Advanced Drilling and Regional Energy Management:

The Impacts of Oil Drilling in El Paso County

The Ad Rem Project

May 11, 2012

Advanced Drilling and Regional Energy Management: The Impacts of Oil Drilling in El Paso County is published by the Ad Rem Project. The report was done as part of the course requirements for FNCE 6100 Problems and Policy in Financial Management in the College of Business and Administration of the University of Colorado Colorado Springs.

Foreword

Elected members of the City of Colorado Springs City Council and the County Commissioners for El Paso County Colorado have wrestled with the possible effects of drilling for oil and, possibly, natural gas in the Banning Lewis Ranch area of Colorado Springs and in unincorporated area of El Paso County. Awareness of this issue was first made public when Ultra Resources announced it planned to drill for oil on approximately 18,000 acres of the bankrupt Banning Lewis Ranch it purchased in 2011. Banning Lewis Ranch is a largely undeveloped parcel of 22,000 acres of land on the eastern edge of the City of Colorado Springs. Ultra Resources also acquired drilling rights on approximately 118,000 acres in unincorporated El Paso County. Concerns ranged from environmental, legal and possible effects on local tax revenues. Little attention has been given to possible economic development effects, Taxpayer Bill of Rights (TABOR) constraints or financial feasibility of the plan to explore and develop commercial production of oil in El Paso County.

This project was developed with the objective to research, analyze and report on issues related to environmental, legal, economic impact and business feasibility of drilling for oil in Colorado Springs and El Paso County. The Ad Rem Team sought to maintain an objective analysis of the question. It did this by limiting its analysis to data that are publicly available. All data can be verified independently. Sources were limited to those that are generally accepted as authorities and/or are professionals in the field of oil drilling. Financial feasibility was based on standard financial viability criteria used in capital budgeting and firm valuation. Profits/losses were examined at a risk adjusted rate of return that is 50 percent higher than prevailing standards in the oil and gas industry.

The Ad Rem Team found drilling for oil can result in environmental damage. Control and mitigation of this problem are generally within the domain of the EPA and the Colorado Oil and Gas Conservation Commission. Local Government can regulate surface issues associated with drilling (zoning, land use …). The analysis is supported with several case studies.

If commercial quantities of developable oil are found in El Paso County, the county lacks the business support services traditionally associated with an oil rich economy. This was expected. If successful, oil drilling could initiate a radical shift in the community's economic base by contributing to a more diversified economic base, raise income levels, expand the demand for housing, roads, retail, housing and skilled jobs ranging from to accountants to welders. Property owners with oil mineral rights could earn hundreds of thousands of dollars a year in royalties. At full production, the oil sector could contribute as much as 5 percent to the local economy's GDP. Local tax revenues will increase significantly. The work is supported with an economic impact analysis and an industry supply chain study.

Financial feasibility was examined with traditional capital budgeting tools used in corporate finance. Worst case scenarios were examined by using conservative estimates of revenues and high estimates of expenses, especially the finance costs to develop a potential oil field. The analysis is supported with a real time spreadsheet tool that can accept changes in any parameters used in the model. Examples of possible changes to inputs for the model include production levels, prices of oil, labor and drilling costs, dry hole rate and the cost of financing. The analysis indicates a rate of return in excess of 50 percent is possible. Cumulative net cash flows over the life of the field could be in the hundreds of billions of dollars. Net Present value is expected to be around $7.3 billion if there are 1,500 productive oil wells. The area has the potential for 3,000 productive oil wells.

The results of the Ad Rem Project 2012 project are enclosed in this report.

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All resources used in the project were provided by the Ad Rem Team members. No financial assistance was provided by any external agencies.

The Ad Rem Team is solely responsible for the analysis and application of the information used in this report. Finally, the Ad Rem Team is responsible for any errors in the document.

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Matthew Bain graduated from the University of Colorado at Colorado Springs with a BS in finance in 2010. Matthew has worked in the finance field since graduation, first as a financial analyst for a defense contracting firm, and currently as a banker with JP Morgan Chase. Matthew is currently pursuing his MBA in finance at UCCS, with aspirations of becoming a Chartered Financial Analyst after graduation. Matthew lives in Fountain, Colorado with his wife Heather. They are expecting their first child in August, 2012.

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Sujatha Gonella is a second year graduate student at UCCS working toward an MBA with emphasis in Finance. She is originally from Hyderabad, India and has moved to Colorado Springs in 2000. She graduated from Osmania University, Hyderabad, India with a Masters in Accounting. Sujatha volunteers at The Da Vinci Academy elementary school and enjoys spending time with family.

Russell Harward is originally from Denver, CO and has lived in Colorado Springs since 2004. He graduated from the University of Colorado at Colorado Springs in 2010 with a Bachelors of Science in Business and a Bachelors of Arts in Economics. Russell is currently working for AAA Northern California Nevada & Utah (AAA NCNU IE) as a Homeowners

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James (Randy) Kennedy spent most of his childhood in Idaho before moving to Colorado Springs during his senior year of high school. He received his undergraduate degree in business with magna cum laude honors from the University of Colorado at Colorado Springs. He immediately began upon his graduate degree and is currently in his second semester. In addition to graduate school, he is also a full time banker at US Bank and dreams of one day using the skills he has learned to start a business with his father.

Andrew Lawson is currently pursuing his MBA in Finance and Accounting. He has significant experience in the construction industry designing solutions to meet the requirements and goals of various contractors. As a Contract Specialist for the Federal Government, Andrew has gained an understanding of government procurement and, the numerous policies and procedures. This experience has developed an understanding of the public process and exposed him to the abundance of stakeholders involved in civil service. His undergraduate degree in Construction Management has provided a sound foundation for his contributions in government acquisition involving construction projects.

Jonathan Malinaric grew up in Colorado and has a background in guest services management and finance. He has worked with large churches on guest relations strategy and implementation as well as with a large financial services organization while completing his MBA. In his spare time, Jonathan enjoys hanging out with friends, watching sports, and cycling. Jonathan graduated from UCCS in 2010 with a degree in Human Resources and finance. He is the current co-president of UCCS Society for Human Resource Management and expects to graduate with an MBA in operations management in May 2012.

Mangesh Mharolkar has worked for over sixteen years with Information Systems and currently works as senior director of Business Intelligence at Xtivia. His group serves client firms of all sizes including Fortune 500 companies and builds industry leading data warehousing and business intelligence solutions. Mangesh holds a Bachelor of Engineering degree in Electronics and Telecommunications. He is currently pursuing his MBA at UCCS with an emphasis in finance. He likes to read, playing chess and listening to Indian/western classical music in his spare time.

Timothy Miller is originally from Georgia and has lived in Colorado Springs for seven years. He graduated with a Bachelor's of Business Administration in Marketing from Clayton State College and University in 1999. He currently is a multi-function financial analyst in the Information Systems & Global Solutions division at Lockheed Martin here in Colorado Springs. Tim has been married for three and half years to his wife, Kim. They plan to start a family this year. His planned graduation date is spring 2014 from the University of Colorado at Colorado Springs with an MBA emphasis in Finance.

Paul Mottram was born in Nutley, NJ. In 1988 Paul received his undergraduate degree in accounting from West Virginia Wesleyan College. In 1996 Paul received his MBA with an emphasis in accounting from the University of Colorado at Colorado Springs (UCCS). Paul worked at several domestic and international companies holding positions including Trust Accountant, Auditor, Lending Manager, Accounting Manager and Auditor. Paul recently started working as the Financial Analyst with the Alliance Development Fund (ADF) which caused him to seek the Finance certificate program from UCCS. ADF is a denominational church loan fund with $300 MM in assets.

Nicholas Pagano was born in St. Louis, MO. Nick graduated from Saint Louis University in May 2008 with a degree in Economics and is pursuing his MBA with an emphasis in Finance. He moved to Colorado Springs in August 2008. Upon moving to Colorado Springs in 2008, Nick accepted a job at T. Rowe Price and has been with the firm for over three years. Nick currently works in the Retirement Plan Sales division as a Sales Liaison. Outside of work, Nick enjoys spending time with his family, hiking, and mountain biking.

Tanya Petersen is a Colorado native and grew up in Colorado Springs. She attended the local university, University of Colorado at Colorado Springs (UCCS) and attained a Bachelors Degree in Finance and Economics in 2006. She is currently pursuing a MBA in Finance, also at UCCS. She is an insurance manager at a financial services company, USAA, and is licensed in Property and Casualty Insurance. She has promoted through various positions at USAA since 2003. She is a member of the Chamber of Rising Professionals. She enjoys world travel with her husband in her spare time.

Dr. Eric Plummer earned undergraduate degrees in Kinesiology and Biology at the University of Colorado at Boulder. Upon completion of his professional degree at the Southern California University of Health Sciences, Eric returned to Colorado to establish his private practice in Castle Rock. An insatiable interest in new medical technologies ultimately led to the decision to pursue a formal business education with the intent of focusing on emerging healthcare and biologic technologies. Currently an MBA student, Eric works on the industry side of healthcare and serves as a Board of Directors member of a Colorado based autologous stem cell company.

Tracie Powers is a second year graduate student at UCCS working toward an MBA with an emphasis in Service Management. She graduated from the University of North Dakota in 2008 with a double major in Business Management and Commercial Tourism. She currently works at Cheyenne Mountain Resort as an Event Planner. Tracie also coaches swimming and enjoys athletic activities in her spare time.

Matthew Prechtel is a senior project manager and engineer currently working for Exelis Corporation, the former defense division of ITT. At Exelis he performs project management for space surveillance and missile warning radar projects on the SENSOR program located in Colorado Springs, CO. His most recent projects are responsible for modernizing computer equipment on the FPS-85 Space Surveillance radar at Eglin AFB. Matt's education includes a Bachelor Degree in Electrical Engineering from the University of Pittsburgh, a Masters Degree in Electrical Engineering from Temple University and is a certified VBLSS Green Belt.

David Sherry has an undergraduate degree in Environmental Design from the University of Colorado. He is an unlicensed professional in the architecture and planning community and has extensive knowledge of building information modeling (BIM) software. As an intern architect, his experience has been largely focused on the design of educational and recreational facilities. David will be graduating from the UCCS MBA program in May, 2012, with an emphasis in finance. Upon graduation, he is interested in transitioning into the commercial real estate profession.

Amy Zirneklis, originally from Waterford, Virginia, has called Colorado Springs home for twelve years. Amy directs Business Development for SRM, a small-sized German manufacturer of premium power measurement systems for bicycles. Formerly a Diplomat for the Republic of Palau to the United States, she covered matters at the United Nations and represented Palau in the General Assembly. Amy will be a 2012 graduate from the MBA program at UCCS, focusing in International Business and Finance. She is an avid cyclist and runner, and is married to professional cyclist Michael Creed.

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1 Overview

1.1 Background

Oil and natural gas exploration is prevalent in the United States as it tries to gain energy independence. According to the Central Intelligence Agency's World Factbook website, the United States consumes approximately 19.15 million barrels of oil each day.1 Large oil and gas basins have been discovered in Pennsylvania, North Dakota, Wyoming, Colorado, among other states. The composition of these basins varies greatly in terms of their respective geology, ground permeability, and depth at which the hydraulic fracturing is operated. In order to extract the oil and gas, companies are using a technique called hydraulic fracturing. This technique has become increasingly more visible to the public and a topic of debate for many communities, towns, environmental activists, energy independent activists, and others. However, what is often not discussed is this technique has been utilized since the late 1940s. Additionally, technical improvements in drilling equipment, and drilling and separation techniques have helped improve hydraulic fracturing to be safer, more efficient, and produce higher yields of oil and natural gas.

This study focuses on three aspects of oil exploration – environmental impacts, economic impacts, and a company perspective to develop a feasibility assessment. Each of these areas goes through a series of subtopics to provide additional information so that the reader may be more informed regarding oil exploration via hydraulic fracturing within El Paso County, Colorado. The permit applications to drill in El Paso County indicated oil is the primary exploration interest. Natural gas is considered a secondary product within this study. Natural gas will be discussed briefly in some sections, but only as a byproduct of oil exploration. The research in this study is intended to be a prospectus to foster further discussions about oil exploration within El Paso County.

1.2 Environmental Impacts of Drilling in El Paso County

Oil drilling has numerous potential impacts on the environment. These range from possible water contamination, water sourcing for hydraulic fracturing, to land reclamation. The environmental impact portion of the study focuses on water, air, and habitat environmental impacts as they pertain to El Paso County. National and state references are provided to give the reader a context of the related topic. Water concerns consist of contaminating the aquifer and groundwater sources, water consumption by drilling operations, drilling waste spilling into ground water, and runoff. Air concerns consist of increases in carbon dioxide from trucks, generators, and other gas/diesel powered machinery; and burning off of natural gas onsite (known as flaring). Habitat concerns consist of destruction of botany, insect, and wildlife habitats with regard to the establishment of drilling

[1] (Central Intelligence Agency n.d.)

pads, infrastructure, spills, and water consumption. In some instances, the topics listed above will overlap to provide the reader with a more complete picture of the environmental impacts.

The environmental impacts portion of the study also contains a condensed risk assessment, information regarding the permitting process and what permits have been approved or are pending approval, and possible mitigations to some of the environmental issues presented. The goal of this portion of the study is provide the reader with verifiable information so the reader may make an informed opinion of the environmental impacts associated with oil exploration.

1.3 Regional Economic Impacts of Drilling in El Paso County

Oil drilling and extraction has a significant impact on the general economy because it touches a broad segment of industries. Among these are chemical production, transportation, and construction, as well as industries outside of the oil production supply chain such as finance and banking, retail, and various service sectors. This regional economic impacts section specifically focuses on the industry's effect on employment, businesses, supply chains, taxes, and real estate in El Paso County. Wherever possible, the study used verifiable data from multiple sources, including the oil industry, drilling regulations, comparable situation I oil producing counties and referencing other studies. The absence of consistent information, at times, required the application of inferences to be made for El Paso County's situation. All inferences were based on case studies and other comparable situations. As of this writing, oil has not been discovered in El Paso County. Because of the high level of uncertainty related to successful oil production, potential economic effects were estimated for three scenarios. The analysis details relevant sources and inferences where appropriate.

The oil industry's impact on employment, business, and the supply chain is separated into direct, indirect, and induced effects. Employment projections will be made based on differing levels of drilling activity in the county. An oil industry employment overview will be provided. This will describe the different jobs in the industry, the skills and education required, and the average wage for each. The indirect and induced jobs that can be expected will also be presented. The supply chain of the oil industry will also be explored. This analysis describes the upstream and downstream industries that are currently located in El Paso County to determine what value-added elements the county can initially expect to keep and what can be expected to leak outside the county. This section will also address which industries might be expected to relocate to the area if drilling proves successful.

Tax implications from the oil and related industries will be broken down at the federal, state, county, and city levels. The taxes that have an effect on the industry at each level will be defined and explained. The expected tax revenue from drilling to Colorado, El Paso County, and Colorado Springs will be presented.

Finally, the impact of the oil industry on residential and commercial real estate will be examined. An overview of the current real estate market in El Paso County will be presented. Next, the direct impact of the migratory and permanent population involved in the oil industry will be presented along with their indirect and induced effects. Within the scope of this project, the direct, indirect and induced effects are expected to provide a complete picture of the possible economic impact that the oil industry will have in El Paso County.

1.4 Financial Assessment of El Paso County Drilling

When deciding whether or not to make an investment to drill for oil in El Paso County, both financial and operational scenarios are considered to determine if the project is financially feasible. In this study, various sources of verifiable data, financial assumptions, and various sensitivity scenarios were used in the capital budgeting process. This process considers a variety of factors to arrive at the total future cash flows. The decision maker would use these to accept or reject a particular project. Data sources and assumptions are clearly identified and explained.

To facilitate the capital budgeting process, a decision framework model was created using various financial analysis techniques that leverage a variety of inputs. Net Present Value (NPV), the technique used most often in these types of decisions, was employed. While the model enables the user to manipulate variable values depending on varying operational conditions, a base case was created against which the financial feasibility of various scenarios may be compared.

The input model was created using forecasted production volumes based upon outputs observed in drilling efforts in similar geographic and geological areas. The model also includes variable values and relevant ranges, including horizontal and vertical well costs and failure rates. Additionally, financial input assumptions were included. These encompassed tax-related stipulations, effective tax rates, operating expenses, tangible and intangible drilling-related costs, interest expense, and other relevant financial data.

Finally, outputs representing different levels of production activity, drilling rates, and applicable discount factor provide critical data used in the decision-making process. These data include expected incremental cash flows, discounted cash flows, cumulative cash flows, revenue, and royalties. These are then analyzed to determine the expected NPV of the project, providing decision makers with the necessary information to either accept or reject the drilling effort.

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2 Environmental Impact Introduction

2.1 Why Drill in El Paso County?

El Paso County sits on the southern edge of the Niobrara Basin (Figure 1). This is part of the Denver (DJ) Basin. Based on success in Weld County and other counties around the state, and given that El Paso County lies within the DJ Basin, oil and gas companies are interested in exploring portions of El Paso County. Currently there are no active production wells in El Paso County. However, Ultra Petroleum has been granted permission to drill three vertical, exploratory wells: Olive Oyl State, Spinach State, and Brutus State. The results from the vertical wells will help Ultra Petroleum decide whether to begin oil drilling and use hydraulic fracturing in El Paso County. As this study was being written, Ultra Petroleum began drilling the vertical, exploratory wells in El Paso County. Figure 1 shows, there is a high concentration of wells north of Denver, which are mostly natural gas wells.

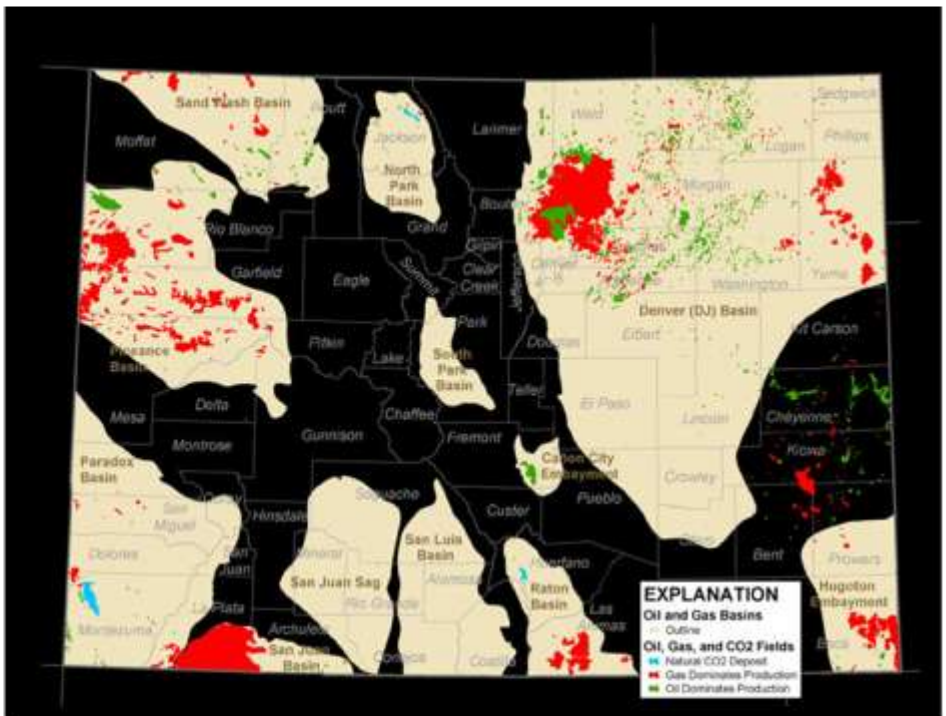

Figure 1. Colorado Geological Survey Oil Map[2]

Red indicates areas where natural gas production is taking place. Green represents existing oil production. Blue indicates the presence of CO2 deposits.

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[2] (Colorado Geological Survey 2011)

The geology of the Niobrara basin is thought to be similar to the Bakken formation in North Dakota. Though it is thought to have smaller amounts of oil and gas pockets, oil and gas companies believe sufficient oil and gas deposits exist to warrant exploration. Recently, Weld County, a community north of Denver, has seen a small scale oil and gas boom similar to what parts of North Dakota have recently experienced. A positive economic impact has been identified in Weld County and the surrounding communities.

The geological make-up of the Niobrara Shale is believed to be rich with oil deposits. Furthermore, the depth of the Niobrara basin is considered a fairly deep geological formation (see Figure 2). Figure 2 also illustrates that the Pierre Shale sits directly above the Niobrara Shale. The Pierre Shale is a wide geological formation, considered to have low permeability. The depth of the Pierre Shale ranges from one-half a mile to over a mile thick. It separates the Niobrara formation from fresh water aquifers.3 Low permeability combined with the thickness of the Pierre Shale means upward migration of fracturing material and particulates is less probable than in other types of geological shale and depths.4 This is desirable and will be explained further in this study.

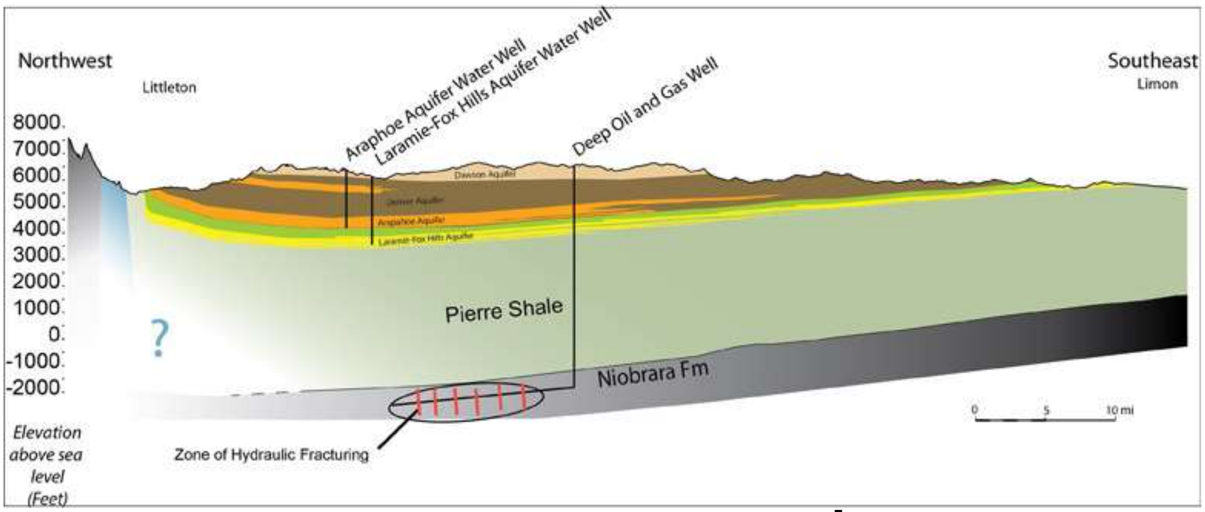

Figure 2. Colorado Geological Survey Niobrara Composition[5]

The Banning Lewis Ranch sits above what is believed to be the western edge of the Niobrara formation. This is where oil companies believe it is possible to find commercially viable quantities of oil. The area extends to the eastern border of El Paso County.[6] This is evident in that "independent landmen who work for the oil companies have booked more than 2,200 [leases] since 2009, says Mark Lowderman, the county assessor."[7] In fact, in the same article by David LaGesse, "the ranchland that stretches east [of Colorado Springs] holds more uncertainty about its oil, but that hasn't stopped land leases from tripling, or quadrupling, in value over the past year or so."[8] Also worth noting from this article, "El Paso

[3] (Colorado Geological Survey 2012)
[4] (Colorado Geological Survey 2012)
[5] (Colorado Geological Survey 2012)
[6] See Figure 25 for an overlay of the Niobrara Shale basin relative to El Paso County and all of Colorado.
[7] (LaGesse 2011)
[8] (LaGesse 2011)

County [hasn't] had an active oil lease since the mid-1980s, much less a producing well…"[9] So why are oil companies eager to explore El Paso County? To answer this question, one has to look toward the northern part of Colorado, specifically, Weld County.

Weld County also sits on the Niobrara formation. According to the Colorado Oil and Gas Conservation Commission (COGCC), Weld County currently has over 10,000 wells, accounting for 40 percent of the total wells in Colorado. According to the COGCC production database, the oil wells in Weld County produced 25,117,450 barrels of oil in 2011. This equates to 68,814 barrels per day (bpd) of oil. Compared to the 2010 US estimated consumptions levels, which were approximately 19,150,000 bpd of oil,[10] it would account for 0.36 percent of the US daily oil expenditure at 2010 rates. This percentage does not appear to be significant, but this is just one county in Colorado. The total oil production for all counties in Colorado equals 37,332,470 annual barrels of oil for 2011, or 102,280 bpd. By comparison, North Dakota's oil production for January 2012 was 546,050 bpd,[11] which is significantly higher than Colorado's. North Dakota is more mature in its oil production life-cycle than Colorado.

There is evidence that North Dakota is experiencing an economic boom as a result of drilling, finding and producing oil – perhaps something Colorado could experience if oil production increases. To place it in perspective, if an average price of $100 per barrel is used, North Dakota oil production resulted in approximately $54.6 million dollars per day for the month of January 2012. If El Paso County oil production is similar to Weld County (68,000 bpd), then El Paso County oil wells could produce approximately $6.8 million in revenues per day, or $2.482 billion in revenues annually ($6.8m multiplied by 365 days per year). These numbers are fairly conservative, yet they make it clear there is an economic interest to begin drilling in El Paso County. Depending upon the various fees and taxes associated with the drilling operations, oil production in El Paso County could provide significant economic benefit for El Paso County and its residents.

Improved economic prosperity may be positive and desired. However, there are numerous environmental impacts to be considered. The following sections describe some of these environmental impacts. The first section provides an overview of the drilling operations and hydraulic fracturing techniques used in the majority of horizontal drilling. The next section highlights the casing process of the well and the importance this stage serves in reducing the inherent environmental risks. This is followed by a discussion of the history of mining and exploration in El Paso County to demonstrate the type and degree of mining projects the community has tolerated in the past. The remaining sections will cover the permitting process, a risk assessment, environmental concerns, and related Federal and state regulations. Finally two relative case studies will be reviewed, mitigations outlined and recommendations proposed.

[9] (LaGesse 2011)
[10] (Central Intelligence Agency n.d.)
[11] (Gebrekidan 2012)

2.2 Drilling Operations

Globally, oil drilling has been around for centuries. The earliest known oil well in the United States was drilled in Titusville, Pennsylvania, in 1857.[12] Although some of today's techniques are similar to how wells were drilled many years ago, technology has allowed for more sophisticated techniques beyond the simple vertical well. Drilling companies are now able to drill vertically, directionally, and horizontally. Vertical drilling is boring a vertical shaft in the earth. Directional drilling involves "drilling wells at multiple angles, not just vertically, to better reach and produce oil and gas reserves."[13]Figure 3 illustrates how directional drilling works.

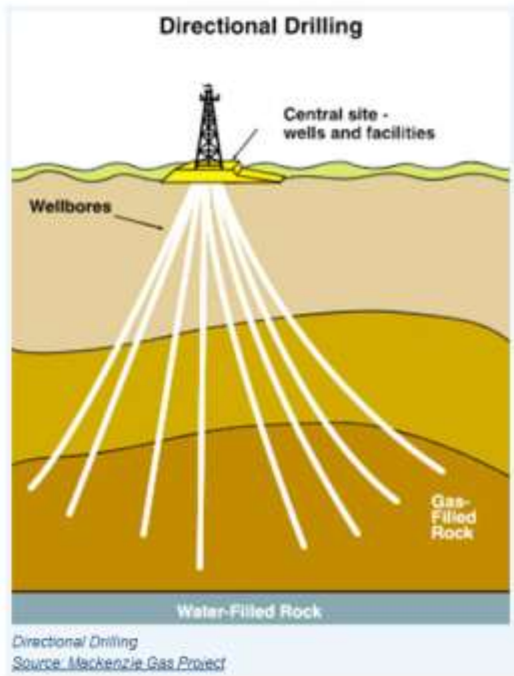

Figure 3. Directional Drilling[14]

Additionally, drilling companies are able to drill horizontally. In a 1993 report by the Department of Energy, horizontal drilling is defined as:

The process of drilling and completing, for production, a well that begins as a vertical or inclined linear bore which extends from the surface to a subsurface location just above the target oil or gas reservoir called the "kickoff point," then bears off on an arc to intersect the reservoir at the 'entry point,' and, thereafter, continues at a near-horizontal attitude tangent to the arc, to substantially or entirely remain within the reservoir until the desired bottom hole location is reached.[15]

[12] (Black 2007)
[13] (Rigzone 2012)
[14] (Rigzone 2012)
[15] (King and Morehouse 1993)

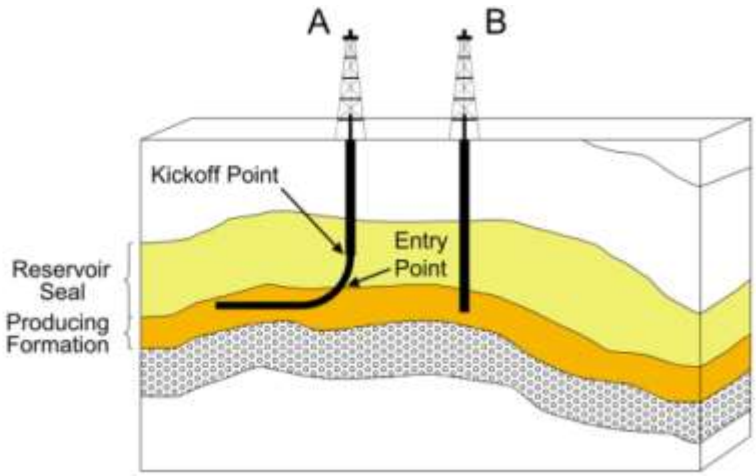

Figure 4. Well Comparison[16]

Figure 4 illustrates how horizontal drilling looks. Well "A" represents the horizontal well, and well "B" represents the vertical well. As described above, well "A" shows a kickoff point where the well bore begins to turn at an angle. As shown, the entry point is where well "A" enters the desired reservoir and begins its nearly horizontal angle. Once the desired horizontal shaft length is completed, the fracturing process begins.

Hydraulic fracturing has been around for nearly sixty years. According to the website, FracFocus.org, "the first commercial application of hydraulic fracturing as a well treatment technology designed to stimulate the production of oil or gas likely occurred in either the Hugoton Field of Kansas in 1946 or near Duncan Oklahoma in 1949."17 According to the website HydraulicFracturing.com, "Hydraulic fracturing is the process of creating fissures, or fractures, in underground formations to allow natural gas and oil to flow."18

As indicated earlier, the Niobrara Shale formation, which is the formation underneath Banning Lewis Ranch, is approximately 9,000 feet deep. Figure 5 illustrates how oil may be accessed in the Niobrara formation. Figure 5 also illustrates the overall drilling process: establishing a drill site, drilling the vertical and horizontal wells, executing the cement casing, and finally the fracturing. The following sections briefly walk through these overall steps.

[16] (Helms 2008)
[17] (Frac Focus 2012)
[18] (Chesapeake Energy 2012)

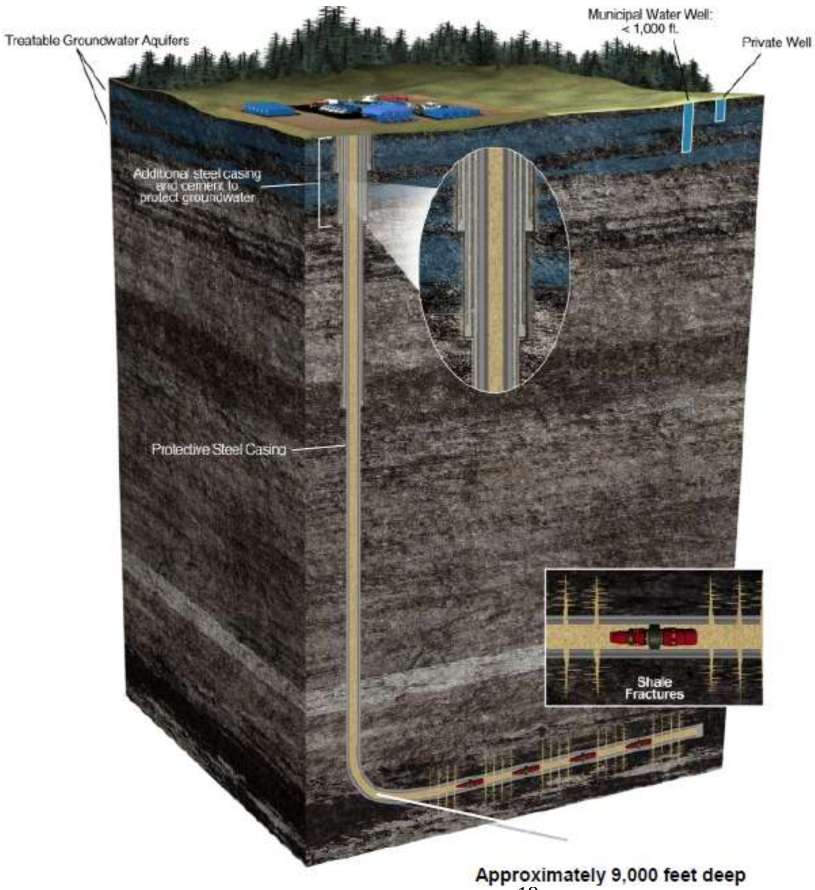

Figure 5. Niobrara Hydraulic Fracturing[19]

Once a drill site has been identified, a drilling rig and crew will begin preparations and then start the drilling process. Drilling preparations begin with establishing the drilling pad by clearing and leveling the drilling area. A drilling pad is installed and the rig constructed. Drilling is then commenced. As the well is being drilled, the drill bit requires lubrication to ensure the bit continues to cut and not burn out. "[The] drilling fluid, or 'mud', [is sent] down the wellbore to lubricate the bit, remove cuttings, and dispose of the wastes."20 The cuttings and waste that are collected must be disposed of properly. If not disposed of properly, these materials can cause environmental damage as they contain oil, natural gas, methane, and other naturally occurring chemicals. These materials are usually captured in a plastic-lined pit. As technology has evolved, some drilling companies are using sophisticated machinery to separate the drilling spit from the fluids. These fluids are then captured in a "closed-loop system." This means the fluids are collected in a tank and not in an open bit. A closed-loop system helps ensure environmental spills are kept to a minimum on a drilling site. However, these systems are more expensive to operate and thus are not always used. Ultra Resources' permit applications indicate a closed-loop system would be used for the exploratory and production wells.

[19] (Chesapeak Energy 2012)
[20] (Darin and Stills 2002)

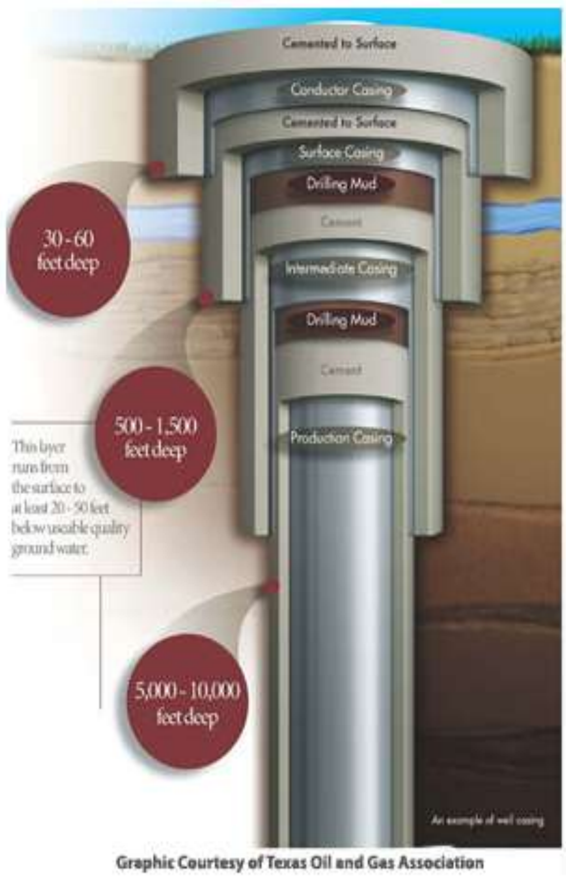

Figure 6. Cement Casing[21]

Regardless of the well type, the next process after drilling the well is to insert steel casing. This steel casing performs two important roles: aquifer protection and easy extraction of oil and natural gas.6 shows protective steel casing is used the entire length of the vertical and horizontal shafts.

Once the horizontal shaft is completed and the steel casing has been inserted, the cementing process begins. The cementing process is critical to constructing a sound and safe well. In fact, the main purpose for cementing is to protect groundwater and underground aquifers. When combined with the steel casing, cementing acts as an additional barrier to protect groundwater sources. State natural gas and oil regulatory programs also place a great emphasis on protecting groundwater. Current well construction requirements consist of installing multiple layers of protective steel casing surrounded by cement that is specifically designed and installed to protect fresh water aquifers.[22]

The cementing process consists of pouring cement in layers around the well head to a depth below the groundwater aquifers. The cement casing helps prevent oil, gas, and other fluids (e.g. drilling fluids, naturally occurring saltwater, etc.) from entering the aquifers as they move up the well bore. Without proper casing, the fluids could enter the aquifer through

[21] (Frac Focus.org 2012)
[22] (Chesapeak Energy 2012)

the well bore and contaminate the water source. Once the cement casing has cured and the steel casing has been reestablished in the well bore, a thin layer of cement is forced down the shaft and out the horizontal steel casing to create a layer of hardened cement. This hardened cement creates a means for the oil and gas to flow into the steel casing once an area of the horizontal well has been fractured. To fracture a horizontal section, explosive charges are placed in the horizontal shaft and detonated to fracture the steel pipe, cement casing, and shale.

For environmental and regulatory reasons, Colorado requires the disclosure of cementing plans on permits prior to approval. The COGCC requires cementing plans, water sourcing plans, and fluid plans be disclosed on permits. Figure 7 shows areas of concern for state permits, such as the type of casing, size of the various holes, thickness, setting depth, and number of cement bags to be used.

DRILLING PLANS AND PROCEDURES

27. Is H2S anticipated? [ ] Yes [X] No If Yes, attach contingency plan.

28. Will salt sections be encountered during drilling? [ ] Yes [X] No

29. Will salt (>15,000 ppm TDS CL) or oil based muds be used during drilling? [ ] Yes [X] No

30. If questions 28 or 29 are yes, is this location in a sensitive area (Rule 901.e)? [ ] Yes [X] No

31. Mud disposal: [X] Offsite [ ] Onsite — **If 28, 29, or 30 are "Yes" a pit permit may be required.**

Method: [ ] Land Farming [ ] Land Spreading [X] Disposal Facility Other: County landfill

Note: The use of an earthen pit for Recompletion fluids requires a pit permit (Rule 905b). If air/gas drilling, notify local fire officials.

Casing Type	Size of Hole	Size of Casing	Wt/Ft	Csg/Liner Top	Setting Depth	Sacks Cmt	Cmt Btm	Cmt Top
CONDUCTOR	24	16	65	0	120	180	120	0
SURF	12+1/4	8+5/8	24	0	300	130	300	0
1ST	7+7/8	5+1/2	17	0	5,545	380	5,545	2,500

32. BOP Equipment Type: [X] Annular Preventer [X] Double Ram [ ] Rotating Head [ ] None

33. Comments Ultra's phased development plan includes Phase I – a small pad for one vertical well. Based on the results of this pilot well, Phase II would include a larger pad for eight horizontal wells.

Figure 7. Ultra Drilling Permit - Casing Section23

Ultra Resources has applied and been approved for two vertical, exploratory wells. As described above, these wells require cementing to be used to protect the water sources. Figure 7 shows a portion of the Spinach State well permit. At the time of this study, Ultra Resources has applied for eight additional permits for both vertical and horizontal wells in El Paso County. It should be noted a wealth of information is available to the public through the Colorado Oil and Gas Conservation Commission website.

Once the explosive fracturing is completed, hydraulic fluids are forced down through the steel casing and out the horizontal, perforated section of the well. These fluids are forced into the fractured shale under high pressure into the fissures to help fracture the shale further to recover oil and natural gas. The fracturing fluids are comprised of water, silica, and other chemicals (discussed further in the study), which are used to "flush" out the oil and natural gas. The oil and gas then flow back into the casing through the perforated cement and steel casings. As the oil and natural gas collect, pumps are used to extract them back up through the metal casing to the well head. They are captured, separated, and collected into holding

[23] (Colorado Oil and Gas Conservation Commission 2012)

tanks or pits. As these tanks or pits fill, they are drained into tanker trucks and hauled off to be further refined and processed, or are pumped to refineries through pipelines.

Hydraulic fracturing operations require a significant amount of equipment in addition to the normal drilling rig, pumping systems, and storage tanks or pipeline connection. Figure 8 shows an example of drilling during the fracturing phase.

Figure 8. Fracturing Operations[24]

Figure 8 shows blending trucks, pumping trucks with hoses, water trucks, and trucks for hauling drilling spit away from the site and recovered water to be properly disposed. The mix of trucks varies depending on the well type (vertical, directional or horizontal) and how deep the well is being fractured. Each fractured well goes through a different stage of having a large number of industrial vehicles located at the well head. From an environmental standpoint, these numerous trucks require temporary roads to be created to reach each site. They can also increase the amount of carbon dioxide released into the atmosphere near a well site, which may have an adverse effect on the local environment. The trucks can increase the amount of noise pollution in an area, which may disturb people and wildlife habitats.

Figure 9 shows an example of the road infrastructure created near a drilling site. As the image depicts, there are numerous dirt roads going to and from each well site, which then connect into the main highways. Each brown section, below the mountain range and to the right of the interstate, indicates a drilling site.

[24] (Frac Focus.org 2012)

Figure 9. Garfield County Aerial[25]

As described above, drilling companies establish a drilling pad to prevent environmental damage to soils and surface areas. The drilling pad is established on the site where the wells will be drilled, providing a drilling operations foundation and an environmental protectant. The drilling rig is set atop the pad prior to the start of drilling operations. The drilling pad helps to soak up any spills that occur from drilling operations such as equipment hydraulic fluids, drilling fluids, fracturing fluids, methane gas, oil, and other fluids. Should a spill occur, drill operators will dig up the drilling pad where the spill occurred and lay down new drilling pad materials to ensure the integrity of the pad stays intact. Typically, the recovered drilling pad section will be disposed with the recovered drilling waste from operations. Figure 10 shows an example of a drilling rig that includes the drilling pad established in a cleared area.

Overall, drilling operations impact the environment as a result of establishing a drill site and the support infrastructure; however, so does the establishment of a new shopping center or a new golf course. A key concern to conducting successful drilling operations is to minimize the unrecoverable environmental damage and maintain a positive awareness of the numerous environmental concerns as discussed in this study.

[25] (AirPhotoNa.com 2005)

Figure 10. Drilling Site Example[26]

2.2.1 Importance of Proper Cementing

Hydraulic fracturing has become more scrutinized in recent years with numerous environmental contamination claims, especially regarding the contamination of ground and aquifer water sources. “Many community activists have said that hydraulic fracturing itself – a process that uses water, sand, and chemicals to break up shale rocks and release gas [and oil] – can pollute drinking water.”[27] However, a number of studies conducted around the United States have concluded that a main cause for water contamination of both ground and aquifer water sources near drilling operations was the result of poor or failed well construction and cementing. In a recent Wall Street Journal article, both

> Energy officials and some environmentalists agree that poorly built wells are to blame for some cases of water contamination. In those cases, officials say, wells weren’t properly sealed with subterranean cement, which allowed contaminants to travel up the well bore from deep underground into shallow aquifers that provided drinking water. [28]

[26] (FrackFacts.com 2010)
[27] (Gold 2012)
[28] (Gold 2012)

Furthermore, in the Pavillion, Wyoming, case study (included later in this report), the Environmental Protection Agency (EPA) found ground water and aquifers were contaminated as a result of wells being drilled near these water sources. However, poor well construction and failed cementing were faulted for allowing the natural gas and oil to migrate out of the well bore and into underground aquifers.

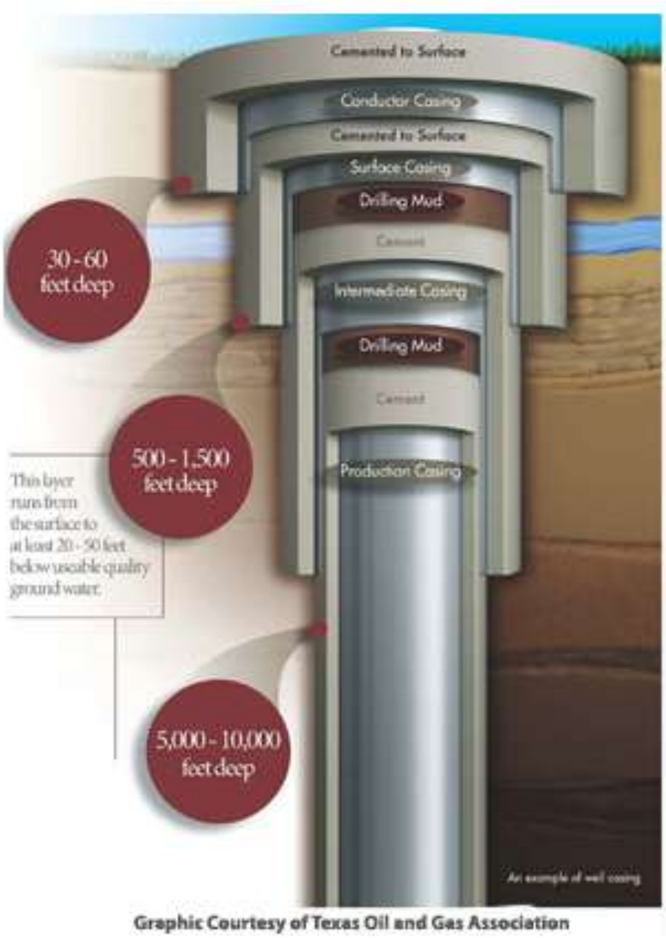

Figure 11. Cement Casing Process, FracFocus.org[29]

In 2010, the states of Pennsylvania and New York passed tighter regulations regarding well construction and cementing practices used by companies drilling for oil and natural gas. In the Plain Language Summary of the Pennsylvania Environmental Quality Board Proposed Regulations for Oil and Gas Well Casing and Cementing (Amendments to Chapter 78), the Pennsylvania Department of Environmental Protection (DEP) proposed new regulations that "will update existing rules for drilling, casing, cementing, testing, monitoring, and plugging of oil and gas wells. The new regulations will also update rules for protecting public and private water supplies."[30] Some of the proposed regulations include more frequent inspections of the wells; more detailed plans regarding well construction including casing and cementing; requiring operators to provide a clean water supply if the

[29] (Frac Focus.org 2012)
[30] (Pennsylvania Department of Environmental Protection 2010)

existing water supply is polluted or reduced; and meeting standards established by the American Society of Testing Materials. (More information can be found at http://www.depweb.state.pa.us.) The COCCG has established similar regulations for the state of Colorado. "In its August report on shale production, the Energy Department committee recommended that companies run tests on every well to identify inadequate cementing, and it called for more inspections to confirm operators promptly 'repair defective cementing jobs.'"[31]

One factor to ensure well construction is completed properly is to inspect well integrity. Performing proper well construction helps to ensure contaminates do not enter water sources, but how do oil companies ensure the integrity of a well once it is constructed? In drilling operations, water penetrating the casing or well contents evacuating out of the casing can be minimized by proper casing inspection.[32] Inspection of the well casing presents a significant challenge, yet helps to provide assurance that the casing is intact. Tools employed in this inspection process can include mechanical means such as calipers and cameras. An alternative approach utilized to inspect well casings relies heavily on Non-Destructive Testing (NDT) technology and methods.[33] The following section outlines a few of these NDT methods.

2.2.2 Inspection Methods and Tools

Cathodic Protection Evaluation Tool (CPET). Electrochemical corrosion is a primary cause of casing corrosion. Casing corrosion can be monitored and detected with the CPET. The CPET measures resistance and potential along the well casings. This typically results in a log that documents potential needs for corrosion protection and the extent of protection necessary.[34]

*Ultrasonic Inspection Tool (USIT) and Ultrasonic Corrosion Inspection Tool (UCIT).*Ultrasonic Testing (UT) uses high frequency sound energy to conduct examinations and make measurements. Ultrasonic inspection can be used for flaw detection/evaluation, dimensional measurements, material characterization, and more. A typical UT inspection system consists of several functional units, such as the pulser/receiver, transducer, and display devices. A pulser/receiver is an electronic device that can produce high-voltage electrical pulses. Driven by the pulser, the transducer generates high-frequency ultrasonic energy. The sound energy is introduced and propagates through the materials in the form of waves. When there is a discontinuity (such as a crack) in the wave path, part of the energy will be reflected back from the flawed surface. The reflected wave signal is transformed into an electrical signal by the transducer and is displayed on a screen.[35]

[31] (Gold 2012)
[32] (Hockway n.d.)
[33] (Acuna and Moseque 2010)
[34] (Cholet 2000)
[35] (NDT 2012)

Electro-Magnetic Imaging Tool (EMIT). These tools are sent down the well casing and can inspect for pitting and corrosion. EMITs use corrosion sensors and two-dimensional imaging of the casing walls to determine internal or external damage.[36]

Cement quality, mixture, and completion practices influence well integrity. Cement quality of the well casing is vital to well safety, fail-safe operation, and environmental protection. Evaluation of cement can be performed by combining pulse-echo technologies with ultrasonic techniques and can be performed on any type of cement (heavy cements, lightweight cements, or traditional slurries). This method can produce real-time information and can differentiate cement contaminants from liquids.[37] Other tools can evaluate the bond between the cement and the steel casing.

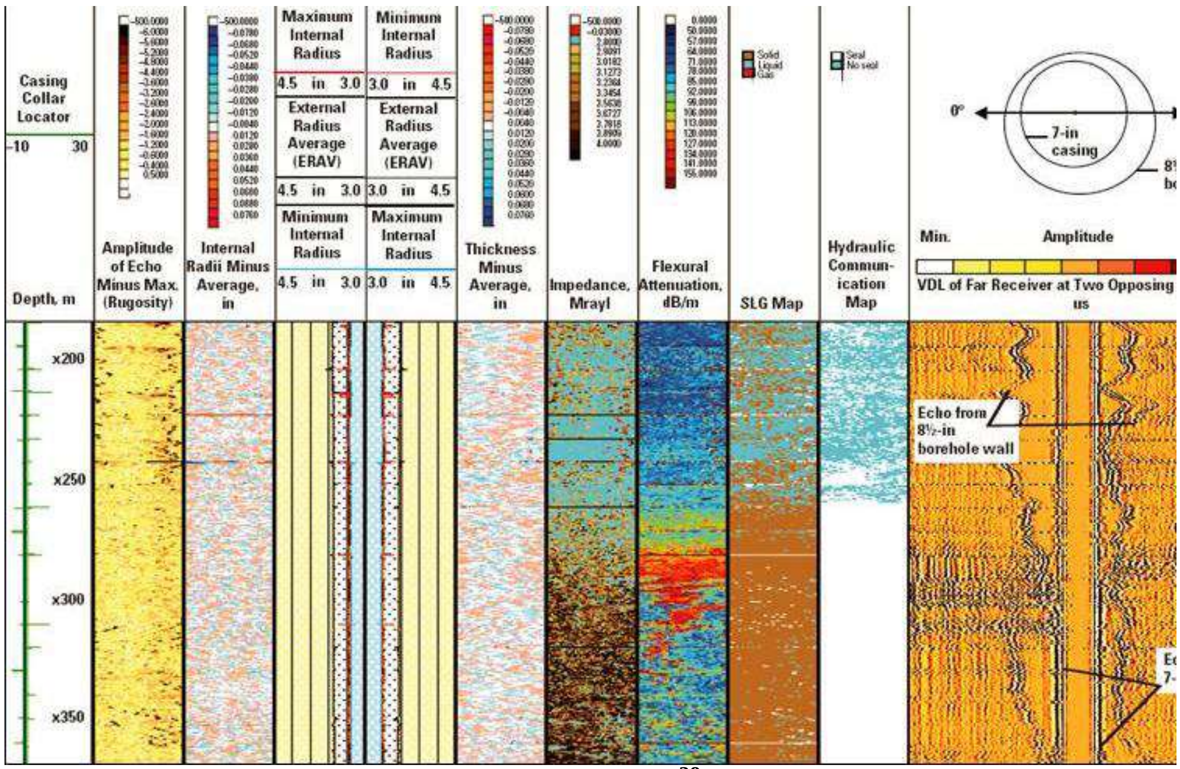

Figure 12. Example of Cement Evaluation Report[38]

Implementation of these methods and techniques helps to ensure the well cementing and steel casing remain intact, which reduces the likelihood of an environmental accident or contamination occurring. Many of these techniques are the result of lessons learned over the years from drilling, mining, and milling throughout the United States.

36 (Acuna and Moseque 2010)
37 (Schlumberger 2010)

El Paso County has a mining and milling history. The next section goes into brief reviews of some of the many mining and milling operations affecting the El Paso County area.

2.3 Mining History of El Paso County

When considering the various economic, environmental, and social impacts that the impending oil exploration at Banning Lewis Ranch would have on the City of Colorado Springs and its surrounding neighbors, it is important to look to the past for perspective. Although the oil exploration and recovery industries are relatively unknown to the current Colorado Springs community, the area has past experience with mining operations and milling industries. These various mining and ore-mill operations have had a long and storied history in the area and have played a vital role in the development of the city and region. There are numerous known mine locations in the greater El Paso County area. Many area mine sites were abandoned or never fully developed, but some stone and sand quarries are still in operation. From the ore-mills in Colorado City (now known as Old Colorado City), which processed much of the ore mined in the Cripple Creek and Victor areas, to the coal mines in northeastern Colorado Springs (Rockrimmon and Austin Bluffs area), to a number of stone quarries scattered around the area (some of which are still in operation), these operations have had impacts on the local economy, culture, and environment. Brief descriptions of these operations are provided next.

Figure 13. Golden Cycle Mill[39]

2.3.1 Ore-Mills

Gold Hill Mesa (Golden Cycle Mill)

A 210-acre parcel of land located on the southeast side of Twenty-First Street and Highway 24 West/Cimarron Street, an area of land roughly the size of Memorial Park, used

[39] (Tingvik 2012)

to be the location of the Golden Cycle Mill. One of five original ore mills located in Colorado City, the Golden Cycle Mill opened in 1906. It extracted gold from the gold bearing ore mined in Cripple Creek. The Golden Cycle Mill employed a revolutionary cyanide and zinc leaching process to extract gold. It proved to be 91 percent to 93 percent effective at leaching gold out of the rock. This new process proved to be so efficient that the other four original mills were driven out of business. However, by the 1940s, the ore coming down from Cripple Creek was decreasing. In 1949, Following a brief revival after World War II, the Golden Cycle Mill was closed in 1949. Operations were moved to Cripple Creek in Teller County. The Golden Cycle Mill dominated the industry and stood out as the king of ore milling for the first half of the 21st century.

In its forty-three years of operation, the Golden Cycle Mill processed nearly 14 million tons of gold-bearing ore. Out of that 14 million tons of ore, the mill extracted over 8 million ounces of gold worth nearly $13.2 billion at today's price. The money generated by the milling operation had a substantial impact on the local economy. Operations conducted at Golden Cycle Mill multiplied through the economy. Private and public sectors grew. Examples of the growth include the old courthouse, the city hall building (now the pioneer museum), the Broadmoor Hotel, and many of the mansions that still line Cascade Boulevard and Wood Avenue. The mill also had a sizable influence on the working class population. Golden Cycle Mill was one of the largest employers at the time, employing upwards of 250 to 300 men during its peak. A mill job was considered by locals to be a good and respectable job. The mill operated 365 days a year, 24 hours a day, using 3 shifts of 8 hours.

After changing ownership a number of times, the property was acquired by Gold Hill Mesa Joint Venture in 1997.[40] The group initially planned to mine the tailings and then develop a residential neighborhood on the site. After having several studies conducted on the site, the decision was made to go forward with the residential development of the location. The Gold Hill Mesa sub-development was approved by Colorado Springs in 2004 and ground was broken in March 2005. The development plan calls for 1,000 new homes and over 800,000 square feet of commercial property.[41]

The Golden Cycle Mill had a tremendous effect on the environment of Colorado Springs. The processes utilized by the mill had a lasting impact on the water, soil, and plant life in the surrounding area. There is an ongoing debate about how much the mill polluted the land that it occupied for over a half century. The mills in Colorado City and those in Cripple Creek used similar processes to extract gold from rock. The ore was first crushed, followed by a roasting process. The remaining material was then dissolved using various types of chemicals. Finally, the material was infused with other chemical substances to leach the gold out. The remaining material was then deposited at a site often just outside the mill. These materials were typically left onsite, which allowed the chemicals to percolate into the surrounding soils.

The Golden Cycle Mill used different chemicals than the other four mills to complete the last two steps of the process. The Portland, the Standard, the Colorado-Philadelphia, and

[40] (Phillips 2006)
[41] (Gold Hill Mesa n.d.)

the Telluride mills all used a chlorine-based chemical solution to dissolve the ore. The Golden Cycle Mill was the first mill to use cyanide to dissolve the rock. Golden Cycle Mill then added zinc to the water-cyanide solution to force the gold to the bottom of the tanks.[42] The mill would then pipe the remaining materials, which are often referred to as the slimes, to a pool located on the gentle hillside just behind the mill. As the muck and tailings gradually built up, a damn was necessary to contain all of the silt. By the time the mill closed in 1949, the damn had reached a height of 120 feet or nearly 12 stories tall. It is this man-made “mountain” that can be viewed driving down I-25 near Cimarron, until a few years ago, this appeared to be a Colorado Springs version of the Badlands. The damage was a result of a slowly eroding dirt cap that was placed over the tailing pile when the mill was closed.

The dirt cap was originally placed over the tailings pile in the early 1950s with the intention of serving two purposes. It prevents the tailings dust from blowing into the surrounding neighborhoods during windy days. Secondly, it averts the chemical and heavy metal infused sludge from washing down into nearby Fountain Creek and contaminating the water. In 1994, the EPA launched an investigation to determine if the site and the tailings pile contained enough toxic waste, posing a serious health risk, to designate the area as a Superfund site. After concluding the investigation, the EPA chose not to label the area as a Superfund site, but it did find that the soil contained cyanide, arsenic, copper, lead, mercury, silver, and other heavy metals in elevated concentrations.[43] The EPA also determined the tailings had been blowing into a nearby mobile home park and had contaminated Fountain Creek. For these reasons, the EPA chose to label the area a Brownfield site. The EPA defines a Brownfield site as real property that the expansion, redevelopment, or reuse of may be complicated by the presence or potential presence of a hazardous substance, pollutant, or contaminant. [44]

Before breaking ground on the Gold Hill Mesa sub-development, the developers undertook a number of projects to comply with the EPA requirements for Brownfield sites and to curb negative public opinion. The massive tailing pile was smoothed. The large ravines that had developed were filled in. The pile was recapped with four feet of new soil, a combination of local soil and tailings-free uncontaminated soil. The land that borders Fountain Creek was repaired and a pond was built at the base of the pile to prevent any future sediment from contaminating the creek. The EPA also required that each house’s yard have a three-foot deep basin must be dug, a plastic liner laid down, and the basin backfilled with fresh uncontaminated topsoil.[45] Even with this fresh soil, there is debate about whether it is safe to grow a vegetable garden or not. Testing has suggested that the levels of arsenic in the area are too low to have an effect on foods grown in the vegetable gardens. To be safe, the Gold Hill Mesa development team has suggested against this practice and has hired landscaping companies to landscape the yards as part of the house-building process in some cases. The developers also commission periodic tests to monitor the contamination levels.

Another environmental aspect worth noting is the amount of water that was consumed by the Golden Cycle Mill. Water, which was necessary for various operations at the mill, was

[42] (Hughes n.d.)
[43] (Stanley 2008)
[44] (United States Environmental Protection Agency n.d.)
[45] (Phillips 2006)

pumped from nearby Fountain creek into several large holding tanks. It is estimated that it took 1,050 gallons of water to processes one ton of ore. If the Golden Cycle Mill processed over 14 million tons of ore during its forty plus years of operation, then that suggests nearly 15 billion gallons of water were required during the mill's lifetime, an equivalent of just over 22 thousand Olympic-sized swimming pools worth of water.[46]

2.3.2 Coal Mines

Coal mining was an important industry in the early years of Colorado Springs. The industry flourished in the area for over a half-century and contributed greatly to payrolls and various businesses in the community. According to the Colorado Springs Planning Department, there are over seventy-seven underground coal mines in El Paso County, with forty-one of them inside Colorado Springs city limits.[47] Coal production in Colorado Springs was continuous from 1882 to 1965 and produced over 15 million tons of coal.

Figure 14. Pikeview Coal Mine[48]

After the last coal mine in Colorado Springs, the Franceville mine, closed in 1965, the industry all but disappeared from the city. There are very few remnants of the coal mining industry in Colorado Springs and few realize that underground mineshafts crisscross the northern part of the city. Abandoned mineshafts can be found all over, from up north by the Air Force Academy to the east, past the University of Colorado at Colorado Springs (UCCS) and towards Austin Bluffs and Academy. The lack of evidence in the form of large dumpsites and the underground mineshafts make it hard to realize that the lower edges of Austin Bluffs up through Pulpit Rock were once the site of numerous, large coal mines. Some of the more prominent mines in Colorado Springs included: Franceville, Pikeview, Rapson, City Coal Mine #1, and Keystone mines.[49] Coal mines are notorious for leaving behind large piles of waste coal, or "bug dust" as some refer to it. However, the coal found in the Colorado

46 (Turner n.d.)
47 (Colorado Springs Planning Department August 1967)
48 (Tingvik 2012)
49 (Colorado Springs Planning Department August 1967)

Springs area tends to be soft and full of moisture, which results in the coal disintegrating much quicker than other types of coal.

The Franceville coalmine is credited with being the first major mining operation in Colorado Springs. Opened in July of 1882, the Franceville mine is actually a group of mines located east of the Colorado Springs airport.[50] Most mines in the Colorado Springs area were of the shaft variety. Some were slope mines. The Franceville mine was the only coal strip mine in the city. The mine operated on and off for over 80 years. It produced about 700,000 tons of coal.

The Pikeview coal mine, near what is now Rockrimmon, originally opened in 1897 and supplied the city and the surrounding towns with coal for nearly sixty years. The mine closed down in 1957 after producing nearly eleven million tons of coal. The Pikeview Mine, also known as the Carlton or Pikes Peak Mine, was a shaft style mine and was the largest and deepest mine in the area. The main mineshaft reached a depth of 175 feet. The Pikeview mine also has the distinction of being the longest continuously operating mine in the city.

The Rapson coal mine was located near what is now Union and North Circle area.[51] It operated from 1900-1916. This mine produced 600,000 tons of coal during its sixteen years of operation. The Curtis mine, known as the City #1 mine, was owned by the Colorado Springs Company and operated from 1898-1945. The Keystone mine was located near Templeton Gap and Union and produced nearly a million tons of coal between 1903 and 1942.

The coal mining industry was a major force on the early economic development of Colorado Springs. The large mines employed up to 250 men and most operated over 200 days a year.[52] Coal mining was a “blue-collar” job and many who immigrated to the city took up employment in the mines. Unlike the gold mines in nearby Cripple Creek, the coal mines didn’t turn many into overnight millionaires, but countless citizens in the city relied on them as a means of income.

Though the coal mining industry was an integral component to the early Colorado Springs economy and a key force that drove other industries to locate to the area, the coal that was found in the El Paso County region was of a very low quality. This made for “cheap” coal ranging in price from $4.50 - $6.50 a ton depending on the mine where it was purchased and the quality of the coal. While the coal mined in most of these mines was used for local domestic purposes, it was this supply of cheap coal that encouraged the ore mills that processed the gold ore from Cripple Creek and Victor to locate in Colorado City. It was much cheaper to ship the gold ore down the pass to Old Colorado City than it was to transport the coal up to Cripple Creek and the surrounding mining towns. These local coal mines also supplied coal to the local railroads, the Colorado Springs Electric Company, and the Broadmoor Hotel. The highest quality coal was sold across eastern Colorado, Kansas and Nebraska.

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[50] (El Paso County Cultural Features: Mines n.d.)
[51] (El Paso County Cultural Features: Mines n.d.)
[52] (Coal Mining Inspection Department 1941,1942,1943,1947,1948,1949,1955,1959)

There have been a number of reports over the years of giant sinkholes developing on the roads located above these abandoned shafts or of houses that have suffered structural damage due to shifting of the mines below. There are several websites designed to give owners of homes built over known mines or potential buyers of these homes information on how to prevent damage. There is also a mine subsidence protection program homeowners can buy into that could help offset the cost of repairs should a collapse damage their homes.[53]

Being that the coal in the area is very wet and moist by coal standards, it's believed that areas above former mines are most susceptible to cave-ins or subsidence during times of drought. During times of normal precipitation, the remaining coal maintains its moist composition and remains comparatively elastic. However, in times of drought, this elasticity is lost and the shafts tend to collapse in on themselves.

In 1967 the Colorado Springs Planning Department commissioned a report aimed as a guide for future land use in known mining areas around the city.[54] The report pointed out that the roof of a mine would collapse up to five feet for every foot of thickness removed. In other words, four feet of caving from the roof of the mine will fill five feet of the bottom. The report states, "Assuming that a ten foot thick coal bed is removed; upward caving should stop about fifty feet above the floor of the mine. The bottom of the void should, at that point, be filled with loose, unconsolidated material to the new roof level thus stopping any further caving." [55]

At the time of the report, there had been six known cave-ins in the city over the previous year and a half. With the rapid expansion of the city, the land that rested above these known mines was needed for residential and commercial space. Regulation and careful planning was necessary to prevent catastrophes in these areas. Several recommendations and regulations were derived from the report that the planning department put together. These recommendations included:

> That evidence be submitted, in accordance with the City Planning Commission Resolution of July 27, 1964, utilizing test drilling, compaction test and seismic or other acceptable techniques in conjunction with the subdivision of land illustrating the extent and depth of undermining and the possible future surface subsidence in areas known to be undermined.[56]
>
> That special foundations, caissons, piling, excavation and re-compaction, etc., be required in areas where undermining occurred or where subsidence is evident.[57]
>
> That the City's comprehensive plan encourage, based on sound planning and engineering principles, high density, multi-family residential; commercial; industrial; public and quasi-public uses; as well as parks; golf courses; and

[53] (Torline 2009)
[54] (Colorado Springs Planning Department August 1967)
[55] (Colorado Springs Planning Department August 1967)
[56] (Colorado Springs Planning Department August 1967)
[57] (Colorado Springs Planning Department August 1967)

> other open space uses on property that has been undermined, to amortize the cost of or eliminate the need for special construction techniques.[58]
>
> The following regulation was signed on July 27, 1964:
>
> If any area known to be or suspected to be undermined is to be subdivided for the purpose of development, then the developer shall, at his expense, furnish a satisfactory engineering report to the Department of Public Works at the time the preliminary plan of subdivision is submitted for Planning Commission approval.[59]

As described, El Paso County has had a long history of mining and milling. Both economic and environmental impacts are attributable to these operations. The economic impacts had a positive impact on the surrounding area. The environmental impacts had an effect on the surrounding area, some of which are negative. These environmental issues require significant remedies and precautions to ensure contaminates from these operations remain contained.

The next section of this report describes the assumptions the authors presumed while researching and compiling this study.

[58] (Colorado Springs Planning Department August 1967)
[59] (Colorado Springs Planning Department August 1967)

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3 Assumptions

In order to maintain consistency and clarity throughout this report, the authors made necessary assumptions where information gaps existed. This report focuses solely on El Paso County in Colorado. Wherever possible, the authors employed primary resources to provide foundational and groundwork data. There are other studies and analyses that have been done (some quite extensive) that will help this report by providing comparative data. However, the analyses for this paper should and will only focus on the impacts of hydraulic fracturing to El Paso County and the encompassing environmental and economic conditions and how these affect the feasibility of drilling wells with enhanced hydraulic fracturing processes. Differences in water table and aquifer sizes and depths, drilling location, soil composition, beginning and ending elevation, and chemicals used can all have significant effects on the overall drilling process and subsequent effects on the surrounding environment.

The area most impacted by hydraulic fracturing in El Paso County is in the Banning Lewis Region on the periphery of the Niobrara formation.[60] In addition, the potential drilling activity is focused on oil, not natural gas. Ultra Resources has already established rigs and begun drilling exploratory wells as of March 2012.

[60] (Commission, 2012)

4 Formation Comparison

This section examines the Bakken formation, the Niobrara formation, and the El Paso County hydrogeology. The purpose of this section is to provide the reader with information regarding other similar formations, namely the Bakken formation. The hydrogeology provides the reader with information solely related to El Paso County, which is important as most drilling operations impact hydrogeology in some manner.

4.1 Bakken Geology

The Bakken is a formation of shale source rock and is currently the largest known reserve of light sweet crude in North America. The Bakken Shale covers 200,000 square miles of North Dakota, Montana and Saskatchewan and is believed to be located somewhere between 8,000 to 11,000 feet underneath the surface area, far below North Dakota's water table. Oil was first discovered here in 1951, but due to technical limitations, it has only been recently with the development of hydraulic fracturing that any significant amount of oil has been recovered in this area. Recent estimates from industry experts have developed figures as high as 24 billion barrels of technically recoverable oil.[61]

North Dakota's state oil output is continuing to set records. New wells are being drilled at the rate of 1,500-2,000 per year, with the number of total producing wells reaching 6,600 in January 2012. In the last five years, the state's output has quadrupled, going from 115,370 barrels of oil per day in November 2006 to 546,000 in March 2012. North Dakota has recently surpassed California in oil production, becoming the third biggest producer in the country.

When drilling a new well, a producer normally digs an open pit and uses it for dumping of oil-drilling muds, as well as diesel fuel and the different chemicals needed during drilling. In February 2012, North Dakota regulators endorsed new rules for oil waste pits in an effort to mitigate environmental impacts. The new rules ban dumping of liquid drilling wastes directly into any open pit, with exceptions for those less than 5,000 feet deep, or if the drilling muds themselves are made up of mostly fresh water. After the oil company is done with the fracturing of a well, the rules will require the company to post information concerning the chemical composition of the fluids that were used over the last 60 days. In addition, every well must carry bonds to cover any cleanup costs if the wells are abandoned. An individual well has to have at least a $50,000 bond in place.[62] Across North Dakota the nighttime sky is illuminated by fire from the deliberate burning/flaring of natural gas by the oil companies. Without the appropriate equipment to transport natural gas and with little

[61] (Bakken Oil 2012)
[62] (Bakken Oil 2012)

economic incentive to capture the gas and bring it to market, the drillers simply burn the natural gas that is rising with the sweet crude oil. This is not the best alternative for the environment, but it's preferable to allowing the gas to naturally vent from the well with its high content of the potent greenhouse gas, methane. [63]

With the oil boom in North Dakota, the city of Williston anticipates that 3,000 to 4,000 trucks drive through town each day. This alone has created demand for a $10 million bypass to be built in the next few months. State tax department records in North Dakota show that diesel fuel consumption has increased 51 percent since 2007, and the oil industry has now surpassed the agriculture industry as the biggest user of diesel in the state. The increase in diesel usage is largely due to the equipment supporting the hydraulic fracturing drilling. Currently, almost 2 million gallons of diesel are used per day, largely powering the trucks and trains needed to move crude oil and materials, as well as the approximately 3,000 gallons of diesel each day to power one drill rig.[64]

While it still remains to be seen what kind of longevity this formation has, and what the total recoverable oil will be, there is no doubt it is the most dynamic discovery currently under production in North America.

4.2 Niobrara Formation

The economic boundaries of oil production from the Niobrara Shale formation will be determined by oil and gas production volume and the price of these commodities, net of expenses. The estimated production zone for the Niobrara formation stretches north into Wyoming and Nebraska, east to the Colorado-Kansas border and south into Colorado's Crowley and Kiowa counties. El Paso County is included in the estimated Niobrara production zone. This is illustrated in Figure 15.

[63] (Krauss 2011)
[64] (Bakken Oil 2012)

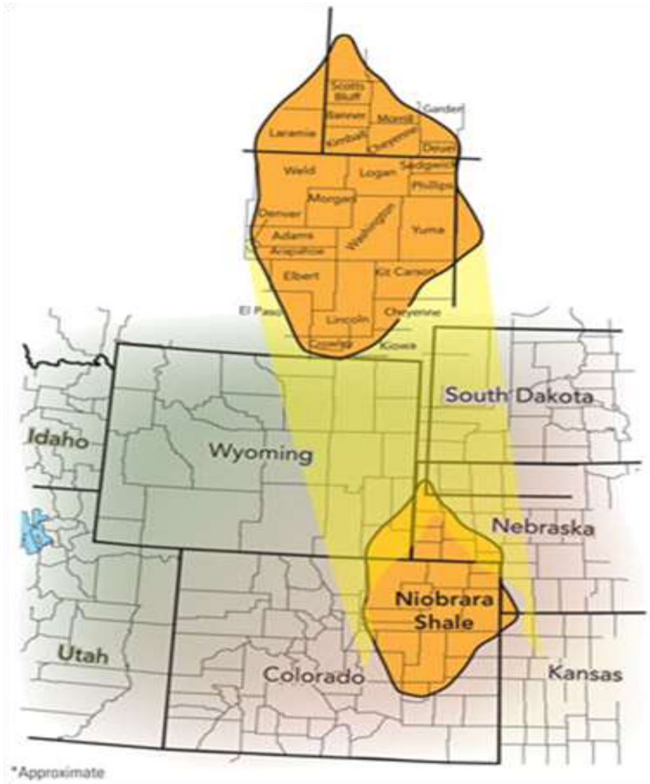

Figure 15. The Niobrara Formation

Figure 16. Cretaceous Period[65]

[65] (Cretaceous Seaway 2012)

4.2.1 Origins of the Niobrara Formation

The Niobrara formation can trace its origin back approximately 90 million years to the Cretaceous period. [66] At that time, the area we now call Colorado was covered in 100 to 1500 feet of salt water (Figure 16). The water would have extended from the current Gulf of Mexico to the current Arctic region (Figure 17. Current Colorado Boundaries and the Denver Basin of Niobrara - Cretaceous Period).[67, 68]

Figure 17. Current Colorado Boundaries and the Denver Basin of Niobrara - Cretaceous[69]

Over the course of several million years, sea life material, plant life, and debris accumulated at the bottom of this ancient water mass. As the ancient water mass gave way to the current Colorado land mass, the accumulation of this seaborne sediment formed the basis of the land in Colorado.

The layers of clay, limestone, chalk, silt and sand that comprise the local sedimentary rock can be studied to provide estimates about the climate and environment some 90 million years ago. Based on this, geologists believe that this was a tropical climate, thus with warmer waters. Other scientists believe that the water temperature changed or fluctuated over time. This explains the various rock types in the region today.

Further indication that the current Colorado region was once a tropical climate, similar to a modern equatorial rainforest, can be found in the rainforest fossils (dated to approximately 65 million years) found just twenty miles north of El Paso County, in Douglas County.[70,71]

---

[66] (Eisinger 2011)
[67] (Colorado Oil & Gas Industry Tax 2011)
[68] (Colorado Oil & Gas Industry Tax 2011)
[69] (Eisinger 2011)
[70] (Perkins June 2002)
[71] (Johnson June 2002)

Figure 18. Rainforest in Colorado[72]

The suggestion of warm waters and tropical climate explain the large masses of carbon-based material found today at depths of up to 10,000 feet below the surface. These deposits of materials in the layers of limestone, chalk, mud and shale comprise the Niobrara Formation.

4.2.2 Niobrara Geologic Composition

The approximate thickness of the Niobrara Formation is 200-400 feet in the eastern Colorado portion of the formation. In this part of the Niobrara, the formation can be divided into two classifications or members of the formation (Figure 19. Stratified Niobrara Members). The deepest level of the Niobrara formation is the Fort Hays Limestone Member. This limestone tends to be no more than about 60 feet thick. This could be termed the "reservoir" rock. Limestone serves as a good reservoir rock due to its sufficient porosity (holes that allow oil to be stored), and permeability (connection between the storage pockets). The Smoky Hill Member is the thicker member of the Niobrara. It can be in excess of 200 feet thick. This portion of the Formation plays an important role in the synthesis of hydrocarbons. It could be termed the "source" rock.[73,74] Overall, the porosity and permeability of the Niobrara are low. Therefore, fracturing of the rock (either naturally, due to geologic activity, or via hydraulic means) is necessary to create channels for oil to collect or to be extracted.[75]

[72] (Vriessen 2002)
[73] (Colorado Oil & Gas Association 2011)
[74] (Colorado Oil & Gas Industry Tax 2011)
[75] (Eisenger 2011)

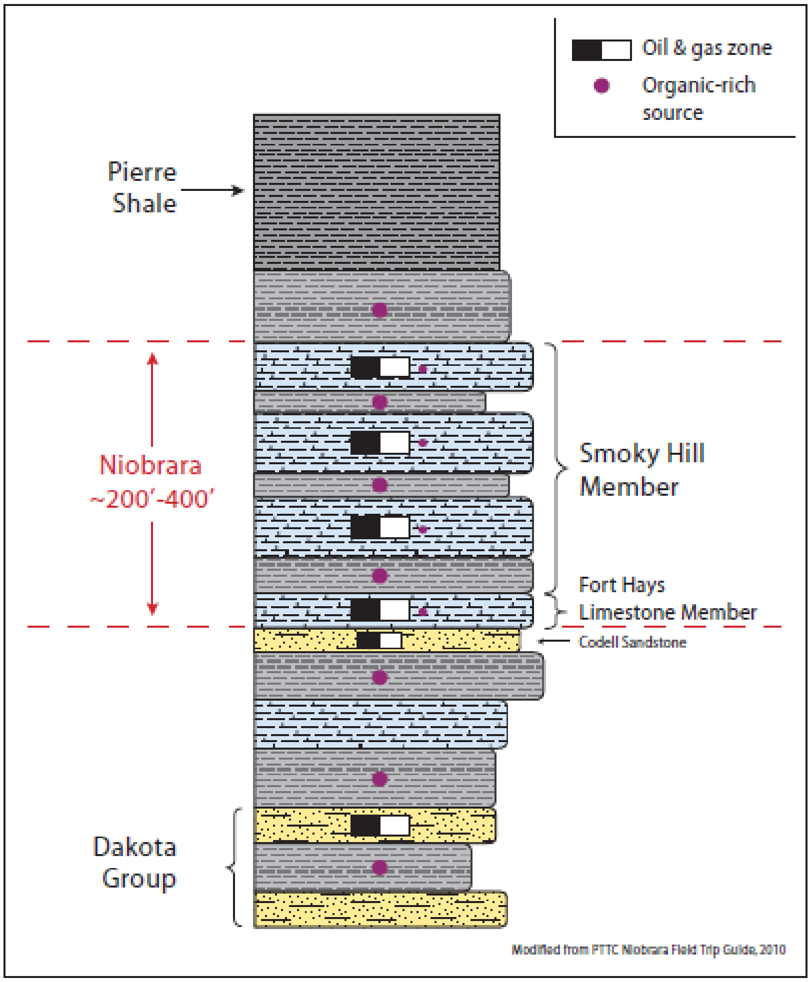

Figure 19. Stratified Niobrara Members[76]

Another means of understanding the geologic design of the Niobrara is to visualize the formation as being comprised of layers of alternating hard, brittle, carbon-rich zones and soft shale layers that tend to seal or prevent migration of hydrocarbons. The layers could be visualized as similar to the layers of a stacked club sandwich. Hydrocarbon storage in the Niobrara occurs in the carbon-rich zones. These zones are susceptible to fracturing due to geologic composition.

4.2.3 Isolation of the Niobrara

The Niobrara is not found immediately under the aquifer tables of El Paso County. Existing under the aquifer tables, but on top of the Niobrara Formation, is another shale formation, the Pierre Shale (Figure 20. Pierre Shale Separates Aquifer and Niobrara). This layer of shale is almost a mile deep, 4900 feet thick, at the Banning-Lewis Ranch in El Paso County.[77] The Pierre Shale formation is an extremely nonporous and non-permeable formation. The depth and low permeability of the Pierre Shale formation provide an ideal

[76] (Eisenger 2011)
[77] (Geolgoy.com 2012)

buffer between the hydrocarbon-producing Niobrara Formation and the freshwater aquifers of El Paso County.[78]

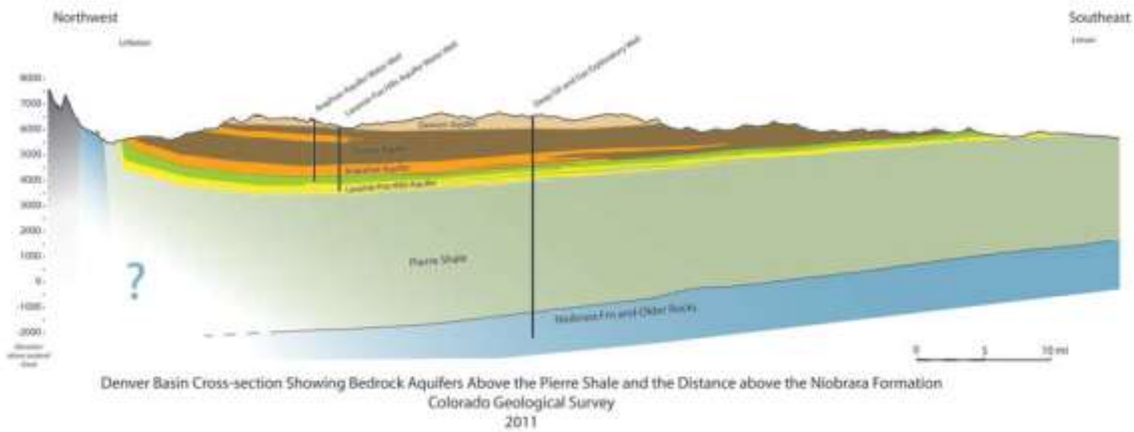

Figure 20. Pierre Shale Separates Aquifer and Niobrara[79]

4.2.4 Creation of Oil in the Niobrara

There are three classifications of carbon deposits: Elemental Carbon, Inorganic Carbon, and Organic Carbon. Examples of Elemental Carbon are coal, graphite, charcoal, and soot. Carbonate materials such as calcite and dolomite, are examples of Inorganic Carbon. Organic Carbon is sourced from anthropogenic sources and varies from highly decomposed humus to less decomposed source material such as leaves, twigs and branches.[80]

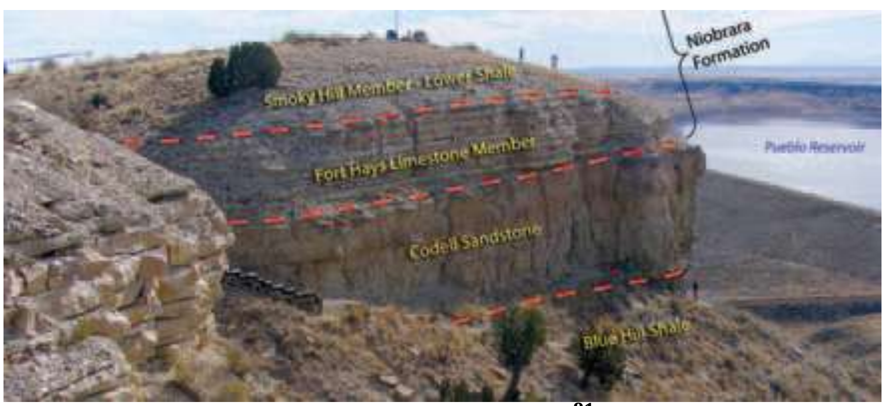

Figure 21. Section of Niobrara Formation[81]

78 (Geolgoy.com 2012)
79 (Eisenger 2011)
80 (Schumacher 2002)
81 (Eisenger 2011)

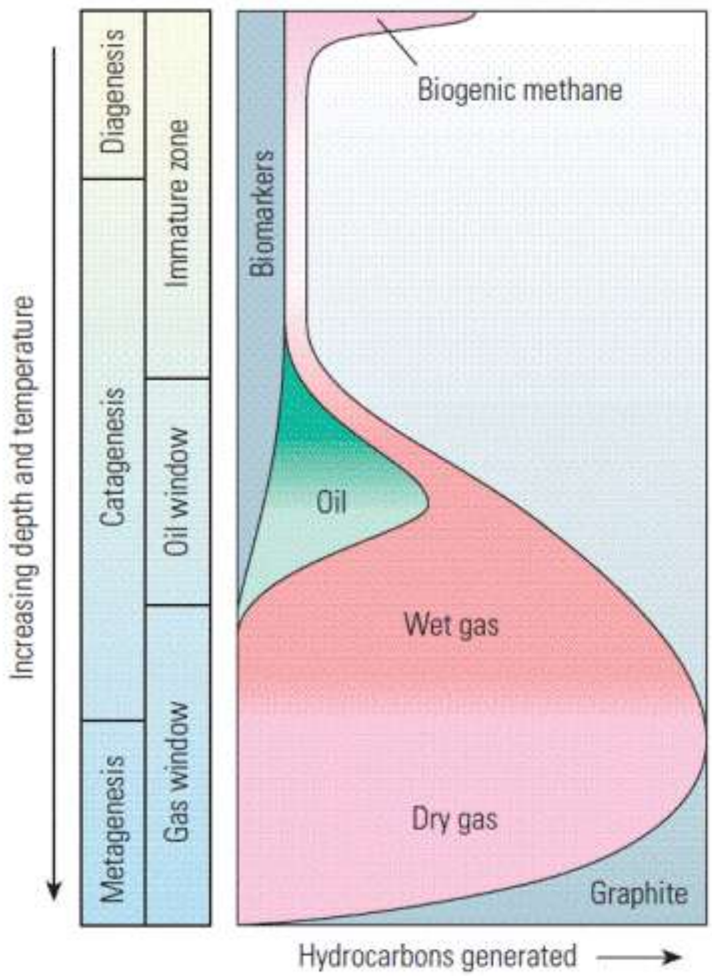

Figure 22. **Three Stages of Oil Production**[82]

There are three stages in the creation of oil. The first stage is diagenesis. This represents the process of transforming a carbon-based mass into the carbon-based substance kerogen. Kerogen is an immature form of oil that is found in the sedimentary rock. Catagenesis, the second stage in the creation of oil, adds heat to the sedimentary rock. When kerogen is exposed to sufficient heat, it can release crude oil (Production and Figure 23. "Oil Window"). The third stage of oil creation is metagenesis. In this phase, additional heat transforms the crude oil into a wet gas and ultimately to a dry gas (natural gas). This is referred to as the "gas window" (Figure 23. "Oil Window").[83] The geothermal gradient (Figure 23. "Oil Window") describes how ambient rock temperatures increases with depth. Insufficient heat and microbial, chemical, and physical decomposition will not result in kerogen production (diagenesis stage of oil formation). Thermal alteration (catagenesis)

[82] (Schlumberger 2012)
[83] (Hunt 1996)

occurs within a specific “oil window” range. Excessive heat will push the hydrocarbon from a liquid (oil) to that of a gas (metagenesis or gas window).84

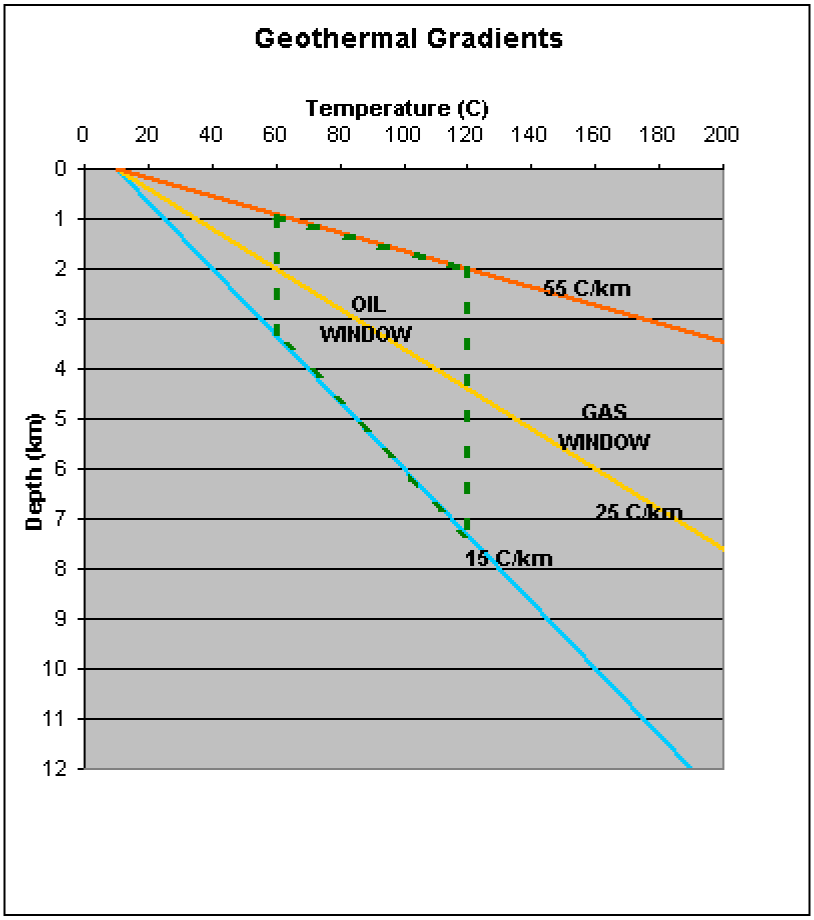

Figure 23. "Oil Window"85

4.2.5 Geologic Predictors and the Niobrara

Total Organic Carbon (TOC) is recognized as an indicator of the potential for finding and producing oil and gas. Average sedimentary rock contains less than 1 percent TOC, while above-average TOC contents may be considered at 5 percent. The Niobrara Formation TOC is in the 8 percent range.[86]

The Niobrara Formation presents an immense deposit of crude oil and natural gas. Several industry insiders, petroleum engineers, and geologists have extraction expectations that exceed 1 billion barrels of crude oil alone. Two of the first wells cited are the Jake well (October 2009) and the Gemini well (a 16-stage fractured well). These wells produced 50,000 barrels over a 90-day period and 1,100 barrels per day at peak, respectively.[87]

[84] (Oil & Gas Financial Journal 2012)
[85] (Toro 2003)
[86] (Eisenger 2011)
[87] (Colorado Oil & Gas Industry Tax 2011)

4.3 The Hydrogeology of El Paso County

The Niobrara Formation is the intended geologic formation of the proposed drilling sites for Ultra Resources. It is an organic-rich shale formation that consists of four water-bearing formations (aquifers) and a primary shale formation, known as the Pierre Shale.[88] El Paso County is located along the southwestern portion of the Niobrara Formation. Figure 24 illustrates the Pierre Shale and Niobrara Formation.

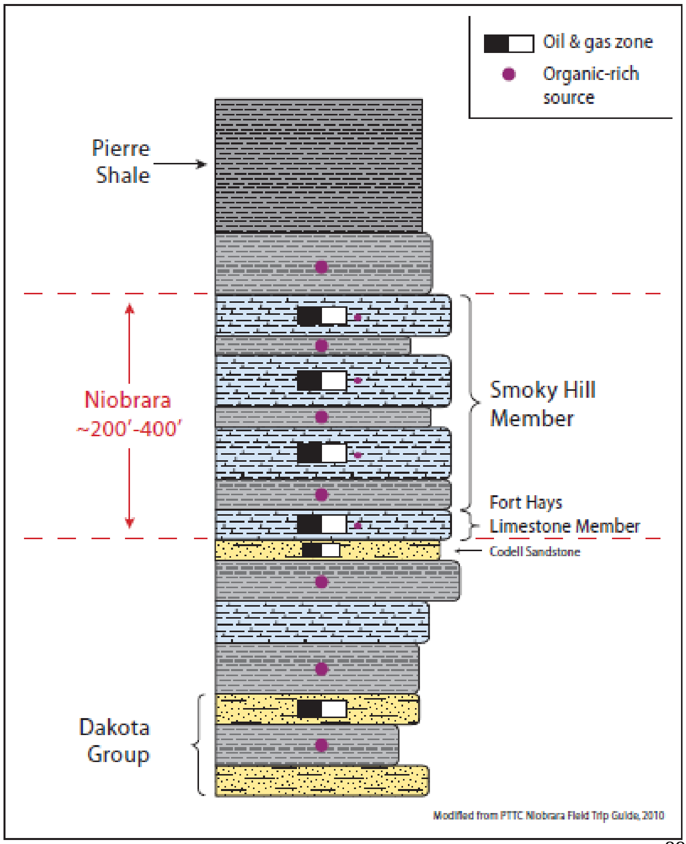

Figure 24. Pierre Shale and Niobrara Formation[89]

[88] (Colorado Geological Survey 2011)
[89] (Colorado Geological Survey 2011)

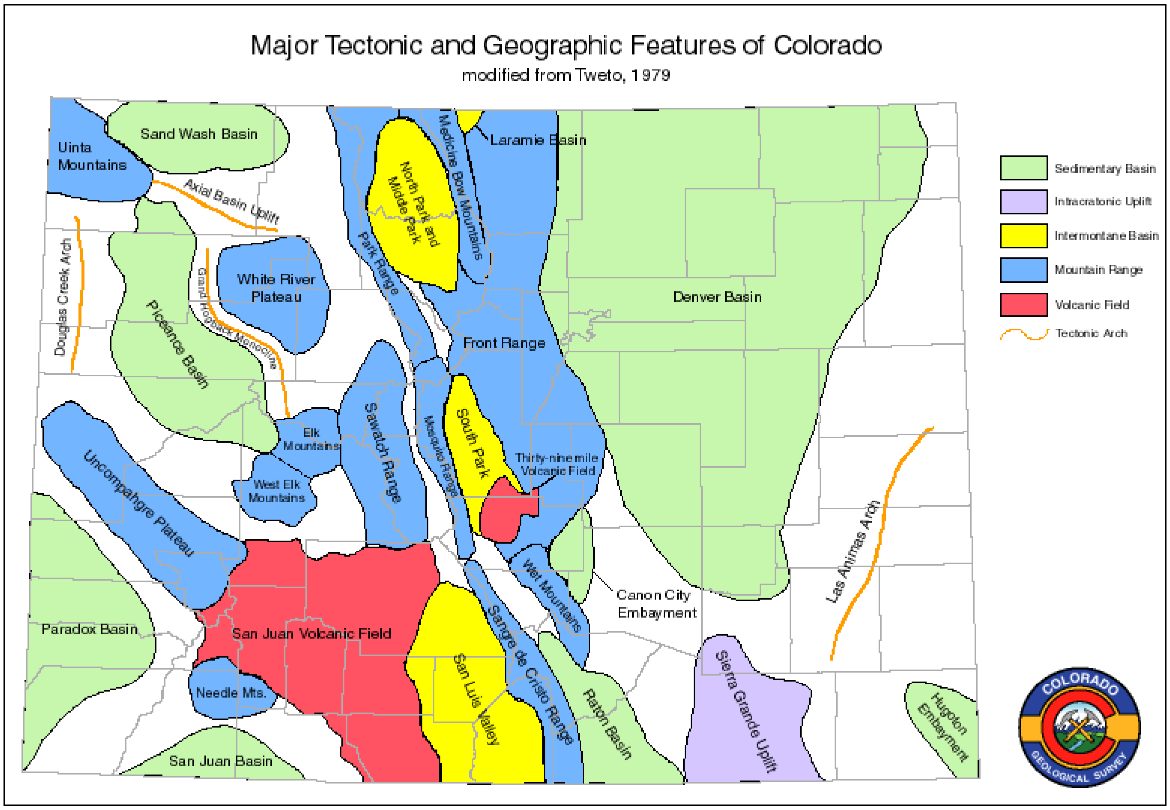

Figure 25. Geologic Features of Colorado

Figure 25 illustrates the major tectonic and geographic features of Colorado. The Denver Basin clearly covers a significant area of central and eastern Colorado.

The Denver Water Basin stretches north-south from Greeley to Colorado Springs, and west-east from the foothills to Limon, Colorado, which is approximately 6,700 square miles. The four confined aquifers are named as: Dawson (Upper and Lower), Denver, Arapahoe (Upper and Lower), and Laramie-Fox Hills.

Because of the inter-layered nature of the sedimentary rocks that make-up the Denver Basin, precipitation immediately impacting the soil does not immediately impact the storage of water in these aquifers. The natural recharge of the deeper bedrock aquifer, such as the Laramie Fox-Hills, is slow enough that it is essentially non-renewable.[90] As drilling operations continue to grow throughout the state of Colorado, it is important to understand how this industry could affect the water levels in the aquifers.

90 (Education, Colorado Foundation for Water 2009)

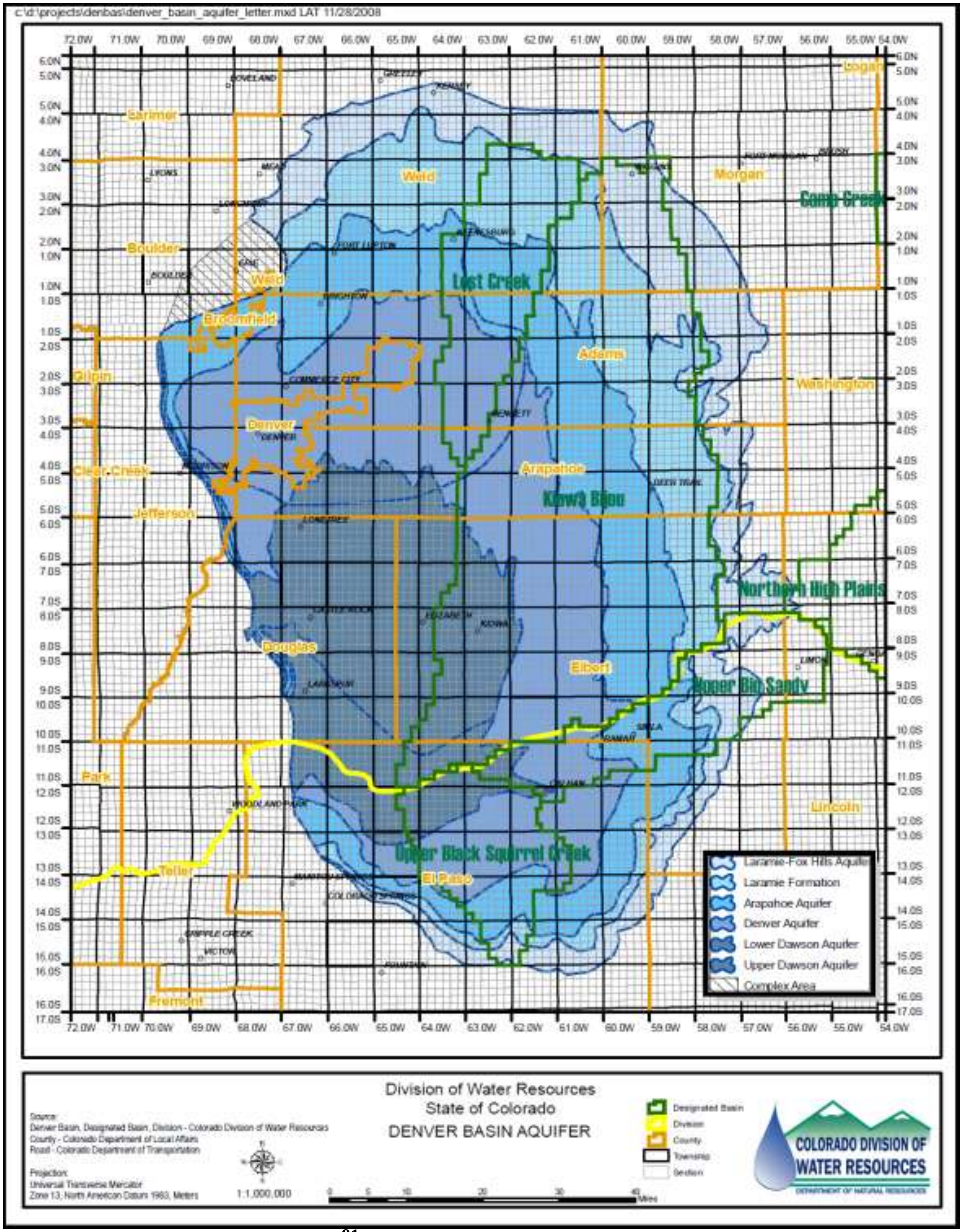

Figure 26. Denver Water Basin[91]

With an understanding of the Niobrara geological makeup and hydrogeology, the next section will examine the hydraulic fracturing process.

[91] (Colorado Division of Water Resources n/a)

5 The Hydraulic Fracturing Process

As mentioned previously, hydraulic fracturing has been used in oil exploration since around 1949. The process has evolved over the past few decades to be a highly successful method for extracting oil and natural gas from shale formations. This section will examine the various processes associated with hydraulic fracturing.

The process of injecting the hydraulic fracturing treatments is tailored to the particular geology of the formation and sequenced typically in four stages, all of which involve water consumption:

Acid Stage: Several thousands of gallons of water are mixed with a dilute acid such as hydrochloric acid or muriatic acid. This clears the cement debris in the wellbore and provides an open pathway for other fracturing fluids by dissolving carbonate minerals and opening fractures near the wellbore.

Pad Stage: This stage uses approximately 100,000 gallons of slickwater. It does not contain proppant. Proppant consists of a fine mesh sand or ceramic material that is intended to keep open, or "prop" the fractures created and/or enhanced during the fracturing operation after the pressure is reduced. The slickwater pad stage fills the wellbore with the slickwater solution, opens the formation, and facilitates the flow and placement of proppant material.

Prop Sequence Stage: This stage may have several substages of water combined with proppant material. These stages may use several hundred thousand gallons of water.

Flushing Stage: During this stage, a sufficient volume of fresh water is injected to flush the excess proppant from the wellbore.[92]

5.1 Disposal of Waste

Ultra Resources will employ a closed-loop system in its on-site waste management procedures. Closed-loop systems are designed to keep all additives, fracturing fluids, mixing equipment and flow-back water within a storage tank, service truck, or flowline. This enclosed fluid capture system will capture flow-back and produced water from hydraulic fracturing events in storage tanks. This type of system reduces exposure to the environment and the potential for spills to occur and leak into the ground or surface water.

In the *Waste Management and Mitigation Measures* submitted by Ultra Resources for permits on the Ranch North 21-27 location, the company indicates the following:

[92] (fracfocus.org 2012)

5.1.1 Ultra Resources Drilling and Completion Operations Waste

Wells will be drilled with a water-based mud system and all drilling waste (cuttings) will be stored in temporary aboveground containment storage bins, treated to pass a paint filter test, and hauled to local landfill. Excess drilling mud will be temporarily stored onsite in aboveground steel tanks and reused at other drilling locations where applicable. Ultra Resources, Inc. ("Ultra") does not utilize hazardous materials in the mud system during drilling operations, nor are petroleum hydrocarbons added. These benign mud systems facilitate the processing of drilling wastes at offsite disposal facilities.

5.2 Drill Cuttings

Ultra plans to store drilling waste (cuttings) temporarily generated while operations are underway. There will be no onsite disposal or discharge of waste generated by drilling. Drilling waste will be collected and stored in temporary aboveground containment bins that are located adjacent to the mud system units. Once the drilling rig is mobilized to next location, drill cuttings will be treated with a reagent for safe hauling to local landfill. Any excess fluids will either be reused where appropriate, or be transported via vacuum truck to an approved water disposal well or to an approved commercial disposal facility.

5.3 Hydraulic Fracturing Flowback / Workover Fluids

During the completions process, after fracking and prior to production, frac flowback will produce a water/oil mix solution that is directed to a temporary separator, which sends water to flowback tanks onsite and any oil to the production storage tanks. The water in the flowback tanks will be sent to an approved disposal well.

5.4 Produced Water

Produced water will be stored onsite in 400 bbl. (barrel tanks) storage tanks following separation from the oil. These tanks are located in a metal containment which is certified compliant to Ultra Resources' Spill, Prevention, Control, and Countermeasure (SPCC) program standards. The produced water will be loaded out through submerged loading and transported by truck to an approved commercial water disposal facility.[93]

This is a good indication of the disposal of waste process across all of Ultra's proposed drilling sites. Ultra Resources is employing industry best practices by employing a closed-loop system and reusing excess fluids. Additionally, Ultra Resources maintains a waste tracking database that tracks the quantity, category, location, and disposal location in order to effectively manage waste and identify areas for improvement.

[93] (Ultra Resources, Inc. n.d.)

6 Proposed Drilling Sites in El Paso County

The proposed drilling sites in El Paso County by Ultra Resources are east of downtown Colorado Springs. The Banning Lewis Ranch is one prospect of Ultra Resources.

As of April 11, 2012, six of Ultra Resources applications to drill for oil have been approved by COGCC. Should each of these exploratory wells result in economic "wet" wells, the following multi-well plans are registered with COGCC (see Table 1).

Table 1. Number of COGCC Approved Drilling Locations - Ultra Resources (as of April 08, 2012)

Drilling Location Name	# of Exploratory Wells	# of Horizontal Wells	Size of Disturbed Area Construction in Acres
Spinach State	1	8	7.74
Olive Oyl State	1	8	7.83
Brutus State	1	8	7.45
Ranch North 21-27	1	8	7.45
Ranch Central 42-23	1	8	7.7
Ponderosa 41-17 1V (includes Ponderosa 41-17 1H-4H)	1	4	8.5
Total # of Proposed Wells		50	

Figure 27. El Paso County Drilling Locations

Table 2. Ultra Resources Proposed Drilling Sites in El Paso County (4/8/2012)[94]

Location Name/Well	Proposed Total Depth (in feet)	Average Depth to the Niobrara Formation (in feet)	Average Thickness of the Pierre Shale (in feet)	Average Depth to Base of Fox Hills Aquifer (in feet)
Spinach State	6,081 (1.15 miles) Exploratory vertical well	4,300	4,100	n/a
Spinach State 41-10 4H	12,000 (2.27 miles)	4,300	4,100	n/a
Spinach State 41-10 3H	12,000 (2.27 miles)	4,300	4,100	n/a
Olive Oyl State N44-16 4H	12,000 (2.27 miles)	5,300	4,500	n/a
Olive Oyl State N44-16 3H	12,000 (2.27 miles)	5,300	4,500	n/a
Brutus State 33-14 4H	12,000 (2.27 miles)	5,300	4,100	500
Brutus State 33-14 3H	12,000 (2.27 miles)	5,300	4,100	500
Ranch North 21-27	8,170 (1.54 miles) Exploratory vertical well	6,900	4,900	1,500
Ranch Central 42-23	6,480 (1.22 miles) Exploratory vertical well	5,900	4,700	n/a
Ponderosa 41-17 1V*	7,625 (1.44 miles) Exploratory vertical well	6,300	4,700	1,100
*Ponderosa 41-17 1H	11,200 (2.12 miles)	6,300	4,700	1,100 or 900*
*Ponderosa 41-17 3H	11,600 (2.19 miles)	6,300	4,700	1,100 or 900*

**Part of same drilling location and pad.*

Figures 28, 29, 30 and 31 illustrate the approximate multi-well plan image overlaying several, but not all, of the proposed drilling site location so that one can visualize the location and the direction of the horizontal drilling. Please note this map is not to scale.

[94] (Colorado Geological Survey 2012)

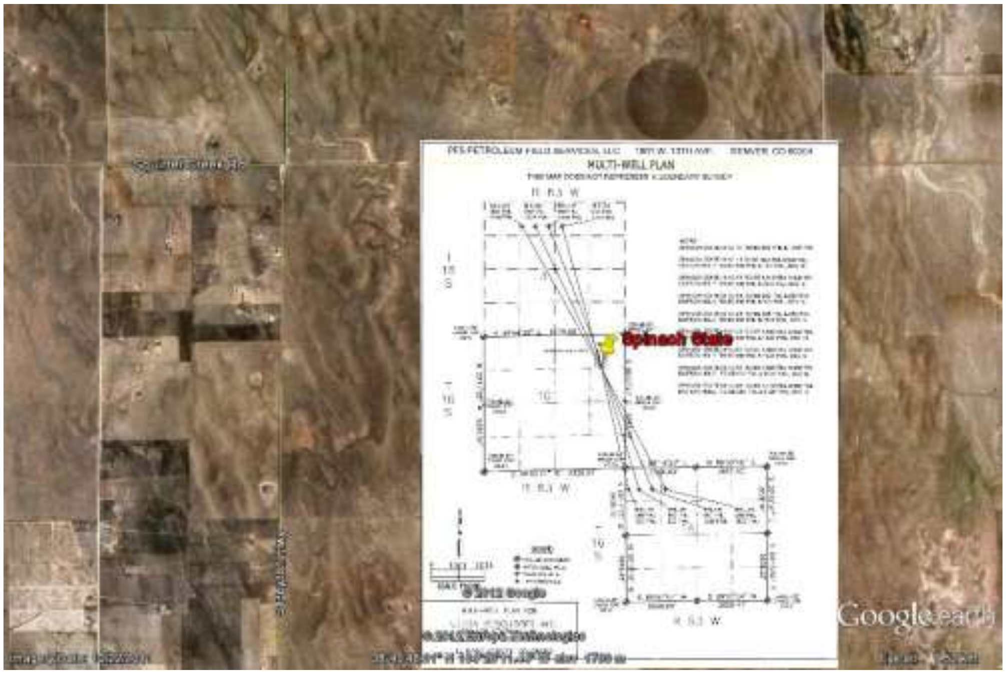

Figure 28. Spinach State Site

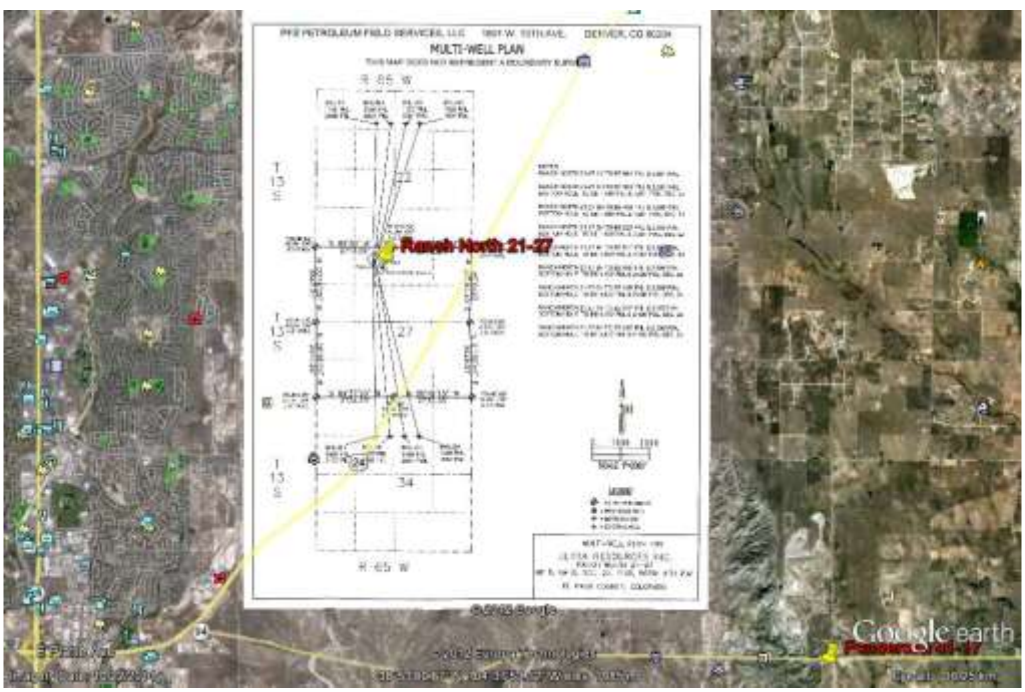

Figure 29. Ranch North 21-27

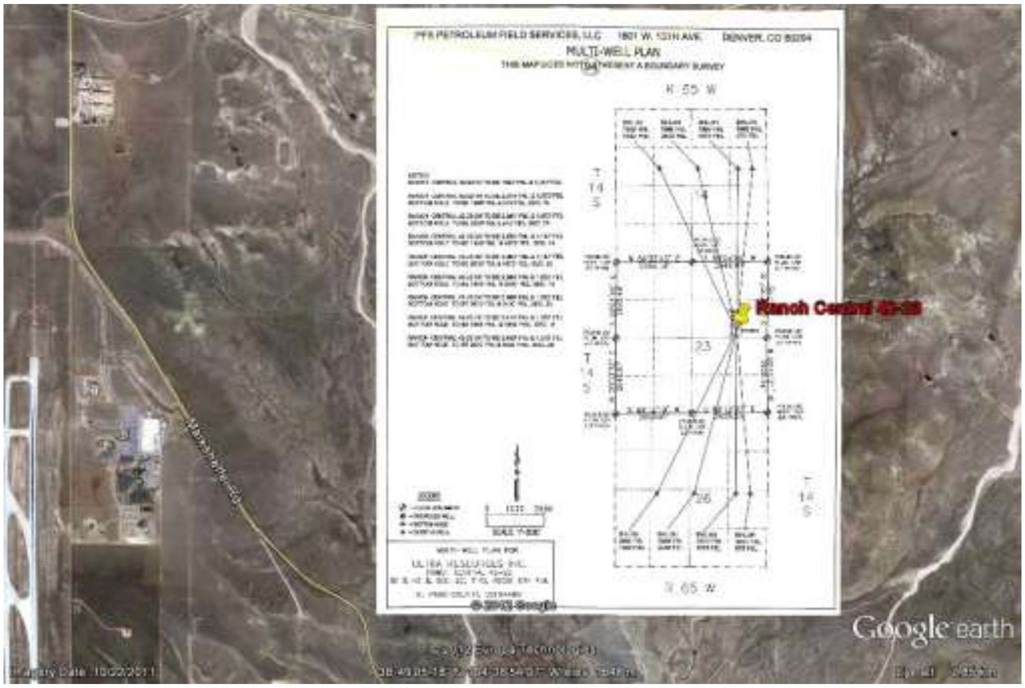

Figure 29. Ranch Central 42-23

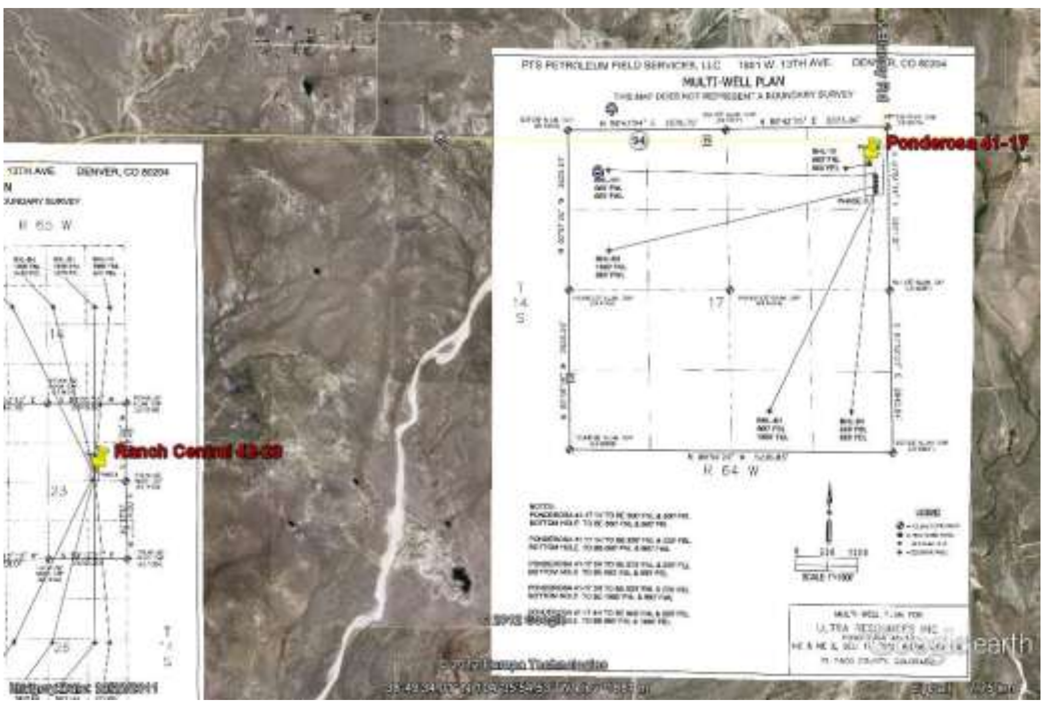

Figure 30. Ponderosa 41-17

6.1 Land Use

From the information registered on the Form 2A permits with COGCC, the size of disturbed area construction in acres describes the well pad plus process areas. The more advanced technologies of hydraulic fracturing include well pads that facilitate multi-well horizontal wells. These disturb surface land area less than the commensurate number of vertical wells.

Table 3. Disturbed Areas Sizes

Location	Size of Disturbed Area Construction in Acres	Size of Location after Interim Reclamation in Acres	Estimated Date that Interim Reclamation Will Begin
Spinach State	7.74	2.00	4/15/2014
Ranch North 21-27	7.45	2.00	6/15/2014
Ranch Central 42-23	7.70	2.00	6/15/2014
Ponderosa 41-17 1V, 1H, 3H	8.50	2.00	8/1/2014

6.2 Habitat, Use, and Reclamation

The vegetation that exists within all the proposed disturbed areas consists of native grasses that include bluestem, grama, wheatgrass, buffalo grass, fescue, oat grass, and brome.

The current and future registered use of the land is non-crop land/rangeland. This categorization as non-crop land under Series 1000 Reclamation Regulations of COGCC means that during soil removal Ultra Resources:

> Shall separate and store the topsoil horizon or the top six (6) inches, whichever is deeper, and mark or document stockpile locations to facilitate subsequent reclamation. When separating the soil horizons, the operator shall segregate the horizon based upon noted changes in physical characteristics such as organic content, color, texture, density, or consistency.

The COGCC Reclamation Regulations state the surface land shall be restored as nearly as practicable to its condition at the commencement of drilling operations.[95]

This mandates that Ultra Resources shall replace all soil horizons to their original relative position and contour as near as possible to achieve erosion control and long-term stability. Ultra can also be expected to till the area adequately in order to establish a proper seedbed. The disturbed area shall then be reseeded in the first favorable season following rig demobilization. The reseeding can be expected to be consistent with the native grassland plant community.

[95] (Commission 2009)

7 Environmental Concerns

This section examines several environmental concerns associated with oil exploration. Each section provides a brief description of the environmental concern and the potential impacts. The authors have selected the below environmental concerns based upon research indicating these concerns had the highest visibility and interest across the United States.

7.1 Water Contamination and its Impacts

Groundwater is water that has drained through surface layers of soil and rock until it reaches a layer of rock material through which it cannot pass, or can pass only very slowly. This produces a water table in rock layers that is above the impermeable layer. The water is stored in gaps in the rock, or between the particles of which the rock is composed. Rock which retains water in this way is called an aquifer as shown in Figure 31.

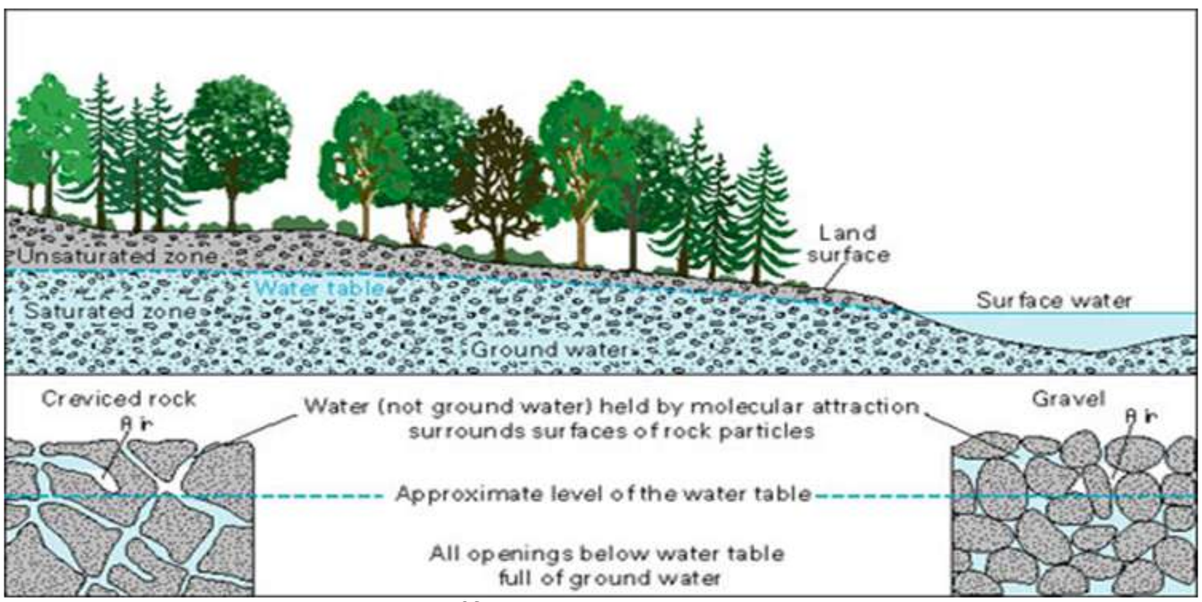

Figure 31. Diagram of an Aquifer[96]

Groundwater is an important part of the global fresh water supply. It is a source for drinking water and irrigation purposes. Groundwater, while protected by the filtering action of soil, can be contaminated by leaking municipal landfills, sewage lagoons, and chemicals from industrial activity (Figure 32).

[96] (Groundwater n.d.)

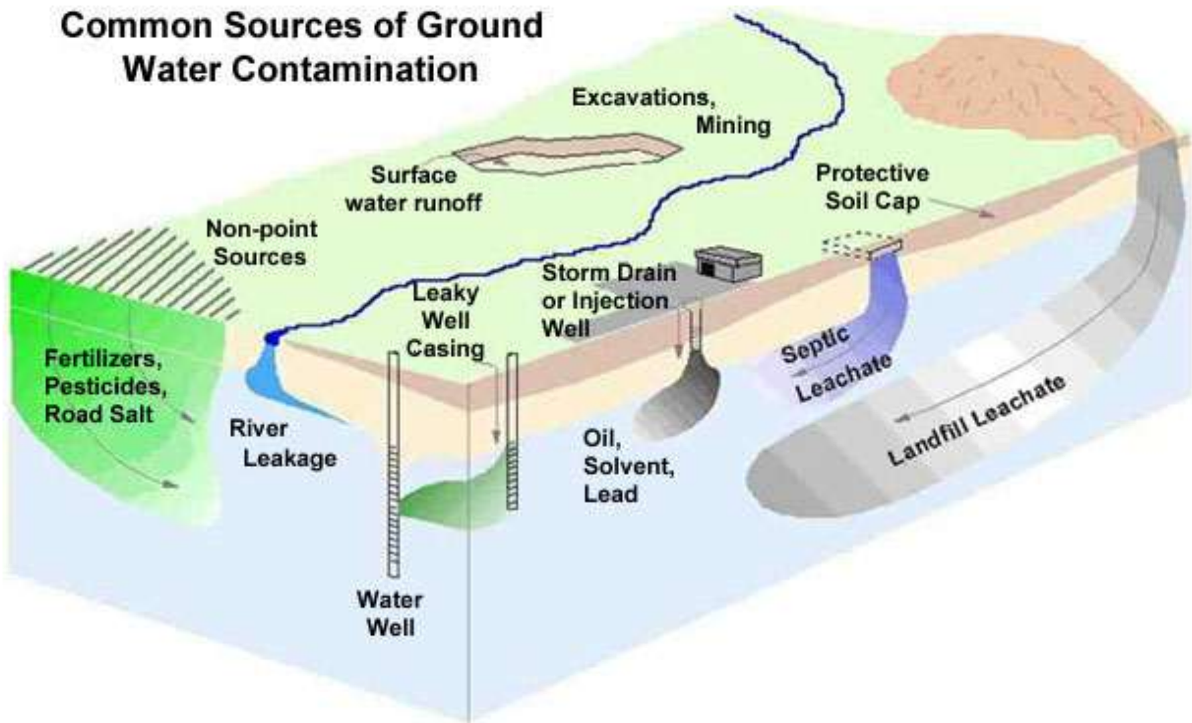

Figure 32. Common Sources of Groundwater Contamination[97]

Major sources of these contaminants are leaking storage tanks, septic systems, hazardous waste sites, landfills, and the widespread use of road salts, fertilizers, pesticides and other chemicals. Leaking underground oil tanks and spills at gas stations account for oil and other chemicals such as benzene and methyl-tertiary-butyl ether (MBTE) found in ground water.

7.1.1 Hydraulic Fracturing – Chemical Introduction

Hydraulic fracturing, as previously discussed, utilizes water, proppants, and various chemicals under high pressure during the process. Water contamination happens when regulations are not properly implemented (e.g., improper well casings being used). Most of the chemicals used in hydraulic fracturing are considered hazardous, and long-term exposure to these chemicals can have serious health consequences.

7.1.2 **Commonly used Chemical Components**

The most commonly used chemicals in hydraulic fracturing are methanol, isopropyl alcohol, ethylene glycol, and crystalline silica. Table 4 contains a list of commonly used chemical components in hydraulic fracturing.[98]

[97] (jnuenvis.nic.in n.d.)
[98] (Chemicals used in Hydraulic Fracturing n.d.)

Table 4. Chemical Components Appearing Most Often in Hydraulic Fracturing Products Used Between 2005 and 2009

Chemical Component	Number of Products Containing Chemical
Methanol (Methyl alcohol)	342
Isopropanol (Isopropyl alcohol, Propan-2-ol)	274
Crystalline silica - quartz (SiO2)	207
Ethylene glycol monobutyl ether (2-butoxyethanol)	126
Ethylene glycol (1,2-ethanediol)	119
Hydro treated light petroleum distillates	89
Sodium hydroxide (Caustic soda)	80

Exposure to the above chemicals is hazardous to health; the BTEX compounds – benzene, toluene, xylene, and ethyl benzene – are Safe Drinking Water Act (SDWA) contaminants. Benzene in particular is a known human carcinogen.[99] When safety and well construction protocols are not followed during hydraulic fracturing, these chemicals can enter public water systems in areas around drilling sites.

These chemicals have the potential to seep in to the water system in several ways, as shown in Table 5.

[99] (Chemicals used in Hydraulic Fracturing n.d.)

Table 5. Methods of Groundwater Contamination

Method of Introduction	Description
Drilling and Completion Process	Fracking leaves behind a toxic sludge, and safely disposing of the sludge is an ongoing challenge. Contaminants in the pit sludge may leak out or overflow the pit and contaminate nearby surface waters and ground water. As noted earlier in this study, Ultra Resources will employ a closed-loop system, reducing the possibility of a chemical spill or leak
Stimulation Technique	Fracturing fluids may be injected into or come in contact with fresh water aquifers. Between 20% and 40% of the toxic chemicals used in the process remain stranded underground where they can contaminate drinking water
Produced Water	Produced water may contaminate drinking water supplies through spills, pipelines breaks, improper casing or cementing, errors in gas well construction, leaks from storage ponds, or movement of injected water into a freshwater aquifer. Methane from fracture wells can leak into ground water, thereby contaminating drinking water, and can create the risk of an explosion.
Separation and Dehydration	Wastewater may contain dissolved hydrocarbons, sand, and metals that can contaminate surface and groundwater.
Gas Compression	Soil and water pollution may occur due to spills or leaks of diesel or other fuel used to power the compressors.

7.2 Leaks and Spills

There have been documented incidents involving the release of oil and gas industry chemicals and waste. The releases involved drilling mud, hydraulic fracturing chemicals, seepage from drilling pits, and vapors from gas condensate pits. Hydraulic fracturing chemicals frequently are found in drinking water supplies near oil and gas development sites. In 2010, at least 34 million gallons of crude oil and chemicals were spilled nationwide[100]. The New Mexico Oil and Gas Conservation Division identified around 400 cases of groundwater contamination from oil and gas pits statewide. According to the data collected by the COGCC, in the period between 2003 and 2008, there were approximately 1,549 spills in the state of Colorado, of which 134 spills were of oil and gas products.[101] A poorly lined pit near Parachute, Colorado leaked 2,500 barrels of drilling mud into a tributary of Garden Gulch. The resulting test samples showed high levels of benzene and acetone.[102] In 2009 and 2010, the EPA informed residents of Pavillion, Wyoming that a number of drinking water wells in their area were contaminated with 2-butoxyenthanol, a chemical associated with

[100] (cbsnews n.d.)
[101] (cogcc- final prehearing statement n.d.)
[102] (2008)

hydraulic fracking. It is known to cause health effects such as narcosis and severe liver and kidney damage.[103]

In most cases, the resulting investigations showed that the reason for a leak or spill incident is not attributable to the hydraulic fracturing process. Negligence and/or a lack of adherence to regulations are the culprits. The oil and gas industry can help minimize the impact on groundwater from this incident type by ensuring that their operators adhere to regulations and utilize best practices to prevent surface spills.

7.3 Air Pollution

A study by the National Oceanic and Atmospheric Administration (NOAA) in 2008 found that plumes of air, that were north of Denver, Colorado, contained high levels of chemical pollutants, including the potent greenhouse gas methane. After taking a series of samples and readings along rural roads, near oil and gas equipment, the study identified a source. The primary source of the unusual air pollutants was oil and gas production in northeastern Colorado's Weld County. "[NOAA] found gas operations in the region leaked almost twice as much methane into the atmosphere as previously estimated…the oil and gas infrastructure [leaked] other air pollutants…including benzene, which is regulated because of its toxicity".[104]

The EPA also investigated the effects that oil and gas extraction has on air pollution. According to the EPA, there are well-documented air quality impacts in areas with active hydraulic fracturing development, with increases in emissions of volatile organic compounds (VOCs), hazardous air pollutants (HAPs), and methane gases.[105]

7.3.1 Volatile Organic Compounds

Volatile organic compounds (VOCs) are emitted as gases from certain solids or liquids. Smog, the primary constituent of ground-level ozone, is formed by a chemical reaction of carbon monoxide, nitrogen oxides, volatile organic compounds, and heat from sunlight. Smog can contribute to short-term and even long lasting respiratory problems. It is caused by a variety of sources, including vehicle emissions, smokestack emissions, paints, and solvents. The process of hydraulic fracturing for natural gas and oil does not contribute significantly to the formation of smog, as it emits low levels of nitrogen oxides and virtually no particulate matter.[106] However, the use of diesel engines in the hydraulic fracturing support equipment and transportation equipment contribute to the levels of particulate matter and nitrogen oxides in the air. The amount of diesel fuel needed to operate equipment supporting one operation well per day is approximately 3,000 gallons. This does not include the amount of diesel required for transportation to and from the wells. In North Dakota, 2

[103] (Article: Propublica.org n.d.)
[104] (Human 2012)
[105] (U.S. EPA: Hydraulic Fracturing 2012)
[106] (Natural Gas and the Enviornment 2011)

million gallons of diesel are used per day to power the trucks and trains needed to move the crude oil and materials from the well site.[107]

7.3.2 Hazardous Air Pollutants

The Clean Air Act requires the EPA to control the emission of 187 Hazardous Air Pollutants (HAPs), which are pollutants that cause or may cause cancer or other serious health effects, such as reproductive effects or birth defects, or adverse environmental and ecological effects. Between the years 2005 and 2009, hydraulic fracturing companies used 595 products containing 24 different HAPs. Hydrogen fluoride is a highly corrosive and systemic HAP that causes severe and sometimes delayed health effects due to deep tissue penetration. In one instance from 2008 to 2009, 67,222 gallons of products containing hydrogen fluoride were used in the fracking process. Methanol appeared most often in products listed by oil and natural gas companies. Other HAPs found in fracking fluids are formaldehyde, hydrogen chloride, and ethylene glycol.[108] To address the use of HAPs, new EPA regulations are scheduled for implementation by April 3, 2012. These new regulations are designed to reduce emissions of VOCs, HAPs, and methane.[109]

7.3.3 Methane and Greenhouse Gases

Methane, CH_4, is a hydrocarbon that is a primary component of natural gas. Its presence in the atmosphere affects the earth's temperature and climate system.[110] There are two different forms of methane gas. Thermogenic methane is formed deep underground at high temperatures and pressures from organic matter over very long time. Biogenic methane is produced at shallower depths and lower temperatures through the transformation of organic matter by tiny microorganisms. Thermogenic methane is captured in gas wells during hydraulic fracturing. Biogenic methane is not associated with hydraulic fracturing.[111]

Methane gases that rise during the extraction process pose a risk of explosion. High concentrations of methane can cause asphyxiation and can affect greenhouse gas emissions significantly. The largest source of methane (enteric fermentation) is when domesticated livestock (cattle, buffalo, sheep, goats, and camels) produce significant amounts of methane as part of their normal digestive processes.[112] The second largest source of methane worldwide is from the production, processing, transmission, and distribution of oil and natural gas (Figure 33).[113]

[107] (Bakken oil 2012)
[108] (Commerce 2011)
[109] (Alfred M. Klausmann 2011)
[110] (Methane to Markets 2008)
[111] (Natural Gas and the Enviornment 2011)
[112] (Methane Sources 2011)
[113] (Natural Gas and the Enviornment 2011)

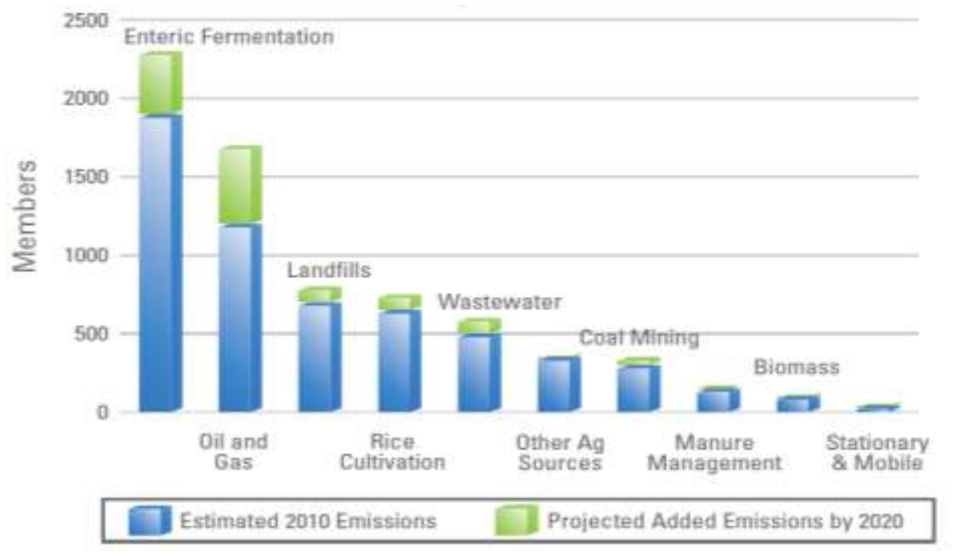

Figure 33. Estimated and Projected Global Methane Emissions by Source

During the lifetime of an average shale-gas well, an estimated 4 to 8 percent of its methane gas production is leaked into the atmosphere.[114] Methane is emitted during normal operation via routine venting, equipment leaks and flow-back return fluids, routine maintenance, and system disruptions. Figure 34 contains a breakdown of aggregate methane emissions in billions of cubic feet (Bcf) by the major oil and natural gas sectors in the United States.[115]

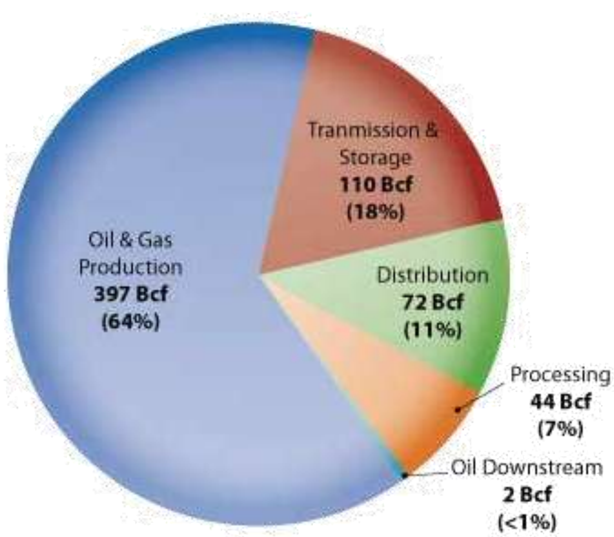

Figure 34. Aggregate Methane Emissions

Emissions can vary from facility to facility and are largely the result of the process and equipment type, operation and maintenance procedures, and equipment conditions.[116] Oil

[114] (Howarth 2011)
[115] (EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2009 2011)
[116] (Global Methane Initiative 2011)

and natural gas production emits the largest amount of methane in the process because of the practices of well venting and flaring. Oil companies are turning to a process called “flaring” to eliminate the excess natural gas produced alongside the crude oil. It is currently less economically feasible to capture and bring the natural gas to market; therefore, drillers are deliberately burning it. With some companies, temporary flaring may be unavoidable, especially in fields where the pipeline infrastructure is incomplete, such as Eagle Ford and the Bakken. In North Dakota’s Bakken field alone, each day more than 100 million cubic feet of natural gas is burned; enough energy to heat half a million homes for a day. This flared gas also spews at least two million tons of carbon dioxide into the atmosphere every year, equivalent to 384,000 automobiles. There are currently few government regulations that limit flaring. Although capturing the gas is the best option, flaring is better for the environment than venting the natural gas into the atmosphere since methane is a heat-trapping greenhouse gas. Figure 35 depicts flaring at an oil well

Figure 35. Gas Flaring in North Dakota

Figure 36 depicts aggregate flaring across North Dakota's Bakken field. Areas in red are locations where flaring is taking place. Areas in white are population centers.

Figure 36. Bakken Oil Field "Flaring" Seen from Space[117]

7.3.4 Emission Reduction Efforts

According to the EPA, emission reduction projects aid in the conservation of natural gas. Furthermore, companies often recover their costs in less than one year, which in turn brings about lasting productivity and environmental performance improvements. Reduction projects often fall into the following categories: replacing existing equipment, improving maintenance practices and operational procedures, and studying and undertaking new capital projects.[118]

"The Global Methane Initiative is an action-oriented initiative; the goal of which is to reduce global methane emissions, enhance economic growth, promote energy security, improve the environment, and reduce greenhouse gas emissions."[119] The expected benefits from this partnership have the potential to deliver, by 2015, annual reductions in methane emissions of more than 180 million metric tons of carbon dioxide equivalent. This reduction can be translated to the amount of energy needed to heat approximately 7.2 million households.

In addition to mitigating climate change, reducing methane emissions delivers health and safety benefits. Many practices in reducing methane also reduce emissions of volatile organic compounds and hazardous air pollutants. This yields health benefits for workers and local populations. Furthermore, reducing methane emissions aids in reducing ozone-related health effects, as it is a precursor of tropospheric ozone.[120]

[117] (Bakken oil 2012)
[118] (Global Methane Initiative 2011)
[119] (Methane to Markets 2008)
[120] (Global Methane Initiative 2011)

7.3.4.1 Natural Gas STAR Program

The Natural Gas STAR Program is a flexible, voluntary partnership that encourages oil and natural gas companies – both domestically and abroad – to adopt cost-effective technologies and practices that improve operational efficiency and reduce emissions of methane.[121] Oil and natural gas operations are the largest human-made source of methane emissions in the United States. Given methane's role as both a potent greenhouse gas and a clean energy source, reducing these emissions can have significant environmental and economic benefits.[122]

7.4 Surface Impacts

There are a number of issues regarding the effects of hydraulic fracturing on the surface of the landscape, including soil, noise, and light pollution. Surface pollution is unavoidable in any ground drilling operation. However, due to the nature of this particular type of drilling (long, narrow, deep wells) the disruption to the surface is far less invasive than most drilling operations. Anadarko (a gas and oil extraction operator) estimates that the typical location for a horizontal well is approximately 8-10 acres in size. Ultra Resources claimed in its initial well permits that the disturbed area for construction will be 7.45 – 8.5 acres depending on the designated well. In addition, the drilling rigs built by Ultra are designed to use a closed-loop system, which forgoes a reserve pit, thereby preventing some surface damage and "reducing the number of loads to haul waste and cuttings by almost 50%."[123]

7.4.1 Noise and Light Pollution

Standing up a well involves a continuous 24/7 operation. Therefore, light pollution is potential concern. This is more disruptive the closer it is to residential housing. While this would be more likely in the more densely populated areas of El Paso County (see Figure 37), the risk of encountering suburban homes and communities is reduced in the Banning Lewis Ranch, as only 300 homes have been built to date.[124]

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[121] (EPA 2012)
[122] (NaturalGasSTAR 2011)
[123] (Anadarko Petroleum Corporation, 2012)
[124] (Laden, 2011)

Figure 37. Greely Well in Subdivision[125]

The same concerns arise and apply to noise pollution. Drilling an oil rig requires a significant amount of materials and enough metal casing to reach depths of up to 10,000 feet. This requires large trucks to transport the materials, generators to supply power for the construction, and a host of construction activities continuing throughout the process. Anadarko estimates that this process requires approximately 8-10 trucks carrying up to 40 loads over the course of 2-3 days to provide the equipment for standing up a rig.[126] Though not directly measurable, the activity of creating an oil rig would generate noise pollution consistent with general construction operations. Table 14 in the environmental regulations section shows limits on noise by zoning area.

[125] (Wineke, 2012)
[126] (Anadarko Petroleum Corporation, 2012)

Figure 38. Aerial View of Well Pad and Equipment[127]

7.4.2 Potential Spills

The hydraulic fracturing process utilizes chemicals that, even in trace quantities, can be extremely harmful to people, plants, and animals. These chemicals have contaminated both water and soil in recent spills and can cause serious health effects. On October 4, 2005, a wellhead valve failed on the Cannon Land 7-35 well, resulting in the release of up to 210 gallons of fracking fluids that returned to the surface from the operation.[128] The fluid sprayed into the air and drifted offsite, primarily onto pasture land, resulting in a visible coating as thick as 1/2 inch. The company also estimated that 15-20 gallons of the fluid entered the Platteville Lateral irrigation ditch, which contained some standing water, but was not flowing at the time that the fluids entered it.

The fluid contained a mix of potassium chloride (2%), a surfactant (DWP-931, run at 1.5 gallons/1000 gallons of water), and a friction reducer (DWP-601, run at 0.5 gallons/1000 gallons of water). DWP-931 contains numerous potentially toxic substances, including "ethoxylated nonylphenol (15-40%); trimethylbenzene (3-7 %); light aromatic naphtha (3-13%); oxyalkylated phenolic resin (15-40%); ethylbenzene (0-2%); xylene (3-13 %); and isobutyl alcohol (10-30%). DWP-601 contains 1-5% ethoxylated nonylphenol."[129] Yet, an October 4, 2005 email from a COGCC employee to the Water

[127] (Anadarko Petroleum Corporation, 2012)
[128] (Earthworks, Hydraulic Fracturing 101 n.d.)
[129] (Earthworks, Hydraulic Fracturing 101 n.d.)

Quality Control Division of CDPHE stated that this spill/release "would be classified as non-significant" due to the amounts not exceeding the significance thresholds required of 5 barrels spilled in one instance.[130]

7.4.3 Habitats

Due to the disruptive effects to the local environment, this report sought to determine the potential effects, deleterious or otherwise, on the local habitat. The US Fish and Wildlife Service Region 6 (which oversees Colorado, Wyoming, and North Dakota) seeks to "protect, improve and restore the quality of fish, wildlife and habitat resources."[131] The agency identifies contaminants and seeks to prevent future environmental problems while also correcting and restoring current contaminant areas. It has offered suggestions to minimize the potential effects of oil and gas exploration and production processes on local wildlife - specifically birds, bats and other wildlife that rely heavily on wetlands.

Figure 39. Habitat Impact

Many of these observed impacts are due to water waste pits. Waste pits include both reserve pits and flare pits used during drilling operations to store drilling fluids. They can also cause bird and wildlife deaths if they contain visible sheens of oil on the surface.

130 (Earthworks, Issues: Oil and Gas Noise 2012)
131 (Service 2012)

Figure 40. Waste Pits[132]

Exposed oil, evidenced by the oil sheen, can attract and subsequently entrap indigenous and migratory birds, bats, food source insects, and other wildlife that rely on wetlands or pools of water for survival. There are approximately 500,000 to 1 million birds killed annually in oil field production skim pits and centralized oilfield wastewater disposal facilities.[133] This is down from an estimated 2 million annual bird deaths in 1997. This would suggest that the impact from oil and gas operations, especially from open water pits, has been decreasing over the last decade. [134]

The problem of open water reserve pits for birds follows a familiar arc. Birds and other wildlife are attracted by the oil sheen atop the water and mistake them for wetlands. Upon landing on the reserve pits, they become exposed to and covered in oil. It does not take a large amount of oil to entrap birds. Thus, it is also so important to ensure that all spilled oil is cleaned up and disposed of properly.

[132] (Service, Region 6 Environmental Contaminants 2012)
[133] (PW 2006)
[134] (Service, Region 6 Environmental Contaminants 2012)

Figure 41. Avian Exposure to Oil[135]

Once exposed to oil, birds are generally weighed down to the bottom of a reserve pit. Another common consequence is that their feathers lose their ability to insulate and death ensues from heat or cold stress. This problem can have compounding food chain effect. For example, many birds are attracted to entrapped insects. These birds, once ensnared in the oil skim, can attract larger birds such as hawks and owls. Reserve pits have also caused negative impacts to these species' reproductive capabilities, as even very small amounts of oil touching eggshells have proven toxic to the embryos.[136]

One way to mitigate the greatest risks posed to local habitats is not to build reserve pits. A simple alternative (see 7.4.4) to waste pits is therefore being implemented by many operators. [137]

7.4.4 Use of Closed Containment Systems

An environmentally friendly solution to a reserve pit is a closed containment system that requires little or no maintenance. The system can also be moved to a new site when the well is capped. Closed-loop systems minimize the risk of soil contamination and reduce the future reclamation expense.

135 (Service, Region 6 Environmental Contaminants 2012)
136 (Service, Region 6 Environmental Contaminants 2012)
137 (Service, Contaminant Issues - Oil Field Waste Pits: Solutions 2012)

Figure 42. Closed Containment Systems[138]

Closed containment systems are ideal for collecting oil field produced water since they isolate oil from the environment and do not attract wildlife. If an operator does use an open water reserve pit, the negative impacts on the surrounding habitats can be reduced by keeping oil out of the pit and separating and removing any oil that seeps into it. Another measure is to create and install physical barriers to ward off curious wildlife. Netting is a proven, effective method for keeping birds out of waste pits, while flagging, reflectors, and strobe lights are ineffective as deterrents. For netting to be effective, it must be properly installed: tight, taut, with small mesh, and suspended no less than 5 feet around and above the reserve pit. This will ensure maximum effectiveness for deterring birds and small game from wandering into an open pit.[139]

7.5 Earthquakes

Forcing fluids under high pressure deep underground introduces subterranean instability and produces increased regional seismic activity.[140] Most of the seismic activity linked to the oil and natural gas industry has been caused by disposal/fluid injection wells, not production wells.[141] When the fluid is injected into the shale under high pressure, it is known to cause slight tremors. Drilling companies often send sensitive instruments called geophones into the drill holes to analyze these tiny tremors to determine if the rock is fracturing as expected. Earthquakes can be set off by the fluid migration into rock formations below the shale. These deeper, older rocks are littered with faults that, although under stress, have reached equilibrium over hundreds of millions of years. States do not require seismic surveys for oil or gas wells. Larger oil development companies routinely conduct seismic

138 (Service, Region 6 Environmental Contaminants 2012)
139 (Service, Contaminant Issues - Oil Field Waste Pits: Solutions 2012)
140 (Daly 2011)
141 (Schuller 2012)

tests as part of exploration. About 7 million barrels of wastewater from drilling have been injected annually into Ohio wells since 1985 without incident because the practice is closely regulated by federal laws and the Ohio Department of Natural Resources. The number of new permits for injection wells increased to 24 from 10 last year and 5 in 2009. [142]

Prior to 2011, Youngstown, Ohio was a seismically quiet town. However, in 2011, Youngstown felt nine minor quakes. These earthquakes were too weak to cause damage or be felt by many people. The strongest one, with a magnitude of 2.7, occurred in late September. When seismologists plotted the quakes' epicenters, most coincided with the location of a 9,000-foot well which was a fracking fluid waste disposal site of a local company.[143] Prior to 2010, Oklahoma typically had about 50 earthquakes a year. However, in 2010, 1,047 quakes shook the state. In an August 2011 study by seismologist Austin Holland, "Examination of Possibly Induced Seismicity from Hydraulic Fracturing in the Eola Field, Garvin County, Oklahoma," the Oklahoma Geological Survey studied 43 earthquakes that occurred on January 18, ranging in intensity from 1.0 to 2.8 md (millidarcies). While the report's conclusions were cautious, it does state, "Our analysis showed that shortly after hydraulic fracturing began small earthquakes started occurring and more than 50 were identified, of which 43 were large enough to be located."[144] In August 1967, a suburb of Denver, Colorado felt a magnitude 5.5 earthquake shake the area. The Colorado School of Mines recorded more than 300 earthquakes from this zone during 1967, all believed to be induced by the pumping of waste fluids into a deep disposal well at the Rocky Mountain Arsenal.[145] Further links of seismic activity to oil and gas extraction have been identified with small tremors arising most notably in Arkansas, Texas, and British Colombia.

In Arkansas, the State Oil and Gas Commission ordered one well be shut down and placed a moratorium on new ones in a 1,100 square mile area. Three other disposal wells closed voluntarily. While small earthquakes are still occurring in the area, the frequency has declined substantially. Austin A. Holland, says there was a "possibility" that a series of small quakes in January were induced by a nearby fracking operation, but he could not make conclusive statements as the data were limited.[146] Colorado hosts 355 active oil and gas disposal wells, 1 percent of all wells in the state.[147] This represents the pool of wells that could possibly be linked to seismic activity related to oil and gas production.

There is no conclusive evidence that hydraulic fracturing or disposal wells create earthquakes. There are thousands of fracking and disposal wells nationwide where no earthquakes have been detected. Furthermore, the relatively shallow depths of the disposal wells mean that any quakes triggered would be minor. Of the two well types, the current data lean toward targeting the source of man-made earthquakes to disposal/fluid injection wells.[148]

[142] (Niquette 2011)
[143] (Fountain 2011)
[144] (Holland 2011)
[145] (USGS 1967)
[146] (Fountain 2011)
[147] (Schuller 2012)
[148] (Fountain 2011)

7.6 Conclusion on Environmental Concerns

In summary, standard oil and gas drilling operations have an impact upon water, air, surface, below surface, and habitat conditions. The process of hydraulic fracturing introduces a specific set of environmental concerns. The chemical component of the proppants in hydraulic fracturing adds a new environmental risk to ground water if well casings and cement are not properly installed. Air quality is impacted by the volume of diesel engines required to run the drilling operation equipment, transportation of the oil and gas, and methane from routine venting. Habitats and wildlife are affected by the use of open waste pits. Surfaces are damaged by spills and leaks. If the spill or leak is large enough, it can also contaminate the ground water. Noise and light pollution occur due to the 24-hour operational schedule and motorized drilling equipment. The current seismic activity data is trending towards an effect of disposal wells rather than production wells.

The following technological advancements have been implemented to address the environmental concerns discussed:

- Properly cased and sealed wells, combined with consistent well monitoring, diminish the contamination risk to ground water.
- Replacing open waste pits with closed-loop systems greatly reduces the discharge of toxic drilling waste on the site and protects surrounding habitats and wildlife.
- Closed-loop systems separate the drill cuttings and drilling fluids allowing the maximization of recycled drilling fluid.
- Flaring the excess natural gas that is produced, as opposed to venting, reduces the methane released.

As technology continues to advance, it can be expected that the oil and gas industry will continue to adopt best practices to reduce the environmental impacts of its operations.

8 Water's Role in Hydraulic Fracturing

Water plays a vital role in hydraulic fracturing. This section discusses how water is used in the hydraulic fracturing process, sourcing, regulatory information, and other related information.

8.1 Expected Water Use

Regional geology and permeability of the formation impacts the volume of water necessary to provide the most effective hydraulic fracturing process. Industry leader Chesapeake Energy reports on their website that hydraulic fracturing of a typical horizontal deep shale oil or natural gas well requires an average of 4.5 million gallons of water per well. A report by Cornell University published in December 2010 examined hydraulic fracturing's effects on water quality in the New York state area. This report concluded the hydraulic fracturing process required 3 to 7 million gallons of water per well.[149]

At the time of this writing, Ultra Resources has applied for permits for 23 wells, 3 of which are exploratory. If deemed economically viable to develop, 20 more wells would be drilled. Using an average of 4.5 million gallons of water per well, this adds up to 103,500,000 gallons of water consumed during the drilling and hydraulic fracturing process.

To provide some framework around this volume of water, the Colorado Springs Utilities 2008-2012 Water Conservation Plan reports that the single-family residential use of water averaged 112 gallons per capita per day from 1990-2006.[150] This means a family of four consumes an average of approximately 163,520 gallons of water annually. The volume of 103,500,000 gallons would sustain approximately 633 families of four in Colorado Springs for one year.

Ultra Resources reported to the Colorado Springs City Council's Oil and Gas Task Force on March 21, 2012 that the maximum number of wells that would be drilled on the Banning Lewis property would be 120. The potential water consumption of 120 wells, estimating 4.5 million gallons per well, is 540 million gallons of water. Using the example above, this would sustain an estimated 3,302 families of four in Colorado Springs for one year.

[149] (Andrea Ramudo, Sean Murphy; Planning, Cornell University City and Regional 2010)
[150] (Colorado Springs Utilities 2008)

The state of Colorado employs many beneficial uses of water across various industries. The table below shows the amount of water currently diverted for beneficial use for all uses in Colorado on an average annual basis.[151]

Table 6. Water Uses in Colorado

Sector	2010 Use (Acre-Feet/Yr)[4]	Percent of State Total
Total	**16,359,700**	
Agriculture	13,981,100	85.5%
Municipal and Industrial	1,218,600	7.4%
Total All Others	1,160,000	7.1%
Breakdown of "All Others"		
Total All Others	**1,160,000**	
Recreation	923,100	5.64%
Large Industry	136,000	0.83%
Thermoelectric Power Generation	76,600	0.47%
Hydraulic Fracturing	13,900	0.08%
Snowmaking	5,300	0.03%
Coal, Natural Gas, Uranium, and Solar Development	5,100	0.03%
Oil Shale Development	0	0.00%

The volume of water used during the hydraulic fracturing process is substantially less than other uses of water in the state of Colorado. However, depletion of the Denver Basin is an issue that needs to be considered within the broader context of meeting future water supply demands within the region since this is a non-renewable resource.

8.2 Water in Colorado

Water is a precious resource in the state of Colorado. The following sections will provide context to how water is administered and defined in Colorado, who currently retains the rights to the water on the proposed drilling locations, and what potential water sources Ultra Resources would use during operations. This section covers some of the significant legislation and regulation affecting the sourcing of water for Ultra's operations, but does not cover all of the regulations that Ultra Resources may be required to follow.

The historic water appropriation system in Colorado was, "first come, first served," meaning those who diverted unappropriated water first for beneficial use, have senior right to the water. A substantial volume of Colorado's water laws regarding the use and development of water are based on this system of prior appropriations for protection of water rights in order of their priority dates. As the understanding of the aquifers has increased, the rules governing the use of the Denver Basin have evolved.

[151] (Colorado Geological Survey 2012)

8.3 Water Administration

The following state laws and regulations will provide a basic understanding to the local regulatory environment with regard to sourcing the water that will be used during the drilling and fracturing process. This is a general introduction to the regulatory environment and not intended to be a comprehensive analysis of related regulations. The Division of Water Resources (DWR), the State Engineer and the Colorado Ground Water Commission, are responsible for ground water administration and enforcement.

Senate Bill 5 (1985): This bill provided a new framework to guide the appropriation of the ground water in the Denver Basin. The state engineer, the director of the Colorado DWR, adopted rules in 1986 to carry out the provisions of Senate Bill 5. Using Senate Bill 5, the related rules, and other state statutes, the Colorado DWR, the water courts in Divisions 1 and 2, and the Colorado Ground Water Commission, finalized decisions on the amount of water individuals may use and how that water may be used.

Senate Bill 5 and the related rules ascertained locations where the use of ground water from the Denver Basin would have a minimal effect on the surface water system. An aquifer with this characteristic is legally identified as non-tributary**.** To be identified as non-tributary, a measurement of the effect on the surface water system must be below a statutory threshold for the ground water at that location. Non-tributary ground water may be used without developing a plan for mitigating effects to the surface water system.[152]

Senate Bill 73-213 (1973): This bill allocated the right for landowners to develop deep non-tributary groundwater underlying their property. To set a limit on pumping rate, the Colorado state legislature adopted a 100-year pumping regiment. Regulations permitted landowners to withdraw up to 1 percent per year of the aquifer resource underlying their property. Prior to 1973, withdrawal of Denver Basin ground water was limited primarily by an assessment of proximity to other ground water appropriations in the same aquifer.[153]

Under normal circumstances, a private individual, a commercial entity, and other landowners, or a party with proper consent, may claim and withdraw ground water from the Denver Basin bedrock aquifers. The right to claim and withdraw this water can be recognized in the Water Court or by the Colorado Ground Water Commission, if located within a Designated Basin.

The rules and regulations applying exclusively to the withdrawal of ground water from the Dawson, Denver, Arapahoe, and Laramie Fox-Hills aquifers are commonly known as **The Denver Basin Rules** and are part of the Code of Colorado Regulations (CCR). The State Engineer is granted the authority to implement the Denver Basin Rules.

Senate Bill 10-165, enacted on March 22, 2010, in summary and except for coal bed methane wells, allows for non-tributary ground water to be removed without the requirement of a well permit if the groundwater being removed will facilitate or permit the mining of

[152] (Division of Water Resources n.d.)
[153] (Division of Water Resources n.d.)

minerals and will only be used by the operators within the geologic basin where the ground water is removed. This bill also exempts the requirement of a well permit where the ground water is removed to facilitate or permit the mining of minerals. Please see the Appendix for further explanation.[154]

8.4 Colorado Statutory Definitions of Water

At this time, four major categories of water exist in Colorado and are defined below. It is meaningful to understand the categories of water, as there are rules and regulations regarding how water may be used is dependent on how its category is defined.

8.4.1 Designated Basin Ground Water

Designated Basin Ground Water is water under natural conditions that would not renew or supplement continuously flowing surface streams. It is specific to deep groundwater underlying the eight designated basin areas located on Colorado's eastern plains and regulated by the Colorado Ground Water Commission. Designated ground water shall not include any ground water within the Dawson-Arkose, Denver, Arapahoe, or Laramie-Fox Hills formation located outside the boundaries of any designated ground water basin that was in existence on January 1, 1983.[155]

8.4.2 Tributary Ground Water

Water that is hydraulically connected to a surface stream that can influence the amount or direction of flow of water in that stream is regulated by the appropriation system, like other surface water rights.[156]

8.4.3 Non-Tributary Ground Water

Non-tributary ground water is water in which the pumping of it in 100 years would not deplete the flow of a natural stream at an annual rate greater than 1/10th of a percent of the annual rate of withdrawal from the well.[157]

Non-tributary ground water is typically produced from aquifers geologically confined such that they have little physical connection to the surface water. With the exception of the uppermost portion of the Dawson aquifer, ground water contained under confined conditions in the Denver Basin aquifers is considered to be non-tributary (2 CCR 402-6).

8.4.4 Not Non-Tributary Ground Water

Denver Basin groundwater that is connected with surface streams or the deeper aquifers where they outcrop. If pumped, these withdrawals would deplete the flow of a

[154] (SENATOR(S) Hodge and also REPRESENTATIVE(S) Hullinghorst 2010)
[155] (Colorado Revised Statue 1965, 1985)
[156] (Education, Colorado Foundation for Water 2009)
[157] (Colorado General Assembly 1965)

natural stream at an annual rate greater than $1/10^{th}$ of one percent the annual rate of withdrawal from the well.[158] [6]

Examples of a *Not Non-Tributary* source are Monument Creek and Cherry Creek.

8.5 Water Rights

Colorado Revised Statute Section 37-92-302(1)(a), allows the owner of land in the Denver Basin to apply for a *determination of water right* for the Denver Basin ground water. Such a right will be determined by the Water Court unless the land lies within the *Designated Basins*. Designated Basins are areas in the eastern plains where water users rely significantly on ground water as their water supply source because there is very little surface water. These basins are managed and controlled by the Colorado Ground Water Commission.

At the time of this writing, it is the understanding of Doug Hollister, Division 2, District 10 Water Commissioner, that the previous owner of the Banning Lewis Ranch transferred the water rights decreed in case 83CW134 for the Non-Tributary Laramie-Fox Hills to the City of Colorado Springs as part of the Annexation agreement, along with the rights to the Not Non-Tributary Denver decreed in 83CW135 and the Not Non-Tributary Arapahoe decreed in case 83CW133. It is unknown if the land purchase by Ultra changes that agreement and makes that water available for Ultra's use.[159]

8.6 Water Source

The Annexation Agreement resolution between Ultra Resources and the city of Colorado Springs will impact directly where Ultra Resources will source the water used during its operations.

All of Ultra Resources' proposed drilling sites also have the following options as potential sources of water:

Transporting water from outside of the state as long as the water, its transport, and its use carry no legal obligation to Colorado. This would increase the economic cost of the project, but would reduce the impact to the water supply of Colorado Springs.

Ultra may enter into an agreement with Colorado Springs Utilities as long as the use of the water is compliant with the water provider's water rights. An opportunity would exist for Colorado Springs to negotiate a special ground water rate and generate revenue from the Banning Lewis portion of the drilling project.

Ultra Resources may choose to use water produced in conjunction with oil production. The water that is produced from an oil or gas well falls under the administrative control of the State Engineer's Office. As a result, it is either non-tributary, in which case, it

[158] (Colorado General Assembly 1965)
[159] (Hollister 2012)

is administered independent of the prior appropriation system or is tributary, in which case, the depletions from its withdrawal must be fully augmented if the depletions occur in an over-appropriated basin. Augmentation means that Ultra Resources would identify a source of water that has been obtained to replace the depleted tributary water. The result in either case is that the produced water is available for consumption for other purposes, including mining for minerals and well construction. The water must not be encumbered by other needs and a proper well permit must be obtained by the operator before the water can be used for well construction. The exception to this permitting requirement is the allowance in Section 37-90-137(7), C.R.S. Produced water from a non-tributary formation using a non-coal-bed methane operation may be applied to uses associated with well construction without a well permit.[160] The annexation agreement decides whether this would be a viable source of water for Ultra to use. If it is, and that water is determined to be non-tributary, this option would carry an environmental impact, as the Laramie- Fox Hills aquifer is one potential source. This aquifer is the deepest of all aquifers and is often cited as the supply of last resort.

8.7 Water Yields

State rules exist that regulate an allowed average annual amount of groundwater withdrawal from a well in one of the Denver Basin aquifers. This is codified in Rule 6, "Determination of Specific Yield for Wells in The Denver Basin." Rule 6 states that allowed yield of the average annual amount of groundwater withdrawal from a well in the Laramie-Fox Hills aquifer is 15 percent.[161]

8.8 Limit on Consumption

Should Ultra Resources source the water from the Laramie-Fox Hills aquifer, there is also potential they would need to abide by the "Limit on Consumption" rule.

Rule 8. Limit on Consumption

In order to assure that no water rights are materially affected by withdrawals of non-tributary ground water from the Denver Basin Aquifers, no more than 98 percent of the water withdrawn annually from a well withdrawing such non-tributary ground water shall be consumed. The applicant must demonstrate to the reasonable satisfaction of the State Engineer prior to the issuance of the permit that not more than 98 percent of the water withdrawn will be consumed. The State Engineer may reasonably require a permittee to demonstrate periodically that no more than 98 percent of the water being withdrawn from the well is being consumed.[162]

In summary, Rule 6 and Rule 8, as they apply to Ultra Resources, say that Ultra's withdrawal and consumption of the non-tributary groundwater of the Laramie-Fox Hills

[160] (Colorado Oil and Gas Conservation Commission January 24, 2012)
[161] (Department of Natural Resources, Division of Water Resources 1986)
[162] (Department of Natural Resources, Division of Water Resources 1986)

aquifer will be limited to 15 percent of the determined amount of water underlying the land. Then, of that 15 percent total yield, not more than 98 percent of it may be consumed.

8.9 Water Source Conclusion

The outcome of the annexation agreement will inevitably impact where Ultra Resources will source the water for its operations. If Ultra purchases the water from the municipality, this could lead to a negotiated source of revenue for Colorado Springs Utilities. If the water rights are awarded to Ultra as part of the annexation, and it determines that it will drill wells for water in the Laramie-Fox Hills aquifer, it will be abiding by the legislation, rules and regulations outlined above, as well as other codes that are not covered in the scope of this study.

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9 Risk Assessment

There are a variety of environmental risks associated with the use of hydraulic fracturing in oil and gas extraction. Issues resulting from these risks have garnered media attention from national television networks such as the CBS weekly news broadcast “60 Minutes”, feature-length movies such as “Gasland,” a variety of professional and homemade videos via YouTube, and a large number of anti-fracking websites. The intent of this section is to outlay the risks, convey risks that have been realized elsewhere, assess industry compliance records, and discuss pre-emptive measures that should be considered before a hydraulic fracturing process occurs.

9.1 Environmental Risks

The environmental effects of oil and gas extraction using hydraulic fracturing are wide ranging. As discussed in previous sections, there are issues associated with air pollution, water usage, surface disturbance, and general ecologic damage associated with converting rural areas into industrial zones. There are also the unplanned events such as spills, erosion, watershed concerns, blowouts, and ground water contaminations. These types of issues result from unforeseen circumstances that are sometimes attributed to natural events and sometimes attributed to poor management practices.

Examples of risks to groundwater that have been documented in published studies are in Section 11.1.These include ground water contamination in Pavillion, Wyoming, and Garfield County, Colorado. Ground water contamination is perhaps the most severe environmental risk posed by hydraulic fracturing because remediation is not economically feasible. On smaller scales, there are documented cases and violations with oil and gas extraction operators discharging polluting materials into the environment. For example, in Pennsylvania’s Marcellus Shale play location, operators have disposed of fracking fluids by spreading them on county roads and discharging them into rivers and streams. In 2009 in Wyoming, air quality violations required Ultra Resources to pay a $200,000 fine for releasing ozone-creating Volatile Organic Compounds (VOCs) into the air. More recently, in February of 2012, Chesapeake Appalachia LLC was fined a total of $565,000 in civil penalties and reimbursement costs for erosion and sediment control violations, wetland encroachment violations, and an April 2011 well control incident. Finally, and less definitively, there has been seismic activity linked to the oil and natural gas industry and the disposal/fluid injection wells used for waste.

9.2 Assessment of Industry Compliance Records

The Pennsylvania Department of Environmental Protection (PA DEP) oversees all oil and gas operations in the state. Pennsylvania as a state is fortunate to have a large amount of organic deposits in the Marcellus Shale play. The Marcellus Shale is a natural gas-rich reservoir over a mile deep (similar to depths of the Niobrara formation in El Paso County). This gas play is currently being exploited using horizontal wells and hydraulic fracturing. Figure 43 shows the geography of this large area.

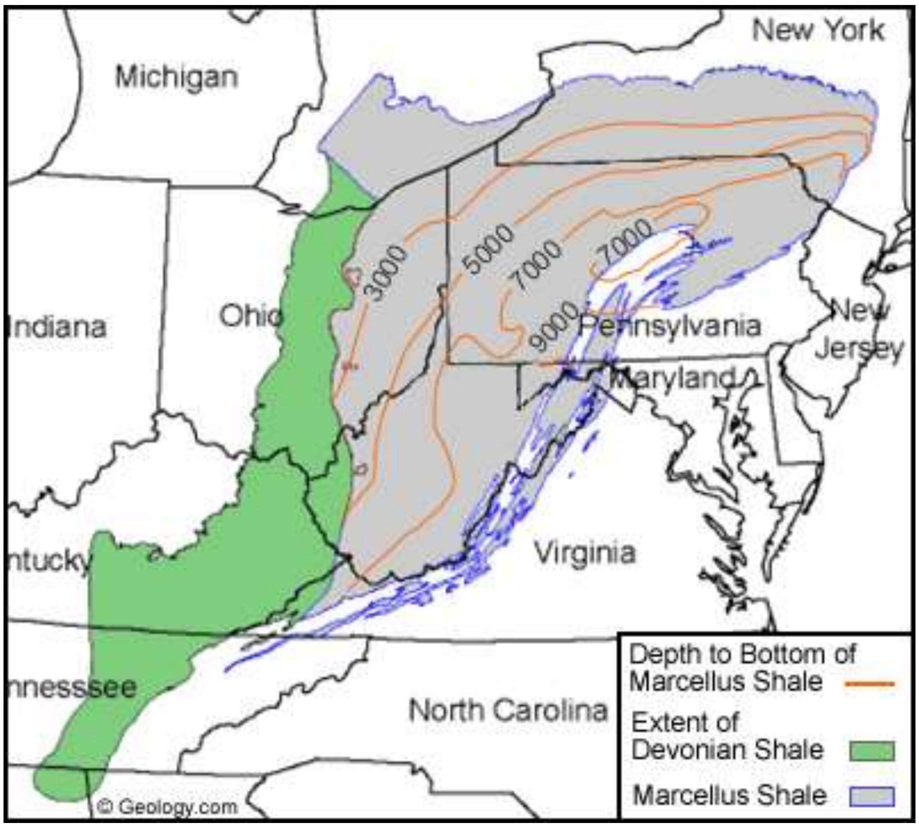

Figure 43. Marcellus Shale Geography

Pennsylvania, like Wyoming and Colorado (see case studies), has had environmental issues with respect to operators working the Marcellus Shale play. The large amount of natural gas deposits and the large number of operators has driven the PA DEP to highly regulate and track oil and gas operators acting within the commonwealth. This oversight resulted in a detailed set of extensive records of all operators and wells drilled in the Marcellus Shale. This can be found at the PA DEP website on oil and gas regulation[163] and the PA State Impact website.[164] These records include the number of inspections, number of violations resulting from inspections, and types of violations per well for all operators.

[163] (Pennsylvania Department of Environmental Protection, Oil and Gas Report)
[164] (Pennsylvania State Impact)

In order to make a risk assessment on a particular extraction operator, there must be background data from which an assessment can be made. The records being kept by the PA DEP are extensive enough to provide a database for statistical risk assessment. However, the risk assessment is not that an individual operator will have an environmental incident, but rather that they will be cited during routine inspections for a well violation. The assumption is that inspections that result in violations against the state's rules for environmental safety and health are correlated to an increased probability that the operator will have an environmental incident at some point in the future. While this assumption is somewhat wide ranging, it can only be surmised that inspections are designed to check that operators are performing oil and gas extraction in a safe and environmental friendly way as deemed by PA DEP.

According to the PA DEP database, 45 different operators are working in the Marcellus Shale, including Ultra Resources, the operator that is drilling in El Paso County. Given the large geographic area and the number of operators and inspections, the PA DEP's management of the Marcellus Shale play can serve to provide a useful set of statistics from which some risk management strategies may be determined.

In October 2010, a study conducted by The Pennsylvania Land Trust Association (PALTA) (www.conserveland.org) used the PA DEP records to generate an assessment of operators drilling for gas in the PA Marcellus Shale.[165] The study cites a sampling period of production wells from January 2008 to August 2010, over which time, 1,614 inspection violations were documented. Of these 1,614 violations, the study discarded 558 incidents as "unlikely to directly endanger the environment and/or the safety of communities." These discarded incidents were likely administrative in nature. From the list of 45 operators, the study reduced the focus to the 26 worst operators. The "worst" operators are those that had abnormally high rates of violations when the number of wells in production was considered. These 26 operators had in total 1,326 producing wells and 1,008 violations. At the top level, the results from these violation and well counts generate a 76 percent chance of an "environmental endangering" violation per well. The breakdown of these identified environmental damaging violations by the 26 worst operators is shown in Table 7:

[165] (Marcellus Shale Drillers in Pennsylvania Amass 1614 Violations since 2008)

Table 7. Table of Violations/Well/Operator in the Marcellus Shale Play (PALTA)

Drilling Company	Violations	Wells	Violations /Well
Chesapeake Appalachia LLC	149	190	0.78
Chief Oil & Gas LLC	110	63	1.75
East Resources MGT LLC	106	26	4.08
Talisman Energy USA INC	104	181	0.57
Cabot Oil & Gas Corp	93	75	1.24
PA Gen Energy Co LLC	46	34	1.35
Seneca Resources Corp	42	45	0.93
Atlas Resources LLC	40	153	0.26
Ultra Resources INC	39	37	1.05
Range Resources Appalachia	32	240	0.13
Williams Production Appalachia	32	7	4.57
J W Operating CO	29	1	29.00
EOG Resources INC	28	69	0.41
Anadarko E&P CO LP	25	75	0.33
XTO Energy INC	25	19	1.32
Citrus Energy Corp	18	2	9.00
Energy Corp of Amer	16	11	1.45
Southwestern Energy Prod CO	15	16	0.94
Phillips Exploration INC	10	9	1.11
EQT Production CO	9	45	0.20
Stone Energy CORP	9	5	1.80
Guardian Exploration LLC	7	1	7.00
Exco Resources PA INC	6	12	0.50
MDS Energy LTD	6	3	2.00
Novus Operations LLC	6	6	1.00
Penn Virginia Oil & Gas CORP	6	1	6.00
Totals & Average per Well	1008	1326	0.76

The distribution of these violations is shown in Figure 44.

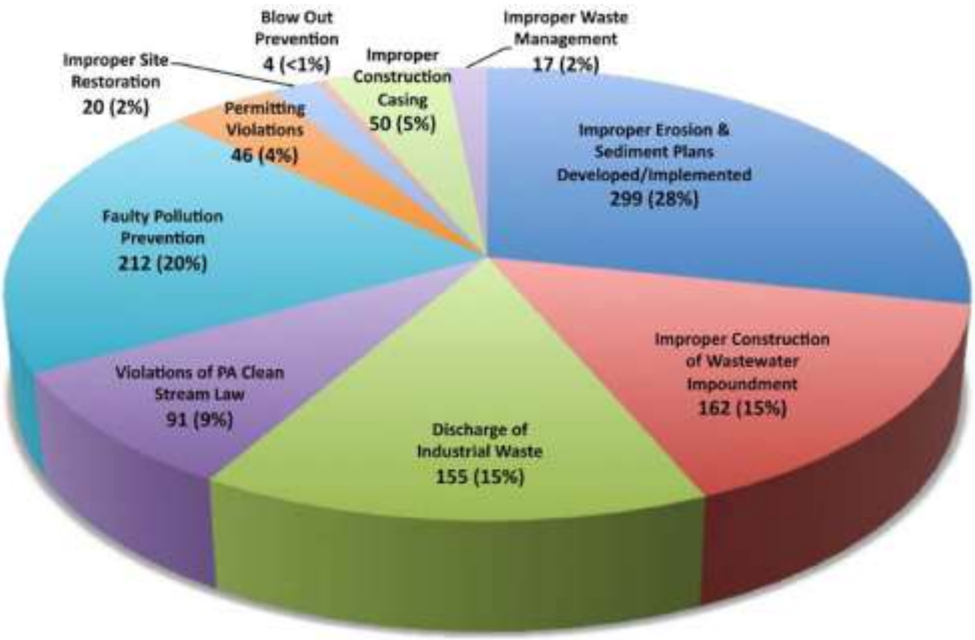

Figure 44. Distribution of Violation Types (PALTA)

In order to validate PALTA's assessment on the 26 worst operators, this project studied Ultra Resources' detailed compliance record as a reference point and further source of investigation. Figure 45 contains the first page summary results of compliance record searches conducted on Ultra Resources in the PA DEP compliance archives for calendar years 2009, 2010, and 2011.

pennsylvania
DEPARTMENT OF ENVIRONMENTAL PROTECTION

**DEP OFFICE OF OIL AND GAS MANAGEMENT
COMPLIANCE REPORT**

2/19/2012 9:17:17 PM

**Operator: ULTRA RESOURCES INC; County: All; Municipality: All; Marcellus Only: No; Resolved Violations Only: No; Inspections With Violations Only: Yes
Inspections from 1/1/2011 to 12/31/2011**

Operator: ULTRA RESOURCES INC – Inspections: 28; Inspections With Violations: 28; Violations: 68; Enforcements: 9

INSPECTION ID	INSPECTION CLIENT NAME	INSPECTION DATE	INSPECTION TYPE	PERMIT #	MARCELLUS	INSPECTION CATEGORY	REGION	COUNTY	MUNICIPALITY	INSPECTION RESULT DESCRIPTION
1945849	ULTRA RESOURCES INC	01/25/2011	Routine/Complete Inspection	117-20498	No	Primary Facility	EP DOGO NCDO Dstr Off	Tioga	Gaines	Violation(s) Noted

Violation Details

VIOLATION ID	VIOLATION DATE	VIOLATION CODE & DESCRIPTION	VIOLATION TYPE	VIOLATION COMMENT	RESOLVED DATE	RELATED ENFORCEMENTS
603670	01/25/2011	102.4 - Failure to minimize accelerated erosion, implement E&S plan, maintain E&S controls. Failure to stabilize site until total site restoration under OGA Sec 206(c)(d)	Environmental Health & Safety	BMP's not installed per plan; construction sequence not followed	09/13/2011	267684

Enforcement Details

ENFORCEMENT ID	ENFORCEMENT CODE & DESCRIPTION	PENALTY FINAL STATUS CODE & DESCRIPTION	COMPLETED DATE	PENALTY AMOUNT	TOTAL AMOUNT COLLECTED	RELATED VIOLATIONS
267684	NOV - Notice of Violation					603670

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**DEP OFFICE OF OIL AND GAS MANAGEMENT
COMPLIANCE REPORT**

2/19/2012 9:20:50 PM

**Operator: ULTRA RESOURCES INC; County: All; Municipality: All; Marcellus Only: No; Resolved Violations Only: No; Inspections With Violations Only: Yes
Inspections from 1/1/2010 to 12/31/2010**

Operator: ULTRA RESOURCES INC - Inspections: 32; Inspections With Violations: 32; Violations: 58; Enforcements: 18

INSPECTION ID	INSPECTION CLIENT NAME	INSPECTION DATE	INSPECTION TYPE	PERMIT #	MARCELLUS	INSPECTION CATEGORY	REGION	COUNTY	MUNICIPALITY	INSPECTION RESULT DESCRIPTION
1856480	ULTRA RESOURCES INC	01/14/2010	Routine/Partial Inspection	105-21620	Yes	Primary Facility	EP DOGO NCDO Dstr Off	Potter	West Branch	Viol(s) Noted & Immediately Corrected

Violation Details

VIOLATION ID	VIOLATION DATE	VIOLATION CODE & DESCRIPTION	VIOLATION TYPE	VIOLATION COMMENT	RESOLVED DATE	RELATED ENFORCEMENTS
579603	01/14/2010	102.4 - Failure to minimize accelerated erosion, implement E&S plan, maintain E&S controls. Failure to stabilize site until total site restoration under OGA Sec 206(c)(d)	Environmental Health & Safety		01/14/2010	
579604	01/14/2010	78.56PITCNST - Impoundment not structurally sound, impermeable, 3rd party protected, greater than 20" of seasonal high ground water table	Administrative		01/14/2010	

No Related Enforcements

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**DEP OFFICE OF OIL AND GAS MANAGEMENT
COMPLIANCE REPORT**

2/19/2012 9:22:19 PM

**Operator: ULTRA RESOURCES INC; County: All; Municipality: All; Marcellus Only: No; Resolved Violations Only: No; Inspections With Violations Only: Yes
Inspections from 1/1/2009 to 12/31/2009**

Operator: ULTRA RESOURCES INC - Inspections: 13; Inspections With Violations: 13; Violations: 25; Enforcements: 8

INSPECTION ID	INSPECTION CLIENT NAME	INSPECTION DATE	INSPECTION TYPE	PERMIT #	MARCELLUS	INSPECTION CATEGORY	REGION	COUNTY	MUNICIPALITY	INSPECTION RESULT DESCRIPTION
1808165	ULTRA RESOURCES INC	06/19/2009	Routine/Complete Inspection		No	Site	EP DOGO NCDO Dstr Off			Viol(s) Noted & Immediately Corrected

Violation Details

VIOLATION ID	VIOLATION DATE	VIOLATION CODE & DESCRIPTION	VIOLATION TYPE	VIOLATION COMMENT	RESOLVED DATE	RELATED ENFORCEMENTS
565747	06/19/2009	102.4 - Failure to minimize accelerated erosion, implement E&S plan, maintain E&S controls. Failure to stabilize site until total site restoration under OGA Sec 206(c)(d)	Environmental Health & Safety		06/19/2009	

No Related Enforcements

Figure 45. PA DEP Summary Records for Ultra Resources 2009 - 2011

Overall, the descriptions of the violations in Figure 45 were found to be consistent with the violation types described. This indicates that the PALTA study used the same sets of records in creating the statistics. However, in the interest of objectivity, the nature of the PA Land Trust Association should be considered. The PALTA mission statement is:

> The Pennsylvania Land Trust Association seeks to protect Pennsylvania's special places—the farms, forests, parks and other green spaces that people love—the places that help to ensure healthy, prosperous and secure communities. To increase the pace and improve the quality of land conservation work, PALTA helps land trusts and other conservation practitioners improve their effectiveness, build public understanding, and advocates for better governmental policy.[166]

The results of the PALTA assessment indicates operators working in the Marcellus Shale play struggle with meeting the established rules and codes for drilling in Pennsylvania. If the rules are designed to monitor environmental risks and protect the environment, then the high rate of violations indicates that operators drilling in PA pose an above acceptable risk to the environment.

The aggregate 76 percent chance of an inspection generating an Environmental Safety and Health (ES&H) violation per well appears to be unacceptable at first glance. However, not all operators had the same rate and type of infractions. For example, Range Resources Appalachia had 32 violations over 240 wells, or a 13 percent likelihood of a violation per well. EQT Production Co. had a 20 percent likelihood of a violation with 9 violations over 45 wells. This is in stark comparison to J W Operating Co., which had 29 violations on its single well (2900%) and Citrus Energy Corp. which had 18 violations across its 2 wells (900%). One trend that appears in the numbers is that the operators with better ES&H violation rates also have a large number of drilled wells. This might indicate that the larger operators are more organized, understand the environmental rules better, and have better processes. If this is the case, then there may be opportunity to reduce the risk for all extraction operators by educating them on best practices for the industry.

9.3 Assessment of Ultra Resources' Compliance Record

Ultra Resources primary operations are in Wyoming and Pennsylvania. It has been cited for environmental violations in both locations. However, Wyoming does not keep the same level of accessible information as the PA DEP. Therefore, the following assessment is based on the data extracted from Pennsylvania only.

Table 8 lists the number of inspections and violations assessed against Ultra Resources from its operations in Pennsylvania for the years 2011 through 2009. This table lists inspections, violations, enforcements, and what percentage of the violations was administrative in nature vs. those that were against ES&H.

[166] (Pennsylvania Land Trust)

Table 8. Ultra Resources Environmental Record in Pennsylvania

ULTRA RESOURCES MARCELLUS SHALE COMPLIANCE RECORD	2011	2010	2009
Inspections	28	32	13
Inspections with Violations	28	32	13
Violations	68	59	25
Enforcements	9	18	8
Percentage of Administrative Violations	52.9%	57.6%	84.0%
Percentage of ES&H Violations	47.1%	42.4%	16.0%

Table 9 lists the number of active wells Ultra Resources produced natural gas from during the time period from July 2011 to December 2011. There were 35 active wells in this time period. Note that the count of 35 wells is near the same number of active wells for Ultra Resources listed in Table 7 (37) which was over a longer period of time. These records were downloaded from the PA DEPs application on gas production by operator.

Table 9. Ultra Resources 2011 Active Wells in Marcellus Shale

Well Permit #	Period Id	Farm Name	Well #	Gas Quantity (Mcf)	Gas Production	Well County	Comment Text
105-21606	2011-1	BUTTON B 901 3H	3H	353056	181	POTTER	Frac water reused at 105-21607
105-21607	2011-1	BUTTON B 901 4H	4H	178895	178	POTTER	Frac water reused at 105-21615
105-21613	2011-1	KEN TON 902 1H	1H	430058	180	POTTER	Frac water reused at 105-21618
105-21614	2011-1	KEN TON 902 2H	2H	283057	181	POTTER	Frac water reused at 105-21617
105-21615	2011-1	KEN TON 902 3H	3H	197380	180	POTTER	Frac water reused at 105-21616
105-21616	2011-1	KEN TON 902 4H	4H	211701	181	POTTER	Frac water reused at 105-21624
105-21617	2011-1	KEN TON 902 5H	5H	332275	179	POTTER	
105-21618	2011-1	KEN TON 902 6H	6H	154541	181	POTTER	Frac water reused at 105-21614
105-21623	2011-1	MITCHELL A 903 4H	4H	141526	181	POTTER	Frac water reused at 117-20346
105-21624	2011-1	MITCHELL A 903 5H	5H	246653	181	POTTER	Frac water reused at 105-21623
105-21645	2011-1	PAUL 906 3H	3H	6554	11	POTTER	Frac water reused at 117-20498
105-21665	2011-1	COON HOLLOW 904 5H	5H	74081	55	POTTER	Frac water reused at 117-20620
117-20185	2011-1	MARSHLANDS UNIT 3	3	9854	171	TIOGA	Frac water resued at 105-21645
117-20309	2011-1	T PIERSON 2H	2H	152962	176	TIOGA	Frac water reused at 117-20320
117-20311	2011-1	T PIERSON 5H	5H	365649	169	TIOGA	Frac water resused at 117-20319
117-20319	2011-1	KJELGAARD 4H	4H	151790	181	TIOGA	Frac water resued at 105-21606
117-20320	2011-1	KJELGAARD 6H	6H	99254	181	TIOGA	Frac water resued at 105-21606
117-20345	2011-1	LICK RUN 6H	6H	174249	181	TIOGA	Frac water reused at 117-20349
117-20346	2011-1	LICK RUN 5H	5H	160679	181	TIOGA	Frac water reused at 117-20348
117-20347	2011-1	LICK RUN 4H	4H	145544	181	TIOGA	Frac water reused at 117-20482
117-20348	2011-1	LICK RUN 3H	3H	168182	181	TIOGA	Frac water reused at 117-20350
117-20349	2011-1	LICK RUN 2H	2H	126173	181	TIOGA	Frac water reused at 117-20347
117-20350	2011-1	LICK RUN 1H	1H	146794	181	TIOGA	Frac water reused at 117-20345
117-20474	2011-1	THOMAS 808 1H	1H	212468	161	TIOGA	Frac water reused at 117-20478
117-20478	2011-1	THOMAS 808 5H	5H	294938	159	TIOGA	Frac water reused at 117-20479
117-20479	2011-1	THOMAS 808 6H	6H	139985	152	TIOGA	Frac water reused at 117-20701
117-20481	2011-1	TRACT 839 815 1H	1H	30434	137	TIOGA	Frac water reused at 117-20484
117-20482	2011-1	TRACT 839 815 2H	2H	25742	141	TIOGA	Frac water reused at 117-20483
117-20483	2011-1	TRACT 839 815 3H	3H	57274	157	TIOGA	Frac water reused at 117-20482
117-20484	2011-1	TRACT 839 815 4H	4H	70541	173	TIOGA	Frac water reused at 105-21613
117-20616	2011-1	PIERSON 810 1H	1H	190008	40	TIOGA	Frac water reused at 105-21645
117-20618	2011-1	PIERSON 810 3H	3H	173886	55	TIOGA	Frac water reused at 117-20621
117-20620	2011-1	PIERSON 810 5H	5H	165846	46	TIOGA	Frac water reused at 117-20616
117-20621	2011-1	PIERSON 810 6H	6H	82638	69	TIOGA	Frac water reused at 117-20620
117-20701	2011-1	THOMAS 808 2H	2H	139464	148	TIOGA	Frac water reused at 117-20618

As previously mentioned, the violations assessed against oil and gas extraction operators by the PA DEP are separated into administrative and environmental safety and health. For the sake of this discussion, those violations listed as administrative are not considered.

Table 10 contains the specific descriptions of Ultra Resources violations categorized under Environmental Safety and Health during operations in the Marcellus Shale in the applicable years:

Table 10. Ultra Resources Violations in Pennsylvania

ULTRA RESOURCES MARCELLUS SHALE COMPLIANCE RECORD Environmental Safety and Health Violations	2011		2010		2009	
102.4 - Failure to minimize accelerated erosion, implement E&S plan, maintain E&S controls.	11	34%	15	60%	4	100%
401CSL - Discharge of pollutional material to waters of Commonwealth.			6	24%		
105NOPERMIT - Encroachment without Permit or Wavier			1	4%		
SWMA301 - Failure to properly store, transport, process or dispose of a residual waste.	9	28%	2	8%		
91.34A - Failure to take all necessary measures to prevent spill. Inadequate diking, potential pollution			1	4%		
402CSL - Failure to adopt pollution prevention measures required or prescribed by DEP by handling materials that create a danger of pollution.	8	25%				
6018.301 - Residual Waste is mismanaged.	2	6%				
6018.610-4 - Handles solid waste contrary to rules and regulations, or orders of the Department, or any permit condition, or in any manner as to create a public nuisance.	1	3%				
691.402 - Potential to pollute waters of the Commonwealth	1	3%				
TOTALS	**32**		**25**		**4**	

In 2009, Ultra had four non-administrative violations. This grew to 25 in 2010, and finally 32 in 2011. There were 35 active wells in 2011. From these statistics, 32/35 yields an ES&H violation rate of 91.4 percent in 2011. The main violation across all sample years for which Ultra was cited is the failure to minimize accelerated erosion, implement E&S plan, and maintain E&S controls. However, Ultra's record on managing waste could also be better. The violation in 2010 for discharging pollutants into the environment is a concern.

A well violation rate of 91.4 percent and the infractions listed in Table 10 should not draw the conclusion that Ultra Resources is a poor operator; however, the inverse is also true. Ultra had near the same number of violations as other medium sized operators and on average fared worse than the aggregate. One point to note is that Ultra Resources has not been fined by PA DEP for its operations in the Marcellus Shale to date. This is not true of several of the larger operators.

9.4 Steps That Should Be Taken to Minimize Risks

The overall point of using these data to predict operator performance is that an ES&H rate of 0.76 violations per well should not be acceptable to the general public. Instead, the public and regulatory organizations should strive for ways to improve operator performance and lower the risk of environmental damage. Some recommendations / observations that should be considered include:

1. **Monitoring through inspections / enhanced tracking information** – The large number of inspections and detailed reports kept by the PA DEP yielded valuable insight as to what and how well operators are

doing in gas and oil extractions in Pennsylvania. By creating database applications accessible to the public, transparency has been added to the oil and gas extraction industry where hydraulic fracturing is applied. During the research of this section, it was stated that Ultra Resources operates in both Wyoming and Pennsylvania. While it was possible to data mine the infractions that Ultra Resources had in Wyoming, collection of the data would be a non-trivial effort. PA DEP's databases enabled the evaluation and creation of statistics that will become more detailed as time progresses. Colorado's Oil and Gas Commission has also provided public database access on permits, inspections, etc. This practice should continue and be refined so that metrics like those presented in this section are more readily obtained.

2. **Application of best practices** – On average, the results of Table 7 indicate a 76 percent likelihood that there will be at least one infraction per well per operator. However, some of the operators were much greater than 76 percent, i.e., J W Operating CO had 29 inspection violations against a single well. When the data are studied in greater detail, the operators that had lower violation rates also had larger numbers of wells. Most of the higher violation rates were against small operators with very few wells. This could imply that more experienced operators tend to commit fewer mistakes and would suggest that there are opportunities for lessons learned across operators. Although it would be outside the scope of this paper, research of the best performing operators and their processes/operating practices could be used to improve the industry as a whole.

3. **Industry training** – The data indicate some violations are more common than others. Identification of the most prevalent ES&H violation types should be paired with industry training that helps reduce and mitigate the most common types of ES&H problems with oil and gas extraction operations.

4. **Baseline water testing** - Baseline water testing is a necessity before a hydraulic fracturing operation occurs in order to determine if the oil or gas extraction has impacted ground water. Though not specifically mentioned in this section, it was a finding in the Pavillion Wyoming EPA study (see Relevant Case Studies).

Environmental and safety risks are associated with oil and gas extraction from natural gas and oil shale formations. However, the need to extract these natural resources is great as well as financially and economically beneficial. Care should be applied where feasible. Strategies should be used that will reduce the risk to the public and the environment.

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10 Environmental Regulations

Environmental regulations impact oil operations and help to protect the environment. This section discusses a number of environmental regulations, which are in place to help ensure the environment is protected. The following sections provide some of the federal, state, and local regulations applicable to oil exploration and operations.

10.1 Resource Conservation and Recovery Act (RCRA) of 1976

Wastes generated during crude oil and natural gas extraction are categorized by the EPA as "special wastes" and are exempt from federal hazardous waste regulations. Since the passage of the RCRA in 1976, there have been 10 additional legislative and regulatory actions taken to clarify regulation of these special wastes.

In some locations, operators use surface storage tanks and open pits for temporary storage of hydraulic fracturing fluids either for reuse or until arrangements are made for disposal. The EPA is evaluating industry practices and state requirements to decide whether there is a need for technical guidance for design, operation, maintenance, and closure of pits under the RCRA.[167]

10.2 Underground Storage Tank Provision of RCRA

The Underground Storage Tank program is regulated by the state where the tanks are physically located, according to the EPA.[168]

10.3 Clean Air Act (CAA)

In areas where natural gas development has occurred, emissions of methane, volatile organic compounds (VOC), and hazardous air pollutants have increased. The CAA also includes regulations on reporting greenhouse gas emissions.[169]

10.4 Clean Water Act (CWA)

The Effluent Guidelines Program of the CWA sets national limits on industrial wastewater discharges. The Effluent Guidelines prohibit on-site discharge of wastewaters from shale gas extraction into any U.S. waters. Some wastewaters are re-injected on-site. However, there are significant quantities of wastewater that remain and need to be disposed.

[167] (Natural Gas Extraction - Hydraulic Fracturing 2012)
[168] (Land and Cleanup Topics 2012)
[169] (Natural Gas Extraction - Hydraulic Fracturing 2012)

These wastewaters are transported to treatment plants. The EPA and states where drilling takes place share responsibility for treatment and disposal of wastewaters from shale gas extraction per the National Pollutant Discharge Elimination System (NPDES).[170] The State of Colorado is partially authorized for treatment and disposal of wastewaters under the NPDES.[171] As of April 2003, Colorado has an approved General Permits Program and a State NPDES Permit Program.[172]

The EPA is also working on recommended changes for chloride water quality criteria for states to use as a basis for establishing state water quality levels. These water quality criteria will set limits on discharges and flowback wastewaters. Wastewaters contain a large amount of Total Dissolved Solids (TDS), of which chlorides are a principal component.

Per the CWA, storm water discharges from oil and gas exploration, production, processing, and treatment operations, including construction activities do not require NPDES permits unless there is a reportable quantity spill or the spill causes or contributes to a water quality violation.[173]

10.5 Oil Pollution Act

The Oil Pollution Act was signed into law in 1990 and improved the government's ability to prevent and respond to oil spills. The act also created a national Oil Spill Liability Trust Fund for spill cleanup, and provided new requirements for contingency planning on both the government's part and on the industry's part. The final provisions of the act increased penalties for noncompliance, increased enforcement authority, and preserved state authority to establish laws governing oil spills and cleanup. Section 1018a indicates that the CWA does not pre-empt state law. States can impose additional liability, funding mechanisms, requirements for removal, and fines for responsible parties.[174]

Facilities are covered by the Oil Pollution Act. According to the Act, a facility is a structure, group of structures, equipment, or device used to explore, drill, produce, store, handle, transfer, process, or package oil. Included in the definition of facility are any vehicles or pipelines used for these purposes.[175]

10.6 Safe Drinking Water Act

The Safe Drinking Water Act provides for identifying, monitoring, and control of contaminants in finished water. The SDWA also provides for enforcement of rules and dissemination of information about utility water.[176] Specific contaminants regulated by the

[170] (Natural Gas Extraction - Hydraulic Fracturing 2012)
[171] (State NPDES Program Authority n.d.)
[172] (National Pollutant Discharge Elimination System (NPDES) 2003)
[173] (Natural Gas Extraction - Hydraulic Fracturing 2012)
[174] (Oil Pollution Act Overview 2011)
[175] (Bell, et al. 2001, 316)
[176] (Bell, et al. 2001, 373)

SDWA include radionuclides such as radium, sulfates, disinfectants and by-products, viruses and bacteria such as cryptosporidium and giardia, lead, copper, and arsenic.[177]

The Safe Drinking Water Act sets guidelines for well siting, construction, and operation to minimize risk to drinking water sources. The Energy Protection Act of 2005 excluded hydraulic fracturing, except when diesel fuel is used. When diesel fuels are used as part of hydraulic fracturing, permits are required. The SDWA also regulates disposal of produced and flowback water.[178]

10.7 Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA)

CERCLA, or Superfund, was enacted to address abandoned hazardous waste sites as well as accidents, spills, and other releases of pollutants and contaminants into the environment.[179] This would apply to hydraulic fracturing in the event of a spill or other release of fluids. There is significant additional regulation at the state level.

10.8 National Environmental Policy Act (NEPA)

The NEPA only applies to federal agencies. This will not apply to private hydraulic fracturing operations.[180]

10.9 Toxic Substance Control Act

The Toxic Substance Control Act regulates asbestos, hexavalent chromium, chlorofluorocarbons, tetrachlorodibenzo-P dioxin, metalworking fluids, and polychlorinated biphenyls. This regulation does not apply to private hydraulic fracturing operations – unless such operation uses any of these regulated substances.[181]

10.10 Federal Insecticide, Fungicide, and Rodenticide Act

This regulation applies to producers of insecticides, fungicides, and rodenticides. It does not apply to private hydraulic fracturing operations.[182]

10.11 Pollution Prevention Act

The Pollution Prevention Act is focused on reducing the amount of pollution through changes in production, operation, and raw material usage.[183]

[177] (Bell, et al. 2001, 383-389)
[178] (Natural Gas Extraction - Hydraulic Fracturing 2012)
[179] (Summary of Superfund 2012)
[180] (Bell, et al. 2001, 487)
[181] (Bell, et al. 2001, 572-577)
[182] (Bell, et al. 2001, 605)
[183] (Summary of the Pollution Prevention Act 2012)

10.12 Emergency Planning and Community Right to Know Act (EPCRA)

The EPCRA was enacted to protect community health. The law is designed to help local communities protect public health, public safety, and the environment from chemical hazards.[184]

10.13 Occupational Safety and Health Act

The Occupational Safety and Health Act (OSHA) was enacted to ensure worker and workplace safety. The goal is to ensure employers provide workers a workplace that is free from recognized threats to safety and health such as exposure to toxic chemicals, excessive noise levels, and mechanical dangers.[185] OSHA subparts B, C, D, G, H, I and J will apply to private hydraulic fracturing operations.

10.14 U.S. Fish and Wildlife Service

The U.S. Fish and Wildlife Service, Region 6, regulates environmental contaminants, such as those found in oil field waste pits for Montana, North Dakota, South Dakota, Wyoming, Nebraska, Utah, Colorado, and Kansas. The pits are used to store the petroleum products and any water produced with them, where the petroleum is skimmed from the mixture. Once the petroleum is separated, the water is discharged into surface waters, injected underground, or transported to commercial treatment plants for disposal. All of these methods involve risk to wildlife and fish resources. In addition, reserve pits used to store drilling fluids can endanger birds and other wildlife if there is a sheen of oil on the surface, and flare pits used to vent hydrogen sulfide gas can also endanger birds and other wildlife.[186] There are several solutions to prevent wildlife mortality, including use of closed containment systems, elimination of pits or preventing oil from collecting on open pits and ponds, and the use of proven wildlife deterrents such as netting.[187]

10.15 Colorado Regulations

Regulations for hydraulic fracturing in Colorado are governed by the Colorado Oil and Gas Conservation Commission (COGCC). The COGCC Rules are broken down into 12 series, shown in Table 11.[188] In addition to these series, the COGCC also provides 8 appendices that provide additional information on COGCC rules. The appendices are listed in

[184] (Summary of EPCRA 2012)
[185] (Summary of the Occupational Safety and Health Act 2012)
[186] (Oil Field Waste Pit Problems n.d.)
[187] (Oil Field Waste Pit Solutions n.d.)
[188] (Commission Rules and Regulations n.d.)

Table 12.[189]

Table 11. COGCC Rules

Series	Title
100	Definitions
200	General Rules
300	Drilling, Development, Producing, and Abandonment
400	Unit Operations, Enhanced Recovery Projects
500	Rules of Practice and Procedure
600	Safety Regulations
700	Financial Assurance and Environmental Response Funds
800	Aesthetic and Noise Control Regulations
900	Exploration and Production Waste Management
1000	Reclamation Regulations
1100	Flowline Regulations
1200	Protection of Wildlife Resources

Table 12. COGCC Appendices

Appendix	Title
I	Information on Completing COGCC Forms
II	None
III	Fee Structure
IV	Due Date / Response Time
V	Oil and Gas Conservation Act Title 34 – Article 60 (Amended)
VI	Public Water Systems
VII	Restricted Surface Occupancy Maps (Amended)
VIII	Sensitive Wildlife Habitat Maps

The COGCC rules can be broken down into the following areas: Construction Requirements, Required Tests and Inspections, Financial Assurance, Operational Requirements, and Reclamation Requirements. These areas are discussed in the following sections.

[189] (Commission Rules and Regulations n.d.)

10.16 Construction Requirements

In high-density areas, tanks are to be designed, constructed, and maintained in accordance with National Fire Protection Association (NFPA) Code 30 (2008 version). Operators must maintain written records that verify proper design, construction, and maintenance, and make these records available for inspection upon request. Tanks are to be constructed according to the specifications in Table 13.[190]

Table 13. Specifications for Storage Tanks

Specifications
Underwriters Laboratories, Inc., No. UL-142, "Standard for Steel above ground Tanks for Flammable and Combustible Liquids," 9th Edition (December 28, 2006)
American Petroleum Institute Standard No. 650, "Welded Steel Tanks for Oil Storage," 11th Edition (June 2007)
American Petroleum Institute Standard No. 12B, "Bolted Tanks for Storage of Production Liquids," 15th Edition (October 2008, effective March 31, 2009)
American Petroleum Institute Standard No. 12D, "Field Welded Tanks for Storage of Production Liquids," 11th Edition (October 2008, effective March 31, 2009)
American Petroleum Institute Standard No. 12F, "Shop Welded Tanks for Storage of Production Liquids," 12th Edition (October 2008, effective March 31, 2009)

All pipe fittings, valves, and unions used in BOPE (Blowout Prevention Equipment), well casings, casinghead, drill pipe, or tubing must have a working pressure rating suitable for the maximum anticipated surface pressure and be kept in good working condition according to generally accepted industry standards.[191]

The operator must place a sign on the public road at the intersection of the rig access road. In addition, the location of the well, number of the public roads used to reach it, and all emergency numbers are to be posted on the drilling rig. The operator also must place a sign at the boundary of the site on the access road which identifies the operator, the lease name, location, and phone numbers where the operator may be reached.[192]

Surface and intermediate casing cement must be of adequate quality to achieve minimum compressive strength of 300 psi (pound per square inch) after 24 hours, and 800 psi after 72 hours. These measurements are taken at 95°Fahrenheit (F) and 800 psi. The surface casing should be cemented with a continuous column from the bottom of the casing to the surface. Cement should be pumped behind the surface and intermediate casing to at least 200 feet above the top of the shallowest known production horizon and in accordance with Rule 317.g. This cement is to set for a minimum of 8 hours or until 300 psi calculated compressive strength is achieved before starting drilling operations. In the event the surface

[190] (Series Safety Regulations 2009)
[191] (Series Safety Regulations 2009)
[192] (Series Safety Regulations 2009)

casing cement falls below the surface or aquifer protection is compromised, remedial cementing operations should be conducted.[193]

Production casing cement must be of adequate quality to achieve minimum compressive strength of 300 psi after 24 hours and 800 psi after 72 hours, measured at 95°F and 800 psi. Following thorough circulation of a wellbore, cement shall be pumped behind the production casing 200 feet above the shallowest known producing horizon. All exposed freshwater aquifers below the surface casing must be cemented behind the production casing. This cement must be a continuous column extending at least 50 feet above the top of the aquifer to at least 50 feet below the bottom of the aquifer. Cement behind the production casing must be allowed to set for at least 72 hours or until 800 psi calculated compressive strength is achieved, prior to completion operations.[194]

Pipeline materials must be able to maintain structural integrity under the anticipated pressure and temperature during operation, must be compatible with the materials to be transported, and must be locatable by a tracer line or other location device placed adjacent to or in the trench where nonmetallic pipe is used. The pipeline must be designed and installed to prevent failure due to corrosion and must be capable of withstanding anticipated internal and external pressures. Installed pipelines must have sufficient cover to prevent damage on cropland. Pipelines must have a minimum cover of three feet.[195]

The following types of pits must be lined: drilling pits intended for use with fluids containing hydrocarbon concentrations exceeding 10,000 ppm (parts per million) TPH (total petroleum hydrocarbon) or chloride concentrations exceeding 15,000 ppm.

- production pits
- special purpose pits
- skim pits
- multi-well pits used to contain produced water
- drilling fluids, or completion fluids to be recycled
- pits at centralized E&P (exploration & production) waste facilities

Lining materials should be impervious and synthetic, having high puncture strength, and resistant to ultraviolet light, weathering, hydrocarbons, aqueous acids, alkali, fungi, or any other substances in the produced water. Liners must have minimum thickness of 24 mils. The liner should cover the bottom and sides of the pit and must be secured with a 12-inch minimum anchor trench all around. The foundation for the liner should be a minimum of 12 inches of soil after compaction, with soil having maximum hydraulic conductivity of 1 X 10^{7} centimeters per second (cm/sec). In sensitive areas, the COGCC Director may require additional pit features such as leak detectors, monitoring systems, and underlying gravel sump pumps.[196]

[193] (Drilling, Development, Producing, and Abandonment 2012)
[194] (Drilling, Development, Producing, and Abandonment 2012)
[195] (Flowline Regulations 2009)
[196] (Exploration and Production Waste Management 2011)

10.17 Required Tests and Inspections

In high-density areas, BOPE is to be tested upon initial rig-up and every 30 days during drilling operations. COGCC Rule 603 (b) defines a high-density area and can be summarized as an average density of one building unit per two acres. Additionally, if an educational facility, assembly building, hospital, nursing home, board and care facility, or jail is located within 1,000 feet of a wellhead or production facility, high density rules apply.[197] Pressure testing is to include the casing string and each component of the BOPE, including the flange connections. Pressure testing is at 70 percent of working pressure or 70 percent of the internal yield of the casing, whichever is less. Results of testing are to be kept for one year for inspection by the COGCC Director. During operation, BOPE must be inspected daily and a preventer operating test must be performed on each round trip, but not more than once every 24-hour period. [198]

Prior to drilling out any string of casing, except conductor pipe, the BOPE and casing string is to be pressure-tested to at least 500 psi and must hold for at least 15 minutes without pressure loss. Drilling operations may not proceed until the BOPE is tested and found to be serviceable.[199]

Pressure control valves activated by a secondary gas supply must be inspected at least every three months to ensure they are working properly and the secondary gas supply has volume and pressure to operate the valve.[200]

The production casing should be adequately pressure tested for all anticipated conditions.[201]

Temporarily abandoned or shut-in injection wells must have a mechanical integrity test within two years of the shut-in date in order to retain its shut-in or temporarily abandoned status. If a temporarily abandoned well does not pass mechanical integrity tests, within six months it must either be repaired or abandoned.[202]

Before operating a pipeline, the operator must test it to the maximum anticipated operating pressure. When conducting tests, the operator must ensure reasonable precautions are in place to protect employees and the general public. These tests are to be conducted once each calendar year and test results must be retained for three years. Flowlines with operating pressure less than 15 psi are exempt from pressure testing mandates.[203]

[197] (Colorado Oil and Gas Conservation Commission 2009)
[198] (Series Safety Regulations 2009)
[199] (Series Safety Regulations 2009)
[200] (Series Safety Regulations 2009)
[201] (Drilling, Development, Producing, and Abandonment 2012)
[202] (Drilling, Development, Producing, and Abandonment 2012)
[203] (Flowline Regulations 2009)

10.18 Financial Assurance

The financial assurance provisions in Series 700 are intended to ensure funding by each operator to perform obligations imposed by the Oil and Gas Conservation Act (the Act), §34-60-106 (3.5), (11), (12) and (17) C.R.S., as well as the use of the Oil and Gas Conservation and Environmental Response Fund, §34-60-124 C.R.S. The financial assurance must be in the form of a surety bond. Any other form of payment allowed in §34-60-106(13) C.R.S. must be approved by the COGCC. The alternate form of financial assurance must provide the same amount of protection provided by a surety bond and may be periodically reviewed by the COGCC. Financial assurance must be held until the COGCC Director is satisfied that the operator has complied with all statutory requirements.[204]

Section 703 calls out provisions to protect surface owners' interests when they are not parties to a lease or other agreement. Determination of crop loss or land damage is made by the COGCC after the surface owner files an application in accordance with the Series 500 rules. Relief for the surface owner may be in the form of corrective action on the land as well as monetary compensation, at the discretion of the COGCC. Operators must provide $2,000 per well for non-irrigated land and $5,000 per well for irrigated land. In lieu of individual amounts, operators are allowed to provide blanket statewide protection in the amount of $25,000.[205]

Section 706 calls out provisions to protect soil, ensure proper plugging and abandonment of the well, and ensure reclamation of the site. Financial assurance amounts are directed by depth of the well. For wells less than 3,000 feet total depth, operators must provide $10,000 per well. For wells greater than or equal to 3,000 feet total depth, operators must provide $20,000 per well. Operators are allowed to provide statewide blanket coverage. For operations of less than 100 wells, operators may provide $60,000, and for operations of greater than or equal to 100 wells, operators may provide $100,000.[206]

Operators are also required to provide financial assurance based on the number of inactive wells. First, excess inactive wells are computed according to Equation 1 for wells less than 3,000 feet or Equation 2 for wells greater than or equal to 3,000 feet.[207]

Equation 1. Calculation for Inactive Wells Less Than 3,000 Feet in Depth

$$x_1 = \frac{Total\ Financial\ Assurance}{\$10{,}000}$$

Equation 2. Calculation for Inactive Wells Greater Than 3,000 Feet in Depth

$$x_2 = \frac{Total\ Financial\ Assurance}{\$20{,}000}$$

[204] (Financial Assurance and Oil and Gas Conservation and Environmental Response Fund 2009)
[205] (Financial Assurance and Oil and Gas Conservation and Environmental Response Fund 2009)
[206] (Financial Assurance and Oil and Gas Conservation and Environmental Response Fund 2009)
[207] (Financial Assurance and Oil and Gas Conservation and Environmental Response Fund 2009)

Once the number of excess wells is established, the operator is assessed $10,000 for each excess inactive well less than 3,000 feet in depth or $20,000 for each excess well greater than or equal to 3,000 feet in depth.[208]

Operators conducting seismic activities must provide $25,000 statewide blanket coverage to ensure proper plugging and abandonment of shot holes and any surface reclamation needed.[209]

Operators of natural gas wells are required to provide $50,000 in statewide blanket coverage, unless there are less than five wells. For less than five wells, the operator may provide $5,000 per well.[210]

Operators of Class II commercial Underground Injection Control (UIC) wells are required to provide $50,000 for each facility.[211]

Operators must carry general liability insurance to cover property damage and bodily injury to third parties in the amount of $1,000,000 per incident.[212]

10.19 Operational Requirements

A copy of the approved Form 2 – Application for Permit to Drill, Deepen, Re-enter, or Recomplete and Operate, is to be posted at the drilling rig. The COGCC Director must be notified within five days of spudding a well on Form 4 – Sundry Notice.[213] “Spudding” is the industry term for drilling an oil well.

If drilling operations are suspended before the production string is run, the COGCC Director must be notified immediately and the operator must take action to ensure no alien water enters the oil or gas strata, or potential freshwater aquifers, during the suspension period. In the event alien water is found to be entering the production stratum or causing significant adverse environmental impact to freshwater aquifers during completion of testing or production, the condition must be promptly remedied.[214]

Log of Operations

The operator is required to log all new drilling operations. This involves, at minimum, a resistivity log with gamma-ray or other petrophysical logs approved by the COGCC Director that adequately describe the stratigraphy of the wellbore. A cement bond log must also be run on all production casings or on intermediate casings when they are run. These logs are to be submitted on Form 5 – Well Completion or Recompletion Report and Log.

[208] (Financial Assurance and Oil and Gas Conservation and Environmental Response Fund 2009)
[209] (Financial Assurance and Oil and Gas Conservation and Environmental Response Fund 2009)
[210] (Financial Assurance and Oil and Gas Conservation and Environmental Response Fund 2009)
[211] (Financial Assurance and Oil and Gas Conservation and Environmental Response Fund 2009)
[212] (Financial Assurance and Oil and Gas Conservation and Environmental Response Fund 2009)
[213] (Drilling, Development, Producing, and Abandonment 2012)
[214] (Drilling, Development, Producing, and Abandonment 2012)

Open hole logs should be run at depths that verify the setting depth of surface casing and any aquifer coverage.[215]

Temporary Well Abandonment

Wells may be temporarily abandoned for up to six months as long as the hole is cased or left in a condition to prevent migration of oil, gas, water, or other substances from the formation horizon where it originally occurred. Temporarily abandoned wells must be closed to the atmosphere with a swedge and valve or a packer or other approved method. The well sign must remain in place.[216]

Well Completion

For completions, green practices must be followed where reservoir pressure, formation productivity, and wellbore conditions may result in free-flowing hydrocarbons at a flammable level or higher at a flow rate of 500 mcf with a backpressure of 500 psi or sales line pressure. Green practices include the use of sand traps, separators, surge vessels, and tanks to maximize resource recovery and minimize releases to the environment and directing well effluent through the items just noted, and other equipment to allow safe separation of salable products and safe disposal of waste products.[217]

Dust Control

Operators are to use dust control methods such as speed restrictors, regular road maintenance, and restriction of construction activity on high wind days. The operator can also use road surfacing, windbreaks, and automated wells to reduce truck traffic.[218]

Fencing

During drilling operations on cropland, the operator must put fencing, berms, or another method around each drill site and along access roads to inhibit surface disturbances. Pits must have fencing around them to prevent livestock from wandering into the pits, unless there are existing fences to keep livestock out. Wells, pits, and production facilities must also be fenced to prevent livestock from wandering into them.[219]

Soil

When preparing a site on cropland, the operator must separate and store all soil from the site and mark each soil type for later reclamation activities. Soil should be separated based on physical characteristics such as organic content, color, texture, density, or consistency. Soil should be segregated to a depth of six feet or down to bedrock, whichever is shallower. For non-cropland, the operator must segregate only the top six inches of soil. When the soil is too rocky or too thin, the operator must segregate to the extent possible and

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[215] (Drilling, Development, Producing, and Abandonment 2012)
[216] (Drilling, Development, Producing, and Abandonment 2012)
[217] (Aesthetic and Noise Control Regulations 2009)
[218] (Aesthetic and Noise Control Regulations 2009)
[219] (Reclamation Regulations 2009)

store the soil. Stored soils must be protected from degradation and erosion from wind and water. Best practices should be followed to prevent weed growth and to preserve microbial activity.[220]

Surface Disturbance

Operators are to minimize surface disturbances. Access roads should be located and maintained to minimize erosion and dust generation. Impacts to wetlands and riparian habitats must be minimized. Operators should consolidate facilities and pipeline right-of-ways to minimize impact to wetlands and other wildlife habitats.[221]

Stormwater

Operators are to follow best management practices to control stormwater runoff that minimizes erosion and transport of sediment off-site. Operators must develop a Post-Construction Stormwater Program in compliance with Series 1000 rules no later than the termination of stormwater permits from the state of Colorado. This Program contains best management practices the operator will use to address potential sources of pollution, which could affect the quality of discharges from production facilities. Examples of these pollution sources include transport of chemicals and materials, vehicle and equipment fueling, produced water and fluids storage, waste disposal practices, leaks and spills, and ground-disturbing maintenance activities.[222]

When pipelines cross cropland, soils should be segregated during trenching. The trench must be backfilled to restore the relative positions and contour of the soils.[223]

Pipelines

Operators must take reasonable precautions to prevent pipeline failures, leakage, and corrosion. If the operator discovers a section of the pipeline whose condition affects the safe operation of the pipeline, corrective action must be taken immediately. If the condition poses an imminent danger, the operator must not use the section of the pipeline until repairs are performed. Repairs to pipelines must be made in a manner which does not endanger employees or cause property damage. Pipes, valves, and fittings must not be used if they do not meet the installation requirements of the 1100 Series rules. Pipelines must be clearly marked with a warning, the material being transported, and contact information where the operator can be reached at all times. Operators are also required to participate in the Colorado One Call program and become a member of the Utility Notification Center. For pipelines governed by the Office of Pipeline Safety, U.S. Department of Transportation, the operator must provide an emergency response plan to the COGCC and to the county sheriff and local government of each county the pipeline crosses.[224]

[220] (Reclamation Regulations 2009)
[221] (Reclamation Regulations 2009)
[222] (Reclamation Regulations 2009)
[223] (Flowline Regulations 2009)
[224] (Flowline Regulations 2009)

Pits

Pits must be operated so that there is always a minimum of two feet of freeboard at all times. A monitoring system must be used to monitor and maintain the required freeboard. Only minimal amounts of hydrocarbon are allowed in the pit at any time. Hydrocarbons above minimal levels must be removed within 24 hours. Pits should be surrounded by fencing or covered by netting to prevent access by wildlife.[225]

Waste

Operators must ensure exploration and production (E&P) waste is properly stored, transported, treated, recycled, or disposed of to prevent environmental impacts to air, soil, water, or biological resources. E&P waste products must conform to the concentration levels shown in Table 910-1 in the Series 900 Rules. E&P waste facilities must be constructed to protect waters of the state from adverse environmental impact.[226]

Produced water must be treated prior to placement in a pit to prevent crude oil and condensate from entering the pit. Produced water may be disposed of in the following ways: injection into a Class II well in accordance with Rule 325, evaporation or percolation in a properly permitted pit, disposal at permitted commercial facilities, dispersal on a lease road outside of sensitive areas as long as the water contains less than 3,500 mg/L of TDS (total dissolved solids) when allowed by the property owner, discharge into state waters in accordance with the Water Quality Control Act, and evaporation in a properly lined pit at a centralized E&P waste facility.[227]

Drilling fluids may also be disposed of in a Class II injection well, disposal at a solid waste facility, or land treatment or land application at a centralized E&P waste facility permitted in accordance with Rule 908. Water-based bentonitic drilling fluids may be disposed of by drying and burial in pits on non-cropland and land application.[228]

Oily waste includes materials containing hydrocarbons such as soil, frac sand, drilling fluids, and pit sludge. Oily waste may be treated or disposed of as follows: disposal at a commercial solid waste facility, land treatment onsite, or treatment at a centralized E&P waste facility.[229]

Flaring

Unnecessary venting or flaring of natural gas is prohibited. Except for gas flared during well upset, purging, maintenance, or productivity testing, natural gas may not be flared without advance approval by the COGCC Director on a Form 4 – Sundry Notice. The operator must indicate the approximate volume of gas to be flared and must indicate whether the gas contains more than 1 part per million (ppm) of hydrogen sulfide gas. To protect

[225] (Exploration and Production Waste Management 2011)
[226] (Exploration and Production Waste Management 2011)
[227] (Exploration and Production Waste Management 2011)
[228] (Exploration and Production Waste Management 2011)
[229] (Exploration and Production Waste Management 2011)

public health and welfare, the COGCC Director may require flaring of natural gas. Gas flared or vented must be listed on Form 7 – Operator's Monthly Production Report. Flared gas subject to Form 4 must be directed in a controlled flare in accordance with Rule 903.b.(2) as efficiently as possible to minimize air contaminants. The operator must notify the emergency dispatcher or local government designee within two hours of any natural gas flaring. When possible, advance notice of flaring should be given.[230]

There are specific operational requirements for operations in sensitive wildlife areas and restricted surface occupancy areas to protect wildlife. During pipeline trenching, wildlife crossings must be installed every ¼ mile for any trenches five feet wide or greater and left open longer than five days. Facilities should be consolidated to minimize impacts to wildlife. All employees must be educated in proper wildlife conservation practices including not harassing or feeding wildlife. Where possible, the rig mobilization and demobilization should be minimized by completing or recompleting all wells on a given pad before moving the rig. Boring rather than trenching should be used when traversing perennial streams that are considered critical fish habitats. Wildlife appropriate fencing should be used. Remote monitoring of well operation is to be used where practicable. Operators should avoid operations in restricted surface occupancy areas to the maximum extent possible except when authorized after consultation in accordance with Rule 306.c.(3), when authorized by a Comprehensive Drilling Plan, upon demonstration that the habitat is actually not present, when specifically allowed by the Colorado Division of Wildlife, or in the event of situations posing a risk to public safety and welfare.[231]

10.20 Safety Requirements

Safety requirements called out in Series 600 are intended to protect the general public during drilling, completion, and operation of wells. Series 600 rules do not apply to workers regulated by the Occupational Safety and Health Act of 1970.[232]

There are several regulations related to fire control. Buildings where flammable liquids are stored must be ventilated to outside air to prevent buildup of flammable vapors. For buildings exceeding 500 square feet, there must be two unobstructed exits leading in different directions. General housekeeping practices should be followed to remove unnecessary flammable materials. The building must be adequately marked as to its fire hazards. No flammable liquid storage is allowed within 50 feet of the well, with exception of fuel within tanks of operating equipment. Combustible materials must be stored in covered metal containers. Any material not in use which could be considered a fire hazard must be moved at least 25 feet from the wellhead. Finally, an adequate number of fire extinguishers must be available and labeled as to their type and usage. All fire protection equipment is to be periodically inspected and kept in proper working order.[233]

[230] (Exploration and Production Waste Management 2011)
[231] (Protection of Wildlife Resources 2009)
[232] (Series Safety Regulations 2009)
[233] (Series Safety Regulations 2009)

BOPE for drilling operations consists of a double ram with blind ram and pipe ram, annular preventer or a rotating head for a rig with Kelly. A Kelly is a long square or hexagonal steel bar with a hole drilled through the middle for a fluid path. The Kelly is used to transmit rotary motion from the rotary table or Kelly brushing to the drillstring, while allowing the drillstring to be lowered or raised during rotation.[234] For rigs without Kelly, BOPE consists of a double ram with blind ram and pipe ram. At least one person per site must be trained and certified in BOPE operation in either Mineral Management certification or COGCC Director approved training. When required by Rule 317, BOPE shall be in accordance with API RP 53: Recommended Practices for Blowout Prevention Equipment Systems, and its amendments. BOPE must contain pipe rams that enable closure on the pipe in use. Choke lines and kill lines must be anchored, tied, or secured to prevent whipping from pressure surges. All rig personnel should be adequately trained in BOPE system operation, and new employees should be trained as soon as practicable.[235]

Backup stabbing valves are required in all operations where reverse circulation is performed.[236]

Statewide setback requirements indicate a minimum distance of 150 feet (or 1-1/2 times the derrick height) from the wellhead to the nearest building unit, public road, above-ground utility line, or railroad. In addition, the wellhead must be located a minimum of 150 feet from the nearest property line. For high density areas, the setback distances increase to 350 feet. In high-density areas, production equipment is to be located 350 feet from building units and 500 feet from educational facilities, assembly buildings, hospitals, nursing homes, board and care facilities, jails, and designated outside activity areas.[237]

Pit level indicators are to be used in high-density areas.[238]

At the time of construction, if a site falls within a high-density area, all pumps, pits, wellheads, and production facilities are to be surrounded by fence at least six feet high. The fence should be constructed in accordance with local standards and must have gates that lock.[239]

In high-density areas, berms must be constructed around all crude oil, condensate, and produced water tanks. The berms must have sufficient capacity to contain 150 percent of the largest tank. The berms must be impervious to contain any spills or released materials. Berms are to be inspected regularly and kept in good condition. No secondary ignition sources are to be installed within the berm, unless the berm surrounds a fired vessel.[240]

Tanks are to be located 2 diameters or 350 feet (whichever is smaller) from the property line on which they are built. Where the property line is a public way, the tanks are to

[234] (Schlumberger 2012)
[235] (Series Safety Regulations 2009)
[236] (Series Safety Regulations 2009)
[237] (Series Safety Regulations 2009)
[238] (Series Safety Regulations 2009)
[239] (Series Safety Regulations 2009)
[240] (Series Safety Regulations 2009)

be located 2/3 of the diameter from the nearest point of the public way. Tanks containing less than 3,000 barrels must be located at least three feet apart, and those containing 3,000 barrels or more must be located at least 1/6 diameter apart. When one tank diameter is less than 1/2 the diameter of another tank, then the tanks must be located 1/2 the diameter of the smaller tank apart. Tanks must be located at least 75 feet from the nearest firing vessel. Tanks must be located at least 50 feet from a separator, well test unit, or other non-fired equipment. Tanks must be located at least 75 feet from any compressor with a 200-horsepower (hp) rating or higher. Tanks must be located at least 75 feet from a wellhead. Vent lines are to be conjoined and the outlet directed away from fired vessels in accordance with API RP 12R-1, 5th Edition (August 1997, reaffirmed April 2, 2008). During hot oil treatments on tanks containing 35 degrees or higher API gravity oil, the hot units must be located at least 100 feet away from the tank being serviced.[241]

In some cases, additional equipment may be required to protect public safety. Wells located within 150 feet of a residence, normally occupied building unit, or well-defined normally occupied outside area must be equipped with a fail-safe automatic control valve which shuts down the well when a sudden change in pressure occurs.

Oil and gas operations must comply with the noise levels called out in Table 14. During the hours of 7:00 a.m. and the following 7:00 p.m., the noise levels in Table 14 may be increased by 10 dBA (decibel A) for no more than 15 minutes each hour. These levels are decreased by 5 dBA for periodic, impulsive, or shrill noise. In remote locations where there are no nearby structures or designated outside areas, acceptable noise levels are the light industrial levels. When the COGCC receives a complaint, noise levels are measured at a distance of 350 feet from the noise source and at a distance greater than 350 feet if the complainant believes it will be more realistic of the noise level. If the oil or gas operation is less than 350 feet from an occupied structure, the noise level is measured at 25 feet from the structure. When topology prevents taking measurements at 350 feet, the noise level is measured closer and extrapolated to the value at 350 feet following the formula in Equation 3.[242]

Table 14. Noise Levels by Zone Type

Zone	7:00 a.m. – 7:00 p.m. Level (dBA)	7:00 p.m. – 7:00 a.m. Level (dBA)
Residential/Agricultural/Rural	55	50
Commercial	60	55
Light Industrial	70	65
Industrial	80	75

241 (Series Safety Regulations 2009)
242 (Aesthetic and Noise Control Regulations 2009)

Equation 3. Extrapolation of Noise Level

$$N_2 = N_1 - 20 \cdot \log_{10} \frac{x_2}{x_1}$$

In Equation 3, N_2 represents the noise level in dBA at distance x_2, N_1 represents the noise level in dBA at distance x_1. Sound levels are to be measured four feet above ground and are to be averaged minute-by-minute for 15 minutes. Ambient noise levels are to be considered for their contribution to the overall noise level generated by the oil or gas operation.[243]

If the noise complaint is for low-frequency noise, the COGCC will measure the noise level 25 feet from the exterior wall of the structure nearest the noise source using a noise meter calibrated in dBc (decibel C) units. If the noise measurement exceeds 65 dBc, the operation must obtain a low-frequency noise impact analysis by a qualified sound expert and should include recommended actions for noise mitigation. The results of this analysis will be made available to the COGCC Director for review and potential action.[244]

Lighting is to be directed downward and internally to avoid glare on surrounding public roads and buildings within 700 feet of the oil or gas operation. Production facilities visible from public roads are to be painted with a uniform, non-contrasting, non-reflective color tone that is similar to the surrounding landscape.[245]

Spills and leaks must be controlled and contained immediately to protect the environment, public health and safety, and wildlife resources. Spills exceeding five barrels must be reported on Form 19 – Spill/Release Report. Spills exceeding 20 barrels must also be reported on Form 19 – Spill/Release Report and must be verbally reported to the COGCC Director as soon as possible but no later than 24 hours from the spill. A spill of any size which threatens state waters, residences, livestock, or public byways must also be reported on Form 19 – Spill/Release Report and must be verbally reported to the COGCC Director as soon as possible but no later than 24 hours after discovery. Spills which threaten any surface water supply area must be reported to the COGCC Director and to the Environmental Release/Incident Report Hotline (1-877-518-5608). Chemical spills and releases must be reported in accordance with applicable state and federal laws.

10.21 Reclamation Requirements

In high-density areas, plugged or abandoned wells are to be indicated with a permanent monument in accordance with Rule 319.a.(5).[246]

Abandoned wells, cores, and other exploratory holes must be plugged to assure that oil, gas, water, and other substances are confined to the reservoir where they originally occurred. The plug must be 50 feet long and extend 50 feet above each zone to be protected.

[243] (Aesthetic and Noise Control Regulations 2009)
[244] (Aesthetic and Noise Control Regulations 2009)
[245] (Aesthetic and Noise Control Regulations 2009)
[246] (Series Safety Regulations 2009)

No substance of any type other than that normally used in plugging operations is allowed to be placed in the well at any time during plugging operations. The final report of plugging and abandonment must be submitted on Form 6 – Well Abandonment Report along with a job log or cement verification report from the plugging contractor.[247]

Abandoned wells are to have a seal or plug at the surface or ground level which will not interfere with soil cultivation or other surface uses. The top of the pipe must be sealed with a cement plug and screw cap or cement plug and steel plate welded to the pipe. An alternate method is to put a permanent monument in place. This consists of a steel pipe at least 4 inches in diameter and at least 10 feet in length. Four feet of this pipe must be above the general ground level, and the remainder of the pipe is to be embedded in cement or welded to the casing.[248]

Wells may be temporarily abandoned for up to six months as long as the hole is cased or left in a condition to prevent migration of oil, gas, water, or other substances from the formation horizon where it originally occurred. Temporarily abandoned wells must be closed to the atmosphere with a swedge and valve or a packer or other approved method. The well sign must remain in place.[249]

To reclaim a site, the operator must ensure all pits, mouse and rat holes, and cellars must be backfilled. All debris must be removed within three months of plugging the well. All access roads must be closed, graded, and recontoured. Culverts associated with access roads must be removed. The operator must perform compaction alleviation, restoration, and re-vegetation of well sites, production facilities, and access roads. Reclamation activities must be completed within three months on cropland and 12 months on non-cropland after the well is sealed.[250]

10.22 Environmental Regulations Relevancy

Ultra Resources and any other companies that choose to explore for oil and natural gas in El Paso County will need to abide by the comprehensive regulations set forth at the state level by the COGCC. It is evident from the information presented that the Colorado level of regulation covers a comprehensive number of areas that do not need duplication from the Federal level. Federal regulations noted above such as the Clean Air Act, sections of the Safe Drinking Water Act, and the Clean Water Act beneficially serve an additional layer of protective regulation to the constituents of areas where oil exploration and production is occurring. The regulatory discussion is relevant to understand the legal environment within which companies must operate and to inform the public of the legal framework that currently exists. As the oil and gas industry continues innovating its technology, it can be expected that the regulatory environment will respond accordingly.

[247] (Drilling, Development, Producing, and Abandonment 2012)
[248] (Drilling, Development, Producing, and Abandonment 2012)
[249] (Drilling, Development, Producing, and Abandonment 2012)
[250] (Reclamation Regulations 2009)

11 Relevant Case Studies

The utility of a case study where environmental impacts appear to have occurred due to hydraulic fracturing is an excellent source of lessons learned and determining what environmental risks exist. It is desirable to separate subjective examples of hydraulic fracturing's harmful effects (such as those found on websites) from objective ones that are conducted in a scientific manner. Finally, it should be noted that there are hundreds of locales throughout the country where hydraulic fracturing is used and no harmful effects are reported or noted. Nonetheless, understanding the environmental impacts of "what has happened" is a source of education and a motivator to ensure that risks are properly managed. This report evaluates two case studies deemed relevant to the extraction operations planned for El Paso County; Pavillion, Wyoming, and Garfield County, Colorado.

11.1 Pavillion, Wyoming Case Study

The Pavillion, Wyoming Case Study is an EPA-led scientific investigation of ground water near Pavillion, Wyoming, attributed to the hydraulic fracturing of gas wells. In 2008, the EPA was asked by residents of the community to investigate their drinking water after they had noticed a change in taste and smell. The EPA's intent during the investigation was to determine if ground water had been contaminated and whether or not the EPA could differentiate between shallow sources of contamination versus deep sources of contamination. The EPA concluded the ground water had been contaminated from both surface storage pits as well as hydraulic fractured gas wells. It should be noted that baseline readings of ground water did not exist prior to the study, which creates some debate as to the validity of the claims based upon this lack of a baseline.

The following sections are entirely extracted (except where specifically noted) from two EPA documents: The Pavillion, Wyoming Groundwater Investigation Fact Sheet[251] published August 2010 and the Draft Investigation of Ground Water Contamination near Pavillion, Wyoming, published by the EPA in December 2011[252].

11.1.1 Site Background

"In early 2008, the U.S. Environmental Protection Agency (EPA) received complaints from several domestic well owners near the town of Pavillion, Wyoming, regarding sustained objectionable taste and odor problems in well water following hydraulic fracturing at nearby gas production wells. In response to these complaints, the EPA initiated

[251] (EPA, The Pavillion, Wyoming Groundwater Investigation Fact Sheet)
[252] (EPA, Draft Investigation of Ground Water Contamination near Pavillion)

a comprehensive ground water investigation in September 2008 under authority of the Comprehensive Environmental Response, Compensation, and Liability Act." Figure 46 highlights the area of interest.

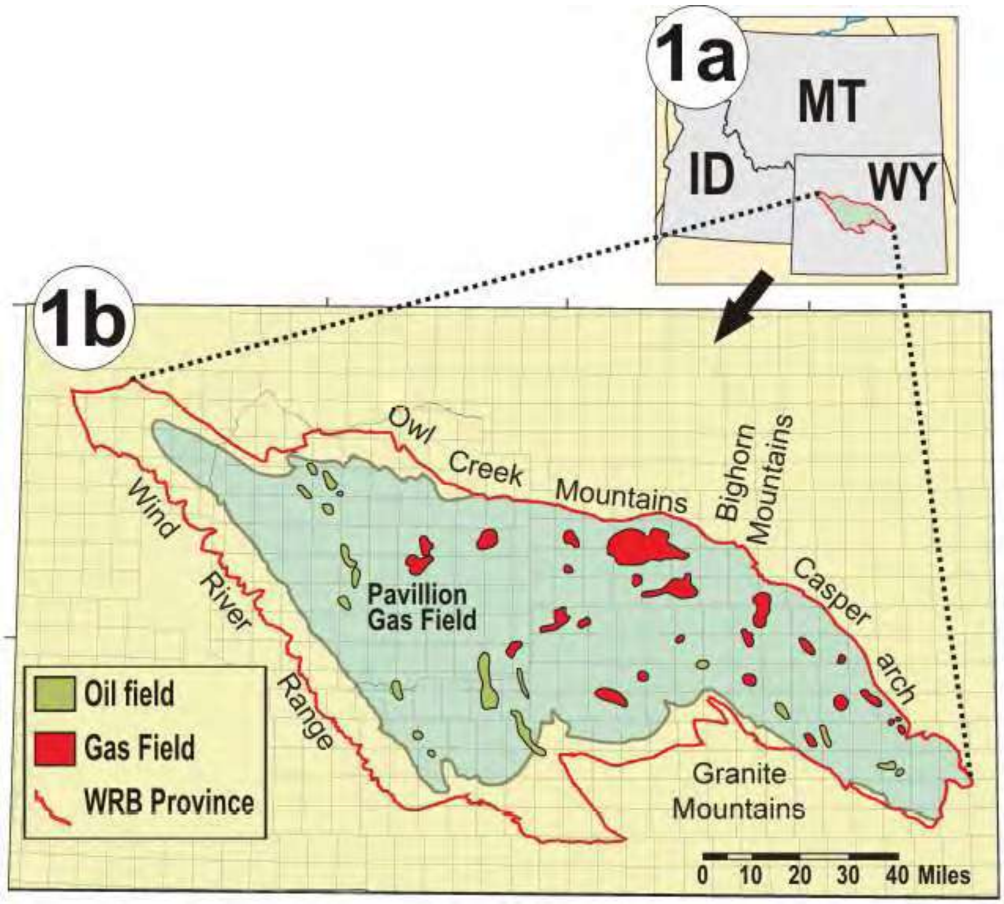

Figure 46. Pavillion Wyoming Area of Study

In this area of Wyoming, 169 vertical gas production wells have been drilled to extract natural gas from the Lower Wind River formation and the Fort Union formation. This area is largely rural with a very low population density. Pavillion has a population of 172 people. The primary gas well operator in this area is EnCana Corporation. Gas and oil extraction operations in this area employ approximately 11 percent of the population. In all cases, residents in the Pavillion, Wyoming area rely on ground water for their source of drinking water.

Figure 47 shows the underlying geologic makeup of the formations that lie under this area of Wyoming. Though a scale is not present in the figure, it is apparent that the Wind River formation is near ground surface with the Fort Union formation slightly deeper. In fact, during the study the EPA found that hydraulic fracturing in some gas wells occurred at very shallow depths; the shallowest stimulation operation occurred at 372 meters, equal to 1,220 feet.

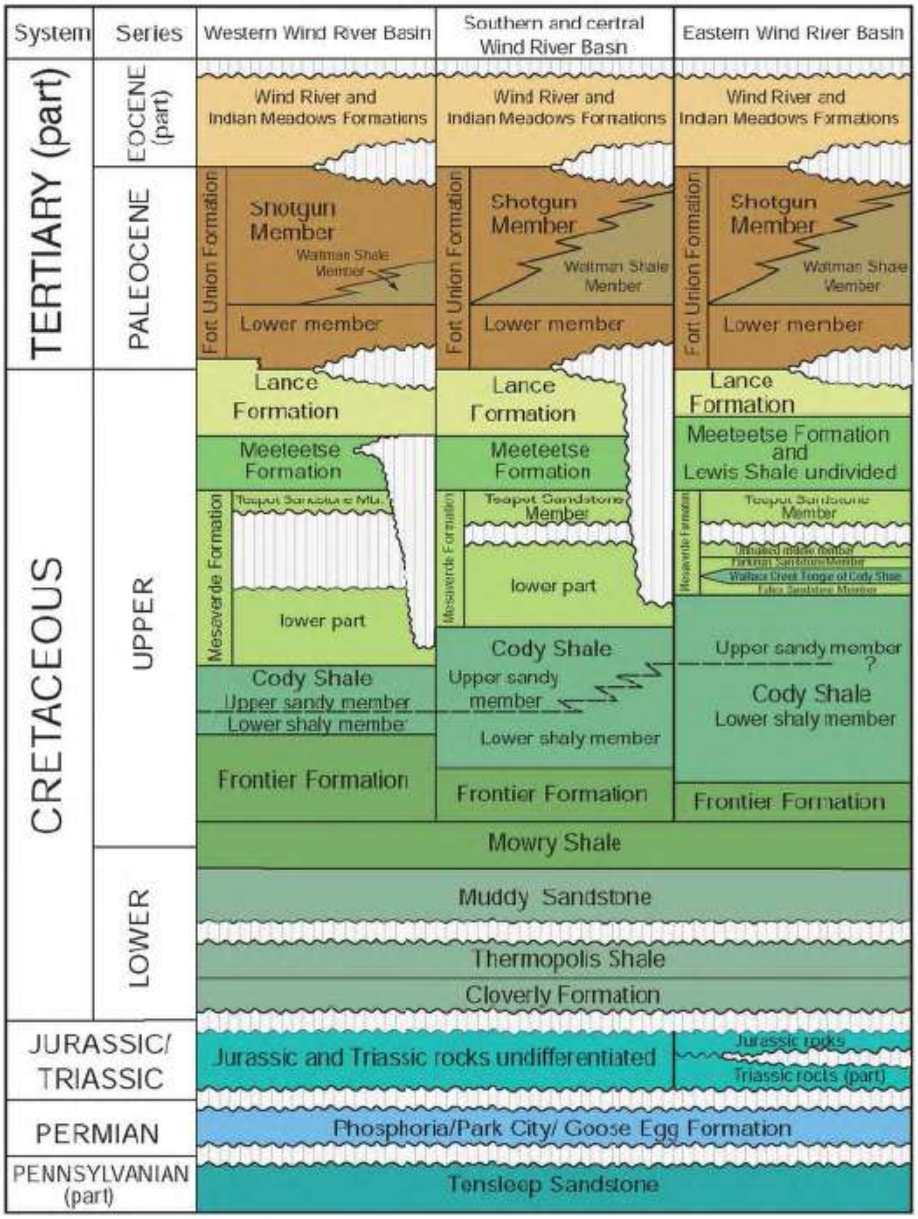

Figure 47. Strata of Wind River Basin in Area of Study

11.1.2 Ground Water Sampling

The study evaluated ground water at many locations throughout the area over a sustained time period, four samplings in all from March 2009 to April 2011.

In March of 2009 (Phase I), the EPA sampled 35 domestic wells and two municipal wells in the town of Pavillion. These initial tests showed detections of methane and dissolved hydrocarbons that prompted further testing.

In January 2010 (Phase II), ground water samples were taken from 17 domestic wells, 4 stock wells, and 2 municipal wells. In addition, a filter sample from a reverse osmosis system, surface-water, and sediment samples along Five-Mile Creek, gas and produced water/condensate samples from five gas production wells, ground water samples from 3 shallow monitoring wells, and soil samples near the perimeter of three known pit locations were taken. The identified pit locations have been used by Encana Corporation (the operator) to store and dispose of residual fracking fluids. This sampling also indicated elevated levels of methane and diesel range organics (hydrocarbons). In particular, these samples were found in deep domestic wells. The EPA responded by installing 2 deep monitoring wells (MW01 and MW02) to differentiate deep well contamination from possible shallow well contaminations. Deep well contamination would likely be from the gas reservoir while shallow well contamination would likely be sourced from surface contamination (e.g., storage pits).

In September 2010 (Phase III), gas samples were collected from well casings from the two monitoring wells. In October 2010, ground water samples were collected from the monitoring wells in addition to two domestic wells.

In April 2010 (Phase IV), the two deep monitoring wells were resampled and tested for additional contaminants. In addition, eight previously sampled domestic wells and three previously sampled stock/irrigation wells were also resampled.

The EPA also used cement bond log/variable density log (CBL/VDL) from the Wyoming Oil and Gas Commission to evaluate production well casing integrities. CBL/VDLs provide an average volumetric assessment of the cement in the casing-to-formation annular space and are considered low-resolution tools. These logs were all done prior to hydraulic fracturing of the wells.

11.1.3 Contaminant Findings

The EPA study evaluated both the inorganic geochemistry properties (minerals, chlorides, sodium, etc.) and the organic geochemistry properties (hydrocarbons) of the sampled wells. The inorganic properties would be more attributable to man-made chemicals used in well stimulation fluids, while the organic properties would indicate the level of contamination from the gas field. From the report:

> The monitoring wells produce ground water near-saturated in methane at ambient pressure, with concentrations up to 19.0 mg/L. Gas exsolution was observed while sampling at both MW01 and MW02. A wide variety of organic chemicals was detected in the monitoring wells including: GRO, DRO, BTEX, trimethylbenzenes, phenols, naphthalenes, acetone, isopropanol, TBA, 2-butoxyethanol, 2-butanone, diethylene glycol, triethylene glycol, and tetraethylene glycol… Concentrations of benzene in MW02 exceed EPA's MCL in drinking by a factor of 49 times.

Figure 48 lists the concentrations of organic compounds found during the Phase III and Phase IV well samplings. Note that DRO equates to Diesel Range Organics and GRO equates to Gasoline Range Organics.

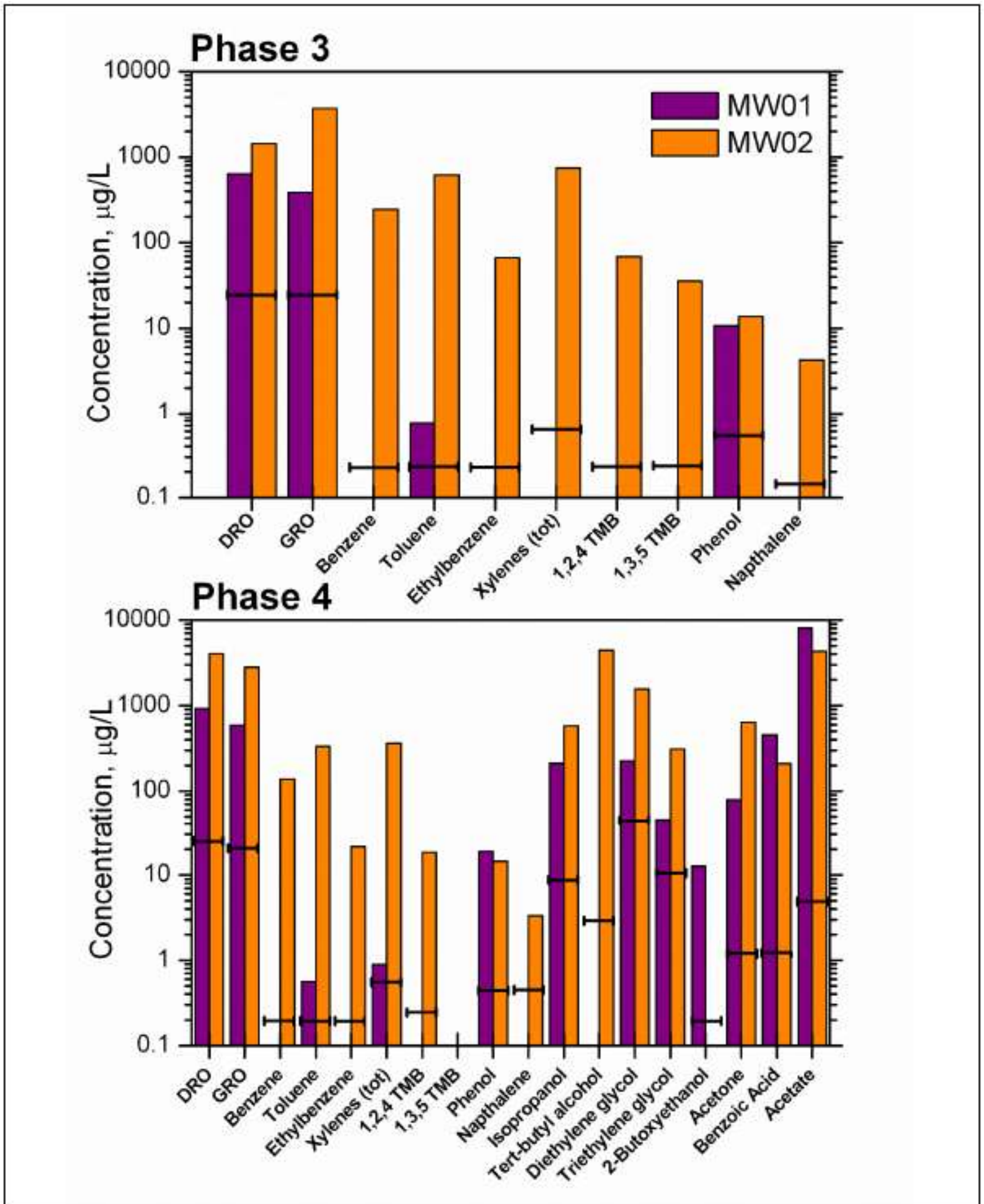

Figure 17. Organic compounds detected in deep monitoring wells MW01 and MW02 during Phase III and IV sampling events. Horizontal bars show method reporting limits for the individual analytes.

Figure 48. Contaminants Concentrations

To put these findings in perspective, Table 15 contains the maximum concentration limits (MCLs) for four of the identified organic compounds in the EPA standards on drinking water. These standards are from the EPA's website on maximum concentration levels for safe drinking water.[253] These four compounds are listed in Figure 48. Note that most of the

[253] (EPA, Safe Water Drinking Standards)

compounds listed in Figure 48 are not listed by the EPA when considering safe drinking water standards.

Table 15. Table of Organic Compounds and EPA MCL for Safe Drinking Water

Contaminant	MCL or TT1 (mg/L)2	Potential Health Effects from Long-Term Exposure Above the MCL (unless specified as short-term)
Benzene	0.005	Anemia; decrease in blood platelets; increased risk of cancer
Toluene	1.00	Nervous system, kidney, or liver problems
Ethylbenzene	0.70	Liver or kidneys problems
Xylenes (total)	10.00	Nervous system damage

Note that DROs and GROs do not have MCLs for safe drinking water. It is assumed that DROs and GROs are not normally present for a drinking water source; therefore, they are not specified by the EPA. Instead, a reference point was used from the Minnesota Department of Health's assessment of safe levels of DROs in drinking water with respect to a body of water called Quarry Lake:

> The Department of Health for the State of Minnesota has set a "Health Based Value" (HBV) of 200 ug/L (microgram per liter) for DROs. The 200 ug/L HBV is set as a guideline. The highest Quarry Lake DRO water measurement is 150 ug/L, below the HBV guideline. We've learned further, however, that the Minnesota Department of Health's HBV of 200 ug/L for DROs assumes daily consumption of two liters of drinking water containing DRO over a long period of time – from several years to a lifetime. Generally, higher exposures can be tolerated over the short-term. Only in an extremely unusual circumstance would recreational use of water result in even a one-time consumption of two liters in a single day.[254]

Whether or not 200 ug/L for DROs is considered safe, it is well below the 1000 – 3000 ug/L found within the MW1 and MW2 deep monitoring well sites as indicated in Figure 48.

In addition to the deep well samples, in Phase II the EPA evaluated shallow wells in the vicinity of storage/disposal pits. These pits are used for the storage and disposal of fracking fluids, produced water, and drilling wastes. The EPA found that "concentrations of DRO, gasoline range organics (GRO), and total purgeable hydrocarbons (TPH) detected in soil samples adjacent to three pits investigated in Phase II were as high as 5010, 1760, and 6600 mg/kg, respectively (EPA 2010)."

[254] (Quarry Lake Environmental Report)

In some of the samples, the organic compounds of benzene and xylene were found in concentrations up to 390 μg/L. In Table 15, the maximum concentration level allowed by the EPA in drinking water is 5 μg/L. From these samples near surface pits, the EPA concluded that surface pits were a contaminant of localized ground water.

The EPA also indicated that contaminants from the hydraulic fracturing process were found in the deep well samples. This conclusion was significantly more scientifically involved and was based on the combination of the following findings:

Abnormally high pH values in the deep monitoring wells – the presence of hydroxide alkalinity was due to a hydraulic fracturing additive. Potassium hydroxide was used as a cross-linker in well stimulation.

Elevated potassium and chloride levels – the results from the deep monitoring wells had concentrations over 10 times the mean value of domestic wells. Material Safety Data Sheets (MSDS) on hydraulic fracturing fluid consisted of 6 percent potassium chloride.

Detection of synthetic organic compounds – Isopropanol, Diethylene glycol, Triethylene glycol and tert-butyl are not naturally occurring compounds. These chemicals are used in well stimulation fluids.

Detection of petroleum hydrocarbons – Petroleum hydrocarbons found in the deep monitoring wells can be correlated to MSDS stimulation fluid sheets.

Breakdown products of organic compounds – Organic compounds that result from the breakdown of other well stimulation fluid compounds were found.

Sporadic bonding outside production casing directly above intervals of hydraulic fracturing – Cement casings designed to protect ground water were found to be incomplete.

Hydraulic fracturing into thin discontinuous sandstone units – the rock structure where fracturing took place tends to be permeable and could allow for vertical migration of stimulation fluids.

11.1.4 Probable Causes

There are two likely causes to the contaminations. First is the previously mentioned contamination near surface storage pits. These open storage pits present a hazard that, when constructed in a faulty manner such that they might leak or with excessive precipitation overflow, present a liability to spilling or leeching fracking chemicals into surface waters that will likely impact watersheds and ground water sources.

The second likely cause is the faulty manufacturing of the cement surface casings designed to protect ground water in combination with hydraulic fracturing. Casing is a layering of specially formulated cement into the bore hole to gradually seal the well bore from the water table. Continuous cement casings should prove adequate in protecting migration of both fracking fluids and hydrocarbons from entering into ground water. However, in the case of Pavillion, Wyoming, CBL/VDL inspections have indicated that the cementing process was not properly administered before hydraulic fracturing took place. This process failure led to incomplete or sporadic bonding of the cement in the well. Figure 49. Well Cross Sections shows twelve different wells and the findings from the CBL/VDLs. The figure also shows where hydraulic fracturing occurred in the wells.

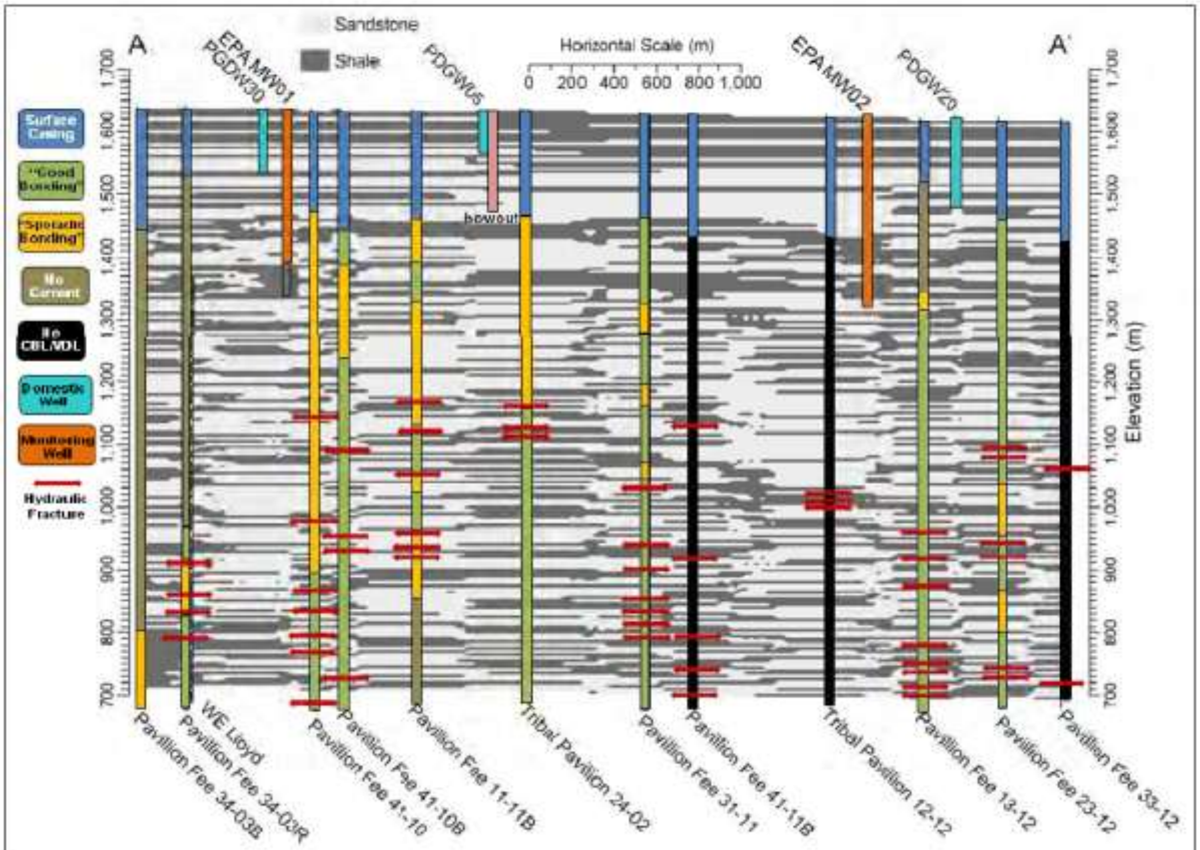

Figure 20. Lithologic cross-section along transect illustrating production wells (with evaluation of CBL/VDLs), domestic wells, and blowout location. Red arrows denote depths of hydraulic fracturing of unknown areal extent. Sandstone units are undifferentiated between fine, medium and coarse-grained units.

Figure 49. Well Cross Sections

Figure 49 indicates the depth where hydraulic fracturing occurred relative to the depth of the domestic water wells – a characteristic of the Wind River Formation and the relatively shallow gas field. The domestic well PDGW20 is roughly 1/3 the depth of the shallowest fracking in well Pavillion Fee 11-11B. Furthermore, with respect to Pavillion Fee 11-11B, it is clearly evident that cement casings were sporadic at the location of the fracking operations. The EPA noted three ways that hydrocarbons can migrate from deep reservoirs to ground water levels:

The first mechanism is aqueous and/or gas transport via boreholes due to insufficient or inadequate cement outside production casing. This is similar to a wicking effect where the hydrocarbons flow vertically through the voids in the wellbore.

The second mechanism is fracture fluid excursion from thin discontinuous tight sandstone units into sandstone units of greater permeability. This possible migration pathway is proportional to the permeable layers of rock above the reservoir.

The third mechanism is the process where the fracturing operation opens up new fractures above the target formation and increases the connectivity of the fracture system.

Of these three pathways, only the first is preventable by an operator. The second and third pathways are inherent risks in hydraulic fracturing operations.

11.1.5 Study Conclusions

The EPA main conclusion from this study effort:

> A line of reasoning approach utilized at this site best supports an explanation that inorganic and organic constituents associated with hydraulic fracturing have contaminated ground water at and below the depth used for domestic water supply… A lines of evidence approach also indicates that gas production activities have likely enhanced gas migration at and below depths used for domestic water supply and to domestic wells in the area of investigation. Hydraulic fracturing in the Pavillion gas field occurred into zones of producible gas located within an Underground Source of Drinking Water (USDW).

While the EPA noted that hydraulic fracturing was a likely cause for contamination of the ground water, there were two other observations that should be considered:

> Collection of baseline data prior to hydraulic fracturing is necessary to reduce investigative costs and to verify or refute impacts to ground water.
>
> Ground water contamination with constituents such as those found at Pavillion is typically infeasible or too expensive to remediate or restore (GAO 1989).

During the study, it appears the EPA strove for objectivity in its research and conclusions. In all cases, the EPA tried to look for all possible natural and non-natural sources of the contaminants in its findings to include natural gas migration pre-hydraulic fracturing. However, it appears that hydraulic fracturing in Pavillion, Wyoming led to an environmental impact on the ground water used by residents as their source of drinking water. The notable challenge to this conclusion is the lack of a baseline water sampling before hydraulic fracturing occurred.

11.2 Hydrogeologic Characterization Study in Garfield County, Colorado

Garfield County, Colorado, is located on the western slope of the Rocky Mountains. It is also located in the middle of a major Colorado oil and gas play, the Piceance Basin. Between the towns of Rifle and Silt, and roughly along the Interstate-70 corridor, and in relatively close proximity to the Colorado River, is Divide Creek. In late March 2004, a leaking natural gas well, operated by EnCana Corporation, the same company involved in the Pavillion, Wyoming, case study, suffered a cement failure following several days of fracturing, and released or “spilled” into Divide Creek. Concerned landowners and citizens notified EnCana of a bubbling in the creek. COGCC oversaw the initial response and initial water sampling. Initial sampling indicated presence of BTEX component benzene and methane traceable to the drilling source.

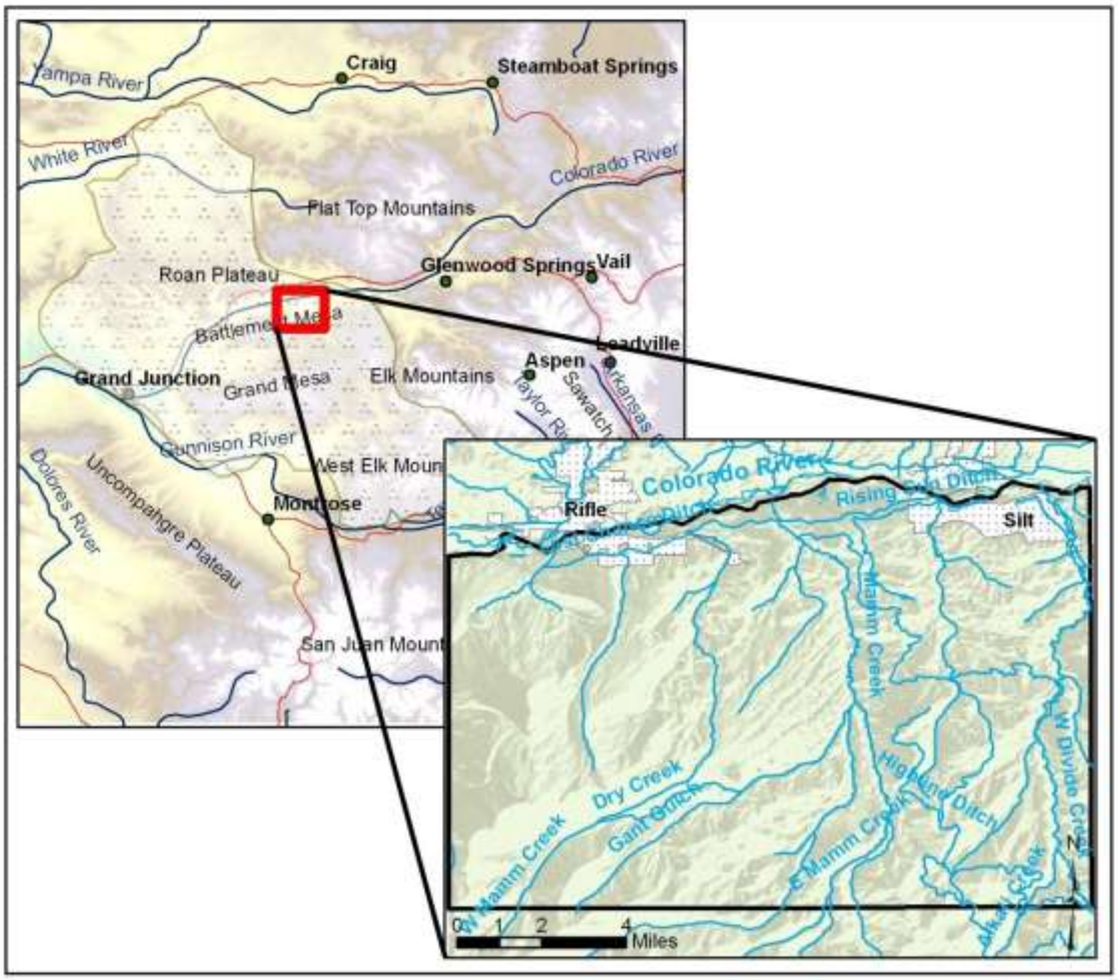

Figure 50. Garfield County Phase I and Phase II study site[255]

255 (Thyne 2008)

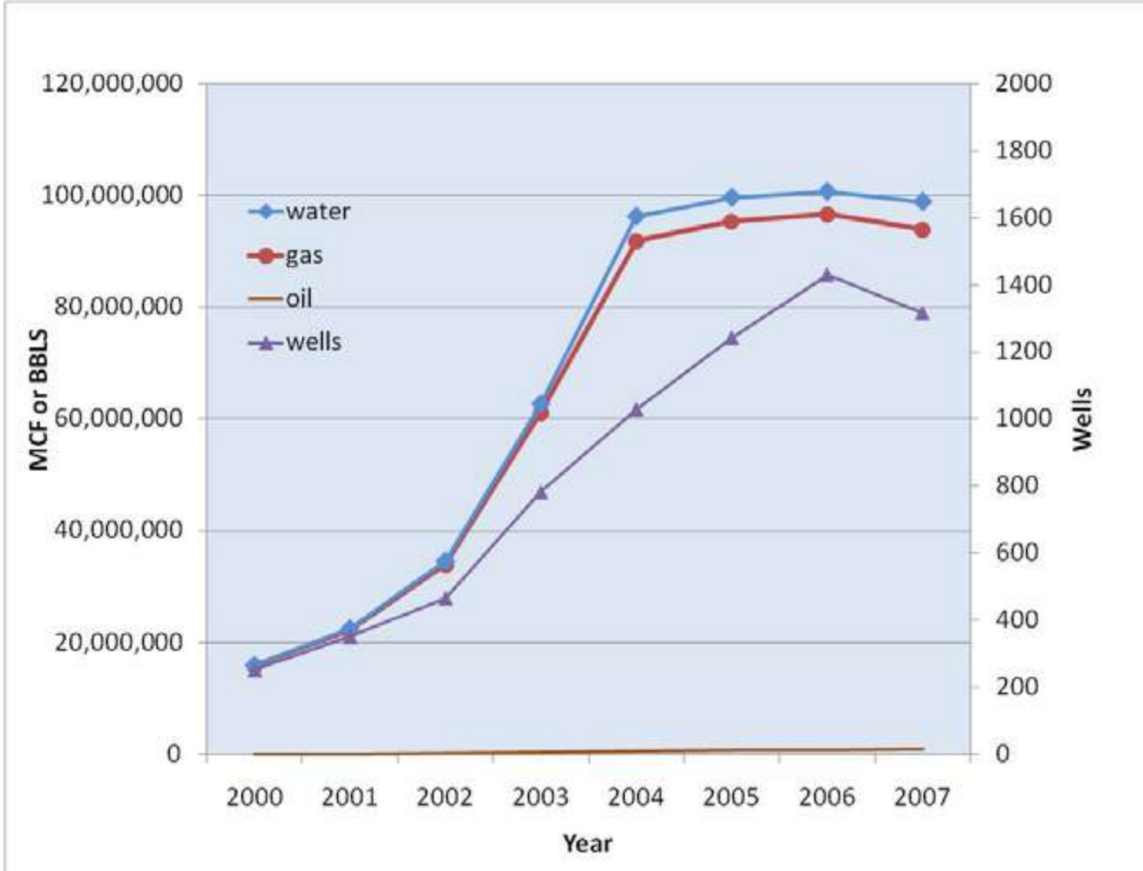

Figure 51. Proliferation of Natural Gas Wells[256]

In August of 2004, EnCana was fined by the state of Colorado the largest fine of its kind, to date, $371,200 (maximum fine of $1,000 per day per violation).[257] Garfield County utilized funding made available through the COGCC Environmental Response Fund (ERF) to sample, evaluate and document water quality from local wells in addition to sampling produced water from local drilling sites. This is referred to as "Phase I Hydrogeologic Characterization of the Mamm Creek Field".[258] The area of study was approximately 110 square miles. This study served as more of a fact-finding exercise than a scientific study from which to draw conclusions. It provided data that will serve as a baseline for future testing and comparison. In September of 2008, the findings of a follow-up study were made public. "Phase II Hydrogeologic Characterization of the Mamm Creek Field" focused on sampling the same wells and drilling sites as the Phase I study. The Phase II study had two tasks. First, water and gas was collected from domestic wells that had previously (Phase I) shown compound concentrations of concern. These samples provided methane stable isotope and sodium chloride (Na-Cl) concentrations. The second task was to examine produced water and natural gas samples from gas wells in the immediate vicinity of domestic wells whose water and gas chemistry sampling results suggested possible potential impacts from deeper

256 (Thyne 2008)
257 (Before the Colorado Oil and Gas Conservation Commission v. EnCana Oil & Gas Inc. 2006)
258 (URS Corp. 2006)

formations or other external sources, whether natural or due to natural gas drilling and/or production activities.[259]

Initial data collected from the first portion of the Phase II study was compared with data from the Phase I study. Sampled water sources that contained thermogenic methane or sodium chloride (NaCl) concentrations were flagged. This allowed a focusing of the sampling to drilling sites in proximity to these wells of concern. Drilling sites within one mile and up-gradient from the flagged well water samples were then targeted. Samples from these drilling locales would include produced water samples if the concern was sodium chloride (NaCl). Produced water and a production gas sample were collected if the well water concern included methane content.[260] Phase I data combined with Phase II data presented researchers with two sets of data that could serve the purposes of analysis and comparative interpretation.

The data were reviewed and presented to Garfield County with the following summary conclusions (quoted to preserve accuracy):

> 1 – The water quality data is sufficient to establish the range of natural background chemistry and delineate the impact of petroleum activities. Impacts from petroleum activity are not currently present at levels that exceed regulatory limits. The impacts are mainly elevated methane and chloride in groundwater wells.

Current regulatory levels for ground water are determined by the Colorado Basic Groundwater Standards (CBGWS), as specified by the Colorado Water Quality Control Commission regulation 5 CCR 1002-41 for domestic groundwater supplies.[261] This means that even though the data is deemed scientifically sufficient to determine inclusion of particulates consistent with petroleum activities, they are present at levels that do not constitute contamination based on State of Colorado standards. Phase I and Phase II data suggest increased levels of Nitrate (NO3), fluoride (F), and/or selenium (Se) that were higher than CBGWS; however, they are not thought to be linked to petroleum activities.[262]

> 2 - There is a temporal trend of increasing methane in groundwater samples over the last seven years that is coincident with the increased number of gas wells installed in the Mamm Creek Field. Pre-drilling values of methane in groundwater establish natural background was less than 1ppm, except in cases of biogenic methane that is confined to pond and stream bottoms. The cases of biogenic methane can be readily identified by stale isotopic characterization of the methane. The isotopic data for the methane samples show that most of the samples with elevated methane are thermogenic in origin.

[259] (S.S. Papadopulos & Associates 2008)
[260] (S.S. Papadopulos & Associates 2008)
[261] (URS Corp. 2006)
[262] (S.S. Papadopulos & Associates 2008)

Methane less < 1 mg/L was not significant. COGCC suggests retesting dissolved methane concentration findings in excess of 2 mg/L.[263] Methane can be found in two primary sources. Biogenic methane is naturally occurring. This form is due to the breakdown of material as in a landfill or a bog. It is present in water supplies and is referenced in this study as being in higher concentrations in stream and creek beds; or "swamp gas". Thermogenic methane is linked to petroleum sources. Another source of thermogenic methane results from anaerobic microbial sources. Isotopic values are used to differentiate the methane source.[264]

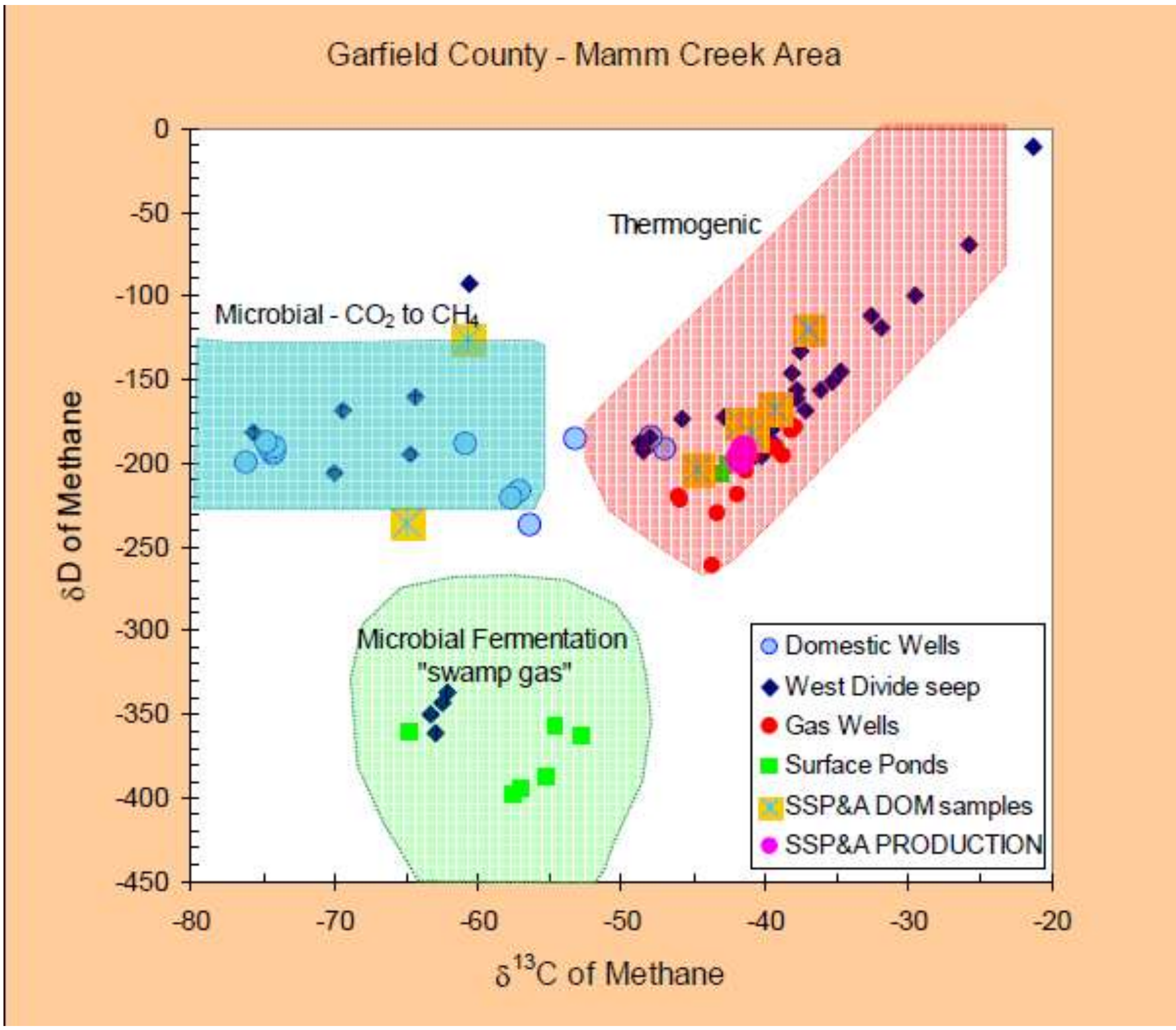

Figure 52. Thermogenic Methane of Hydrocarbon and Microbial Origin and Biogenic "Swamp Gas"[265]

263 (S.S. Papadopulos & Associates 2008)
264 (Thyne, Review of Phase II hydrogeologic Study 2008)
265 (Thyne, Summary of PI and PII Hydrogeologic Characterization Studies Mamm Creek Area, Garfield county 2008)

$\delta^{13}C$ is the ratio of carbon-13 to carbon-12 in a sample relative to the same ratio for an accepted standard material.[266] δD The ratio of hydrogen-2 to hydrogen-1 in a sample relative to the same ratio for an accepted standard material.[267]

3 - Concurrent with the increasing methane concentration, there has been an increase in groundwater wells with elevated chloride that can be correlated to the number of gas wells. Chloride is derived from produced water.

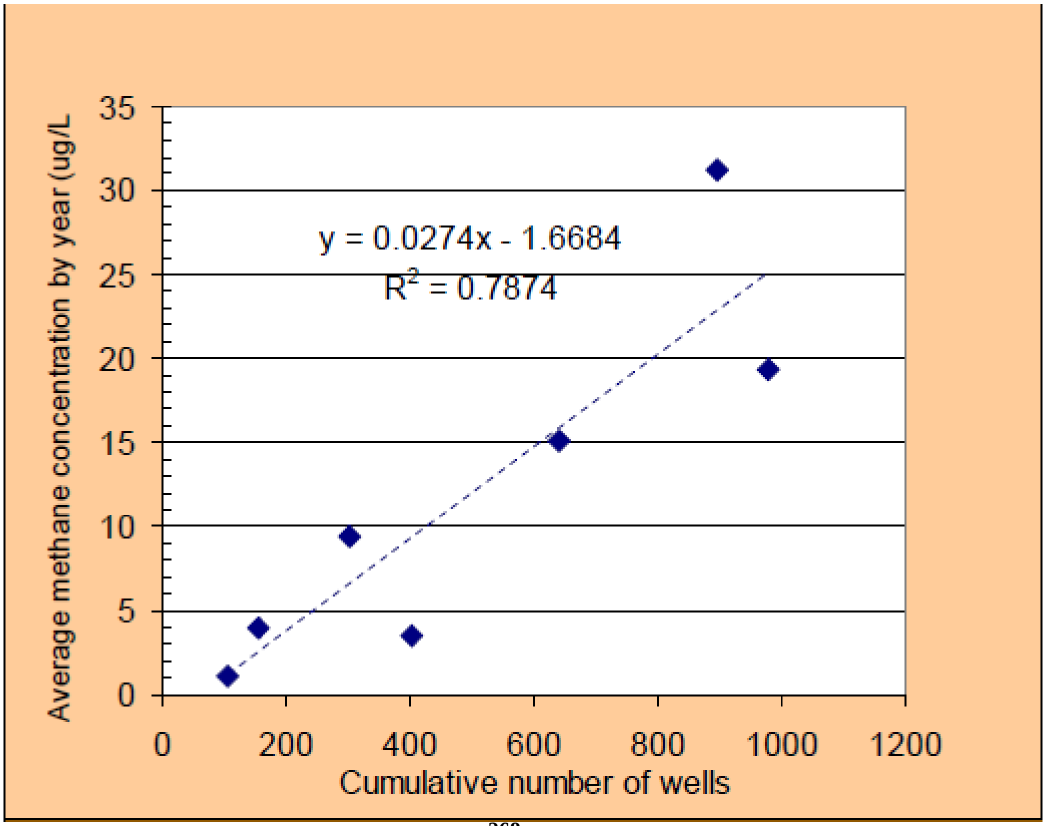

Figure 53. Methane concentrations.[268]

Chloride is present due to its association with sodium. Sodium chloride (NaCl) is found in saltwater, seawater, and brackish water. In general, the deeper the water source the greater the concentration of chloride. Produced water from deep in the well or from the fractured seams would be the source of the chloride content, according to this interpretation of the data. The presence of total dissolved solids (TDS) at a concentration of 1,500 milligrams/liter (mg/L) or greater, with sodium and chloride concentrations that could potentially indicate the mixing of NaCl water in the domestic water supply aquifer.[269]

266 (S.S. Papadopulos & Associates 2008)
267 (S.S. Papadopulos & Associates 2008)
268 (Thyne, Summary of PI and PII Hydrogeologic Characterization Studies Mamm Creek Area, Garfield county 2008)
269 (S.S. Papadopulos & Associates 2008)

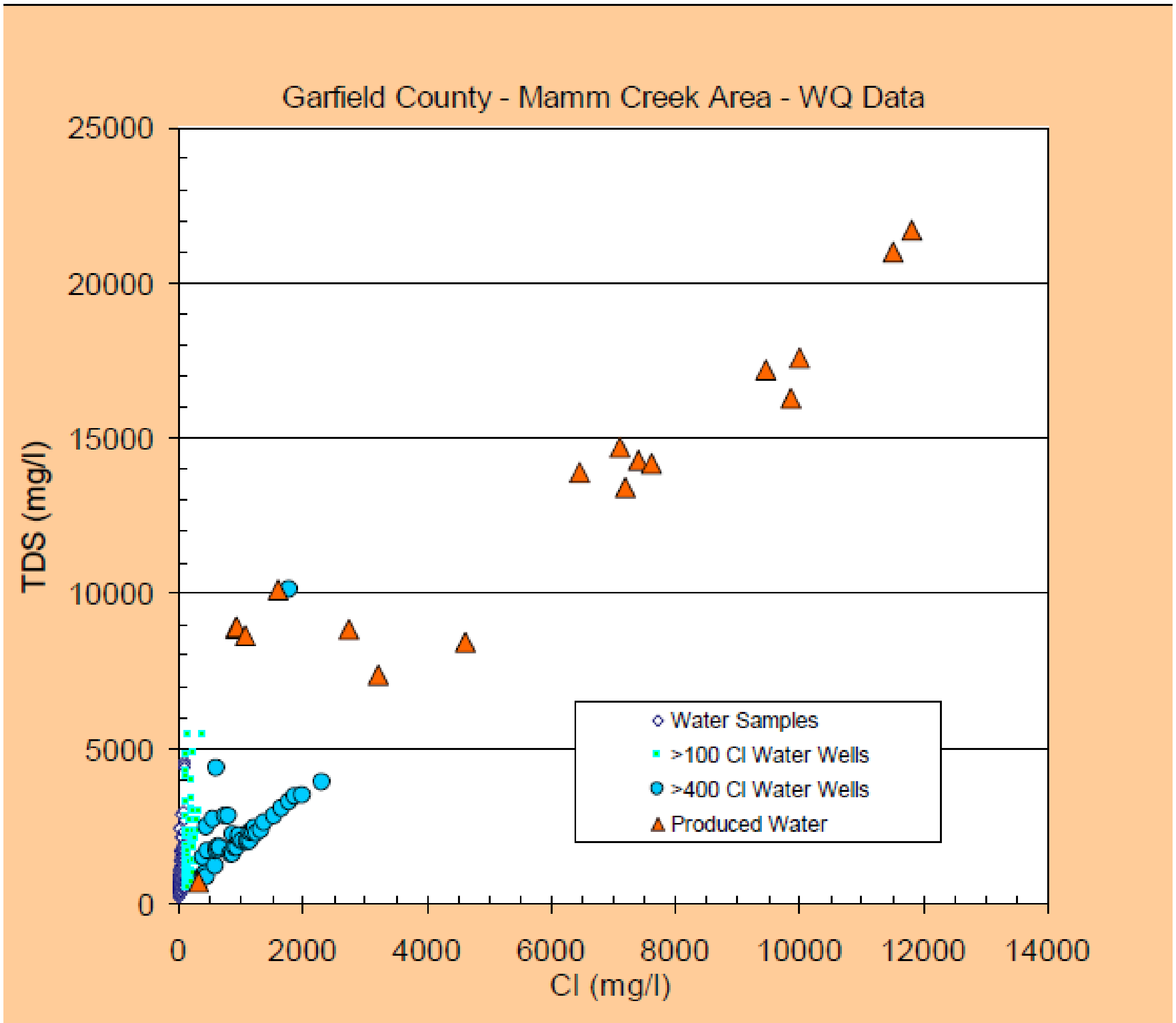

Figure 54. Higher Chloride (Cl) levels in Produced Water samples.[270]

4 - The increasing methane and chloride will not trigger regulatory action since there is no regulated limit on methane and the majority of chloride values are below regulatory limits, however, as more gas wells are drilled the chloride value may reach the regulatory limit.

Chloride levels have gradually increased in the study field. This is postulated to be due to poorer quality (higher chloride content) water sourced from a deep (Wasatch) groundwater source. The supporting theory is that the hundreds of well bores, now over 1,400, are allowing upward migration of this deep water source.[271]

5 - Currently the only monitoring mechanism to evaluate the impact of gas well drilling and gas production to groundwater quality is the existing domestic water wells and surface water bodies. The number of water wells

[270] (Thyne, Review of Phase II hydrogeologic Study 2008)
[271] (Thyne, Summary of PI and PII Hydrogeologic Characterization Studies Mamm Creek Area, Garfield county 2008)

> (<200) and their spatial distribution is inadequate to monitor and locate potential source of contamination from the more than 1400 potential point sources (gas wells and produced water pits). There are only a few cases where COGCC has been able to identify gas wells as point sources of the observed more widespread increase in impact (West Divide Creek seep and the Amos well).[272]

One suggestion was to establish and implement an ongoing comprehensive water monitoring program.[273]

These conclusions were not met without controversy. Consultants representing the oil and gas industry presented various explanations and objections. One objection was that the data were limited, untimely, and too wide in scope to come to any conclusions. Another argument against the conclusions was that there were likely other sources for the methane and chloride. For example, it has long been known that residential water from the Wasatch formation has contained gas (methane).[274]

11.3 EPA Study

In 2010, Congress mandated the EPA to study the potential effects of hydraulic fracturing on the nation’s drinking water supplies. This was in direct response to public concern over the potential effects of hydraulic fracturing. Congress made certain that this study would be transparent, be peer-reviewed, and utilize independent data. The study will include a review of published literature, analysis of existing data, scenario evaluation and modeling, laboratory studies, and case studies. Ultimately, the study is intended to provide data where there is a lack of adequate information and to contribute to resolving scientific uncertainties.[275]

The initial data is due to be released by the end of 2012. Final analysis and data are expected to be released in 2014.[276]

The EPA has, to date, requested chemical composition of fracking fluids from industry representatives. Also included in the study is review of well file data provided by well owners/operators. This study will focus only on drinking water, not on other ecosystem topics or potential impacts (air quality, occupational risks, etc.).[277]

In June of 2011, the EPA announced five retrospective and two prospective case study locations. One of those locations, Raton Basin, is located in Colorado. This location will be studied for potential methane gas contamination of drinking water supplies.[278]

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272 (Thyne, Review of Phase II hydrogeologic Study 2008)
273 (Thyne, Review of Phase II hydrogeologic Study 2008)
274 (Jaffe 2009)
275 (Anastas 2011)
276 (Anastas 2011)
277 (Case Study Locations for Hydraulic Fracturing Study 2011)
278 (Case Study Locations for Hydraulic Fracturing Study 2011)

The data are not currently available for review or consideration in our analysis of the El Paso County project, but a review of existing data and case studies can be considered. Additionally, the oversight of federal, state of Colorado, and local agencies can be highlighted.

11.4 Case Studies Conclusion

Drawing a specific conclusion on the impact hydraulic fracturing has on local ground water sources from the two presented case studies is difficult. In the Pavillion, Wyoming, study, the EPA found compelling indications that ground water had been contaminated due to gas extraction practices. However, baseline water readings did not exist. Without the baseline water readings, asserting the conclusive tie to the gas extraction operation was not possible. This lack of a baseline ultimately provided an opening for debate on the findings that continues today. In the Garfield County study, a critique was levied against the quality of the data presented and critics postulated that alternative naturally occurring phenomena could be the source of the contaminations. Furthermore, the level of contamination was not deemed a hazard to public health as the data indicated levels below regulatory requirements.

In conclusion, hydraulic fracturing has opened access to vast domestic reserves of oil and natural gas that could provide an important stepping stone to a more independent energy future. Questions about the safety of hydraulic fracturing persist, as seen in the Pavillion and Garfield case studies. Hydraulic fracturing, in general, is a viable technique to extract oil and natural gas when proper well construction, proper casing, proper cementing, frequent well integrity inspections, and closed containment systems are used by companies. Complying with these industry best-practices ensure the companies are protecting the environment and reducing the environmental risks associated with oil exploration. Finally, companies should expect, and the state should conduct, regular inspections to ensure companies are adhering to regulations.

It is clear that every position against oil and gas extraction from an environmental standpoint hasan equal and opposite position for oil and gas extraction that touts the economic and financial benefits that will be discussed in the remaining sections of this study. In many cases, empirically obtained information needs to be correlated and contrasted against factual, scientifically obtained data. The previous sections and studies presented give insight as to the complexity of the environmental issues associated with oil and gas extraction practices. To reduce the competing positions, specific and quantifiable information is needed to allow regulators, overseers, and local and state governments to determine what is acceptable and unacceptable in allowing these resources to be mined using hydraulic fracturing processes.

Environmental impacts are just one aspect to consider when deciding if oil exploration is a favorable opportunity for El Paso County. Another aspect is economic impacts. The next major section discusses the potential economic impacts associated with oil exploration.

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1 Economic Impact Executive Summary

If a significant quantity of oil is discovered in El Paso County, the expected economic impacts to the city of Colorado Springs and the county would be substantial. However, the impacts would be affected by the amount of oil exploration that would take place in the county, which is unknown at this time. Therefore, conservative estimates of low, medium, and high activity scenarios of horizontal drilling will be presented throughout this section to articulate the economic effect of varying levels of activity. The low activity scenario is five drilling rigs operating continuously until 500 wells have been drilled. In the medium activity scenario, 10 rigs will be in continuous operation until 1,500 wells have been drilled. Finally, the high activity scenario is 15 rigs drilling continuously until 3,000 wells have been drilled.

The highest employment levels would occur during the “boom.” This phase is expected to last for seven to fifteen years, depending upon the level of activity. The highest level of jobs expected within this phase will be during the last full year of drilling. This is when the highest level of drilling jobs is combined with the jobs required during the production phase. The low activity scenario could be expected to generate a peak of 2,813 total jobs. The medium activity scenario could generate a peak of 6,007 total jobs. Finally, the high activity scenario could be expected to generate a peak of 9,582 total jobs.

Oil wells can generally be expected to produce for 20-30 years, and new technology may lengthen this amount of time. When the drilling has been completed, and until the wells are no longer producing oil at a profitable rate, the expected production level jobs are much lower. During the “bust” phase, the low activity scenario would retain 366 total jobs. The medium activity scenario would hold on to a total of 1,099 jobs. In the high activity scenario, 2,199 total jobs would be expected to remain as a result of the producing wells.

The direct economic impact of oil explorations in El Paso County varies with the number of wells. Based on the low, medium, and high activity scenarios, the direct output would peak at $2.3 billion, $6.6 billion, and $12.8 billion, respectively. The direct output includes revenue generated from drilling and extraction activities. Sensitivity analysis with different numbers of wells drilled in a year shows a steeper ramp in output and a higher output when more rigs are used for drilling. The production would, however, deplete faster.

Indirect economic impact depends on the number of upstream supply chain establishments located in the region. With the lack of these establishments in El Paso County, the indirect economic multiplier is 0.046 compared to 0.146 and 0.292 for Colorado and U.S, respectively. This means for every dollar of revenue generated from direct output, 4.6 cents of indirect economic impact is also generated. In order to capture higher indirect economic impacts, the number of establishments that supply goods and services to the oil industry has to be increased. A few of the missing industries in the county include environmental consulting, hazardous waste treatment, transportation rental and leasing, chemical manufacturing and pipeline constructions.

Oil and natural gas production in Colorado, specifically in El Paso County, has tax implications on the Federal, State, County, and City levels. Each level has specific taxes and exemptions for oil and natural gas production. Oil and natural gas royalties would increase with production in Colorado. There are additional tax implications to consider in the State of Colorado and City of Colorado Springs, including Taxpayer's Bill of Rights (TABOR). The potential tax impact to El Paso County is most relevant in the Ad Valorem Tax and is up to $18 million. Additional tax revenue to state and local governments would come from property taxes, personal income tax, indirect business tax and sales/use taxes. Overall, Colorado stands to gain significant tax revenue

Additionally, a larger demand on apartment rentals is to be expected over home purchases. The current inventory of available homes and apartments is large enough to accommodate the employment for migrant oil workers with these levels of production.

2 Economic Impact Introduction

The economic impact analysis conducted for El Paso County consisted of researching published studies and data accumulation. The analysis applied published industry data figures to extrapolate likely industry trends in El Paso County, thereby putting the economic impact into context. The various economic impacts will be described as total impacts or separated into their direct, indirect, and induced components.

Direct impacts are measured as the employment, wages, and value added within the oil industry.

Indirect impacts are measured as the employment, wages, and value added within other industries that supply goods or provide services to the oil industry.

Induced impacts are measured as the employment, wages, and value added that result from household spending of income earned directly or indirectly from the oil industry.

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3 Employment Impact

The majority of oil and gas industry jobs are associated with the extraction phase. This includes drilling, completion, and recompletion. Of these three specialties, drilling is by far the most human-capital intensive. Therefore, drilling measured by rig counts served as a proxy for employment projections.[279]

The extraction phase can last a few months and includes site preparation, drilling, casing, cementing, and hydraulic fracturing. At this point, the well is considered "completed." The production phase initiates once the well is completed. The average life of an oil well is 20 to 30 years. Emerging technology may enable the industry to find new ways to extend the life of wells by as much as 10 to 20 additional years by re-fracturing a well multiple times.[280]

Projections of employment within the oil and gas industry are extremely difficult to make with precision. Due to data and resource constraints of this project, much of the analysis was done using secondary data from studies on employment impact within the oil and gas industry. Other studies used in this report addressed natural gas drilling as opposed to oil drilling. Allowing for these differences, independent research and discussion with industry experts indicate drilling operations in each scenario are virtually identical. Every effort was made to select the best proxy data for each portion of the analysis. At various points throughout the analysis, assumptions were made to derive employment projections.

3.1 Overview of Oil and Gas Employment

As mentioned earlier, the majority of employment in the life-cycle of the oil and gas extraction process is associated with drilling. This labor-intensive activity is referred to as the "boom" in the life-cycle of extraction. The "bust" is the production phase of the oil wells. It is referred to as the "bust" due to the limited labor demands of a producing well. Approximately 1.5 percent[281] of the required employment for the extraction phase is required for the production phase. Many employment impact studies use hours as the unit of measure for the extraction phase. This is due to the inconsistency of hours demanded per occupation. In other words, a few occupations are extremely labor-intensive per well – the vast majority of their workday is attributable to one well, while other occupations may spend a fraction of their workday at one well. On average, each hydraulically fractured well requires the services

[279] (Haggerty 2012)
[280] (Encana Corporation 2011)
[281] .19 FTE are required in production phase and 12.9 FTE are required in pre-drilling and drilling phase. (.19/12.9=.0147) (Marcellus Shale Education & Training Center 2011)

of over 420 people from 150 different occupations.[282] Presenting employment demands by number of people or occupations associated with one well would misrepresent the data (paint a rosy picture). Therefore, this report utilizes Full-Time Equivalents (FTEs) per well as the unit of measure. One FTE is essentially the number of hours an average U.S. employee works annually. This is computed by calculating 40 hours per week for 52 weeks per year. This figure equates to 2,080 hours per year.

Extracting oil via horizontal directional drilling and hydraulic fracturing is more scientific and technical than traditional vertical oil drilling. This workforce consists of low skilled workers such as traditional roustabouts (oil rig workers) and many highly trained and educated workers such as engineers and geologists.

3.2 Occupational Categories in the Horizontal Drilling Workforce

The majority of the workforce will be low-skilled to semi-skilled workers. This segment makes up approximately 70-80 percent of the total workforce required. Most of these workers require no formal post-secondary education. Few require specialized licenses or industry certifications. Among these are the jobs that require a commercial driver's license (CDL), X-ray, or welding skills. Despite the lack of formal education needed in these jobs, they almost all require extensive experience in the oil industry that is usually obtained through on-the-job training.[283]

The remaining 20-30 percent of the workforce is white-collar in nature and consists of jobs such as supervisors, project managers, lawyers, engineers and geologists. The chart below shows the typical breakdown by occupation of the horizontal drilling workforce.[284]

[282] (Marcellus Shale Education & Training Center 2011)
[283] (Marcellus Shale Education & Training Center 2011)
[284] (Marcellus Shale Education & Training Center 2011)

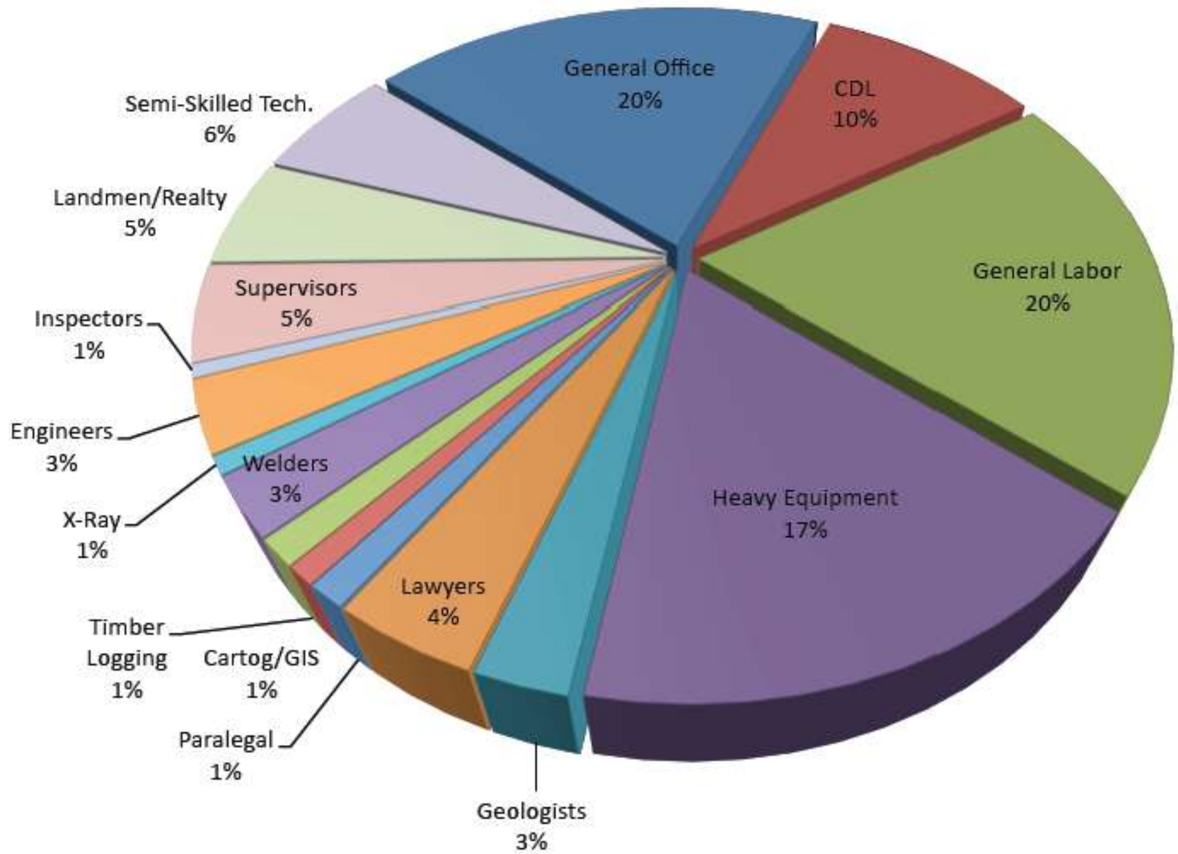

Figure 55. Horizontal Drilling Workforce Breakdown[285]

3.3 Education and Training Requirements

The majority of the initial workforce will be transient workers who travel around the country from drilling site to drilling site. In a mature industry, opportunities will exist for local colleges and universities to offer oil-industry related training and degrees to train the skills needed to work in the industry. El Paso County has a robust network of post-secondary institutions providing an opportunity to leverage this network to train not just the future oil-industry workforce in El Paso County, but also drill site workers elsewhere in the state of Colorado and the rest of the country where hydraulic fracturing is being used.

Colleges in El Paso County currently offer degrees and certifications in fields like geology, computer science, welding, real estate, accounting, and general business. These satisfy the needs of many professions in the industry. However, these jobs make up a small amount of the total workforce. The growth opportunity for local schools will be the development of vocational or one to two-year programs that will provide the industry-specific technical knowledge and skills needed.

[285] (Marcellus Shale Education & Training Center 2011)

The Marcellus Shale Education & Training Center (MSETC) conducted a survey of industry employers in Pennsylvania and asked what education or training programs are most needed. Figure 56 shows that employers were in primary need of workers with technical college, vocational degrees, and trade and industry certifications. Forty percent of respondents indicated that trade and industry certifications were most needed. Twenty-seven percent of respondents indicated a primary need for workers with one- to two-year technical college or vocational degrees, while 9 percent said they that needed workers with four-year college degrees.[286]

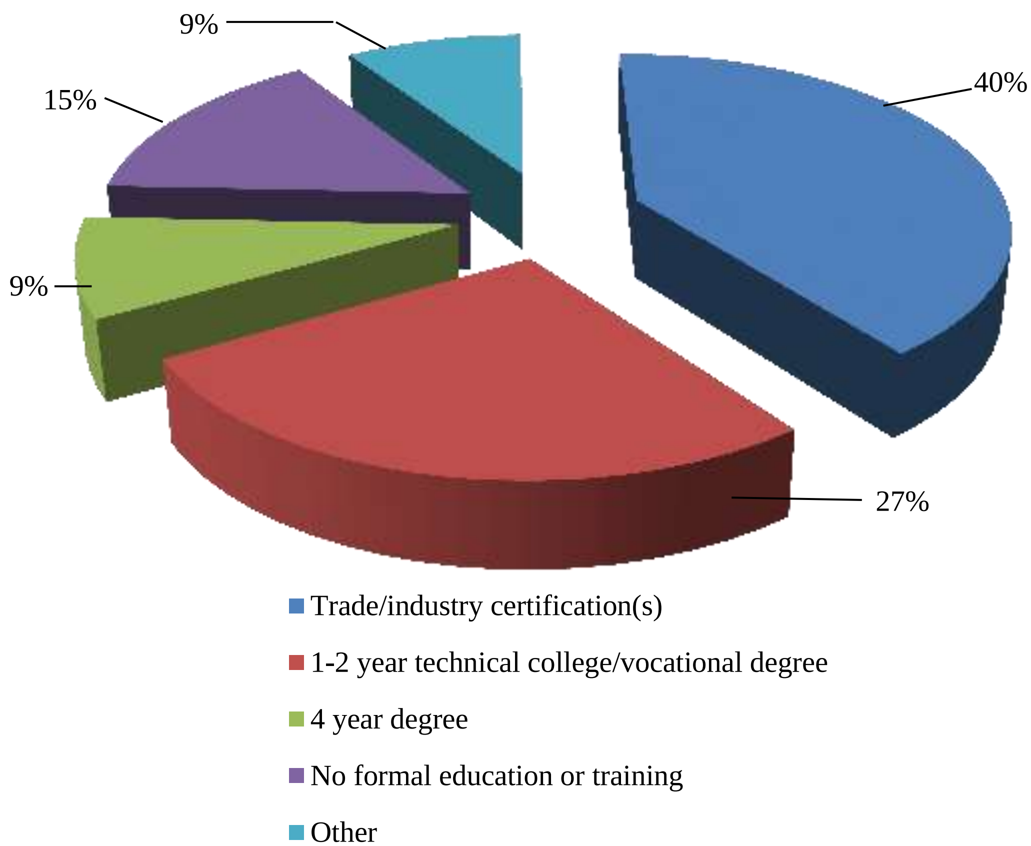

Figure 56. Education and Training Programs Most Needed [287]

When MSETC asked industry employers what their biggest challenges were in finding new workers, 43.3 percent of respondents said that the greatest challenge was finding workers with the technical skills needed. Finding qualified workers was the largest challenge for 15.4 percent of the firms. This is summarized in Table 16.

[286] (Marcellus Shale Education & Training Center 2011)
[287] (Marcellus Shale Education & Training Center 2011)

Table 16. MSETC Survey Results[288]

MSETC Survey Results: What are Biggest Challenges to Finding New Workers? (check all that apply)	
Hard to find workers with the experience needed	76.90%
Hard to find workers with the basic skills or background needed	65.40%
Hard to find workers willing to do the work and/or work the hours needed	53.80%
Hard to find workers with the technical skills needed	42.30%
Hard to find workers with the proper degree or certifications needed	15.40%
Hard to find workers with the proper interpersonal skills needed	15.40%
Other	3.80%

The number of oil-focused rigs in the United States hit a new 25-year high of 1,318 for the week ending March 30, 2012. This was 50 percent more than the same week in 2011.[289] As this industry grows, more specialized workers will be needed to meet industry demand. El Paso County is in a position to meet these educational needs. Whether or not oil exploration proves successful in the county, investing in oil and gas industry education could be a strategic move for local colleges and universities.

3.4 Wages within the Oil Industry Workforce

Information from the Bureau of Labor Statistics for Colorado was used to determine the wages of the oil industry workforce in Colorado. A weighted average annual income was calculated using this information to provide an estimate of the average wages of the various major occupational categories. This weighted average yearly income is $86,177 for the occupations listed.

Table 17. Oil Industry Wages

Occupation - Colorado	Employment	Percent of Total	Average Earnings	Contribution
Geoscientists	6390	15%	$ 132,210	$ 19,284
Petroleum Engineers	13270	30%	$ 138,130	$ 41,839
Pump Operators, Refinery Operators, Gaugers	6450	15%	$ 59,770	$ 8,800
Roustabouts	9680	22%	$ 37,160	$ 8,211
Wellhead Pumpers	8020	18%	$ 43,940	$ 8,044
Total	43810	100%		
Weighted Average Annual Income →				$ 86,177

[288] (Marcellus Shale Education & Training Center 2011)
[289] (Silha 2012)

3.5 Direct Employment Projection Methodology

The Marcellus shale is a large formation on the east coast of the United States. The Marcellus Shale Workforce Needs Assessment was selected as the primary source of data for direct employment projections. This report focuses specifically on Pennsylvania's workforce needs arising from natural gas drilling in the state.

The limitation of using this assessment is that there are minor expected variations between the workforce demands of drilling for gas in Pennsylvania and drilling for oil in Colorado. The main advantage of using this assessment is that there are strong similarities between the proposed drilling in El Paso County and the operation in Pennsylvania. For example, the depths of the wells in both locations are similar and both utilize the hydraulic fracturing process. An overwhelming majority of the direct employment demands stem from the pre-drilling and drilling phases of each operation, and these phases are nearly identical. Due to the similarities regarding direct employment demand, it was determined that the limitations of the Marcellus Shale Workforce Needs Assessment are negligible and the advantages more than compensated for the limitations.

Another advantage of using this report is the vast amount of data and detail presented. The study breaks down the labor needs by hours, total workers, and various phases of drilling each well. It also breaks down the relative needs and individual education and training requirements of each profession.

From 2009 to the summer of 2010, the Marcellus Shale Education & Training Center (MSETC) worked with major regional sources of employment within the industry. This includes energy companies, drilling companies, and other service providers. During the initial assessment, MSETC was able identify nearly 150 occupational categories and/or skill groups required for each well. After this, in-depth interviews were conducted with the same companies. Finally, the interviews were followed-up with an online workforce needs assessment.[290]

Conducting this research allowed MSETC to determine the number and types of workers needed for each well. Also, MSETC was able to determine how long, on average, each category of employee worked on a single well. As mentioned, MSETC utilized a full time equivalent (FTE) unit of measure. The study cites that most occupational categories require 1/10 to 1/100 of a FTE per well, while the labor-intensive categories (heavy equipment operators, office staff, and drilling rig operators) require as many as 2 FTEs per well. The report presented a total of 12.9 FTEs required per well for the pre-drilling and drilling phases. Finally, the production phase requires 0.19 FTEs per well.[291]

The FTEs in the pre-drilling and drilling phases are not cumulative on an annual basis. These workers are only needed while wells are being drilled. The total FTEs are a product of the wells drilled and the number of rigs operating. For example, if 20 wells are drilled each year for 20 years, 258 (12.9 * 20) total workers will be needed for the 20-year

[290] (Marcellus Shale Education & Training Center 2011)
[291] (Marcellus Shale Education & Training Center 2011)

operation. In contrast, the production-phase FTEs are cumulative. Given the same scenario, FTEs attributable to the production phase would increase by roughly 3.8 (0.19 * 20) FTEs annually. The growth in production FTEs cease upon completion of the drilling phase. In other words, there is no demand for additional production FTEs unless new wells are developed. Employment from pre-drilling and drilling terminates upon completion of the drilling phase. Production employment remains static until the wells stop producing.

Overall, the study found that 13.09 FTEs are required for each independent well; 12.9 FTEs are required during the pre-drilling and drilling phase, and 0.19 FTEs are required for the production phase. A significant part of the pre-drilling and drilling phase is construction of the well pad. In recent years, the advent of directional and horizontal drilling has facilitated operators the ability to drill multiple wells per well pad. As such, the total FTEs required for the pre-drilling and drilling phase of a well drilled on an existing pad drops to 9.46 FTEs. Production FTEs remain constant at 0.19.

Research was unable to determine the current industry average for wells drilled on a single well pad. Drilling company Devon Energy Corporation reported drilling 36 wells on a single pad in north Texas.[292] Many of the multi-well pad permits submitted by Ultra Resources indicates 8 wells per well pad. For this reason, 8 wells per pad have been used as the model for employment projections. Using the following formula ((12.9 + (9.46 * 7))/ 8), the per well composite FTE equates to 9.89 FTEs.

3.6 Direct Employment Impact

Oil discovery, and ultimately, production, is far from assured. The models presented are based on the assumption that oil exists in portions of El Paso County in similar quantities as it does in Weld County, CO. This assumption was incorporated to present the potential employment impacts on El Paso County. Information released by Ultra Petroleum's Director of Exploration states that preliminary tests indicate El Paso County is every bit as prospective as the area in Weld County, CO.[293]

Weld County, CO was used as the primary reference for potential drilling activity. The county currently has about 18,000 wells. Using wells per acre as a metric, Weld County has one well for every 142.98 acres. Using this figure to project the potential number of wells in El Paso County equates to 9,532 wells. However, Weld County is more rural than El Paso County. It has about half the population and twice the area. Also, many of the wells in Weld County are not horizontal and do not have the spacing requirements of a horizontal well. For these reasons, it was determined one well per 142.98 acres is unrealistic for El Paso County.

Information from interviews with oil rig operators and from Ultra Petroleum indicates that its expects 160-320 acre spacing per horizontally drilled well in El Paso County. 3,000 wells would equal about 35 percent of El Paso County drilled at a density of one well per 160 acres. While El Paso County could potentially support more drilling, this figure has been

[292] (Devon Energy Corporation 2008)
[293] (Thompson Reuters 2011)

selected as a conservative upper limit of projected wells. Using 3,000 wells as the high activity scenario led to selecting 1,500 wells as the medium activity scenario. 500 wells were then selected as the low activity scenario.

Today, El Paso County has one operator applying for drilling permits – Ultra Resources, a wholly owned subsidiary of Ultra Petroleum. Ultra Petroleum purchased 18,000 acres of the Banning Lewis Ranch within the Colorado Springs city limits. The company also holds leases on 116,000 additional acres in unincorporated El Paso County.[294] If Ultra Petroleum's holdings in El Paso County prove successful, it is logical to assume there will be an influx of other operators. This wide range of possibilities further justifies analysis based on three different activity levels.

Direct employment will be presented as a function of operating drilling rigs and total wells. This will provide the peak level of employment for any given scenario as well as the duration of the "boom" phase in El Paso County. The following graphs represent end-of-year FTEs based on the following assumptions and limitations:

1. A composite of 9.89 FTEs per well was used in all models (one 12.9 FTE well for every seven 9.46 FTE wells).
2. 0.19 FTEs (cumulative) required per well for production phase
3. Each drilling rig drills 13 wells per year.
4. Wells are continuously drilled using the same number of rigs until all wells have been drilled.
5. Graph does not account for technological improvements that increase rig efficiency.
6. Graph does not display diminishing production phase workforce due to dry wells after 20-30 years.

Equation 4.

Direct Employment = (# of Rigs*13*((12.9 + (9.46 * 7))/ 8)) + (Total Wells Drilled*.19)

As Figure 57 illustrates, direct jobs and the duration of the "boom" are dependent upon the number of drilling rigs operating per year. If 15 rigs operate in El Paso County, drilling 3,000 wells, 1,966 jobs are projected to be attributable to direct oil employment by the end of the first year. Direct employment steadily increases to 2,484 jobs in year 15, where it drops drastically, leaving 570 jobs related to production. As mentioned, the graph does not display the steady decline in the production phase workforce. Depending on the useful life of each well, this decline will vary. For instance, the production phase workforce will diminish at a more rapid rate if the useful life of each well is 20 years. In contrast, the production phase workforce will diminish at a slower rate if the useful life of each well is 40 years.

[294] (Whitley 2012)

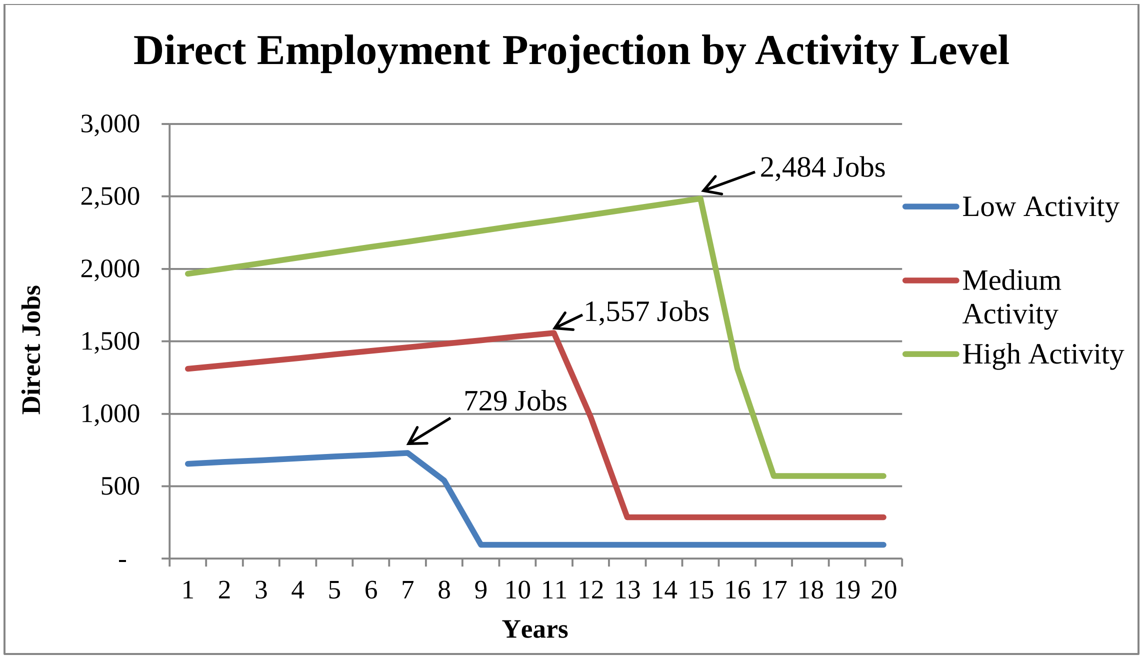

Figure 57. Direct Employment Projection by Activity Level

If 10 rigs were operating until 1,500 wells were drilled, 1,310 direct jobs would be expected to be created by the end of the first year. This would increase to 1,557 jobs by the end of the "boom" at the end of year 11. During the bust phase, 285 production jobs would be expected to remain.

If 5 rigs were operating and drilled until 500 wells had been completed, the initial direct employment number would be 655. This figure climbs to 729 at the end of year seven. Only 95 production-level jobs are expected in this scenario. Even though total wells decreased by about 66 percent, half the rigs of the previous scenario, this results in an initial employment number that is half the size. Given the same number of total wells, this would result in the "boom" phase lasting twice as long.

3.7 Direct Jobs Related to the 18,000 acres of The Banning Lewis Ranch

Figure 58 represents the direct and indirect employment impact of the prospective drilling on the 18,000 acres of the Banning Lewis Ranch acquired by Ultra Resources. Once again, employment is a product of the number of rigs operating at the same time. Development of 112 wells assumes that each well is spaced evenly at 160 acres. This estimate illustrates a best-case employment impact scenario.

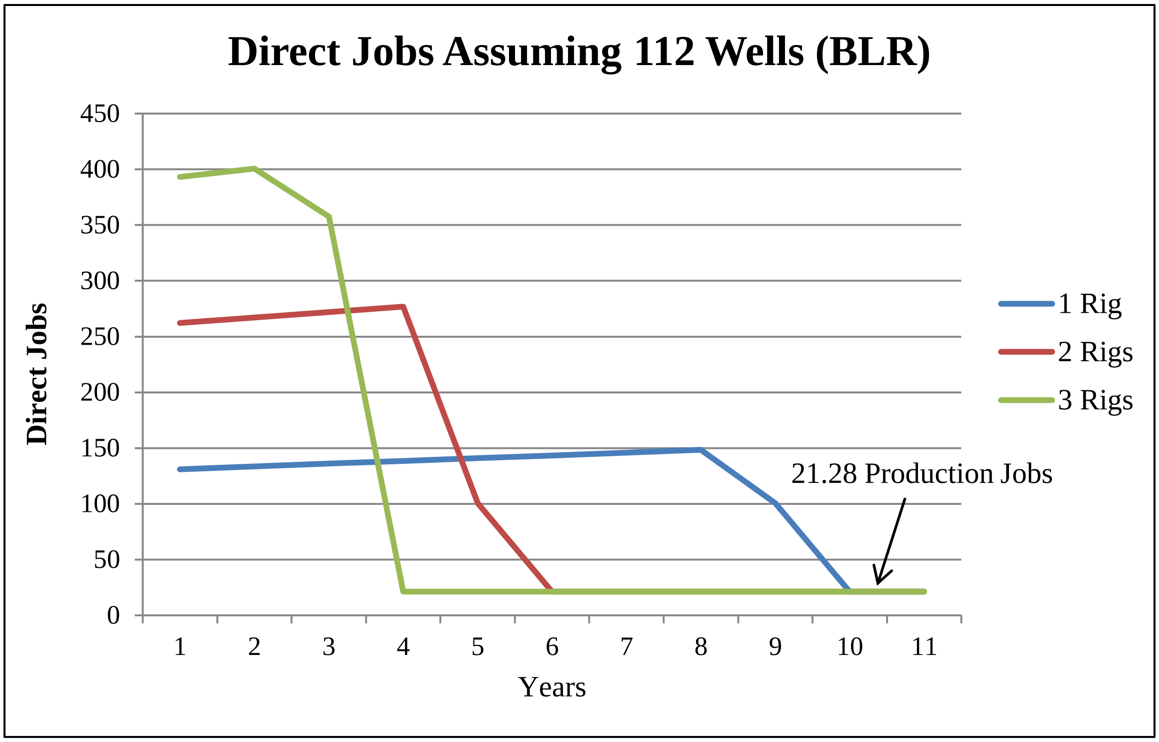

Figure 58. Direct Jobs from Banning Lewis Drilling

Regardless of the actual number of wells that could actually fit within those 18,000 acres on banning Lewis Ranch, the real impact is dependent upon the rig count. Production jobs are linear on a per well basis. For example, if 56 wells are expected to be drilled, the "boom" phase jobs will remain very nearly the same, while the "bust" phase job estimate would be cut in half to 10.64 production jobs.

3.8 Indirect and Induced Employment Impacts

The Marcellus Shale Workforce Needs Assessment was a comprehensive source of the expected direct employment impacts from drilling activities. The report does not project the indirect or induced employment impacts. For this information, research by PricewaterhouseCoopers was used. This research examined the economic impacts the oil and natural gas industry had on the United States economy. This reports contains detailed employment, labor income, and value-added information for the United States and states where oil drilling takes place. The study concluded that in Colorado, each job created in the oil and natural gas industry creates 2.86 additional jobs in the state economy.[295]

3.9 Indirect Employment Impact

Indirect employment created by the oil industry encompasses many different industries. Some examples include auto and equipment repair, trade schools or colleges

[295] (PricewaterhouseCoopers Inc. 2009)

providing oil industry education and training, and gas stations. These are jobs created to provide needed goods and services to the oil industry. For every direct job in the oil industry in Colorado, 0.94 indirect jobs are created. The heaviest indirect industry impacted is the service sector. Of the 0.94 jobs created for every direct oil job, 0.427 jobs are created in the service sector.[296]

3.10 Induced Employment Impact

Induced employment includes jobs that result from expenditures for local resident services by the direct and indirect oil drilling workers. These jobs are in retail, eating and drinking establishments, and other places where the direct and indirect employee spends their wages. For every direct job created in the oil industry, 1.916 induced jobs are expected to be created. Again, the most impacted induced industry is the service sector, which accounts for over 51 percent of the overall induced employment impact. The induced impact on the service sector is greater than the entire indirect impact. For every direct oil industry job, 0.99 induced jobs are created in the service sector alone.[297]

3.11 Total Employment Expectation

This section will provide the total direct, indirect, and induced employment expectations of three scenarios outlined previously. The first scenario will be a low activity scenario consisting of 5 rigs operating in El Paso County drilling a total of 500 wells. The second will consist of a medium activity scenario where 10 rigs are operating in the area drilling a total of 1,500 wells. Finally, the effects of a high activity scenario in which 15 rigs are operating drilling a total of 3,000 wells will be shown.

3.11.1 Low Activity

In this scenario, the total number of new jobs expected by the end of the first year would be about 2,527. This number would steadily climb by about 48 jobs per year to a total of 2,813 jobs by the end of year eight. After eight years, the active drilling phase will end slowly. By the end of the ninth year, the only direct jobs remaining will be those associated with the production phase. The total direct, indirect, and induced jobs would drop to about 366 during this period. This employment is expected to remain steady as long as the wells are producing at a profitable rate.

3.11.2 Medium Activity

In the medium activity scenario, the total number of new jobs expected by the end of the first year would be about 5,054. This number would steadily climb by about 95 jobs per year to a total of 6,007 jobs by the end of year eleven. When the drilling has finished, the production phase of 1,500 producing wells is expected to support a total of 1,099 jobs.

[296] (PricewaterhouseCoopers Inc. 2009)
[297] (PricewaterhouseCoopers Inc. 2009)

3.11.3 High Activity

In this scenario, the total number of new jobs expected by the end of the first year would be about 7,581. This number would steadily climb by about 143 jobs per year to a total of 9,582 jobs by the end of year fifteen. After drilling is complete, 3,000 producing wells would be expected to support a total of 2,199 jobs.

These three scenarios are presented graphically below for comparison. This graph assumes that all wells will be drilled at the same rate per year until all wells are drilled. It assumes that all drilling ends within a year and only production jobs and their impacts remain. The value in this graph lies in its ability to show an estimate of the number of jobs that El Paso County could expect at different levels of activity.

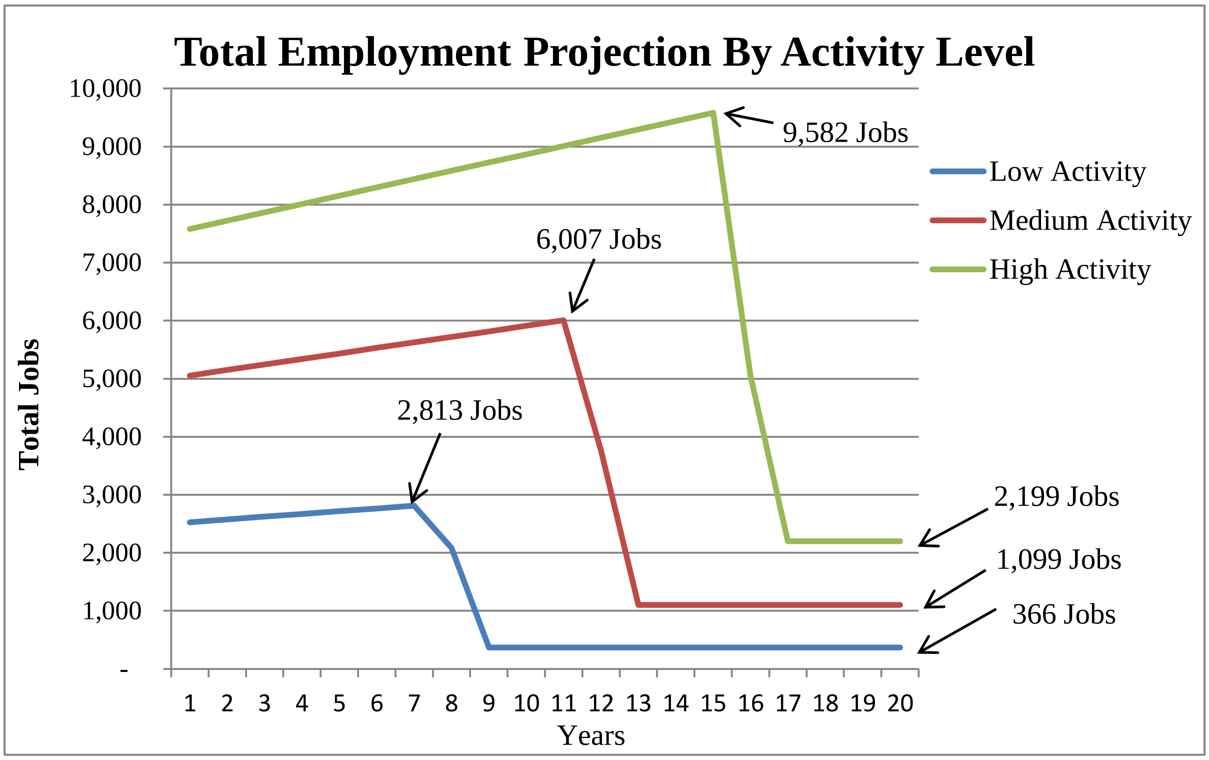

Figure 59. Total Employment Projection

4 Supply Chain Analysis

In order to determine the economic impact of the oil industry as a whole, its direct impact, the impact from its supply chain, and its induced impact are analyzed. The direct impact is related to the drilling and extraction activities as a direct measure of oil output activities. Indirect impact includes support activities and industries supplying materials, infrastructure, and services to the oil industry. Indirect impact is derived from and correlated with the amount of drilling and extraction activities taking place. The economic impacts to the other unrelated industries, which are not directly or indirectly linked to the oil industries, are considered as induced impact.

The indirect impact of supply chain activities can be categorized into upstream, midstream, and downstream.[298] Since the upstream and midstream are made up of input activities supplying to the oil drilling and extraction activities, they are lumped as upstream. The upstream data for the U.S.[299] and Colorado[300] are available on the U.S. Department of Commerce's Bureau of Economic Analysis (BEA).[301] The El Paso County data are available on the County Business Pattern (CBP) database of the U.S. Census Bureau.[302] Since there are few downstream or value-added activities derived from the crude oil, this section is not included in the study.

In addition, the economic impact to Weld County before and after the oil boom is analyzed to study the possible economic impact and future business demographic due to oil activities in El Paso County. Some of the impact is not felt immediately, but has a long-term effect on the local business establishments.

4.1 Direct Economic Impact

4.1.1 US and Colorado

The total U.S. oil and gas industry direct economic impact has been growing since the late 1990s. It peaked in 2008 and contracted in 2009 and 2010 due to the U.S. economic slowdown. As the domestic economy recovers and the rapid growth in developing countries, demand for crude oil is projected to increase.[303]

[298] Oil and Gas Value Chain, 2011.
[299] BEA's Gross Domestic Product (GDP) by Industry Data, 2010.
[300] BEA's Gross Domestic Product (GDP) Regional Data, 2009.
[301] BEA's Interactive Access to Industry's Economic Account Data – Input-output accounts, 2010.
[302] U.S. Census Bureau's County Business Pattern (CBP), 2009.
[303] World Oil Outlook by OPEC, 2011.

In 2009, the entire direct oil and gas output in the U.S. totals $241 billion. In comparison, the direct output in Colorado is $5.3 billion, or about 2.90 percent of the U.S. direct output.[304] Observation shows an increasing trend for oil output in Colorado, increasing six fold compared to a decade ago.

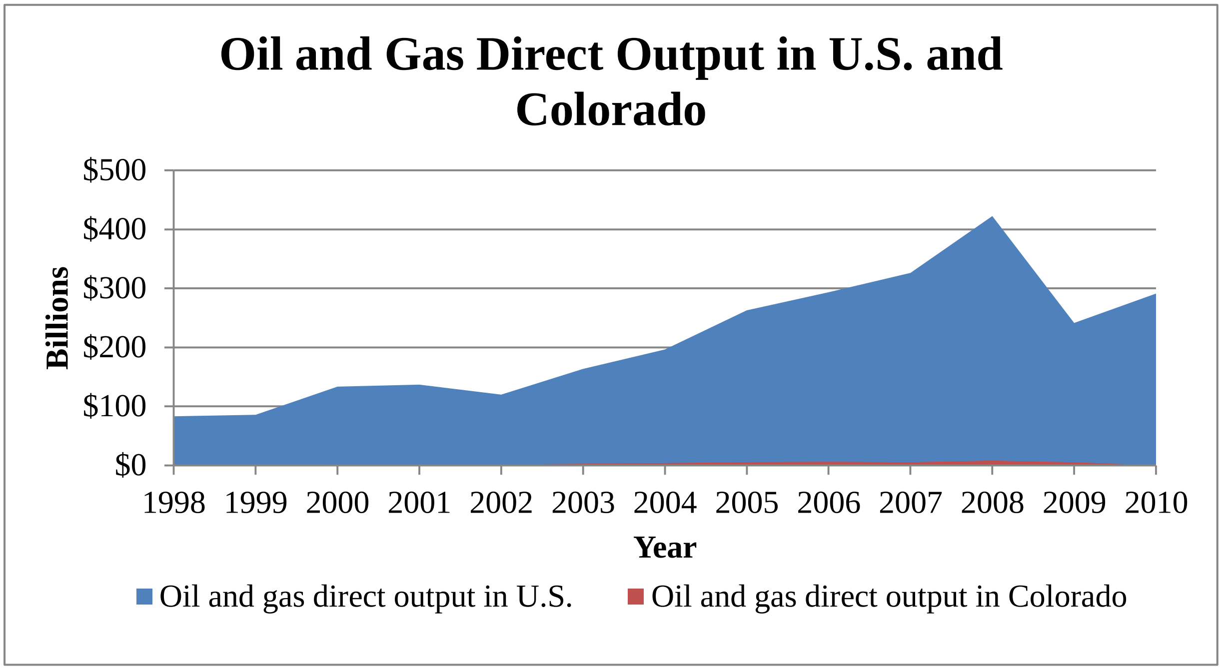

Figure 60. Oil and Gas Industry Direct Economic Impact to U.S. and Colorado

4.1.2 El Paso County

Currently, oil and natural gas development does not exist in El Paso County. With advancement in exploration and drilling technology, opportunity exists to extract oil and gas from the Niobrara shale stretching to the northeast of Colorado down to El Paso County. The increasing trend of the crude oil prices should also encourage investment in this industry.[305] It was determined that companies planning to invest in El Paso County are interested only in oil extraction. Therefore, the assessment of the direct economic impact will be focused on oil drilling and activities.

In order to determine the direct economic impact of oil drilling and extraction activities in El Paso County, the number of wells have to be determined. A limited number of exploratory wells have been drilled and the results have not been released. Therefore, the amount of oil exploration that will take place in the county is an unknown commodity at this time. Analysis has shown that El Paso County can support in excess of 3,000 wells.

Conservative estimates of low, medium, and high activity scenarios of horizontal drilling have been presented throughout this section to articulate the economic effect of varying levels of activity. The low activity scenario is five drilling rigs operating

[304] BEA only provides Colorado GDP for oil and gas extraction, which excludes oil and gas drilling activities.
[305] Crude Oil (Petroleum) Monthly Price – U.S. Dollars per Barrel, 2012.

continuously until 500 wells have been drilled. For the medium activity scenario, 10 rigs will be in continuous operation until 1,500 wells have been drilled. The high activity scenario is 15 rigs drilling continuously until 3,000 wells have been drilled. Finally, for the activity level scenario at Banning Lewis Ranch, 2 rigs will be in continuous operation until 112 wells have been drilled. Each of the rigs is able to drill 13 wells in a year.

Based on publicly available information, about 750,000 barrels of oil could be extracted from each well over its lifetime. Expected economic life of a well is 45 years. The cost of drilling of each well is $4.8 million. The oil production output is expected to decrease at a rate of 8 percent each year once the well is in production. The current $106 price of a barrel of oil is expected to increase at a rate of 2.3 percent every year after.[306]

The oil direct output projection that includes drilling and extraction activities in El Paso County are determined and shown in Figure 61. The oil direct output ramps up faster at the early phase with oil drilling and extraction activities. The production output peaks and starts to drop once the oil drilling activity stops as the targeted number of wells have been drilled. The direct output will be sustained by the oil extraction activities in the county.

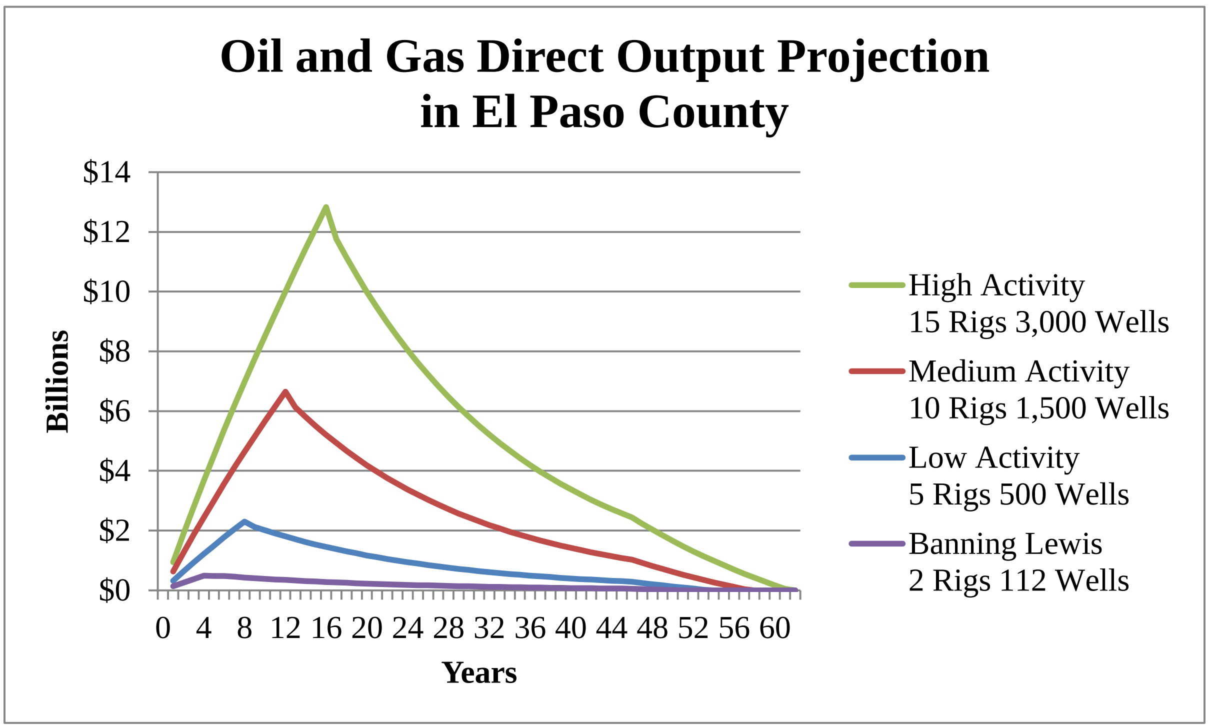

Figure 61. Direct Impact of Oil Drilling and Extraction in El Paso County Based on Different Production Scenarios

The number of wells drilled and started operating in a year has direct economic impact to drilling and extraction activities. Figure 62 shows the sensitivity of analysis with 3 different numbers of rigs used and wells drilled in a year using the medium activity scenario

[306] This is explained in further detail in the financial feasibility section (heading 4.2.1).

of 1,500 wells. As more rigs are used to drill more wells, the oil direct output has a steeper ramp and higher maximum output, but the oil production will deplete faster.

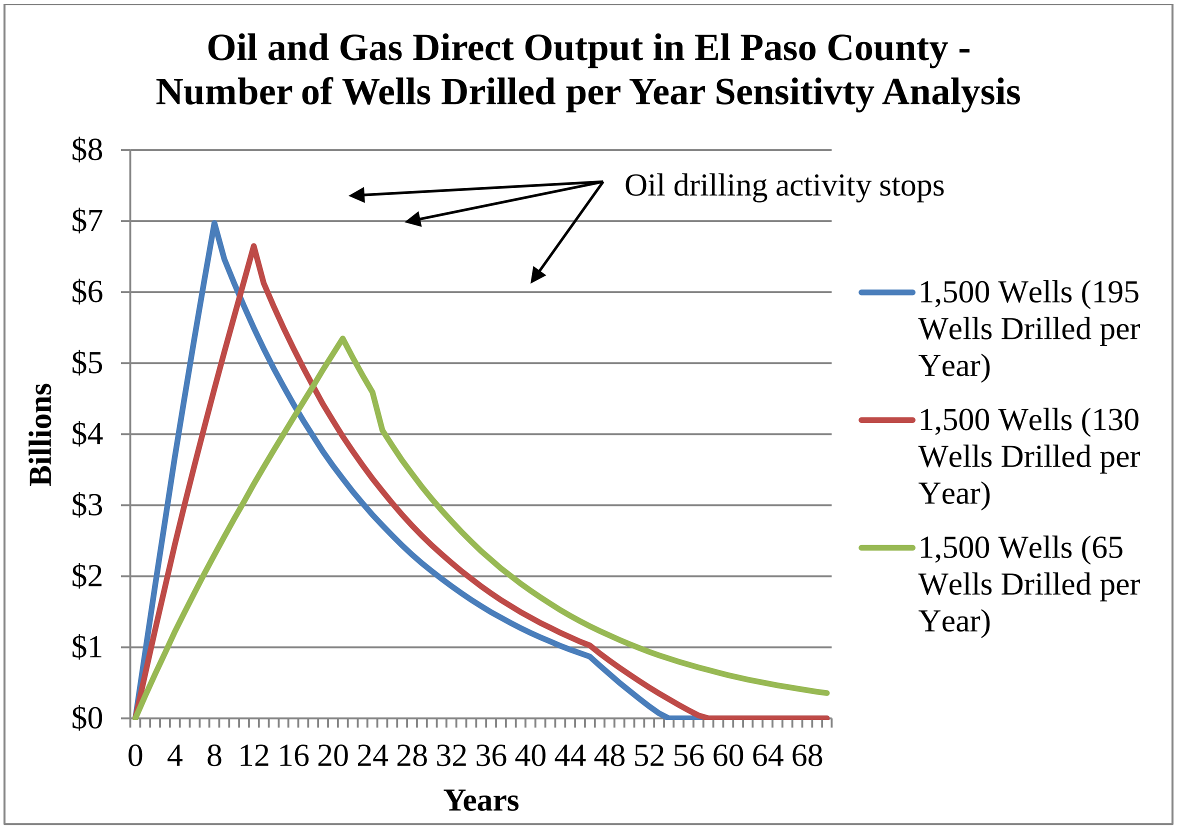

Figure 62. Number of Wells Drilled per Year Sensitivity Analysis to the Oil Production in El Paso County

4.2 Indirect Economic Impact

In 2010, oil output direct impact in U.S. was $291 billion. The indirect economic impact from support activities and industries was $85 billion.[307] The ratio of the indirect input to the direct output, which is the indirect economic multiplier for oil and gas output, was 29.2 Percent. For every dollar generated from the direct output, 29.2 cents of goods and services were consumed. The indirect economic multiplier is an approximation to the indirect economic impact and it varies every year. From 2006 and 2010, the variation ranges between 22.5 percent and 29.2 percent.

Equation 5.

Indirect economic impact (Indirect input) = Direct output * Indirect economic multiplier

[307] BEA's Interactive Access to Industry's Economic Account Data – Input-output accounts, 2010.

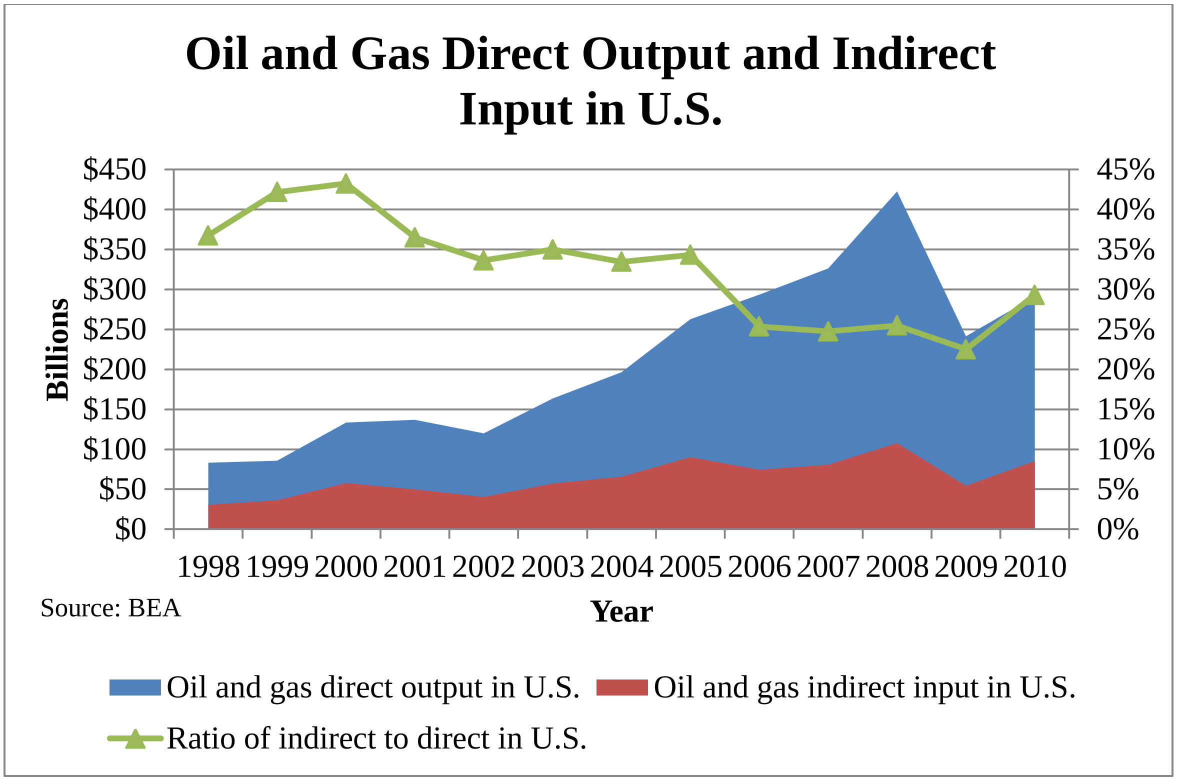

Figure 63. Oil and Gas Direct Output and Indirect Input in the U.S.

In order to determine the indirect economic impact of oil drilling and extraction activities in Colorado and El Paso County, the retention ratio or regional supply ratio (RSR) was worked out. The RSR represents the amount of indirect input that is retained regionally because local suppliers are able to provide goods and services to the oil industry. The higher the RSR, the larger the indirect economic multiplier for the region.

Equation 6.

Regional indirect economic multiplier = U.S. indirect economic multiplier * RSR

Equation 7.

Regional indirect economic multiplier = 29.2% * RSR

According to CERI research in 2007, the Colorado RSR is approximately 50 percent. This means approximately 50 percent of the indirect spending for supplies stays inside Colorado. The rest leaves the state for other materials and equipment supplied from outside of the state.[308] Therefore, the indirect economic impact to Colorado is only half of the 29.2 percent of its oil and gas output in 2010. For every dollar generated from the direct impact of oil output, 14.6 cents of indirect economic impact is generated.

[308] Colorado Oil and Gas Economic Impact Analysis on page 64, 2007.

Equation 8.

Colorado indirect economic multiplier = U.S. indirect economic multiplier * Colorado RSR

= 29.2% * 50% = 14.6%

The direct output in Colorado has not been released for 2010. The indirect economic impact can be approximated at 14.6 percent of the direct output. In 2009, Colorado direct oil output was $5.3 billion and it generated an approximated indirect economic impact of $773.8 million using the indirect economic multiplier of 14.6 percent.

To determine the RSR for El Paso County, further analysis of the industry establishments in El Paso County and Colorado are necessary to determine the indirect economic multiplier and impact.

4.2.1 Upstream Supply Chain Analysis

The BEA database indicates more than 40 business sectors supply goods and services to the US oil and gas drilling and extraction activities. Construction tops the chart. This is followed by management, rental, scientific, and computer system design services. Other oil and gas related industries include mining support activities, petroleum and coal products, and pipeline transportations.

In order to analyze the RSR of upstream businesses that could be retained in El Paso County, the detail industries supplying to the oil and gas operation have to be identified. While Figure 64 shows the high-level view of the industry, it is necessary to break this information down into lower levels. This was done with the North American Industry Classification System (NAICS). The information was then used to assess the availability of upstream supply chain establishments in El Paso County. Table 19 summarizes the major sectors and breaks them down into detail industries that provide supplies and/or services to the oil and gas industry.

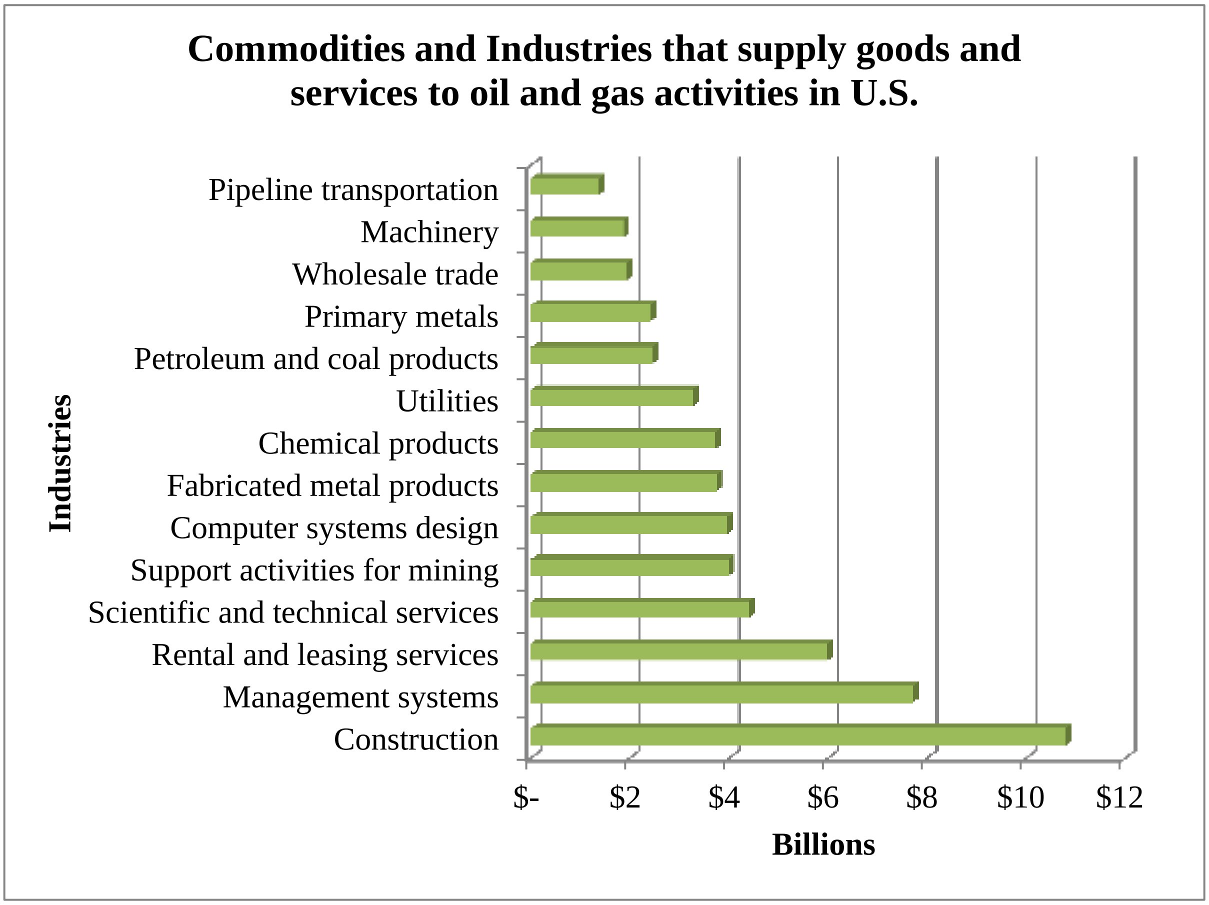

Figure 64. Industries that Supply Goods and Services to Oil and Gas Activities in the U.S. for the Year 2010

Table 18. Sector and NAICS Breakdown of the Major Inputs to the U.S. Oil and Gas Extraction Industry

Sector Code	Sector Description	Detail NAICS Code	Detail NAICS Description
211	Oil and gas extraction	21111	Oil and gas extraction
		211111	Crude petroleum and natural gas extraction
		211112	Natural gas liquid extraction
213	Support activities for mining	213111	Drilling oil and gas wells
		213112	Support activities for oil and gas operations
22	Utilities	221100	Electric power generation, transmission, and distribution
		22131	Water supply and irrigation systems
		22132	Sewage treatment facilities
23	Construction	23711	Water and sewer line and related structures construction
		23712	Oil and gas pipeline and related structures construction
		23713	Power and communication line and related structures construction
324	Petroleum and coal products	32411	Petroleum refineries
325	Chemical products	32518	Other basic inorganic chemical manufacturing
		325199	All other basic organic chemical manufacturing
331	Primary metals	331200	Steel product manufacturing from purchased steel
332	Fabricated metal products	332912	Fluid power valve and hose fitting manufacturing
		332996	Fabricated pipe and pipe fitting manufacturing
333	Machinery	33313	Mining and oil and gas field machinery manufacturing
42	Wholesale trade	42383	Industrial machinery and equipment merchant wholesalers

Sector Code	Sector Description	Detail NAICS Code	Detail NAICS Description
		42384	Industrial supplies merchant wholesalers
486	Pipeline transportation	4861	Pipeline transportation of crude oil
		4862	Pipeline transportation of natural gas
		48691	Pipeline transportation of refined petroleum products
532RL	Rental and leasing services and lessors of intangible assets	532411	Transportation equipment rental and leasing
5412OP	Miscellaneous professional, scientific, and technical services	54136	Geophysical surveying and mapping services
		54162	Environmental consulting services
		5416A0	Environmental and other technical consulting services
5415	Computer systems design and related services	541512	Computer systems design services
		54151A	Other computer related services, including facilities management
55	Management of companies and enterprises	550000	Management of companies and enterprises
562	Waste management and remediation services	562112	Hazardous waste collection
		56221	Waste treatment and disposal
		562211	Hazardous waste treatment and disposal
		562910	Remediation services

Based on the NAICS breakdown, CBP data were used to identify establishments and specific industries that provide supplies to the oil and gas extraction industry and are located in El Paso County.309 Comparing the number of establishments in Colorado and El Paso County provides an approximation of which industry establishments are available and missing in the county. When the establishment for a specific industry is available in the county, the revenue is retained, but if the establishment is missing, the revenue is left out. The total retained revenue is then divided over the Colorado indirect impact. The El Paso

[309] U.S. Census Bureau's County Business Pattern (CBP), 2009.

County to Colorado indirect economic ratio is used in the Equation 3 to obtain the El Paso County RSR.

Equation 9.

El Paso County indirect economic multiplier = 29.2% * El Paso County RSR

Equation 10.

El Paso County RSR = Colorado RSR * El Paso County over Colorado indirect economic ratio

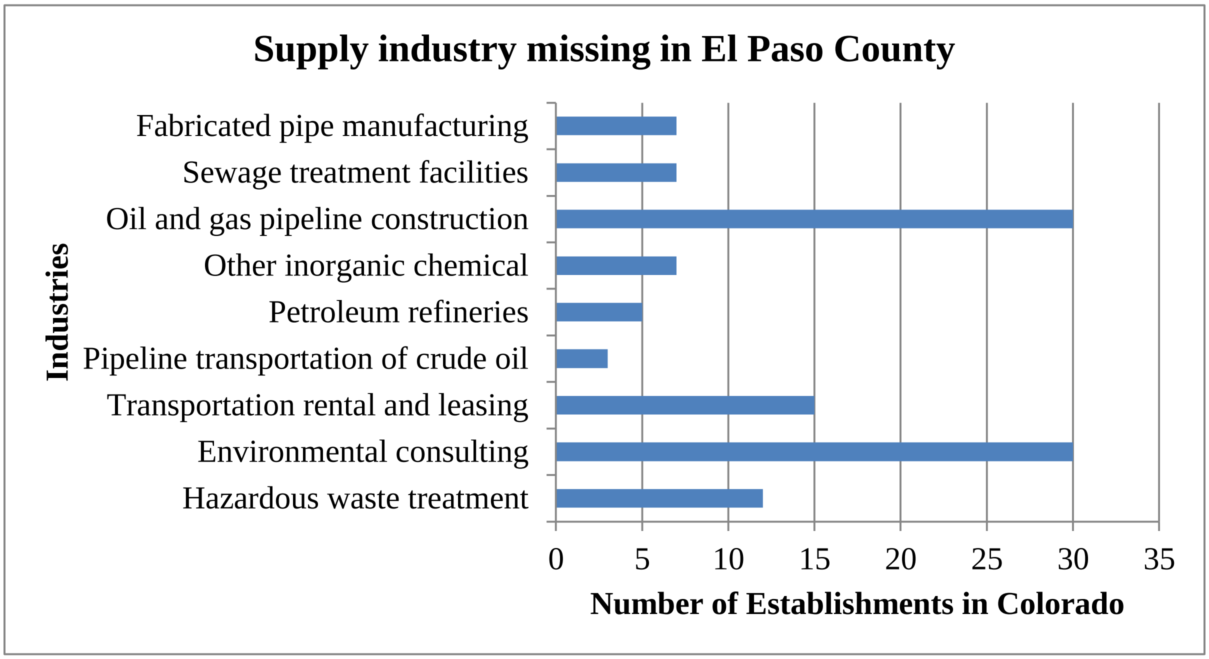

Figure 65. Supply Industry Establishments Missing in El Paso County when Compared to Colorado

Factoring in the missing establishments in El Paso County, the ratio of indirect economic impact in El Paso County using available establishments is determined. Figure 66 shows the ratio of indirect economic impact from upstream supply chain in Colorado and El Paso County. The El Paso County over Colorado indirect economic ratio is 31.7 percent. Using Equation 6, the El Paso County RSR is determined to be 15.9 percent.

Equation 11.

El Paso County RSR = 50% * 31.7% = 15.9%

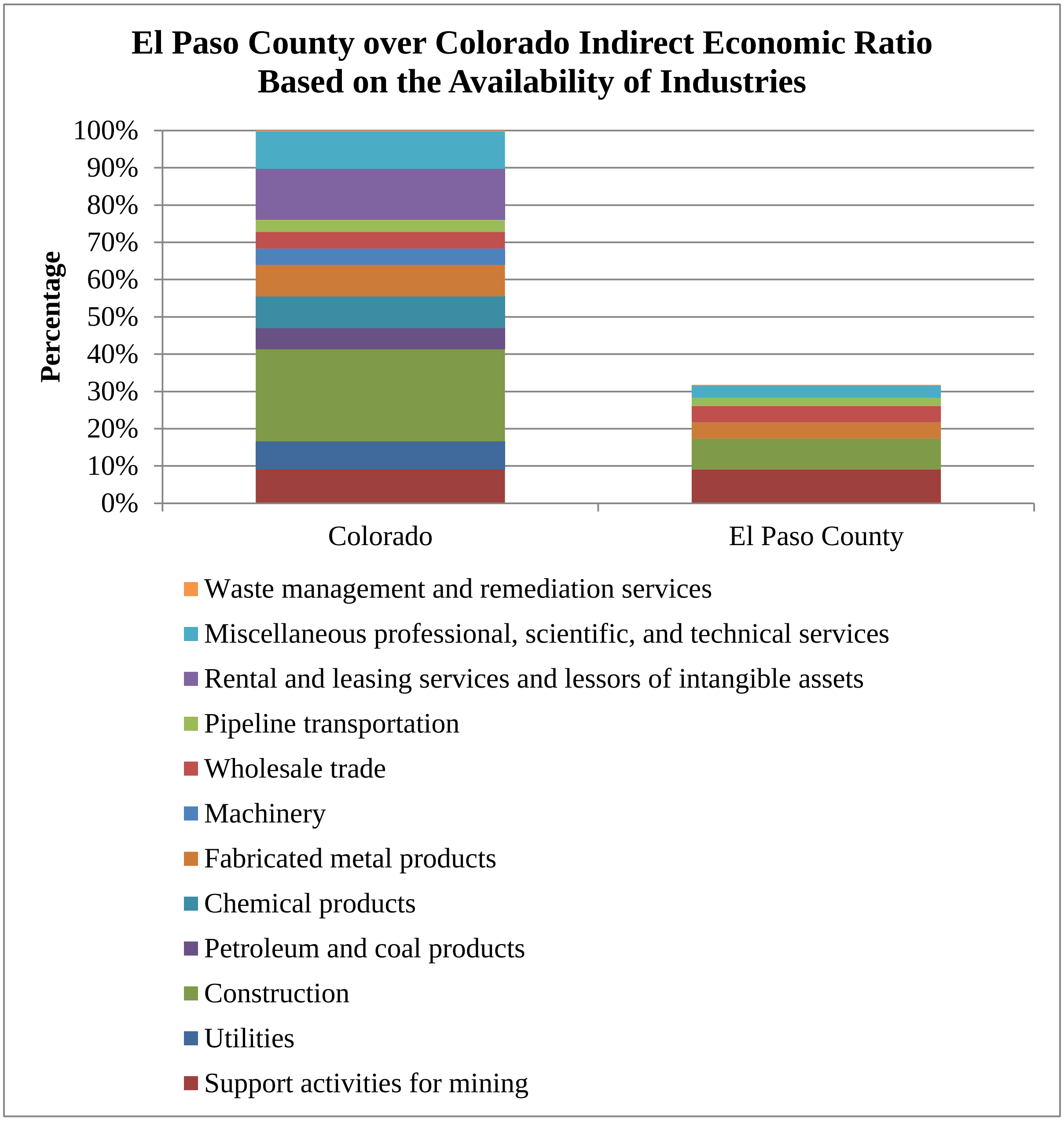

Figure 66. El Paso County over Colorado Indirect Economic Ratio Based on Available Establishments

Using the El Paso County RSR, the indirect economic multiplier is determined to be 4.6 percent. For every dollar generated from the direct impact of oil output, 4.6 cents of indirect economic impact is generated. Equation 12 shows the indirect economic multiplier for the U.S., Colorado and El Paso County.

Equation 12.

El Paso County indirect economic multiplier = 29.2% * 15.9% = 4.6%

The high activity scenario with a peak direct oil output at $12.8 billion would generate an indirect economic impact of $589 million in El Paso County based on the 4.6 percent indirect multiplier. Since fewer industry establishments are located in the region, the indirect economic is not maximized. Locating the missing industries in the El Paso County can spur further economic growth over time. If these industries are locally located, the growth in oil and gas industry can benefit the local economies. Neighboring counties could get their supplies from El Paso County, possibly leading to a higher indirect effect.

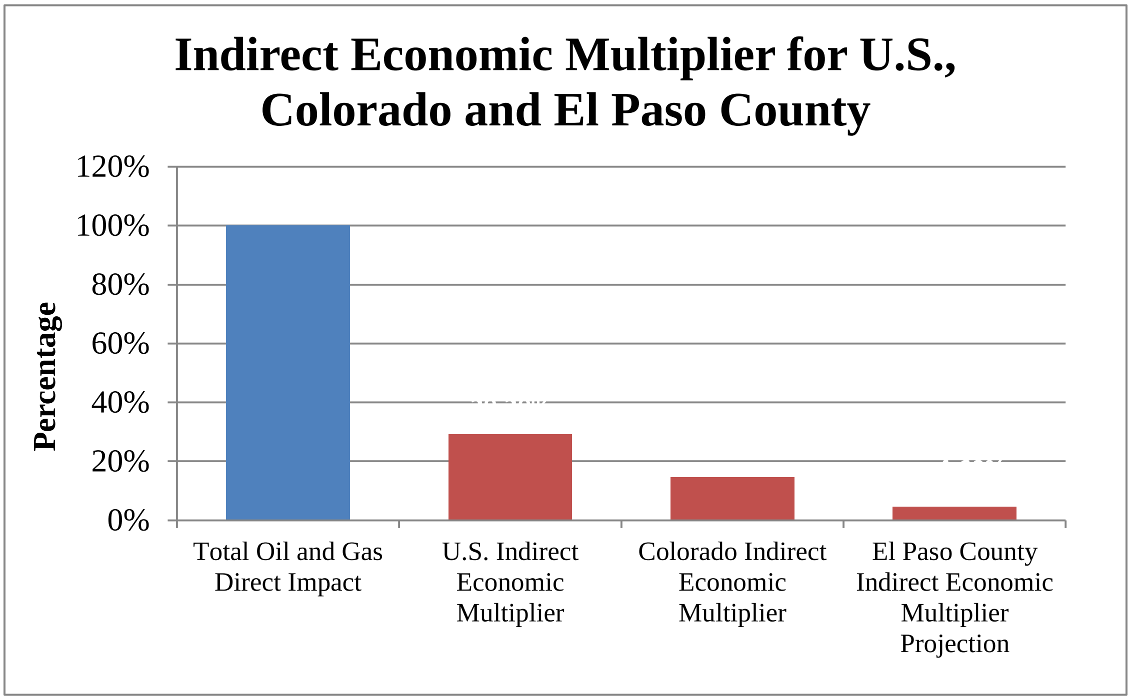

Figure 67. Indirect Economic Multiplier Comparison for the U.S., Colorado and El Paso County

4.3 Indirect Economic Impact Comparison between El Paso and Weld County

4.3.1 Downstream Supply Chain Impact

There are more than 22 sectors that contribute to the downstream supply chain from the oil and gas industries. Major sectors are depicted in Figure 68. These industries contribute a large amount to their local economies, because typically much of this purchasing occurs in the state or locality where the oil drilling or extraction occurs. According to the Colorado Energy Research Institute (CERI) at the Colorado School of Mines, up to 60-90 percent of this spending will occur in the state of Colorado, but from out–of-state vendors.[310] The location of spending for the oil and natural gas drilling and the related suppliers is critical to understanding the economic impact, as these suppliers have a direct impact on many other

[310] CERI – Colorado Energy Research Institute, pg 33, 2007-1 Report on Oil and Gas Economic Impact Analysis

industries and create additional jobs across all sectors including restaurants, retail, gas stations, among others.

Summary Code	Summary Description	Detail NAICS	Detail NAICS Description
213	Support Activities for Mining	213112	Support activities for oil and gas operations
22	Natural Gas Distribution	22121	Natural Gas Distribution
		22132	Sewage treatment facilities
42	Whole Sale Trade	42383	Industrial machinery and equipment merchant wholesalers
		42384	Industrial supplies merchant wholesalers
484	Truck Transportation	484220	Specialized Freight Trucking, Long-Distance
486	Pipeline Transportation	4861	Pipeline transportation of crude oil
		4862	Pipeline transportation of natural gas
		48691	Pipeline transportation of refined petroleum products
532RL	Rental and Leasing services and lessors of intangible assets	53241	Heavy Machinery Equipment Rental & Leasing
		532411	Transportation equipment rental and leasing
55	Management of Companies and Enterprises	551112	Offices of other holding companies
562	Waste Management & Remediation Services	562112	Hazardous waste collection
		56221	Waste treatment and disposal
		562211	Hazardous waste treatment and disposal
		562910	Remediation services

Figure 68. Oil and Natural Gas Downstream Supply Chain

4.3.2 Downstream Supplier Analysis

Figure 68 shows an overall view of the industry at the sector level. To further understand the suppliers that contribute to the downstream portion of the business of oil and gas drilling, the detail industries on the downstream supply chain have to be identified based on their contributions to the industry.,

To understand the industries that contribute to the oil and gas industry, several tools were used. Data from the Bureau of Economic Analysis and County Business Patterns were used to determine the final economic impact based on industries. Other surveys were also used as a baseline to understand the impact of these industries, including the 2009 report by CERI. The study also uses a comparison of Weld County, Colorado as a direct comparison for potential future impact. The interest in exploration of oil in Weld County provides an excellent comparison for the growth in El Paso County, as Weld County started with about 4,200 wells[311] in 1990, the beginning year of the comparison, and today has over 17,000 wells throughout the county. This is a 305 percent increase in the number of wells. It translates to a significant increase in the number of establishments apart of the downstream oil extraction supply chain that have moved into Weld County. A graph of the current number of establishments based on the sectors that have been previously identified to demonstrate a direct comparison between current employment in these sectors and the state of Colorado as of 2010[312] is provided in Figure 69. Weld County was added to provide a

[311] Environ International Corporation, "*Development of 2010 Oil and Gas Emissions Projections for the Denver-Julesburg Basin,"* John Grant, Ron Friesen, Alison K. Pollack (4-27-2008)
[312] U.S. Census Bureau, County Business Patterns, Establishment Data for Colorado, Weld County, & El Paso County (2009)

perspective on the number of industries that may be required in each county within the downstream supply chain to support oil and gas drilling.

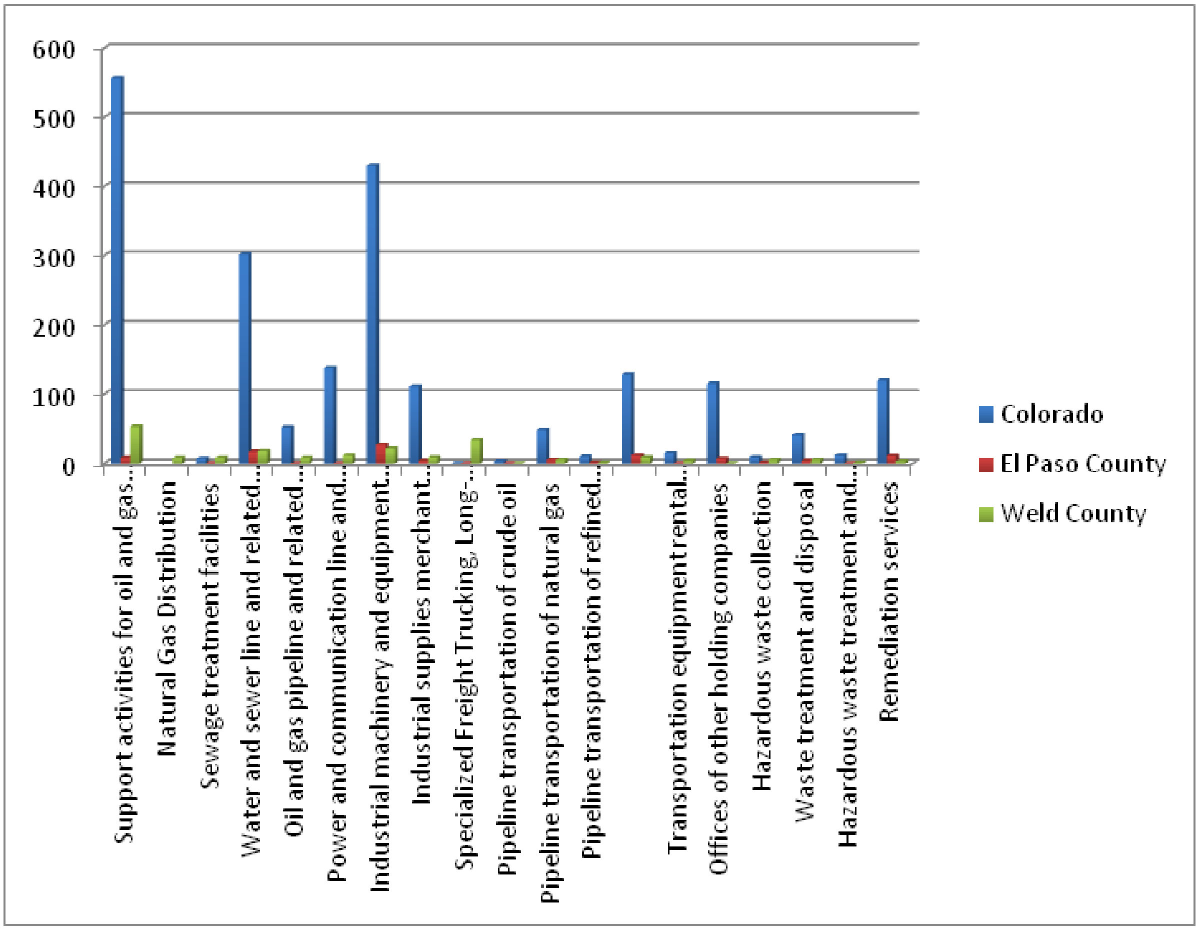

Figure 69. Supply Industries Contributing to the Downstream Supply Chain of Oil and Natural Gas Extraction

El Paso County currently has no identifiable organizations that would meet the criteria of working with oil and gas extraction when compared with these activities in either Colorado or Weld County. The analysis currently demonstrates that businesses matching the criteria for the downstream supply chain such as sewage treatment facilities and waste treatment and remediation may have one or more establishments within El Paso County. Additional analysis would be required at the individual establishment level to determine the level of focus on oil and gas extraction.

The largest industries that are contributors in the downstream supply chain for oil and natural gas drilling are the services and support sector for oil drilling, pipeline transportation, ground transportation, and water and sewer lines and related structures construction, as shown in Figure 69. Pipeline transportation of natural gas and water and sewer line structures and related construction currently have similar levels of establishments in El Paso County as in Weld County. However, these workers are currently not working in areas related to oil drilling or extraction. Prior to March 3, 2012, there was no active drilling or exploration within El Paso County.[313] Currently, the drilling activity taking place in El Paso County consists of oil exploration to determine what minerals are currently under the county. Employment in transportation of natural gas is high due to El Paso pipeline operations[314] and the distribution and maintenance facilities necessary for natural gas transportation and delivery to residential homes and businesses within the Colorado Springs/El Paso County Metro area. Similarly, the water and sewer lines and related structures construction have current levels of establishments similar to that of Weld County. Much of this is due to the larger population and employment by Colorado Springs Utilities and other El Paso County Utilities providers to manage these existing government services.

Support services for oil and natural gas drilling would be the industry that would grow the largest, because it consists of the direct services to the oil fields that are needed immediately when oil and natural gas drilling commences on the downstream supply chain. These support services include a variety of different trades that might exist in some form in El Paso County, but not in the current form to support oil and natural gas extraction, including pipeline maintenance, welding and machine shops, mechanics, derrick maintenance, and repair. Jobs in the support services are the quickest to grow. They represent a large portion of the spending of oil and natural gas extraction as products reach the downstream of the industry.

Support services also contribute to the oil and natural gas drilling long after the drilling has finished. They provide the long-term employment and tax dollars that would greatly benefit the county and all related organizations in the county. Currently, there are a few organizations that perform these services in the county. They are primarily focused on natural gas distribution (El Paso Corp.) and direct pipeline services to Colorado Springs Utilities and local residences and business.

Many of the industries linked to the downstream supply chain require specialized permits or training in order to operate establishments, generating significant revenue. Because the organizations currently only exist outside of El Paso County, the revenue will be driven outside of El Paso County. For example, hazardous waste treatment and disposal and remediation services may require special permits from the Colorado Department of Public Health and Environment and the Environmental Protection Agency. However, the only disposal sites for hazardous drilling liquids are outside El Paso County. The nearest site is located at Deer Trail in eastern Colorado according to the Colorado Department of Public Health and Environment.

The scope of this study precluded determining if the establishments currently located within El Paso County would be able to service the needs of oil and gas fields. Additional business by business analysis and surveying would be required to determine if these existing businesses would be able to support oil and gas fields or expand to support these activities.

[313] Colorado Springs Gazette, Public Affairs, *Oil exploration now a reality for El Paso County*
[314] El Paso Corporation, Pipeline Overview, www.elpaso.com/pipelines, 04/06/12

4.3.3 Induced Economic Impact

Oil and Natural gas extraction generates significant revenue for businesses and organizations outside of the actual supply chain to the extraction processes. Counties and states currently experiencing a boom in drilling can be used as demonstration sites for the potential of oil and natural gas drilling activities and the business activities that they encourage.

For the purposes of comparison, Weld County, Colorado will be used to understand the induced impact generated by those involved in the oil extraction industry. According to CERI, Weld County has experienced a significant boom in oil drilling activities since 2005.[315] Weld County is several years into its current oil boom, making it a primary candidate for comparison with El Paso County to understand the potential future impacts. To understand the potential impacts on oil drilling in El Paso County, an analysis was performed to compare the number of establishments to the population in Weld County over three specific years: 1990, 1995, and 2008. This analysis provided direct information on how El Paso County would look based on normal population growth and keeping the number of businesses per 50,000 residents the same. This analysis, which will be covered later in this section, will show the impact of oil and gas extraction on the basis that Weld County may have certain industries that do not match the expected growth rate, but instead exceed it. As a part of the analysis, it was determined that many of the industries that experienced significant, higher-than-normal growth rates were correlated to the rates of the population growth. Additionally, Weld County experienced higher levels of growth both in population and business establishments due to the high levels of oil and gas drilling in the county.

4.3.4 Induced Impact Multiplier

The total induced economic impact to the oil and natural gas industry of $90.254 billion dollars is significant. [316] The total induced impact of the oil and natural gas extraction industry was $100.978 billion as of 2010. [317] This equates to an economic multiplier of 1.118 for all industries that receive induced impact. In other words, the economic multiplier of 1.118 means that $1 of production in oil and gas extraction results in $1.118 in additional induced economic impact, based on the state of Colorado. To further define the induced impact created by oil and gas drilling, the total Induced Impact was divided by the Total Direct Impact in order to obtain a figure that works out on a per well basis. This figure was calculated on the basis that 43,354 wells existed in the State of Colorado in the year 2010. Based on the 2010 well figure, 100 wells will produce an estimated induced economic impact of $232.91 million. As a demonstration of the induced economic impact, an estimated revenue calculation has been provided in Table 19 based on the IMPLAN numbers for 2010 showing the total potential economic impact for El Paso County based on estimated production levels of 500, 1,500, and 3,000 wells in production.

[315] CERI 2009 Oil and Gas Economic Analysis
[316] IMPLAN: Colorado Oil, 2012 Dataset
[317] IMPLAN: Colorado Oil, 2012 Dataset

Table 19. Induced Impact Revenue Calculations for High, Medium, and Low Production Scenarios

	Low	Medium	High
# of Oil Wells	500	1,500	3,000
Estimated Induced Revenue	$1,164,577	$3,493,732	$6,987,464

In order to calculate the economic multiplier for the induced impact, an IMPLAN scenario was run to demonstrate the potential impact of oil drilling in Colorado. The economic multiplier was extracted from the IMPLAN output table by using the equation demonstrated in Table 19. The resulting figure showed that each dollar spent on extraction resulted in a specific dollar amount in additional value added in various other industries. An analysis of the County Business Patterns data from the U.S. Census produced 144 industries that receive induced impact from the oil and gas extraction production spending.[318]

4.3.5 Induced Impact of Oil and Gas Drilling

Oil and Gas extraction shows induced impact to nearly all industries within El Paso County, but this study will specifically focus on a select number of the top 25 industries that receive induced impact on the basis of revenue as demonstrated in Table 19. The comparison that was performed as a part of this study was to compare Weld County, Colorado with El Paso County, Colorado to understand the differences between the counties over the time frame of 1980 through the present. This comparison allows for the induced impact to be compared over the future to clearly understand what successful drilling in El Paso County would mean for businesses that receive a side impact from oil and natural gas drilling.

[318] U.S. census Bureau, County Business Patterns, 2009 Data Set

Table 20. Top 25 Industries Identified by IMPLAN as Industries with Induced Revenue from Oil Drilling Activities

Industry	Induced Revenue
Imputed rental activity for owner-occupied dwellings	$5,996,482
Real estate establishments	5,545,284
Construction of new nonresidential commercial & health care structures	4,708,403
Wholesale trade businesses	4,191,414
Food services and drinking places	3,275,369
Construction of new residential, permanent site single/multi-family structures	3,154,134
* Employment and payroll only (state & local government, education)	3,117,606
Offices of physicians, dentists, and other health practitioners	2,934,994
Telecommunications	2,724,016
Insurance carriers	2,675,031
* Employment & payroll only (state/local government, non-education)	2,463,978
* Employment and payroll only (federal government, military)	2,286,851
Construction of other new nonresidential structures	2,125,236
Architectural, engineering, and related services	2,117,712
Private hospitals	2,028,447
* Employment & payroll only (federal government, non-military)	1,925,489
Monetary authorities & depository credit intermediation activities	1,880,164
Securities, commodity contracts, investments, & related activities	1,686,170
Custom computer programming services	1,584,391
Non-depository credit intermediation and related activities	1,194,731
Retail Stores - Food and beverage	1,191,087
Legal services	1,144,068

In order to demonstrate the impact of the induced side of oil drilling, the industries that make up the top 25 induced impacts are industries that were selected as part of this analysis. While the simulation covered all 144 businesses sectors that receive induced impact, there were many businesses that received a small impact due to the fact that they do not contribute as much to this area of the economy or its employees. The top 25 industries are ones which have significant impacts on the local economy due to the breadth of their reach in terms of both product or service offered as well as locations that are available to service the clients. These industries are important because they are induced effects from expenditures by employees within the oil and natural gas extraction industry and its suppliers.

The study used two data sets to reference and understand the comparison between Weld County and El Paso County to identify the top industries and the expected growth. The first method used was to analyze data for three periods using the County Business Patterns and perform a population analysis on this data. The original county business patterns data used the SIC Coding system versus the current NAICS system used by the U.S. Census Bureau, Therefore, a conversion had to be performed on each industry before a population-based analysis of industry growth could be performed. For the purposes of this study, the 2009 NAICS data were converted back to the SIC data. The next step taken was to divide the population of these two counties by 50,000 for the years 1990, 1995, and 2009. These years were selected for the initial analysis to provide information on the existing businesses before the primary oil boom, in the 90's when oil growth in Weld County was beginning to occur more, and finally in 2009 during the current oil boom. Additionally, the limitations of one of the tools being used prevented the data from going back as far as 1980, a base period for County Business Pattern Data. The population basis used to calculate the growth in each of the following sectors is shown in Table 21 and Figure 70, which shows the population over the period. Data from the 2009 County Business Patterns, the most recent available, were used and matched with 2010 population.

The second part of the analysis used a Shift-Share procedure to assess the impact of additional factors on the industries selected. Shift-Share analysis is a methodology that accounts for changes in employment by industry by controlling for growth in employment at the national level, local level and industry level. This analysis was performed with data for 1990 through 2010. Based on the Shift-Share results for El Paso County and Weld County, some of the growth that occurred in both counties can be directly correlated to the growth in the national economy between 1990 and 2010. National employment grew 17.7 percent[319] during this period, meaning that there were additional jobs being created that contributed to additional businesses being established.

Table 21. Population Multiplier Basis for Calculation of Induced Impact

	1990		**1995**		**2010**	
	Population	**Multiplier**	**Population**	**Multiplier**	**Population**	**Multiplier**
Colorado	3,294,394	65.89	3,738,061	74.76	5,024,748	100.50
Weld County	131,821	2.64	147,998	2.96	252,825	5.06
El Paso County	397,014	7.94	464,775	9.30	622,263	12.45

[319] University of Georgia, Shift-Share Analysis: El Paso County (1990-2010)

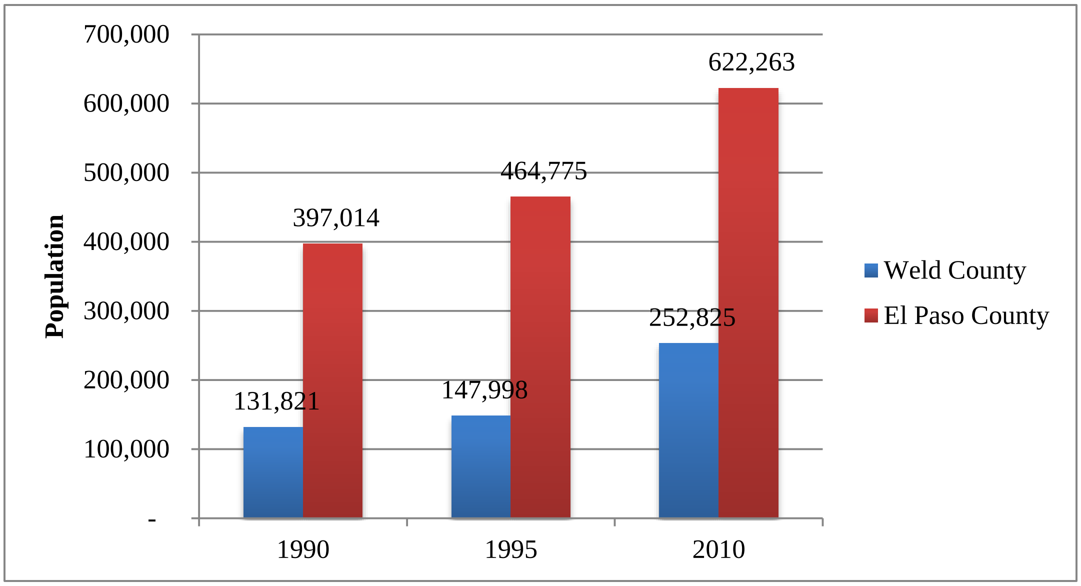

Figure 70. Chart of Total Population for El Paso & Weld Counties for 1990-2010

Real estate establishments and all industries related to real estate become an important aspect of these economies in terms of induced impact due to the other businesses located where oil drilling is booming. Not only do organizations locate where an oil boom is taking place, workers also migrate into those areas. Together, they generate additional revenue and support for land sales and leases in the local economy. The number of real estate establishments in Weld County is 242 percent[320,321] of what it was in 1990s, with the number of business establishments moving from 77 in 1990 to over 172 establishments in 2009. This significant increase is not only due to a growth in population, as Weld County added approximately 100,000 people in the last 15 years. Growth in the real estate business greatly accelerated between 1990 and 2009 due to the increased growth in oil and gas extraction. The study of County business patterns also found that the number of real estate establishments increased at a rate higher than that of the original amount of establishments of 52 per 50,000 residents. El Paso County currently has 852 real estate establishments. The current number of firms is at least partly related to the total population – 622,263 in El Paso County (2010), versus 252,825 in Weld County (2010).[322]

[320] University of Virginia Library, County Business Patterns: 1980-2001 County Level Data, Geospatial & Statistical Data Center
[321] U.S. census Bureau, County Business Patterns, 2009 Data Set
[322] U.S. Census Bureau, Population Estimates for Colorado Counties (2009), El Paso County, Weld County, & State of Colorado

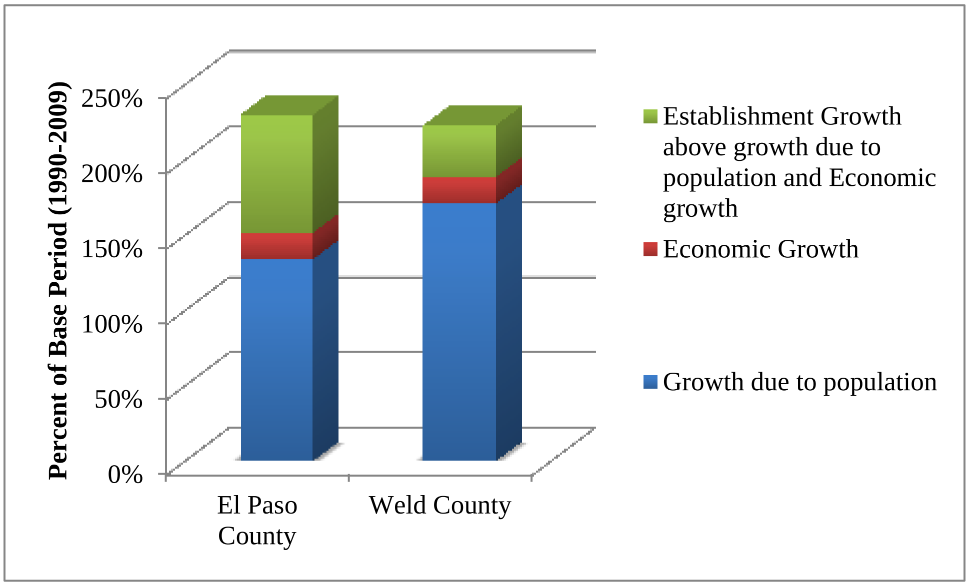

Figure 71. Growth in Real Estate Firms, Weld County vs. El Paso County (1980-2009)

Commercial and healthcare structure construction also becomes important because of the lack of suitable, existing facilities for certain industries. Colorado Springs is a location where this will occur due to the lack of available commercial real estate, according to local real estate broker Hoff & Leigh. Similarly, new residential structures will also take up some of this, because of the contribution to additional residential single and multi-family construction. The Sublette County economic impact study shows that from 2000-2005, 1,000 new permanent residences were added to the county. Although the overall county of Sublette is small, with a total population around 10,000, this represents significant population growth. It also demonstrates the power of oil and gas in the construction industries. The growth in both the commercial and healthcare structure industry and residential structure construction that occurred in Sublette County can also be compared with the growth that occurred in El Paso and Weld counties during this period for a more accurate analysis. These specific sectors grew during the time period grew to 273 percent of the base in Weld County and 219 percent of the base in El Paso County. While the population did grow in Weld County, the shift-share analysis indicates that the growth rose 189 percent due to other factors, specifically oil drilling in Weld County.[323]

[323] University of Georgia, Shift-Share Analysis: El Paso County (1990-2010)

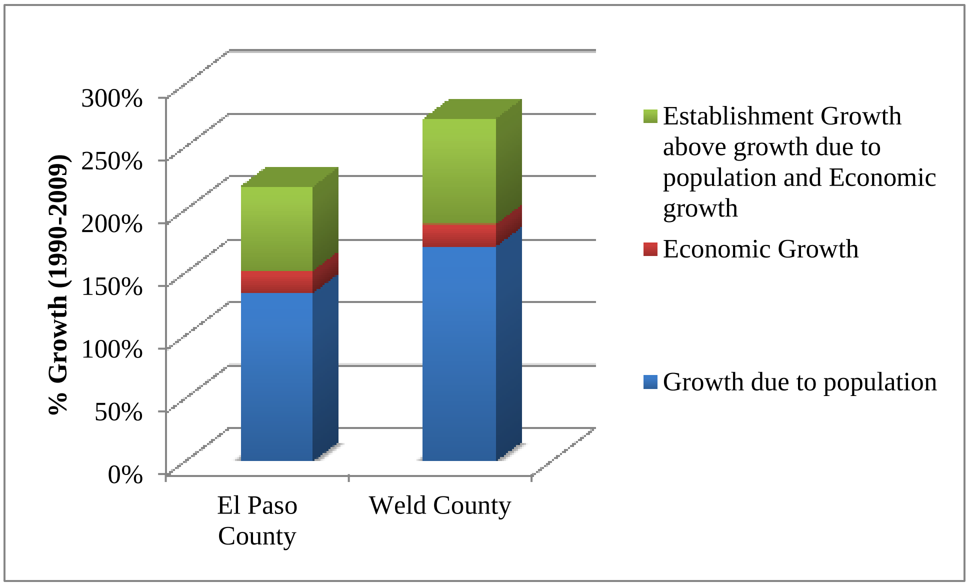

Figure 72. Growth Comparison between El Paso County and Weld County of Construction & General Contracting Establishments

Healthcare is another area that sees a large amount of growth when oil booms occur and the population grows. There is also a need for healthcare surrounding oil-drilling areas due to the inherently dangerous nature of the job. Hospitals, physicians, dentists, and other healthcare providers represent almost $16 billion dollars in economic impact based on oil drilling in the state of Colorado in 2010. A growth in oil drilling would propel the growth in this sector and create a need for additional hospitals and other medical providers. Weld County demonstrates the growth in the medical fields that occurs not only due to population growth, but also because of the side effects of oil and gas drilling. In 1980, establishments covering health services such as dentists, doctors, and the like totaled 133 establishments, or 54 for every 50,000 people in the county, whereas in El Paso County establishments totaled 504, or 81 establishments for every 50,000 people. Due to population growth, Weld County was predicted to have approximately 371 establishments pertaining to healthcare, but instead Weld County had 449 establishments in 2009, or 98 establishments per 50,000 people. This is an increase of 258 percent over the 1990 figures, indicating that population was not the only driver.[324,325] El Paso County experienced similar growth, but much of its growth can be related to the significant growth in population from 309,424 in 1980 to 604,542 in 2009.[326]

[324] University of Virginia Library, County Business Patterns: 1980-2001 County Level Data, Geospatial & Statistical Data Center
[325] U.S. census Bureau, County Business Patterns, 2009 Data Set
[326] U.S. Census Bureau, Population Estimates for Colorado Counties (2009), El Paso County, Weld County, & State of Colorado

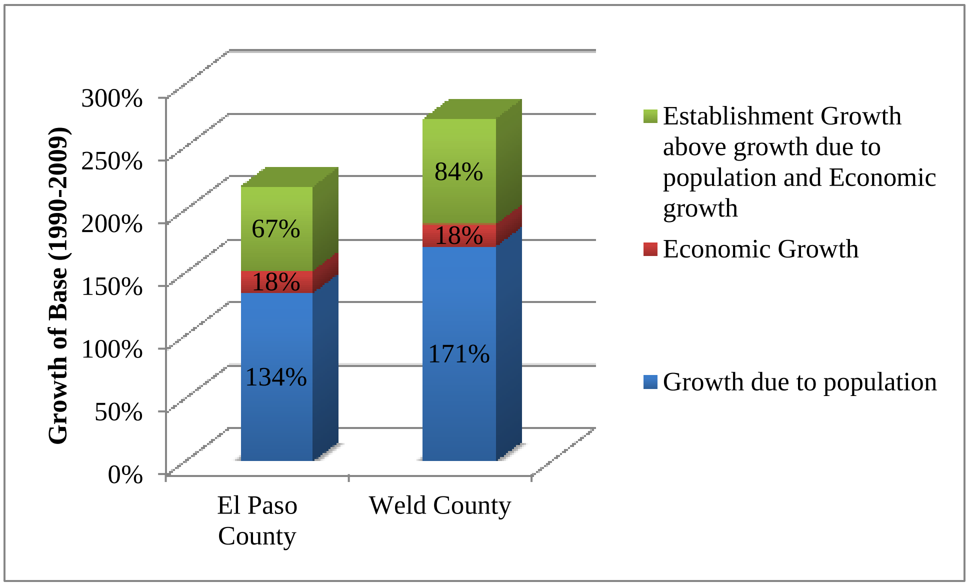

Figure 73 Comparison of Establishment Growth of Healthcare Establishments in Weld County and El Paso County

Insurance carriers, credit providers, and telephone companies contribute significant impact to the community and would likely see significant growth. Based on their overall contribution from oil and natural gas of $25 billion dollars to the local economy. Weld County is a demonstration of the growth of the insurance, credit provider, and telephone company industry due to drilling. As of 1990, Weld County had 54 establishments that provided insurance brokers, carriers, and service, or 14 per 50,000. Based on population growth, this figure was expected to be 106 establishments by 2009. Instead, the figure grew to over 109 establishments or a growth of 102 percent since 1980 (202% of base).[327,328] This investment will be driven as the population grows, because these institutions provide vital services that are necessary or in some cases required to not only operate a business, but live in a thriving, vibrant community. Similarly, the insurance brokers, credit providers, and telephone companies, collectively, grew by 13.2 percent during the period 1990-2010. Growth above that, as explained in the Shift-Share analysis, indicates that the growth was due to oil drilling.[329] This can also be demonstrated with the idea that Weld County had approximately 4,000 active oil wells in 1990 and today the county has over 17,000 active wells.

Food and drink establishments and food stores are two sectors of business that would be among the quickest to grow in any oil and gas extraction market. These two sectors provide essential services to workers, families, and the community through food and other essentials. Food and drink stores such as the supermarket grew from 55 food stores in 1980

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[327] University of Virginia Library, County Business Patterns: 1980-2001 County Level Data, Geospatial & Statistical Data Center
[328] U.S. census Bureau, County Business Patterns, 2009 Data Set
[329] University of Georgia, Shift Share Analysis

to 62 in 1995 and 90 in 2009.[330] Growth over the time period represents an increase brought the number of 141 percent of the base. During the same period, El Paso County saw this grow 137 stores in 1980 to 225 stores in 2009, or an increase of 164 percent. This, however, is directly correlated to the population growth in combination with the global recession and indicates that even though the growth was greater than expected, retailers also may have cut back slightly. This still does not diminish the fact that areas with significant oil extraction activities will experience growth. Food and drink establishments also experienced significant growth in both counties. Weld County's growth over the period was significantly higher. In Weld County, 182 Food and eating establishments existed in 1990. By 2009, there were 355 establishments, 195 percent of the base level.[331,332] This represents a significant increase in the value of the industry in Weld County. It also shows the increase can be significant based on the level of impact received from oil and gas extraction.

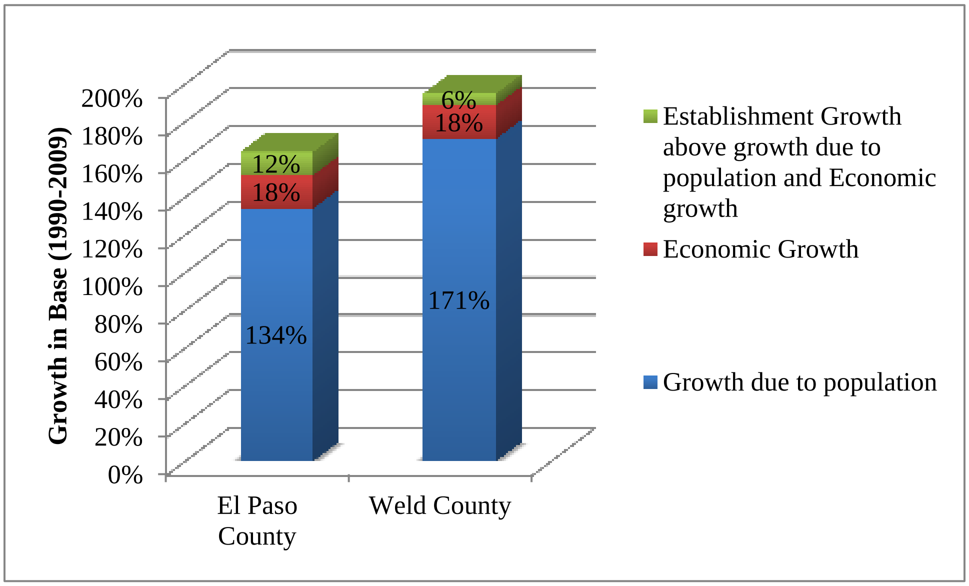

Figure 74. Comparison of Establishment Growth of Food and Eating Establishments (Weld County vs. El Paso County: Growth 1990-2009)

The few industries covered in this section demonstrate the great impact of oil and gas extraction on a local community. The growth in these industries also further demonstrates that communities with oil and gas development retain the potential to see increased growth in many industries due to the spending that occurs in these areas due to drilling and extraction of oil.

[330] University of Virginia Library, County Business Patterns: 1980-2001 County Level Data, Geospatial & Statistical Data Center
[331] University of Virginia Library, County Business Patterns: 1980-2001 County Level Data, Geospatial & Statistical Data Center
[332] U.S. census Bureau, County Business Patterns, 2009 Data Set

4.3.6 Summary of Induced Impacts

To maximize the impact of the induced section, it is important for both El Paso County and the City of Colorado Springs to focus on the industries that directly work with the oil and gas industry. Areas to focus on that would be critical to support growth of oil and gas development and increasing the revenue base within the county would include the following support industries: Wholesale Trade, Construction, Real Estate, & Food and drink establishments. Wholesale trade is important at both the induced level and indirect levels because it provides goods and services all along the oil and gas supply chain. Wholesale trade for the oil and gas industry consists of establishments such as welders, pipe supply and journey tradesman, among others. Similarly, food and drink establishments would also be extremely important because of the popularity of restaurants among oil and gas employees. Additional induced facts would result as the population increases. A city or county, such as Colorado Springs or El Paso County, or Colorado Springs that encourages these types of businesses will be able to generate additional tax revenue where oil drilling takes place by focusing on these sectors.

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5 Tax Impact

The tax impact analysis of oil and natural gas production in Colorado includes review of taxes at the Federal, State, County, and City levels. Each level has specific taxes and exemptions for oil and natural gas production. There are additional tax implications to consider in the State of Colorado, El Paso County, and the City of Colorado Springs.

5.1 Federal Tax Impact

U.S. oil and natural gas companies pay more in taxes compared to the average manufacturing company. In 2009, oil and gas companies paid 48.4 percent of net income in taxes compared to 28.1 percent of net income for the rest of the S&P industrials (Figure 75). There is a 20-point gap between the oil and gas companies and the other S&P industrials. U.S. oil and gas companies also pay the federal government significant rents, royalties, and lease payments for production access, totaling more than $100 billion since 2000.

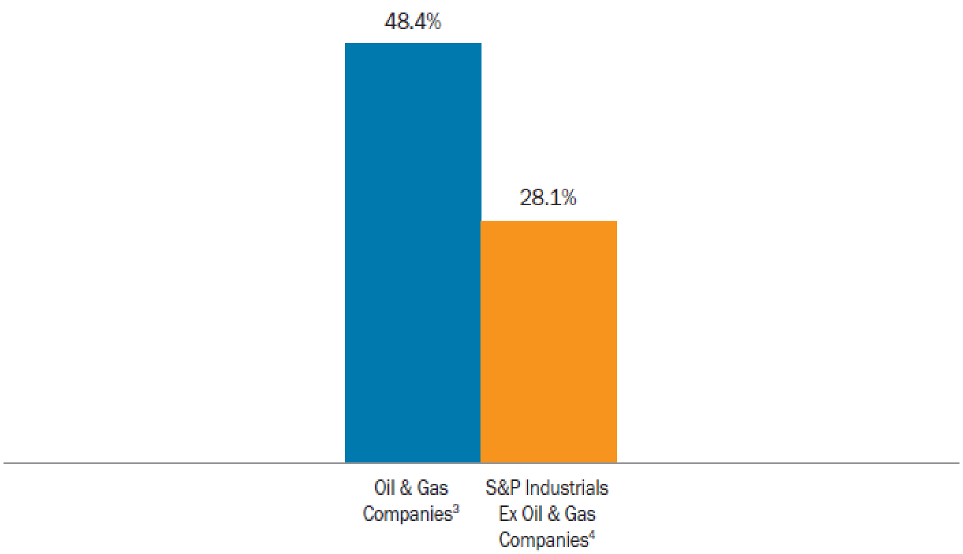


Figure 75. Income Tax Expenses as Share of Net Income before Income Taxes (2009)[333]

The oil and natural gas industry has an effective tax rate above the federal statutory rate of 35 percent because its operations generate state income tax obligations or payments in addition to federal taxes. U.S. based oil and gas companies must structure their operations and invest substantial capital where the resource is found rather than where the best tax options are.

[333] (Putting Earnings into Perspective 2012)

5.2 Colorado State Business Taxation

Colorado has an attractive tax climate for business. Colorado's taxation is equitable and broadly based. Examples of the high legislative priority placed on business taxation issues include the elimination of the state and county sales and use tax on manufacturing equipment, and the reduction of the corporate income tax rate to a flat 4.63 percent. The Colorado legislature has provided for reductions in personal property tax on equipment, allowed for fees for credit card operations, and allowed for certain sales tax exemptions. Taxes affecting businesses are briefly described below. Certain incentives exist which could modify tax calculations, such as location or expansion in the El Paso County Enterprise Zone.[334]

Retail Sales Tax: The tax to be collected and remitted by a retailer on sales taxed under City Tax Code.

Retail sales of most tangible goods are subject to sales taxes. Exceptions are gasoline, newspapers, food purchased in grocery stores, medical prescriptions, and items bought for resale. Most services are not taxed. Sales tax rates are as follows: State, 2.9 percent; El Paso County, 1.0 percent; City, 2.5 percent; Pikes Peak Rural Transportation Authority, 1.0 percent. This totals 7.4 percent on retail purchases made within the city of Colorado Springs. Throughout the state, retail sales tax rates vary by city or county.

Use Tax: The tax paid or required to be paid by a purchaser or consumer for using, storing, distributing, or otherwise consuming tangible personal property or taxable services inside the city.

The state and city impose their respective use taxes on most business purchases that are not intended for resale. Use taxes generally apply when items are purchased outside of the state or city and brought into jurisdictions without payment of a comparable rate of sales tax elsewhere. The use tax rates are the same as the retail sales tax rates noted above. The state and city each levy their own use taxes. El Paso County imposes 1.0 percent use tax only on the purchases on construction materials and automobiles.

5.3 How Colorado Compares to Other States

5.3.1 State and Local Taxation

Throughout the state of Colorado, there is as much revenue collected at the local level as at the state level. Fiscal year 2009 U.S. census data shows that 53.69 percent of all state and local tax receipts were generated by Colorado's local governments. In the collections per capita of state and local taxes, Colorado ranked 27th among 50 states for fiscal year 2008. Colorado ranks below most other states in state taxes, but above most states in local taxes. Colorado compares more favorably when 2009 state and local taxes are expressed as a percentage of personal income. Colorado ranks 42nd based on U.S. Census data. Colorado's

[334] (Colorado Geological Survey 2012)

tax collection per $1,000 of personal income was $86.00 versus the national average of $98.00. [335]

5.3.2 Property Taxes

Per capita property taxes in Colorado were $1,242 and the national average was $1,346 in fiscal year 2008. Based on property taxes per capita, Colorado ranked 21st among 50 states.

5.3.3 Sales Taxes

Colorado's state sales tax burden is low, while local sales taxes are higher compared to the other states that collect sales tax. In fiscal year 2008, combined state and local sales taxes were $1,066 per capita, slightly higher than the national average of $1,000.

5.3.4 Income Taxes

In 2008 Colorado ranked 19th among the 43 states with an individual income tax. Fiscal year 2009 taxes were $876 per capita. [336]

5.3.5 Overall

In October 2009, the Tax Foundation rated Colorado's "Business Tax Climate" as 15th best of the 50 states. [337] Colorado compares very favorably to other states and scores in the top nine states with a low individual income tax because of the single low tax rate. As seen in Figure 76, Colorado ranks 34th for State and Local Tax burdens overall for fiscal year 2008.

[335] (Colorado Geological Survey 2012)
[336] (State Fact Finder Series State Rankings 2011)
[337] (Background Paper: State Business Tax Climate Index 2010)

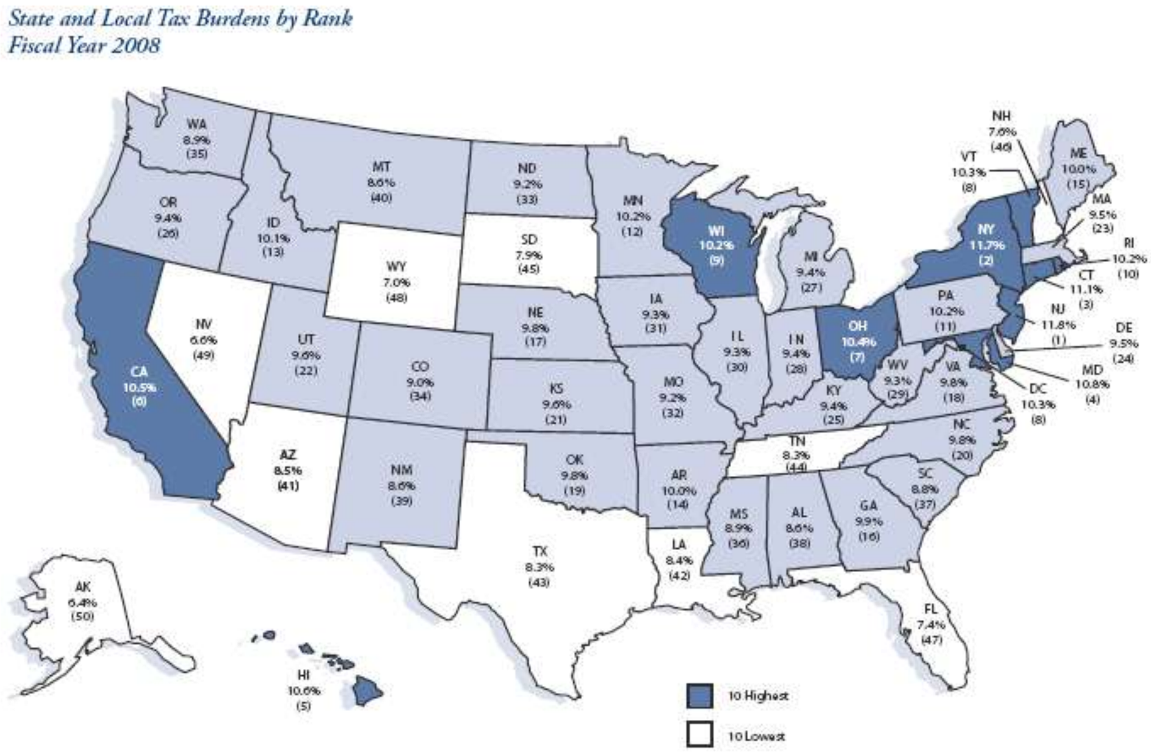


Figure 76. 2008 State and Local Tax Burdens by Rank[338]

5.4 Colorado State Tax Impact on Production of Oil and Natural Gas

The state of Colorado levies three direct taxes on production of oil and natural gas. Some of the tax paid at the local level can be deducted from the state severance tax to provide revenues and encourage public investment and job creation in energy-producing counties.

Colorado Tax Structure

- The State.
- The County where the production occurs.
- The Colorado Oil and Gas Conservation Commission (COGCC).

State Severance Tax: A tax on what is “severed” from the earth, i.e. oil, gas, minerals. This is a progressive tax in Colorado going up to 5 percent, depending on sales volume.

Table 22 shows the progressive tax. Tax income to the state is volatile due to fluctuating prices and output of oil and gas.

[338] (Tax Foundation 2008 No. 163)

Table 22. Colorado Severance Tax Rates [339]

Colorado Gross Oil and Gas Income	**Colorado Severance Tax Rate**
Under $25,000	2% of Gross Income
$25,000 - $99,999	$500 plus 3% of the excess over $24,999
$100,000 - $299,999	$2,750 plus 4% of the excess over $99,999
$300,000 and over	$10,750 plus 5% of the excess over $299,999

Colorado statute exempts stripper well oil production from severance tax (Colorado's Revised Statute 39-29-105(1)b): "except that oil produced from any wells that produce fifteen barrels per day or less of oil and gas produced from wells that produce ninety thousand cubic feet or less of gas per day for the average of all producing days during a taxable year." Severance revenues from oil and gas for Colorado's fiscal year 2009 were $274 million. This accounted for 96 percent of all Severance Revenues ($285 Million).[340]

Stripper Well: A mature well whose output has declined to a point where operating the well costs more than the generated revenues. The well still produces oil and gas. This tax exemption allows existing wells to be operated longer by offsetting the operating costs and thus decreases the amount of new wells and surface disturbance. These wells would become uneconomic and have to shut earlier than necessary without Colorado's Stripper well severance tax exemption. Stripper wells contribute approximately 17.8 percent of domestic oil production and 9 percent of domestic gas production.[341]

County Ad Valorem Tax: An Ad Valorem tax is based on the assessed value of the property being taxed. In Colorado, local governments tax oil and gas production at an assessed value of 87.5 percent. By comparison, residential property is assessed at 7.96 percent of value while commercial property is assessed at 29 percent. Local Ad Valorem rates range from 4 percent to 15 percent throughout Colorado. The Ad Valorem Tax rate is 8 percent for Weld County, 7 percent for Garfield County, and 7 percent for El Paso County.

The purpose of the local ad valorem tax is to ensure that revenues stay in the local communities that have mineral development operations. Colorado's Revised Statute (CRS) 39-7-102 establishes that in the case of oil properties: "the assessor shall value such oil and gas leaseholds and lands for assessment, as real property, at an amount equal to eighty-seven

[339] (Colorado Oil and Gas Conservation Commission Home Page 1997)
[340] ((DOLA) 2010)
[341] (Quick Facts 2012)

and one-half percent of the selling price of the oil and gas sold there from during the preceding calendar year…"[342]

In Colorado, working or royalty interest owners can reduce their severance tax liability by filing Colorado tax form DR 21. Under Colorado law, severance taxes can be reduced by a credit equal to 87.5 percent of the ad valorem taxes paid. Working or royalty interest owners can receive a full refund of severance taxes, depending on the applicable severance and ad valorem tax rates. The total production taxes paid can be limited to the ad valorem tax rate as a result.

Severance and Ad Valorem Tax Volatility: Severance tax and ad valorem tax on production are driven by prices and volume. Tax revenues from oil and gas production have been difficult to predict due to price volatility. Additional severance tax volatility occurs because of the timing of the ad valorem tax credit. The two taxes are not aligned with the same production year. The severance tax payment and reporting cycle are completed by the middle of the year following production. The ad valorem tax cycle is not complete until two years after production. The ad valorem tax credit generated by a given year's production is not available until the severance tax cycle ends in the fourth year after production for cash basis tax payers. The timing is of no real consequence when prices and production are relatively flat, as is often the case with mature wells. The timing difference can be significant.

New wells produce large volumes of oil and gas in the first couple of years before production levels off. There is no ad valorem credit available for cash basis taxpayers to use against the severance tax associated with high production years. The ad valorem tax credit is based on the first year's production (high volume and high tax year) and is applied to a different year's production (low volume and lower tax year) often eliminating the severance tax altogether. Ultimately, there is misalignment in the two taxes with the same production year. This misalignment creates volatility and difficulty forecasting future revenues.

The volatility associated with progressive taxes based on production volumes creates windfalls in years of high price and production and can contribute to deficits in years of low price and production. An unexpected drop in price and/or production can create revenue shortfalls for local governments.

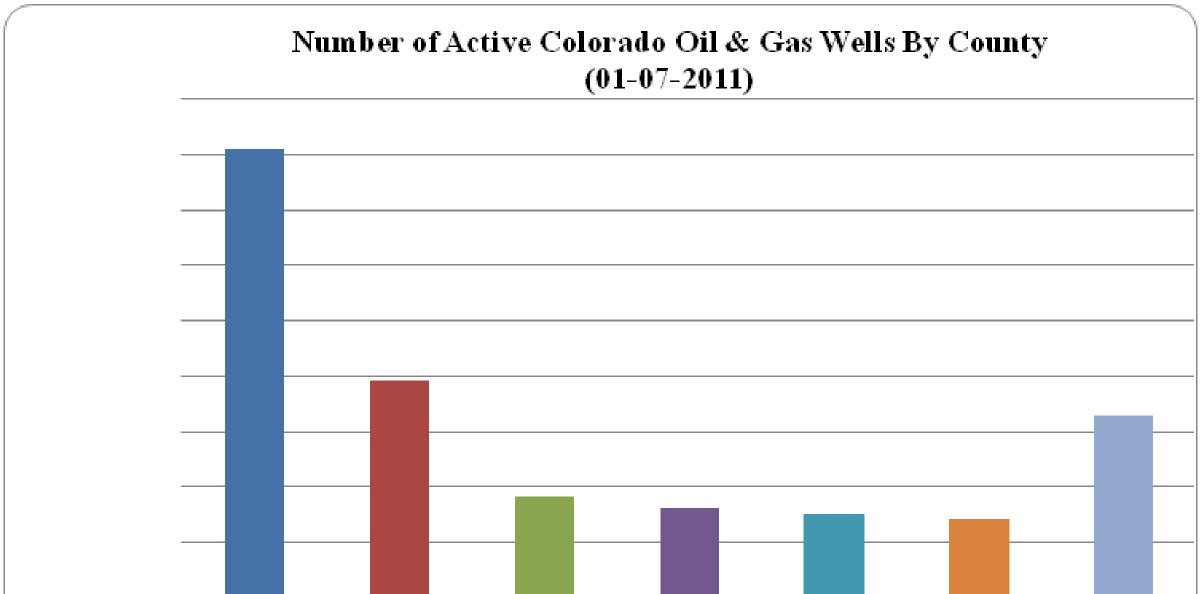
5.5 County Tax Impact

Oil and gas production in El Paso County has yet to be proven successful. A look at Weld and Garfield Counties provide insight to the potential economic impacts. More specifically, how the production levels and value may impact local government budgets. Mark Lowderman, El Paso County Tax Assessor, recently addressed oil and gas production in El Paso County. He said, "The County stands to receive roughly $9,000 a year from a primary oil well that generates $1.2 million a year in production. A less-productive well is

[342] (Colorado Oil & Gas Industry Tax 2011)

assessed at a lower rate and might generate only $700 a year in property taxes,"[343] His examples were from actual wells in Weld County.

Figure 77 shows the total number of active wells by county. Garfield County has 7,825 active wells and received $46.6 Million in tax revenues which equates to $5,955.27 per active well. This is subject to the production of the well and the current price for oil and gas. The dollar amount changes based on the level of price and production as Ad Valorem taxes are progressive. There will be resulting tax revenues if El Paso County produces oil and gas. The success of Garfield and Weld County do not guarantee similar results in El Paso County.



	Weld	Garfield	Yuma	La Plata	Las Animas	Rio Blanco	36 Other
# of Wells	16,195.00	7,825.00	3,644.00	3,243.00	3,033.00	2,827.00	6,565.00

Figure 77. Active Wells by County [344]

Garfield County property tax revenues, as shown in Figure 78, the County received over $40 million in property tax revenue in 2011 and is estimating over $50 million in 2012. Garfield County reported an additional $10 million in sales tax revenue as a result of sales taxes charged directly to companies within the industry, sales taxes charged to companies that supply or support the industry, and sales taxes generated as a result of spending by households who are employed directly or indirectly by the oil and gas industry.[345]

[343] (Wineke 2012)
[344] (4th Quarter Report to BOCC 2010)
[345] (Dawson 2011)

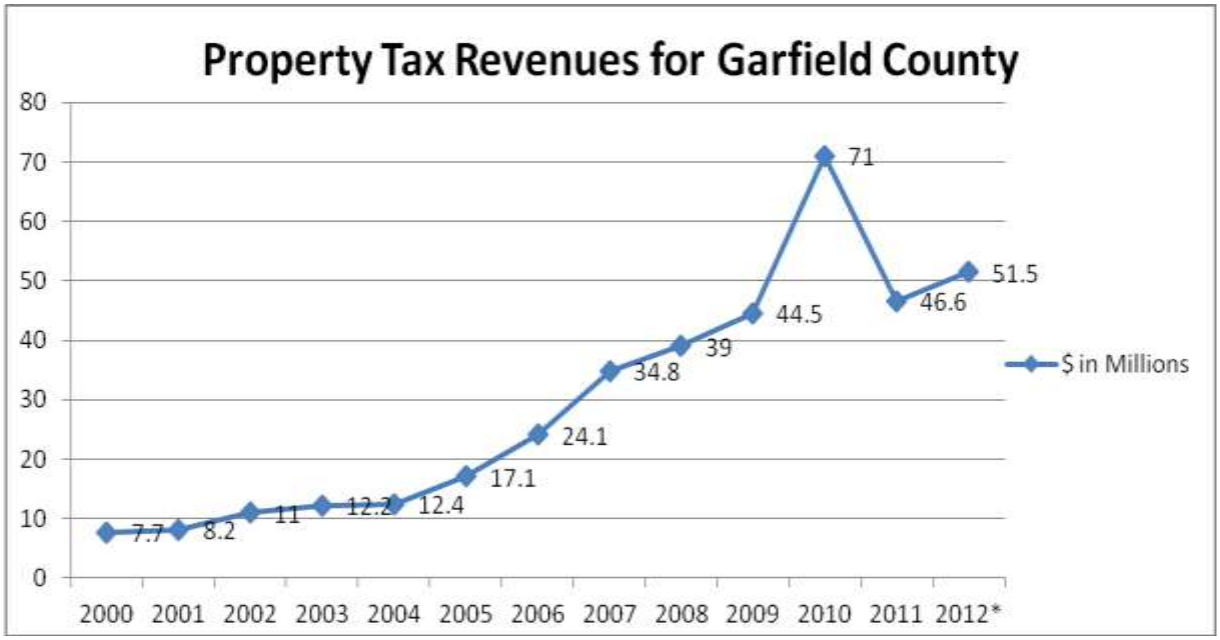


Figure 78. Property Tax Revenue for Garfield County[346]

Weld County has also seen the benefits of tax revenues from the oil and gas industry. Weld County reported over $20 million in revenue from oil and gas development in 2009. In 2011, Weld County reported no long term debt. Weld County has also done away with its county sales tax. Weld County collects no sales tax and is the only county in Colorado to be free of long-term debt. There are other factors including conservative budgeting and other government policies such as purchasing land for open space or parks. Clearly, the presence of a successful oil and gas industry has contributed to the financial well-being of Weld County government.[347]

El Paso County outstanding debt was $126,023,921 as of the end of 2008.[348] This amount of debt is relatively small when compared to other counties in Colorado. Figure 79 includes outstanding debt in larger population counties across Colorado.

[346] (Dawson 2011)
[347] (Whaley 2011)
[348] (www.colorado.gov 2011)

Figure 79 Long-term Debt, by County, in Colorado[349]

5.6 City of Colorado Springs Sales Tax Rate

The current combined sales and use tax rate for the City of Colorado Springs is:

- 2.5% Colorado Springs (as of January 1, 2002 - present)
- 2.9% State of Colorado
- 1.0% El Paso County
- 1.0% Pikes Peak Rural Transportation Authority
- 7.4% Combined Sales and Use Tax

[349] (Whaley 2011)

Sales and use taxes are collected on tangible personal property only. Sales and use tax is, effectively, one tax. Use tax assessed if items are purchased outside of Colorado and no “external” sales tax liability exists. This is equivalent to Sales Tax.[350]

Distinctions between Sales and Use Tax

The primary distinction between the sales tax and use tax is the sales tax is collected by persons engaged in business in Colorado Springs from the purchaser, and that person pays the tax to the city. The use tax is levied directly upon the person who purchases the commodities or services, either within or outside the city, and uses them in Colorado Springs. The person must remit the tax directly to the city, together with returns, showing the purchase and the use of articles which are subject to the tax.

Any person engaged in business in Colorado Springs and making sales of property or specific services is subject to the sales tax in accord with City Tax Code. Even those not maintaining an office in the city must collect and remit the sales tax on these sales in like manner as City residents collect and remit the sales tax.

Sales Made Outside the City

Every retailer is required to collect the tax imposed by this City Tax Code, including, but not limited to, the following situations:

Solicitation By Retailer: The consumer's order or the contract sale is delivered, mailed or otherwise transmitted by the consumer to the retailer at a point outside of the City as a result of solicitation by the retailer through the medium of a catalog or other written advertisement or by any other means; or

Closing Contract Outside City: The consumer's order or contract of sale is made or closed by acceptance or approval outside the City or before the tangible personal property enters the City; or

Procurement Or Manufacture Outside City: The consumer's order or contract of sale provides that the property shall be, or it is in fact procured or manufactured at a point outside of the City and shipped directly to the consumer from that point of origin; or

Transportation Costs: The property is mailed to the consumer in the City from a point outside the City or delivered to a carrier, FOB, or otherwise, and directed to the retailer in the City regardless of whether the cost of transportation is paid by the retailer or by the consumer; or

Delivery Outside City: The property is delivered directly to the consumer at a point outside the City; provided that in subsections A through E of this section, the property is intended to be brought into the City for use, storage or consumption in the City. (1968 Code - 3-74; Ord. 76-168; Ord. 91-161; Ord. 01-42)

[350] (Colorado Geological Survey 2012)

The sale of tangible personal property shall be exempt from the operation of this City Tax Code if both the following conditions exist:

- The sale is to a person who resides or does business outside the City; and
- The article purchased is to be delivered to the consumer outside the City by common, contract or commercial carrier who is employed to effect delivery by the seller, or by the conveyance of the seller, or by mail, provided that the article purchased and delivered is to be used, stored, distributed or consumed outside the City. (1968 Code 3-75; Ord. 76-168; Ord. 91-161; Ord. 01-42) [351]

Sales and Use Tax Exemption on Manufacturing Equipment

Machinery and machine tools in excess of $500 are exempt from State (2.9%), County (1.0%), and Pikes Peak Rural Transportation Authority (1.0%) sales and use tax. Colorado Springs has an exemption that phases out the rate of tax on manufacturing equipment purchased in a calendar year. The phase out of the tax starts when purchases exceed $5 million, and the rate of tax is incrementally reduced to 0 percent when total purchases exceed $20 million.[352]

The city may exempt from sales tax the purchase of existing manufacturing machinery and equipment located within the city only if the new owner retains and uses the equipment located within the city. The purchase may be exempt from city sales tax if the new owner retains and uses the equipment for manufacturing and maintains the same (prior) level of employment for two years.

City of Colorado Springs Property Taxes

The Constitution of Colorado states that taxes for all property must be equally assessed and levied. Personal property that is for non-business use is exempt. El Paso County is responsible for assessment and collection of all property taxes in El Paso County.

Components of Property Tax Calculations:

- Market Value of Property.
- Assessment Ratio.
- Mill Levy.

Market Value of Property: The County Assessor, in accordance with state regulations, estimates actual market value of real property. The company subject to audit by the County Assessor must declare the value of commercial and industrial personal property.

Assessment Ratio: The assessment level for commercial and industrial real and personal property is 29 percent of market value. This is subject to adjustment every other year.

[351] (Article 7 Sales and Use Tax 2009)
[352] (Business Taxation 2010)

Mill Levy: Mill levies are independently set by various taxing authorities; i.e., county, city, school districts, library district, special districts, etc. The average total mill levy in 2009, for application 2010, was approximately 67 mills.

5.7 Oil and Natural Gas Royalties

Oil and natural gas leases contain a royalty clause where the royalty is the landowner's share of the gross production, which is free of the costs of production. The royalty is the most important part of the lease to the landowner. The costs of drilling and producing a paying oil or gas well are divided between the production company and the landowner. The production company bears the exploration, production, and marketing costs unless there is a clause in the lease that states differently. Expenses that occur after production can be borne by the production company or shared by the production company and the landowner.

The royalty clause can specify the royalty be established at the well. Which means the landowner's royalty payment is free of production costs. The landowner's royalty can also bear a share of the costs that occur after production. A new set of costs occur and are part of the deductions from the royalty if the lease reads that the royalty is fixed in the pipeline or at the place of sale or at some other delivery point. The landowner is subject to taxes on the royalty from the production company. The landowner can also be subject to the cost of moving the oil or gas from the well to the refinery and storage tanks.

Royalty interests on a lease can be sold in part or in the entirety by the landowner. A royalty can be split among several persons, such as surviving relatives and family members for the life of the lease.[353] According to Interior Secretary Ken Salazar, the Interior Department is considering a proposal to calculate royalties using a market price based on the geography of a region in Colorado. The change would streamline the current royalty process, in which the department conducts complicated analyses to determine the royalties owed to the government.[354]

Federal oil and natural gas royalties are generally 12.5 percent of production value.[355] Federal oil and natural gas royalties are projected to decrease primarily due to the decrease in projected prices. Colorado oil and natural gas royalties have been adversely affected by oil and gas prices. Colorado collected $122.9 million in royalties from mineral production on federal land in 2007. This was a 16.5 percent decrease from the year before and the first drop since 2002. Colorado's portion was fourth-largest in the U.S. Wyoming led all states with $925 million. This is followed by New Mexico with $553 million and Utah with $135 million.[356]

[353] (How Royalties are Calculated 2006)
[354] (Staff-Posted 2011)
[355] (Colorado Oil & Gas Association 2011)
[356] (Vuong, Colorado mineral royalties drop 16.5% 2007)

5.8 Taxpayer Bill of Rights (TABOR): Revenue Limit

The Taxpayer Bill of Rights (TABOR) – Article X, Section 20 of the Colorado Constitution – limits the state's revenue growth to the sum of the inflation plus population growth in the previous calendar year. Under provisions of TABOR, revenue collected above the TABOR limit must be returned to taxpayers, unless voters decide the State can retain the revenue. In November 2005, voters approved Referendum C, which allows the State to retain all revenue through FY 2009-10, during a five-year TABOR "time out." Referendum C also set a new cap on revenue starting in FY 2010-11. Table 23 summarizes the forecasts of TABOR revenue, the TABOR revenue limit, and the revenue cap under Referendum C.

Beginning in FY 2010-11, the amount of revenue that the State may retain under Referendum C (line 9) is computed by multiplying the revenue limit between FY 2005-06 and FY 2009-10 associated with the highest TABOR revenue year (FY 2007-08) by the allowable TABOR growth rates (line 6) for each subsequent year. The Office of Strategic Planning and Budgeting does not project that any refunds will occur during the forecast period (line10).

TABOR requires that the population estimates used to determine the revenue limit be adjusted every decade to match the federal census. The 2010 federal census indicates that Colorado's population was overestimated during the 2000s decade. The percent change in population (line 4) that will affect the FY 2011-12 revenue limit was lowered in order to account for this overestimate.

Table 23. TABOR Revenue & Referendum C Revenue Limit[357]

Line No.		Preliminary FY 2010-11	December 2011 Estimate by Fiscal Year FY 2011-12	FY 2012-13	FY 2013-14
	TABOR Revenues:				
1	General Fund /A	$7,057.7	$7,353.5	$7,436.0	$7,900.3
	Percent Change from Prior Year	*8.9%*	*4.2%*	*1.1%*	*6.2%*
2	Cash Funds	$2,366.9	$2,445.5	$2,498.2	$2,514.3
	Percent Change from Prior Year	*13.3%*	*3.3%*	*2.2%*	*0.6%*
3	**Total TABOR Revenues**	**$9,424.6**	**$9,799.1**	**$9,934.2**	**$10,414.7**
	Percent Change from Prior Year	*10.0%*	*4.0%*	*1.4%*	*4.8%*
	Revenue Limit Calculation:				
4	Previous calendar year population growth	*1.8%*	*0.1%*	*1.4%*	*1.5%*
5	Previous calendar year inflation	*-0.6%*	*1.9%*	*3.5%*	*2.3%*
6	**Allowable TABOR Growth Rate**	***1.2%***	***2.0%***	***4.9%***	***3.8%***
7	TABOR Limit	$8,654.4	$8,827.5	$9,260.0	$9,611.9
8	General Fund Exempt Revenue Under Ref. C /B	$770.3	$971.6	$674.2	$802.8
9	**Revenue Cap Under Ref. C /C**	**$10,684.9**	**$10,898.6**	**$11,432.6**	**$11,867.0**
10	*Amount Above/(Below) Limit*	*($1,260.2)*	*($1,099.5)*	*($1,498.4)*	*($1,452.4)*
11	TABOR Reserve Requirement	$282.7	$294.0	$298.0	$312.4

Dollar Amounts in Millions

[357] (The Colorado Outlook 2011)

Colorado Springs is the only city in Colorado that is subject to two TABORs – a city law and a state law. The city TABOR law is generally considered to be more restrictive. Even if TABOR provisions were relaxed, the changes would not relieve local conditions.

The TABOR dollar figure for the City of Colorado Springs is established through a calculation based upon inflation and local growth during the previous year. If the previous year's revenue collections were less than the TABOR limit for that year, then the lower figure – the actual collections – are used in the formula to compute the current year's TABOR limit.

The law requires the excess to be returned to taxpayers in years when revenue exceeds legal cap. Alternatively, elected officials may ask voters – through an election – for permission to retain the money. The City of Colorado Springs revenue has exceeded the cap nine times since TABOR was enacted in 1991. Voters have permitted the City to keep the average five times for specified capital construction projects. Voters have received a refund four times and the refund has averaged approximately nine dollars per household.[358]

5.9 Federal Mineral Leasing Revenue

The federal government and the state of Colorado realize a share of revenue from production activity when federal lands are leased for mineral extraction. Continued production on federal lands, particularly in northwest Colorado, is expected to increase Federal Mineral Leasing (FML) revenue. Lower natural gas prices in 2012 will temper the FY 2012-13 potential increases. Table 24 outlines the forecast of FML revenue in Colorado. FML revenue comes from the federal government and is exempt from TABOR.

Table 24. Federal Mineral Leasing (FML) Payments [359]

Fiscal Year	Bonus Payments	Non-Bonus Payments	Total FML Revenue	Percentage Change
FY 2009-10	$5.20	$117.20	$122.50	-46.1%
FY 2010-11	$2.26	$147.2	$149.48	22.0%
FY 2011-12	$5.1	$165.0	$170.10	13.8%
FY 2012-13	$6.1	$168.6	$174.70	2.7%
FY 2013-14	$9.5	$179.7	$189.13	8.3%

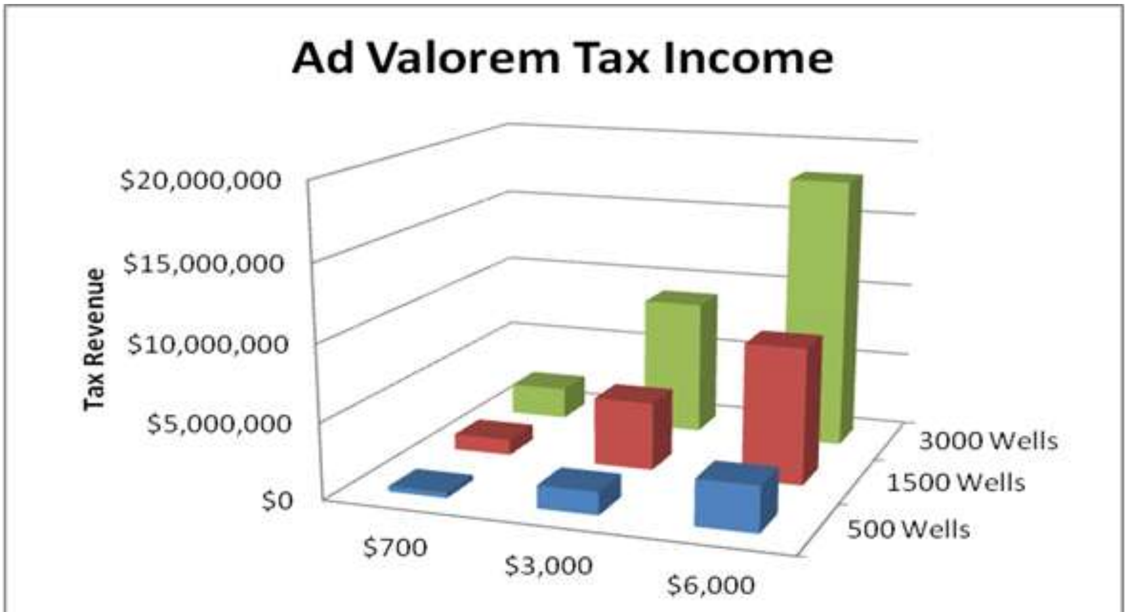
Dollar Amounts in Millions

FY 2009-10 and 2010-11 figures reflect actual collections, and FY 2011-12 through FY 2013-14 are projections.

[358] (Public Communications Department of the City of Colorado Springs 2008)
[359] (The Colorado Outlook 2011)

5.10 Potential Tax Revenue

The most significant tax revenue for El Paso County would be the Ad Valorem Tax if oil and gas production is successful. El Paso County would collect taxes based on the value of oil and gas sold. Ad Valorem Tax rate is progressive and increases with the production value. Tax revenues would be dependent on the price of oil and gas and the level of production. Wells tend to be high producers in early years and level off in later years. Their taxable revenue would change throughout their serviceable life. Figure 80 includes potential tax revenues. The potential tax income can range from $350,000 in the most pessimistic prediction and up to$ 18 million in the most optimistic prediction.

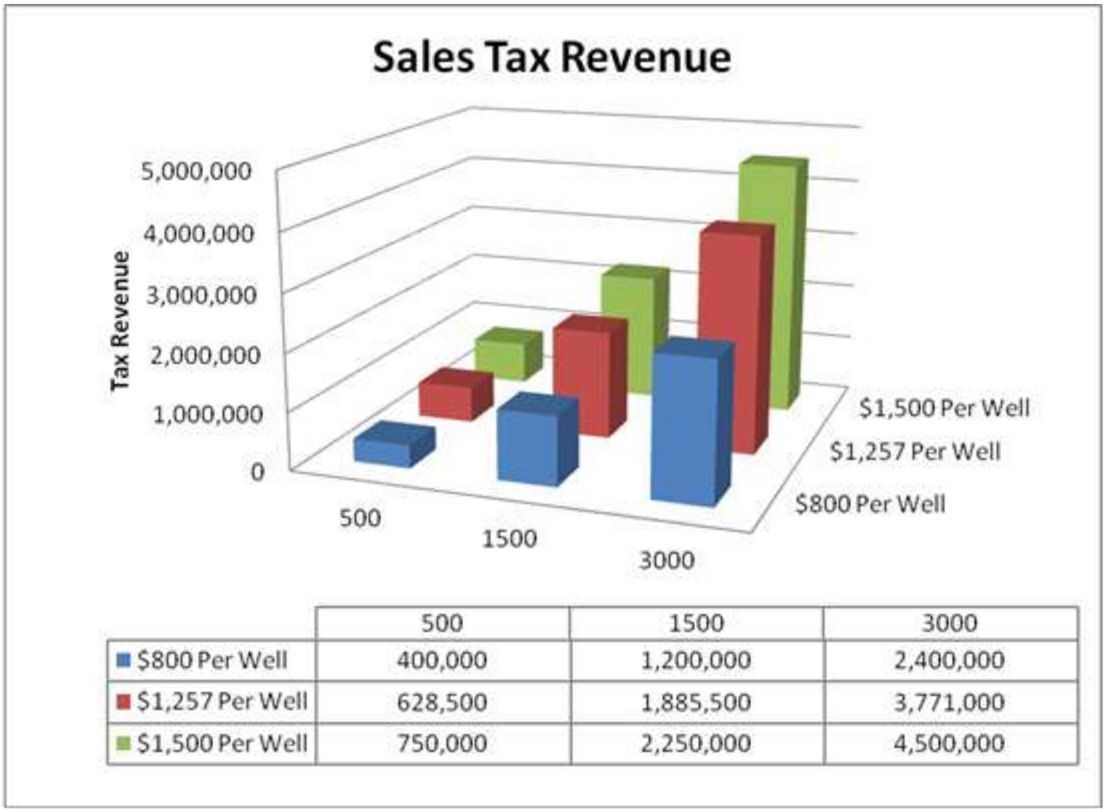


	$700	$3,000	$6,000
500 Wells	$350,000	$1,500,000	$3,000,000
1500 Wells	$1,050,000	$4,500,000	$9,000,000
3000 Wells	$2,100,000	$9,000,000	$18,000,000

Figure 80. Projected Ad Valorem Tax Income by Activity Level

5.11 Sales Tax Revenue

Oil and Gas industry sales tax revenues are more modest but still significant. Sales tax revenues depend on the local rate of taxation and the level of activity that can be taxed. A way to estimate the potential tax revenues for El Paso County would be to refer Garfield and Weld Counties. In 2011, Garfield and Weld Counties had 7,825 and 16,195 active wells respectively. Garfield County reported sales tax revenue of $10 million whereas Weld County reported sales tax revenue of $20 million. The average tax revenue per well for Garfield County equals $1,278 and for Weld County equals $1,235 by comparing active wells to sales tax revenue. Figure 81 shows the potential sales tax revenues for El Paso County based on the average for Garfield and Weld Counties of $1,257 per well.



	500	1500	3000
$800 Per Well	400,000	1,200,000	2,400,000
$1,257 Per Well	628,500	1,885,500	3,771,000
$1,500 Per Well	750,000	2,250,000	4,500,000

Figure 81. Projected Sales Tax Revenue by Activity Level

5.12 Income Tax Revenue

Table 25 represents average wages for a select field within the oil and gas industry. The table also displays the potential estimated income in total and on a per employee basis.

Table 25. Wages within the Oil and Gas Industry[360]

Industry*	Average Wage	Estimated Colorado Effective Tax Rate	Employ-ment estimate	Total Wages (Millions)	Estimated Income Taxes (Millions)	Estimated Income Taxes Per Person
Extraction	$133,962	2.69%	8,661	$1,160.3	$31.21	$3,603
Drilling Wells	$79,680	2.85%	2,142	$170.7	$4.86	$2,271
Total - Selected Wages				$1,331.0	$36.08	$5,874

** Data only for selected fields within oil and gas industry.*

360 (United States Census Bureau 2012)

The following is an estimate of level of employment for drilling in El Paso County:

Table 26 outlines the estimated income taxes at a state level based on the assumed number of wells and related employees.

Table 26. Projected Income Tax by Activity Level

Number of Wells	Estimated Peak Direct Employees	Estimated Income Taxes for Drilling
500	729	$1,655,472
1,500	1,557	$3,535,760
3,000	2,484	$5,640,866

5.13 Additional Impacts

Weld and Garfield Counties are used as comparisons to show the potential economic impacts that El Paso County could experience. Weld and Garfield counties differ from El Paso County in that they both have mature oil and gas industries. Oil and gas production has yet to be proven successful in El Paso County. El Paso County may not ever have an oil and gas industry as successful as Weld and Garfield Counties. The oil and gas industry has direct, indirect, and induced benefits which are difficult to quantify their effect on a local economy. The oil and gas employees would spend their income at local establishments in turn additional sales tax income would be gained. Additional property taxes would also be gained for those employees who purchase properties. A boom in the oil and gas industry may also lead to suppliers locating to the area which would add further benefit to the local tax impact.

A successful oil and gas industry could contribute to the deterioration of local roads. Local roads would have more wear and tear by trucks servicing the wells than to normal vehicle traffic. Quantifying this impact would depend on the costs to resurface roads and what portion of this cost would be attributed to the oil and gas industry versus normal use.

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6 Real Estate and Housing Impact

6.1 Oil Booms

There are many instances of boom towns around the country resulting from the extraction of oil and natural gas. North Dakota towns have been inundated as thousands of workers migrate into small rural communities to take part in drilling oil and gas wells. Towns in Wyoming, Texas, Pennsylvania, and the Western Slope of Colorado have seen similar effects that are related with oil and gas extraction. As workers flood these towns to take part in new drilling operations, vacancies decrease quickly, housing values rapidly appreciate, and there is additional demand for new businesses and schools. A recent Huffington post article talks about local schools in the Town of Williston having to absorb 450 new students with an additional 1,200 expected the following year. Additionally, the Mayor of Watford City describes how McKenzie County is expected to grow from 1,750 people to over 7,500 people. The economic impact to these communities is significant as thousands of jobs are required meet the additional demands on the infrastructure, real estate market, and local businesses.[361]

6.2 Scope

The purpose of this section of the study is to examine the induced economic effects of oil and gas drilling and to see how that activity is related to population migration, housing prices and rental rates, and whether or not drilling in El Paso County is likely to lead to new development in the real estate market. Housing activity is a common measure of economic activity and lends insight into how a community is growing.

6.3 Three-County Comparison

The following counties were examined to see the relationship between drilling and real estate trends: Sublette County, WY, Garfield, CO, and Weld County, CO. These counties are important to the study because they vary in size from small to large and allow the examination of effects in three different sized communities.

6.3.1 Sublette County

Sublette County is a small rural county in Western Wyoming with three small towns; Pinedale, Cora, and Mableton. A study of Sublette county conducted by the Sonora institute

[361] (Huffington Post 2012)

highlights a 22 percent population gain from 1990-2000. This percentage increase in population makes Sublette one of the fastest growing counties in Wyoming over the time period. In order to gain a better perspective, it is important to consider the actual size of the population growth which grew from 4,843 in 1990 to 5,920 in 2000. At the time of the study, the future growth for the county was projected to be an additional 17 to 30 percent increase by 2014. The last estimate in 2010 shows the population at 10,247, a 73 percent increase since the year 2000. This equates to an annual growth rate of 7.2 percent per year, which exceeded previous population projections for the county. Most importantly, over half the growth in population and new home construction was believed to be attributed to the production of new oil field drilling.[362] The Sublette county assessor's offices highlights data that show single family home prices nearly doubled between 2000 and 2005 from $126K to $249K. Additionally, rental rates nearly doubled as well from $566 a month in 2000 to $1,195 per month in 2006.

The following figures (82, 83, 84 ad 85) summarize these price patterns and incorporate the drilling activity over the same period. In order to examine the relationship between drilling activity and home prices, the data is presented as an index measurement. The index methodology is described below:

A baseline year is established for home values measuring the average home sales price or Home Price Index. A baseline for well or rig counts is also established. Yearly changes are measured against the baseline year to see any changes in the relationship between the two data sets.

Equation 13.

Baseline Housing index= HPI_1 / HPI_1 ..., $HPI_2/HPI_{1\ldots}$

Equation 14.

Baseline Well Index= Well # in $year_1$ / Well # in $year_1$ ..., Well # in $year_2$ / Well # in $year_1$

[362] (R. Carpenter 2004)

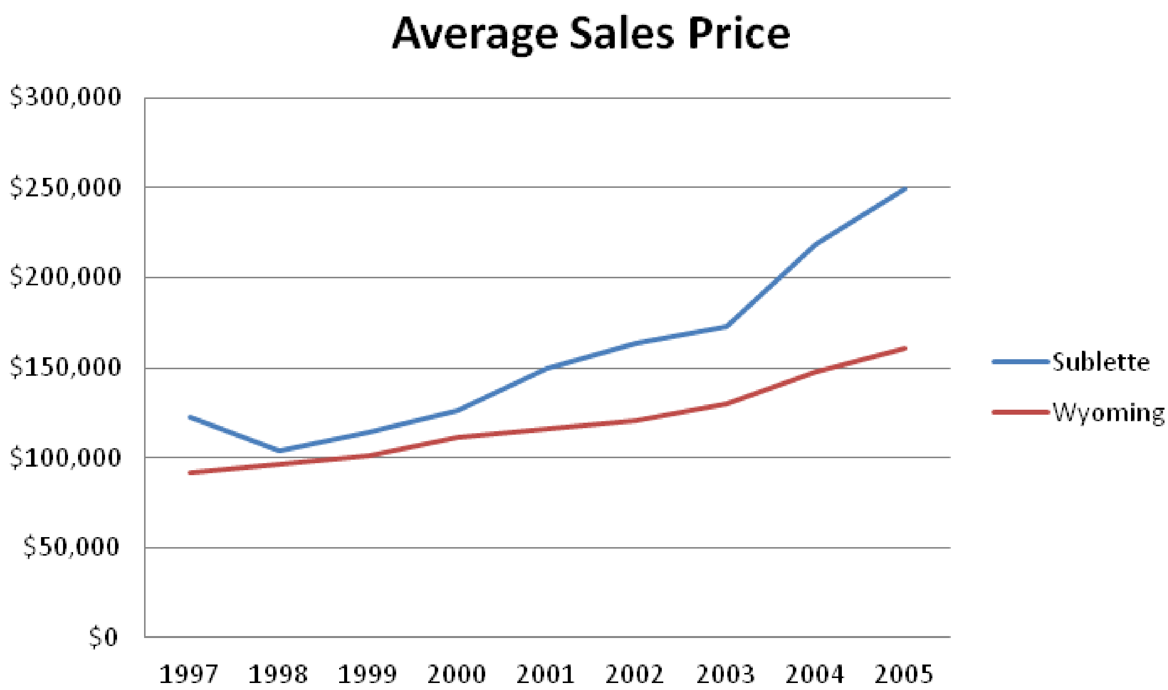

Figure 82. Average Home Sales Price Sublette County vs. Wyoming

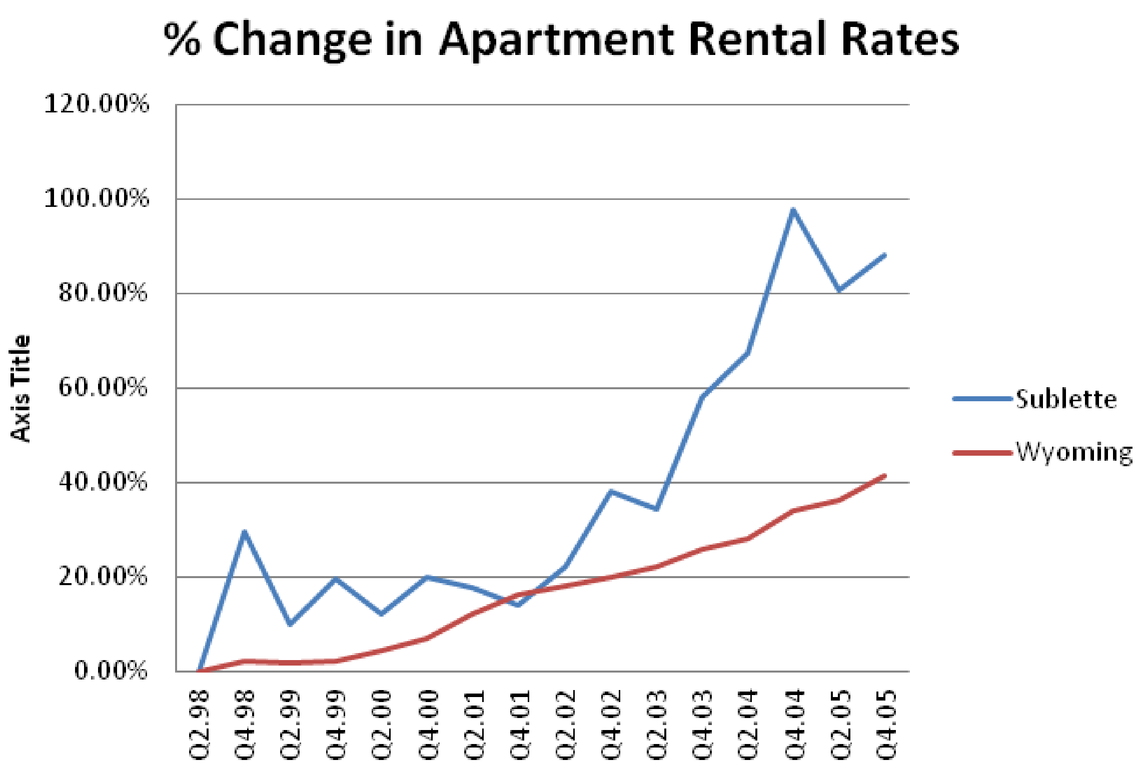

Figure 83. Percent Change in Apartment Rental Rates Sublette County vs. Wyoming

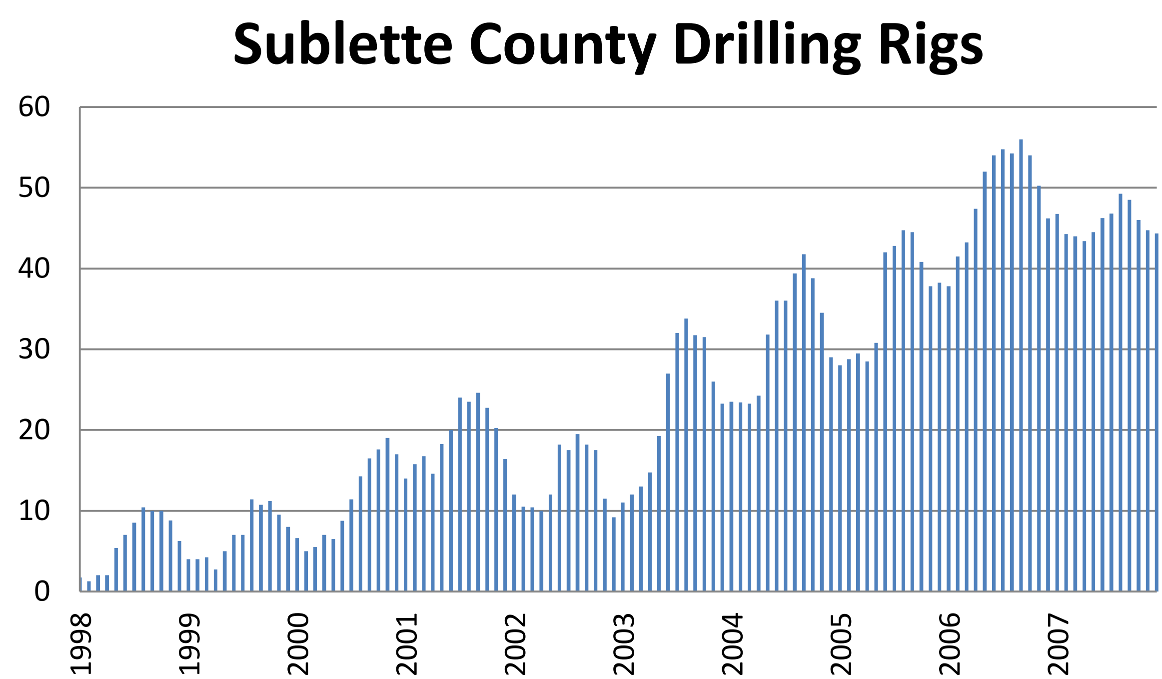

Figure 84. Rigs Operating in Sublette County

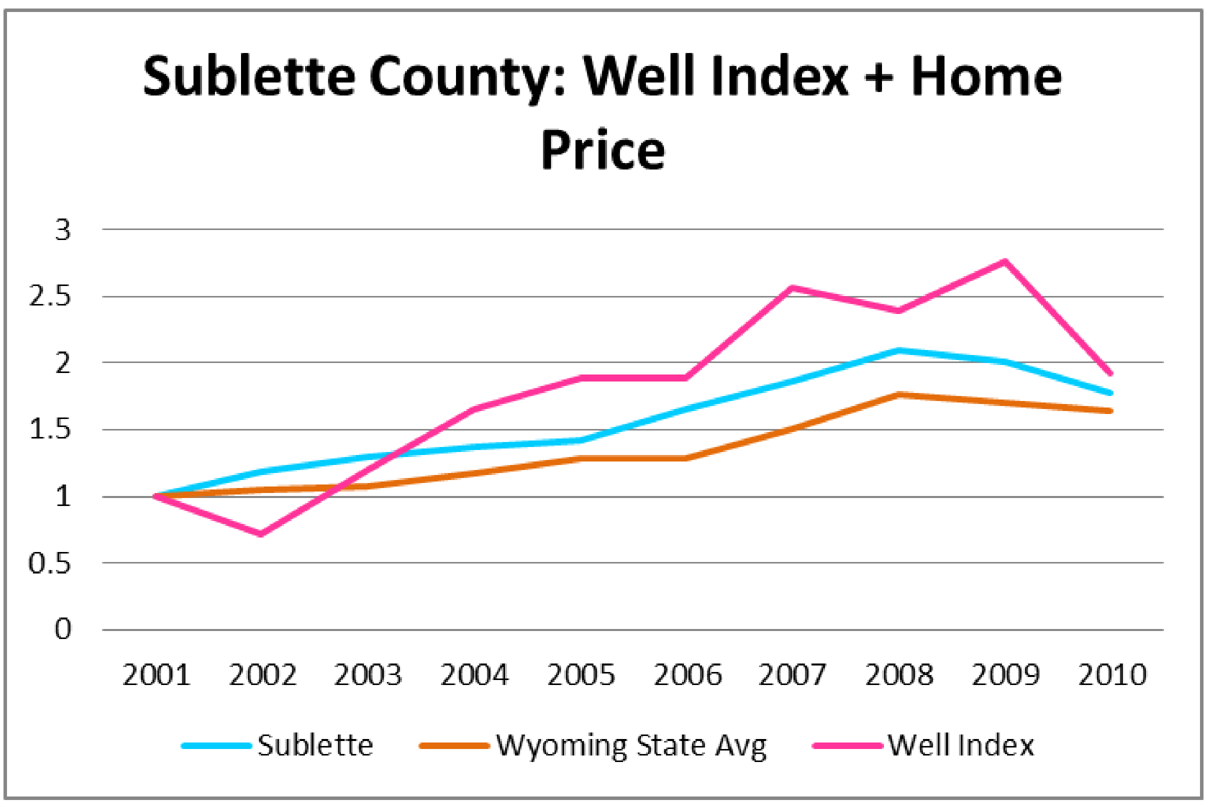

Figure 85. Sublette County Housing Index Compared to Rig Index

Drilling rigs in Sublette County increased from 2 in 1998 to around 30 operating rigs in 2005. Actual wells drilled from 2000 - 2005 are estimated at 1,400. During the years 2000-2005, Sublette County added and estimated 1,000 new permanent residences and had a significant amount of temporary residents entering the area. The patterns of temporary migratory workers are hard to assess, but their impact is significant on small rural communities as they quickly drive up prices for homes and apartment rents.

6.3.2 Garfield County

Garfield County Colorado is one of several oil producing Counties in Colorado. It has a significantly larger population than Sublette County. With several towns in the County, Garfield has grown from 47,388 people in 2003 to 56,139 as of 2011. The average home price in Garfield is much higher than the state average. Garfield is an attractive mountain county that is popular with retirees and owners of second homes looking to enjoy the many amenities in the area. The index measurement chart suggests that homes values and well drilling were trending together until the height of the real estate bubble in late 2007. Post-recession drilling activity grew and homes prices have continued to fall. The data suggest there may be no relationship between drilling activity and home prices in Garfield County.

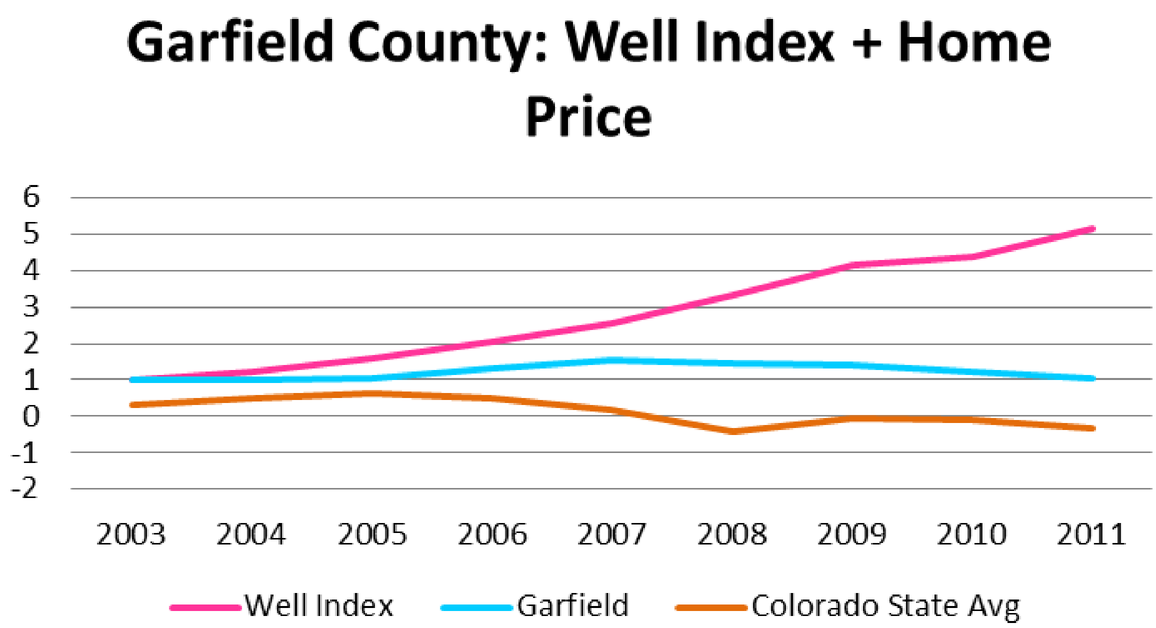

Figure 86. Garfield County Home Values Compared to Well Index

6.3.3 Weld County

Weld County, Colorado, has both a very rich agricultural economy and contains the highest amount of oil and gas wells of any county in Colorado. The county's population has grown from 210,635 in 2003 to 254,270 people in 2011. The index measurement obtained for Weld County shows an even more drastic divergence of the two data sets. Home values started falling in 2005 and continued to fall through the recession. During this same time period, well drilling activity grew significantly. Overall well counts grew from approximately 8,700 in 2003 to nearly 17,000 wells in 2011.

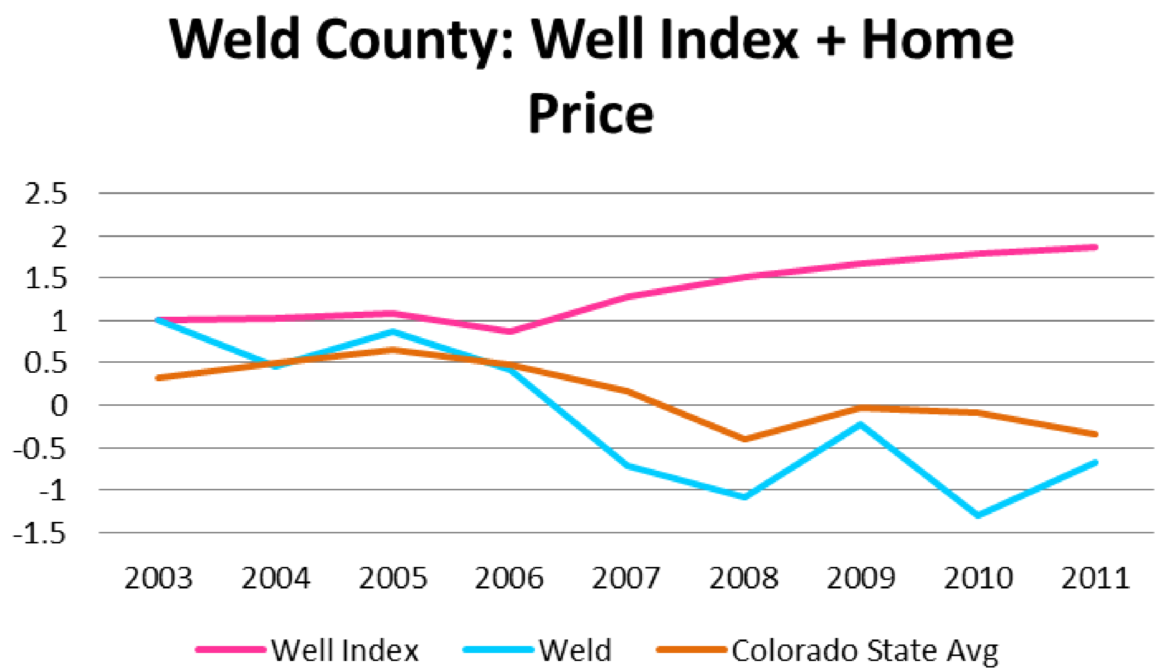

Figure 87. