DISSERTATION

WATER MANAGEMENT AND REUSE STRATEGIES FOR UNCONVENTIONAL OIL AND GAS FIELDS

Submitted by

Stephen A. Goodwin

Department of Civil and Environmental Engineering

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Doctoral Committee:

Advisor: Kenneth Carlson

Thomas Bradley
Ken Knox
Reagan Waskom

ABSTRACT

WATER MANAGEMENT AND REUSE STRATEGIES FOR UNCONVENTIONAL OIL AND GAS FIELDS

Optimizing water management in unconventional oil and gas fields is essential to minimize the risks and highly publicized concerns, but the uncertainty in oil and gas field development makes it risky to invest, plan, and design water infrastructure in a rapidly changing field. Furthermore, the variability in the quantity of the flowback and produced water creates challenges for water treatment planning and design if these volumes are not correctly modeled. By developing a framework to model water volumes and the impact specific water infrastructure decisions have in a rapidly changing oil and gas field will improve the accuracy and speed of water planning and management.

Traditional water management strategies for an unconventional oil and gas field require tedious calculations for each scenario and development plan. By incorporating flexible development plans and water infrastructure decisions in a single graphical user interface, the tedious calculations are replaced with instant visualization and quantifiable measures associated with each development plan and water infrastructure decision. Furthermore, a spatial and temporal multicriteria decision analysis on water infrastructure placement is incorporated into the model to allow the user to weight specific criteria within the field and see what parameters have the strongest influence on the final decision.

The flexibility in the graphical user interface allows the user to instantly visualize the impact water management decisions have on the field. For example, if the user is considering

piping the flowback and produced water to several mobile treatment facilities within the field because he or she is concerned about the price of disposal using Class II injection wells, both scenarios can be quickly visualized within the model to determine what the price increase, rate of development, and cost of treatment will need to be in the field to make a rational water management decision. Currently, this water management comparisons are made on a case-by-case basis with tedious calculations. By speeding up and quantifying the decision-making process, several scenarios and strategies can be rapidly compared and the engineering design and planning stages can be decreased dramatically.

Water is the single largest operating material by volume and directly impacts the social (i.e. induced seismic activity, risk of fatal accidents), environmental (i.e. risk of spills, greenhouse gas emissions) and economic risks. In the coming years, as an increasing number of ballots include hydraulic featuring restrictions or moratoriums and oil and gas development becomes more concentrated, optimizing water management will become essential to continue operations in populated and semi-arid regions. Water treatment and reuse will be a key part of an optimized water management strategy. A simple brute-force solution using a single centralized treatment facility for a field or a mobile treatment facility at each pad cannot provide an optimized solution. Blending fresh, flowback, and produced waters to achieve the treatment targets developed in Chapter 7 provides a more optimized solution that reduces the social, environmental, and economic impacts of treatment. This solution is much more complicated and requires a spatial and temporal understanding of the water volumes, quantities, and treatment requirements within a field.

The modeling framework developed in this dissertation fills this gap by giving the operator the ability to visualize, model, and quantify water volumes and qualities throughout a field based on flexible development plans. Water management scenarios can be modeled with the development plans to assess the efficiency and impacts of each scenario. The operator can assign a relative specific risks (e.g. environmental, social, etc.) throughout the field to provide a spatial and temporal multi-criteria decision analysis for each development plan and water management scenario.

The objective of this dissertation is to model and quantify the social, environmental, and economic implications that water infrastructure decisions have within an uncertain and rapidly changing oil and gas field.

Chapters 4 through 6 show that influent and effluent water volumes for each component shown in Figure 10.1 can be accurately and precisely estimated in the Wattenberg Field. Chapter 6 incorporates water quality estimates for the flowback and produced water as well as several case studies for each component shown in Figure 10.1. The impact water quality has on the development and performance of gelled hydraulic fracturing fluids, which provides water quality treatment targets for designing water treatment facilities, is assessed in Chapter 7.

Chapter 8 provides a framework to spatially and temporally model water volumes and quality as well as social, environmental, and economic impacts for a hypothetical field by incorporating the research developed in previous chapters. Chapter 9 provides case-studies that apply the hypothetical model framework to a variety of actual oil and gas development scenarios to compare different water management scenarios. The model framework allows operators to visualize, compare, and quantify several water management scenarios for a variety of oil and gas development plans. Incorporating the research into a spatial and temporal model allows operators to minimize key criteria for a specific area (e.g. environmental impact, truck traffic, etc.) to optimize the size, location, number, and duration of treatment facilities in the field.

ABSTRACT

1. Introduction

Natural gas is often touted as a critical bridge fuel that will transition the global community towards less carbon intensive energy economies. Two innovative technologies, horizontal drilling and multi-stage hydraulic fracturing, have brought the "Golden Age of Gas" [12] by economically unlocking abundant supplies of unconventional gas (coal bed, shale, and tight gas). The dramatic domestic boom in oil and gas created affordable domestic energy, domestic energy supply, and decreased carbon intensity. However, oil and gas development from shale has been riddled with controversy ranging including land use issues, community impacts, water contamination concerns, and water resource degradation.

Nearly every public health and environmental concern associated with unconventional oil and gas from shale stems from the large volumes of water required for hydraulic fracturing. Water and energy are vital, interdependent, and limited resources. In the United Staes, the energy sector accounts for 41% of the water withdrawals and 6% of the water consumption. [13] Water consumption is projected to increase by 7% in the next 25 years, with the energy sector contributing to 85% of the increase. [13] Domestic biofuels followed by unconventional oil and gas production are anticipated to account for the majority of the increased demand.

As the United States transitions from coal to natural gas and energy demands increase in a changing global climate, water management will have increasing importance particularly in the semi-arid West. Water is the single largest material required for unconventional oil and gas development and also the largest waste stream. [14] Improving the design of water infrastructure supporting oil and gas development can dramatically reduce the impacts to local communities and environment, supporting the social license to operate while improving operational efficiency.

In order to optimize water management and water reuse strategies, accurate predictions of water quantity, quality, and spatial distribution are required. Waste management strategies for developing unconventional shale resources typically need to address strong temporal and spatial variations in water quantity and quality. In addition, the location of facilities for water collection, treatment and/or recycling and water needs for drilling and hydraulic fracturing are constantly changing as a field develops.

Water data (particularly water requirements, flowback water, and water quality data) has been sparse and not readily available in literature. The lack of authoritative water data has been well documented. [15, 16, 13] Energy companies [9, 17], regulatory agencies [18], journalists [19], and academics [20] have provided either broad estimates or a single value without uncertainty. In a 2012 report [21], The Government Accountability Office found that “making effective policy choices will continue to be challenging without more comprehensive data and research.” A better understanding of water requirements, wastewater volumes, and water reuse potential is required to minimize the environmental, public health, and community impacts while developing unconventional shale gas.

In this document, a review of literature with an emphasis on water management associated with unconventional oil and gas development is provided in Chapter 2. An outline of the research objectives is presented in Chapter 3. Chapters 4 through 7 provide an analysis of water volumes and water qualities that are used to develop a water infrastructure model for a hypothetical oil and gas field in Chapter 8. The framework for this model is applied to oil and gas field development in Northern Colorado to better quantify a variety of challenges.

2. Literature Review

2.1. Natural Gas as a Bridge Fuel

2.1.1. Energy and Carbon Intensity

The gross domestic product (GDP) of the United States (U.S.) is projected to grow 2.5% per year through 2040 and the growth will be fueled by an increase in energy consumption of 0.3% per year and a population increase of 0.9% per year. [1] Despite an increase in energy consumption, the efficiency of energy use is expected to improve. Both the energy intensity (energy use per dollar of GDP) and CO2 emission intensity (metric tons of CO2 per billion Btu) are anticipated to decrease slightly through 2040 (Figure 2.1). This is primarily a result of increasing use of renewable energy technology, transportation efficiency standards, and natural gas replacing other fossil fuels (particularly coal) for electricity generation. [1] Natural gas is widely considered a critical bridge fuel to transition the U.S. economy towards a productive and less carbon intensive energy economy.

However, over 85% of the CO2 emissions occur outside of the U.S. and climate change is a global issue. Global economic growth and energy use worldwide is expected to grow faster than in the U.S. and is sharply divided between countries inside and outside of the Organization for Economic Cooperation and Development (OECD). Global

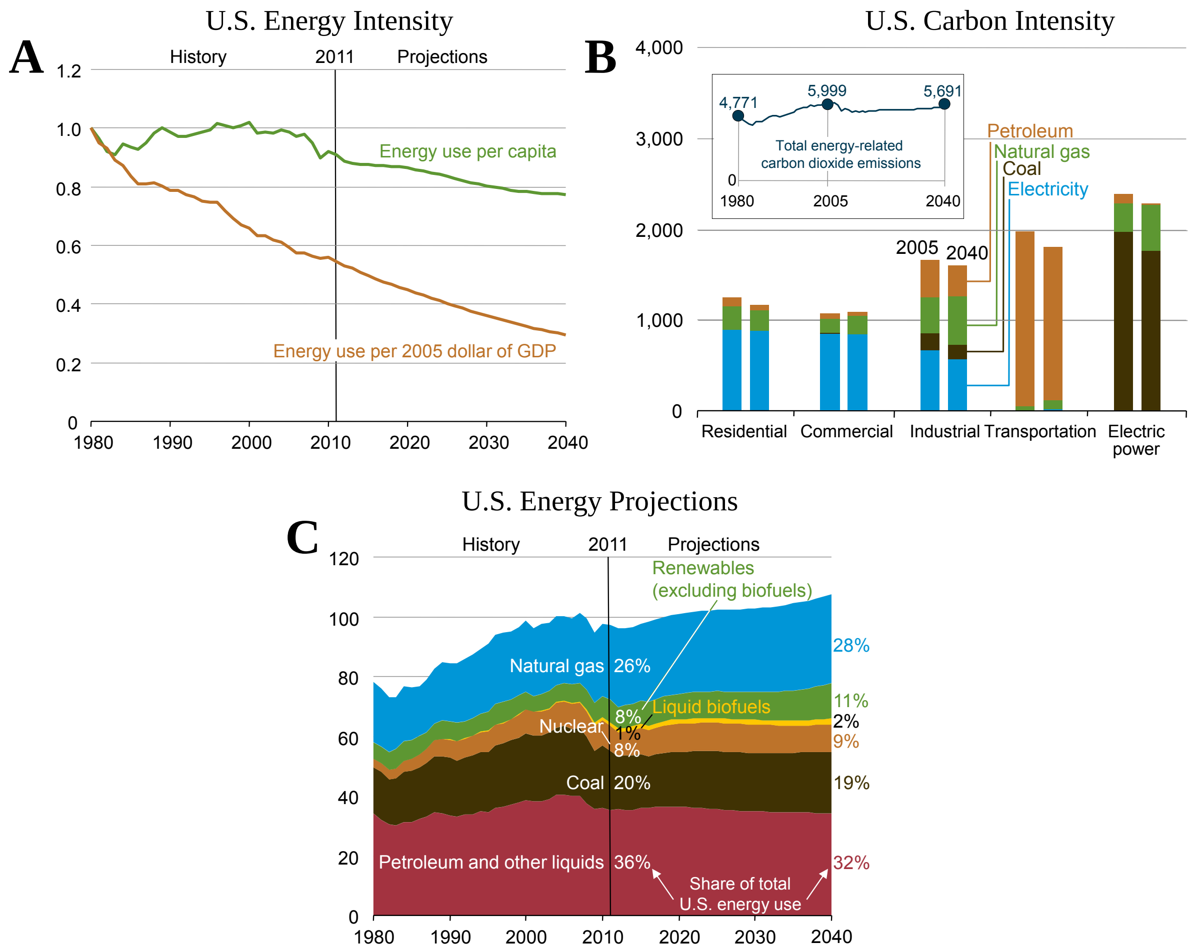

Figure 2.1: A.) Energy intensity (both energy use per person and energy use per dollar of gross domestic product). (index, 1980=1) B.) Carbon dioxide emissions by sector and fuel in the United States (million metric tonnes) C.) Primary energy use by fuel (quads) [1]

energy consumption is projected to increase by 1.5% per year (0.5% increase per year in OECD countries and 2.2% increase per year in Non-OECD countries) and global population is projected to increase by 0.8% per year (0.4% increase per year in OECD countries and 0.9% increase per year in Non-OECD countries). Non-OECD are projected to account for more than 85% of the increase in energy use, with China and India combining to account for 34% of the increase. Non-OECD countries in Asia, particularly India and China, have some of the fastest growing economies despite a global recession. Global gross domestic product is projected to rise 3.6% per year (2.1% increase per year in OECD countries and 4.7% increase per year in Non-OECD countries).[2]

The world energy intensity and carbon intensity are both projected to decrease (Figure 2.2), indicating increasing energy efficiencies worldwide. Global energy intensity is also projected to decrease by 2.0% per year (1.6% increase per year in OECD countries and 2.5% increase per year in Non-OECD countries) and global carbon intensity is projected to decrease by 0.2% per year (0.3% increase per year in OECD countries and 0.3% increase per year in Non-OECD countries).

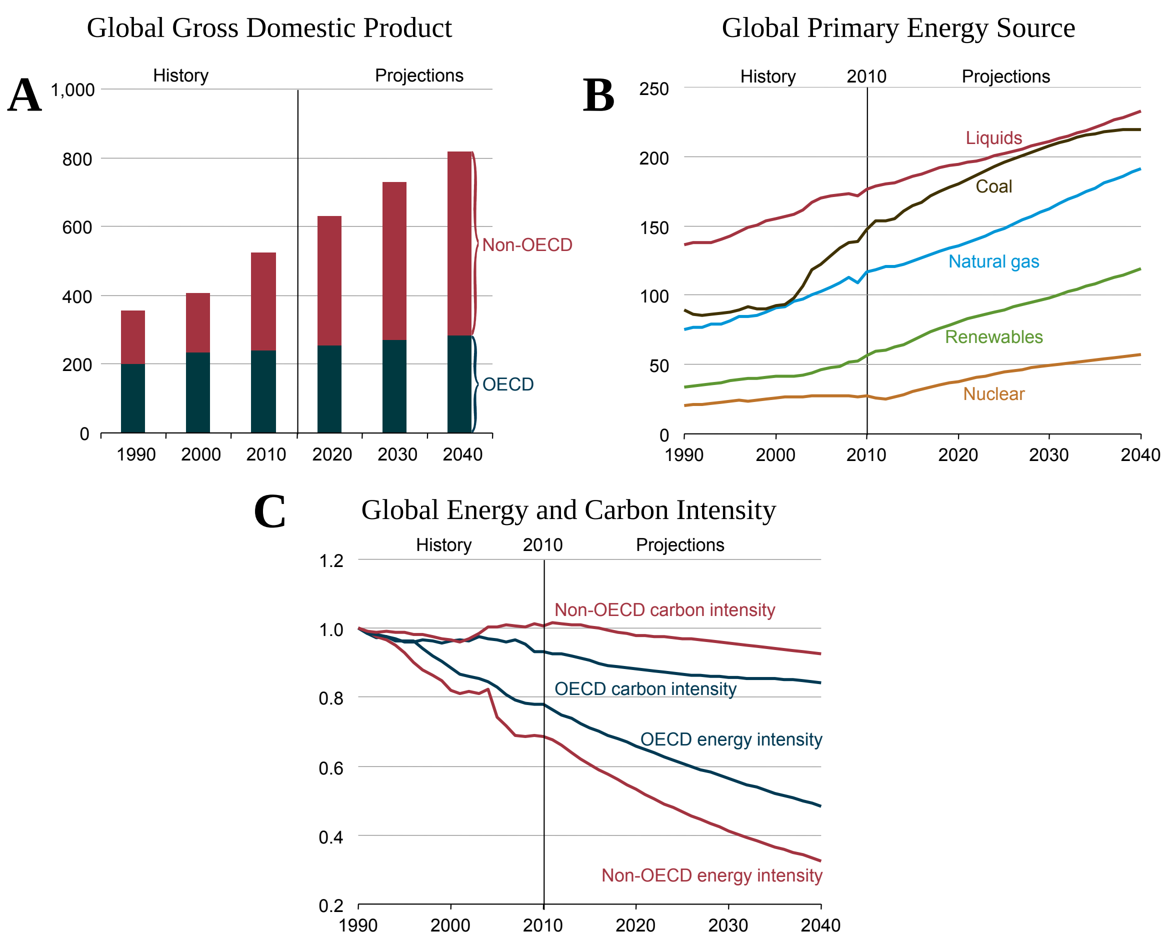

Figure 2.2: A.) Global gross domestic product B.) Global primary energy source C.) Global energy and carbon intensity [2]

2.1.2. Greenhouse Gas Emission Targets

Despite decreasing energy and CO_2 emission intensities worldwide, CO_2 and other greenhouse gas emissions are still rising and increasing the rate of climate change. In the most recent report from the Intergovernmental Panel on Climate Change (IPCC) [22], the climate panel concluded, “warming of the climate system is unequivocal, and since the 1950s, many of the observed changes are unprecedented over decades to millennia. The atmosphere and ocean have warmed, the amounts of snow and ice have diminished, sea level has risen, and the concentrations of greenhouse gases have increased.”

The report continues, “Throughout the 21st century, climate change impacts will slow down economic growth and poverty reduction, further erode food security and trigger new poverty traps, the latter particularly in urban areas and emerging hotspots of hunger. Climate change will exacerbate poverty in low and lower-middle income countries and create new poverty pockets in upper-middle to high-income countries with increasing inequality.” [22]

More than 100 countries have adopted a global warming limit of 2^oC (3.6^oF) or below (relative to pre-industrial levels from 1750) to provide an upper limit on greenhouse gas emissions. [23] For the first time, the IPCC formally embraced this upper limit and estimates no more than one trillion tons of carbon can be released since the industrial revolution into the atmosphere before this limit is exceeded. [22] It is estimated that 531 billion tones of carbon has been released since 1750 and one trillion tons will be reached in 2040 at current rates. [24] The American Geophysical Union (AGU) estimates that greenhouse gas emissions must be cut in half to keep temperatures from rising 2^oC (3.6^oF). [25] The IPCC climate panel concluded:

"By the mid-21st century the magnitude of the projected changes are substantially affected by the choice of emissions scenario."

A transition from coal to natural gas is touted as a short-term solution to reduce greenhouse gas emissions while technical (e.g. intermittency, scalability) and economic (e.g. cost of implementation) barriers associated with a carbon-free renewable energy economy are solved. Carbon dioxide has the highest radiative forcing value, followed by methane, halocarbons, and nitrogen oxide (Figure 2.3). Natural gas burns nearly half the carbon dioxide and three fourths less nitrogen oxide of coal per unit of energy. [26] Natural gas also emits almost no sulfur dioxide, carbon monoxide, black carbon, particulates, or mercury, making natural gas the cleanest fossil fuel. [27]

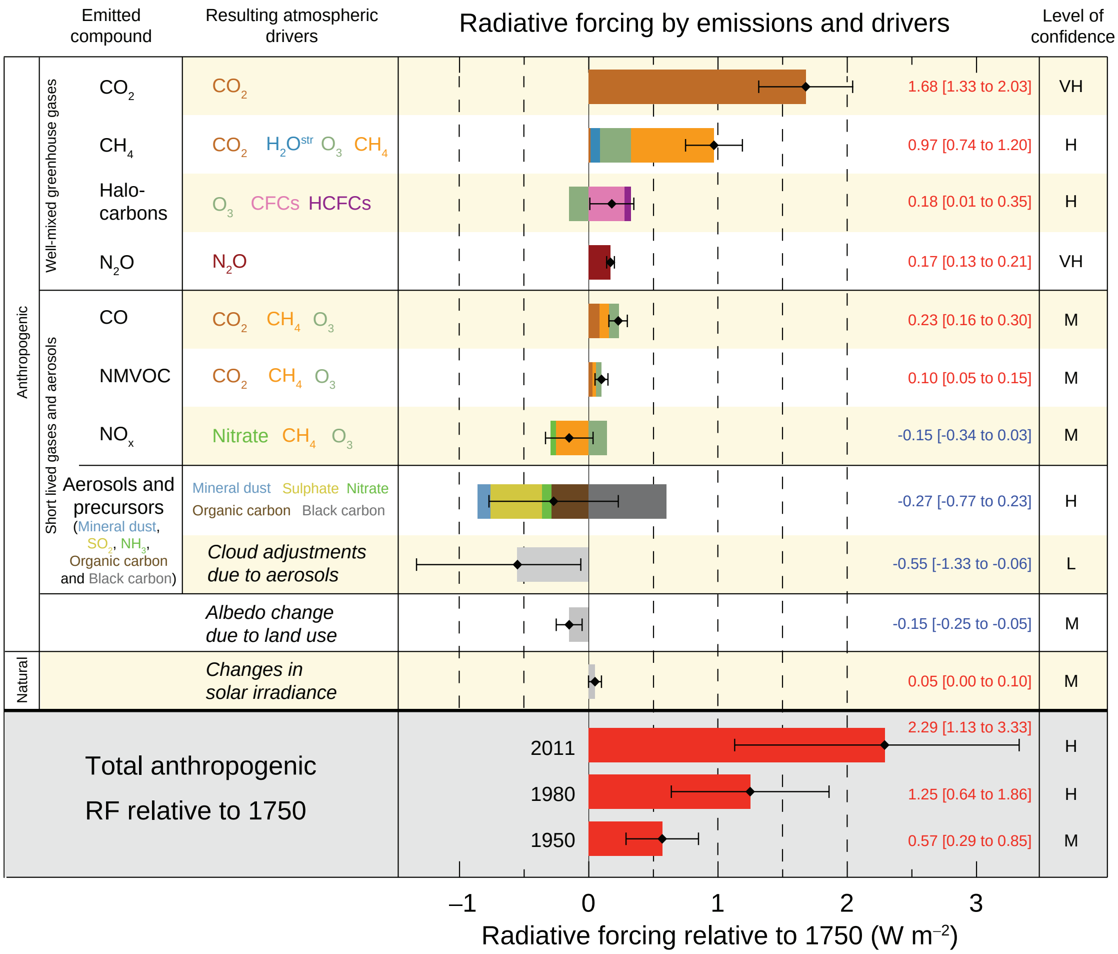

Figure 2.3: Radiative forcing estimates of the main drivers of climate change relative to pre-industrial levels from 1750 and aggregated uncertainties. [3]

Table 2.1: Greenhouse gas metrics and emissions factors, from [10]

GHG Metric	Specification	CO_2	CH_4	NO_x	O_3	SO_2	BC	CO	Hg	PM
Tropospheric Conc.	Pre-1750	280.0	700	270	25					
(CO2: ppm, other: ppb)	As of 2000	388.5	1870	323	34					
Lifetime (years)		100	12	114	Hours	Hours				
Global warming potential	20 year	1	72.0	289						
(CO2 standardized)	100 year	1	25.0	298						
	500 year	1	7.6	153						
Net radiative forcing	Abundance	1.690	0.480	-0.110	0.370	-0.380				
(W/m2)	Emissions	1.690	0.990	-0.290	0.250	-0.250				
Emission factor	Specification	CO_2	CH_4	NO_x	O_3	SO_2	BC	CO	Hg	PM
Coal										
Primary energy (kg/GJ)		25.00		0.196		0.240	0.040	0.089	$6.90x10^6$	1.179
Electricity (kg/GJ)		78.10		0.614		0.750	0.130	0.279	$2.10x10^5$	3.684
Fugitive (CO_2: kg/GJ, CH_4: Tg/GtC)		7.22	7.06							
Natural Gas										
Primary energy (kg/GJ)		15.00		0.040		$3.00x10^4$	$2.20x10^7$	0.017	0.000	0.003
Electricity (kg/GJ)		25.00		$5.00x10^4$	$3.70x10^7$	0.029	0.000	0.005		
Fugitive (CO_2: kg/GJ, CH_4: Tg/GtC)		1.5	13.33							

2.2. Shale Gas Revolution

Two innovative technologies, horizontal drilling and multi-stage hydraulic fracturing have unlocked abundant supplies of unconventional gas (coal bed, shale, and tight gas) and has brought the "Golden Age of Gas" [12] in the United States. Although the recent boom in shale gas development began as early as 2005, Texon drilled the first horizontal well in 1929 and hydraulic fracturing was first introduced by Standard Oil (with exclusive license to Halliburton Oil Well Cementing Company) in 1949 (Figure 2.4). [4] However, the high costs were not justified until the technology was refined and the costs decreased. A $92 million research investment throughout the 1970s by the U.S. Department of Energy is credited with advancing the technology and reducing the cost that has stimulated the dramatic recent development of domestic gas from shale. [28]

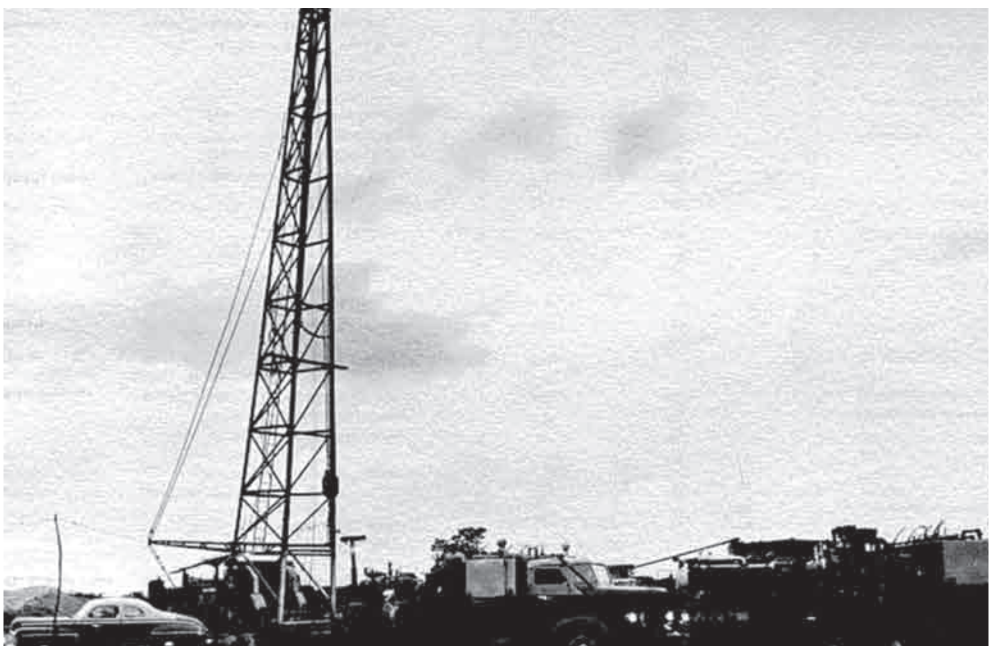

Figure 2.4: A photograph of the first commercial hydraulic fracturing treatment, conducted by Halliburton Oil Well Cementing Company (HOWCC) in Stephens County, Oklahoma on March 17, 1949 [4]

The advances in technology have increased the estimated U.S. natural gas reserves 72% since 2000 and 49\% since 2005 (Figure 2.5), adding over 1,000 TCF of additional natural gas resources. [5] At the current rate of consumption (24 TCF per year) in the United States, the domestic reserves are expected to last 100 years. [29] The abundance of domestic unconventional natural gas can provide many benefits to the United States: affordable energy to jumpstart a stagnant economy [30, 31] and decreased unemployment rates [32], less reliance on unstable foreign energy sources [33], and a more environmentally sensitive energy source [34]. U.S. production rates have increased exponentially with six plays accounting for nearly of all of the production (Figure 2.6), and the U.S. is expected to become a net exporter of natural gas by 2020. [33]

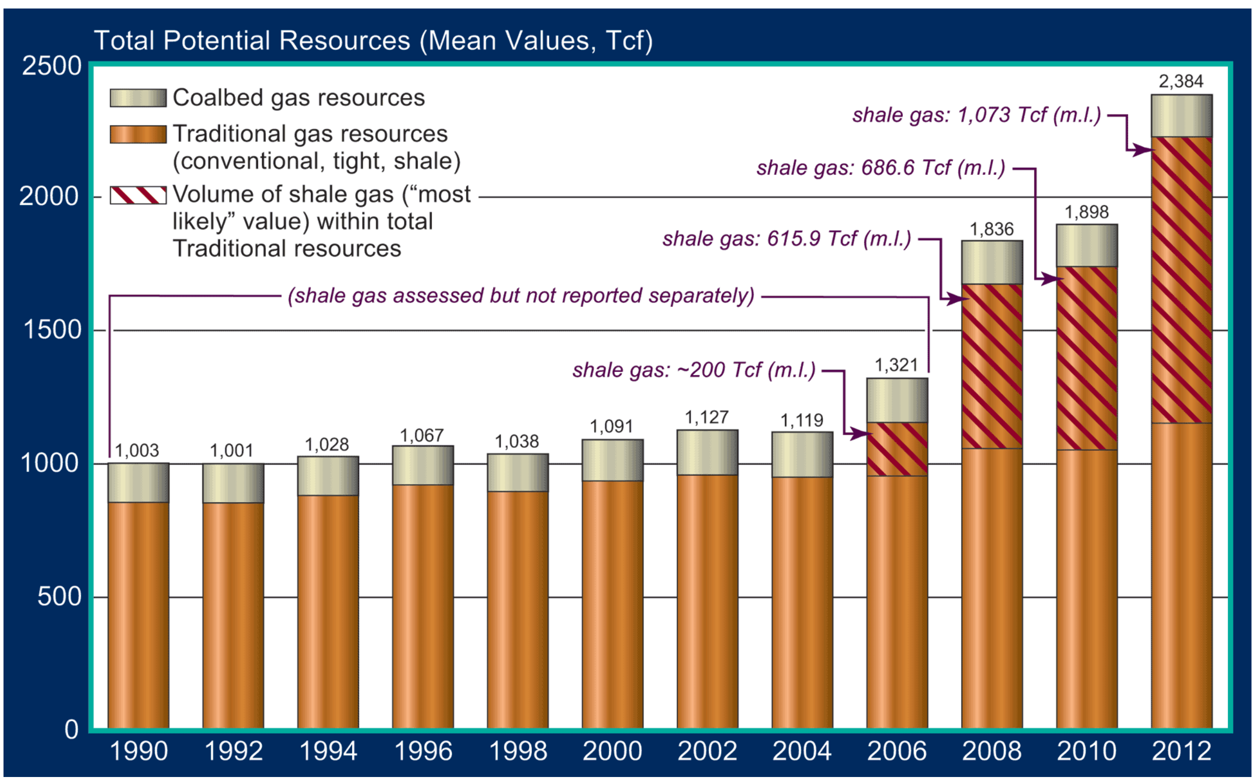

Figure 2.5: Resource assessments made by the Potential Gas Committee at the Colorado School of Mines from 1990-2012 [5]

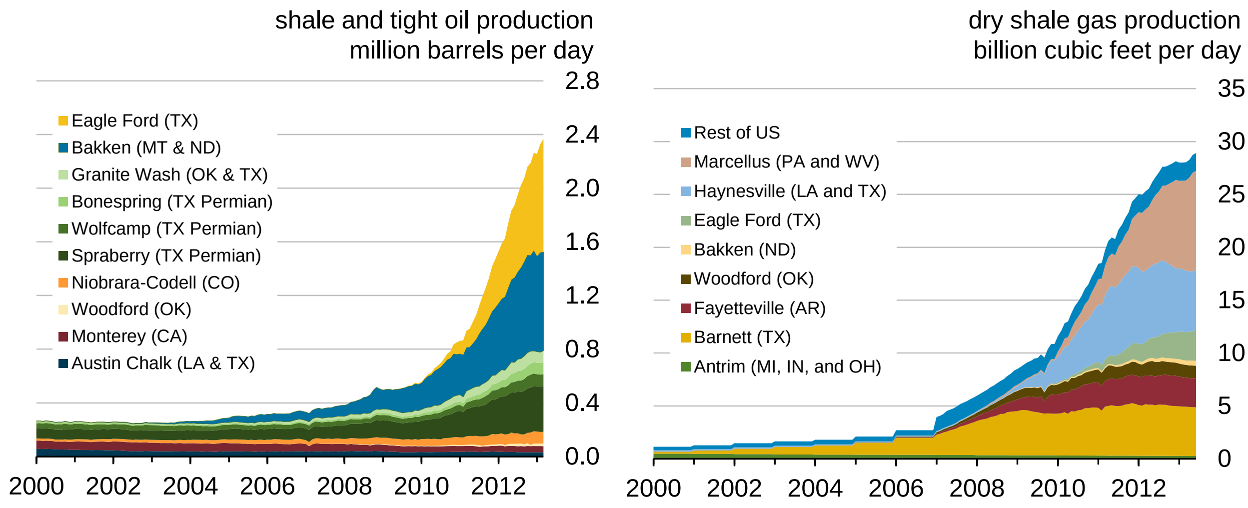

Figure 2.6: Six plays account for nearly all of the recent growth in oil and gas production: Bakken, Eagle Ford, Haynesville, Marcellus, Niobrara, and Permian [6]

2.3. Concerns Associated with Unconventional Shale Oil and Gas

The benefits have been largely overshadowed by reports and headlines expressing environmental concerns associated with hydraulic fracturing operations. These concerns and have led to several moratoriums along Colorado's Front Range and throughout the United States. The environmental issues have ranged from land use to air pollution to water depletion and contamination.

2.3.1. Land Issues

The development of unconventional shale oil and gas, at least temporarily, transforms the landscape and has led to concerns about vulnerable ecosystems, indigenous species, and watershed impacts.[10] Fthenakis and Kim provided a comprehensive review of the land intensity (a ratio of transformation and the total energy recovered) of various energy sources. The review found that natural gas (110 m^2/GWh) has the one of the lowest land intensities followed by energy from nuclear (120 m^2/GWh), photovoltaic solar (160-550m^2/GWh), and coal (200-400 m^2/GWh) (Figure 2.7). [7]

The land intensities of natural gas may be even lower when the higher efficiencies of natural gas combined cycle power plants, less storage space requirements, and multiple horizontal wells from a single pad are considered. [7] For example, four horizontal wells can deliver the same volume of gas as 16 vertical with 90% less land transformation area. [10]

2.3.2. Air Issues

Natural gas as a bridge fuel was first challenged by Howarth at Cornell University. He hypothesized that increased methane emissions, a more potent greenhouse gas emissions, will offset any carbon dioxide emission reductions from natural gas. In his paper, "Methane and the greenhouse gas footprint of natural gas from shale formations," [35] he estimates 3.6% to 7.9% of methane from shale gas production escapes to the atmosphere over the lifetime of the well (30% to 100% more than conventional wells) and concludes that this results in a 20% to 100% greater carbon footprint for natural gas from shale than coal on a 20-year horizon. Over a 100-year horizon, he concludes that coal and natural gas are similar.

Two papers quickly challenged Howarth's claim that natural gas from shale has a larger carbon footprint than coal. Carnegie Mellon University researchers concluded that natural gas from shale has a 20% to 50% smaller carbon footprint than coal, assuming a leakage rate of 2% [36]. Catheles, also from Cornell, provided an official comment [37] attacking Howarth for significantly overestimating methane emission rates. The National

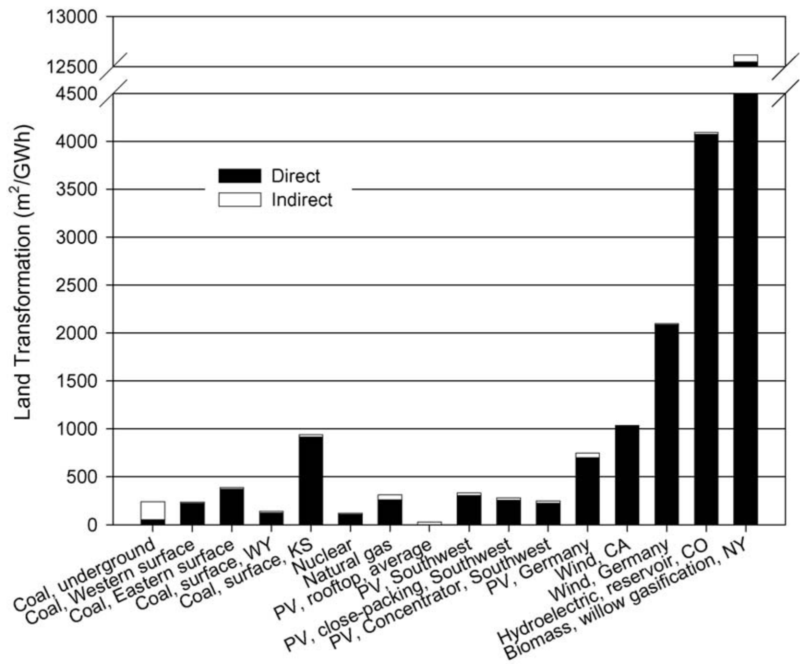

Figure 2.7: The life-cycle land transformation intensity based on a 30-year timeframe is shown for various energy sources [7]

Energy Technology Lab (NETL) provided a more detailed analysis, improving many of the assumptions made by Howarth. [11] NETL found that unconventional natural gas has a slightly higher global warming potential than conventional natural gas, but is much less than coal (Table 2.2).

Fugitive emissions must be properly managed with shale gas to realize the benefits of natural gas and the industry has responded by incorporating bleed-less pneumatics and increased fugitive emissions monitoring. Although fugitive emissions values are continually refined with a variety of approaches and studies [36, 38, 39], a leakage rate of 2-3% is generally accepted. It is also well accepted that shale gas has a smaller greenhouse gas footprint than coal but slightly higher than conventional gas at or below a leakage rate of 2-3%. [10]

Table 2.2: Global warming potential estimates from NETL [11]

Global Water Potential	Average Coal	Average Conventional Gas	Average Unconventional Gas
20-years horizon (lb CO2e/MWh)	2661	1484	1613
100-years horizon (lb CO2e/MWh)	2453	1140	1179

Public health concerns associated with hydraulic fracturing range from increased ground levels of ozone to hazardous air pollutants to reported increased headaches and nosebleeds. Most of Colorado's Front Range is in non-attainment zones due to high concentrations of ground-level of ozone and is subjected to much tighter regulations with the State Implementation Plan to reduce ambient ozone levels. [40] The dominant wintertime source of volatile organic compounds, an ozone precursor, was found to be oil and gas operations in the Wattenberg Field of Northeastern Colorado. [40] Volatile organic compounds and ground-level ozone are known to worsen respiratory conditions such as bronchitis, emphysema, and asthma. [41] However, the study did not extrapolate high levels of volatile organic compounds and ground-level ozone to health impacts.

The Colorado School of Public Health studied the health implications of air pollution from oil and gas development and concluded unconventional shale gas development can contribute to "acute and chronic health problems for those living near natural gas drilling sites." [42] However, the study received harsh criticisms for using out-of-date emissions data before Colorado updated its air quality rules [43], and the author notes, the "EPA standards are designed to be public health proactive and may overestimate risk."

Several studies have attempted to incorporate externalities, such as pollution and public health impacts, to compare the "social cost" of various energy sources. [44, 45, 46] Although the "social cost" is incredibly difficult to estimate, all of the studies conclude the cost of externalities from coal exceed the cost of externalities from natural gas. The true cost of coal, including externalities, is approximately 180% [46] to 560% [44] higher, while the true cost of natural gas is estimated to be only 4% higher. [45]

In the United States, an estimated 23,600 premature deaths are a direct result of coal-fired power stations and in China, with less developed pollution controls, it is estimated that over 500,000 premature deaths are caused by coal combustion. [34] In addition to the decrease in emissions per unit of energy discussed previously, gas-fired plants have a greater efficiency resulting in approximately 70% smaller carbon dioxide footprint compared to coal-fired steam plants. [10]

2.4. Water Issues

It is generally well accepted that natural gas from shale is an improvement from coal for land and air quality, but questions still remain about water as water has emerged as the primary environmental concern. Initially, water concerns focused on aquifer contamination and contamination pathways created from hydraulic fractures. Groundwater contamination concerns due to oil and gas wells have been evaluated extensively and best practices have been adopted by the industry. [47, 47] However, shale oil and gas expanded development into new areas of the country closer to populations that are not accustomed to the oil and gas industry and raised concern.

In May 2011, Duke University researchers were the first to publish a study linking groundwater methane contamination with the proximity to oil and gas wells. [48] The study collected and analyzed water samples from 68 private wells in the Marcellus. Although the study found no evidence of contamination from hydraulic fracturing fluids, it did find the concentration of methane increased in wells that are closer to wells that have been hydraulically fractured and the methane is more likely to be from a thermogenic source based on isotopic analysis.

A number of anecdotal reports of contamination were widely publicized. These reports included cows drinking fracturing water and dying [44], lighting tap water on fire in the movie "Gasland" [49], reports of high concentrations of methane in Colorado, Ohio, Pennsylvania, Texas, and West Virginia [50], and Cabot Oil & Gas Corporation supplying Pennsylvania residents with bottled water after a well explosion. [10]

Several subsurface water quality studies followed [51, 52, 53, 54], including a follow-up to the Duke study. [55] In 2011, the EPA announced plans to study the “Potential Impacts of Hydraulic Fracturing on Drinking Water Resources” to assess systematic failures associated with hydraulic fracturing. [56]

As a result, service companies and operators have been pressured to disclose chemicals used for hydraulic fracturing and to increase monitoring of nearby water sources. On April 1, 2012 the Colorado Oil and Gas Conservation Commission (COGCC) Rule 205a was implemented, requiring, “a service provider who performs any part of a hydraulic fracturing treatment and a vendor who provides hydraulic fracturing additives directly to the operator for a hydraulic fracturing treatment shall, with the exception of information claimed to be a trade secret, furnish the operator with the information required.” [57] The data is publicly available at FracFocus.org. [58]

The COGCC also implemented a statewide groundwater baseline sampling and monitoring plan. COGCC Rule 609 requires operators to establish a baseline water quality assessment and regularly monitor the water after hydraulic fracturing. This data is also publicly available. [57] In Colorado, real-time water monitoring programs are being led by Colorado State University and the University of Colorado is assessing pathways for water contamination. [59] Despite widespread publicity concerning water contamination, at this time, it appears water contamination is likely a result of isolated rare events and not a systematic problem.

Water monitoring is an important step in recognizing and understanding the risks of groundwater contamination associated with oil and gas development, but it does not directly mitigate any of the risk. Water is the single largest material required for unconventional oil and gas development and also the largest waste stream. [14] Reducing the volume of water handled and transported can dramatically reduce the risks of accidents, spills, and leaks contaminating freshwater aquifers. In addition to reducing water contamination risks, improving water management and water reuse within a field has the potential to also reduce impacts to local communities, land disturbances, air pollution, and depletion of regional water resources (Figure 2.8).

Water data (particularly water requirements, flowback water, and water quality data) has been sparse and not readily available in literature. The lack of authoritative water data has been well documented. [15, 16, 13] Energy companies [9, 17], regulatory agencies [18], journalists [19], and academics [20] have provided either broad estimates or a single value without uncertainty. In a 2012 report [21], The Government Accountability Office found that “making effective policy choices will continue to be challenging without more comprehensive data and research.”

Water use data within the energy sector is challenging for several reasons. Primarily, the U.S. energy sector is private and compatibility issues such as data consistency, accuracy, and currency often limit data availability. [13] Collecting and maintaining high-quality data for a rapidly changing industry is also costly and time-consuming and provides little benefit to operations. [13]

The Railroad Commission of Texas requires operators to report water use for completion and maintains the data in a public database. [60] Using this data, Nicot and Scanlon provided the most comprehensive review of water use available. [14] In Colorado, the COGCC has taken similar steps. In addition to chemical disclosure required COGCC’s Rule 205a, operators are required to disclose the total volume of water used in the hydraulic fracturing treatment for all wells drilled after April 1, 2012. [57] The water volumes are also publicly available on FracFocus.org. [58]

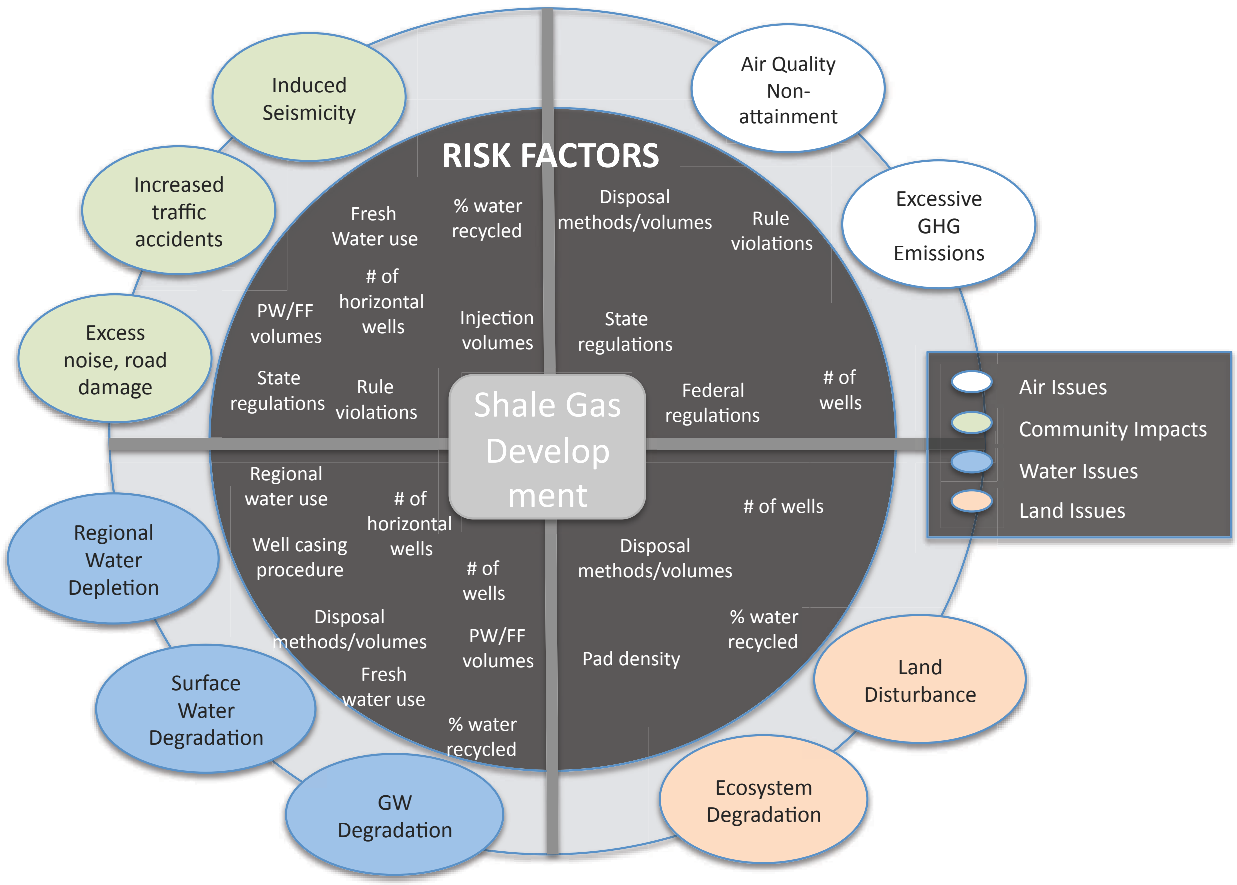

Figure 2.8: The factors contributing to the perceived risks associated with unconventional oil and gas development. Improving water reuse and water management is a factor impacting every perceived risk that is presented. [8]

Few studies have been completed that assess the water required for shale gas development and production in the United States [61, 9] and nearly all of the studies provide only broad, general estimates based on assumptions [62, 20, 9] or disjointed databases [63]. In Northeastern Colorado, attempts have been made to characterize water use per well and future water requirements [17, 18] but an in-depth assessment of water requirements has not been done. Most commonly water use is estimated to be between one to five million gallons per well. [64]

Considering the lack of in-depth water use assessments of unconventional oil and gas from shale, a surprising number of reports estimate the water intensity values and compare the estimates with other energy sources. Water intensity is typically defined as a ratio of the water required to develop an energy source and the energy recovered. Water intensity can provide a better comparison of how efficiently water is being used to develop an energy source.

Gleick [65] provided one of the first broad reviews of water intensity, presenting direct, consumptive water intensity values for each life cycle phase (i.e. mining, fuel preparation, generation, etc.) of several different fuel sources in 1994. Sovacool and Sovacool [66] expanded the scope of a water intensity analysis to separate water use into both water withdrawals and consumption. Fthenakis and Kim [67] were the first to include upstream water use in the analysis, which includes water requirements associated with energy and material inputs to each life-cycle phase of electricity generation technologies.

In recent years, increasing concern about water and energy resources in the U.S. has led to significantly more available literature particularly from government agencies [68, 69, 70, 71, 72, 73, 74, 75, 76], most notably, a 2006 report to Congress from the Department of Energy. [68] The report was a response to a Congressional directive asking for “a report on energy and water interdependencies, focusing on threats to national energy production that might result from limited water supplies.”

Perhaps the most comprehensive and recent review of water intensity comes from the Harvard Kennedy School, titled Water Consumption of Energy Resource Extraction, Processing, and Conversion. [20]

Several regional studies [75, 76, 77, 74, 78, 79] have assessed water resource challenges with increasing demands for water. The majority of these studies provide a broad estimate of water requirements, without a detailed analysis of water use on an individual well basis. An analysis of the water intensity of each individual well provides a more detailed and accurate assessment of the water intensity. Other studies focus solely on electricity generation[69, 80, 81, 82, 83, 84, 72, 85, 86] or transportation[87, 88, 89], the two largest energy sectors in the United States.

Water management requires an understanding of both water used to develop the well and wastewater returning to the surface. Wastewater is typically separated into flowback (wastewater before production) and produced water (wastewater after production). In Colorado, monthly produced water volumes are publicly available from the COGCC along with monthly oil and gas production for each well. [90] However, currently flowback water volumes are not publicly disclosed in Colorado. Initial flowback rates can be as high as 1,000m3/d and the flowback period can last anywhere from a few days to a few weeks. [91] Both the water volumes and water composition can change significantly as a function of time. [91]

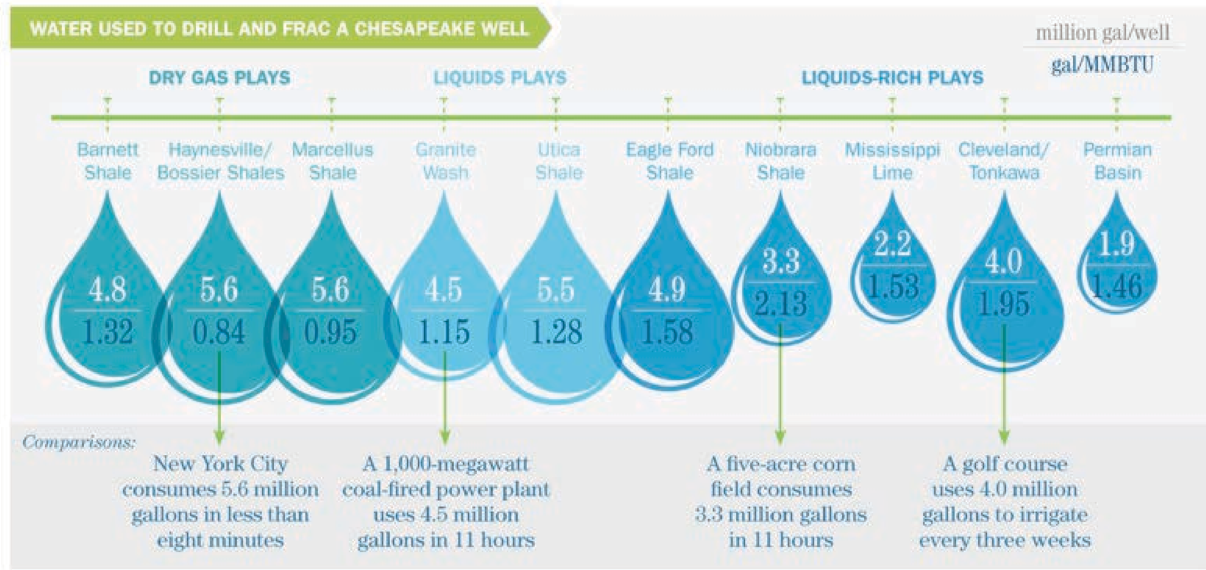

Figure 2.9: Water use and water intensity estimates made by industry to fill the gap in authoritative peer-reviewed analyses. [9]

Flowback water can provide either the largest waste stream for disposal or a new source of water to supplement freshwater demands. Without public disclosure of either flowback water volumes or composition, the water reuse potential is not well documented, particularly in areas that require gelled hydraulic fracturing fluids such as Northeastern Colorado. The chemical composition of hydraulic fracturing fluid is still partially confidential and the chemical composition of hydraulic fracturing is tailored for each well to accommodate a wide-range of water qualities and geologic conditions. [58, 92, 91]

Water reuse strategies are challenged with two moving targets: (1) temporally and spatially changing wastewater quantities and qualities and (2) rapidly changing water treatment targets based on new hydraulic fracturing fluid development. Flowback water qualities are typically presented as a wide-range of values without any temporal or spatial resolution. [91, 93, 94, 95] Without long-term data, produced water estimates can be estimated based on existing conventional wells and USGS data. [96]

Several studies have assessed the impact specific treatment methods have on treating produced water [97, 98, 99, 100], but no study has assessed the impacts of the treated water on developing a hydraulic fracturing fluid or more importantly the production of a well using the hydraulic fracturing fluid. A recent Halliburton study claims water reuse with 285,000 mg/l of total dissolved solids is possible. [101] Although another recent study has alluded to high dissolved solids content improving production because of a similar composition to the formation, but high suspended solids impeded hydraulic fracturing fluid development. [93] Water quality impacts on hydraulic fracturing fluid rheology tests are incredibly sparse in literature and a consensus has not been reached.

Recently water management associated with shale gas development is receiving more attention in literature, but all of the published journal articles have focused on the Marcellus. Rahm presents a detailed analysis of water management trends in the Marcellus. [102] and several versions life-cycle analyses of shale gas in the Marcellus have also been recently published [63, 103, 104]. Northeastern Colorado and much of the West’s semi-arid environment and widespread use of gelled hydraulic fracturing fluid present dramatically different water management challenges.

3. Research Objectives

3.1. Research Objectives

Water resources in Colorado and the western U.S. are constantly strained given the historical agricultural needs, burgeoning development, and the semi-arid environment. With continued population increases and the importance of agriculture to the overall economy, the pressure on water and other natural resources is expected to intensify. Even though the oil and gas industry has long been a part of the economy in Colorado and the West, recent technological advances have stimulated considerable growth in oil and gas development and operations and therefore have increased the industry's need for water resources.

In October, 2011 the State Review of Oil and Natural Gas Environmental Regulations (STRONGER) organization issued a report on the Colorado hydraulic fracturing program and the rules developed by the Colorado Oil and Gas Conservation Commission (COGCC) related to this. [15] The report, which was generally positive, made five recommendations for improvement. One of the key recommendations in this report was regarding the availability of water:

> *"The review team recommends that the COGCC and the DWR jointly evaluate available sources of water for use in hydraulic fracturing. Given the significant water supply issues in this arid region, this project should also include an evaluation of whether or not availability of water for hydraulic fracturing is an issue and, in the event that water supply is an issue, how best to maximize water reuse and recycling for oil and gas hydraulic fracturing."*

Other recommendations regarding the management of water resources associated with hydraulic fracturing were made by the Natural Gas Subcommittee of the Secretary of Energy's Advisory Board (SEAB) in November, 2011. [105] The subcommittee was charged in April 2011 to study ways to improve the safety and environmental performance of natural gas hydraulic fracturing from shale formations.

In its final report, the subcommittee stated "At present neither EPA or the states are engaged in developing a systems/lifecycle approach to water management". They recommend that new partnerships or mechanisms be developed to study the lifecycle of water resources as one approach to protecting the quality of water resources in the future.

Working with Noble Energy, Inc. a framework is proposed to assess the water and energy flows in the Wattenberg (Figure 5.2) to address the concerns raised by these and other studies. Currently water and energy values within this framework are not well reported in literature, particularly for Northern Colorado. Water use for drilling and hydraulic fracturing may be the only exceptions, but are often cited with a wide range of values. Perhaps the most cited estimate of water use for Northern Colorado comes from the Colorado Oil and Gas Association, which estimates the water required is between two to five million gallons of water per well. [64]

A wide range of estimated water use requirements coupled with rapidly changing oil and gas development plans allow for dramatically different presentations of the impacts on water resources. The Colorado Oil and Gas Conservation Commission estimated hydraulic fracturing to account for 4.5 billion gallons of water annually, or only 0.08% of the total 2010 water withdrawals in Colorado, while agriculture withdrew 4.6 trillion gallons or 85.5%. [106] In contrast, Western Resource Advocates estimates 7.2-13 billion gallons of water annually or [107], or enough water to serve 166,000-296,100 people per year.

As Colorado's population continues to grow and is expected to double to 10 million people by 2050, the demand for water will continue to strain water resources. By 2050, the Colorado Water Conservation Board anticipates an annual water shortfall of 175-264 billion gallons. [76] As operators increase the volumes of flowback and produced water being used to reduce impacts on water resources, it is important to accurately predict produced water volumes and qualities. It is also important to understand how the water quality impacts hydraulic fracturing fluid development and performance. A better understanding and characterization of the water quantities and quality associated with each stage of oil and gas development in Colorado to assist policy-makers in providing enough water for Colorado, optimize water infrastructure planning, and water reuse strategies.

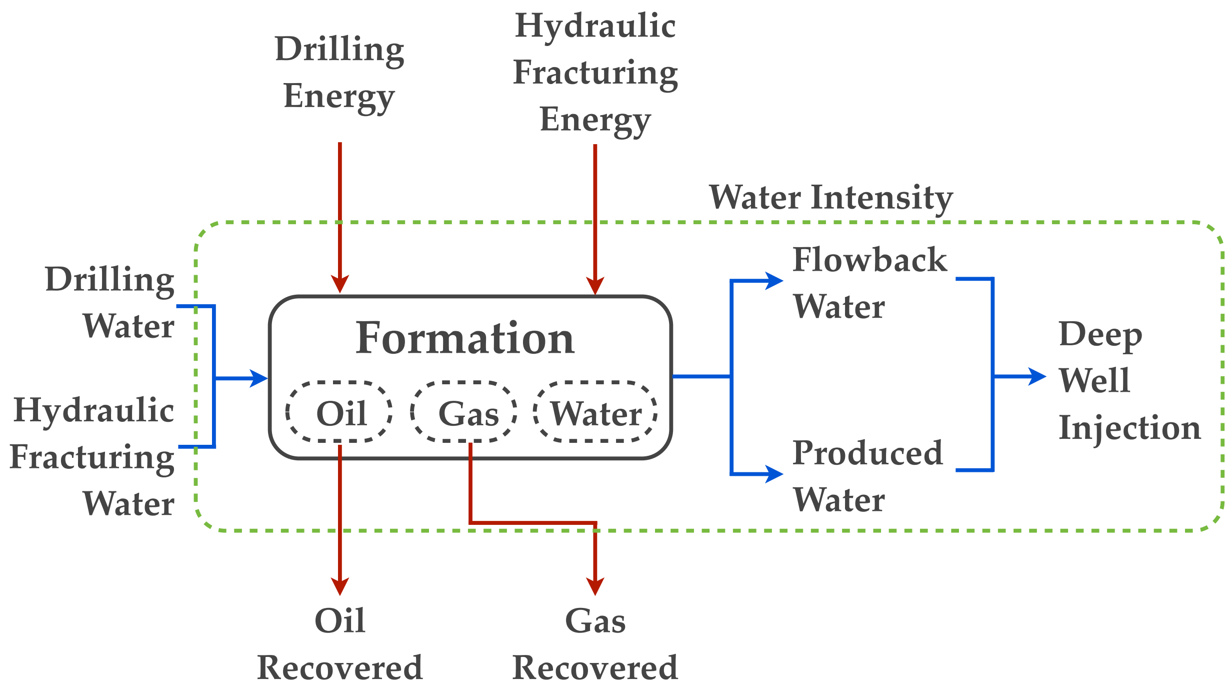

Figure 3.1: A materials and energy balance defining the flows of water (blue lines) and energy (red lines) in an oil and gas field.

The technical challenge of optimizing water reuse and water management is not a lack of water treatment technology. Fundamental water treatment technology has been developed and refined for decades in several industrial water treatment applications. The technical challenge lies in implementing infrastructure to optimize oil and gas production while minimizing water use as well as other environmental and social impacts. This requires a detailed understanding and characterization of water use and wastewater in an oil and gas field as well as an understanding of how treated reuse water quality influences the development and performance of hydraulic fracturing fluid.

