexico	85,341,000	674,902,000	7.9
New York	360,000	208,000	0.6
North Dakota	243,272,000	284,426,000	1.2
Ohio	5,063,000	4,860,000	1.0
South Dakota	1,754,000	5,296,000	3.0
Virginia	9,700	54,400	5.6
Wyoming	45,382,000	1,646,601,000	36.3
Total Volume	905,327,200	8,291,584,100	
Weighted Average WOR			9.2

Suitable data were available for 21 states. The WORs ranged from 0.6 bbl/bbl for New York to 36.3 bbl/bbl for Wyoming. The weighted average for those states with suitable data sets was 9.2 bbl/bbl. Two of the key water producing states (Texas and Oklahoma) were unable to distinguish the water generated from oil wells vs. water coming from gas wells. Both of those states have large numbers of older wells from mature fields that typically have very high WORs (much higher than the weighted average). 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 than 10 bbl/bbl.

WOR data from North Dakota were particularly interesting. The WOR for conventional oil was 6.2 bbl/bbl. The WOR for unconventional oil was just 0.6 bbl/bbl. The combined WOR for both types of oil (the value shown in Table 4-5) was 1.2 bbl/bbl. Unconventional oil made up 91% of all oil produced in North Dakota, yet it generated only 46% of the water from oil wells. North Dakota's unconventional oil production from the Bakken Shale generated less water per unit of hydrocarbon than did the conventional production.

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

State	Total Gas (Mmcf)	Water from Gas (bbl/year)	WGR
Alabama	216,000	68,761,000	318
Alaska	3,182,000	1,019,000	0.3
Arizona	116	14,200	122.4
Arkansas	1,137,000	10,253,000	9.0
California	174,000	3,222,000	18.5
Indiana	8,800	8,635,000	981.3
Kansas	299,000	90,010,000	301.0
Michigan	130,000	92,000,000	707.7
Mississippi	437,000	3,167,000	7.2
Montana	67,000	3,748,000	55.9
Nebraska	1,200	769,000	640.8
New Mexico	1,252,000	101,028,000	80.7
New York	27,000	301,000	11.1
North Dakota	259,000	6,721,000	25.9
Ohio	86,000	682,000	7.9
Virginia	146,000	3,177,000	21.8
Wyoming	2,079,000	531,464,372	255.6
Total Volume	9,501,116	924,971,572	
Weighted Average WGR			97

Suitable data were available for 17 states. The WGRs ranged from 0.3 bbl/Mmcf for Alaska to 981 bbl/Mmcf for Indiana – a very broad range. The weighted averaged for those states with suitable data sets was 97 bbl/Mmcf.

A few states had WGR data calculated separately for conventional gas and unconventional gas. Arkansas, Kansas, and New Mexico showed similar WGRs for conventional vs. unconventional production. Alabama showed a much higher WGR for CBM production (727 bbl/Mmcf) than for conventional gas (21 bbl/Mmcf). Virginia showed the same trend (22 bbl/Mmcf for CBM production and 2 bbl/Mmcf for conventional gas). Indiana and Wyoming showed higher WGRs for conventional production than for unconventional production (Indiana – 31,981 vs. 916 bbl/Mmcf; Wyoming – 392 vs. 42 bbl/Mmcf). As demonstrated from these examples, not all unconventional production has comparable water production and WGRs.

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 2012. Some states provided complete data, others provided partial data, and a few were unable to share any information on how produced water was managed. Table 4-7 shows a state-by-state breakout of how water was managed and the volumes managed in each category.

Some of the cells in Table 4-7 and elsewhere in this report contain entries other than positive numbers. "0" was used to represent that there was none of the quantity or volume designated for the cell (e.g., there was no evaporation used for water management in that state). "No data" was used to represent that no information was provided by the agency to allow entry of a number. "Uncertain" was used for cases when it was known or probable that there could be an entry for that cell, but the agency did not have information to quantify the number (e.g., several states believed that flowback water was being reused, but they had no data that tracked the volume).

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 was transported to disposal wells in Ohio. The Ohio volume for water managed greatly exceeded the volume of produced water generated in the state. Much of the incremental volume came from Pennsylvania.

The total volume of produced water managed in 2012 is estimated to be 20,609,274,000 bbl. The total volume of water managed was somewhat lower than the total volume of water generated. In part, this reflects the lack of information on how some of the produced water was managed. Nevertheless, accounting for 97% of the water generated is useful and shows the major trends. Discussion of the different water management practices is found in Section 4.5.2.

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. For those states without Class II primacy, data were requested from the EPA regional offices.

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 with large injection volumes (Texas and New Mexico as well as the federal offshore) 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. A procedure for this is described in section 5.27.1 for Texas.

Table 4-7 — Produced Water Management Practices and Volumes

State	Injection for Enhanced Recovery (bbl/yr)	Injection for disposal (bbl/yr)	Surface discharge (bbl/yr)	Evaporation (bbl/yr)	Offsite Commercial Disposal (bbl/yr)	Beneficial Reuse (bbl/yr)	Total Prod Water Managed (bbl/yr)
Alabama	2,000,000	38,451,000	66,102,000	0	66,000	0	106,619,000
Alaska	652,028,000	84,662,000	32,463,000	0	0	0	769,153,000
Arizona	0	98,000	0	0	0	0	98,000
Arkansas	41,385,000	141,269,000	0	0	213,000	2,000,000	184,867,000
California [a]	1,412,090,000	623,012,000	60,298,000	649,184,000	283,750,000	46,251,000	3,074,585,000
Colorado	123,855,000	123,890,000	40,315,000	35,002,000	22,392,000	47,648,000	393,102,000
Florida	47,676,000	14,965,000	0	0	0	0	62,641,000
Illinois	105,268,000	no data	no data	no data	no data	no data	105,268,000
Indiana	43,131,000	14,377,000	58,000	0	0	0	57,566,000
Kansas	276,299,000	784,721,000	0	0	0	uncertain	1,061,020,000
Kentucky	18,597,000	1,092,000	no data	no data	no data	no data	19,689,000
Louisiana	31,336,000	857,417,000	0	0	38,881,000	0	927,634,000
Michigan	17,000,000	100,000,000	0	0	uncertain	uncertain	117,000,000
Mississippi	127,180,000	104,056,000	0	0	0	0	231,236,000
Missouri	1,748,000	354,000	0	0	0	0	2,102,000
Montana	106,797,000	56,536,000	19,500,000	no data	no data	no data	182,833,000
Nebraska	34,368,000	18,760,000	0	5,476,000	0	0	58,604,000
Nevada	0	4,743,000	0	0	0	0	4,743,000
New Mexico [b]	381,160,000	381,160,000	0	0	0	0	762,320,000
New York	27,000	1000	uncertain	0	uncertain	uncertain	28,000
North Dakota	52,484,000	161,978,000	0	0	76,685,000	0	291,147,000
Ohio [c]	605,000	14,157,000	0	0	0	756,000	15,518,000
Oklahoma	1,098,312,000	1,087,080,000	0	0	139,760,000	0	2,325,152,000
Pennsylvania	0	4,220,000	780,000	0	0	29,082,000	34,082,000
South Dakota	3,025,000	2,271,000	0	0	0	0	5,296,000
Tennessee	0	0	0	1,480,000	0	0	1,480000
Texas [d]	3,717,830,000	2,922,805,000	371,178,000	0	795,025,000	uncertain	7,806,838,000
Utah	71,535,000	85,534,000	11,589,000	0	12,968,000	uncertain	181,626,000
Virginia	0	3,232,000	0	0	0	0	3,232,000
West Virginia [e]	3,660,000	3,876,000	2,846,000	0	3,391,000	uncertain	13,773,000
Wyoming	855,756,000	312,944,000	uncertain	uncertain	uncertain	uncertain	1,168,700,000
State Total	9,225,152,000	7,947,716,000	605,129,000	691,142,000	1,373,131,000	125,737,000	19,967,952,000
Federal Offshore [b]	62,703,000	62,703,000	515,916,000	0	0	0	641,322,000
Federal Total	62,703,000	62,703,000	515,916,000	0	0	0	641,322,000
U.S. Total	9,287,855,000	8,010,364,000	1,121,045,000	691,142,000	1,373,131,000	125,737,000	20,609,274,000

<u>Notes for Table 4-7</u>: Full explanations of the values in each cell are found in Chapter 5. A few key points are highlighted here.
[a] California did not specify how much water was beneficially reused. California combined all water not managed by injection, discharge, evaporation, or commercial disposal as "Other". Presumably, much of the "Other" water was beneficially reused, and is shown in that category here.
[b] New Mexico and the Federal Offshore did not segregate water injected for enhanced recovery from water injected for disposal. *This report assumes that 50% of the total injected water was managed by each method*.
[c] Much of the water injected for disposal in Ohio was sent to offsite commercial wells. Ohio did not provide separate volumes for commercial vs. non-commercial injection.
[d] Texas did not segregate injected water similar to New Mexico and Federal Offshore (note b). For Texas, 50% of the total injected water was assigned to injection for enhanced recovery. The other 50% was injection for disposal, but part of that total was assigned to the offsite commercial disposal column.
[e] West Virginia managed water from CBM wells by land application. This volume is shown under the Discharge category.

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. The data collected during preparation of this report indicated that the total water injected for enhanced recovery included 9,287,855,000 bbl of produced water and 572,825,000 bbl of makeup water from some other source.

Data on water management practices other than injection were less robust. Availability of detailed data varied among states. Wyoming and New York reported a much higher volume of generated produced water than the volume managed. Those oil and gas agencies did not have information on how the produced water was managed.

4.5.2 Comparison between 2012 and 2007

Table 4-8 provides a comparison of the volumes and percentages of water managed in 2012 and 2007 from both onshore and offshore wells. This analysis assumes that all water shown for the states comes from onshore wells and all water shown for federal comes from offshore wells. While not fully accurate, the assumption is a reasonable approximation.

The 2012 water management data were more complete than the comparable data compiled in 2007. The 2007 data showed "no data" for all water management categories in eight states, whereas the 2012 data showed at least some water management data for all 31 states. Further the 2012 water management data set contained more management categories than did the 2007 data set.

Table 4-8 — Distribution of Water Management Practices in 2012 and 2007

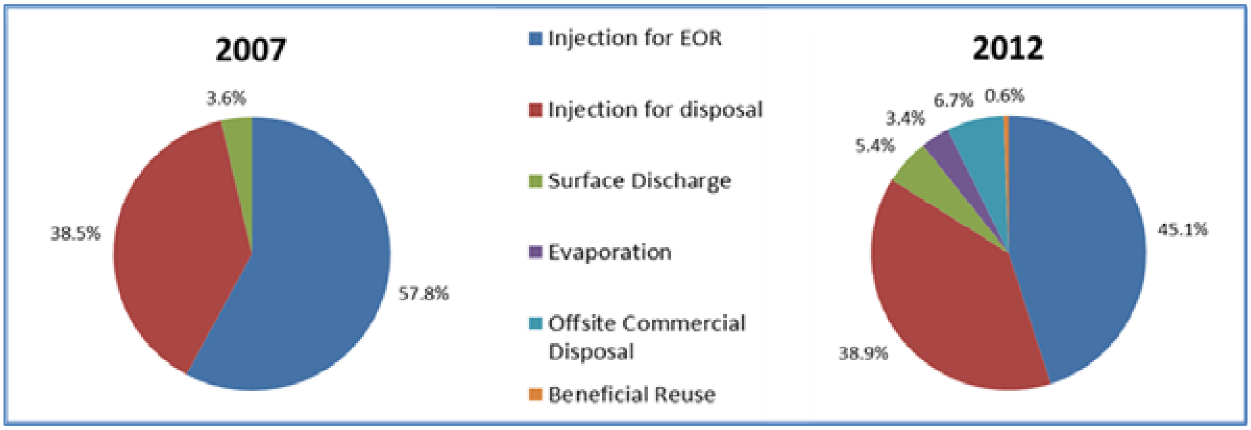
	Injection for Enhanced Recovery (bbl/yr)	Injection for disposal (bbl/yr)	Surface discharge (bbl/yr)	Evaporation (bbl/yr)	Offsite Commercial Disposal (bbl/yr)	Beneficial Reuse (bbl/yr)	Total Prod Water Managed (bbl/yr)
2012							
Onshore Total	9,225,152,000	7,947,716,000	605,129,000	691,142,000	1,373,131,000	125,737,000	19,968,007,000
%	46.2	39.8	3.0	3.5	6.9	0.6	100.0
Offshore Total	62,703,000	62,703,000	515,916,000	0	0	0	641,322,000
%	9.8	9.8	80.4	0.0	0.0	0.0	100.0
U.S. Total	9,287,855,000	8,010,364,000	1,121,045,000	691,142,000	1,373,131,000	125,737,000	20,609,274,000
%	45.1	38.9	5.4	3.4	6.7	0.6	100.0
2007							
Onshore Total	10,676,530,000	7,144,071,000	139,002,000	No data	No data	No data	17,959,603,000
%	59.4	39.8	0.8	No data	No data	No data	100.0
Offshore Total	48,673,000	1,298,000	537,381,000	No data	No data	No data	587,353,000
%	8.3	0.2	91.5	No data	No data	No data	100.0
U.S. Total	10,725,203,000	7,145,369,000	676,383,000	No data	No data	No data	18,546,955,000
%	57.8	38.5	3.6	No data	No data	No data	100.0

In 2012, about 93% of the water from onshore wells was injected. 46% was injected for enhanced recovery, 40% was injected into non-commercial injection wells, and 7% was injected into commercial disposal wells. About 3% was discharged, 3.5% was evaporated, and 0.6% was beneficially reused. The 2007 data showed a higher percentage of water injected for enhanced recovery. That is somewhat misleading because the 2007 data included all water injected for enhanced recovery (both produced water and makeup water), whereas the 2012 data were adjusted for several states to show just the produced water portion of the water injected for enhanced recovery. As another complicating factor, the allocation of injected water in Texas between enhanced recovery and disposal was different in 2007. Because Texas made up more than one third of all the water managed, any shift in allocation would change the final results.

In 2012, about 80% of the produced water from offshore wells was discharged. The remaining 20% was injected. The percentage of offshore produced water injected in 2012 was considerably higher than in 2007. Since no information was available for federal wells to determine the percentage of water injected for enhanced recovery vs. for disposal, it was assumed that 50% of the injected produced water went to each type of injection well. Much of the injected water total was attributable to offshore wells in the federal waters off of California.

Figure 4-1 graphically compares how produced water was managed by percentage between 2007 and 2012. Note that the 2007 data did not include any evaporation, offsite commercial disposal, or beneficial reuse. Those water management practices were used in 2007, but data were not collected for them. The percentages of the produced water management practices shifted slightly since 2007, but the major trends remain the same.

Figure 4-1 — Water Management Practices by Percentage in 2007 and 2012



When the 2012 onshore and offshore data are combined to give the U.S. total, the results are:

- 90.6% of the produced water was injected (45.1% was injected for enhanced recovery, 38.9% was injected at non-commercial disposal wells, and 6.7% was injected at offsite commercial disposal facilities).
- 5.4% was discharged.
- 3.6% was evaporated, primarily in several arid western states, from onsite ponds and pits.
- 7% was managed by sending it to offsite commercial facilities, where the water was treated and disposed. 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. Most of these facilities managed water by injection into disposal wells. Nearly all of the water managed at offsite commercial facilities in states other than Colorado and Utah was injected into disposal wells (estimated at 98%). Most of the water sent to commercial facilities in those two states (~2%) was evaporated. For the sake of calculating national totals in this report, all water managed at commercial disposal facilities was considered as having been injected.
- 0.6% was put to some beneficial reuse 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 2012. Much of the reuse was done by recycling flowback water and produced water to make drilling fluids and frac fluids for new wells in the same fields. Other portions of produced water may be used for irrigation (when the water has low salinity) or for dust and ice control on roads.

