The Water-Energy Nexus for Hydraulic Fracturing

Andrew John Kondash

Department of Earth and Ocean Sciences
Duke University

Date:_____
Approved:

_____
Avner Vengosh, Supervisor

_____
Gary Dwyer

_____
Lincoln Pratson

_____
Dalia Patino Echeverri

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Nathaniel Warner

Dissertation submitted in partial fulfillment of
the requirements for the degree of Doctor
of Philosophy in the Department of
Earth and Ocean Sciences in the Graduate School
of Duke University

2019

ABSTRACT

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Abstract

The water energy nexus represents the intersection of water use, fuel extraction, electricity generation, and waste generation and disposal. The rapid rise of unconventional natural gas and oil production through the combined processes of horizontal drilling and hydraulic fracturing have shifted the energy dynamic in the United States. Concurrently, the rising utilization of unconventional gas and oil production has intensified the water use for hydraulic fracturing and generation of flowback and produced water associated with shale gas and tight oil production. Among the major environmental risks associated with the rise of unconventional oil and gas exploration water availability, water contamination from leaking or disposal of wastewater, and adequate disposal of the wastewater are the key issues associated with the water-energy nexus. This dissertation aims to quantify the water use for hydraulic fracturing across the U.S., evaluate the water use for electricity production from natural gas in comparison to coal combustion, estimate the flowback and produced water production, and assess possible recycling of oilfield water through irrigation in California.

This dissertation describes the water footprint of hydraulic fracturing by examining total water use, water use per well, water use per length of horizontal well, and the changes in water use through time. The data show that hydraulic fracturing

water use per well has been increasing between early stages (2008-2012) to later stages (2012-2016) of operation. In addition to water use, this dissertation estimated waste water generated from unconventional oil and gas wells and find a concurrent increase in flowback and produced water (FP water) per well through time. Using salinity as a marker to distinguish FP water from water injected for hydraulic fracturing, this dissertation observes the sequestration of the injected freshwater, while the return flow composed primarily of more saline formation brines entrapped within the shale formations.

In addition, this this dissertation explored two downstream impacts of the increasing water use and FP water generation. First, as abundant natural gas resources from the expansion of hydraulic fracturing have shifted the electricity sector from primarily coal- to primarily natural gas-fired, this study examined the impact increasing water use associated with hydraulic fracturing has had on power plant lifecycle water consumption and withdrawal. The study found that despite increasing water use for hydraulic fracturing, natural gas-fired generation on average used less water for cooling relative to coal-fired generation. Finally, this this dissertation examined the risks from recycling of oilfield produced water (OPW) as an agricultural makeup water source. The data from field studies in California show that by using low salinity OPW, farmers are able to successfully recycle OPW without risking metals accumulation in soil and consequently in crop and human health.

Dedication

I would like to dedicate this work to my father, Andrew Kondash. Thank you for pushing me to go above and beyond what I thought I was capable of. I miss you.

Contents

Abstract iv

List of Tables xi

List of Figures xiii

Acknowledgements xvii

1. Introduction 1

1.1 Unconventional Natural Gas and Oil 1

1.1.1 Hydraulic Fracturing Background 1

1.1.2 Hydraulic Fracturing Water Use 4

1.1.3 Hydraulic Fracturing Flowback and Produced Water 5

1.2 Water Use for Electricity Generation 7

1.3 Use of Oilfield Produced Water in Agriculture 9

1.4 Dissertation Objectives 10

2. Water Footprint of Hydraulic Fracturing 13

2.1 Introduction 13

2.2 Data Sources and Methods 15

2.2.1 Water Use per Well 15

2.2.2 Water, Oil, and Gas production 16

2.2.3 Total Oil and Gas Well Counts 17

2.2.4 Water per Energy Intensity 18

2.3 Results and Discussion 19

2.3.1 Water Use 19

2.3.2 Flowback and Produced Water 20

2.3.3 Water Use and Produced Water Intensity 23

3. Quantity of Flowback and Produced Waters from Unconventional Oil and Gas Exploration 26

3.1 Introduction 26

3.2 Methods 30

3.2.1 Data Sources 30

3.2.2 Data Analysis 31

3.2.3 Wastewater Distinction 33

3.3 Results 38

3.3.1 Water Quantity Analysis 38

3.3.2 Salinity Analysis 41

3.4 Discussion 42

3.5 Conclusions 49

4. The Intensification of the Water Footprint of Hydraulic Fracturing 51

4.1 Introduction 51

4.2 Results 56

4.3 Discussion 62

4.4 Materials and Methods 67

4.4.1 Experimental Design 67

4.4.2 Data Acquisition 68

4.4.3 Statistical Methods 69

4.4.4 Production Predictions 70

5. Quantification of the water-use reduction associated with the transition from coal to natural gas in the U.S. electricity sector 72

5.1 Background 72

5.2 Results 76

5.2.1 Water Use for Power Plant Operations: Volume and Intensity 76

5.2.2 Water Use for Fuel Extraction, Processing, and Transportation: Volume and Intensity 79

5.2.3 Differential Impacts of Power Plant Type and Cooling Technology 82

5.2.4 Projections of Future Water Use 84

5.2.5 Relationships between Water Use for Energy and Water Stress 86

5.3 Discussion 89

5.4 Conclusions 90

5.5 Methods 91

5.5.1 Data Collection 91

5.5.2 Data Organization 92

5.5.3 Upstream and Total Water Use Calculations 93

6. Use of Oilfield Produced Water for Irrigation in Bakersfield, CA 95

6.1 Introduction 95

6.1.1 History of OPW use in Kern County 96

6.1.2 OPW use Regulations 97

6.2 Materials and Methods 98

6.2.1 Sample Collection and Analysis 98
6.3 Results 100
6.3.1 Oilfield produced water characterization 100
6.3.2 Irrigation Water Quality 102
6.4 Discussion 104
7. Conclusion 111
Appendix A: Supplementary Information for Chapter 2 113
Appendix B: Supplementary Information for Chapter 3 138
Appendix C: Supplementary Information for Chapter 4 148
Appendix D: Supplementary Information for Chapter 5 157
References 164
Biography 179

List of Tables

Table 1: Median Water Use, Average Flowback and Produced (FP) water, WUI, and PWI among the Prominent Unconventional Shale Gas and Oil Formations. 16

Table 2: Well water use and production totals. 18

Table 3: Estimated water, gas, and oil production. 40

Table 4: Water production volume (million Liters) and percent of the first 3 (left) and 6 (right) months of oil and gas wells operation from different unconventional basins..... 40

Table 5: Volume of injected HF water (million L), Total FP water (million L), estimated Cumulative Injected HF water (million L) 42

Table 6: Major element chemistry of water samples for groundwater, canal water, and OPW used for irrigation in Kern County, CA. 103

Table 7: Trace metal concentrations of water sample for groundwater, canal water, and OPW used for irrigation in Kern County, CA. 104

Table 8: Calculation parameters for pHc. 109

Table 9: Comparison of water use data..... 117

Table 10: Comparison of oil and gas production data 118

Table 11: Comparison of flowback and produced water data..... 119

Table 12: Copy of Table 1 from the main text of the paper, reporting average values ... 122

Table 13: Copy of Table 2 from the main body of the paper utilizing mean values..... 122

Table 14: Tables of the median water use for hydraulic fracturing 124

Table 15: Percentages of wells from drilling info listed as oil or gas. 129

Table 16: Estimates of water use between 2012 and 2014..... 134

Table 17: Percentages of Horizontal, Vertical, and Directional wells. 137

Table 18: FP water, oil, and gas production median, mean and confidence intervals. ... 146

Table 19: Estimates of maximum TDS in each formation. ... 146

Table 20: The average number of days reporting data in the first 2 months of well production ... 147

Table 21: Production volumes in unconventional gas producing formations. ... 148

Table 22: Production volumes in unconventional oil producing formations. ... 149

Table 23: Example calculation for future production estimate, business-as-usual scenario. ... 150

Table 24: Example calculation for future production estimate, future growth scenario. 151

Table 25: Mean, Median, Max, and Min consumption and withdrawal intensities for each combination of fuel source, plant type, and cooling type. ... 157

Table 26: Life cycle components for upstream processes related to coal and natural gas production. ... 158

Table 27: Volumes of coal and natural gas sent to power plants in the United States through time ... 158

Table 28: Upstream consumption and withdrawal intensity for coal and natural gas ... 159

Table 29: Water stress index for coal mining in the United States. ... 159

List of Figures

Figure 1: Differentiating conventional from unconventional production for gas and oil resources. 3

Figure 2: Shale plays of Canada and the United States. 4

Figure 3: Dissertation aims and objectives. 12

Figure 4: Water use for hydraulic fracturing across the United States. 13

Figure 5: Decline curves of Flowback and Produced (FP) water over the course of well production for unconventional oil (left) and shale gas (right) formations. 22

Figure 6: Quantity of Flowback and Produced Waters (FP Water) from Unconventional Oil and Gas Exploration. 26

Figure 7: Temporal increase in total dissolved salts (TDS) with time (days after hydraulic fracturing) in flowback and produced waters from individual oil and gas wells. 35

Figure 8: Best fit curves of the calculated brine fraction in flowback waters with time 36

Figure 9: Water source characterization and decline. 37

Figure 10: Salinity (black line) and cumulative water production (blue line) through the first 6 months of oil and gas production. 48

Figure 11: Map of water stress and shale plays. 55

Figure 12: Box plots of water use with lateral lengths. 56

Figure 13: Oil, gas, and FP water variations with time. 61

Figure 14: The changes in the water intensity of hydraulic fracturing with time. 62

Figure 15: New shale gas and tight oil well installations compared to oil and gas prices. 67

Figure 16: Changes in energy sources for the U.S. electricity sector. 75

Figure 17: Map of the U.S. showing the location of coal and natural gas thermal plants. 76

Figure 18: Previous and projected water consumption and withdrawals in the U.S. 78

Figure 19: Variations of water consumption and withdrawals intensity and annual volume in the U.S. 79

Figure 20: Water consumption and intensity values sorted by plant types and cooling systems. 84

Figure 21: Projections of water use reduction from transition of coal to natural gas. 86

Figure 22: Electricity production in plant of different cooling systems located different water-stress areas in the U.S. 88

Figure 23: Map of sample sites, Cawelo water district, and relevant oil fields in Kern County, CA 96

Figure 24: Oilfield produced water salinity in Kern County, CA. 101

Figure 25: Boron and chloride concentrations across Kern County. 102

Figure 26: Water quality guidelines verses measured samples. 103

Figure 27: Adjusted sodium adsorption ratio (adj SAR) for water samples collected from Kern County, California. 108

Figure 28: Box plots of water use for hydraulic fracturing in all of the major unconventional shale gas formations in the United States. 120

Figure 29: Box plots of water use for hydraulic fracturing in all of the major unconventional oil formations and the Permian Basin in the United States. 121

Figure 30: WUI calculations for each unconventional gas formation. 125

Figure 31: WUI calculations for each unconventional oil formation. 125

Figure 32: Map of total water use for all major formations 126

Figure 33: Map of FP water production per well for all major formations. 127

Figure 34: Map of total FP water production for all major formations 128

Figure 35: Water/Oil ratio (WOR) reported as a function of time. 129

Figure 36: Individual type curve for oil producing formations. 131

Figure 37: Type curves for a typical unconventional shale gas well from each formation. 132

Figure 38: Total oil and gas production coupled with total water use for each of the formations and basins 136

Figure 39: Scatter plot of FP water (x-axis) vs. water use (y-axis) in the Bakken Formation 137

Figure 40: Decline curve analysis for each of the formations in this study showing oil (Bbl) and gas (MCF) monthly production as a function of time. 140

Figure 41: FP water decline Curve analysis for each of the formations in this study. 141

Figure 42: Count of wells with production data. 142

Figure 43: Histogram of cumulative water production in months 1 through 6 in the Bakken formation. 142

Figure 44: Graphs of percent of final TDS as a function of time. 143

Figure 45: Final salinity of formation brines in each of the producing formations. 144

Figure 46: Well production rate from Hayes (2009) showing a rapid decline in production rate following the first several months of production. 145

Figure 47: Cumulative production comparison. 152

Figure 48: Volumetric water use intensity. 153

Figure 49: Total water use for hydraulic fracturing. 153

Figure 50: Water use intensity for other energy-producing materials. 154

Figure 51: Projected water use for hydraulic fracturing operations in the United States. 155

Figure 52: Projected first year FP water derived from future hydraulic fracturing operations in the United States. 156

Figure 53: Water consumption and withdrawal intensity for plant and fuel types. 160

Figure 54: Coal mines across the United States shown on top of water stress index..... 161

Figure 55: Total natural gas production for each state (conventional + unconventional + offshore) in billion MCF. 162

Figure 56: Estimated water stress index on a state level. 163

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1. Introduction

From the development of fossil fuel resources to the process used to spin turbines, water has always played a key role in the generation of electricity. Understanding the water-energy nexus is critical globally for multiple stakeholders with political, economic, and social implications as it will continue to drive human progress.(1) As the energy sector continues to evolve, different media for electricity generation have come into and out of vogue. Currently, with a move away from coal-fired power and towards "greener," renewable energy sources, the development of the natural gas industry in the United States has been viewed as both a short-term bridge and a quickly responding backup electricity source, allowing for cleaner electricity generation, while new sustainable technologies are being developed and implemented.(2)

1.1 Unconventional Natural Gas and Oil

1.1.1 Hydraulic Fracturing Background

There is a long history of gas and oil production in the United States, beginning with the first commercially produced natural gas well in 1821.(3, 4) From 1821-2002 over 28,000 shale gas wells have been drilled, but it wasn't until the mid 2000's that the processes of horizontal drilling and hydraulic fracturing converged to became economically viable.(3, 5) Resource rich shales occur in Paleozoic and Mesozoic rocks and are in many cases sources for conventional reservoirs.(3, 6) Shales are formed from

fine grained sediments which lead to low permeability and porosity with thickness ranging from 30-100m.(3, 6) Because of their low permeability and porosity, most shales and tight oil formations cannot be produced by conventional methods. To access these "unconventional" reservoirs, gas and oil companies had to develop alternative methods; namely horizontal drilling and hydraulic fracturing (Figure 1). Horizontal drilling is the process of curving a well by up to 90 degrees to maximize contact area within a formation, and was first done in the 1930's and common by the 1970's.(4) Hydraulic fracturing was developed as a commercial technology in the 1950's to increase permeability in conventional wells and is the process of using large volumes of water injected at high pressure to widen natural and perforated fractures to create new flow paths to stimulate natural gas and oil to flow.(4) Horizontal drilling and hydraulic fracturing were first used together to access unconventional formations in the 1970's, but wasn't economically viable until the 2000's.(4) In 2012, shale gas production from horizontal drilling and hydraulic fracturing overtook conventional sources as the primary method for natural gas production in the United States, while horizontal drilling and hydraulic fracturing for unconventional oil overtook conventional oil production in 2014 (Figure 2).(7-9)

The process of hydraulic fracturing uses large volumes of water to break apart impermeable shales several miles underground, releasing trapped natural gas, oil, and formation water from secluded pores.(5, 10, 11) This formation water is most likely

paleo-seawater, previously trapped and partially evaporated, giving it a hypersaline nature.(12, 13) Years of being trapped within the low permeability shale has allowed to the water to interact with formation rock, increasing the levels of natural occurring radioactive material (NORM) along with other trace metals. These water rock interactions, coupled with evaporation isotherms allow scientists to reliably identify and trace these formation brines when they enter the environment.(14-17) While the gas and oil is captured and processed for beneficial uses, the water that is co-produced with them is currently viewed as a harmful waste product and is disposed of through the most economical means available; typically this is through either limited treatment and reuse or injection into disposal wells. (18, 19)

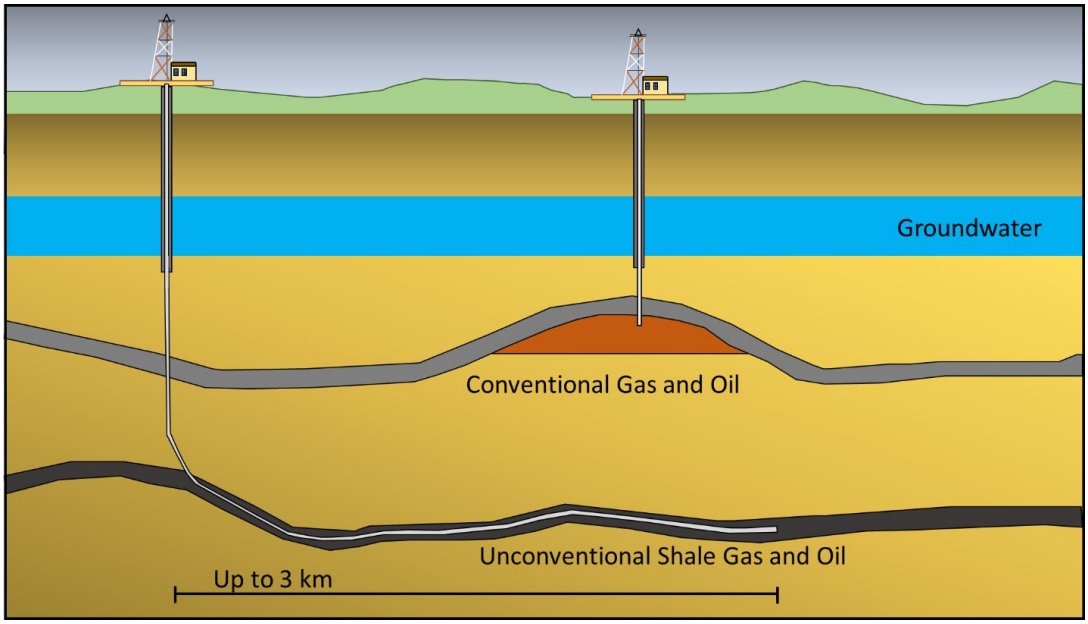

Figure 1: Differentiating conventional from unconventional production for gas and oil resources.

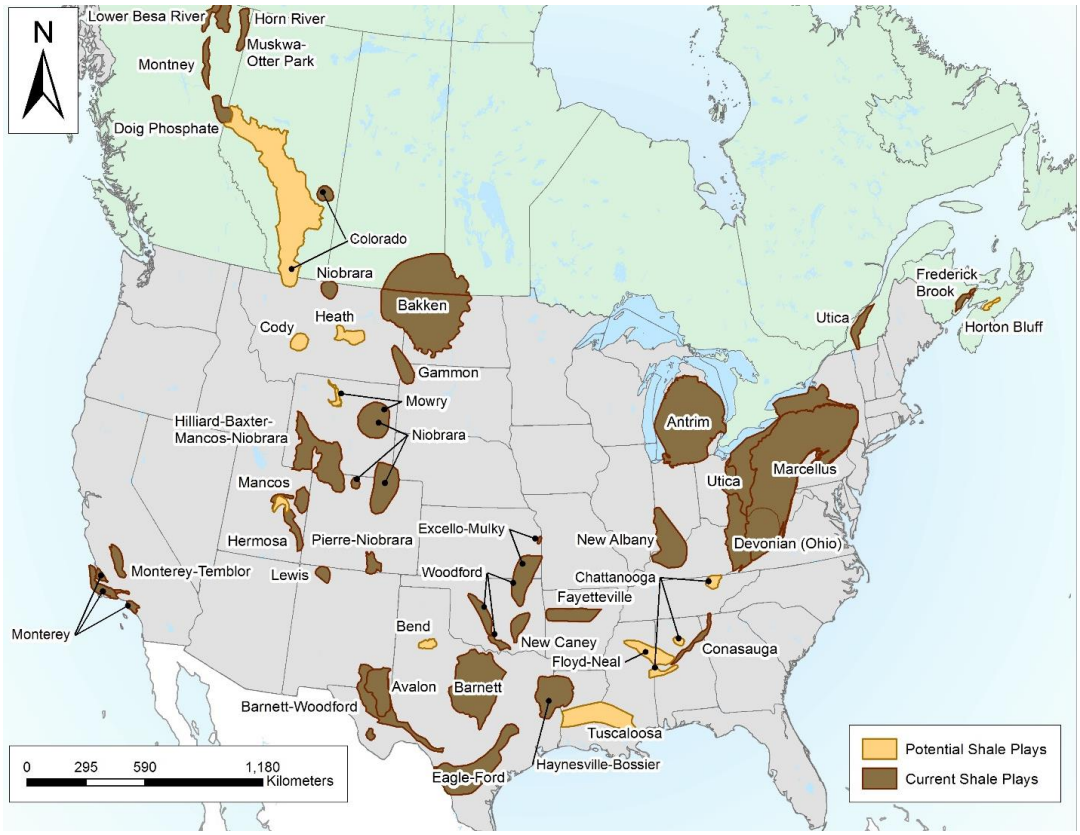

Figure 2: Shale plays of Canada and the United States.(9)

1.1.2 Hydraulic Fracturing Water Use

When a horizontal well is drilled into an unconventional formation, the lateral length (reaching up to 3 km) is divided into up to 20 stages.(4, 6) Starting with the end of the well, a perforation gun is used to create holes in the well liner and formation. These holes, along with natural fractures in the formation are forced apart by large volumes of water being pumped at high pressure into the well, creating a network of fractures that oil and gas can flow through. Once this process is completed, that stage is sealed, and a new stage is started. From perforation to sealing, hydraulically fracturing one stage can take between 1 and 4 hours.(4) In total, the process of hydraulically fracturing a

horizontal well can use between 5,000 and 60,000 m^3 of water per well.(20) In addition to water (making up 98-99% of the injected fluids), hydraulic fracturing fluid is composed of sand or another proppant (up to 1.36 million kg), scale inhibitors, acid, friction reducers, disinfectants, gelling agents, and corrosion inhibitors.(4, 21)

Fresh water is the primary ingredient in hydraulic fracturing fluids, coming from a mix of groundwater and surface water sources.(21-24) Until recently, the use of additional chemicals to facilitate gas and oil flow was cited as the main reason alternative sources of water could not be used.(4, 22) In water stressed regions and in areas where disposal of flowback and produced water is not economical, there has been a push for the use of alternative brackish and marginal water sources along with the reuse of flowback and produced water generated in other wells.(22)

1.1.3 Hydraulic Fracturing Flowback and Produced Water

Once all stages are fractured, the seals are removed and the well is allowed to flowback. The high pressure from the fracturing drives the injected water, along with gas, oil, and water from the formation back up out of the well. One study found that initial flowrates can be as high as 950 liters per minute, but can drop to 100 liters per minute after the first day, and 0.25 liters per minute by the end of the first week.(4) Despite this rapid reduction in the production of flowback water, through time, significant volumes of water are generated.(18, 20, 22, 25) Through the flowback period, the water flowing back is a mixture of the injected water and formation water that was released through the

process of hydraulic fracturing with an increasing percentage of flowback water being made up of the formation water.(18) After several weeks of flowing back, the well begins production in earnest. During the production period, the water generated from a well is called produced water. The produced water is made up primarily of formation brines and typically has high salinity, naturally occurring radioactive materials (NORM), metals, and organic compounds.(12, 14-17, 26-29) Total volumes of flowback and produced water can be as high as 70,000 m^3 per well, with up to 20-50% of that being generated within the first 6 months after hydraulic fracturing.(18, 20) Management options include treatment and disposal, treatment and reuse, evaporation, and injection into class II saltwater disposal wells.(5, 28, 30-33) Treatment of the flowback and produced water has evolved through time in the United States with evaporation and treatment for disposal being limited by regulation after negative environmental consequences have been reported.(16, 28) Recently, injection into class II saltwater disposal wells has been linked to increased seismicity across the United States, further complicating the management of flowback and produced water.(34-37) Finally, spills of flowback and produced water have left lasting environmental impacts, adding risk to the transportation of fluids to management facilities.(14, 38) There is hope however that emerging technologies such as evaporation with mechanical vapor compression, reverse osmosis, membrane distillation, forward osmosis, and biological desalination can be used to safely clean waste water to dischargeable levels.(39)

1.2 Water Use for Electricity Generation

Electricity is created when a turbine spins a generator. There are several configurations with which power plants spin generators, known as prime movers. In the U.S., the most common prime movers for coal and natural gas plants are steam turbines and combustion turbines. In 2016 steam turbines produced 55% of total net generation in the U.S., with 99.7% of coal generation coming from steam turbines and only 7.1% of natural gas generation.(40, 41) Steam turbines require the burning of a fuel in a boiler to heat water into steam, which is then passed at high pressure through a turbine, spinning a generator. In coal plants subcritical, supercritical, and ultrasupercritical are a distinction between the heat and efficiency at which a plant can burn fuel. Subcritical turbines can average 46% efficiency at converting stream into energy, while supercritical turbines can average 50%, and ultrasupercritical can average 54% or higher.(7) A newer and more efficient system of generation called a combined cycle plant uses a combination of gas turbines and steam turbines in series to spin generators. The waste heat from several combustion turbines are used to boil water to spin a generator. Combined cycle plants account for approximately 30% of the United States power generation in 2016, with 81% of total natural gas generation in 2016 coming from combined cycle plants. Finally, gas combustion turbines, not connected to the combined cycle plants are used to provide instant balancing to the power grid and accounted for 9% of total natural gas generation in 2016.

In order to cool down the steam which was used to spin steam turbines, plants use dry cooling, recirculating cooling, and once through cooling. Dry cooling utilizes convective heat transfer using air instead of water to cool and condense spent steam from turbines.(42) While the use of water is completely eliminated through this method, it increases capital costs by approximately 10-fold relative to once through cooling systems, and the efficiency of the system becomes dependent on the local humidity and temperature.(42) Recirculating cooling systems withdraw water from a reservoir to cool and condense the steam in either ponds or towers, saving and recycling the cooling water for future cooling. Recirculating plants withdraw water to make up for losses due to evaporation and leakage in the system as well as to balance increasing salinity of cooling water. To deal with increasing salinity as evaporation takes place, a portion of the saline water within the recirculating system is discharged as "blowdown," and replaced with fresh water.(42) Because the water is removed from the reservoir and not replaced, consumption is typically higher for recirculating plants, while withdrawals are low. Recirculating cooling systems account for approximately 90% of water consumption and only 31% of water withdrawals for coal and natural gas generation. Once through plants withdraw water from a reservoir using it to cool and condense steam in towers or ponds, but after cooling, it is returned to the source. Water consumption from once through cooling is attributed to evaporation and water losses

but is typically very low. Once through cooling accounts for 61% of water withdrawals for coal and natural gas cooling while consuming only 10% of water.

Recirculating cooling is the most common cooling method for natural gas fueled plants, with 62% of generators being cooled with recirculating systems. Once through cooling systems account for 27% of cooling systems, while 10% of generators are cooled with dry cooling systems. In coal plants, 59% of generators were cooled with recirculating systems, while 40% were cooled with once through and remaining 1% were cooled with dry cooling systems.(40, 41)

1.3 Use of Oilfield Produced Water in Agriculture

Beneficial reuse of waste water products in becoming more important as drought and water scarcity grip different parts of the country. In California, where constant drought conditions have led to wildfires and fierce competition for water rights, utilization of marginal water sources is pivotal to sustaining its agriculture industry.(43, 44) In Bakersfield, CA, a large presence of both agriculture and oil production have facilitated the movement of high quality oil-field produced water (OPW) from producers to farms through a network of water supply districts.(44-49) Since 1994, water districts have been supplying groundwater and surface water mixed with OPW to farms within the Cawelo district, supporting the growth of almonds, grapes, pistachios, and citrus.(45) There are strict monitoring guidelines on the quality of OPW being provided to water districts, limiting concentrations of chloride (200 mg/L), boron (1 mg/L), and

arsenic (10 μg/L) through the Water Quality Control Plan for the Tulare Lake Basin (called the Basin Plan).(44-48, 50)

1.4 Dissertation Objectives

This dissertation aims to 1) quantify and characterize the water use volumes and waste water production and quality associated with unconventional natural gas and oil development, 2) to develop a framework for how this upstream water use volume impacts downstream electricity generation, and 3) to explore alternative uses of waste products from fossil fuel development (Figure 3). To achieve these aims, chapter 2 through 6 of this dissertation complete the following objectives.

Chapter 2: *Water footprint of hydraulic fracturing*. (Environmental Science & Technology Letters, **2**, 276-280, 2015) This chapter presents a quantification of the water use and waste water production associated with unconventional natural gas and oil production. It also serves to introduce the concepts of water use and waste water intensity, while estimating total annual water use for hydraulic fracturing in the United States.

Chapter 3: *Quantity of flowback and produced waters from unconventional oil and gas exploration*. (Science of the Total Environment, **574**, 314-321, 2017) This chapter quantify water use and waste water production, providing a characterization of waste water quality throughout the life of a well. It introduces the concept of using decline curves to estimate ultimate wastewater production associated with hydraulic fracturing.

Chapter 4: *The intensification of the water footprint of hydraulic fracturing*. (Science Advances, **4**(8), 2018) This chapter characterizes the change in water use and waste water production volumes through the maturation of unconventional natural gas and oil development. It finds both increasing water use and waste water generation from 2012-2016.

Chapter 5: *Quantification of the water-use reduction associated with the transition from coal to natural gas in the U.S. electricity sector.* This chapter examines the impact that increasing water use for unconventional natural gas production has had on electricity generation in the United States. Specifically, as the United States transitions from a primarily coal fired electricity sector to a primarily natural gas fueled sector, we show that lifecycle water withdrawals and consumption have decreased as more coal is replaced with natural gas.

Chapter 6: *Use of Oilfield Produced Water for Irrigation in Bakersfield, CA*. This chapter assesses an alternate use of oilfield waste water as an irrigation make-up water source. By supplementing irrigation water with low salinity produced water, we show how farmers in California have successfully and safely utilized a marginal water source to grow produce.

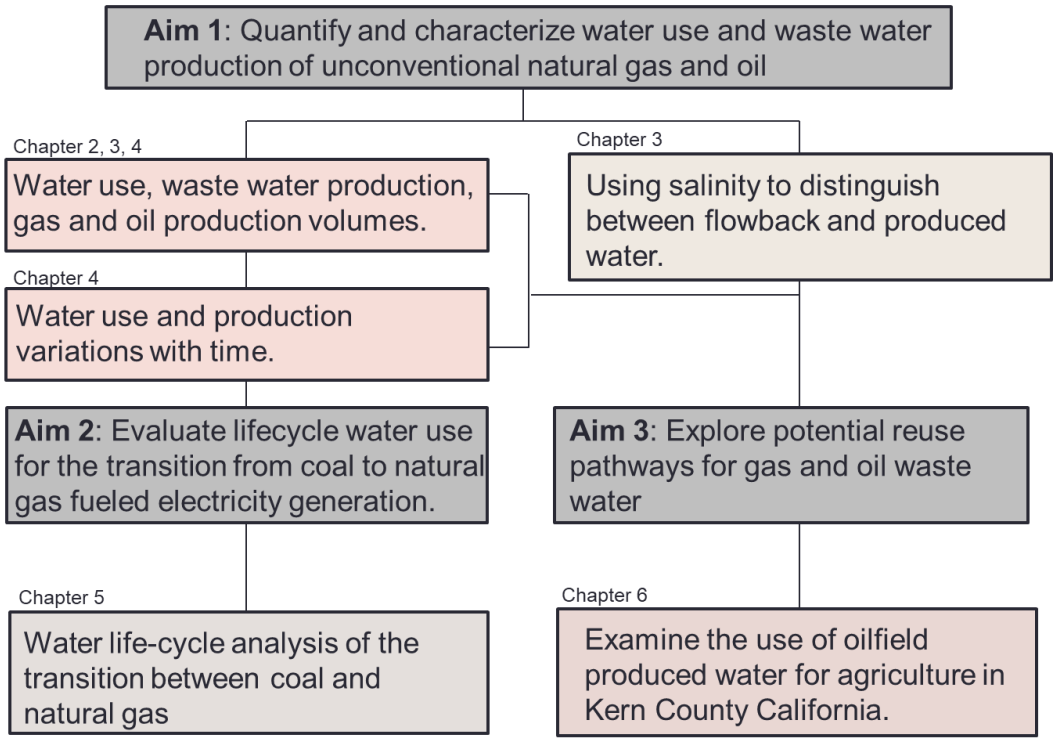

Figure 3: Dissertation aims and objectives.

2. Water Footprint of Hydraulic Fracturing

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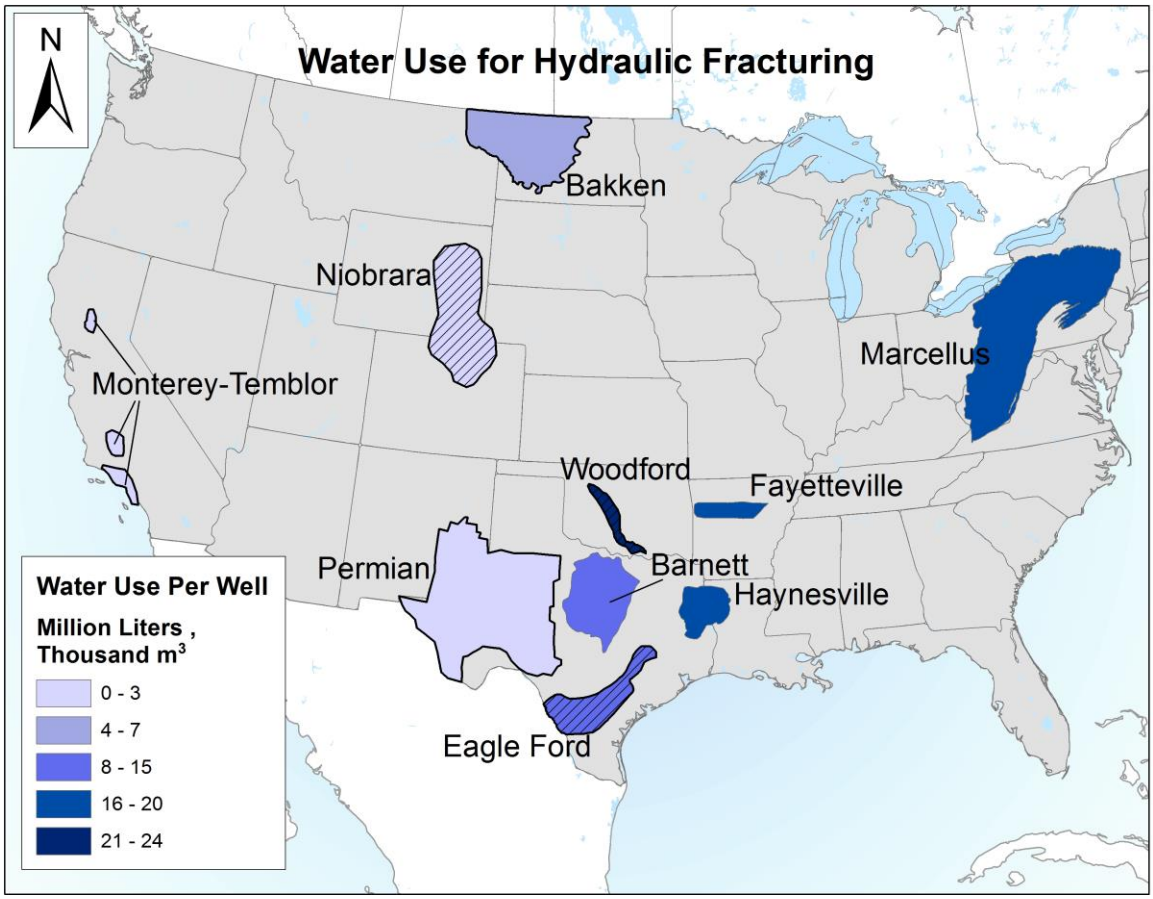

Figure 4: Water use for hydraulic fracturing across the United States

2.1 Introduction

The rapid rise of unconventional shale gas and oil production through hydraulic fracturing has intensified water use for the oil and gas industry in the United States.(6, 15, 21-24, 51-54) Previous research has provided a wide range of water use, with reports

for specific basins or small groups of them.(6, 51-53, 55-57) Yet few studies have evaluated the overall volume of water used for hydraulic fracturing and the volume of wastewater generated from unconventional oil and gas production.(11, 22, 54, 58-60) The increasing volume of oil and gas wastewater, which typically contains high levels of toxic elements, has become a major national concern owing to the rise of induced seismicity in areas of deep-well injection(6, 34, 35, 37) and the environmental and human health risks associated with the disposal of oil and gas wastewater to unlined impoundments(61, 62) or streams and rivers without adequate treatment.(16, 27) While several of the previous studies have evaluated portions of the water cycle of oil and gas production including water intensity for processing and electricity generation, (6, 22, 23, 51, 53, 63) this study focuses on the water use and wastewater generation from hydraulic fracturing and their relationship to energy production.

Here we report, for the first time, an integrated and comprehensive evaluation of both water use and flowback-produced waters (FP) generated as part of unconventional shale gas and oil (shale oil, tight sand) production across the United States. One of the challenges of generating such a complete data set is the lack of a single and reliable data source and fragmentation of the information distributed among different sources. In this study, we thus integrate and compare data from multiple sources including FracFocus,(55, 57) DrillingInfo,(64) EIA,(65) state agencies,(66-68) industry sources,(69) and previous publications(6, 11, 22-24, 51-54) in order to generate a complete data set of

water use and FP water as normalized to the energy content of oil and shale gas production. Metrics reported for this study include water use per well (with a distinction between gas and oil wells), shale gas and oil production, water use intensity (WUI; water use normalized to gas and oil energy content, L/GJ), produced water volume per well, produced water intensity (PWI; volume of produced water per energy content or per volume of oil), and the overall water footprint of hydraulic fracturing. Water footprints associated with hydraulic fracturing observed in this study could be used to project future water allocations and produced water volumes in other basins worldwide that are expected to develop unconventional oil and shale gas resources.

2.2 Data Sources and Methods

2.2.1 Water Use per Well

Well water use data were extracted from the EPA's Analysis of Hydraulic Fracturing Fluid Data from the FracFocus Chemical Disclosure Registry 1.0 and SkyTruth's FracFocus Chemical Database Download.(55, 56) Because FracFocus does not report well orientation, median water use per well is reported for both vertical and horizontal (each individual lateral segment) unconventional wells (Table 1; average values reported in Table 12). Additionally, water use data from the EPA report were compared with state databases,(70, 71) other studies,(22-24, 51, 53, 60) and values

reported by Chesapeake Energy.(69) For most unconventional shale gas and oil plays, the FracFocus data were in agreement with other sources (see comparison in Table 9).

Table 1: Median Water Use, Average Flowback and Produced (FP) water, WUI, and PWI among the Prominent Unconventional Shale Gas and Oil Formations. Water use volumes are in ×10⁶ L/well, ×10⁶ gallons/well and WUI is in L/GJ. For unconventional oil, the ratios of FP water to oil production and water use to oil production are also shown.

shale gas	*water use (median)*	*flowback and produced water*	*water use intensity (WUI)*	*produced water intensity (PWI)*
Barnett	14.42, 3.80	12.40, 3.28	7.40	6.36
Eagle Ford	13.7, 3.61	25.87, 6.83	5.38	10.16
Fayetteville	20.06, 5.29		9.32	
Haynesville	19.45, 5.13	17.51, 4.63	3.22	2.90
Marcellus	16.12, 4.25	5.20, 1.37	3.14	1.01
Niobrara	1.51, 0.39	5.68, 1.50	0.73	2.73
Woodford	23.77, 6.27		8.58	

unconventional oil	*water use (median)*	*flowback and produced water*	*water use intensity (WUI)*	*produced water intensity (PWI)*	*FP water/oil ratio*	*water use/oil ratio*
Bakken	7.49, 1.97	12.25, 3.24	4.99	8.17	0.36	0.22
Permian	3.06, 0.80		2.42			0.13
Monterey-Temblor	0.30, 0.07	14.30, 3.78	1.60	76.43	3.22	0.07
Eagle Ford	15.06, 3.97	22.75, 6.01	7.53	11.38	0.56	0.37
Niobrara	1.32, 0.34	8.04 ,2.12	1.11	6.79	0.44	0.07
Woodford	7.79, 2.05		7.15			0.74

2.2.2 Water, Oil, and Gas production

The DrillingInfo Desktop Application(64) was used to develop type curves for each of the unconventional oil and shale gas target formations. Type curves for FP, oil, and gas

production reported by DrillingInfo cover the entire production history of the wells in each formation; thus, estimated ultimate recovery (EUR) was assumed to be the cumulative of all production from the type curve for each play. In many cases, this covers 10+ years (Bakken, Barnett, Fayetteville, Haynesville, and Permian), but in others, less than 10 years of production data were available (Eagle Ford, 6 years; Marcellus, 9 years; Niobrara, 8 years). We include the Permian basin instead of the individual formations (Bone Spring, Spraberry, Wolfcamp) for comparison to production data from the EIA's Drilling Productivity Report.(65) In order to separate unconventional from conventional wells, type curves were made for only horizontal wells in DrillingInfo (see Table 15 for percentages of horizontal wells).(60)

2.2.3 Total Oil and Gas Well Counts

Using a combination of state government data,(66-68, 70, 72) EPA's FracFocus report,(55) previous reports,(22-24, 53, 73) and the Baker and Hughes well count data from 2012 to 2014,(74) a complete count of wells in each unconventional play was developed (Table 2).