Optimizing water management and reuse requires quantitative tools to assess the implications of a variety of water infrastructure scenarios. In a rapidly changing and uncertain oil and gas field, the implications of mobile vs. fixed treatment facilities, pipelines vs. trucking, the location of water resources, or degree of treatment require an integrated model to asses and visualize the implications of each decision. The quantitative tool requires flexibility in both the development plans for the field and the values placed on economic, social, and environmental implications.

A general schematic of the model is shown in Figure 3.2. To model and optimize water infrastructure for the entire field, each component is studied individually to determine the best approach to model each piece of infrastructure. The following chapters provide a detailed analysis of the most influential factors influencing each component. For example, the most influential factors that determine drilling and hydraulic fracturing water use is estimated and the most influential factors are used to develop a model of water use for individual wells.These factors are used to incorporate a model of each individual component into a larger model of the field where a variety of water management and reuse scenarios can be assessed with a range of field development scenarios.

The objective of this dissertation is to:

> **Model and quantify the social, environmental, and economic implications that water infrastructure decisions have within an uncertain and rapidly changing oil and gas field.**

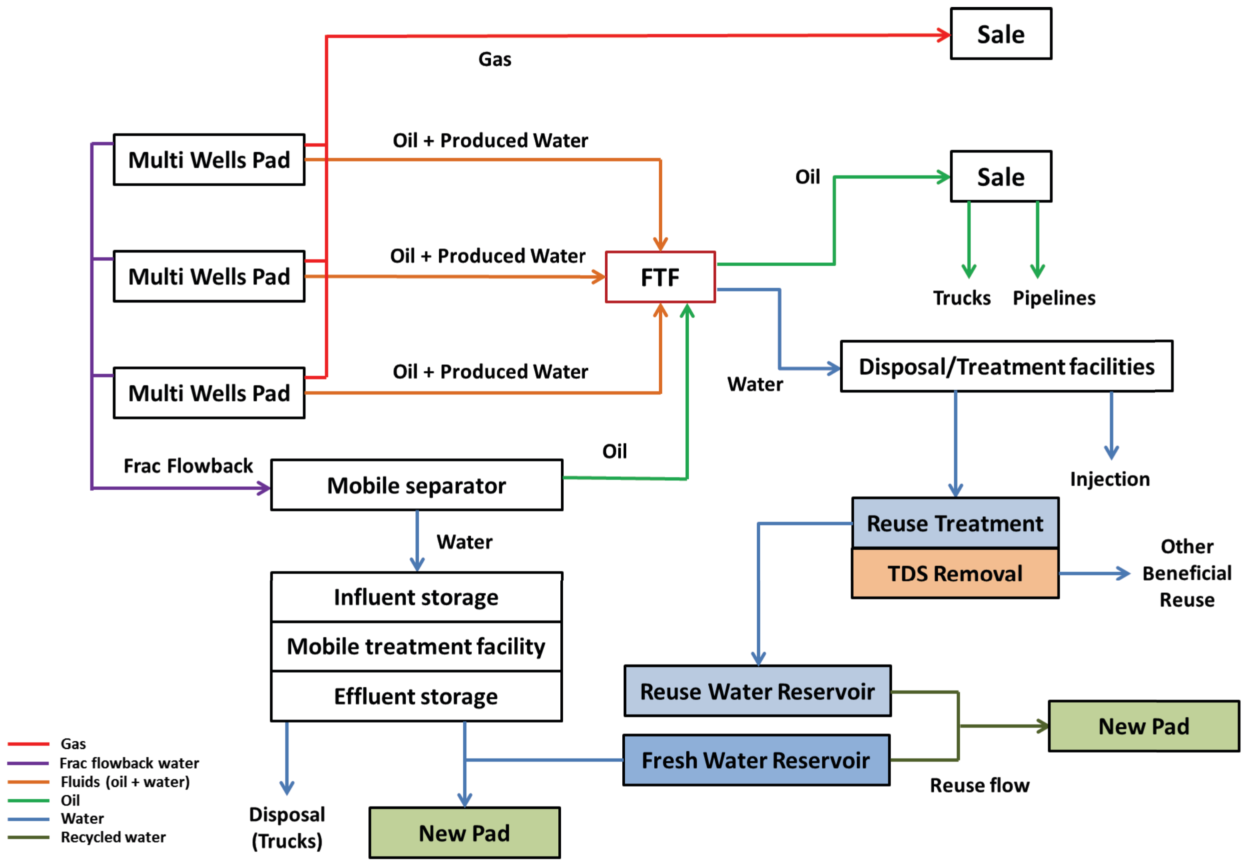

Figure 3.2: A schematic defining the oil, gas, and water flows within a typical oil and gas field.

A brief description of each individual component is given below along with the modeling approach and the corresponding chapter with a detailed analysis:

- **Multi Wells Pad:** Typically multiple wells are drilled from a single pad. Water, followed by sand, are the two largest material requirements and flowback/produced water is the single largest waste stream. The water required, oil and gas produced, water produced, and produced water quality all need to be modeled for this component. An explanation of how each piece is modeled is given below:

Water Volume Required: A sample set of wells are used to determine the most influential factors influencing the water use per well. The most influential factors are used to model the water use for drilling and hydraulic fracturing for future development. This study was developed as part of this dissertation and the results are published in the Journal of Water Resource and Protection.

Oil and Gas Produced: A decline curve analysis was performed to estimate the water intensity for wells in the DJ Basin. The decline curves developed for this study will be used to model oil and gas production rates. This study is under a second review for publication in Environmental Science and Technology.

Water Volume Produced: A similar, but more detailed, analysis of water production decline curves was in collaboration with Colorado State University and Noble Energy, Inc.. The curves developed in this study will be used to model the flowback and produced water volumes for each well. This study was published in the Journal of Petroleum Science and Engineering. The decline curve will be used in the model, but the journal article will not be used in the dissertation.

Quality of Flowback/Produced Water: Five wells have been sampled to characterize the temporal changes in water quality. The five wells were chosen to measure different either different hydraulic fracturing fluids (guar-based vs. synthetic) or different types of hydraulic fractures (gelled vs. slickwater vs. hybrid).

- **Fixed Treatment Facilities (FTF):** A fixed treatment facility is typically a large centrally located treatment facility. Oil and water is separated and the wastewater is either treated or injected. In order to model this component, the influent water quality, target effluent water quality, influent oil and water volumes, and optimized location need to be modeled. An explanation of how each piece is modeled is given below:

Influent Water Quality: The influent water quality is modeled using the modeled flowback/produced water quality and the completion schedule included in the development plans.

Target Effluent Water Quality: In order to effectively design wastewater treatment facilities estimates of the influent and effluent water quality needs to be understood. Water quality is estimated based on the flowback/produced water sampling campaigns. However, the effluent water quality depends on how specific water quality parameters influence hydraulic fracturing fluid performance. An ongoing study has been attempting to characterize the influence and interactions between individual water quality parameters on the performance of specific hydraulic fracturing fluids. This is a key part of the dissertation and will allow for optimized water treatment (e.g. designing specific unit processes) and water management strategies (e.g. deciding when water should be treated, diluted, or disposed of). Due to the proprietary nature of this work, a journal article has not yet been published for this work.

Fixed Treatment Facility Size: The size of the separator, treatment facility, and injection well depend on the average and peak volumes being sent to the fixed treatment facility. The daily oil and water volume is modeled by summing up the decline curve models for every well in the field based on the development plans.

Fixed Treatment Facility Location: The location of the fixed treatment facility can be located to minimize the distance water needs to be transported, which reduces the risk of spills, road damage, pumping costs, and greenhouse gas emissions. For this model, the distance will be calculated by multiplying the linear distance to (wastewater) and from (recycled freshwater) the fixed treatment facility by the volume of water to obtain bbl-miles for each fixed facility location. The location that minimizes the number of bbl-miles will be assumed to be the best location. In addition, several collaborative efforts with environment and mechanical engineers at Colorado State University are working to optimize the site location based on pipeline pumping requirements, truck traffic emissions, well density, and other key factors. Although these models can be incorporated in future versions of the model, these research projects are beyond the scope of this model at this time and will not be incorporated into this dissertation.

- **Mobile Treatment Facilities:** Mobile treatment facilities are modeled as fixed treatment facilities that can be added, removed, or moved in the field. The mobile treatment facilities will be more expensive to move and operate. However, a mobile treatment facility will reduce the trucking/piping costs and can supplement fixed treatment facilities by treating the peak loads.

All of the components are integrated into a graphical user interface (GUI) that allows the user to estimate water volumes within a field, adjust development plans and decline curves, and place water infrastructure throughout the field. The financial, environmental, and social implications of placing and sizing water infrastructure can be clearly visualized as key variables are adjusted using the GUI. Furthermore, the average and peak influent and effluent flows for each piece of infrastructure can be easily calculated using the GUI. A range of development plans for a field can be used to determine the robustness of water infrastructure decisions. Also, the placement of mobile and fixed treatment facilities can be determined using the GUI, as shown in Figure 3.4.

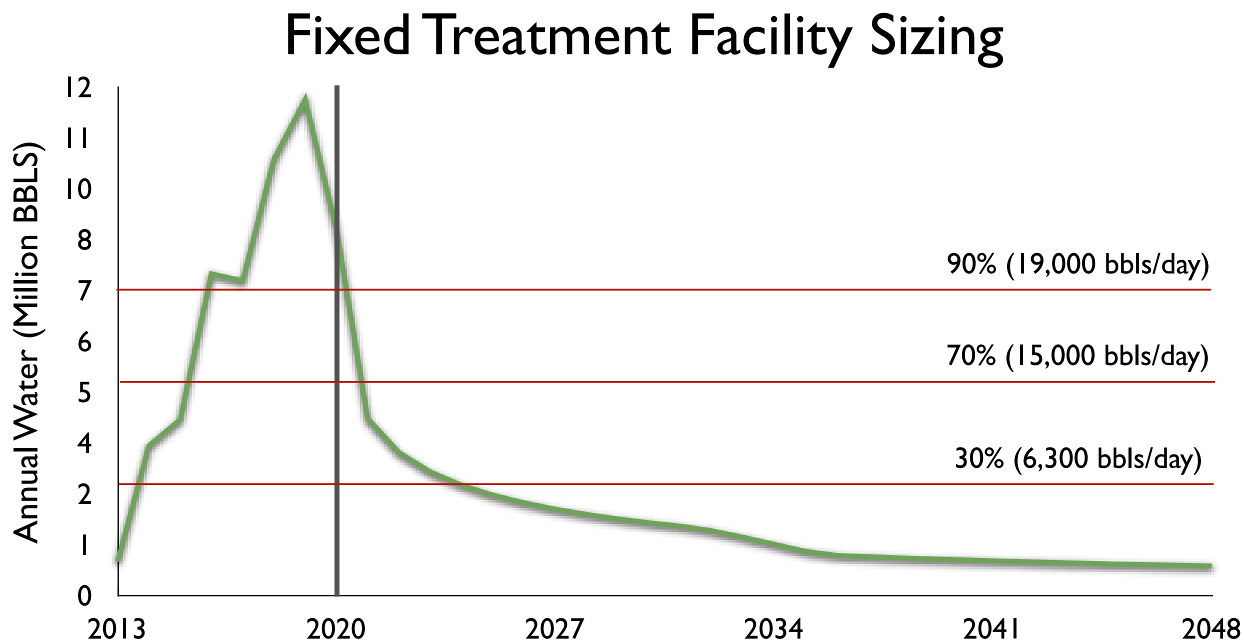

Figure 3.3: The challenge of sizing a fixed treatment facility is illustrated in the figure. The annual volume of wastewater increases as a field develops and peaks right before the development period ends (represented by the gray vertical line). The facility needs to be optimized to capture an economically feasible volume of water, while not being oversized after development ends. Three fixed treatment facility sizes are represented by the red horizontal lines.

The user can also place value on key costs, including environmental, social, transportation (tucking vs. piping), injection, and treatment strategies. A relative cost score from 0-100 is used to place value on each category. By adjusting the weighting criteria for each water management scenario, the user can better understand which values are driving the final water infrastructure decisions.

The objective of the model is to quantify the social, environmental, and economic implications that water infrastructure decisions have within an uncertain and rapidly changing oil and gas field. This will provide operators with a tool to better organize and understand the factors and implications driving water infrastructure decisions in an oil and gas field.

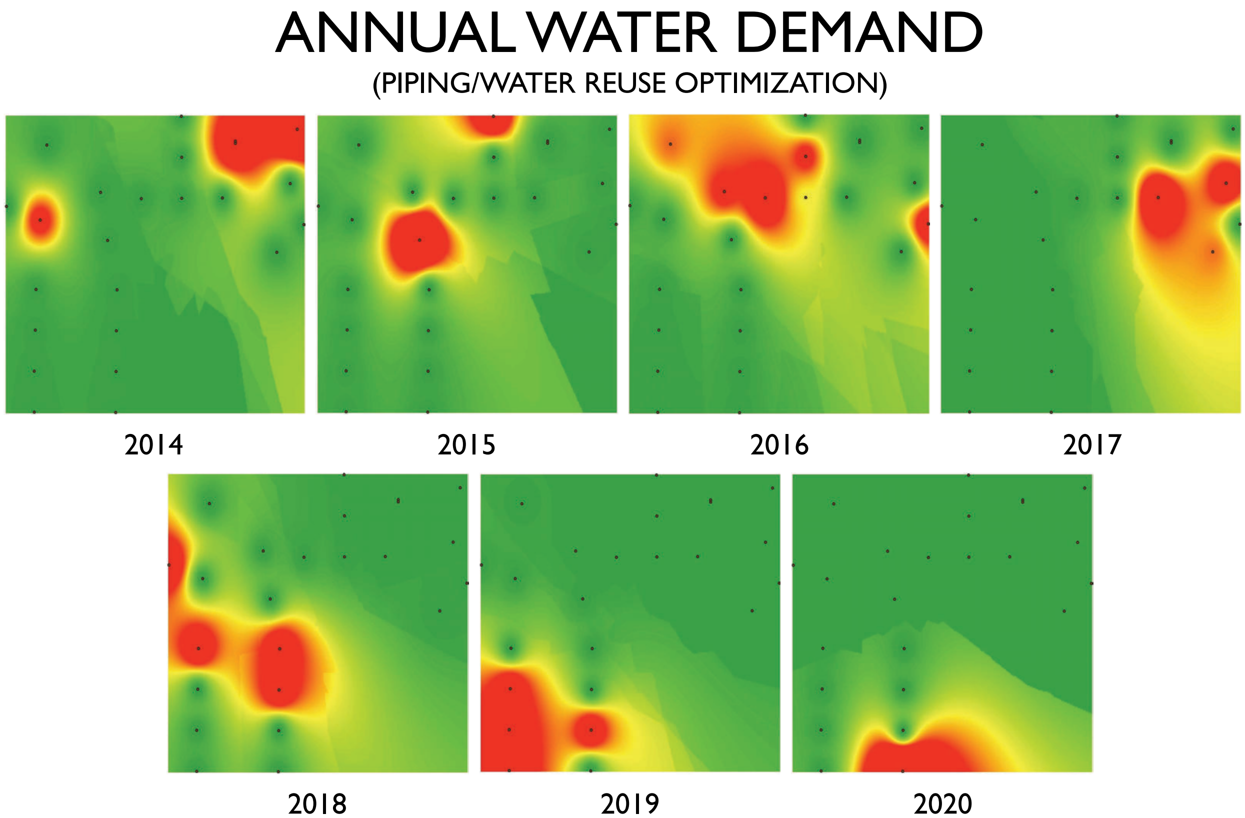

Figure 3.4: An interpolated plot of annual cumulative wastewater volume in shown as a field develops. Ideally, treatment facilities should be placed where the largest volumes of wastewater is produced and where the treated water needs to be sent. However, it is expensive to move treatment facilities or build multiple facilities. The model will help answer questions about siting a facility.

4. Improved Water Use Estimates for Drilling and Hydraulic Fracturing in Northeastern Colorado[i]

4.1. Overview

The development of unconventional resources in tight shales has stimulated considerable growth of oil and gas production in Northeastern Colorado, but has led to concerns about added demands on the region's strained water resources. Northeastern Colorado's semi-arid environment, population growth, competing water demands, and uncertainty about drilling and hydraulic fracturing water requirements has resulted in scrutiny and conflict surrounding water use for tight shales. This study collects water use data from wells in Northeastern Colorado to improve water estimates and to better understand important contributing factors. Most water resource studies use estimates for the number of future wells to predict water demands. This study shows the number of hydraulic fracturing stages is a better measure of the future water demands for horizontal wells. Vertical wells use significantly less water than horizontal wells and will be less prevalent in the future.

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[i] **As Published in the Journal of Water Resources and Protection**

S. Goodwin[a], K. Carlson[a], B. Bai[a], K. Knox[b], C. Douglas[b], L. Rein[b]

[a] Colorado State University, Department of Civil and Environmental Engineering, Campus Delivery, Fort Collins, CO 80523, USA

[b] Noble Energy, Inc., Environmental Engineering: Denver Office, 1625 Broadway Suite 2200, Denver, CO 80202, USA

4.2. Introduction

Water resources in Northeastern Colorado and the western United States are constantly strained given the historical agricultural needs, burgeoning development, and the semi-arid environment. With continued population growth and the importance of agriculture, the pressure on water resources in the region is expected to intensify. The oil and gas industry has long been a part of Northeastern Colorado's economy, but recent advances in technology have stimulated considerable growth in the region that has increased the industry's demand for water resources.

Several studies have assessed water resource demands in Northeastern Colorado [75, 76, 77, 74, 78, 79]. All of these studies base the total water demands on the number of wells. Typically the water required to drill and hydraulically fracture a well is estimated to be between one and five million gallons per well [76, 9]. These general estimates of water use have led to increased uncertainty and conflict surrounding water development for the oil and gas industry in Northeastern Colorado.

As competition over water resources between agricultural, recreational, municipal, and industrial demands, including oil and gas operations continues to escalate, it is important to understand more precisely the demands the oil and gas industry will place on water resources. Several organizations have voiced concerns about a lack of water use data to assess impacts on water resources. In October 2011 the State Review of Oil and Natural Gas Environmental Regulations (STRONGER) organization issued a report on rules developed by the Colorado Oil and Gas Conservation Commission (COGCC) related to hydraulic fracturing. One of the five recommendations of the report included the following:

> *"The review team recommends that the COGCC and the DWR jointly evaluate available sources of water for use in hydraulic fracturing. Given the significant water supply issues in this arid region, this project should also include an evaluation of whether or not availability of water for hydraulic fracturing is an issue and, in the event that water supply is an issue, how best to maximize water reuse and recycling for oil and gas hydraulic fracturing."*

The Natural Gas Subcommittee of the Secretary of Energy's Advisory Board (SEAB) made other recommendations regarding the management of water resources associated with hydraulic fracturing in November 2011. [105] The subcommittee was charged in April 2011 to study ways to improve the safety and environmental performance hydraulic fracturing from natural gas shale formations. In its final report, the subcommittee stated "At present neither EPA or the states are engaged in developing a systems/lifecycle approach to water management." They recommend that new partnerships or mechanisms be developed to study the lifecycle of water resources as one approach to protecting the quality of water resources in the future.

This study addresses these concerns by examining the water use of individual wells to provide governing agencies, industries, and the greater public empirical data to make informed decisions regarding future water and energy development. The objective of this study is to provide a detailed assessment of current water use and to determine the factors that have the strongest influence on the total water use per well. These factors include the well type (vertical, horizontal, or extended horizontal), number of hydraulic fracturing stages, water use (drilling or hydraulic fracturing), temporal, and spatial distribution.

Traditional quantification of water use based upon the number of energy wells developed is misleading and no longer practical. An accurate and applicable measure of accurate water development is the number of stages used in completion of an energy well, commonly referred to as hydraulic fracturing. This investigation illustrates the value and importance of applying this new metric in water resources management for energy development.

4.3. Method

The wells included in the water use analysis are limited to wells located in the Wattenberg field located in Northeastern Colorado, drilled between January 1, 2010 and July 1, 2013, and operated by Noble Energy, Inc. (Noble) with complete water use records available. For this study, the Wattenberg field is defined by the Colorado Oil Gas Conservation Commission's (COGCC) GIS shape file accessed on July 1, 2013 (Figure 4.1). To best assess current water requirements and predict future demands only wells drilled after 2010 are included in the study. Noble is the largest operator in the Wattenberg field.

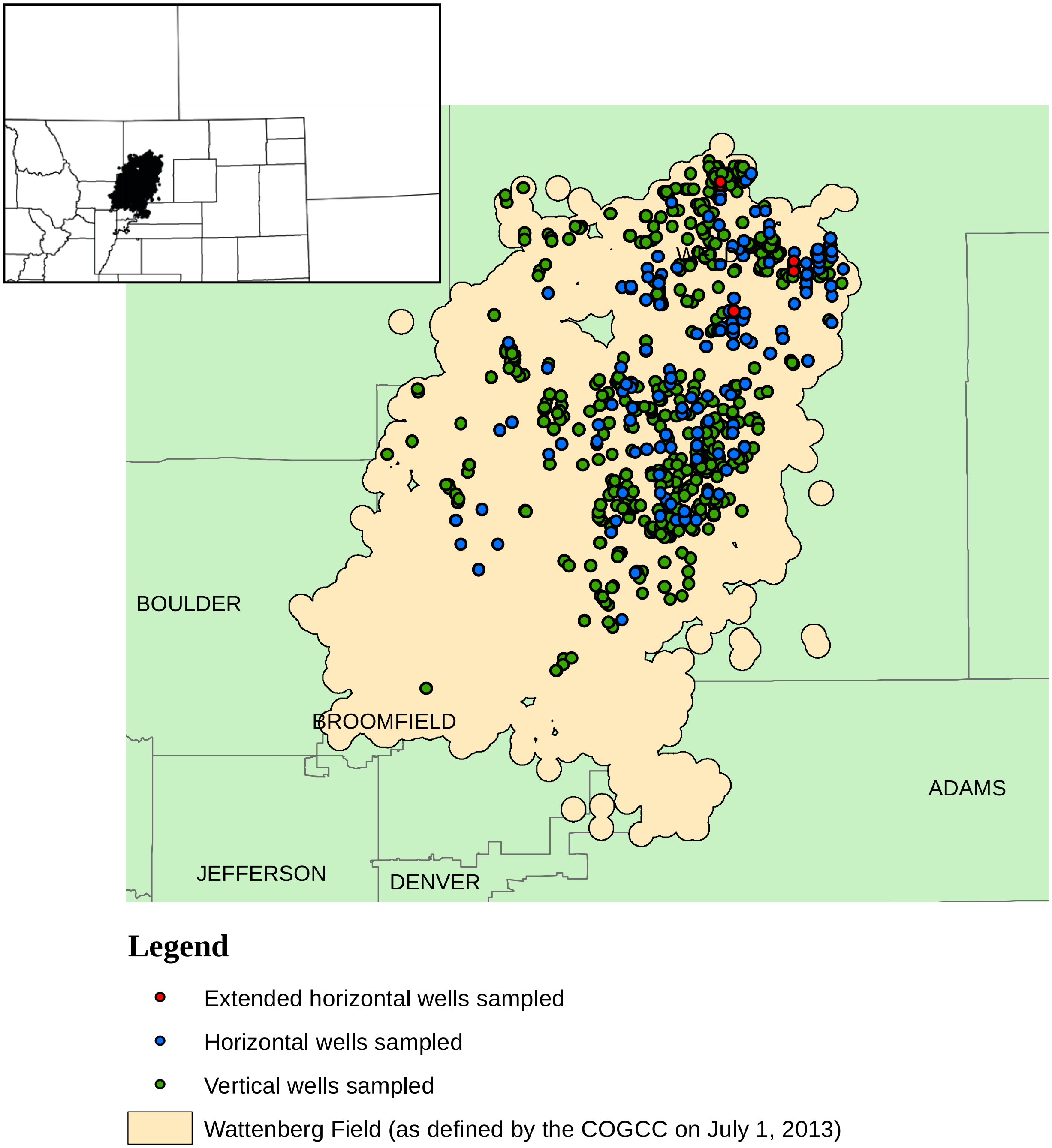

Figure 4.1: The spatial distribution of sampled wells used in this study. Sampled vertical wells are shown in green, sampled horizontal wells are shown in blue, and extended horizontal wells are shown in red. The Wattenberg field as defined by the COGCC on July 1, 2013 is shown in tan.

A total of 1,220 wells are included (Table 4.1) and categorized using: A) drilling water consumed; B) hydraulic water consumed; C) total water consumed; D) well type (vertical, horizontal, or extended horizontal); E) hydraulic fracturing stages or distance; F) hydraulic fracturing fluid; G) well coordinates; H) year; and I) target formation, if available.

Table 4.1: The count of sampled wells separated by year and well type.

	Vertical	Horizontal	Extended Horizontal
2010	181	6	0
2011	408	65	2
2012	227	182	6
2013	5	117	21

Water use is categorized as either drilling or hydraulic fracturing water. Water used to drill the well, prepare the borehole, and set the casings is defined as drilling water. Water used to fracture the shale, carry the proppant used to maintain fracture geometry, and flush the well is defined as hydraulic fracturing water.

Drilling and hydraulic fracturing water consumption records for each well are collected using Noble Energy's WellView software [108] and separated by year. WellView is part of the Peloton suite of software used for collecting and organizing oil field data. A Noble employee adds drilling and hydraulic fracturing reports to WellView that is on location at each drilling and hydraulic fracturing site. Noble Energy's accounting department verifies the water consumption totals and any conflicts are reconciled in WellView. The water use data was downloaded from Noble Energy's WellView software on July 1, 2013. The drilling and hydraulic fracturing water use are summed, if both are available, to estimate the total water consumed.

Wells are separated by type (vertical, horizontal, or extended horizontal) using Noble's well naming system or the number of hydraulic fracturing stages, if available. Directional and deviated wells are categorized as vertical wells for this study because of similar water requirements. Horizontal wells are separated from extended horizontal wells by Noble's well naming system or the number of hydraulic fracturing stages used when available. A horizontal well will typically be hydraulically fractured in 20 stages. Recently, Noble has drilled and hydraulically fractured longer horizontal wells that can include over 40 stages to hydraulically fracture. Horizontal wells that require over 25 hydraulic fracturing stages are defined as extended horizontal wells in this study.

The type of hydraulic fracturing fluid used and the number of hydraulic fracturing stages per well are collected from Noble Energy's WellView software. The well coordinates, year, and target formation are all collected COGCC's online facilities database.

An Anderson-Darling test [109] is used to test the normality of each subset of data. The difference between water use for each subset of data is tested using a non-parametric Kruskal-Wallis test. A Dunn-Šidák post-hoc comparison [110] is used to compare any differences between samples that are found using the Kruskal-Wallis test. A 95 percent confidence interval is used throughout the analysis. The number of hydraulic fracturing stages is correlated using a simple linear regression. A coefficient of determination is used to measure how well the regression correlates the hydraulic fracturing water use and the number of stages. Spatial autocorrelations are measured with ArcGIS Spatial Analyst tool [111] using Moran's I with inverse distance weighting and a 95 percent confidence interval.

942 wells have both drilling and hydraulic fracturing water and are included in the study. Wells that are drilled but not hydraulically fractured (260 sampled wells) are typically conventional wells recovering from an oil and gas trap. Wells that are hydraulically fractured but

not drilled (25 sampled wells) are typically existing wells that are reworked or restimulated using hydraulic fracturing.

4.4. Results

A Kruskal-Wallis test reveals there is a significant difference between the median total water use for vertical, horizontal, and extended horizontal wells ($\chi 2(2)=622$, $p<0.05$). Dunn-Šidák post-hoc comparisons of the total water for the three well groups indicates that vertical wells (Mdn=360,000) use significantly less total water than either horizontal (Mdn=2,871,000) or extended horizontal wells (Mdn=5,620,000). Horizontal wells also use significantly less water ($p<0.05$) than vertical wells, which is expected due to the decreased number of hydraulic fracturing stages. Horizontal wells that have been re-stimulated several years after the initial drilling and hydraulic fracturing were not included in the comparison, because insufficient data was available.

The total water use for each well type does not show significant temporal (Figure 4.3) or spatial variation (Figure 4.7) within the Wattenberg field. Only vertical wells show any significant spatial autocorrelation ($I=0.66$, $p<0.05$). The significant clusters for vertical wells appear to be randomly distributed throughout the Wattenberg field and do not present an obvious trend in water use spatially. Horizontal ($I=0.53$, $p=0.60$) and extended horizontal ($I=-0.082$, $p=0.70$) wells do not show any significant spatial autocorrelation.

The type of hydraulic fracturing fluid used significantly influences the water use for vertical wells. The normalized hydraulic fracturing water use is significantly less for gelled fractures (Mdn=544 gallons per foot) than slickwater fractures (Mdn=1,340 gallons per foot) for vertical wells ($\chi 2(1)=42.4$, $p<0.05$). Horizontal wells do not have enough slickwater data to compare gelled and slickwater hydraulic fracturing water use. Gelled fractures typically require less water per stage because the high viscosity fluid is more efficient at creating larger fractures and carrying the proppant into the fractures.

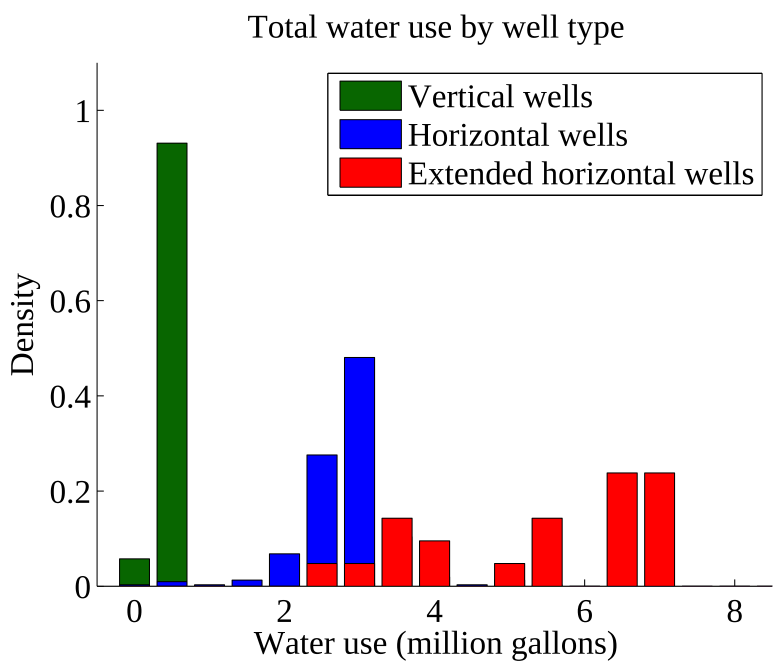

Figure 4.2: A histogram of the distribution of drilling and hydraulic fracturing water use for vertical, horizontal, and extended horizontal wells. Vertical wells are shown in green, horizontal wells are shown in blue, and extended horizontal wells are shown in red.

The majority of the water used for each well is used for hydraulic fracturing. Vertical wells use a median of 81 percent (Q1=77 percent, Q3=85 percent) of the total water for hydraulic fracturing. Horizontal and extended horizontal wells use a median value of 96 percent (Q1=95 percent, Q3=97 percent) and 97 percent (Q1=97 percent, Q3=98 percent) for hydraulic fracturing, respectively.

Table 4.2: Descriptive statistics for total water use separated by well type.

Total	Vertical	Horizontal	Extended Horizontal
Q1	332,900	2,600,000	3,721,000
Q2	360,000	2,871,000	5,620,000
Q3	461,900	3,108,000	6,830,000
IQR	129,000	510,100	3,109,000
Skewness	9.1	4.6	-0.44
Kurtosis	99	54	-1.3

There is a significant difference between the median drilling water use across the three well types ($\chi2(2)=387.24$, $p<0.05$). Vertical wells use significantly less total water than either horizontal or extended horizontal wells and horizontal wells use significantly less water than extended horizontal wells (Figure 4.5). Vertical wells use the least water (Mdn=74,760) followed by horizontal wells (Mdn=116,300), and extended horizontal wells (Mdn=180,800).

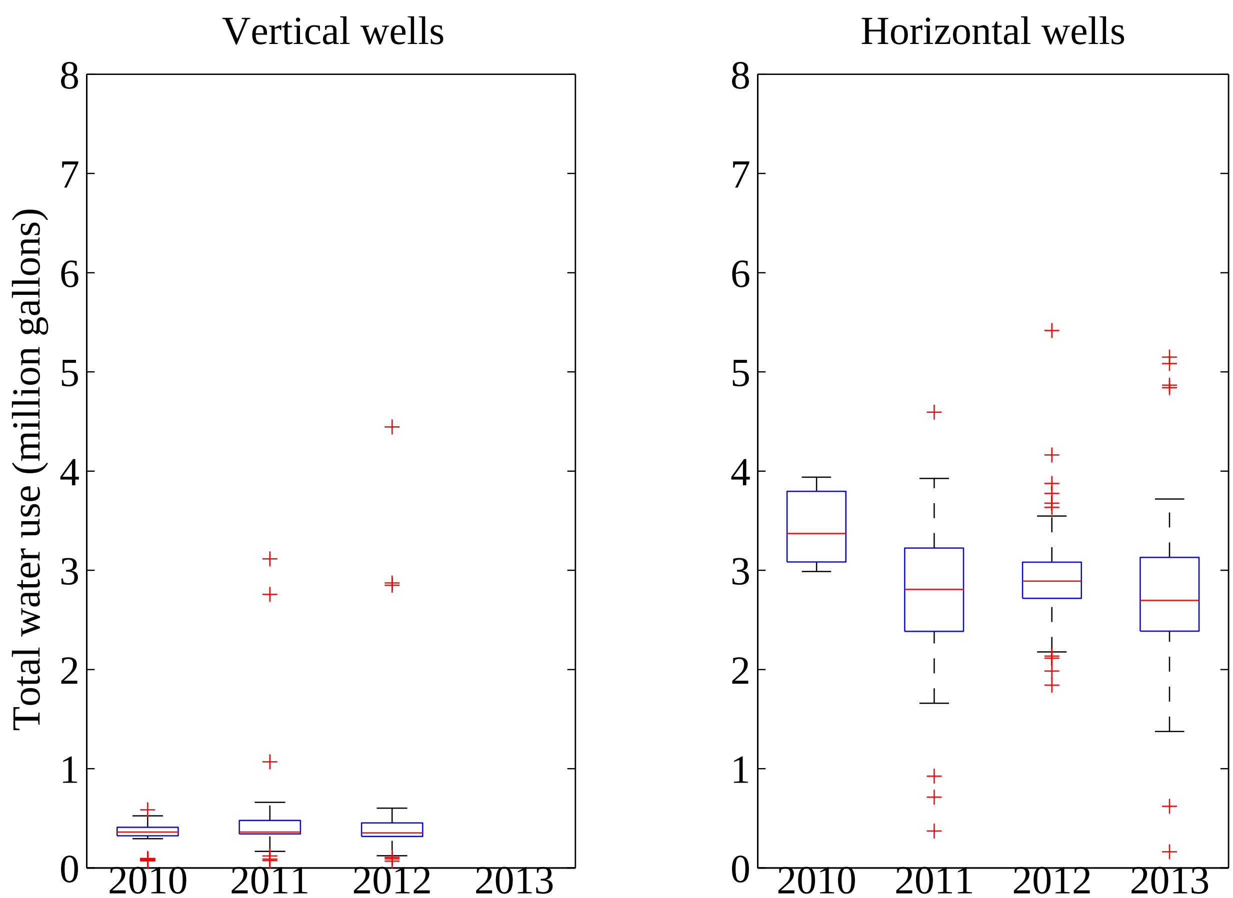

Figure 4.3: The water use for vertical wells and horizontal wells separated by year. The 25th and 75th percentiles are represented with a blue box, the 50th percentile is represented with a red line, the 10th and 90th percentiles are represented with black lines, and the outliers are represented with red plus signs.

There is also a significant difference between the median hydraulic fracturing water use across the three well types ($\chi2(2)=619.71$, $p<0.05$). Vertical wells use significantly less hydraulic fracturing water than either horizontal or extended horizontal wells and there is not a significant difference between the total water use between horizontal and extended horizontal wells. Vertical wells use the least water (Mdn=278,900) followed by horizontal wells (Mdn=2,792,000), and extended horizontal wells (Mdn=6,517,000).

Table 4.3: Descriptive statistics for drilling and hydraulic fracturing water use separated by well type.

Drilling	Vertical	Horizontal	Extended Horizontal
Q1	62,160	94,660	121,400
Q2	74,760	116,200	149,900
Q3	89,040	140,700	184,000
IQR	26,880	46,080	62,580
Skewness	12	3.1	-0.085
Kurtosis	240	25	0.8
Hydraulic Fracturing	Vertical	Horizontal	Extended Horizontal
Q1	269,400	2,483,000	3,593,000
Q2	278,900	2,753,000	5,458,000
Q3	395,000	2,995,000	6,803,000
IQR	125,700	512,300	3,210,000
Skewness	9.2	2.9	-0.39
Kurtosis	100	20	-1.5

The total water use for horizontal and extended horizontal wells correlates (r2=0.64) with the number of stages used to hydraulically fracture each well (Figure 4.6). Wells defined as horizontal wells (less than 25 stages) are shown in blue region and the wells defined as extended horizontal wells are shown in the red region. A linear regression using a least-squares linear fit is also shown.

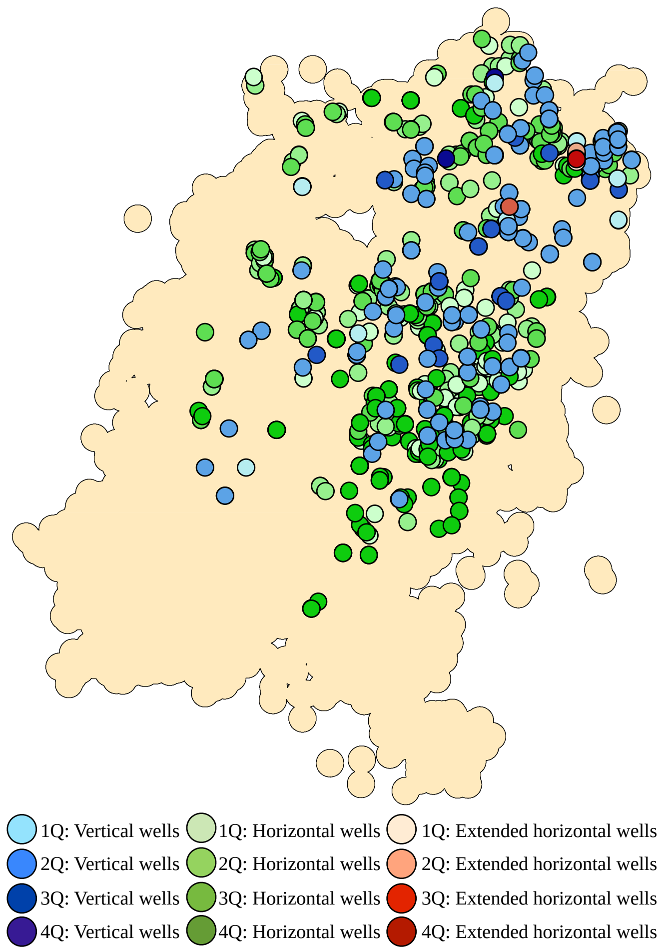

Figure 4.4: The total water use is separated into quartiles with the lightest shade representing the first quartile (least water use) of the total water use and the darkest shade representing the fourth quartile (most water use). Vertical wells are shown in green, horizontal wells are shown in blue, and extended horizontal wells are shown in red.

When the total water use is normalized by the number of hydraulic fracturing stages, the water use for horizontal and extended horizontal is not statistically different ($\chi 2(1)=2.85$, $p<0.05$). The distribution is also similar for horizontal and extended horizontal wells (Figure 4.7). Vertical wells do not show any correlation between the total water use ($r2=0.081$) or hydraulic fracturing water use ($r2=0.073$).

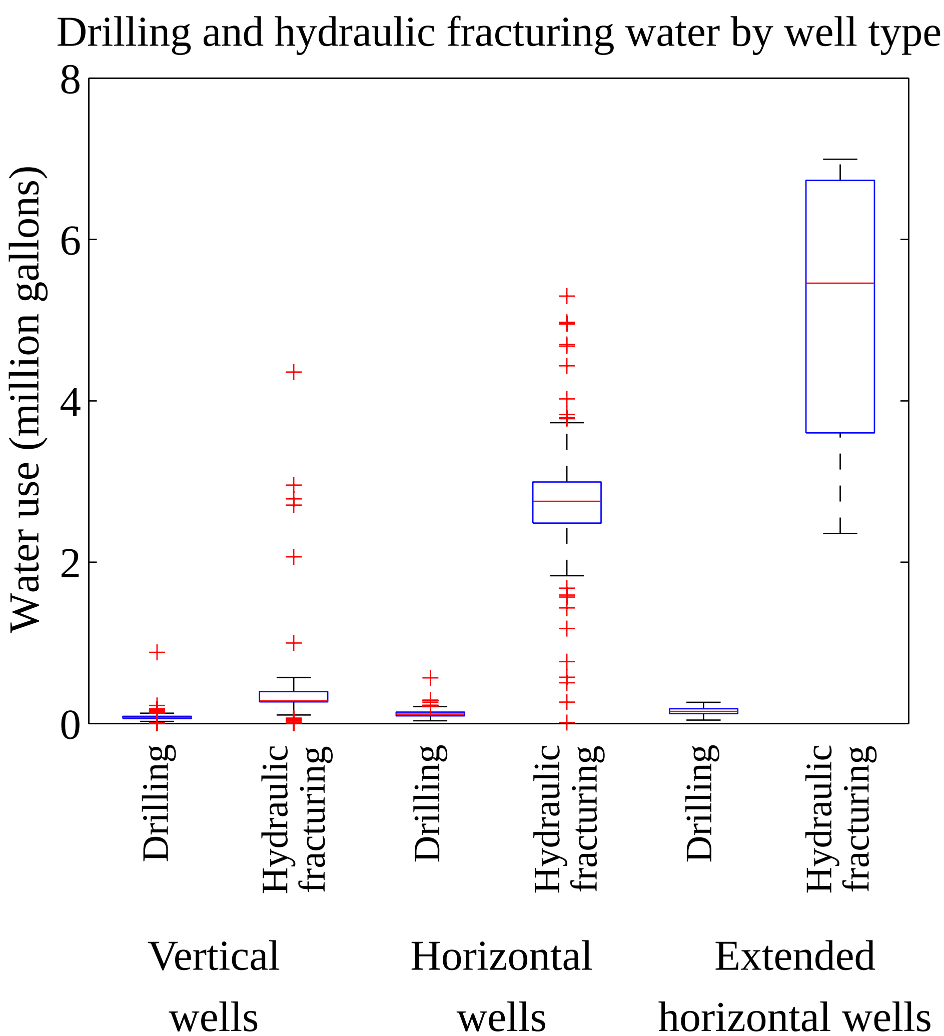

Figure 4.5: The distribution of drilling and hydraulic fracturing water use for vertical, horizontal, and extended horizontal wells. The 25th and 75th percentiles are represented with a blue box, the 50th percentile is represented with a red line, the 10th and 90th percentiles are represented with black lines, and the outliers are represented with red plus signs.

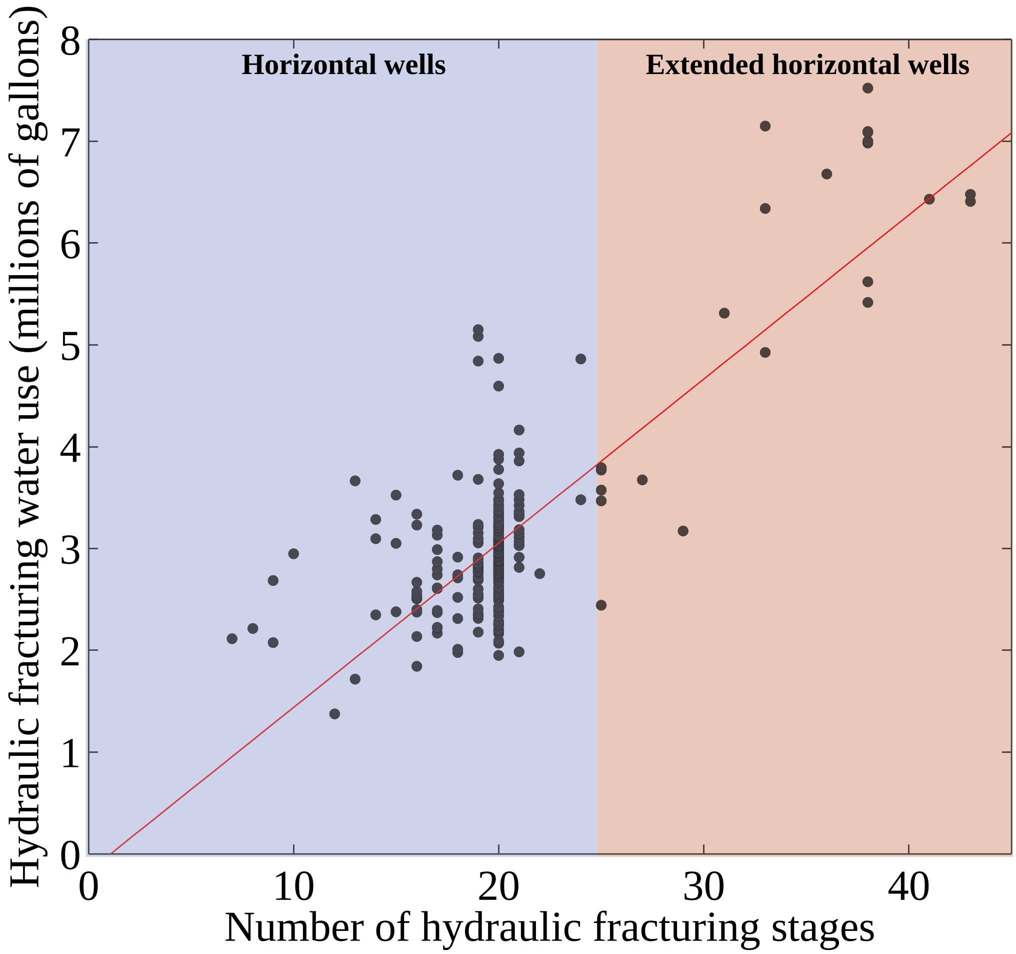

Figure 4.6: A simple linear regression between the number of hydraulic fracturing stages and the volume of hydraulic fracturing water used. Horizontal wells (less than 25 stages) are shown in the blue region and extended horizontal wells are shown in the red region.

4.5. Discussion

The most important factors with estimating the total water use for a well are the well type and the number of hydraulic fracturing stages. The fracturing fluid type (gelled vs. slickwater) also influences the water use to a lesser degree. Vertical wells use significantly less water than horizontal wells. The water total water use for vertical wells remains relatively constant.

However, the total water use for horizontal wells can vary from a few hundred thousand gallons up to nearly eight million gallons per well. Accounting for the number of hydraulic fracturing stages used can reduce the variability in the total water use for horizontal wells. The majority of the total water use per well is used for hydraulic fracturing. When the number of hydraulic fracturing stages normalizes the total water use, the water use is similar for all of the horizontal wells.

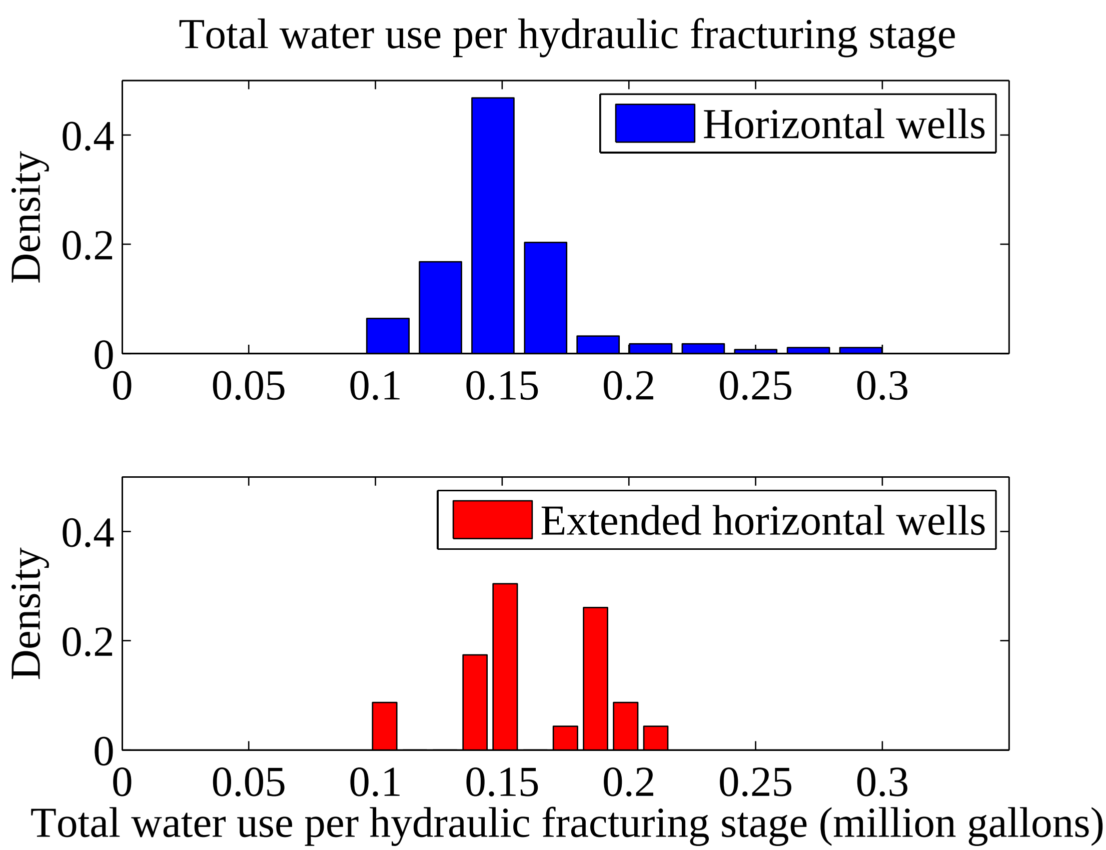

Figure 4.7: The distribution of the total water use for horizontal and extended horizontal water use normalized to the number of hydraulic fracturing stages.

The median total water use per well has remained constant or decreased slightly since 2010 for both vertical and horizontal wells. As drilling and hydraulic fracturing technology improves, the water use per well may continue to decrease slightly or remain constant. However, the number of wells in the Wattenberg field has been increasing from 2010 to 2013 and is very likely continue to increase. The water use does not show any strong spatial correlation within the field. The same water demand predictions can be made throughout the Wattenberg.

Flowback or produced water estimates for each well were not included in this study. As water treatment and reuse becomes more prevalent in the Wattenberg field, the net water use should also be considered when estimating demands on water resources. Produced water volumes may show significant temporal and spatial variation and further complicate water demand predictions.

The volume of oil and gas recovered for each gallon of water used should also be considered. This measure of water intensity is important to deter mine how efficiently water is being used and to compare different well types and sizes. The efficiency of additional factors beyond water quantity, such as community impacts, air and water quality, land disturbances, should be considered.

4.6. Conclusions

Estimates of the total water use and demands on water resources can be dramatically improved by taking the well type and number of hydraulic fracturing stages into consideration. Spatial and temporal variations do not have a strong influence on the water use for the different well types. As horizontal wells become more prevalent in the future, water demand predictions should be based on the number of hydraulic fracturing stages rather than the number of wells. The number of hydraulic fracturing stages can range from three to 45 and the total water use can vary from a few hundred thousand gallons up to nearly eight million gallons per well. It is a mistake to simply assume that all of the wells use a specific volume of water, particularly as the lateral lengths of horizontal wells are becoming longer to minimize surface impacts and maximize hydrocarbon recovery.

5. Water Intensity Assessment of Shale Gas Development in Northeastern Colorado[ii]

5.1. Overview

Efficient use of water, particularly in the western U.S., is an increasingly important aspect of many activities including agriculture, urban and industry. As the population increases and agriculture and energy needs continue to rise, the pressure on water and other natural resources is expected to intensify. Recent technological advances have stimulated growth in oil and gas development as well as increasing the industry's need for water resources. This study provides an analysis of how efficiently water resources are used for unconventional shale development in the Wattenberg Field, located in northeast Colorado. The water efficiency, or water intensity, is measured using a ratio of the net water consumption and the net energy recovery. The water and energy use as well as energy recovery data was collected from over 200 Noble Energy Inc. wells to estimate the water intensity. The consumptive water intensity of unconventional shale in the Wattenberg is compared with the consumptive water intensity for extraction of other fuels for other energy sources including coal, natural gas, oil, and nuclear. Although large volumes are

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S. Goodwin[a], K. Carlson[a], K. Knox[b], C. Douglas[b], L. Rein[b]

[a] Colorado State University, Department of Civil and Environmental Engineering, Campus Delivery, Fort Collins, CO 80523, USA

[b] Noble Energy, Inc., Environmental Engineering: Denver Office, 1625 Broadway Suite 2200, Denver, CO 80202, USA

required to drill and hydraulically fracture horizontal wells in the Wattenberg Field, over the lifespan of the well the water intensity is estimated to be between 1.8 and 2.9 gal/MMBtu. The water intensity is similar to surface coal mining.

5.2. Introduction

Water use is a major concern related to the development of shale gas in semi-arid regions of the western United States. Historical agricultural needs, burgeoning development, population growth, and considerable growth in oil and gas activity in these regions are all competing and placing growing demands on regional water and energy resources.

The development of unconventional shale resources requires large volumes of water, but the efficiency of the water use in terms of energy recovery is not often considered. Water and energy resources are intricately connected and cannot be assessed independently when formulating rational energy or water policies. A small number of studies have assessed the water use required for shale gas development [14, 9, 63] future regional water demands [75, 78], and estimated energy recovery. In 2006, Congress issued a directive asking for a report on energy and water interdependencies, focusing on threats to national energy production that might result from limited water supplies. [105] Increasing concerns about water and energy resources in the United States has led to significantly more available literature particularly from government agencies. [68, 72, 70]

Water intensity is a common measure of how efficiently water resources are used to extract energy resources. For this study, water intensity is defined as the ratio of the net consumption of water used and the net energy recovered. Although several additional impacts must be considered (e.g. water quality, air emissions, energy quality, etc.), water intensity allows for the comparison of water use efficiency between different energy sources. This study estimates the water intensity of hydraulically fractured horizontal wells in northern Colorado. The water intensity is compared with the extraction of coal, oil, natural gas, nuclear, renewables, and biofuels.

Several studies have compared the water intensity values for other energy extraction processes, and others have expanded the water intensity to end uses including electricity generation and transportation. Gleick [65] provided one of the first broad reviews of water intensity, presenting direct, consumptive water intensity values for each life cycle phase (i.e. extraction, preparation, electricity generation, etc.) of several different fuel sources in 1994. Perhaps the most comprehensive review and comparison of water intensity of energy extraction, processing, and conversion comes from the Harvard Kennedy School, titled Water Consumption of Energy Resource Extraction, Processing, and Conversion. [67]

Other studies have expanded the definition of water intensity beyond consumed water to include withdrawn [66] and embedded [67] water. These definitions are more important when considering the water intensity of electricity generation, particularly the type of cooling used. Because this study is limited to the extraction of shale oil and gas, only consumptive water use is assessed.

A comprehensive water intensity study of the Wattenberg Field has not been performed, despite the concerns about water use and oil and gas development in the region. This study provides a better understanding of water use and energy recovery estimates in the area.

5.3. Method

A random sample of 200 energy wells was used for the study. The sampled wells were limited to wells in the Wattenberg (as defined by the COGCC on July 1, 2013), operated by Noble Energy, Inc. (Noble), drilled between January 1, 2010 and July 1, 2013, with complete water and energy records, and at least 100 days of production data. The sampled wells are shown in Figure 5.1.

The drilling and hydraulic fracturing energy use and water volumes were collected for each sampled well using Merrick System's WellView software on July 1, 2013. [66] WellView is part of the Peloton suite of software used for collecting and organizing oil field data. An on-site Noble employee adds drilling and hydraulic fracturing data, including energy and water use, to WellView for each well. The accounting department at Noble verifies the energy and water use data.

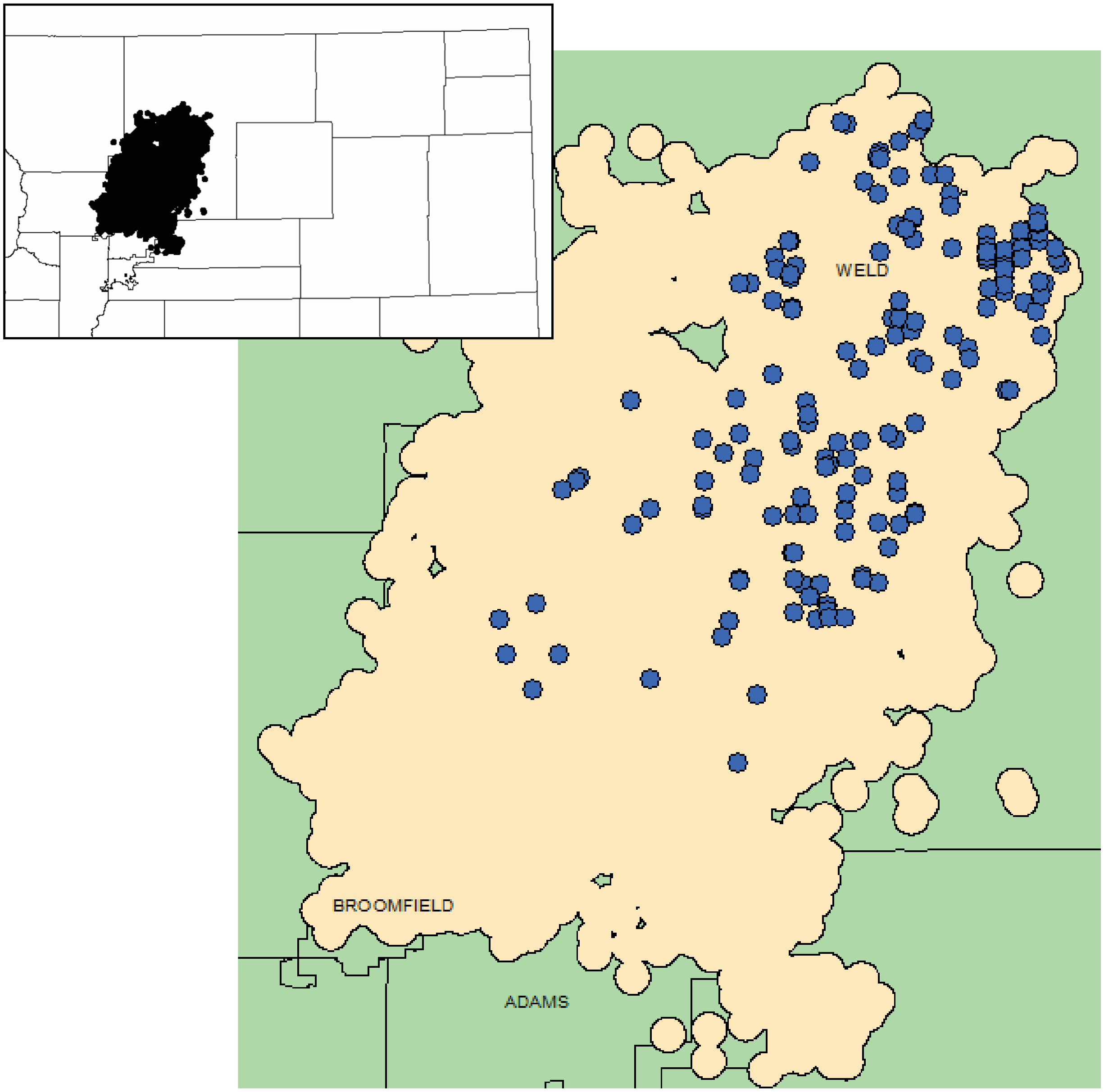

Figure 5.1: The spatial distribution of the sampled wells used in this study.

Drilling water is defined as water that is used to drill the well, prepare the borehole, and set the casings. Hydraulic fracturing water is defined as water that is used to perform the coil tubing, fracture the shale, carry the proppant, and flush the well. Energy use is not separated as either drilling or hydraulic fracturing; rather, the total volume of diesel or a combination of diesel and liquefied natural gas is reported.

Daily oil and gas production records during production are collected using Merrick System’s Carte program. Daily oil production is measured in the storage tanks and verified when the oil is sold. The lease operator remotely adds oil production data to Carte. Gas production is measured at the well using a total flow meter and reconciled when the gas is sold. Gas meters are calibrated every quarter and are equipped with a data logger to track historical data.