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.

In this chapter the exact quantities (bbl, Mmcf) as provided by the agencies or as derived from other references are shown. As these data values are combined into the summary table in Chapter 4, they are rounded to give a more realistic estimate of the precision of the numbers.

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 2012:

- 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.

EIA estimates oil production through a methodology that includes data obtained from states, other federal agencies, and a commercial oil and gas data vendor. The data are evaluated using a statistical model to make estimates. The oil estimation methodology is explained in a document provided by EIA.[7]

EIA estimates gas production by collecting survey data directly from a subset of producers as well as from a commercial oil and gas data vendor, and then conducts statistical modeling of those data to extrapolate to statewide production. The gas estimation methodology is available on EIA's website at http://www.eia.gov/oil_gas/natural_gas/data_publications/eia914/eia914meth.pdf.

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[7] The document "Methodology for Monthly Crude Oil Production Estimates," dated August 2014, was sent by EIA to John Veil on March 2, 2015 as an attachment to an email. EIA noted that the document has not been published, but EIA would send it to people who ask for it.

These estimates were compared to the estimates provided by the state agencies. Where state-supplied numbers appear to be incomplete or in the absence of state-supplied numbers, the EIA values were used.

Three states (Arkansas, North Dakota, and Pennsylvania) showed a substantially different relationship between oil and gas production and water production between the years 2007 and 2012. Additional discussion of those results is provided in those state sections.

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 those 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 overall volume of produced water generated matched the overall volume managed. This process was used for Alaska, California, Montana, North Dakota, and South Dakota.

5.1 Alabama

The State Oil and Gas Board of Alabama provided produced water generation and management data.[8] Tables 5-1 and 5-2 show the replies to the questionnaire. At the end of 2012, Alabama had 7,139 wells producing hydrocarbons, with the majority of these wells producing CBM (5,780 wells). The remaining wells produced conventional oil (917 wells), conventional gas (331 wells), and condensate (111 wells).

The natural gas production values provided by the State Oil and Gas Board were compared to EIA's 2012 gas production figures for Alabama. The conventional gas production and total gas production figures from the Board were considerably higher. After reviewing the discrepancy with the Board, we agreed to use the EIA values. The volumes shown on these lines and the total line reflect the EIA values.

The statewide total produced water volume for 2012 was 106,619,333 bbl. CBM production generated about 62% of that total, and conventional oil contributed another 35%. Conventional gas added about 2% more. The condensate wells contributed a fraction of a percent.

Using the hydrocarbon and water production data, the following ratios were determined: WOR of 3.3 bbl/bbl, WGR of 21 bbl/Mmcf for conventional gas, and WGR of 727 bbl/Mmcf for CBM. The combined WGR for gas wells was 319 bbl/Mmcf.

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[8] Emails from the State Oil and Gas Board of Alabama to John Veil on October 3 and 28, 2014.

Table 5-1 — 2012 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	917	37,578,819	9,525,213 bbl/yr
Natural gas from conventional formations	331	2,658,727	125,385 Mmcf/yr
Crude oil from unconventional formations	0	0	0
Natural gas from unconventional formations	5,780	66,102,425	90,325 Mmcf/yr
Other (condensate)	111	279,362	1,784,834 bbl/yr
Total	7,139	106,619,333	11,310,047 bbl/yr 215,710 Mmcf/yr

Table 5-2 — 2012 Produced Water Management Practices for Alabama

Management Practice	# Wells Using That Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced oil recovery (estimated)	128	2,000,000	1.8%
Injection for disposal	83	38,451,191	36%
Surface discharge	5,780	66,102,425	62%
Evaporation	0	0	0
Offsite commercial disposal	54	65,717	0.06%
Beneficial Reuse	0	0	0
Total Volume Managed		106,619,333	

Unlike most other states, the majority 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[9] 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 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 62% of produced water management in Alabama. Injection for disposal managed 36% of produced water, and about 2% was injected for enhanced recovery. The remaining small percentage of produced water was managed through offsite commercial disposal. There was no beneficial reuse of produced water in Alabama.

5.2 Alaska

The Alaska Oil and Gas Conservation Commission (AOGCC) provided produced water generation and management data.[10] Tables 5-3 and 5-4 show the replies to the questionnaire. In 2012, Alaska had 3,087 wells with the majority of these wells producing conventional oil (2,709 wells). The remaining 297 wells produced conventional gas. No unconventional production was reported.

The statewide total produced water volume for 2012 was 769,152,512 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 AOGCC confirmed that the numbers shown in Table 5-3 do include offshore hydrocarbon and water production from wells located within State waters (i.e., Cook Inlet as well as North Slope offshore developments such as Spy Island and Oooguruk drilling islands).

These produced water volumes resulted in a WOR of 4 bbl/bbl for oil and WGR of 0.3 bbl/Mmcf for gas.

In their data submittal, the AOGCC noted that three fields in Alaska have dedicated water source wells. The majority of the water produced from those water wells (24,568,682 bbl in 2012) was reinjected into producing formations for enhanced recovery. Alaska also utilized water from surface sources. Those volumes were not recorded in the AOGCC database and were not included in produced water totals in Table 5-3 since they represented water unrelated to oil and gas production wells.

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[9] The oil and gas exploration and production discharge standards are found at 40 CFR Part 435.
[10] Emails from AOGCC to John Veil on August 7, 2014 and November 21, 2014.

Table 5-3 — 2012 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	2,790	768,133,879	192,368,220 bbl/yr
Natural gas from conventional formations	297	1,018,633	3,182,115 Mmcf/yr
Crude oil from unconventional formations	0	0	0
Natural gas from unconventional formations	0	0	0
Total	3,087	769,152,512	192,368,220 bbl/yr 3,182,115 Mmcf/yr

Table 5-4 — 2012 Produced Water Management Practices for Alaska

Management Practice	# Wells Using That Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	1,277	652,027,895 bbl (produced water portion) 1,045,382,575 bbl total	85%
Injection for disposal	64	84,661,778 includes all volumes of fluids in Class I and Class II disposal wells (e.g., muds)	11%
Surface discharge	??	32,462,839	4%
Evaporation	0	Minimal	0
Offsite commercial disposal	0	0	0
Beneficial reuse	0	Minimal	0
Total Volume Managed		769,152,512	

The AOGCC reported an injection volume of 1,045,382,575 bbl of water at 1,277 wells for enhanced recovery. This volume exceeded the total volume of available produced water due to the addition of seawater and other water sources injected for enhanced recovery. An additional 84,661,778 bbl of fluids (produced water plus other fluids) were injected into 64 disposal wells. The total injected volume greatly exceeded the volume of produced water generated. To more accurately account for just the produced water, 393,354,680 bbl of the water injected for enhanced recovery were assumed to be makeup water, leaving 652,027,895 bbl of produced water injected for enhanced recovery. This value was used in Table 5-4.

The total volume of fluids injected into disposal wells was 84,661,778 bbl. This included produced water as well as other types of fluids. Alaska has primacy for the Underground Injection Control (UIC) Class II program, but does not have primacy for Class I wells. These were regulated and permitted by Region 10 of the EPA. Most injection wells used for disposing oil and gas wastewater (mainly produced water) were permitted as Class II wells. However some Alaskan injection wells injected fluids other than those brought to the surface as part of oil and gas activities (e.g., treated sewage and other domestic wastewater, other nonhazardous industrial waste material). Therefore, EPA Region 10 has chosen to permit those wells as Class I wells. Class I wells are typically subject to stricter construction and operational requirements than are Class II wells. It was not possible to determine how much of the total fluid volume injected into the Class I and II disposal wells was produced water. For the sake of this report, the entire volume was treated as produced water.

The AOGCC does not regulate discharges to surface water from offshore platforms. Therefore the water management data submitted by the AOGCC did not show any produced water being discharged. However the three platforms in Cook Inlet do generate produced water. It was not discharged at the platform but was piped to shore for treatment and was discharged from shore-based facilities. Data on the volume of treated produced water discharged to Cook Inlet were provided by EPA Region 10.[11] During 2012, 32,462,839 bbl of treated produced water were discharged – this number was added to Table 5-4. Region 10 noted that during 2012, primacy for the NPDES program was transferred from Region 10 to the Alaska Department of Environmental Conservation.

5.3 Arizona

The Arizona Geological Survey provided produced water generation and management data.[12] Tables 5-5 and 5-6 show the replies to the questionnaire. In 2012, Arizona had just 25 oil and gas wells with 21 of them producing conventional oil. The remaining 4 wells produced conventional gas and some condensate. No unconventional production was reported.

The statewide total produced water volume for 2012 was 80,903 bbl. Conventional oil production generated about 82% of that total with conventional gas wells contributing about 18% of the produced water volume. These produced water volumes resulted in a WOR of 1.3 bbl/bbl of crude oil and WGR of 122 bbl/Mmcf of conventional gas.

[11] Email from EPA Region 10 to John Veil on December 9, 2014.
[12] Email from Arizona Geological Survey to John Veil on July 21, 2014.

All produced water in Arizona was managed by injection into 2 disposal wells. The annual injected volume was slightly higher than the annual produced water volume. 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.

Table 5-5 — 2012 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	21	66,700	49,972 bbl/yr
Natural gas from conventional formations	4	14,203	1,976 bbl/yr condensate 116 Mmcf/yr
Crude oil from unconventional formations	0	0	0
Natural gas from unconventional formations	0	0	0
Total	25	80,903	51,948 bbl/yr 116 Mmcf/yr

Table 5-6 — 2012 Produced Water Management Practices for Arizona

Management Practice	# Wells Using That 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	0
Injection for disposal	2	97,505	100%
Surface discharge	0	0	0
Evaporation	0	0	0
Offsite commercial disposal	0	0	0
Beneficial reuse	0	0	0
Total Volume Managed		97,505	

5.4 Arkansas

The Arkansas Oil and Gas Commission provided produced water generation and management data.[13] Tables 5-7 and 5-8 show the replies to the questionnaire. In 2012, Arkansas had 15,599 oil and gas wells with 7,061 of them producing conventional oil. 4,132 wells produced conventional gas. Arkansas had significant unconventional gas production from the Fayetteville Shale – this included 4,406 wells in 2012.

The statewide total produced water volume for 2012 was 184,866,828 bbl. Conventional oil production generated about 93% of that total. Conventional gas wells contributed less than 1% of the total produced water volume. Unconventional gas wells contributed the remaining 5% of the total produced water.

Table 5-7 — 2012 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**
Crude oil from conventional formations	7,061	174,613,539	6,567,573 bbl/yr
Natural gas from conventional formations	4,132	694,810	105,911 Mmcf/yr
Crude oil from unconventional formations	0	0	0
Natural gas from unconventional formations	4,406	9,558,479	1,030,816 Mmcf/yr
Total	15,599	184,866,828	6,567,573 bbl/yr 1,136,727 Mmcf/yr

The Oil and Gas Commission noted several caveats when providing those numbers.

- Produced water associated with oil production was reported to the Commission on a well-by-well basis.
- Produced water associated with conventional and unconventional gas production was not reported to the Commission on a well-by-well basis. The volume shown in Table 5-7 is the reported amount of produced water disposed at Class II disposal wells. However,

[13] Emails from Arkansas Oil and Gas Commission to John Veil on August 3 and 5, 2014, and other emails containing revised data on February 17 and 18, 2015.

an unknown amount may have been transported to other states for disposal and is not reflected in the volume given.

- The unconventional gas water volume was primarily flowback water following hydraulic fracturing operation. The Fayetteville Shale reservoir produces very little formation water.

These produced water volumes resulted in a WOR of 26.6 bbl/bbl of crude oil, a WGR of 6.6 bbl/Mmcf of conventional gas, and a WGR of 9.3 bbl/Mmcf of unconventional gas. The overall WGR for all gas production was 9 bbl/Mmcf.

The Oil and Gas Commission reported that produced water was managed in several different ways in Arkansas. About 22% of the water was injected into producing formations through 165 injection wells to enhance oil recovery. Another 76% was injected into 640 disposal wells. An estimated 2 million bbl (1%) of the water was flowback water from Fayetteville Shale wells that was reused to make up new frac fluids for fracturing other Fayetteville Shale wells. The number of wells where recycled water was used varies depending upon the number of wells fractured at any given time. A fraction of 1% of the produced water was sent to a commercial land farming operation.

Table 5-8 — 2012 Produced Water Management Practices for Arkansas

Management Practice	# Wells Using That Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	165	41,384,953	22.4%
Injection for disposal	640	141,269,299	76.4%
Surface discharge	0	0	0
Evaporation	0	0	0
Offsite commercial disposal (land farm)	1	212,576	0.1%
Beneficial reuse (make new frac fluids)	no data	2,000,000 (estimated)	1.1%
Total Volume Managed		184,866,828	

5.4.1 Changes from 2007 to 2012

It is interesting to compare the information collected for 2012 with what was provided by the Arkansas Oil and Gas Commission for 2007 (as reported in Clark and Veil 2009). Table 5-9 compares the water management practices for the two years.

Table 5-9 — Comparison of Water Management Practices for Arkansas in 2007 and 2012

Management Practice	# Wells Using That Practice in 2007	Total Volume of Produced Water Managed by That Practice in 2007 (bbl/year)	# Wells Using That Practice in 2012	Total Volume of Produced Water Managed by That Practice in 2012 (bbl/year)
Injection for enhanced recovery	106	45,488,886	165	41,384,953
Injection for disposal	448	120,169,316	640	141,269,299
Other injection (unspecified)	no data	352,997	no data	no data
Offsite commercial disposal	no data	no data	1 land farm	212,576
Beneficial reuse	no data	no data	reuse to make new frac fluids	2,000,000 (estimated)
Total		166,011,199		184,866,828

The total volume of produced water managed increased from 166,011,199 bbl in 2007 to 184,866,828 bbl in 2012 – an increase of 11%. The number of wells used for enhanced recovery increased by 56% from 2007 to 2012, but the volume of water injected for enhanced recovery decreased by 9%. The number of wells used for disposing produced water increased by 43%, and the total volume of water managed by disposal wells increased by 18%.

Clark and Veil (2009) note that 2007 hydrocarbon production volumes in Arkansas were 6,102,538 bbl of oil and 271,846 Mmcf of gas (the 2007 data do not distinguish between conventional and unconventional gas production). Compared to the 2012 data, the oil volumes were similar, but the volume of gas produced was much higher in 2012. Total gas production in 2012 jumped to 1,136,727 Mmcf, with most of that coming from unconventional production in the Fayetteville Shale.

Specific volumes for gas produced from different formations can be found in EIA's data for Arkansas.[14] The volume of gas produced from conventional gas wells and gas produced as associated gas from conventional oil wells both dropped from 2007 to 2012. However, gas produced from shale formations jumped from 84,049 Mmcf in 2007 to 1,021,484 Mmcf in 2012 (more than twelve-fold increase). One possible interpretation from these data is that unconventional production, at least from the Fayetteville Shale formation that contains little natural formation water, generated much less water per unit of energy than did conventional oil or gas production.