Table 2: Well water use and production totals. Calculated Number of Wells, Total Water Use, Gas Production, Oil Production, and Flowback and Produced (FP) water for the Major Unconventional Shale Gas and Oil Formations. Water use is reported in $\times 10^9$ L, $x10^9$ gal, gas production in $x10^{12}$ cubic feet, oil production in $x10^6$ bbl and FP water in $x10^9$ L, $x10^9$ gallons.

shale gas	*number of wells*	*total water use*	*total gas production*	*total oil production*	*total flowback and produced water*
Barnett	16874	243.32, 64.27	23.44	46.62	209.24, 55.27
Eagle Ford	5846	80.08, 21.15	8.01	723.52	151.22, 39.94
Fayetteville	5850	117.35, 31.00	9.04		
Haynesville	3172	61.70, 16.29	13.75	0.19	55.541, 14.67
Marcellus	8307	133.91, 35.37	30.41	47.59	43.20, 11.41
Niobrara	2281	3.44, 0.90	3.02	104.04	12.95, 3.41
Woodford	2861	68.01, 17.96	5.58	29.58	

unconventional oil	*number of wells*	*total water use*	*total gas production*	*total oil production*	*total flowback and produced water*
Bakken	9704	72.68, 19.20	1.97	2065.16	118.92, 31.41
Permian	9857	40.81, 10.77	5.24	1915.64	
Monterey-Temblor	703	0.35, 0.09	0.02	32.69	16.73, 4.41
Eagle Ford	7156	107.78, 28.47	3.19	1829.58	162.84, 43.01
Niobrara	2418	5.26, 1.38	1.97	456.04	32.02, 8.45
Woodford	680	5.30, 1.39	0.48	44.88	

2.2.4 Water per Energy Intensity

Water use and produced water data were normalized by the energy content of extracted shale gas and unconventional oil and associated liquids. This was done by converting from EUR (BBL or MCF) to GJ of energy. Energy content of natural gas was defined as 1.0836 GJ/MCF (1.027×10^6 BTU/MCF), whereas oil had an energy content of 6.0679

GJ/BBL (5.751 × 10^6 BTU/BBL). (37) Additionally, we accounted for all associated hydrocarbons (see Appendix A).

2.3 Results and Discussion

2.3.1 Water Use

Analysis of the EPA's FracFocus database reveals large variations in water use, with typically higher water use for shale gas (a range of 13.7 to 23.8 × 10^6 L per well, 3.6 to 6.3 ×10^6 gal per well, excluding data from Niobrara formation) relative to unconventional oil (1.3 to 15.1 × 10^6 L per well, 0.3 to 4.0 × 10^6 gal per well excluding data from the Monterey-Temblor formation) extraction (Table 1). These values are consistent with data reported in previous studies for some of the plays included in this study, particularly with water use data reported recently by Gallegos et al.(60) (Table 9). For the Eagle Ford, Niobrara, and Woodford plays that extract both shale gas and oil, we show differential water use values for hydraulic fracturing shale gas and oil wells (Table 9). Our analysis shows that water use per well did not change significantly with time from 2011 to 2013 (Table 14).

Between 2005 and 2014, an estimated total of 940 × 10^9 L (940 × 10^6 m^3, 248 × 10^9 gal) was used to hydraulically fracture wells in the 10 formations included this study (Table 2). Hydraulic fracturing for shale gas (708 × 10^9 L, 708 × 10^6 m^3, 187 × 10^9 gal) has used three times more water than unconventional oil wells (232 × 10^9 L, 232 × 10^6 m^3, 61 × 10^9 gal). The Barnett Shale led the United States with a total water use of 243 × 10^9 L (64 ×

10^9 gal) over the course of its production history. Because of its location in a semi-arid region of Texas and the growing stress on both ground and surface water resources with population growth, water use for future well development in the Barnett formation could be a limiting factor.(24, 53) In the Monterey-Temblor Formation, water use per well (0.3×10^6 L, 0.08×10^6 gal) and total water use (0.35×10^9 L, 0.35×10^6 m^3, 0.09×10^9 gal) are relatively low. This can be largely attributed to most hydraulic fracturing (well stimulation) occurring on vertical wells in higher permeable formations as opposed to horizontal wells in other plays.(68, 70)

Overall, we estimate that between 2012 and 2014 the annual water use for hydraulic fracturing in the United States was 116×10^9 L (31×10^9 gal) per year for shale gas and 66×10^9 L (17×10^9 gal) per year for unconventional oil (combined 183×10^9 L or 48×10^9 gal per year; Table 16). This estimated water use is 0.87% of the total industrial water used in the United States (2.07×10^{13} L, 5.5×10^{12} gal per year) and only 0.04% of the total fresh water use per year (4.23×10^{14} L, 1.11×10^{14} gal per year) in the United States.(75)

2.3.2 Flowback and Produced Water

Flowback water is typically the first water produced from a well following hydraulic fracturing and is made up of injected hydraulic fracturing fluids blended with formation water (a range of 1.8 to 4.1×10^6 L, 0.5 to 1.1×10^6 gal for the Marcellus shale

after 90 days)(16) and is typically associated with high rates of oil and gas production. Over time the produced water that is generated with gas and oil is composed of almost entirely of the formation water,(13) and the production rates gradually decrease parallel to the oil and gas production (Figure 36 and Figure 37).(58) While it is possible to distinguish flowback from produced water based on water chemistry, data reported by producers to government agencies typically does not distinguish the two types of fluids, and thus, we report here combined volumes as flowback and produced waters (FP water). Previous studies have evaluated the FP water volume after a relatively short period, whereas in this study, we provide a longer integrated time of FP water production between 6 to 10 years.(22, 24, 59) A comparison between the results of this study to previous studies is shown in Table 11.

In some unconventional shale gas and oil formations, the volume of FP water after 1 to 2 years exceeds the volume of water injected for hydraulic fracturing (Bakken, Eagle Ford, Niobrara, and Monterey-Temblor), while in other formations (Barnett, Haynesville, and Marcellus), the volume of produced water, even after 8 to 9 years of operation, is typically lower (Table 2). In all cases, FP water generation drops dramatically after the first year and levels off to a constant rate of production in the following years (Figure 5). Integration of all of the data over the 6 to 10 years of available data yielded a large variation of FP water volume for different shale gas formations, between 5.2×10^6 L (1.4×10^6 gal) per well for the Marcellus shale and 25.9×10^6 L (6.8

x10^6 gal) per well for the Eagle Ford. Produced water from unconventional oil production had a smaller range of 8.0 × 10^6 L (2.1 × 10^6 gal) per well for the Niobrara formation to 22.7 × 10^6 L (6.0 × 10^6 gal) per well in the Eagle Ford (Table 1).

Overall, we estimate a total of 803 × 10^9 L (803 × 10^6 m^3, 212 × 10^9 gal) of FP water returned to the surface since the early 2000s until today (2015) from unconventional shale gas and oil operations in the 10 plays included this study (Table 2). Shale gas plays in sum produced slightly less water (472 × 10^9 L, 125 × 10^9 gal) than was used for hydraulic fracturing (708 × 10^9 L, 187 × 10^9 gal), while unconventional oil wells (331 × 10^9 L, 87 × 10^9 gal) produced more FP water than was used to fracture them (232 × 10^9 L, 61 × 10^9 gal). Given the high levels of contaminants, several studies have highlighted the challenges associated with the management and disposal of FP water, (6, 16, 37, 62) thus, the fact that the amount of generated FP water in the United States is on the same level as water use is startling.

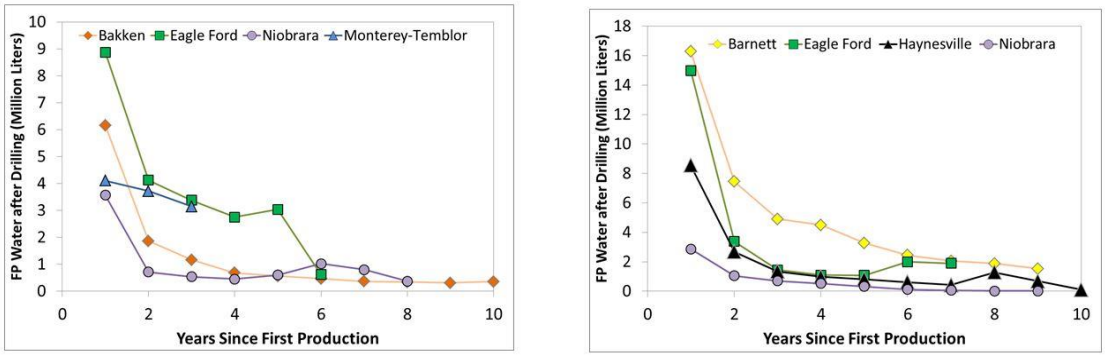

Figure 5: Decline curves of Flowback and Produced (FP) water over the course of well production for unconventional oil (left) and shale gas (right) formations. Note: For the Barnett shale, data from DrillingInfo (64) were used in the figure, while data from Nicot et al.(6) were used for the calculation of total FP water.

2.3.3 Water Use and Produced Water Intensity

In order to compare shale gas and unconventional oil to each other and to other energy sources, the water use intensity (WUI) and produced water intensity (PWI) parameters were used. Upon normalizing water use and FP water production to energy production, the WUI of shale gas (combined dry and wet gases) had a range from 0.7 to 9.3 L/GJ, similar to the range obtained for unconventional oil (1.1 to 7.5 L/GJ). Our data show that WUI for both shale gas and unconventional oil did not change in most plays with time (Figure 30 and Figure 31). WUI calculations in this study only accounted for water used in the hydraulic fracturing of wells and excluded the water use for drilling (640 to 1080 × 10^3 L, 169 to 285 × 10^3 gal per well) and cement (70 to 140 × 10^3 L, 18 to 37 × 10^3 gal per well), as well as the potential for refracturing of wells.(51, 76) WUI values obtained in this study are significantly higher relative to reported WUI values for water allocation for drilling and cementing associated with conventional oil and gas extraction, (~0.7 L/GJ).(3, 25) Yet, enhanced oil recovery, particularly through tertiary recovery techniques, would have a much higher WUI of 120 L/GJ.(76) Likewise, both unconventional shale gas and oil have much lower WUI values (for extraction) relative to coal (underground mine, 28.4 L/GJ; surface mine, 3.2 L/GJ) and uranium (23.8 L/GJ) extractions.(63)

The WUI for unconventional oil production can also be calculated by the volumetric ratio of water use to oil production during a time interval. The range of WUI

of this metric for unconventional oil extraction by hydraulic fracturing is 0.07 (Monterey-Temblor) to 0.74 in the Woodford formation (Table 1). By comparison, the average WUI for conventional oil extraction was 8.6 over the lifetime of a well. Yet enhanced oil recovery through tertiary recovery techniques could increase the WUI to up to 300.(76)

The produced water intensity (PWI) for unconventional oil production (6.8–11.4 L/GJ) is only slightly higher than that of shale gas (1.0–10.2 L/GJ). In the Monterey-Temblor play in California, the production of FP water is much higher (PWI of 76.6 L/GJ), probably due to the relatively higher permeability of the formations in which well stimulation is occurring. The other PWI metric is the volumetric ratio of FP water to oil production. Our data indicate that the FP water to oil ratio (in barrels) varies from 0.36 to 0.56 in horizontal on-shore unconventional oil production, with an average water-to-oil ratio of 0.44. Monterey-Temblor vertical unconventional production had a higher ratio of 3.22 (Table 2). The data show that volumetric PWI values in all unconventional oil wells except the Monterey-Temblor formation remains constant during 6 to 10 years of production (Figure 35), and the significant reduction in oil production after the first year is paralleled by similar reduction in FP water production. This pattern is opposite of typical conventional oil wells, where produced water and the water–oil ratio increase with well age.(51) The FP water–oil ratios of unconventional oil wells are also lower than

estimates for produced water–oil ratios of 3(77) to 7(30) reported for conventional oil in the United States.

While new exploration of unconventional shale gas and oil formations in the United States has increased the overall water use for hydraulic fracturing (a total of 940 billion liters from 2005 to 2104) and has generated new sources of highly saline and toxic wastewater (a total of 775 billion liters), our water use and produced water intensity evaluation indicates that hydraulic fracturing is not extracting more water and generating more wastewater relative to conventional oil or coal mining while normalized to the energy production.

3. Quantity of Flowback and Produced Waters from Unconventional Oil and Gas Exploration

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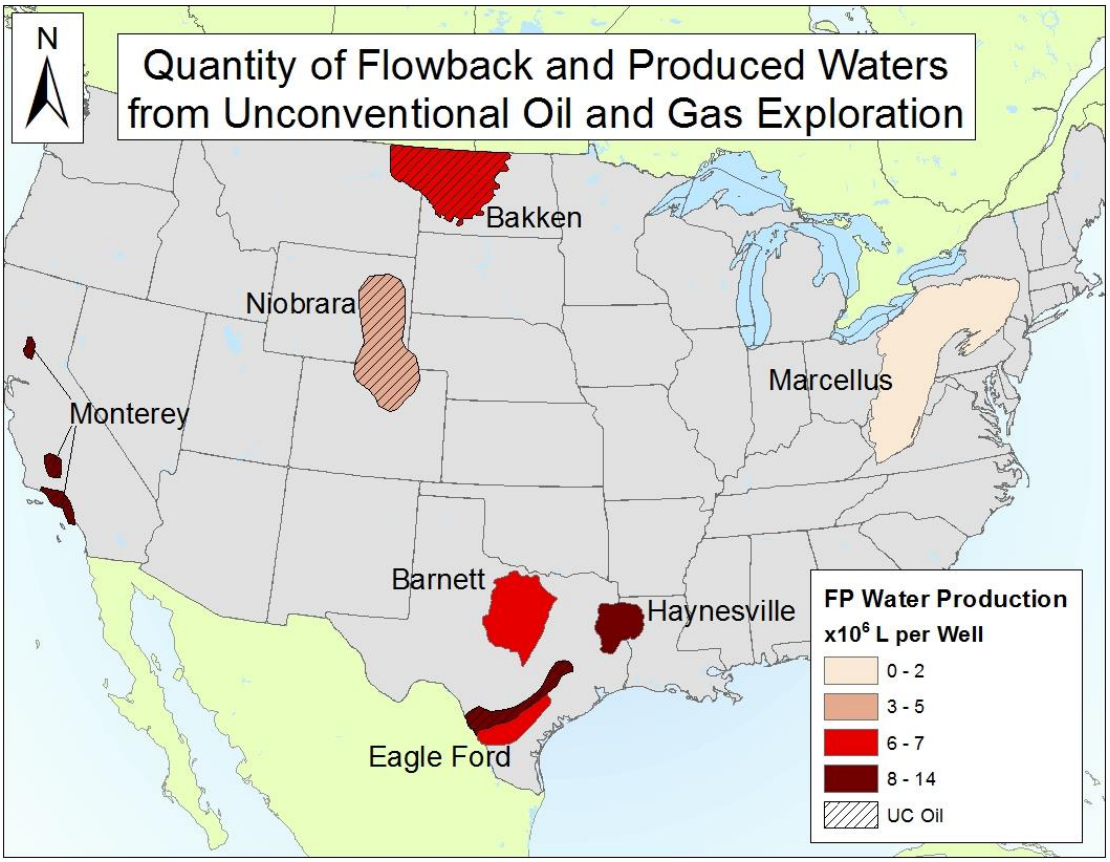

Figure 6: Quantity of Flowback and Produced Waters (FP Water) from Unconventional Oil and Gas Exploration

3.1 Introduction

Following the rapid development of unconventional oil and gas in the United States, problems arising from the management, disposal, and spills of associated

wastewater have become major environmental issues associated with hydraulic fracturing (14, 16, 38, 78, 79). Over the last decade, the most common disposal practice in the U.S. has involved injection of FP water into Class 2 brine disposal wells, which has recently been reported to induce micro-scale earthquakes (15, 30, 32, 36, 37), and in one case, also contamination of surface water (29, 80). Geological limitations for injection wells, technological and economic barriers to treatment prior to disposal, water scarcity issues and other management practices have led to an increased interest in evaluating the potential for reuse of FP water (11, 30, 32, 33, 81). Currently, well lifetimes are projected to be around 30 years, meaning that during downturn periods when only few new wells are being drilled, as is currently (summer and fall 2016) the case, thousands of wells already in production nation-wide will continue producing wastewater (58). Long term projections estimate that the growth of the hydraulic fracturing waste water treatment and recycling technologies will be significant, accounting for an estimated $3.8 billion in revenue by 2025 (82). This projected growth calls for the necessity for a better understanding of the volumes and quality of wastewater produced from unconventional oil and gas exploration.

When a well is hydraulically fractured, it is done so in stages, with each stage being plugged, while the next is being drilled and fractured (83, 84) This creates an increase in pressure and a backup of both fluids and gas, while further stages are drilled. When the final stage is drilled, the fluids and gas are allowed to flow up out of the well

for a period of time of up to about 2 months (31). Many operators call this stage the "Flowback" period, where the water returning from the well is made up partially of drilling and the injected hydraulic fracturing fluids, and formation brines that are entrapped in the target formations which are extracted together with the oil and gas (5, 33, 85). Water generated after the flowback period, during the lifetime of oil and gas production, is commonly called "produced water" (5, 31) . The distinction between "flowback" and "produced water" definitions can be subjective when reporting data, and combined flowback and produced water (FP Water) data are reported in many instances without a specific distinction. In this study, we examine the volume and salinity of FP water generated through time, and use the water salinity data to distinguish between the water types: water that is made up of a blend of naturally occurring formation brine and returned hydraulic fracturing fluid, and water that is composed of only formation brine (5, 13, 16, 30-33, 58, 77, 86). In many cases hydraulic fracturing is conducted with freshwater, although reuse of FP water is becoming more common in some areas like in the Marcellus Formation. When using freshwater for hydraulic fracturing, the FP water initially has low salinity, yet mixing with formation brines quickly raises the salinity of the water generated during the first several days of production and eventually leveling out to values that represent the maximum level of salinity of the formation brines between 2 and 3 months since first production (85, 87).

When quantifying the variations of water production volumes across formations with time, several methods have been used to generalize production rates within unconventional oil and gas basins in the U.S. (11, 22-25, 53, 58, 87, 88). Depending on the method used to interpret the data, vastly different quantities of wastewater have been reported for the same basin over similar time periods (23, 25). In order to evaluate the reason for these discrepancies, we examine three different methods for quantifying FP water volume (mean, median, and DrillingInfo Desktop's Type Curve tool, a software that provides data on oil and gas wastewater volume (64)), and show that the different methodologies could result in different volumetric estimates for FP water from unconventional oil and gas exploration.

Based on the integration of the wastewater volume and flowback water salinity data, this study aims to evaluate the overall and dynamic volume variations and differential salinity of wastewater generated from unconventional oil and gas wells. The ultimate objective of this study is to evaluate the relative proportions of returned hydraulic fracturing fluids relative to naturally occurring formation water in FP water during the lifetime of unconventional oil and gas wells. Through understanding the temporal variability in water quantity and water quality, researchers and industry professionals could evaluate, design and implement best management practices for FP water (32, 73, 81).

3.2 Methods

3.2.1 Data Sources

The DrillingInfo Desktop application was used to download data for wells in the major unconventional gas and oil formations in the United States, focusing on the oil, gas, and FP water production values of each well on a monthly basis (64). We used two methods to extract production values from DrillingInfo (DI) Desktop. The application's "Type Curve" function produces a decline curve for the reservoir of interest, compiling monthly production data and adjusting the curves as if each well began at the same time. This average monthly data was then downloaded and graphed to produce the first decline curve reported in this paper (light blue line in Figure 40 and Figure 41). DrillingInfo Desktop also allows the raw data to be downloaded for each well. We compiled monthly raw water, oil, and gas production data from the DI Desktop program, similarly adjusting first production to begin all wells at the same time, then created individual decline curves based on both the mean and median values obtained from the downloaded raw data. We calculated bootstrap confidence intervals of monthly production data for both the mean and median data sets (Figure 40 and Figure 41). The process of calculating bootstrap confidence intervals involves randomly sampling with replacement, from the original dataset to form a new distribution of sampled mean or median values (11, 89). This process is often called resampling. Bootstrap confidence intervals were calculated by resampling from the original dataset

to form distributions of the resampled means and medians. Each resample was the same size as the original sampled data and the resampling process was repeated 10,000 times to form the resampled distributions. The 95% confidence intervals were gleaned from the resampled distributions (values at the 0.025 and 0.975 percentiles). The bootstrap confidence interval provides a reliable estimate of the variations of production at any point in time (shaded regions of Figure 40, Figure 41, Table 18).

3.2.2 Data Analysis

Decline curves were first used by Arps (1945) to estimate ultimate recovery of currently producing conventional wells using limited data from initial production. Since then, varying empirical and theoretical methods have emerged attempting to estimate ultimate recovery of oil, natural gas, and FP water (6, 58, 84, 90-93). We used data provided by DrillingInfo to generate decline curves for both oil and gas production from unconventional oil and gas wells (Figure 40), and similarly FP water generation (Figure 41). These decline curves were generated by aligning all historical production information to the same arbitrary starting time, month 1, then taking the mean, median and a bootstrap confidence interval of each, using available data for each month of production. From this, the trend through time of production was examined, while cumulative production was developed using the integral of each decline curve from 0 to 10 years. Hydraulically fractured wells are projected to have lifespans of 30 or more years, however, our estimated ultimate recovery (EUR) was capped at 10 years because

hydraulic fracturing has only been used on a widespread basis for the past 5-10 years. Additionally, we find that the amount and quality of long-term data (>10 years) degrades with time (Figure 42), evidenced by widening bootstrap confidence intervals with time (Figure 41). Consequently, in order to maintain consistent precision of the dataset, we needed to trim the well production decline curves short of the 10 years goal in some cases. In all cases however, we assumed that the total volume present after the time period shown represents the full EUR, and note that the continued production may add only a relatively small volume to the total EUR.

Bootstrap confidence intervals have previously been used to estimate the variation of recovery of FP water (11). Using the FP water generation, natural gas and oil production data, 95% bootstrap confidence intervals for both means and medians values were calculated for each month of production in each unconventional oil and gas formation. Using R software package, bootstrap resamples were drawn with replacement from each month's empirical distribution, using the same sample size as the original data. Mean and medians values were calculated for each resample. This process was repeated 10,000 times to form bootstrap distributions for the mean and median for each month in each formation. From the bootstrap distribution, the 0.025 and 0.975 percentile values were gleaned to form each of the confidence intervals. Comparisons of the bootstrap means and medians to the empirical values suggest very little bias in the confidence intervals.

3.2.3 Wastewater Distinction

Previous geochemical studies have shown that FP salinity increases during the first months of flow from shale gas and tight oil wells. Based on chemical and isotopic variations of the FP water, most studies have suggested the rise of the salinity reflects blending of typically low-saline injected hydraulic fracturing (HF) fluids and hypersaline formation brines (12, 13, 59, 81, 87, 94). In most cases, initial FP production had low salinity (TDS), matching that of the injected fracturing fluid, but quickly increased in salinity with time (Figure 7).

We analyzed the variations of FP salinity from different time series that monitored the TDS variations in FP water following hydraulic fracturing. To distinguish the transition time from "flowback" water to "produced" water, we assume that FP is composed of a mixture between injected water (TDS ~ zero in cases where fresh water is used, or higher TDS in cases where recycled water is used for hydraulic fracturing) and naturally occurring brine with TDS equal to the level measured at the endpoint of the dataset. We used dataset with long time series (> 3 months after HF) of flowback water monitoring from the Marcellus shale (Rowan et al. (2015), Hayes (2009)(13, 59), and new data from Duke University) and Barnett shale (Galusky and Hayes (2011)(94). We calculated the relative fraction of the brine by using a mass-balance calculation between the injected water and the endpoint of each data string that represents the final TDS value (i.e., the brine). The TDS of FP was then used to calculate the relative fraction of

the brine in the FP water blend (Figure 8). For cases where the injected water was from recycling water with TDS > 0, we used a mass-balance mixing equation between day 1 and final TDS. For example, Well A from Rowan et al (2015)(13) reported an initial TDS of 100,000 mg/L and a final TDS of 169,000 mg/L on day 438 after hydraulic fracturing, which we defined as "final TDS" because it was the final reported TDS value for that well. Using the following mass balance approach:

$$Percentage\ of\ Final\ TDS = \frac{[TDS\ (x) - TDS\ (day\ 1)]}{[TDS\ (final) - TDS\ (day\ 1)]}$$

where TDS(x) represents the TDS of the flowback water at day x after hydraulic fracturing (Figure 7). In the case of well A reported by Rowan et al. (2015)(13), Day 1 then had a value of 0% brine contribution, while day 20, which reported a TDS of 140,000, had a value of 58% of the natural occurring brine in the FP blend. In our data analysis, we only included data strings containing 3 or more months' worth of data, assuming that the highest reported TDS for each data set represented close to 100% formation water (Figure 44). The 3-month cutoff was selected because all of the long-term data series show a relative leveling off by this point (Figure 7 and Figure 44). We then used that line of best fit to calculate the relative mixing proportions of formation brines and returned hydraulic fracturing water (Figure 9 and Figure 44).

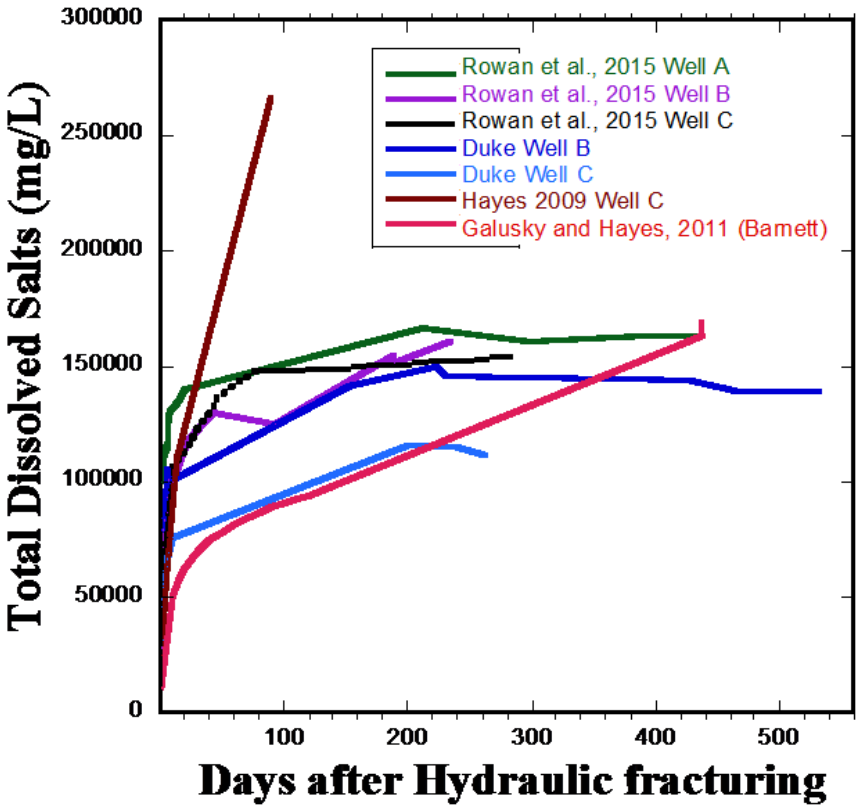

Figure 7: Temporal increase in total dissolved salts (TDS) with time (days after hydraulic fracturing) in flowback and produced waters from individual oil and gas wells. Data from the Marcellus shale (Hayes, 2009; Rowan et al., 2015; Duke University unpublished data)(13, 59) and Barnett shale (Galusky and Hayes, 2011)(94) are used. The data show a rapid rise of the salinity during the first 30 days, followed by a period of leveling off.

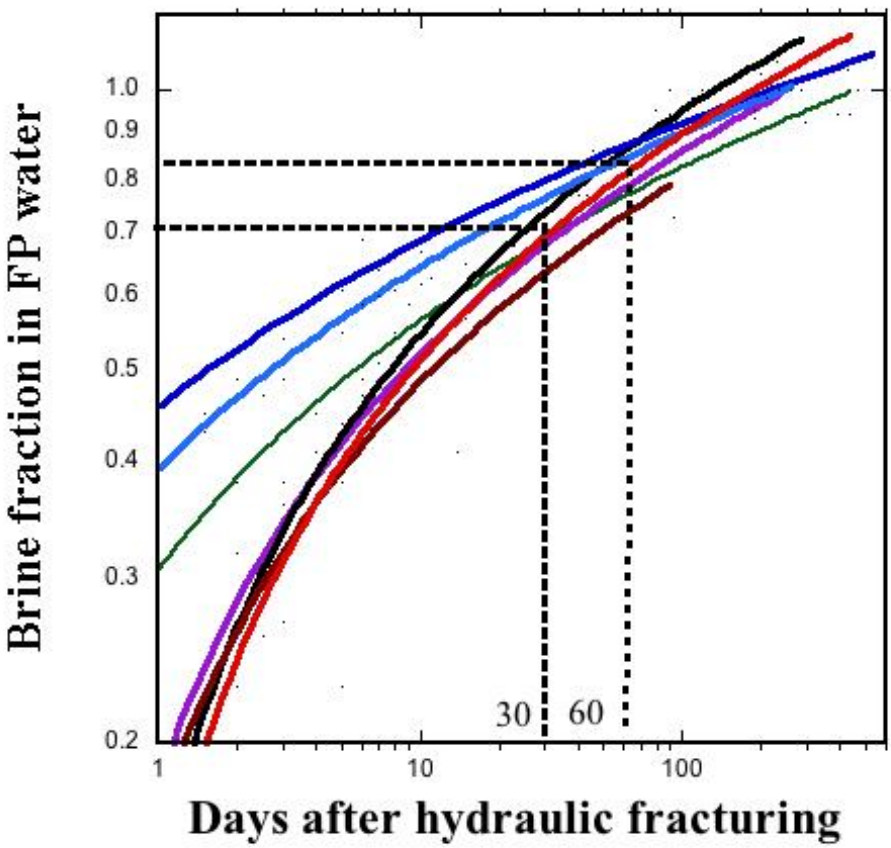

Figure 8: Best fit curves of the calculated brine fraction in flowback waters with time (days after hydraulic fracturing; log scale), from individual wells with long TDS monitoring record (>3 months) from the Marcellus and Barnett shales (see line symbols in Figure 7). The rapid increase of TDS with time following hydraulic fracturing infers a high contribution of the naturally occurring brine component in the blend, with a mean of ~70% after 30 days and 85% after 60 days following hydraulic fracturing.

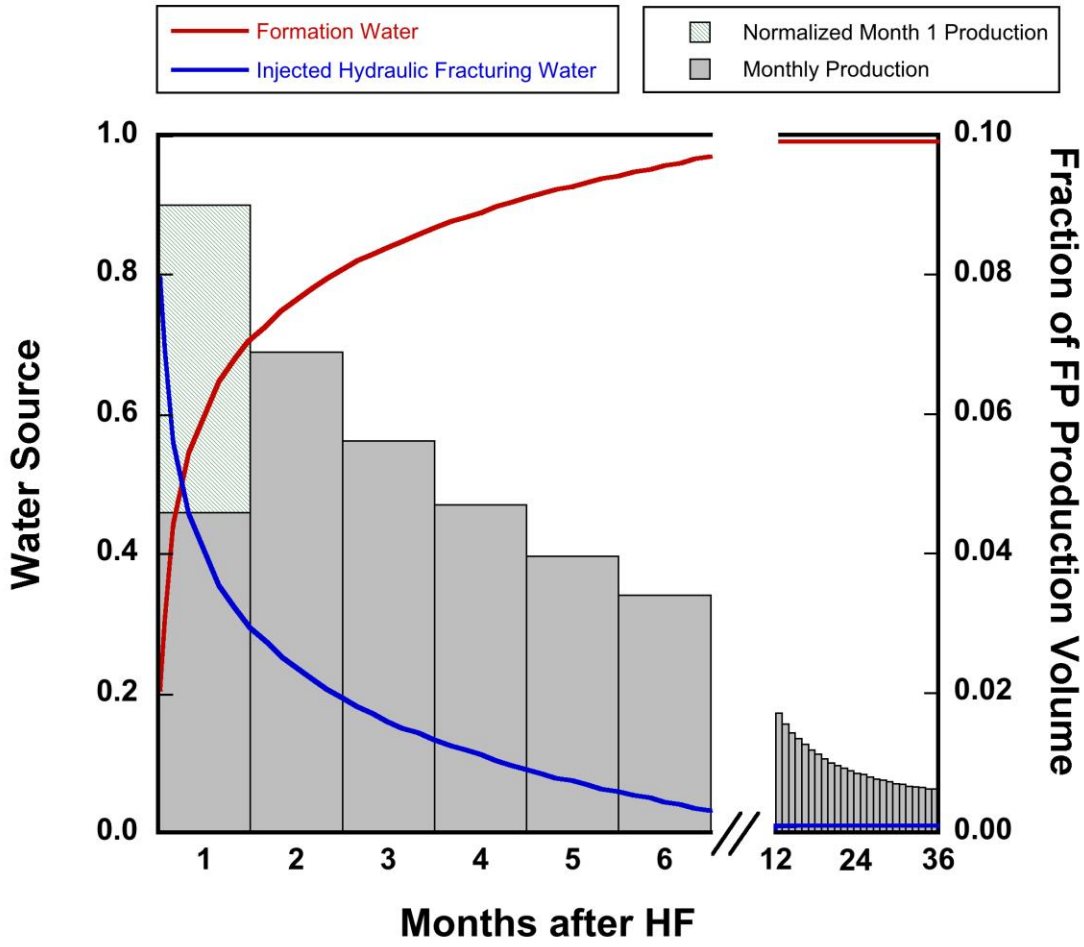

Figure 9: Water source characterization and decline. Temporal variations of the fractions of the two water sources that compose the FP water (left Y-axis) and the fraction of FP production volume relative to the overall FP water volume production (right y-axis), following hydraulic fracturing (HF).The two water sources include the retuned hydraulic fracturing water and the shale formation brine that together compose the FP water. Fraction data of the water source was synthesized from integrated FP water time series datasets (see also Figure 8 and Figure 44). The mixing relationships were based on TDS mass-balance calculations between the injected water with low TDS and formation brine with high TDS, represented by FP waters collected at later stages after hydraulic fracturing (data combined from Figure 1, R2=0.84, n=132 time points; see Figure 44). We show normalized month 1 production because well production data is available by calendar month, it is likely that for many wells, month 1 production is not representative of a full month of production (see Table 20 and Figure 46).

3.3 Results

3.3.1 Water Quantity Analysis

Our data show that the total FP production volumes in the major unconventional basins in the U.S. ranged from 1.72 to 14.32 million liters (0.45 to 3.78 million gallons) per well (

Table 3). FP production is commonly associated with oil and gas production rates (5, 77) and is characterized by high flow rates in the first few months, followed by a slow leveling off of production in subsequent months to years (Figure 41). In most cases, production values calculated from the median values were substantially lower than both the mean values and the DrillingInfo type curve methods. This is most likely a result of upper skewed nature of the empirical distributions of the datasets (Figure 43), combined with larger outliers disproportionally affecting the mean values and the values extracted from the DrillingInfo type curve method. We observe large bootstrap confidence intervals for the mean of Eagle Ford Oil data, while in many of the other basins; we see an increase in the spread of data through time along with fewer data points (Figure 42). Examining the temporal nature of production, we see that between 10% and 20% of the total FP production of a well over its lifetime (restricted to 10 years) occurs during the first three months, while an estimated 20-50% of total FP production volume occurs within the first 6 months (Table 4).

Table 3: Estimated water, gas, and oil production. Estimated FP water (million liters per well) and Oil (shaded gray; million bbl per well) and Gas (left white; million MCF per well) derived using the median ("Median Water", "Median OG"), mean ("Mean water", "Mean OG"), and DrillingInfo decline curve methods ("DI water", "DI OG").Data from oil producing formations have their cells within the table shaded grey, while gas producing formations were left white. Data for FP production (*) from the Marcellus formation along with FP production and oil production (**) from the Monterey formation in California were not available on DrillingInfo and were downloaded from state government websites. (62, 66, 68)

Total FP Water

Basin	Median Water	Mean Water	DI Water
Bakken	6.82	22.87	30.53
Barnett	9.01	28.99	73.91
Eagle Ford Gas	6.09	20.06	20.49
Eagle Ford Oil	12.28	67.73	23.66
Haynesville	11.55	17.70	18.13
Marcellus*	1.72	3.94	NA
Monterey**	14.32	28.34	NA
Niobrara	5.70	18.45	6.09

Total Oil (grey) and Gas (white) Production

Basin	Production Type	Median OG	Mean OG	DI OG
Bakken	Oil	0.16	0.21	0.24
Barnett	Gas	1.06	1.26	1.43
Eagle Ford Gas	Gas	1.26	1.53	1.54
Eagle Ford Oil	Oil	0.20	0.61	0.24
Haynesville	Gas	3.25	3.74	4.10
Marcellus	Gas	2.76	3.45	3.92
Monterey**	Oil	0.02	0.02	
Niobrara	Oil	0.09	0.11	0.10

Table 4: Water production volume (million Liters) and percent of the first 3 (left) and 6 (right) months of oil and gas wells operation from different unconventional basins. In each case, only 10-25% of total FP water is generated during the first 3 months of well operation, while an estimated 20-50% of FP water is generated during the first 6 months of operation. Shaded and white cells refer to unconventional oil and shale gas producing formations, respectively.

First 3 Months FP Production (Million Liters)

Basin	Median Water	Mean Water	DI Water
Bakken	0.82	1.55	3.61
Barnett	0.94	2.79	9.16
Eagle Ford Gas	1.50	4.20	4.09
Eagle Ford Oil	2.53	5.98	3.80
Haynesville	2.19	3.44	3.16
Niobrara	0.91	2.83	1.37

First 6 Months FP Production (Million Liters)

Basin	Median Water	Mean Water	DI Water
Bakken	1.29	2.56	5.87
Barnett	1.71	5.01	16.09
Eagle Ford Gas	2.93	8.40	8.11
Eagle Ford Oil	4.55	10.29	6.45
Haynesville	3.51	5.80	5.57
Niobrara	1.22	3.78	1.83

First 3 Months % of Total Production

Basin	Median Water	Mean Water	DI Water
Bakken	12%	7%	12%
Barnett	10%	10%	12%
Eagle Ford Gas	25%	21%	20%
Eagle Ford Oil	21%	9%	16%
Haynesville	19%	19%	17%
Niobrara	16%	15%	22%

First 6 Months % of Total Production

Basin	Median Water	Mean Water	DI Water
Bakken	19%	11%	19%
Barnett	19%	17%	22%
Eagle Ford Gas	48%	42%	40%
Eagle Ford Oil	37%	15%	27%
Haynesville	30%	33%	31%
Niobrara	21%	21%	30%

3.3.2 Salinity Analysis

The salinity of the FP water rapidly increases through time following hydraulic fracturing (Figure 7). Previous studies have shown that the changes in the salinity chemistry during the first few days to weeks reflect mixing between the returned injected water and hypersaline formation brine (Figure 7) (12, 13, 59, 94). Based on this geochemical criterion, we calculated the relative brine component in FP water for individual wells with long (> 3 months) monitoring data. The data show that the average brine faction values for the 7 case studies are 0.71±0.05 and 0.81±0.05 for FP water after 30 days and 60 days, respectively (Figure 8). Consequently, the brine constitute ~70% of the FP water after a month and ~80% after two months from initial hydraulic fracturing. Our analysis shows that the rise of the salinity, and thus the contribution of the formation brine to the FP blend, is far more rapid than the decline of the production rate (Figure 9). Consequently, during the high peak of FP production, the FP water is predominantly composed of the formation brine.

Previous studies have shown that the absolute volume of the flowback water is much lower than the volume of the injected water (59) . Yet the results shown in this study suggest that the FP water is mainly composed of brine and thus the relative volume of the injected water that is returned to the surface is even lower than previously estimated. These results reinforce previous scenario that suggested that the majority of the injected hydraulic fracturing and drilling fluids have been sequestered into the shale

formations through imbibition after about 3 months, and in many cases even sooner (95) Based on mass-balance calculations, we find that during the lifetime of a well a maximum of 8% of the total FP water is composed of returned hydraulic fracturing fluids (Table 3). When compared to the production volumes and amount of water used for hydraulic fracturing (25, 60) Table 19and Table 20) it is clear that most of the injected water is retained in the shale or tight sand formations, and the return flow is mainly composed of naturally occurring formation brine.

Table 5: Volume of injected HF water (million L), Total FP water (million L), estimated Cumulative Injected HF water (million L) returned to the surface (based on the salinity mass-balance), Percent of the volume of the returned injected water compared to the volume of water used for hydraulic fracturing in the different basins (data from Kondash and Vengosh (2015)(25)), and Percent of the total volume of FP water made up of returned HF water. Cumulative injected water was calculated by multiplying the production from each month (Figure 41) by the percentage of injected water (Figure 9 and Figure 44) at the midpoint of each month of oil and gas wells production.

