THESIS

PREDICTIONS OF PRODUCED WATER QUALITY AND QUANTITY

FOR SPATIALLY-DISTRIBUTED WELLS IN NIOBRARA FORMATION

Submitted by

Ildus F. Mingazetdinov

Department of Civil and Environmental Engineering

In partial fulfillment of the requirements

For the Degree of Master of Science

Colorado State University

Fort Collins, Colorado

Fall 2012

Master's Committee:

    Advisor: Kenneth Carlson

    Sally Sutton
    Kimberly Catton

ABSTRACT

PREDICTIONS OF PRODUCED WATER QUALITY AND QUANTITY FOR

SPATIALLY-DISTRIBUTED WELLS IN NIOBRARA FORMATION

Two main problems facing the oil and gas industry are the availability of water for well construction and disposal of the produced water. Produced water is typically only treated for a limited number of constituents, and common disposal options have been deep well injection, evaporation or discharge to wastewater treatment plants. However, because of factors such as regulations, local water shortage, and bans on disposal via deep well injection, the future will require much of the produced water be treated and eventually recycled and reused for future field development or other beneficial uses. Multiple cost effective produced water treatment methods have been developed but limited research has been done to understand produced water production volumes and quality from oil and gas fields. Accurate predictions of produced water volumes and quality over a period of time can be used to optimize design and siting of water handling and treatment facilities in a spatially heterogeneous shale oil and gas field. The information can also be used to model availability of water resources and plan long term recycling strategies for augmenting regional surface water supplies.

This study describes protocols to estimate and predict produced water quantity and quality from shale gas wells and applies these to a case study of Noble Energy Inc. wells in Yuma County, CO. Three different protocols of water production prediction were developed based on temporal and spatial variations of water quantity. Dissolution kinetics and geospatial data were used to develop a water quality prediction framework.

A Microsoft Excel based tool, which uses a combination of water quantity and quality protocols, was developed to predict water production and total dissolved solids (TDS) from Noble Energy Inc. wells in Yuma County for different field development scenarios. A framework for interactive web based applications based on developed protocols is also provided. This study also provides a framework for development of GIS based web applications, which can provide an analysis platform for producers and consulting firms to predict water production and/or water quality, optimize location of treatment facilities, truck routings and help make other decisions related to water management.

The study showed that using decline models to predict water production from shale gas fields will provide better long term predictions rather than using historical production average values. The case study and scenarios used for Noble Energy wells in Yuma County demonstrate that these prediction methods can be used in any other shale gas field by altering decline models and coefficients.

Keywords: Produced water volume prediction, produced water quality prediction, hydraulic fracturing, flow back water, shale gas, Niobrara, water resources, water management, produced water recycling, produced water reuse, produced water treatment.

ACKNOWLEDGMENT

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

1. INTRODUCTION

1.1 Origin of the problem

Produced water is the largest waste stream of the oil and gas industry. According to Clark and Veil (2009) approximately 20 billion barrels of produced water (PW) was generated from nearly one million onshore wells in 2007. Most of this water was managed through injection for enhanced oil recovery (10.7 billion barrels) or disposal (7 billion barrels) and 0.65% (139 million barrels) was discharged to water bodies (Clark et al., 2009). On the other hand, development of unconventional resources requires large amounts of fresh water, sometimes up to five million gallons of fresh water to complete a single well (Jason et al., 2012). Moreover, an average unconventional shale gas well might be completed several times over its lifetime in order to maintain hydrocarbon production. As the population grows, demand for hydrocarbons will increase, which will inevitably raise the rate of fresh water consumption by the oil and gas industry (Hutchings, 2010). Many of the new areas under consideration for shale oil and gas exploration are located in ecologically sensitive regions with semi-arid environments, remote or drought areas, where water availability for drilling and stimulation is critical (Jason et al., 2012). Expanding municipal and industrial demands will also intensify competition over water resources (Goodwin et al., 2012). Disposal options for produced water and water availability for drilling and stimulation are the two main barriers to the development of many shale gas plays (GE, 2011). However, there is a great opportunity in treating, reusing and recycling this waste stream of oil and gas operations and converting it into a valuable resource, which can be utilized for future field development, industry or other beneficial uses. The Colorado Oil and Gas Conservation Commission (COGCC) has also identified the need for an assessment of the water supply in Colorado for the oil and gas industry with the explicit need to identify the potential for

water reuse (STRONGER, 2011). Many factors including geological restrictions, local water scarcity, legislation, and PW disposal bans will drive producers to increase recycle and beneficial reuse of produced water.

Many cost effective PW recovery methods that have been developed and many PW pilot treatment facilities built across the nation in major oil and gas plays (Acharya et al. 2011; Das, 2012; Dores, 2012; Jason et al., 2012), but limited research has been done to understand produced water production volumes and quality with time from the shale oil and gas field. Accurate predictions of produced water volumes and the quality over a period of time are important as they can be used by producers and consulting firms to optimize design and siting of water handling and treatment facilities in a spatially heterogeneous gas field, as they are key factors for initial capital investments and operational costs (Muraleedaaran, 2009). The information can also be used to model availability of water resources and plan long term recycling strategies for augmenting regional surface water supplies.

This study is a part of research that is being conducted at Colorado State University for developing a GIS-based Optimized Fluids Management (OFM) tool. Fluids management is a key element to enhance safety and environmental protection during the development of domestic natural gas and other petroleum resources. Optimized management of fluids can minimize community impacts such as truck traffic, noise and road damage, reduce air quality concerns such as the release of air toxics, and influence well pad siting and density decisions that result in a reduction of disturbance to the landscape. In addition, a comprehensive tool that manages fluids can result in a smaller regional water footprint and through coordination of logistics minimize the risk of spills and leaks that could impact surface and ground water quality. This study provides protocols for estimating and predicting produced water quality and volumes as

they are the core elements of optimized fluid management. Analysis is conducted using information about wells in Yuma County, CO from all producers. Example predictions are made for Noble Energy wells located in Yuma County, one of the target areas for water management optimization in CSU's research program.

1.2 Objectives

The main objectives of this thesis are as follows:

1. Develop protocols to estimate and predict produced water production from a shale gas field based on historical data. Apply the developed protocol to predict produced water production from existing Noble Energy Inc. wells in Yuma County.

2. Develop a framework for estimating and predicting water quality from existing shale gas wells.

3. Combine water quantity and quality protocols to estimate temporal and spatial trends for water quality and quantity for selected wells. Develop an interactive Excel based tool to predict water production and quality from Noble Energy Inc. wells in Yuma County for different development scenarios.

4. Provide a framework for a web-based tool that can implement these protocols.

1.3 Structure of Thesis

The thesis is divided into three sections: (i) an extensive review of existing literature about unconventional resources, water production and use from oil and gas operations, produced water quality, water management strategies and environmental issues related to the oil and gas industry, (ii) protocols for estimating produced water flow and framework for water quality estimation from a shale gas field, including different water production scenarios in case study of Noble Energy wells in Yuma County. This section is written in the form of a journal paper,

which will be submitted to SPE (Society of Petroleum Engineers) Journal (iii) application of developed protocols in the form of a Microsoft Excel based tool and proposed online GIS based web application.

2. LITERATURE REVIEW

2.1 Introduction

Hydrocarbons are the primary energy resource used worldwide. Natural gas is a naturally occurring hydrocarbon gas mixture, which has no color or smell, mainly consisting of methane (Encana, 2012). Compared to other fossils fuels, natural gas emits less carbon dioxide during combustion, while releasing significant amounts of energy. Natural gas is formed beneath the earth's surface and trapped in porous sedimentary rock with impermeable layers on the top of it (Naturalgas.org, 2012). After extraction and purification, gas is delivered through the network of pipelines to end-users domestically and internationally. More than 90% of natural gas consumed in the US is produced domestically (EIA, 2011). According to US Energy Information Administration (EIA, 2011), consumption of natural gas is expected to increase, mostly due to gasification of coal-fired power plants. Most of technologically recoverable natural gas in the USA is in the form of shale gas, tight sands and coal bed methane, which are also known as unconventional resources. It is predicted (Figure 2.1) that unconventional natural gas will account for

Figure 2.1. U.S. natural gas production, 1990-2035 (trillion cubic feet) (EIA, 2011).

77% of total domestic natural gas production by 2035 (EIA, 2012). Figure 2.2 provides a map of major shale gas plays in the US.

Unlike conventional gas resources, development of shale gas is more complex and requires additional technology, resources and energy. The two most important components are horizontal drilling and hydraulic fracturing (Jones et al., 2011).

Figure 2.2. Major shale gas plays in US (EIA, 2011).

Hydraulic fracturing is the process of injecting fracturing fluid into the target source rock at high pressures in order to increase permeability of the formation by creating additional fractures through which hydrocarbons can flow to the wellbore (API, 2010). The process of hydraulic fracturing is a highly sophisticated engineering process which involves many stages. Fracturing fluid contains water, sand and chemical additives with different purposes. Each chemical has its own use such as reducing viscosity, preventing scaling, controlling bacterial growth, pH buffering and others. Horizontal drilling is a method where the wellbore is drilled vertically to

the target formation and continues horizontally through it. This technique allows producers to consolidate many gas wells into one pad, which reduces the surface footprint by up to 90% (API, 2010).

2.2 Major environmental concerns of shale gas development.

Recent developments in hydraulic fracturing and horizontal drilling have unlocked large amounts of unconventional resources located throughout the USA and made them economically feasible to recover. However, these practices have aroused many concerns about the potential impact of shale gas development on water resources and the environment (Sakmar, 2011). Table 2.1 provides a list of environmental challenges of shale gas development and different mitigation strategies.

Table 2.1. Shale gas development major environmental issues and mitigation strategies.

Environmental Issues	Description	Mitigation or management programs (Jones F, 2011).
Potential subsurface contamination of groundwater	**Possibility of contaminant migration from target formation through (Broderick, 2011):** • fractures, created during hydraulic fracturing; • naturally occurring faults and cracks; • outside space of casing; • other casing failures related to corrosion, poor construction or improper plugging. **Failure or loss of integrity of the well casing (wellbore) during drilling, stimulation or operation (Broderick, 2011).**	• Micro-seismic monitoring of hydraulic fracturing job (Only 3% of frac jobs are seismically monitored (Kent, 2010)) • API best practices and standards to ensure well integrity. • Disclosure of chemicals used for hydraulic fracturing. • Detailed geological and hydrogeological analysis of subsurface structures. • Integrity testing of casing of the wells. • Groundwater quality monitoring near hydraulic fracturing operations.
Potential soil and surface water or near surface groundwater impacts	**Blowouts (Blowouts were reported in Pennsylvania and West Virginia during drilling operations (Zoback et al., 2010)).** **Spills, overflow or leaching from cuttings/mud pits (Broderick, 2011):** • storage capacity limitations; • human error; • heavy rain or storm; • pit liner failure; **Spill of fracturing chemicals during transportation and mixing (Broderick, 2011):** • failure of pipes; • human error; • integrity of tanks;	• Determination of accurate information about subsurface structure; • Personnel trained for unusual situations. • Proper liquid management (Storage of frac water and flowback water in close containers) • Detailed baseline monitoring before starting operations (soil, groundwater, methane, noise, wastewater, waste); • Application of spill prevention procedures;

7

	Spill of flowback water while transferring to storage/disposal/treatment facility (Broderick, 2011):: • Pipeline failure; • Insufficient storage capacity; • Human error **Other spillage of frac fluids and frac flowback fluids during transportation, storage or disposal.**	
Water consumption, production and disposal	**Water availability for field development can be an issue in:** • Drought, remote, water shortage, environmentally sensitive areas **Produced water disposal issues:** • Bans on disposal wells; • Regulations; • Risk of formation plugging; • Seismic activity; • Social perception; • Clean water act.	Optimized fluid management • Develop detailed fluid management plans; • Treat, recycle, reuse for industry or other beneficial reuse; • GIS optimization • Carefully select and audit contractors to avoid waste issues; • Work with local communities regarding storage and transport of waste to offsite facilities.
Surface Impacts / Footprint	**Land disturbance (Lechtenbohmer, 2011):** High well density (up to 6 wells/km^2) Road network Pipeline network Hauling	• Using multiwell pads; • Reduction of visual impacts by strategically placing operations with respect to natural barriers (forests, hills, etc.) • Flaring operations only during day light hours to minimize visual impacts; application of seismic techniques with minimum surface impact • Land reclamation programs such as reseeding and erosion control of the well pad after stimulation and drilling operations.
Air Emissions /Noise	**Emission sources:** **Well development (noise, particulate matter, SO_2, NO_x, VOC, CO, CO_2) (Lechtenbohmer, 2011):** • Drill rigs • Truck traffic • Frac pumps • Frac ponds • Completion venting • Fugitives • Valves and Pneumatics • Other drilling equipment • Flaring	• Detailed emission monitoring program for (air, wastewater, waste, noise, greenhouse gas) • Share monitoring data with agencies and stakeholders involved • Green completions
Earthquakes	**Aduschkin, 2000; AGS, 2011; Michaels, 2010 and Lechtenbohmer, 2011 reported induced seismic activity due to oil and gas operations**	• Treatment and recycling of produced water instead of disposal.
Other issues: • Mobilization of naturally occurring radioactive elements • Large consumption of resources • Impact on biodiversity		

2.3 Water use and water production in the development of unconventional resources

Large quantities of water are required for successful shale gas development. The majority of this water is used for drilling and completion operations. Water requirements for shale gas wells may vary widely, but typically require 1.7 - 4 million gallons of water over the lifetime of the well (INGAA, 2008). For example, the average water use per hydraulic fracturing in Colorado and Texas is 1.1 and 2.7 million gal per job according to FracFocus (Figures 6.7-6.10 in appendix A). As energy production decreases, the well can be restimulated several times during its lifespan to economically recover energy. Although the amount of water used for developing these unconventional resources might seem large, it represents a relatively minor volume of total water use in the exploration area compared to use by agriculture and municipalities (DOE, 2009). Many sources of water are used for hydraulic fracturing such as surface water, municipal water supplies, irrigation water purchased from landowners, groundwater, wastewater from municipal waste water treatment plants, reused or recycled well construction and stimulation water and recycled produced water (COGCC, 2012). Table 2.2 shows the estimated water use for drilling and stimulation in different shale plays.

Table 2.2. Water use for well construction in different shale gas plays (Chesapeake Energy, 2008).

	Water used, bbls/well			Wells/year	Water used per year, MM bbls/year
	Drilling	Fracturing	Total		
Barnett	10000	70000	80000	600	48
Fayetteville	1500	70000	71500	250	18
Haynesville	25000	65000	90000	200	18
Marcellus	2000	90000	92000	600	55

When construction of the well is completed, along with oil and gas, it starts producing water, which is called produced water. The amount of this water varies significantly according to several factors. Three important factors are the type of hydrocarbon being produced, the

geographical location of the field and the method of production (Clark et al., 2009). The type of hydrocarbon will determine not only the volume but also the time when water is generated during the life of the well. The reason is that different hydrocarbons are found in different formations with different physical and chemical properties, which can greatly influence water production. For example, coal bed methane generates the majority of water in the beginning of well life, while conventional oil and gas wells start producing more water as they get more mature. With coal bed methane, water is pumped out from the formation in order to decrease pressure, so gas can flow to the surface. For conventional oil, on the other hand, less water is produced in the early stages of production, when pressure is high enough to let oil flow to the surface by itself. As the well matures, water production increases as oil pumped out of the reservoir replenishes with water from neighboring formations. Water flooding used to stimulate the production in conventional wells will increase the water to oil ratio even more (GOA, 2012).

Geographical location is another factor influencing water production. For example, according to the USGS (2000), the average water production per coal bed methane well in the Powder River Basin in Wyoming and Montano is more than 15 times larger than water production from San Juan Basin in Colorado and New Mexico. Wells located in the same field at some distance from each other will also have differences in water quantity.

The method of production is another key factor affecting the volumes of water produced. Wells that need stimulation such as waterflooding or hydraulic fracturing will produce significantly more water than wells that can produce under existing pressures. Produced water from hydraulically fractured wells will consist of naturally occurring formation water and the rest of the fracturing water.

According to Clark et al (2009) almost 21 billion barrels of produced water were generated from offshore (600 million bbl) and onshore (20.4 billion bbl) oil and gas wells in the United States in 2007. In Colorado, water produced from the oil and gas fields in 2011 was estimated at 330 million barrels according to the COGCC database (Figure 2.3). Eighty six percent (86%) of Colorado's 47,871 active wells are located in 6 counties: Weld, Garfield, Yuma, La Plata, Las Animas, Rio Blanco.
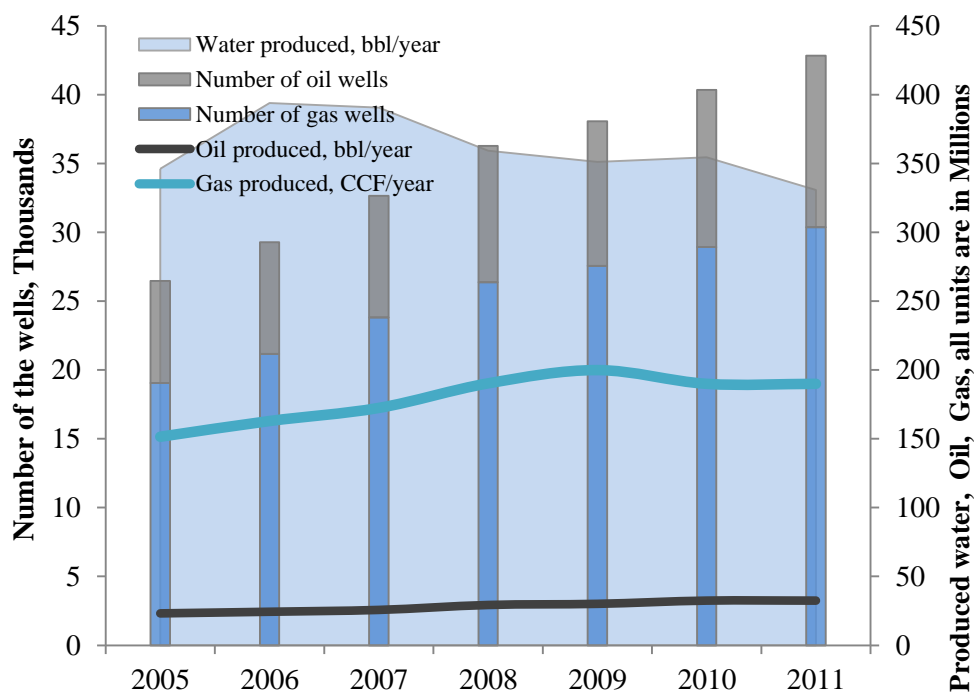
Figure 2.3. 2011 Oil, gas water production in Colorado (COGCC, 2012).

However, counties that contribute the greatest amount of produced water are not necessarily those that have the greatest number of the wells. While Weld County has the highest number of active wells (40% of the total wells in Colorado, 17558 wells), it contributes only 3% (one million bbl) of total produced water generated in Colorado (Figure 2.4). Las Animas on the other hand, contributes 20% (70 million bbl) of produced water in Colorado, with only 6% (2885 wells) of active wells. This can be explained by the fact that the majority of wells in Las Animas

are coal bed methane wells (2299 wells), while most of the wells in Weld County are in shale formations.
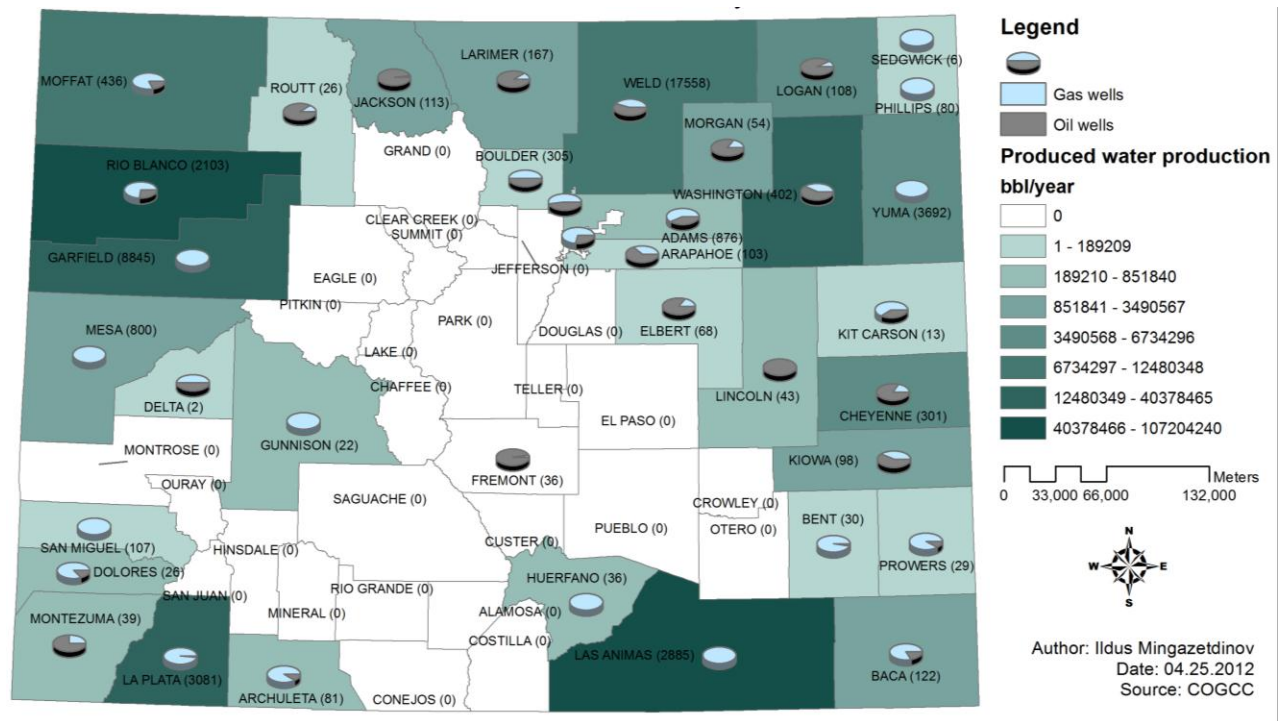
Figure 2.4. Produced water production distribution by Counties in Colorado. (Number of the wells in each County is provided in parenthesis. Data source: COGCC, 2012).

Yuma County, which is the target area of this research has 3892 (8.2% of total Colorado wells) active wells and all of them are classified as natural gas wells. Yuma county contributed 1.4% (5 million barrels) of Colorado's produced water generated in 2011.

2.4 Produced water quality

Just as no two water sources are the same, no two identical oil and gas wells exist. Each well has its own individual physical-chemical and geological properties. Produced water quality varies widely depending on the target geological formation, geographical location, the depth of the formation, production stimulation methods, type of hydrocarbon, chemicals used during

drilling and stimulation and maturity of the field (Clark et al., 2009). Average and maximum TDS values from different shale plays are shown in table 2.3.

Table 2.3. Flowback water TDS from different shales (Acharya et al. 2011).

Shale	Average TDS, mg/l	Maximum TDS, mg/l
Fayetteville	13000	20000
Woodford	30000	40000
Barnett	80000	150000
Marcellus	120000	280000
Haynesville	110000	200000

Salts, scaling metals, oil and grease, suspended solids, formation organic compounds and radioactive elements are constituents found in produced water (Clark et al., 2004). In addition to naturally occurring constituents, produced water also contains chemicals added during drilling, completion and the oil/water separation processes. Exposure to many of these components is hazardous, toxic or harmful to human health and the environment. Hence, proper management of this largest oil and gas waste stream in an environmentally friendly manner is vital to protect human health, ground and surface water, minimize environmental impacts and decrease future fresh water use (DOE, 2009).

Main water characteristics that will dictate treatment processes needed are: oil/and grease, hardness/metals (Ba, Ca, Fe, Mg, Mn, Sr), bacteria, TDS (mainly Cl and Na), and total suspended solids. Concentrations of all of these constituents are mainly dictated by the formation rocks and secondarily the feed water used for stimulation or drilling. As seen in Tables 2.4 and 2.5, fracturing fluid constituents are a relatively small fraction when compared with water quality after 30 days of flow back.

Table 2.4. Change in flowback water constituents over time. Location 1, Marcellus shale. (McElreath, 2011).

Parameter	Hydraulic fracturing fluid	Concentration in produced formation water following hydraulic fracturing (mg/l)				
		6 hours	Day 1 24 hours	Day 2	Day 9	Day 30
TKN	41.3	523	3770	5200	315	257
Ammonia	38.5	110	140	201	273	352
Chloride	126	16500	25500	39600	46500	65800
Sulfate	165	91.6	82.1	28.8	31.6	8.47
TDS	1500	39300	54100	68300	140000	138000
Sodium	94.9	7260	10800	14700	27100	38100
Boron	0.0785	0.075	17.5	20.6	28.8	<50
Benzene	<1	4.15	6.34	11	7.69	10.1
Toluene	1.44	1.01	1.04	1.43	1.30	2.45

Table 2.5. Change in flowback water constituents with time. Location 2, Marcellus shale (McElreath, 2011).

Parameter	Hydraulic fracturing fluid	Concentration in produced formation water following hydraulic fracturing (mg/l)				
		6 hours	12 hours	Day 5	Day 10	Day 30
Sulfate	35.3	86	50	27.2	8.9	1.56
TKN	97.2	112	104	224	150	139
Ammonia	9.62	39.3	42.5	70.2	60.9	160
Chloride	2790	31200	30800	78300	60600	81500
TDS	7700	39400	43200	94300	119000	148000
Sodium	793	7940	9570	19500	26200	29100
Benzene	77	64.7	129	625	797	740
Toluene	198	62.6	554	833	1540	1650

Oil and grease and suspended solids are removed by well-known treatment methods such as clarification, media filtration and adsorption (Acharya et al. 2011). TDS (salinity) and hardness/metal removal requires methods such as membrane desalination and softening and can account for the majority of the capital cost of a produced water treatment system (Kimbal, 2011). It is therefore important to understand current and predict future concentrations of these constituents (TDS, hardness and metals) to design a treatment plant. Key contaminants of produced water, their impact on reuse and treatment options are shown in Table 2.6.

Table 2.6. Produced (flowback water) water key contaminants and impact for reuse (Acharya et al. 2011)

Constituents	Impact for reuse	Treatment options
Particulates Suspended solids	Plugging	Clarification: coagulation, flocculation, settling and filtration
Oil and grease Dissolved organics Volatile organics	Fluid stability	Adsorption: activated carbon, walnut shells or other sorbents Electrocoagulation
Total dissolved solids Chlorides		Membrane desalination Thermal evaporation
Sulfates Iron Hardness (Ca, Mg) Barium Strontium Silica	Scaling	Softening: Precipitation with lime softening
Biological counts	Bacterial growth	UV, biocides
Naturally occurring Radioactive Materials (NORM)	Radioactivity	Dissolution and extraction

With recent concerns of unconventional gas development and its potential impact to ground water supply, the USGS and other government agencies (e.g. COGCC) started conducting temporal and spatial analysis of surface and groundwater supply to reveal potential impact. However, there has been no research done to model produced water quality change over the lifetime of the well. Some studies such as Acharya, 2011, McElreath, 2011, Vidic, 2010 provide TDS and other constituent's kinetics for flow back water quality, but most of the data is limited to 30 days of sampling. Figure 2.5 shows the variation of main water quality parameters such as TDS, calcium, sodium and chloride with time.
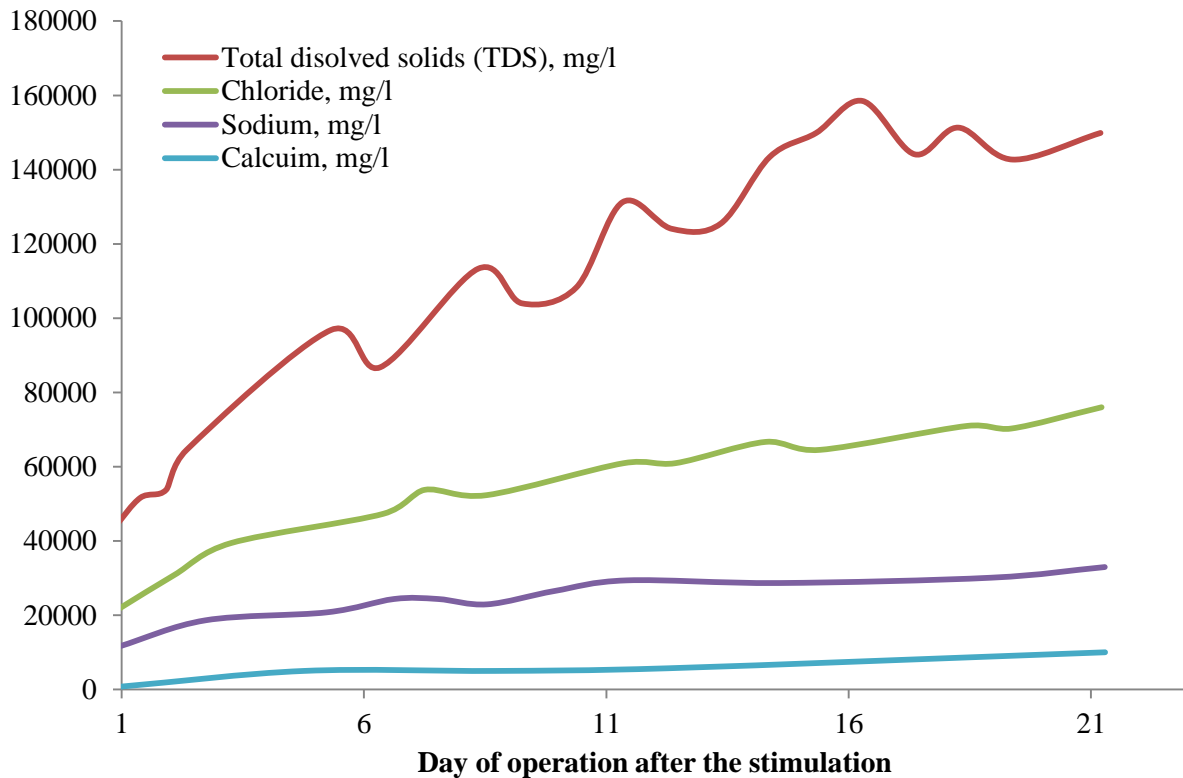
Figure 2.5. Variation of flowback composition with time for one well in Marcellus shale (reproduced from Vidic, 2010)

2.5 Summary

The development of the shale gas industry provides economic benefits including direct and indirect jobs, contributes additional government revenues and increases energy security. However environmental and social concerns still surround shale gas development. Recycling of produced water is one of the key water management strategies that can address water availability, water disposal and some environmental issues. Installation of a central treatment facility or an onsite treatment system is a key component of a succesful recycling strategy. Accurate predictions of produced water quantity and the quality from shale gas wells over a period of time can be used in optimization of design and siting of water handling and treatment facilities in a spatially heterogeneous shale gas field. The information can also be used to model

16

the availability of water resources and plan long term recycling strategies for augmenting regional surface water supplies.

The oil and gas industry has more than a century of history in the United States, and there is a lot of research that has been done in this field. Many methods and models have been built and developed around forecasting hydrocarbon production, but there is a lack of research done to predict water quality and quantity from shale gas wells. The goal of this study is to increase the understanding of produced water quantity and quality from shale gas wells and to propose a protocol for predicting future trends. A user interface for the proposed potocol is developed in the MS Excel and a framework for migration to GIS based web tools is described.

17

3. DEVELOPMENT OF PROTOCOLS FOR PREDICTING PRODUCED WATER FLOW AND QUALITY FROM NIOBRARA FORMATION

Summary

Two main problems facing the oil and gas industry are the availability of water for well construction and disposal of the produced water. Produced water is typically only treated for a limited amount of constituents, and common disposal options have been deep well injection, evaporation or discharge to wastewater treatment plants. However, because of factors such as regulations, local water shortage, and bans on disposal via deep well injection, the future produced water treatment methods have been developed but limited research has been done to understand produced water production volumes and quality from oil and gas fields. Accurate predictions of produced water volumes and quality over a period of time can be used to optimize design and siting of water handling and treatment facilities in a spatially heterogeneous shale oil and gas field. The information can also be used to model availability of water resources and plan long term recycling strategies for augmenting regional surface water supplies. The ability to aggregate this information for a group of wells and predict how this might change with continued field development is also important for designing reuse strategies.

This study describes protocols to estimate and predict produced water quantity and quality from shale gas wells. In addition, the protocols are applied to Noble Energy wells in Yuma County, CO. Three different protocols for water production prediction have been developed based on temporal and spatial variations of water quantity. Dissolution kinetics and geospatial data were used to propose a water quality prediction framework. Both water quantity and quality protocols were applied to Noble Energy wells in Yuma County as a case study.

The study showed that using decline models to estimate water production from shale gas fields will provide better long term prediction than using historical production average values.

The case study and scenarios used for Noble Energy wells in Yuma County demonstrates that these prediction methods can be used in other shale gas fields by altering decline models and coefficients.

3.1 Introduction

Produced water (PW) is the largest waste stream of the oil and gas industry. According to Clark and Veil (2009), approximately 20 billion barrels of PW was generated from nearly one million onshore wells in 2007. The majority, 95.2%, of this water was managed through injection for enhanced oil recovery (55.4% of injected PW or 8.6 billion barrels) or disposal (38.9% of injected PW or 6 billion barrels), with 4.4% discharged to water bodies (Clark et al., 2009). However, many factors such as geological restrictions, local water scarcity, legislation, PW disposal bans will drive producers to recycle and beneficially reuse their waste PW for future field development or other industry uses (Dores et al., 2012). There are many cost effective PW recovery methods that have been developed and multiple PW pilot treatment studies that have been conducted across the nation in major oil and gas plays (Das, 2012; Dores, 2012; Jason et al., 2012; Acharya et al. 2011), but very limited research has been done to understand PW production volumes and quality from the shale oil and gas field. Accurate predictions of PW volumes and PW quality for a life of the well will allow producers to optimize design and siting of water handling and treatment facilities in a spatially heterogeneous gas field. The information can also be used to model availability of water resources and plan long term recycling strategies for augmenting regional surface water supplies.

In this study protocols were developed to estimate PW quantity and quality from shale gas wells. The decline curve analysis is commonly used in the oil and gas industry to estimate hydrocarbons recovery rate in time. Water production decline curve analysis is used to develop protocols for estimation and prediction of PW production from shale gas wells in Yuma County Colorado. Example predictions are made for Noble Energy wells located in Yuma County, as

Yuma County is one of the target areas for water management optimization in studies conducted by Colorado State University.

A conceptual methodology for estimating and predicting PW quality has been developed using dissolution kinetics and geospatial data. This methodology was also applied to Noble Energy wells in Yuma County.

3.2 Drivers for produced water reuse or recycling

Historically considered a waste stream, PW is becoming a valuable resource for energy extraction. Many environmental, economic, regulatory, and social factors will cause the petroleum industry to change the way it deals with PW in the future (Dores et al., 2012). Table 3.1 summarizes the main driving factors in treating, recycling and reusing PW from oil and gas operations.

3.3 Study area location and description

Yuma County is located in the northeastern corner of Colorado. The county shares a border with both Nebraska and Kansas. According to the 2010 census, the population of the county is just over 10,000 people, with a population density of 4 people per square mile. Nineteen operators have over 3600 wells with annual gas production of 37 billion cubic feet, predominantly from the Niobrara shale formation (COGCC, 2011). Most of the wells produce dry gas with a negligible amount of oil.

Yuma County (Fig. 3.1) is one of the target areas for water management optimization in a larger study being conducted by CSU in collaboration with Noble Energy, Inc. Optimization includes developing long term water recycling and reuse strategies, as well as treatment options and optimal siting of water treatment facilities.

Table 3.1. Important factors driving PW treatment, reuse and recycling (Dores et al., 2012; Das, 2012).

Factor	Description
Local water availability/scarcity	Many of the new areas under consideration for shale oil and gas exploration are located in ecologically sensitive regions with semi-arid environment, remote or drought areas, where water availability for drilling and stimulation is critical (Jason et al., 2012). Moreover, expanding municipal and industrial demands can create conflicts over water resources (Goodwin et al., 2012).
Increased regulatory/legislation scrutiny	Regulations related to PW disposal will continue to be stringent. Bans on disposal wells are already common in several regions of the US. Zero liquid discharge is imposed by local authorities in many areas of the US and Canada. It is expected that other regions will adopt stringent regulations.
Clean water act	Produced water cannot be discharged into open water bodies.
Risk associated with formation plugging or limited disposal capacity	Risk of formation plugging increases with time. Produced water from thousands of wells is brought and disposed of in a limited number of disposal wells. Disposal formations that intake PW might reach their capacity, which might result in production being stopped.
Cost of disposal via injection	Some wells are located in remote areas with no available nearby disposal wells. Long distance hauling of the PW can significantly increase operational costs in addition to disposal costs; therefore, onsite treatment and reuse is an option considered by operators.
Water allocation for drilling and stimulation	Development of unconventional resources requires large amounts of fresh water, sometimes up to five million gallons of fresh water to complete a single well (Jason et al., 2012). As the population grows, demand for hydrocarbons increases, which will inevitably raise the rate of fresh water consumption by the oil and gas industry (Hutchings et al., 2010). With proper treatment, PW can be the source water for production operations.
Well injection has the potential to contaminate fresh water aquifers	Continued injection under high pressure of vast amounts of PW can lead to migration of PW to fresh water aquifers through natural faults, cracks or along casings. Corrosion or other factors can lead to the failure of casings in aged wells, which can also pose the risk of contamination.
Social perception	In water shortage regions, use of large volumes of water for oil and gas operations is not socially responsible. In some areas where fresh water is not readily available, disposal of PW instead of seeking beneficial uses for it might be socially unacceptable.
Induced seismic activity	Aduschkin, 2000; AGS 2011; Michaels 2010 and Lechtenbohmer 2011 have reported induced seismic due to excessive injection during oil and gas operations
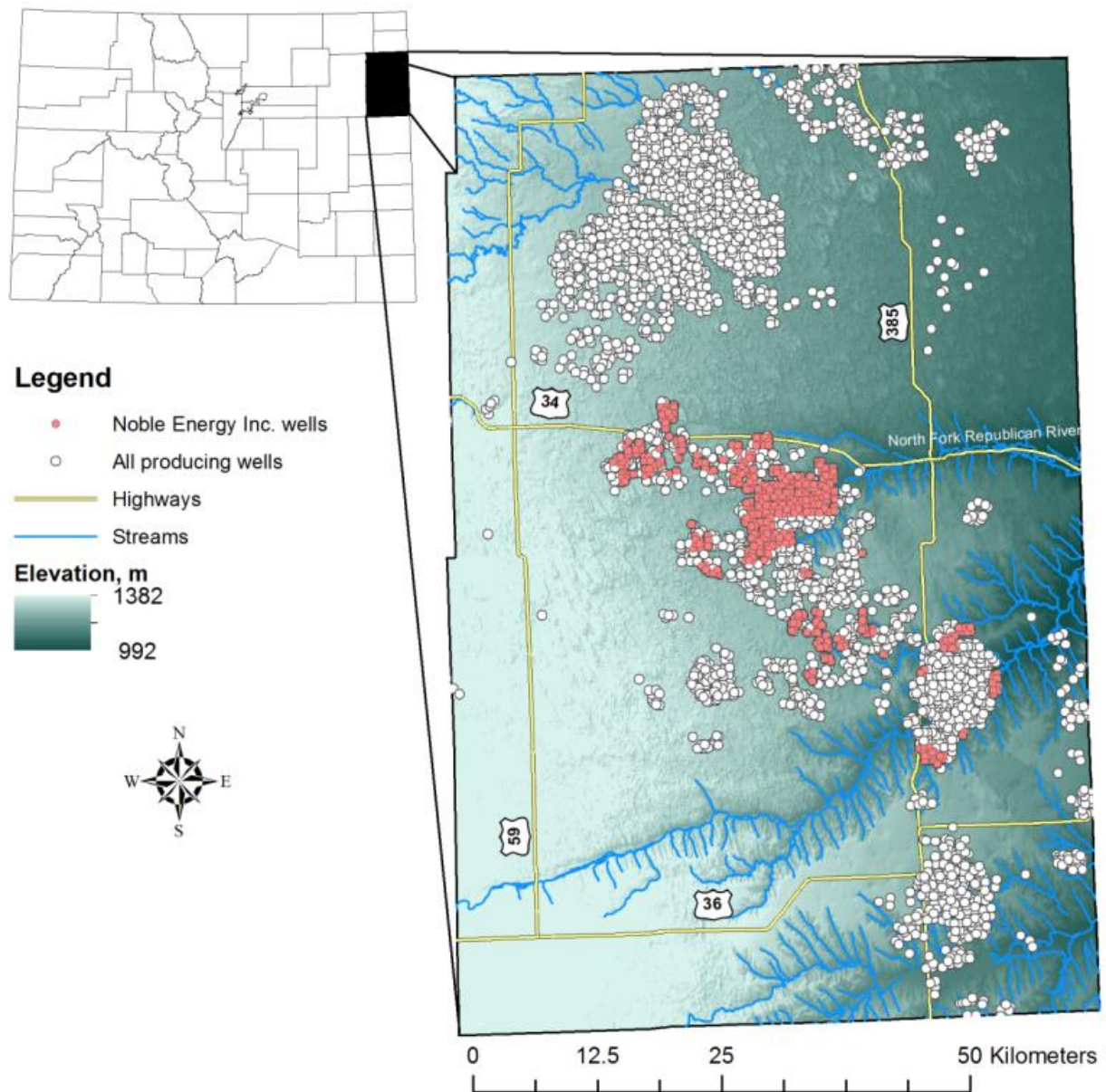
Figure 3.1. Map of the study area. Natural gas producing wells are represented as circles; Noble Energy wells are shown in red, and other producers are white.

3.4 Data collection

Information about PW annual
production volumes, gas
production, production days and
first production dates from 1999 to
2011, and well location ESRI
ArcGIS shapefiles were obtained
from the publicly available
Colorado Oil and Gas Conservation
Commission database (COGCC,
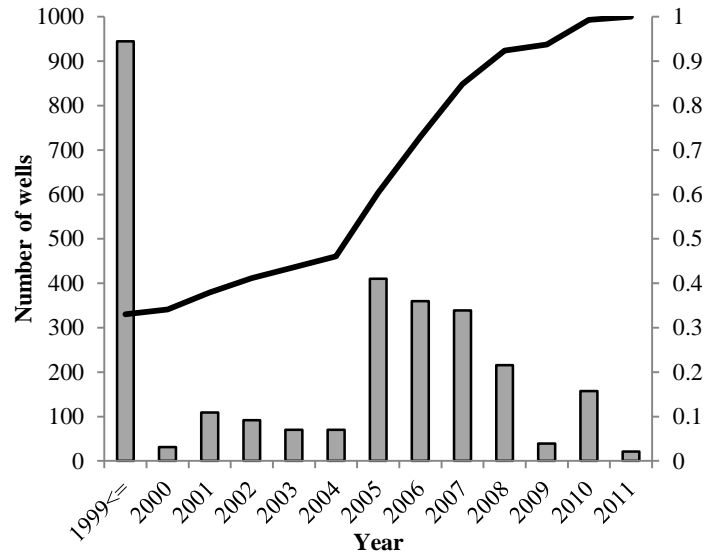
Figure 3.2. Wells drilled in each year in Yuma County from all
operators (COGCC, 2012).

2012b). Fig. 3.2 shows the
distribution of wells by age. Information about completion, recompletion dates, as well as water
used for stimulation and frac flowback volumes were provided by Noble Energy, Inc. as a
separate MS Excel spreadsheet for each well. All data from the COGCC database and Noble
Energy data were downloaded in February 2012.

3.5 Water production model

3.5.1 Prediction basis

The empirical Arp's equation is a traditional decline curve analysis which was first proposed
nearly sixty years ago to predict hydrocarbon production rate (Arps, 1944; Baihly et al., 2010;
Kewen et al., 2003). This equation relates production rate and time for oil wells during a pseudo
steady-state period and can be written as:

$$q(t) = \frac{q_i}{(1+bD_i t)^{\frac{1}{b}}}$$ (1)

24

where $q(t)$ - production rate at t, q_i- initial rate, D_i – decline rate, b - degree of curvature.

Even though there have been other prediction approaches proposed since that time, the Arp's equation is still widely used by industry because of its simplicity and applicability in almost any situation (Ebrahimi, 2010). Exponential and harmonic decline functions are special cases of Arp's equation when b is equal to 0 and 1, respectively. The hyperbolic decline function uses both parameters D_i and b, where $0 < b < 1$. Most of the time all three functions can be well fitted to historical water production data, however each results in significantly different long term forecasts as shown in Fig. 3.3.
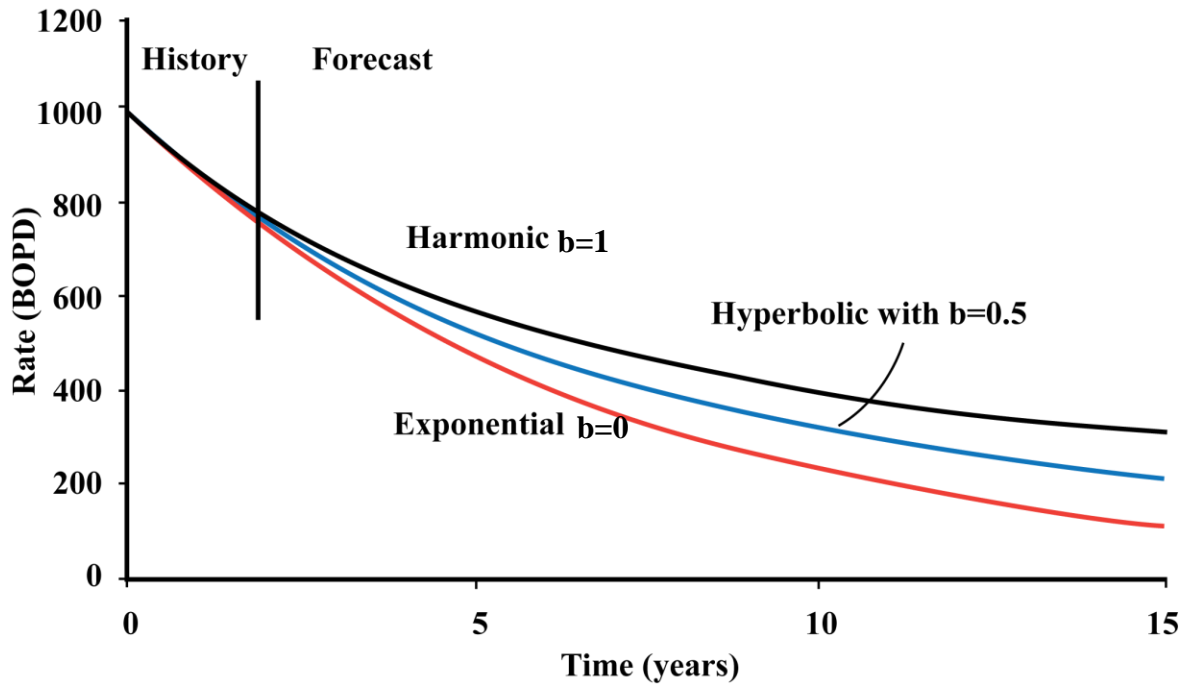
Figure 3.3. Representation of special cases of Arp's equation: harmonic (b=1), hyperbolic (0<b<1) and exponential (b=0) (Lee, 1996).

The exponential decline curve has the highest decline rate and will lead to the most conservative forecast when predicting oil production, while the harmonic function has a smaller decline rate, providing less aggressive decline predictions. In this study a decline curve analysis

25

(DCA) was performed using harmonic (b=1) and exponential (b=0) decline functions to demonstrate the expected range of results.