Oil and gas production during the flowback period are recorded by the flowback companies and reported to Noble. Well coordinates and spud dates are collected from the Colorado Oil and Gas Conservation Commission’s database. [112]

Daily oil and gas production records are used to fit an empirical harmonic decline curve to the data. A least-squares fit is used to estimate the initial production and the initial decline rate using the MATLAB Curve-Fitting Toolbox. [113] The curve is used to extrapolate future production rates and the estimated ultimate recovery (EUR). Without long-term historical production data in the Wattenberg, it is assumed that a harmonic decline can be used and that the wells will be productive for a 30-year period.

The water intensity is estimated by taking the ratio of the net water consumed (drilling water + hydraulic fracturing water) and the net energy produced (oil recovered + gas recovered - drilling energy - hydraulic fracturing energy). For this study, water reuse is assumed to be zero and all of the flowback and produced water is injected in disposal wells (Figure 5.2). As water reuse becomes more prevalent in the Wattenberg, the water intensity will decrease. Flared gas is not included in the water intensity assessment. Oil produced during the flowback period is included in the water intensity assessment.

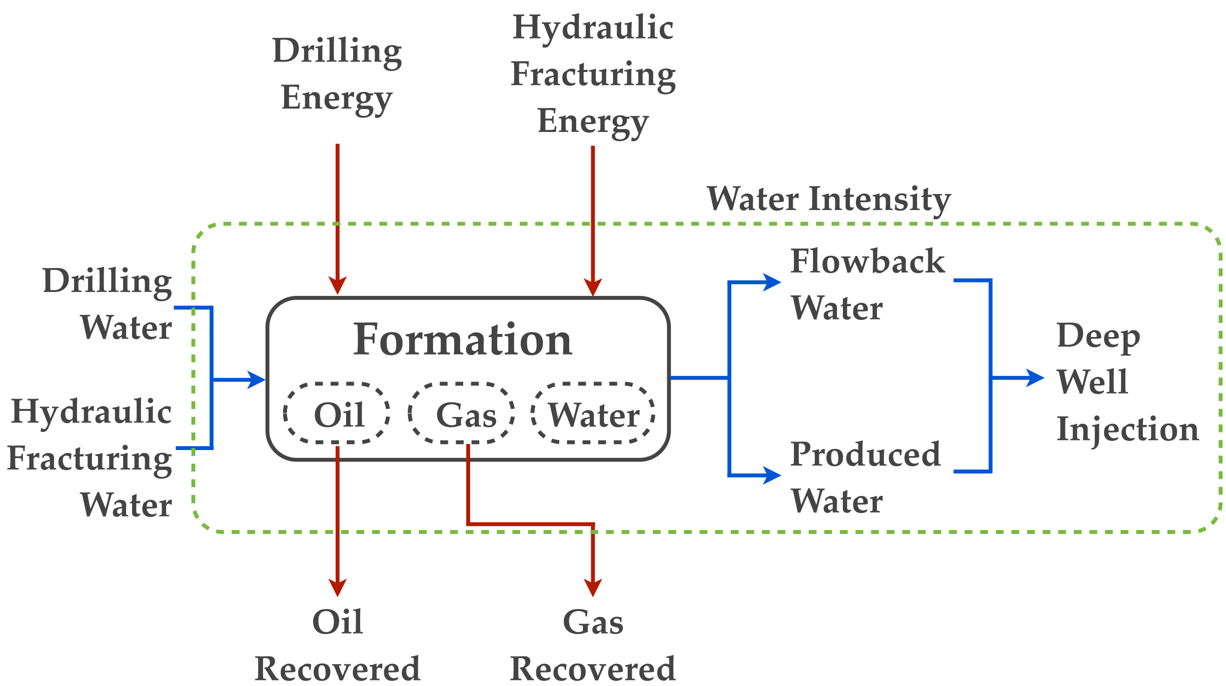

Figure 5.2: Water and energy balance defining the water intensity assessment. The blue lines represent the flow of water, the red lines represent the flows of energy, and the green line defines the materials balance water intensity assessment.

5.4. Results

A median value of the total water use for the sampled wells is three million gallons of water. Total water use has a range of 1.5 to 7.5 million gallons depending on the number of hydraulic fracturing stages, with increasing water correlating with increasing number of stages. [114] The stages range from 7 to 38, with 20 stages being the most common.

The majority (median=96 percent) of the total water use is used for hydraulic fracturing. A median value of 116,000 gallons of water is used for drilling and 2.88 million gallons are used for hydraulic fracturing, as shown in Table 5.1 and Figure 5.3.

Table 5.1: The drilling and hydraulic fracturing water, the energy use, the estimated ultimate energy recovery, and the water intensity is shown for the sampled wells.

Percentile	Drilling Water Use	Hydraulic Fracturing Water Use	Total Water Use	Total Energy Use	30-Year Total Production	Water Intensity
	(Gallons)			(MMBtu)		(Gal/MMBtu)
10th	69,200	2,380,000	2,500,000	1,250	817,000	1.5
25th	87,700	2,640,000	2,740,000	1,720	1,070,000	1.8
50th	116,000	2,880,000	2,990,000	2,820	1,330,000	2.2
75th	140,000	3,140,000	3,240,000	3,630	1,820,000	2.9
90th	175,000	3,780,000	3,870,000	4,750	2,320,000	3.5

The median total energy use is 2,820 MMBtu for drilling ing. Eighty percent of the wells used only diesel, the rest diesel and liquefied natural gas.

The median estimated ultimate oil and gas recovery is 1.33 million MMBtu. A large uncertainty exists in this estimate (the interquartile range is nearly 750,000 MMBtu) due to the fact that all of the wells have less than four years of production data to extrapolate 30-years of production. The uncertainty is illustrated in Figure 5.3. The median is shown with the red line, the interquartile range is shown in blue, and the 10th and 90th percentiles are shown with the dashed black line.

The water intensity is estimated to be between 1.5 and 3.5 gal/MMBtu with a median value of 2.2 gal/MMBtu.

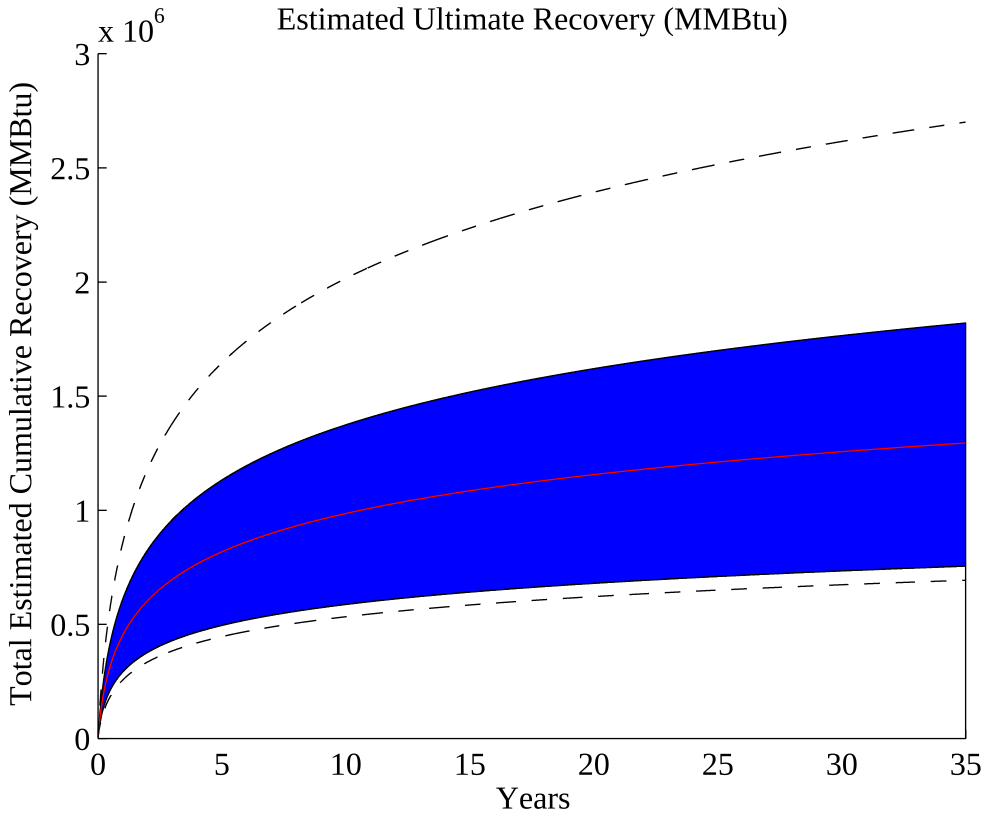

Figure 5.3: The estimated cumulative energy recovered over the projected lifespan of the well. The median value is shown with the red line. The range between 25th and 75th percentiles is represented in blue. The 10th and 90th percentiles are represented with the dashed black lines.

5.5. Discussion

The water intensity for extraction is similar to surface mining of coal (1-4 gal/MMBtu) [65, 67] and primary oil recovery (1.5 gal/MMBtu). [65] Conventional natural gas recovery is slightly lower (1 gal/MMBtu). [68, 20] Uranium mining is higher (1-16 gal/MMBtu) [65, 67, 68]and secondary oil recovery, enhanced oil recovery, and oil sands are all higher as well (Table 5.1 and Figure 5.4). Biofuels have the highest water intensity values (2,500-29,000 gal/MMBtu) due to the significant irrigation water typically required in arid regions.

Coal mining requires water for dust suppression, underground coal cutting, and removing impurities. The water requirement varies throughout the country and depends on local geology, mining methods, and water resources. The type of coal and extraction process has the strongest influence on the water requirements. Typically underground mining (approximately 65 percent of Appalachian coal mining) requires more water than surface mining (approximately 90 percent of western coal mining. Coal also requires small additional volumes of water for processing. Appalachian coal is washed to reduce the sulfur content and requires 2.3 to 5.0 gal/MMBtu of additional water [67, 73] but western coal requires little to no additional processing. [67, 73]

The water requirement for oil extraction varies substantially depending on the region, geology, recovery method, and reservoir depletion. Enhanced oil recovery methods are the most water intensive methods of oil extraction and account for nearly 80 percent of the total U.S. oil production. [115] Steam injection and CO2 injection are the most commonly used enhanced oil recovery methods and have consumptive water intensities of 39 gal/MMBtu and 94 gal/MMBtu respectively. [115] CO2 injection has a higher water intensity because the recovery method is typically used conventional oil pumping techniques and water flooding (secondary recovery) are no longer productive or economical. CO2 injection can capture an addition 10% to 15% of the original oil in place by injecting CO2 and water as a liquid under very high pressures to act as a solvent to mobilize additional oil. Finally, the water requirements for oil sands extraction ranges from 14 to 33 gal/MMBtu, depending on the solvents used. [20] Oil refineries in the U.S. typically have water intensities between 7.2 and 13 gal/MMBtu.[20]

Conventional natural gas wells consume small amounts of water (zero to three gal/MMBtu) [68] for drilling during the extraction phase. Water consumption for shale gas extraction is front-loaded, requiring large amounts of water for drilling (69.2 to 175 thousand gallons) and hydraulic fracturing (2.38 to 3.78 million gallons) for extraction.[20] However, the water intensity for the lifetime of the well is relatively low (0.8 to 9.7 gal/MMBtu). [20]Coal bed methane has a negligible water intensity; however, production can result in substantial volumes of produced water. [20]

Uranium mining water requirements are very similar to coal mining and depend mostly on geography and mining methods. Underground mining requires approximately six gal/MMBtu and surface mining requires one gal/MMBtu. [65] Refining and enriching uranium in the U.S. has consumptive water intensities of four to eight gal/MMBtu, depending on the enrichment process. [65]

Renewable energy sources, particularly solar and wind energy are difficult to compare because an energy extraction stage is not clearly separated from the electricity generation stage. The embedded water intensity (e.g. water required to build photovoltaics or wind turbines) becomes more important with renewable energy sources. In general, the consumptive water intensity of solar and wind energy sources can be assumed to be zero. [67] Hydropower has large water losses due to evaporation although this is not always attributed to power generation since reservoirs are constructed for other purposes. [68] Cooling towers consume the most water for electricity generation, no matter what energy source is used.

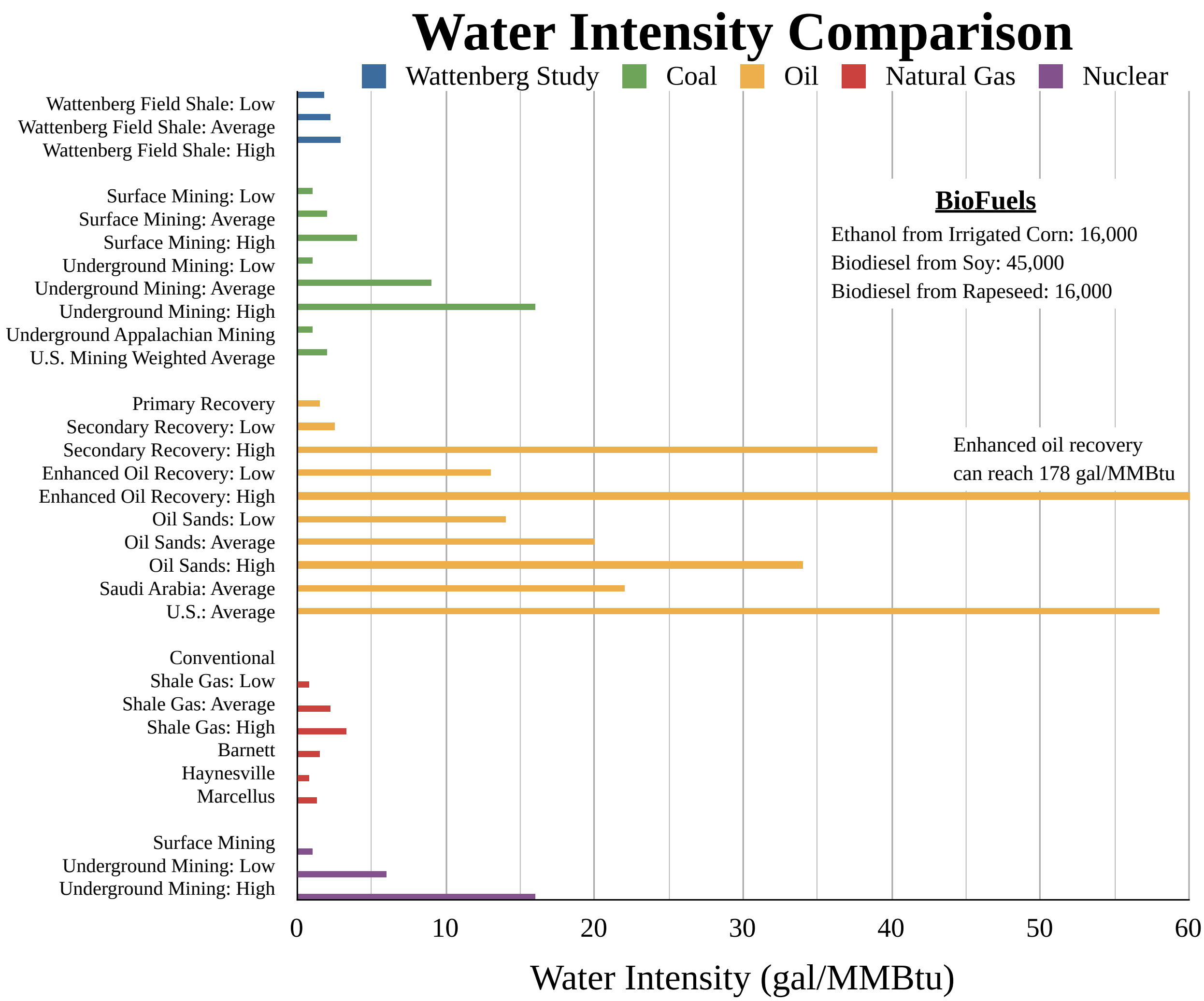

Figure 5.4: A comparison of the consumptive water intensity values for a variety of energy sources.

Biofuels require the largest amounts of water for extraction and processing with significant variation in water intensities depending on geography and associated irrigation requirements. For example, in one study corn ethanol grown in Indiana was reported to have a water intensity of 83 gal/MMBtu [116] and corn ethanol grown in Kansas was reported to have a water intensity of 3,805 gal/MMBtu. [9] However, a more detailed study estimated that the water intensity of biofuels has a range of 2,500 to 29,000 gal/MMBtu. [68] The water intensity of biofuels is highly dependent on the volume of irrigation water that is required. Bar graphs for BioFuels are not provided in Figure 5.4 due to the magnitude differences in net water consumption and scale.

Electricity generation is the single largest energy sector in the U.S. [117] and significant amounts of water is required to carry heat from the condensers. In 2005, thermoelectric power plants accounted for 45 percent of the freshwater withdrawals in the United States, but only three percent of the freshwater consumed. [118] The cooling requirements can be classified as once-through or recirculation configurations. Once-through cooling uses withdrawn water for cooling and returns the water to the source approximately 20oF warmer. [79] Evaporation accounts for all of the consumed water in this configuration. Once-through cooling has low capital and operating costs, but can impact downstream ecosystems due to the increased temperature and is uncommon for new power plants today. [119] Recirculating cooling configurations include closed loop or wet cooling (e.g. cooling ponds, wet tower) and dry cooling (e.g. dry cooling tower). These configurations have much lower water withdrawals than once-through cooling, but often have higher consumptive water requirements. Dry cooling is the least water intensive, but it is also the most expensive. One study estimates dry cooling to be nearly ten times more expensive than once-through cooling. [119] Closed-loop cooling has become the most common configuration for modern power plants and low water withdrawals are required, but more water is consumed than a once-through configuration.

5.6. Conclusion

As water resources in the western U.S. become increasingly strained due to competing demands from activities including, agriculture, urban, industry, and energy, it is important to consider the efficiency of the water use as well as the total water use. This study provides an assessment of how efficiently water is used for unconventional shale resources in the Wattenberg Field in northern Colorado. The water intensity is estimated to be between 1.8 and 2.9 gal/MMBtu. Compared to other energy sources only wind (0 gal/MMBtu), solar (0 gal/MMBtu), primary oil recovery (1.5 gal/MMBtu), and conventional natural gas (1.5 gal/MMBtu) had slightly lower water intensities. Although, unconventional shale resources in the Wattenberg has a low water intensity volume large volumes of water are required upfront. As more data becomes available, the impact restimulating wells and well workovers need to be examined. It is important to manage water responsibly to prevent acute and local strain on water resources. Large volumes of water return to the surface after hydraulic fracturing. This provides an opportunity to capture, treat, and reuse large volumes of water to further reduce the water intensity. Noble and other operators in the field are developing and improving water management and water reuse strategies.

Table 5.2: A comparison of the consumptive water intensity values for a variety of energy sources.

Energy Source	Water Intensity (gal/MMBtu)	Source
Wattenberg Field Shale		
Low	1.8	
Average	2.2	
High	2.9	
Coal		
Surface Mining: Low	1	[65, 67]
Surface Mining: Average	2	[65, 67]
Surface Mining: High	4	[65, 67]
Underground Mining: Low	1	[65, 67]
Underground Mining: Average	9	[65, 67]
Underground Mining: High	16	[65, 67]
Underground Appalachian Mining	1	[65, 67]
U.S. Mining Weighted Average	2	[65, 67]
Oil		
Primary Recovery	1.5	[65]
Secondary Recovery: Low	2.5	[115]
Secondary Recovery: High	40	[115]
Enhanced Oil Recovery: Low	13	[115]
Enhanced Oil Recovery: High	178	[115]
Oil Sands: Low	14	[65, 115]
Oil Sand: Average	20	[65, 115]
Oil Sands: High	34	[65, 115]
Saudi Arabia: Average	22	[116]
U.S. Average	58	[116]
Natural Gas		
Conventional	1.5	[20]
Shale Gas: Low	0.8	[9]
Shale Gas: Average	2.2	[9]
Shale Gas: High	3.3	[9]
Barnett	1.5	[20]
Haynesville	0.8	[20]
Marcellus	1.3	[20]
Nuclear		
Uranium Surface Mining	1	[20]
Uranium Underground Mining: Low	6	[20]
Uranium Underground Mining: High	16	[20]
Nuclear		
Biofuels: Low	2,500	[68]
Biofuels: High	29,000	[68]
Corn Ethanol: Indiana	83	[68]
Corn Ethanol: Kansas	3,805	[20]

6. Modeling of Frac Flowback and Produced Water Volume from the Wattenberg Oil and Gas Field[iii]

6.1. Overview

The objective of this study was to develop models that could be used to predict frac flowback and produced water volumes considering the unique decline rates that exist for different types of oil and gas wells. Specifically, water production data from the Colorado Oil and Gas Conservation Commission (COGCC) and Noble Energy Inc. were used to develop models for water production for vertical and horizontal wells, a distinction made largely due to the different amounts of water used for each. If centralized water treatment and handling facilities are going to be designed and constructed, it is important to have a reliable estimate of the water that will be produced in the future as wells are completed and brought on line. An Excel-based tool was developed utilizing the horizontal and vertical well models for predicting total volume of water production by current and future wells in Wattenberg Field. Two case studies have been conducted including one with all of the Noble wells in Wattenberg Field and one with a subset assuming a regional treatment center might be established. Uncertainty of the predictions was determined using standard error calculations on the two modeling parameters for water flow decline rates. An interactive Excel-based spreadsheet has been developed to allow

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B. Bai[a], S. Goodwin[a], K. Carlson[a]

[a] Colorado State University, Department of Civil and Environmental Engineering, Campus Delivery,

Fort Collins, CO 80523, USA

predictions of water production based on the number of horizontal and vertical wells drilled in the future.

6.2. Introduction

By the end of 2010, the proven reserves of crude oil in the U.S. were 19.1 billion barrels [120], and the natural gas reserves were estimated to be greater than 300 trillion cubic feet [121]. Since more than 60% of the total US energy is supplied by oil and gas, it is likely that the number of wells drilled over the next few decades will continue to increase as a result of increased energy demand [122]. In the oil and gas industry, water is a major concern, not only because of its demand in drilling and hydraulic fracturing, but also because of the water produced from oil and gas wells. For drilling and hydraulic fracturing of a horizontal shale well, an average of 3-6 million gallons of water is used [9] and in the Wattenberg field in northern Colorado, each vertical and horizontal well uses an average of 0.39 million and 2.8 million gallons of water respectively [123, 114]. Increased water demand for the oil and gas industry will stress already scarce water supplies in Colorado. However, after the completion of a well, a large amount of water, known as frac flowback and produced water returns with the extracted oil and gas. This water has higher total dissolved solids (TDS) and lower water quality [94, 124] and can be difficult to handle and treat. Water pollution from frac flowback and produced water has drawn attention recently and will likely continue to be a controversial topic in the future. One of the best strategies to mitigate some of the water related risks in the oil and gas industry is to recycle and reuse water. Therefore it is important to know the volume and quality of water so that the appropriate treatment processes can be chosen for reusing and recycling the water [125, 95].

In this paper, water production trends were analyzed for both vertical and horizontal wells. Based on the models developed from actual production data, an Excel tool was developed to predict future water production from the studied field. It will provide reference for the design of centralized water supply and wastewater treatment facilities.

Nomenclature

q	water flow rate (bbl/year)
t	well age (year)
k	vertical well water production decay rate (year^{-1})
k_1	horizontal well frac flowback production decay rate (year^{-1})
D_i	horizontal well produced water production decay rate (year^{-1})
A	vertical well initial water flow rate (bbl/year)
A_1	horizontal well initial frac flowback flow rate (bbl/year)
q_i	horizontal well initial produced water flow rate (bbl/year)

6.3. Methods and Materials

6.3.1. Site Location

The Wattenberg field is an unconventional shale play located northeast of Denver, Colorado. With an estimated 195.3 billion cubic feet reserve of wet natural gas in 2009, Wattenberg field is ranked as the 10th largest natural gas field in the United States [126]. Also some estimates have predicted that Wattenberg field could yield as much as 1-2 billion bbls of oil equivalent comprised of 70% oil and 30% natural gas [127]. Lying in the Denver-Julesburg Basin, the Wattenberg field has five major formations: J Sandstone, Codell Sandstone, Niobrara Formation, Hygiene Sandstone and Terry Sandstone. By August 2011, there were over 18,000 active wells in Wattenberg field with approximately 7700 operated by Noble Energy [90]. This paper focuses on Noble Energy wells in Wattenberg field because water production data was available from Noble

Energy Inc. Figure 6.1 shows the locations of Noble wells for analysis in Wattenberg field in Colorado.

6.3.2. Methods and Data Collection

Based on the different types of oil and gas wells, separate methods of analysis were performed to study life-cycle water production trends of vertical and horizontal wells.

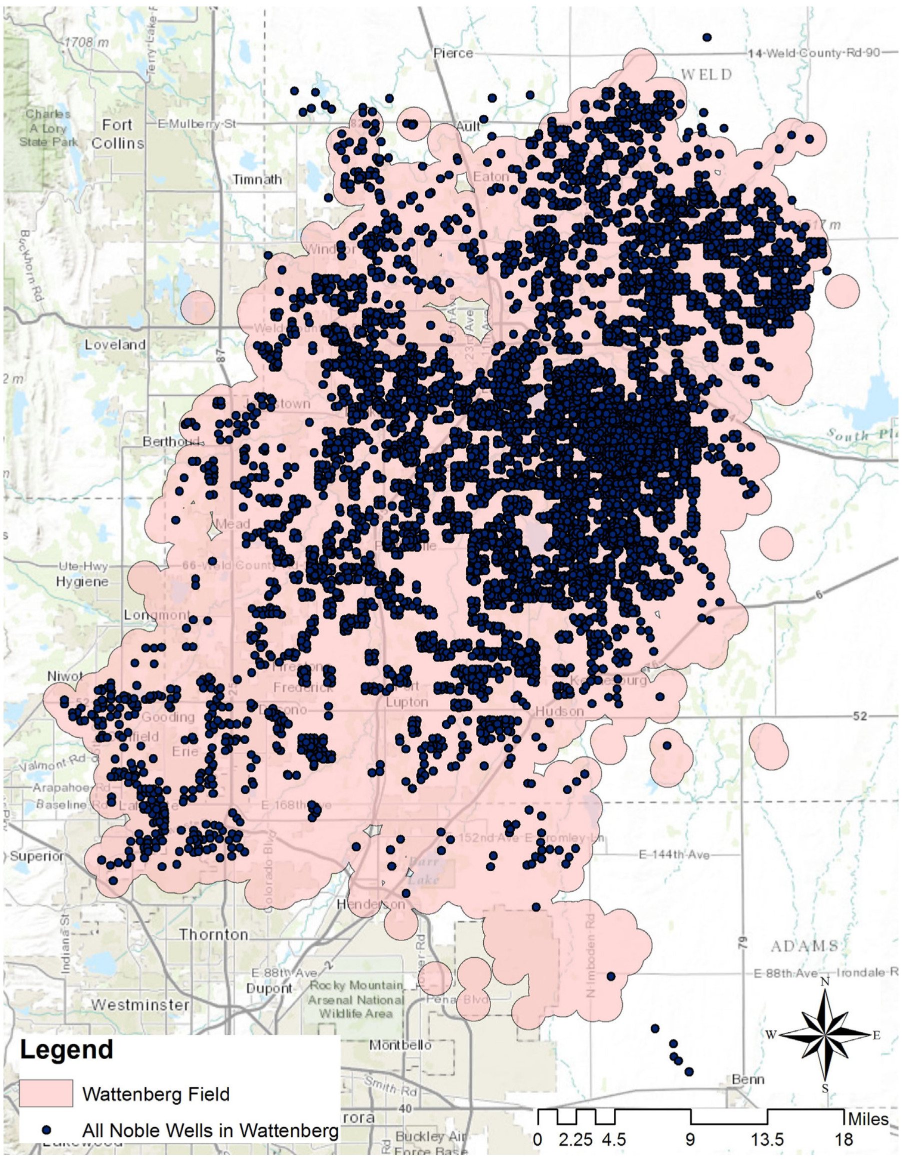


Figure 6.1: Location of Noble oil and gas wells in the Wattenberg field of Colorado.

6.3.2.1. Methods and Data Collection for Vertical Oil and Gas Wells

For vertical wells, annual water production data was obtained from the Colorado Oil and Gas Conservation Commission (COGCC) database. Because COGCC does not have production data for wells before 1999, only a sample of 1677 Noble Energy wells was chosen for the study from 1999 to 2011. According to the dates of completion and first production, new wells in each year were selected for this study as shown in Table 6.1.

Table 6.1: New wells from 1999 to 2011 and number of wells in each operating year.

Year	New wells	Years in operation	Number of wells	Average producing days
1999	6	1	1677	324
2000	10	2	1494	337
2001	29	3	1324	339
2002	28	4	1140	342
2003	65	5	807	342
2004	105	6	535	348
2005	131	7	374	354
2006	161	8	243	346
2007	227	9	138	350
2008	333	10	73	339
2009	184	11	45	322
2010	170	12	16	339
2011	183	13	6	333

The selected wells were then classified according to well age to study the water production trend for 13 years. This subset of Noble Energy wells was used to make water production predictions for the 30 year life-cycle of vertical wells in the Wattenberg field, a timeframe that was chosen to represent the maximum well life.

6.3.2.2. Methods and Data Collection for Horizontal Oil and Gas Wells

The drilling of horizontal wells in the DJ Basin is relatively new (first started in 2010 in Wattenberg) and the production data is limited. Although there are currently approximately 200 horizontal wells for Noble Energy in the Wattenberg field, only 32 of these wells has complete datasets and could be studied for this research. Daily frac flowback and produced water data were acquired from Noble Energy production database. Based on the existing frac flowback and produced water data, predictions of water production for the 30 year life-cycle of horizontal wells in the Wattenberg field were made.

6.3.3. Development of Models

6.3.3.1. Methods and Data Collection for Horizontal Oil and Gas Wells

The model for vertical wells is based on both frac flowback and produced water data. Total water production in each operating year was summed for the chosen subset of vertical wells and the average number of producing days in each operating year was calculated based on the distribution of existing Noble Energy data (Table 6.1). Average daily water production per well was computed from operating years 1-13 and annual water production was calculated by multiplying average daily water production with the average number of producing days. High water flow rates were observed in the first year of operation because of the intrinsic frac flowback period (typically 1-2 days of high volume water production) included in that year. Based on the results of these calculations, predictions of water production for future years were made to an assumed well life-cycle of 30 years.

Based on the existing 13 years of water production data, an exponential decline curve was applied to the water production trend for predicting future water generation ($Q = Ae-kt$). After fitting the curve with different functions, exponential decline curve was chosen for this subset of wells because it best fits the behavior of vertical water production in the Wattenberg field. However, some fields with more connate water will have a different best-fit curve. Based on the average value of A and k (rate constant) from all 1677 vertical wells, and the days of production from Table 6.1, the equation of water production rate is:

$$q = 1.81e^{-0.1614t} \tag{6.1}$$

Eq. 6.1 shows the average water production rate from vertical wells in Wattenberg Field. However, from the water production data, it is known that the water production varies throughout the Wattenberg field. In order to understand the relationship between the spatial location of wells and the decay rate constant, an ArcGIS map was interpolated based on the decay rate constant (k value) of each vertical well as shown in Fig. 6.2. Based on the interpolated GIS map of k values shown in Fig. 6.2, the average k value for a selected subset of the Wattenberg field can be calculated in ArcGIS. An example of using ArcGIS to calculate average k value for a particular case study is described later in the paper.

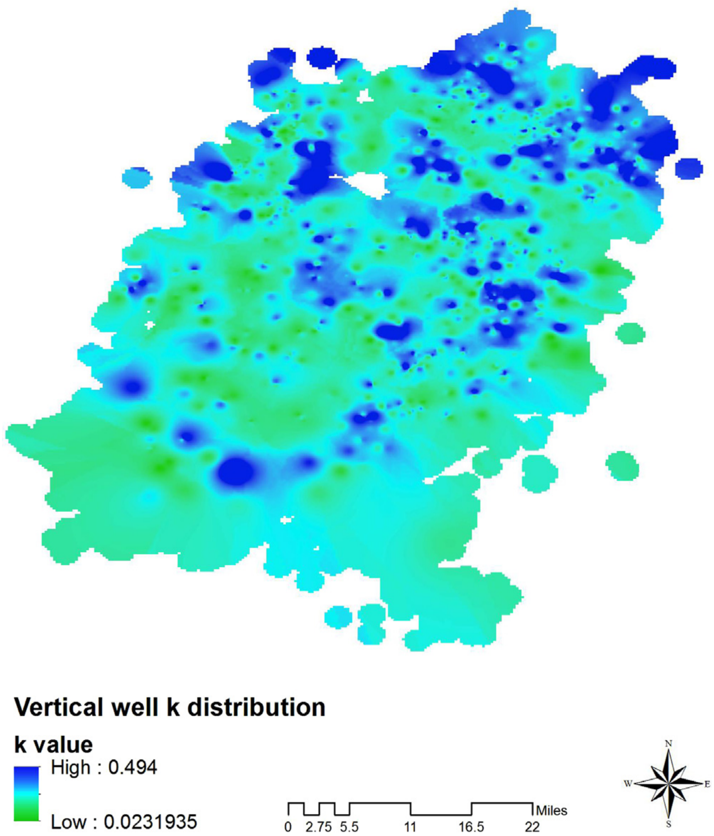


Figure 6.2: Interpolated k values of Noble Energy vertical oil and gas wells in Wattenberg field. (For interpretation of the references to color in this figure, the reader is referred to the web version of this article.)

In Fig. 6.2, the k (decay rate) of water production from vertical wells varies from 0.023 (half-life of 30.14 years) in the southwest to 0.494 (half-life of 1.41 years) in the northeast of the Wattenberg field. The reason for the large variation in *k* or half-life may be due to geologic formation differences that can be studied in the future. Additionally, the newer a well is, the less water production data are available. This may lead to a higher *k* and shorter half-life prediction. It is also observed that the *k* value is not homogeneous, as shown by the dark blue pockets in light green areas. Therefore, to adequately determine the proper *k* value, a spatial area must be defined. In Eq. 6.1, the *k* value was defined as the average *k* across the 1677 vertical wells.

6.3.3.2. Modeling of Produced Water for Horizontal Wells

Unlike vertical wells, horizontal wells use more water for drilling and fracturing, while having longer frac flowback periods that last up to 2 months. The model for horizontal wells is based on both frac flowback and produced water data. However, since there are only about 200 horizontal wells in the Wattenberg field, all of which were completed after 2010, the same 32 horizontal wells from Noble Energy were chosen for the estimation of water production rates.

When production data is plotted as a function of years in operation, it is seen that the water production decline rate is different for frac flowback and produced water. Therefore distinct rate models need to be developed. To distinguish flowback from produced water, two methods of analysis were performed on the data of the 32 horizontal wells. Raw data analysis uses the flowback report from Noble Energy as the flowback period and the day after the period as the first day of produced water generation. However, the water production rate is still high during the first few days when produced water starts to be generated. As a result, a modified approach was developed using the intersection point of first order decay trend lines of flowback and produced water curves as the first day of produced water generation. Both methods can be seen in Fig. 6.3.

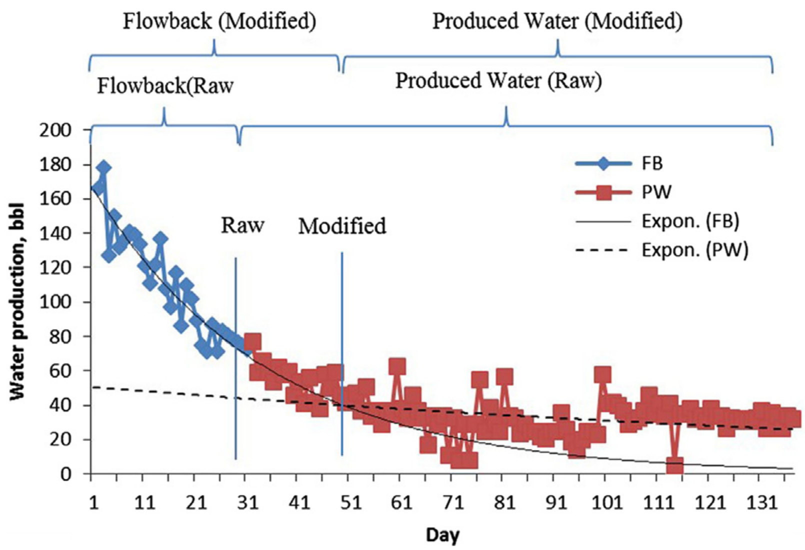


Figure 6.3: A comparison of two methods (raw and modified data analysis) of example horizontal well 70 Ranch BB21-65HN.

After applying the raw data analysis to all 32 wells, it was found that the average time defined as being flowback-influenced for a horizontal well was 74 days. And from the modified analysis the average frac flowback period for horizontal wells in Wattenberg field is 61 days. After analyzing the frac flowback and produced water production curves for the 32 wells based on the modified analysis method, the average curve was plotted and a prediction of future water production was made. For frac flowback water, exponential decay function was used to calculate the water production rate. Based on the average A_1 and k_1 for all 32 horizontal wells, the equation of frac flowback water production for horizontal wells in the first 61 days is:

$$q = 264.4e^{-0.043t} \tag{6.2}$$

However for produced water, since the harmonic function provides a better fit to the observed data as well as a higher flow rate, the production rate was modeled with a harmonic function. The equation of harmonic decay is q(t) = qi , (1+Dit) in which qi is the initial water production rate and Di is the initial decay rate. After applying a harmonic function to each horizontal well, the average qi and Di value of 32 wells was calculated and the equation of produced water production for horizontal wells is:

$$q = \frac{88.86}{(1 + 0.0447t)} \tag{6.3}$$

The average number of production days in each operating year used in the analysis is the same as the vertical wells, and for the 162 days in the first operating year, there are assumed to be 61 days of frac flowback and 101 days of produced water production. ArcGIS interpolated maps are used to estimate the spatially defined k1 value (frac flowback decay rate constant) in Eq. 6.2 and a value (produced water decay rate constant) in Eq. 6.3. Fig. 6.4 shows how k1 and Di for horizontal wells differ spatially throughout the Wattenberg field. Like the decay rate of vertical wells (k), the distribution of k1 and Di are not homogeneous. Therefore, in the analysis of all horizontal wells in the Wattenberg field, an average k1 value of 0.043 (half-life of 16.1 days) and average Di value of 0.0447 (half-life of 15.5 years) was used. The average is depicted in Eqs. 6.2 and 6.3.

Based on Eqs. 6.1-6.3, averaged water production curves of horizontal and vertical wells in the Wattenberg field are shown in Fig. 6.5. With more fracturing water use and longer frac flowback time, horizontal wells have a higher water production rate than vertical wells. Also shown in Fig. 6.5, horizontal wells have a faster decay in the first year of operation because of the large volume of frac flowback generated in the first year.

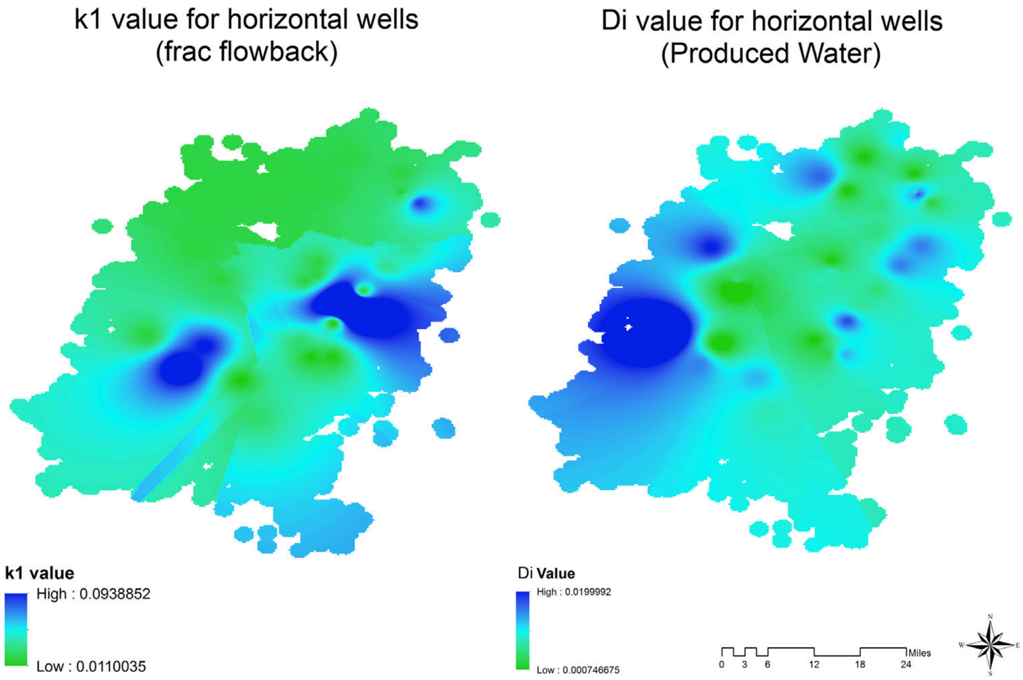


Figure 6.4: K1 and Di for horizontal oil and gas wells in the Wattenberg field.

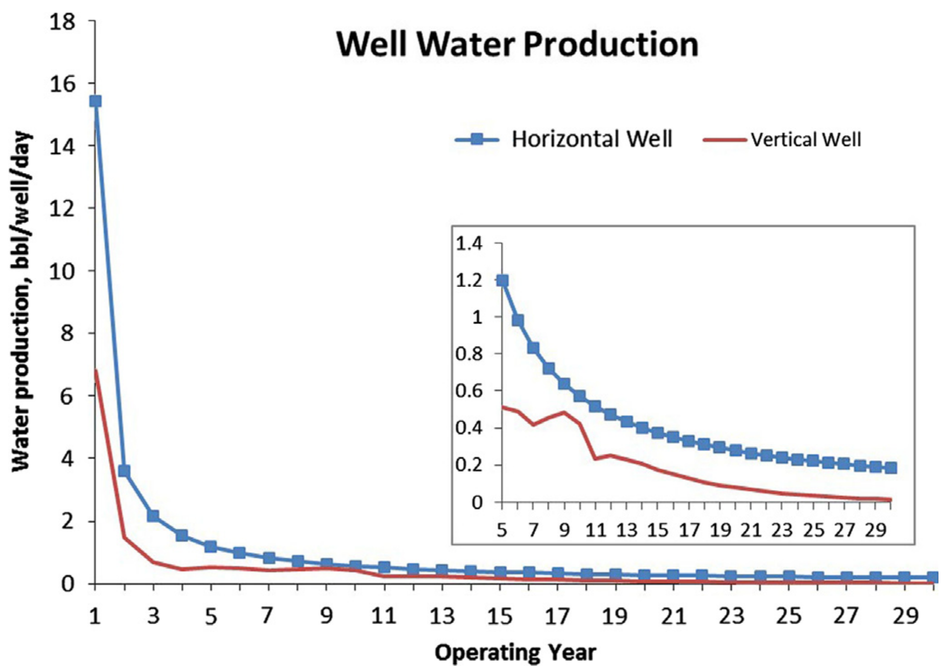


Figure 6.5: Horizontal and vertical well water production curve.

6.3.4. Uncertainty Analysis

Water production trends of vertical wells, as well as frac flowback water production trends of horizontal wells were fitted with an exponential decay function of the form $q=Ae^{-kt}$. Produced water production trends of horizontal wells were fitted with a harmonic decay function of the form $q(t)=q_i/(1+D_it)$. For the model, average values of A, k, qi and Di for all Wattenberg field wells studied were used but as shown in Figs. 6.2 and 6.4, k, k_1, and D_i can vary significantly. Other variables, A and qi, also will have variability from well to well. Therefore, uncertainty analyses were performed for all parameters.

For all 1677 vertical wells, the water production decline trend for each well was analyzed and fitted to an exponential decay function. Since 438 of the vertical wells had limited water production data and another 113 wells did not fit the decay function, only 1126 k values were used in the uncertainty analysis. A smaller subset of 153 wells was chosen randomly for evaluation of A variability. The distribution of k and A is shown in Fig. 6.6.

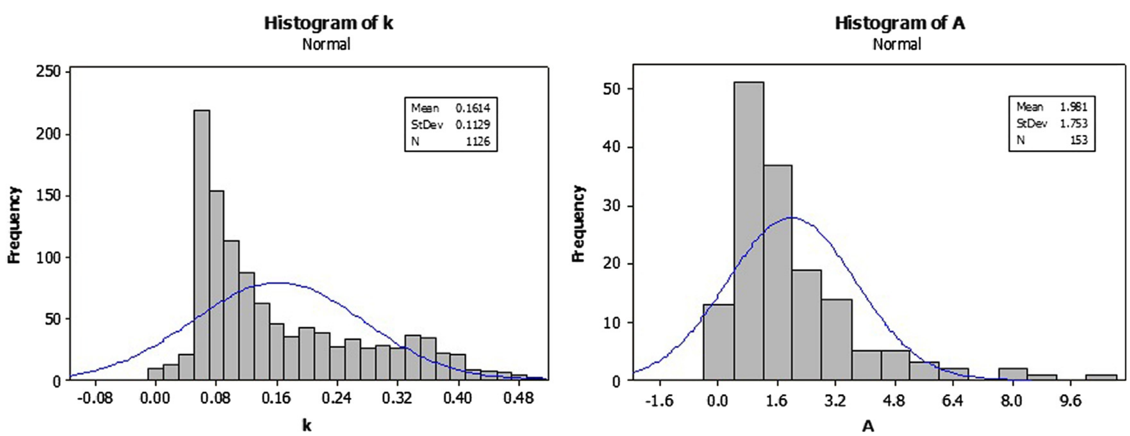


Figure 6.6: Distribution of k and A for vertical wells.

Since horizontal wells in the Wattenberg field are modeled by two separate functions for flowback and produced water, four variables (A1 and k1 for flowback and qi and Di for produced water) were analyzed for uncertainty using the same statistical method. Fig. 6.7 shows the distribution of k1, A1 , qi and Di values of horizontal wells. Assuming the parameter values for both vertical and horizontal wells are normally distributed, the z score for 95% confidence interval is 1.645 and the calculated statistical values are shown in Table 6.2.

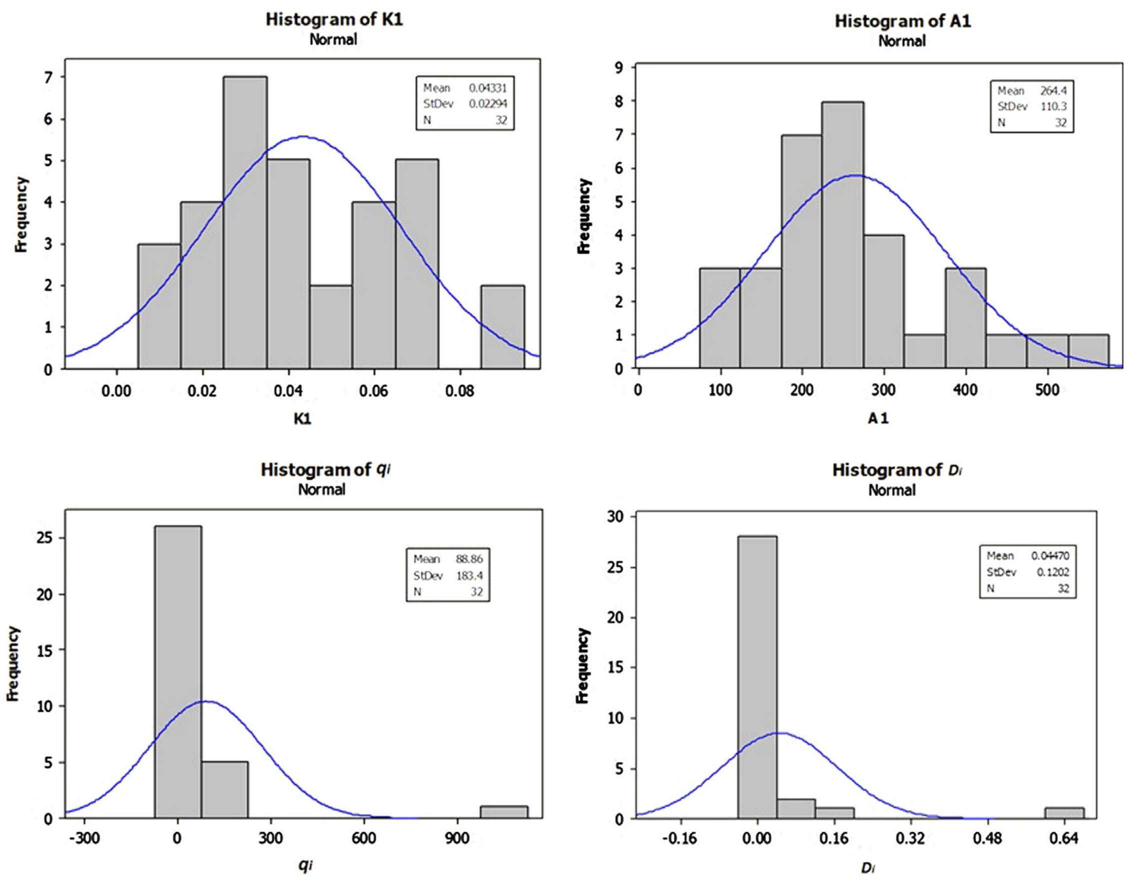


Figure 6.7: Distribution of k1, A, qi, and Di for horizontal wells.

Table 6.2: Uncertainty analysis and acceptable range of variables.

Parameter	k	A	k_1	A_1	q_i	D_i
μ	0.1613	1.981	0.0434	264.4	88.8638	0.0447
σ	0.0033	0.141	0.0040	19.4	32.4282	0.0212
5% CI	0.1558	1.748	0.0366	232.3	35.5194	0.0098
95% CI	0.1669	2.214	0.0499	296.5	142.208	0.0796

6.4. Development of a Model for Predicting the Frac Flowback and Produced Water Volumes from the Watteberg Oil and Gas Field

6.4.1. Introduction of the Model

After combining the models of vertical and horizontal wells, a water production prediction model was developed to predict frac flowback and produced water volumes for existing wells in the Wattenberg field. This was achieved through the development of the water production curves, based on current well counts and historical production data. As seen from the Wattenberg vertical and horizontal well models, water production prediction models can be fitted with a single curve or with multiple curves.

The tool can also be used to predict water production for future proposed development from given oil and gas fields (or other spatially defined areas) based on the historical data. In order to perform the calculation, the required historical data includes the number of existing wells, the type of wells, and the associated production dates and volumes in the given area so that the years of operation of each well can be determined. Once curves are developed from existing wells in the area, the models can be applied to future annual drilling and fracturing.

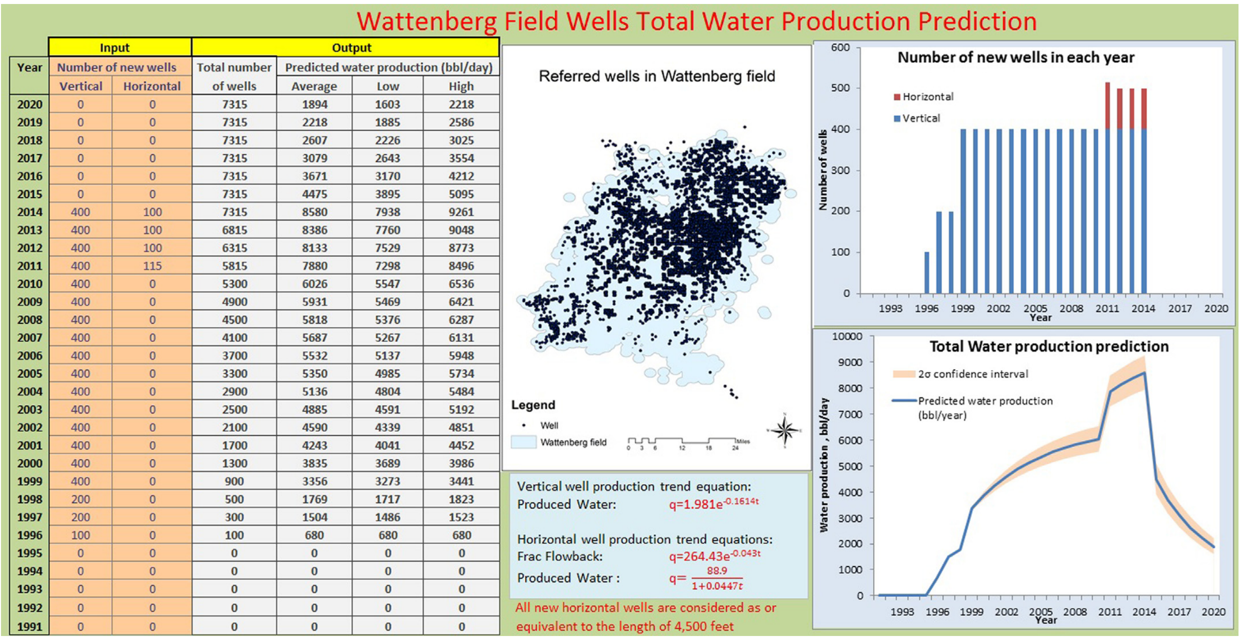
Prediction of total water production in future years is calculated after inputting the planned new wells and their types for each year, and by summing water produced from both existing wells and proposed wells.

6.4.1.1. Inputs and Outputs of the Model

The model, based on the model developed with spatially-relevant historical data, has two inputs: the number of new vertical wells and the number of new horizontal wells for each future year. Because the water production rate changes with the length of wellbore, and all historical Noble wells were relatively homogeneous with the length of 4500 feet, new wells are quantified as a multiple of this typical well (e.g. a 9000 foot horizontal well would be input as 2). The output of the tool is the predicted water production in each future year for the defined area. Fig. 6.8 shows the screen shot of the model (Available on the Colorado Energy Water Consortium website: http:// cewc.colostate.edu).

6.4.1.2. Prediction Method

From the described models, using historical water production data, area-specific water production equations can be determined. These equations can be used to model the future water production of existing wells. Additionally, the equations can be used to forecast water production for future, proposed wells within the defined boundaries. By default, a prediction of water produced from existing wells is made based on no new wells in future years. However, the effect of future wells on water production can be determined by inputting the planned number of each type of new wells into the model.



Year	Input		Output			
	Number of new wells		Total number of wells	Predicted water production (bbl/day)		
	Vertical	Horizontal		Average	Low	High
2020	0	0	7315	1894	1603	2218
2019	0	0	7315	2218	1885	2586
2018	0	0	7315	2607	2226	3025
2017	0	0	7315	3079	2643	3554
2016	0	0	7315	3671	3170	4212
2015	0	0	7315	4475	3895	5095
2014	400	100	7315	8580	7938	9261
2013	400	100	6815	8386	7760	9048
2012	400	100	6315	8133	7529	8773
2011	400	115	5815	7880	7298	8496
2010	400	0	5300	6026	5547	6536
2009	400	0	4900	5931	5469	6421
2008	400	0	4500	5818	5376	6287
2007	400	0	4100	5687	5267	6131
2006	400	0	3700	5532	5137	5948
2005	400	0	3300	5350	4985	5734
2004	400	0	2900	5136	4804	5484
2003	400	0	2500	4885	4591	5192
2002	400	0	2100	4590	4339	4851
2001	400	0	1700	4243	4041	4452
2000	400	0	1300	3835	3689	3986
1999	400	0	900	3356	3273	3441
1998	200	0	500	1769	1717	1823
1997	200	0	300	1504	1486	1523
1996	100	0	100	680	680	680
1995	0	0	0	0	0	0
1994	0	0	0	0	0	0
1993	0	0	0	0	0	0
1992	0	0	0	0	0	0
1991	0	0	0	0	0	0

Figure 6.8: Screen shot of the Excel tool with inputs and outputs.

In Fig. 6.8, the model depicts a Wattenberg-wide water prediction analysis where historical well counts for each year and associated water production were obtained from COGCC (pre 2009) and Noble Energy (after 2010). Example future well development was input for years of 2012-2014 to include 400 new vertical wells and 100 new horizontal wells annually in the defined area. These future development plans do not reflect Noble Energy's true well development forecasts for the Wattenberg field. Fig. 6.9 shows how future water production is affected by existing wells and proposed wells. It is seen that water production will continue to increase along with well development but after drilling stops, water production can decline rapidly. Additionally, Fig. 6.9 depicts the default prediction of the model where no new wells are drilled and completed. In this example, water production drops off drastically in the first few years and then settles into a gentler decay, which is consistent with the water production trend shown in the models developed.

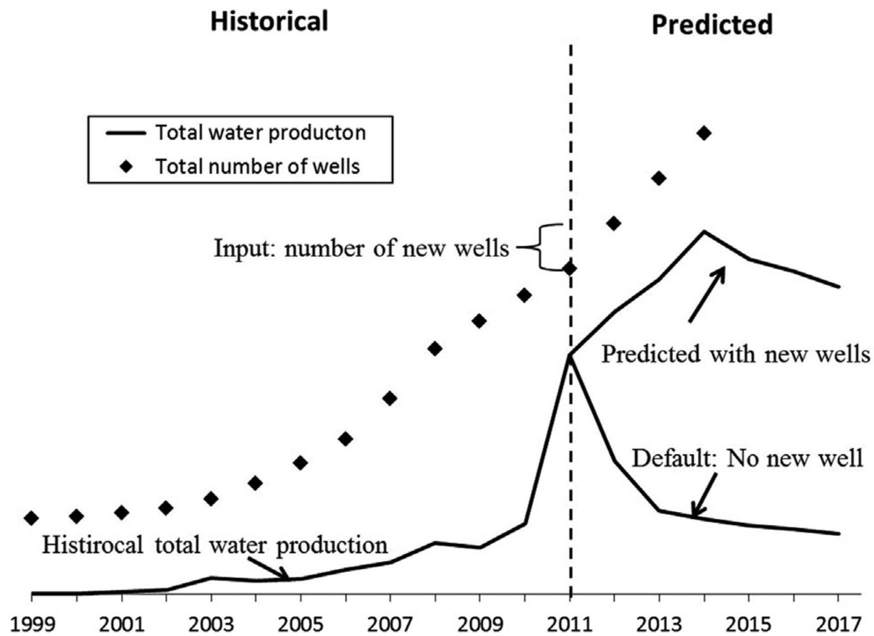


Figure 6.9: Description of method for predicting future total water production.

6.4.1.3. Assumptions

Due to the complexity of the historical data, several assumptions were made during the development of the model:

1. Though there are more than 7000 Noble Energy vertical wells in Wattenberg field, only 1677 vertical wells have available timeline information such as drilling dates and first production dates. Therefore, these 1677 wells were chosen as a subset to develop the water production curves. This subset will affect assumptions about field-wide production curves.

2. Water production changes with the length of wellbore, since the horizontal wells modeled using Noble data were relatively homogeneous with the wellbore length of 4500 feet, all new wells are considered equivalent to 4500 feet long. If a well has a different length, it would be entered as an equivalent well (e.g. a well with a wellbore length of 6750 feet would be 1.5 well-equivalents).

3. When a well is plugged and abandoned, it is assumed to have an operating life greater than 10 years so that it is producing very little water. Additionally, only around 10-20 wells are plugged and abandoned in each year. Hence, the impact from plugged and abandoned wells on total water production in that year was assumed negligible.

4. Refractured wells are considered to behave as newly completed wells. This assumption will be verified in future work.

5. Future wells are assumed to behave the same as historical wells.

6.4.2. Case Study of Noble Wells in the Wattenberg Field

A case study to estimate total water production for all Noble Energy wells from 2012 to 2017 in Wattenberg field was conducted using the developed water production prediction model. Historical total water production and well count data was acquired for all Noble wells in Wattenberg Field each year from 1999 to 2011. Data from 1999 to 2009 were extracted from the COGCC website database, and the data for 2010 and 2011 was taken directly from the Noble Energy Carte database.

By the end of 2011, a total of 7486 wells from Noble Energy were producing in the Wattenberg field. Overall, there were 7371 vertical wells and 115 horizontal wells. Each of these wells was modeled with the appropriate Wattenberg-average decay functions (Eqs. 6.1-6.3) and their specific well age. All water production from existing wells in the Wattenberg field was projected out to 2017.

After applying the model to all existing wells in the Wattenberg field, a development assumption was made where 100 new horizontal wells and 200 new vertical wells would be drilled and completed each year from 2012 to 2017. For each of these proposed wells, the appropriate water production algorithm was applied using the model. This assumption of well development is used to demonstrate the planning capabilities of the model if a company would like to know how their new well plans will affect future water production.

The additive predicted volume of water production from both existing and proposed wells from 2012 to 2017 is shown in Fig. 6.10. Additionally, the case where no new wells are drilled is shown in Fig. 6.10. Finally, the 95% confidence interval for both cases is also shown in Fig. 6.10. The 95% or 2σ confidence interval is calculated using values from Table 6.2. For the high limit of the 95% confidence interval, the biggest A and smallest k value was used in the calculation. This means the water production curve has the biggest initial flow rate and slowest decay rate. For the lower limit of the 95% confidence interval, the smallest A and biggest k value was used in the model.