Basin	Volume Injected Fluids	Total FP Water	Cumulative Injected Water Returning	Fraction of Injected Fluids Returning	Fraction of Total FP Water
Bakken	7.49	6.82	0.27	4%	4%
Barnett	14.42	9.01	0.29	2%	3%
Eagle Ford Gas	13.70	6.09	0.46	3%	8%
Eagle Ford Oil	15.06	12.28	0.77	5%	6%
Haynesville	19.45	11.55	0.69	4%	6%
Niobrara	1.32	5.70	0.29	22%	5%

3.4 Discussion

There are a number of ways to analyze and quantify production data on a basin-wide scale (6, 11, 22, 25, 58, 84, 88, 90-93). Several studies have shown estimated ultimate recovery of oil, natural gas, and FP water values similar to the results generated in this

study, mostly agreeing with the reported median FP production values (22, 23, 53). Our data show that the production rate and salinity of FP water from unconventional oil and gas exploration vary significantly during the lifetime of a production well, with high rates and relatively lower salinity during the first phase (up to 2-3 months) relative to significant (order of magnitude) lower production rates and typically much higher salinity during the rest of a well lifetime (Figure 9 and Figure 41). These dynamics require differential management modes during oil and gas operations; management of relatively large volume of FP water during the early stages of unconventional oil and gas well operation and transport to offsite water treatment plants for reuse or injection into class II underground injection wells. In contrast, operation during most of a well lifetime (i.e., > 6 months) involves a much lower volume. Because the return of most injected hydraulic fracturing fluids is restricted to the first few months after initial production, the wastewater that will be generated during that time could contain some of the injected hydraulic fracturing additive chemicals, since the FP water is a blend of returned injected fluids and formation brine. We expect that the risks associated with man-made chemicals found in hydraulic fracturing fluids would be negligible after the first several months of operation, since the FP water is composed of mostly naturally occurring formation brine. Consequently, many of the risks associated with hazardous chemicals in hydraulic fracturing fluids are restricted to 4-8% of the total FP wastewater volume. Nonetheless, we argue that the major concern with long-term FP water

production rests with the hazards associated with the naturally occurring constituents of the formation water, among which are halides, heavy metals, metalloids, naturally occurring radioactive materials (NORM), and other contaminants such as ammonium and iodide (14-16, 26, 27, 85, 96-98).

Prediction of the wastewater volume that is expected to come from unconventional oil and gas operations is an important factor for sustainable operations. While many studies have attempted to predict oil and gas production using both empirical and theoretical models (88, 90, 92, 93), few have used these methods to predict wastewater production.(25, 58, 99) Here we present baseline values within different formations, where FP water production assessments are provided. Because of the right skewed distribution of the data (Figure 43) reported in this study, we suggest that using mean production values may significantly overestimate FP production. Instead, we posit that using bootstrapped median confidence intervals is the most appropriate approach to generalizing production, and thus caution future studies to take the distribution of the data into account when creating models for projected wastewater production rates.

Several studies have identified and defined different contaminants commonly found in injected hydraulic fracturing fluids based on the chemicals toxicity (38, 78, 79, 100-102). With a better understanding of the hazards associated with hydraulic fracturing fluids, it is possible to use our estimates of the percentage of brine in flowback water (Figure 9) in order to predict the concentration of contaminants of interest in

water, which could be used to assess the environmental impact of spilled water, or alternatively, to adjust targeted treatment processes on recovered water.

Due to the relatively large volume of FP water that is generated during the first few months, there might be some incentive to capture that FP water for reuse, as it will only require a relatively lower degree of treatment and dilution before being able to be utilized again as hydraulic fracturing fluid (Figure 10). However, saline formation waters that compose 92-96% of FP water are characterized by higher salts, metals, and NORM, which require much more intensive treatment or dilution to become useable for beneficial reuse. Alternatively, recent studies have suggested that new HF technologies can utilize hypersaline brines with TDS up to 90,000 mg/L, depending on the scale potential and ions present such as calcium, sulfate, and magnesium, allowing for minimal pretreatment before it is reused for HF (59, 103)

Based on the large variations in the salinity of formation water in the U.S. (Figure 10), we can distinguish between formations associated with high (TDS> 200,000 mg/L; such as the Marcellus and Bakken formation), medium (50,000 to 100,000; Haynesville, Barnett), and lower (<50,000 mg/L; Niobrara, California, Eagle Ford) salinity brines. We use seawater salinity (TDS~35,000 mg/L) as a useable threshold for economic treatment. Our data show the rise of the salinity of the flowback water during the first few months results in different salinity ranges for the different basins; from high proportions of

manageable water with relatively low salinity (Niobrara basin) to hypersaline brines (Bakken, Marcellus; Figure 10).

Based on these variations, we estimate that the western basins (Niobrara, California, Eagle Ford) with relatively low salinity have more potential for reuse for hydraulic fracturing and/or other beneficial use. Based on the relationships between the median EUR values reported for oil (Eagle Ford, California, Niobrara) and gas (Eagle Ford), and median FP water values (

Table 3), we estimate that the FP intensity (i.e., FP water volume per energy unit) for the low saline FP in these basins is approximately 60 L/bbl and 5 L/MCF for tight oil and shale gas, respectively. Consequently, we estimate that since the beginning of the unconventional oil and gas operations, a total volume of 22,000, 10,000, and 120,000 million liters have been generated in Niobrara, California, and Eagle Ford basins, respectively. Future research should examine the potential of utilizing the relatively low saline FP water from these basins for other beneficial uses such as irrigation and the role and possible limiting factors of other chemical constituents of the FP waters in these basins.

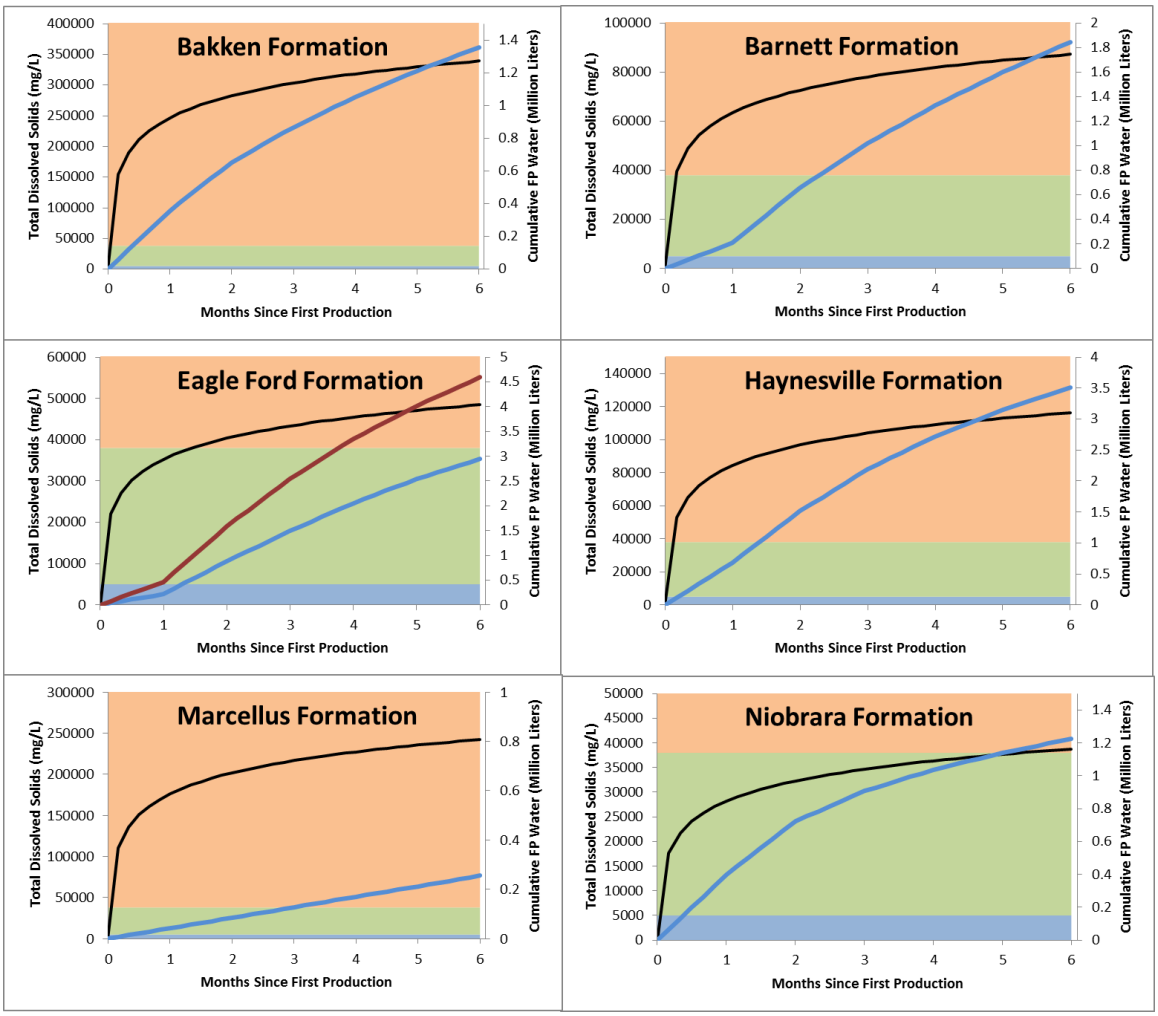

Figure 10: Salinity (black line) and cumulative water production (blue line) through the first 6 months of oil and gas production interpolated using percentage values obtained from Figure 9 multiplied by the final production TDS found in Figure 45 (and Table 20). The red line on the Eagle Ford graph shows water for oil while the blue shows water for gas. The shaded regions represent a classification of water as brackish (blue ~5,000 mg/L TDS) saline (green 5,000-33,000 mg/L TDS), and hypersaline brine (orange >33,000 mg/L TDS).

3.5 Conclusions

By examining the results from different statistical methods of decline curve development of FP water from unconventional oil and gas operations (Figure 40 and Figure 41) we show a pattern that begins with high production rates during the first few months of production, followed by an order of magnitude reduction and flattening out of production rates over the course of production. This is consistent with observations made in previous studies (22, 84, 91). In many cases, over 50% of the FP water is generated within the first year of an unconventional well, with a majority of that FP water composed of hypersaline formation water (Figure 9 and Figure 10). Due to the large differences seen in the estimated per well production using different data-generalization methods, we suggest that the selected method used to generalize FP production data and determine an EUR rate may have a significant impact on the estimated value of the volume of FP water during the lifetime operation of an unconventional oil and gas well (

Table 3). Our analysis demonstrates that using bootstrapped median approach is the most valid method with lower uncertainty relative to the other statistical methods that suffer from large variations and skewed data towards higher values.

While the initial production volumes in each formation are significant, they only represent a small fraction of the volume of the water injected for hydraulic fracturing (Table 19) as well as a small fraction (10-25%) of total FP production (Table 4). Additionally, we show that it is possible to differentiate between injected fluids and produced water using the combined salinity and geochemistry of the FP water, and that the ratio of injected fluids to produced water is consistently low among different unconventional oil and gas formations. Finally, we estimate that about 4-8% of total FP water is made up of the retuned injection fluids with potentially toxic hydraulic fracturing chemicals, while the majority (92-96%) of wastewater generated from unconventional oil and gas wells is composed of naturally occurring formation brines, which nonetheless contain other chemicals with potential environmental, human health, and treatment technology issues.

4. The Intensification of the Water Footprint of Hydraulic Fracturing

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4.1 Introduction

The environmental impacts of a fossil fuel–powered economy have led many nations across the world to begin developing greener energy and transportation solutions. In particular, the water footprint of fossil fuel exploration and electricity production has been projected to have major environmental impacts. It has been estimated that global water withdrawal for energy production constitutes 15% of the world's total water consumption.(2) Rapidly diminishing global water resources due to population growth and climate change have further exacerbated energy dependence on water availability, particularly in water-scarce regions.(1, 24, 52, 104) The beginning of the 21st century marks a special era with respect to global energy and water resources. The development of new drilling technologies and production strategies such as horizontal drilling and hydraulic fracturing has significantly improved the production

of natural gas and oil by stimulating fluid flow from impermeable shale rocks previously not considered viable energy sources. Since the mid-2000s, these developments have spurred exponential growth of unconventional gas and oil well drilling across the United States and are spreading now to other parts of the world (Figure 11 and Figure 12).(6, 9, 15, 52, 99, 105) The rise of unconventional energy development has generated public debate on its environmental implications (14, 78, 80, 101, 102, 106), especially with respect to both water availability and quality.(23, 24, 32, 52, 99, 107-109)

The process of hydraulic fracturing uses large volumes of water mixed with chemicals and proppant (sand) to fracture and hold open fractures in low-permeability shale and tight oil rocks to allow extraction of hydrocarbons. Despite higher water intensity (the amount of water used to produce a unit of energy; for example, liters per gigajoules) of hydraulic fracturing compared to conventional vertical oil and gas wells, it has been shown that the overall water withdrawal for hydraulic fracturing is negligible compared to other industrial water uses on a national level.(6, 15, 18, 25) On a local scale, however, water use for hydraulic fracturing can cause conflicts over water availability, especially in arid regions such as western United States, where water supplies are limited.(24, 53, 108, 110)

The wastewater generated from hydraulic fracturing is composed of a blend of returned injected hydraulic fracturing water and typically high saline formation water

that flows back out of the well after hydraulic fracturing to generate flowback and produced (FP) waters. Over time, the contribution of the saline formation water increases, which results in an increase in the salinity of the FP water. The salts, toxic elements, organic matter, and naturally occurring radioactive material in the FP water pose contamination risks to local ecosystems from spills (14, 38) and mismanagement.(15, 16, 28, 36) In addition to these risks, treatment of the FP water to safely return and release to the environment is energy-intensive and expensive; thus, many operators are forced to either recycle the FP water onsite for future hydraulic fracturing operations or reinject it into deep-injection wells.

Current technological limitations to the efficiency of hydraulic fracturing include a rapid decrease (20 to 50% of total production after the first year) in unconventional gas and oil production through time after initial production, and the fact that a significant portion of the gas in the shale formations is left unproduced.(18, 111) Despite these limitations, advancements in hydraulic fracturing and horizontal drilling technology have increased production of gas and oil from shale regions; between 2007 and 2016, the shale gas production has increased by eightfold in the United States.(2) Two recent studies have suggested that intensification of the hydraulic fracturing process through drilling longer horizontal laterals has resulted in increased water use and hydrocarbon production.(108, 110) Given the relatively long history of hydraulic fracturing in United States, understanding how the water footprint of hydraulic fracturing has evolved

through time with technological advancements and shifting economic conditions is critical.(18, 25) Lessons learned from U.S. production development can directly influence planning and implementation of hydraulic fracturing practices, as other countries such as China bring their natural gas reserves online.

For the first time, this study presents systematic temporal data on water use, unconventional shale gas and tight oil production rates, and volume of FP water from major shale-producing regions in the United States. In addition, we combine several databases to estimate the efficiency of production from both hydrocarbons and water perspective on a year-by-year basis, showing that the water footprint of hydraulic fracturing has been steadily increasing through time.

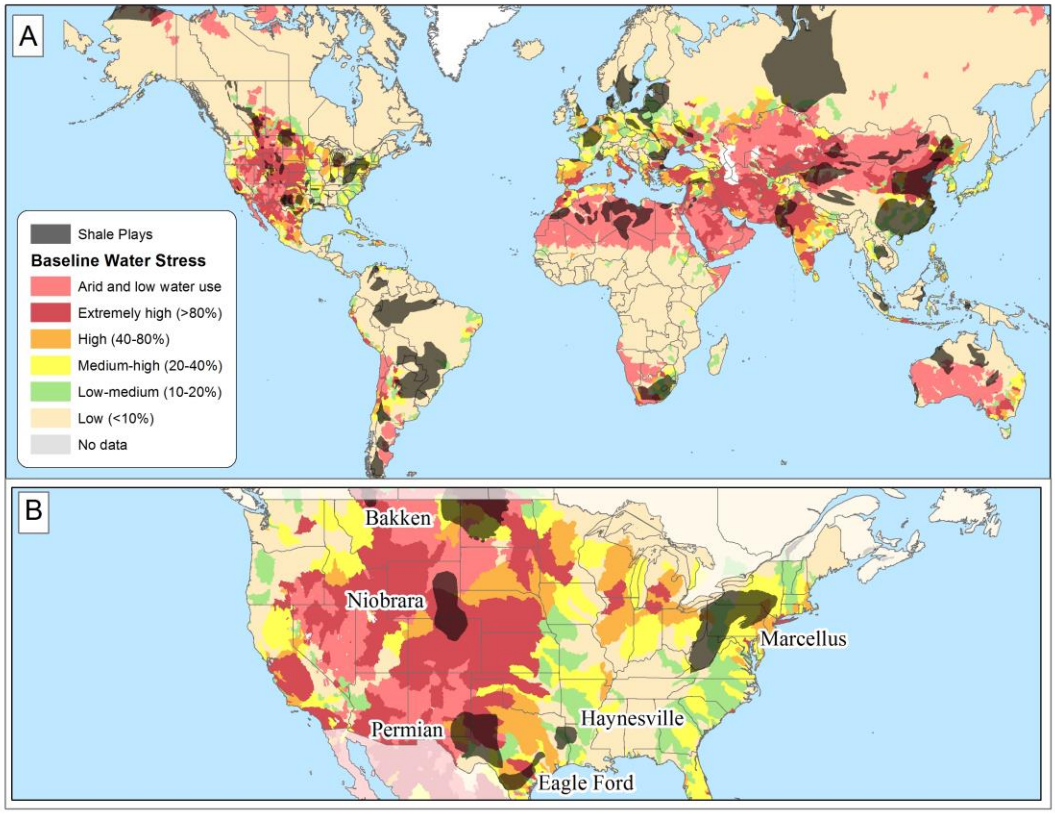


Figure 11: Map of water stress and shale plays. (A) Map showing the global water stress overlaid with shale formations across the world. (B) Water stress and shale regions in the United States examined in this study.(9, 104)

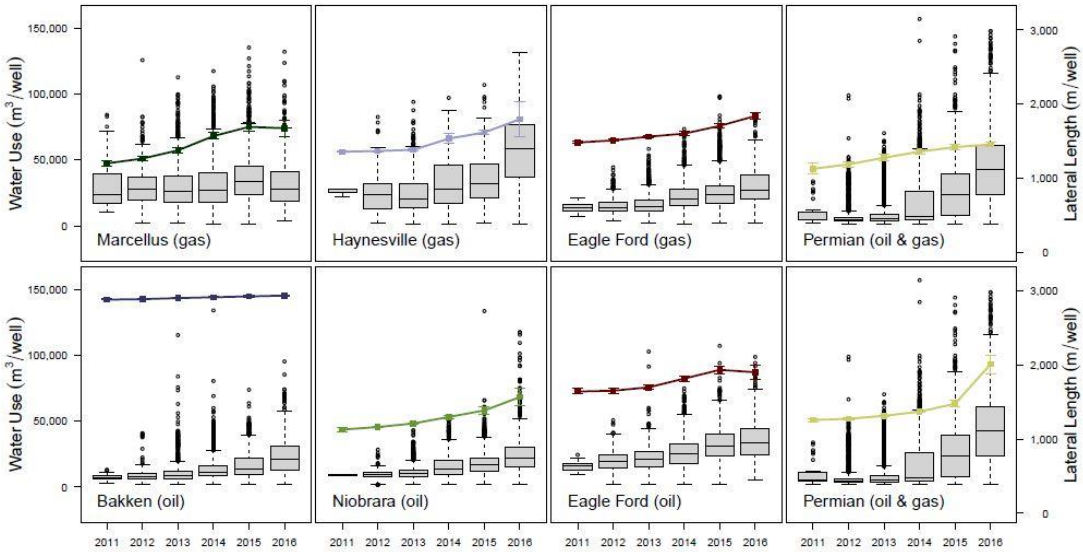


Figure 12: Box plots of water use with lateral lengths. Water use per well data (cubic meter per well; left *y* axis) for shale gas (top row) and tight oil regions (bottom row) with median lateral lengths per well (meter per well; right *y* axis) for each region plotted as colored lines. The central line of each box is the median, while the top and bottom of each box represent the third and first quartile, respectively. Whiskers on the box plot represent maximum and minimum values, while circles above the box plots show outliers in the data. Whiskers on the colored lateral length lines show the 95% bootstrap confidence intervals.

4.2 Results

In each of the six regions studied in this report, water use per well is increasing (Figure 12, Table 21 and Table 22). The Marcellus region (Pennsylvania and West Virginia) had the lowest increase in water use (20%), from a median value of 23,400 m^3 per well in 2011 to 27,950 m^3 per well in 2016, while the Permian Basin (Texas and New Mexico) had the largest increase in water use (770%), from 4900 m^3 per well in 2011 up to 42,500 m^3 per well in 2016. Median water-use volumes varied largely among regions, with the Bakken region using the least water (21,100 m^3 per well in 2016) and the

Permian basin using the most water (42,500 m^3 per well in 2016). Horizontal drilling requires producers to drill vertically to a target depth and then curve the well horizontally through shale formations, maximizing the surface area producing oil and gas. The length of the portion of the well that was drilled horizontally is referred to as the lateral length, with hydraulic fracturing events occurring in stages as a well is drilled further horizontally. Over the period of 2011–2016, the median length of lateral section of horizontal wells also increased (Table 21 and Table 22), most likely due to technological development and economic considerations to increase the extraction yields from individual wells. We show below that the hydrocarbon extraction intensity has similarly increased during this period. Parallel to the increase in lateral lengths of the horizontal wells and hydrocarbon extraction yields through time, the water use has also increased. The relative increase in lateral length (4 to 60%) was, however, significantly lower than the increase in water use (14 to 770%). When water use per well is normalized to the length of lateral section of the horizontal well, in almost every case among oil producing regions, we observed an increase in water use per length of the horizontal well. This pattern is most evident in the Permian region, where water use increased from 4.4 m^3 per meter in 2011 to 29.3 m^3 per meter in 2016 for gas-producing wells, and from 3.9 m^3 per meter in 2011 to 21.1 m^3 per meter in oil-producing wells (Table 21 and Table 22). The smallest observed changes were in the Marcellus and Eagle

Ford gas regions, where water use per horizontal length has been relatively consistent through time.

In all cases with the exception of Marcellus in 2016, the FP water generation was also increasing through time, with particularly higher rates after 2014 (Figure 13, Table 21 and Table 22). Both the gas- and oil-producing portions of the Eagle Ford region showed large increases through time, with a 550% increase in FP water in the oil-bearing section (from 2302 m^3 per well in 2011 to 15,119 m^3 per well in 2016) and a 390% increase in the gas-bearing section (from 1414 m^3 per well in 2011 to 6940 m^3 per well in 2016). The smallest increase in FP water occurred in the Niobrara region, where production increased from 1980 m^3 per well in 2011 to 3080 m^3 per well in 2016. Coupled with the increase in water use and FP water production rates, unconventional natural gas production shows an upward trend in production, with volumes increasing through time among the regions. Year 1 shale gas production in the Permian region increased from 10.0 × 106 m^3 per well in 2011 to 15.8 × 106 m^3 per well in 2015 before falling to 11.6 × 106 m^3 per well in 2016 (Figure 13). Similarly, year 1 shale gas production in the Marcellus formation increased through time, from 23.4 × 106 m^3 per well in 2011 to 46.9 × 106 m^3 per well in 2016. In contrast, in the Eagle Ford formation, year 1 production remained relatively constant from 2011 through 2016. Unconventional oil production shows a consistent increase in year 1 oil production volume per well through time, with values falling only in the Bakken region from 2011 to 2012. The largest increase was in

the Permian region, where oil production increased from 4763 m^3 per well in 2011 to 18,788 m^3 per well in 2016, a 290% increase (Figure 13). When comparing our estimate of total year 1 hydrocarbon production (year 1 estimate multiplied by well count estimate) to total hydrocarbon production reported by the Energy Information Administration (EIA) (Figure 47) (112), we see that year 1 production parallels total oil production in most regions in the United States.

We define the water-use intensity for hydraulic fracturing as the amount of water used for hydraulic fracturing to generate a unit of energy from the produced gas and oil (see Materials and Methods).(23, 25, 113) In gas-producing regions, water-use intensity (for the first 12 months of production) ranges from 9.2 liters/GJ (Haynesville) to 20.3 liters/GJ (Marcellus) in 2011 and grew to between 11.5 liters/GJ (Haynesville) and 56.8 liters/GJ (Permian) in 2016 (Figure 14, Table 21 and Table 22). In the Marcellus region, water use intensity decreased through time. Unconventional oil regions also have increasing water-use intensities, increasing from 14.3 liters/GJ (Bakken) in 2011 to 46 liters/GJ (Permian) in 2016. For comparison, the average water intensity of conventional natural gas is only 4 liters/GJ for drilling and extraction, while coal mining constitutes a mean value of 43 liters/GJ (Figure 50).(114) Water-use intensity is also calculated as the ratio between the volume of water used and the volume of hydrocarbon produced (Table 21, Table 22 and Figure 48). The increase of the water use to hydrocarbon production ratios with time seen in many regions indicates that the

intensification of the hydraulic fracturing process to increase hydrocarbon production rates involves net addition of water, and thus, the water intensity has increased with time.

When comparing the volume of FP water production rates to the water used for hydraulic fracturing, we show that, in many cases, more water is used for hydraulic fracturing than returns as FP water over the first year (Figure 14; FP water/water use ratio < 1). In shale gas–producing regions, we see an increase in the ratio until 2014, followed by a decrease in the ratio through 2016. The Permian region is unique as the FP water/water use ratios for both unconventional oil and gas wells are consistently higher than 1. Unconventional oil-producing regions follow the same trend as the gas-producing regions in the FP water/water use ratio (Figure 14 and Table 22).

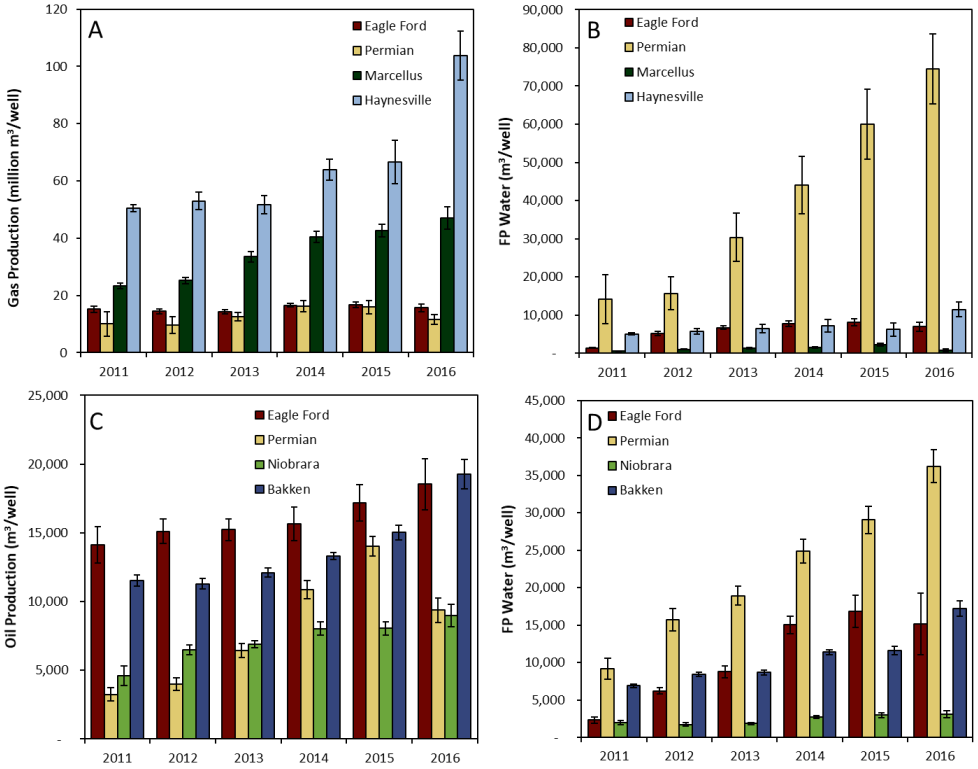


Figure 13: Oil, gas, and FP water variations with time. Annual shale gas (A), tight oil (C), and FP water (B and D) productions in shale gas–producing regions (A and B) and oil-producing regions (C and D). Whiskers on the bar graphs represent 95% bootstrap confidence intervals (Table 21).

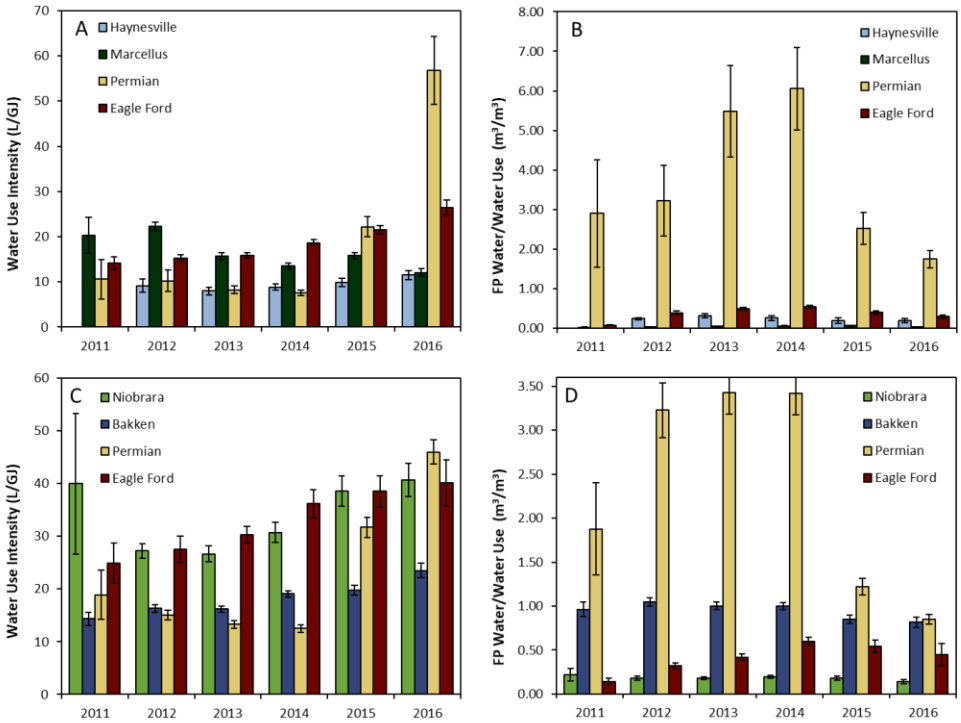


Figure 14: The changes in the water intensity of hydraulic fracturing with time. Water-use intensity variations with time for hydraulic fracturing of shale gas (A) and tight oil (C) regions and corresponding FP water/water use ratios in shale gas (B) and tight oil (D) regions. Water-use intensity is defined as the amount of water required to generate a unit of energy. (A) and (B) show the water-use intensity for shale gas producing regions, while (C) and (D) show water-use intensity for unconventional oil-producing regions. Whiskers represent 95% bootstrap confidence intervals.

4.3 Discussion

Much of the controversy surrounding hydraulic fracturing revolves around the use of large volumes of water to hydraulically fracture wells. Concern is especially high in semiarid regions (Figure 11), where water withdrawals for hydraulic fracturing can account for a significant portion of consumptive water use within a given region, even contributing to groundwater resource depletion.(24) Overall, there have been calls to increase the use of alternative water sources such as brackish water or recycling FP

water, minimizing the strain on local freshwater resources.(24, 110) Previous studies have suggested that hydraulic fracturing does not use significantly more water for exploration and production than other energy sources (Figure 50) and, at the same time, indicated that water use for hydraulic fracturing makes up only a small fraction of the industrial water utilization in the United States.(6, 18, 25, 114) These evaluations were based on aggregated water footprint data during the early years (2011–2014) of hydraulic fracturing in the United States. Here, we show, however, steadily increasing volumes of water use with time in all the major unconventional gas and oil regions (Figure 12, Table 21 and Table 22). Parallel to the increase of shale gas and tight oil production intensity, we also show that the water intensity of hydraulic fracturing is increasing for most unconventional gas and oil regions (Figure 14, Table 23, and Table 24). In addition, the water used for hydraulic fracturing is retained within the shale formation; only a small fraction of the fresh water injected into the ground returns as flowback water, while the greater volume of FP water returning to the surface is highly saline, is difficult to treat, and is often disposed through deep-injection wells. This means that despite lower water intensity compared to other energy resources (Figure 50), the permanent loss of water use for hydraulic fracturing from the hydrosphere could outweigh its relatively lower water intensity.

The period of 2014–2015 marks a turning point, where water use and FP water production began to increase at higher rates. During this period, gas and oil prices

dropped significantly, causing producers to scale back the number of new installed wells (Figure 15, Table 21, and Table 22). In each of the oil-producing regions, the water use/oil production ratio increased, suggesting that the increase in water use for hydraulic fracturing outpaces the increasing oil production on a per-well basis (Figure 14, Figure 48, and Table 22). In the shale gas–producing regions, this trend is also present in each region except the Marcellus (Figure 14, Figure 48, and Table 21). Consequently, (excluding the Marcellus) while increasing lateral length of horizontal drilling and water use for hydraulic fracturing (Figure 12) have resulted in increasing oil production (per well), the net water-use efficiency, particularly for unconventional oil production, has decreased (that is, higher water intensity).

By combining the increasing trends in both water use and FP water production with the increasing FP water/water use ratios in some regions, we can see that the overall water footprint of hydraulic fracturing is increasing through time; more water is being used for hydraulic fracturing operations, while, at the same time, comparatively more FP water is being generated. We observed increasing total water use (water use per well multiplied by well count; Figure 49) in oil-producing regions despite the recent slowdown in oil production rates (Figure 15). Assuming that the recent economic downturn eventually subsides and the drilling of new wells again reaches levels seen during the heyday of hydraulic fracturing in the early 2010s, the total water impact of hydraulic fracturing is poised to increase markedly in both shale gas and oil-producing

regions. On the basis of modeling future hydraulic fracturing operations in the United States in two scenarios of drilling rates, we project cumulative water use and FP water volumes to increase by up to 20-fold in unconventional gas-producing regions and up to 13-fold in unconventional oil-producing regions from 2018 to 2030, assuming that the growth of water use matches current growth rates and the drilling of new wells again matches peak production (Figure 51, Table 23, and Table 24). Even if future drilling rates will stay at 2016 levels (that is, low oil gas prices), we predict a large increase of the total water use for both unconventional oil and shale gas basins (Figure 51). Likewise, we predict a large increase in the FP water volume for the two scenarios, with particularly high total FP water production in the Permian basin (Figure 51).

The increase in the water footprint of hydraulic fracturing shown in this study has serious implications for local communities, where increased drilling volumes will lead to large instantaneous water demands, and resulting in increasing FP water burdens that will have to be managed into the future. The predicted increasing water use and FP water production in the Permian and Eagle Ford basins are alarming given the extreme water scarcity in these regions (Figure 11). The results presented in this study are consistent with previous studies in the Permian (23) and Eagle Ford (110) basins that have shown that local water resources could be affected by increasing water demands for hydraulic fracturing. At the same time, other studies have shown that water use for hydraulic fracturing in water-rich areas such as the Sichuan basin in China

(99, 115) will constitute only a small fraction of the available local water resources. The water intensity during the early stages of hydraulic fracturing (<30 liters/GJ in many cases) was comparable and even lower than that of coal mining (43 liters/GJ; Figure 50), the recent (2014–2016) intensification of hydraulic fracturing has increased the water intensity, particularly for unconventional oil (up to 46 liters/GJ; Figure 50). Additional studies are needed to analyze the local impacts of hydraulic fracturing on water resource depletion in light of increasing water demand for hydraulic fracturing and the increasing volumes of FP water that need to be managed, particularly in areas vulnerable to induced seismicity from injection of large volumes of oil and gas wastewater. As unconventional gas and oil exploration is expanding globally and other countries begin to follow the U.S. shale revolution (for example, China) (115), the results of this study should be used as a guidance for the expected water footprint of hydraulic fracturing at different stages of energy development.

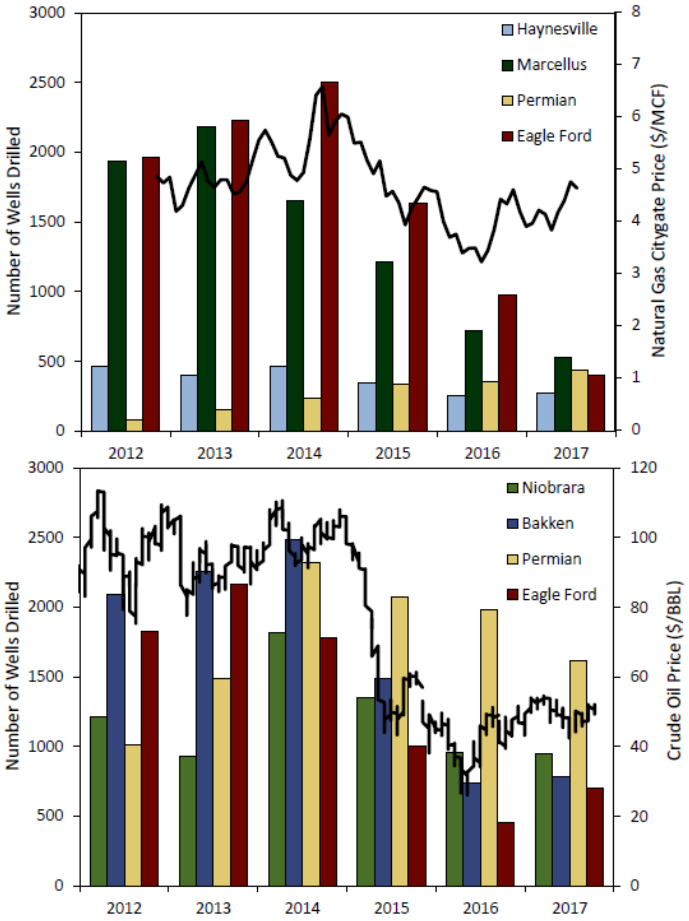


Figure 15: New shale gas and tight oil well installations compared to oil and gas prices. Variations of installed well counts (left y axis) and gas and oil prices (right y axis) with time for shale gas–producing regions plotted with corresponding natural gas citygate price (top) and for oil-producing regions with corresponding crude oil price (bottom). The data show the number of new well installations corresponding closely with the contemporary gas and oil prices. MCF, thousand cubic feet; BBL, barrel.

4.4 Materials and Methods

4.4.1 Experimental Design

The goal of this study was to synthesize and collate production volumes for unconventional gas and oil production, associated FP water, and water use for hydraulic

fracturing per shale gas/oil well. We downloaded production data for each of these components from the major shale gas and tight oil regions identified in this study using multiple sources and separated by year of initial production. Once organized, data were reported based on the first 12 months of the well lifetime to see how production and water-use values compared on a year-by-year basis.

4.4.2 Data Acquisition

Production volumes for gas, oil, and FP water for each reporting well in our target regions were downloaded using the DrillingInfo Desktop application.(64) Data were downloaded by primary well production type (gas or oil). FP water data were not available from the Marcellus region, and thus, data from the Marcellus Formation were downloaded from the gas and oil reporting website of the Pennsylvania Department of Environmental Protection (PA DEP).(66) Water-use data were downloaded from the FracFocus Chemical Disclosure Registry.(57) Well counts from 2014 to 2016 were taken from the EIA Drilling Productivity Report (DPR) (112), while well counts from 2012 to 2014 were taken from Baker Hughes' onshore well counts.(74) The well counts provided did not indicate if they were taken from conventional or unconventional oil-producing wells or in regions producing both gas and oil, and whether the well was classified as an oil well or gas well. Consequently, we used DrillingInfo to find the ratio of conventional to unconventional wells and the ratio of oil to gas wells for each region for each year and multiplied that by the number of wells reported by Baker Hughes and in the DPR. In

addition, wells drilled in the Bakken formation were not reported by the Baker Hughes report. As a result, Bakken Formation well counts from 2012 to 2013 were taken from the North Dakota Oil and Gas Division.(67) Combining data from several resources can introduce bias and error into results using these values. Values reported in this study were found to be comparable to those reported in previous studies. Natural gas and oil historical prices were taken from the EIA.(112)

4.4.3 Statistical Methods

Data from over 39,000 individual wells were organized by producing region, American Petroleum Institute (API) number, first production year, and cumulative production over the first 12 months. The median values among all API numbers reporting data within a given year were calculated for each region and year included in this study.(18, 25) A similar analysis was done with the PA DEP Marcellus data. The region for each water-use data point was determined spatially using the latitude and longitude provided by FracFocus to locate points within unconventional gas and oil plays (shapefile provided by the U.S. EIA).(112) Water-use data were then sorted by region, and the median water-use value was calculated for each spud year. Consequently, the same water use data from the Permian region was used for both oil and gas wells. Energy intensities were calculated by converting production volumes of gas and oil to energy production using their energy content. Energy content for natural gas was assumed to be 0.038 and 38.18 GJ/m^3 for oil.(24) Calculations for gas-producing

wells also included associated oil production with an energy content of 85% that of crude oil, or 32.45 GJ/m^3, as well as the shrinkage of 25% of the wet gas stream to natural gas liquids with an energy content of 25.54 GJ/m^3.(24, 25, 113) For oil wells, associated gas production with an energy content of 0.038 GJ/m^3 was added. Bootstrap confidence intervals were used to estimate variation in water use, gas production, oil production, and FP water production.(11, 18) For each data set, 95% bootstrap confidence intervals of the median for each year of production were calculated. We drew bootstrap resamples with replacement from each year's empirical distribution. This was repeated 1000 times, and distributions were drawn from the 0.025 and 0.975 percentile values.(18) In cases where data with errors were used to calculate new terms, error was propagated through the calculation.