3.5.2 Average field decline function (FDF)

Annual water production (AWP) data and production days (PD) from 2859 wells, the majority vertical with a few directional were downloaded and placed in a database. The annual water production rate was then converted to the equivalent average daily water production rate (DWPR) based on AWP and PD. Wells drilled prior to 2005 were eliminated to account for only recent technology and completion techniques. Wells with missing or incomplete water production information were also eliminated from analysis. The average daily water production data for each year from the all wells were classified from the first to seventh year of operation, so that the production data could all use the same start date, based on the production days information. For example, when one well began production in 2005 and another began in 2010, the data would be organized by first, second etc. year of production regardless of the drilling year. After that, quality control of the data was performed for DWPR values of each year of operation by excluding values above the 99th percentile and below the first percentile to remove outliers (Some wells had DWPR values over a few orders of magnitude
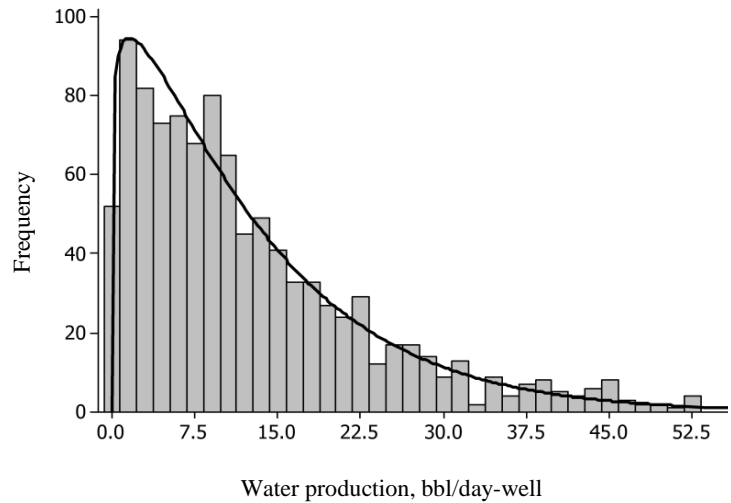
Figure 3.4. Distribution of average daily water production for the operational year 2 ($\alpha = 1.1064, \beta = 12.945$). Field data presented as columns, Weibull distribution fitted to the data is shown as solid line. Coefficients: year 1 ($\alpha = 0.9264, \beta = 13.72$), year 2 ($\alpha = 1.1064, \beta = 12.945$), year 3 ($\alpha = 1.087, \beta = 9.696$), year 4 ($\alpha = 1.12, \beta = 8.5676$), year 5 ($\alpha = 1.2074, \beta = 7.1794$), year 6 ($\alpha = 1.3335, \beta = 6.9312$), year 6 ($\alpha = 1.3695, \beta = 6.137$).

26

from the average). Next, mean and 95th percentile of DWPR values and distributions were calculated for each operating year (Fig. 3.5). Weibull distribution (Fig. 3.4) was found to be best at describing each operational year distribution of DWPR.

A decline curve analysis (DCA) was performed using harmonic and exponential functions by least square error (LSE) fitting to the mean values of DWPR (Table 3.2- 3.3 and Fig. 3.6) to model average field water production decline over time.
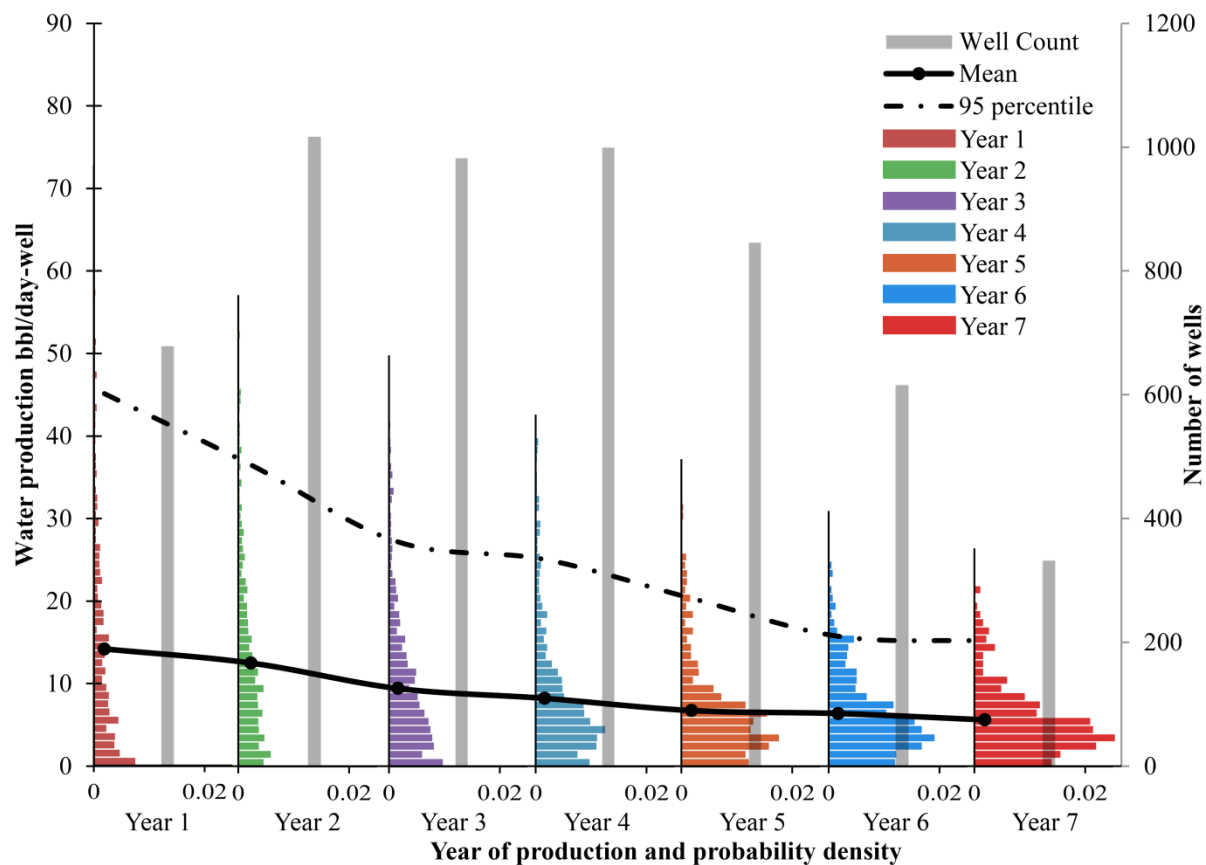
Figure 3.5. Daily water production histogram for each operational year is color coded; mean and 95th percentile are shown with black lines, columns are number of production data records available for each year.

Table 3.2. Different functions fitted to the data and correlation coefficients for them.

Fitting curve	R^2	Equation
Harmonic decline	0.981	$y = \dfrac{19.74}{1 + 0.35 \cdot x}$
Exponential decay	0.979	$y = 16.77 \cdot e^{-0.17 \cdot x}$
Logarithmic	0.976	$y = -4.69 \ln(x) + 14.72$
Power law	0.941	$y = 14.97 \cdot x^{-0.45}$

* Correlation coefficient found using squared CORREL function in MS Excel

Table 3.3. Summary table of the field decline model

Statistics				Models			
Year	Count	95 percentile	Mean, bbl/day	Harmonic, bbl/day	Exponential, bbl/day	Logarithmic, bbl/day	Power law, bbl/day
1	679	45.13	14.20	14.60	14.15	14.72	14.98
2	1017	36.48	12.49	11.58	11.93	11.47	10.95
3	982	27.18	9.41	9.59	10.06	9.56	9.12
4	1000	25.04	8.21	8.19	8.49	8.21	8.01
5	846	20.33	6.73	7.14	7.16	7.16	7.24
6	617	15.73	6.37	6.33	6.04	6.31	6.67
7	333	15.18	5.61	5.69	5.09	5.59	6.22

Unlike conventional oil and gas reservoirs, Fig. 3.5 shows that average water production declines for shale gas wells. Production in the beginning of the well life is high due to flowback of mainly fracturing water used during stimulation and high initial formation pressures. Water production declines over time and formation water replaces fracturing fluid.

Correlation coefficients, obtained from fitting water production data to harmonic and exponential decline functions are 0.981 and 0.979 respectively (Table 3.2). Both of these decline curves can be used for water production modeling; however, exponential decline function might underestimate water production when used for long term predictions, potentially leading to building an undersized treatment plant. For this reason, the authors decided to use the harmonic decline function to model water production from wells in the study area, which will provide less aggressive decline predictions. The harmonic decline function in general can be shown as:

$$q(t) = \frac{q_i}{1 + D_i t} \qquad (2)$$

where $q(t)$ production rate at year t, $\frac{\text{bbl}}{\text{day-well}}$; D_i – decline rate $(year^{-1})$, q_i – initial water production rate, $\frac{\text{bbl}}{\text{day-well}}$. For Yuma County field data $D_i = 0.35, q_i = 19.74 \frac{bbl}{day-well}$ (Table 3.2 and Fig. 3.6).
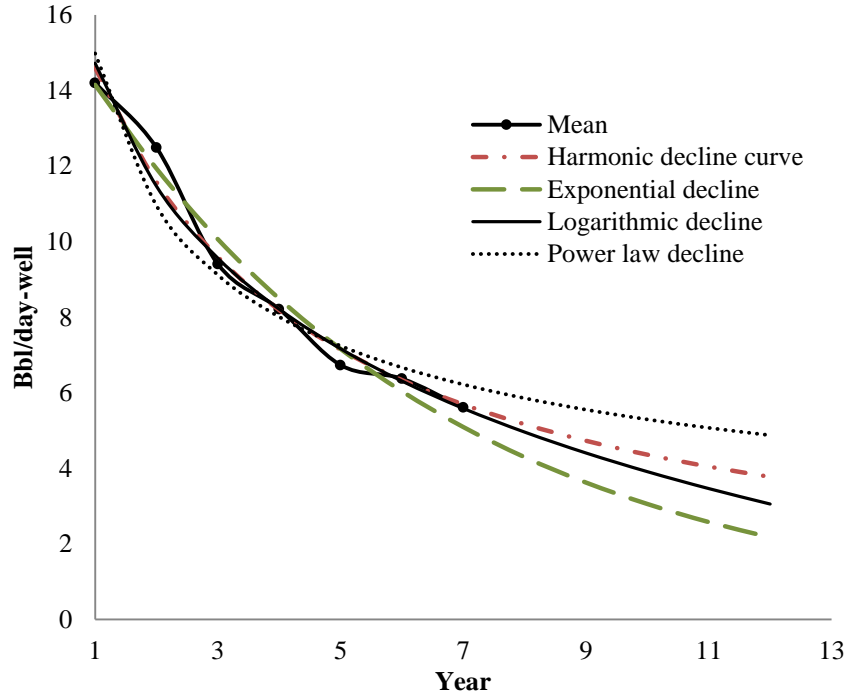
Figure 3.6. Curve fitting to the average daily production data in each operational year.

Field decline function (FDF) is a function, which describes decline in average water production rate in the field. From this function, one can get obtain information about how water production declines over time from an average well in the field. Equation 3 is a FDF which is generated for Yuma County wells. This function is further used to model water production from shale gas wells in Yuma field.

$$q(t) = \frac{19.74}{1 + 0.35 \cdot t} \qquad (3)$$

where $q(t)$ is a production rate for any corresponding operational year, $19.74 \frac{bbl}{day}$ is a water

production rate at the initial time, and $0.35\ year^{-1}$ is the calculated decline rate for the Yuma

County field. In the following sections $t = 1$ is considered as a new well (first operational year),

$t \geq 2$ is considered as a well operated 2 years or more, i.e. if a prediction is made for 2011 based

on data prior to and including 2010, wells drilled in 2011 have $t = 1$, wells drilled in 2010 or

earlier have $t = 2$ or more.

3.5.3 Prediction methods

The field decline function is used to develop three different water production prediction

methods. For each method D_i (decline rate), q_i (initial production rate) and t (operational year of

a well) are model parameters. Table 3.4 and Figure 3.7 show parameters used in different

prediction methods.

Table 3.4. Parameters used in different prediction methods.

Prediction method	q_i	D_i	t
Method 1	Fixed	Fixed	Variable
Method 2	Variable	Fixed	Variable
Method 3	Variable	Variable	Variable
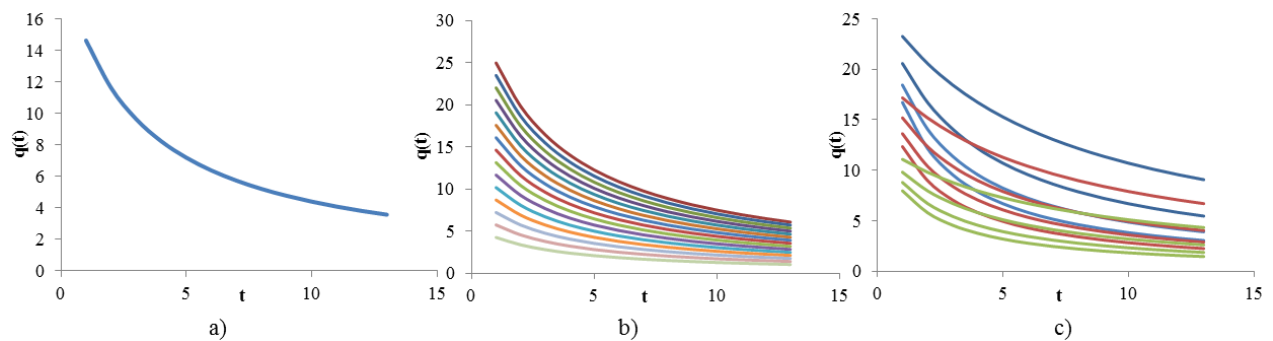
Figure 3.7. a) Method 1, t as a variable, b) Method 2, t and q_i as a variable, c) Method 3, t, q_i and D_i as a variable.

3.5.3.1 Method (1) of water production prediction based on FDF and age of the wells.

In this method, age of the wells and the FDF is used to model water production. Individual water production behavior (Example: fracturing) is not accounted for in this method of prediction. All wells that have the same age (t) will have the same predicted daily and annual water production. To calculate annual water production from a well, daily water production is multiplied by the average for field production days in a year. Equation 4 is an equation that can be used to calculate water production from selected wells.

$$WP = \sum_1^n \left(\frac{19.74}{1 + t_n \cdot 0.35} \right) \cdot N_a + \sum_1^m \left(\frac{19.74}{1 + 1 \cdot 0.35} \right) \cdot N_n \qquad (4)$$

where, n is number of wells with operational year $t \geq 2$, m number of proposed new or refractured wells ($t = 1$), t_n – age of each $t \geq 2$ well by the year of prediction , N_n – field average operation days for a first operational year (when $t = 1$), N_a – average annual operational days after first operational year (when $t \geq 2$). For Yuma County wells: $N_a = 362 \ days$, and $N_n = 184 \ days$, found averaging production days from historical data.

This method can be used for quick estimation of water production from a field with a large number of wells and can be implemented to predict future water production by changing (increasing) the age of the well for each additional future year.

Table 3.5 shows a calculation example of total water production for 2011 from Noble Energy, Inc. wells in Yuma County. First, age of the wells has to be determined (wells count column shows how many wells have different ages (t) by 2011). Thirty-one wells were drilled in 2010 ($t = 2$), so they were 2 years old in 2011; therefore, the water production rate for a 2-year-old well from the field decline curve is $11.6 \ \frac{bbl}{day-well}$ from equation 2 when $t = 2$. In 2011, these 31 wells would produce $Q = 31 \ wells \cdot 11.6 \frac{bbl}{day \cdot well} \cdot 362 \frac{days}{year} = 129914 \frac{bbl}{year}$. Similar

calculations were made for all wells, except that the wells drilled in 2011 have 184 production days instead of 362 days. To predict water quantity for 2012, the corresponding production rate has to be changed for each group of wells.

Table 3.5. Example water production prediction calculation for the year 2011 based on data before 2010

Operational year, t	Well drilled	Well count, n	Field decline curve	Sum, bbl
1	2011	0	14.6	0
2	2010	31	11.6	129914
3	2009	0	9.6	0
4	2008	4	8.2	11857
5	2007	27	7.1	69821
6	2006	32	6.3	73383
7	2005	138	5.7	284285
8	2004	12	5.2	22439
9	2003	12	4.7	20543
10	2002	27	4.4	42619
11	2001	28	4.0	41003
12	2000	0	3.8	0
13	1999 and older	152	3.5	194473
				890337

For existing Noble Energy wells, this method over-predicts 2011 water production values by 13%. This is related to the fact that all of the wells in last group (1999 and older) were assumed to be 13 years old, while in reality most of them are much older.

3.5.3.2 *Method (2) of water production prediction based on individual initial production modeling with constant field decline rate.*

In this method of prediction it is assumed that water production from all existing wells decline with the same rate. Therefore, decline rate is taken as a field decline rate when decline curve fitted to the data. All proposed new or refractured wells are assumed to have the same decline rate as FDF and variable initial water production.

To determine the production rate decline for each existing well, a harmonic decline curve is fitted to historical daily production data with a least square method for wells older than $t \geq 2$,

solving for q_i (initial water production) as it is assumed that decline rate D_i is constant throughout the field. Wells could be fractured multiple times over their lifetime to maintain hydrocarbon production, therefore it is important to locate the last fracturing job for older wells and fit the curve from the fracturing year. An Excel based filter was developed to find the fracturing year using multiple criteria. After location of the fracturing year, curve fitting is conducted for each well and correlation coefficients are calculated. An example flowchart of the methodology is shown in Figure 6.14 – 6.15 in the supplementary appendix A. New or refractured wells ($t = 1$) are modeled using FDF described by equation 3.

To calculate overall water production for a particular year, equation (5) can be used:

$$WP = \sum_{i=1}^{i} \frac{q_i}{1+0.35\cdot t_i} \cdot N_a + \sum_{j=1}^{j} \frac{19.74}{1+0.35\cdot 1} \cdot N_n \qquad (5)$$

where $q_{i,}, t_i$ are initial flow rate and operational year for each older than 1 year ($t \geq 2$) i well. q_i is found by LSE fitting the data to the function. j – number of proposed new or refractured wells ($t = 1$), N_n – first year average production days, N_a – average operational days after first year.

3.5.3.3 Method (3) of water production prediction based on individual decline model.

To predict water quantity from the selected area, wells are divided into three categories based on operational year: wells with $t > 2$, $t = 2$ and $t = 1$ (proposed new or refractured wells). A harmonic decline curve fitting with least square method is used to model each existing well with $t > 2$ by solving for D_i and q_i (three data points are assumed to be enough for curve fitting). If fractured multiple times, a curve fitting is used from the last fractured year. For each dataset curve fit, the correlation coefficients are calculated and compared with those found in the model using decline rate only (Method 2). Curves with the highest correlation coefficients are selected to describe flow from a particular well. For wells with $t = 2$, the fitting curve is found by solving

for q_i only, as in the previous section. New or fractured wells ($t = 1$) are assumed to have the same production behavior as FDF. Therefore, initial and decline rate is the same as FDF.

To calculate overall water production from selected wells, equation (6) is used:

$$WP = \sum_{i=1}^{i} \frac{q_i}{1+D_i \cdot t_i} \cdot N_a + \sum_{k=1}^{k} \frac{q_k}{1+0.35 \cdot t_k} \cdot N_a + \sum_{j=1}^{j} \frac{19.74}{1+0.35 \cdot 1} \cdot N_n \qquad (6)$$

where $q_{i,}, D_i, t_i$ are initial flow rate, decline rate and operational year for each $t > 2$ i well. q_k, t_k are initial flow rate and operational year for each $t = 2$ k well. D_i, q_i, q_k are found by LSE fitting the data to the function. j – number of proposed new or refractured wells ($t = 1$), N_n – first year average production days, N_a – average operational days after first year.

3.5 Summary for water production prediction protocols

Three water production prediction protocols are summarized in Table 3.4. Example of prediction methods modeling for single well is shown in figure 3.8.
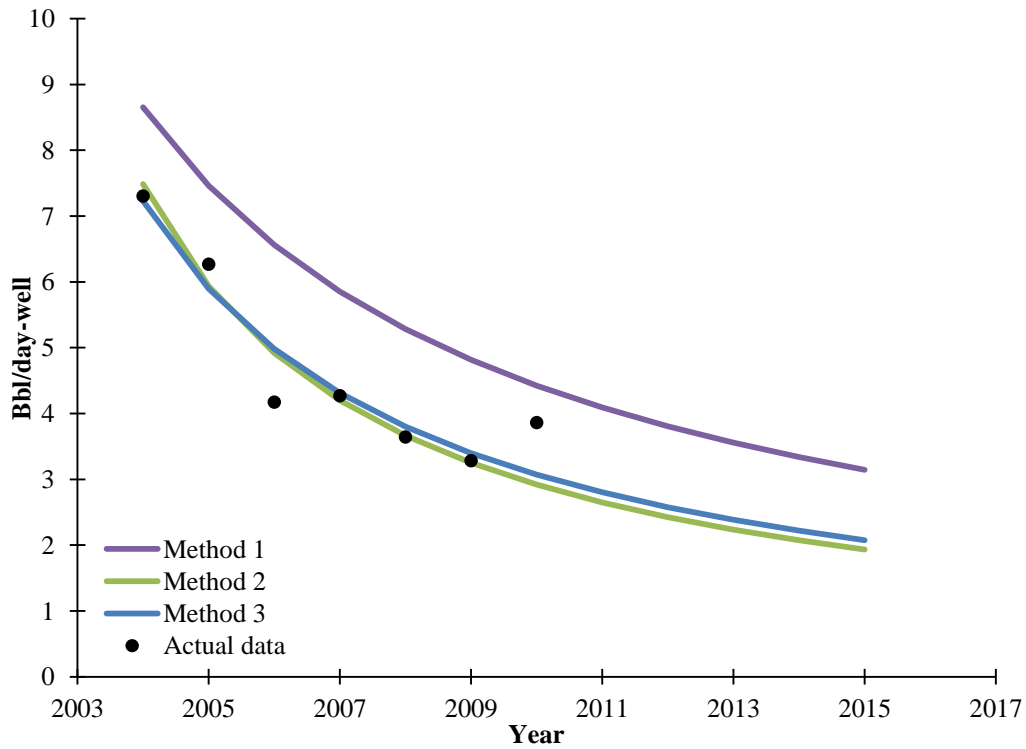
Figure 3.8. Example of prediction modeling for the well 05-125-02382.

Table 3.4 Summary table of prediction methods.

Prediction methods	Prediction from wells operated more than 2 years ($t > 2$)	Prediction from wells operated more than 1 year and less or equal to 2 years ($t = 2$)	Prediction from new or refractured wells ($t = 1$)	Advantages and disadvantages
Method (1) of prediction based on field production decline curve	Age of the wells and FWPDC is used to determine production rate for particular year.		Number of production days for new wells or refractured wells is 184 days. Water production rate is taken from FDF.	P: Quick prediction of water production from entire field. Low complexity, easy to automate. C: Prediction not accounting for individual well behavior (Each well with same age has same production rate)
	Based on production rate and production days, overall water production is calculated.			
Method (2) of prediction based on individual water production decline with constant field decline rate	LSE harmonic decline curve is fitted solving for initial production rate (q_i), decline rate constant, $D_i = conts$.		Number of production days for new wells or refractured wells is 184 days. Water production rate is taken from FDF.	P: Accounts for variation in initial water production from different wells. More accurate long term predictions. C: Assumes that the decline rate is the same for all wells. Complex in terms of calculation
Method (3) of prediction based on individual decline model for a field	LSE harmonic decline curve is fitted solving for initial production rate (q_i) and decline rate (D_i).	LSE harmonic decline curve is fitted solving for initial production rate (q_i), decline rate constant, $D_i = conts$.	Number of production days for new wells or refractured wells is 184 days. Water production rate is taken from FDF.	P: Accounts for variation in initial water production and decline rates from different wells. More accurate long term predictions. Compares correlation coefficients from method (2) and chooses highest one. C: Complex calculations.
	Correlation coefficient calculated for each well data with fitted curve and compared with those calculated in method (2). Curve with highest correlation coefficient is left.			

The first method does not account for spatial variation and temporal variation of water production. It uses the same initial production rates and same decline rate for all wells with the

same age/operational year. Therefore, use of this method should be limited to quick estimations of water production in the near future from existing wells.

Figure 3.5 (water production distribution for a first year) shows that initial water production is highly variable. The second method accounts for variation in initial water production from existing wells, but the average decline rate for the field is used for each individual well. The decline rate may fluctuate from one well to another, therefore, there can be differences in water production.

The third method also accounts for variation in initial production and decline rates for all existing wells. The field decline curve is used for all new or refractured wells. Therefore it is believed that this method will give the most accurate forecasts. However, use of this method requires the most complex calculations and modeling.

3.5.4 Prediction scenarios

This section shows three scenarios using the prediction methods described above. Predictions made are based on data prior to and including 2010. Prediction methods include:

- Prediction using average 2010 production data;
- Prediction based on method (1);
- Prediction based on method (2);
- Prediction based on method (3).

Fig. 3.9 shows *scenario one,* which assumes no field development for the next 10 years (no drilling in 2011-2020, just existing wells). Fig 3.10 shows *scenario two*, which assumes constant field development (20 new wells or refracs per year) for the same period. Figure 3.11 shows *scenario three,* which assumes constant aggressive field development (100 new wells or frac jobs each year) for 10 year forecast.

36
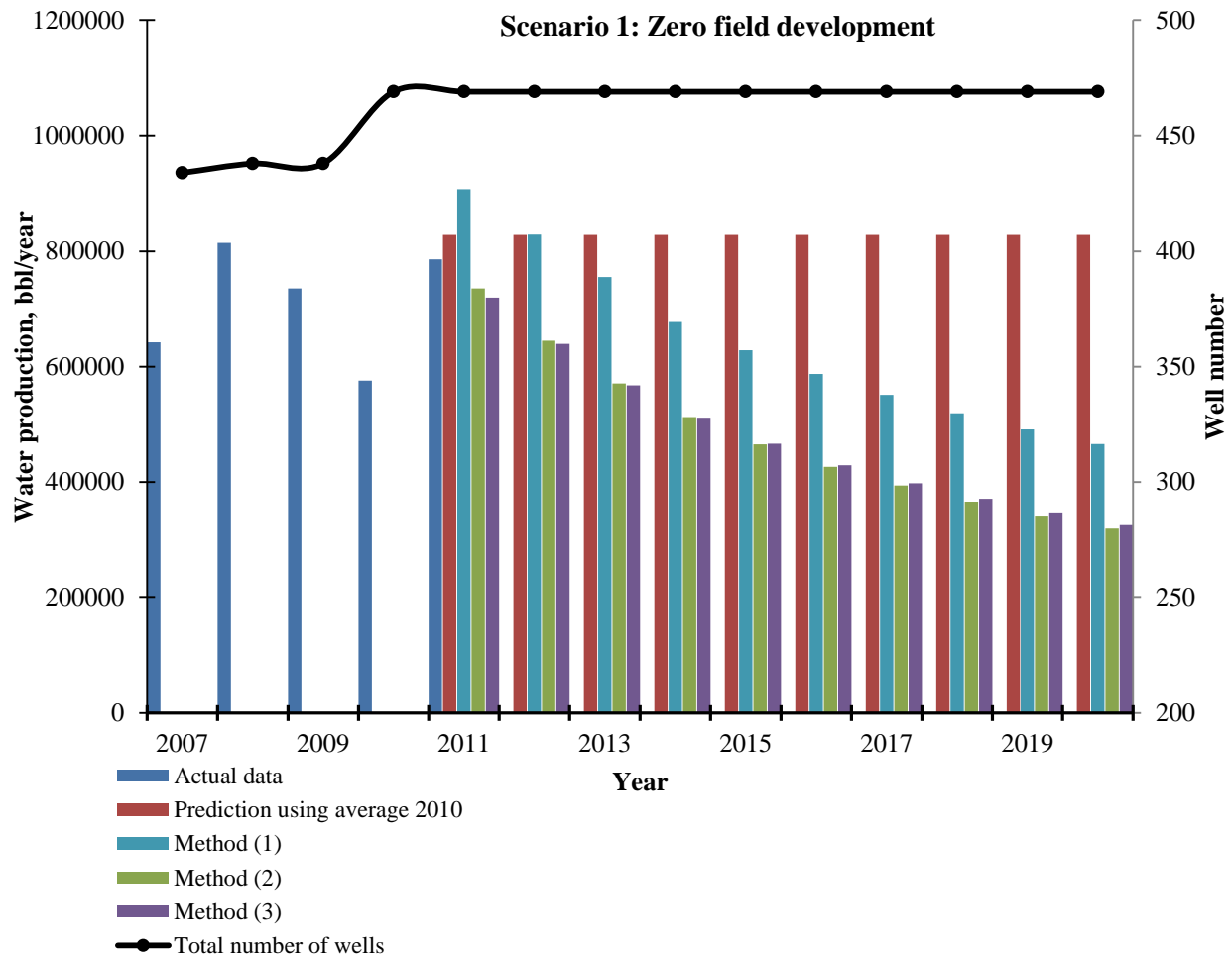
Figure 3.9. Scenario 1. No field development for the next 10 years. . Predictions made are based on data prior to and including 2010 wells.

Predictions with all three of the methods were compared with estimations made using average production data from 2010. To predict produced water production using average 2010 data, for the same set of wells average annual water production was calculated (1776 bbl/well-year). The number of wells in each year was multiplied by the 2010 average to estimate total water production for that year.
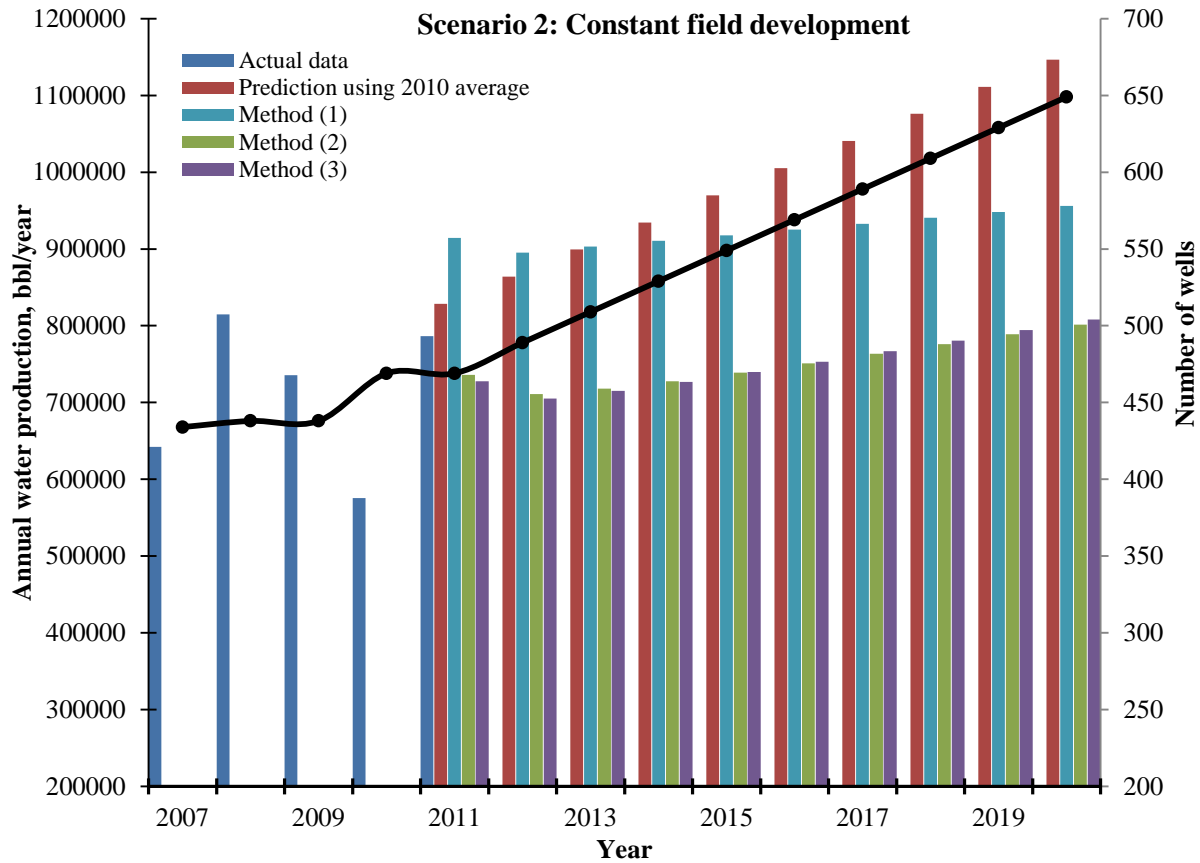
Figure 3.10. Scenario 2. Constant field development of 20 new wells or frac jobs per year. Predictions made are based on data prior to and including 2010.

It can be seen from all three scenarios that under the assumptions made (zero, constant and aggressive field development), there is a significant difference in estimated volumes between prediction methods accounting for water production decline and prediction methods using only historical average values. Actual 2011 water production was 790000 bbl from 469 selected wells, 9 of them were refractured. Prediction using average 2010 overestimated water production by 5% (830000 bbl), method (1) overestimated by 16% (910000 bbl), method (2) underestimated by 6% (770000 bbl) and method 1 underestimated by 7% (730000 bbl). Prediction methods 2 and 3 were close for near future predictions as well as long term predictions. Predictions differences using average 2010 and prediction method 3 were 500000 and 340000 bbl for scenario 1 and 2 respectively over a 10 year forecast.
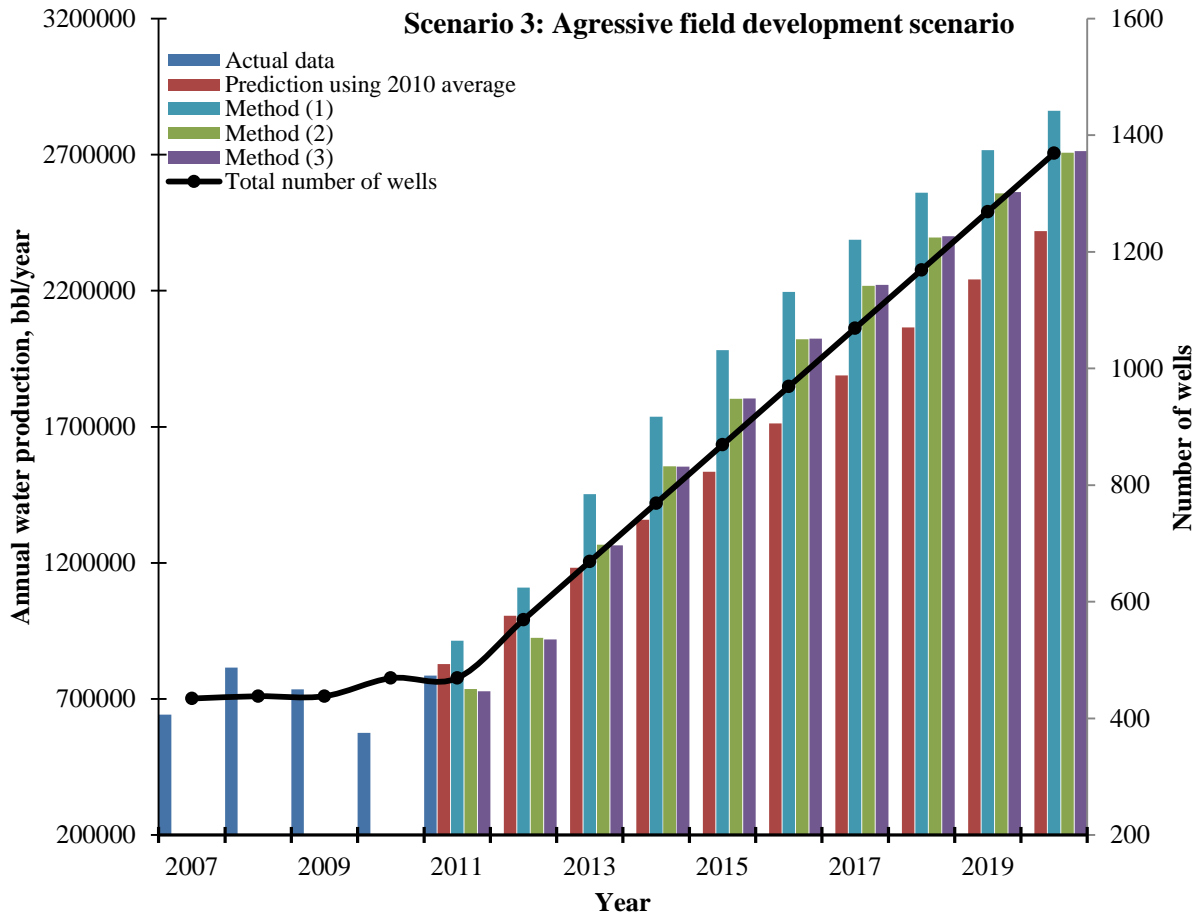
Figure 3.11. Scenario 3. Constant aggressive field development of 100 new wells or frac jobs per year (20% of existing wells). Predictions made are based on data prior to and including 2010.

From provided scenarios, it is clear that water production prediction using only historical average values can lead to overestimation in slow development years (Scenarios 1 and 2) and underestimation in aggressive development periods (scenario 3).

Accurate well-based water prediction is important when dealing with small groups of wells or when siting a treatment plant (water handling facility). Flows from each well can be accounted for to minimize pumping costs. As method 3 uses water production rate decline modeling for each existing well, resulting water production prediction is accurate for individual wells and small group of wells. All the proposed new wells or refractured wells are modeled using FDF. Use of individual well based modeling water production from proposed wells drilled after the

last known water production data and before the predicting year has to be cumulatively accounted as well.

3.6 Assumptions and limitations

In reality, many factors affect water production. Some wells are drilled and have just started producing, some wells are plugged or abandoned, and some wells are closed for maintenance.

When predicting water production, some assumptions have to be made:

a. Water production volumes available from the COGCC database are assumed to be accurate. The database contained many missing or zero values for annual water production, while gas production and production days were present. Noble Energy specialists confirmed that some production information was not uploaded completely to the COGCC database as it was reported to them. Therefore, missing or unavailable water production data is ignored during calculations and analysis.

b. The field decline curve used to describe water production from wells is based on the statistical average field water production values. This curve gives only a general idea or trend of water production within a particular field. Well stimulation and drilling is done differently by different operators or service providers. Therefore, water decline might be different for different wells.

c. When a well is plugged or abandoned, it is assumed to be very old in well age, and has very small water production according to the decline curve; therefore, the impact on total water production from closed or abandoned wells is assumed to be negligible.

d. Refractured wells are assumed to have the same impact on water production as new, just completed wells.

3.7 Water quality model

Produced water quality varies widely depending on many factors such as the geological formation, the geographical location, the depth of the formation, production stimulation methods, type of hydrocarbon, chemicals used during drilling and stimulation, and maturity of the field (Clark C.E. et al., 2009). Salts, scaling metals, oil and grease, suspended solids, formation organic and inorganic compounds, and radioactive elements are the major constituents of produced water (Clark C.E. et al., 2004). In addition to naturally occurring constituents, produced water also contains chemicals added during drilling, completion and oil/water separation processes. Concentrations of all of these constituents are mainly dictated by formation rocks and formation water with a very minor effect of the feed water used for stimulation or drilling. Oil and grease and suspended solids are removed by treatment methods such as clarification, media filtration and adsorption (Acharya R., et al. 2011). TDS (salinity) is decreased by membrane desalination or thermal distillation, hardness/metals removed by softening. Desalination and softening can account for the majority of capital cost of a produced water treatment system (Kimbal, B. 2011). Knowledge of current and predicted water quality parameters can aid in optimal design of a produced water treatment facility. This study shows a framework for predicting water quality parameters contributed mainly by formation rocks such as TDS, Ca, Mg and other metals. A water quality parameter (WQP), which is used further in the text, is any measurable constituent (element or group of elements like Ca, Mg, Sr, TDS etc) in produced water which is dissolved directly from formation rocks surrounding produced water.

3.7.1 Concept background

The water-rock interaction is a complicated process, and more information can be obtained about it from the work of Brantley et al. (2008). For ease of use, simplifications and assumptions are made for the dissolution process in this study.

Initially, water in the formation is in chemical equilibrium with host rocks, minerals and hydrocarbons. Hydraulic fracturing introduces bulk quantities of relatively fresh water, which dilutes the formation water. As any chemical system needs some time to reach its equilibrium, water in the formation will dissolve formation rocks or precipitate solids until it reaches equilibrium for given conditions. In other words, the quality of the water will change with time as it gets exposed to formation rocks. Kinetics of dissolution is driven by many factors such as the activity of the constituent, temperature, pH, pressure, and the presence of other elements. For formation water, all of these factors are mainly dependent on the geology (characteristics) of the formation and the depth of the well.

Kinetics of dissolution can be derived from Fick's First Law of diffusion (Eq. 7) and the integrated form is equivalent to the equation of first order reaction kinetics (Eq. 8) (Smith, 2004):

$$\frac{dn}{ds} = -DS\frac{dc}{dx} \tag{7}$$

where: dn [mol] - the amount of the dissolved substance within time interval dt [s], D [$\frac{m}{s}$] - diffusion coefficient; S [m^2] - the total surface of the dissolved solid substance; $\frac{dc}{dx}$ - concentration gradient;

$$C = C_s(1 - e^{-kt}) \tag{8}$$

where: k – reaction rate, C_s – maximum concentration of substance or concentration at equilibrium.

For the case of PW quality from oil and gas wells, one more term has to be added to account for concentration of WQP in the initial water (Eq. 9):

$$WQP = C_s \cdot (1 - e^{-kt}) + C_i \tag{9}$$

where t is age of well, WQP is water quality parameter, C_i is the initial concentration of water quality parameter, k is reaction rate and C_s is saturation concentration of WQP.

There is limited reported research on temporal variation of water quality during the lifecycle of a well, but examples of TDS and other constituents' kinetics provided for flowback water by Acharya, et al. (2011) are found to be a close to first order reaction kinetics. Therefore, it is assumed that the change of WQP with time can be modeled using first order kinetics. Reaction rates for different WQPs can be determined by back solving equation (9) using a series of actual measurements of WQPs at constant time intervals.

Any real world phenomena like elevation, characteristics of the formation (geology), as well as the depth of formation gradually change spatially and can be modeled using classical interpolation techniques. For this reason, it is expected that reaction rate (k) and the maximum concentration (C_s) for a particular WQP should gradually vary spatially for wells producing from the same formation. If k and C_s values for a WQP are given for a set of points (wells) in the field, then spatial interpolation can be implemented to build a surface of k and C_s values. With this interpolation map, each well in the field can be given its own k and C_s values extracted from the surface using the location of the well. Finally, each well will have its own water quality estimation curve.

3.8 Combined water quality and production model

Concentration of particular WQPs for a selected area can be estimated using the individual water production and water quality models described earlier. In order to determine the concentration of WQPs from selected wells, a simple mass balance has to be done using the following equation (Eq. 10):

$$C(WQP) = \frac{\sum_{i=1}^{i} WQP_i \cdot WP_i}{\sum_{i=1}^{i} WP_i} \tag{10}$$

where WPQ_i, WP_i – water quality parameter and water production for particular well.

An example of combined model implementation is described in the next section.

3.8.1 Example of water quality model use.

This section provides implementation of combined water quality and production methods in a case study of Noble Energy wells in Yuma County. Fig. 3.12 shows the Noble Energy, Inc. well age distribution in Yuma County.

Dissolution of the formation is one of the reasons why produced water from the wells deteriorates with well age. Initially, the produced water has a high quality (low concentration of metals, salts and other constituents), but as production continues, concentration of
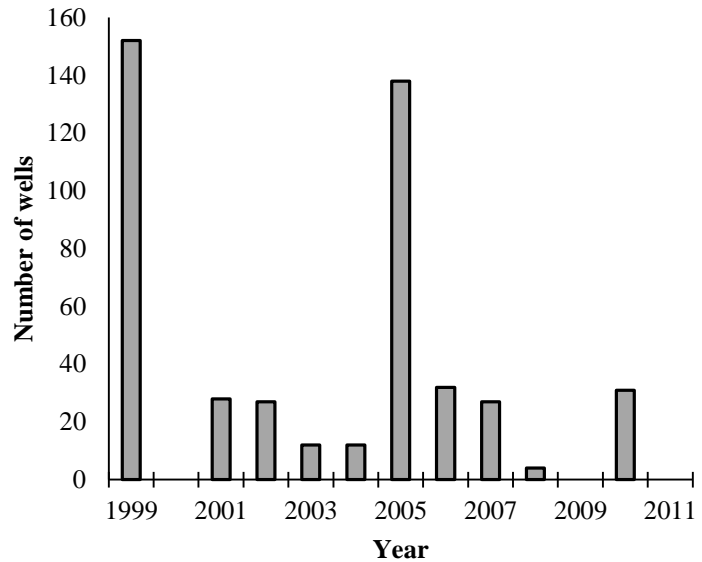
Figure 3.12. Wells drilled in each year in study area

constituents, directly impacted by formation rocks, will increase until it reaches the saturation point. For the Yuma case study, it is assumed that produced water total dissolved solids (TDS) is one of the water quality parameters of interest. Instead of TDS, metals or other formation dependent constituents can also be modeled using a first order reaction rate (graphical representation shown in Fig. 3.13) by applying Equation 9.

44
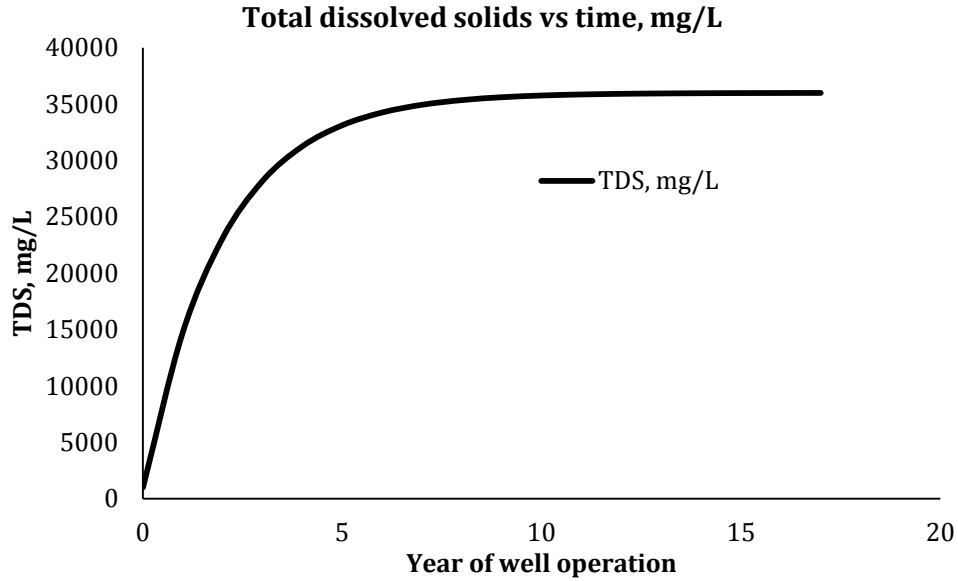
Figure 3.13. Example of temporal TDS increase in produced water for well with C_s=35000 and k=0.5.

For this case study, it was assumed that a temporal water quality analysis of 6 wells across the shale gas field was conducted (at least 3 sample points, age of the well and initial water quality (C_i) are needed to determine C_s and k values) and C_s and k values were determined. Table 3.6 shows assumed values.

Table 3.6. Wells with known k and Cs values.

API	Well name	X, m	Y, m	TDS, mg/L	$k, year^{-1}$	C_S, mg/L
05-125-06132	1-4 SCHAFER	729370	4430677	34027	0.59	30000
05-125-08315	13-12 PARISET	714801	4428667	37090	0.60	32000
05-125-09492	23-14 STATE 243	742909	4418542	39118	0.72	38000
05-125-10044	31-32 STONE	719583	4442423	27802	0.55	27000
05-125-10144	12-2 VONDERWAHL	704304	4439859	19883	0.50	25000
05-125-10711	34-12 ALLEN	735702	4409796	39109	0.75	37000

X and Y coordinates of the wells are in UTM 13N, NAD 1983

After using kriging or an inverse weighted spatial interpolation technique (in ESRI ArcGIS a spatial analysis toolbox can be used (Childs, 2004)) C_s and k values can be predicted for the entire field using values provided in table 3.4. Results of interpolation are shown in fig. 3.14-3.15.
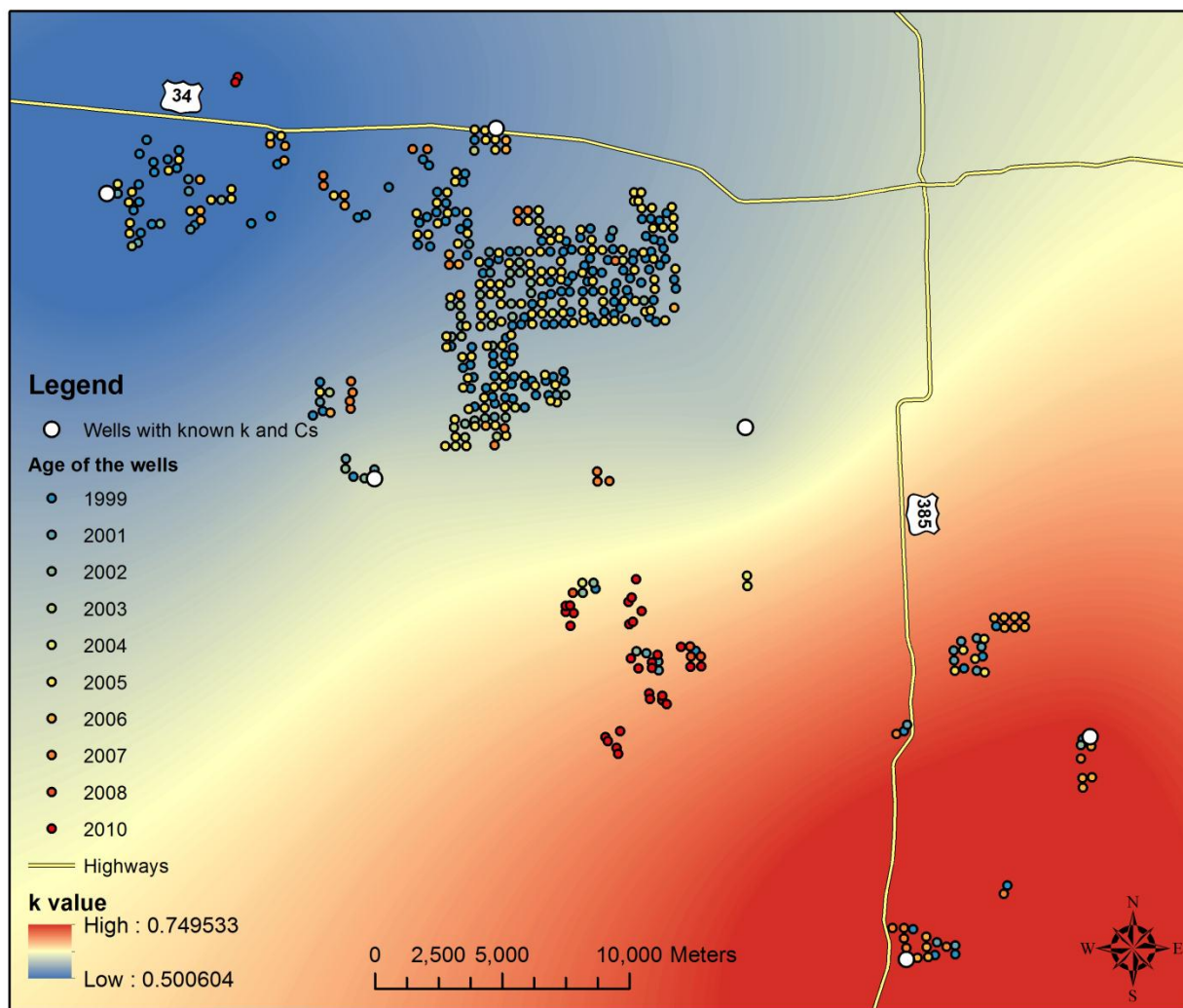
Figure 3.14. Interpolated *k* (dissolution rate) values across the field using 6 known points.
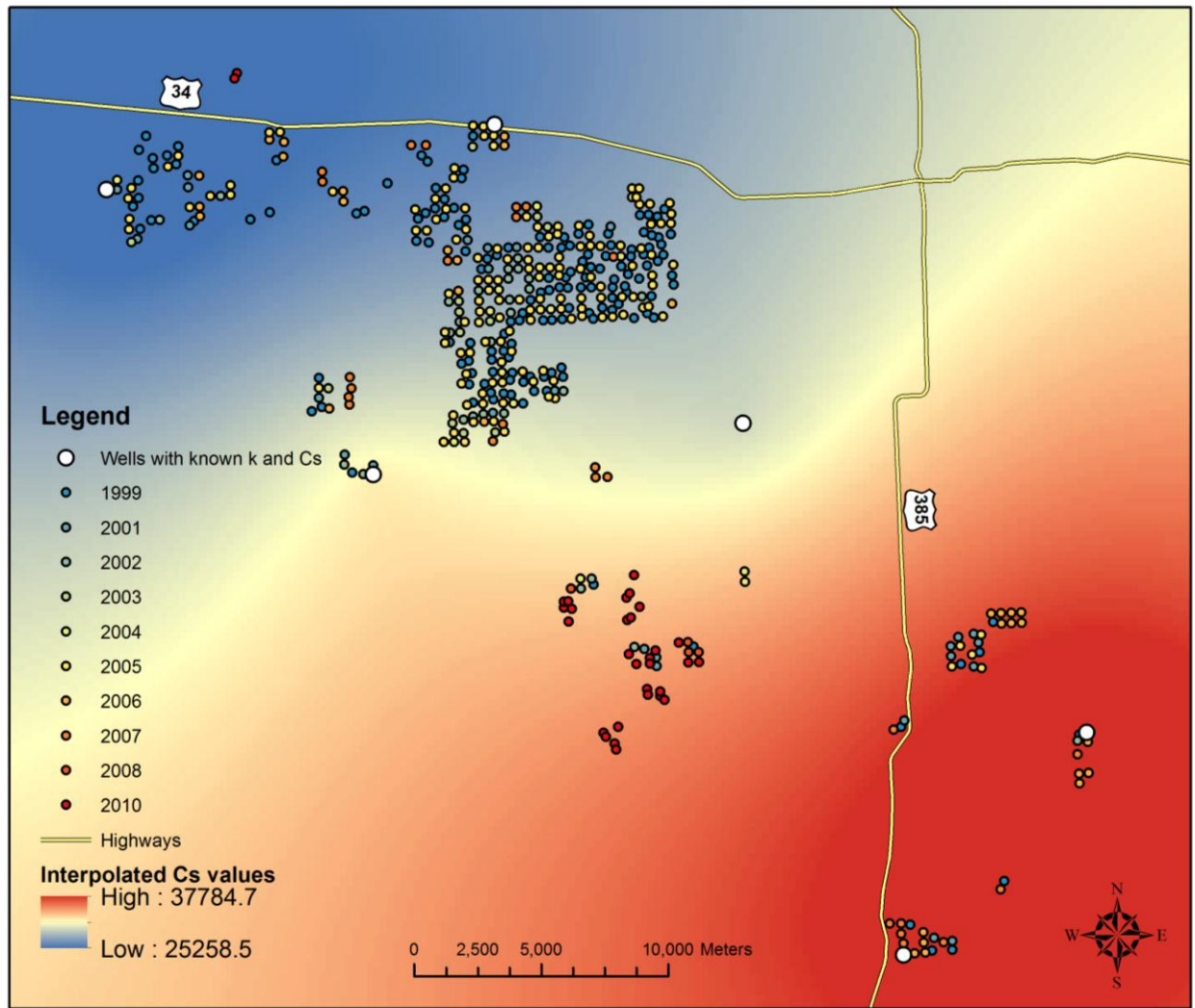
Figure 3.15. Interpolated C_s (maximum concentration) values across the field using 6 known points.

After creating "k" and "C_s" surfaces, each well in the study area can be given k and C_s values based on spatial location (extract point values tool was used from ESRI ArcMap). Predicted and current water quality can be estimated using found k, C_s values, age of the well and C_i using eq. 9 (Table 3.7).

Table 3.7. Random 8 wells with determined k and Cs values.

API	Well name	X, m	Y, m	TDS, mg/L	C_s, mg/L	k, $year^{-1}$	Age by 2011	Drilled/ fractured
05-125-02379	12-28 WILTFANG	729435	4424854	34082	32895	0.44	8	2004

47

05-125-06132	1-4 SCHAFER	729370	4430677	34027	30185	0.39	13	1999
05-125-08288	23-7 ALLEN	736900	4410457	39110	37012	0.55	11	2001
05-125-08313	21-17 ROUNDTREE	719323	4437561	37701	28186	0.36	10	2002
05-125-08844	12-26 DICKSON	722980	4424570	33819	32469	0.43	7	2005
05-125-10251	33-33 ALLISON	739939	4423238	39120	35797	0.49	6	2006
05-125-10466	33-7 ALLEN FEDERAL	737283	4410288	39110	37004	0.55	5	2007
05-125-11324	43-6B Wingfield Trust	727648	4421296	34067	33824	0.46	4	2008

X and Y coordinates of the wells are in UTM 13N, NAD 1983

Using the discussed water quality framework and method of water quantity prediction (3) discussed in previous sections, two development scenarios are shown for Noble Energy wells in Yuma County. For the scenario (1) of no field development, prediction of water quality for area of study is shown in fig. 3.16.
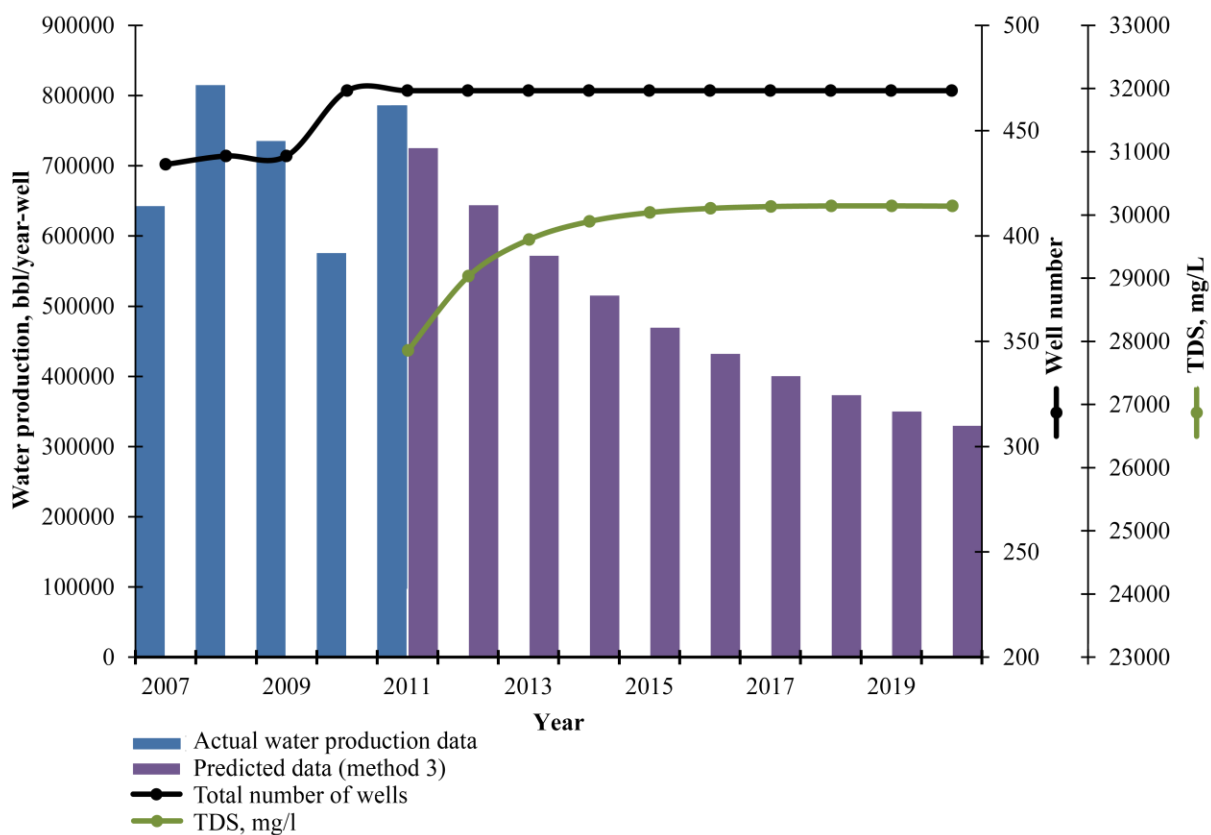
Figure 3.16. Scenario 1. Interpolated C_s and k values are used to predict water quality in combination with water production from existing wells (scenario 1).

To predict water quality for a scenario of constant field development, some assumptions should be made. As seen from spatial distribution of well ages (fig. 3.14), most recent wells were developed a little bit south of the middle of the map. So we can assume that for next years, drilling will take place in that area. From Fig. 3.14-15 we can assume $k=0.5$ and $C_s=32000$ for new drilled wells.

For scenario (2) of constant field development, prediction of water quality for the area of study is shown in Fig. 3.17.
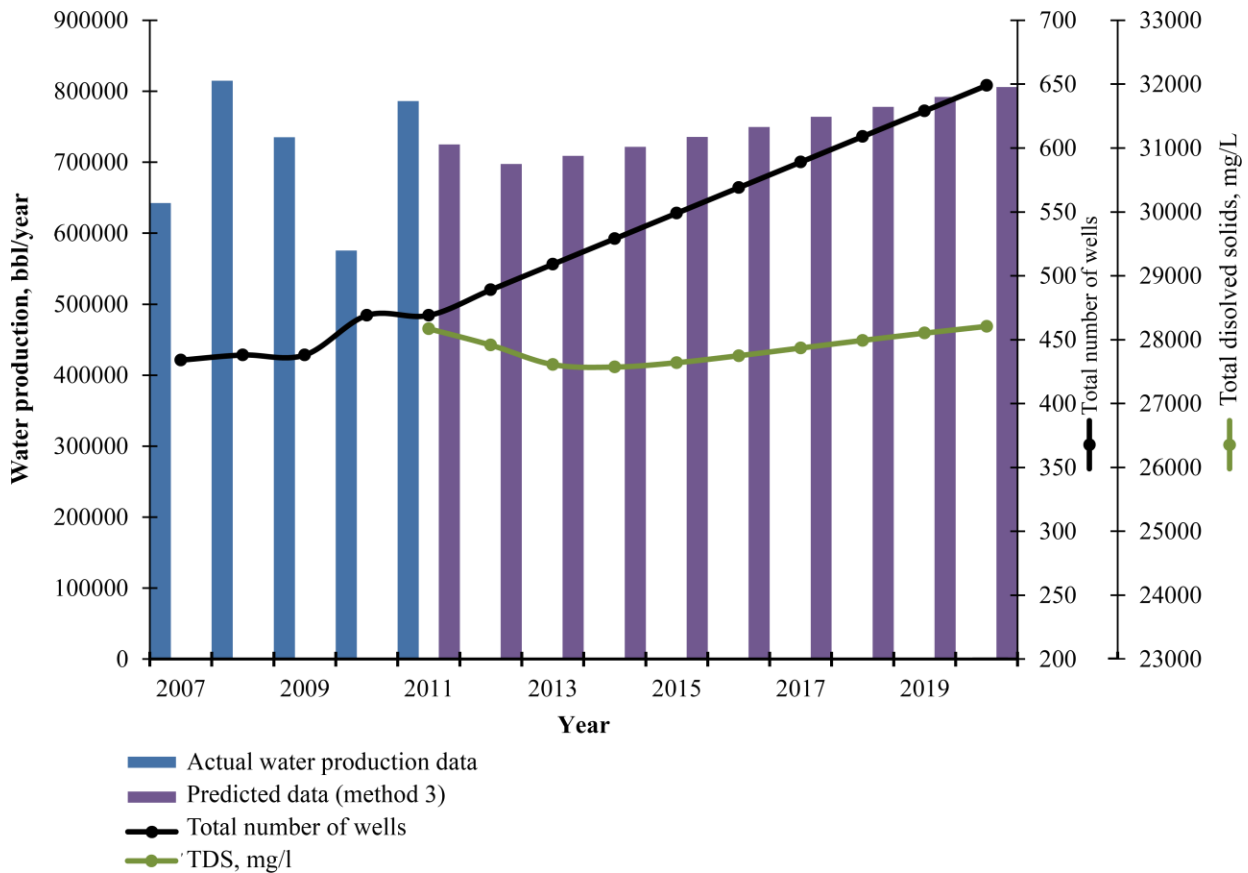
Figure 3.17. Scenario 2. Constant field development. Interpolated C_s and k values are used to predict water quality from existing wells, $k=0.5$ and $C_s=32000$ are used to predict water quality from new drilled wells.

Water produced and water quality could be estimated and predicted for a range of future development options. Based on proposed spatial location, water quality kinetic parameters can be

estimated and historical water production data from nearby fields can be used to generate a decline model for a well. This information is valuable to make better water management decisions, hence provide more accurate information about water production and quality, greatly improving the ability to treat and reuse PW.

3.8.2 Limitations

This is only a conceptual method of predicting and estimating water quality from shale gas wells producing from one formation. Further validation of this procedure is needed to prove the methodology. Produced water quality from shale gas wells in Yuma County has relatively low TDS, below 30000; therefore, predicted water quality temporal changes are not significant. For the scenario of no field development, water quality changes only by 10%. For Marcellus shale, where TDS values as high as 200000 mg/L, results might be significantly different. This conceptual methodology assumes that geology varies gradually spatially, however this might not be a case in some instances. Local changes might be due to different events that happened locally millions of years ago. For example, if a lake evaporated it could have left a formation with much higher TDS or other constituents.

Another limitation is that this methodology assumes that the majority of constituents dissolve from the producing shale formation. However, in some cases fractures can propagate near formations or create connections to other aquifers, which could dictate water quality.

3.9 Conclusions

Spatial and temporal understanding of produced water production and quality from shale gas is important to plan long term recycling strategies and optimize design and siting of water handling and treatment facilities. Three different protocols of water production prediction have been developed based on decline curve analysis for a field. A water quality prediction framework

was proposed based on dissolution kinetics and geospatial data. Among three different methods, it is recommended using the produced water prediction method based on individual well water decline modeling (method 3) because it accounts for all the spatial, temporal and stimulation variations in water production, leading to more accurate well-based predictions in a small or large field. From provided scenarios, it is clear that water production prediction using only historical average values can lead to overestimation in slow development years and underestimation in aggressive development periods. Dissolution kinetics and the spatial relationships used in water quality modeling account for temporal and spatial variations in water quality and are therefore believed to be more accurate. Further validation of the method is required. The case study and scenarios used for Noble Energy wells in Yuma County demonstrates that these prediction methods can be used in any other shale gas fields by altering decline models and coefficients.

Information on how current and future development of oil and gas fields will affect water quality and production can help make better decisions about water treatment, disposal, transportation, and the efficacy of pursuing development in a given field.

4. APPLICATION OF PREDICTION TOOLS

4.1 Excel based tool for predicting water production and quality from Noble Energy shale gas vertical wells in Yuma County.

4.1.1 Introduction to the tool

Water production and quality prediction protocols described in chapter 3 as the foundation for a MS Excel-based tool to predict produced water volumes and TDS from Noble Energy Inc. vertical shale gas wells located in Yuma County. The tool can be used by stakeholders to predict future water production and TDS for different field development scenarios. Predictions are based on existing wells historical production data and an assigned schedule of well development for future years. Water quantity predictions from existing wells are based on method (3) (individual well decline modeling) using historical data, new or refractured wells modeled using method (1) described in chapter 3. Water quality (TDS) prediction uses assumed values from section 3.7. Water production and TDS prediction from proposed wells are based on FDF development (section 3.1) and TDS kinetic coefficients (section 3.8). Screen shots of the tool can be seen in Fig. 4.1. This tool can also be used to forecast water production and water quality from any other shale gas field with vertical wells by altering the field decline model, water kinetics coefficients and historical data.

4.1.2 Inputs and outputs of the tool

The number of new or refractured wells for each future year, field water decline model and TDS kinetics coefficients are the main inputs of the tool. The user can input new wells that are planned in each future years starting from 2012. A water production decline and quality model for Yuma County wells that is developed in chapter 3 (equations 3 and 7) is used in this tool to predict water production and TDS.

Year	NW	WPew	WPnw	WPda	TDSew	TDSnw	TDSda	TTDS	Count	TWP
2011	5	612882	13452		27079	13591		26789	446	626334
2012	10	535992	26905	21017	27966	13591	21228	27061	456	583914
2013	10	480078	26905	59464	28553	13591	22586	27216	466	566446
2014	10	435634	26905	91780	28943	13591	24194	27412	476	554318
2015	10	399327	26905	119660	29203	13591	25422	27605	486	545891
2016	50	369033	134524	144178	29377	13591	26346	25424	536	647735
2017	10	343324	26905	334198	29493	13591	24122	26338	546	704427
2018	10	321200	26905	325250	29571	13591	26855	27620	556	673355
2019	10	301938	26905	322928	29622	13591	28270	28290	566	651772
2020	10	285002	26905	324320	29656	13591	29024	28654	576	636226

Initial water quality and parameter for new wells

q_i	19.74	initial water production rate	Input
D_i	0.35	field decline rate	
C_i	1000	initial TDS of frac fluid	
k	0.5	Dissolution rate for new wells	
C_s	32000	Maximum concentration for new wells	
N_a	362	average production days during operating year	
N_n	184	average production days during first year of production	
NW		new or refractured wells	
WPew		Water production from existing wells	
WPnw		Water production from new wells	
WPda		Water production from wells that drilled after 2011	
TWP		Total water production	
TDSew		TDS existing wells	
TDSnw		TDS new wells	

Figure 4.1. Screen shot of MS Excel based tool for water production and TDS estimation from Noble Energy Inc. wells in Yuma County.

Outputs of the tool:

- Water production from existing wells (WPew, wells drilled before predicted years - 2011 included).

  ✓ Calculation based on historical data using method (3);

- ✓ Predictions are made using developed decline curves for each well.

- Water production from wells drilled or refractured in predicted years during first operational year (WPnw).

  - ✓ Calculation is based on FDF. Number of new wells multiplied by the average water production rate and average production days in first operational year. For example, if 5 wells were drilled in 2015, then fraction of water produced in 2015 by this new wells is $Q = 5 \; wells \cdot (\frac{19.74}{1+1\cdot0.35}) \frac{bbl}{day \cdot well} \cdot 184 \frac{days}{year} = 13450 \frac{bbl}{year}$.

- Water production from wells drilled or refractured in predicted years in second or above operational years (WPda).

  - ✓ Calculation based on FDF. This output shows water produced by wells which is drilled in predicted years, but not in first operational year. For example, if in 2012, 2013 and 2014 were drilled 10 wells in each, then in 2015 water production from this wells (30 wells drilled in 2012-2014) will be $Q_{2015} = 10 \; wells^{2012} \cdot \left(\frac{19.74}{1+4\cdot0.35}\right) \frac{bbl}{day \cdot well} \cdot 362 \frac{days}{year} + 10 \; wells^{2013} \cdot \left(\frac{19.74}{1+3\cdot0.35}\right) \frac{bbl}{day \cdot well} \cdot 362 \frac{days}{year} + 10 \; wells^{2014} \cdot \left(\frac{19.74}{1+2\cdot0.35}\right) \frac{bbl}{day \cdot well} \cdot 362 \frac{days}{year} = 106681 \frac{bbl}{year}$.

- Total water production for predicted year (TWP).

  - ✓ Sum of water production from existing and proposed new or refractured wells.

- TDS from existing wells

✓ TDS for each existing well is predicted for 2012-2020 using water quality prediction protocol described in section 3.

✓ Using predicted water production and simple mass balance, TDS from all wells is calculated: $C_n = \frac{\int_{i=1}^{i} WP_i \cdot TDS_i}{\sum_{i=1}^{i} WP_i}$, where WP_i is a predicted annual water production from i well in year n, TDS_i is a predicted TDS values from i well in year n, C_n is a TDS in year n from existing wells.

- TDS from wells drilled or refractured in predicted years during first operational year

  ✓ Same mass balance applied for this wells using corresponding water production information.

- TDS from wells drilled or refractured in predicted years in second or above operational years

  ✓ Same mass balance applied for this wells using corresponding water production information.

- Graphs of water production and TDS values.

4.2 GIS based web application

4.2.1 Overview

GIS is used to visualize, interpret and analyze spatial data in many ways that reveal trends, relationships, patterns in the form of maps, reports and charts (ESRI, 2012). This section provides a framework for a GIS based web application that can provide an analysis platform to producers and consulting firms to predict water production and/or water quality, optimize location of treatment facilities, truck routings and help make other decisions related to water management using their own uploaded information. The application can serve public and

government agencies by providing information about well locations, production, regulations, violations and others.

Protocols for produced water production and quality predictions that have been developed in Chapter 3 are quite complex and require a lot of effort to implement. These protocols can be integrated as one of the modules into a web application. Development of a web application can be done using different open source and commercial resources. The author recommends developing an application using commercial software from ESRI (Environmental Systems Research Institute) – ArcGIS for Server. ESRI is one of the world's leading GIS service software company and offers a powerful framework for creating rich Internet based web applications. ArcGIS for Server is one of the ESRI products which can provide GIS functionality to any web server. GIS functionality can include web mapping, different spatial analysis tools like siting of treatment facility, minimizing piping distance, spatial interpolation and many other geo-processing tools. Figure 4.2 shows a brief data flow chart and interaction between different components of web application. Figure 4.3 shows possibilities of application and outputs.

4.2.2 Components of web application

- User interface
    - ✓ Web browser interface, where user can interact with application: Import data, see prediction graphs, locate treatment facility etc.
    - ✓ Based on MS Silverlight interface.
- Calculation engine
    - ✓ Calculates FDF based imported production data.
    - ✓ Calculates predicted values of water production for existing wells based on FDF.
    - ✓ Predicts water quality parameter based on k and C_s values for existing wells.

56
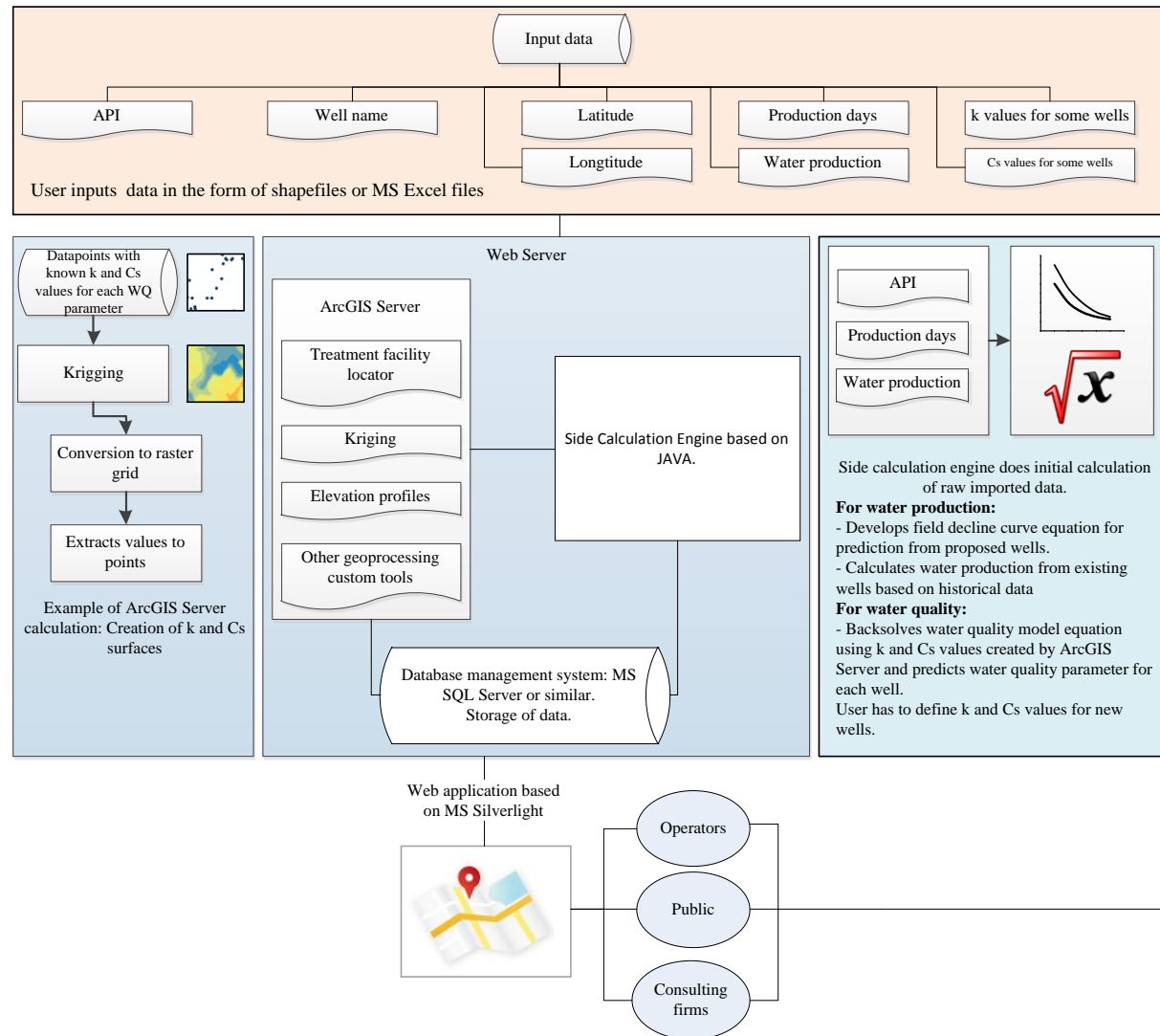
Figure 4.2. Flow chart of web based GIS application.
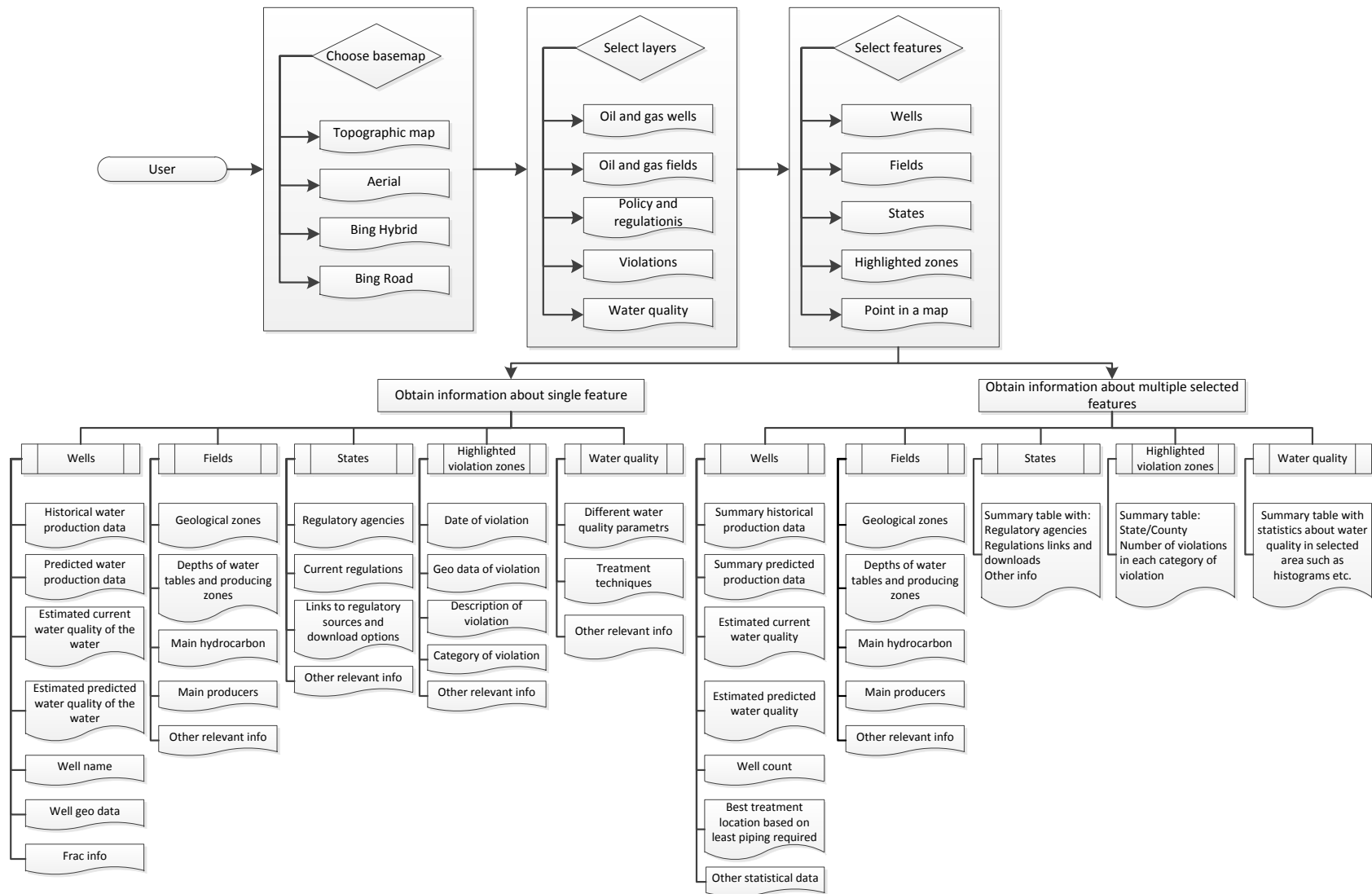
Figure 4.3. Outputs of web application.

- ✓ Predicts water quality parameter based on k and C_s values inputted by user for proposed wells.

- ArcGIS for Server

  - ✓ Provides mapping

  - ✓ Provides interpolation service

  - ✓ Provides tool and means for location optimization

  - ✓ Other GIS services

- Database Management System

  - ✓ Controls creation, maintenance and use of database

  - ✓ Stores data

4.2.3 Clients of web application

Main clients of the web application:

- Oil and gas producers

- Oil and gas service companies

- Consulting firms

- Public

- Government agencies

4.2.4 Data input and outputs

Input for a web tool can be different databases including publicly available databases or internal industry databases. All the information should be standardized in order to upload. A standardized form of an upload file should be decided during programming stage.

Producers and consulting firms can use the application to analyze their well data to make better decisions. Table 4.1 shows outputs of the application depending on what data is uploaded for analyses.

Table 4.1. Information provided and outputs of the tools from wells location, production and quality data.

Information	Tool outputs		
	Basic treatment facility locator, mapping	Water quantity prediction. Advance treatment facility locator (incorporates water production).	Water quantity and quality prediction from existing wells, treatment facility siting optimization
Well name(API)*			
Latitude/Longitude*			
Oil/Gas/Water production data			
Production days			
k and C_s values for number of wells			

Table 4.2. Information that can be on the web site for public availability.

Feature type	Name	What information contains
Point feature	Wells	• Name • Geo-location • Operator • Producing formation • Water used for drilling • Water used for stimulation • Oil/gas/water production data • Water quality
	Violation zones/points*	• Information about violations in oil and gas industry.
Polygon	Oil and gas fields	• Information about main oil and gas fields. • Description of main producing zones/formations and other relevant information about oil and gas fields.
	States/County	• Information about oil and gas regulations in each state.

*Violation zones can be point or polygon feature

Figures 4.4-4.6 shows possible user interface of the GIS based web application
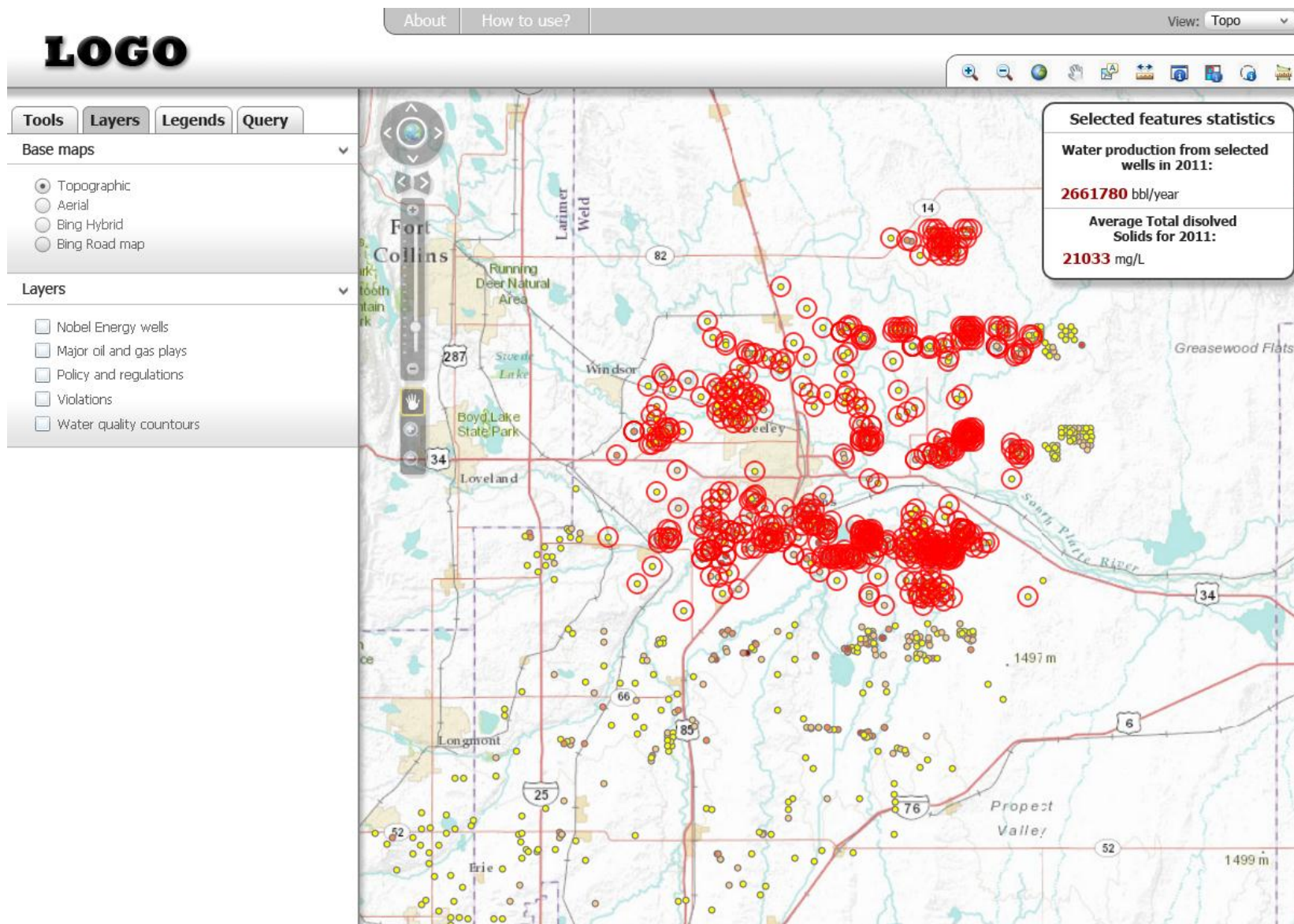
Figure 4.4. Possible user interface of web tool: layers tab
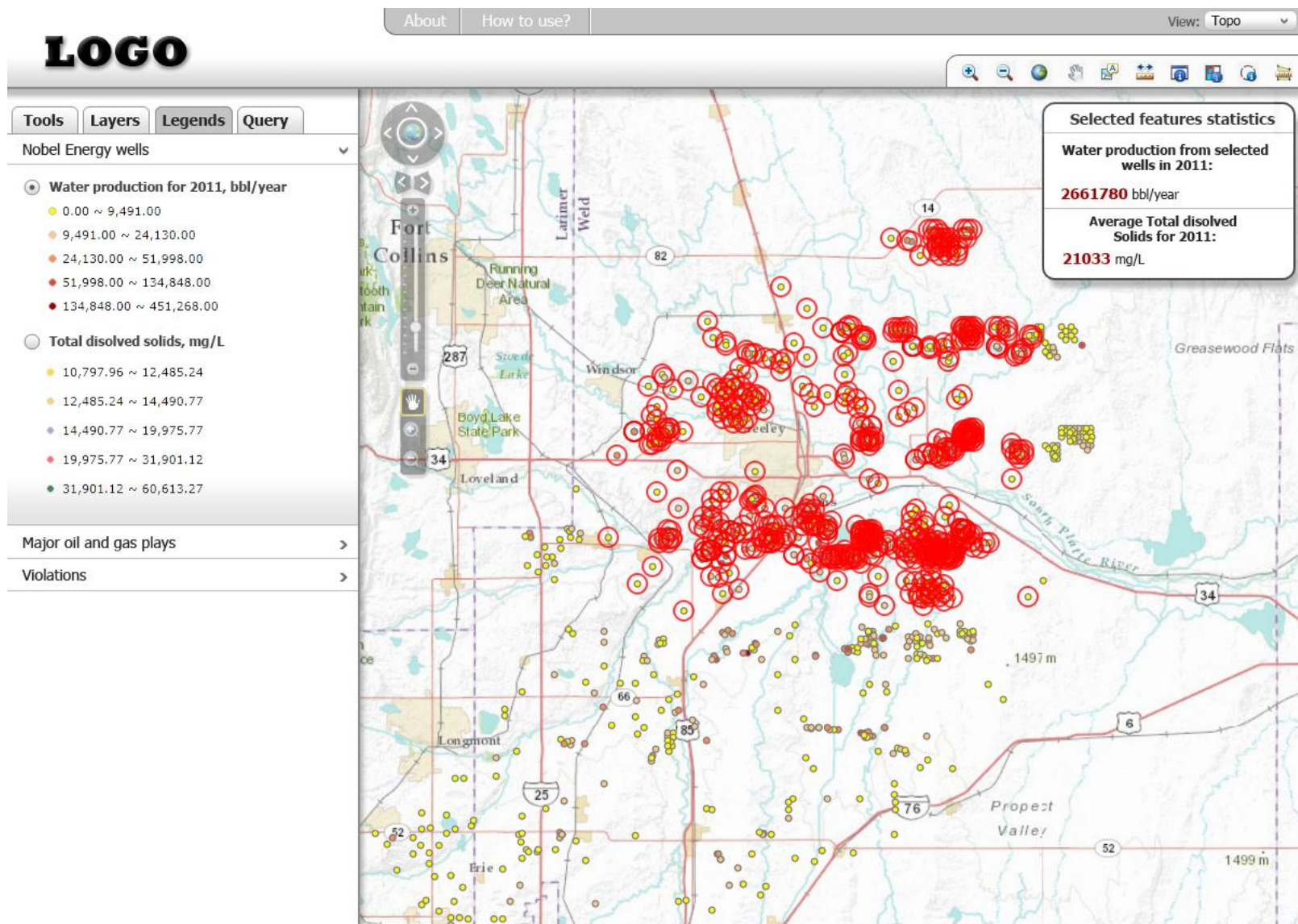
Figure 4.5. Possible user interface of web tool: legends tab
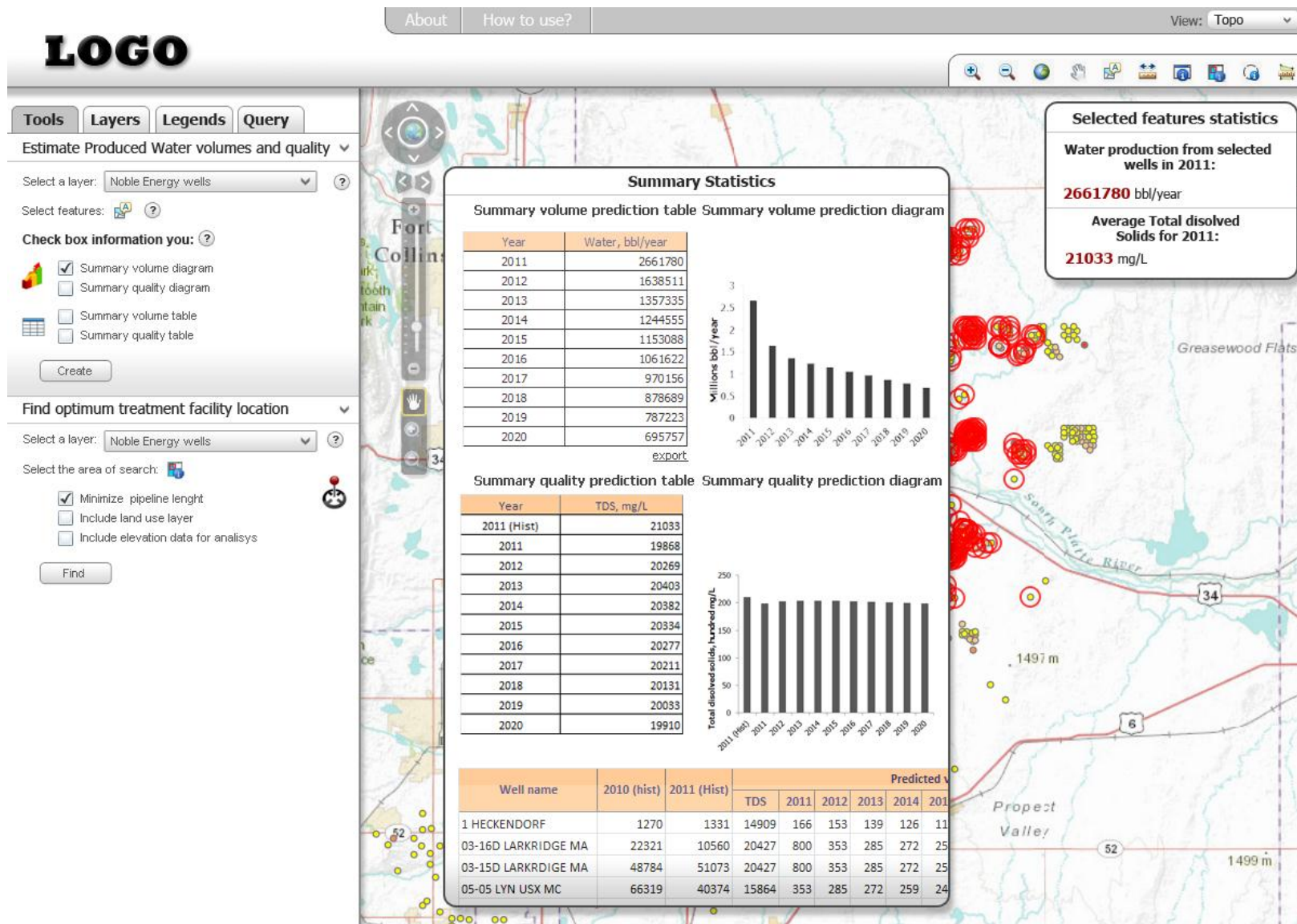
Figure 4.6. Possible user interface of web tool: tools tab

5. CONCLUSIONS

Produced water production and quality from vertical shale gas wells were studied to better understand spatial and temporal changes in these parameters. A literature review showed that the water management is a key element to enhance safety and environmental protection during the development of domestic natural gas and other petroleum resources. In addition, since water is an operations material, its availability is critical to meeting production goals. Large amounts of water are used and produced during the development of unconventional resources and most of produced water is deep well injected for disposal.

Many factors, such as geological restrictions, local water availability, policies and regulations, environmental risks, public perception and others provide an incentive to operators to treat and recycle their produced water. Research on treatment processes is fairly developed but studies related to management of water in a spatially and temporally distributed environment are limited. The objective of this study was to fill this gap and provide a framework for future research.

Three different protocols for water production prediction have been developed based on decline curve analysis in the Yuma field. A water quality prediction framework was proposed based on dissolution kinetics and geospatial data. Among the three different methods, it is recommended using a produced water prediction method based on individual well water decline modeling (method 3). This method accounts for all the spatial, temporal and geological variations in water production, which will lead to more accurate well based predictions in a small or large (field) scale. However, complex calculation required for this method is a downside of it. From all scenarios, it is clear that water production prediction using only historical average values can lead to overestimation in slow development years and possibly underestimation in aggressive development periods. For the scenario of zero field development, ten-year forecast

results were 2.5 times higher for predictions made using average historical data in comparison with method (3) which accounts for water production decline in each existing well. For the same prediction methods, in case of aggressive field development scenario of 100 new wells each year (20% of existing wells), use of prediction based on average historical data might under predict water production already for second year forecast. Dissolution kinetics and spatial data were used in water quality modeling to account for temporal and spatial variations in water quality. Further validation of the method is required. The case study and scenarios used for Noble Energy wells in Yuma County demonstrates that these prediction methods can be used in other shale gas fields by altering decline models and coefficients.

An Excel-based tool, which incorporates water quantity and quality protocols, was developed to predict water production and TDS from Noble Energy Inc. wells in Yuma County for different field development scenarios. Stakeholders can make better water management decisions and plan long term recycling strategies using the outputs of this tool.

GIS based web applications can provide analysis platforms to producers and consulting firms to predict water production and/or water quality, optimize location of treatment facilities, truck routings and help make other decisions related to water management, while public and government agencies can acquire valuable information about wells, production, regulations, violations and others. This study provided a framework for development of GIS based application.

REFERENCES

Acharya R., et al. 2011. Cost Effective Recovery of Low-TDS Frac Flowback Water for Reuse. Department of Energy: DE-FE0000784

Aduschkin V.V., Rodionov V.N., Turuntaev S., Yudin A. 2000. Seismicity in the Oilfields, Oilfield Review Summer 2000, Schlumberger, URL: http://www.slb.com/resources/publications/industry_articles/oilfield_review/2000/or2000sum01_seismicity.aspx (Accessed: June 2012)

American petroleum institute (API). 2010. Water Management Associated with Hydraulic Fracturing. First edition. June 2010

Arkansas Geological Servey (AGS). 2011. Arkansas Earthquake Updates, internet-database with survey of earthquakes in Arkansas, Arkansas Geological Survey. 2011. URL: http://www.geology.ar.gov/geohazards/earthquakes.htm (Accessed: June 2012)

Arps J. J. 1944. "Analysis of Decline Curves", Trans. AIME (1945) 228, Petroleum Technology, September 1944

Baihly J., Altman R., Malpani, R., Luo F. 2010. Shale gas production decline treand comparision over time and basins. SPE paper 135555. SPE Annual technical conference and exhibition, Florence, Italy. September, 2010

Brantley S. L., Kubicki J. D. and White A. F.. 2008. "Kinetics of Water-Rock Interaction". ISBN 978-0-387-73562-7, 2008

Broderick J., Anderson K., Wood R., Gilbert P., Sharmina M. 2011. Shale gas: an updated assessment of environmental and climate change impacts, Tyndall Centre, University of Manchester, 2011.

Carlson, K. 2012. Improving Water Resource Management in the Niobrara. Niobrara Report (May, 2012)

Chesapeake Energy. 2008. Managing Water Resource Challenges in Select Natural Gas Shale Plays. GWPC Annual Forum, September 20-24, 2008 http://mail.gwpc.org/meetings/forum/2008/proceedings/Ground%20Water%20&%20Energy/ SatterfieldWaterEnergy.pdf (Accessed: June 2012)

Clark, C.E., and J.A. Veil, 2009. Produced Water Volumes and Management Practices in the United States, ANL/EVS/R-09/1, prepared by the Environmental Science Division, Argonne National Laboratory for the U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory, September 2009

COGCC. 2012. Water Sources and Demand for the Hydraulic Fracturing of Oil and Gas Wells in Colorado from 2010 through 2015 (January 2012): http://cogcc.state.co.us/ (Accessed: June 2012)

Colorado oil and gas conservation commission database: http://cogcc.state.co.us/ (Accessed: April 2012)

Das, P. C. 2012. Selection of technology for produced water treatment. SPE paper 151864. North Africa technical conference and exhibition, Cairo, Egypt. February, 2012

Department of Energy (DOE). 2009. Modern Shale Gas Development in the United States: A Primer, 2009

Dores R., Hussain A., M. Katebah, Adham S. 2012. Using advanced water treatment technologies to treat produced water from the petroleum industry. SPE International Production and operations Conference and Exhibition, Doha, Qatar May 2012

67

Encana. 2012. Natural gas 101. What is natural gas? http://www.encana.com/natural-gas/natural-gas-101/ (Accessed: May 2012)

Energy information administration (EIA). 2011. Natural gas year-in-review 2010. Release date December 2011. http://www.eia.gov/naturalgas/review (Accessed: May 2012)

Energy information administration (EIA). 2012. Annual Energy Outlook 2012. Available online: http://www.eia.gov/forecasts/aeo/er/pdf/0383er%282012%29.pdf (Accessed: May 2012)

GOA. 2012. Energy-water nexus. Information on the Quantity, Quality, and Management of Water Produced during Oil and Gas Production, 2012

Goodwin, S. 2012. Lifecycle Analysis of Water Use and Intensity of Noble Energy Oil and Gas Recovery in the Wattenberg Field of Northern Colorado.

http://coloradoenergynews.com/2012-niobrara-report/ (accessed 30 May 2012)

Hutchings N. R., Appleton E. W., McGinnis R. A., SPE. 2010. Making high quality frac water out of oilfield waste. SPE paper 135469. Presented at SPE Annual technical conference and exhibition. Florence, Italy. September, 2010

INGAA Foundation. 2008. Availability, economics, and production potential of North American unconventional natural gas supplies. ICF International

Jason E.B., Haggstrom J., SPE. 2012. An environmental solution to help reduce freshwater demands and minimize chemical use. SPE paper 153867. SPE/EAGE European unconventional resources conference and exhibition, Viena, Austria. March, 2012

Jones F., SPE, Zimmerman M., SPE, Heinz W., SPE. 2011. Managing Environmental Risks from Shale Gas Exploration - Applying Lessons Learned in the US to New Ventures in Poland. SPE European Health, Safety and Environmental Conference in Oil and Gas Exploration and Production, Vienna, Austria, February 2011

Kent P. 2010. Gas Technology Institute (GTI), personal communication with Mark Zoback, 9 June, 2010

Kewen Li, Ronald N. 2003. A decline curve analysis model based on fluid flow mechanisms. SPE Western Regional/AAPG Pacific Section Joint Meeting held in Long Beach, California, U.S.A., 19–24 May 2003.

Kimbal, B. 2011. Key Considerations for FracFlowback/Produced Water Reuse and Treatment. Presentation in NJWEA Annual Conference, Atlantic City, USA. May 2011.

Lechtenbohmer S., Altmann M., Capito S. 2011. Impacts of shale gas and shale oil extraction on the environment and on human health, June, 2011. http://europeecologie.eu/IMG/pdf/shale-gas-pe-464-425-final.pdf (accessed: May 2012)

Lee J., Wattenbarger R., 1996. *Gas reservoir engineering.* Society of Pertoleum Engineers, Dallas, TX, SPE textbook series.

McElreath D. 2011. Comparison of Hydraulic Fracturing Fluids Composition with Produced Formation Water following Fracturing – Implications for Fate and Transport. http://www.epa.gov/hfstudy/comparisonofhffluidscompositionwithproducedformationwater.pdf (Accessed: June 2012)

Michaels, C., Simpson, J. L., Wegner, W. 2010. Fractured Communities: Case Studies of the Environmental Impacts of Industrial Gas Drilling. September 2010

Muraleedaaran S, SPE, Li X., SPE, Li L., SPE, and Lee R., SPE. 2009. Is Reverse Osmosis Effective for Produced Water Purification? Viability and Economic Analysis. SPE Western Regional Meeting, San Jose, USA, March 2009

NaturalGas.org. 2012. Overview of Natural Gas. Background. www.naturalgas.org/overview/background.asp (Accessed: May 2012)

Sakmar S. 2011. Shale gas development in North America: An overview of regulatory and environmental challenges facing industry. North American Unconventional Gas Conference and Exhibition, The Woodlands, Texas, USA, June 2011

Smith W.F. 2012. Foundations of Materials Science and Engineering 3rd ed., McGraw-Hill (2004)

USGS. 2012. Water Produced with Coal-Bed Methane, November 2000 http://pubs.usgs.gov/fs/fs-0156-00/fs-0156-00.pdf (Accessed: May 2012)

Vidic, R. D. 2012. Sustainable Water management for Marcellus shale development, 2010. URL: http://www.temple.edu/environment/NRDP_pics/shale/presentations_TUsummit/Vidic-Temple-2010.pdf (Accessed: May 2012)

Zoback M., Kitasei S., Copithorne B. 2010. Addressing the environmental risks from shale gas development. Worldwatch institute, July 2010.

APPENDIX A: SUPPLEMENTARY INFORMATION

A.1 Information about gas wells in Colorado and Yuma County.
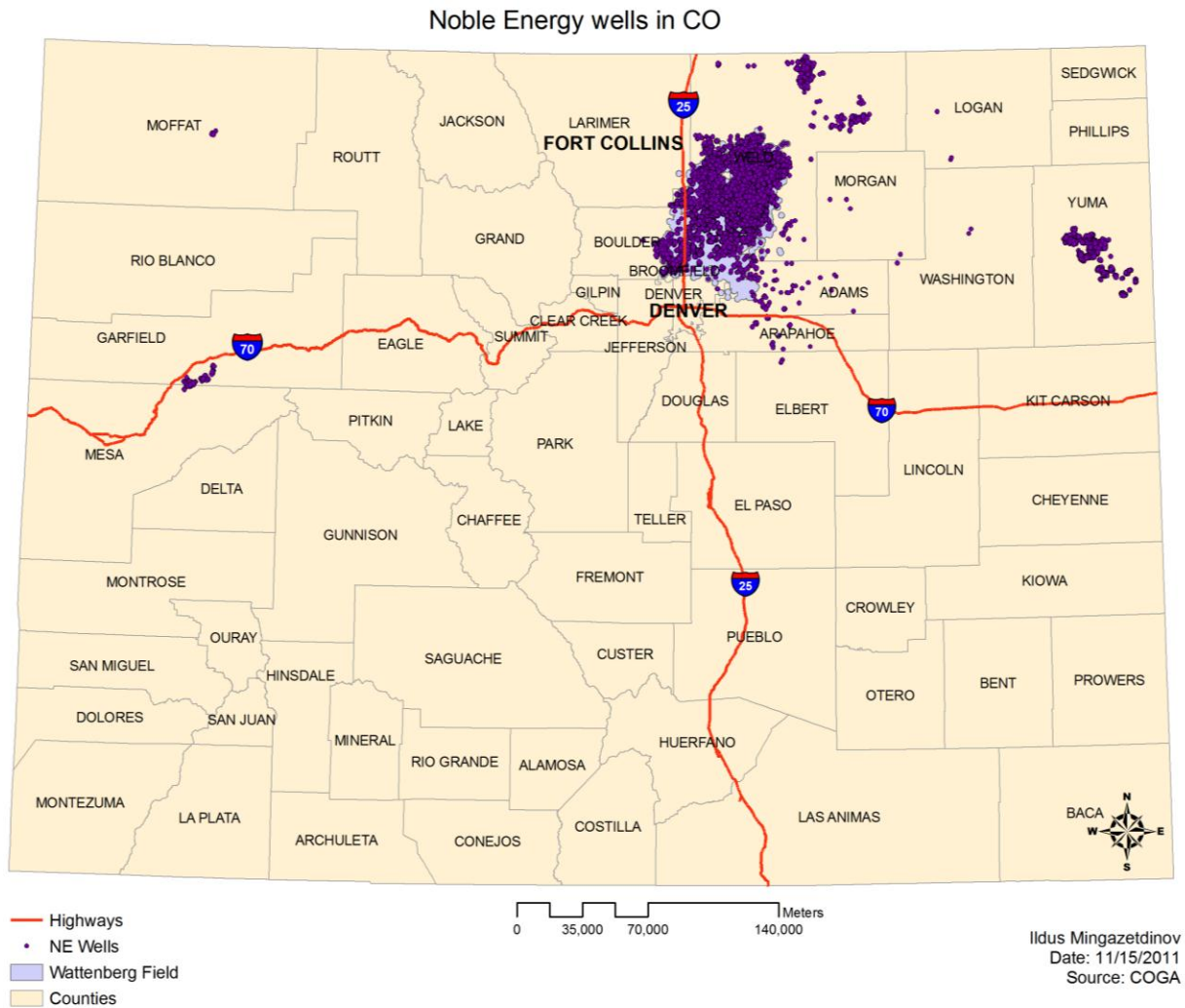
Figure A.1.1. Spatial distribution of Noble Energy wells in Colorado
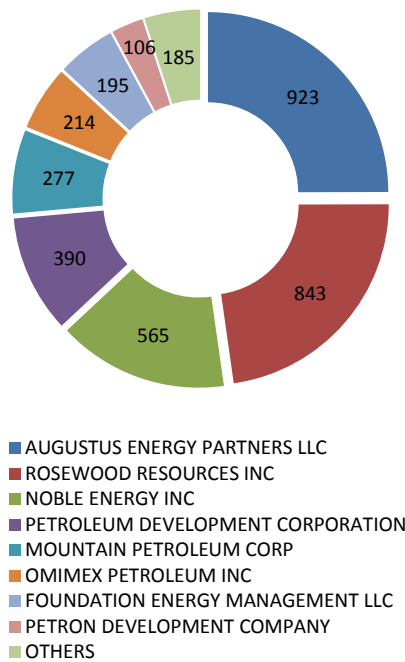
Figure A.1.2. Well owners in Yuma County.

Table A.1.1. Oil, gas and water production from different counties in Colorado.

County	Number of gas wells	Number of oil wells	Water production, Bbl/year	Oil Production, Bbl/year	Gas production, Bbl/year
RIO BLANCO	1541	562	107204240	4815314	93689736
LAS ANIMAS	2881	4	70402032	1024	119595317
GARFIELD	8828	17	40378465	2300854	639160668
WASHINGTON	166	236	27330317	483137	1530083
LA PLATA	3004	77	23174294	33396	422008661
MOFFAT	352	84	12480348	318364	19436387
WELD	7663	9895	9945703	20715892	218395822
CHEYENNE	53	248	6734296	1342134	6156049
LOGAN	10	98	6122754	195599	335799
YUMA	3692	0	4913286	3391	39297634
27 Others	2175	1232	22068923	2251747	339722532

A.2 Water used for fracturing
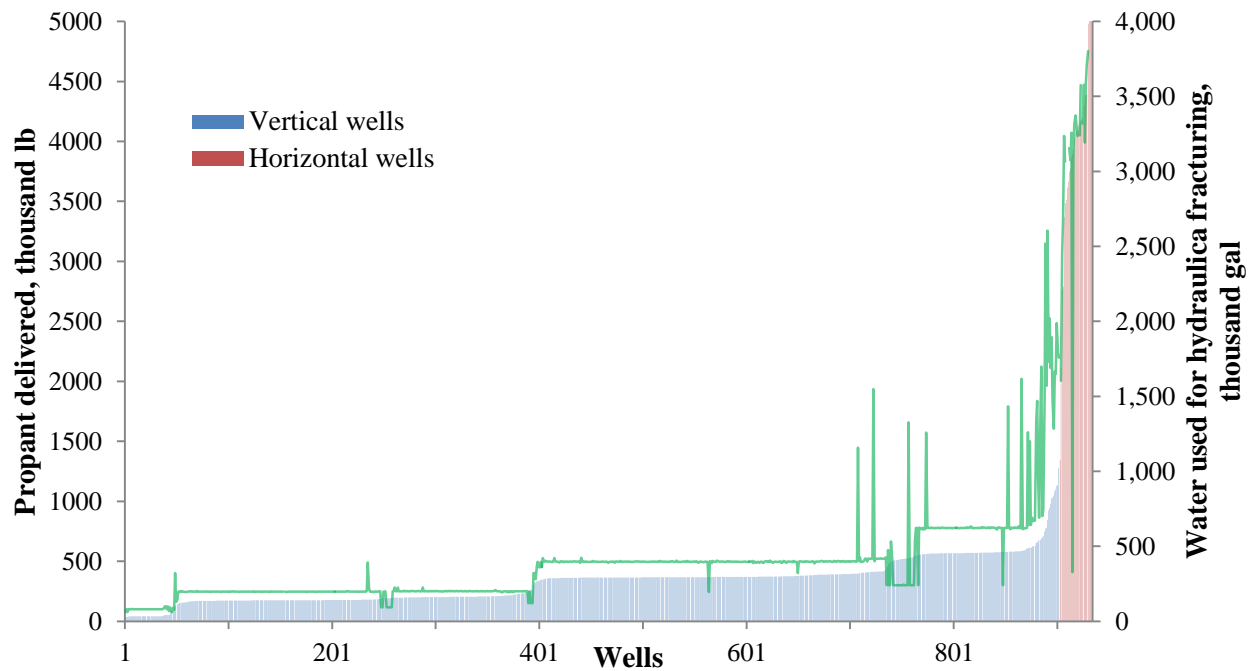
Figure A.2.1. Water and sand used for hydraulic fracturing. 934 Noble Energy Inc. wells stimulated in 2011 (Noble Energy Inc.).
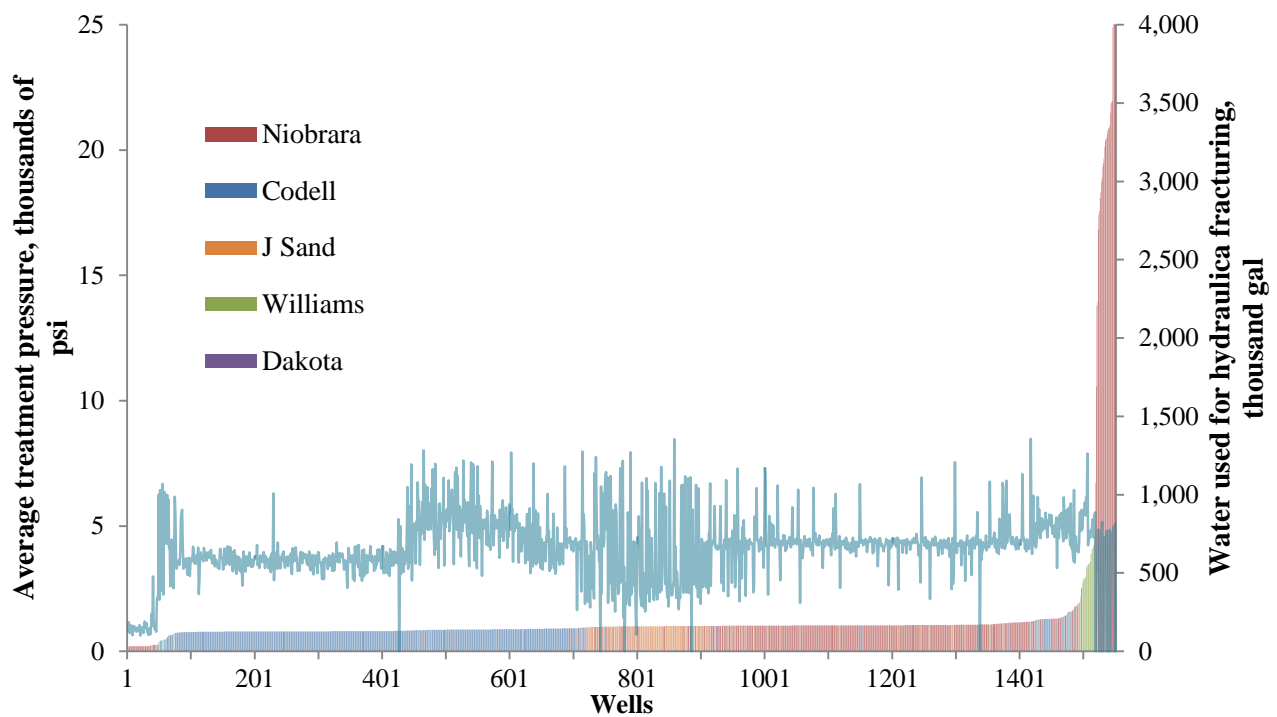
Figure A.2.2. Water used for hydraulic fracturing by formation. Noble Energy Inc. 934 wells hydraulically fractured in 2011.   (Noble Energy Inc.).
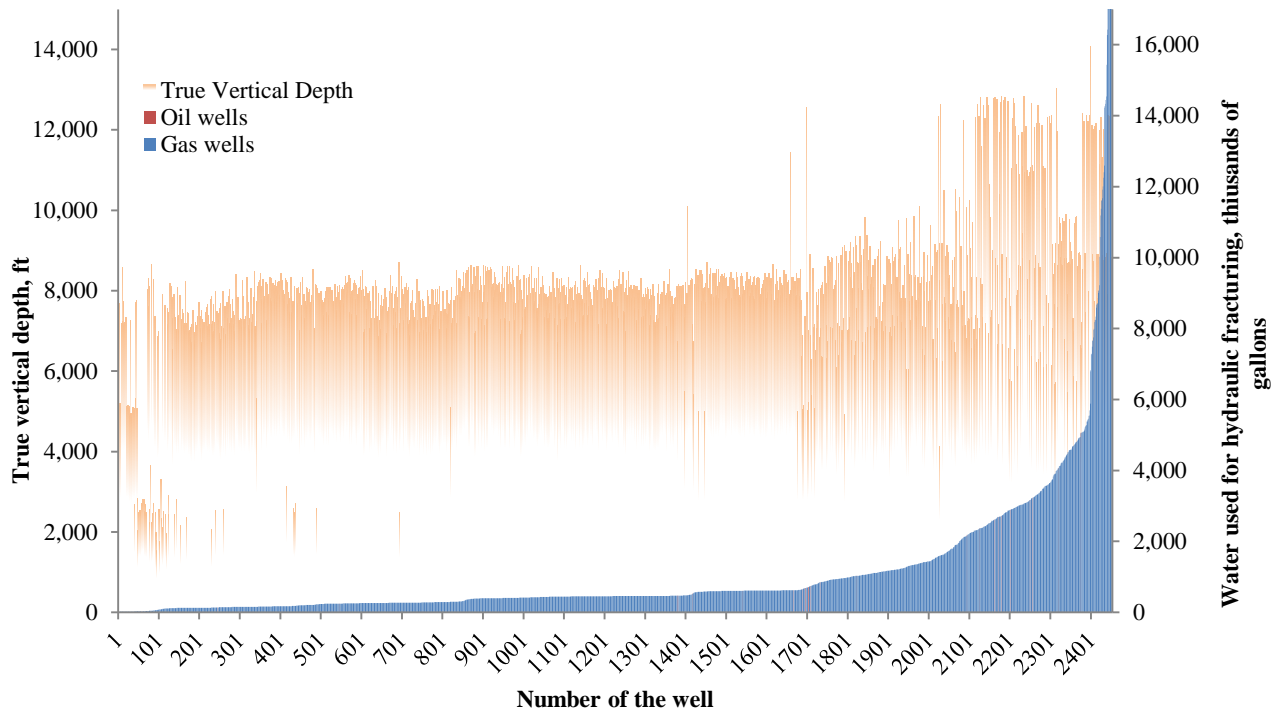
Figure A.2.3. Distribution of water use for hydraulic fracturing in Colorado (FracFocus.org, 2454 wells)
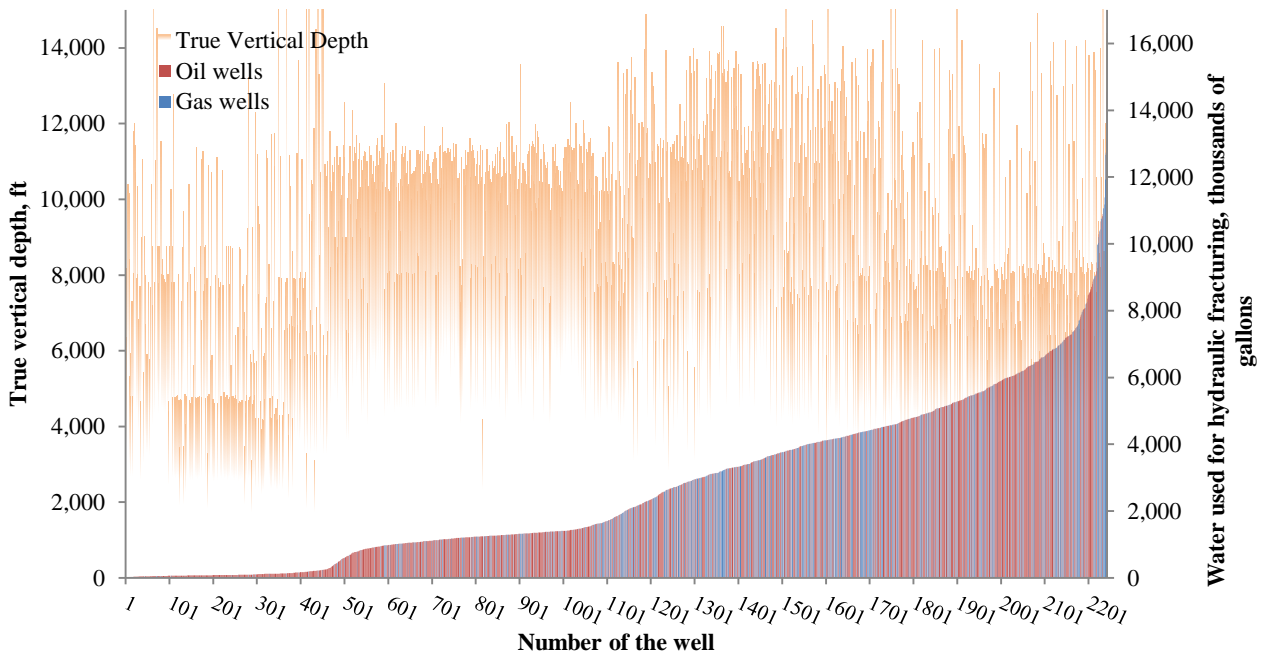
Figure A.2.4. Distribution of water use for hydraulic fracturing in Texas (FracFocus.org, 2243 wells)
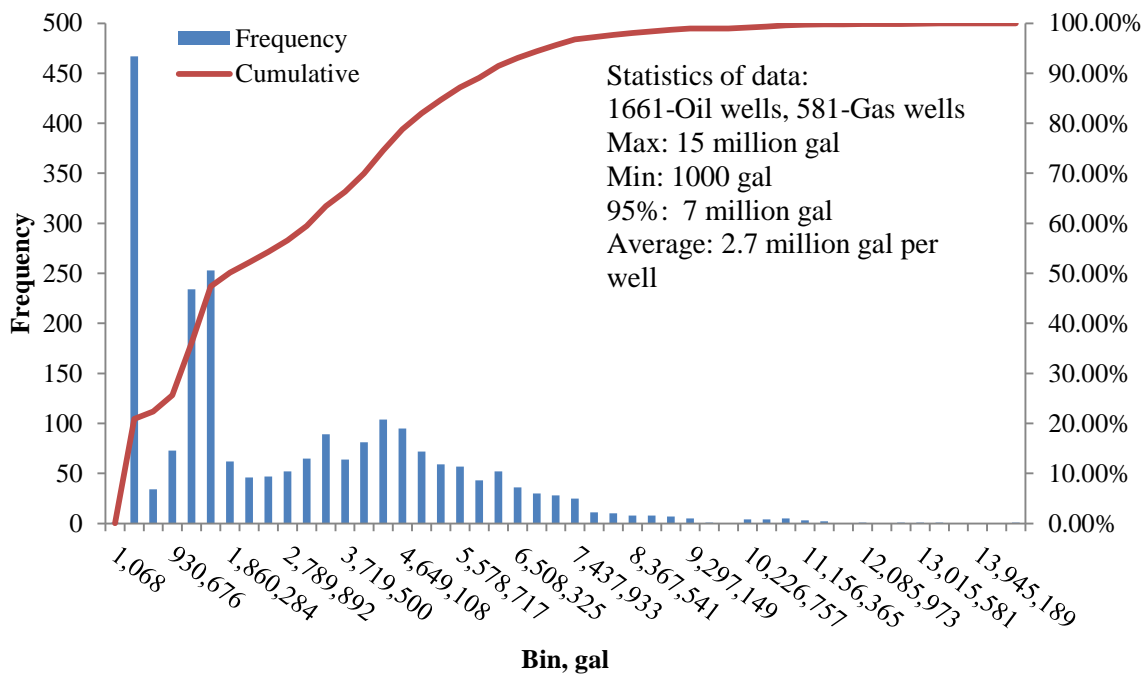
Figure A.2.5. Density distribution of water use for hydraulic fracturing in Texas (FracFocus.org).
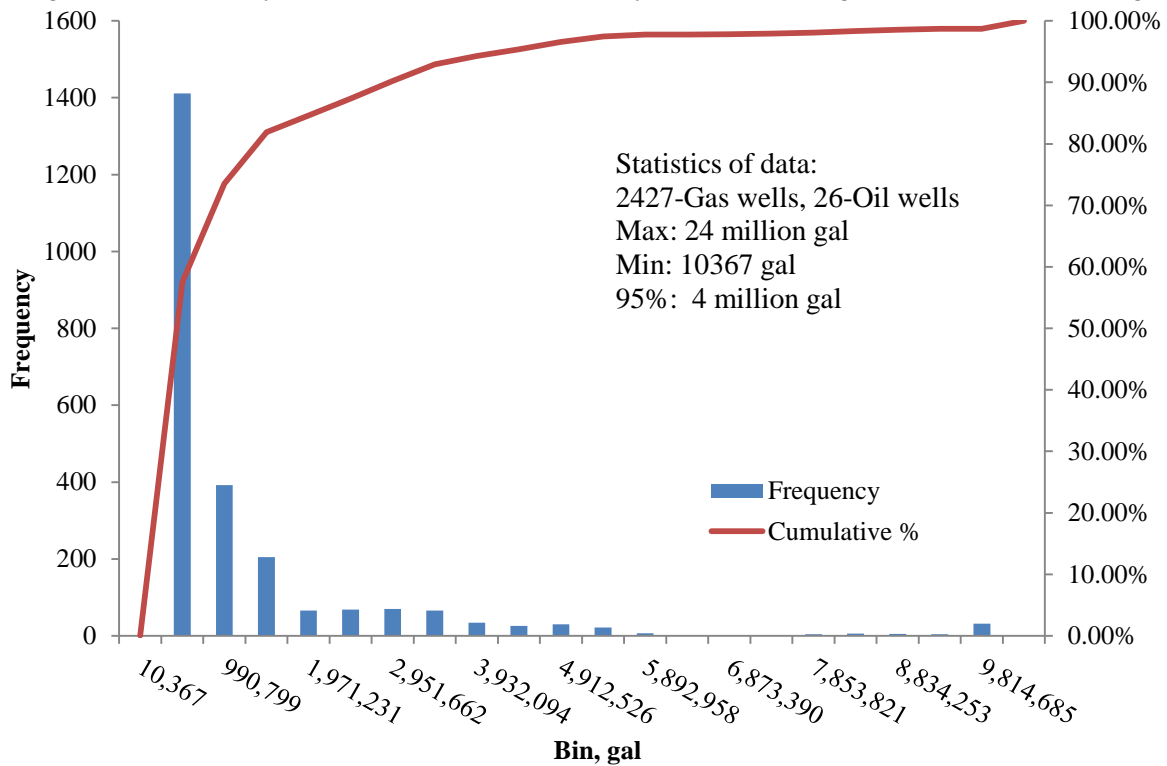
Figure A.2.6. Density distribution of water use for hydraulic fracturing in Colorado (FracFocus.org).

75

A.3 VBA code to automate curve fitting

Below the VBA code for MS Excel to automate curve fitting process.

```
Sub Individual_Curve_fitting()
Dim R As Long
Dim Target
Dim ChgCells
'//Solver settings
SolverOptions AssumeLinear:=True
SolverOptions AssumeNonNeg:=True
For R = 3 To 480 'Row 1 to 480
SolverReset
Target = Cells(R, 116).Address 'Choosing target cells
ChgCells = Cells(R, 114).Resize(1, 1).Address 'Choosing changeable cells
SolverOk SetCell:=Target, MaxMinVal:=2, ByChange:=ChgCells 'Minimizing target cell by changing ChgCells

SolverSolve True
Next R
End Sub
```

A.4 Determination of treatment facility location minimizing total pipeline distance

One of the factors for optimal siting of treatment or water handling facilities is minimization of pipeline length. ArcGIS provides an easy spatial tool, which can find a location of facility minimizing sum of the distances from all wells to facility. Additional factors for optimum siting can account for:

1. Land use
    a. Land use should be accounted when routing a pipe. Some territories have limited access and routing should avoid it. Examples of limited access are private lands, restricted areas (National parks etc), water bodies (lakes, rivers, ponds) and other.

2. Slope
    a. Construction of a pipe is cheaper on flat than on steep surface. Therefore, slope is another factor, which should be accounted while routing a pipelines.
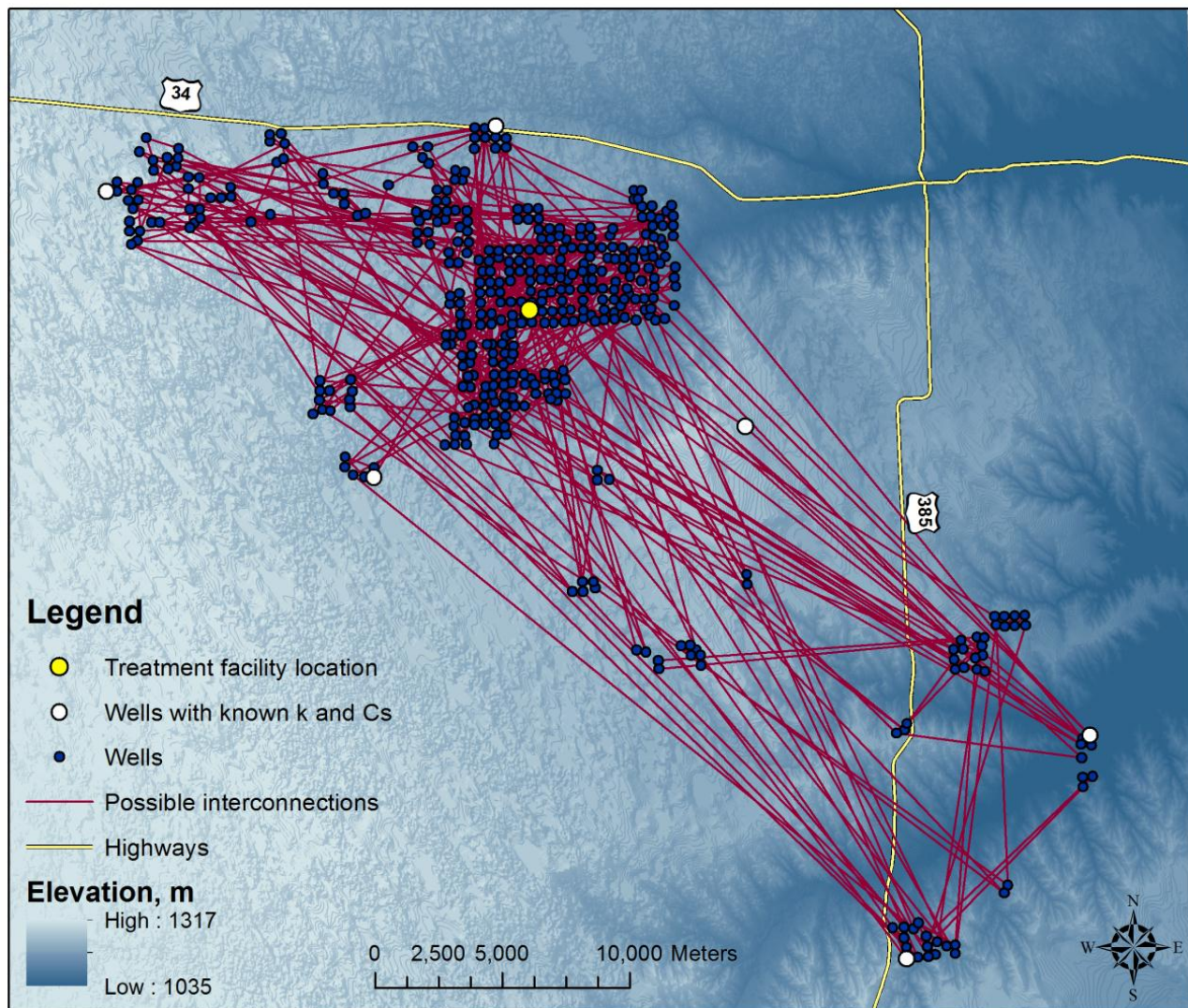
Figure A.4.1. Treatment facility location minimizing pipeline distance (Proposed location 720898, 4435216 UTM 13).
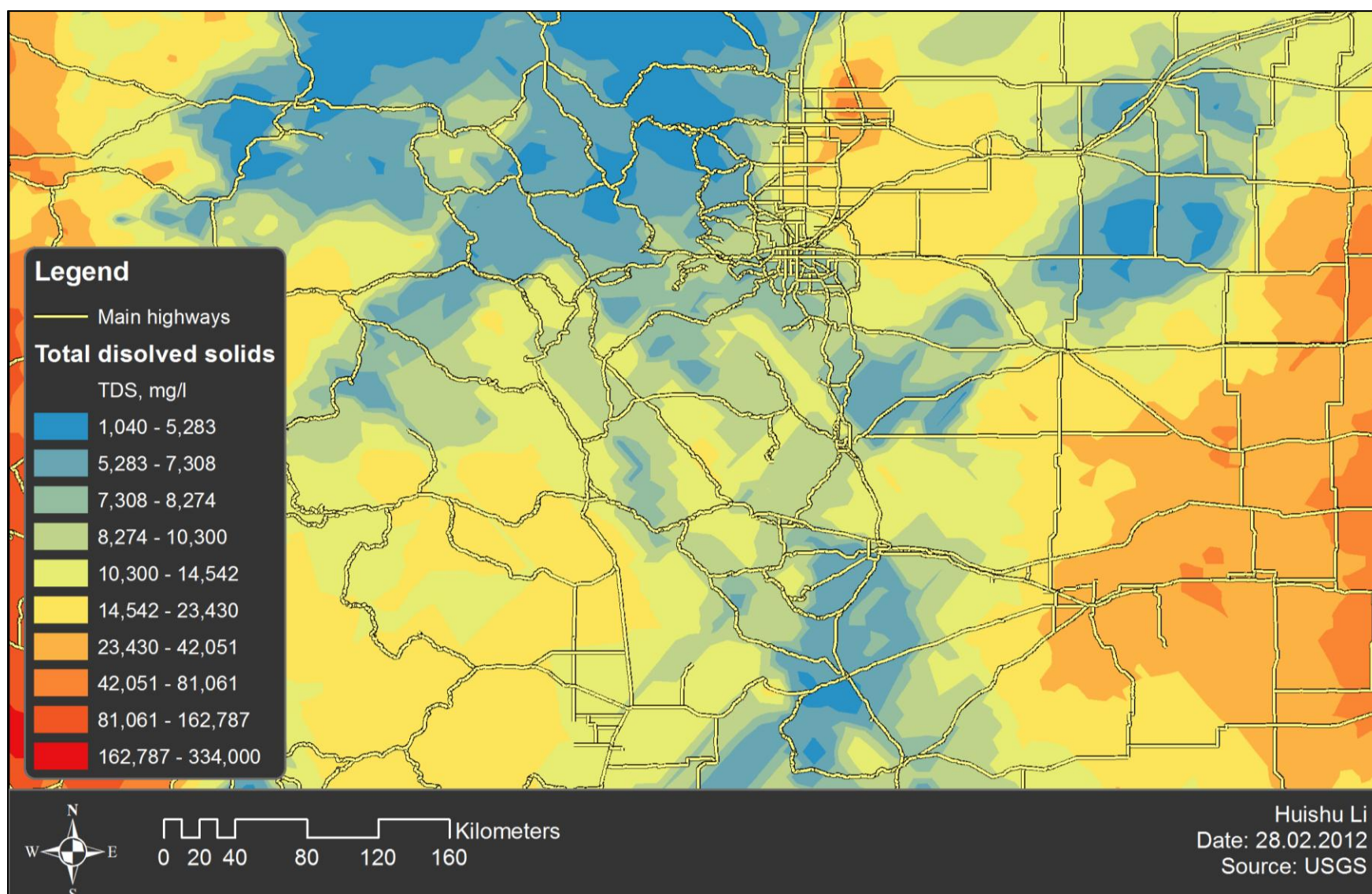
Figure A.4.2. Colorado TDS map from oil and gas wells (USGS, 2011)

Figure A.4.3. Fractured and producing Noble Energy Inc. wells in 2011

79

Figure A.4.4. Well selection methodology for sampling. Method 1: Random sampling

Figure A.4.5. Well selection methodology for sampling. Method 1: Random sampling and 5 random wells from each age group.

Api	Daily water production											
	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
05-125-06143	0.391	0.003	0.507	0.645	1.723	2.082	1.621	1.536	10.291	7.604	5.797	5.711

Look for maximum value X(i)=max

Api	Daily water production											
	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
05-125-06143	0.391	0.003	0.507	0.645	1.723	2.082	1.621	1.536	10.291	7.604	5.797	5.711

Check if previous year value X(i-1) is greater than 0.8X(i)

Api	Daily water production											
	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
05-125-06143	0.391	0.003	0.507	0.645	1.723	2.082	1.621	1.536	10.291	7.604	5.797	5.711

If YES, than leave the value and check for previous again till NO

If NO

Delete everything before

Add array

Year	1	2	3	4
Data	10.291	7.604	5.797	5.711

Solve for qi only minimizing Error (RSS) for harmonic decline curve with known field decline rate Di

Solve for Di and qi minimizing Error (RSS) for harmonic decline curve

Compare correlation coeficients

Result of method 2

Result of method 3

qi – initial rate
Di – decline rate

Error	B	A
0.458	14.95	0.467
0.645	13.54	0.35

Year	1	2	3	4
Data	10.291	7.604	5.797	5.711
Curve	10.190	7.729	6.226	5.212
Curve	9.885	7.783	6.418	5.461

R2
0.984
0.980

Final result Best fit

From field decline model

Actual year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Error	B	A
Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14			
Data	10.291	7.604	5.797	5.711													
Curve, daily, bbl/day	10.190	7.729	6.226	5.212	4.482	3.931	3.501	3.156	2.873	2.636	2.436	2.263	2.114	1.983	0.458	14.95	0.47
Curve, Annual, bbl/year					1546	1356	1208	1089	991	909	840	781	729	684			

Figure A.4.6. Filtering for fracturing year and curve fitting for wells older than 2 years.

Year/Api	Daily water production, bbl/day	
	2009	2010
05-125-10007	20.47	15.58

—Add array—→

Year	1	2
Data	20.47	15.58

—Curve fitting, solving for qi only. Di is constant field decline rate—

Year/Api	Daily water production, bbl/day
	2010
05-125-11757	19.71

—Add array—→

Year	1
Data	19.71

—Curve fitting, solving for qi only. Di is constant field decline rate—

Actual year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Error	B	A
Year	1	2	3	4	5	6	7	8	9	10	11	12			
Data	20.47	15.58													
Curve, daily, bbl/day	20.15	15.98	13.24	11.30	9.86	8.74	7.86	7.13	6.53	6.02	5.58	5.21	0.27	27.26	0.35
Curve, Annual, bbl/year	7293	5785	4793	4092	3570	3165	2844	2581	2363	2179	2021	1885			

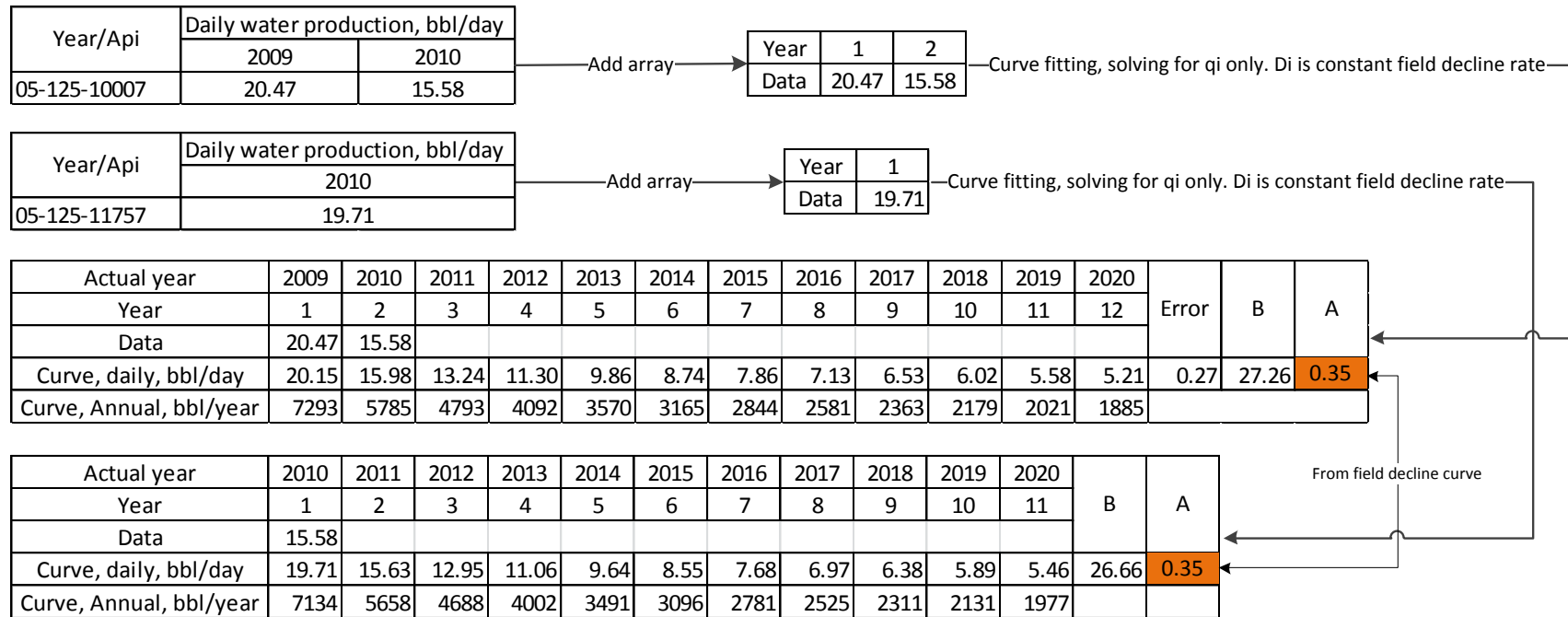| Actual year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	B	A
Year	1	2	3	4	5	6	7	8	9	10	11		
Data	15.58												
Curve, daily, bbl/day	19.71	15.63	12.95	11.06	9.64	8.55	7.68	6.97	6.38	5.89	5.46	26.66	0.35
Curve, Annual, bbl/year	7134	5658	4688	4002	3491	3096	2781	2525	2311	2131	1977		

From field decline curve

Figure A.4.7. Harmonic decline curve fitting solving for B only for wells which has 1 or 2 year water production information (Used in prediction method 2 and 3)

LIST OF ABBREVIATIONS

AWP - Annual water production

COGCC – Colorado Oil and Gas Conservation Commission

DCA – Decline curve analysis

DWPR – Daily water production rate

EIA – Energy Information Administration

FDF – Field decline function

FWPDC – Field water production decline curve

GHG – Greenhouse Gases

GIS – Geographic Information Systems

LSE – Least square error

PD – Production days

PW – Produced water

TDS – Total Dissolved Solids

WP – Water production

WQP – Water quality parameter