From Fig. 6.10, a few observations can be drawn. A large jump in water production is seen in 2010. This is due to the introduction of horizontal wells. From the prediction made by the model, it is clear that total water production increases to 5 million bbls from 2012 to 2017. If no new wells are drilled, water production is seen to drop from approximately 3 million bbls in 2011 to about 1 million bbls in 2017. This is expected since without new wells, the water production trend would revert to the produced water rate after 2011, as seen in Fig. 6.5.

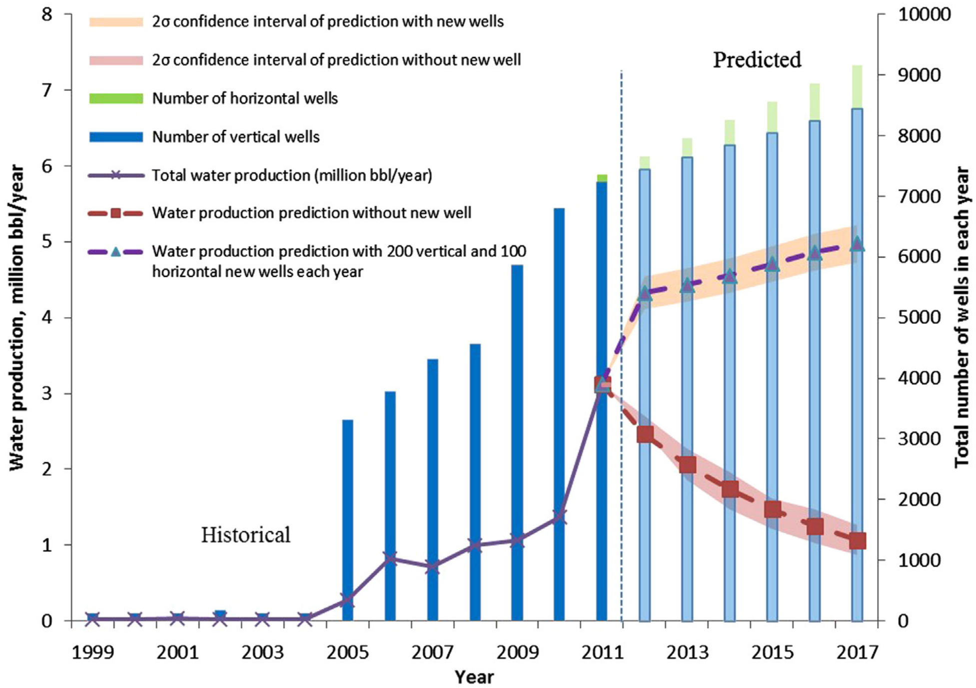


Figure 6.10: Total water production prediction of all Noble wells in the Wattenberg field from 2012 to 2017.

6.4.3. Case Study of Selected Noble Wells in the Northeast Portion of the Wattenberg Field

In the previous case study estimating water production for all 7486 Noble wells in the Wattenberg field, the k values for both vertical and horizontal wells were average values for the whole field. However, according to Figs. 6.2 and 6.5, k values vary spatially throughout the Wattenberg field. To make a more precise water production prediction, a smaller area can be chosen where the k value is estimated with more resolution. Therefore in order to understand the water produced in a smaller geographic area, a case study of selected wells in the northeast Wattenberg field was conducted using both the predictive k value tool in ArcGIS and the water production model. The selection of wells is shown in Fig. 6.5.

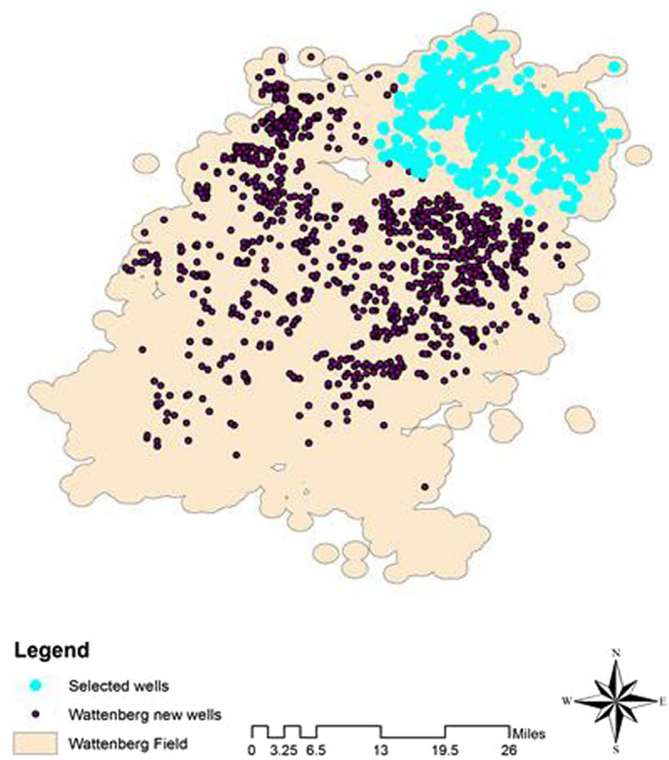


Figure 6.11: Selection of wells in northeast Wattenberg field.

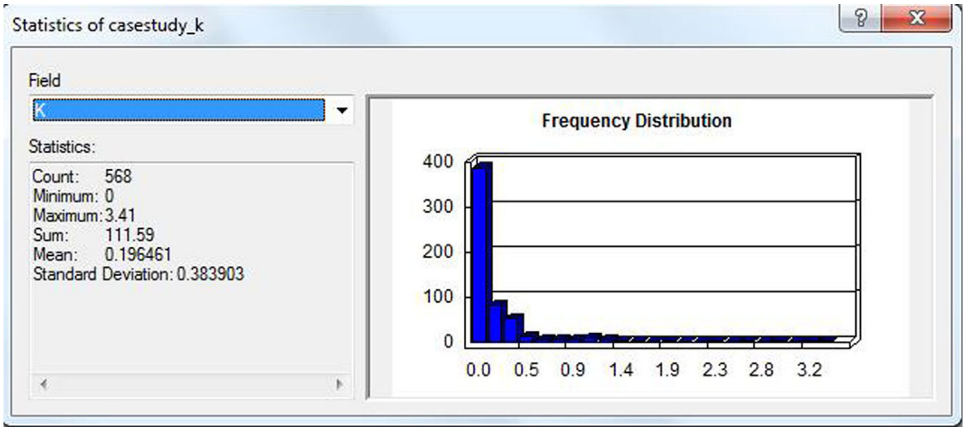


Figure 6.12: Distribution of k values of selected vertical wells in ArcGIS.

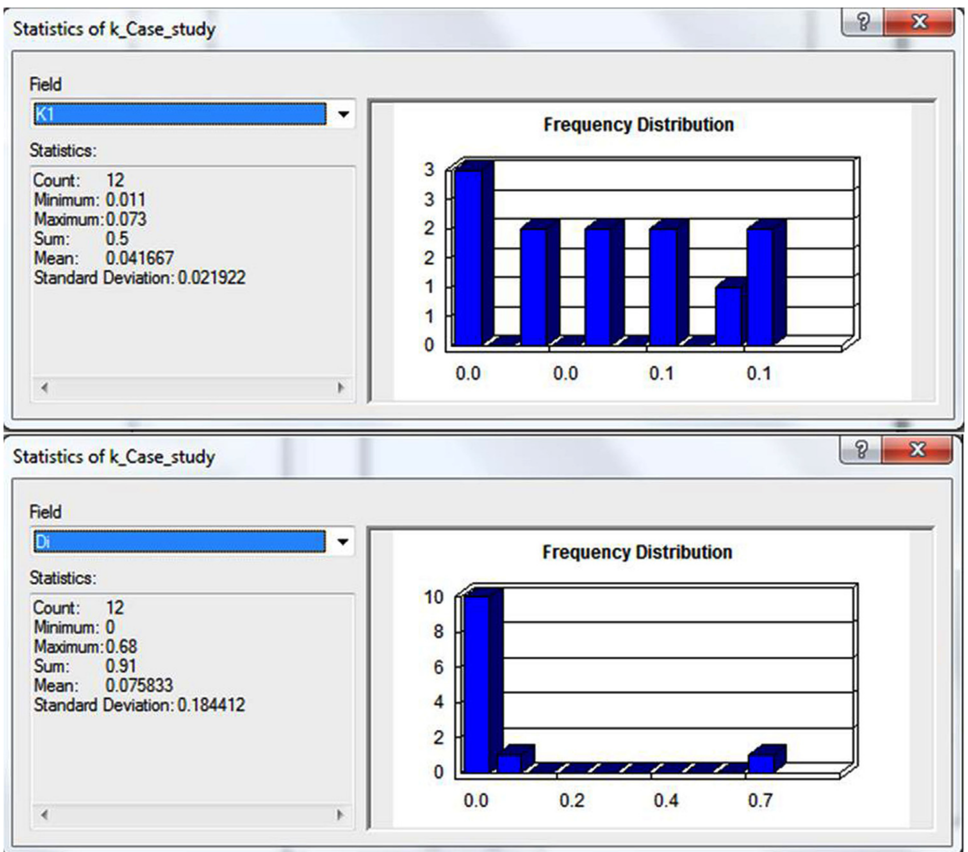


Figure 6.13: Distribution of k1 and Di values of selected horizontal wells in ArcGIS.

From the GIS attribute table of the selected region, 568 vertical and 12 horizontal wells were analyzed, and the average k values for both types of wells were computed in ArcGIS, as shown in Figs. 6.12 and 6.13.

After applying the computed, spatially relevant k, k1 and Di into Eqs. 6.1-6.3, the water production functions for wells in the selected area of the Wattenberg field were modified from the averaged equations. And for the selected wells, the average value of A, A1 and qi was 2.003, 259.9 and 143.0 respectively. As a result, the equation for predicting vertical well water production for the selected area is:

$$q = 2.003e^{-0.197t} \tag{6.4}$$

The equation for predicting horizontal well frac flowback water production for the selected area is:

$$q = 259.9e^{-0.042t} \tag{6.5}$$

The equation for horizontal well produced water production for the selected area is:

$$q = \frac{143}{(1 + 0.0758t)} \tag{6.6}$$

Water production for selected vertical and horizontal wells was calculated using the water production model. Figs. 6.14 and 6.15 show the comparison of water production trends for both vertical and horizontal wells between Wattenberg field-average k value and area-specific k values from selected wells in northeast Wattenberg Field.

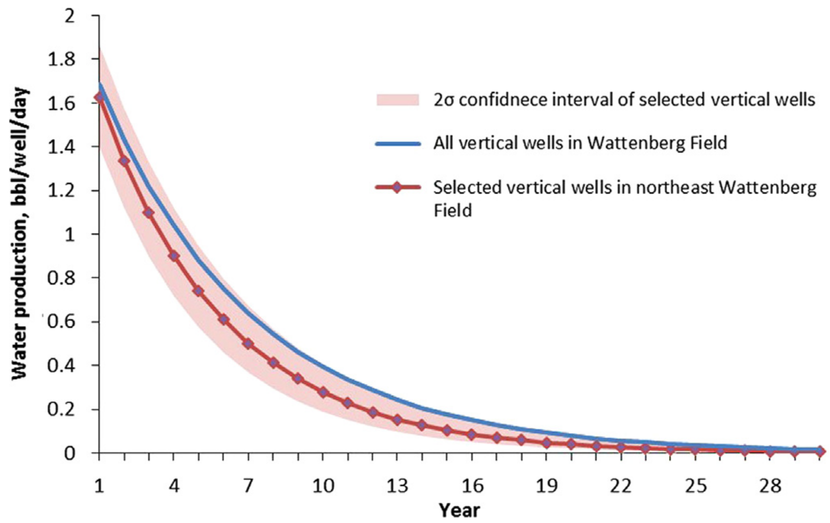


Figure 6.14: Comparison of water production trends between all vertical wells and selected vertical wells in northeast Wattenberg field.

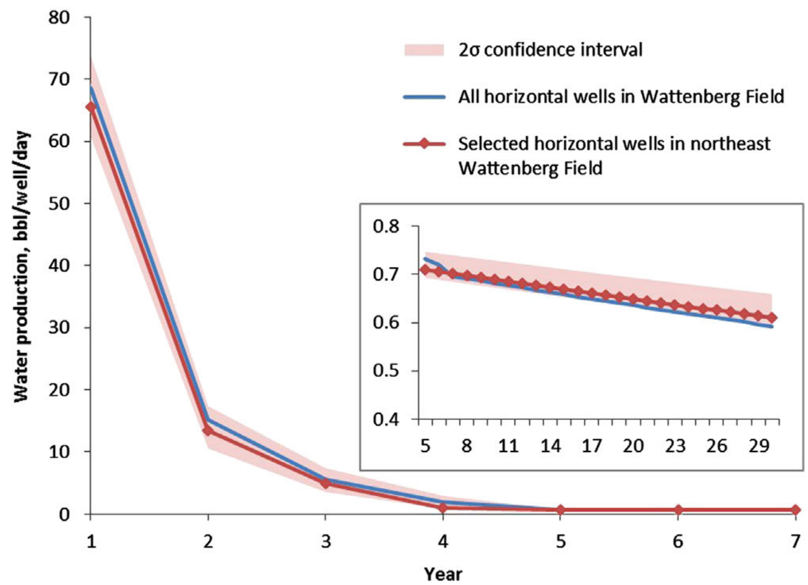


Figure 6.15: Comparison of water production trends between all horizontal wells and selected horizontal wells in northeast Wattenberg field.

In this case study, the difference in k, k1, and Di values for a chosen subset area (northeast part) of the Wattenberg field is compared to the entire field model. Different k, k1, and Di values result in different equations for both vertical and horizontal wells when predicting the water production. As shown in Figs. 6.14 and 6.15, the model used for predictions of the well subset is different from the one of the whole Wattenberg field. It may be more accurate at predicting subset water production than applying the field-wide model. This case study shows the value of applying ArcGIS with the water production model to predict water production based on spatial locations.

6.5. Conclusion

In this study, models have been developed for predicting total water production from the Wattenberg field. The models constitute the exponential and harmonic decay functions. Exponential fitting was chosen for modeling water production from vertical wells, and two separate decay curves were determined for modeling water production from horizontal wells: exponential curve for flowback and the harmonic curve for produced water. According to the result of two case studies, it was observed that water production rates varied drastically over an area and it was difficult to model all wells in an area. Therefore, in order to accurately predict the total water production, keen knowledge of historical data (both area development and water production data) and project boundary geologic information is required. Once the accurate forecast is done, it will be helpful for decision making surrounding water treatment, reuse, disposal, transportation, and the efficacy of pursuing development in a given field.

6.6. Supporting Information

Supplementary data associated with this article can be found in the online version at http://dx.doi.org/10.1016/j.petrol.2013.05.003.

7. The Influence of Water Quality on Hydraulic Fracturing Fluid Performance: An Initial Assessment[iv]

7.1. Overview

Hydraulic fracturing fluids typically consists of at least 98 percent water by volume and the quality of the water used can dramatically influence the performance hydraulic fracturing fluid. To better understand how water quality influences the development and performance of hydraulic fracturing fluids, a comparison of the water quality used to develop 73 hydraulic fracturing fluids is made. The water quality is compared based on hydraulic fracturing fluid performance. Basic water quality measurements are reconciled with OLI Electrolyte Simulation (OLI), an aqueous thermodynamic water quality modeling software program, and compared statistically using the Wilcoxon rank sum test based on hydraulic fracturing fluid performance viscosity tests. Scaling tendencies, solid and aqueous chemical species, as well as solid and aqueous chemical elements are all reconciled with OLI and separated into two populations: ideal/ sufficient fluids and bad fluids. Eureqa is used to detect underlying mathematical relationships between water quality parameters with statistically significant separation.

The aqueous concentration of aluminum, barium, bromine, chloride, potassium, sodium, strontium, and zinc were all shown to impact the development and performance of the hydraulic

[iv] ***S. Goodwin[a], K. Carlson[a],A. Prior[b],***
[a] Colorado State University, Department of Civil and Environmental Engineering, Campus Delivery, Fort Collins, CO 80523, USA
[b] Noble Energy, Inc., Environmental Engineering: Denver Office, 1625 Broadway Suite 2200,

Denver, CO 80202, USA

fracturing fluid with statistical significance. 42 modeled aqueous chemical speciations of these elements were also shown to impact the development and performance of the hydraulic fracturing fluid with statistical significance. Modeled scaling tendencies were found to be mediocre predictors of the development and performance of the hydraulic fracturing fluid. The solid element and solid chemical species concentrations both do not predict hydraulic fracturing fluid performance with any certainty.

Drilling and hydraulic fracturing of the Niobrara shale formation in Northern Colorado typically requires large volumes of water (three to five million of gallons of water per well). Currently, the most common water sources are municipal water, groundwater, or fresh water sources and the wastewater (i.e. flowback and produced water) is disposed of in deep injection wells. To reduce the demand on water resources and minimize the volume of wastewater disposed in deep injection wells, Noble Energy, Inc. (Noble) is working to develop hydraulic fracturing fluid from treated flowback and produced water. It is important to understand how water quality impacts hydraulic fracturing fluid performance to design treatment facilities and optimize water reuse.

7.2. Introduction

A water source is tested to determine if a hydraulic fracturing fluid can be developed from the water and how it will perform. Basic water quality parameters (e.g. pH, conductance, etc.) and the most common inorganic chemical constituents are measured, but a detailed water analysis is not routinely performed. Approximately three to twelve proprietary chemicals are added to the water and the viscosity of a hydraulic fracturing fluid is measured as a function of time at the temperature anticipated downhole. The chemical additions are adjusted until a successful hydraulic fracturing fluid is developed. A successful hydraulic fracturing fluid will have a high initial viscosity to carry the proppant into the fractures to hold the fractures open after the pressure is released. After about an hour the viscosity of the fluid needs to be low enough to leave the proppant in the fractures and return the fluid to the surface, allowing oil and gas to flow.

In Northern Colorado, hydraulic fracturing fluids are composed almost entirely of water (at least 98 percent by volume). A typical horizontal well in Northern Colorado requires three to five million gallons to drill and hydraulically fracture. To reduce the demand on municipal and surface water resources Noble is exploring how other sources of water including treated flowback and produced water can be used to develop hydraulic fracturing fluids.

It is important for service companies to have access to a high quality source water with minimal variation in the water quality. This minimizes the amount of testing and chemical additions that need to be made to develop a hydraulic fracturing fluid. Traditionally, sources of water have included municipal sources or groundwater aquifers, with small variations in water quality. However, flowback and produced water quality can vary dramatically both temporally and spatially, which presents challenges in both water treatment and hydraulic fracturing fluid development. Understanding the impact water quality has on hydraulic fracturing fluid performance is a key part to maximizing the reuse of flowback and produced water.

To optimize the reuse of flowback and produced water, the influence of each water quality parameter on hydraulic fracturing fluid development needs to be better understood. This will help treatment facilities optimize treatment processes, energy companies to choose the best source of water for hydraulic fracturing fluid development or mix multiple sources, and it will also allow energy companies to compare the costs and benefits of adding chemicals over choosing a different water source. The benefits of reusing water include reducing wastewater injection and the risk of induced seismicity, limiting truck traffic, reducing demands on water resources and in some cases adding a new water resource, reducing air emissions, and increasing production.

Noble has provided Colorado State University (CSU) access to water quality data and hydraulic fracturing fluid development test results to determine which water quality parameters impact the quality of the hydraulic fracturing fluid development. This analysis consists of three specific tasks: (1) estimate a complete chemical species profile and scaling tendencies from the basic water quality measurements, (2) separate the water quality data by hydraulic fracturing fluid performance, (3) determine what water quality parameters are statistically different for each population, and (4) estimating the water quality limits for each significant parameter.

7.3. Method

OLI Systems, Inc., a chemical equilibrium modeling software program, is used to estimate the complete chemical species profile and scaling tendencies from the basic water quality measurements provided by Noble. The water quality data generated by OLI is separated into two groups based on hydraulic fracturing fluid performance described in Table 7.1. The first group consists of water that has achieved ideal or sufficient hydraulic fracturing fluid performance at least once. The second group consists of water that never achieved ideal or sufficient hydraulic fracturing fluid performance.

A water quality sample is sent to Halliburton's hydraulic fracturing fluid labs to test if the water quality is appropriate to use to develop a hydraulic fracturing fluid for a specific well. Chemical packages are added to the water to develop a hydraulic fracturing fluid. The fluid is placed into a Chandler 5500 HPHT Viscometer to measure the viscosity of the fluid under high temperature and high pressure that simulates downhole conditions. The initial peak viscosity needs to be high enough to carry the proppant downhole and then loose the viscosity to leave the proppant in place once it reaches the fractures.

Table 7.1: Viscosity and performance characteristics of ideal, sufficient, and bad hydraulic fracturing fluids

	Ideal Fluid	Sufficient Fluid	Bad Fluid
Initial Peak (cP @ 40/sec)	1,800-2,200	1,500-1,800	>1,500
45 Minute Break (cP @ 40/sec)	>500	>500	<500
60 Minute Break (cP @ 40/sec)	250-500	250-500	<250
Break Profile	Constant Fall/Linear	Constant Fall	

A Wilcoxon rank sum test is used to compare the two populations by testing the null hypothesis that the ideal/sufficient water data has the same mean as the bad water data. The chemical additions and adjustments are not taken into account in this analysis. This analysis is simply used to determine if there is a difference between water that can be made into a sufficient hydraulic fracturing fluid and water that cannot and what water quality characteristics determine this separation.

Eureqa is an open source software program developed by Cornell Creative Machines Lab and is used to begin to identify hidden mathematical relationships in the statistically significant water quality parameters. The ideal separation between the ideal/sufficient and bad runs is determined using Eureqa. The most representative and simple mathematical relationship using the statistically significant water quality parameters is also developed using Eureqa.

Sixteen different water quality values were tested and a total of 73 attempts at developing an appropriate hydraulic fracturing fluid were made. The 16 different water quality samples are described in Table 7.2. All of the data was provided to CSU by Noble. Source water quality data was provided to Noble by Colorado Analytical Laboratories, Inc. and Halliburton Company (Halliburton). Fresh water quality data was provided to Noble by Colorado Analytical Laboratories, Inc. and Halliburton. The dilutions were provided by Noble. The hydraulic fracturing formulation (i.e. chemical additions) and results were provided to Noble by Halliburton.

7.4. Results

7.4.1. Scaling Tendencies

The scaling tendency is defined by OLI as a ratio of the activity product (Q) for an equilibrium to the solubility product (Ksp) for the same equilibrium, as defined in equation 7.1.

$$ST = \frac{Q}{K_{sp}} \tag{7.1}$$

The solubility product defines the distribution of mass between reactants and products at chemical equilibrium. However, depending on the ionic strength of the fluid as well as temperature and pressure, some reactions may not be at the theoretical equilibrium. In concentrated solutions ions tend to behave chemically as if they are less concentrated than they are theoretically predicted to be. There are two reasons for this: (1) background ions in the solution shield the charge and interactions between ion and (2) the formation of ion complexes. The activity product defines the total activity of free ion species. When the activity product of the solution is greater than the solubility product, a thermodynamic driving force exists to form solids. Conversely, when the activity product of the solution is less than the solubility product, a thermodynamic driving force does not exist to form solids. OLI defines any scaling tendency greater than or equal to one as one. In this analysis, a scaling tendency equal to one defines a solution with a thermodynamic driving force to form solids.

Table 7.2: A description of the 16 unique water quality values used in the analysis

Sample number	**Sample Date**	**Sample Description**	**Attempted runs**	**Best Run**
1	6/25/12	High Sierra treated effluent	8	Bad
2	9/10/12	High Sierra treated effluent	1	Bad
3	9/10/12	1:1 High Sierra treated effluent and Greeley Municipal water	1	Bad
4	9/10/12	1:3 High Sierra treated effluent and Greeley Municipal water	1	Ideal
5	9/10/12	1:7 High Sierra treated effluent and Greeley Municipal water	1	Ideal
6	10/7/12	1:3 Unknown sample and Greeley Municipal water	2	Sufficient
7	10/7/12	1:3 Unknown sample and pond water	2	Sufficient
8	10/7/12	1:7 Unknown sample and Greeley Municipal water	2	Ideal
9	10/7/12	1:7 Unknown sample and pond water	2	Sufficient
10	10/7/12	1:7 Unknown sample and pond water with biocide	2	Sufficient
11	10/25/12	1:7 Weist effluent and Greeley Municipal water	5	Sufficient
12	11/2/12	1:7 Weist effluent and Greeley Municipal water	10	Ideal
13	11/2/12	Greeley Municipal water	3	Ideal
14	12/2/12	1:7 Keely effluent and Greeley Municipal water	26	Ideal
15	No Date	Water Rescue Services treated flowback	5	Bad
16	No Date	Water Rescue Services treated flowback	5	Bad

Carbonate salts (calcium carbonate, sodium aluminum dihydroxide carbonate, sodium bicarbonate, strontium carbonate, zinc carbonate), strontium sulfate, and aluminum hydroxide are all rejected by the null hypothesis that the medians are equal using the Wilcoxon rank sum test. Aluminum hydroxide, calcium carbonate, strontium carbonate, and strontium sulfate all showed higher scaling tendencies with the ideal/sufficient runs than the bad runs, as shown in

Figure 7.4 and Table 7.3. Sodium aluminum dihydroxide carbonate, sodium bicarbonate, and zinc carbonate all showed lower scaling tendencies with the ideal/sufficient runs than the bad runs, as shown in Figure 7.11 and Table 7.4.

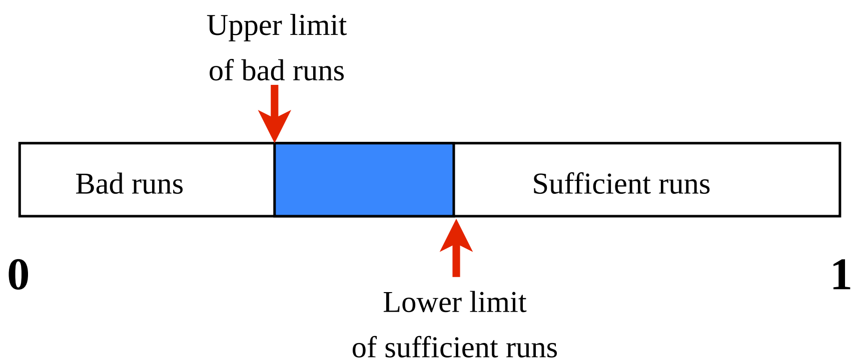


Figure 7.1: A schematic defining Table 7.3

Table 7.3: The following scaling tendencies are all rejected by the null hypothesis that the medians of the two groups are equal at the 0.05 significance level using the Wilcoxon rank sum test.

Scaling Tendencies	Upper limit of bad runs	Lower limit of sufficient runs	Number correctly predicted	Total	Percentage
Aluminum hydroxide	0.999	1.000	8	10	80.0 %
Calcium carbonate	0.477	0.892	14	16	87.5 %
Strontium carbonate	0.238	0.310	6	9	66.7 %
Strontium sulfate	0.019	0.024	7	10	70.0 %

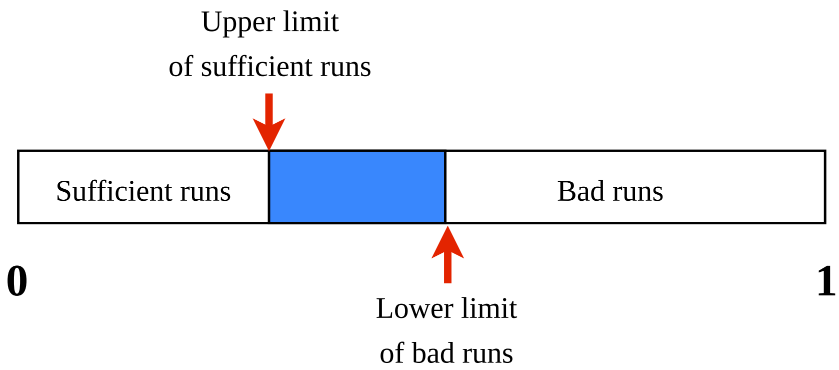


Figure 7.2: A schematic defining Table 7.4

Table 7.4: The following scaling tendencies are all rejected by the null hypothesis that the medians of the two groups are equal at the 0.05 significance level using the Wilcoxon rank sum test.

Scaling Tendencies	Lower limit of bad runs	Upper limit of sufficient runs	Number correctly predicted	Total	Percentage
Sodium aluminum dihydroxide carbonate	1.00	0.818	8	10	80.0 %
Sodium bicarbonate	0.002	0.001	8	10	80.0 %
Zinc carbonate	0.009	0.002	6	10	60.0 %

The quality of the hydraulic fracturing fluid can be predicted using the scaling tendencies with Equations 7.2 and 7.3. If the scaling tendency of calcium carbonate is less than the scaling tendency of sodium aluminum dihydroxide carbonate, an ideal/sufficient hydraulic fracturing fluid cannot be developed. If the scaling tendency of calcium carbonate is greater than or equal to the scaling tendency of sodium aluminum dihydroxide carbonate, an ideal/sufficient hydraulic fracturing fluid cannot be developed.

Sample number three (1:1 High Sierra treated effluent and Greeley Municipal water) is the only sample that does not fit this model. This sample has shown up as an outlier throughout the analysis. The sample has an ideal water quality but only one hydraulic fracturing fluid was developed and it was considered bad. It is likely that this water could have been developed into an ideal or sufficient hydraulic fracturing fluid if more attempts were made to develop the fluid.

$$ST_{CaCO_3} > ST_{ALCH_2NaO_5} \Rightarrow \text{ideal/sufficient hydraulic fracturing fluid development} \tag{7.2}$$

$$ST_{CaCO_3} \leq ST_{ALCH_2NaO_5} \Rightarrow \text{bad hydraulic fracturing fluid development} \tag{7.3}$$

The median, 5th, and 95th percentiles are shown for all of the modeled scaling tendencies in the box-and-whisker plot in Figure 7.3. The scaling tendencies that are not rejected by the null hypothesis are not included in Tables 7.3 and 7.4, but are included in Figure 7.3. The red line represents the median and the box represents the 5th, and 95th percentiles. Outliers are shown with red plus signs.

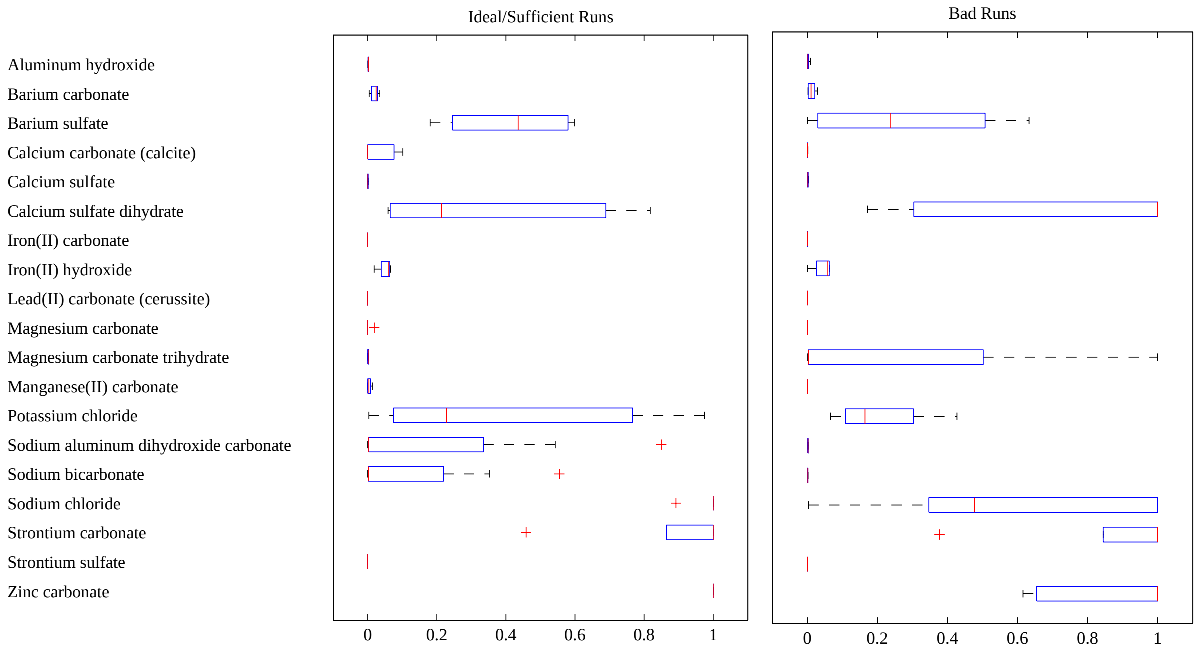


Figure 7.3: A comparison of scaling tendencies of the deal/sufficient runs and bad runs. The blue lines represent the 5th, and 95th percentiles and the red line represents the median.

7.4.2. Solid Concentrations

OLI's stream analyzer is used to model the solid precipitation of the solution. The model estimates solid precipitation based on the temperature, pressure, pH and composition of the solution. The solid precipitatant concentration of aluminum hydroxide, calcium carbonate, and total solids all reject the null hypothesis that the medians of each group are equal using the Wilcoxon rank sum test. Aluminum hydroxide and calcium carbonate have a higher scaling tendency for ideal/sufficient runs than bad runs. The scaling tendency of total solids has an upper limit between 9.89×10^{-4} and 34.7, which predicts 9 out of 15 of the samples.

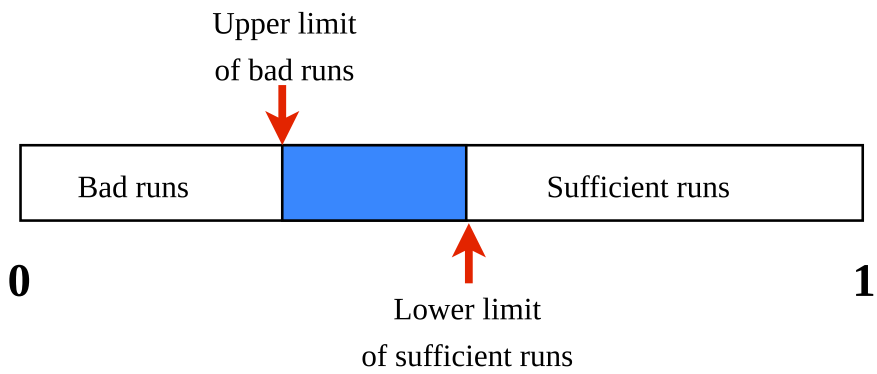


Figure 7.4: A schematic defining Table 7.5.

Table 7.5: The following solid concentrations are rejected by the null hypothesis that the medians of the two groups are equal at the 0.05 significance level using the Wilcoxon rank sum test. Values are given in mg/L.

Solids (mg/L)	Upper limit of bad runs	Lower limit of sufficient runs	Number correctly predicted	Total	Percentage
Aluminum hydroxide	0.000	$1.99\text{x}10^{-7}$	8	10	80.0 %
Calcium carbonate	0.000	$3.24\text{x}10^{-4}$	13	15	86.7 %

Table 7.6: The following scaling tendencies are rejected by the null hypothesis of bad runs that the medians of the two groups are equal at the 0.05 significance level using the Wilcoxon rank sum test. Values are given in mg/L.

Solids (mg/L)	Lower limit of sufficient runs	Upper limit of bad runs	Number correctly predicted	Total	Percentage
Total solids	$9.89\text{x}10^{-4}$	34.7	9	15	60.0 %

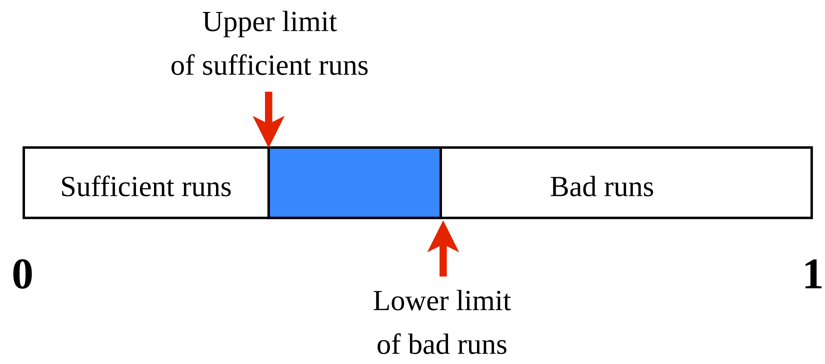


Figure 7.5: A schematic defining Table 7.6.

The quality of the hydraulic fracturing fluid can be predicted using the modeled solid precipitation with Equations 7.4- 7.6. Equations 7.4 and 7.5 describe a relationship between the concentration of total solids and calcium carbonate that can be used to predict hydraulic fracturing quality. If the total solids concentration is composed of less than 92 percent an ideal/ sufficient hydraulic fracturing fluid cannot be developed. If the total solids concentration is composed of more than 92 percent an ideal/sufficient hydraulic fracturing fluid can be developed. In general when the calcium carbonate composes less than 92 percent of the ideal/ sufficient hydraulic fracturing fluid, aluminum hydroxide and sodium aluminum dihydroxide carbonate compose a higher percentage of the total solids.

$$\frac{CaCO_3(S)}{S_{total}} > 92\% \Rightarrow \text{ideal/sufficient hydraulic fracturing fluid development} \tag{7.4}$$

$$CaCO_3(S)+2.63 > S_{total} \Rightarrow \text{ideal/sufficient hydraulic fracturing fluid development} \tag{7.5}$$

When the concentration of sodium aluminum dihydroxide or aluminum hydroxide is greater than 3.5 percent of the total solids an ideal/sufficient hydraulic fracturing fluid cannot be developed, as shown in Equation 7.6. If the concentration of sodium aluminum dihydroxide or aluminum hydroxide is greater than 3.5 percent of the total solids an ideal/sufficient hydraulic fracturing fluid can be developed. Some of the ideal/sufficient fluids had small concentrations of aluminum hydroxide, but none of the ideal/sufficient fluids had any sodium aluminum dihydroxide carbonate present.

$$\frac{AlCH_2NaO_5(S)}{S_{total}} \vee \frac{Al(OH)_3(S)}{S_{total}} < 3.5\% \Rightarrow \text{ideal development} \qquad (7.6)$$

Sample number three (1:1 High Sierra treated effluent and Greeley Municipal water) is the only sample that does not fit these models. This sample has shown up as an outlier throughout the analysis. The sample has an ideal water quality but only one hydraulic fracturing fluid was developed and it was considered bad. It is likely that this water could have been developed into an ideal or sufficient hydraulic fracturing fluid if more attempts were made to develop the fluid.

The total solid concentration of the ideal/sufficient runs is lower than the bad runs. The median, 5th, and 95th percentiles are shown in the box-and-whisker plot in Figure 7.6.

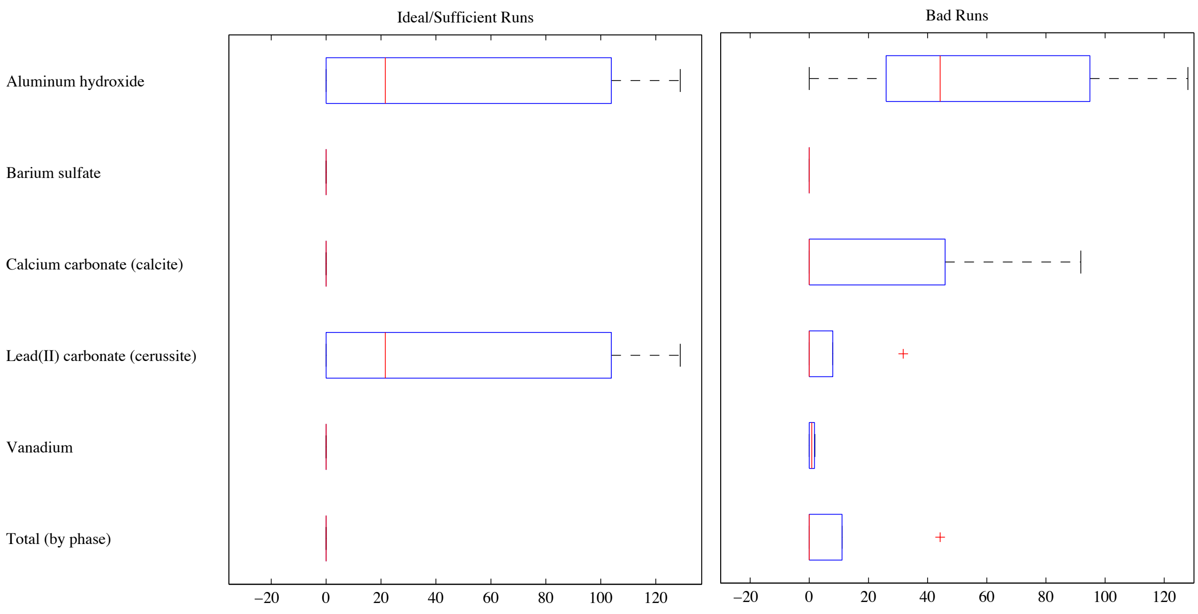


Figure 7.6: A comparison of solid concentration of the ideal/sufficient runs and bad runs. The blue lines represent the 5th, and 95th percentiles and the red line represents the median. Values are given in mg/L.

7.4.3. Aqueous Concentrations

OLI's stream analyzer is used to model the aqueous chemical concentration of the solution. The model estimates aqueous concentrations based on the temperature, pressure, pH and composition of the solution. Although the aqueous species have a wide range of concentrations, the aqueous concentrations show a much clearer separation between ideal/ sufficent runs and bad runs than either the scaling tendency or solid precipitations.

The aqueous concentration of aluminum, barium, potassium, sodium, strontium, and zinc complexes tend to reject the null hypothesis that the medians of each group are equal using the

Wilcoxon rank sum test, as shown in Tables 7.8 and 7.9. All of the aqueous species that reject the null hypothesis have a lower concentration in the ideal/sufficient runs than the bad runs. Sample number three (1:1 High Sierra treated effluent and Greeley Municipal water) continues to be an outlier. In Tables 7.8 and 7.9, when only one sample is not predicted correctly (e.g. Aluminum chloride dihydroxide) the unpredicted sample is always sample three.

Nearly all of the aqueous species correctly predict the performance of the hydraulic fracturing fluid for all of the water samples, except sample three. There is no need for an Eureqa analysis because any number of single variables adequately predict the development of a hydraulic fracturing fluid.

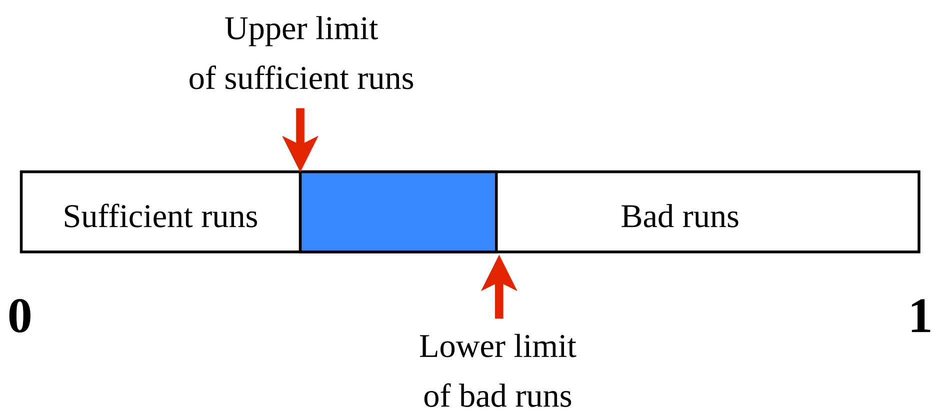


Figure 7.7: A schematic defining Tables 7.8 and7.9.

A comparison of the high (Figure 7.8), medium (Figure 7.9), low (Figure 7.10), concentration aqueous species are shown in the following box-and-whisker plots. Chloride, potassium, and sodium ion concentration are the only aqueous concentrations that rejected the null hypothesis in the high concentration group. Barium, bromide, potassium chloride, potassium sulfate, sodium bicarbonate, and sodium bromide, sodium sulfate, and strontium ion concentrations are the only aqueous concentrations that rejected the null hypothesis in the medium concentration group. Barium bicarbonate, barium chloride, sodium carbonate, strontium sulfate zinc bicarbonate, zinc chloride, zinc, zinc monohydroxide, and zinc trihydroxide ion concentrations are the only aqueous concentrations that rejected the null hypothesis in the low concentration group.

Table 7.7: A comparison of aqueous concentrations of the ideal/sufficient runs and bad runs that are rejected by the null hypothesis that the medians are equal at the 0.05 significance level. Values are given in mg/L.

Aqueous (mg/L)	Upper limit of sufficient runs	Lower limit of bad runs	Number correctly predicted	Total	Percentage
Aluminum chloride dihydroxide	$3.33\text{x}10^{-28}$	$4.08\text{x}10^{-23}$	9	10	90.0 %
Aluminum chloride hydroxide ion(+1)	$3.64\text{x}10^{-14}$	$4.23\text{x}10^{-9}$	9	10	90.0 %
Aluminum dihydroxide ion(+1)	$2.27\text{x}10^{-11}$	$1.13\text{x}10^{-6}$	9	10	90.0 %
Aluminum disulfate ion(-1)	$4.16\text{x}10^{-17}$	$1.55\text{x}10^{-13}$	9	10	90.0 %
Aluminum hydroxide	$2.37\text{x}10^{-9}$	$1.09\text{x}10^{-4}$	9	10	90.0 %
Aluminum ion(+3)	$4.35\text{x}10^{-15}$	$8.71\text{x}10^{-11}$	9	10	90.0 %
Aluminum monohydroxide ion(+2)	$3.81\text{x}10^{-13}$	$1.24\text{x}10^{-8}$	9	10	90.0 %
Aluminum monosulfate ion(+1)	$6.92\text{x}10^{-16}$	$1.16\text{x}10^{-11}$	9	10	90.0 %
Aluminum tetrahydroxide ion(-1)	$1.55\text{x}10^{-7}$	$1.14\text{x}10^{-4}$	9	10	90.0 %
Barium bicarbonate ion(+1)	$2.52\text{x}10^{-8}$	$3.96\text{x}10^{-4}$	9	10	90.0 %
Barium carbonate	$1.34\text{x}10^{-9}$	$1.43\text{x}10^{-9}$	10	10	100.0 %
Barium chloride ion (+1)	$1.35\text{x}10^{-7}$	$8.01\text{x}10^{-3}$	9	10	90.0 %
Barium hydroxide ion(+1)	$3.74\text{x}10^{-13}$	$2.04\text{x}10^{-10}$	9	10	90.0 %

Table 7.8: A comparison of aqueous concentrations of the ideal/sufficient runs and bad runs that are rejected by the null hypothesis that the medians are equal at the 0.05 significance level. Values are given in mg/L.

Aqueous (mg/L)	Upper limit of bad runs	Lower limit of sufficient runs	Number correctly predicted	Total	Percentage
Barium ion(+2)	1.28×10^{-6}	5.03×10^{-2}	9	10	90.0 %
Bromide ion (-1)	5.16×10^{-4}	25.4	9	10	90.0 %
Chloride ion(-1)	2,800	5,790	15	16	93.8 %
Hydrogen bromide	1.04×10^{-19}	1.07×10^{-14}	9	10	90.0 %
Potassium bisulfate(VI)	2.11×10^{-13}	3.03×10^{-9}	8	9	88.9 %
Potassium chloride	1.51×10^{-5}	0.0380	8	9	88.9 %
Potassium ion(+1)	0.0235	179	8	9	88.9 %
Potassium sulfate(VI) ion(-1)	4.47×10^{-5}	0.242	8	9	88.9 %
Sodium bicarbonate	0.411	9.52	13	15	86.7 %
Sodium bromide	1.55×10^{-6}	0.0703	9	10	90.0 %
Sodium carbonate ion(-1)	1.66×10^{-4}	2.35×10^{-3}	12	15	80.0 %
Sodium ion(+1)	906	2,170	14	15	93.3 %
Sodium sulfate ion(-1)	5.64	10.1	14	15	93.3 %
Strontium ion(+2)	7.43×10^{-5}	0.185	9	10	90.0 %
Strontium monohydroxide ion(+1)	7.78×10^{-11}	8.79×10^{-9}	8	10	80.0 %
Strontium sulfate	1.31×10^{-6}	0.0144	9	10	90.0 %

Table 7.9: A comparison of aqueous concentrations of the ideal/sufficient runs and bad runs that are rejected by the null hypothesis that the medians are equal at the 0.05 significance level. Values are given in mg/L.

Aqueous (mg/L)	Upper limit of bad runs	Lower limit of sufficient runs	Number correctly predicted	Total	Percentage
Zinc bicarbonate ion(+1)	5.73×10^{-9}	7.57×10^{-4}	9	10	90.0 %
Zinc bromide	2.32×10^{-16}	7.14×10^{-11}	8	10	80.0 %
Zinc bromide ion(+1)	6.12×10^{-12}	8.35×10^{-7}	9	10	90.0 %
Zinc chloride	8.29×10^{-10}	1.54×10^{-4}	9	10	90.0 %
Zinc chloride ion(+1)	9.41×10^{-9}	1.17×10^{-3}	9	10	90.0 %
Zinc hydroxide, amorphous	1.56×10^{-9}	3.36×10^{-7}	9	10	90.0 %
Zinc ion(+2)	2.00×10^{-7}	0.0106	9	10	90.0 %
Zinc monohydroxide ion(+1)	3.09×10^{-9}	3.25×10^{-5}	9	10	90.0 %
Zinc tetrahydroxide ion(-2)	2.29×10^{-18}	5.00×10^{-18}	8	10	80.0 %
Zinc tribromide ion(-1)	4.47×10^{-19}	9.31×10^{-14}	9	10	90.0 %
Zinc trichloride ion(-1)	4.19×10^{-11}	1.13×10^{-5}	9	10	90.0 %
Zinc trihydroxide ion(-1)	1.71×10^{-13}	3.70×10^{-13}	8	10	80.0 %

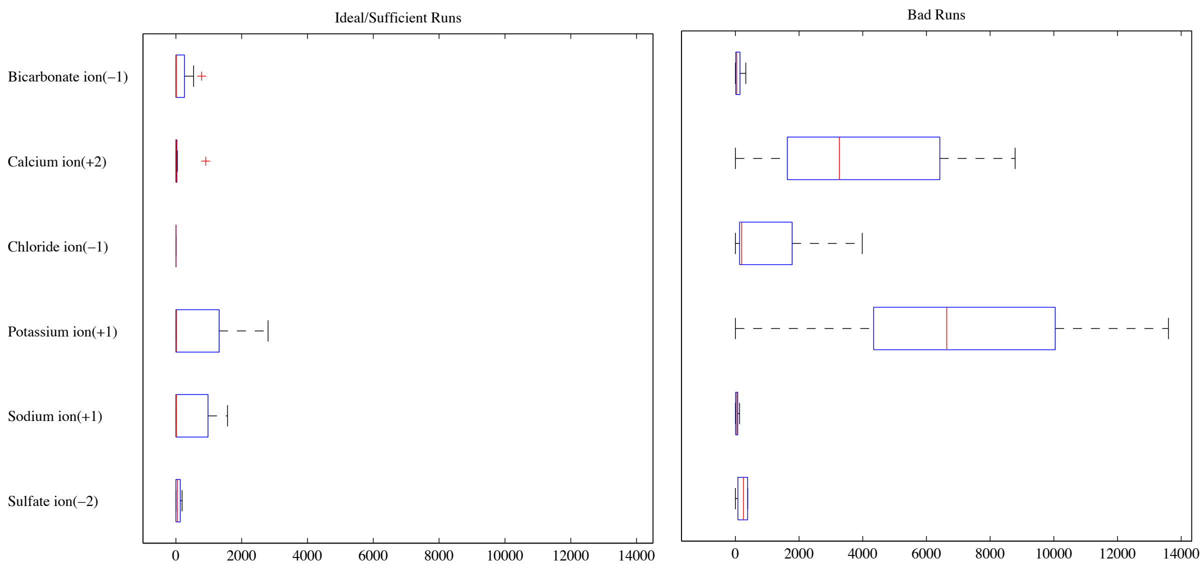


Figure 7.8: A comparison of high concentration of aqueous species of ideal/sufficient runs and bad runs. The blue lines represent the 5th, and 95th percentiles and the red line represents the median. Values are given in mg/L.

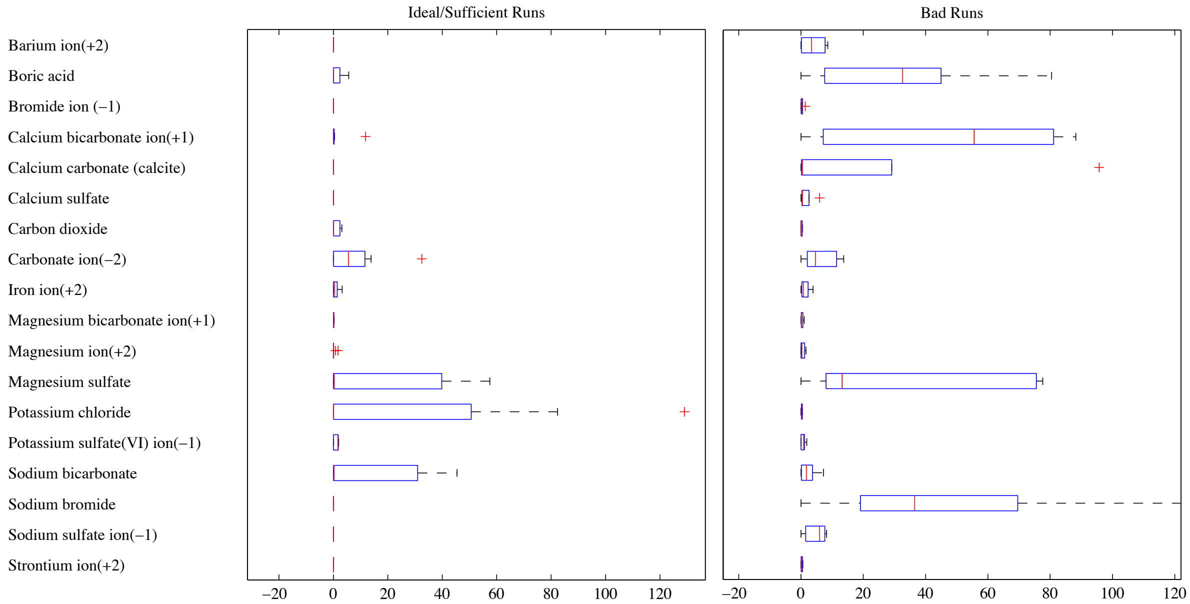


Figure 7.9: A comparison of medium concentration of aqueous species of ideal/sufficient runs and bad runs. The blue lines represent the 5th, and 95th percentiles and the red line represents the median. Values are given in mg/L.

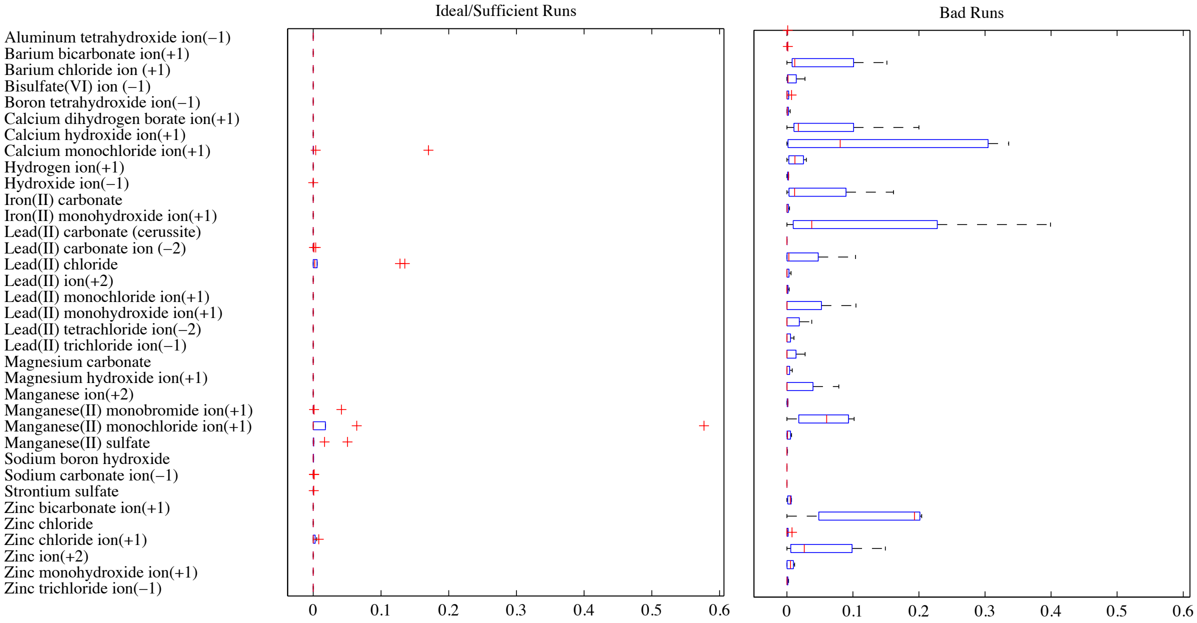


Figure 7.10: A comparison of low concentration of aqueous species of ideal/sufficient runs and bad runs. The blue lines represent the 5th, and 95th percentiles and the red line represents the median. Values are given in mg/L.

7.4.4. Element Concentrations

OLI's stream analyzer is used to model the solid element precipitation and aqueous element concentration of the solution. The solid precipitation did not adequately predict hydraulic fracturing fluid performance. The aqueous element concentration was the best indicator of hydraulic fracturing fluid performance. The aqueous element concentration of aluminum, barium, bromine, chloride, potassium, sodium, strontium, and zinc are all rejected by the null hypothesis that the medians of each group are equal using the Wilcoxon rank sum test, as shown in Tables 7.10. All of the aqueous elements that reject the null hypothesis have a lower concentration in the ideal/sufficient runs than the bad runs. Sample number three (1:1 High Sierra treated effluent and Greeley Municipal water) continues to be an outlier and was the only sample not correctly predicted in Table 7.10. A comparison of the high (Figure 7.12), medium (Figure 7.13), and low (Figure 7.14) concentration of aqueous elements are shown in the following box-and-whisker plots.

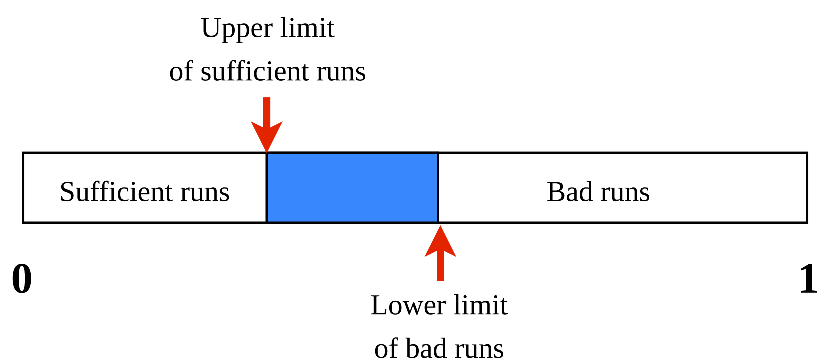


Figure 7.11: A schematic defining Table 7.10 .

Table 7.10: A comparison of aqueous element concentrations of the ideal/sufficient runs and bad runs that are rejected by the null hypothesis that the medians are equal at the 0.05 significance level. Values are given in mg/L.