[14] The EIA data can be found at: http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_sar_a.htm.

5.5 California

The California Department of Conservation (CDOC) Division of Oil, Gas, and Geothermal Resources (DOGGR) provided produced water generation and management data.[15] Tables 5-10 and 5-11 show the replies to the questionnaire. In 2012, California had 55,039 active oil and gas wells with 97% of them producing conventional oil. Another 3% of the wells produced 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 2012 was 3,074,584,714 bbl. Conventional oil production generated more than 99% of that total. Conventional gas wells contributed less than 1% of the total produced water volume. According to a CDOC annual report of 2012 data (CDOC 2013) offshore wells in state waters accounted for about 14% of the statewide total of produced water, about 7% of the oil, and about 3% of the gas.

These produced water volumes resulted in a WOR of 15.5 bbl/bbl for crude oil and WGR of 18.5 bbl/Mmcf for gas.

Table 5-10 — 2012 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	53,596	3,071,362,259	197,749,217 bbl/yr
Natural gas from conventional formations	1,443	3,222,455	174,220 Mmcf/yr
Crude oil from unconventional formations	0	0	0
Natural gas from unconventional formations	0	0	0
Total	55,039	3,074,584,714	197,749,217 bbl/yr 174,220 Mmcf/yr

The produced water management data initially submitted by DOGGR showed 28,461 wells using injection for enhanced recovery and for disposal for a combined total water volume of 2,035,101,925 bbl. He notes that DOGGR does not segregate wells used for injection for enhanced recovery and injection for disposal in their oil and gas database. However, their injection database indicated that there were 25,808 active EOR injection wells and 970 active

[15] Emails from DOGGR to John Veil on November 25 and December 8, 2014.

injection disposal wells in 2012. The total reported volumes were 1,489,785,432 bbl (includes all water injected as steam and as water) and 623,012,380 bbl (water only), respectively.

The total water volume shown in Table 5-11 (3,152,280,602 bbl) was larger than the water volume in Table 5-10 (3,074,584,714 bbl). 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 balance the produced water generated with the produced water managed, the volume injected for enhanced recovery was reduced to 1,412,089,544 bbl, with the remaining 77,695,888 bbl being considered as makeup water.

These numbers were substituted into Table 5-11. California 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 half of the produced water was managed by injection for enhanced recovery in water flooding and steam flooding operations. Injection for disposal accounted for 20% of produced water, surface discharge for 2%, evaporation for 21%, and disposal at offsite commercial facilities for 9%.

Table 5-11 — 2012 Produced Water Management Practices for California

Management Practice	**# Wells Using That Practice**	**Total Volume of Produced Water Managed by That Practice (bbl/year)**	**Percentage of Produced Water Managed by That Practice**
Injection for enhanced recovery	25,808	1,412,089,544 bbl (produced water portion) 1,489,785,432 bbl total	46%
Injection for disposal	970	623,012,380	20%
Surface discharge	3,241	60,298,193	2%
Evaporation	13,296	649,183,681	21%
Offsite commercial disposal	6,685	283,749,708	9%
Beneficial reuse	no data	no data	no data
Other	721	46,251,208	1.5%
Total Volume Managed		3,074,584,714	

The DOGGR data showed that about 1.5% of the state's produced water was managed in some other way. DOGGR clarified that the Other category covers everything not listed in the available categories. This could include the disposition of water in multiple ways, yet the reporting program can only accept one option. In addition, if water was recycled and used for other purposes, it would be included under the Other category. DOGGR does not provide any more detail on the disposition of the water shown in the Other category.

It is interesting to note that no estimates were available for beneficial reuse in California. Several well-documented projects do 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. Up to 50,000 barrels of brackish produced water per day (BWPD) was transformed into freshwater for agricultural reuse, which was enough to irrigate about 800 acres of farmland per year (Myers 2014).

5.6 Colorado

Data for Colorado were obtained through the Colorado Oil and Gas Conservation Commission (COGCC) online website. COGCC does not track production from conventional wells and unconventional wells separately. The author also contacted Thom Kerr, a consultant who formerly worked as a manager at COGCC, where he had familiarity with the agency's data.

Table 5-12 shows production information in a format similar to that used for other states. The numbers in the table were compiled by the author using data sources described below.

Data on water production were initially obtained from a large database called "2012 Production Report" on the COGCC website. The database was downloaded from http://cogcc.state.co.us/downloads/production/co%202012%20Annual%20Production%20Summary-xp.zip. Data provided by Mr. Kerr included a more recent and slightly different compilation of 2012 water volumes.[16] Mr. Kerr's data were used in Table 5-12.

The volume of flowback water from wells that had been hydraulically fractured is typically not included in the disposal volumes reported on the monthly production reports. The flowback was stored in temporary tanks and later hauled off. Data from Mr. Kerr included a 2012 flowback volume of 27,039,785 bbl – this was added to calculate a total produced water volume.

Data for 2012 oil and gas production were obtained from EIA. The EIA data break out gas production from shale and CBM formations (unconventional). Unfortunately, the water production data do not make that distinction.

[16] Email from Thom Kerr, Thom Kerr LLC, to John Veil, on December 6, 2014.

Table 5-12 — 2012 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 and unconventional formations	18,000	331,349,662	49,361,146 bbl/yr
Natural gas from conventional and unconventional formations	32,000		1,104,038 Mmcf/yr
Crude oil from unconventional formations	no data		no data
Natural gas from unconventional formations (shale and CBM)	no data		605,339 Mmcf/yr
Other – flowback water from hydraulically fractured wells	no data	27,039,785	no data
Total	50,000	358,389,447	49,361,146 bbl/yr 1,709,377 Mmcf/yr

Slightly less than 50,000 oil and gas wells produced hydrocarbons in Colorado during 2012. This estimate was extrapolated from a graph in a recent Colorado weekly and monthly oil and gas statistics document (dated December 2, 2014) http://cogcc.state.co.us/Library/Statistics/CoWklyMnthlyOGStats.pdf. The data were not broken out by oil vs. gas or by conventional vs. unconventional wells. EIA provides an estimate of 32,000 gas wells in Colorado for 2012. By subtraction, this suggests that about 18,000 wells produced oil in Colorado during 2012.

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.

Data on produced water management methods were not available from the COGCC website. Communication with COGCC staff suggested that they do receive monthly reports of operations from the oil and gas operators.[17] The reports must indicate how much water was managed in one of five ways:

- Commercial disposal facility (this represents water sent to commercial pits).
- Onsite pit (most of the water evaporates, or the excess water was hauled to disposal wells).

[17] Telephone conversations between the COGCC and John Veil on December 2 and 5, 2014.

- Central disposal pit (These are central facilities owned by a single producer. 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. Roughly half of this water was injected for purposes of enhanced recovery).
- Surface discharge (This water was either fresh or treated to acceptable standards and discharged to a surface water body).

The COGCC maintains this information in an internal database that is available for searching by the public as individual records. Mr. Kerr was able to query the database to provide the composite volumes of water managed in each of those general categories. Table 5-13 shows the data provided by Mr. Kerr.

Table 5-13 — 2012 Produced Water Management Data from COGCC Database

Disposal method	**Volume (bbl/yr)**
Onsite pit	35,002,477
Surface discharge	40,315,420
Commercial disposal facility	22,392,182
Injected	168,040,839
Central disposal pit	65,582,942
Total	331,333,860

Mr. Kerr also provided estimates of the volume of water injected for disposal (123,918,252 bbl/yr) vs. the volume injected for enhanced recovery (123,854,742 bbl/yr). These volumes were the volumes reported to the COGCC's UIC program on a monthly basis by the operators of the Class II wells (producer or commercial disposal company). The volumes of the Class II injection wells reports did not balance with the total reported injected volumes reported by the producers (the Injected category). It is likely that the operators of enhanced recovery projects augmented produced water supplies with water from other sources, such as fresh water.

Other than the common practice of reinjecting produced water for enhanced recovery projects, there was some degree of reuse or recycling of flowback water for use in the oil and gas fields. Mr. Kerr notes that some of the central disposal sites were currently used for recycling water and some of the disposal wells were recycling water as well. Based on a different set of data provided by Mr. Kerr, operators reported that in 2012, 77,910,189 bbl of frac fluids were used to stimulate wells in Colorado. About 35% of that volume (27,039,785 bbl) returned to the surface as flowback water. 61% of the frac fluids (47,648,287 bbl) were made from recycled flowback and produced water.

Mr. Kerr reported that 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 data provided by Mr. Kerr were very helpful but they required some recalculation and assumptions before entering them into the water management tabular format used for the other states. Table 5-14 shows those data in the preferred tabular format. A list of assumptions is provided following the table.

Table 5-14 — 2012 Produced Water Management Practices for Colorado

Management Practice	# Wells Using That Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	445	123,854,742	31.5%
Injection for disposal	292	123,889,551	31.5%
Surface discharge	no data	40,315,420	10.3%
Evaporation	no data	35,002,477	8.9%
Offsite commercial disposal (pits)	no data	22,392,182	5.7%
Beneficial reuse (recycled produced water and flowback used to make new frac fluids)	no data	47,648,287	12.1%
Total Volume Managed		393,102,659	

The major assumptions used to estimate water volumes for Table 5-14 are:

- The volume injected for enhanced recovery and for disposal come from the monthly reports of operations. There is no way of telling how much extra water (not produced water) was included in the reported volumes for enhanced recovery. For the sake of this report, the injected volume in disposal wells was assumed to be all produced water.
- Mr. Kerr's spreadsheet shows that Colorado had 737 active Class II wells (292 disposal wells and 445 enhanced recovery wells) during 2012.
- The surface discharge volume and the offsite commercial disposal volumes were taken directly from Table 5-13.
- The evaporation volume was assumed to equal the onsite pit volume from Table 5-13.
- The beneficial reuse volume was the portion of the new frac fluids that was derived from recycled flowback and produced water. In addition, at least some of the water managed by surface discharge had a beneficial use for wildlife even though it was not listed under that heading.

The total volume of water managed in 2012 was estimated at 393,102,659 bbl. About one third was injected for enhanced recovery, another third was injected for disposal, 12% was put to beneficial reuse, and 10% was discharged. Evaporation and offsite commercial disposal made up the remaining water volume. Although the total water volume managed exceeds the total water volume generated, given the complex calculations and assumptions already applied, no attempt was made to back out the makeup water portion of the water injected for enhanced recovery.

Two other documents indicated the percentages for the various water management options. Although they followed the same trends, the actual percentages differed from one source to another. This highlights the challenge to estimate consistent and accurate data relating to produced water generation and management practices.

The COGCC website contains a report prepared by the COGCC and provided to the Water Quality Control Commission and the Colorado Department of Public Health and Environment (COGCC 2012). This report included a summary of COGCC activities and changes in ground water protection programs that were made during the preceding year. It states:

> *"Approximately 50% of the water co-produced with oil and gas is disposed of or used for enhanced recovery by underground injection. Most produced water that is not injected is disposed in evaporation and percolation pits or discharged under Colorado Discharge Permit System (CDPS) permit. A small amount of produced water is used for dust suppression on oil and gas lease roads. In addition, to minimize waste and the use of fresh water, more operators are reusing and recycling produced water and other fluids for drilling and well completion activities including hydraulic fracture treatment ("fracing")."*

The Colorado Oil and Gas Association posted a short fact sheet on its website that provided some insights into produced water management (http://www.coga.org/pdfs_facts/produced_water_fastfacts.pdf). The fact sheet, dated June 14, 2011, states:

> *"In Colorado, most of the flowback water is recycled. The rest of the water is disposed according to COGCC guidelines. Of the water disposed, approximately 60 percent is disposed of in underground injection wells, 20 percent is managed in evaporation ponds, and 20 percent is discharged to surface waters under permits by the Colorado Department of Public Health and Environment (CDPHE)."*

5.7 Florida

The Florida Department of Environmental Protection (FDEP) Oil and Gas Section did not submit a completed questionnaire.[18] However, the agency contact advised that the requested data

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[18] Email from FDEP to John Veil on November 12, 2014.

could be found on the FDEP Oil and Gas Program website http://www.dep.state.fl.us/water/mines/oil_gas/production.htm#apr.

Table 5-15 — 2012 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	64	62,640,879 bbl/yr	2,171,144 bbl/yr 18,787 Mmcf/yr
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	64	62,640,879 bbl/yr	2,171,144 bbl/yr 18,787 Mmcf/yr

The FDEP indicated that Florida produced oil and gas in two areas of the state. All wells were permitted as oil-producing wells. The South Florida Fields produce very little gas with the oil. All produced water was sent to disposal wells that inject to the boulder zone.

Table 5-16 — 2012 Produced Water Management Practices for Florida

Management Practice	# Wells Using That 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	47,675,606	76%
Injection for disposal	7	14,965,273	24%
Surface discharge	0	0	0
Evaporation	0	0	0
Offsite commercial disposal	0	0	0
Beneficial reuse	0	0	0
Total Volume Managed		62,640,879	

The Northwest Florida fields produce a large amount of both oil and gas. In these fields, all produced water was injected back into the producing formations. The data from the FDEP website were entered into the questionnaire tables (Tables 5-15 and 5-16) by the author.

5.8 Illinois

Neither the Illinois Department of Natural Resources, Office of Oil and Gas Resource Management nor the Illinois State Geological Survey (ISGS) submitted a questionnaire. The Oil and Gas Resource Management website notes that Illinois has about 32,100 oil and gas production wells and 10,500 Class II injection wells. No year is associated with these statistics. EIA data show that Illinois produced 8,908,000 bbl of oil and 2,125 Mmcf of gas during 2012.

Table 5-17 — 2012 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	32,100	99,142,423	8,908,000 bbl/yr
Natural gas from conventional formations			2,125 Mmcf/yr
Crude oil from unconventional formations	no data	no data	no data
Natural gas from unconventional formations	no data	no data	no data
Total		99,142,423	8,908,000 bbl/yr 2,125 Mmcf/yr

Illinois did not provide any summary information on produced water generation or how produced water was managed in 2012. Much of Illinois's oil production is from older low-production wells known as stripper wells. Older fields often rely heavily on water injection for enhanced recovery. Operators injecting water for enhanced recovery in Illinois were required to submit Form OG-17 Secondary/Tertiary Oil Recovery Project Annual Report http://www.dnr.illinois.gov/oilandgas/documents/oilandgasfillableforms/og17annualreportsecondarytertiaryoilrecoveryform.pdf each year to the ISGS. That form provides estimates of the volume of water injected for enhanced recovery as well as the volume of water generated from the wells. However, due to staffing shortages, the paper copies of Form OG-17 were never entered into an electronic database or otherwise tabulated. Rather, they were stored as paper records.[19]

[19] Telephone conversation between the ISGS and John Veil on December 3, 2014.

In late December 2014, the ISGS sent the author 282 completed copies of Form OG-17. The author transcribed data from the paper forms into a spreadsheet to give total produced water generated and total water injected for 2012 enhanced recovery projects. Using the Form OG-17 data, 99,142,423 bbl of produced water were generated, and 105,267,787 bbl were injected in Illinois for enhanced recovery during 2012. In the absence of any other information about produced water management, all produced water for Illinois was assumed to be reinjected for enhanced recovery.

Table 5-18 — 2012 Produced Water Management Practices for Illinois

Management Practice	# Wells Using That Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	no data	105,267,787	100%
Injection for disposal	no data	no data	no data
Surface discharge	no data	no data	no data
Evaporation	no data	no data	no data
Offsite commercial disposal	no data	no data	no data
Beneficial reuse	no data	no data	no data
Total Volume Managed		105,267,787	

5.9 Indiana

Produced water data were provided by the Division of Oil and Gas of the Indiana Department of Natural Resources (IDNR).[20] Tables 5-19 and 5-20 show the replies to the questionnaire. In 2012, Indiana had 5,614 active oil and gas wells, with 88% of them producing conventional oil. Less than 1% of the wells produced conventional gas, and 11% produced unconventional gas.

The statewide total produced water volume for 2012 was 57,565,831 bbl. Conventional oil production generated more than 85% of that total. Conventional gas wells contributed about 1% of the total produced water volume. Unconventional gas wells contributed the remaining 14%.

[20] Emails from IDNR to Mike Nickolaus, GWPC, on August 28, 2014, and from IDNR to John Veil, on August 29, 2014.

Table 5-19 — 2012 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	4,960	48,930,957	2,350,035 bbl/yr
Natural gas from conventional formations	32	575,658	18 Mmcf/yr
Crude oil from unconventional formations	no data	no data	no data
Natural gas from unconventional formations	622	8,059,216	8,795 Mmcf/yr
Total	5,614	57,565,831	2,350,035 bbl/yr 8,813 Mmcf/yr

These produced water volumes resulted in a WOR of 21 bbl/bbl of crude oil, and a WGR of 980 bbl/Mmcf for gas.

The primary management practice for produced water was injection for enhanced recovery, which injected 43,131,200 bbl (75%) of produced water annually into 1,041 injection wells. Produced water was also managed through 208 disposal wells, which accounted for another 25% of produced water. A small fraction of produced water (0.1%) was managed through surface discharge. This water comes from CBM operations and has low salinity. NPDES permits were issued to authorize those discharges.

Table 5-20 — 2012 Produced Water Management Practices for Indiana

Management Practice	# Wells Using That Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	1,041	43,131,200	75%
Injection for disposal	208	14,377,066	25%
Surface discharge	77	57,565	0.1%
Evaporation	0	0	0
Offsite commercial disposal	0	0	0
Beneficial reuse	0	0	0
Total Volume Managed		57,565,831	

5.10 Kansas

Produced water data were provided by the Kansas Corporation Commission (KCC).[21] Tables 5-21 and 5-22 show the replies to the questionnaire.

Table 5-21 — 2012 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	49,230	948,580,647	42,621,194 bbl/yr
Natural gas from conventional formations	24,866	87,254,676	289,855 Mmcf/yr
Crude oil from unconventional formations	172	22,428,540	1,121,427 bbl/yr
Natural gas from unconventional formations	23	2,755,324	9,432 Mmcf/yr
Total	74,291	1,061,019,187	43,742,621 bb/yr 299,287 Mmcf/yr

In 2012, Kansas had 74,291 active oil and gas wells, with 66% of them producing conventional oil. Another 33% of the wells produced conventional gas. Kansas had a small number of unconventional oil and gas wells too.

The statewide total produced water volume for 2012 was 1,061,019,187 bbl. Conventional oil production generated more than 89% of that total. Conventional gas wells contributed about 8% of the total produced water volume. Unconventional oil and gas wells contributed the remaining 3%.

These produced water volumes resulted in a WOR of 22 bbl/bbl of crude oil and a WGR of 300 bbl/Mmcf of gas.

Produced water was managed by injection wells in Kansas. About three quarters of the produced water was injected to 3,523 disposal wells. The remaining 26% of the produced water was injected for enhanced recovery through 6,604 injection wells. The KCC indicated that they did not have information about the beneficial reuse of produced water.

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[21] Email from the KCC Conservation Division to Mike Nickolaus, GWPC on October 27, 2014.

Table 5-22 — 2012 Produced Water Management Practices for Kansas

Management Practice	# Wells Using That Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	6,604	276,298,594	26%
Injection for disposal	3,523	784,720,593	74%
Surface discharge	0	0	0
Evaporation	0	0	0
Offsite commercial disposal	0	0	0
Beneficial reuse	uncertain	uncertain	uncertain
Total Volume Managed		1,061,019,187	

5.11 Kentucky

The Kentucky Department for Natural Resources, Division of Oil and Gas submitted a partial questionnaire, which included estimates of oil and gas production for 2012 but no produced water data.[22] The Division of Oil and Gas noted that the number of producing wells is accurate, but the volume of gas produced is skewed too high because some counties were including liquids in their natural gas production. The Division reported 2012 gas production of 293,290 Mmcf, but the EIA data showed 106,122 Mmcf. The EIA number was used in Table 5-23.

There were 47,500 wells in Kentucky in 2012. Crude oil was produced from 57% of the wells, with natural gas being produced from the remaining wells.

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 produced water volumes. The total estimated produced water volume for Kentucky was 19,689,387 bbl/yr, which equaled the volume of produced water injected into Class II wells during 2012.

To get an indication of how produced water was managed in Kentucky in 2012, an inquiry was made to EPA Region 4, which administers the UIC Class II program for Kentucky. The purpose of the inquiry was to learn the number of injection wells and volumes of produced water actually injected in 2012. Region 4 required that the request be submitted as a Freedom of Information

[22] Email from the Kentucky Division of Oil and Gas to John Veil on September 9, 2014.

Act (FOIA) request – this was submitted on December 5, 2014 and received more than six weeks later.[23]

Table 5-23 — 2012 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	27,000	19,689,387	3,197,924 bbl/yr
Natural gas from conventional and unconventional formations	20,500		106,122 Mmcf/yr
Total		19,689,387	3,197,924 bbl/yr 106,122 Mmcf/yr

Table 5-24 shows the injection data but has no entries for other methods of water management. The Oil and Gas Division reported that nearly all produced water from Kentucky wells was reinjected into Class II wells.

Table 5-24 — 2012 Produced Water Management Practices for Kentucky

Management Practice	# Wells Using That Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	440	18,597,470	94%
Injection for disposal	27	1,091,917	6%
Surface discharge	no data	no data	no data
Evaporation	no data	no data	no data
Offsite commercial disposal	no data	no data	no data
Beneficial reuse	no data	no data	no data
Total Volume Managed		19,689,387	

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[23] Letter from EPA Region 4 to John Veil on January 20, 2015 (sent by email and by surface mail).

5.12 Louisiana

The Louisiana Department of Natural Resources, Office of Conservation provided data on oil, gas, and water.[24] Tables 5-25 and 5-26 show the replies to the questionnaire.

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 927,634,655 bbl of produced water was generated in 2012. 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 5-25 — 2012 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 formations	19,235	927,634,655	82,111,159 bbl/yr
Natural gas from conventional formations	16,572		1,277,149 Mmcf
Crude oil and natural gas from unconventional formations	13 wells in Tuscaloosa Marine Shale (TMS) and 2,145 wells in Haynesville Shale (HS)		TMS - 251,461 bbl/yr oil and 142 Mmcf gas HS – 418,818 bbl/yr condensate and 2,069,724 Mmcf gas
Total	37,965	927,634,655 (based on total water managed)	82,781,438 bbl/yr crude oil (includes condensate) 3,347,015 Mmcf

[24] Emails from the Louisiana Office of Conservation to John Veil on August 7, 2014 and February 11, 2015.

Just over half of the 37,965 wells produced conventional oil. Another 44% of the wells produced conventional gas. About 6% of the wells produced condensate and gas from the unconventional Haynesville Shale, with less than 1% of the wells producing oil and gas from the unconventional Tuscaloosa Marine Shale.

Nearly all produced water in Louisiana was injected. More than 92% of the produced water was injected into 3,321 producer-operated disposal wells. About 4% of water was injected for disposal at offsite commercial disposal facilities. The remaining 3% of produced water was reinjected for enhanced recovery at 401 wells. The Office of Conservation also noted that 4 wells reused their produced water for hydraulic fracturing fluids.

Table 5-26 — 2012 Produced Water Management Practices for Louisiana

Management Practice	# Wells Using That Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	401	31,336,098	3.4%
Injection for disposal	3,231	857,417,339	92.4%
Surface discharge	0	0	0
Evaporation	0	0	0
Offsite commercial disposal	44	38,880,938	4.2%
Beneficial reuse	4 (reuse of flowback)	280	0
Total Volume Managed		927,634,375	

5.13 Michigan

The Michigan Department of Environmental Quality's Office of Oil, Gas, and Minerals provided produced water generation and management information.[25] Tables 5-27 and 5-28 show the replies to the questionnaire.

In 2012, Michigan had 14,600 active oil and gas wells, with 70% of them producing unconventional gas. Another 26% of the wells produced conventional oil, and 4% produced conventional gas.

[25] Email from Michigan Department of Environmental Quality to John Veil on September 8, 2014.

The statewide total produced water volume for 2012 was 117,000,000 bbl. Unconventional gas production generated about 79% 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 3.4 bbl/bbl for oil and the WGR was 708 bbl/Mmcf for gas.

Table 5-27 — 2012 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	3,800	25,000,000	7,400,000 bbl/yr
Natural gas from conventional formations	515	no data	22,000 Mmcf/yr
Crude oil from unconventional formations	0	no data	0
Natural gas from unconventional formations	10,285	92,000,000	108,000 Mmcf/yr
Total	14,600	117,000,000	7,400,000 bbl/yr 130,000 Mmcf/yr

Nearly all of the produced water in Michigan was managed through underground injection. The large majority of produced water (85%) was injected into disposal wells, while 15% was injected for enhanced recovery. The Department of Environmental Quality noted that some produced water was sent to offsite commercial disposal facilities where it was commingled with other exploration and production wastes prior to management. The volume of the produced water component was not quantified.

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. That Division reported that it currently had 23 entities that discharged under that permit.[26] Permit holders were 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.

[26] Email from Michigan DEQ to John Veil on December 9, 2014.

Table 5-28 — 2012 Produced Water Management Practices for Michigan

Management Practice	# Wells Using That Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	525	17,000,000	15%
Injection for disposal	710	100,000,000	85%
Surface discharge	0	0	0
Evaporation	0	0	0
Offsite commercial disposal	uncertain	uncertain	uncertain
Beneficial reuse	Some used for road deicing	uncertain	uncertain
Total Volume Managed		117,000,000	

5.14 Mississippi

The Mississippi Oil and Gas Board provided produced water generation and management information.[27] Tables 5-29 and 5-30 show the replies to the questionnaire.

Table 5-29 — 2012 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	1,800	226,515,010	23,864,051 bbl/yr
Natural gas from conventional formations	1,509	3,166,661	436,789 Mmcf/yr
Crude oil from unconventional formations	42	1,554,444	282,361 bbl/yr
Natural gas from unconventional formations	0	0	0
Total	3,351	231,236,115	24,146,412 bbl/yr 436,789 Mmcf/yr

[27] Email from Mississippi Oil and Gas Board to John Veil on July 24, 2014.

In 2012, Mississippi had 3,351 active oil and gas wells. 54% of them produced conventional oil and 45% produced conventional gas. A small number of wells produced unconventional oil.

The statewide total produced water volume for 2012 was 231,236,115 bbl. Conventional oil production generated about 98% of that total. Conventional gas production contributed about 1.4% of the total produced water volume and unconventional oil production contributed less than 1% of produced water.

The water production data were split between oil production and gas production. The resulting WOR was 9.4 bbl/bbl and the WGR was 7.2 bbl/Mmcf.

Table 5-30 — 2012 Produced Water Management Practices for Mississippi

Management Practice	**# Wells Using That Practice**	**Total Volume of Produced Water Managed by That Practice (bbl/year)**	**Percentage of Produced Water Managed by That Practice**
Injection for enhanced recovery	574	127,179,863	55%
Injection for disposal	494	104,056,252	45%
Surface discharge	0	0	0
Evaporation	0	0	0
Offsite commercial disposal	0	0	0
Beneficial reuse	0	0	0
Total Volume Managed		231,236,115	

In 2012 all of the produced water in Mississippi was managed through underground injection. 55% of produced water was injected for enhanced recovery, while 45% was injected into disposal wells. The data provided by the Oil and Gas Board for 2012 showed an exact match between the volume of produced water generated and the volume managed.

5.15 Missouri

The Missouri Geological Survey provided produced water generation and management information.[28] The information is shown in Tables 5-31 and 5-32.

Missouri had 594 active oil and gas wells during 2012. 97% of those wells produced oil from unconventional formations. The other 19 wells produced gas from conventional formations. The oil wells generated 2,102,516 bbl of produced water. The Missouri Geological Survey did

[28] Email from Missouri Geological Survey to Mike Nickolaus, GWPC on November 3, 2014.

not have water production data for the gas wells. With only 19 gas wells in all, the volume of produced water is likely to be very small in comparison with the water volume from oil wells.

The WOR for the oil wells was 12 bbl/bbl. The volume of gas produced was too small to calculate a meaningful WGR.

Table 5-31 — 2012 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	0	0	0
Natural gas from conventional formations	19	no data	11,592 Mmcf/yr
Crude oil from unconventional formations	575	2,102,516	175,101 bbl/yr
Natural gas from unconventional formations	0	0	0
Total	594	2,102,516	175,101 bbl/yr 11,952 Mmcf/yr

The Missouri Geological Survey reported that all produced water in 2012 was managed by injection. 83% of the produced water was injected into 390 wells for enhanced recovery, and 17% was injected into 18 disposal wells.

Table 5-32 — 2012 Produced Water Management Practices for Missouri

Management Practice	# Wells Using That Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	390	1,748,050	83%
Injection for disposal	18	354,446	17%
Surface discharge	0	0	0
Evaporation	0	0	0
Offsite commercial disposal	0	0	0
Beneficial reuse	0	0	0
Total Volume Managed		2,102,496	

5.16 Montana

The Montana Board of Oil and Gas Conservation (BOGC) provided produced water generation and management information.[29] Additional data to populate Tables 5-33 and 5-34 were obtained from various sources as described below. The oil and gas production volumes were taken from EIA. They compared closely with data found in the Annual Review 2012 report published by the BOGC (BOGC 2012). The well counts for conventional production were extracted from BOGC (2012). The well count for CBM wells was extracted from Meredith and Kuzara (undated).

Montana had more than 11,299 active oil and gas wells in 2012. Most of those wells produced oil (42%) and gas (55%) from conventional formations. The remaining 3% produced CBM.

Montana generated 182,833,415 bbl of produced water in 2012. The conventional oil wells generated about 91% of the water. The conventional gas wells generated 2%. CBM wells generated the remaining 7%.

The WOR for conventional oil was 6.2 bbl/bbl. The WGR for CBM was 3,612 bbl/Mmcf. The WGR for combined gas was 257 bbl/Mmcf.

Table 5-33 — 2012 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	4,713	165,607,086	26,495,000 bbl/yr 20,085 Mmcf/yr
Natural gas from conventional formations	6,254	3,748,224	43,137 Mmcf/yr
Crude oil from unconventional formations	0	0	0
Natural gas from unconventional formations (CBM)	332	13,478,105	3,731 Mmcf/yr
Total	11,299	182,833,415	26,495,000 bbl/yr 66,953 Mmcf/yr

The water management data provided by the BOGC showed only injection volumes for produced water, with a total injected volume of 186,549,310 bbl. 130,013,219 bbl was injected

[29] Email from Montana BOGC to John Veil on December 17, 2014.

for enhanced recovery. About 10% of the water used for enhanced recovery was injected on Indian lands, with the majority being injected on other lands. 56,536,091 bbl was injected to disposal wells.

Although the BOGC did not report any produced water being managed through evaporation, surface discharge, offsite commercial disposal, or beneficial reuse, some of the CBM produced water, which has low salinity in the Powder River Basin, was managed by discharge or beneficial reuse and some other produced water was managed by evaporation or beneficial use.

Table 5-34 — 2012 Produced Water Management Practices for Montana

Management Practice	# Wells Using That Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	no data	106,797,324 bbl (produced water portion) 130,013,219 bbl total	58%
Injection for disposal	no data	56,536,091	31%
Surface discharge	no data	19,500,000	11%
Evaporation	no data	no data	no data
Offsite commercial disposal	no data	no data	no data
Beneficial reuse	no data	no data	no data
Total Volume Managed		182,833,415	

The Montana Department of Environmental Quality issued a general discharge permit for produced water discharges from CBM operations. The Department was able to provide some information about those CBM facilities that actually made a discharge during 2012 and also provided tips on using EPA's national data system called ECHO (Enforcement and Compliance History Online)[30] to locate other dischargers. The data supplied by the Department of Environmental Quality included results from 24 facilities covered by the CBM general discharge permit. The spreadsheet listed flow results from 17 facilities. The data were expressed in units of gallons per minute (gpm). The total composite flow from the 17 facilities was 659 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 8,200,000 bbl/yr.

[30] Email from Department of Environmental Quality, Water Protection Bureau to John Veil on December 23, 2014.

Using ECHO, three other oil and gas facilities having individual discharge permits (not covered by the CBM general permit) were identified. The flow rates from those three facilities totaled 1.3 million gallons per day. As noted previously, no information was available to determine if the flows were continuous or intermittent. As above, the flows were assumed to be continuous flows on a 24/7 basis. Following that assumption, the flow volume equaled 11,300,000 bbl/yr. Combining the flows from both groups of dischargers gave a total surface discharge volume of 19,500,000 bbl/yr. This volume was added to Table 5-34.

The total water volume managed in 2012 was 206,049,310 bbl. This exceeded the volume of water generated (182,833,415 bbl). Presumably the difference represented water sources other than produced water that were injected for enhanced recovery. The actual enhanced recovery water volume provided by the BOGC was 130,013,219 bbl. This also includes 23,215,895 bbl of makeup water. The number shown in Table 5-34 reflects the actual produced water contribution to the total injected for enhanced recovery.

5.17 Nebraska

The Nebraska Oil and Gas Conservation Commission provided both water production and management information.[31] The information is shown in Tables 5-35 and 5-36. In 2012, there were 1,606 active wells, with 82% of those wells producing conventional oil. The remaining 18% of the wells produced conventional gas.

Table 5-35 — 2012 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	1,315	57,872,598	2,513,356 bbl/yr
Natural gas from conventional formations	291	768,627	1,221 Mcf/yr
Crude oil from unconventional formations	0	0	0
Natural gas from unconventional formations	0	0	0
Total	1,606	58,641,225	2,513,536 bbl/yr 1,221 Mmcf/yr

[31] Email from Nebraska Oil and Gas Conservation Commission to John Veil on August 25, 2014.

Those wells generated 58,641,225 bbl of produced water. More than 98% of the water came from the oil wells. The WOR was 23 bbl/bbl, and the WGR was 630 bbl/Mmcf.

The Nebraska Oil and Gas Conservation Commission data showed that 59% of produced water was injected into 411 wells for enhanced recovery. Another 32% was injected into 113 disposal wells. The remaining 9% was evaporated in pits.

Table 5-36 — 2012 Produced Water Management Practices for Nebraska

Management Practice	# Wells Using That Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	411	34,368,160	59%
Injection for disposal	113	18,760,291	32%
Surface discharge			
Evaporation	660	5,476,049	9%
Offsite commercial disposal	0	0	0
Beneficial reuse	0	0	0
Total Volume Managed		58,604,500	

5.18 Nevada

The Nevada Division of Minerals supplied water production and management data.[32] The information is shown in Tables 5-37 and 5-38. In 2012, there were 71 active wells producing conventional oil and some associated gas.

Those wells generated 5,865,043 bbl of produced water. More than 98% of the water came from the oil wells. The WOR was 16 bbl/bbl.

[32] Email from Nevada Division of Minerals to John Veil on September 16, 2014.

Table 5-37 — 2012 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	71	5,865,043	367,994 bbl/yr
Natural gas from conventional formations	0	0	3.6 Mmcf/yr (associated with oil production)
Crude oil from unconventional formations	0	0	0
Natural gas from unconventional formations	0	0	0
Total	71	5,865,043	367,994 bbl/yr 3.6 Mmcf/yr

The Division of Minerals' data indicate that all produced water was injected into 10 disposal wells. The volume of injected water (4,742,835 bbl) was less than the volume generated.

Table 5-38 — 2012 Produced Water Management Practices for Nevada

Management Practice	# Wells Using That 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	0
Injection for disposal	10	4,742,835	100%
Surface discharge	0	0	0
Evaporation	0	0	0
Offsite commercial disposal	0	0	0
Beneficial reuse	0	0	0
Total Volume Managed		4,742,835	

5.19 New Mexico

The Oil Conservation Division (OCD) of the New Mexico Energy, Minerals, and Natural Resources Department provided produced water and hydrocarbon production information.[33] The OCD did not submit the two completed tables that were part of the questionnaire. Instead, the OCD provided a link to an online database of production data https://wwwapps.emnrd.state.nm.us/ocd/ocdpermitting/Reporting/Production/ExpandedProductionInjectionSummaryReport.aspx. Data on oil, gas, and water production, as well as water injection were taken from that database (the database had been updated through January 31, 2015). The data were added to Tables 5-39 and 5-40 by the author.

Table 5-39 — 2012 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 formations	no data	674,902,374	85,340,282 bbl/yr
Natural gas from conventional formations	no data	64,245,515	892,607 Mmcf/yr
Crude oil from unconventional formations	no data	no data	no data
Natural gas from unconventional formations (San Juan and Raton)	no data	36,782,414	359,380 Mmcf/yr
Total	no data	775,930,303	85,340,282 bbl/yr 1,251,987Mmcf/yr

The total volume of produced water from New Mexico wells in 2012 was 775,930,303 bbl. 87% of the water was generated from conventional oil production. Conventional gas wells generate 8% of the total, and unconventional gas wells produced the remaining 5% of the water.

The WOR from these data was 8 bbl/bbl. The WGR for conventional gas was 72 bbl/Mmcf. The WGR for unconventional gas was 102 bbl/Mmcf. The WGR for all gas combined was about 81 bbl/Mmcf.

[33] Email from New Mexico Oil Conservation Division to Mike Nickolaus, GWPC, on July 25, 2014, and an email from the Division to John Veil, on February 11, 2015.

Table 5-40 — 2012 Produced Water Management Practices for New Mexico

Management Practice	# Wells Using That Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	no data	381,160,348	50% (assumes even split with disposal wells)
Injection for disposal	no data	381,160,348	50%
Surface discharge	no data	no data	no data
Evaporation	no data	no data	no data
Offsite commercial disposal	no data	no data	no data
Beneficial reuse	no data	no data	no data
Total Volume Managed		762,320,696	

The OCD receives monthly injection volumes from the operators, but those forms do not indicate whether injection was for enhanced recovery or for disposal. The OCD does not track injection water separately. The total volume of water injected in 2012 was 762,320,696 bbl. For the sake of this report, it was assumed that half of the water was injected for enhanced recovery and half for disposal.

5.20 New York

The New York State Department of Environmental Conservation (NYDEC) Division of Mineral Resources provided oil, gas, and water production information.[34] The NYDEC data and other information compiled by the author are shown in Tables 5-41 and 5-42. New York had 13,178 active oil and gas wells in 2012, with 40% of the wells producing oil and 60% producing gas.

Those wells generated 509,562 bbl of produced water. Oil wells generated about 40% of the water with gas wells generating the remaining 60%. The WOR from these data was 0.6 bbl/bbl. The WGR for gas was 11 bbl/Mmcf.

The NYDEC had limited information on how the produced water was managed. The NYDEC submittal showed that 69 wells were used to inject 13,778 bbl of water for enhanced recovery. However, it noted that the NYDEC does not have regulatory primacy for the Class II UIC program. Class II UIC permits within New York are issued and managed by EPA Region 2.

[34] Email from Division of Mineral Resources, NYDEC, to Mike Nickolaus, GWPC, on November 24, 2014, and an email from NYDEC to John Veil, on January 29, 2015.

Table 5-41 — 2012 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	5,293	208,453	359,669 bbl/yr
Natural gas from conventional formations	7,885	301,109	26,595 Mmcf/yr
Crude oil from unconventional formations	0	0	0
Natural gas from unconventional formations	0	0	0
Total	13,178	509,562	359,669 bbl/yr 26,595 Mmcf/yr

For more clarification on injection activities, EPA Region 2 was contacted. Region 2 provided details of Class II injection for New York during 2012.[35] Six wells had valid injection permits for disposal in 2012, but only two of them were active during the year. A total of 586 bbl was injected in 2012.

Eight projects were permitted for enhanced recovery using multiple wells per facility. Only two of these were active during 2012 using up to 27 wells. They injected 26,836 bbl of water for enhanced recovery. EPA indicated that the majority of the water injected at the enhanced recovery facilities was fresh makeup water rather than produced water.

Other management practices for produced water in New York are not subject to regulations that require oil and gas brine volumetric reporting by the authorized haulers, recipients, or end users. The NYDEC indicated that some volume of produced water was managed by surface discharge, offsite commercial disposal, and by beneficial reuse. They were unable to provide a volumetric estimate and suggested that the term “uncertain” be used instead. The NYDEC indicated that some of the produced water was beneficially reused for roadspreading under the BUD (Beneficial Use Determination) program. However, volumes were not required to be reported.

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[35] Email from EPA Region 2 to John Veil on November 26, 2014.

Table 5-42 — 2012 Produced Water Management Practices for New York

Management Practice	# Wells Using That 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	26,836	98%
Injection for disposal	2	586	2%
Surface discharge	uncertain	uncertain	uncertain
Evaporation	0	0	uncertain
Offsite commercial disposal	uncertain	uncertain but is in the tens of thousands of bbls	uncertain
Beneficial reuse	uncertain	uncertain but is in the tens of thousands of bbls	uncertain
Total Volume Managed		27,422 + other not quantified	

Clark and Veil (2009) reported that all produced water that was hauled from well sites requires an NYDEC waste transporter permit. At that time, the NYDEC allowed produced water disposal at publicly owned treatment works, with approved industrial pretreatment or mini-pretreatment programs. No information was available to verify if these practices were allowed in 2012.

5.21 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.[36] The data were shown in Tables 5-43 and 5-44. North Dakota had 8,349 active oil and gas wells in 2012, with 61% of the wells producing from the unconventional Bakken Shale. Another 34% of the wells produced conventional oil, and the remaining 5% produced conventional gas.

North Dakota generated 291,147,202 bbl of produced water in 2012. The unconventional oil wells generated 46% of the water, the conventional oil wells generated 51%, and the conventional gas wells generated the rest. The WOR for conventional oil was 6.2 bbl/bbl. The WOR for unconventional oil was just 0.6 bbl/bbl. The combined WOR for oil was 1.2 bbl/bbl. The WGR for conventional gas was 190 bbl/Mmcf.

[36] Email from the NDIC to John Veil on November 24, 2014.

Table 5-43 — 2012 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	2,846	149,049,700	21,604,201 bbl/yr 20,126 Mmcf/yr
Natural gas from conventional formations	430	6,721,355	15,225 Mmcf/yr 2,310,853 bbl/yr
Crude oil from unconventional formations	5,073	135,376,147	219,356,755 bbl/yr 223,152 Mmcf/yr
Natural gas from unconventional formations	0	0	0
Total	8,349	291,147,202	243,271,809 bbl/yr 258,503 Mmcf/yr

Nearly all of the produced water in North Dakota in 2012 was managed by injection. 56% of the water was injected into disposal wells by the producers. Another 26% was sent offsite for commercial disposal – most of which goes into large disposal wells. The remaining 18% was managed through injection into enhanced recovery wells.

Table 5-44 — 2012 Produced Water Management Practices for North Dakota

Management Practice	# Wells Using That Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	629	52,484,071 bbl (produced water portion) 128,086,890 bbl total	18%
Injection for disposal	350	161,977,724	56%
Surface discharge	0	0	0
Evaporation	0	0	0
Offsite commercial disposal	99	76,685,407	26%
Beneficial reuse	0		0
Total Volume Managed		291,147,202	

However, the total water volume injected for enhanced recovery was considerably larger than the 52,484,071 bbl shown in the table. The actual enhanced recovery water volume provided by the NDIC was 128,086,890 bbl. This also included 75,602,819 bbl of makeup water.

5.21.1 Changes from 2007 to 2012

During the period from 2007 to 2012, total oil production increased dramatically from 44,543,000 bbl to 243,272,000 bbl (546% increase). Unconventional oil production from the Bakken Shale made up 90% of North Dakota's oil for 2012. The Bakken Shale activity grew rapidly during the 2007-2012 period.

Natural gas production, while remaining low, still increased by 365%. Over that same period, however, water production increased by only 216%.

The WORs also showed a change over time. The 2007 overall WOR for North Dakota was 3 bbl/bbl. During 2012, the overall WOR was 1.2 bbl/bbl. Much of the cause of the lower WOR in 2012 was the expanded Bakken Shale production. There was a clear difference between conventional oil production (6.2 bbl/bbl) and unconventional Bakken Shale oil production (0.6 bbl/bbl). These data suggest that unconventional oil production generated water at a much lower rate than did conventional production.

5.22 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.[37] The data were shown in Tables 5-45 and 5-46.

Ohio had 51,742 active oil and gas wells in 2012 – nearly all of them produced both oil and gas from conventional formations. A few unconventional wells produced during 2012 as Ohio's Utica Shale activity was beginning. Although only 86 unconventional wells produced during 2012, they had a disproportionate share of the hydrocarbon production. Those few wells accounted for 12% of the total oil and 15% of the total gas produced during the year.

Ohio generated 5,541,502 bbl of produced water in 2012. The conventional oil wells generated 88% of the water. The unconventional wells generated the remaining 12% of the water. Because water production was not provided separately for oil and gas wells, it was not possible to calculate WORs or WGRs.

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[37] Emails from DOGRM to John Veil on November 18 and 19, 2014.

Table 5-45 — 2012 Production for Ohio

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 gas from conventional formations	51,656	4,859,817	4,426,787 bbl/yr 73,230 Mmcf/yr
Crude oil and gas from unconventional formations	86	681,685	635,876 bbl/yr 12,831 Mmcf/yr
Total	51,742	5,541,502	5,062,663 bbl/yr 86,061 Mmcf/yr

Most produced water in Ohio was managed through injection, with 91% 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. Ohio does have an active group of commercial disposal well facilities that managed water from both Ohio and Pennsylvania.

The DOGRM noted that the beneficial reuse totals represented two separate types of reuse: 129,575 bbl were used for deicing and dust control on roads, and 626,208 bbl were recycled to make new drilling fluids and frac fluids.

Table 5-46 — 2012 Produced Water Management Practices for Ohio

Management Practice	# Wells Using That Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	125	604,693	4%
Injection for disposal	190	14,157,886	91%
Surface discharge	0	0	0
Evaporation	0	0	0
Offsite commercial disposal		Included in injection for disposal	Included in injection for disposal
Beneficial reuse	0	755,783	5%
Total Volume Managed		15,518,362	

The total volume of produced water managed in Ohio during 2012 (15,518,362 bbl) greatly exceeded the volume generated in the state (5,541,502 bbl). This discrepancy in volumes was noted to the DOGRM. They replied: *"In 2012 the conventional industry in Ohio was slowing and unconventional drilling was just starting. Marcellus activity in Pennsylvania was in full swing and we were receiving significant volumes from operators in that state."*

It was not possible to determine if out-of-state produced water accounted for the entire excess disposal vs. generation volume. In any case, it represented a significant volume of water. Because it was produced water (and not makeup water), it was counted under Ohio's total water management.

The volume of water managed in 2012 was more than double the volume managed in 2007. The increase in water volume corresponded with rapid production growth in the Marcellus Shale and Utica Shale formation.

5.23 Oklahoma

The Oklahoma Corporation Commission (OCC) was unable to provide produced water volume data for this study because they do not receive produced water volume data from the oil and gas operators.[38] Although the OCC did not submit a completed questionnaire, they do have detailed data on the volume of fluids injected into Class II wells – that database is available on the OCC website. A spreadsheet titled "UIC Injection Volumes 2012" was downloaded from http://www.occeweb.com/og/ogdatafiles2.htm. It shows the monthly injected volume from each Class II well. By sorting and summing the different Class II well types, data were compiled into Table 5-47.

Table 5-47 — 2012 Injection Volumes and Well Count

Well Class	2012 Total Volume Injected (bbl)	# Wells
2D	663,588,934	2,743
2DCm	139,760,197	271
2DNC	336,233,517	1,041
2R	772,523,366	4,492
2RIn	324,725,454	1,614
2RSI	1,063,102	11
SWD	87,257,515	237
Total	**2,325,152,584**	**10,409**

[38] Email from OCC to John Veil on November 17, 2014.

The Well Class abbreviations were clarified by the OCC.[39] 2D, 2DCm, 2DNC, and SWD wells were all used for disposal. 2DCm wells were designated as commercial disposal wells, whereas 2DNC wells were non-commercial disposal wells. The wells classified as 2D and SWD have not been designated as commercial or non-commercial. Wells classified as 2R, 2RIn, and 2RSI were all used for enhanced recovery. The 2RSI wells were used for simultaneous injection operations (water generated from an oil and gas producing zone was injected into a lower injection zone in the same well without bringing the water to the surface).

The number of injection wells in each well class changed throughout the year as new wells were approved and older wells were closed. The numbers shown in Table 5-47 were considered to be an approximation. A presentation by the OCC (Griffith 2013) noted that Oklahoma had 10,800 active injection or disposal wells in 2012. The well count from that presentation was close to the well count from the OCC spreadsheet.

Table 5-48 shows the information from Table 5-47 converted to the format used for the other states. Although not an exact match, the volume of water injected for disposal and for enhanced recovery was assumed to be equal to the volume of produced water generated for the sake of this report.

Table 5-49 was prepared by the author to be comparable with the results shown for each other state. It uses a water volume equal to the injection volume, oil and gas production volumes from EIA, and well counts from Griffith (2013).

Table 5-48 — 2012 Produced Water Management Practices for Oklahoma

Management Practice	# Wells Using That Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	6,117	1,098,311,922	47%
Injection for disposal	4,021	1,087,079,966	47%
Surface discharge	0	0	0
Evaporation	0	00	
Offsite commercial disposal (injection)	271	139,760,197	6%
Beneficial reuse	0	0	0
Total Volume Managed		2,325,152,584	

[39] Telephone conversation between OCC and John Veil on December 1, 2014.

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 — 2012 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	117,000	2,325,152,584	92,988,000 bbl/yr
Natural gas from conventional formations	65,500		1,448,579 Mmcf/yr
Natural gas from unconventional formations	No data		574,882 Mmcf/yr
Total	182,500	2,325,152,584	92,988,000 bbl/yr 2,023,461 Mmcf/yr

5.24 Pennsylvania

The Pennsylvania Department of Environment Protection (PADEP) did not submit a completed questionnaire that provided information on production and management of produced water related to oil and gas activities. However the PADEP website contains links to various production and waste management databases https://www.paoilandgasreporting.state.pa.us/publicreports/Modules/Welcome/Agreement.aspx.

These were used by the author to compile information as shown in Tables 5-50, 5-51, and 5-52. The well counts and production data were obtained from the 2012 production databases. The water management data for both flowback and produced water were obtained from the 2012 waste management databases. Because data were available separately for flowback and produced water in the PADEP databases, volumes for both water streams were shown separately in Table 5-50 but were combined in the Total row. The PADEP provided separate production and waste management information for conventional wells and for Marcellus Shale (unconventional) wells.

Pennsylvania had 92,843 active oil and gas wells in 2012. 93% of the wells produced from conventional formations. The remaining 7% of wells produced from the Marcellus Shale. Conventional wells produced primarily crude oil – 97% of the state's oil came from these wells. The Marcellus Shale wells produced 90% of the state's gas and 92% of the condensate. Condensate was added to the crude oil volume to represent total oil. 57% of the total oil (crude oil + condensate) came from the unconventional wells.

The PADEP production data did not show the actual produced water generation volume. The volume was estimated by assuming that the total volume of flowback water and produced water managed was equal to the volume of water generated (34,088,756 bbl). Conventional wells generated 6,962,524 bbl of water, with 98% of the water being produced water. Marcellus Shale wells generated 27,126,232 bbl of water, with 64% being produced water. The proportion of flowback water was far higher in the Marcellus Shale wells (36%) than in the conventional wells (2%), as would be expected from unconventional wells. It was not possible to calculate the WORs and WGRs for Pennsylvania.

Table 5-50 — 2012 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	86,670	150,221 (flowback) 6,812,303 (produced water)	2,286,004 bbl/yr (oil) 162,523 bbl/yr (condensate)
Natural gas from conventional formations			218,141 Mmcf/yr
Crude oil from unconventional formations	6,173	9,719,945 (flowback) 17,406,287 (produced water)	65,160 bbl/yr (oil) 1,786,612 bbl/yr (condensate)
Natural gas from unconventional formations			2,041,753 Mmcf/yr
Total	92,843	34,088,756 (based on volume of water managed)	4,300,299 bbl/yr 2,259,894 Mmcf/yr

The water management data for Pennsylvania were detailed – water management volume and practice were shown separately for each of the thousands of wells. By sorting and combining the rows and columns in the databases, totals can be derived. They include other management methods not found commonly in the other states. In addition, data on management practices for flowback water and produced water were provided separately.

The PADEP defines flowback as "*the return flow of water, fracturing/stimulation fluids, and/or formation fluids recovered from the well bore of an oil or gas well within 30 days following the release of pressures induced as part of the hydraulic fracture stimulation of a target geologic formation, or until the well is placed into production, whichever occurs first*." It defines Brine/Produced Fluids (comparable to produced water) as "*water and/or formation fluids,* *including natural salt water separated at oil and gas wells that are recovered at the wellhead after the flowback period*."[40]

Table 5-51 provides the full distribution of water management data. Table 5-52 combines the data into the same tabular format used for other states.

The water management categories in Table 5-51 are described below:

- Centralized treatment plant – the water was trucked to a centralized plant where it was treated then returned to the field for reuse.
- Injection for disposal – Pennsylvania has very few disposal wells. Most of the water managed in this way was trucked to Ohio or West Virginia. This could potentially lead to double counting of the water in both Pennsylvania and whichever other state receives the water. Given that the total volume of injected water was a bit more than 4 million bbl, its impact on national produced water volume estimates was very small. This is noted as an area of uncertainty, but is tolerated because of the insignificant magnitude of any impact of double counting.
- Residual waste processing – The PADEP issued a general permit allowing residual waste (flowback and produced water are considered to be residual waste) to be recycled. Only a small portion of the wastewater was managed under the general permit.
- Reuse other than roadspreading – most of this wastewater was given some degree of treatment in the field and was then reused in other wells.
- Storage waiting for disposal. 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.
- Landfill – most liquid wastes were not allowed to be disposed in landfills. The wastewater shown in these categories may have been incorrectly entered on reporting forms. In any case, this was a very small volume of wastewater.
- Discharge – This category covered two types of activities. The PADEP requires a very high degree of treatment before Marcellus Shale wastewater can be discharged to surface waters. A few centralized treatment plants offer advanced levels of treatment, including desalination. The very small volume of wastewater managed in this way is shown under the discharge category. In addition, about 11% of the conventional well wastewater was managed by sending it to municipal wastewater treatment plants. Marcellus Shale wastewater is no longer permitted for disposal in this way.
- Roadspreading – some of the conventional produced water and a very small amount of the unconventional produced water was applied to roads in winter months for deicing.

[40] These definitions are part of the "Oil and Gas-Related Residual Waste Code (RWC) Descriptions" found in a document posted at http://www.portal.state.pa.us/portal/server.pt/document/1468452/tenorm_monthly_spreadsheet_instructions_pdf?qid=24478749&rank=9.

Table 5-51 contains a great deal of interesting information that shows differences in management practices between conventional and unconventional production as well as differences in how flowback water was managed compared to produced water. Readers are encouraged to study this table to learn the different strategies used during 2012.

Table 5-51 — Detailed Water Management Data for Pennsylvania

	Unconventional				Conventional				Combined	
	Flowback	Prod Water	Total	%	Flowback	Prod Water	Total	%	Total	%
Centralized treatment for reuse	1,398,438	2,131,496	3,529,934	13	141,167	2,136,033	2,277,200	33	5,807,134	17
Injection - disposal	70,679	3,493,527	3,564,206	13	1,879	653,945	655,824	9	4,220,030	12
Residual waste processing and reuse	30,612	105,358	135,970	0.5	0	0	0	<0.1	135,970	0.4
Reuse other than roadspreading	8,149,339	11,418,150	19,567,489	72	2,996	2,975,695	2,978,691	43	22,546,180	66
Storage waiting for disposal or reuse	63,981	256,948	320,929	1.2	0	5,100	5,100	<0.1	326,029	1.0
Landfill	6,366	278	6,644	<0.1	0	109	109	<0.1	6,753	<0.1
Discharge	105	105	210	<0.1	4,100	775,554	779,654	11	779,864	2.2
Roadspread	425	425	850	<0.1	79	265,867	265,946	4	266,796	1.0
Total	**9,719,945**	**17,406,287**	**27,126,232**	**100**	**150,221**	**6,812,303**	**6,962,524**	**100**	**34,088,756**	**100**

To combine this into the tabular format in Table 5-52, the last two columns on the right from Table 5-51 were used. The Injection-Disposal and Discharge totals were used directly. The Centralized Treatment for Reuse, Residual Waste Processing, Reuse Other than Roadspreading, Storage, and Roadspread categories were combined and placed into the Beneficial Reuse row. The very small volume shown in the Landfill category was not included in Table 5-52.

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.

5.24.1 Changes from 2007 to 2012

Oil and gas activity in Pennsylvania changed dramatically between 2007 and 2012. The Marcellus Shale went from being a new promising play in 2007 to a major gas-producing play in 2012. Conventional production also increased. In 2007, Pennsylvania produced oil and gas from about 71,000 wells – nearly all were conventional wells. In 2012, Pennsylvania operated 86,670 conventional wells and 6,173 Marcellus Shale wells.

Table 5-52 — 2012 Produced Water Management Practices for Pennsylvania

Management Practice	# Wells Using That Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	no data	0	0
Injection for disposal	no data	4,220,030	12.4%
Surface discharge	no data	779,864	2.3%
Evaporation	no data	0	0
Offsite commercial disposal	no data	0	0
Beneficial reuse	no data	29,082,109	85.3%
Total Volume Managed		34,082,003	

In 2007, gas production was 172,367 Mmcf (Pennsylvania was the 16th highest gas-producing state). In 2012, the conventional gas production was 218,141 Mmcf, plus there was a large gas production from Marcellus Shale wells of 2,041,753 Mmcf. The total gas production was 2,259,894 Mmcf, which was 13 times larger than the 2007 total. This moved Pennsylvania into 4th place among gas-producing states.

In 2007, the oil production (presumably including any condensate) was 1,537,347 bbl. This put Pennsylvania in 25th place in oil production among the states. In 2012, the oil and condensate production from conventional wells was 2,448,527 bbl. The Marcellus Shale wells contributed another 1,851,772 bbl. The combined total of 4,300,299 bbl was 2.8 times larger than oil production in 2007. This moved Pennsylvania into 19th place among oil-producing states.

The total produced water volume in 2007 was 3,912,456 bbl. This water volume ranked Pennsylvania 28th among the 31 producing states. The conventional water volume in 2012 was 6,962,524 bbl, and the Marcellus Shale wells contributed another 27,126,232 bbl for a total of 34,088,756 bbl (8.7 times larger than the 2007 total). This moved Pennsylvania into 22nd place among produced water generating states.

To gauge the impact of the Marcellus Shale wells, they can be studied separately from the conventional wells. The increase in production from 2007 to 2012 for conventional wells was 27% for gas, 59% for oil, and 78% for water.

Only minimal production came from Marcellus Shale wells in 2007. In 2012, Marcellus Shale wells produced 2,041,753 Mmcf of gas, 1,858,772 bbl of oil and condensate, and 27,126,232 bbl of water. The increase in produced water from Marcellus Shale wells in 2012 was significant compared to the total produced water generated in 2007. But putting it in perspective of water production in all other states, it was not a substantial increase (Pennsylvania remains in the bottom third of state produced water volumes).

Another way of looking at the data was to evaluate production on a per-well basis. On average, each conventional well generated 2.5 Mmcf of gas, 28 bbl of oil and condensate, and 80 bbl of water per year. In comparison, each Marcellus Shale well generated 331 Mmcf of gas, 300 bbl of oil and condensate, and 4,394 bbl of water (64% of the water was produced water). Each Marcellus Shale well produced 11 times more oil, 132 times more gas, and 55 times more water than each conventional well.

5.25 South Dakota

The South Dakota Department of Environment and Natural Resources, Geological Survey Program provided information on production and management of produced water related to oil and gas activities.[41] The data are shown in Tables 5-53 and 5-54.

South Dakota had 253 active oil and gas wells in 2012, with all wells producing from conventional formations. 62% of the wells produced oil and 38% produced gas. The Geological Survey estimated a total gas production of 15,108 Mmcf. 555 Mmcf came from gas wells – the remainder was associated gas from oil wells. The Geological Survey maintains a detailed production database on its website at http://denr.sd.gov/des/og/producti.aspx.

During 2012, South Dakota wells generated 5,296,179 bbl of produced water. Nearly all the water came from the oil wells. The WOR was 3 bbl/bbl. The volume of water from gas wells was so small (642 bbl) that calculation of a WGR was not meaningful.

According to the Geological Survey, all produced water was injected. The total water managed by injection (5,981,240 bbl) was greater than the total volume of produced water generated. The Geological Survey acknowledged that some of the water used for water flood projects comes from other sources. The actual enhanced recovery water volume provided by the Geological Survey was 3,709,852 bbl. That total can be allocated to make produced water volumes balance. 3,024,791 bbl was assumed to be produced water, with the remaining 685,061 bbl being makeup water.

[41] Emails from South Dakota Geological Survey to John Veil on July 18, 2014 and February 23, 2015.