4.4.4 Production Predictions

Cumulative future water use (and year 1 production) was defined as the number of wells drilled in a given year and region, multiplied by the water use per well (plus year 1 FP water production). We outlined two scenarios to predict cumulative future water use and year 1 production. The first was a business-as-usual scenario, where we assumed that the number of new wells drilled each year remained constant from 2018 to 2030 and was equal to the number of new wells drilled in 2016 in each formation. We then multiplied this well count by an estimate of the future water use per well (or year 1 FP water per well). Future water use per well and future year 1 FP water predictions

were made using the maximum respective increases from 1 year to another for each formation (Figure 12 and Figure 13 and Table 21 through Table 24). This calculation yielded a linear increase in cumulative water use and year 1 FP water through time (Figure 51 and Figure 52). A second scenario was created to predict the results of a return to previously high drilling rates (that is, high oil prices). Our calculation for future water use per well and future year 1 FP water remained the same. To estimate the number of new wells drilled each year, we calculated the slope of the largest increase in well count from 1 year to another for each region and added that slope to 2016 well counts, resulting in a linear increase in the number of new wells drilled each year. This resulted in a parabolic increase in cumulative future water use through time (Figure 51 and Figure 52).

5. Quantification of the water-use reduction associated with the transition from coal to natural gas in the U.S. electricity sector

5.1 Background

The advent of hydraulic fracturing fundamentally transformed the electric power sector of the U.S., allowing natural gas to displace coal as a major energy source in the electricity sector. While in the 2000s the share of electricity generated with coal was more than three times the fraction generated by gas (52% coal in 2000, 16% natural gas), in 2015 natural gas overtook coal as the primary electricity generating resource (up to 32% natural gas relative to 30% coal in 2017 (Figure 16 and Figure 17)).(116) Since 2000, only 58 new coal fired generators with a combined capacity of 19,300 MW have come online, while 3,075 new natural gas generators with a combined capacity of 333,000 MW (of which 1231 were natural gas combined cycle (NGCC) generators with total capacity of 225,000 MW) have been installed.(40, 41)

Approximately 40% of the total water withdrawn in the U.S. is used for cooling thermal power plants. (117) The large volume of water utilized by this sector, compounded with climate change, a growing population, degradation of water quality may exacerbate future water availability problems.(24, 108, 118) Reduced water availability could also have important implications for reliability of the electric power sector, as suggested by 18 episodes from 2000-2015, when coal plants were unable to generate electricity because of insufficient or high-temperature water supplies.(119, 120)

In almost all incidents the curtailments happened in the summer months during drought periods.

The literature examining the water-energy nexus over the past decade has grown substantially, with a focus on electricity generation constraints due to impacts of climate change and water stress. (1, 7, 76, 104, 105, 118, 120-122) Assuming the same electricity generation profile of today, it has been estimated that water consumption for the electricity sector in the southwest U.S. will increase 3-7% by 2095. However, rapid changes in the electricity sector, including increased penetration of wind and photovoltaic energy, along with retrofits of thermal plants with dry cooling systems, suggests that water consumption could rather decrease by up to 50%. (123)

Recent reports examining the threats that climate change pose to the future U.S. economy highlight the CO_2 emissions reductions that could be achieved by decommissioning coal plants.(105, 119, 123-126) Nonetheless, with natural-gas becoming the predominant energy source for the electricity sector, the intensification of shale gas production in the U.S., and the significant increase in the intensity of water consumption of this process, (20) poses questions about the implications of the transition from coal to natural gas on water availability.

Here, we examine water-use changes derived from the ongoing transition from coal to natural gas in the U.S. electricity sector. We analyzed historical energy and water-use data to quantify the water intensity of coal relative to natural gas for different

power generation and cooling technologies, and in this way examined the water-footprint of systems with different shares of both natural gas and coal. Water intensity of electricity generation reflects the amount of water directly and indirectly consumed or withdrawn throughout the life-cycle of electricity, divided by the amount of net electricity generation in a plant (m^3/MWh), and it includes water use at both the power plant and at all upstream processes. At the power plant level, water withdrawn is water taken out of a reservoir for cooling and plant operation purposes, while water consumption is the net water loss from the hydrological cycle due to evaporation, leakage, and recharge to the deep subsurface, or withdrawal for recirculating cooling systems. Direct water consumption and withdrawals for upstream processes refer to water used directly in coal mining, drilling, hydraulic fracturing, transportation, and refinement of coal and natural gas, while indirect water consumption and withdrawals refer to water used indirectly as a product embedded in the fuels and electricity used in these upstream processes. In addition to the evaluation of the water footprint of electricity generated with natural gas and coal, we examine the effects of the evolution of power plant cooling technologies from once-through to recirculating and dry cooling, showing that from 2013-2016 both total water consumption and withdrawal volumes for electricity generation in the U.S. have decreased despite constant electricity net generation.

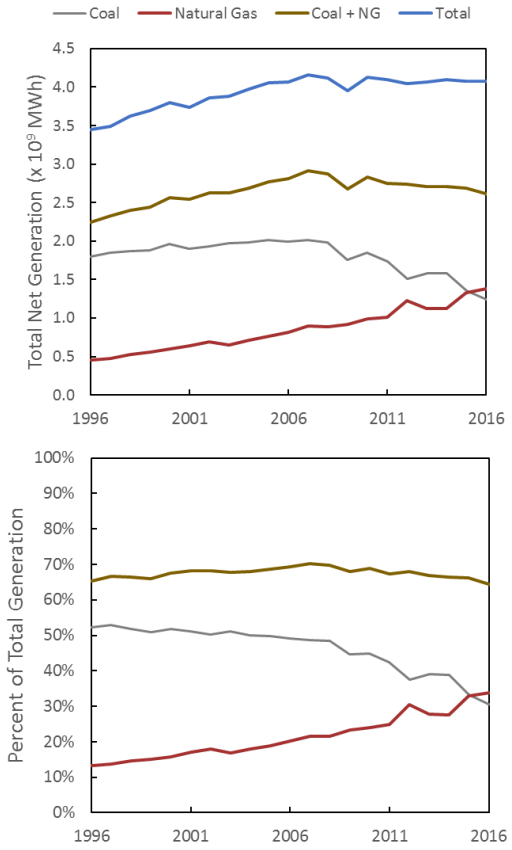


Figure 16: Changes in energy sources for the U.S. electricity sector. Total and differential electricity generation of coal and natural gas in the U.S. (top) and their relative proportions (bottom) during 1996 to 2016. This decade shows a transition from primarily coal fueled generation to a natural gas fueled electricity system. Data from the EIA Primary Energy Production by Source dataset.(116)

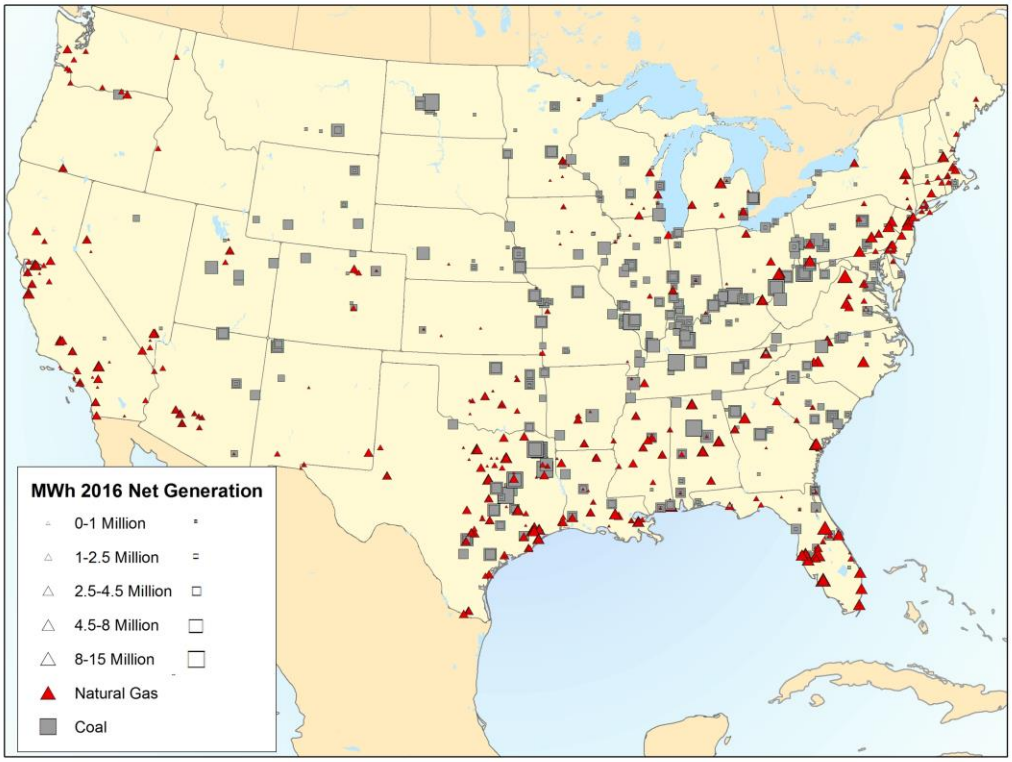


Figure 17: Map of the U.S. showing the location of coal and natural gas thermal plants. Distribution of coal and natural gas power plants across the United States, sorted by their 2016 net generation (MWh). Data for the map was retrieved from EIA forms 860 and 923.(40, 41)

5.2 Results

5.2.1 Water Use for Power Plant Operations: Volume and Intensity

In 2016, coal combustion accounted for 30 % of the total U.S. electricity generation, while natural gas accounted for 34% (Figure 16 and Figure 17).(7) Nonetheless, given that the water-consumption intensity of natural gas is lower than that of coal, the total volume of water consumed at coal-fired power plants (1.75×10^9 m^3) was almost twice as much as the water consumed to cool natural gas power plants (1.07×10^9 m^3;Figure 18).(40, 41) Moreover, during the 2013-2016 period, the gap between

water use efficiency of coal compared to natural gas widened; as the water consumption intensities of coal-fired power plants did not change through time, those of natural gas plants decreased, while the withdrawal intensity of coal-fired plants increased and those of natural gas plants decreased. The average water consumption intensity for coal power plant operations (i.e., the average volume of water (m^3) consumed by power plants to generate 1 MWh of energy) has slightly dropped, from 1.41 m^3/MWh in 2013 to 1.35 m^3/MWh in 2015 (Figure 19). Over that same time period, the average water consumption intensity for natural gas generation decreased from 1.26 m^3/MWh to 0.78 m^3/MWh. Water withdrawal intensity for coal increased from 67.20 m^3/MWh in 2013 to 70.56 m^3/MWh in 2016, while withdrawal intensity for natural gas has decreased from 52.42 m^3/MWh in 2013 to 33.07 m^3/MWh in 2016 (Figure 19).

Despite higher water consumption intensity, the total volume of water consumed for cooling coal plants has been steadily declining since 2014, due to the significant reduction in electricity generation from this fuel (Figure 16). Over the same time period, total water consumption for cooling natural gas plants has also seen a decrease in consumption, reflecting the addition of newer, more efficient natural gas combined cycle (NGCC) plants to replace the load lost from coal (Figure 18). The reduced water intensity of natural-gas fired power plants, together with the replacement of a number of once-through cooled coal plants with NGCC plants using recirculating water-cooling

systems, have caused a steady decline in water used to generate electricity since 2014.

(see Supplement Information for description of the different types cooling systems).(127)

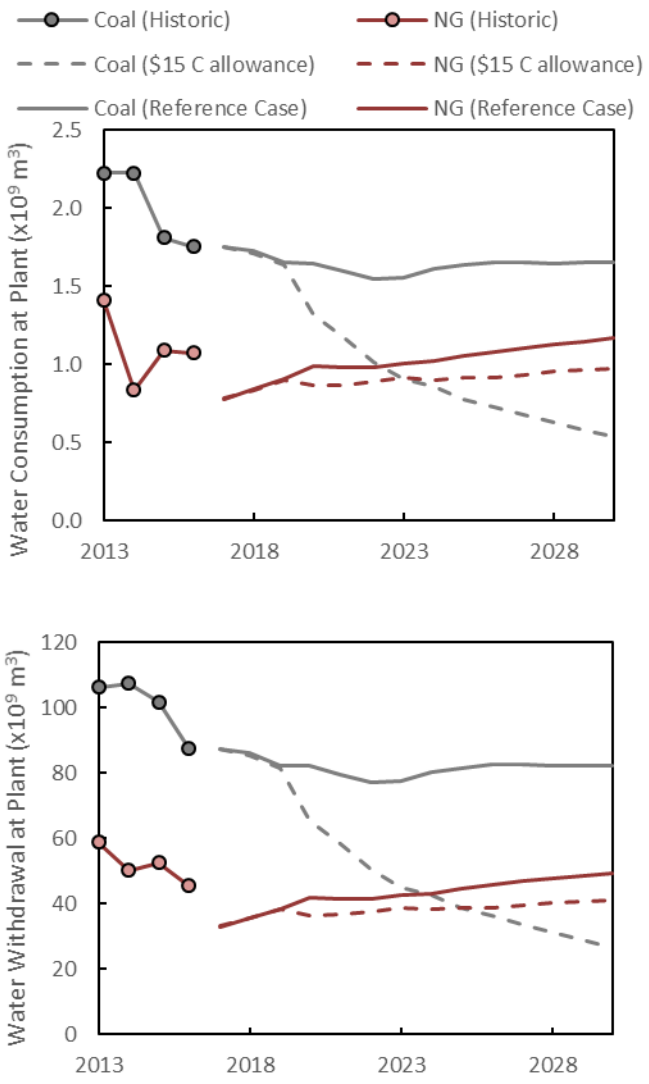


Figure 18: Previous and projected water consumption and withdrawals in the U.S. Total plant level water consumption (top) and water withdrawal (bottom) volumes of electricity generated with coal (grey) and natural gas (red) in the United States from 2013-2030. Future projections were calculated by multiplying 2016 withdrawal intensity and 2016 consumption intensity by EIA estimates for reference case electricity generation and their $15 carbon allowance scenario through 2030.(7)

These values are based on integrating water use intensities for both power plant cooling upstream water use for the extraction of the fossil resources.

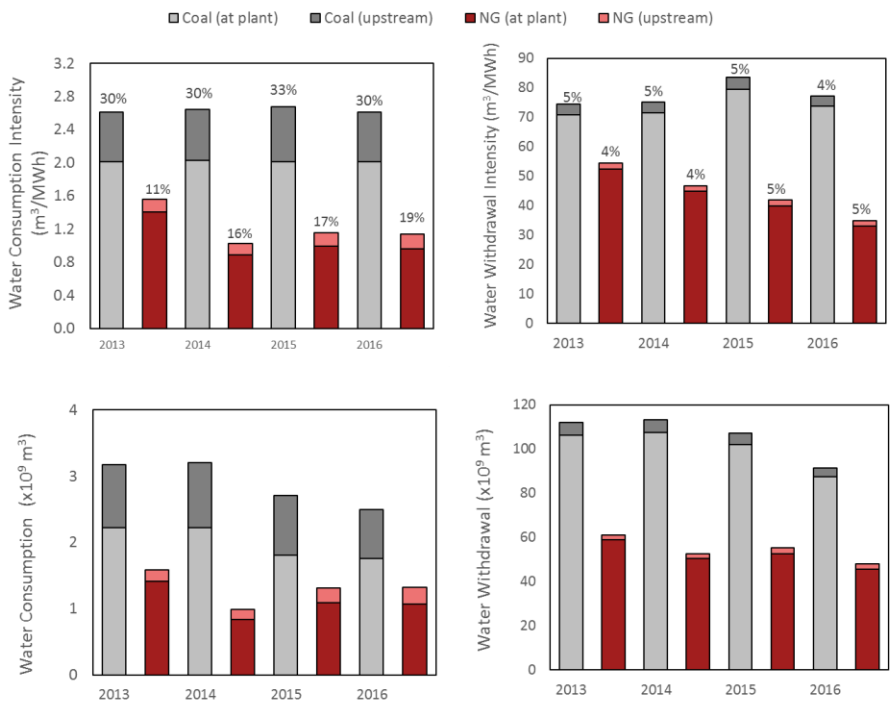


Figure 19: Variations of water consumption and withdrawals intensity and annual volume in the U.S. Water consumption and withdrawal intensities (top) and volumes (bottom) broken down by the upstream and at plant water use processes. Percentage values in upper charts reflect the proportions of the water intensity in the upstream processes relative to the water intensity of cooling thermoelectric plants. Upstream processes such as mining and transportation play a significant role in the water consumption, while representing only a small amount of water withdrawals.

5.2.2 Water Use for Fuel Extraction, Processing, and Transportation: Volume and Intensity

In order to calculate the life-cycle water use of electricity generated from coal and natural gas, we estimated the water intensity of the processes that are upstream of the power plants, which include mining, drilling, transportation and processing of coal and

natural gas. To this end, we used data from the Unit Process Library provided by the National Energy Technology Laboratory (NETL), which presents a life-cycle inventory of both energy and material movements from cradle to gate and grave for a number of industrial processes.(128) We accounted for direct (i.e., water physically used in the processes) and indirect water used (water used to generate the electricity and fuels that are inputs to the processes). We define the water use derived from the combination of all of these processes as *upstream water consumption* (UWC, in cubic meters, Table 26 and Table 27, equation in **Methods** section).

Because the NETL data (128) does not differentiate between water withdrawal and consumption, we assume all water used in upstream processes is consumed. By adding the direct and indirect water consumption estimates for fossil fuel extraction, transportation and refinement, we estimate upstream water consumption of coal as 0.60 m^3/MWh, while natural gas upstream processes consume 0.18 m^3/MWh in 2016. From 2013 through 2015 water consumption intensity for coal upstream processes has increased before falling in 2016 (from 0.60 m^3/MWh in 2013 to 0.66 m^3/MWh in 2015 and back down to 0.60 m^3/MWh in 2016), while the water consumption intensity of natural gas upstream processes increased only by 0.03 m^3/MWh (from 0.15 m^3/MWh in 2013 to 0.18 m^3/MWh in 2016; Table 28). Due to the intensification of hydraulic fracturing during this period(20), UWC of natural gas increased from 11% of total natural gas water consumption in 2013 to 19% in 2016. Taking these estimates together with the average

volume of water used at power plants in 2016, we find that upstream water consumption accounts for 30% of the total water consumption intensity of coal-fired electricity, while representing only 19% of total water consumption intensity for natural gas (calculations for the upstream processes can be seen in the Methods section and SI). The water withdrawal intensity for coal and natural gas behaved similarly from 2013-2016, decreasing from 2013 to 2014, before peaking in 2015 and reaching its lowest level in 2016 (3.59 m^3/MWh in 2013 to 3.29 m^3/MWh for coal, and from 2.03 m^3/MWh in 2013 to 1.80 m^3/MWh in 2016 for natural gas; Table 28)

We find that coal-fired electricity has been responsible for 2.49×10^9 m^3 of water consumption in 2016, down from 3.20×10^9 m^3 in 2014. Upstream coal processes in 2016 represent 30% (7.41×10^8 m^3) of the total consumption, while plant operations represent 69% (1.75×10^9 m^3). In comparison, upstream natural-gas fired electricity in 2016 accounted for 19% (2.49×10^8 m^3) of total water consumed (1.32×10^9 m^3), which was an increase from 2013 (1.68×10^8 m^3, Figure 19). In 2016, average water consumption at natural-gas fired power plants was lower than in 2013 (Figure 18, 1.41×10^9 m^3 in 2013 to 1.07×10^9 m^3 in 2016)), however, the increase in upstream consumption most likely from the intensification of hydraulic fracturing(20) slightly offset this reduction (Figure 19). Withdrawals for coal were down from 1.13×10^{11} m^3 in 2014 to 9.15×10^{10} m^3 in 2016, while the withdrawals for cooling natural gas plants in 2016 (4.80×10^{10} m^3) were lower than estimated in 2013 (6.11×10^{10} m^3), despite steadily rising from 2013-2015 Figure 19).

Upstream processes made up a much smaller portion to total water withdrawals (from 4-5% for both coal and natural gas).

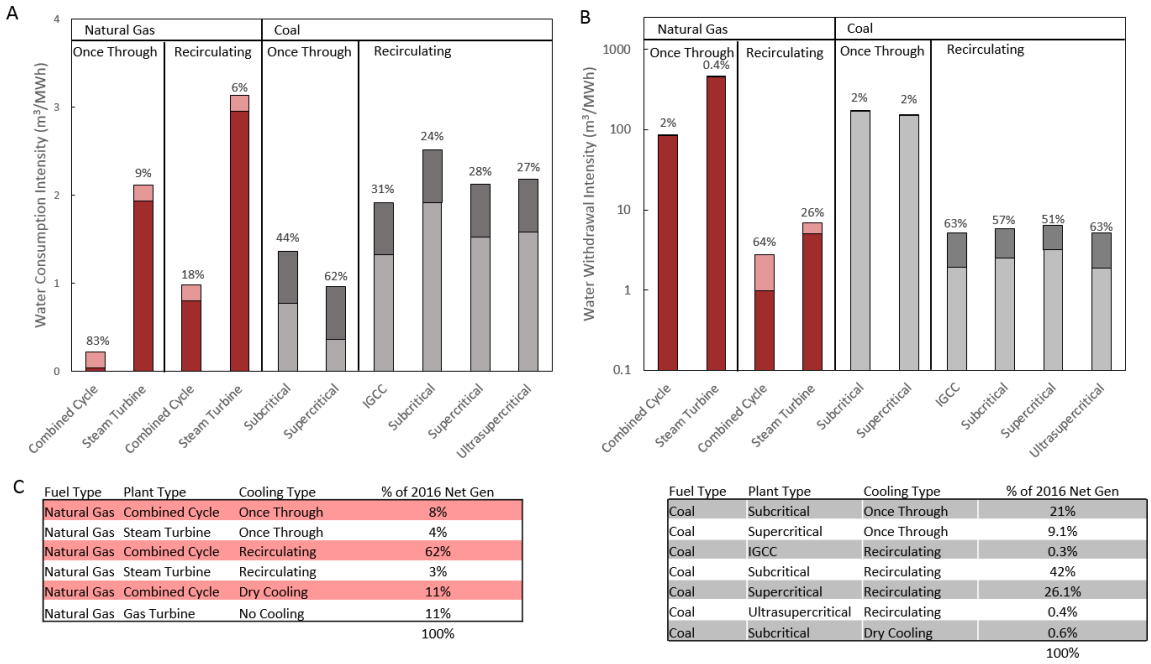
5.2.3 Differential Impacts of Power Plant Type and Cooling Technology

The previous section presented intensities and volumes of water use in coal and natural gas fired plants. These calculations used aggregated data for volumes of water consumption and withdrawal from coal and natural gas, calculating average power-plant water intensity by dividing water volumes by net generation from coal and natural gas, respectively. Here, we look at the differential water use by plant type and cooling technology in order to understand the role of technological change in power plant water use. We disaggregated data from coal-fired power plants into subcritical, supercritical, ultra-supercritical, and integrated coal-gasification combined cycle plants, while natural-gas fired plants were separated into combined cycle or steam turbine plants (Figure 20 and Table 25).(63, 129) Cooling technologies can be of three types: once through cooling, recirculating cooling, and dry cooling.(42, 63, 129, 130) Detailed descriptions of each generation and cooling technology can be found in the introduction of this dissertation. In general, plants with once-through cooling systems had a slightly lower average water consumption intensity, but a much higher withdrawal intensity (10 times or more) than plants with recirculating cooling systems (Figure 20). NGCC plants with recirculating cooling systems had a much lower withdrawal intensity (100-1000 times lower than natural-gas steam turbines), while having almost the same water consumption intensity,

and also compared favorably to coal subcritical and supercritical plants with once-through and recirculating cooling systems. However, the two advanced coal fired power plants (one ultra-supercritical and one integrated coal gasification combined cycle), which have both recirculating cooling systems, had lower water withdrawal intensities than the NGCC, while having lower or almost the same water consumption intensity (Figure 20).

From 2013 through 2016, subcritical and supercritical coal plants with once through cooling systems showed a decrease in median consumption intensity (from ~1.3 m^3/MWh in 2013 to 0.4 m^3/MWh). The annual water consumption intensity of almost all coal plants cooled with recirculating water systems remained relatively stable through the study period (with median values between 1.5 and 1.9 m^3/MWh), with an exception of the only integrated gasification combined cycle plant, for which water consumption decreased through time (from 3.6 m^3/MWh in 2014 to 1.3 m^3/MWh in 2016) (Figure 53 and Table 25). During this same time period, median water withdrawal intensities increased in all types of coal plants using both once-through and recirculating cooling (Figure 53). Similarly, for natural gas plants of all types and cooling systems, median water consumption intensity also increased, while median water withdrawal intensity remained constant (Figure 53). Overall, our data analysis shows that while natural gas plants generally withdraw less water for cooling than those of coal plants, installation of

advanced and more efficient coal plants can also result in reduction of the water withdrawal.



C

Fuel Type	Plant Type	Cooling Type	% of 2016 Net Gen
Natural Gas	Combined Cycle	Once Through	8%
Natural Gas	Steam Turbine	Once Through	4%
Natural Gas	Combined Cycle	Recirculating	62%
Natural Gas	Steam Turbine	Recirculating	3%
Natural Gas	Combined Cycle	Dry Cooling	11%
Natural Gas	Gas Turbine	No Cooling	11%
			100%

Fuel Type	Plant Type	Cooling Type	% of 2016 Net Gen
Coal	Subcritical	Once Through	21%
Coal	Supercritical	Once Through	9.1%
Coal	IGCC	Recirculating	0.3%
Coal	Subcritical	Recirculating	42%
Coal	Supercritical	Recirculating	26.1%
Coal	Ultrasupercritical	Recirculating	0.4%
Coal	Subcritical	Dry Cooling	0.6%
			100%

Figure 20: Water consumption and intensity values sorted by plant types and cooling systems. Median water consumption intensities (A), withdrawal intensities (B), and percentage values of 2016 net natural gas and coal generation (C) for different plant cooling systems and electricity generation technologies. For water consumption and withdrawal intensities we present the value and percentage of the upstream section relative to the water use for cooling the thermoelectric plants using the differential electricity generation technology and cooling systems.

5.2.4 Projections of Future Water Use

Using EIA estimates(7) for the share of fuels and technologies for future electricity generation in the U.S. (Figure 18), and assuming the coal and natural gas water consumption intensities remain as calculated for 2016, we project steady unchanged plant level water consumption and withdrawals through 2030 (Figure 18).(7) This is based on the assumption that the coal and natural gas proportions in the mix will

remain constant following the EIA's reference case scenario. However, were the trend of replacements of old coal-fired subcritical power plants with NGCC to continue, there would result in a large water use reduction (Figure 21). EIA has an estimate of future production where a $15 carbon allowance fee is instituted.(7) This scenario results in a 69% decrease of coal generation from 2016- 2030, while NG generation increases by 30%. Keeping water consumption and withdrawal intensities at 2016 levels, we estimate that by 2030, 1.83×10^9 m^3 water consumption and 6.71×10^9 m^3 water withdrawal will be reduced with respect to the reference scenario. We further estimate that a scenario of which 100% of coal fired power plants were replaced with natural gas combined cycle power plants with recirculating cooling would result in a reduction of 4.72×10^{10} m^3 per year of water withdrawals, and 1.28×10^9 m^3 of water consumption (Figure 21). For comparison, these water reductions are respectively equivalent to 232% and 6% of the total water use for the industrial sector in the U.S. in 2015 (2.04×10^{10} m^3 per year).(131) These reductions would occur if water withdrawal and consumption for upstream processes account as in 2016, for less than 19% of the water used throughout the life-cycle of natural-gas fired electricity, which makes the total life-cycle water intensity of electricity from natural gas less than half of the intensity of electricity from coal (Figure 19). The water benefits from this transition could be lower given that shale gas is becoming the major source of natural gas in the U.S. (55% of natural gas use in 2016, up from 40% in 2013(132)), and that water consumption intensity for hydraulic fracturing is

increasing every year (20), but nonetheless would still be significant. If we assume that 2016 production were fueled entirely by shale gas, upstream water consumption would increase by 27%, from 2.49×10^8 m^3 to 3.17×10^8 m^3, which will consist 24% of the total water consumed for natural gas.

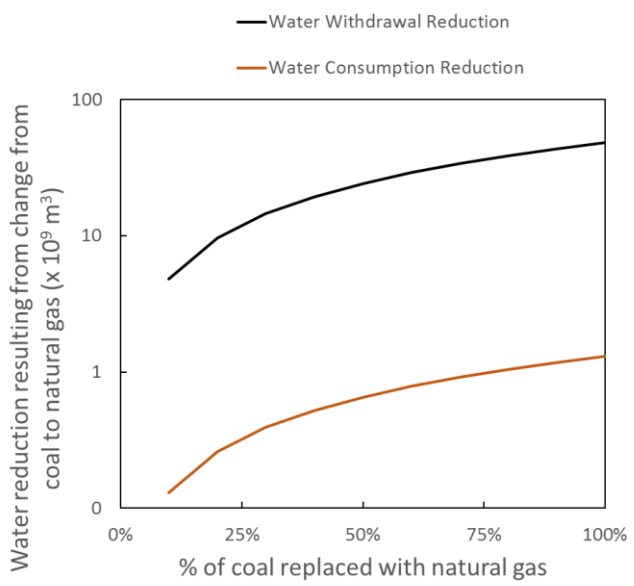


Figure 21: Projections of water use reduction from transition of coal to natural gas. Projections for reduction of annual water consumption and withdrawal upon increasing the fraction of natural gas from transitioning from coal to natural gas as the predominant energy source for the electricity sector in the U.S.

5.2.5 Relationships between Water Use for Energy and Water Stress

We evaluated regional water consumption and withdrawals and compared them with estimates of water stress indicators across the U.S. (Figure 54 and Figure 55).(104) We find that both cooling technology in thermoelectric plants and their location in the U.S. are favorable with respect to the goal of avoiding exacerbation of water stress. The majority (70%) of power plant cooling in all regions is through recirculating systems

(Figure 22, Figure 54, and Figure 55) (104), and most of electricity generation takes place in areas deemed to have relatively low water stress. Currently, there is only marginally more net generation from natural gas than coal in high and extremely high water-stressed areas (1.56×10^8 MWh natural gas vs. 1.42×10^8 MWh coal) with most plants being cooled using recirculating technology. Natural gas water consumption for plant operations in high and extremely high stress areas was 1.31×10^8 m^3, accounting for approximately 17.5% of total water consumption for natural gas in the U.S. (based on consumption for plants with available data). For coal, consumption for plant operations in high and extremely high stress areas was 1.75×10^8 m^3, accounting for only 11.6% of total water consumption for coal. Natural gas water withdrawal in high and extremely high stress areas was 7.49×10^9 m^3, accounting for approximately 23.5% of total water withdrawal for natural gas. For coal, withdrawal in high and extremely high stress areas was 1.01×10^{10} m^3, accounting for approximately 13.4% of total water consumption for coal in the U.S. In contrast, a larger proportion of upstream water consumption for coal is located in water stress areas; 37% of coal mining in the U.S. was extracted via surface mining in high or extremely high stressed areas, which infers water consumption of 3.06×10^8 m^3 out of 7.41×10^8 m^3 total water consumption for coal in the U.S (41%; Figure 54 and Table 29).(94, 104) In contrast, about 50% of natural gas is generated in basins located in high or extremely high water-stress areas, which has water consumption of 58% (1.45×10^8 m^3 relative to 2.49×10^8 m^3) of the total water consumption for natural gas

in the U.S (Figure 55, Figure 56,and Table 29).(8, 20, 104) If 100% of current natural gas generation was fueled by unconventional shale gas, and assuming that 44% of shale gas is generated in areas that are under high or extremely high water stress, up to 1.38×10^8 m^3 out of 3.17×10^8 m^3 (43%) would be consumed in water stressed areas.

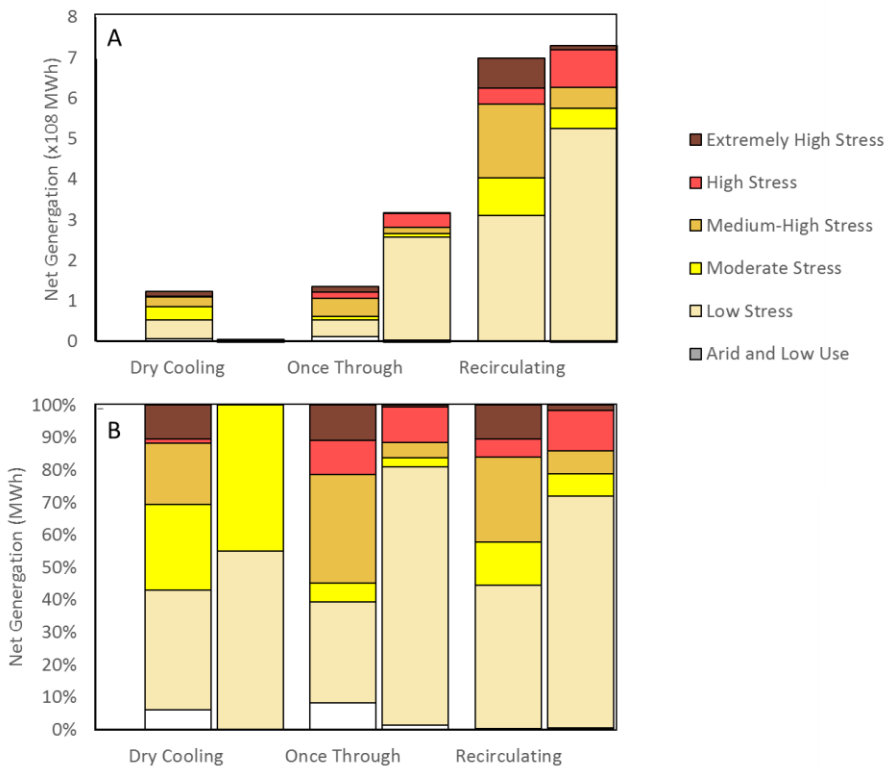


Figure 22: Electricity production in plant of different cooling systems located different water-stress areas in the U.S. The amount of 2016 net electricity generation attributed to dry, once through, and recirculating cooling processes for natural gas and coal, sorted by the water-stress status of the plant location in the U.S. (A), and the proportions of generation within each category (B). Colors within each bar show how much of the net generation took place in water stressed areas. In 2016, almost all generation using dry cooling applied for natural gas plants, while a majority of generation using once through cooling applied for coal plants.

5.3 Discussion

In 2015, natural gas displaced coal as the primary source for electricity generation in the U.S. (Figure 16). For every MWh of electricity generated in 2016, the conversion to natural gas from coal results in a reduction of 1.05 m^3 for water consumption and 38.98 m^3 for water withdrawal. If all the electricity generated with coal plants in 2016 (1.24×10^9 MWh) had been generated with the average natural gas-fired power plant, the would have been reduction of as much as 1.30×10^9 m^3 of water consumption and 4.83×10^{10} m^3 of water withdrawn (Figure 21). The reduction in water use for electricity generation has been caused not only by the replacement of older sub- and super-critical coal plants with newer, more efficient NGCC plants, but also by retrofits to use reclaimed wastewater, better plant management, and replacement of the water-cooling methods.(42, 130). Of water-cooling technologies, recirculating cooling systems have become the most common, accounting for 67% of electricity generation in 2016. This technology requires lower withdrawal and causes less thermal pollution of water returning to the environment relative to once-through water cooling systems. These reductions are necessary because up to 30% of electricity generation and water consumption and withdrawal in the U.S. occurs in highly water-stressed areas (Figure 7), and because climate change, population growth, water quality degradation, and other factors are likely to exacerbate the challenge of meeting water needs for other sectors in the U.S.

Water intensity of electricity could increase if carbon capture and sequestration (CCS) techniques are implemented to reduce emissions from fossil fuel plants.(123, 133, 134) Previous studies of the water impacts of CCS implementation, have estimated an increase of 0.50 m^3/MWh in water consumption and 0.73 m^3/MWh increase in water withdrawal for supercritical pulverized coal plants at 40% carbon capture, and a 0.16 m^3/MWh increase in water consumption for an NGCC plant at 40% carbon capture.(133) Due to the low water intensity of renewable energy such as solar PV and wind (Meldrum 2014 estimates solar PV consumes 0.35 m^3/MWh, while wind consumes 0.0037 m^3/MWh), widespread installation of these renewables energy would result in important and even more significant reductions of water intensity of U.S. electricity.(63) Another mechanism that could greatly reduce the water footprint of thermoelectric generation is switching from wet (once through and recirculating) to dry cooling. Switching from wet to dry cooling is expensive with capital costs estimates of $83 million for a dry cooling system in a 600 MW gross NGCC plant vs $29 million for a wet cooled system(135). Dry cooling systems also reduce plant efficiency and raises coal/natural gas resources consumption, which introduces a tradeoff between increased carbon emissions and water use.(135)

5.4 Conclusions

We have showed that the transition from a coal to natural gas fueled electricity sector in the U.S. during 2013-2016 has resulted in reduced water consumption and

withdrawals; every MWh of electricity that transitioned from coal to natural gas resulted in an annual reduction of water consumption of 1.05 m^3 and a reduction of water withdrawal of 38.98 m^3. Further, we estimate that if all coal generation were replaced by natural gas, there would be an annual reduction of as much as 1.30×10^9 m^3 of water consumption and 4.83×10^{10} m^3 of water withdrawn. By combining upstream water consumption and withdrawal, we show that despite an increase in the water use intensity of hydraulic fracturing for natural gas production, switching from coal to natural gas fueled generation can still result in reductions in the overall volume of water use. Yet most thermal plants in the U.S. (59% of 2016 net generation) are located in low water-stress areas, while a large proportion of water consumption for upstream coal (41%) and natural gas (58%) extractions occurs in high water-stress areas. Further research should address the growing proportion of renewables such as wind, solar, and biofuels and how they play into the water consumption and withdrawal intensity of the electricity sector.

5.5 Methods

5.5.1 Data Collection

Forms EIA 860 and EIA 923 were downloaded from the EIA website for 2013-2016. Previous years were available, but data quality concerns prevented them from being used in this analysis. There are a number of potential error sources within this dataset that bear mentioning: wide ranges on median values reported here (Figure 53)

may impact the quality and reliability of reported numbers. Also, because this is self-reported data, concerns about entry error and misreported data may impact conclusions. Despite these concerns, data values for downloaded years match well with other literature values, providing confidence in the results reported in this study. (7, 63, 73, 117, 129)

5.5.2 Data Organization

Plant technology was classified based on EIA 860, form 3_1_Generator_Y20XX using a combination of "Prime Mover" and "Energy Source 1." For generators using coal as the primary energy source, generators were classified as "subcritical," "supercritical," or "ultrasupercritical" based off of columns in 3_1_Generator_Y20XX indicating these fields. IGCC coal plants were identified by their fuel source, coal-derived synthesis gas, "SGC." Plants burning both coal and natural gas in many cases used different cooling towers for their natural gas burning equipment than for their coal burning equipment. In cases where cogeneration plants used the same cooling tower, water consumption and withdrawal were divided based on their proportion of net generation.

We neglect several lifecycle terms for this study including the water footprints of plant zoning and construction in addition to the water footprints for the manufacturing of plant parts, mining equipment, and transportation equipment. We also neglect pond cooling as a distinction within once through and recirculating plants. Pond cooling systems can operate similarly to either once through or recirculating systems.(129)

Carbon capture and storage (CCS) is a technology that is being considered in a number of regions across the United States. CCS systems can greatly increase the water consumption and withdrawal for plants using the technology.(105, 129, 133, 134) Despite this, we did not estimate any potential CCS additions.