Aqueous (mg/L)	Upper limit of sufficient runs	Lower limit of bad runs	Number correctly predicted	Total	Percentage
Al(+3)	0.234	15.3	9	10	90.0 %
Ba(+2)	0.0699	1.82	9	10	90.0 %
Br(-1)	25.5	138	9	10	90.0 %
Cl(-1)	5,790	13,600	15	16	93.8 %
K(+1)	179	4,020	8	9	88.9%
Na(+1)	2,190	8820	12	13	92.3%
Sr(+2)	0.193	8.63	9	10	90.0%
Zn(+2)	0.0120	0.177	9	10	90.0 %

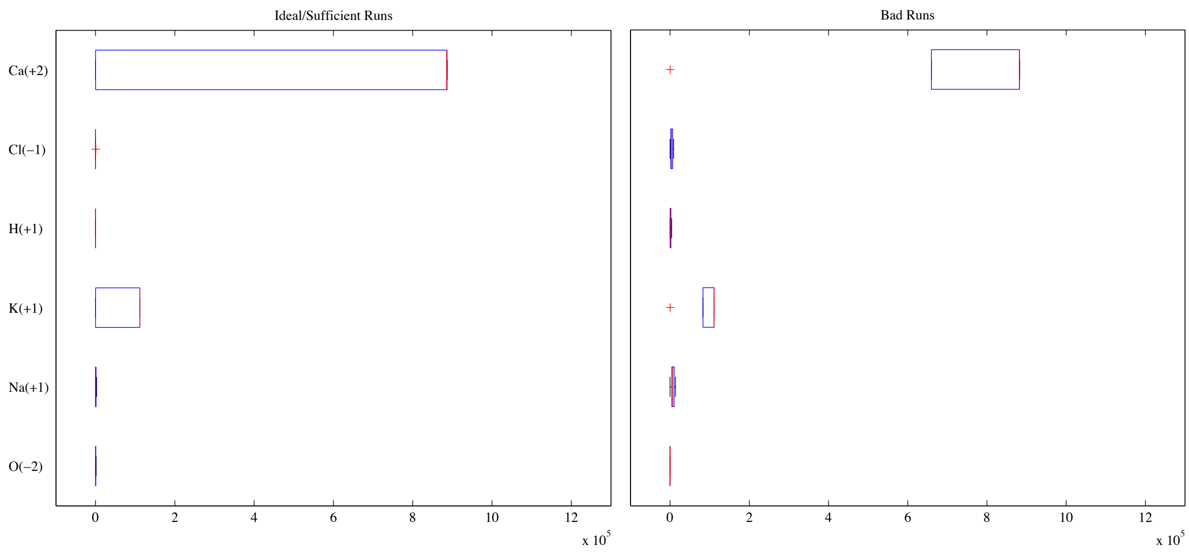


Figure 7.12: A comparison of low concentration of total elements of ideal/sufficient runs and bad runs. The blue lines represent the 5th, and 95th percentiles and the red line represents the median. Values are given in mg/L.

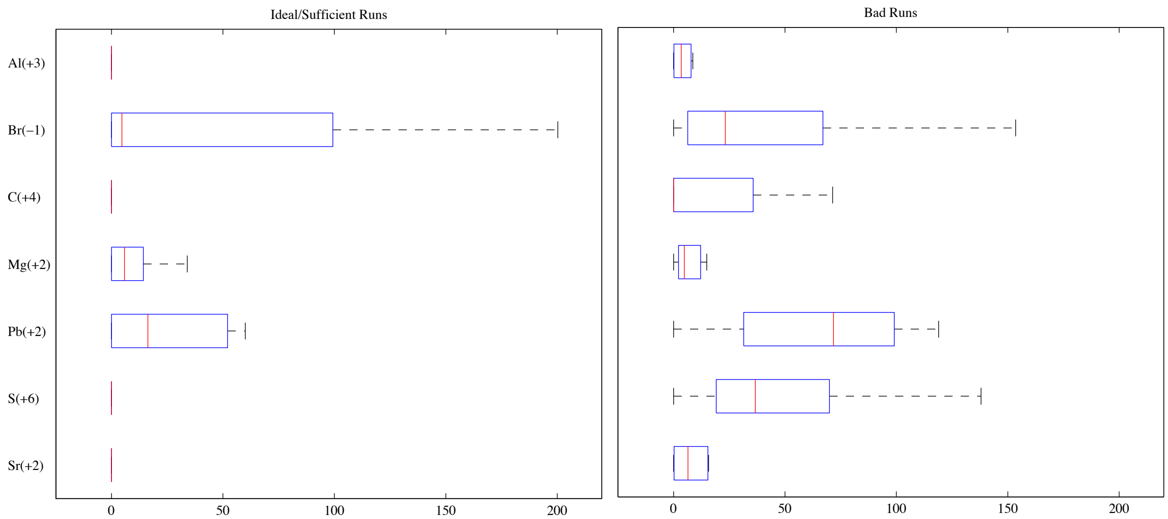


Figure 7.13: A comparison of medium concentration of total elements of ideal/sufficient runs and bad runs. The blue lines represent the 5th, and 95th percentiles and the red line represents the median. Values are given in mg/L.

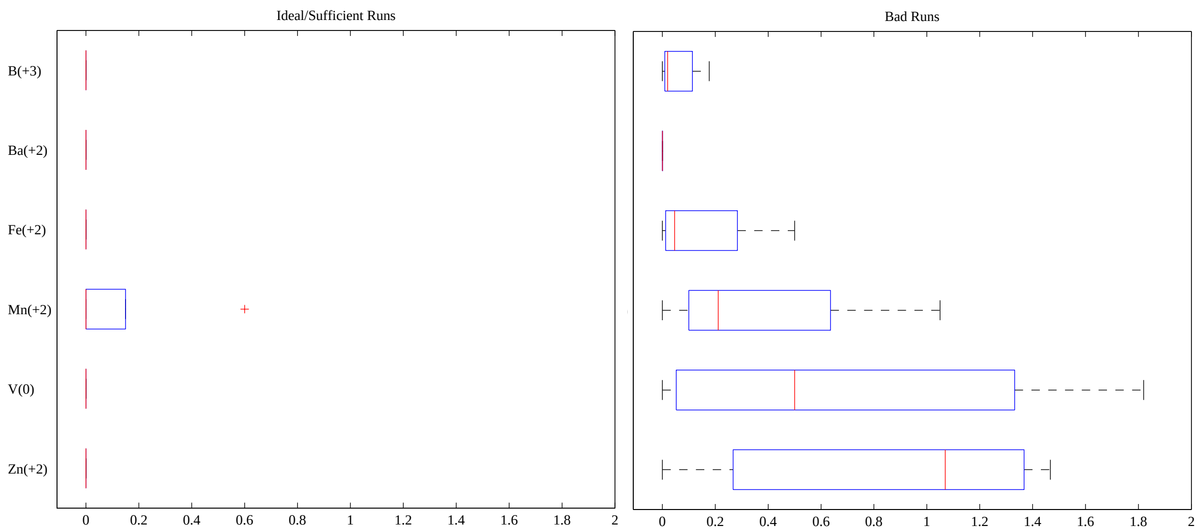


Figure 7.14: A comparison of high concentration of total elements of ideal/sufficient runs and bad runs. The blue lines represent the 5th, and 95th percentiles and the red line represents the median. Values are given in mg/L.

7.5. Discussion

A concern with this analysis is the detail of the initial water quality measurements. Basic water quality measurements are made with samples of the source and dilution water, often by separate laboratories. The source water is either analyzed by Colorado Analytical Laboratories, Inc. or Halliburton. Colorado Analytical Laboratories, Inc. provide the most detailed analysis of source water. The analysis includes the parameters shown in Table 7.11 using either standard methods or EPA methods. The lower quantifiable limit, analysis date, and the person that performed the analysis were all included in the analysis. Halliburton provides a much less comprehensive analysis of water quality and does not report the analysis methods or lower quantifiable limits. The dilution water from the City of Greeley and the South Platte are measured by Baker Hughes, Inc. The samples used to measure the water quality were both taken on September 4, 2012 and the samples used for dilution in the hydraulic fracturing fluid development were taken on different dates.

The basic water quality measurements are made with low resolution and provide the input to the high resolution OLI aqueous thermodynamic model to create the water quality data. Although OLI tries to reconcile incomplete water quality inputs for alkalinity, pH, and CO2, an initial low resolution input cannot be completely reconciled. For example, Colorado Analytical Laboratories, Inc. is the only laboratory that measures aluminum concentration. This means that only water samples analyzed at this lab will have an aluminum concentration input to OLI. Water samples from the other two laboratories will not report an aluminum concentration. OLI will then try to reconcile a water quality that is different from the true water quality. The Wilcoxon rank sum test takes into account non reported samples. So, if the Aluminum concentration is only reported in four water samples the analysis will ignore the samples without an Aluminum concentration, but this can dramatically reduce a small sample set. If the sample set is reduced below half of the original data set, the analysis is not included.

For this reason, the most confidence is placed in water quality measurements that are made at all three laboratories. The confidence in the results decreases with the number of laboratories that make the water quality measurement. Furthermore a water quality parameter that is measured at all three laboratories will have the largest sample size and increase the confidence in the statistical analysis.

The analysis also has a limited data set of only 16 unique water quality samples. Many of these samples include the same source water with different dilutions of fresh or municipal water quality. As the data set grows in size and a more complete water quality analysis is done, the confidence and accuracy of the analysis will improve. At this point, the limited data is a limiting factor in the analysis.

Table 7.11: Water quality parameters measured at each laboratory.

Measurement	Colorado Analytical Laboratories, Inc.	Halliburton	Baker Hughes, Inc.
	Source Water		Dilution Water
Aerobic Bacteria		X	
Aluminum	X		
Anaerobic Bacteria		X	
Barium	X	X	
Bicarbonate	X	X	X
Boron	X		
Bromide	X		
Cadmium	X		
Calcium	X	X	X
Calcium Hardness	X		
Carbonate	X	X	X
Chloride	X	X	X
Chromium	X		
Conductivity		X	
Copper	X		
Hydroxide		X	
Iron	X	X	X
Lead	X		
Magnesium	X	X	
Manganese	X		X
Molybdenum	X		
Nickel	X		
Nitrate as Nitrogen	X		
Nitrite as Nitrogen	X		
Oil/Grease	X		
pH	X	X	X
Potassium	X	X	X
Resistivity-Calc		X	
Silica	X		
Sodium	X	X	X
Specific Conductance	X	X	X
Specific Gravity		X	
Strontium	X		
Sulfate	X	X	X
Temperature		X	X
Total Alkalinity	X		
Total Dissolved Solids	X	X	X
Total Hardness	X	X	
Vanadium	X		
Zinc	X		

7.6. Conclusion

The aqueous elements have the clearest separation between the ideal/sufficient runs and the bad runs. Aluminum, barium, bromine, chloride, potassium, sodium, strontium, and zinc all predicted the performance of the hydraulic fracturing fluid by placing an upper limit on the acceptable concentration in the water. Chloride was measured in 15 of the 16 samples and showed the largest separation between the ideal/sufficient runs and bad runs. The best indicator appears to be chloride with an upper limit between 5,790 and 13,600 mg/L. Other strong indicators are shown in Table 7.12 with varying degrees of confidence. There is a high confidence that Carbonate salts, Chloride, Potassium, Sodium, Sulfate, and Total dissolved solids are likely to be important water quality parameters that determine the performance of hydraulic fracturing fluid development. There is less confidence that Aluminum, Barium, Bromide, Strontium, and Zinc determine the performance of hydraulic fracturing fluid development, as shown in Table 7.12.

The aqueous chemical species are also a good indicator of hydraulic fracturing fluid performance. 42 chemical species can be used as indicators with varying degrees of success, as shown in Tables 7.8 and 7.9. The scaling tendency of aluminum hydroxide and sodium aluminum dihydroxide carbonate may be adequate indicators, although will be difficult to measure in the field and may be more useful in modeling applications. The solid precipitation is not a good indicator of hydraulic fracturing fluid performance. Sample number three (1:1 High Sierra treated effluent and Greeley Municipal water) is consistently an outlier throughout the analysis and was the only sample not correctly predicted in the aqueous elements listed. The sample had a relatively high dilution with municipal water and only one hydraulic fracturing fluid was attempted to be developed from. It is likely an ideal/sufficient hydraulic fracturing fluid could have been developed from the water with additional attempts.

Table 7.12: The water quality parameters that are likely to be strong predictors in the performance of hydraulic fracturing fluid development.

Likely Indicators	High	Medium	Low
	Confidence Level		
Aluminum			X
Barium		X	
Bromide			X
Carbonate	X		
Chloride	X		
Potassium	X		
Sodium	X		
Strontium			X
Sulfate	X		
Total Dissolved Solids	X		
Zinc			X

There is a high confidence that Calcium, Iron, and pH are not likely to be important water quality parameters that determine the performance of hydraulic fracturing fluid development. There is less confidence that Cadmium, Chromium, Copper, Lead, Manganese, Molybdenum, Nickel, Nitrate, Nitrite, Silica, or Vanadium determine the performance of hydraulic fracturing fluid development, as shown in Table 7.13.

Table 7.13: The water quality parameters that are unlikely to be strong predictors in the performance of hydraulic fracturing fluid development.

Unlikely Indicators	High	Medium	Low
	Confidence Level		
Boron			X
Cadmium			X
Calcium	X		
Chromium			X
Copper			X
Iron	X		
Lead			X
Magnesium		X	
Manganese		X	
Molybdenum			X
Nickel			X
Nitrate			X
Nitrite			X
pH	X		
Silica			X
Temperature		X	
Vanadium			X

7.7. Case Studies

Three case studies are briefly presented to give insight into: (1)treatment process element removal, (2)variation in flowback water quality, and (3) the difference between flowback and produced water treated with electric coagulation.

7.7.1. High Sierra Treatment Results for June 25, 2012 Sample

On June 25, 2012 Noble collected three samples from the High Sierra C6 water treatment facility: an influent sample, a sample after dissolved air flotation (DAF) treatment, and an effluent sample. A schematic of the treatment process is shown in Figure 7.15. The samples were analyzed by Colorado Analytical Laboratories, Inc. OLI was used to reconcile the water quality data.

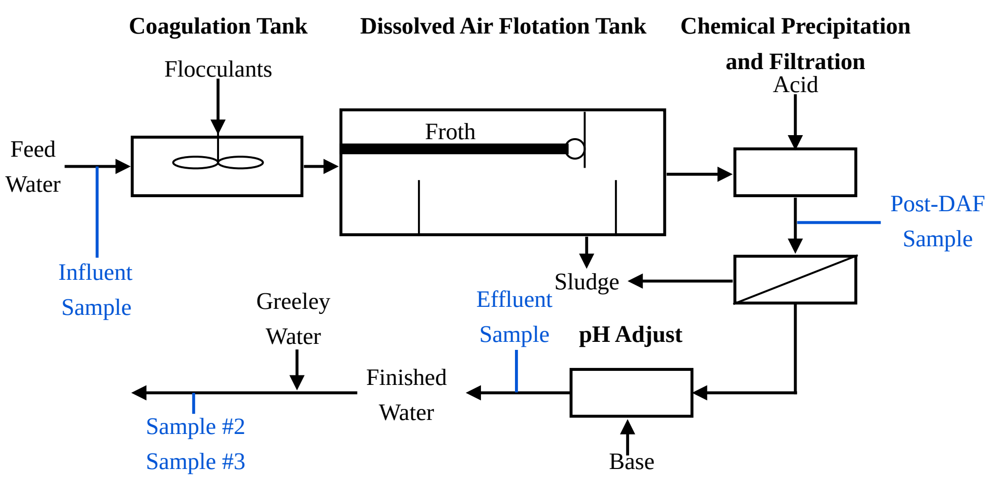


Figure 7.15: High Sierra treatment facility schematic and sampling locations. Values are given in mg/L.

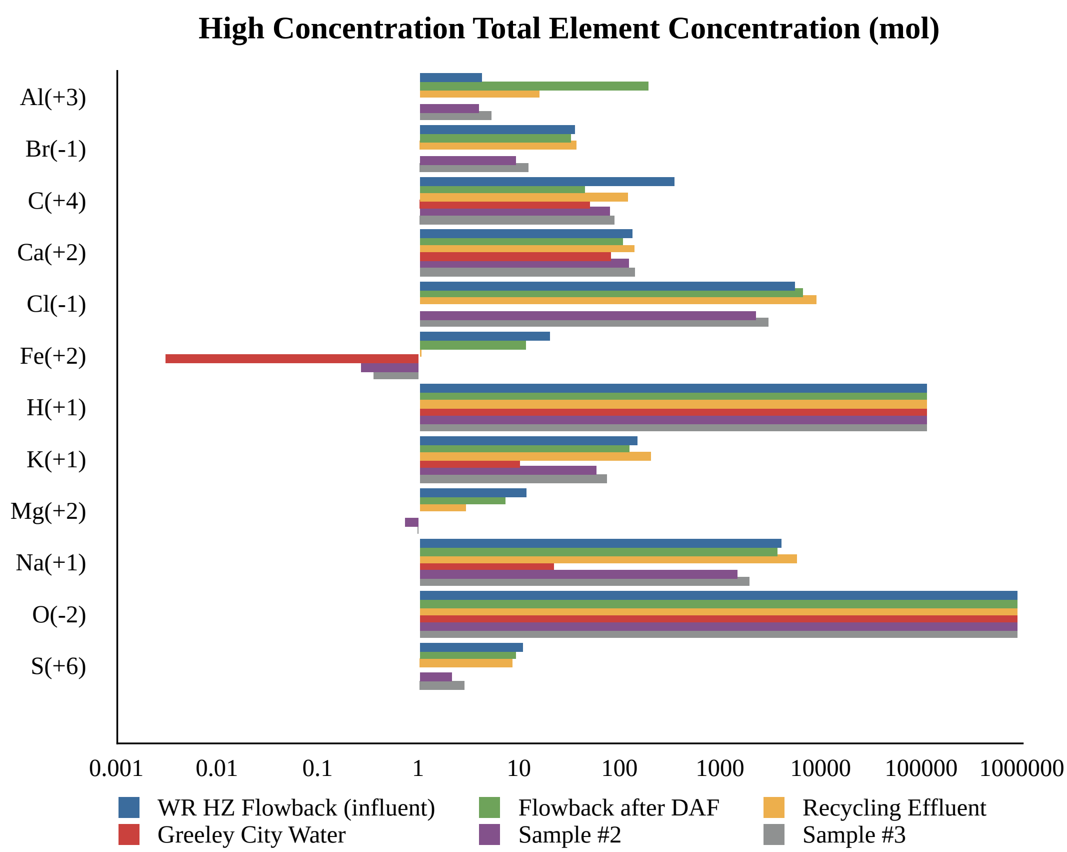


Figure 7.16: Total element concentration at High Sierra treatment facility schematic and sampling locations with high concentrations. Values are given in mg/L.

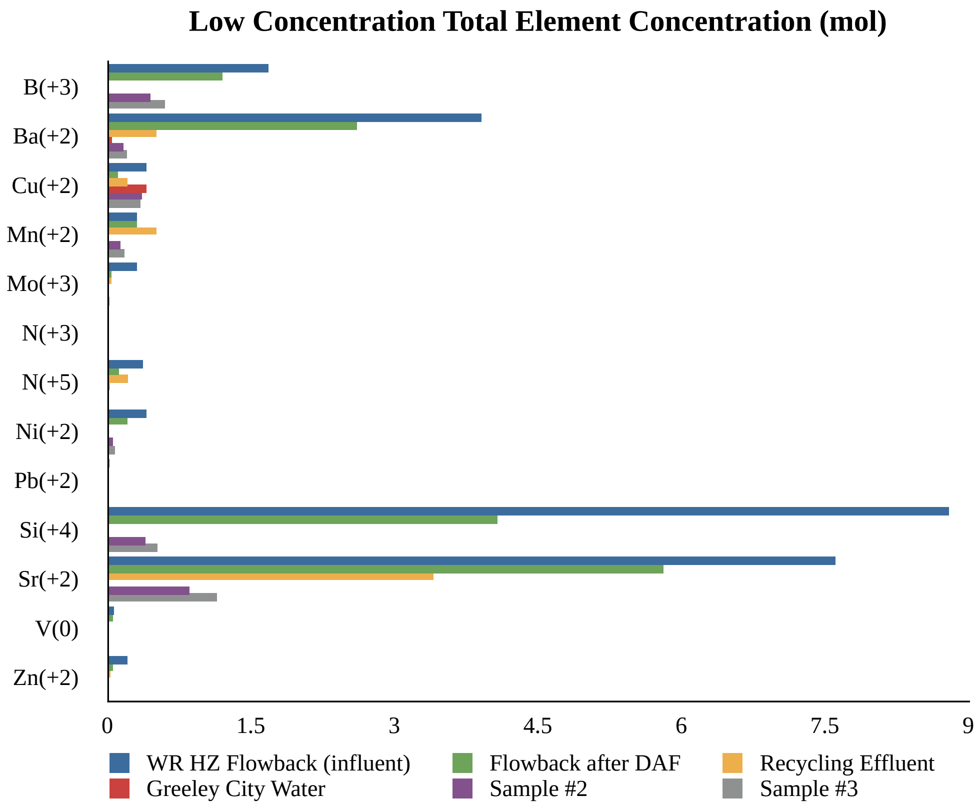


Figure 7.17: Total element concentration at High Sierra treatment facility schematic and sampling locations with low concentrations. Values are given in mg/L.

7.7.2. High Sierra Treatment Results for High Sierra Keely Effluent

On December 12, 2012 Noble collected three samples from Noble's Keely B11-63-1HN frac tanks and one sample of the effluent of the composite water treated by the High Sierra C6 water treatment facility. A schematic of where each sample was taken is shown in Figure 7.18. This case study gives insight into the variability of flowback water quality.

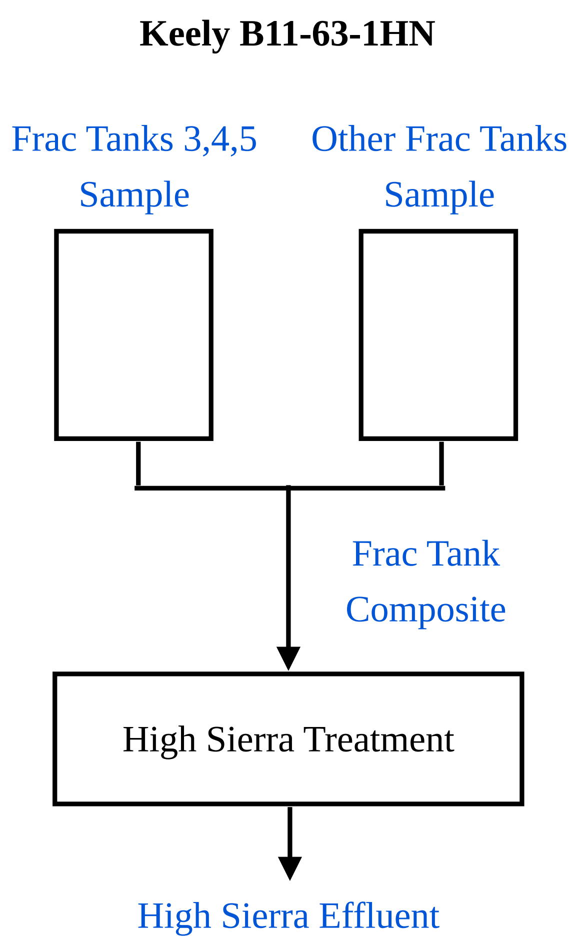


Figure 7.18: High Sierra treatment of Keely effluent schematic.

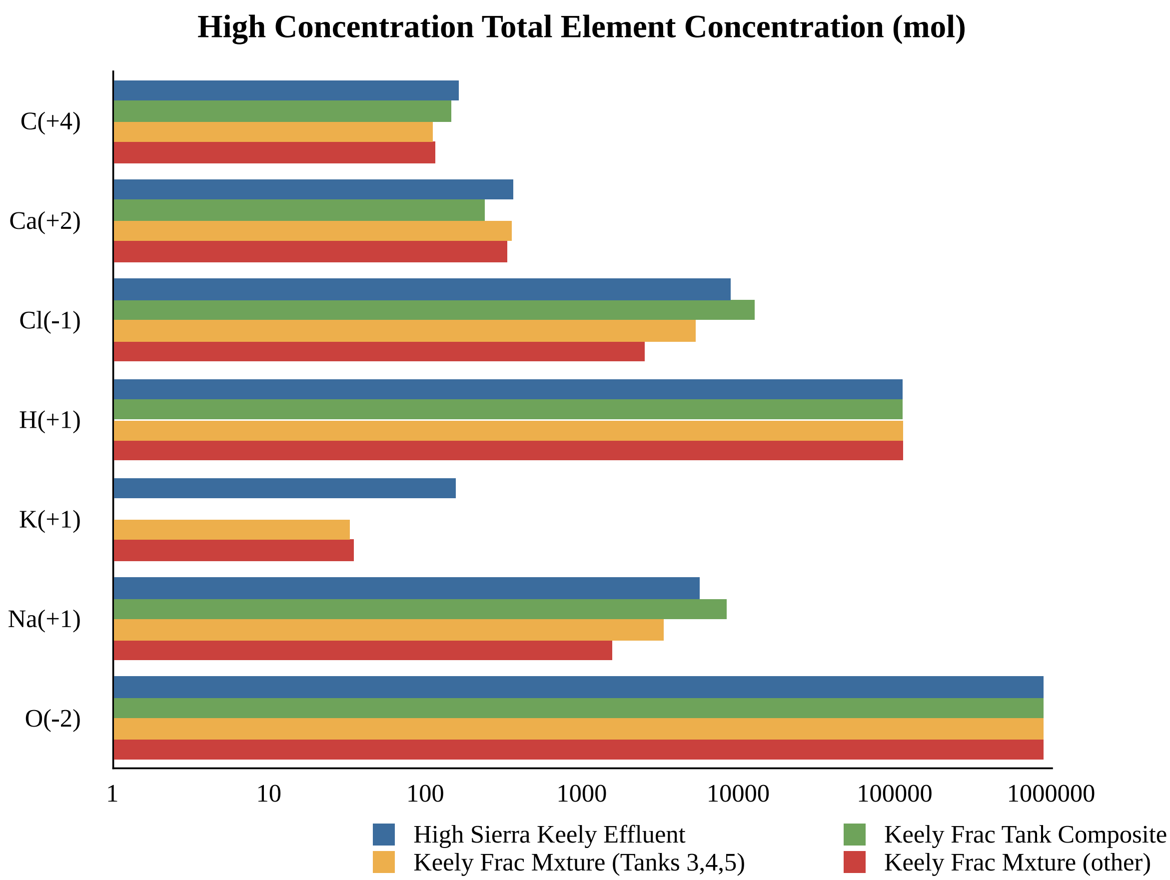


Figure 7.19: Total element concentration of Keely flowback water with high concentrations. Values are given in mg/L.

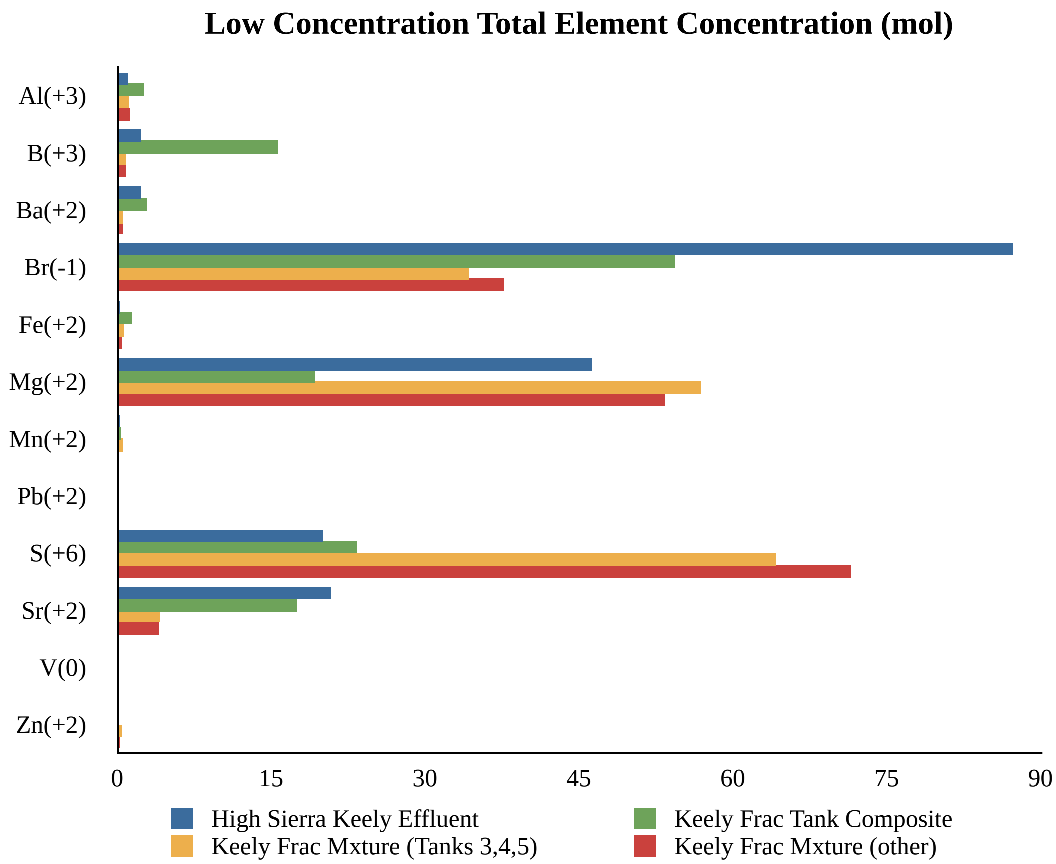


Figure 7.20: Total element concentration of Keely flowback water with low concentrations. Values are given in mg/L.

7.7.3. Water Rescue Services Treatment Results for Flowback and Produced Water

Water Rescue Services provides on-site water treatment services. Flowback and produced water pass through an electric coagulation unit and settled before the water is filtered. The treatment results of flowback and produced water are shown below. This case study gives insight into the difference between treated flowback and produced water quality.

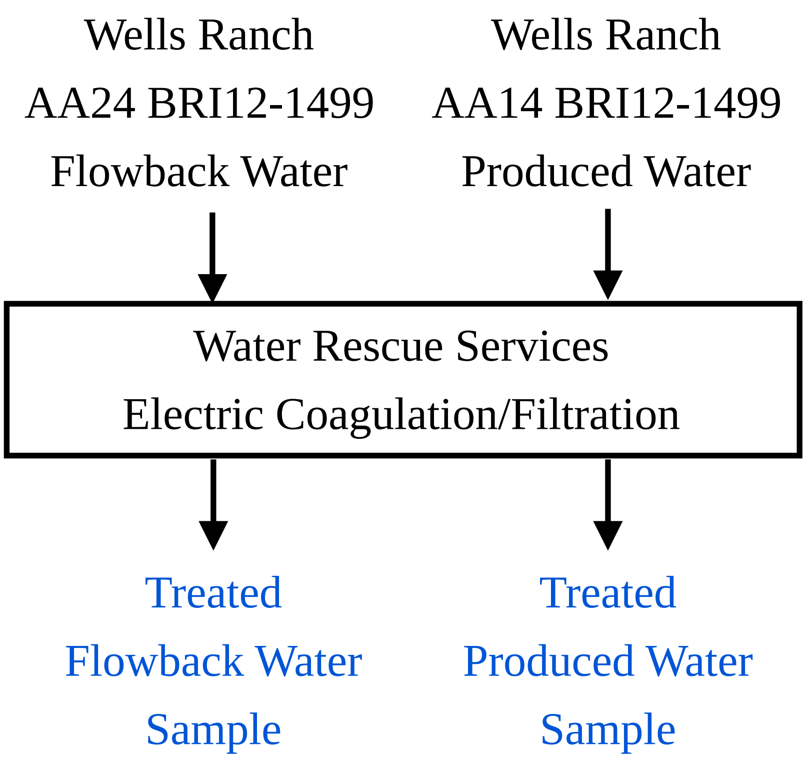


Figure 7.21: Water Rescue treatment results of flowback and produced water. Values are given in mg/L.

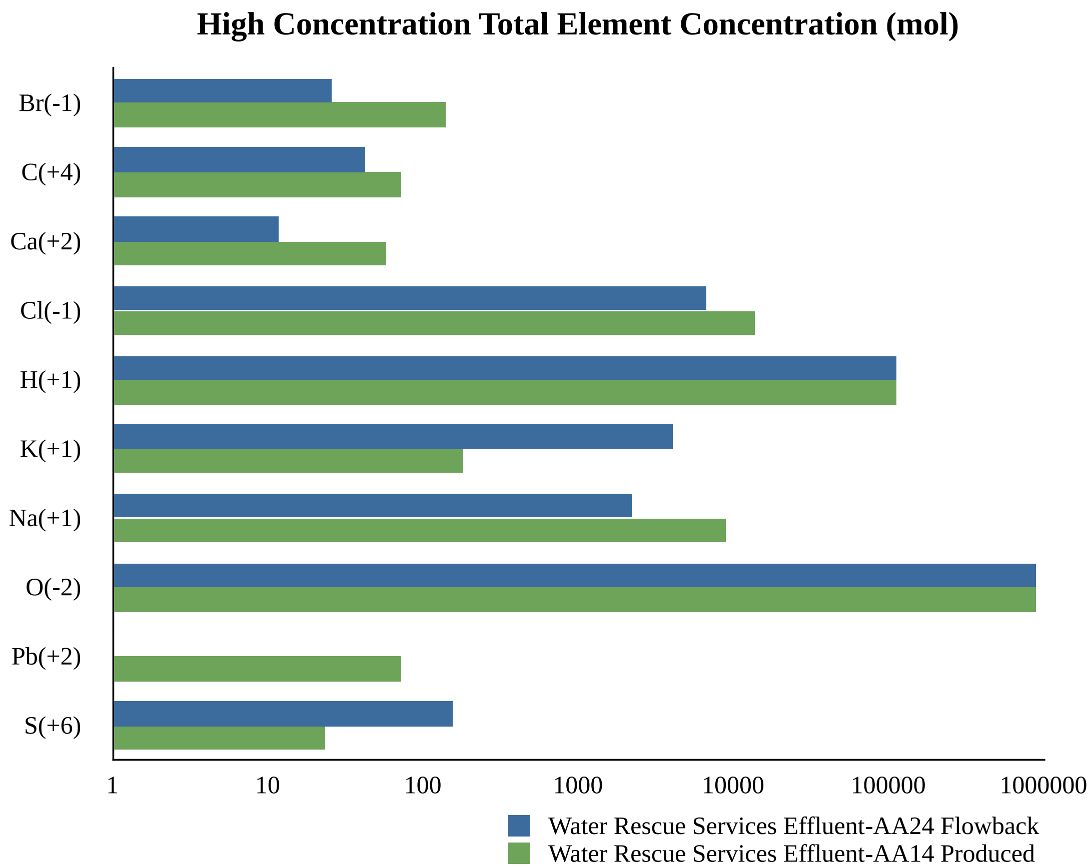


Figure 7.22: Total element concentration of flowback and produced water treated with electric coagulation by Water Rescue Services with high concentrations. Values are given in mg/L.

8. Modeling Water Infrastructure in a Hypothetical Oil and Gas Field[v]

8.1. Overview

A model is developed to allow operators to quantitatively compare a variety of water management and reuse scenarios based on their concerns by integrating the prediction methods of water volumes, water quality, treatment targets, and treatment efficiency developed in previous chapters with future well development plans. The model allows operators to predict water volumes, dilution ratio, and the implications of water infrastructure decisions within the field. The robustness of water infrastructure decisions can be assessed by varying the development plans.

An interactive multi-criteria decision analysis of water infrastructure placement within the field is also built into the model. This allows operators to spatially and temporally score the location of wastewater treatment facilities based on key criteria (e.g. future reuse potential, wastewater volumes, environmental sensitivity, etc.) and existing as well as future water infrastructure (e.g. other treatment facilities, pipelines, etc.) The objective is to model and optimize water infrastructure decisions based on water quantity and quality characterizations within a rapidly changing and uncertain unconventional oil and gas field to minimize social, environmental, and operating risks and costs.

[v] ***S. Goodwin[a], K. Carlson[a], A. Prior[b],***
[a] Colorado State University, Department of Civil and Environmental Engineering, Campus Delivery, Fort Collins, CO 80523, USA

8.2. Introduction

The technical challenge of optimizing water reuse and water management is not a lack of water treatment technology. Fundamental water treatment technology has been developed and refined for decades in several industrial water treatment applications that can be applied to flowback and produced water volumes. The technical challenge lies in implementing infrastructure to minimize treatment costs with dilution and optimize oil and gas production while minimizing water use as well as other environmental and social impacts. This requires a detailed understanding and characterization of water use and wastewater in an oil and gas field as well as an understanding of how treated reuse water quality influences the development and performance of hydraulic fracturing fluid.

An integrated water management plan needs to take into account the spatial and temporal distribution of the water, transportation requirements, treatment and disposal facilities, water separation, and water storage facilities. A generic schematic of the water, oil, and gas flows with the infrastructure requirements within an oil and gas field is shown in Figure 8.1. From this general schematic three infrastructure scenarios are used to model model water infrastructure implementation in the hypothetical field. The goal is to allow operators to easily add development plans and water management strategies to compare a variety of scenarios and visualize implementation plans in a rapidly changing field.

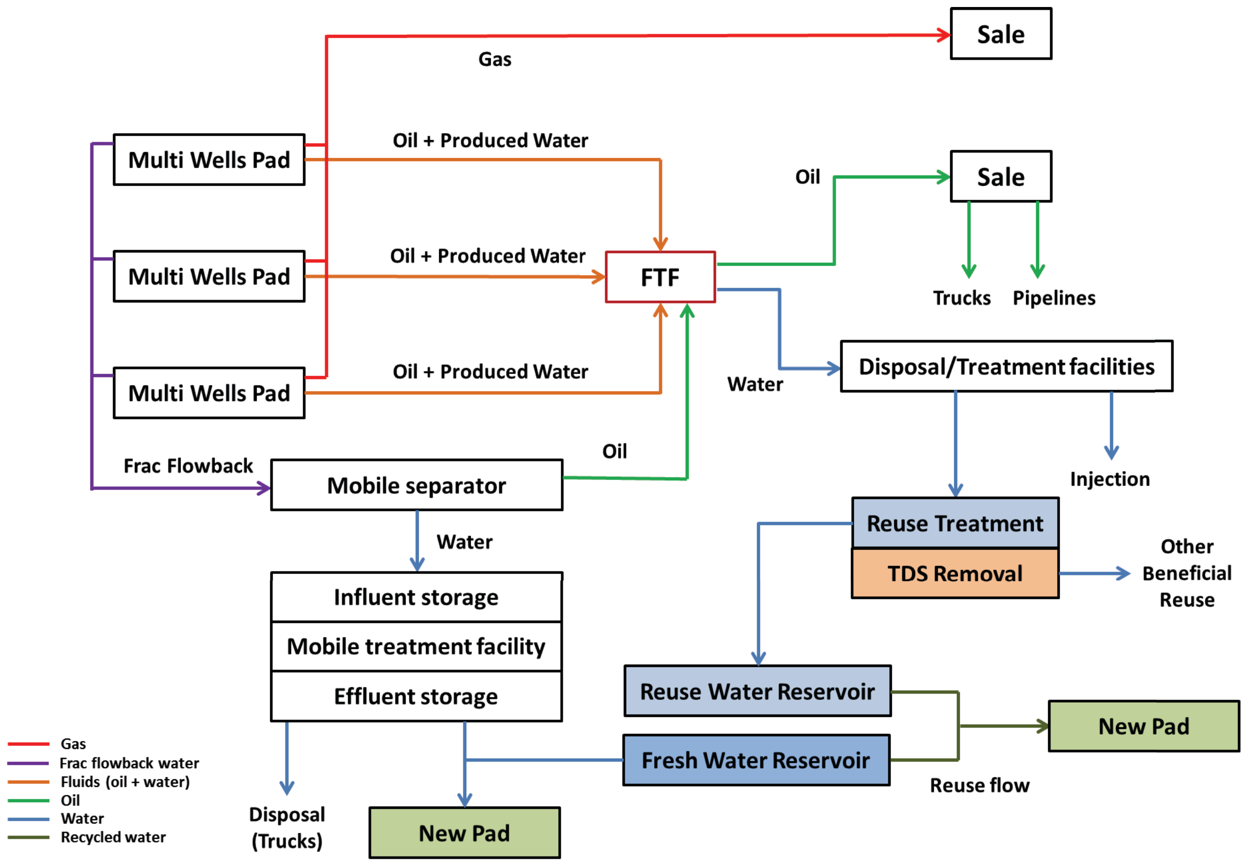


Figure 8.1: A schematic of the generic flows of water, oil, and gas along with the infrastructure requirements within an oil and gas field.

Critical design decisions are required for each component of infrastructure that dramatically impacts other components of the entire water infrastructure system. For example, if an operator treats the water at a single centralized facility the operating costs increase dramatically; however, the operator can now store the water in open pits, easily reuse the water without any additional blending, and discharge the water to surface sources. To further complicate water infrastructure design, the development plans for a field are highly dependent where the highest producing wells are located, energy prices, and regulations. Water quality requirements for reuse in future wells is not well understood and a plugged well typically costs millions of dollars. This makes the most flexible option with the lowest capital investment the most attractive for most operators.

A model is developed based on a hypothetical oil and gas field to predict water volumes and to assess the financial, environmental, and social implications of various water management scenarios. Three scenarios are examined as case studies to demonstrate the model capabilities and applications.

8.3. Methods

8.3.1. Development of a Hypothetical Oil and Gas Field

A hypothetical oil and gas field is shown in Figure 8.2 and used to develop and present the water infrastructure modeling approach and compare four water infrastructure scenarios. The hypothetical oil and gas field is defined by the border of two townships (each 6 miles by 6 miles). One section (1 square mile) is developed completely each month before moving onto the next section. For the hypothetical scenario sections are not developed in parallel. The field is developed over a five-year period. The month each section is developed is chosen randomly and is defined in Figure 8.2.

Figure 8.2: The buildout plan for the hypothetical oil and gas field used to develop the model.

The pace of development is assumed to be increasing each each year, starting with 15 wells per month in the first year and increasing by 5 wells per month in each of the following years. Within each township, the wells are randomly distributed. Two well lengths are used for the model: 5,000 feet (normal) and 7,500 feet (extended). The well length for each individual well is modeled with a normal distribution with a mean of 5,000 feet and 7,500 feet and a standard deviation of 500 feet for normal and extended wells, respectively.

Table 8.1: The count of sampled wells separated by year and well type.

Year	Wells per Month
2014	15
2015	20
2016	25
2017	30
2018	35

Flexibility with input data is a key consideration for the model is to allow for rapidly changing development plans. To improve flexibility, only three inputs are required for the model: well location, spud date, and well length. A detailed version of the development plan with these inputs for each well can be found in Appendix M. Two freshwater resources and one injection well are defined in Figure 8.2 with blue dots.

8.3.2. Defining the Development Plans in MATLAB

The time and location each well is developed is defined based on a single matrix for the development plans. This matrix will be referred to as the "development plan matrix." Each column of the development plan matrix represents a section (one square mile) of the field and each row represents a month/year, as shown below. The number of wells developed for each section for a given month is defined as each element of the matrix. The matrix used for the hypothetical field can be found in Appendix M.

$$\text{Development Plan (DP)}_{\text{Month,Section}} = \begin{array}{cc} & \begin{matrix} \mathbf{A1} & \mathbf{A2} & \cdots & \mathbf{B36} \end{matrix} \\ \begin{matrix} \mathbf{Jan.\ 13} \\ \mathbf{Feb.\ 13} \\ \vdots \\ \mathbf{Dec.\ 13} \end{matrix} & \begin{pmatrix} \text{Wells} & \text{Wells} & \cdots & a_{2,n} \\ \text{Wells} & \ddots & \cdots & a_{2,n} \\ \vdots & \vdots & \ddots & \vdots \\ \text{Wells} & \cdots & \cdots & \text{Wells} \end{pmatrix} \end{array}$$

The development plan matrix is used as the basis to make all of the water prediction calculations (e.g. water requirements, flowback/produced water). By calculating the volume of water required or produced each month for each section, the water volumes can be visualized throughout the field. Using the water volume calculations the impact water infrastructure scenarios handles the water volumes can also be visualized. These methods are explained in later sections.

First, the development plan matrix needs to be translated into a matrix that represents the field. The matrix representing the field will be referred to as the "field matrix." Each element of the field matrix represents one square mile section of the field and corresponds to a column of the development plan matrix. For the hypothetical field, defined in Figure 8.2, the development plan (DP) matrix is translated into the field matrix by converting each column of the development plan matrix to the corresponding element of the field matrix. The field matrix is presented as two separate matrices for each township for simplicity as shown below:

$$\text{Field}_{m,n} = \left[\begin{matrix} DP(:,6) & DP(:,5) & DP(:,4) & DP(:,3) & DP(:,2) & DP(:,1) & \cdots \\ DP(:,7) & DP(:,8) & DP(:,9) & DP(:,10) & DP(:,11) & DP(:,12) & \cdots \\ DP(:,18) & DP(:,17) & DP(:,16) & DP(:,15) & DP(:,14) & DP(:,13) & \cdots \\ DP(:,19) & DP(:,20) & DP(:,21) & DP(:,22) & DP(:,23) & DP(:,24) & \cdots \\ DP(:,30) & DP(:,29) & DP(:,28) & DP(:,27) & DP(:,26) & DP(:,25) & \cdots \\ DP(:,31) & DP(:,32) & DP(:,33) & DP(:,34) & DP(:,35) & DP(:,36) & \cdots \end{matrix}\right.$$

$$\left.\begin{matrix} DP(:,42) & DP(:,41) & DP(:,40) & DP(:,39) & DP(:,38) & DP(:,37) \\ DP(:,43) & DP(:,44) & DP(:,45) & DP(:,46) & DP(:,47) & DP(:,48) \\ DP(:,54) & DP(:,53) & DP(:,52) & DP(:,51) & DP(:,50) & DP(:,49) \\ DP(:,55) & DP(:,56) & DP(:,57) & DP(:,58) & DP(:,59) & DP(:,60) \\ DP(:,66) & DP(:,65) & DP(:,64) & DP(:,63) & DP(:,62) & DP(:,61) \\ DP(:,67) & DP(:,68) & DP(:,69) & DP(:,70) & DP(:,71) & DP(:,72) \end{matrix}\right]$$

Figure 8.3: The matrix used to translate the development plan matrix into a matrix that represents the hypothetical oil and gas field.

8.3.3. Defining the Start and End Period

The start month/year and end month/year are used to define which rows of the development plan matrix that should be used to visualize water volumes in the field matrix. By giving the user the opportunity to select a specific periods to analyze, different water infrastructure scenarios can be implemented as the field develops. For example, if mobile treatment facilities will be moved throughout the field at the end of each year, the flowback/ produced water volumes for each year can be visualized to choose the location with the highest volumes of flowback/produced water.

The user can select a start month and end month for development period with the GUI from a drop down menu. The selected start and end months are passed from the GUI into MATLAB as a value that corresponds to the month number (e.g. Jan=1, Feb=2, March=3, etc.) The start year is selected from a drop down menu with values of 2013, 2014,...2020 and is passed into MATLAB as a value that corresponds to the years after 2012 (e.g. 2013=1, 2014=2, 2015=3, etc.) The end year drop down menu is reversed to make 2020 (i.e. the end of the development period) the default entry. If the end year started with 2013, the default range would be zero years and a new user may not understand why the GUI appears to not give meaningful results.

Equations 8.1 and 8.2 are used to convert the start month/year and end month/year to the corresponding row of he development plan matrix. The development plan matrix can be redefined based to not include columns less than S or greater than E.

$$S = \text{start month} + 12 \cdot (\text{start year} - 1) \tag{8.1}$$

$$E = \text{end month} + 12 \cdot (8 - \text{end year}) \tag{8.2}$$

8.3.4. Visualizing Water Volumes Required

Chapter 4 concluded that the water volume required for drilling and hydraulic fracturing correlates linearly with the length of the well, as shown in Equation 8.3. In the hypothetical field all of the wells are assumed to have a length of 5,000 feet. Every well in the hypothetical field is assumed to require 95,400 bbls of water. The GUI allows the user to adjust the water use per foot (i.e. the coefficient before the length variable) and change the water required for each well. For the hypothetical field, the water required is shown in Equation 8.4. This allows the user to account for changes in operations and to estimate a range of water requirement scenarios.

$$\text{Water Required (bbls)} = 2,900 + 18.5 \cdot \text{Length} \tag{8.3}$$

$$\text{Water Required (bbls)} = 2,900 + \text{Water per Foot} \cdot \text{Length} \tag{8.4}$$

The development plan matrix needs to be covered from a well count to the volume of water required for each section and month using Equation 8.4 to visualize the water required per well. After the matrix is converted, each column (i.e. section) of the development plan matrix is summed between rows with the start and end dates (Equations 8.1 and 8.2). This sum is used to define the water required within the field according the field matrix. The water required to develop the hypothetical field is shown in Figure 8.4.

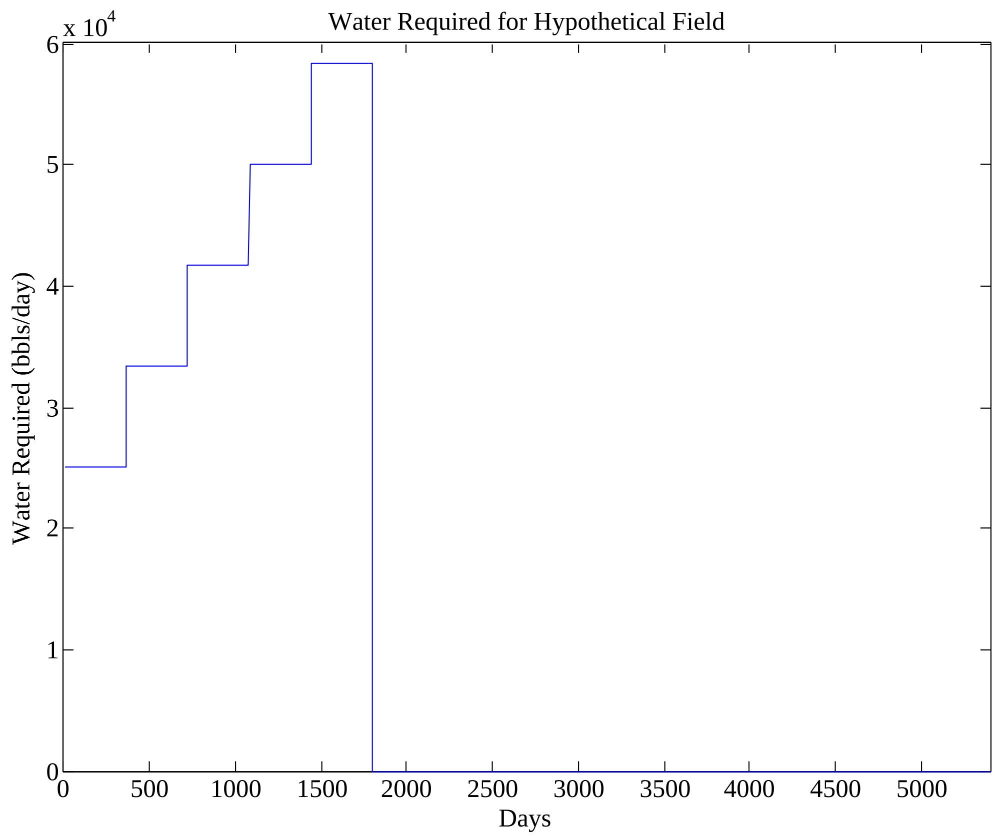


Figure 8.4: The water required for drilling and hydraulic fracturing in the hypothetical oil and gas field.

Once the field matrix is updated to reflect the water requirements for each section, the matrix is plotted in the GUI with a pseudocolor (checkerboard) plot. The water required for each section is color coded based on the water volume required between the start and the end dates, as shown in Figure 8.5. The GUI is programmed to instantly update the water use plot when a change in water use per foot or start/date ends are changed. This allows the user to instantly visualize the how the water use changes in the field.

Figure 8.5: The graphical user interface that allows the user to input the start/end dates and the water use (bbls/ft) and visualize the water required in the hypothetical oil and gas field.

The total, average (bbls/month), and peak (bbls/month) volumes of water required between the start and end date are calculated and displayed in the "Flows" panel of the GUI. These volumes are important for planning acquisition and storage of freshwater resources for the field. It is also important for making water treatment and injection decisions. These volumes can be used to estimate the volume of water that can be reused in the same field based on future demand.

Equation 8.4 is used to translate the development plan matrix into a matrix representing the volume of flowback and produced water between the start and end dates defined by the user. This matrix is defined as the Water Required matrix (WR matrix) and is represented in the same format as the development matrix, where the each column represents a square mile section and each row represents a month of development. Each element of the matrix represents the volume of water required for the corresponding month and section. The WR matrix is translated into the field matrix, to visualize where the water is required, using the MATLAB code shown below.

```
start_month=get(handles.start_month,'Value');
start_year=get(handles.start_year,'Value');
end_month=get(handles.end_month,'Value');
end_year=get(handles.end_year,'Value');

S=start_month+(start_year-1)*12;
E=end_month+(8-end_year)*12;

EP=[0 0 0 0 0 0 0 0 0 0 0 0 0
    sum(X(S:E,6)) sum(X(S:E,5)) sum(X(S:E,4)) sum(X(S:E,3)) sum(X(S:E,2))
    sum(X(S:E,1)) sum(X(S:E,42)) sum(X(S:E,41)) sum(X(S:E,40))
    sum(X(S:E,39)) sum(X(S:E,38)) sum(X(S:E,37)) 0;
    sum(X(S:E,7)) sum(X(S:E,8)) sum(X(S:E,9)) sum(X(S:E,10)) sum(X(S:E,11))
    sum(X(S:E,12)) sum(X(S:E,43)) sum(X(S:E,44)) sum(X(S:E,45))
    sum(X(S:E,46)) sum(X(S:E,47)) sum(X(S:E,48)) 0;
    sum(X(S:E,18)) sum(X(S:E,17)) sum(X(S:E,16)) sum(X(S:E,15)) sum(X(S:E,14))
    sum(X(S:E,13)) sum(X(S:E,54)) sum(X(S:E,53)) sum(X(S:E,52))
    sum(X(S:E,51)) sum(X(S:E,50)) sum(X(S:E,49)) 0;
    sum(X(S:E,19)) sum(X(S:E,20)) sum(X(S:E,21)) sum(X(S:E,22)) sum(X(S:E,23))
    sum(X(S:E,24)) sum(X(S:E,55)) sum(X(S:E,56)) sum(X(S:E,57))
    sum(X(S:E,58)) sum(X(S:E,59)) sum(X(S:E,60)) 0;
    sum(X(S:E,30)) sum(X(S:E,29)) sum(X(S:E,28)) sum(X(S:E,27)) sum(X(S:E,26))
    sum(X(S:E,25)) sum(X(S:E,66)) sum(X(S:E,65)) sum(X(S:E,64))
    sum(X(S:E,63)) sum(X(S:E,62)) sum(X(S:E,61)) 0;
    sum(X(S:E,31)) sum(X(S:E,32)) sum(X(S:E,33)) sum(X(S:E,34)) sum(X(S:E,35))
    sum(X(S:E,36)) sum(X(S:E,67)) sum(X(S:E,68)) sum(X(S:E,69))
    sum(X(S:E,70)) sum(X(S:E,71)) sum(X(S:E,72)) 0];

WU=get(handles.WU,'String');
WU=str2num(WU);
WR=EP.*WU.*5000;
WR=flipud(WR);

axes(handles.Disp);
[X,Y] = meshgrid(0.5:12.5, 0.5:6.5);
pcolor(X,Y,(WR));
view(2)
axis([0.5 12.5 0.5 6.5])
colormap jet
h=colorbar;
title('Water Use (bbls)')


 tot=sum(sum(WR));
 avg=mean(mean(WR));
 peak=max(max(WR));

 set(handles.flows_tot,'String',num2str(round(tot)))
 set(handles.flows_avg,'String',num2str(round(avg)))
 set(handles.flows_peak,'String',num2str(round(peak)))
```

8.3.5. Visualizing Flowback/Produced Water Volumes

Flowback and produced water returns to the surface over the lifespan of the well at varying rates, which makes them more challenging to model. Decline curves were fit to existing daily rates of flowback and produced water in Chapter 6. Three decline curves were used: flowback, transition, and produced volumes, to predict the rate of production within 10%. In the GUI, each well is assumed to have the decline curves that were used in Chapter 6, shown in Equations 8.5, 8.6, 8.7. However, in specific versions described in Chapter 9 the user can adjust variables in the equations to better fit the field or to provide some uncertainty analysis.

$$\text{Flowback Water (bbls/day)} = \frac{1590}{(1+0.249t)^{1/0.946}} \tag{8.5}$$

$$\text{Transition Water (bbls/day)} = \frac{166}{(1+0.057(t-30))^{1/1.347}} \tag{8.6}$$

$$\text{Produced Water (bbls/day)} = \frac{33.6}{(1+0.00837(t-132))^{1/1.2}} \tag{8.7}$$

In Equations 8.5, 8.6, 8.7 the variable t (time) is given in days. The flowback period is defined as the first 30 days water returns to the surface, the transition period is defined as the next 131 days (i.e. days 31-162), and the produced water period defines the water production after day 162 (i.e. days 163-end of well life). The decline curve for an individual well is shown in Figure 8.6.

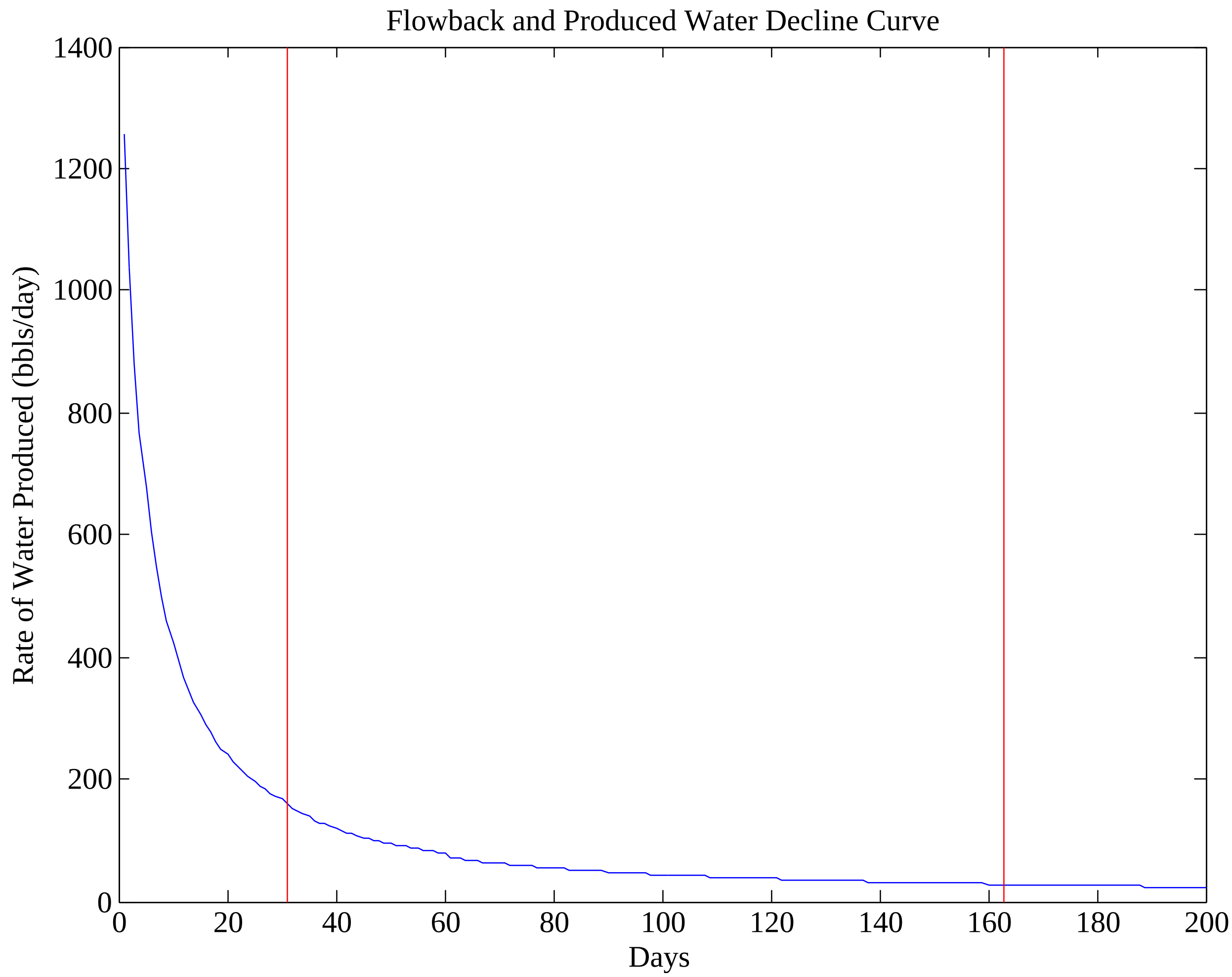


Figure 8.6: The decline curve used for an individual well to model the rate of flowback and produced water volumes for the hypothetical oil and gas field used to develop the model.