Table 5-53 – 2012 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	158	5,295,537	1,754,207 bbl/yr
Natural gas from conventional formations	95	642	15,108 Mmcf/yr (includes gas from the 95 gas wells and associated gas from the oil wells)
Crude oil from unconventional formations	0	0	0
Natural gas from unconventional formations	0	0	0
Total	253	5,296,179	1,754,207 bbl/yr 15,108 Mmcf/yr

Table 5-54 — 2012 Produced Water Management Practices for South Dakota

Management Practice	# Wells Using That Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	34	3,024,791 bbl (produced water portion) 3,709,852 bbl total	57%
Injection for disposal	15	2,271,388	43%
Surface discharge	0	0	0
Evaporation	0	0	0
Offsite commercial disposal	0	0	0
Beneficial reuse	0	0	0
Total Volume Managed		5,296,179	

Clark and Veil (2009) reported that South Dakota managed 4% of produced water in 2007 through surface discharge or beneficial reuse as water for livestock. These alternate management practices were not identified in the Geological Survey's reply in 2014. The Geological Survey noted that these alternate practices were not tracked through oil and gas production data. He also added that it was unlikely that produced water would be used for livestock purposes.

5.26 Tennessee

The Tennessee Oil and Gas Program in the Department of Environment and Conservation provided information about oil and gas production.[42] This information and other information compiled by the author are shown in Tables 5-55 and 5-56.

Tennessee had 2,339 active oil and gas wells in 2012. About 53% of these wells produced oil from conventional formations. The other 47% of the wells produced gas from conventional formations.

Table 5-55 — 2012 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	1,236	1,480,405 (extrapolated)	372,251 bbl/yr
Natural gas from conventional formations	1,103		5,891 Mmcf/yr
Crude oil from unconventional formations	0		0
Natural gas from unconventional formations	0		0
Total	2,339	1,480,405 (extrapolated)	372,251 bbl/yr 5,891 Mmcf/yr

Tennessee does not collect produced water information on oil and gas wells. Most of the oil and gas production in Tennessee is located in the north central portion of the state along its border with Kentucky. An extrapolation procedure based on using Kentucky's oil, gas, and water volumes was used to estimate a produced water volume for Tennessee. The volume of oil produced in Kentucky in 2012 was 8.6 times larger than in Tennessee. The volume of gas produced in Kentucky in 2012 was 18 times larger than in Tennessee. Water production for Kentucky was estimated as a single number, without allocating volumes to oil production and

[42] Email from Tennessee Oil and Gas Program to John Veil on December 9, 2014.

to gas production. The 2012 water production for Tennessee is likely to be somewhere between 8.6 to 18 times lower than Kentucky's volume.

Without any other basis for evaluating those ratios, the two numbers were averaged, yielding an estimated state-to-state differential factor of 13.3. Kentucky's 2012 water production volume (19,689,387 bbl) was divided by 13.3. The resulting extrapolated estimate was 1,480,405 bbl of produced water generated in Tennessee during 2012.

The Tennessee Oil and Gas Program reported that produced water was not injected for enhanced recovery or for disposal in 2012. The Program noted that surface discharge, evaporation, and offsite commercial disposal were the practices used in Tennessee, but she had no information on the volumes managed by each practice.

The Tennessee Oil and Gas Association explained that most oil and gas production in Tennessee comes from gas-drive formations (gas in the formation helps maintain downhole pressure). As a result, very little produced water comes to the surface. Typically, the small amounts of produced water were placed in pits where much of the water evaporates[43]. For the sake of this report, all produced water for 2012 was assumed to be evaporated from pits.

Table 5-56 — 2012 Produced Water Management Practices for Tennessee

Management Practice	# Wells Using That 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	0
Injection for disposal	0	0	0
Surface discharge	0	0	0
Evaporation	common	1,480,405 (estimated)	100%
Offsite commercial disposal	0	0	0
Beneficial reuse	0	0	0
Total Volume Managed		1,480,405	

[43] Telephone conversation between the Tennessee Oil and Gas Association and John Veil, on December 18,2014.

5.27 Texas

The Railroad Commission of Texas (RRC) provided information on produced water and hydrocarbon production.[44] The data are shown in Tables 5-57 and 5-58. Oil and gas activity in Texas was far larger than in any other state. The RRC reported 270,082 active oil and gas wells in Texas during 2012. Oil wells made up 62% of the total wells. The oil and gas production data and well counts did not distinguish between conventional and unconventional production.

The total volume of produced water reported from all wells was 7,435,659,156 bbl – much larger than the volume reported for any other state. The RRC was unable to provide a breakout of water production from oil well vs. gas wells or from conventional vs. unconventional wells. As a result, it was not possible to calculated WORs or WGRs.

Looking at how that water was managed, the RRC was able to provide a total volume of water injected during 2012 (7,435,659,156 bbl). The RRC data broke out the volume injected into commercial disposal wells (795,024,609 bbl). Unfortunately the RRC's databases could not be queried in a way to provide separate estimates of the volume of water injected for enhanced recovery and the volume injected for disposal in non-commercial wells. The total volume for both types of injection was shown as a single estimate (6,640,634,547 bbl).

Table 5-57 — 2012 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	167,864	7,435,659,156	608,213,317 bbl
Natural gas from conventional and unconventional formations	102,218		8,136,884 Mmcf
Total	270,082	7,435,659,156	608,213,317 bbl 8,136,884 Mmcf/yr

Although about 95% of the produced water in Texas was managed by injection, about 5% of produced water (having the low salinity) was managed by discharge to surface water bodies. The RRC also characterized the low salinity produced water discharge as a beneficial reuse of the water. In addition to the produced water that was discharged, the RRC estimated that 15% to 20% of Texas flowback water was reused – no specific volume was provided for the flowback.

[44] Email from RRC to John Veil on November 7, 2014.

Because of the size of Texas' oil and gas industry, the Texas data were very important proportionally in developing the national estimates. Additional inquiries were made within the RRC to learn if the proportions of water injected for enhanced recovery vs. disposal could be estimated. The individuals contacted were unanimous in confirming that the RRC databases could not be queried to segregate water estimates in those two categories. In a follow-up inquiry to J-P Nicot, oil and gas water specialist at the University of Texas, Bureau of Economic Geology, Dr. Nicot agreed that the RRC database could not be readily sorted or queried to distinguish the type of injection.

Table 5-58 — 2012 Produced Water Management Practices for Texas

Management Practice	# Wells Using That Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	24,717	6,640,634,547(RRC estimate) 3,717,829,578 (redistributed)	48%
Injection for disposal - noncommercial	6,455	2,922,804,969 (redistributed)	37%
Surface discharge (this was put to a beneficial reuse)	60	371,178,296	5% (fresh produced water)
Evaporation	0	0	0
Offsite commercial disposal- injection	1,006	795,024,609	10%
Beneficial reuse	uncertain	uncertain	Estimated 15-20% of flowback fluid
Total Volume Managed		7,806,837,452	

In his reply to the author,[45] Dr. Nicot provided the results of several queries he ran on the RRC's Annual Disposal/Injection Well Monitoring Report (Form H-10) database. The data highlighted the challenges in querying massive databases. The outputs should accurately reflect the query settings, but the person making the query may not use exactly the same sets of settings or assumptions on different queries. When the same database was queried in different ways, the resulting outputs could yield results that were similar but not exactly the same. Likewise, when alternate databases that are intended to house the same information were queried, they often

[45] Email from Jean-Phillipe Nicot, University of Texas, Bureau of Economic Geology, to John Veil, on December 13, 2014.

provided results that were close to, but not the same as the first database. Table 5-59 shows the differences in 2012 injection volume estimates using different queries and sources.

Table 5-59 — Injection Volume Estimates from Different Sources

Data Source	Total Injected Volume (bbl/yr)
Questionnaire provided by RRC	7,435,659,156
H-10 Database – query for fluid type volumes (includes Salt Water, Fresh Water, Fracture Water Flow Back, Steam, and Other fluids)	7,435,586,803
Same as above, but omit Other fluids	7,377,220,312
H-10 Database – query for injection volumes	7,437,897,785
Separate Vendor-Compiled Database	7,421,046,425

The difference between the highest and lowest estimates was about 60 million bbl. For the Texas total volume, that was just a fraction of a percent difference. But compared to the total produced water volumes from many other states, 60 million bbl was a significant volume. For example, the entire 2012 produced water volume for Nebraska was about 58 million bbl – virtually the same as the difference between the highest and lowest Texas estimates.

5.27.1 Alternate Method to Determine Proportion of Water Injected for Enhanced Recovery vs. Disposal

The RRC's website provides some background on underground injection (http://www.rrc.state.tx.us/about-us/resource-center/faqs/oil-gas-faqs/faq-saltwater-disposal-wells/).

> *"There are three different categories of underground injection used to manage the disposal of oil and gas produced wastewater:*
>
> *1. Oil and gas produced wastewater may be returned to the reservoir where it originated by injection for secondary or enhanced oil recovery. These injection wells are referred to as "injection wells" or wells involved in "secondary recovery/injection wells" (permit applications are filed on Form H-1/H-1A);*
>
> *2. Oil and gas produced wastewater may be disposed of by injection into underground porous rock formations not productive of oil or gas that are isolated from useable quality groundwater and sealed above and below by unbroken and impermeable strata. Injection wells of this type are referred to as "disposal wells" or are wells involved in "disposal into a non-productive zone" (permit applications are filed on Form W-14); or*
>
> *3. Oil and gas produced wastewater may be disposed of by injection back into the productive zone where it originated with the associated oil or natural gas that it was*

> *produced with. This type of waste management is referred to as "disposal" because it occurs without the added benefit of "secondary recovery" as in the first category, and is also referred to as "disposal into a productive zone" (these permit applications are also filed on Form H-1/H-1A).*
>
> *The vast majority of wells in Texas are injection wells, not disposal wells. As of calendar year 2013, Texas has more than 50,000 permitted oil and gas injection and disposal wells with approximately 35,000 currently active as of calendar year 2013. Of these 35,000 active injection and disposal wells, about 7,500 are wells that are disposal wells and the remainder are injection wells."*

The estimated number of injection wells indicated in the completed questionnaire submitted by the RRC (32,178 in 2012) was compatible with the estimate of approximately 35,000 active wells in 2013 shown above.

In order to make a rough estimate of the volume of water injected for enhanced recovery and or disposal, the only piece of evidence available was the distribution method used in Clark and Veil (2009). The person who managed the UIC program for the RRC at that time (he has since retired) provided an estimate that 32% of the produced water was injected into a non-producing formation for disposal and 18% was injected into a producing formation for disposal. The remaining 50% was injected for enhanced recovery. Clark and Veil (2009) combined the percentage disposed into producing formations with the percentage injected for enhanced recovery. This portion (68%) was assumed to be injected for enhanced recovery. However, in this current report, that allocation was revisited and changed. The 50% injected for enhanced recovery remains. The 32% and 18% of water injected for disposal were combined for a total of 50% injected for disposal. This assumed distribution of 50% enhanced recovery and 50% disposal was also used for several other states that do not break out the two types of injection.

<u>Note</u>: This set of assumptions does not necessarily reflect actual 2012 data. But in the absence of any other way to make an estimate, it was used here. The decision to combine the 18% of water injected for disposal in a producing formation with the 32% injected for disposal into a non-producing formation was a different approach than the one used in Clark and Veil (2009). The author believes the revised approach is more representative, but acknowledges that it will make comparison of the 2007 data to the 2012 data more complicated.

Following those assumptions estimates were revised. The total injected volume in 2012 was 7,435,659,156 bbl. 50% of the total injected water (3,717,829,578 bbl) was assumed to be used for enhanced recovery The volume injected at commercial disposal facilities (795,024,609 bbl) was all injected for disposal. The difference (2,922,804,969 bbl) was assumed to be the volume injected for disposal at non-commercial facilities.

As a further caveat, it is worth noting that the produced water generated volume exactly matched the produced water injected volume – those were the figures provided by the RRC. The volume of produced water discharged augmented the total injected volume, thereby making the total produced water managed volume slightly larger than the total generated volume. Given the range of other assumptions already employed to estimate volumes for Texas, no further attempt was made to balance the water generated volume with the water managed volume.

5.28 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.[46] The data are shown in Tables 5-60 and 5-61.

Utah had 11,014 active wells during 2012. 62% of the wells produced gas, and 38% produced oil. During 2012, these wells generated 166,945,372 bbl of water. The DOGM did not differentiate between conventional and unconventional production, nor did it have separate water volumes for oil and for gas wells. Therefore, it was not possible to calculate WORs and WGRs.

The DOGM provided water management data for the year 2013 (not for 2012). Presumably the numbers were not much different between the two years. Utah managed 181,626,602 bbl of produced water during 2013. 47% of the water was injected for disposal, and 40% was injected for enhanced recovery. The DOGM noted that the volume shown in Table 5-60 for enhanced recovery represented only produced water (therefore no reduction was made to account for the presumed makeup water). In actual practice, other sources of makeup water were added to augment the total volume.

Table 5-60 — 2012 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	4,232	166,945,372	30,194,727 bbl/yr
Natural gas from conventional and unconventional formations	6,782		490,857 Mmcf/yr
Total	11,014	166,945,372	30,194,727 bbl/yr 490,857 Mmcf/yr

[46] Email from Utah DOGM to John Veil on November 19, 2014.

Another 6% of the produced water was discharged to surface waters in the Ashley Valley field. The water from that formation has low salinity and can be used for irrigation and later discharged. The discharged volume in 2013 (11,589,167 bbl) was only about half of the volume discharged in that field in 2007 (Clark and Veil 2009). Utah producers send 7% of the state's produced water to offsite commercial disposal facilities that employ large evaporation ponds.

The DOGM indicated that 0.5% of the produced water was managed for beneficial reuse. They did not provide any details. Clark and Veil (2009) reported that 476,945 bbl of produced water were reused in drilling and workover fluids in 2007. The use of the Ashley Valley water for irrigation was also a beneficial reuse as well as a surface discharge.

Table 5-61 — 2013 Produced Water Management Practices for Utah

Management Practice	# Wells Using That Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	1,881	71,534,655	40%
Injection for disposal	118	85,534,167	47%
Surface discharge	no data	11,589,301	6%
Evaporation	no data	0	0
Offsite commercial disposal (evaporation ponds)	no data	12,968,479	7%
Beneficial reuse	no data	uncertain	0.5%
Total Volume Managed		181,626,602	

5.29 Virginia

The Virginia Department of Mines, Minerals, and Energy (DMME) provided oil, gas, and water production information as well as produced water management information.[47] The information is shown in Tables 5-62 and 5-63. Virginia had 7,858 active oil and gas wells during 2012. 75% of the wells produced CBM (unconventional gas), and 25% produced conventional gas. Three wells produced conventional oil.

Virginia wells generated 3,231,508 bbl of produced water during 2012. 98% of the water came from the CBM wells. The conventional gas wells generated the remaining 2% of produced water. No produced water was associated with the 3 conventional oil wells. Therefore no WOR

[47] Email from Virginia DMME to John Veil on August 25, 2014.

could be calculated. The WGR for CBM wells was 22 bbl/Mmcf. The WGR for conventional gas wells was 2 bbl/Mmcf. The WGR for combined gas was 22 bbl/Mmcf.

Table 5-62 — 2012 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	3	0	9,659 bbl/yr
Natural gas from conventional formations	1,931	54,427	26,300 Mmcf/yr
Crude oil from unconventional formations	0	0	0
Natural gas from unconventional formations (CBM)	5,927	3,177,081	119,900 Mmcf/yr
Total	7,858	3,231,508	9,659 bbl/yr 146,200 Mmcf/yr

The DMME reported that all produced water was injected for disposal into 4,879 disposal wells.

Table 5-63 — 2012 Produced Water Management Practices for Virginia

Management Practice	# Wells Using That 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	0
Injection for disposal	4,879	3,231,508	100%
Surface discharge	0	0	0
Evaporation	0	0	0
Offsite commercial disposal	0	0	0
Beneficial reuse	0	0	0
Total Volume Managed		3,231,508	

5.30 West Virginia

The West Virginia Department of Environmental Protection (WVDEP) Office of Oil and Gas provided information on production activities and produced water management.[48] The data are shown in Tables 5-64 and 5-65. The data provided by the WVDEP showed 70,588 wells in four categories, but the WVDEP noted that just 60,002 of them were active in 2012. Of the total number of wells, 83% produced conventional gas, and 15% produced conventional oil. The remaining 2% of wells (306 oil wells and 1,050 gas wells) produced from unconventional formations. However, the unconventional wells showed considerably higher production rates. The 1,050 unconventional gas wells produced 62% of all West Virginia gas in 2012. The 306 unconventional oil wells produced 39% of West Virginia's oil.

The WVDEP did not track produced water generation volumes. They were unable to provide those volumes directly. But the WVDEP did provide information on how the produced water was managed. For the sake of this study, the total volume of produced water managed was assumed to equal the volume generated (13,772,094 bbl). While this is not an exact comparison, it serves as a reasonable estimate. The WVDEP indicates that much of the flowback water from fracturing operations was reused for future frac jobs. No information was provided for those volumes.

Table 5-64 — 2012 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 from conventional formations	10,280	13,772,094 (based on total water managed)	1,559,883 bbl
Natural gas from conventional formations	58,952		202,910 Mmcf
Crude oil from unconventional formations	306		1,001,324 bbl
Natural gas from unconventional formations	1,050		336,570 Mmcf
Total	60,002	13,772,094 (based on total water managed)	2,561,207 bbl 539,481 Mmcf

Nearly 80% of the produced water was managed by injection. 27% was injected for enhanced recovery. 28% was injected to non-commercial disposal wells, and 25% was injected into

[48] Email from WVDEP to John Veil on November 12, 2014.

commercial disposal wells. The remaining 20% of produced water (representing water from CBM wells) was managed by land applications, which allowed produced water of a certain quality to be dispersed on the ground under authority of a water pollution control permit (http://www.dep.wv.gov/oil-and-gas/Documents/Fact%20Sheet%20GP-WV-1-07.pdf).

Table 5-65 — 2012 Produced Water Management Practices for West Virginia

Management Practice	# Wells Using That Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	450	3,660,000	27%
Injection for disposal	64	3,875,957	25%
Surface discharge	0	0	0
Evaporation	0	0	0
Offsite commercial disposal (disposal wells)	16	3,390,587	28%
Other (land application of CBM water)	41	2,845,550	20%
Beneficial reuse	Much of the flowback water in frac operations was recycled for other frac jobs	uncertain	uncertain
Total Volume Managed		13,772,094	

5.31 Wyoming

The Wyoming Oil and Gas Conservation Commission (WOGCC) provided information on production activities and produced water management.[49] The data are shown in Tables 5-66 and 5-67. Wyoming had 39,389 active oil and gas wells in 2012. The WOGCC noted that it did not specifically track conventional vs. unconventional oil and gas wells. For the purposes of the submitted data, the WOGCC included all horizontal well as unconventional and all vertical wells as conventional. The EIA oil and gas total production volumes were reasonably close to the total oil and total gas volumes provided by the WOGCC. However, the proportions of conventional gas vs. unconventional gas were quite different between the two sets of estimates. Nevertheless, the WOGCC data are used in Table 5-65.

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[49] Email from WOGCC to John Veil on August 12, 2014.

About 60% of the wells produced conventional gas, and another 25% produced conventional oil. 12% of the wells produce unconventional gas, and 3% produced unconventional oil.

In 2012, Wyoming wells generated 2,178,065,378 bbl of produced water. The conventional oil wells generated 62% of the total, with conventional gas wells producing 23% of the water. 14% of the water came from unconventional oil wells, with the remaining small portion coming from unconventional gas wells.

Table 5-66 — 2012 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	9,988	1,344,497,804	32,006,166 bbl/yr
Natural gas from conventional formations	23,500	497,836,513	1,268,498 Mmcf/yr
Crude oil from unconventional formations	1,134	302,103,202	13,375,817 bbl/yr
Natural gas from unconventional formations	4,767	33,627,859	810,571 Mmcf/yr
Total	39,389	2,178,065,378	45,381,983 bbl/yr 2,079,070 Mmcf/yr

The Wyoming data allowed calculation of WORs and WGRs. The WOR for conventional oil was 42 bbl/bbl, and for unconventional oil it was 23 bbl/bbl. The WGR for conventional gas was 392 bbl/Mmcf, and for unconventional gas it was 42 bbl/Mmcf. If conventional and unconventional production volumes were combined, the overall WOR was 36 bbl/bbl, and the overall WGR was 256 bbl/Mmcf.

The WOGCC provided data on produced water injection. A total of 1,168,699,739 bbl of water was injected during 2012. 73% of the water was injected for enhanced recovery through 2,759 wells. The remaining 27% was injected for disposal.

The total volume of generated produced water in 2012 exceeded the volume injected by about 1 million bbl. The WOGCC acknowledged that some produced water was managed by each of the other methods in Table 5-66, but added that it did not track those volumes. From prior experience studying CBM activities in the Powder River Basin region of Wyoming, the author is aware that the CBM water has low salinity allowing it to be discharged to surface water bodies or reused for irrigation or livestock watering.

Table 5-67 — 2012 Produced Water Management Practices for Wyoming

Management Practice	# Wells Using That Practice	Total Volume of Produced Water Managed by That Practice (bbl/year)	Percentage of Produced Water Managed by That Practice
Injection for enhanced recovery	2,759	855,755,837	73%
Injection for disposal	335	312,943,902	27%
Surface discharge	uncertain	uncertain	uncertain
Evaporation	uncertain	uncertain	uncertain
Offsite commercial disposal	uncertain	uncertain	uncertain
Beneficial reuse	uncertain	uncertain	uncertain
Total Volume Managed		1,168,699,739	

The following text was included in the Wyoming summary in Clark and Veil (2009):

> *"Information on historic trends that was provided for produced water management in the Powder River Basin indicate that since 1987, 4.784 billion bbl have been produced from coal beds. Approximately 54% has been discharged to ephemeral and perennial streams, 35% has been managed using off-channel pits, 5% has been reused for irrigation projects, 3% has been managed through injection, and 3% has been treated and then discharged into streams. Much of the produced water from conventional gas activities in the Big Horn Basin was also managed through agricultural reuse, although the actual volume is unknown."*

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 ONRR, BOEM, and directly from DOI. Several regional offices of the EPA provided produced water management information. EPA Regions 9 and 10 provided volumes of produced water discharged to the ocean from offshore wells. Regions 4 and 6 did not respond to similar requests for discharge volumes from offshore wells to the Gulf of Mexico. Regions 2 and 4 provided information on UIC injection volumes for New York and Kentucky respectively.

6.1 Federal and Tribal Onshore Lands

Production data for federal onshore lands was provided by the ONRR.[50] In 2012, onshore oil production on federal lands was 126,390,609 bbl. Onshore gas production was 3,674,718 Mmcf, and onshore water production was 2,174,518,759 bbl.

A subsequent request for production data on tribal lands was made to ONRR. The author was directed to file an FOIA request to the DOI. The FOIA request was made, the data were provided by DOI,[51] and the author was billed for the FOIA processing time. In 2012, oil production on tribal lands was 36,443,082 bbl. Gas production was 309,411 Mmcf, and water production was 258,168,746 bbl. It was not clear why ONRR provided the federal onshore data through a routine request, but insisted on an FOIA request with billing for the tribal data.

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 were included in the state summaries in the previous chapter. Therefore, the volumes of oil, gas, and water provided in this section were not included in the summary table in Chapter 4 to avoid double counting.

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[50] Email from ONRR to John Veil on July 24, 2014.
[51] Letter from Department of the Interior, Office of the Secretary, to John Veil, on January 21, 2015.

6.2 Federal Offshore Production

The BOEM Gulf of Mexico OCS office provided production data for the federal offshore activities in the Outer Continental Shelf in the Gulf of Mexico.[52] The 2012 production included 465,095,235 bbl of oil, 1,536,101 Mmcf of gas, and 509,159,846 bbl of water.

The BOEM Gulf of Mexico OCS office forwarded information from the BOEM Alaska office indicating that no produced water had been generated from offshore wells on the Alaska Outer Continental Shelf. Note that Alaska does have some "offshore" production in the Cook Inlet. However, Cook Inlet is classified as state waters, not federal waters. Therefore it is not under the jurisdiction of the BOEM.

The BOEM Pacific OCS office provided a link to an online database that included production data for the federal offshore activities in the Outer Continental Shelf of California[53] http://www.data.bsee.gov/homepg/data_center/production/PacificFreeProd.asp. The 2012 production included 17,678,497 bbl of oil, 27,262 Mmcf of gas, and 115,601,971 bbl of water.

While some produced water generated from offshore activities was injected, most was managed through discharge to the ocean after treatment on the platforms. It was not clear if the injected volume was only produced water or if it also included seawater.

In the Gulf of Mexico OCS region, 52,043,434 bbl of water were injected. The actual discharge volume could not be obtained from BOEM or EPA. It was estimated by subtracting the injection volume from the total produced water volume (509,159,846 bbl) to give 457,116,412 bbl.

For the Pacific OCS region, 73,363,232 bbl of water were injected during 2012. The EPA Region 9 office provided the 2012 produced water discharge volumes from 12 offshore California platforms (2 others had no discharge).[54] The total of those discharges was 58,800,000 bbl.

The total volume from both OCS regions combined was 482,773,732 bbl oil, 1,563,363 Mmcf gas, and 624,761,817 bbl water. The volume of produced water injected was 125,406,666 bbl. In the absence of any knowledge of the proportion of injected water going to enhanced recovery vs. disposal, this report assumes that total volume was split equally between the two categories. The total volume discharged was 515,916,412 bbl.

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[52] Email from BOEM Gulf of Mexico OCS Region to John Veil on November 21, 2014.
[53] Email from BOEM Pacific OCS Region to John Veil on December 10, 2014.
[54] Email from EPA Region 9 to John Veil on December 19, 2014.

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 2012 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 2012 was about 21.2 billion bbl or 890 billion gallons. This equals an average of 58 million bbl/day or 2.4 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 total produced water volume estimates. Texas, with more than 7.4 billion bbl, represented 35% of the national total. Other states with produced water volumes exceeding 1 billion bbl included California (15%), Oklahoma (11%), Wyoming (11%), 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.

Many organizations with an interest in water assumed that with the large increase in unconventional oil and gas production between 2007 and 2012, the total volume of produced water generated would climb significantly. However, the data did not bear out that assumption. U.S. oil production increased by 29% between 2007 and 2012, and U.S. gas production increased by 22% during those years. During the same period, however, U.S. water production increased by less than 1%.

7.1.2 Produced Water Volume by Hydrocarbon Type

This study attempted to collect produced water generation volumes separately for oil and for gas. It also sought separate water volumes from wells producing from conventional formations and from unconventional formations. Some states were able to provide separate volume estimates. Those are described in detail in Chapter 5. Unfortunately, several of the largest water-producing states were unable to provide separate water volumes for hydrocarbon types or for conventional vs. unconventional. Therefore, it was difficult to draw any national conclusions from the available data.

Some evidence was available from states like Arkansas, North Dakota, and Pennsylvania, which had tremendous growth in unconventional oil and gas production between 2007 and 2012.

- For Arkansas, 2012 oil production increased nearly 8% over 2007 volumes, and gas (mostly from the unconventional Fayetteville Shale) increased by over 400%. But over the same period, total water production increased by just 11%.
- For North Dakota, 2012 oil production (mostly from the unconventional Bakken Shale) increased by over 500% compared to 2007 volumes, and gas increased by over 300%. But the water production over the same period increased by just 216%.
- For Pennsylvania, 2012 oil production increased by 280% between 2007 and 2012, and gas production (mainly from the unconventional Marcellus Shale) increased by more than 1,300%. But the water production increased by 870%.

Another benefit of receiving separated water volume data is that it allows calculation of the amount of water generated for each unit of oil (bbl) or gas (Mmcf). The national weighted average WOR was 9.2 bbl of water/bbl of oil. The WORs ranged from 0.6 bbl/bbl for New York to 36.3 bbl/bbl for Wyoming. Several states with large numbers of older wells producing from mature formations were unable to provide data separately for oil wells and gas wells. Had the water usage from those states been averaged with the other states, it is very likely that the national WOR would have been greater than 10 bbl of water/1 bbl of oil. The weighted average WGR was 97 bbl of water/Mmcf of gas. The WGRs ranged from 0.3 bbl/Mmcf for Alaska to 981 bbl/Mmcf for Indiana. The range of state values for the WGRs was so large that a weighted average WGR is probably not a meaningful number.

7.1.3 Produced Water Management Practices

This report describes the practices used by oil and gas producers to manage produced water during 2012. Most U.S. produced water was injected. About 93% of produced water from onshore wells and about 90% of the produced water from all wells was injected underground. Slightly more than half of that was injected into producing formations to maintain formation pressure and increase the output of production wells (i.e., for enhanced recovery). Slightly less than half of the injected produced water was injected to non-commercial and commercial disposal wells.

About 80% of the produced water from offshore wells was treated on the platform and discharged to the ocean. Only about 3% of onshore produced water was discharged. The percentage discharged from all wells (onshore and offshore combined) was about 5.4%.

Nearly 7% of produced water was managed by sending it to an offsite commercial facility. Most such facilities managed water by injection into disposal wells. Several facilities in Colorado and Utah managed water by evaporation from large ponds.

The 2012 data showed that about 3.6% of all produced water was evaporated, and 0.6% was put to a beneficial reuse. Much of the reuse was done by recycling flowback water and produced water to make drilling fluids and frac fluids for new wells in the same fields. Other portions of produced water may be used for irrigation (when the water has low salinity) or for dust and ice control on roads.

7.1.4 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 state agencies were helpful in suggesting other resources for obtaining the information. 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, figures in the summary tables in Chapter 4 were rounded up. 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 the same procedure used in a 2009 report that studied produced water in the 2007 calendar year. Some procedures and estimation methods were revised and improved for the 2012 report.

The total volume of produced water generated in 2012 was slightly greater than the volume generated in 2007. Given the inherent limitations of the raw data and the need to apply many assumptions and extrapolations, it is unlikely that the 2012 volume can be shown to be different from the 2007 volume. Nevertheless, finding a relatively level volume of water during a period of rapid oil and gas growth was a useful and not necessarily anticipated conclusion. Many had assumed that the large increase in oil and gas production (much of it from unconventional formations) between 2007 and 2012 would have led to a large increase in produced water generation too.

Information on management practices has not changed significantly from the 2007 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 2007, but the major trends remain the same.

A final important conclusion of this study (this was also highlighted in the 2009 study) 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 useful 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.

In the absence of a consistent methodology to collect produced water volumes and management information, it is unlikely that the challenges of estimating produced water volumes and management practices will decrease in the future.

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