5.5.3 Upstream and Total Water Use Calculations

Upstream water consumption and water withdrawal intensity were calculated using a combination of indirect and direct water uses in the mining, processing, and transportation of coal and natural gas. Because there was no distinction between water consumption and water withdrawal, we assume that in all upstream processes, water consumption is equal to water withdrawal. For coal, the following equation describes the upstream water use:

$$UWC = WCCM_{mt} * VC_{mt} + WCCC * VC_{Total} + CTT * VC_{Total} + E_p * VC_{Total} * EI + VC_{Total} * VD_{Total} * VC_{total} * DI + VD_{Total} * DF * EI$$

Where WCCM is water consumption from coal mining for both surface and underground mines (mt = surface or underground) in m^3/kg coal, VC is the volume of coal sent to power plants originated from surface and underground mines (mt, Table 26 and Table 27), WCCC is water consumption from cleaning coal (WCCC) in m^3/kg coal, CTT is water consumption for transportation of coal (CTT) in m^3/kg coal. Indirect water use is calculated by multiplying E_p, the electricity used in each upstream processes (MWh/kg coal) by the water intensity for electricity generation of the electricity grid

(m^3/MWh) calculated using an input output (IO) model to iterate the additions of upstream processes to power plant level water consumption and withdrawal. VD is the diesel fuel used onsite to power mining and transportation equipment (in kg diesel/kg coal), DI is the water intensity for diesel fuel extraction (m^3 of water per kg diesel) and DF is the electricity requirement for a petroleum refinery (MWh/kg diesel).

Similarly, for natural gas, we repeated this calculation:

$$UWC = WCNG_{Drill\,Type} * VNG_{Drill\,Type} + VD_{Total} * VNG_{total} * DI + VD_{Total} * DF * EI + E_p * EI * VNG_{Total}$$

Where the water consumption for natural gas generation is split up between offshore, onshore conventional, and onshore unconventional drilling. Further, due to recent increasing trends in water use for hydraulic fracturing (unconventional natural gas drilling), we further split $WCNG_{UC}$ up by year. Indirection consumptive processes included diesel used for well construction VD_{Total} (kg diesel/MCF NG) and electricity for well drilling, liquid separation, compression, and pipeline transport.

Total water consumption (TWC) and total water withdrawal (TWW) were calculated by adding water use due to plant operations to UWC:

$$TW(C\ or\ W) = Plant\ Level\ (C\ or\ W) + UWC_{NG\,or\,Coal}$$

6. Use of Oilfield Produced Water for Irrigation in Bakersfield, CA

6.1 Introduction

For the past 100 years, California has been a national leader in both agriculture and oil production.(136) Over this same time span, it has also been one of the driest regions in America.(43, 137) Due to consecutive drought periods and reduction in natural water availability, water districts throughout California were formed to help supplement the local water supply for the irrigation. In Kern County, water districts utilize a combination of groundwater, surface water, and reclaimed water resources, including oilfield produced water (OPW) in several districts (Cawelo, Jasmin Mutual, Kern-Tulare, and North Kern, Figure 23).(45-48, 138) By blending treated OPW and freshwater sources, these water districts are able to extend the amount of water available for irrigation. While water quality monitoring has been conducted, the effects of using OPW for irrigation are not well documented in either soil or crops. To ensure both crop health and food safety while optimizing the potential and important use of alternative irrigation sources, this chapter evaluates the inorganic contaminants in OPW used for irrigation in Cawelo District and potential impact on soil and crops. We find that blended OPW sources in the Cawelo region are characterized by low salinity and trace metal concentrations, which pose low risks for metals accumulation in soil and therefore supports the utilization of OPW for irrigation water in the water stressed region of southern

California.

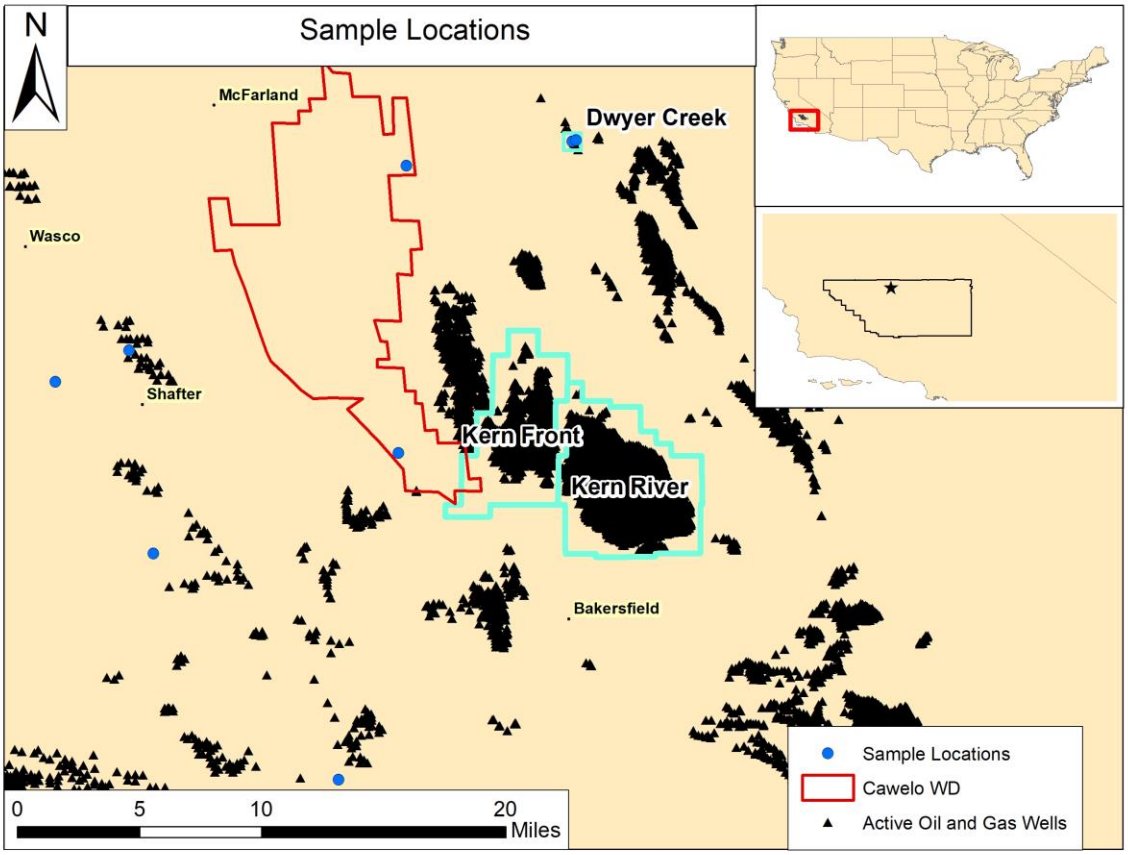


Figure 23: Map of sample sites, Cawelo water district, and relevant oil fields in Kern County, CA

6.1.1 History of OPW use in Kern County

Through time, farms and oil companies have developed a symbiotic relationship: agriculture fields serve as prime locations to place oil wells, while beneficial byproducts of oil production such as anhydrous ammonia fertilizer and soil fumigant D-D have been produced and used in agriculture, beginning in the 1940s.(136) By the early 1990s, water scarcity led to the first beneficial reuses of oilfield produced water in southern

California. In 1994, Texaco Extrapolation and Production Inc. (now Chevron) and the Cawelo water district signed a water supply agreement to pump treated produced water to the district.(45) In 2006, SOC Resources, Inc. was issued a permit to store produced water in an unlined surface impoundment, where a large portion of the wastewater was transferred from the impoundment through the Schaefer Pipeline.(138) The pipeline moves the wastewater from the impoundment to the Cawelo water district, where it is blended with fresh water and distributed for irrigation.(138) The Texaco (Chevron) deal was renewed in 2006, then again in 2012. The 2012 renewal granted Chevron permission to pipe 33.5 million gallons per day to the Cawelo water district to be used to help meet irrigation demand.(45) The water supplied to the district is treated with mechanical separation, sedimentation, air floatation, and filtration to meet Basin Plan standards and delivered to the Cawelo district.(45) Other permits were issued to Valley Waste Disposal Company in 2007 (46), E&B Natural Resources in the Jasmin Mutual Water District (Jasmin Oil Field) in 1998 (47), and to California Resources Production Corporation in the North Kern Water Storage District (Kern Front Oil Field) in 2015 (48).

6.1.2 OPW use Regulations

There are a number of regulations laying strict guidelines for the quality of water allowed to be used in agriculture in Kern County, CA.(45, 138) To address increasing salinity and nitrate in local groundwater, a program call the Central Valley Salinity Alternatives for Long-Term Sustainability (CV-SALTS) was created to recommend and

implement management practices to reduce salinity.(139) With respect to irrigation water, the Water Quality Control Plan for the Tulare Lake Basin (called the Basin Plan), sets guidelines on acceptable irrigation water quality.(44) These guidelines limit the maximum salinity for reclaimed irrigation water at electric conductivity (EC) of 1000 μS/cm, chloride at 200 mg/L, and boron at 1 mg/L.(44) These values are derived from Ayers & Westcot's "Water Quality for Agriculture,"(50) highlighting maximum contaminant loads various crop products can handle. In addition to following the Basin Plans' water quality control plan, districts also aim to follow a set water quality standards outlined in "A Compilation of Water Quality Goals (17th Edition, January 2016)" setting guidelines for water quality associated with various reuse options.(140) These include aluminum (5,000 μg/L), beryllium (100 μg/L), cadmium (10 μg/L), hexavalent chromium (100 μg/L), cobalt (50 μg/L), copper (200 μg/L), fluoride (1,000 μg/L), iron (5,000 μg/L), lead (5,000 μg/L), manganese (200 μg/L), nickel (200 μg/L), selenium (20 μg/L), and vanadium (100 μg/L).(50, 140) Additional limits on arsenic concentrations of 10 μg/L were added to limit potential contamination within distribution canals by the Cawelo water district.(45)

6.2 Materials and Methods

6.2.1 Sample Collection and Analysis

Through four sampling campaigns (April 2017- August 2018), we have collected seven water samples from oilfield formations including one sample from the Edison

formation, five from the Dyer Creek oil field, and one from the Midway Sunset field. We have collected seventeen irrigation water samples in areas used to grow pistachios, alfalfa, and almonds, eight from groundwater sources and 7 from canal water sources. All water samples were filtered before being collected and preserved in high density polyethylene, airtight bottles following USGS field sampling protocols.(141) Water samples were run for major cations on a Thermo Scientific Aquion IC operating isocratically at constant room temperature. Calibration standards include eight levels for six cations (Li, Na, NH4, K, Mg, Ca) ranging from 5:1 to 2000:1 dilutions of Thermo Scientific six-cation standard solution (Li= 50 ppm, Na, K, Mg = 200 ppm, NH4 = 400 ppm, CA = 1000 ppm Major anions were run on a Dionex Ion Chromatograph DX-2100. Bicarbonate was calculated via titration to pH 4.5 in duplicate. Nitrate was analyzed via QuickChem Method 10-107-04-2-D (Nitrate/Nitrite in Waters by Hydrazine Reduction). Trace metals were analyzed using a VG PlasmaQuad-3 inductively coupled plasma mass-spectrometry (ICP-MS). Trace-metals accuracy was assessed by measuring the National Institute of Standards and Technology (NIST) standard reference material (SRM) for trace elements in groundwater (1643e). All samples were pre-diluted based on total conductivity to stay at or below a conductivity of 200 μS/cm.

6.3 Results

6.3.1 Oilfield produced water characterization

Currently, OPW from the Deer Creek, Jasmin, Mount Poso, Kern Front, and Kern River oil fields are being used for irrigation. The Cawelo water district, located north of Bakersfield, CA utilizes water from both the Kern River and Kern Front oil fields (Figure 24). While we did not measure samples from these oil fields, previous studies have reported that produced waters from the Kern River and Kern Front oil fields are characterized by low salinity (TDS up to 1350 mg/L) with chloride concentrations ranging from 38 to 290 mg/L.(86) Additionally, sodium (up to 350 mg/L), calcium (up to 80 mg/L), and magnesium (up to 22 mg/L) concentrations are low. Boron data from the Kern River and Kern Front fields was not available. New data collected in this study show consistently large variations in salinity across oil fields in Kern county, with chloride concentrations ranging from 110 mg/L (Fruitvale field) to as high as 23,500 mg/L (Belridge field). Samples collected from the Dyer Creek formation northeast of Bakersfield, CA had high boron (up to 2.2 mg/L) and chloride (up to 480 mg/L) concentrations with low arsenic (1 μg/L). Dwyer Creek samples are being used for private irrigation, outside of water district regulation. In contrast to low saline eastern oil fields, produced water from fields located on the western parts of the valley (Figure 24) such as the Midway-Sunset and Edison fields had much high salinity (ranging from 1280 to 6700 mg/L Cl). The variations of boron versus chloride (Figure 1) show that large

dilution and/or further treatment of the low-saline OPWs to meet salinity standards would be required to get boron levels below this threshold. This means that water treatment for boron reduction or further dilution is necessary for using the OPW with boron content below the plant toxicity threshold of 1 mg/L. Boron concentrations ranged from 0.6 mg/L (Fruitvale field) to 168 mg/L (Lost Hills field) (Figure 25). The available data (McMahon 2018 (142) and this study) indicate that the low saline OPW samples have boron concentrations above the guideline threshold value of 1 mg/L. Additional data on chemistry of OPW in Kern County can be found in McMahon (2018).(142)

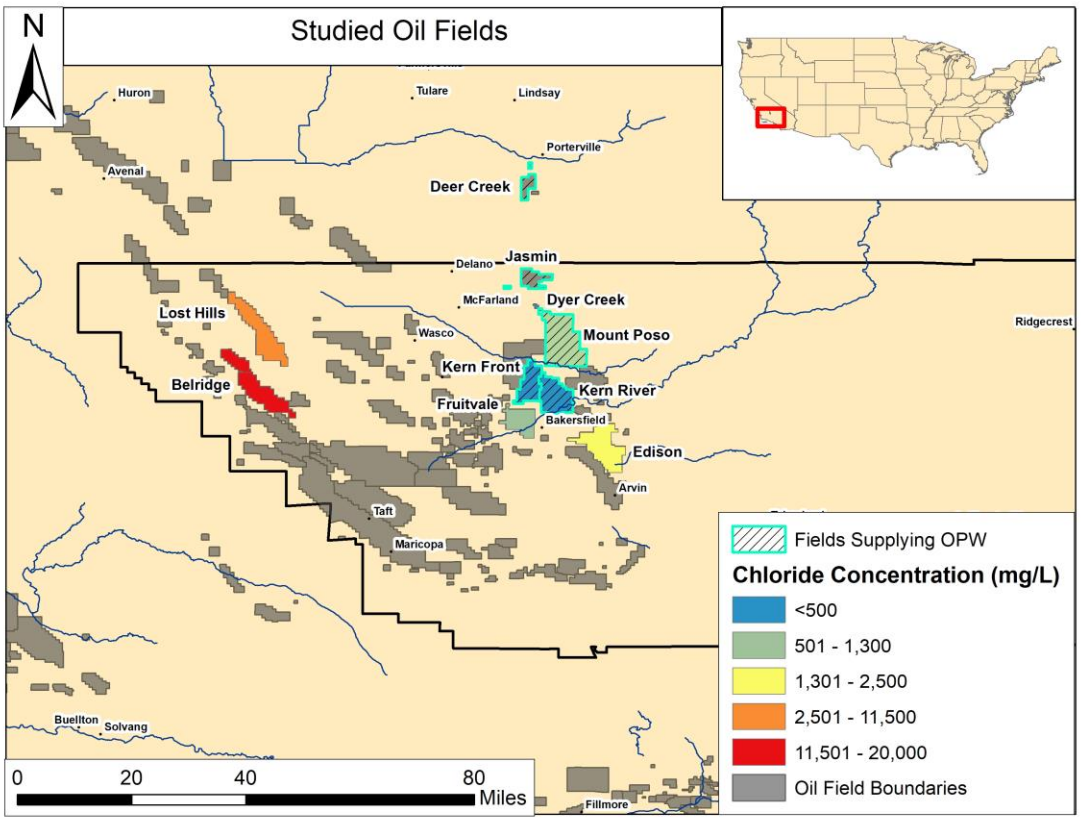


Figure 24: Oilfield produced water salinity in Kern County, CA.

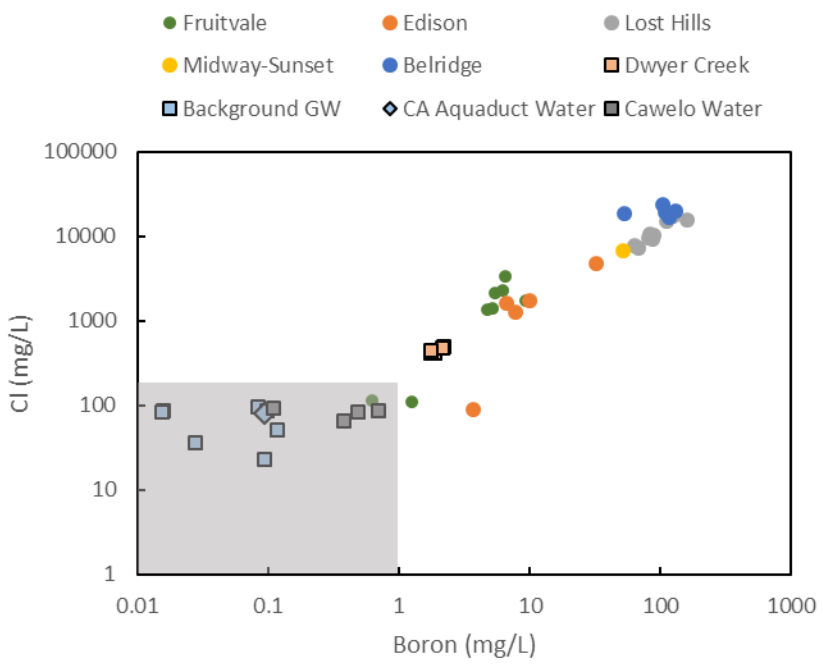


Figure 25: Boron and chloride concentrations across Kern County. The grey box represents Basin Plan limits on boron (1 mg/L) and chloride (250 mg/L).(44)

6.3.2 Irrigation Water Quality

Groundwater investigated in this study had chloride values ranging from 22 to 94 mg/L, while OPW-diluted water collected from the Cawelo canal had chloride ranging from 64-92 mg/L. Although the OPW from Cawelo had higher salinity relative to the groundwater samples, both were below the Basin Plan guideline of 200 mg/L.(44) A similar trend was observed for boron, as boron in groundwater (0.02-0.12 mg /L) was lower than those observed for Cawelo canal (0.11-0.69 mg/L), but still below the guideline for boron of 1 mg/L (Table 6). Arsenic concentration above the Cawelo implemented guideline of 10 µg/L was observed in all but one of the Cawelo canal water samples (range of 8.7-26.5 µg/L), while only one groundwater sample had high arsenic

(range of 1.3 to 13.4 µg/L) (Figure 26 and, Table 7).(50) Concentrations of nitrate, iron, and manganese in groundwater and Cawelo water exceed EPA primary and secondary MCLs.(143, 144)

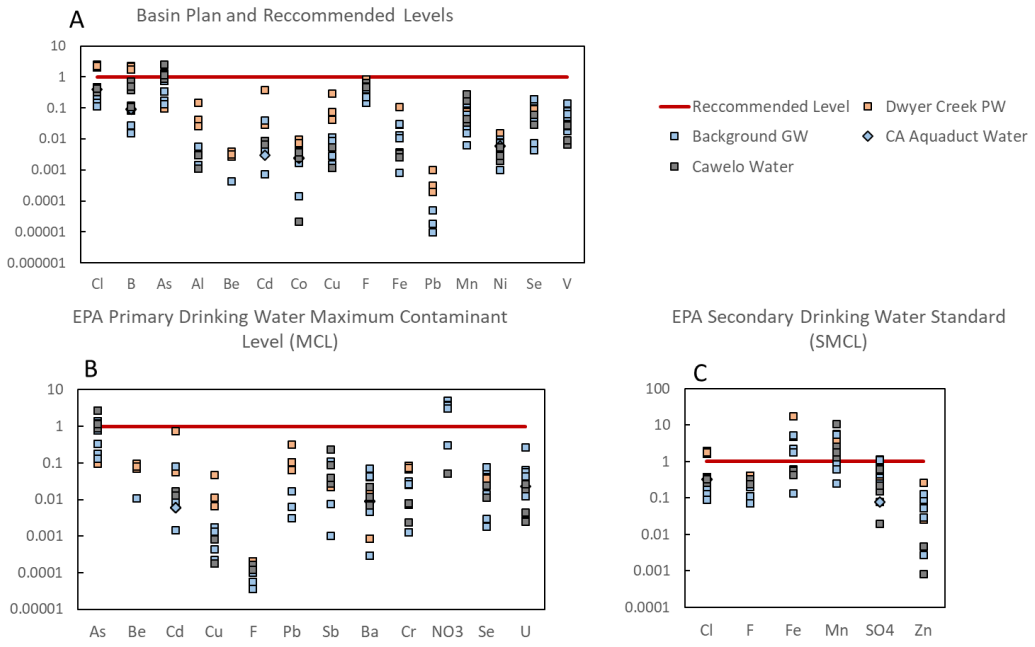


Figure 26: Water quality guidelines verses measured samples. Irrigation water quality data (points) compared to water quality guideline levels (red lines). Values above 1 are above recommended levels for the Basin Plan and Ayers and Westcot (1976) recommendations (A),(44, 50) EPA primary drinking water maximum contaminant level (B),(143) and secondary drinking water standard levels (C).(144)

Table 6: Major element chemistry of water samples for groundwater, canal water, and OPW used for irrigation in Kern County, CA. Values are in mg/L.

Class	B	HCO3	F	Cl	Br	NO3	SO4	K	Ca	Mg	Sr	Na	Fe	Ba	Mn	Si
Cawelo Canal Water	0.108	79	BDL	92	BDL	BDL	150.0	BDL	33.6	2.115	0.353	128	0.03	0.032	0.023	25.419
Cawelo Canal Water	0.689	287	0.642	87	0.329	0.507	4.9	BDL	16.3	2.839	0.298	136	0.029	0.075	0.024	33.362
Cawelo Canal Water	0.377	149	0.481	65	BDL	BDL	37.7	2.515	19.4	1.898	BDL	82	BDL	BDL	BDL	BDL
Cawelo Canal Water	0.488	185	0.472	82	BDL	BDL	55.1	3.026	25.5	2.371	BDL	104	BDL	BDL	BDL	BDL
Groundwater	0.027	115	BDL	35	0.165	49.225	111.8	BDL	368.8	33.548	2.719	193	BDL	0.483	0.134	59.382
Groundwater	0.015	212	0.142	87	0.349	38.331	283.1	BDL	99.6	1.437	1.142	68	0.043	0.119	0.012	8.048
Groundwater	0.015	95	0.144	83	0.276	37.198	267.3	BDL	109.7	1.377	1.226	72	0.04	0.121	0.011	8.682
Groundwater	0.082	67	BDL	94	BDL	BDL	167.8	BDL	32.9	1.845	0.344	128	0.034	0.037	0.01	23.784
Groundwater	0.097	71	0.429	85	BDL	BDL	139.2	3.299	25.4	0.85	BDL	124	BDL	BDL	BDL	BDL
Groundwater	0.093	67	0.389	23	BDL	3.088	19.8	BDL	6.7	0.085	0.104	40	0.008	0.012	0.005	7.612
Groundwater	0.117	57	0.222	51	BDL	30.251	63.3	2.038	38.6	BDL	BDL	45	BDL	BDL	BDL	BDL
OPW irrigation	1.876	215	0.793	409	1.376	BDL	65.8	BDL	36.1	2.633	0.423	379	BDL	0.075	0.096	15.092
OPW irrigation	2.209	199	0.551	487	1.565	BDL	45.1	BDL	40.9	3.076	0.496	414	0.055	0.083	0.118	15.197
OPW irrigation	2.141	180	0.649	481	1.579	BDL	84.0	BDL	39.3	2.995	0.483	419	BDL	0.079	0.096	14.896
OPW irrigation	1.766	257	0.787	413	BDL	BDL	124.5	5.499	19.0	BDL	BDL	406	BDL	BDL	BDL	BDL
OPW irrigation	1.747	212	0.829	446	1.15	BDL	161.8	4.817	20.2	BDL	BDL	389	BDL	BDL	BDL	BDL

Table 7: Trace metal concentrations of water sample for groundwater, canal water, and OPW used for irrigation in Kern County, CA. Values are in μg/L.

Class	Li	Be	Al	V	Cr	Co	Ni	Cu	Zn	As	Se	Rb	Sr	Mo	Ag	Cd	Sb	Ba	Pb	U
Cawelo Canal Water	20.832	BDL	5.609	0.659	0.78	BDL	0.45	0.226	0.397	12.277	0.56	0.997	200.643	39.928	BDL	0.084	0.512	13.438	BDL	0.13
Cawelo Canal Water	33.891	BDL	15.024	0.899	0.231	BDL	0.4	1.037	2.32	26.257	BDL	2.924	180.245	6.306	0.008	0.064	1.375	44.094	BDL	0.072
Cawelo Canal Water	21.07	BDL	BDL	2.583	BDL	0.119	0.56	BDL	BDL	8.766	BDL	1.924	219.283	5.724	BDL	BDL	0.164	23.443	BDL	0.582
Cawelo Canal Water	29.144	BDL	BDL	2.64	BDL	0.187	1.085	BDL	BDL	11.511	1.219	2.661	325.133	6.071	BDL	BDL	0.232	43.325	BDL	0.771
Groundwater	7.367	0.042	28.572	7.558	2.54	0.136	1.913	2.256	44.171	1.519	0.693	0.106	554.051	2.791	0.044	0.034	0.045	82.998	0.247	7.799
Groundwater	9.361	BDL	14.911	4.731	3.062	0.147	1.499	1.702	62.903	1.742	3.193	2.018	835.086	0.78	0.034	0.4	BDL	140.845	BDL	1.879
Groundwater	7.047	BDL	6.454	5.2	2.615	0.083	1.422	0.56	25.46	1.301	3.719	0.68	1012.63	0.847	BDL	0.041	0.006	86.067	BDL	1.644
Groundwater	23.149	BDL	7.131	0.69	0.123	BDL	0.485	BDL	14.47	13.455	0.088	0.906	216.46	49.289	0.006	0.062	0.636	14.002	0.092	0.079
Groundwater	28.466	BDL	BDL	1.744	BDL	0.208	0.691	BDL	BDL	7.56	BDL	1.389	157.853	13.861	0.098	0.041	BDL	0.584	BDL	0.375
Groundwater	1.837	BDL	14.927	14.195	0.73	0.007	0.196	0.293	1.347	9.806	0.144	0.052	75.766	2.553	0.023	0.007	0.222	9.361	0.047	0.695
Groundwater	4.78	BDL	BDL	6.326	BDL	0.123	0.995	BDL	91.205	3.331	BDL	0.175	493.374	2.334	BDL	0.044	BDL	43.392	BDL	1.254
OPW irrigation	61.347	0.385	724.567	3.259	6.724	0.478	3.104	59.207	127.549	1.042	3.107	11.485	364.735	0.606	0.673	3.749	0.129	42.263	4.809	BDL
OPW irrigation	71.422	0.274	204.711	3.522	8.378	0.25	1.523	14.397	26.893	1.029	3.709	12.238	418.182	0.231	0.247	0.32	BDL	28.194	1.54	BDL
OPW irrigation	69.417	0.311	131.464	3.344	7.273	0.157	1.139	8.383	12.549	0.942	1.864	11.729	411.365	0.193	0.189	0.279	BDL	28.157	0.972	BDL
OPW irrigation	62.288	BDL	BDL	BDL	BDL	0.34	BDL	BDL	BDL	BDL	BDL	11.537	373.197	3.49	BDL	BDL	BDL	BDL	BDL	BDL
OPW irrigation	63.375	BDL	BDL	BDL	BDL	0.363	BDL	BDL	BDL	BDL	BDL	11.737	392.852	3.667	BDL	BDL	BDL	1.715	BDL	BDL

6.4 Discussion

Plants absorb water from soil through osmotic potential, exerting a force on the water that is greater than the force holding water to the soil.(50) In soil irrigated with high salinity water, its osmotic potential is reduced, which infers less water is available for plants.(50) In arid regions such as California, the buildup of salt in the soil is of even greater concern because a large portion of the water applied to the soil quickly evaporates, concentrating salts in the remaining soil water. Using sub-optimal quality water can dramatically speed up this process in the soil by introducing more salt to the system. Three of the main crops grown in Kern County California, almonds, grapes, and oranges are all classified as sensitive to the salinity of both irrigation water and soil, suggesting soil salinity in areas irrigated with OPW should be of increased concern.(50) Of the irrigation water quality parameters, boron and arsenic were found to be elevated above recommended levels in measured samples.

Boron is an essential nutrient for plant health, as it is responsible for providing structure to the cell wall.(145, 146) In soil, boron is typically found in concentrations

ranging from 0.4 to 5 mg/kg and exists primarily as boric acid ($B(OH)_3$) which is readily taken up by plants.(147, 148) Boron is highly mobile in soil, adsorbing and desorbing rapidly. In arid and semi-arid regions, where there precipitation is low, boron leaching out is restricted and thus can accumulate, allowing for increasing concentrations in soil through time. When present in large concentrations in irrigation water, accumulation in soil can be exacerbated. Ayers & Westcot (1976) proposed guidelines for water quality in agricultural use, citing concentrations of boron in irrigation water at 1 mg/L, 5 mg/L, and 10 mg/L depending on the crop tolerance to boron, while others recommend a range of 0.3 mg/L for sensitive plants and up to 4 mg/L for more tolerant plants.(50, 148) When too much boron is present in the soil-plant interface, the production of reactive oxygen species (ROS) can increase, causing oxidative damage to the cellular membrane, leading to decreased growth and or leaf necrosis, lower chlorophyll concentrations and decreased photosynthesis, defined as "boron toxicity".(145, 147, 149, 150) While boron levels in irrigation water investigated in this study rarely reached these levels, many of the districts within the Central Valley have adopted a 1 mg/L limit on irrigation water derived from recycled OPW.(140, 150) Boron levels measured in groundwater and Cawelo samples ranged from 0.01 to 0.6 mg/L with Cawelo canal samples having higher concentrations than groundwater (Figure 25 and Table 6). In the case of the Dwyer Creek oil field site, where the OPW was not diluted with fresh water, we show that the

OPW used for irrigation had boron values higher than the recommended limit of 1, but within the acceptable range for more tolerant plants (<10 mg/L).

Arsenic is a known carcinogen and has been linked with heart problems, diabetes, and keratosis as well as numerous other health effects.(143, 151, 152) As such, it is regulated in drinking water, with a maximum contaminant level of 10 μg/L.(143) While Ayers (1976) recommends a limit of 100 ppb As in irrigation water, it is likely that the stricter limit of 10 ppb imposed by the basin plan aims to protect wildlife and humans who could come in contact with the canals supplying the irrigation water on a regular basis.(44, 50) Arsenic concentrations found in groundwater in Kern county ranged from 1-13 μg/L, while values measured in Cawelo canal water ranged from 8-26 μg/L (Table 7). While arsenic concentrations were found to be above the recommended maximum concentration they were not at levels that could compromise plant health.

In addition to the toxicity of specific ions in irrigation water to plants, the chemical composition of the irrigation water can affect the properties and suitability of the soil in which crops are grown. A classic measure of irrigation water suitability for agriculture is the sodium adsorption ratio (SAR) and adjusted SAR.(50) Adjusted SAR is defined as:

$$adj\ SAR = \frac{[Na]}{\sqrt{\frac{[Ca]+[Mg]}{2}}} * (1 + (8.4 - pHc))$$

Where concentrations are in meq/L and pHc is calculated as the sum of A (sum of concentrations of Na, Ca, and Mg), B (sum of concentrations of Ca and Mg), and C (alkalinity concentration) from Table 8.(50) Soils irrigated by water high in sodium relative to calcium and magnesium could reduce its permeability and thus lower soil infiltration capacity, making it harder for water to reach the subsoil. Soils with an adjusted SAR between 6 and 24 can have permeability related problems, while severe problems are present in soils above 24.(50) Water samples measured in both groundwater and Cawelo blended OPW had adjusted SAR between 2 and 9, while Dwyer Creek OPW samples had values ranging from 24 to 33 (Figure 27). There was no observable difference between adjusted SAR values in groundwater and Cawelo blended OPW. To help manage high SAR in soils, it is common to add sulfuric acid to irrigation water and gypsum to irrigated soils.(50) Both of these practices were observed in groundwater irrigated and Cawelo irrigated fields.

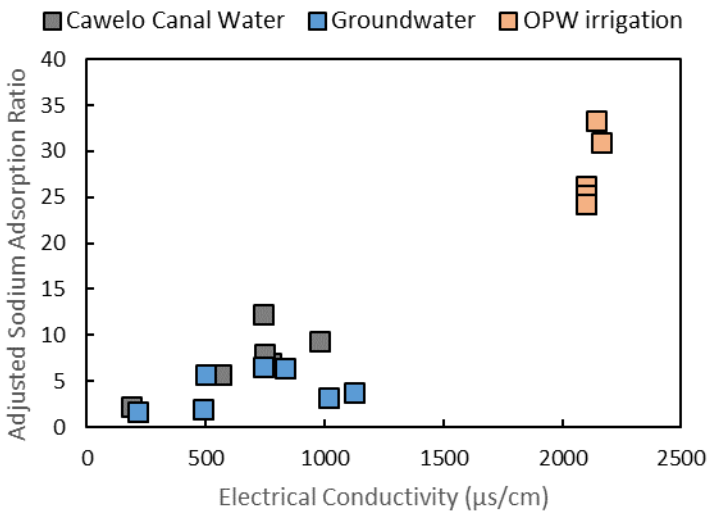


Figure 27: Adjusted sodium adsorption ratio (adj SAR) for water samples collected from Kern County, California.

Table 8: Calculation parameters for pHc. For each X_i, the relevant concentrations (in meq/L) should be added up, then looked up in the first column. Values for A, B, and C can then be added together to find pHc.(50)

X_i	A	B	C
Value	X_1= [Na]+[Ca]+[Mg]	X_2 = [Ca]+[Mg]	X_3= [Alkalinity]
0.05	2	4.6	4.3
0.1	2	4.3	4
0.15	2	4.1	3.8
0.2	2	4	3.7
0.25	2	3.9	3.6
0.3	2	3.8	3.5
0.4	2	3.7	3.4
0.5	2.1	3.6	3.3
0.75	2.1	3.4	3.1
1	2.1	3.3	3
1.25	2.1	3.2	2.9
1.5	2.1	3.1	2.8
2	2.2	3	2.7
2.5	2.2	2.9	2.6
3	2.2	2.8	2.5
4	2.2	2.7	2.4
5	2.2	2.6	2.3
6	2.2	2.5	2.2
8	2.3	2.4	2.1
10	2.3	2.3	2
12.5	2.3	2.2	1.9
15	2.3	2.1	1.8
20	2.4	2	1.7
30	2.4	1.8	1.5
50	2.5	1.6	1.3
80	2.5	1.4	1.1

6.5 Conclusion

We conclude that blended OPW provided by the Cawelo water district is of comparable quality to the groundwater in the region. Direct ruse of OPW without dilution with fresh water however, as was seen in the case of the Dwyer Creek samples, can introduce higher concentrations of salinity and boron into the field, creating boron toxicity in crops and soil permeability issues. Because the water received by the Cawelo

district is of high quality and is blended with low-saline groundwater and surface water sources, many of the potential contamination issues can be averted.

7. Conclusion

As water demand and competition for clean water resources continues to expand, the energy sector will continue to play a key role in global water management. The development and growth of water intensive technologies such as hydraulic fracturing have added to competition for fresh water, but efforts are being made to utilize alternative water sources.

This dissertation fills a significant knowledge gap in the understanding of water use and wastewater generation associated with hydraulic fracturing across the United States. Characterization of water use volumes have revealed that annually, hydraulic fracturing represents only a small fraction of industrial water use. While flowback and produced (FP) water volumes are similar to water use volumes, this dissertation shows that most of the returning FP water is made up of saline formation brines and not injected water. Despite this, evaluation of trends in both water use and FP water production show a staggering increase from 2011-2016: 770% for water use per well and 550% for FP water after the first 12 months of production. At the same time, the water use intensity (ratio of water use to energy production) has almost ubiquitously increased from 2011-2016.

As the popularity of hydraulic fracturing has risen, this dissertation points out a transition from coal to natural gas as the primary energy resource powering the United States. It shows that despite increasing water use for hydraulic fracturing, the transition

from coal to natural gas has led to less lifecycle water consumption and withdrawal for power plants. Finally, this dissertation showed that with proper treatment and management, it is possible to reuse waste water from oil and gas production in alternative settings. This dissertation highlights farms in California successfully utilizing oilfield produced water for agricultural irrigation water without raised concentrations of metals.

The findings of this dissertation highlight the need for the development of alternative water resources for energy development and shows successful utilization pathways through which this occurs. Future work is needed to encourage and justify the use of alternative source water for hydraulic fracturing, power plant cooling, and agriculture. This dissertation lays a framework for the adoption of alternative water sources and highlights the proper management of waste water streams, in some cases utilizing waste water streams as the sought-after alternative water source.

Appendix A: Supplementary Information for Chapter 2

1. Evaluation of Data Reliability and Sources of Error

In their database, FracFocus(31) reports each well case with latitude and longitude coordinates, but not with the target formation in which the fracture job occurred. In the EPA report, the coordinates of the oil and gas wells to spatially distinguish the geological formations that the wells are located within(55). This means that in cases of overlapping formations such as the Marcellus, Utica, and Devonian, a data report could potentially be for any of the formations. To fix this problem, we matched well data to the American Petroleum Institute well number (API number) from different state databases to get a higher resolution distribution of the oil and gas wells.(66, 67)

Because DrillingInfo Desktop(64) does not specify which of the wells are unconventional, we used only horizontally-drilled wells for quantifying produced water, oil, and gas production data since all horizontal drilling is always paired with hydraulic fracturing. We did not include vertically-drilled unconventional wells in the analysis because we were unable to identify them as unconventional. Since most of the unconventional wells drilled in California are vertical and not horizontal however, data from the California Department of Conservation's Monthly Production and Injection Databases(90) were used for oil and gas data from the Monterey-Temblor formation. While the California database has no distinction between conventional and

unconventional, 703 wells were identified as unconventional wells based on API number and the EPA FracFocus database.(55)

DrillingInfo's type curve function provides data on gas, oil, and produced water generation values on a month to month basis as a daily average, going from well completion to final or current production. The DrillingInfo Desktop Application tool plots all of the wells for which production data is available, then reports one single type curve as the average for all of the target geological formation or area of interest. This average could potentially be different for core areas compared to perimeter areas and because it is an average, could be skewed by this uneven distribution of the well production data.

The type curve method of production analysis was compared to oil, gas, and produced water in the Bakken formation from a data set provided by the North Dakota Industrial Commission Department of Mineral Resources Oil and Gas Division(67) and to oil and gas production data in the Marcellus Shale formation from the Pennsylvania Department of Environment Protection (PADEP) Bureau of Oil and Gas Management's Oil and Gas reporting website.(66) The data from the different methods of evaluating produced water volume was consistent (Table 9, Table 10, Table 11), validating the DrillingInfo evaluation method. In the case of the Fayetteville, Marcellus and Woodford formation, data on produced water was not available, thus estimates were made using state government data and values when reported in the literature.(11, 66) Produced

water data reported in DrillingInfo for the Barnett Shale (45 x10^6 liters per well) and Permian Basin (95 x10^6 liters per well) were several times higher than values reported in the literature and outside the ranges seen for shale gas (5-25 x10^6 liters) and unconventional oil (8 to 23 x10^6 liters). Nicot et. al. (2012)(53) reports produced water in the Barnett shale of 12.4 x10^6 liters per well. For the purposes of the total production calculations (Table 2), 12.4 x10^6 liters was used. Additionally, estimates of total FP water did not include data from the Fayetteville, Woodford, or Permian basins, which could underestimate the total amount of FP Water generated in the United States.

While we report the best current estimate, there are several potential errors in using these well counts for total production and water use data; not all drilled wells are fractured, in some cases wells can be re-fractured, and the final well count may miss counting wells that were at one point fractured but no longer active. Furthermore, the Eagle Ford, Niobrara, and Woodford formations produce both gas and oil, and have regions and wells specifically designed to produce both resources. When computing well counts, the percentage of oil wells and gas wells in each of these formations were taken from DrillingInfo and applied to the total number calculated for the formation (Table 14). We did not use actual well counts from DrillingInfo in this study because we found them to be lower than values reported from other sources. Additionally, median values were reported instead of average values to address outliers and data entry errors

in the database. This could lead to inconsistencies with other reported data, so we also report all data with averages for water use in Table 12 and Table 13.

Data from Gallegos et. al. (2015)(60) was reported by USGS hydrologic unit code, so formation average values were derived using ArcGIS software. A field of total water use (Number of wells *water use per well) was added to each USGS 8 Digit HUC code within ArcMAP, then all hydrologic units within each unconventional shale gas or oil formation were spatially identified. Total water use within each formation was calculated by adding total water use from each individual HUC within the formation. Finally, the average water use per formation (Table 9) was calculated by dividing total formation water use by the cumulative number of wells from the selected HUC 8 for each formation.

Table 9: Comparison of water use data between values found in this study(55) and values reported in the literature.(6, 22, 23, 60, 69, 71) All values are reported in millions of liters. Dates of the years specific states have adopted FracFocus as their mandatory reporting platform are available from the US Department of Energy Task Force Report on FracFocus 2.0.(153)

Shale Gas	Water Use (Median)	Water Use (Mean)	Water Use (Other Studies)	Water Use (Gallegos et al. (2015))	Water Use (Chesapeake Energy)
	$x10^6$ L	$x10^6$ L	$x10^6$ L	$x10^6$ L	$x10^6$ L
Barnett	14.42	15.25	18.93, Nicot et al. (2014)	12.20	18.93
Eagle Ford	13.70	15.57	18.22, Scanlon et al. (2014)	17.08	18.17
Fayetteville	20.06	19.75		18.40	
Haynesville	19.45	20.75	21.5, Nicot et al.(2014)	17.19	21.20
Marcellus	16.12	16.76	14.8, Jackson et al. (2014)	11.65	21.20
Niobrara	1.51	2.60		4.59	12.49
Woodford	23.77	23.18	15.20, Murray et al. (2013)	11.96	

Unconventional Oil	Water Use (Median)	Water Use (Mean)	Water Use (Other Studies)	Water Use (Gallegos et al. (2015))	Water Use (Chesapeake Energy)
	$x10^6$ L	$x10^6$ L	$x10^6$ L	$x10^6$ L	$x10^6$ L
Bakken	7.49	7.96	8.68, ND SWC (2014)	9.27	
Permian	3.06	3.99		4.93	
Monterey-Temblor	0.30	0.50		0.61	
Eagle Ford	15.06	16.34	18.22, Scanlon et al. (2014)	11.76	
Niobrara	1.32	4.32		4.59	12.49
Woodford	7.79	13.35	15.20, Murray et al. (2013)	11.96	

Table 10: Comparison of oil and gas production data between values found in this study(64) and values reported in the literature(22, 23, 53, 66, 67) and from the United States EIA's Drilling Productivity Report.(65)

Shale Gas	EUR Gas Production per well (this study)	Total Formation Gas Production (this study)	EUR Gas Production per well	Totoal Formation Gas Production (USEIA) 2007-Current
	$x10^9$ Cubic Feet	$x10^{12}$ Cubic Feet	$x10^9$ Cubic Feet	$x10^{12}$ Cubic Feet
Barnett	1.39	23.44	1.90, Nicot et al. (2014)	
Eagle Ford	1.37	8.01	0.79, Scanlon et al. (2014)	11.92
Fayetteville	1.55	9.04		
Haynesville	4.33	13.75	2.50, Nicot et al. (2012)	22.37
Marcellus	3.66	30.41	1.91, PA DEP (2015)	22.48
Niobrara	1.32	3.02		14.80
Woodford	1.95	5.58		

Unconventional Oil	EUR Oil Production per well	Total Formation Oil Production (this study)	EUR Oil Production per well	Totoal Formation Oil Production (USEIA) 2007-Current
	$x10^6$ Barrels	$x10^6$ Barrels	$x10^6$ Barrels	$x10^6$ Barrels
Bakken	0.20	2065.16	0.15, ND OGD (2015)	1938.59
Permian	0.39	1915.64		3897.64
Monterey-Temblor	0.02	32.69		
Eagle Ford	0.45	1829.58	0.12 Scanlon et al. (2014)	1952.90
Niobrara	0.50	456.04		698.90
Woodford	0.70	44.88		

Table 11: Comparison of flowback and produced water data between this study(64) and values reported in the literature.(11, 22, 67) Data from the Eagle Ford formation in Scanlon et. al. (2014)(24) is based off a FP/HF ratio of 2/5 after the first 2 years. Values reported here are cumulative of up to 10 years of waste production of both flowback water and produced brines, which can account for the difference.

Shale Gas	Flowback and Produced Water (This Study)	Flowback and Produced Water (Other Studies)
	$x10^6$ L	$x10^6$ L
Barnett	12.40	12.40, Nicot et al. (2014)
Eagle Ford	25.87	5.48 Scanlon et al. (2014)
Fayetteville		
Haynesville	17.51	
Marcellus	5.20	Data used from Lutz (2013)
Niobrara	5.68	
Woodford		

Unconventional Oil	Flowback and Produced Water (This Study)	Flowback and Produced Water (Other Studies)
	$x10^6$ L	$x10^6$ L
Bakken	12.25	15.40, ND OGD (2015)
Permian		
Monterey-Temblor	14.30	
Eagle Ford	22.75	5.48 Scanlon et al. (2014)
Niobrara	8.04	
Woodford		

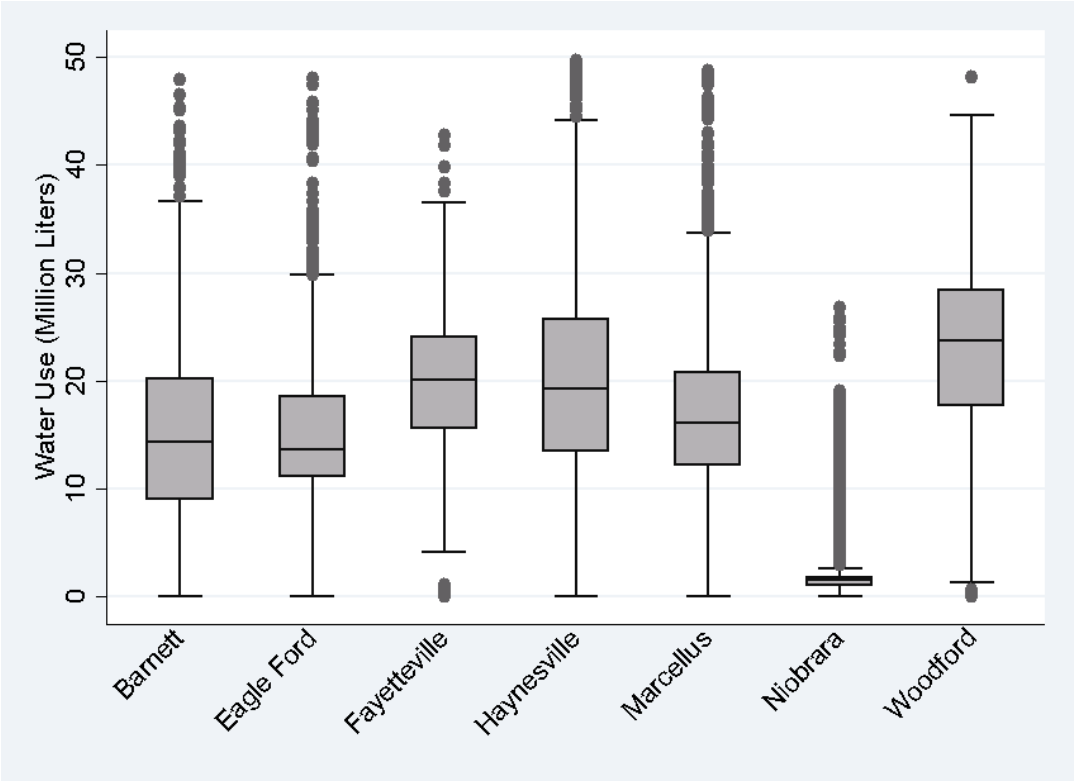


Figure 28: Box plots of water use for hydraulic fracturing in all of the major unconventional shale gas formations in the United States.(55)

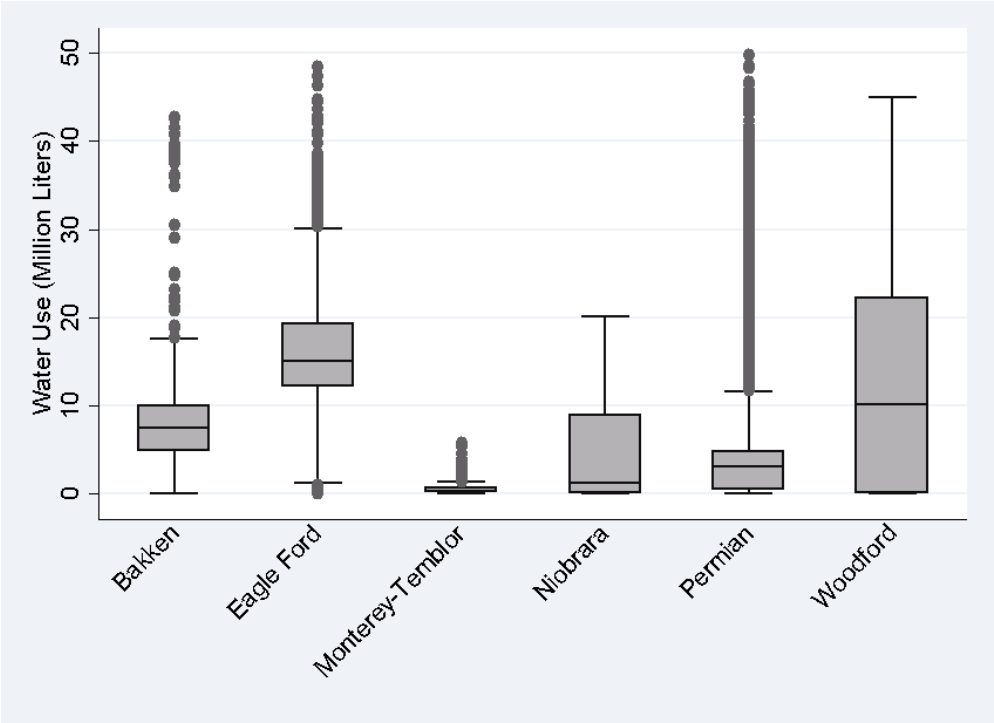


Figure 29: Box plots of water use for hydraulic fracturing in all of the major unconventional oil formations and the Permian Basin in the United States.(55)

Table 12: Copy of Table 1 from the main text of the paper, reporting average values from the EPA's FracFocus report(55) instead of the medians reported in the paper.

Shale Gas	FracFocus Mean Water Use		Flowback and Produced Water		Water Use Intensity (WUI)	Produced Water Intensity (PWI)
Barnett	15.25,	4.03	12.40,	3.28	7.83	6.36
Eagle Ford	15.57,	4.11	25.87,	6.83	6.11	10.16
Fayetteville	19.75,	5.21			9.17	
Haynesville	20.75,	5.48	17.51,	4.63	3.44	2.90
Marcellus	16.76,	4.42	5.20,	1.37	3.27	1.01
Niobrara	2.60,	0.68	5.68,	1.50	1.25	2.73
Woodford	23.18,	6.12			8.37	

Unconventional Oil	FracFocus Mean Water Use		Flowback and Produced Water		Water Use Intensity (WUI)	Produced Water Intensity (PWI)	Water/Oil Ratio	Water Use / Oil Ratio
Bakken	7.96,	2.10	12.25,	3.24	5.31	8.17	0.36	0.24
Permian	3.99,	1.05			3.16			0.17
Monterey-Temblor	0.50,	0.13	14.30,	3.78	2.69	76.43	3.22	0.11
Eagle Ford	16.34,	4.31	22.75,	6.01	8.18	11.38	0.56	0.40
Niobrara	4.32,	1.14	8.04,	2.12	3.66	6.79	0.44	0.24
Woodford	13.35,	3.52			12.25			1.27

Table 13: Copy of Table 2 from the main body of the paper utilizing mean values from the EPA's FracFocus report instead of median values reported in the paper.(55)

Unconventional Gas Formation	Number of Wells	Total Water Use		Total Gas Production	Total Oil Production	Total FP Water	
Barnett	16874	257.48,	68.02	23.44	46.62	209.24,	55.27
Eagle Ford	5846	91.02,	24.04	8.01	723.52	151.22,	39.94
Fayetteville	5850	115.57,	30.52	9.04	0.00		
Haynesville	3172	65.83,	17.39	13.75	0.19	55.54,	14.67
Marcellus	8307	139.26,	36.78	30.41	47.59	43.20,	11.41
Niobrara	2281	5.94,	1.57	3.02	104.04	12.95,.	3.41
Woodford	2861	66.32,	17.52	5.58	29.58		

Unconventional Oil Formation	Number of Wells	Total Water Use		Total Gas Production	Total Oil Production	Total FP Water	
Bakken	9704	77.29,	20.41	1.97	2065.16	118.92,	31.41
Permian	9857	53.26,	14.06	5.24	1915.64		
Monterey-Temblor	703	0.59,	0.15	0.02	32.69	16.73,	4.41
Eagle Ford	7156	116.95,	30.89	3.19	1829.58	162.84,	43.01
Niobrara	2418	17.24,	4.55	1.97	456.04	32.02,	8.45
Woodford	680	9.08,	2.39	0.48	44.88		

2. FracFocus Yearly Data

The EPA's FracFocus database(55) is limited to the years 2011 and 2012. Because of this limitation and to get a better grasp on the change of water use with time, data was added from SkyTruth's 2013 FracFocus database. After looking at median values of fracture water used per well, the changes between years were in most cases minimal, allowing us to assume that the median for each year was (2005-2015), allowing us to calculate total water use.

Table 14: Tables of the median water use for hydraulic fracturing as reported by FracFocus in the EPA report (2011-2012)(55) and SkyTruth (2013)(56). Note, not enough data was present to get meaningful medians for oil wells in the Woodford formation during 2011 and 2013.

	Oil Wells Median Water Use (FracFocus) (Million Liters per well)					
Date	Bakken	Eagle Ford	Monterey-Temblor	Niobrara	Permian	Woodford
2011	6.62	14.64	1.05	2.3	2.46	
2012	7.83	15.06	0.3	1.58	3.25	7.79
2013	7.68	16.39	0.26	2.91	3.44	
	Oil Wells Median Water Use (FracFocus) (Million Gallons per well)					
Date	Bakken	Eagle Ford	Monterey-Temblor	Niobrara	Permian	Woodford
2011	1.75	3.87	0.28	0.61	0.65	
2012	2.07	3.98	0.08	0.42	0.86	2.06
2013	2.03	4.33	0.07	0.77	0.91	

	Gas Wells Median Water Use (FracFocus) (Million Liters per well)						
Date	Barnett	Eagle Ford	Fayetteville	Haynesville	Marcellus	Niobrara	Woodford
2011	14.27	13.93	18.85	20.1	16.46	1.51	21.27
2012	12.87	13.62	20.81	19.83	15.55	1.51	25.96
2013	16.42	13.32	23.01	16.42	16.35	1.51	23.01
	Gas Wells Median Water Use (FracFocus) (Million Gallons per well)						
Date	Barnett	Eagle Ford	Fayetteville	Haynesville	Marcellus	Niobrara	Woodford
2011	3.77	3.68	4.98	5.31	4.35	0.4	5.62
2012	3.4	3.6	5.5	5.24	4.11	0.4	6.86
2013	4.34	3.52	6.08	4.34	4.32	0.4	6.08

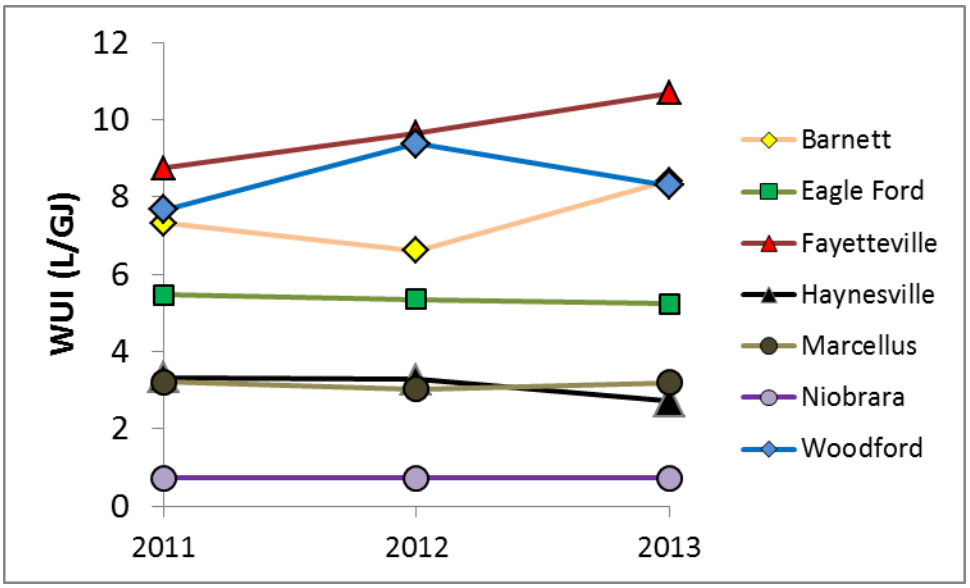


Figure 30: WUI calculations for each unconventional gas formation. There is not a major change in WUI with respect to time in any of the formations, with the Fayetteville having the most dramatic increase from 8.75 to 10.69.

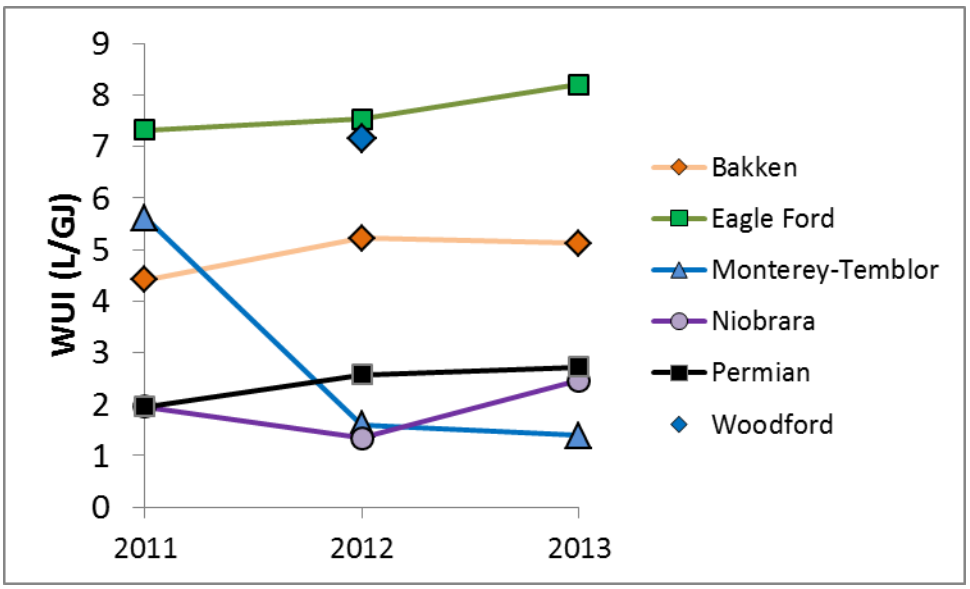


Figure 31: WUI calculations for each unconventional oil formation. The only major change in WUI is found in the Monterey-Temblor formation, with a decrease in WUI from 5.61 to 1.39 from 2011 to 2012.

3. Maps

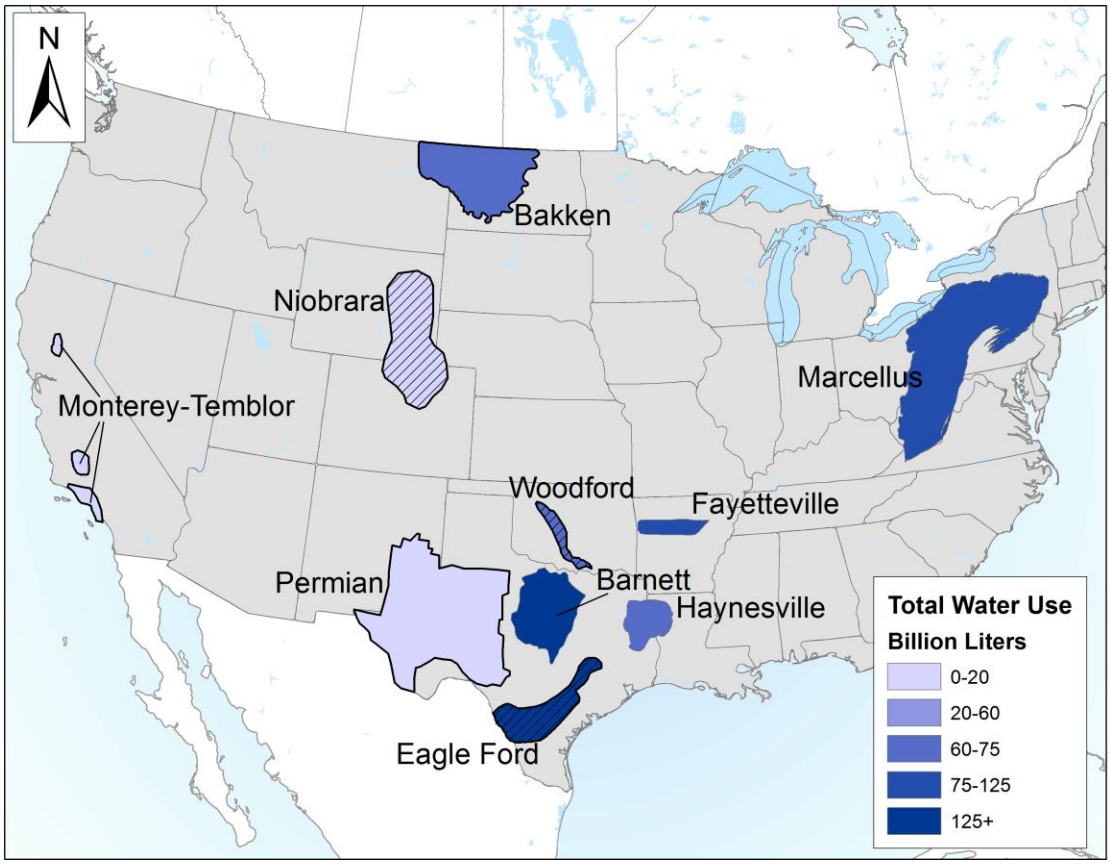


Figure 32: Map of total water use for all major formations reported in this study. Values reported in mixed formations represent the dominant production form (oil vs. gas) see Table 14 for breakdowns of the dominant production form.

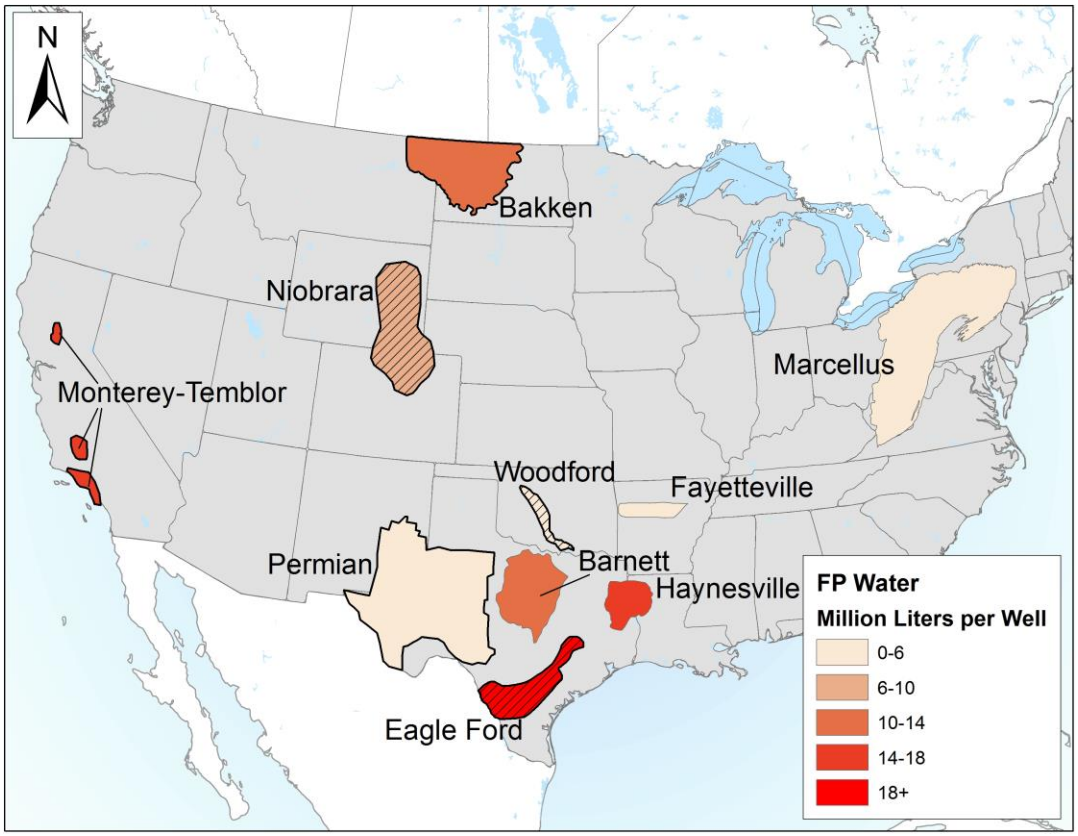


Figure 33: Map of FP water production per well for all major formations reported in this study. Values reported in mixed formations represent the dominant production form (oil vs. gas) see Table 14 for breakdowns of the dominant production form.

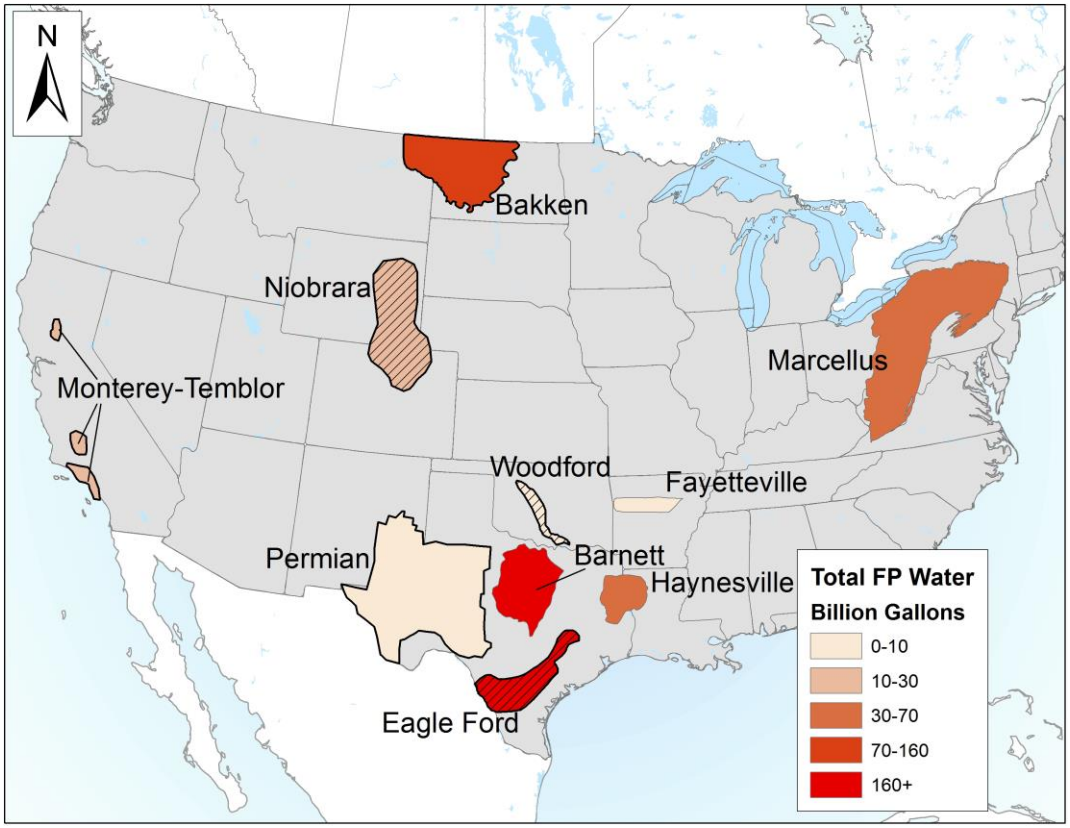


Figure 34: Map of total FP water production for all major formations reported in this study. Values reported in mixed formations represent the dominant production form (oil vs. gas) see Table 14 for breakdowns of the dominant production form.

Table 15: Percentages of wells from drilling info listed as oil or gas.

Eagle Ford Split	
55%	Oil
45%	Gas

Niobrara Split	
64%	Oil
36%	Gas

Woodford Split	
19%	Oil
81%	Gas

4. WOR as a function of time

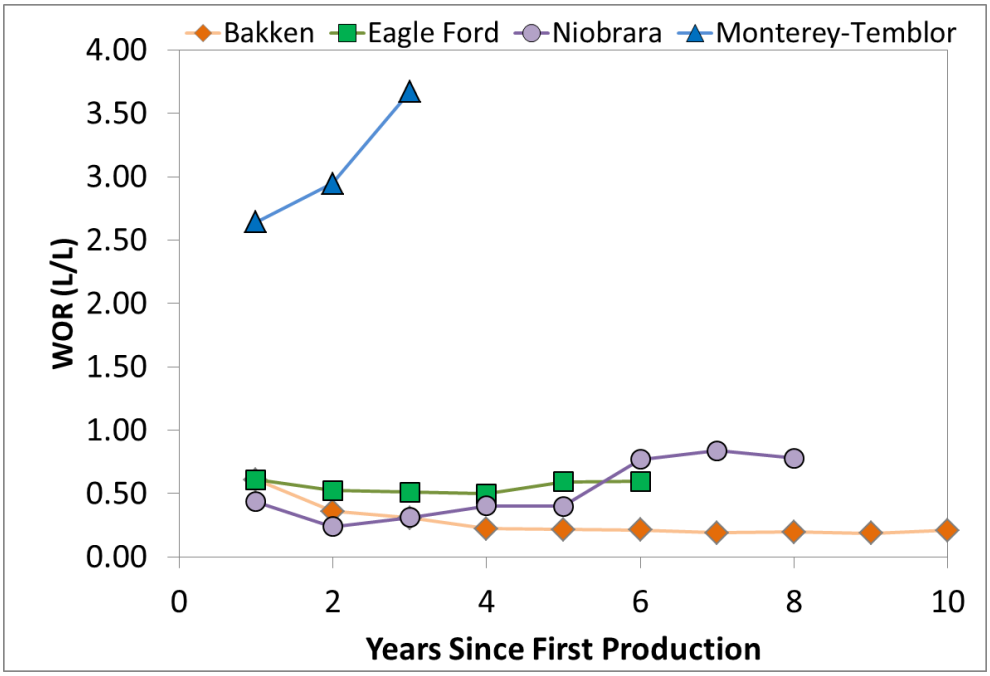


Figure 35: Water/Oil ratio (WOR) reported as a function of time. In the Bakken, Eagle Ford, and Niobrara formations, WOR stays steady, while in the Monterey-Temblor, WOR increases with time.

5. Individual formation type curves

Per well production through time for each of the plays included in this study. In some cases water use data was not reported and for the report taken from other sources. In the example of the Marcellus, produced water was unavailable from DrillingInfo,(64) but other sources(11, 66) reported values cumulatively, which were included in the total production table included in the main text of the paper. In these cases, production of FP water was not included in the graphs shown below. In the case of the Permian and Barnett plays, data from DrillingInfo was used to plot the decay curves of FP water shown below, despite our inclusion of average values from the literature in the main analysis.

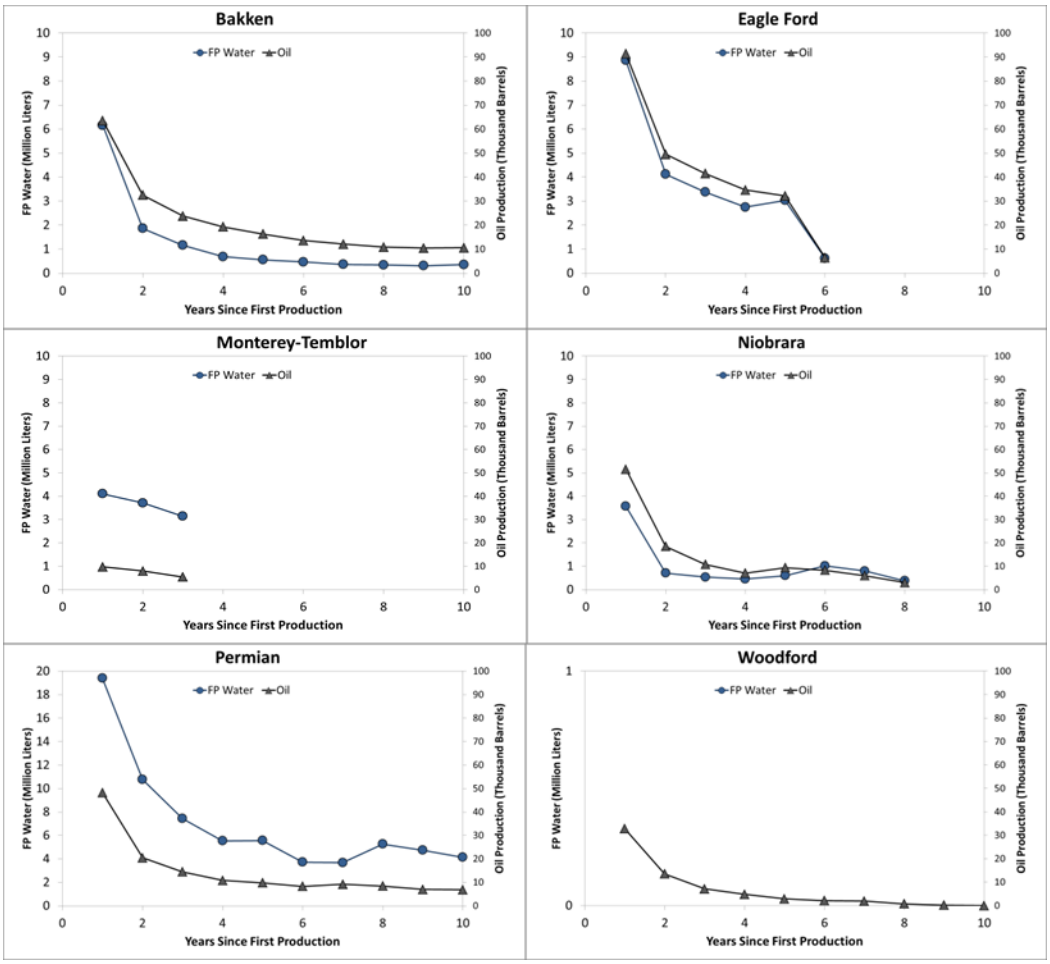


Figure 36: Individual type curve for oil producing formations.

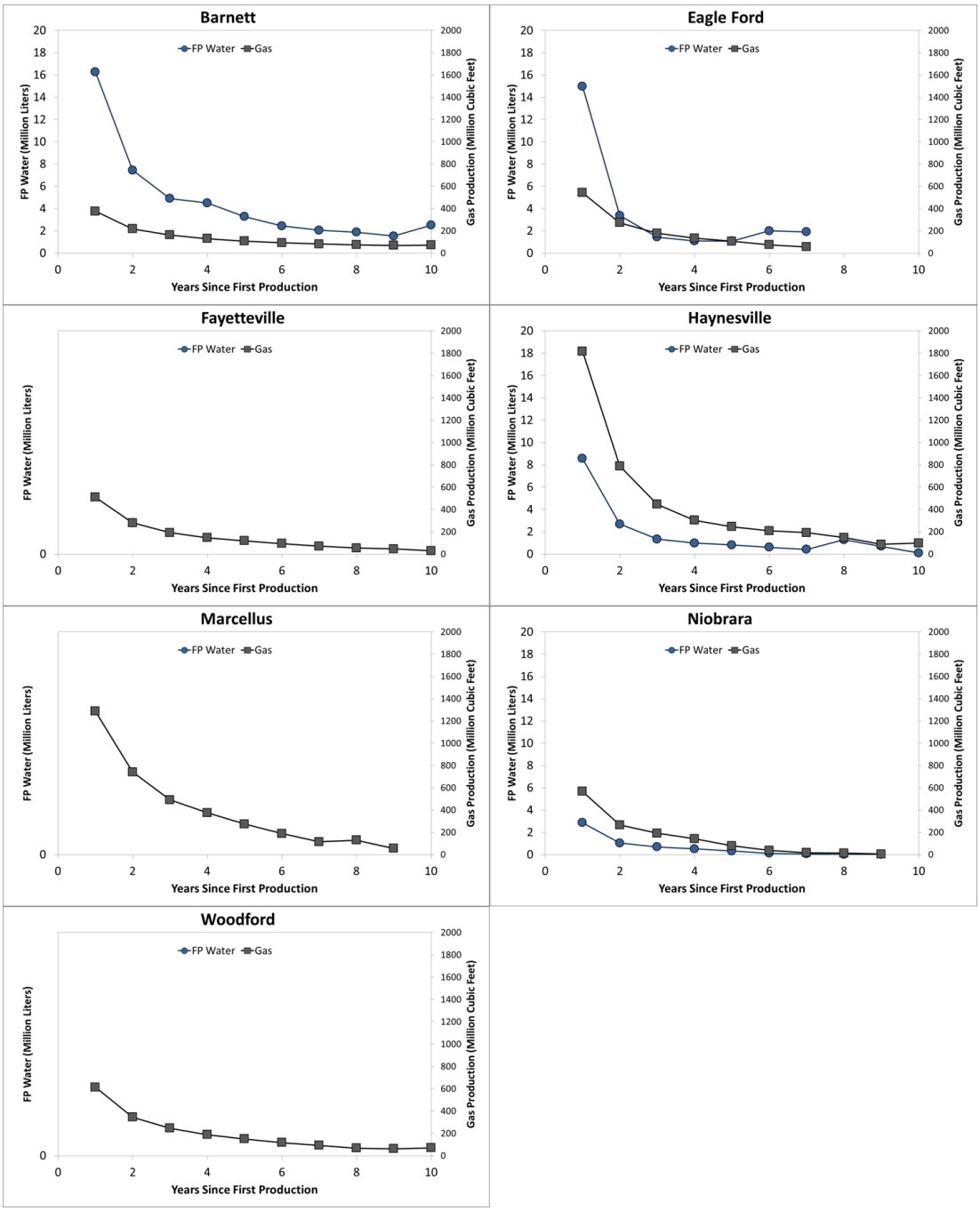


Figure 37: Type curves for a typical unconventional shale gas well from each formation.

6. Estimation of water use

Surprisingly, no total well count or history of drilled wells exists for any of the major oil and gas producing formations/basins. Instead, data exists in short snapshots from a number of different sources. Previous studies have used numbers obtained from FracFocus,(23, 24, 52) independent reporting companies such as IHS,(22-24, 53) while others have used data from state government offices.(11, 58) In each case though, data was reported as a subset of years and no information on the total number of wells drilled and producing is available. To get an accurate well count, data from multiple sources was used and where available spilt into the number of new wells per year (Table 15).(55, 66, 67, 71, 74, 90)

Table 16: Estimates of water use between 2012 and 2014. Data was taken mainly from the Baker and Hughes well count database,(74) North Dakota Oil and Gas Division,(67) and FracFocus.(55, 56) Estimates of percentages of oil and gas wells are based on Table 15. Because we were unable to find a well count for 2014 in the Permian Basin and the Monterey-Temblor Formation, the average for the Unconventional Oil total water use was only based on 2012 and 2013.

	Well Counts (Baker and Hughes except Bakken (from ND state) Permian and Monterey-Temblor (from FracFocus))									
Date	Woodford	Barnett	Niobrara	Eagle Ford	Fayetteville	Haynesville	Marcellus	Bakken	Permian	Monterey-Temblor
2012	578	2032	1778	3806	708	512	1938	1050	6500	583
2013	597	1602	1540	4400	638	479	2182	2515	4353	517
2014	575	1089	1202	4709	540	460	2087	2104		

	Water Use per well (million liters)									
Use Gas	23.77	14.42	1.51	13.70	20.06	19.45	16.12			
Use Oil	7.79		1.32	15.06				7.49	3.06	0.30

	Ratios									
% Gas	81%		36%	45%						

	Gas Yearly Water Use (million liters)									
2012	11101	29301	978	23443	14202	9958	31241			
2013	11466	23101	847	27101	12798	9317	35174			
2014	11044	15703	661	29005	10832	8947	33642			

	Oil Yearly Water Use (million liters)									
2012	864		1492	31549				7865	19890	175
2013	893		1293	36472				18837	13320	155
2014	860		1009	39034				15759		

	Total Water (billion liters)	
	Gas	Oil
2012	120.22	61.83
2013	119.80	70.97
2014	109.83	56.66

Average	116.62	66.40

7. Energy Content of Oil and Gas

In addition to using the energy content of total oil and gas produced, other associated oil and gas was assumed to be produced. For wells classified as gas producing by DrillingInfo and state government sources, some associated oil production was listed. This oil was assumed to have an energy content of 85% of crude oil: 5.1577 GJ/L (4.8883 x 10^6 BTU/BBL).(23) When wet gas is produced, the entire wet stream does not make it

through processing, but a small fraction is converted to condensate or natural gas liquids (NGLs) in a process called shrinkage. Estimates of this "shrinkage" can range from 10% in the case of associated gas in oil wells to 25% of the value of wet gas stream in natural gas wells.(23) Typically, a volume of 0.14 BBL/MCF (6 gallons/MCF) of NGLs, having an energy content of 4.0621 GJ/BBL (3.85 $x10^6$ BTU/BBL) are created during production.(113)

8. Total Production and Water Use

Below we detail cumulative oil and gas production from the US EIA's drilling productivity report(154) and compare it with total water use for each formation/basin included in this study. In almost every case, total water use closely mirrors the total production of each formation/basin.

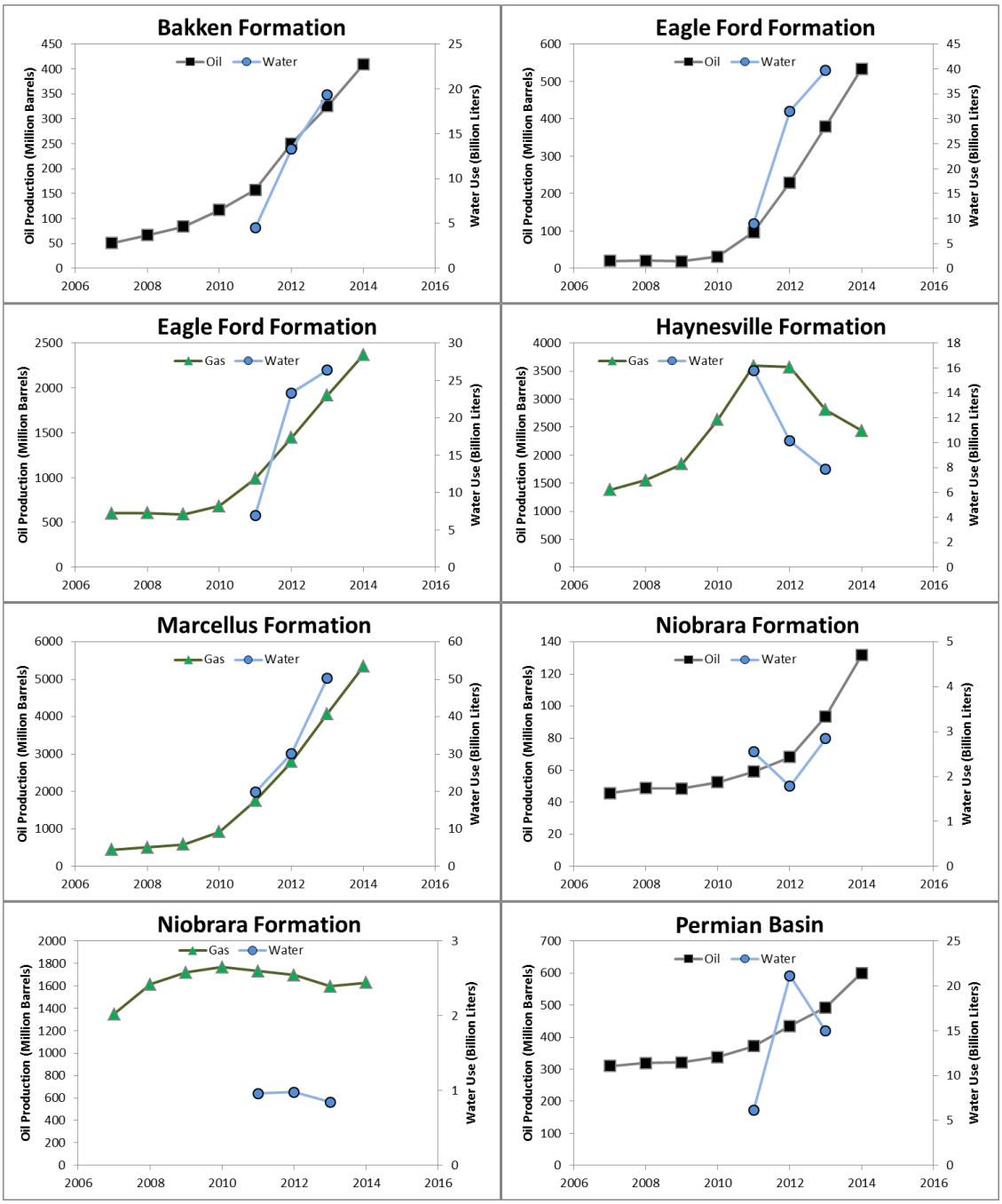


Figure 38: Total oil and gas production coupled with total water use for each of the formations and basins included in this study.

Table 17: Percentages of Horizontal, Vertical, and Directional wells. Data was acquired from Gallegos (2015)(60) using the method established in section 1 of this SI.

Formation/Basin	Horizontal	Vertical	Directional
Bakken	100%	0%	0%
Barnett	65%	33%	1%
Eagle Ford	92%	7%	1%
Fayetteville	95%	5%	0%
Haynesville	76%	17%	6%
Marcellus	58%	41%	1%
Monterey-Temblor	5%	49%	46%
Niobrara	35%	26%	39%
Permian	17%	79%	4%
Woodford	70%	27%	3%

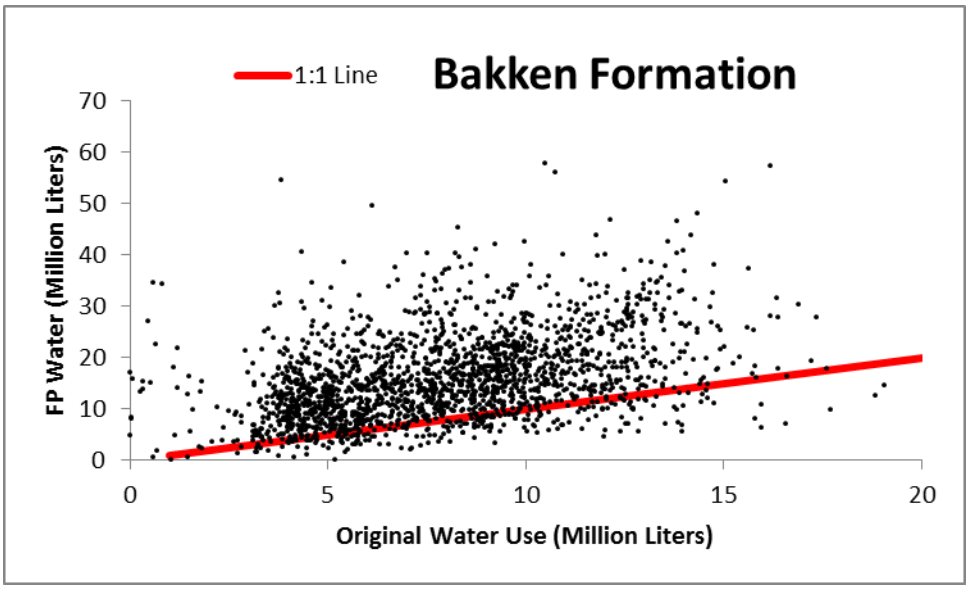


Figure 39: Scatter plot of FP water (x-axis) vs. water use (y-axis) in the Bakken Formation based on ~42,000 data points obtained directly from the North Dakota Oil and Gas Division.(67)

Appendix B: Supplementary Information for Chapter 3

Introduction

Figures shown in this SI were created using data downloaded from DrillingInfo's Desktop application(64). The graphs generated for Figure 40 and Figure 41 were created by downloading monthly production data for each well within a target formation which was horizontal and produced oil/gas. For the Eagle Ford formation, we compiled and downloaded one data set for oil producing wells and one data set for gas producing wells. Data downloaded from DrillingInfo's Desktop application has information on the well identification code (API number), month production data was from and oil, gas, and water generation that month. Using pivot tables in Microsoft Excel, we were able to normalize production for each well to the same start point, creating a database of production information for each unique well based on API number containing oil, gas, or water production on a month to month basis. Using that information we took either the mean or median of each month using available data from each formation. The number of unique API numbers providing information in any given month of production is shown in Figure 42. Using STATA statistical software package, we then generated histograms of the first 6 months of production, highlighting the right skewed distribution of the data (Figure 43).

Temporal salinity data was taken from a number of sources, and then used to estimate a curve representing the percentage of final TDS assuming the latest reported

TDS values in each data string represented the maximum value that string would eventually reach (Figure 44).

Sources of Error

Because well data is reported using calendar months, the "first month" of production reported may not represent a full month's worth of production data. For example, a well beginning production on September 28 would report production from 3 days, the 28th, 29th, and 30th, as the "total month 1 production" while a well beginning production September 1 would report a full 30 days' worth of production. This potential source of error is exhibited in the decline curves pictured in Figure 40 and Figure 41 for the Barnett, Eagle Ford Oil and Gas, and the Haynesville formation where month one begins low, peaking in month 2 and declining from there (Table 20). The literature shows that production is characterized by high flow rates in the first month after hydraulic fracturing, followed by a steady decline in the rate of production with time (Figure 46), indicating that the lull shown in month one for the formations shown above is due to this difference in reporting time.

Appendix B: Figures

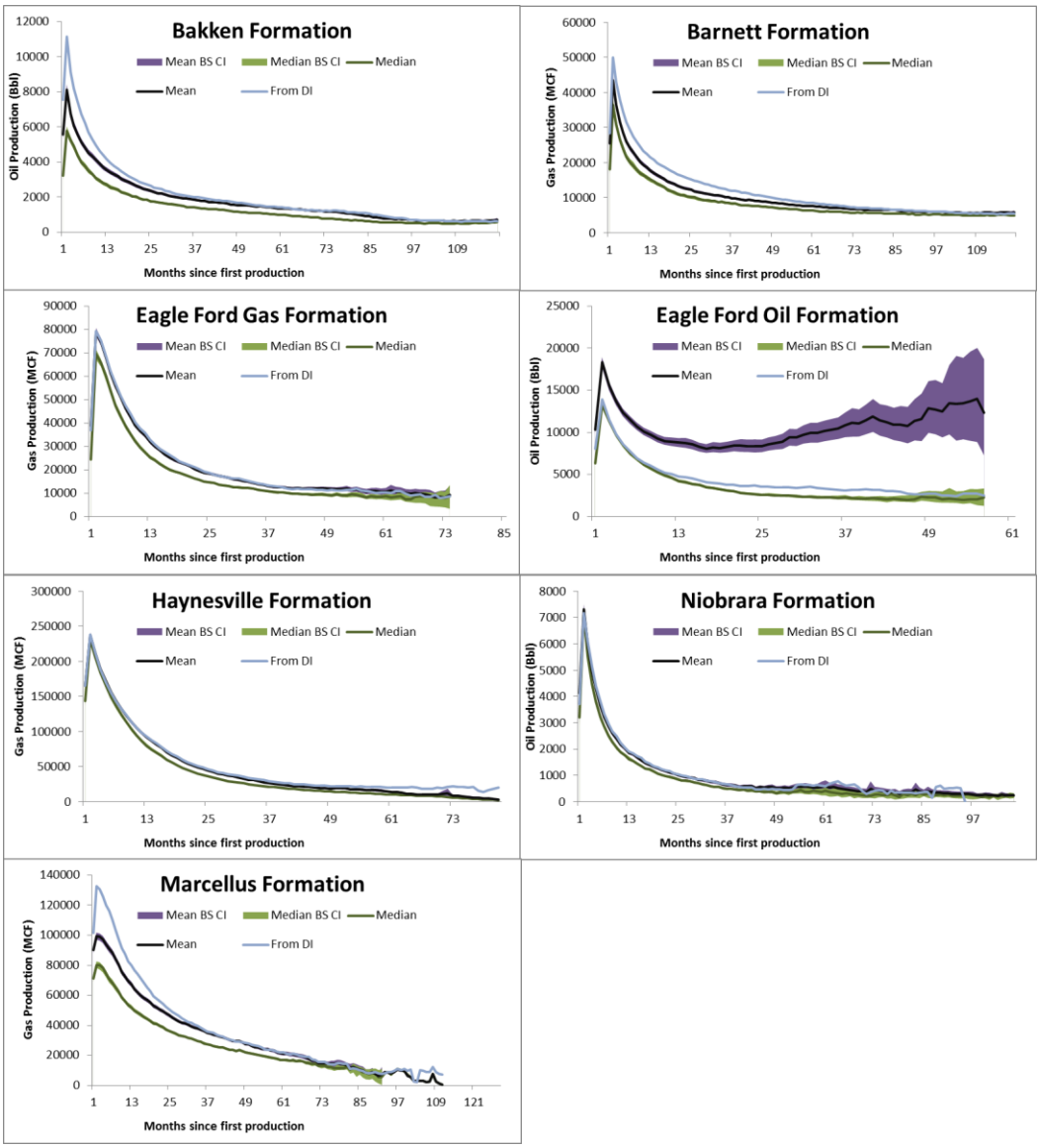


Figure 40: Decline curve analysis for each of the formations in this study showing oil (Bbl) and gas (MCF) monthly production as a function of time. Monthly production data downloaded from DrillingInfo's Type Curve tool is shown in light blue while median data is shown with a dark green line and mean data is shown with a black line.(64) Median bootstrap confidence intervals are shown in light green, while mean bootstrap confidence intervals are shown in purple.

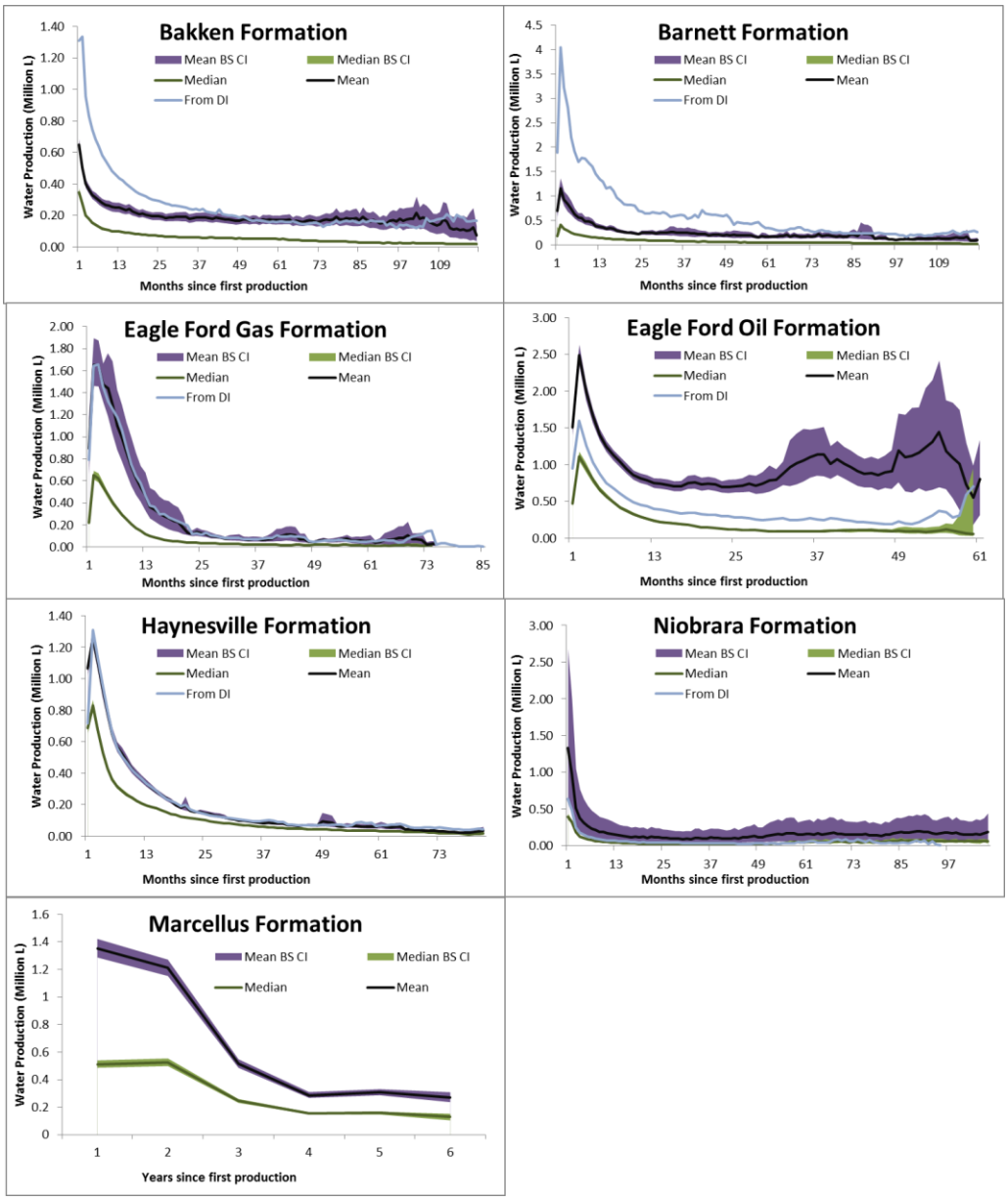


Figure 41: FP water decline Curve analysis for each of the formations in this study. Data are reported as combined flowback and produced water (million liters) per month except in the case of the Marcellus formation, where data was only available on a yearly basis. Monthly production data downloaded from DrillingInfo's Type Curve tool is shown in light blue while median data is shown with a dark green line and mean data is shown with a black line.(64) Median bootstrap confidence intervals are shown in light green, while mean bootstrap confidence intervals are shown in purple.

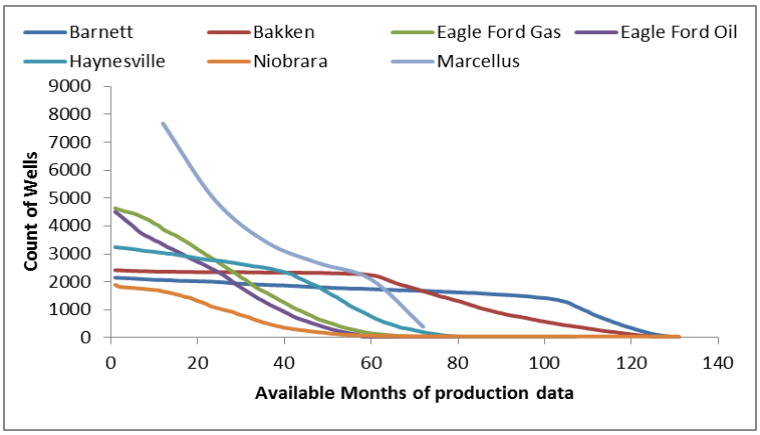


Figure 42: Count of wells with production data. In each case, there were only a small number of wells reporting data for longer periods of time. Because of this, the bootstraps and our estimates of EUR had to be truncated because of a lack of reliable data.

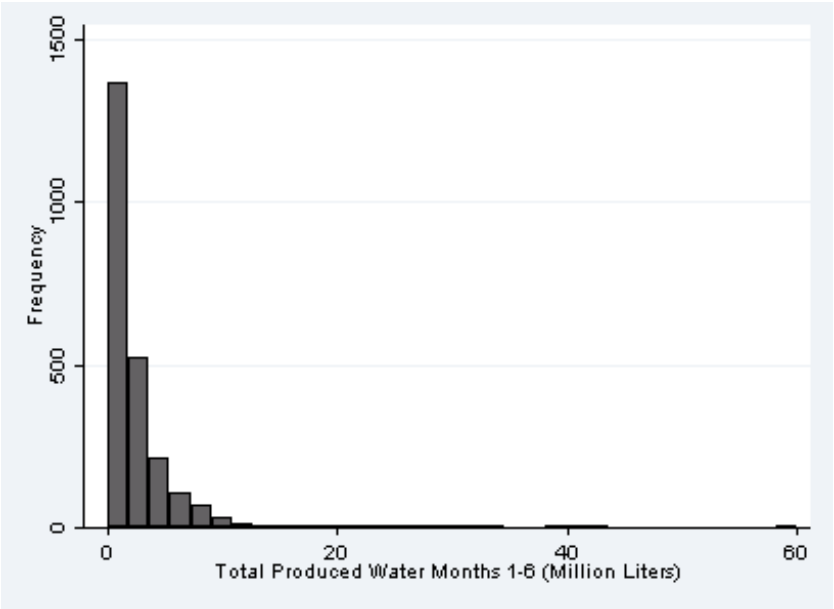


Figure 43: Histogram of cumulative water production in months 1 through 6 in the Bakken formation. Frequency on the y-axis shows the number of well records falling under each category. This histogram is representative of all of the formations and because of this; medians are reported in addition to the means because of the non-normal distribution of the data.

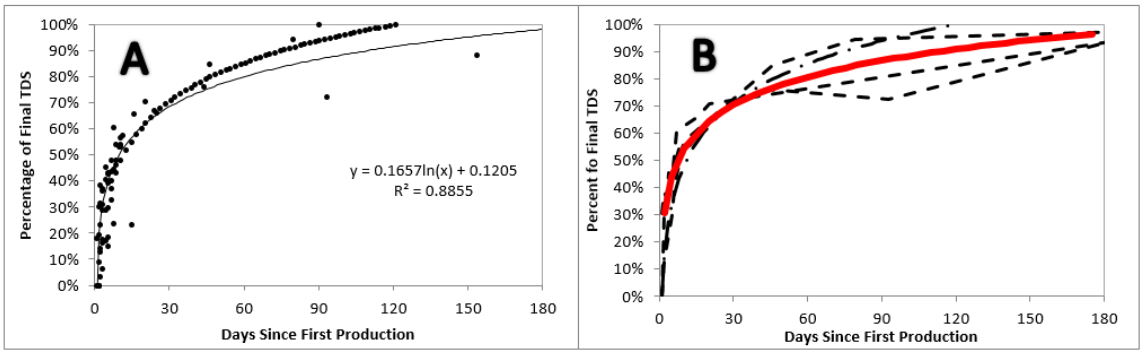


Figure 44: Graphs of percent of final TDS as a function of time. The percentage of final TDS was calculated using only the data strings where 90+ days of data were available and assuming that the maximum TDS at the end each data set's time period was the highest it would reach in that case. In most of the cases with more than 90 days of data, the is a sharp increase in TDS representing the quick transition from flowback to produced water, followed by a period of leveling off with TDS slightly increasing with time. In graph A on the left we plotted all data normalized by percent and used a logarithmic trendline to estimate a line of best fit. That line is shown in graph B on the right along with individual well data set info from each of the Barnett (dash and dot) and Marcellus (dashes).

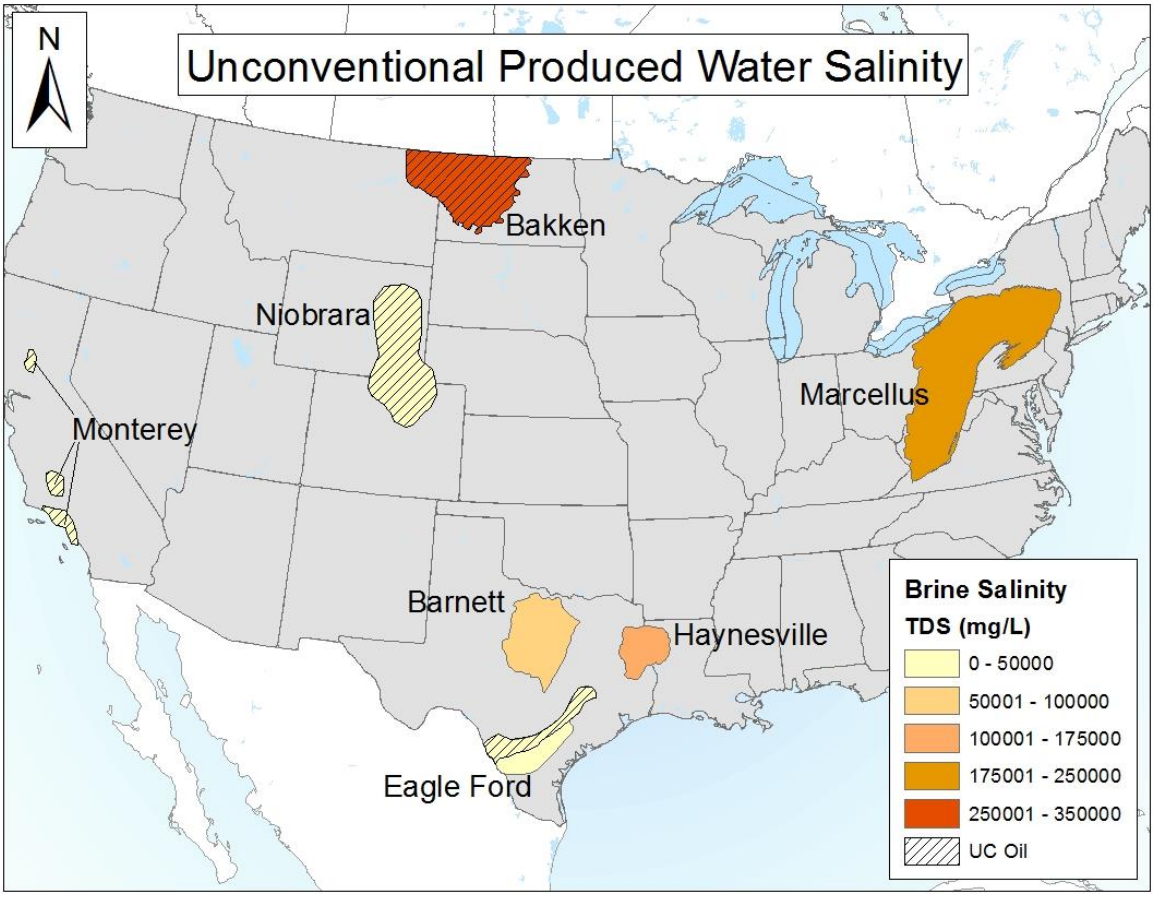


Figure 45: Final salinity of formation brines in each of the producing formations. Areas with thatching show unconventional oil producing regions, while areas with no thatching show unconventional gas producing regions.(31, 86)

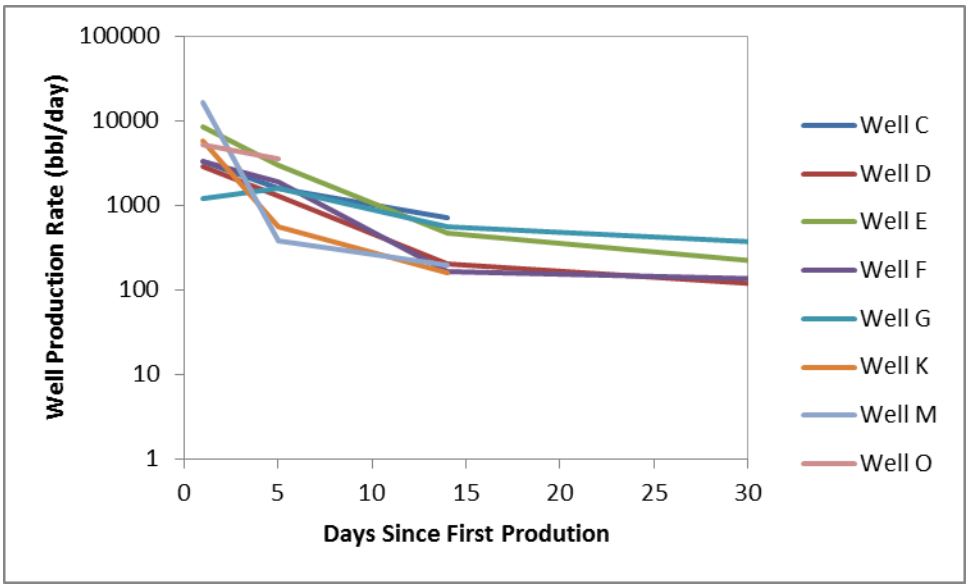


Figure 46: Well production rate from Hayes (2009) showing a rapid decline in production rate following the first several months of production. (59)

Appendix B: Tables

Table 18: FP water, oil, and gas production median, mean and confidence intervals. FP water (top table, million liters per well) and Oil (bottom table gray (Bbl per well)) and Gas (bottom table, million MCF per well) derived using the median ("Median Water", "Median OG"), mean ("Mean water", "Mean OG") data taken from month 24 and displaying the 95% bootstrap confidence intervals. Data from oil producing formations have their cells within the table shaded grey, while gas producing formations had their cells left white.

Table A: FP Water (Million Liters per well)

Basin	Median Water	Median CI 2.5%	Median CI 97.5%	Mean Water	Mean CI 2.5%	Mean CI 97.5%
Bakken	0.0715	0.0683	0.0751	0.1945	0.1711	0.2213
Barnett	0.1016	0.1140	0.0751	0.2251	0.2015	0.2527
Eagle Ford Gas	0.0374	0.0355	0.0396	0.1334	0.1014	0.1753
Eagle Ford Oil	0.1200	0.1102	0.1297	0.7003	0.6135	0.7958
Haynesville	0.1052	0.1014	0.1092	0.1514	0.1403	0.1683
Niobrara	0.0258	0.0238	0.0286	0.1139	0.0508	0.2387

Table B: Oil/Gas (Million Bbl (grey) Million MCF (white))

Basin	Production Type	Median OG	Median CI 2.5%	edian CI 97.5	Mean OG	Mean CI 2.5%	Mean CI 97.5%
Bakken	Oil	0.0018	0.0018	0.0019	0.0024	0.0023	0.0025
Barnett	Gas	0.0103	0.0098	0.0107	0.0125	0.0121	0.0130
Eagle Ford Gas	Gas	0.0150	0.0146	0.0154	0.0188	0.0182	0.0194
Eagle Ford Oil	Oil	0.0026	0.0025	0.0028	0.0083	0.0076	0.0092
Haynesville	Gas	0.0378	0.0367	0.0389	0.0470	0.0456	0.0484
Marcellus	Gas	0.0373	0.0363	0.0383	0.0478	0.0466	0.0491
Niobrara	Oil	0.0009	0.0008	0.0010	0.0011	0.0010	0.0011

Table 19: Estimates of maximum TDS in each formation.(31, 86)

Formation	TDS (mg/L)
Bakken	350,000
Barnett	90,000
Eagle Ford	50,000
Haynesville	120,000
Marcellus	250,000
Monterey	20,000
Niobrara	40,000

Table 20: The average number of days reporting data in the first 2 months of well production, taken from the DrillingInfo database(64). Because on average, month one only includes 16-18 days compared to 28 for the next month, the first month production data is lower than would be expected if month 1 included a full month's worth of production.

Basin	Month 1 Average Days Producing	Month 2 Average Days Producing
Bakken	16.1	26.4
Niobrara	18.3	27.9

Appendix C: Supplementary Information for Chapter 4

Tables:

Table 21: Production volumes in unconventional gas producing formations. Estimates of well count, median values for water use, gas, oil, and FP production per well from each of the gas producing regions. Marcellus data was available on a year by year basis from 2011-2016, and thus all Marcellus FP water data is reported as 12 month cumulative production. EUR estimate was calculated by assuming that the first 12 months of production represent approximately 35% of total well production. Note: this calculation is simple model of estimating ultimate recovery; performing decline curve analysis can give a much more realistic estimate for ultimate recovery.

Formation	Year	Well Counts	Water Use	Laterals (meters/well)	Water Use/Lateral Length	Gas Production (m^3/well)	Oil Production (m^3/well)	FP Water (m^3/well)	Water Use Intensity for All Products	Water Use Intensity for All Products	Waste Water Intensity for All Products	Water Use/Gas	Water Use/FP Water
		New Wells/ Year	(m^3/well)	Lateral Length	(m^3/m)	First 12 Months	First 12 Months	First 12 Months	(L/GJ) EUR Estimate	(L/GJ) First 12 months	(L/GJ) First 12 months	m^3/m^3	m^3/m^3
EF (gas)	2011		17870	1481	12.07	15242778	5878	1414	4.97	14.20	1.50	0.0012	0.08
EF (gas)	2012	1966	13360	1509	8.85	14457709	5716	5233	5.33	15.23	5.84	0.0009	0.39
EF (gas)	2013	2230	13652	1560	8.75	14281182	6095	6725	5.56	15.88	7.47	0.0010	0.49
EF (gas)	2014	2503	14297	1601	8.93	16589949	8436	7822	6.54	18.69	7.18	0.0009	0.55
EF (gas)	2015	1639	20363	1705	11.94	16706969	8199	8082	7.55	21.56	7.43	0.0012	0.40
EF (gas)	2016	973	23457	1838	12.76	15706876	7591	6940	9.25	26.43	6.81	0.0015	0.30
Haynesville	2011			1355		50437884	2	5046					
Haynesville	2012	461	23943	1367	17.52	52988690	8	5728	3.21	9.18	2.20	0.0005	0.24
Haynesville	2013	397	20359	1381	14.74	51670939	54	6495	2.80	8.00	2.55	0.0004	0.32
Haynesville	2014	467	27804	1533	18.13	63924709	57	7189	3.09	8.84	2.28	0.0004	0.26
Haynesville	2015	340	32328	1616	20.00	66659050	30	6223	3.45	9.86	0.00	0.0005	0.19
Haynesville	2016	251	58777	1795	32.75	103750235	17	11509	4.03	11.52	0.00	0.0006	0.20
Marcellus	2011		23401	1199	19.52	23401825	129	567	7.09	20.25	0.49	0.0010	0.02
Marcellus	2012	1938	27703	1263	21.93	25178817	241	1054	7.78	22.23	0.85	0.0011	0.04
Marcellus	2013	2182	25955	1374	18.89	33487037	231	1342	5.49	15.68	0.81	0.0008	0.05
Marcellus	2014	1649	26995	1567	17.22	40459299	168	1564	4.73	13.53	0.78	0.0007	0.06
Marcellus	2015	1210	33357	1692	19.72	42624373	210	2204	5.55	15.86	1.05	0.0008	0.07
Marcellus	2016	720	27958	1674	16.70	46967448	188	820	4.22	12.07	0.35	0.0006	0.03
Permian (gas)	2011		4897	1125	4.35	10037966	3243	14233	3.71	10.61	16.71	0.0005	2.91
Permian (gas)	2012	82	4868	1186	4.10	9605002	3990	15680	3.58	10.23	29.22	0.0005	3.22
Permian (gas)	2013	150	5531	1275	4.34	12585005	6427	30372	2.89	8.26	42.74	0.0004	5.49
Permian (gas)	2014	232	7277	1357	5.36	16291646	10863	44084	2.64	7.55	43.55	0.0004	6.06
Permian (gas)	2015	334	23812	1419	16.78	15894390	14005	60031	7.77	22.21	55.61	0.0015	2.52
Permian (gas)	2016	358	42560	1454	29.27	11600062	9362	74471	19.88	56.79	46.40	0.0037	1.75

Table 22: Production volumes in unconventional oil producing formations. Estimates of well count, median values for water use, gas, oil, and FP production per well from each oil producing region. Water use intensity, waste water intensity, and water use/gas and water use/FP water ratios for oil producing regions. The EUR estimate was calculated by assuming that the first 12 months of production represent approximately 35% of total well production. Note: this calculation is simple model of estimating ultimate recovery; performing decline curve analysis can give a much more realistic estimate for ultimate recovery.

Formation	Year	Well Counts	Water Use	Laterals (meters/well)	Water Use/Lateral Length	Gas Production (m^3/well)	Oil Production (m^3/well)	FP Water (m^3/well)	Water Use Intensity for All Products	Water Use Intensity for All Products	Waste Water Intensity for All Products	Water Use/Oil	FP Water/ Water Use
		New Wells/Year	(m^3/well)	Lateral Length	(m^3/m)	First 12 Months	First 12 Months	First 12 Months	(L/GJ) EUR Estimate	(L/GJ) First 12 months	(L/GJ) First 12 months	m^3/m^3	m^3/m^3
Bakken	2011		7166	2829	2.53	1672815	11534	6909	5.02	14.33	13.82	0.62	0.96
Bakken	2012	2086	8047	2886	2.79	1733470	11292	8415	5.72	16.33	17.08	0.71	1.05
Bakken	2013	2254	8655	2892	2.99	2084329	12098	8673	5.66	16.16	16.19	0.72	1.00
Bakken	2014	2480	11381	2907	3.92	2527657	13306	11382	6.67	19.07	19.07	0.86	1.00
Bakken	2015	1483	13661	2918	4.68	3364531	15031	11603	6.92	19.76	16.78	0.91	0.85
Bakken	2016	738	21128	2930	7.21	4729132	19275	17215	8.21	23.46	19.12	1.10	0.81
EF (oil)	2011		16028	1645	9.74	3025593	14129	2302	8.69	24.84	3.57	1.13	0.14
EF (oil)	2012	1822	19110	1656	11.54	3343152	15115	6209	9.64	27.54	8.95	1.26	0.32
EF (oil)	2013	2165	20856	1701	12.26	3067998	15235	8752	10.59	30.26	12.70	1.37	0.42
EF (oil)	2014	1778	25112	1819	13.81	2763309	15638	15035	12.65	36.15	21.65	1.61	0.60
EF (oil)	2015	999	31071	1937	16.04	4337256	17177	16843	13.48	38.52	20.88	1.81	0.54
EF (oil)	2016	457	33492	1905	17.58	3647558	18530	15119	14.03	40.08	18.09	1.81	0.45
Niobrara (oil)	2011		8997	1131	7.96	1408081	4620	1980	13.99	39.98	8.80	1.95	0.22
Niobrara (oil)	2012	1217	9682	1165	8.31	3181421	6470	1732	9.53	27.22	4.87	1.50	0.18
Niobrara (oil)	2013	933	10324	1213	8.51	3630709	6899	1858	9.33	26.66	4.80	1.50	0.18
Niobrara (oil)	2014	1814	13971	1301	10.74	4351698	8022	2712	10.75	30.73	5.97	1.74	0.19
Niobrara (oil)	2015	1347	16570	1389	11.93	3583746	8047	2977	13.49	38.54	6.92	2.06	0.18
Niobrara (oil)	2016	959	22296	1569	14.21	6069352	8972	3080	14.22	40.62	5.61	2.48	0.14
Permian (oil)	2011		4897	1260	3.89	2270328	4763	9188	6.61	18.87	35.41	1.03	1.88
Permian (oil)	2012	1009	4868	1277	3.81	2488679	6251	15710	5.26	15.02	48.48	0.78	3.23
Permian (oil)	2013	1487	5531	1316	4.20	2948968	8242	18943	4.65	13.29	45.52	0.67	3.42
Permian (oil)	2014	2319	7277	1373	5.30	3783974	11857	24889	4.37	12.48	42.67	0.61	3.42
Permian (oil)	2015	2070	23812	1480	16.08	4738420	15408	29048	11.08	31.67	38.63	1.55	1.22
Permian (oil)	2016	1977	42560	2013	21.14	6058068	18788	36217	16.08	45.95	39.10	2.27	0.85

Table 23: Example calculation for future production estimate, business-as-usual scenario. This data set was used to generate Figure 51 A and C. Water use slope is the maximum difference between two consecutive years of production. In the case of the Bakken, water use in 2016 was 21,128 m^3/well and water use in 2015 was 13,661 m^3/well (Figure 48). The difference between those two, 7,467 m^3/well is the slope, or maximum amount of change seen in water use over a one-year period.

Region		Bakken	Eagle Ford (oil)	Niobrara	Permian (oil)	Eagle Ford (gas)	Haynesville	Marcellus	Permian (gas)
Slope (additional wells per year)		0	0	0	0	0	0	0	0
2016 Well Count		738	457	959	1977	973	251	720	358
2016 Water Use (m^3)		21128	33492	22296	42560	23457	58777	27958	42560
2016 FP Water (m^3)		17215	16843	3080	36217	8082	7189	2204	74471
Water Use Slope ($m^{3/}$well/year)		7467	5959	5726	18749	6067	4524	6362	18749
FP Water Slope ($m^{3/}$well/year)		5612	6283	854	5945	260	695	640	15947
New Wells Drilled This Year	2018	738	457	959	1977	973	251	720	358
	2019	738	457	959	1977	973	251	720	358
	2020	738	457	959	1977	973	251	720	358
	2021	738	457	959	1977	973	251	720	358
	2022	738	457	959	1977	973	251	720	358
	2023	738	457	959	1977	973	251	720	358
	2024	738	457	959	1977	973	251	720	358
	2025	738	457	959	1977	973	251	720	358
	2026	738	457	959	1977	973	251	720	358
	2027	738	457	959	1977	973	251	720	358
	2028	738	457	959	1977	973	251	720	358
	2029	738	457	959	1977	973	251	720	358
	2030	738	457	959	1977	973	251	720	358
Cumulative Water Use (10^6 m^3)	2018	24	21	23	108	23	15	21	27
	2019	28	24	24	119	24	15	22	32
	2020	32	27	25	131	24	15	22	38
	2021	36	30	25	143	24	16	22	44
	2022	40	33	26	155	24	16	23	49
	2023	45	35	27	166	25	16	23	55
	2024	49	38	28	178	25	16	24	61
	2025	53	41	29	190	25	16	24	67
	2026	57	44	30	202	25	17	25	72
	2027	61	47	30	213	26	17	25	78
	2028	65	50	31	225	26	17	26	84
	2029	69	53	32	237	26	17	26	89
	2030	74	56	33	249	26	17	27	95

Table 24: Example calculation for future production estimate, future growth scenario. This data set was used to generate Figure 51 B and D. Slope is the maximum difference between two consecutive years' worth of data.

Region		Bakken	Eagle Ford (oil)	Niobrara	Permian (oil)	Eagle Ford (gas)	Haynesville	Marcellus	Permian (gas)
Slope (new wells per year)		558	343	881	832	263	70	244	102
2016 Well Count		738	457	959	1977	973	251	720	358
2016 Water Use (m^3)		21128	33492	22296	42560	23457	58777	27958	42560
2016 FP Water (m^3)		17215	16843	3080	36217	8082	7189	2204	74471
Water Use Slope (m^3/well/year)		7467	5959	5726	18749	6067	4524	6362	18749
FP Water Slope (m^3/well/year)		5612	6283	854	5945	260	695	640	15947
New Wells Drilled This Year	2018	1296	800	1840	2809	1236	321	964	460
	2019	1854	1143	2721	3641	1499	391	1208	561
	2020	2412	1486	3602	4473	1762	461	1452	663
	2021	2970	1829	4483	5305	2026	531	1696	765
	2022	3528	2172	5364	6137	2289	601	1940	866
	2023	4086	2514	6245	6969	2552	671	2184	968
	2024	4644	2857	7126	7800	2815	741	2428	1070
	2025	5202	3200	8006	8632	3079	811	2672	1171
	2026	5760	3543	8887	9464	3342	881	2916	1273
	2027	6318	3886	9768	10296	3605	951	3160	1374
	2028	6876	4229	10649	11128	3868	1021	3404	1476
	2029	7434	4571	11530	11960	4132	1091	3648	1578
	2030	7992	4914	12411	12792	4395	1161	3892	1679
Cumulative Water Use (10^6 m^3)	2018	42	37	44	153	30	19	28	34
	2019	70	60	68	220	36	24	36	51
	2020	105	87	93	297	43	28	44	71
	2021	146	119	119	383	50	33	53	94
	2022	193	155	147	480	57	38	62	120
	2023	247	195	177	587	65	43	71	149
	2024	307	239	208	703	72	48	80	182
	2025	373	288	240	829	79	53	90	218
	2026	445	341	274	965	87	58	100	257
	2027	524	399	310	1112	95	63	111	300
	2028	608	460	347	1268	103	69	121	345
	2029	699	526	385	1433	111	74	132	394
	2030	797	597	425	1609	119	80	144	446

Figures:

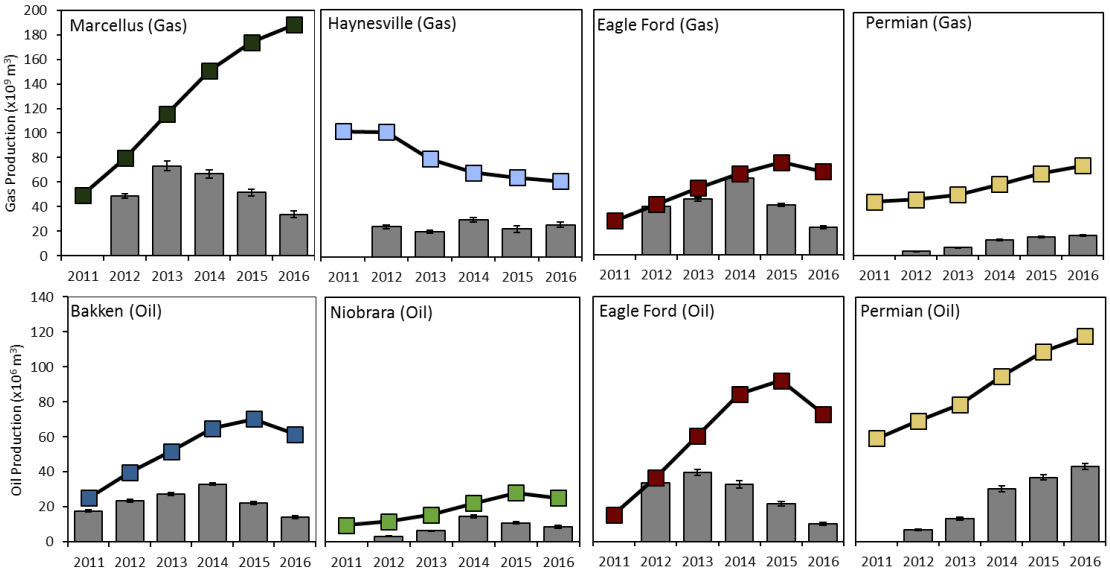


Figure 47: Cumulative production comparison. Total hydrocarbon production (connected squares) and year-one cumulative production (bars) for each unconventional shale gas producing region (top row) and unconventional tight oil producing region (bottom). Total annual hydrocarbon production volumes were calculated by multiplying daily production values for each month from the EIA's drilling productivity report by the number of days in that month, then adding up monthly production for each year (*31*). Year one cumulative hydrocarbon production was calculated by multiplying the well count estimate by the production per well volumes for each year (Table 21 and Table 22). Whiskers represent 95% bootstrap confidence intervals.

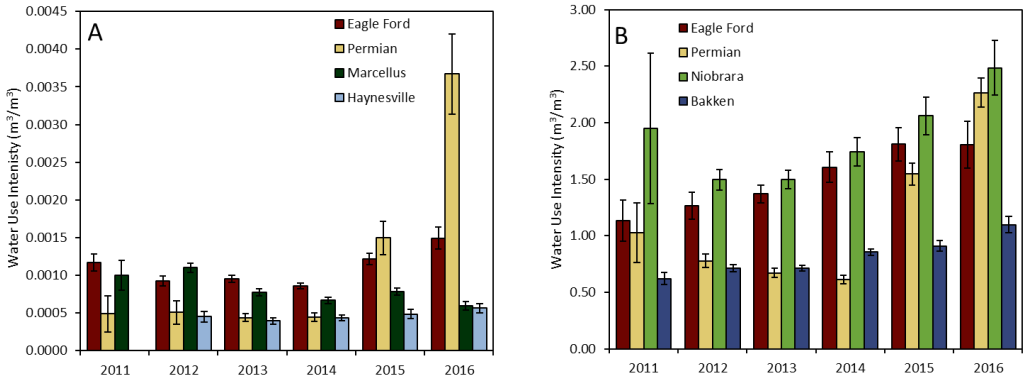


Figure 48: Volumetric water use intensity. Volumetric water use intensities for shale gas (A) and tight oil (B) basins. Ratios are reported as the ratio between volume of injected water (m^3) and volume of produced hydrocarbon (m^3). Whiskers represent 95% bootstrap confidence intervals.

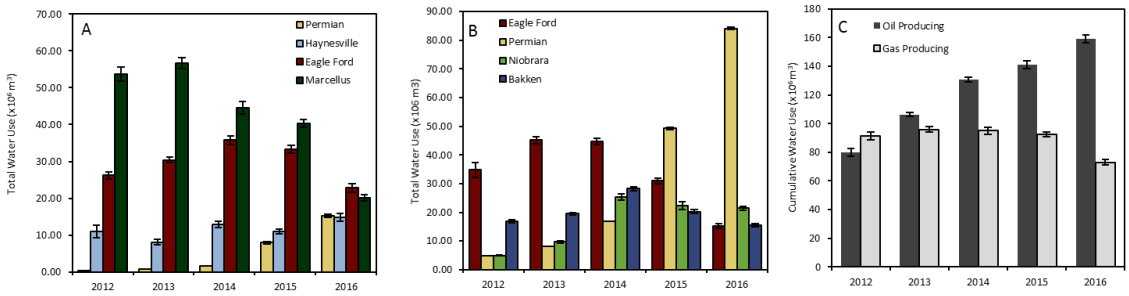


Figure 49: Total water use for hydraulic fracturing. Total water use for hydraulic fracturing in shale gas (A) and tight oil (B) producing formations. Total water use was calculated by multiplying the number of wells in each year by the median production volume within a given year (Table 21 and Table 22). Cumulative water use volume (C) for shale gas (grey) and tight oil (black) producing regions in this study from 2012 to 2016 was calculated by adding up values in panel A and B. Whiskers represent 95% bootstrap confidence intervals.

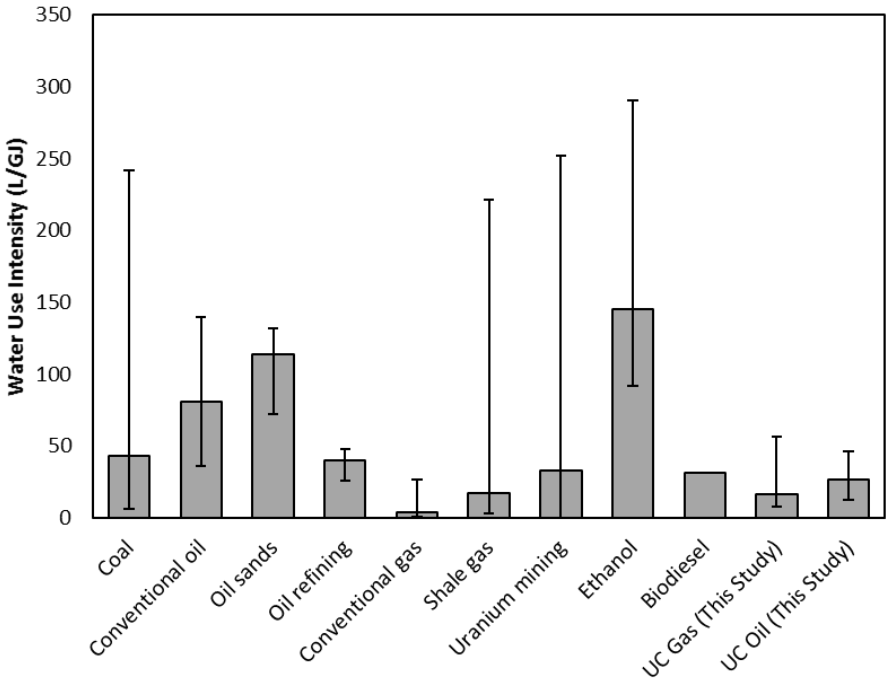


Figure 50: Water use intensity for other energy-producing materials. Water use intensity (L/GJ) for a number of energy sources compared to the results for this study (*33*). Shaded columns indicate average water use intensity, while the whiskers show minimum and maximum observed values.

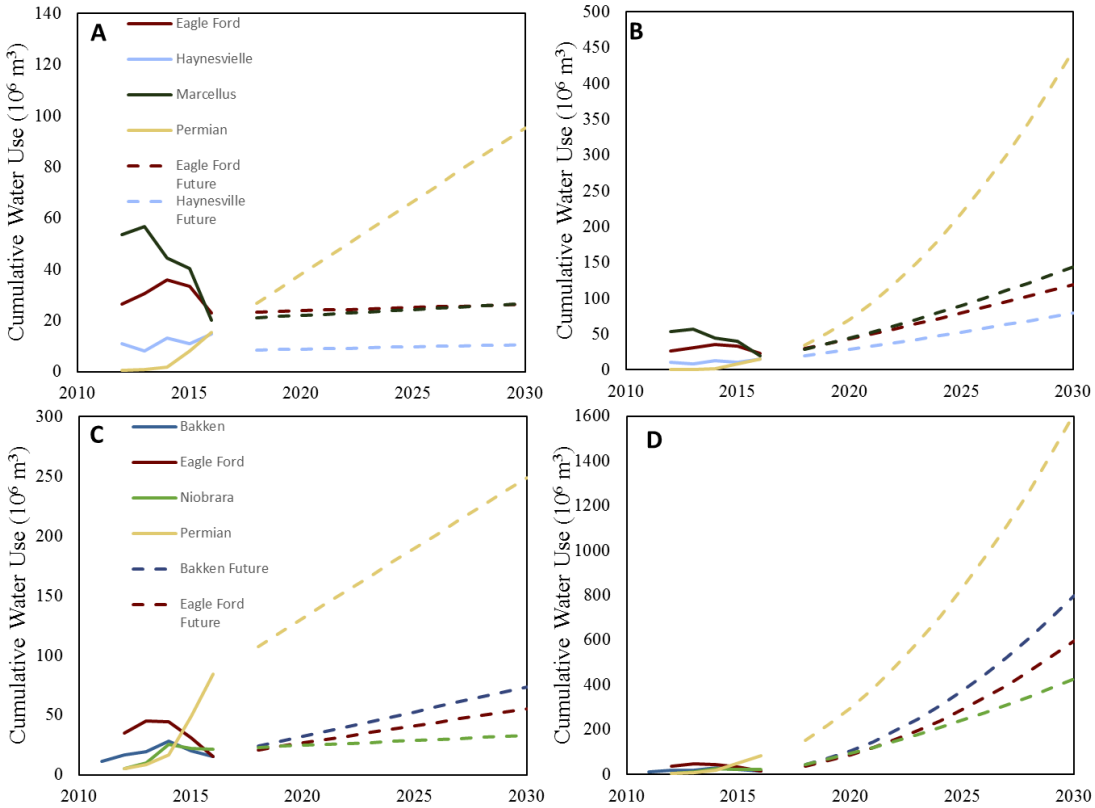


Figure 51: Projected water use for hydraulic fracturing operations in the United States. Water use (in million m³) predictions for unconventional gas (A and B) and unconventional oil (C and D) producing regions. Predictions for the business as usual scenario (A and C) show total water use predictions assuming drilling rates stay at 2016 levels, while the future increase scenario (B and D) shows total water use predictions by assuming drilling rates will match the previously seen high rates seen in each basin.

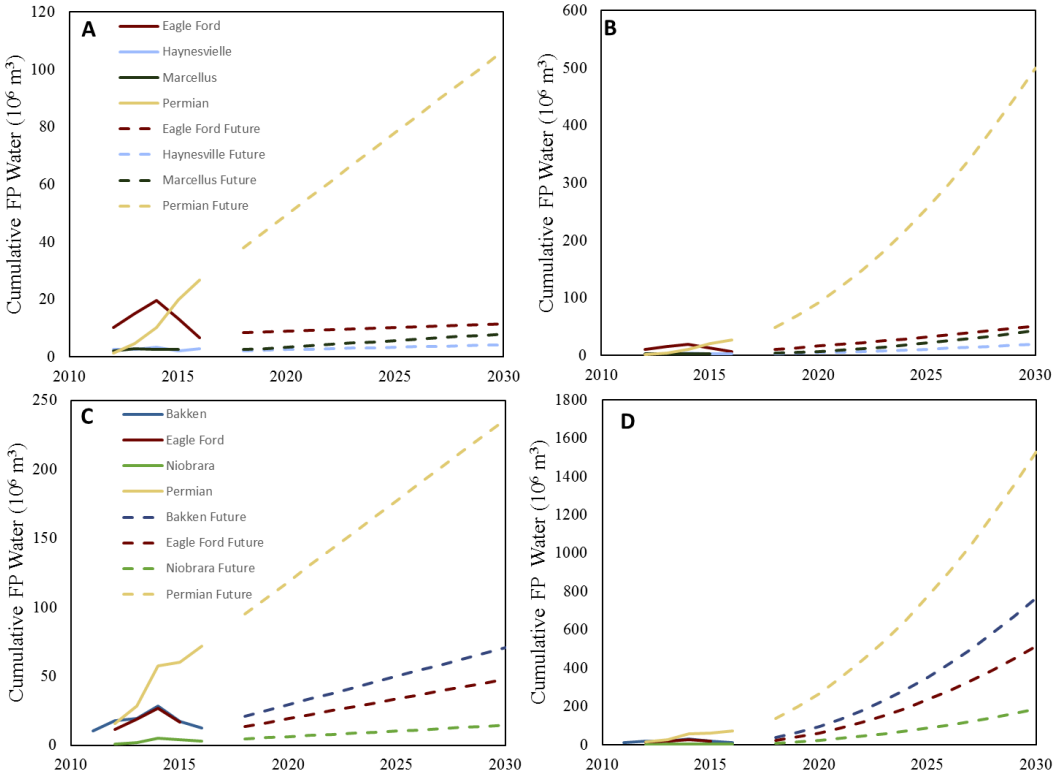


Figure 52: Projected first year FP water derived from future hydraulic fracturing operations in the United States. Cumulative FP water from the first 12 months of production (in million m³) predicted for unconventional gas (A and B) and unconventional oil (C and D) producing regions. Predictions for the business as usual scenario (A and C) show total water use predictions assuming that drilling rates will stay at 2016 levels, while the future increase scenario (B and D) shows FP water predictions assuming that drilling rates will match previously seen high drilling rates seen in each shale basin.

Appendix D: Supplementary Information for Chapter 5

Tables:

Table 25: Mean, Median, Max, and Min consumption and withdrawal intensities for each combination of fuel source, plant type, and cooling type. Net generation, generator type, cooling technology, and cooling water withdrawal data were collected and merged from EIA 860 and 923. (40, 41)

Fuel Source	Plant Type	Cooling Type	Year	n	Mean Consumption (m^3/MWh)	Median Consumption (m^3/MWh)	Max Consumption (m^3/MWh)	Min Consumption (m^3/MWh)	Mean Withdrawal (m^3/MWh)	Median Withdrawal (m^3/MWh)	Max Withdrawal (m^3/MWh)	Min Withdrawal (m^3/MWh)
Natural Gas	Combined Cycle	Once Through	2013	23	0.27	0.02	1.0	0.002	117.73	90.33	427.37	1.24
Natural Gas	Combined Cycle	Once Through	2014	32	4.02	3.60	8.9	0.003	129.23	100.77	488.70	49.93
Natural Gas	Combined Cycle	Once Through	2015	30	1.81	0.04	4.8	0.001	112.70	86.52	419.75	11.58
Natural Gas	Combined Cycle	Once Through	2016	30	1.67	0.04	5.0	0.001	105.46	85.63	362.73	11.16
Natural Gas	Steam Turbine	Once Through	2013	102	27.55	1.50	396.0	0.011	1017.61	428.79	12812.62	1.12
Natural Gas	Steam Turbine	Once Through	2014	114	2.70	1.32	27.2	0.248	1429.56	490.26	45271.87	6.86
Natural Gas	Steam Turbine	Once Through	2015	112	9.08	1.87	72.8	0.019	751.51	454.75	8259.26	70.91
Natural Gas	Steam Turbine	Once Through	2016	122	9.99	1.93	64.4	0.229	707.79	468.44	13690.60	4.01
Natural Gas	Combined Cycle	Recirculating	2013	219	2.00	0.81	164.5	0.001	5.30	0.97	390.28	0.01
Natural Gas	Combined Cycle	Recirculating	2014	234	4.19	0.83	682.7	0.000	6.82	1.01	682.69	0.02
Natural Gas	Combined Cycle	Recirculating	2015	251	0.97	0.82	10.8	0.000	3.38	1.00	132.48	0.01
Natural Gas	Combined Cycle	Recirculating	2016	248	0.94	0.80	9.5	0.000	3.86	0.99	163.86	0.00
Natural Gas	Steam Turbine	Recirculating	2013	75	2.95	2.42	11.0	0.016	213.22	5.31	2616.72	0.21
Natural Gas	Steam Turbine	Recirculating	2014	75	9.21	2.59	270.9	0.014	136.39	5.00	1944.87	0.01
Natural Gas	Steam Turbine	Recirculating	2015	86	10.37	2.67	179.9	0.221	413.26	5.08	7719.64	0.01
Natural Gas	Steam Turbine	Recirculating	2016	85	5.24	2.95	63.4	0.000	315.87	5.07	4460.46	0.00
Coal	Subcritical	Once Through	2013	231	3.45	1.32	33.54	0.004	255.88	156.96	2622.42	0.57
Coal	Subcritical	Once Through	2014	234	2.43	1.06	26.40	0.002	222.13	151.01	3678.60	2.61
Coal	Subcritical	Once Through	2015	194	1.64	0.56	22.86	0.000	288.96	174.46	11211.59	2.75
Coal	Subcritical	Once Through	2016	157	2.38	0.77	36.54	0.001	582.35	169.74	32167.49	0.17
Coal	Supercritical	Once Through	2013	36	1.28	1.33	5.72	0.011	151.67	141.39	348.08	2.35
Coal	Supercritical	Once Through	2014	43	1.33	1.40	3.05	0.020	136.83	129.16	355.29	2.14
Coal	Supercritical	Once Through	2015	33	1.22	0.37	8.22	0.017	155.20	144.26	365.55	2.09
Coal	Supercritical	Once Through	2016	34	1.25	0.36	6.37	0.036	152.75	150.00	306.79	2.74
Coal	IGCC	Recirculating	2013	1	0.00	0.00	0.00	0.000	1.46	1.46	1.46	1.46
Coal	IGCC	Recirculating	2014	1	3.65	3.65	3.65	3.645	5.28	5.28	5.28	5.28
Coal	IGCC	Recirculating	2015	1	2.73	2.73	2.73	2.730	3.96	3.96	3.96	3.96
Coal	IGCC	Recirculating	2016	1	1.32	1.32	1.32	1.319	1.91	1.91	1.91	1.91
Coal	Subcritical	Recirculating	2013	193	3.07	1.95	25.13	0.001	23.94	2.78	257.85	0.10
Coal	Subcritical	Recirculating	2014	233	12.41	1.92	1738.72	0.001	54.25	2.42	6369.85	0.10
Coal	Subcritical	Recirculating	2015	213	2.79	1.91	56.12	0.104	24.56	2.51	315.96	0.11
Coal	Subcritical	Recirculating	2016	210	2.37	1.91	17.01	0.049	26.73	2.51	352.02	0.05
Coal	Supercritical	Recirculating	2013	59	2.13	1.48	30.43	0.014	9.41	2.23	170.93	0.08
Coal	Supercritical	Recirculating	2014	61	2.42	1.83	22.65	0.005	17.30	2.42	148.95	0.62
Coal	Supercritical	Recirculating	2015	66	1.87	1.64	6.23	0.128	41.70	3.14	216.44	0.61
Coal	Supercritical	Recirculating	2016	65	1.93	1.52	6.41	0.113	39.71	3.21	219.90	0.65
Coal	Ultrasupercritical	Recirculating	2013	1	1.22	1.22	1.22	1.219	1.54	1.54	1.54	1.54
Coal	Ultrasupercritical	Recirculating	2014	1	1.63	1.63	1.63	1.626	1.88	1.88	1.88	1.88
Coal	Ultrasupercritical	Recirculating	2015	1	1.57	1.57	1.57	1.574	1.92	1.92	1.92	1.92
Coal	Ultrasupercritical	Recirculating	2016	1	1.58	1.58	1.58	1.578	1.90	1.90	1.90	1.90

Table 26: Life cycle components for upstream processes related to coal and natural gas production. Sources for each unit process are shown on the far right.(20, 128)

Component	Parameter	Variable Name	Value	Units	Source
Coal	Water Consumed Surface Coal Mining	$WCCM_{surface}$	3.03E-05	m^3/kg coal	NETL Unit Process Library
	Water Withdrawal Underground Mining	$WCCM_{underground}$	3.04E-04	m^3/kg coal	
	Coal Cleaning at surface and unground mines water	WCCC	1.00E-03	m^3/kg coal	
	Coal Train Transportation	CTT	5.13E-06	m^3/kg coal	
	Coal Cleaning at surface and unground mines electricity	$E_{cleaning}$	1.04E-06	MWh/kg coal	
	Coal Grinding	$E_{grinding}$	3.07E-05	MWh/kg coal	
	Electricity at underground coal mine for extraction	$E_{extraction}$	1.97E-05	MWh/kg coal	
	Electricity at underground coal mine for ventilation	$E_{venting}$	4.26E-05	MWh/kg coal	
	Diesel Fuel at surface coal mine	$VD_{surface}$	1.43E-03	kg diesel/kg coal	
	Diesel Fuel at underground coal mine	$VD_{underground}$	1.46E-03	kg diesel/kg coal	
	Truck Transport	VD_{truck}	2.42E-03	kg diesel/kg transported	
	Barge Transport	VD_{barge}	1.24E-06	kg diesel/kg transported	
Natural Gas	Offshore Conventional NG Water Use	$WCNG_{offshore}$	0	m^3/MCF	NETL Unit Process Library
	Onshore Conventional Associated NG Water Use	$WCNG_{conventional}$	1.17E-02	m^3/MCF	
	Onshore Unconventional NG Water Use 2013	$WCNG_{UC2013}$	1.69E-02	m^3/MCF	Kondash 2018
	Onshore Unconventional NG Water Use 2014	$WCNG_{UC2014}$	1.55E-02	m^3/MCF	
	Onshore Unconventional NG Water Use 2015	$WCNG_{UC2015}$	2.22E-02	m^3/MCF	
	Onshore Unconventional NG Water Use 2016	$WCNG_{UC2016}$	2.50E-02	m^3/MCF	
	NG Well Construction diesel	$VD_{construction}$	3.44E-03	kg/MCF	NETL Unit Process Library
	Drilling NG Wells	$E_{drilling}$	1.60E-05	MWh/MCF	
	NG Liquid seperation	$E_{seperation}$	2.63E-04	MWh/MCF	
	Wellhead Compressor	$E_{compressor}$	3.35E-03	MWh/MCF	
	NG Pipeline Transport	$E_{pipelines}$	8.12E-06	MWh/MCF	
Diesel Fuel	Petrolium Refinery Water Use	$DI_{refinery}$	1.48E-03	m^3/kg diesel	NETL Unit Process Library
	Petrolium Refinery Electricity	$DF_{electricity}$	4.70E-05	MWh/kg diesel	

Table 27: Volumes of coal and natural gas sent to power plants in the United States through time taken from EIA 923.(41) Water use intensity of electricity generation (EI) was calculated by iterating input-output water use data for the US grid. After the fourth iteration, the change in EI (0.001%) was small enough to accept the I-O generated EI value.

Component	Parameter	Variable Name	2013	2014	2015	2016	Units
Coal	Volume of coal sent to power plants from surface mines	$VC_{underground}$	5.19E+11	5.30E+11	4.94E+11	4.03E+11	kg
	Volume of coal sent to power plants from underground mines	$VC_{surface}$	1.75E+11	1.98E+11	1.72E+11	1.50E+11	kg
	Volume of coal sent to power plants from all coal mines	VC_{total}	7.38E+11	7.67E+11	7.04E+11	5.83E+11	kg
	Volume of coal moved by train	VC_{train}	5.71E+11	5.88E+11	5.49E+11	4.50E+11	kg
	Volume of coal moved by truck	VC_{truck}	9.13E+10	1.00E+11	8.49E+10	7.75E+10	kg
	Volume of coal moved by barge	VC_{barge}	7.45E+10	7.79E+10	6.91E+10	5.56E+10	kg
Natural Gas	Volume of unconventional natural gas sent to power plants	$VNG_{unconventional}$	3.43E+09	3.75E+09	4.73E+09	5.625E+09	MCF
	Volume of conventional onshore natural gas sent to power plants	$VNG_{conventional}$	4.53E+09	4.20E+09	4.56E+09	4.11E+09	MCF
	Volume of conventional offshore natural gas sent to power plants	$VNG_{offshore}$	5.35E+08	4.84E+08	5.46E+08	5.39E+08	MCF
	Volume of natural gas total	VNG_{Total}	8.50E+09	8.43E+09	9.84E+09	1.03E+10	MCF
Electricity	Average water consumption intensity of electiricty generation	EI	1.84	1.64	1.65	1.62	m^3/MWh
Electricity	Average water withdrawal intensity of electiricty generation	EI	70.00	65.44	67.63	62.34	m^3/MWh

Table 28: Upstream consumption and withdrawal intensity for coal and natural gas.

Consumption		2013	2014	2015	2016
Coal	Upstream Water (m^3)	9.49E+08	9.76E+08	8.94E+08	7.41E+08
NG	Upstream Water (m^3)	1.68E+08	1.58E+08	2.18E+08	2.49E+08

Withdrawal		2013	2014	2015	2016
Coal	Upstream Water (m^3)	5.68E+09	5.58E+09	5.26E+09	4.07E+09
NG	Upstream Water (m^3)	2.28E+09	2.12E+09	2.56E+09	2.47E+09

Net Generation		2013	2014	2015	2016
Coal	Net Gen (MWh)	1.58E+09	1.58E+09	1.35E+09	1.24E+09
NG	Net Gen (MWh)	1.12E+09	1.12E+09	1.32E+09	1.38E+09

Upstream Consmuption Intensity		2013	2014	2015	2016
Coal	Upstream (m^3/MWh)	0.60	0.62	0.66	0.60
NG	Upstream (m^3/MWh)	0.15	0.14	0.16	0.18

Upstream Withdrawal Intensity		2013	2014	2015	2016
Coal	Upstream (m^3/MWh)	3.59	3.53	3.91	3.29
NG	Upstream (m^3/MWh)	2.03	1.89	1.94	1.80

Table 29: Water stress index for coal mining in the United States.(104, 155) Coal mine point data were categorized based on their spatial location into different water stress indices.

Water Stress Index	Surface $x10^6$ Short Tons	Underground $x10^6$ Short Tons	Total $x10^6$ Short Tons	Total %
Extremely High Stress	191.06		191.06	25%
High Stress	90.69		90.69	12%
Medium-High Stress	2.09	0.22	2.31	0%
Moderate Stress	28.17	0.58	28.75	4%
Low Stress	122.24	270.61	392.85	51%
Arid and Low Use	52.51	1.72	54.23	7%
(blank)	14.72		14.72	2%

Figures:

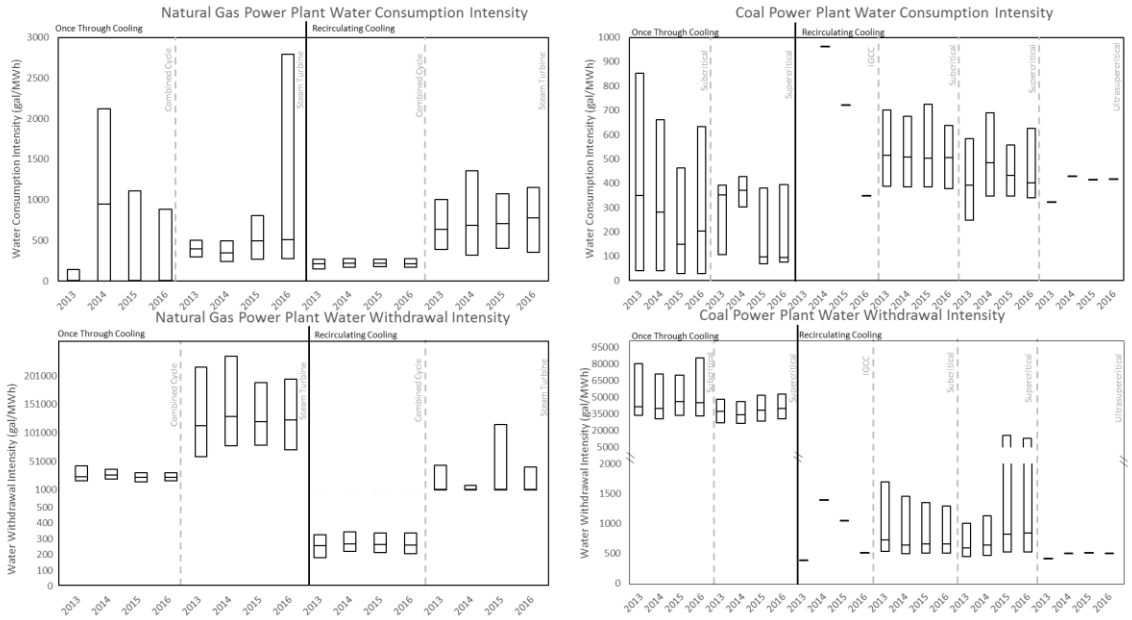


Figure 53: Water consumption and withdrawal intensity for plant and fuel types. The water consumption (top) and withdrawal (bottom) intensities for natural gas (left) and coal (right) in the United States from 2013-2016 broken down by the power plant generator and cooling system type.Median values are shown by the central line within each box and 1st and 3rd quartiles are shown as the box range. Does not include upstream processes.(40, 41)

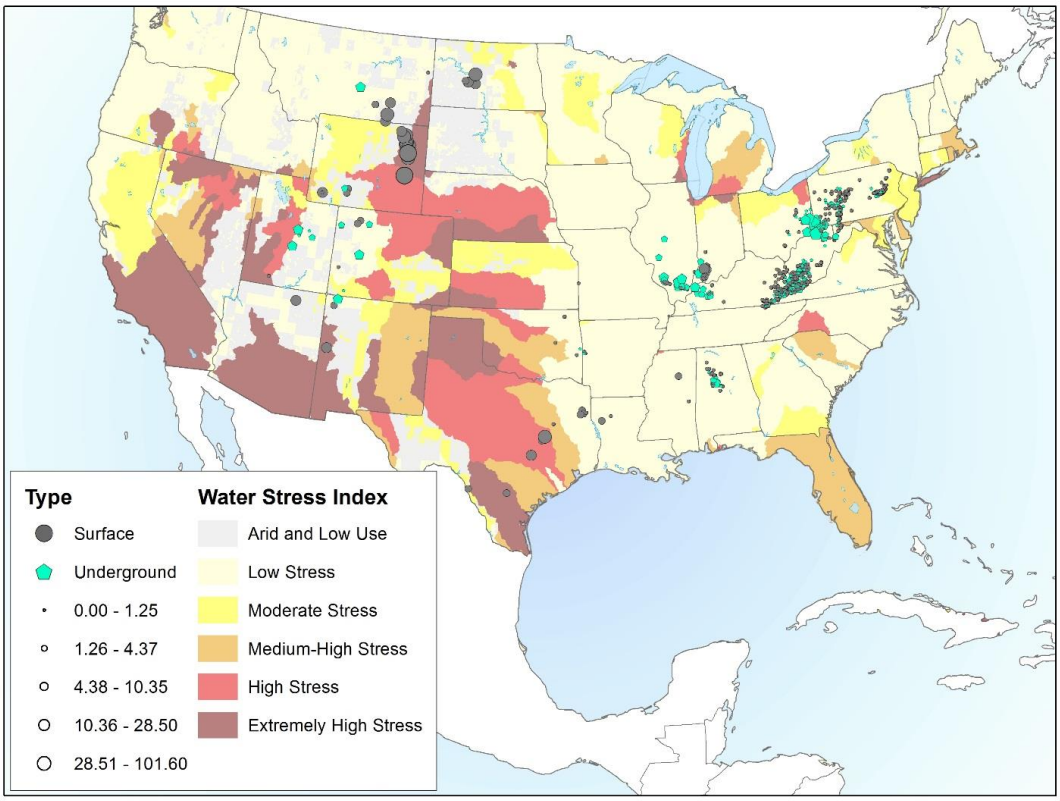


Figure 54: Coal mines across the United States shown on top of water stress index.(104, 155) 2016 mine production is shown by size of symbols in x10^6 short tons.

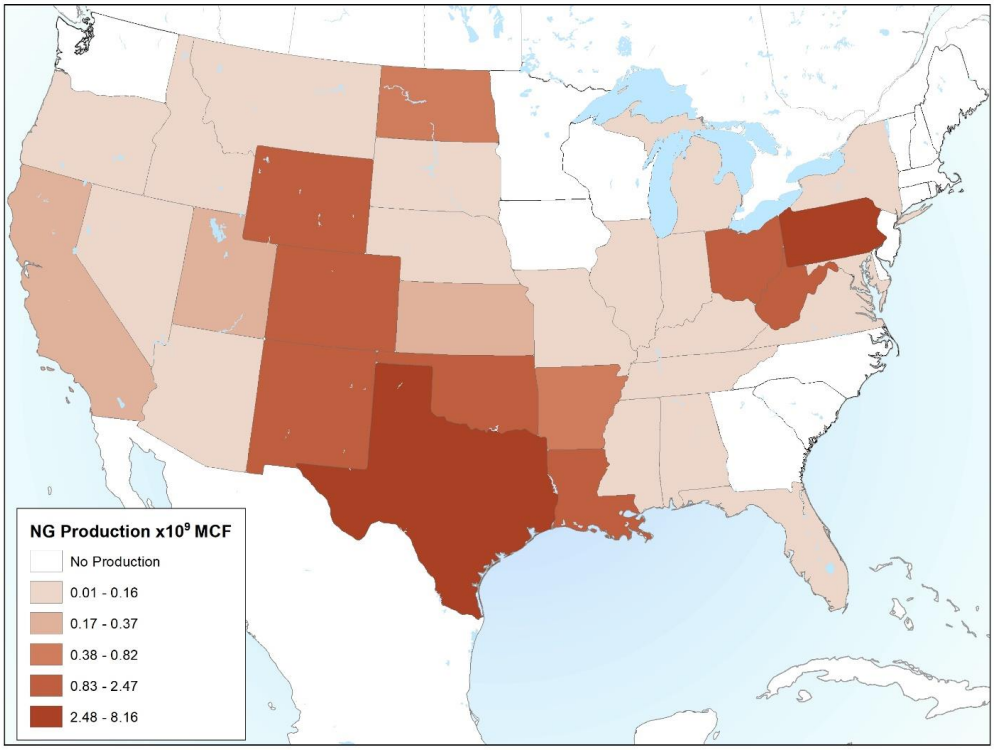


Figure 55: Total natural gas production for each state (conventional + unconventional + offshore) in billion MCF.(8)

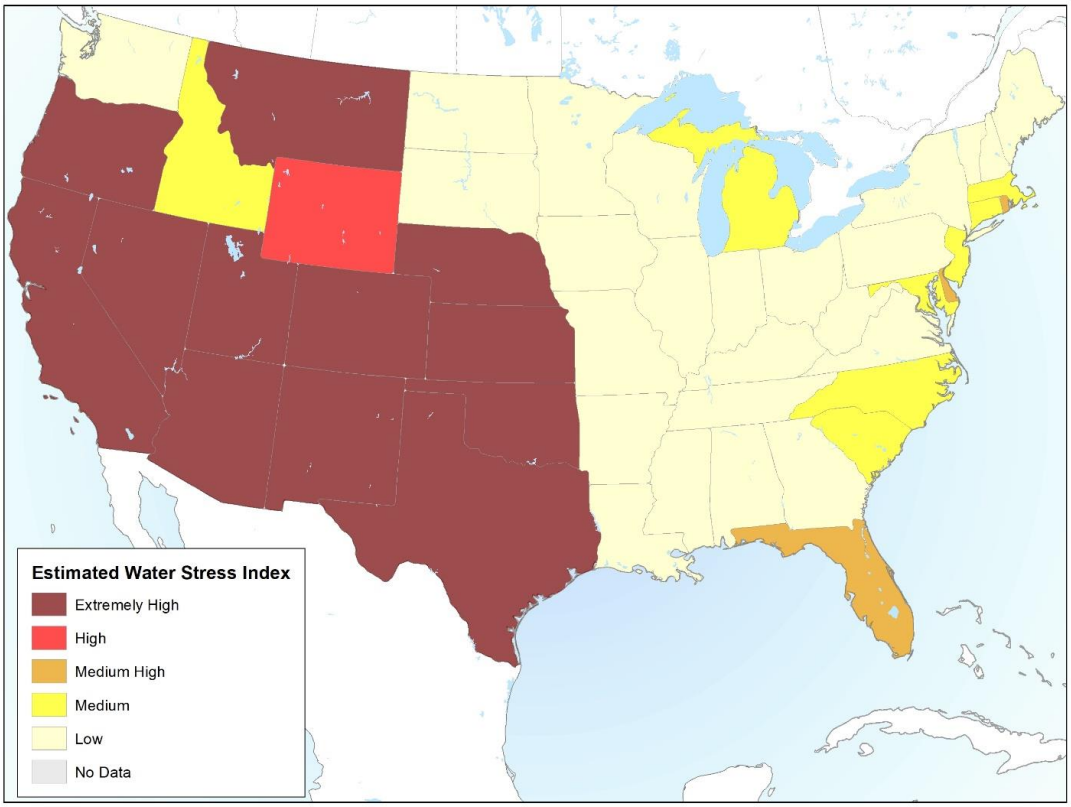


Figure 56: Estimated water stress index on a state level. Water stress index is a calculation of the available water divided by the water use for each region. The value is then sorted into classes: Low <10%, Medium 10-20%, Medium High 20-40%, High 40-80%, and Extremely High above 80%.(104) To produce our estimate, we used a weighted average for each state of the area within that state occupied by a specific water stress index level.

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Biography

Andrew Kondash received a Bachelor of Arts in Political Science and Minors in Science Technology and Society and Natural Science from the Pennsylvania State University in University Park, PA in 2010. In 2013 he received a Master of Environmental Management with a focus in Energy and the Environment and a Geospatial Analysis certificate from Duke University. He started work on his PhD in 2014 at the Nicholas School of the Environment Division of Earth and Ocean Sciences at Duke University. During his time at Duke, he has authored 4 papers: Radium and Barium Removal through Blending Hydraulic Fracturing Fluids with Acid Mine Drainage (2014, *Environmental Science & Technology*, vol. 48), Water footprint of hydraulic fracturing (2015, *Environmental Science & Technology Letters*, vol. 2), Quantity of flowback and produced waters from unconventional oil and gas exploration (2017, *Science of the Total Environment*, vol. 574), and The intensification of the water footprint of hydraulic fracturing (2018, *Science Advances*, vol. 4). He has also helped to co-author 8 papers during that time. Andrew was awarded the Nicholas School of the Environment Scholarship in 2011 and 2012. He also received an the Editor's Choice Award for his paper, Water Footprint of Hydraulic Fracturing in 2015 which also received Environmental Science & Technology Letters Selected Most Read Articles Award in 2017.