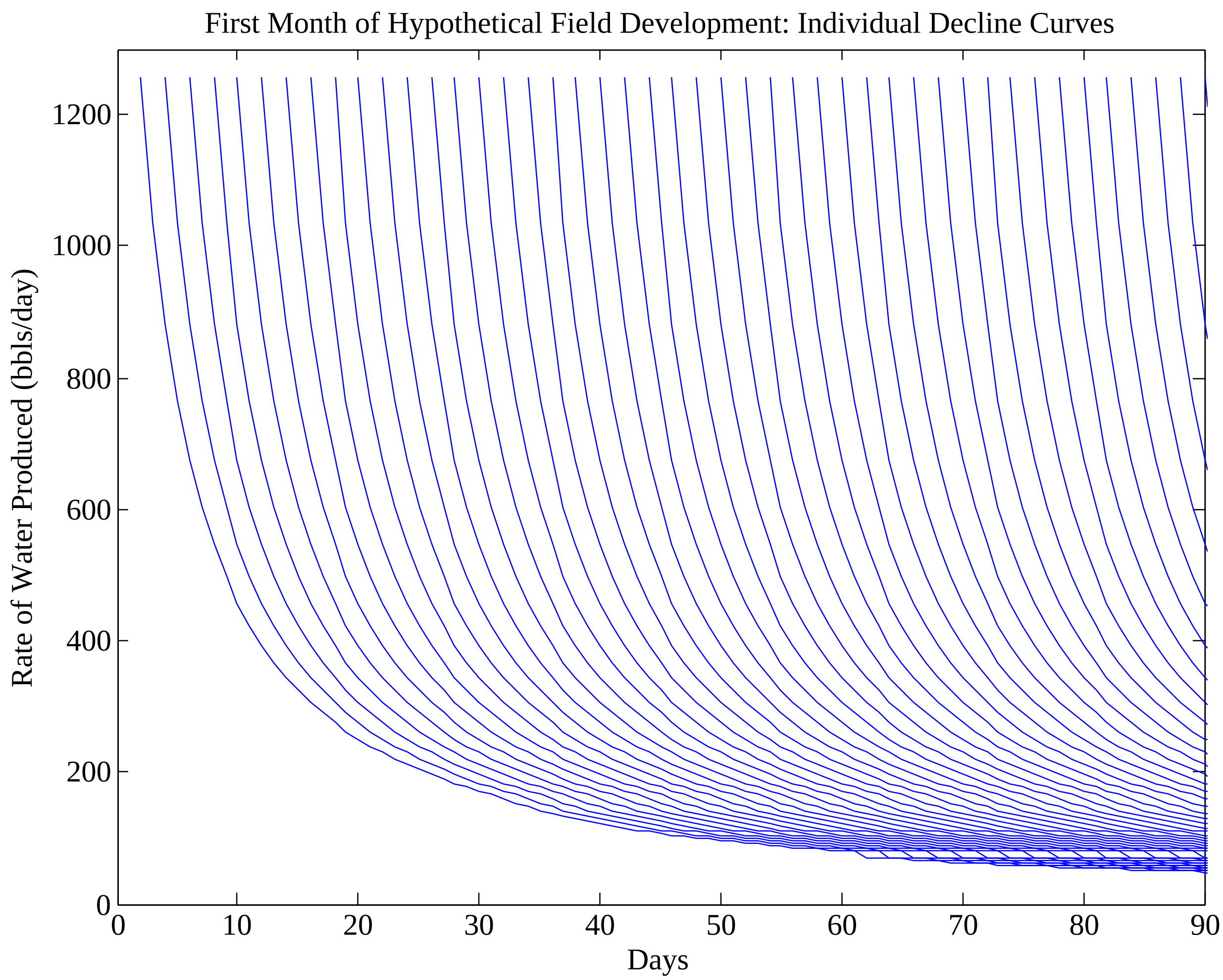


Figure 8.7: Decline curves of multiple wells overlaid to model the cumulative rate of flowback and produced water volumes for the hypothetical oil and gas field.

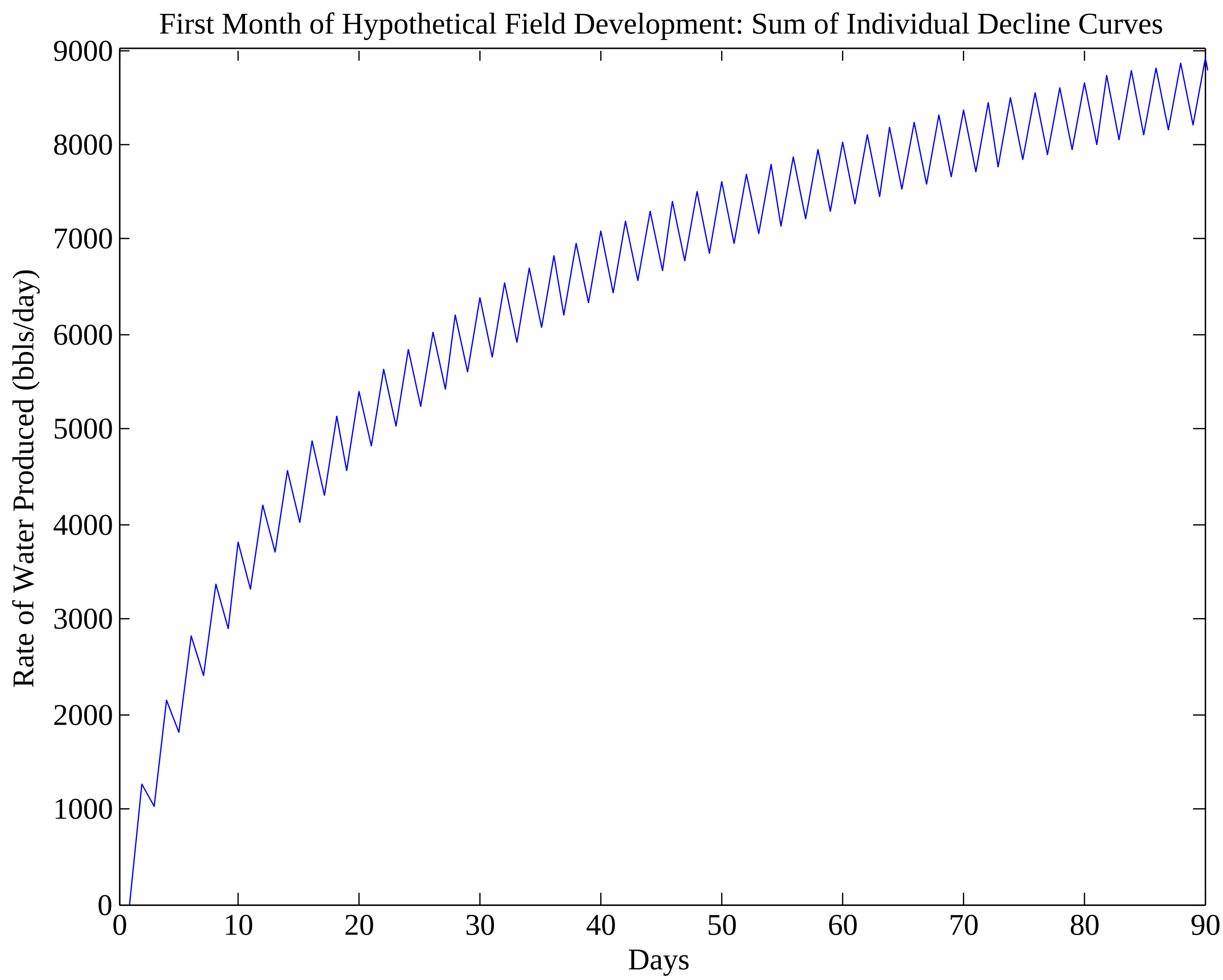


Figure 8.8: The cumulative rate of flowback/produced water for the entire field for the first three months of development.

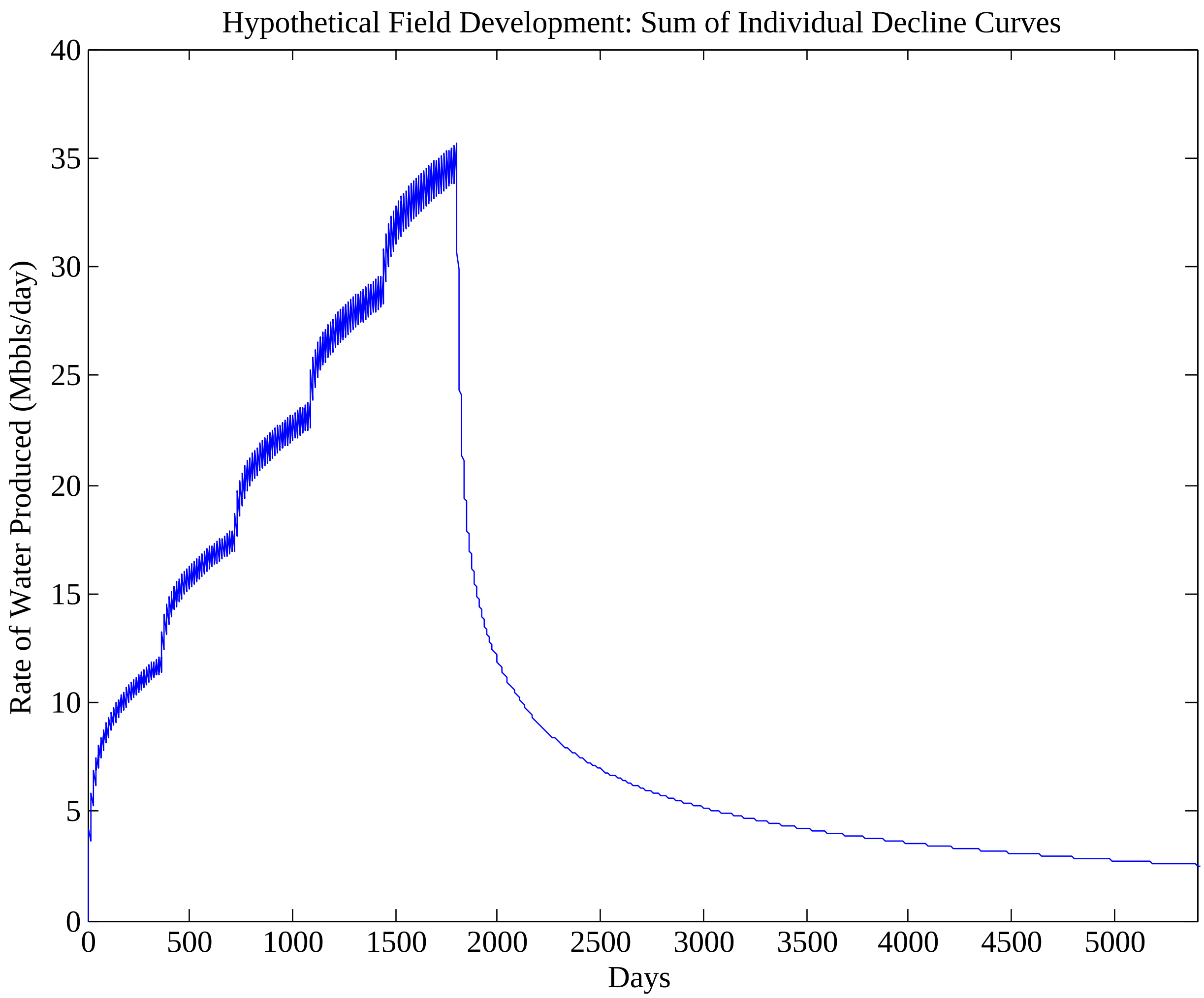


Figure 8.9: The cumulative rate of flowback/produced water for the entire field for the entire development period.

The total volume of water available in a specific area or an entire field depends on the number of wells and age of each well. To estimate the volume of flowback and produced water for an entire area, the decline curve from each well is overlaid on the other decline curves in the area, as shown in Figure 8.7, and summed, as shown in Figure 8.8 and Figure 8.9.

Equations 8.5, 8.6, and 8.7 are used to translate the development plan matrix into a matrix representing the volume of flowback and produced water between the start and end dates defined by the user. This matrix is defined as the Produced Water matrix (PW matrix) and is represented in the same format as the development matrix, where the each column represents a square mile section and each row represents a month of development. Each element of the matrix represents the volume of flowback/produced water for the coresponding month and section. The MATLAB code used to translate the DP matrix to the PW matrix is shown below:

```
start_month=get(handles.start_month,'Value');
start_year=get(handles.start_year,'Value');
end_month=get(handles.end_month,'Value');
end_year=get(handles.end_year,'Value');

S=start_month+(start_year-1)*12;
E=end_month+(8-end_year)*12;

for i=1:E
    for j=1:size(DP,2)
        for k=1:size(DP,1)
            if i<S | i>E
                A(i,j)=0;
            elseif i==S
                A(i+k-1,j,k)=(DP(k,j))*(1590/((1+0.2492*30*(i-S))^(1/0.9457)));
            elseif i==S+1 | i==S+2 | i==S+3 | i==S+4
                A(i+k-1,j,k)=(DP(k,j))*(165.93/((1+0.057*30*(i-S))^(1/1.347)));
            else
                A(i+k-1,j,k)=(DP(k,j))*(33.62/((1+0.00837*30*(i-S))^(1/1.2)));
            end
        end
    end
end

PW=sum(A,3);
```

To convert the PW matrix into a field representation, the following MATLAB code is used:

```
EP=[0 0 0 0 0 0 0 0 0 0 0 0 0
    sum(PW(S:E,6)) sum(PW(S:E,5)) sum(PW(S:E,4)) sum(PW(S:E,3)) sum(PW(S:E,2))
    sum(PW(S:E,1)) sum(PW(S:E,42)) sum(PW(S:E,41)) sum(PW(S:E,40)) sum(PW(S:E,39))
    sum(PW(S:E,38)) sum(PW(S:E,37)) 0;
    sum(PW(S:E,7)) sum(PW(S:E,8)) sum(PW(S:E,9)) sum(PW(S:E,10)) sum(PW(S:E,11))
    sum(PW(S:E,12)) sum(PW(S:E,43)) sum(PW(S:E,44)) sum(PW(S:E,45)) sum(PW(S:E,46))
    sum(PW(S:E,47)) sum(PW(S:E,48)) 0;
    sum(PW(S:E,18)) sum(PW(S:E,17)) sum(PW(S:E,16)) sum(PW(S:E,15)) sum(PW(S:E,14))
    sum(PW(S:E,13)) sum(PW(S:E,54)) sum(PW(S:E,53)) sum(PW(S:E,52)) sum(PW(S:E,51))
    sum(PW(S:E,50)) sum(PW(S:E,49)) 0;
    sum(PW(S:E,19)) sum(PW(S:E,20)) sum(PW(S:E,21)) sum(PW(S:E,22)) sum(PW(S:E,23))
```

To convert the PW matrix into a field representation, the following MATLAB code is used:

```
    sum(PW(S:E,24)) sum(PW(S:E,55)) sum(PW(S:E,56)) sum(PW(S:E,57)) sum(PW(S:E,58))
    sum(PW(S:E,59)) sum(PW(S:E,60)) 0;
    sum(PW(S:E,30)) sum(PW(S:E,29)) sum(PW(S:E,28)) sum(PW(S:E,27)) sum(PW(S:E,26))
    sum(PW(S:E,25)) sum(PW(S:E,66)) sum(PW(S:E,65)) sum(PW(S:E,64)) sum(PW(S:E,63))
    sum(PW(S:E,62)) sum(PW(S:E,61)) 0;
    sum(PW(S:E,31)) sum(PW(S:E,32)) sum(PW(S:E,33)) sum(PW(S:E,34)) sum(PW(S:E,35))
    sum(PW(S:E,36)) sum(PW(S:E,67)) sum(PW(S:E,68)) sum(PW(S:E,69)) sum(PW(S:E,70))
    sum(PW(S:E,71)) sum(PW(S:E,72)) 0];

FBP=flipud(EP);

axes(handles.Disp);
[X,Y] = meshgrid(0.5:12.5, 0.5:6.5);
pcolor(X,Y,(FBP));
view(2)
axis([0.5 12.5 0.5 6.5])
colormap jet
h=colorbar;
title('Water Use (bbls)')

tot=sum(sum(FBP));
avg=mean(mean(FBP));
peak=max(max(FBP));

set(handles.flows_tot,'String',num2str(round(tot)))
set(handles.flows_avg,'String',num2str(round(avg)))
set(handles.flows_peak,'String',num2str(round(peak)))
```

8.3.6. Location and Size of Freshwater Resources, Injection, and Treatment Facilities

Using the GUI, the user can select the number, size, and location of the freshwater resources, injection wells, and treatment facilities. When the user selects the number of locations for each component from a drop down menu, as shown in Figure 8.10, a crosshair cursor appears on the map to allow the user to select the location of each component. The user can also input the capacity (bbls/day) for each component.

Figure 8.10: The GUI allows the user to select the number, capacity, and location of freshwater sources, injection wells, and treatment facilities in the field.

To reduce the complexity of the model, the user can select specific start and end dates to "move" components throughout the field. For example, if the user wants to move a mobile treatment facility every year the user would first select a start date of 2013 and an end date of 2014 and place/size the treatment facility. The user would then move to the next year 2014 to 2015 and place the new location of the mobile treatment facility.

The locations of the water source, injection well, and treatment facility are passed into as the pixel number of the selected location when the development figure is displayed. To convert the pixel number to coordinates Equations 8.10 and 8.9 are used. For the hypothetical field a pseudocoordinate system is used where the origin (0,0) is located at the most Southwestern point in the field.

Each square mile from the Western edge of the field is labeled from zero to 12. Similarly, each square mile from the Southern edge of the field is labeled from zero to 12. Using this system, the middle of the Northeastern most section would be located at (12, 6).

$$\text{Latitude} = \text{Horizontal Pixel Number}/150 \tag{8.8}$$

$$\text{Longitude} = (6 - \text{Horizontal Pixel Number})/150 \tag{8.9}$$

The MATLAB code to input and convert the coordinates for freshwater sources, injection wells, and treatment facilities are nearly identical. For this reason, only the code for the treatment facilities is shown:

```
DPdisp=get(handles.DP_disp,'Value')


CPF_num=get(hObject,'Value')-1;
if CPF_num==0
    set(handles.CPFx1,'String',' ')
    set(handles.CPFy1,'String',' ')
    set(handles.CPFx2,'String',' ')
    set(handles.CPFy2,'String',' ')
    set(handles.CPFx3,'String',' ')
    set(handles.CPFy3,'String',' ')
else
    CPF=ginput(CPF_num)
    if DPdisp==1
        CPF=CPF/150;
        CPF(:,2)=6-CPF(:,2);
        if CPF_num==1
            set(handles.CPFx1,'String',ceil(CPF(1,1)))
            set(handles.CPFy1,'String',ceil(CPF(1,2)))
            set(handles.CPFx2,'String',' ')
            set(handles.CPFy2,'String',' ')
            set(handles.CPFx3,'String',' ')
            set(handles.CPFy3,'String',' ')
        elseif CPF_num==2
            set(handles.CPFx1,'String',ceil(CPF(1,1)))
            set(handles.CPFy1,'String',ceil(CPF(1,2)))
            set(handles.CPFx2,'String',ceil(CPF(2,1)))
            set(handles.CPFy2,'String',ceil(CPF(2,2)))
            set(handles.CPFx3,'String',' ')
            set(handles.CPFy3,'String',' ')
        elseif CPF_num==3
            set(handles.CPFx1,'String',ceil(CPF(1,1)))
            set(handles.CPFy1,'String',ceil(CPF(1,2)))
            set(handles.CPFx2,'String',ceil(CPF(2,1)))
            set(handles.CPFy2,'String',ceil(CPF(2,2)))
```

```
            set(handles.CPFx3,'String',ceil(CPF(3,1)))
            set(handles.CPFy3,'String',ceil(CPF(3,2)))
        end
    else
        if CPF_num==1
            set(handles.CPFx1,'String',ceil(CPF(1,1)))
            set(handles.CPFy1,'String',ceil(CPF(1,2)))
            set(handles.CPFx2,'String',' ')
            set(handles.CPFy2,'String',' ')
            set(handles.CPFx3,'String',' ')
            set(handles.CPFy3,'String',' ')
        elseif CPF_num==2
            set(handles.CPFx1,'String',ceil(CPF(1,1)))
            set(handles.CPFy1,'String',ceil(CPF(1,2)))
            set(handles.CPFx2,'String',ceil(CPF(2,1)))
            set(handles.CPFy2,'String',ceil(CPF(2,2)))
            set(handles.CPFx3,'String',' ')
            set(handles.CPFy3,'String',' ')
        elseif CPF_num==3
            set(handles.CPFx1,'String',ceil(CPF(1,1)))
            set(handles.CPFy1,'String',ceil(CPF(1,2)))
            set(handles.CPFx2,'String',ceil(CPF(2,1)))
            set(handles.CPFy2,'String',ceil(CPF(2,2)))
            set(handles.CPFx3,'String',ceil(CPF(3,1)))
            set(handles.CPFy3,'String',ceil(CPF(3,2)))
        end
    end
end
```

8.3.6.1. Optimization of Location and Capacity

The user has the option of choosing the optimum location for the freshwater source, injection well, and treatment facility by selecting the Optmize buttons. The optimum location of the freshwater source is defined as the section with the largest volume of water required between the selected start and end date. The optimized capacity is defined as the peak water required (bbls/month) between the selected start and end dates. Similarly, the injection wells and treatment facilities are chosen in the same manner based on the flowback and produced water volumes.

8.3.7. Treated Water and Injected Water

The volume of treated water is calculated by passing the sum of the capacity of all of the treatment facilities into MATLAB. If the capacity is greater than the volume of flowback/ produced water for the defined period, all of the flowback/produced water is sent to a treatment facility and the waste stream that is injected is defined by the treatment type. Reverse osmosis typically has a waste stream that is close to 40% of the influent water volume in an oil and gas field. Ultrafiltration typically has a waste stream that is close to 10% of the influent water volume in an oil and gas field. Using the GUI, the user can define the type of treatment and the percent of the influent that is defined as the waste stream and sent to an injection well for disposal.

If the monthly treatment capacity is less than the flowback/produced water volume for the field, the excess water is sent to an injection well for disposal. The volume of water sent to the injection well is added to the waste stream coming from the treatment facility to estimate the total water injected. The peak and average flows for injection and treatment are displayed in the Flows panel.

8.3.8. Dilution Ratio

In order to most efficiently treat and reuse flowback and produced water as well as meet the water requirements for future development, some dilution with freshwater is typically required. When dilution is used for treatment, the volume of water reused in an oil and gas field can be either quality or quantity limited. For example, in the Wattenberg Field a dilution ratio of 1 part recycled produced water and 7 parts freshwater is typically used (1:7). However, a few wells have successfully used a dilution ratio of 1:5 and a dilution ratio of 1:3 has been successful with bench-scale testing. In this scenario, treatment includes solids removal and softening described in Figure 7.15.

Figure 8.11 shows an example of the dilution ratio where a field is quality limited. In this example, dilution ratio is defined as the ratio of the annual water produced and the annual water demand. The black line shows the amount of dilution required if all of the flowback and produced water is reused in the field. The green section represents an ideal dilution ratio of 1:7. The yellow section represents a sufficient dilution ratio of 1:5. The orange and red sections show a dilution that has not been proven in the field. Water reuse will be limited by the dilution ratio that can be used in the field. In order to reuse all of the water, the ideal and sufficient dilution ratios must be increased by either increasing treatment (e.g. reverse osmosis) or adjusting the hydraulic fracturing fluid formulation to accommodate a wider range of water qualities.

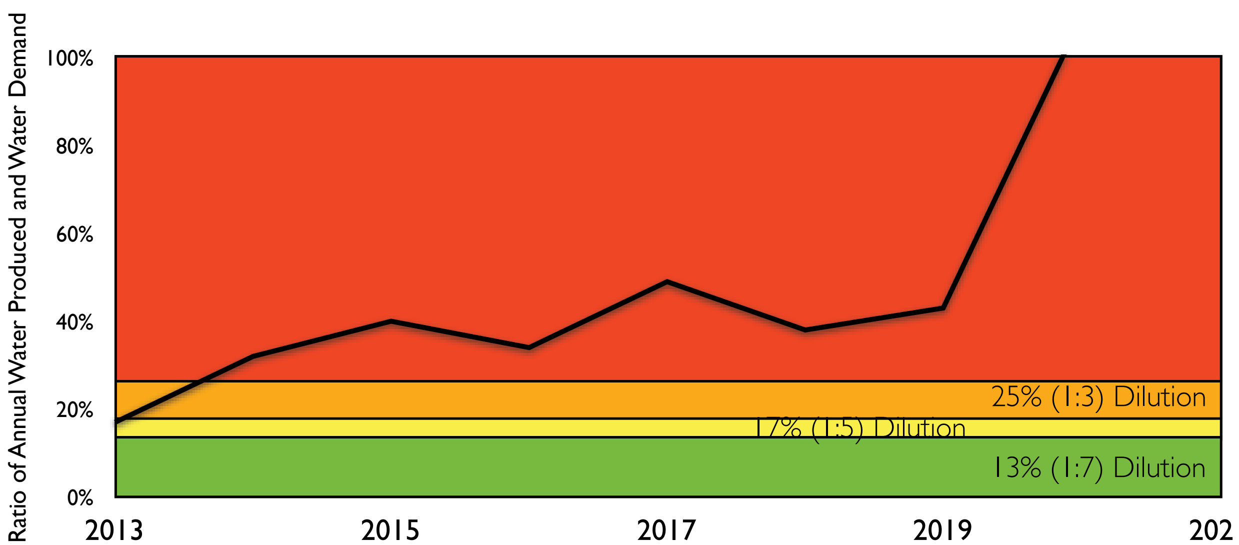


Figure 8.11: The maximum possible dilution ratio overlaid on the water quality limits based on dilution. In the example, the field water quality is limited after 2014.

The GUI allows for the user to visualize the dilution ratio required to reuse all of the water in the field by selecting the Dilution Ratio display button. When this button is selected, a ratio of the flowback and produced water and freshwater for each section in between the start and end dates is displayed. The volume of produced water and water required are calculated in the same manner described in Sections 8.3.4 and 8.3.5. By visualizing the dilution ratio for each section, the type of treatment required for each section can be better understood.

$$\text{Dilution ratio in GUI} = \frac{\text{Produced water from start and end date}}{\text{Water required in the month of the end date}} \quad (8.10)$$

The dilution ratio can be either presented as a percentage (e.g. 12.5%) or as a ratio (e.g. 1:7). A ratio is more commonly used in industry; however, ratios are typically less intuitive to a general audience because a higher ratio implies a lower percentage of water reused. For this reason, the GUI presents the dilution ratio as a percentage using the code shown below, where PW and WR are given as the field matrix representing produced water and water required, respectively. The comment on the second line can be added to display the dilution ratio as a ratio instead of a percent.

```
DR=FBP./WR;
%DR=1./DR-1;
[m,n]=size(DR);
for i=1:m
    for j=1:n
        if DR(i,j)==inf
            DR(i,j)=NaN;


        end
    end
end
```

8.3.9. Environmental and Social Impact

Environmentally and socially sensitive areas can be incorporated into the GUI for the hypothetical field. Environmentally sensitive areas can include endangered or sensitive species habitats (e.g. Sage-Grouse), wetlands, areas with significant flood risks, and geologically hazardous areas. Socially sensitive areas can include areas near schools and neighborhoods, areas that require trucking on congested roads, areas that obstruct views, areas that create noise and light pollution issues. Each section of the field is scored on a scale of 0 to 100 to assess the environmental and social impact of adding water infrastructure in the specific section.

Each component of the field matrix is randomly scored for both the environmental and social impacts. Environmental and social impacts are used as an example to score specific concerns for a specific region. For example, recent floods in Northern Colorado have spurred concern about any development, including oil and gas development, in flood plains in Eastern Colorado. A field matrix can be used to map the probability of a flood occurring in each section. Similarly, permitting and leasing issues can be incorporated in a field matrix. These matrices can either be incorporated into the GUI individually to allow the user to quickly adjust the weighting of each matrix and visualize the impacts or a weighted matrix containing several similar concerns (e.g. environmental impacts) can be added to allow the user to quickly adjust the weighting of all environmental impacts.

$$\text{Env Impact}_{x,y} = \begin{pmatrix} 40 & 42 & 34 & 24 & 58 & 4 & 55 & 37 & 49 & 82 & 35 & 21 \\ 8 & 5 & 90 & 40 & 6 & 17 & 30 & 63 & 44 & 79 & 94 & 30 \\ 24 & 90 & 37 & 10 & 23 & 65 & 74 & 78 & 45 & 64 & 88 & 47 \\ 12 & 94 & 11 & 13 & 35 & 73 & 19 & 8 & 31 & 38 & 55 & 23 \\ 18 & 49 & 78 & 94 & 82 & 65 & 69 & 93 & 51 & 81 & 62 & 84 \\ 24 & 49 & 39 & 96 & 2 & 45 & 18 & 78 & 51 & 53 & 59 & 19 \end{pmatrix}$$

$$\text{Soc Impact}_{x,y} = \begin{pmatrix} 23 & 43 & 26 & 22 & 9 & 49 & 52 & 37 & 10 & 11 & 89 & 50 \\ 17 & 18 & 41 & 12 & 26 & 58 & 23 & 99 & 26 & 65 & 33 & 48 \\ 23 & 90 & 59 & 30 & 80 & 24 & 49 & 4 & 34 & 49 & 70 & 90 \\ 44 & 98 & 26 & 32 & 3 & 46 & 62 & 89 & 68 & 78 & 20 & 61 \\ 31 & 44 & 60 & 42 & 93 & 96 & 68 & 91 & 14 & 72 & 3 & 62 \\ 92 & 11 & 71 & 51 & 73 & 55 & 40 & 80 & 72 & 90 & 74 & 86 \end{pmatrix}$$

In the same manner that a DP matrix is used to define the timing of well development and the timing of the water required and water produced, a DP matrix can be used to define the timing of environmental and social impacts. In the hypothetical field example, the development lasts five years. The environmental impact can change dramatically during the development period. The environmental and social impacts will also likely change and can be incorporated in the GUI based on the start and end dates, as outlined in Sections 8.3.4 and 8.3.5.

8.3.10. Relative Cost per BBL

The GUI allows the user to assign weights to eight key criteria: trucking, piping: freshwater, piping: produced water, treatment (ultra filtration), treatment (reverse osmosis), injection, environmental impact, and social impact. Transportation scores (trucking and piping) are scored on a per (bbl)(mile) basis, treatment and injection scores are scored on a per bbl basis, and environmental and social impact scores are based on the filed matrices described in Section 8.3.9.

Slider bars allow the user to input a relative weighting for the cost each criteria using a scale of 0-100. A score of 100 implies the criteria (e.g. injection) is the most expensive for the operator. A relative scoring is used to incorporate costs beyond financial costs, such as environmental and social costs. For example, in some scenarios piping is financially less expensive than trucking water, but an operator may choose to score trucking lower because of the operational flexibility it offers. On the other hand, the emissions and public safety concerns associated with truck traffic may be more expensive for an operator than piping water.

For these reasons, relative costs are used instead of a detailed cost assessment. By working with an operator and engineering consulting firms, more detailed and accurate cost assessments can be made. However, a detailed cost assessment is beyond the scope of work for this dissertation.

8.4. Case Study

The relative costs of three water management strategy are assessed and compared using the hypothetical water model. The first water management scenario (the base scenario) assumes all of the water is trucked from the water source to the well pad and all of the flowback/produced water is disposed of in injection wells. The second strategy assumes 70% of the water is treated with ultra filtration and the rest is disposed of with injection wells. All of the water is transported by pipeline in this scenario. The final scenario assumes all of water is treated with reverse osmosis and only the waste stream is injected in a disposal well.

For all three scenarios, the injection well is located at (11,3) and the freshwater source is located at (2,5). For the second and third scenarios, the treatment facility is located at (3,1). Ultra filtration is assumed to have a 5% waste stream and reverse osmosis is assumed to have a 40% waste stream.The following relative costs are assumed for all three scenarios:

• **Trucking:** 30

• **Freshwater Piping:** 50

• **Produced Water Piping:** 70

• **Treatment with Ultra Filtration:** 35

• **Treatment with Reverse Osmosis:** 75

•**Injection:** 10

• **Environmental Impact:** 50

• **Social Impact:** 75

For all of the scenarios, a start date of January 2013 and an end date of January 2020 is used. A water requirement of 10 bbls/foot is used for all three scenarios.

8.4.1. Base Scenario: Trucking to One Injection Well (0% Reuse)

The base scenario (Figure 8.12) assumes all of the flowback and produced water is trucked to disposal wells in the region. Freshwater is used to develop new oil and gas wells. This scenario is typical of a low-density, undeveloped field. It is also commonly used as a field is first being developed.

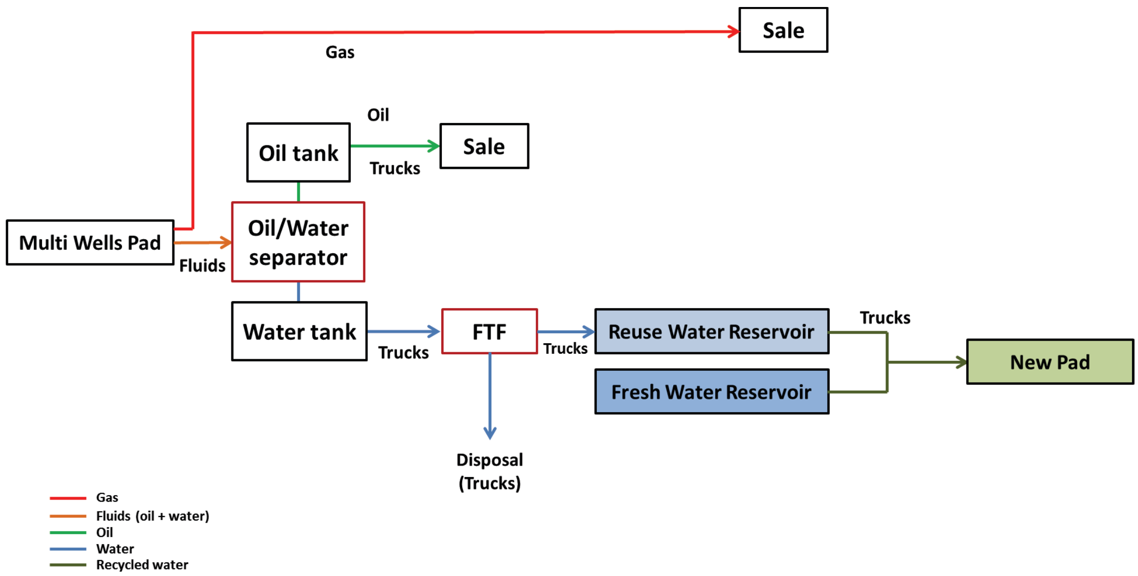


Figure 8.12: A schematic of the base scenario: trucking to one injection well.

The base scenario has a total relative cost of 28. The low cost of trucking and injection helps bring the relative costs of this scenario down. The water source and injection wells are located on sections with relatively low costs as well.

8.4.2. Scenario 1: Piping to Fixed Treatment Facility/Injection Well (70% Reuse)

The next scenario (Figure 8.14) assumes the base water treatment load is piped to a fixed treatment facility. From Figure 8.15, the base load is assumed to be 70% of the peak load for the field or approximately 12,000 bbls/day. A central processing facility will be design to handle 12,000 bbls/day with the excess peak load being injected at the same location. This scenario assumes treatment facility is built next to an existing injection well to handle the increasing volumes of produced water as a field develops.

The base scenario has a total relative cost of 57. The higher costs of piping and treatment increases the relative costs of this scenario compared with the first scenario.

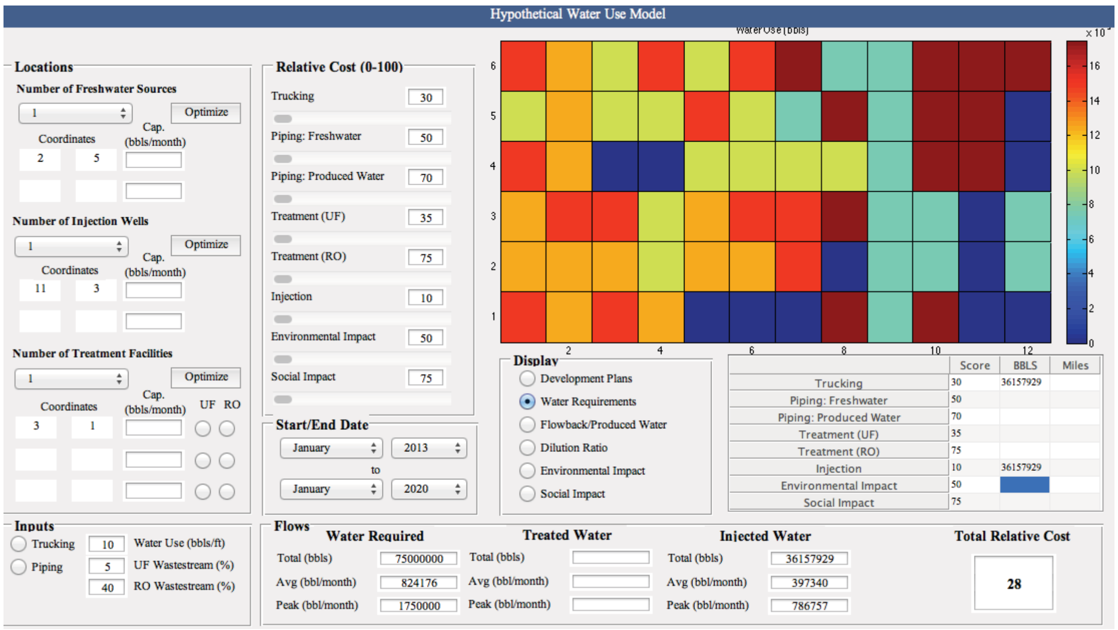


Figure 8.13: The GUI output for the base scenario.

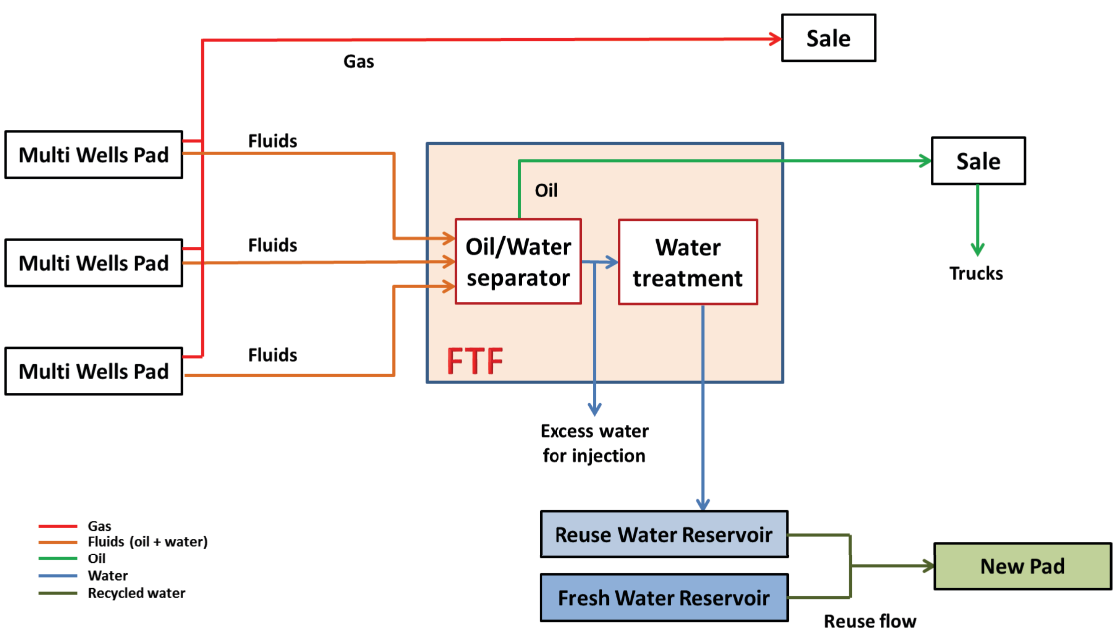


Figure 8.14: A schematic of the base scenario: trucking to one injection well.

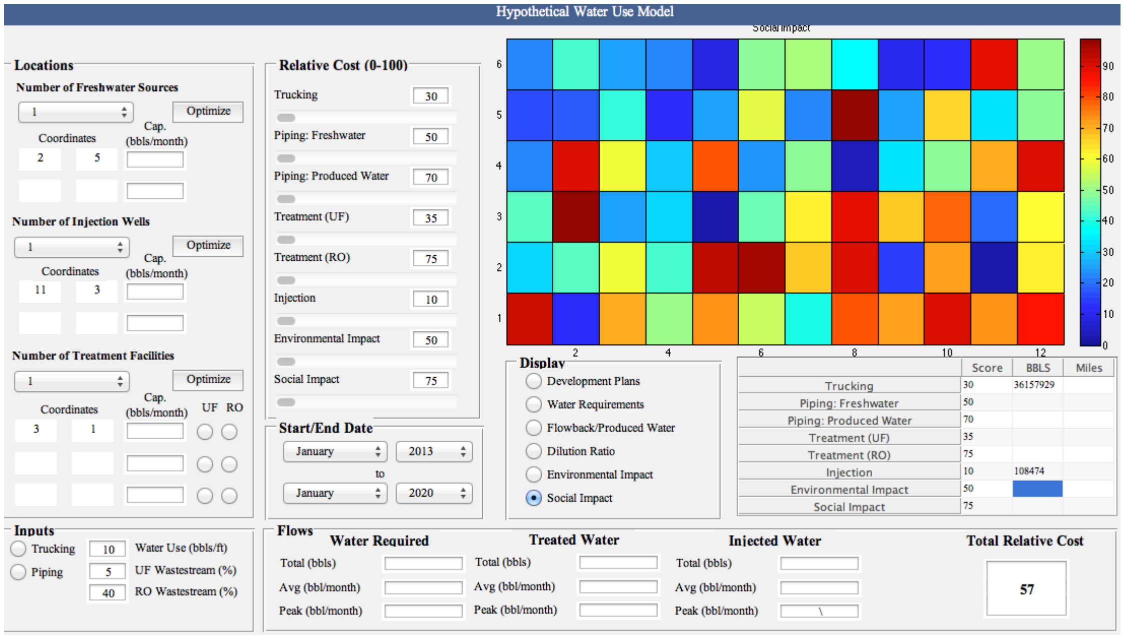


Figure 8.15: The GUI output for the reverse osmosis scenario.

8.4.3. Scenario 2: Piping to Fixed Treatment Facility and Mobile Treatment Facility (100% Reuse)

The final scenario (Figure 8.16) assumes the same conditions as scenario 1, but treats the peak load with modular treatment facilities instead of injecting the water. Reverse osmosis is used for all of the treated water. This scenario is used to examine the challenges associated with a complete water reuse plan and the implementation of mobile/temporary treatment facilities. This scenario is also used to improve modeling capabilities associated with mobile/temporary facilities.

8.5. Summary

Economics, social and environmental impacts, and operator goals play a critical role in the optimization of this model. The modeling approach outlined in this chapter is developed within a flexible framework that allows operators quickly change key modeling parameters, development plans, and accommodate critical social and environmental impacts. The costs are possibly the most volatile variable and, although they are not directly incorporated in the model, the relative cost scores can be adjusted within the GUI using the slider bars.

As a field develops, it is important to understand what key parameters are driving the decisions being made in the field. By working with operators and surrounding communities these key parameters can be better assessed. For example, some communities may be most concerned with truck traffic, while others may be in non-attainment areas and air emissions are a critical concern. Similarly, the operator's goals will determine the proposed development plans in a field. As more information about the field's production becomes available development plans and water reuse strategies may change. A sensitivity analysis to changing operating goals will provide insight into risks and benefits for water infrastructure investments throughout the field.

The objective of the modeling approach is to support discussions operators have about siting water infrastructure in the field and organize a value system to understand how key decisions are being made. The models are only as good as the input from the operator and are not intended to automatically generate the best solution for the field without any input from the operators. A key to maintaining the accuracy and precision with the models is to constantly check and update the inputs based on the latest values from the field. For example, the water volumes predicted with the decline curves should be compared to the volumes found in the field and updated if there is a discrepancy.

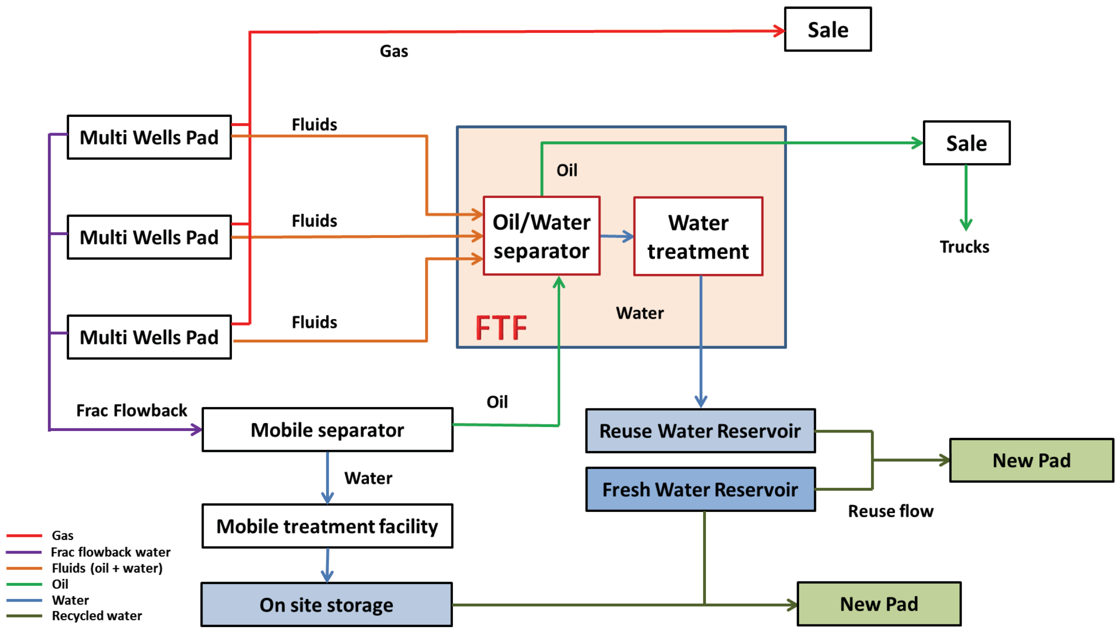


Figure 8.16: Piping to Fixed Treatment Facility and Mobile Treatment Facility (100% Reuse)

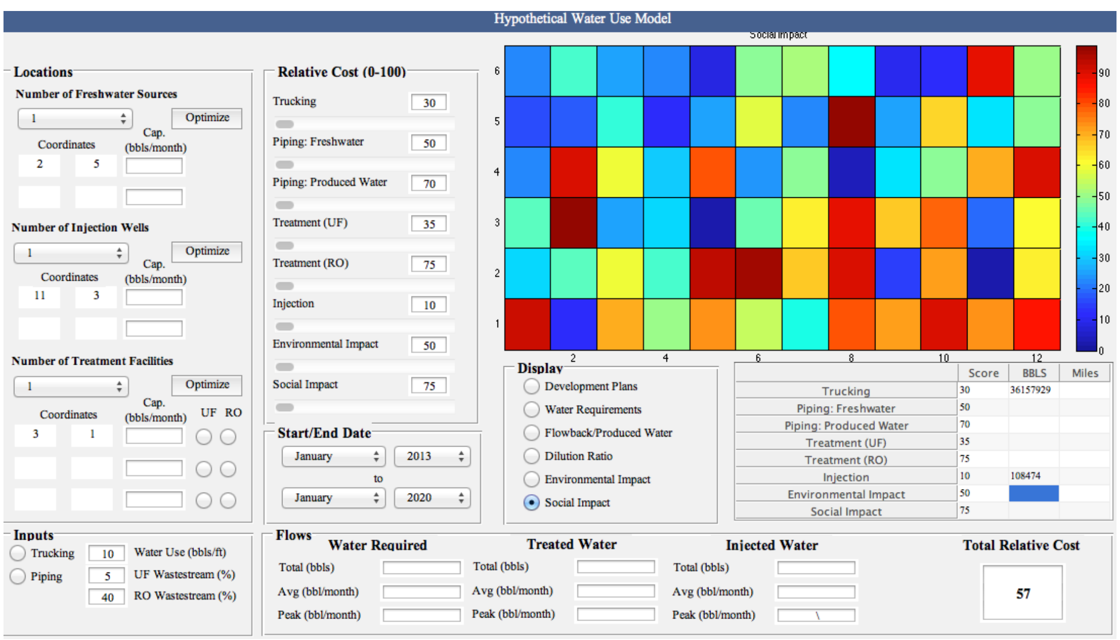


Figure 8.17: The GUI output for the ultra filtration scenario.

9. Modeling Water Infrastructure in a Oil and Gas Field[vi]

9.1. Introduction

Using the approach outlined in Chapter 8 with a hypothetical field, three models are developed using development plans to quantify specific water-related issues in unconventional oil and gas fields. Noble Energy, Inc. (Noble) is developing seven areas in the Wattenberg Field, as shown in Figure 9.1. Wells Ranch has been the first area developed and has been the focus of most of the analysis in this dissertation. East Pony is the next region that will be developed.

The first model allows an operator to predict the volume of water required to develop East Pony as well as the volume flowback/produced water. Unlike the hypothetical model, the user can adjust the decline curve used and the development plans within the GUI. This allows the operator to asses and change a variety of development scenarios as the field develops. In addition, as the field develops water production decline curves will become more accurate and can be adjusted within the GUI. Water production decline curves can also be adjusted to estimate a range of flowback/produced water estimates. The average and peak freshwater and flowback/produced water volumes are calculated to size water infrastructure and storage requirements in the field.

[vi] ***S. Goodwin[a], K. Carlson[a], A. Prior[b],***
[a] Colorado State University, Department of Civil and Environmental Engineering, Campus Delivery, Fort Collins, CO 80523, USA

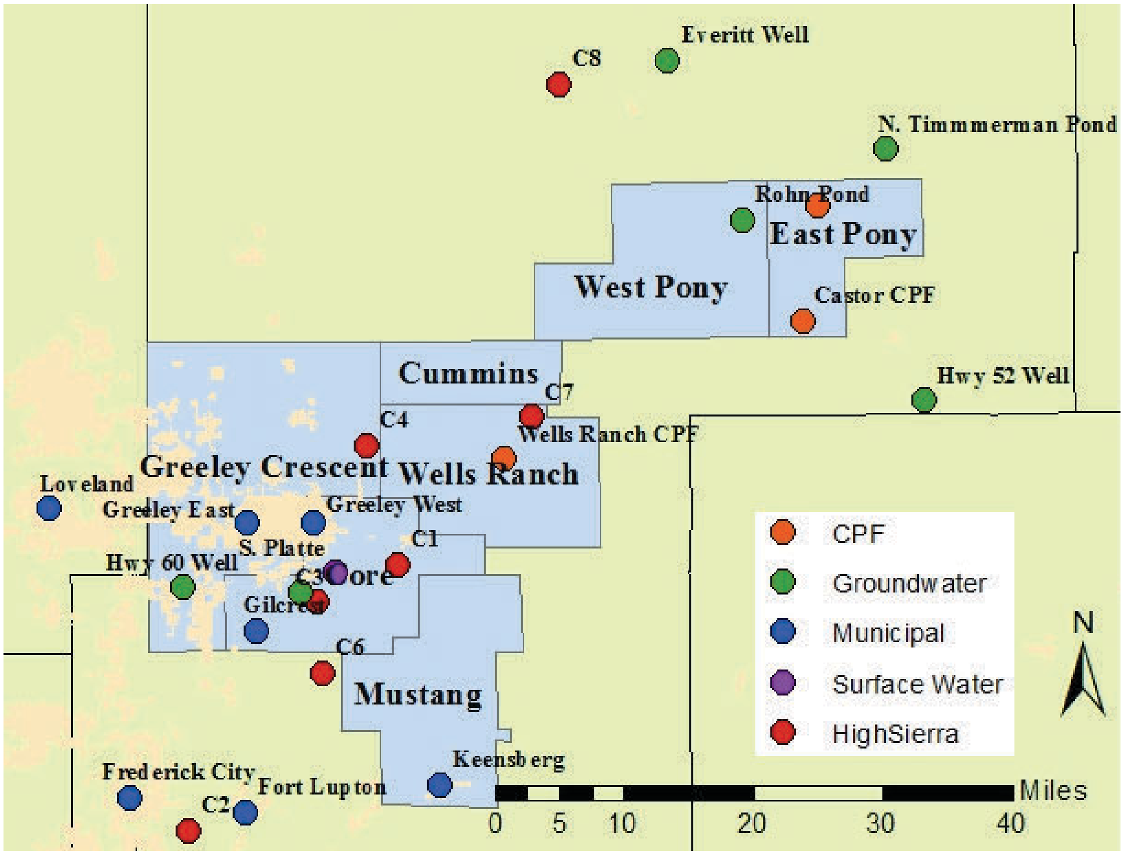


Figure 9.1: A map of the Noble Energy's development areas are shown in blue, injection wells are shown in red, and freshwater sources are shown in green (groundwater), blue (municipal water), and purple (surface water).

The second model provides an operator with a spatial multi-criteria decision analysis tool for placing water treatment facilities in East Pony. The operator can use the GUI to weight specific criteria (e.g. proximity to future development, distance required to transport flowback/ produced water, environmental impact, and distance to existing treatment facilities) to help understand the trade-offs between different water treatment facility locations within East-Pony.

The final model expands on the second model to quantify the implications of water treatment facility siting within the entire Wattenberg Field. The operator can place water treatment facilities in the field using Figure 9.1 to estimate the impacts on key metrics such as truck traffic, greenhouse-gas emissions, and water reuse volumes.

9.2. Water Volume Prediction Tool

The water volume prediction tool allows the user to input the development plan into the GUI as a spreadsheet, as shown in Figure 9.2. Two lateral lengths can be used in the GUI normal (NLL) or extended (ERL). The user has the ability to adjust the average length of the laterals and the average water use per foot. These changes are reflected in the equations to estimate the water requirements and the flowback/produced water volumes. The user can also adjust the values in the decline curves as well as the well lifespan to adjust the estimated rate and total flowback and produced water that is produced.

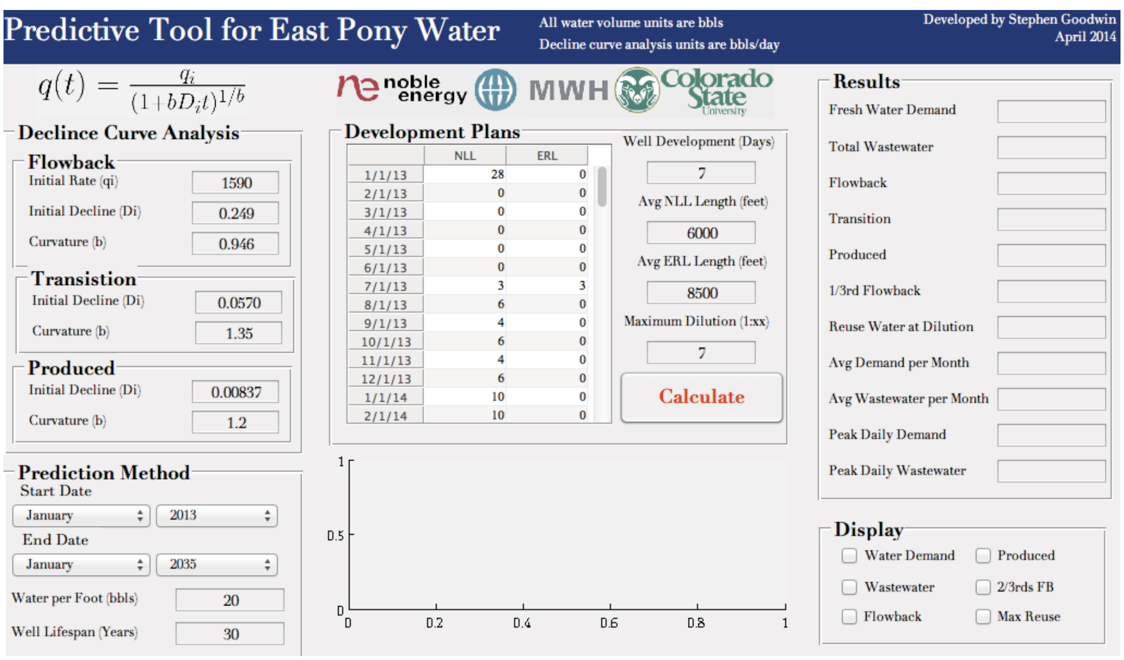


Figure 9.2: The GUI used to prediction freshwater requirements and flowback-/produced water volumes in Noble's East Pony Field.

The development plan table in the GUI is used as the DP matrix outlined in Chapter 8. This GUI is slightly different because the user can pass the variables directly into the MATLAB code. In addition, this GUI doesn't visualize the data in the field. So, a field matrix is not required.

The most novel part of the GUI is the ability to take the development plans as the number of wells per month and the average time it takes to develop a well (or the number of rigs in a field) and provide a worst-case scenario prediction of the water requirements and flowback/ produced water volumes. If the well development is assumed to take seven days, as shown in Figure 9.2, and 10 wells are developed in the month, the worst-case scenario calculated by the GUI is: day 1= 3 wells, day 8= 3 wells, day 15= 2 wells, and day day 22= 2 wells. Using this scenario, peak freshwater demand would occur on days 1 and 3 and the volume would be significantly different than if only a monthly average was used to asses the peak freshwater demand.

When the *Calculate* button is pressed in the GUI the following code is run to estimate water volumes in the *Results* panel and to plot the selected volumes over time in the *Display* panel.

```
%Get start/end dates and redefine the development plans
start_month=get(handles.StartMonth,'Value');
start_year=get(handles.StartYear,'Value');
end_month=get(handles.EndMonth,'Value');
end_year=get(handles.EndYear,'Value');

S=12*(start_year-1)+start_month;
E=(23-end_year)*12+end_month-1;

s=datenum([start_year+2012,start_month, 1]);
e=datenum([23-end_year+2013,end_month, 1]);

%Set an error if end date is before start date
if S>=E
    set(handles.FreshWaterRes,'String','Date Error')
    set(handles.TotalWaterRes,'String','Date Error')
    set(handles.FlowbackWaterRes,'String','Date Error')
    set(handles.TransitionWaterRes,'String','Date Error')
    set(handles.ProducedWaterRes,'String','Date Error')
    set(handles.OthRes,'String','Date Error')
    set(handles.ReuseRes,'String','Date Error')
    set(handles.AvgDemandFresh,'String','Date Error')
    set(handles.AvgWasteRes,'String','Date Error')
    set(handles.PeakDemandFresh,'String','Date Error')
    set(handles.PeakWasteRes,'String','Date Error')
    set(handles.FreshWaterRes,'String','Date Error')
end


%Import table
```

```
DP=get(handles.Table, 'Data');

%Redefine the table based on start/end dates
if E>length(DP)
    dp=DP(S:length(DP),:);
else
    dp=DP(S:E,:);
end

Dev=get(handles.devdays,'String');
Dev=str2num(Dev);
if Dev>28
    set(handles.FreshWaterRes,'String','DP Error')
    set(handles.TotalWaterRes,'String','DP Error')
    set(handles.FlowbackWaterRes,'String','DP Error')
    set(handles.TransitionWaterRes,'String','DP Error')
    set(handles.ProducedWaterRes,'String','DP Error')
    set(handles.OthRes,'String','DP Error')
    set(handles.ReuseRes,'String','DP Error')
    set(handles.AvgDemandFresh,'String','DP Error')
    set(handles.AvgWasteRes,'String','DP Error')
    set(handles.PeakDemandFresh,'String','DP Error')
    set(handles.PeakWasteRes,'String','DP Error')
    set(handles.FreshWaterRes,'String','DP Error')
end




wellcount=[];
NLLlength=str2num(get(handles.NLL,'String'));
ERLlength=str2num(get(handles.ERL,'String'));
LRatio=(ERLlength-NLLlength)/NLLlength;

for i=1:length(dp)
    month=[];
    NLL=dp(i,1);
    ERL=dp(i,2);
    TOT=NLL+ERL;
    ms=datenum([start_year+2012,start_month+i-1, 1]);
    me=datenum([start_year+2012,start_month+i, 1]);
    month=zeros(1,me-ms);
    rem_ERL=rem(Dev*ERL,me-ms);
    rem_NLL=rem(Dev*NLL,me-ms);
    rig_ERL=ceil(Dev*ERL/(me-ms));
    rig_NLL=ceil(Dev*NLL/(me-ms));
    rig_TOT=ceil(Dev*TOT/(me-ms));
    for j=1:floor((me-ms)/Dev)
        month(j*Dev)=1*rig_TOT;
    end
    sm=sum(month);
    month(Dev)=month(Dev)+TOT-sm;
    eERL=ERL*.5;
    for j=1:(me-ms)
        if month(j)~=0
```

```
            if eERL>month(j)*LRatio
                initial=month(j);
                month(j)=month(j)+LRatio*month(j);
                eERL=eERL-initial*LRatio;
            elseif eERL>0
                initial=month(j);
                month(j)=month(j)+eERL;
                eERL=eERL-initial*LRatio;
            end
        end
    end
    wellcount=cat(2,wellcount,month);
end

sum(wellcount)


waterfoot=str2num(get(handles.wfoot,'String'));
Freshwater=wellcount*waterfoot*NLLlength;

t=e-s;
length(Freshwater);
%t=datevec(s:e)

for i=1:(e-s)
    td(i)=datenum([start_year+2012,start_month, i]);
end

tdv=datevec(td);
tyear=tdv(:,1);



TOTFresh=sum(Freshwater);
if E>85
    E=85;
end


Flowback=zeros(1,length(wellcount)+30);

qi_fb=str2num(get(handles.qi_fb,'String'));
Di_fb=str2num(get(handles.Di_fb,'String'));
b_fb=str2num(get(handles.b_fb,'String'));

for i=1:length(wellcount)
    if wellcount(i)~=0
        for j=1:30
            Flowback(i+j-1)=Flowback(i+j-1)+wellcount(i)
            *Flowback(i+j-1)+qi_fb/((1+Di_fb*j)^(1/b_fb));
        end
    end
end

Transition=zeros(1,length(wellcount)+133);
```

```
qi_trans=qi_fb/((1+Di_fb*30)^(1/b_fb));
Di_trans=str2num(get(handles.Di_trans,'String'));
b_trans=str2num(get(handles.b_trans,'String'));

for i=1:length(wellcount)
    if wellcount(i)~=0
        for j=1:133
            Transition(i+j-1)=Transition(i+j-1)+wellcount(i)*qi_trans/
            ((1+Di_trans*(j+31))^(1/b_trans));
        end
    end
end



qi_prod=qi_trans/((1+Di_trans*164)^(1/b_trans));
Di_prod=str2num(get(handles.Di_prod,'String'));
b_prod=str2num(get(handles.b_prod,'String'));

lifespan=str2num(get(handles.lifespan,'String'));
Produced=zeros(1,length(wellcount)+(e-s)+lifespan*365);

for i=1:length(wellcount)
    if wellcount(i)~=0
        for j=1:lifespan*365
            Produced(i+j-1)=Produced(i+j-1)+wellcount(i)*qi_prod/
            ((1+Di_prod*(j+165))^(1/b_prod));
        end
    end
end


Wastewater=sum(Flowback)+sum(Produced)+sum(Transition);

AvgFresh=round(sum(Freshwater)/(E-S));
AvgWaste=round(sum(Wastewater)/(E-S));
PeakFresh=max(Freshwater);
set(handles.FreshWaterRes,'String',num2str(TOTFresh))
set(handles.AvgDemandFresh,'String',num2str(AvgFresh))
set(handles.AvgWasteRes,'String',num2str(AvgWaste))
set(handles.PeakDemandFresh,'String',num2str(PeakFresh))
set(handles.FlowbackWaterRes,'String',num2str(round(sum(Flowback))))
set(handles.OthRes,'String',num2str(round((1/3)*sum(Flowback))))
set(handles.TransitionWaterRes,'String',num2str(round(sum(Transition))))
set(handles.ProducedWaterRes,'String',num2str(round(sum(Produced))))
set(handles.ProducedWaterRes,'String',num2str(round(sum(Produced))))
set(handles.TotalWaterRes,'String',num2str(round(Wastewater)))

axes(handles.Figure);
FreshwaterPlot=get(handles.WaterDemand,'Value');
WastewaterwaterPlot=get(handles.WastewaterCheck,'Value');

if FreshwaterPlot==1
    plot(Freshwater/10^6,'b.')
```

```
%elseif WastewaterwaterPlot==1
 %   plot(Wastewater/10^6,'r.')
end
xlabel('Date')
ylabel('MMbbls of Water')
```

9.3. Treatment Facility Siting GUI Tool: East Pony

The treatment siting tool for East Pony uses a development plan matrix and field matrix approach described in Chapter 8. In this tool the concept is expanded to beyond freshwater requirements and flowback/produced water volumes to include other key siting criteria, including environmental sensitivity and distance from existing treatment facilities. Any number of criteria can be input in the same manner. For example, residential areas, sensitive habitats, or flood risks can be incorporated by assigning either a relative risk or quantitative value.

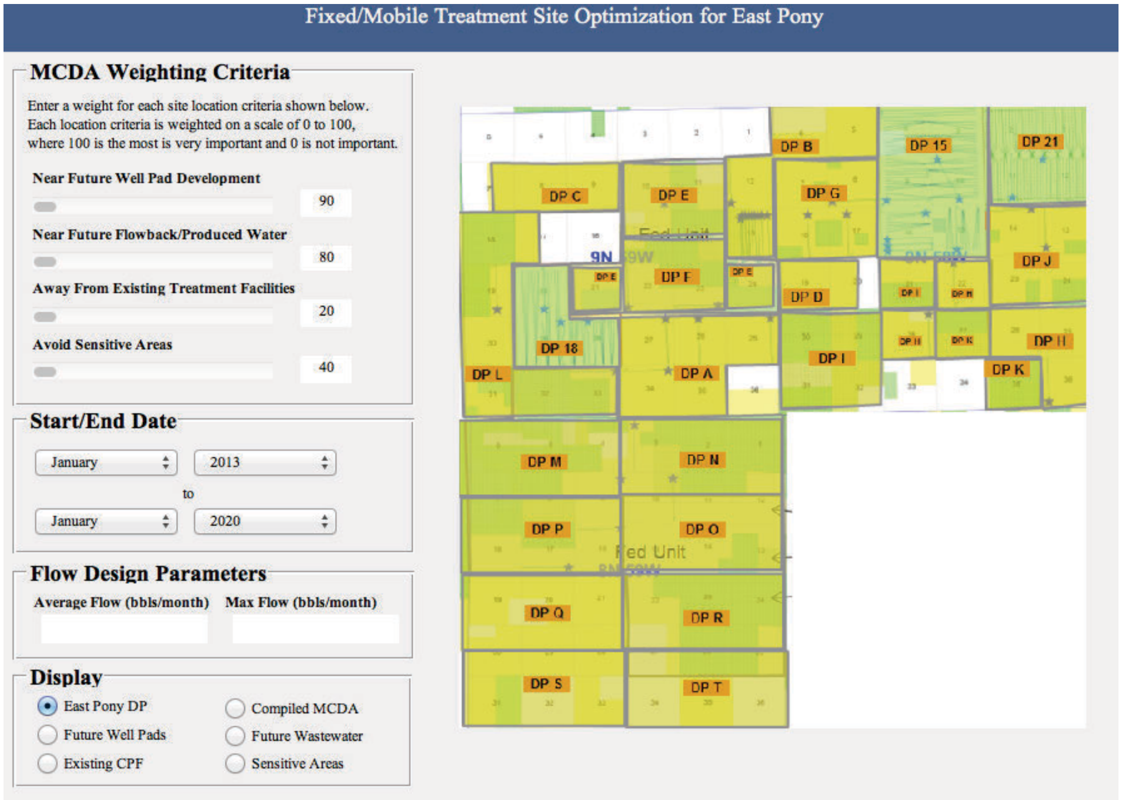


Figure 9.3: The treatment facility siting GUI tool with East Pony development plans shown.

The siting tool weights each layer based on the value given by the user in the GUI, shown in Figure 9.4, and provides an aggregated score for each section for the user defined start and end dates. The score based on a relative score of 0-100, where 100 is the best location for a treatment facility. This tool allows users to change their weighting criteria and/or start and end dates to better understand which factors are most strongly driving the final decision. In this example, very few environmentally sensitive areas are defined in the field matrix. As a result, for most scenarios the multi-criteria decision analysis (MCDA) is not strongly impacted by the weighting value of the environmental impact.

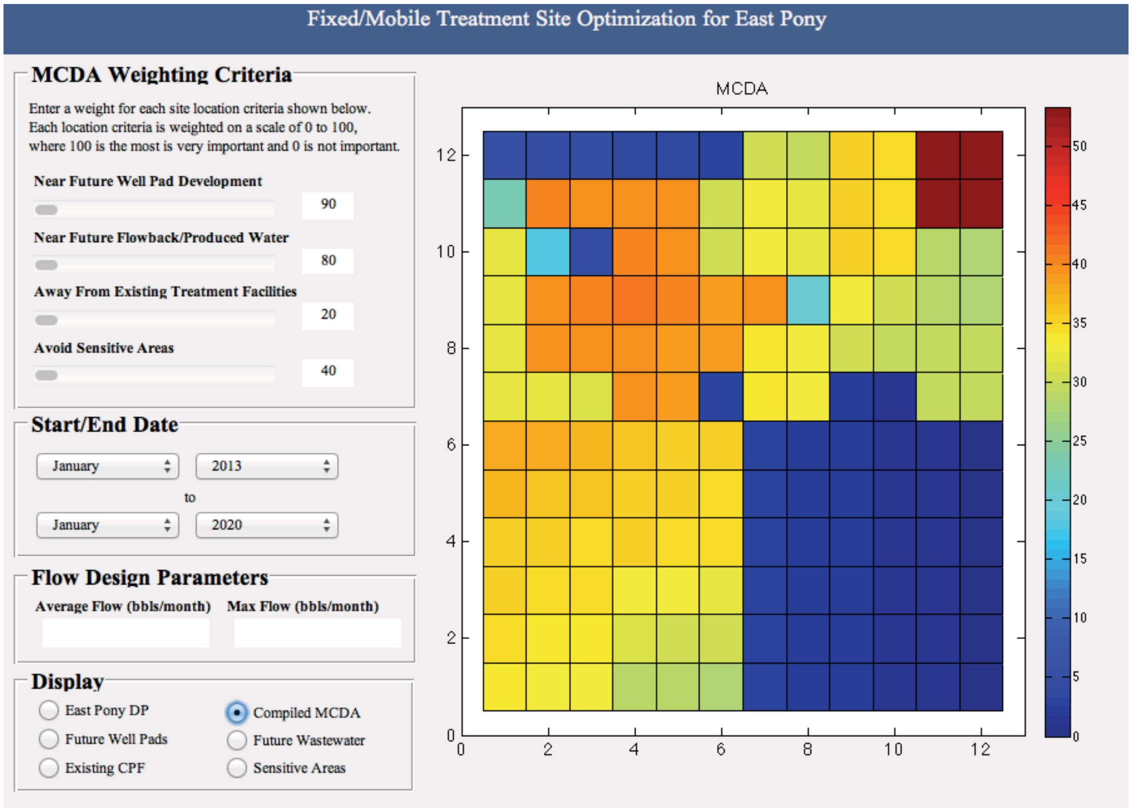


Figure 9.4: The treatment facility siting GUI tool for East Pony with the compiled multi-criteria decision analysis results shown.

The GUI also provides the average and peak flows for the value selected in the Display panel (e.g. Future Well Pads or Future Wastewater). This is done in the same manner outlined in previous sections and can be useful for sizing water infrastructure and storage. Water volumes are visualized using a scale of bbs/month, but are converted to a relative scale of 0-100 when entered into the MCDA. This is done using the following code:

```
DPW_s=get(handles.waste_box,'String');
DPW=str2num(DPW_s).*EP./max(max(EP));
```

The MATLAB code used for the analysis is shown below:

```
 NS=[1    6    3    4    5    4    2.5 1.5 5    3    4    5    5    4    2    6.5 4.5
 4.5 4.5 4.5 4.5 4.5 4.5 4.5];


start_month=get(handles.start_month,'Value');
start_year=get(handles.start_year,'Value');
end_month=get(handles.end_month,'Value');
end_year=get(handles.end_year,'Value');

S=start_month+(start_year-1)*12;
E=end_month+(8-end_year)*12;

Pads=get(handles.Pads,'Value');
CPF=get(handles.CPF,'Value');
MCDA=get(handles.MCDA,'Value');
Waste=get(handles.Waste,'Value');
BLM=get(handles.BLM,'Value');

if Pads==1;
    EP=[   0 0 0 0 0 0 0 0 0 0 0 0 0
    0 0 0 0 0 0 sum(X(S:E,6))/NS(6) sum(X(S:E,6))/NS(6) sum(X(S:E,2))/NS(2)
    sum(X(S:E,2))/NS(2) sum(X(S:E,4))/NS(4) sum(X(S:E,4))/NS(4) 0
    sum(X(S:E,7))/(NS(7)*2) sum(X(S:E,7))/NS(7) sum(X(S:E,7))/NS(7)
    sum(X(S:E,9))/NS(9) sum(X(S:E,9))/NS(9) sum(X(S:E,6))/NS(6)
    sum(X(S:E,11))/NS(11) sum(X(S:E,11))/NS(11)
    sum(X(S:E,2))/NS(2) sum(X(S:E,2))/NS(2) sum(X(S:E,4))/NS(4)
    sum(X(S:E,4))/NS(4) 0
    sum(X(S:E,16))/NS(16) sum(X(S:E,16))/(NS(16)*2) 0
    (sum(X(S:E,9))/NS(9)+sum(X(S:E,10))/NS(10))/2
    (sum(X(S:E,9))/NS(9)+sum(X(S:E,10))/NS(10))/2 sum(X(S:E,6))/NS(6)
    sum(X(S:E,11))/NS(11)
    sum(X(S:E,11))/NS(11) sum(X(S:E,2))/NS(2)  sum(X(S:E,2))/NS(2)
    sum(X(S:E,14))/NS(14)
    sum(X(S:E,14))/NS(14) 0
    sum(X(S:E,16))/NS(16) sum(X(S:E,3))/NS(3) sum(X(S:E,9))/NS(9)
    sum(X(S:E,10))/NS(10)
    sum(X(S:E,10))/NS(10) sum(X(S:E,9))/NS(9) sum(X(S:E,8))/NS(8)
    sum(X(S:E,8))/(NS(8)*2)
    sum(X(S:E,13))/NS(13) sum(X(S:E,12))/NS(12) sum(X(S:E,14))/NS(14)
    sum(X(S:E,14))/NS(14) 0
    sum(X(S:E,16))/NS(16) sum(X(S:E,3))/NS(3) sum(X(S:E,3))/NS(3)
    sum(X(S:E,5))/NS(5)
    sum(X(S:E,5))/NS(5) sum(X(S:E,5))/NS(5) sum(X(S:E,13))/NS(13)
    sum(X(S:E,13))/NS(13)
    sum(X(S:E,12))/NS(12) sum(X(S:E,15))/NS(15) sum(X(S:E,12))/NS(12)
    sum(X(S:E,12))/NS(12) 0
    sum(X(S:E,16))/NS(16) sum(X(S:E,16))/NS(16) sum(X(S:E,16))/NS(16)
     sum(X(S:E,5))/NS(5)
    sum(X(S:E,5))/NS(5) 0 sum(X(S:E,13))/NS(13) sum(X(S:E,13))/NS(13)
    0 0 sum(X(S:E,15))/NS(15)
    sum(X(S:E,12))/NS(12) 0
    sum(X(S:E,17))/NS(17) sum(X(S:E,17))/NS(17) sum(X(S:E,17))/NS(17)
    sum(X(S:E,18))/NS(18)
     sum(X(S:E,18))/NS(18) sum(X(S:E,18))/NS(18) 0 0 0 0 0 0 0
    (sum(X(S:E,17))/NS(17)+sum(X(S:E,20))/NS(20))/2
    (sum(X(S:E,17))/NS(17)+sum(X(S:E,20))/NS(20))/2
    (sum(X(S:E,17))/NS(17)+sum(X(S:E,20))/NS(20))/2
    (sum(X(S:E,18))/NS(18)+sum(X(S:E,19))/NS(19))/2
```

```
    (sum(X(S:E,18))/NS(18)+sum(X(S:E,19))/NS(19))/2
    (sum(X(S:E,18))/NS(18)+sum(X(S:E,19))/NS(19))/2
    0 0 0 0 0 0 0
    sum(X(S:E,20))/NS(20) sum(X(S:E,20))/NS(20) sum(X(S:E,20))/NS(20)
    sum(X(S:E,19))/NS(19)
    sum(X(S:E,19))/NS(19) sum(X(S:E,19))/NS(19) 0 0 0 0 0 0 0
    sum(X(S:E,21))/NS(21) sum(X(S:E,21))/NS(21) sum(X(S:E,21))/NS(21)
    sum(X(S:E,22))/NS(22)
     sum(X(S:E,22))/NS(22) sum(X(S:E,22))/NS(22) 0 0 0 0 0 0 0
    (sum(X(S:E,21))/NS(21)+sum(X(S:E,23))/NS(23))/2
    (sum(X(S:E,21))/NS(21)+sum(X(S:E,23))/NS(23))/2
    (sum(X(S:E,21))/NS(21)+sum(X(S:E,23))/NS(23))/2
    (sum(X(S:E,22))/NS(22)+sum(X(S:E,24))/NS(24))/2
    (sum(X(S:E,22))/NS(22)+sum(X(S:E,24))/NS(24))/2
    (sum(X(S:E,22))/NS(22)+sum(X(S:E,24))/NS(24))/2
    0 0 0 0 0 0 0
    sum(X(S:E,23))/NS(23) sum(X(S:E,23))/NS(23) sum(X(S:E,23))/NS(23)
    sum(X(S:E,24))/NS(24)
    sum(X(S:E,24))/NS(24) sum(X(S:E,24))/NS(24) 0 0 0 0 0 0 0];

WU=3750*flipud(EP);

axes(handles.Map);
[X,Y] = meshgrid(0.5:12.5, 0.5:12.5);
pcolor(X,Y,(WU));
view(2)
axis([0 13 0 13])
colormap jet
h=colorbar;
title('Water Required (MMBBLs)')

set(handles.Max,'String',num2str(round(max(max(WU)))));
set(handles.Avg,'String',num2str(round(mean(mean(WU)))));

elseif Waste==1
    for i=2:size(X,1)
    for j=1:size(X,2)
        X(i,j)=X(i,j)+X(i-1,j);
    end
end

for i=1:E
    for j=1:size(X,2)
        for k=1:size(X,1)
            if i<S | i>E
                A(i,j)=0;
            elseif i==S
                A(i+k-1,j,k)=(X(k,j)/25)*(1590/((1+0.2492*15*(i-S))^(1/0.9457)));
            elseif i==S+1
                A(i+k-1,j,k)=(X(k,j)/25)*(165.93/((1+0.057*45*(i-S))^(1/1.347)));
            else
                A(i+k-1,j,k)=(X(k,j)/25)*(33.62/((1+0.00837*30*(i-S))^(1/1.2)));
            end
        end
    end
```

```
end

DPW=sum(A,3);


    EP=[   0 0 0 0 0 0 0 0 0 0 0 0 0
    0 0 0 0 0 0 sum(X(S:E,6))/NS(6) sum(X(S:E,6))/NS(6) sum(X(S:E,2))/NS(2)
    sum(X(S:E,2))/NS(2) sum(X(S:E,4))/NS(4) sum(X(S:E,4))/NS(4) 0
    sum(X(S:E,7))/(NS(7)*2) sum(X(S:E,7))/NS(7) sum(X(S:E,7))/NS(7)
    sum(X(S:E,9))/NS(9) sum(X(S:E,9))/NS(9) sum(X(S:E,6))/NS(6)
    sum(X(S:E,11))/NS(11) sum(X(S:E,11))/NS(11)
    sum(X(S:E,2))/NS(2) sum(X(S:E,2))/NS(2) sum(X(S:E,4))/NS(4)
    sum(X(S:E,4))/NS(4) 0
    sum(X(S:E,16))/NS(16) sum(X(S:E,16))/(NS(16)*2) 0
    (sum(X(S:E,9))/NS(9)+sum(X(S:E,10))/NS(10))/2
    (sum(X(S:E,9))/NS(9)+sum(X(S:E,10))/NS(10))/2 sum(X(S:E,6))/NS(6)
    sum(X(S:E,11))/NS(11)
    sum(X(S:E,11))/NS(11) sum(X(S:E,2))/NS(2)  sum(X(S:E,2))/NS(2)
    sum(X(S:E,14))/NS(14)
    sum(X(S:E,14))/NS(14) 0
    sum(X(S:E,16))/NS(16) sum(X(S:E,3))/NS(3) sum(X(S:E,9))/NS(9)
    sum(X(S:E,10))/NS(10)
    sum(X(S:E,10))/NS(10) sum(X(S:E,9))/NS(9) sum(X(S:E,8))/NS(8)
    sum(X(S:E,8))/(NS(8)*2)
    sum(X(S:E,13))/NS(13) sum(X(S:E,12))/NS(12) sum(X(S:E,14))/NS(14)
    sum(X(S:E,14))/NS(14) 0
    sum(X(S:E,16))/NS(16) sum(X(S:E,3))/NS(3) sum(X(S:E,3))/NS(3)
    sum(X(S:E,5))/NS(5)
    sum(X(S:E,5))/NS(5) sum(X(S:E,5))/NS(5) sum(X(S:E,13))/NS(13)
    sum(X(S:E,13))/NS(13)
    sum(X(S:E,12))/NS(12) sum(X(S:E,15))/NS(15) sum(X(S:E,12))/NS(12)
    sum(X(S:E,12))/NS(12) 0
    sum(X(S:E,16))/NS(16) sum(X(S:E,16))/NS(16) sum(X(S:E,16))/NS(16)
     sum(X(S:E,5))/NS(5)
    sum(X(S:E,5))/NS(5) 0 sum(X(S:E,13))/NS(13) sum(X(S:E,13))/NS(13)
    0 0 sum(X(S:E,15))/NS(15)
    sum(X(S:E,12))/NS(12) 0
    sum(X(S:E,17))/NS(17) sum(X(S:E,17))/NS(17) sum(X(S:E,17))/NS(17)
    sum(X(S:E,18))/NS(18)
     sum(X(S:E,18))/NS(18) sum(X(S:E,18))/NS(18) 0 0 0 0 0 0 0
    (sum(X(S:E,17))/NS(17)+sum(X(S:E,20))/NS(20))/2
    (sum(X(S:E,17))/NS(17)+sum(X(S:E,20))/NS(20))/2
    (sum(X(S:E,17))/NS(17)+sum(X(S:E,20))/NS(20))/2
    (sum(X(S:E,18))/NS(18)+sum(X(S:E,19))/NS(19))/2
    (sum(X(S:E,18))/NS(18)+sum(X(S:E,19))/NS(19))/2
    (sum(X(S:E,18))/NS(18)+sum(X(S:E,19))/NS(19))/2
    0 0 0 0 0 0 0
    sum(X(S:E,20))/NS(20) sum(X(S:E,20))/NS(20) sum(X(S:E,20))/NS(20)
    sum(X(S:E,19))/NS(19)
    sum(X(S:E,19))/NS(19) sum(X(S:E,19))/NS(19) 0 0 0 0 0 0 0
    sum(X(S:E,21))/NS(21) sum(X(S:E,21))/NS(21) sum(X(S:E,21))/NS(21)
    sum(X(S:E,22))/NS(22)
     sum(X(S:E,22))/NS(22) sum(X(S:E,22))/NS(22) 0 0 0 0 0 0 0
    (sum(X(S:E,21))/NS(21)+sum(X(S:E,23))/NS(23))/2
    (sum(X(S:E,21))/NS(21)+sum(X(S:E,23))/NS(23))/2
```

```
     (sum(X(S:E,21))/NS(21)+sum(X(S:E,23))/NS(23))/2
     (sum(X(S:E,22))/NS(22)+sum(X(S:E,24))/NS(24))/2
     (sum(X(S:E,22))/NS(22)+sum(X(S:E,24))/NS(24))/2
     (sum(X(S:E,22))/NS(22)+sum(X(S:E,24))/NS(24))/2
     0 0 0 0 0 0 0
     sum(X(S:E,23))/NS(23) sum(X(S:E,23))/NS(23) sum(X(S:E,23))/NS(23)
     sum(X(S:E,24))/NS(24)
     sum(X(S:E,24))/NS(24) sum(X(S:E,24))/NS(24) 0 0 0 0 0 0 0];

PW=flipud(EP);

axes(handles.Map);
[X,Y] = meshgrid(0.5:12.5, 0.5:12.5);
pcolor(X,Y,(PW));
view(2)
axis([0 13 0 13])
colormap jet
h=colorbar;
title('Flowback/Produced Water (MMBBLs)')

set(handles.Max,'String',num2str(round(max(max(PW)))));
set(handles.Avg,'String',num2str(round(mean(mean(PW)))));

elseif MCDA==1
    EP=[   0 0 0 0 0 0 0 0 0 0 0 0 0
    0 0 0 0 0 0 sum(X(S:E,6))/NS(6) sum(X(S:E,6))/NS(6) sum(X(S:E,2))/NS(2)
    sum(X(S:E,2))/NS(2) sum(X(S:E,4))/NS(4) sum(X(S:E,4))/NS(4) 0
    sum(X(S:E,7))/(NS(7)*2) sum(X(S:E,7))/NS(7) sum(X(S:E,7))/NS(7)
    sum(X(S:E,9))/NS(9) sum(X(S:E,9))/NS(9) sum(X(S:E,6))/NS(6)
    sum(X(S:E,11))/NS(11) sum(X(S:E,11))/NS(11)
    sum(X(S:E,2))/NS(2) sum(X(S:E,2))/NS(2) sum(X(S:E,4))/NS(4)
    sum(X(S:E,4))/NS(4) 0
    sum(X(S:E,16))/NS(16) sum(X(S:E,16))/(NS(16)*2) 0
    (sum(X(S:E,9))/NS(9)+sum(X(S:E,10))/NS(10))/2
    (sum(X(S:E,9))/NS(9)+sum(X(S:E,10))/NS(10))/2 sum(X(S:E,6))/NS(6)
    sum(X(S:E,11))/NS(11)
    sum(X(S:E,11))/NS(11) sum(X(S:E,2))/NS(2)  sum(X(S:E,2))/NS(2)
    sum(X(S:E,14))/NS(14)
    sum(X(S:E,14))/NS(14) 0
    sum(X(S:E,16))/NS(16) sum(X(S:E,3))/NS(3) sum(X(S:E,9))/NS(9)
    sum(X(S:E,10))/NS(10)
    sum(X(S:E,10))/NS(10) sum(X(S:E,9))/NS(9) sum(X(S:E,8))/NS(8)
    sum(X(S:E,8))/(NS(8)*2)
    sum(X(S:E,13))/NS(13) sum(X(S:E,12))/NS(12) sum(X(S:E,14))/NS(14)
    sum(X(S:E,14))/NS(14) 0
    sum(X(S:E,16))/NS(16) sum(X(S:E,3))/NS(3) sum(X(S:E,3))/NS(3)
    sum(X(S:E,5))/NS(5)
    sum(X(S:E,5))/NS(5) sum(X(S:E,5))/NS(5) sum(X(S:E,13))/NS(13)
    sum(X(S:E,13))/NS(13)
    sum(X(S:E,12))/NS(12) sum(X(S:E,15))/NS(15) sum(X(S:E,12))/NS(12)
    sum(X(S:E,12))/NS(12) 0
    sum(X(S:E,16))/NS(16) sum(X(S:E,16))/NS(16) sum(X(S:E,16))/NS(16)
     sum(X(S:E,5))/NS(5)
    sum(X(S:E,5))/NS(5) 0 sum(X(S:E,13))/NS(13) sum(X(S:E,13))/NS(13)
    0 0 sum(X(S:E,15))/NS(15)
```

```
    sum(X(S:E,12))/NS(12) 0
    sum(X(S:E,17))/NS(17) sum(X(S:E,17))/NS(17) sum(X(S:E,17))/NS(17)
    sum(X(S:E,18))/NS(18)
     sum(X(S:E,18))/NS(18) sum(X(S:E,18))/NS(18) 0 0 0 0 0 0 0
    (sum(X(S:E,17))/NS(17)+sum(X(S:E,20))/NS(20))/2
    (sum(X(S:E,17))/NS(17)+sum(X(S:E,20))/NS(20))/2
    (sum(X(S:E,17))/NS(17)+sum(X(S:E,20))/NS(20))/2
    (sum(X(S:E,18))/NS(18)+sum(X(S:E,19))/NS(19))/2
    (sum(X(S:E,18))/NS(18)+sum(X(S:E,19))/NS(19))/2
    (sum(X(S:E,18))/NS(18)+sum(X(S:E,19))/NS(19))/2
    0 0 0 0 0 0 0
    sum(X(S:E,20))/NS(20) sum(X(S:E,20))/NS(20) sum(X(S:E,20))/NS(20)
    sum(X(S:E,19))/NS(19)
    sum(X(S:E,19))/NS(19) sum(X(S:E,19))/NS(19) 0 0 0 0 0 0 0
    sum(X(S:E,21))/NS(21) sum(X(S:E,21))/NS(21) sum(X(S:E,21))/NS(21)
    sum(X(S:E,22))/NS(22)
     sum(X(S:E,22))/NS(22) sum(X(S:E,22))/NS(22) 0 0 0 0 0 0 0
    (sum(X(S:E,21))/NS(21)+sum(X(S:E,23))/NS(23))/2
    (sum(X(S:E,21))/NS(21)+sum(X(S:E,23))/NS(23))/2
    (sum(X(S:E,21))/NS(21)+sum(X(S:E,23))/NS(23))/2
    (sum(X(S:E,22))/NS(22)+sum(X(S:E,24))/NS(24))/2
    (sum(X(S:E,22))/NS(22)+sum(X(S:E,24))/NS(24))/2
    (sum(X(S:E,22))/NS(22)+sum(X(S:E,24))/NS(24))/2
    0 0 0 0 0 0 0
    sum(X(S:E,23))/NS(23) sum(X(S:E,23))/NS(23) sum(X(S:E,23))/NS(23)
    sum(X(S:E,24))/NS(24)
    sum(X(S:E,24))/NS(24) sum(X(S:E,24))/NS(24) 0 0 0 0 0 0 0];

WU=0.003750*EP;
WU_s=get(handles.req_box,'String');
WU=str2num(WU_s)*WU./max(max(WU));

for i=2:size(X,1)
    for j=1:size(X,2)
        X(i,j)=X(i,j)+X(i-1,j);
    end
end

for i=1:E
    for j=1:size(X,2)
        for k=1:size(X,1)
            if i<S | i>E
                A(i,j)=0;
            elseif i==S
                A(i+k-1,j,k)=(X(k,j)/25)*(1590/((1+0.2492*15*(i-S))^(1/0.9457)));
            elseif i==S+1
                A(i+k-1,j,k)=(X(k,j)/25)*(165.93/((1+0.057*45*(i-S))^(1/1.347)));
            else
                A(i+k-1,j,k)=(X(k,j)/25)*(33.62/((1+0.00837*30*(i-S))^(1/1.2)));
            end
        end
    end
end

DPW=sum(A,3);
```

```
EP=[   0 0 0 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 sum(X(S:E,6))/NS(6) sum(X(S:E,6))/NS(6) sum(X(S:E,2))/NS(2)
sum(X(S:E,2))/NS(2) sum(X(S:E,4))/NS(4) sum(X(S:E,4))/NS(4) 0
sum(X(S:E,7))/(NS(7)*2) sum(X(S:E,7))/NS(7) sum(X(S:E,7))/NS(7)
sum(X(S:E,9))/NS(9) sum(X(S:E,9))/NS(9) sum(X(S:E,6))/NS(6)
sum(X(S:E,11))/NS(11) sum(X(S:E,11))/NS(11)
sum(X(S:E,2))/NS(2) sum(X(S:E,2))/NS(2) sum(X(S:E,4))/NS(4)
sum(X(S:E,4))/NS(4) 0
sum(X(S:E,16))/NS(16) sum(X(S:E,16))/(NS(16)*2) 0
(sum(X(S:E,9))/NS(9)+sum(X(S:E,10))/NS(10))/2
(sum(X(S:E,9))/NS(9)+sum(X(S:E,10))/NS(10))/2 sum(X(S:E,6))/NS(6)
sum(X(S:E,11))/NS(11)
sum(X(S:E,11))/NS(11) sum(X(S:E,2))/NS(2)  sum(X(S:E,2))/NS(2)
sum(X(S:E,14))/NS(14)
sum(X(S:E,14))/NS(14) 0
sum(X(S:E,16))/NS(16) sum(X(S:E,3))/NS(3) sum(X(S:E,9))/NS(9)
sum(X(S:E,10))/NS(10)
sum(X(S:E,10))/NS(10) sum(X(S:E,9))/NS(9) sum(X(S:E,8))/NS(8)
sum(X(S:E,8))/(NS(8)*2)
sum(X(S:E,13))/NS(13) sum(X(S:E,12))/NS(12) sum(X(S:E,14))/NS(14)
sum(X(S:E,14))/NS(14) 0
sum(X(S:E,16))/NS(16) sum(X(S:E,3))/NS(3) sum(X(S:E,3))/NS(3)
sum(X(S:E,5))/NS(5)
sum(X(S:E,5))/NS(5) sum(X(S:E,5))/NS(5) sum(X(S:E,13))/NS(13)
sum(X(S:E,13))/NS(13)
sum(X(S:E,12))/NS(12) sum(X(S:E,15))/NS(15) sum(X(S:E,12))/NS(12)
sum(X(S:E,12))/NS(12) 0
sum(X(S:E,16))/NS(16) sum(X(S:E,16))/NS(16) sum(X(S:E,16))/NS(16)
 sum(X(S:E,5))/NS(5)
sum(X(S:E,5))/NS(5) 0 sum(X(S:E,13))/NS(13) sum(X(S:E,13))/NS(13)
0 0 sum(X(S:E,15))/NS(15)
sum(X(S:E,12))/NS(12) 0
sum(X(S:E,17))/NS(17) sum(X(S:E,17))/NS(17) sum(X(S:E,17))/NS(17)
sum(X(S:E,18))/NS(18)
 sum(X(S:E,18))/NS(18) sum(X(S:E,18))/NS(18) 0 0 0 0 0 0 0
(sum(X(S:E,17))/NS(17)+sum(X(S:E,20))/NS(20))/2
(sum(X(S:E,17))/NS(17)+sum(X(S:E,20))/NS(20))/2
(sum(X(S:E,17))/NS(17)+sum(X(S:E,20))/NS(20))/2
(sum(X(S:E,18))/NS(18)+sum(X(S:E,19))/NS(19))/2
(sum(X(S:E,18))/NS(18)+sum(X(S:E,19))/NS(19))/2
(sum(X(S:E,18))/NS(18)+sum(X(S:E,19))/NS(19))/2
0 0 0 0 0 0 0
sum(X(S:E,20))/NS(20) sum(X(S:E,20))/NS(20) sum(X(S:E,20))/NS(20)
sum(X(S:E,19))/NS(19)
sum(X(S:E,19))/NS(19) sum(X(S:E,19))/NS(19) 0 0 0 0 0 0 0
sum(X(S:E,21))/NS(21) sum(X(S:E,21))/NS(21) sum(X(S:E,21))/NS(21)
sum(X(S:E,22))/NS(22)
 sum(X(S:E,22))/NS(22) sum(X(S:E,22))/NS(22) 0 0 0 0 0 0 0
(sum(X(S:E,21))/NS(21)+sum(X(S:E,23))/NS(23))/2
(sum(X(S:E,21))/NS(21)+sum(X(S:E,23))/NS(23))/2
(sum(X(S:E,21))/NS(21)+sum(X(S:E,23))/NS(23))/2
(sum(X(S:E,22))/NS(22)+sum(X(S:E,24))/NS(24))/2
(sum(X(S:E,22))/NS(22)+sum(X(S:E,24))/NS(24))/2
```

```
    (sum(X(S:E,22))/NS(22)+sum(X(S:E,24))/NS(24))/2
    0 0 0 0 0 0 0
    sum(X(S:E,23))/NS(23) sum(X(S:E,23))/NS(23) sum(X(S:E,23))/NS(23)
    sum(X(S:E,24))/NS(24)
    sum(X(S:E,24))/NS(24) sum(X(S:E,24))/NS(24) 0 0 0 0 0 0 0];

DPW_s=get(handles.waste_box,'String');
DPW=str2num(DPW_s).*EP./max(max(EP));

C=[0 0 0 0 0 0 0 0 0 0 0 0 0
    12 11 10 9 8 7 6 5 4 3 2 1 0
    12 11 10 9 8 7 6 5 4 3 2 1 0
    12 11 10 9 8 7 6 5 4 3 2 1 0
    12 11 10 9 8 7 6 5 4 3 2 1 0
    12 11 10 9 8 7 6 5 4 3 2 1 0
    12 11 10 9 8 7 6 5 4 3 2 1 0
    12 11 10 9 8 7 6 5 4 3 2 1 0
    12 11 10 9 8 7 6 5 4 3 2 1 0
    12 11 10 9 8 7 6 5 4 3 2 1 0
    12 11 10 9 8 7 6 5 4 3 2 1 0
    12 11 10 9 8 7 6 5 4 3 2 1 0
    12 11 10 9 8 7 6 5 4 3 2 1 0];

C_s=get(handles.CPF_box,'String');
C=str2num(C_s).*C./max(max(C));

EI=[0 0 0 0 0 0 0 0 0 0 0 0 0
    0 0 0 0 0 0 1 1 1 1 1 1 0
    0.5 1 1 1 1 1 1 1 1 1 1 1 0
    1 0.5 0 1 1 1 1 1 1 1 1 1 0
    1 1 1 1 1 1 1 0.5 1 1 1 1 0
    1 1 1 1 1 1 1 1 1 1 1 1 0
    1 1 1 1 1 0 1 1 0 0 1 1 0
    1 1 1 1 1 1 0 0 0 0 0 0 0
    1 1 1 1 1 1 0 0 0 0 0 0 0
    1 1 1 1 1 1 0 0 0 0 0 0 0
    1 1 1 1 1 1 0 0 0 0 0 0 0
    1 1 1 1 1 1 0 0 0 0 0 0 0
    1 1 1 1 1 1 0 0 0 0 0 0 0];

EI_s=get(handles.BLM_box,'String');
EI=str2num(EI_s).*EI./max(max(EI));

MCDA=(EI+C+DPW+WU)./4;
MCDA=flipud(MCDA);

axes(handles.Map);
[X,Y] = meshgrid(0.5:12.5, 0.5:12.5);
pcolor(X,Y,(MCDA));
view(2)
axis([0 13 0 13])
colormap jet
h=colorbar;
title('MCDA')
```

```
set(handles.Max,'String',' ');
set(handles.Avg,'String',' ');

elseif CPF==1
    CPF=get(hObject,'Value');
if CPF==1
    set(handles.EastPonyDP,'Value',0)
    set(handles.Pads,'Value',0)
    set(handles.MCDA,'Value',0)
    set(handles.Waste,'Value',0)
    set(handles.BLM,'Value',0)
end

C=[0 0 0 0 0 0 0 0 0 0 0 0 0
    12 11 10 9 8 7 6 5 4 3 2 1 0
    12 11 10 9 8 7 6 5 4 3 2 1 0
    12 11 10 9 8 7 6 5 4 3 2 1 0
    12 11 10 9 8 7 6 5 4 3 2 1 0
    12 11 10 9 8 7 6 5 4 3 2 1 0
    12 11 10 9 8 7 6 5 4 3 2 1 0
    12 11 10 9 8 7 6 5 4 3 2 1 0
    12 11 10 9 8 7 6 5 4 3 2 1 0
    12 11 10 9 8 7 6 5 4 3 2 1 0
    12 11 10 9 8 7 6 5 4 3 2 1 0
    12 11 10 9 8 7 6 5 4 3 2 1 0
    12 11 10 9 8 7 6 5 4 3 2 1 0];

C=flipud(C);

axes(handles.Map);
[X,Y] = meshgrid(0.5:12.5, 0.5:12.5);
pcolor(X,Y,(C));
view(2)
axis([0 13 0 13])
colormap jet
h=colorbar;
title('Environment')

set(handles.Max,'String',' ');
set(handles.Avg,'String',' ');

elseif BLM==1
    EI=[0 0 0 0 0 0 0 0 0 0 0 0 0
    0 0 0 0 0 0 1 1 1 1 1 1 0
    0.5 1 1 1 1 1 1 1 1 1 1 1 0
    1 0.5 0 1 1 1 1 1 1 1 1 1 0
    1 1 1 1 1 1 1 0.5 1 1 1 1 0
    1 1 1 1 1 1 1 1 1 1 1 1 0
    1 1 1 1 1 0 1 1 0 0 1 1 0
    1 1 1 1 1 1 0 0 0 0 0 0 0
    1 1 1 1 1 1 0 0 0 0 0 0 0
    1 1 1 1 1 1 0 0 0 0 0 0 0
    1 1 1 1 1 1 0 0 0 0 0 0 0
    1 1 1 1 1 1 0 0 0 0 0 0 0
    1 1 1 1 1 1 0 0 0 0 0 0 0];
```

```
EI=flipud(EI);

axes(handles.Map);
[X,Y] = meshgrid(0.5:12.5, 0.5:12.5);
pcolor(X,Y,(EI));
view(2)
axis([0 13 0 13])
colormap jet
h=colorbar;
title('Environment')

CPF=get(hObject,'Value');
if CPF==1
    set(handles.EastPonyDP,'Value',0)
    set(handles.Pads,'Value',0)
    set(handles.MCDA,'Value',0)
    set(handles.Waste,'Value',0)
    set(handles.BLM,'Value',0)
end

C=[0 0 0 0 0 0 0 0 0 0 0 0 0
    12 11 10 9 8 7 6 5 4 3 2 1 0
    12 11 10 9 8 7 6 5 4 3 2 1 0
    12 11 10 9 8 7 6 5 4 3 2 1 0
    12 11 10 9 8 7 6 5 4 3 2 1 0
    12 11 10 9 8 7 6 5 4 3 2 1 0
    12 11 10 9 8 7 6 5 4 3 2 1 0
    12 11 10 9 8 7 6 5 4 3 2 1 0
    12 11 10 9 8 7 6 5 4 3 2 1 0
    12 11 10 9 8 7 6 5 4 3 2 1 0
    12 11 10 9 8 7 6 5 4 3 2 1 0
    12 11 10 9 8 7 6 5 4 3 2 1 0
    12 11 10 9 8 7 6 5 4 3 2 1 0];

C=flipud(C);

axes(handles.Map);
[X,Y] = meshgrid(0.5:12.5, 0.5:12.5);
pcolor(X,Y,(C));
view(2)
axis([0 13 0 13])
colormap jet
h=colorbar;
title('Environment')

set(handles.Max,'String',' ');
set(handles.Avg,'String',' ');

end
```

9.4. Treatment Facility Siting GUI Tool: Wattenberg Field

The treatment facility siting GUI tool for the Wattenberg Field allows the user to place freshwater sources, treatment facilities, and injection wells in the Wattenberg Field, as shown in Figure 9.5. The volume of water required for development of the field is estimated along with the flowback/produced water volumes. The geodesic distance between the freshwater source, the well pad, and the treatment facility/injection well is calculated. Using this distance and the water volumes, the number of truck trips (assuming 130 bbls/truck) is calculated using Equation 9.1.

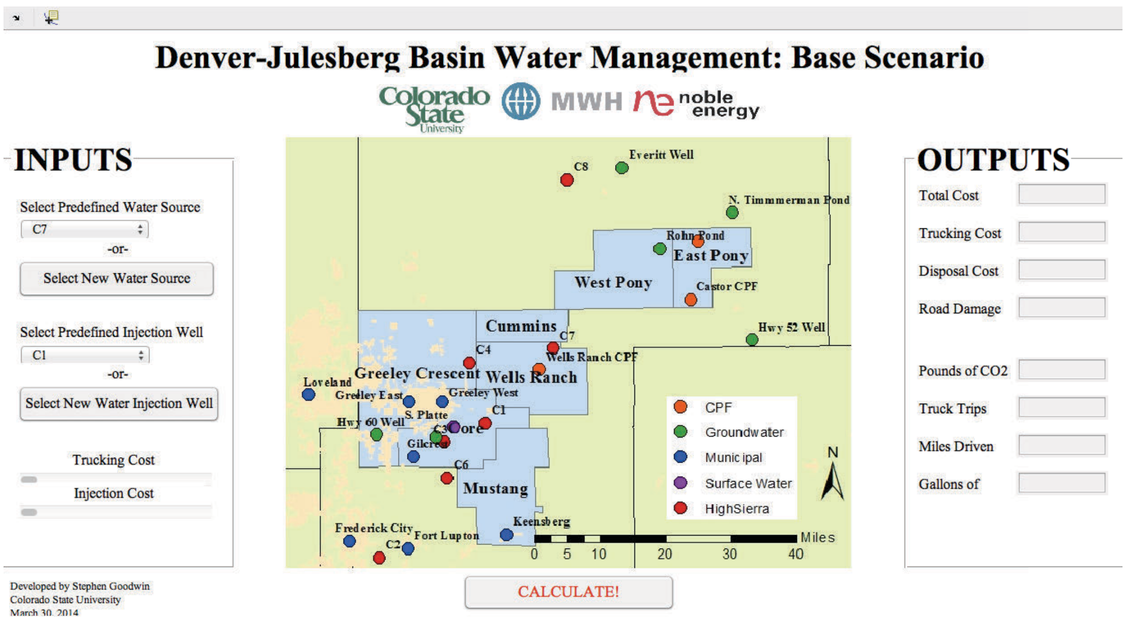


Figure 9.5: The treatment facility siting GUI tool for the Wattenberg Field.

$$\text{Truck Trips} = \sum_{Pad=1}^{n} \frac{(\text{Freshwater+Produced Water})_{\text{Pad}}}{150} \tag{9.1}$$

The number of truck trips can be multiplied by two times the geodesic distance to calculate the total number of miles driven. If a diesel fuel efficiency of 7 miles per gallons for an unloaded truck is assumed and 4 miles per gallon for a loaded truck is assumed, Equation 9.2 can be used to estimate the amount of diesel that will be required. The projected air emissions from trucking can be estimated, assuming all of the fuel is combusted, by multiplying the volume of diesel fuel by an air emissions conversion factor. For example, the U.S. Energy Information Agency estimates 22.38 pounds of CO2 is emitted for every gallon of diesel combusted.

$$\text{Diesel Fuel} = \frac{(\text{Distance})(\text{Loaded Truck Trips})}{(4\ \text{mpg})} + \frac{(\text{Distance})(\text{Unloaded Truck Trips})}{(7\ \text{mpg})} \tag{9.2}$$

Similarly, the costs associated with water infrastructure can be roughly estimated and compared for a variety of scenarios. Currently, Noble pays trucking and disposal rates on a per bbl basis in the Wattenberg Field and distance does not directly impact the costs. Trucking and disposal costs can be estimated based on the water volume requirements. However, indirect costs (e.g. road damage) are a function of the distance and are calculated based on both the water volumes and geodesic distance.

As shown in Figure 9.5, the user can adjust the cost of both trucking and injection to assess the robustness of water infrastructure decisions as future prices increase. The user can also select from either a drop down menu of existing water sources and injection wells or select a predefined location. When the Calculate! button is pressed, the key outputs are presented on the right side of the GUI. This simple GUI allows operators to better quantify water infrastructure decisions.

9.5. Summary

The objective of this chapter is to highlight some of the tools that can be developed from the framework outlined in Chapter 8. A variety of tools be developed based on the operator's needs and concerns surrounding a particular field. Input and feedback from the operators is critical to successfully developing valuable modeling tools. An operator understands key information and tradeoffs that are driving key water infrastructure decisions in a field. These tradeoffs can be modeled using the framework outlined in Chapter 8 to quantify the impacts of the decisions. Furthermore, spatial MCDA approaches can be used to understand how valuing specific criteria drives a decisions.

These models can be further expanded to address water quality and treatment requirements. For example, if the temporal changes in flowback and produced water quality (see Appendix A) are accurately modeled and the water quality targets are well understood (see Chapter 7), dilution and treatment strategies can be modeled within the field. A better understanding of water quality can be used to model influent water quality and optimize treatment by reducing the amount of bench-scale jar testing that is required.

The uncertainty and rapidly changes in an oil and gas field requires models to be extremely flexible and relatively simple in the analysis. If the development of a field changes based on the production of existing wells, these tools can be used to assess the costs of moving or removing water infrastructure against increasing the transportation requirements. Operators can use these tools to quantitatively justify key water infrastructure decisions and understand the key factors that are driving these decisions.

By developing these models and tools in a flexible framework with the input from operators, these models can provide tools to improve water infrastructure decisions by quantifying the economic, environmental, and social impacts of these decisions. In fields with dense unconventional oil and gas development, these tools can be used to help operators to minimize the demands on water resources, increase public acceptance, and reduce environmental impacts.

10. Conclusion

The objective of this dissertation is to:

> **Model and quantify the social, environmental, and economic implications that water infrastructure decisions have within an uncertain and rapidly changing oil and gas field.**

Chapters 4 through 6 show that influent and effluent water volumes for each component shown in Figure 10.1 can be accurately and precisely estimated in the Wattenberg Field. Chapter 6 incorporates water quality estimates for the flowback and produced water as well as several case studies for each component shown in Figure 10.1. The impact water quality has on the development and performance of gelled hydraulic fracturing fluids, which provides water quality treatment targets for designing water treatment facilities, is assessed in Chapter 7.

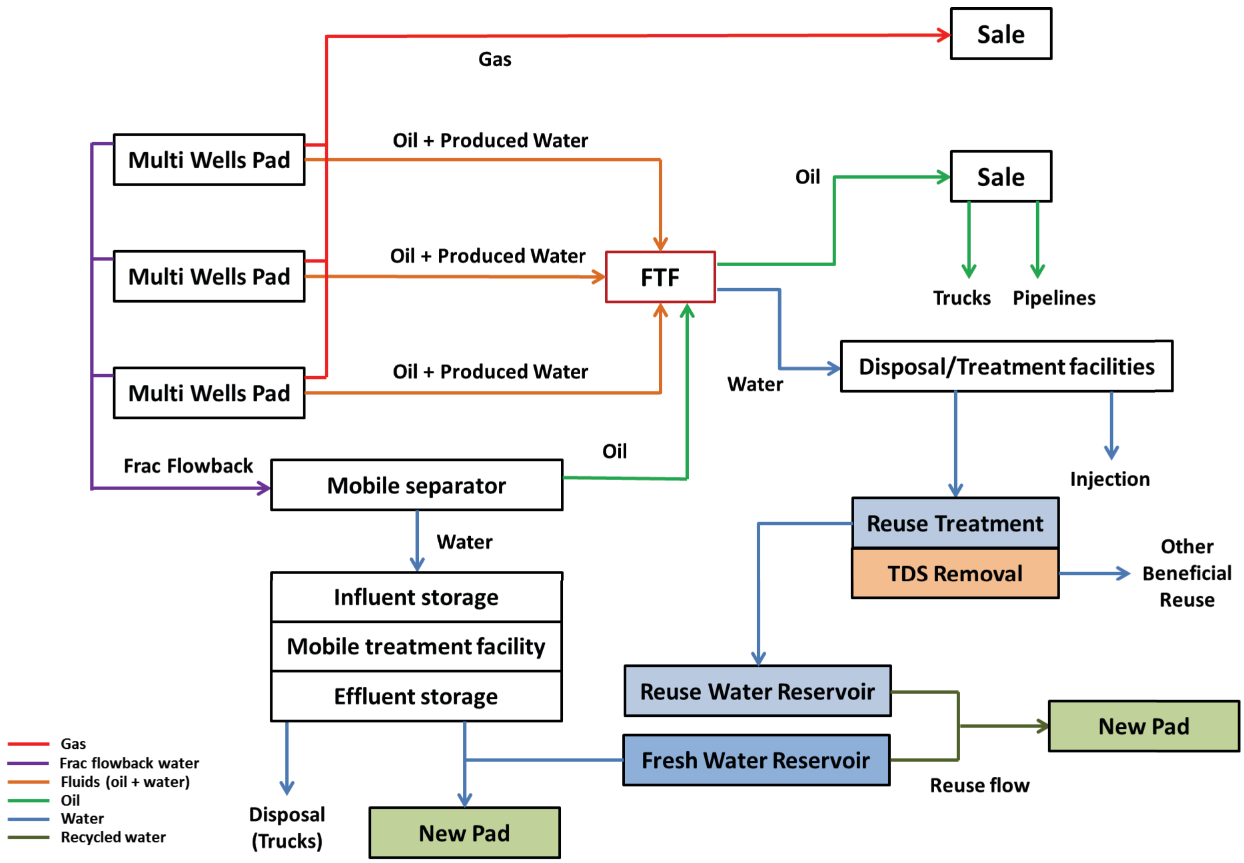


Figure 10.1: A schematic of the generic flows of water, oil, and gas along with the infrastructure requirements within an oil and gas field.

Chapter 8 provides a framework to spatially and temporally model water volumes and quality as well as social, environmental, and economic impacts for a hypothetical field by incorporating the research developed in previous chapters. Chapter 9 provides case-studies that apply the hypothetical model framework to a variety of actual oil and gas development scenarios to compare different water management scenarios. The model framework allows operators to visualize, compare, and quantify several water management scenarios for a variety of oil and gas development plans. Incorporating the research into a spatial and temporal model allows operators to minimize key criteria for a specific area (e.g. environmental impact, truck traffic, etc.) to optimize the size, location, number, and duration of treatment facilities in the field.

Optimizing water management in unconventional oil and gas fields is essential to minimize the risks and highly publicized concerns, but the uncertainty in oil and gas field development makes it risky to invest, plan, and design water infrastructure in a rapidly changing field. Furthermore, the variability in the quantity of the flowback and produced water creates challenges for water treatment planning and design if these volumes are not correctly modeled. By developing a framework to model water volumes and the impact specific water infrastructure decisions have in a rapidly changing oil and gas field will improve the accuracy and speed of water planning and management.

Traditional water management strategies for an unconventional oil and gas field require tedious calculations for each scenario and development plan. By incorporating flexible development plans and water infrastructure decisions in a single graphical user interface, the tedious calculations are replaced with instant visualization and quantifiable measures associated with each development plan and water infrastructure decision. Furthermore, a spatial and temporal multicriteria decision analysis on water infrastructure placement is incorporated into the model to allow the user to weight specific criteria within the field and see what parameters have the strongest influence on the final decision.

The flexibility in the graphical user interface allows the user to instantly visualize the impact water management decisions have on the field. For example, if the user is considering piping the flowback and produced water to several mobile treatment facilities within the field because he or she is concerned about the price of disposal using Class II injection wells, both scenarios can be quickly visualized within the model to determine what the price increase, rate of development, and cost of treatment will need to be in the field to make a rational water management decision. Currently, this water management comparisons are made on a case-by-case basis with tedious calculations. By speeding up and quantifying the decision-making process, several scenarios and strategies can be rapidly compared and the engineering design and planning stages can be decreased dramatically.

Water is the single largest operating material by volume and directly impacts the social (i.e. induced seismic activity, risk of fatal accidents), environmental (i.e. risk of spills, greenhouse gas emissions) and economic risks. In the coming years, as an increasing number of ballots include hydraulic featuring restrictions or moratoriums and oil and gas development becomes more concentrated, optimizing water management will become essential to continue operations in populated and semi-arid regions. Water treatment and reuse will be a key part of an optimized water management strategy. A simple brute-force solution using a single centralized treatment facility for a field or a mobile treatment facility at each pad cannot provide an optimized solution. Blending fresh, flowback, and produced waters to achieve the treatment targets developed in Chapter 7 provides a more optimized solution that reduces the social, environmental, and economic impacts of treatment. This solution is much more complicated and requires a spatial and temporal understanding of the water volumes, quantities, and treatment requirements within a field.

The modeling framework developed in this dissertation fills this gap by giving the operator the ability to visualize, model, and quantify water volumes and qualities throughout a field based on flexible development plans. Water management scenarios can be modeled with the development plans to assess the efficiency and impacts of each scenario. The operator can assign a relative specific risks (e.g. environmental, social, etc.) throughout the field to provide a spatial and temporal multi-criteria decision analysis for each development plan and water management scenario.

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Appendix A: Temporal Characterization of Flowback and Produced Water quality from Shale Gas Resources in Northeastern Colorado

The volume of water reused depends on the flowback/produced water volume, flowback/ produced water quality, and how the water quality impacts hydraulic fracturing fluid performance. The volume and quality of flowback and produced water are sampled to better understand the temporal changes.

Water volumes are estimated and characterized using the flowback/produced water volumes of 200 horizontal wells that are hydraulically fractured in the Wattenberg Field.

The temporal changes in water quality of the flowback/produced water from two of the wells are analyzed to characterize the water quality. A guar-based gelled hydraulically fracturing fluid with a high pH was used to hydraulically fracture one of the wells. A cellulosic-based gelled hydraulically fracturing fluid with a low pH was used to hydraulically fracture the other well. 35 water samples were collected and analyzed from each well over a 145-day period.

Table A.1: The water use (drilling and hydraulic fracturing water volumes), the water returned (flowback and produced water volumes) and the maximum water reuse potential (ratio of water use and water recovered).

Percentile	Drilling Water Use	Hydraulic Fracturing Water Use	Total Water Use	Flowback Water	Estimated 30-Year Produced Water	Estimated Total Water Recovered	Reuse Potential
10^{th}	3,410	123,000	126,000	4,110	28,000	32,100	0.27
25^{th}	4,590	134,000	139,000	9,640	39,600	49,300	0.35
50^{th}	5,810	144,000	150,000	17,900	61,000	78,900	0.5
75^{th}	7,170	166,000	173,000	24,500	90,500	115,000	0.63
90^{th}	9,140	181,000	190,000	41,400	126,000	167,000	0.88

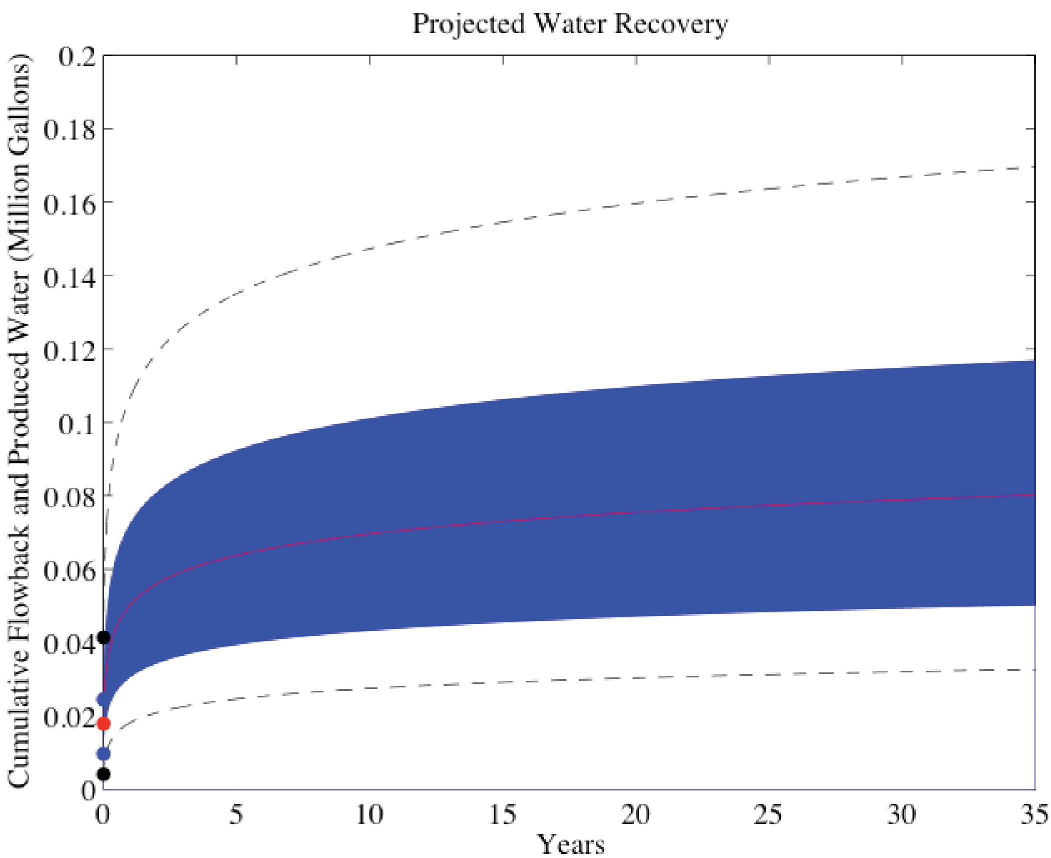


Figure A.1: The cumulative flowback and produced water volumes per stage are shown. The 10th and 90th percentiles are represented with black dashed lines, the 25th and 75th percentiles are represented with blue and the 50th percentile is represented with a red line.

Table A.2: The water use (drilling and hydraulic fracturing water volumes), the water returned (flowback and produced water volumes) and the maximum water reuse potential (ratio of water use and water recovered).

Percentile	Drilling Water Use	Hydraulic Fracturing Water Use	Total Water Use	Flowback Water	Estimated 30-Year Produced Water	Estimated Total Water Recovered	Reuse Potential		
	0 hours	2 hours	4 hours	6 hours	8 hours	10 hours	12 hours	14 hours	16 hours
TDS	1200	9250	12677	12969	13385	13040	14621	13157	13166
TSS	314	203	189	117	106	46	88	120	551
COD	240	1470	600	800	760	360	940	2200	840
TOC	361	2903	2430	2373	2397	2391	2452	2512	2934
pH	7.26	6.76	7.06	6.88	6.96	7.03	7.06	7.05	7.08
alkalinity	325	935	1118	1200	1179	1179	1118	813	1281
Aluminum	0.858	0.96	1.17	1.07	0.97	0.917	1.01	1.06	1.12
Barium	0.097	1.85	3.46	3.53	3.44	3.59	3.54	3.79	3.72
Boron	2.82	13.5	15.1	13.5	16.9	16.4	14	18.4	18.2
Calcium	185	95.7	95.7	105	102	106	101	110	111
Iron	10.3	56.8	57.6	56.5	56.1	53.1	48.3	54.5	53.7
Magnesium	42.1	19.1	16.3	16.4	18.1	17.7	16.3	18.6	18.3
Potassium	27.7	129	93.2	99.1	103	103	99.1	107	105
Sodium	179	2971	4463	4615	4787	4652	4774	4762	4706
Stronitium	1.94	9.67	13.6	13.5	14.4	14.6	13.8	15.2	15.4
Chloride	89.9	4200	6480	6630	6870	6600	6960	6720	6790
Sulfate	361	629	127	141	179	191	1278	186	190
Bicarbonate	288	1070	1240	1210	1170	1220	1250	1090	1080
Silicon	10.6	39	45.7	45.1	47.7	48.7	45.4	51.4	51.5
Zirconium	0.433	14.9	25.1	19.7	16.2	13.2	16.9	19.2	21.7

Table A.3: The water use (drilling and hydraulic fracturing water volumes), the water returned (flowback and produced water volumes) and the maximum water reuse potential (ratio of water use and water recovered).

Percentile	Drilling Water Use	Hydraulic Fracturing Water Use	Total Water Use	Flowback Water	Estimated 30-Year Produced Water	Estimated Total Water Recovered	Reuse Potential		
	18 hours	20 hours	22 hours	1 day	1 day 6 hours	1 day 12 hours	1 day 18 hours	2 day	2 day 6 hours
TDS	12823	12404	13469	11933	13379	13731	9937	11562	13809
TSS	349	12	391	210	4971	9054	6670	20	528
COD	610	920	470	905	2325	6140	8800	250	1380
TOC	1955	2539	2448	2833	2454	2985	2515	2416	2453
pH	7.03	7.05	7.06	7.1	7.44	7.47	7.41	7.59	7.38
alkalinity	1240	1281	1118	1179	1220	1220	1261	1200	1220
Aluminum	1.17	1.16	1.21	1.62	1.18	1.34	4.01	1.31	1.25
Barium	3.58	3.72	3.77	4.16	3.34	3.54	3.26	4.13	3.92
Boron	17.5	17.5	19	12.8	15.4	18.4	9.58	11.4	19.3
Calcium	105	106	111	102	104	107	117	100	117
Iron	50.4	53.6	56.3	50.7	39.6	31.3	31	27.6	37.1
Magnesium	17.9	17.9	18.8	16.5	16.7	18.3	15.3	16.4	19.5
Potassium	102	102	105	171	95.6	98.6	88.8	177	102
Sodium	4616	4371	4804	4183	4831	4896	3253	4026	5039
Stronitium	14.7	15.1	15.9	14.7	14.5	15.4	13.8	15.5	16.9
Chloride	6510	6360	6930	6300	6980	7170	5100	6120	7220
Sulfate	111	90.6	154	117	106	130	293	103	103
Bicarbonate	1200	1190	1170	960	1100	1160	1008	960	1050
Silicon	49.2	50.1	53.7		46.2	49.2			53.5
Zirconium	24.8	25.1	26.6		25.3	31.8			26.1

Table A.4: The water use (drilling and hydraulic fracturing water volumes), the water returned (flowback and produced water volumes) and the maximum water reuse potential (ratio of water use and water recovered).

Percentile	Drilling Water Use	Hydraulic Fracturing Water Use	Total Water Use	Flowback Water	Estimated 30-Year Produced Water	Estimated Total Water Recovered	Reuse Potential		
	2 day 12 hours	2 day 18 hours	3 day	3 days 12 hours	4 day	4 days 12 hours	5 day	5 days 12 hours	6 days 12 hours
TDS	15392	11970	12257	12840	12816	12575	12989	13104	13733
TSS	1348	3834	760	1590	1480	250	1170	310	1550
COD	5540	12180	10025	11775	660	2370	4610	7030	2215
TOC	2203	3450	2672	2417	2236	2638	2432	2252	2319
pH	7.53	7.63	7.31	7.31	7.37	7.49	7.33	7.56	7.61
alkalinity	1179	1322	1118	1078	1078	1159	1159	1220	1159
Aluminum	1.1	3.2	1.33	1.4	1.53	1.11	1.17	1	1.44
Barium	3.71	2.82	4.28	4.23	4.63	3.93	4.55	4.17	4.59
Boron	15.3	14.6	11.5	11.1	13.3	11.4	14.5	11.9	12.3
Calcium	111	127	101	104	114	104	112	114	121
Iron	32.4	42.5	27.5	27.7	31.4	16	35.5	16	22.4
Magnesium	18	16.9	17	17.4	18.4	17.4	18.9	19	19.6
Potassium	103	34	175	179	184	176	170	188	190
Sodium	5554	4158	4216	4506	4377	4360	4513	4616	4929
Stronitium	15.6	14.5	16.2	16.2	17.1	16.4	17.3	17.4	18.1
Chloride	8040	6020	6650	7020	6960	6840	7020	7080	7380
Sulfate	103	226	104	88.2	99.1	57.1	97.6	101	62.9
Bicarbonate	1320	1210	933	865	996	972	984	936	972
Silicon	49.5	47.1							
Zirconium	24.9	53.1							

Table A.5: The water use (drilling and hydraulic fracturing water volumes), the water returned (flowback and produced water volumes) and the maximum water reuse potential (ratio of water use and water recovered).

Percentile	Drilling Water Use	Hydraulic Fracturing Water Use	Total Water Use	Flowback Water	Estimated 30-Year Produced Water	Estimated Total Water Recovered	Reuse Potential
	8 days 4 hours	9 days 12 hours	10 days 12 hours	11 days 12 hours	3 days 12 hours	20 days 12 hours	
TDS	15339	17276	16820	16710	17553	19427	
TSS	1103	11987	29497	9500	97	760	
COD	5480	4000	7410	5120	1170	1040	
TOC	2215	1930	1335	2416	1864	1727	
pH	7.56	7.65	7.47	6.53	6.06	6.78	
alkalinity	1057	1078	1139				
Aluminum	0.881	0.783	0.911	0.904	0.89	0.935	
Barium	4.1	3.91	4.26	4.61	4.98	6.4	
Boron	16	16.7	17.7	17.8	19	18	
Calcium	133	132	141	144	144	184	
Iron	21.4	20.4	28.1	45.7	60.6	72.5	
Magnesium	21.8	22.4	23.3	24	25	29.7	
Potassium		105	102	103	107	116	
Sodium	5721	6458	6273	6280	6507	7351	
Stronitium	19	19.9	20.9	21.8	22.6	26.7	
Chloride	8250	9360	9120	9070	9600	10820	
Sulfate	44.2	31.1	43.6	49.6	30.1	6.2	
Bicarbonate	1050	1060	990	890	970	738	
Silicon	44.3	37.1	42.8	48.3	50.9	49.5	
Zirconium	13.8	8.77	12.1	10	11	8.15	

Appendix B: Decline Curve Analysis

The Arps Equation used for the decline curves is shown below:

$$q(t) = \frac{q_i}{(1+D_i t)^{1/b}} \quad \text{where} \qquad \text{Eq-5}$$

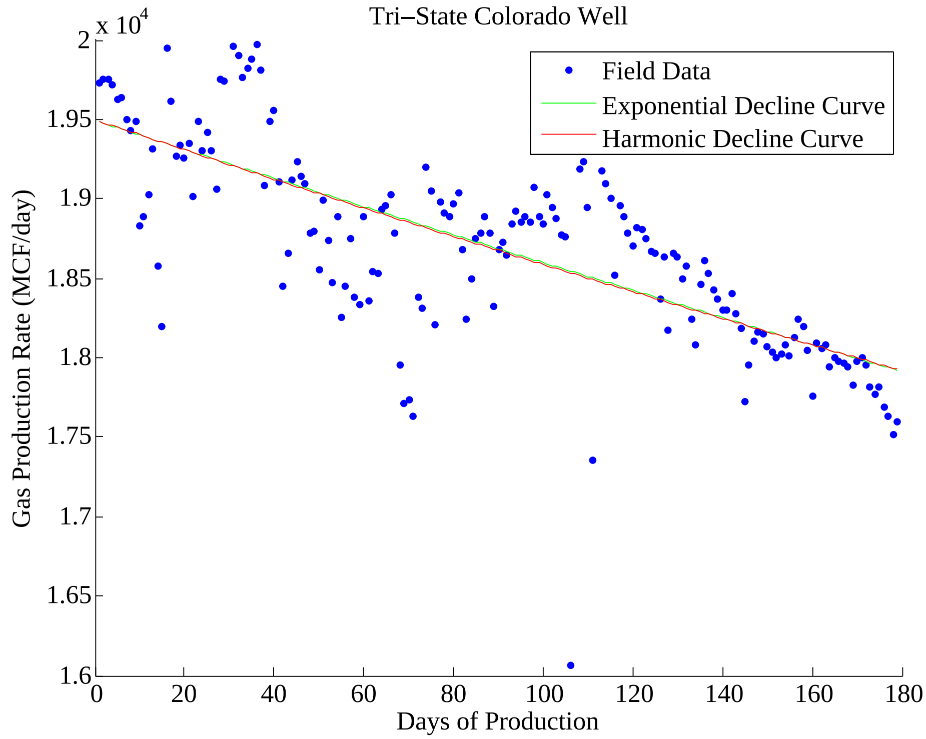
q(t) = Future production rate
qi = Initial production rate
Di = Initial decline rate
t = Time
b = Degree of curvature

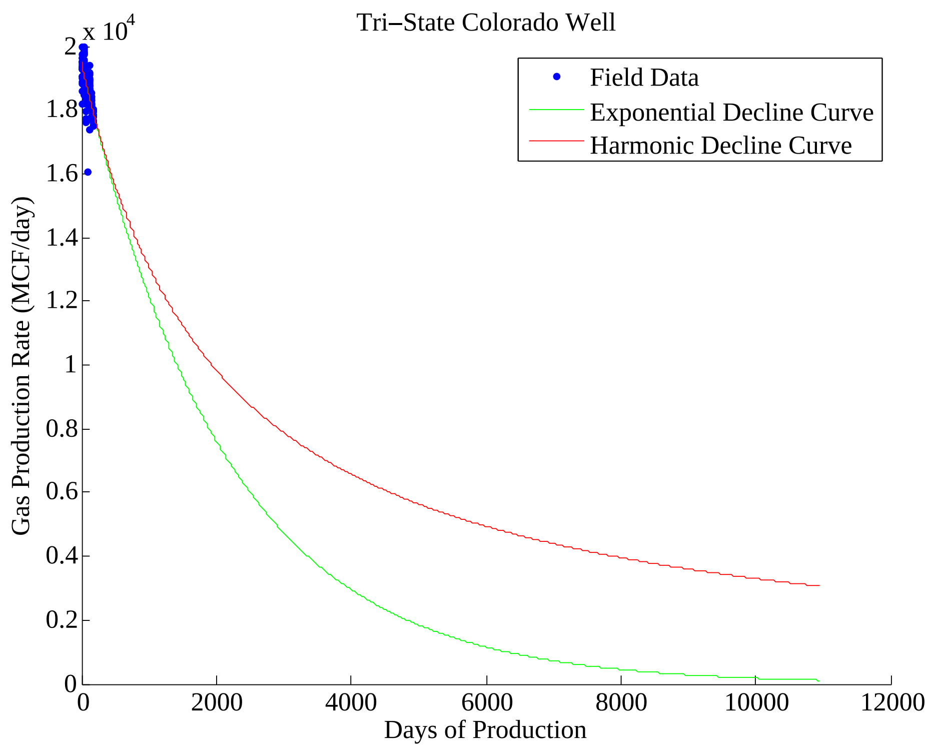
When b = 0 ⇒ $q(t) = q_i e^{D_i t}$ (Exponential Decline Curve) (Low Production Scenario) Eq-6

When b = 1 ⇒ $q(t) = \frac{q_i}{1+D_i t}$ (Harmonic Decline Curve) (High Production Scenario) Eq-7

A least-squares method was used to generate the decline curves for each well. The MATLAB code used to generate, plot and integrate the decline curves is shown:

```
clear
close all
clc

clear
close all
clc

%Oil Gas and Water Production


X=1:length(Y);
x=X';

%z=z';

%Least squares method to estimate exponential decay
%Y is an array of the oil or gas production each day
%x is an array of the number of days since the well was first productive.

%Plots actual data
hold on
plot(x,Y,'.')
xlabel('Days of Production')
ylabel('Gas Production Rate (MCF/day)')
title('Tri-State Colorado Well')

% %Plots exponential decline curve
z=log(Y);

a0=(sum(x.^2)*sum(z)-x'*z*sum(x))/(length(x)*sum(x.^2)-sum(x)^2);
a1=(length(x)*x'*z-sum(x)*sum(z))/(length(x)*sum(x.^2)-sum(x)^2);

b=exp(a0);
a=a1;
x=1:10950;
x=x';
pe=b*exp(a*x);
plot(x,pe,'green')

X=1:length(Y);
x=X';

%Plots projected harmonic decline curve
z=1./(Y);

a0=(sum(x.^2)*sum(z)-x'*z*sum(x))/(length(x)*sum(x.^2)-sum(x)^2);
a1=(length(x)*x'*z-sum(x)*sum(z))/(length(x)*sum(x.^2)-sum(x)^2);

b=1/a0;
a=a1/a0;
x=1:10950;
x=x';
ph=b./(1+a*x);
plot(x,ph,'red')
legend('Field Data','Exponential Decline Curve','Harmonic Decline Curve')
%
% %Uses trapezoidal integration to estimate ultiamate recovery
EUR_exp=trapz(x,pe)
%BOE_exp=EUR_exp*10^3/6000

EUR_har=trapz(x,ph)
%BOE_har=EUR_har*10^3/6000
```


Tri−State Colorado Well
x 10^4
Field Data
Exponential Decline Curve
Harmonic Decline Curve
Gas Production Rate (MCF/day)
Days of Production
2
1.95
1.9
1.85
1.8
1.75
1.7
1.65
1.6
0
20
40
60
80
100
120
140
160
180


Tri−State Colorado Well
x 10^4
Field Data
Exponential Decline Curve
Harmonic Decline Curve
Gas Production Rate (MCF/day)
Days of Production
2
1.8
1.6
1.4
1.2
1
0.8
0.6
0.4
0.2
0
0
2000
4000
6000
8000
10000
12000

Appendix C: Coal Water Intensity

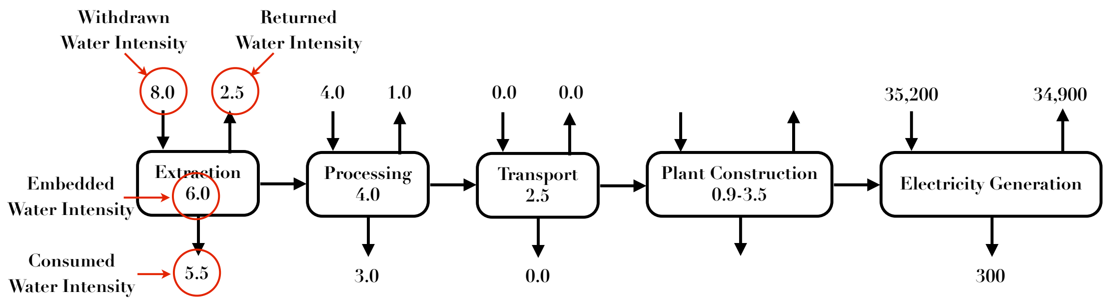


Figure C.1: Water intensity associated with each stage of electricity generation from coal.

Table C.1: Consumptive water intensity of coal extraction

Coal Extraction	Consumptive Water Intensity (gal/MMBtu)	Source
Reclamation	0.014	[61]
Dust Suppression	0.46	[61]
Underground Appalachian Mining	1	[68, 20]
Surface Mining: Low	1	[67, 128, 65]
Western Surface Mining	2	[68, 20]
Surface Mining: Average	2	[67, 128, 65]
Underground Mining: Low	1	[67, 128, 65]
U.S. Mining Weighted Average	2	[68, 20]
Surface Mining: High	4	[67, 128, 65]
Underground Mining: Average	9	[67, 128, 65]
Underground Mining: High	16	[67, 128, 65]

Table C.2: Withdrawn water intensity of coal extraction

Coal Extraction	Withdrawn Water Intensity (gal/MMBtu)	Source
Eastern Surface Mining	3	[67, 128]
U.S. Coal Mining	8	[67, 65, 126]
Eastern Underground Mining	15	[67, 128]

Table C.3: Embedded water intensity of coal extraction

Coal Extraction	Embedded Water Intensity (gal/MMBtu)	Source
Western Surface Mining	1	[67]
Eastern Surface Mining	11	[67]
Eastern Underground Mining	39	[67]

Table C.4: Consumptive water intensity of coal processing

Coal Processing	Consumptive Water Intensity (gal/MMBtu)	Source
Coal Preparation	0.26	[61]
Washing: Low	2.3	[67, 73]
Benefication: Low	3.3	[67, 128]
Benefication: Average	3.4	[67, 128]
Benefication: High	3.5	[67, 128]
Washing: Average	3.6	[67, 128]
Washing: High	5.0	[67, 128]
Coal Gasification or Liquefacation	10	[61]
Synfuel Coal Gasification: Low	11	[9, 68]
Synfuel Coal Gasification: Average	19	[9, 68]
Synfuel Coal Gasification: High	26	[9, 68]
Coal-to-Liquids:Low	41	[9, 68]
Coal-to-Liquids:Average	51	[9, 68]
Coal-to-Liquids: High	60	[9, 68]

Table C.5: Withdrawn water intensity of coal processing

Coal Processing	Withdrawn Water Intensity (gal/MMBtu)	Source
Benefication	>3.5	[67, 128]

Table C.6: Embedded water intensity of coal processing

Coal Processing	Embedded Water Intensity (gal/MMBtu)	Source
Benefication	4.1	[67]

Table C.7: Consumptive water intensity of coal transport

Coal Transport	Consumptive Water Intensity (gal/MMBtu)	Source
Slurry Pipeline, 70 Percent Recycling: Low	3.3	[68, 20]
Slurry Pipeline, 70 Percent Recycling: Average	5.5	[68, 20]
Slurry Pipeline, 70 Percent Recycling: High	7.2	[68, 20]
Slurry Pipeline, No Recycling: Low	11	[9, 68, 20]
Slurry Pipeline, No Recycling: Average	18	[9, 68, 20]
Slurry Pipeline, No Recycling: High	24	[9, 68, 20]
Slurry Pipeline: Low	33	[67, 128, 65]
Slurry Pipeline: Average	50	[67, 128, 65]
Slurry Pipeline: High	67	[67, 128, 65]

Table C.8: Withdrawn water intensity of coal transport

Coal Transport	Withdrawn Water Intensity (gal/MMBtu)	Source
Slurry Pipeline	35	[67, 128, 65]

Table C.9: Embedded water intensity of coal transport

Coal Transport	Embedded Water Intensity (gal/MMBtu)	Source
Train: Low	2	[67]
Train: Average	2.5	[67]
Train: High	3	[67]
Slurry Pipeline	240	[67]

Table C.10: Embedded water intensity of coal-fired power plant construction

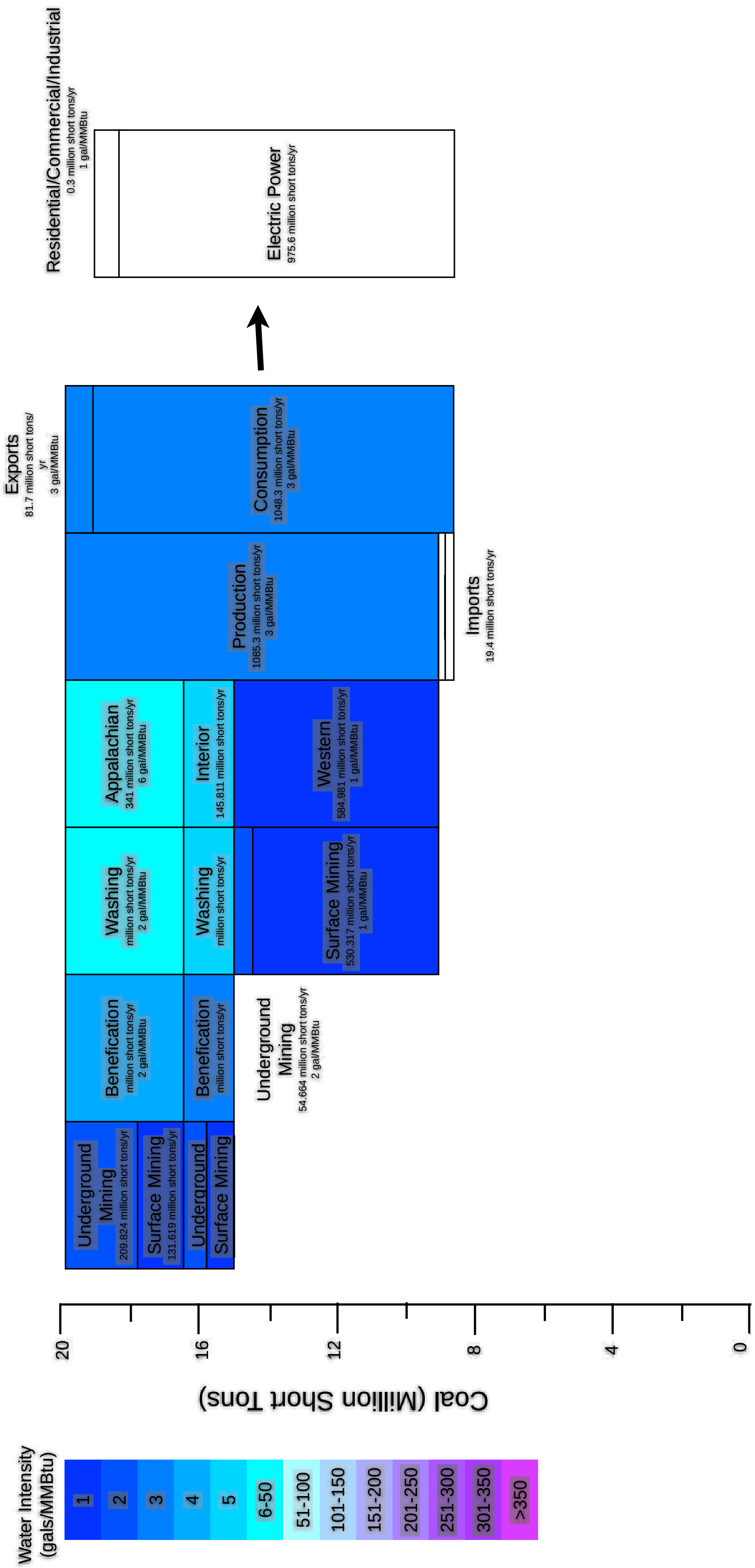
Coal Plant Construction	Embedded Water Intensity (gal/MMBtu)	Source
Low	0.9	[67]
Average	2.2	[67]
High	3.5	[67]

Table C.11: Consumptive water intensity of coal-fired power plant electricity generation

Coal Electricity Generation	Consumptive Water Intensity (gal/MWh)	Source
Dry: Low	0	[68, 81, 20]
Dry: Average	15	[68, 81, 20]
Dry: High	30	[68, 81, 20]
Cooling Pond, Supercritical	64	[67, 72]
Once-Through, Supercritical	120	[67, 72]
Once-Through, Subcritical	140	[67, 72]
Once-Through, Fluidized Bed	250	[67, 72]
Wet Tower, Supercritical	250	[67, 65]
Cooling Pond: Low	260	[67, 72]
Once-Through: Low	300	[68, 81, 20]
Closed-Loop: Low	300	[68, 81, 20]
Once-Through: Low	300	[67, 119]
Once-Through: Average	300	[67, 119]
Once-Through: High	300	[67, 119]
Once-Through: Average	315	[68, 81, 20, 82, 9, 129]
Once-Through	320	[67, 65]
Once-Through: High	330	[68, 81, 20]
Wet Tower, Retrofitted with Carbon Capture	340	[67, 130]
Cooling Pond: Average	380	[67, 119]
Closed-Loop: Average	405	[68, 81, 20, 82, 9, 129]
Closed-Loop with Carbon Capture	420	[82, 9]
Wet Tower: Low	450	[67, 119]
Wet Tower, Subcritical	460	[67, 72]
Wet Tower: Average	480	[67, 119]
Cooling Pond: High	500	[67, 119]
Wet Tower: High	500	[67, 119]
Wet Tower, Western U.S.	500	[67, 128]
Closed-Loop: High	510	[68, 81, 20]
Wet Tower, Supercritical	600	[67, 131]
Wet Tower, Subcritical	680	[67, 131]
Wet Tower, Eastern U.S.	740	[67, 128]
Cooling Pond, Subcritical	800	[67, 72]
Wet Tower	820	[67, 65]
Wet Tower, Supercritical	1000	[67, 132]
Wet Tower, Subcritical	1200	[67, 132]
Wet Tower, Supercritical with Carbon Capture	1200	[67, 131]
Wet Tower, Subcritical with Carbon Capture	1330	[67, 131]

Table C.12: Withdrawn water intensity of coal-fired power plant electricity generation

Coal Electricity Generation	Withdrawn Water Intensity (gal/MWh)	Source
Dry: Average	30	[68, 81, 20]
Dry: High	30	[68, 81, 20]
Dry: Low	30	[68, 81, 20]
Wet Tower, Subcritical	230	[67, 72]
Cooling Pond: Low	290	[67, 119]
Closed-Loop: Low	330	[68, 81, 20]
Cooling Pond: Average	450	[67, 119]
Closed-Loop: Average	480	[68, 81, 20, 82, 9, 129]
Wet Tower: Low	5000	[67, 119]
Wet Tower: Average	5600	[67, 119]
Closed-Loop with Carbon Capture	563	[82, 9]
Wet Tower, Supercritical	600	[67, 131]
Cooling Pond: High	610	[67, 131]
Wet Tower: High	610	[67, 131]
Closed-Loop: High	630	[68, 81, 20]
Wet Tower, Supercritical	660	[67, 72]
Wet Tower, Subcritical	690	[67, 131]
Wet Tower, Supercritical	1000	[67, 132]
Wet Tower, Subcritical	1200	[67, 132]
Wet Tower, Supercritical with Carbon Capture	1300	[67, 131]
Wet Tower, Subcritical with Carbon Capture	1500	[67, 131]
Wet Tower, Retrofitted with Carbon Capture	9500	[67, 130]
Cooling Pond, Supercritical	15100	[67, 72]
Cooling Pond, Subcritical	17900	[67, 72]
Once-Through: Low	20030	[68, 81, 20]
Once-Through: Low	20100	[67, 119]
Once-Through, Supercritical	22700	[67, 72]
Once-Through, Subcritical	27300	[67, 72]
Once-Through: Average	35030	[68, 81, 20, 82, 9, 129]
Once-Through: Average	35200	[67, 119]
Once-Through: High	50030	[68, 81, 20]
Once-Through: High	50300	[67, 119]


Residential/Commercial/Industrial
0.3 million short tons/yr
1 gal/MMBtu
Electric Power
975.6 million short tons/yr
Exports
81.7 million short tons/yr
3 gal/MMBtu
Consumption
1048.3 million short tons/yr
3 gal/MMBtu
Production
1085.3 million short tons/yr
3 gal/MMBtu
Imports
19.4 million short tons/yr
Appalachian
341 million short tons/yr
6 gal/MMBtu
Interior
145.811 million short tons/yr
Western
584.981 million short tons/yr
1 gal/MMBtu
Washing
million short tons/yr
2 gal/MMBtu
Washing
million short tons/yr
Surface Mining
530.317 million short tons/yr
1 gal/MMBtu
Benefication
million short tons/yr
2 gal/MMBtu
Benefication
million short tons/yr
Underground Mining
54.664 million short tons/yr
2 gal/MMBtu
Underground Mining
209.824 million short tons/yr
Surface Mining
131.619 million short tons/yr
Underground
Surface Mining
Coal (Million Short Tons)
20
16
12
8
4
0
Water Intensity (gals/MMBtu)
1
2
3
4
5
6-50
51-100
101-150
151-200
201-250
251-300
301-350
>350

Appendix D: Oil Water Intensity

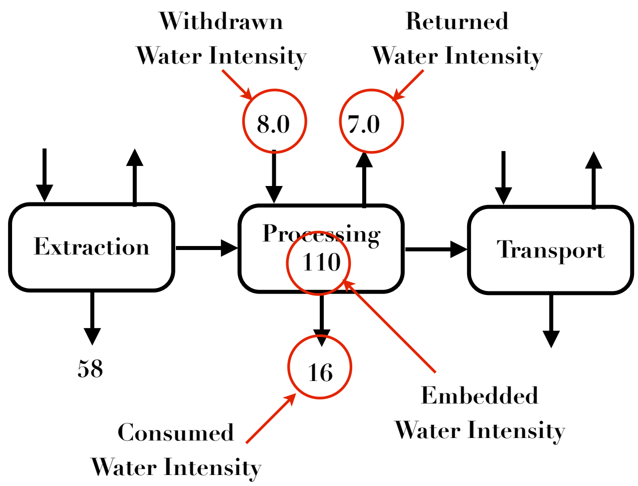


Figure D.1: Water intensity associated with each stage of crude oil production.

Table D.1: Consumptive water intensity of oil extraction

Oil Extraction	Consumptive Water Intensity (gal/MMBtu)	Source
Primary	1.4	[116, 20]
Primary	1.5	[65]
PADD II	2	[116]
PADD III	2.2	[116]
Steam-Assisted Gravity Drainage	2.2	[116, 20]
Steam Stimulation	2.5	[115]
Steam Drive	5	[115]
PADD V	5.1	[116]
In-Situ Comustion	5.5	[115]
Oil Sands: Low	7	[116]

Oil Extraction	Consumptive Water Intensity (gal/MMBtu)	Source
Upgrading to Syncrude	7.2	[116, 20]
Oil Shale: Low	7.96	[133]
Conventional: Low	8	[9, 68]
PADD I	8	[134]
PADD IV	8	[134]
Cyclic Steam Stimulation	8.7	[116, 20]
SAGD with Upgrade	9.4	[116, 20]
Saudi Arabia: Low	10	[116, 20]
Saudi Arabia: Ghawar Field	10	[116, 135]
Micellar Polymer Injection	11	[115]
CO2 Miscible Flooding	13	[115]
Oil Shale: Average	13.61	[133]
Conventional: Average	14	[9, 68]
Forward Combustion/Air Injection	14	[116, 20, 65]
Oil Sands: Low	14	[116, 20]
CSS with Upgrade	164	[116, 20]
Bitumen Oil Sands via Surface Mining	16	[136, 116]
Oil Shale: High	19.25	[133]
Conventional: High	20	[9, 68]
Oil Sands: Average	20	[116]
Enhanced Oil Recovery: Low	21	[9, 68]
Saudi Arabia: Average	22	[116]
Oil Shale: Low	22	[9]
Oil Sands: Average	24	[116, 20]
Oil Sands: Low	27	[9]
Caustic Injection	28	[116, 20]
Surface Mining (Athabasca)	28	[116]
Bitumen Oil Sands via Surface Mining	29	[137, 116]
Upgrading	29	[137, 116]
Caustic Flooding	30	[115]
CO2 Injection	31	[116, 65]
Saudi Arabia: High	33	[116, 20]
Saudi Arabia: North 'Ain Dar Field, 2005	33	[116]
Oil Sands: High	33	[116, 20]
Oil Sands: High	34	[116]
Bitumen Oil Sands via Surface Mining	35	[116, 65]
CSS (Cold Lake)	35	[116]
Steam Injection	39	[116, 20]
Oil Shale: Average	39	[9]
Polymer Assisted Water Flooding	40	[115]
Saudi Arabia: North 'Ain Dar Field, 1999	43	[116]

Oil Extraction	Consumptive Water Intensity (gal/MMBtu)	Source
Multi-Scheme (Peace River)	47	[116]
Oil Sands: Average	48	[138, 116, 20]
Oil Shale: High	56	[9]
2005 U.S. On-Shore Average Recovery	58	[116]
Secondary Conventional	62	[116, 20]
Enhanced Oil Recovery	62	[116]
Other	63	[116, 20]
Oil Sands: High	68	[138, 20, 115]
CO2 Injection	94	[116, 20, 115]
SAGD (Athabasca)	155	[116]
CO2 Injection	178	[115]
Micellar Polymer Injection	2485	[116, 20]
Enhanced Oil Recovery: High	2500	[9, 68]

Table D.2: Consumptive water intensity of oil processing

Oil Processing	Consumptive Water Intensity (gal/MMBtu)	Source
U.S. Refineries: Low	7.2	[116, 20, 65]
U.S. Refineries: Average	10	[116, 20]
U.S. Refineries: High	13	[116, 20]
Oil Shale Petroleum: Low	22	[9]
Oil Sands: Low	27	[9]
Oil Shale Petroleum: Average	39	[9]
Oil Sands: Average	48	[9]
Oil Shale Petroleum: High	56	[9]
Oil Sands: High	68	[9]

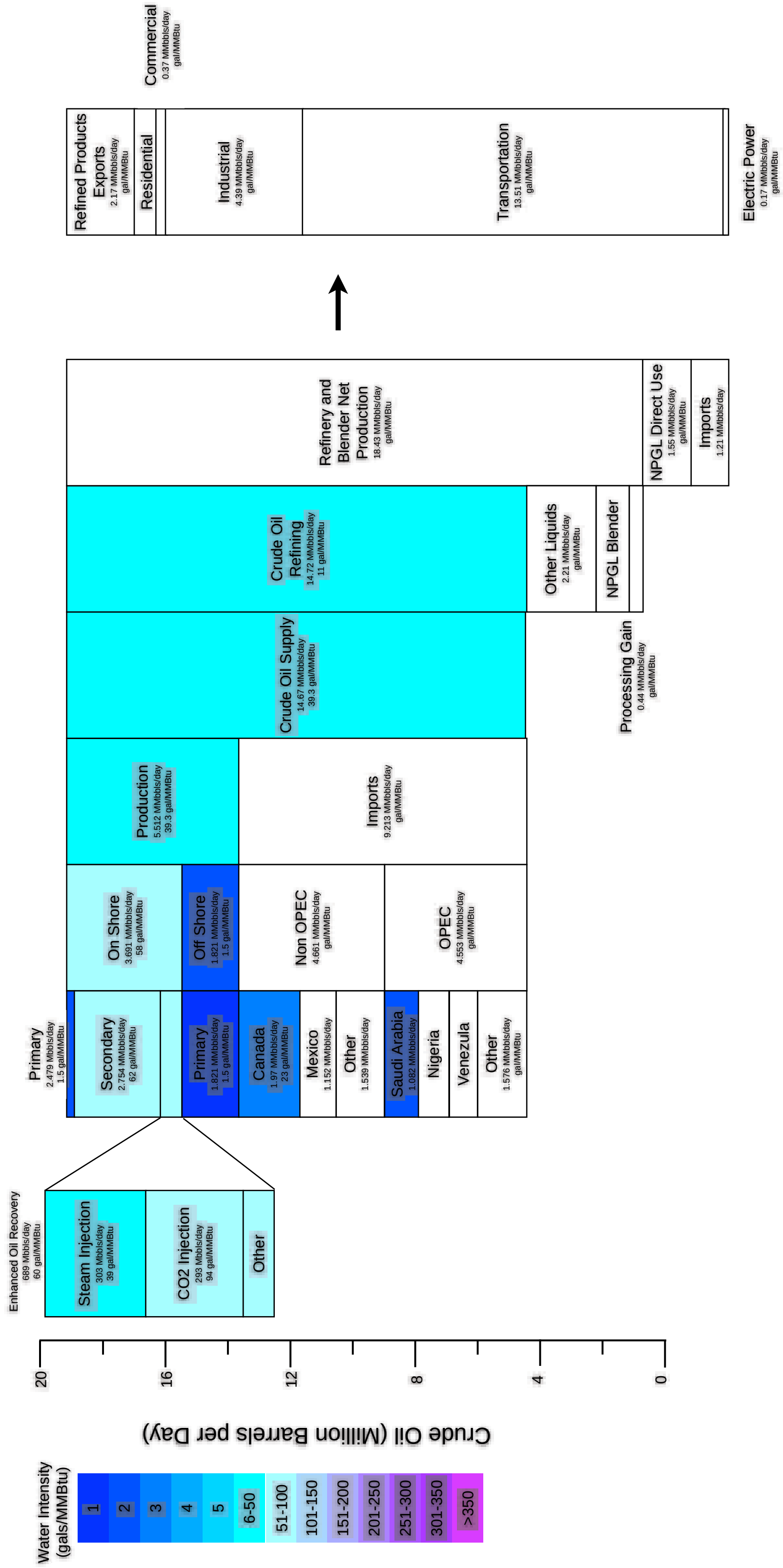


Figure D.2: Water intensity and U.S. consumption associated with each stage of U.S. crude oil production.

Appendix E: Natural Gas Water Intensity

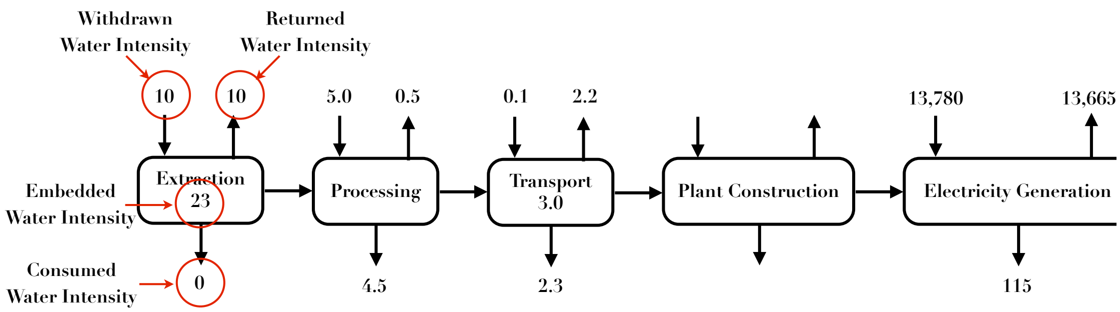


Figure E.1: Water intensity associated with each stage of electricity generation from conventional natural gas.

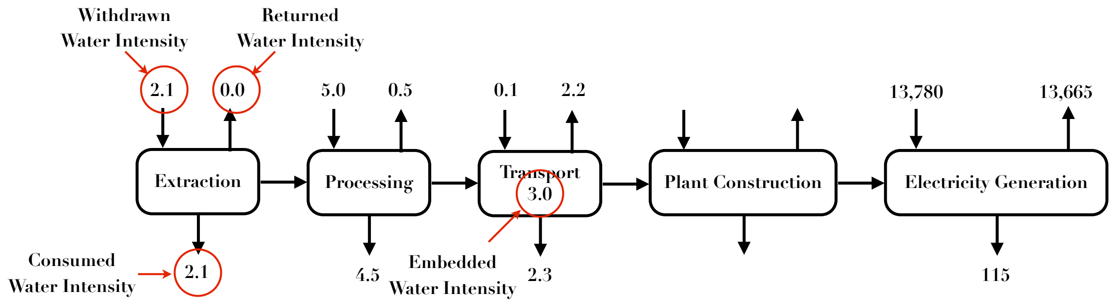


Figure E.2: Water intensity associated with each stage of electricity generation from shale natural gas.

Table E.1: Consumptive water intensity of natural gas extraction

Gas Extraction	Consumptive Water Intensity (gal/MMBtu)	Source
Conventional	0	[68, 20]
On-Shore	0	[67]
Off-Shore	0	[67]
Shale Gas: Low	0.6	[20]
Typical Minimum	0.6	[9, 20]
Haynesville	0.8	[9, 20]
Shale Gas: Low	0.84	[9]
Conventional: Low	1	[9]
Marcellus	1.2	[20]
Barnett, Vertical Wells	1.2	[20]
Marcellus	1.3	[9, 20]
Typical Maximum	1.3	[9, 20]
Barnett	1.5	[9, 20]
Fayetteville	1.7	[9, 20]
Typical Average	1.8	[9, 20]
Conventional: Average	2	[9]
Shale Gas: Average	2.08	[9]
Shale Gas: Average	2.2	[20]
Shale Gas: High	2.4	[20]
Conventional: High	3	[9]
Barnett, Horizontal Wells	3.1	[20]
Shale Gas: High	3.32	[9]

Table E.2: Withdrawn water intensity of natural gas extraction

Gas Extraction	Withdrawn Water Intensity (gal/MMBtu)	Source
On-Shore	10	[67]
Off-Shore	0	[67]

Table E.3: Embedded water intensity of natural gas extraction

Gas Extraction	Embedded Water Intensity (gal/MMBtu)	Source
On-Shore	23	[67]
Off-Shore	0	[67]

Table E.4: Consumptive water intensity of natural gas processing

Gas Processing	Consumptive Water Intensity (gal/MMBtu)	Source
Processing and Transport: Low	0	[9, 20]
Processing and Transport: Average	1	[9, 20]
Processing and Transport	2	[65, 20]
Processing and Transport: High	2	[9, 20]
Gas-to-Liquids: Low	19	[139, 20]
Gas-to-Liquids: Average	42	[139, 20]
Gas-to-Liquids: High	86	[139, 20]

Table E.5: Consumptive water intensity of natural gas transport

Gas Transport	Consumptive Water Intensity (gal/MMBtu)	Source
Transport: Low	0	[9]
Transport: Average	1	[9]
Transport: High	2	[9]
Pipeline	2.3	[67]

Table E.6: Withdrawn water intensity of natural gas transport

Gas Transport	Withdrawn Water Intensity (gal/MMBtu)	Source
Pipeline	0.1	[67]

Table E.7: Embedded water intensity of natural gas transport

Gas Transport	Embedded Water Intensity (gal/MMBtu)	Source
Pipeline	3	[67]

Table E.8: Consumptive water intensity of natural gas power plant electricity generation.

Gas Electricity Generation	Consumptive Water Intensity (gal/MWh)	Source
Dry: Low	0	[68, 81, 20]
Combined-Cycle Gas Dry: Low	0	[68, 81, 20]
Dry: Average	15	[68, 81, 20]
Combined-Cycle Gas Dry: Average	15	[68, 81, 20]
Combined-Cycle Once-Through	20	[67, 72]
Dry: High	30	[68, 81, 20]
Combined-Cycle Gas Dry: High	30	[68, 81, 20]
Once-Through	90	[67, 72]
Combined-Cycle Gas Once-Through: Low	100	[67, 72]
Combined-Cycle Gas Once-Through: Low	100	[67, 131]
Combined-Cycle Gas Once-Through: Average	100	[67, 131]
Combined-Cycle Gas Once-Through: High	100	[67, 131]
Cooling Pond	110	[67, 72]
Combined-Cycle Gas Once-Through: Average	115	[67, 72]
Combined-Cycle Gas Once-Through: High	130	[67, 72]
Combined-Cycle Wet Tower	130	[67, 72]
Wet Tower	160	[67, 72]
Combined-Cycle Gas Closed-Loop: Low	180	[67, 72]
Combined-Cycle Wet Tower	180	[67, 131]
Combined-Cycle Gas Closed-Loop with Carbon Capture	190	[67, **?**]
Combined-Cycle Gas Closed-Loop: Average	195	[67, 131]
Combined-Cycle Gas Closed-Loop: High	210	[67, 131]
Combined-Cycle Gas Cooling Pond	240	[67, 72]
Once-Throug	250	[67, 128]
Combined-Cycle Wet Tower	270	[67, 131]
Once-Through	290	[67, 65]
Once-Through: Low	300	[68, 81, 20]
Closed-Loop: Low	300	[68, 81, 20]
Once-Through: Average	315	[68, 81, 20, 82, 9]
Once-Through: High	330	[68, 81, 20]
Closed-Loop: Average	405	[68, 81, 20, 82, 9]
Closed-Loop with Carbon Capture	420	[82]
Combined-Cycle Wet Tower	500	[67, 132]
Combined-Cycle Wet Tower with Carbon Capture	500	[67, 131]
Closed-Loop: High	510	[68, 81, 20]
Wet Tower	820	[67, 65]

Gas Electricity Generation	Consumptive Water Intensity (gal/MWh)	Source
Dry: Low	30	[68, 81, 20]
Dry: Average	30	[68, 81, 20]
Dry: High	30	[68, 81, 20]
Combined-Cycle Gas Dry: Low	30	[68, 81, 20]
Combined-Cycle Gas Dry: Average	30	[68, 81, 20]
Combined-Cycle Gas Dry: High	30	[68, 81, 20]
Combined-Cycle Wet Tower	150	[67, 72]
Combined-Cycle Gas Closed-Loop with Carbon Capture	217	[67, 131]
Combined-Cycle Wet Tower	230	[67, 131]
Wet Tower	250	[67, 72]
Combined-Cycle Gas Closed-Loop: Low	260	[67, 131]
Combined-Cycle Gas Closed-Loop: Average	260	[67, 131]
Combined-Cycle Gas Closed-Loop: High	260	[67, 131]
Combined-Cycle Wet Tower	270	[67, 131]
Closed-Loop: Low	330	[68, 81, 20]
Closed-Loop: Average	480	[68, 81, 20, 82, 9]
Combined-Cycle Wet Tower	500	[67, 132]
Combined-Cycle Wet Tower with Carbon Capture	560	[67, 131]
Closed-Loop with Carbon Capture	563	[82, **?**]
Closed-Loop: High	630	[68, 81, 20]
Combined-Cycle Gas Once-Through: Low	7400	[67, 131]
Combined-Cycle Gas Once-Through: Low	7530	[67, 72]
Cooling Pond	7900	[67, 72]
Combined-Cycle Once-Through	9020	[67, 72]
Combined-Cycle Gas Once-Through: Average	13780	[67, 72]
Combined-Cycle Gas Once-Through: Average	13800	[67, 131]
Once-Through: Low	20030	[68, 81, 20]
Combined-Cycle Gas Once-Through: High	20030	[67, 72]
Combined-Cycle Gas Once-Through: High	20100	[67, 131]
Once-Through	22700	[67, 72]
Once-Through: Average	35030	[68, 81, 20, 82, 9]
Once-Through: High	50030	[68, 81, 20]

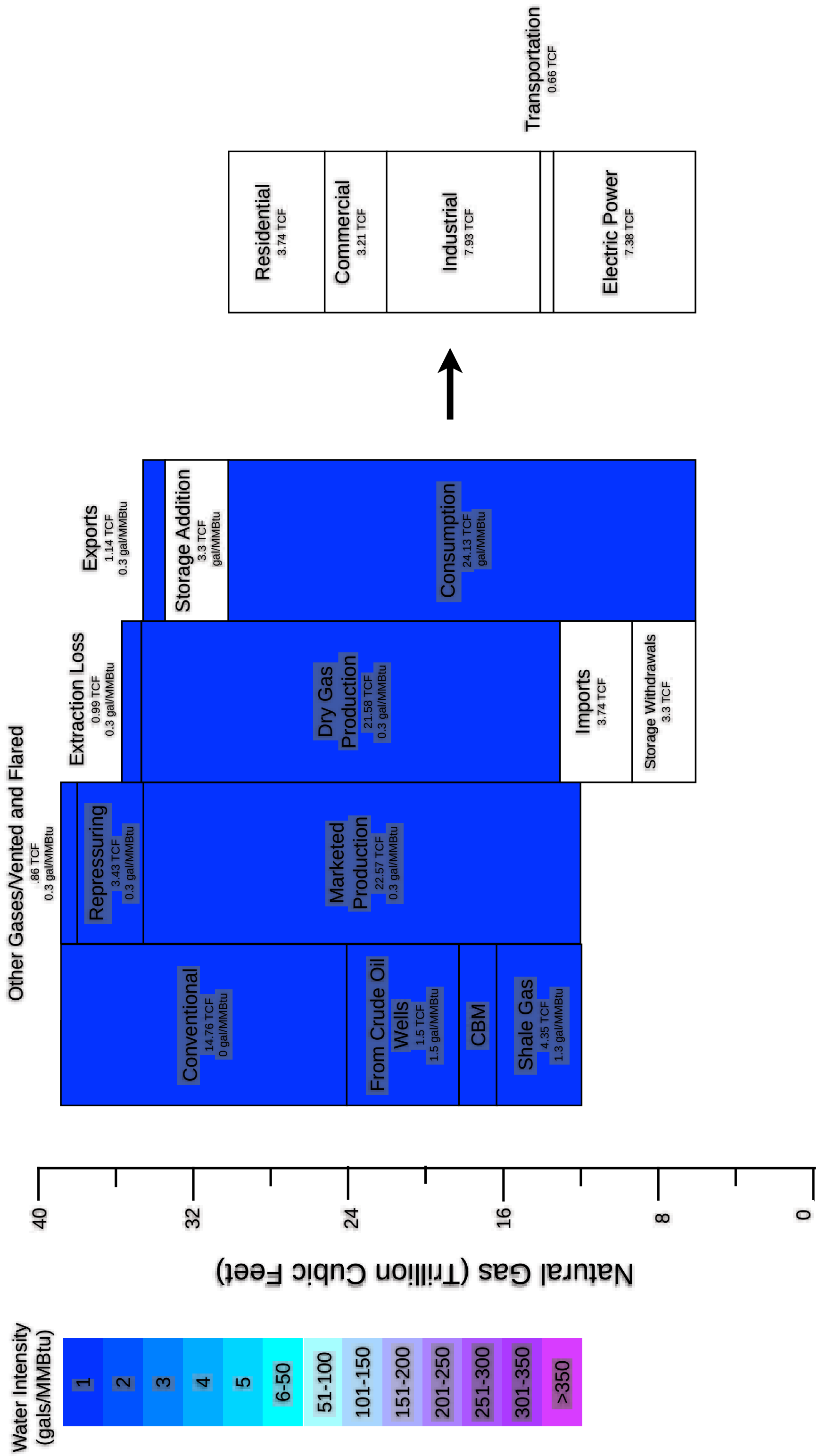


Figure E.3: Water intensity and U.S. consumption of natural gas associated with each stage of electricity generation.

Appendix F: Uranium Water Intensity

Table F.1: Consumptive water intensity of uranium extraction

Uranium Extraction	Consumptive Water Intensity (gal/MMBtu)	Source
Underground Mining	1	[65, 68, 20]
Underground Mining	1	[67, 128]
Surface Mining	6	[65, 68, 20]
Surface Mining	16	[67, 128]

Table F.2: Withdrawn water intensity of uranium extraction

Uranium Extraction	Withdrawn Water Intensity (gal/MMBtu)	Source
Underground Mining	3	[67, 128]
Surface Mining	3	[67, 128]

Table F.3: Embedded water intensity of uranium extraction

Embedded Extraction	Embedded Water Intensity (gal/MMBtu)	Source
Underground Mining	1	[67, 128]
Surface Mining	1	[67, 128]

Table F.4: Consumptive water intensity of uranium processing

Uranium Processing	Consumptive Water Intensity (gal/MMBtu)	Source
Uranium Ore Milling	0	[61]
Enrichment with Centrifuge: Low	0.1	[67, 128]
Fuel Fabrication	0.9	[67, 128]
Enrichment with Centrifuge: Average	1	[67, 128]
Enrichment with Centrifuge: High	1.5	[67, 128]
Conversion	3	[67, 128]
Enrichment with Diffusion: Low	3	[67, 128]
Enrichment with Centrifuge: Low	4	[65, 68, 20]
Enrichment with Centrifuge: Average	5	[65, 68, 20]
Enrichment with Centrifuge: High	5	[65, 68, 20]
Milling: Low	6	[67, 128]
Enrichment with Diffusion: Low	7	[65, 68, 20]
Milling: Average	7	[67, 128]
Enrichment with Diffusion: Average	7	[67, 128]
Enrichment with Diffusion: Average	8	[65, 68, 20]
Enrichment with Diffusion: High	8	[65, 68, 20]
Milling: High	8	[67, 128]
Mining and Processing: Low	8	[67, 128]
Enrichment with Diffusion: High	10	[67, 128]
Mining and Processing: Average	11	[67, 128]
Mining and Processing: High	14	[67, 128]

Table F.5: Withdrawn water intensity of uranium processing

Uranium Processing	Withdrawn Water Intensity (gal/MMBtu)	Source
Spent Fuel Disposal	0	[67]
Fuel Fabrication	0.2	[67, 128]
Enrichment with Centrifuge: Low	1	[67, 128]
Enrichment with Centrifuge: Average	1	[67, 128]
Enrichment with Centrifuge: High	1	[67, 128]
Conversion	1.2	[67, 128]
Milling: Low	1.5	[67, 128]
Milling: Average	1.5	[67, 128]
Milling: High	1.5	[67, 128]
Enrichment with Diffusion: Low	6	[67, 128]
Enrichment with Diffusion: Average	6	[67, 128]
Enrichment with Diffusion: High	6	[67, 128]

Table F.6: Embedded water intensity of uranium processing

Uranium Processing	Embedded Water Intensity (gal/MMBtu)	Source
Fuel Fabrication	0	[67, 128]
Conversion	1	[67, 128]
Spent Fuel Disposal	1.5	[67]
Milling: Low	5	[67, 128]
Milling: Average	5	[67, 128]
Milling: High	5	[67, 128]
Enrichment with Centrifuge: Low	8	[67, 128]
Enrichment with Centrifuge: Average	8	[67, 128]
Enrichment with Centrifuge: High	8	[67, 128]
Enrichment with Diffusion: Low	89	[67, 128]
Enrichment with Diffusion: Average	89	[67, 128]
Enrichment with Diffusion: High	89	[67, 128]

Table F.7: Consumptive water intensity of uranium electricity generation

Electricity Generation	Consumptive Water Intensity (gal/MWh)	Source
Dry: Low	0	[81, 68, 20]
Dry: Average	15	[81, 68, 20]
Dry: High	30	[81, 68, 20]
Wet Tower (HTGR)	60	[67, 65]
Once-Through	140	[67, 72]
Once-Through: Low	400	[81, 68, 20]
Closed-Loop: Low	400	[81, 68, 20]
Once-Through: Low	400	[67, 119]
Once-Through: Average	400	[67, 119]
Once-Through: High	400	[67, 119]
Once-Through: Average	415	[81, 68, 20, 82, 9, 129]
Once-Through: High	430	[81, 68, 20]
Cooling Pond: Low	450	[67, 119]
Closed-Loop: Average	575	[81, 68, 20]
Closed-Loop with Carbon Capture	590	[82, 9]
Wet Tower	610	[67, 72]
Cooling Pond: Average	680	[67, 119]
Wet Tower: Low	740	[67, 119]
Closed-Loop: High	750	[81, 68, 20]
Wet Tower: Average	820	[67, 119]
Wet Tower (PWR)	820	[67, 128]
Wet Tower (LWR)	850	[67, 65]
Cooling Pond: High	900	[67, 119]
Wet Tower: High	900	[67, 119]
Wet Tower (BWR)	900	[67, 128]

Table F.8: Withdrawn water intensity of uranium electricity generation

Electricity Generation	Withdrawn Water Intensity (gal/MWh)	Source
Dry: Low	30	[81, 68, 20]
Dry: Average	30	[81, 68, 20]
Dry: High	30	[81, 68, 20]
Cooling Pond: Low	500	[67, 119]
Closed-Loop: Low	530	[81, 68, 20]
Closed-Loop with Carbon Capture	590	[82, 9]
Cooling Pond: Average	800	[67, 119]
Wet Tower: Low	800	[67, 119]
Closed-Loop: Average	830	[81, 68, 20]
Wet Tower: Average	950	[67, 119]
Cooling Pond: High	1100	[67, 119]
Wet Tower	1100	[67, 72]
Wet Tower: High	1100	[67, 119]
Closed-Loop: High	1130	[81, 68, 20]
Once-Through: Low	25030	[81, 68, 20]
Once-Through: Low	25100	[67, 119]
Once-Through	31500	[67, 72]
Once-Through: Average	42530	[81, 68, 20]
Once-Through: Average	43000	[67, 119]
Once-Through: High	60030	[81, 68, 20]

Appendix G: Renewables Water Intensity

Table G.1: Consumptive water intensity of large-scale concentrating solar power

Large-Scale CSP	Consumptive Water Intensity (gal/MWh)	Source
Dish, Stirling	4	[67]
Dish/Engine	20	[68, 20]
Parabolic Troughs	78	[68, 20]
Parabolic Troughs, Dry Cooling	80	[67]
Power Tower	90	[68, 20]
Power Tower	500	[68, 20]
Trough	550	[67]
Concentrating Solar	750	[82, 9]
Tower	770	[67]
Parabolic Troughs	800	[20]
U.S. Weighted Average for CSP	800	[20]
: Tower, Wet Cooling	820	[67]
Parabolic Troughs, Wet Cooling	820	[67]
Parabolic Troughs, Wet Cooling: Low	820	[67]
Tower	850	[67]
Parabolic Troughs, Wet Cooling Average	910	[67]
: Parabolic Troughs, Wet Cooling	980	[67]
Fresnal	1000	[68, 20]
Parabolic Troughs, Wet Cooling: High	1000	[67]

Table G.2: Withdrawn water intensity of large-scale concentrating solar power

Large-Scale CSP	Withdrawn Water Intensity (gal/MWh)	Source
Dish, Stirling	4	[67]
Parabolic Troughs, Dry Cooling	8	[67]
Trough	550	[67]
Concentrating Solar	760	[82, 9]
Tower	770	[67]
Tower, Wet Cooling	820	[67]
Parabolic Troughs, Wet Cooling	820	[67]
Parabolic Troughs, Wet Cooling: Low	820	[67]
Tower	850	[67]
Parabolic Troughs, Wet Cooling: Average	910	[67]
Parabolic Troughs, Wet Cooling	980	[67]
Parabolic Troughs, Wet Cooling: High	1000	[67]

Table G.3: Consumptive water intensity of photovoltaic solar power

Photovolatics	Consumptive Water Intensity (gal/MWh)	Source
Solar Photovoltaics	0	[68, 20]
Photovoltaic	0	[67]
Concentrated Solar Photovoltaics	0	[67]
Concentrated Solar Photovoltaics	4	[140, 141, 20]
Photovoltaic	4	[67]
Concentrated Solar Photovoltaics	4	[67]

Table G.4: Withdrawn water intensity of photovoltaic solar power

Photovolatics	Withdrawn Water Intensity (gal/MWh)	Source
Frame	0	[67]
CdTe	0	[67]
Photovoltaic	0	[67]
Concentrated Solar Photovoltaics	0	[67]
BOS	0.1	[67]
Photovoltaic	4	[67]
Concentrated Solar Photovoltaics	4	[67]
Mono-Si	15	[67]
Multi-Si	16	[67]

Table G.5: Consumptive water intensity of wind power

Wind	Consumptive Water Intensity (gal/MWh)	Source
Wind Power	0	[68, 20]
Wind	0	[67]
Wind	1	[67]

Table G.6: Withdrawn water intensity of wind power

Wind	Withdrawn Water Intensity (gal/MWh)	Source
Wind	0	[67]

Table G.7: Embedded water intensity of wind power

Wind	Embedded Water Intensity (gal/MWh)	Source
Denmark, On Land	130	[67]
Denmark, Off Shore	130	[67]
Spain, On Land	160	[67]
Denmark, Off Shore	180	[67]
Italy, On Land	190	[67]
Denmark, On Land	250	[67]

Table G.8: Consumptive water intensity of geothermal power

Geothermal	Consumptive Water Intensity (gal/MWh)	Source
Geothermal	1400	[68, 81, 20, 9]
Geothermal: Low	2700	[142, 20]
Geothermal: Average	3600	[142, 20]
Geothermal: High	4500	[142, 20]

Table G.9: Consumptive water intensity of hydropower

Hydropower	Consumptive Water Intensity (gal/MWh)	Source
Hydropower	4500	[68, 81, 20, 9]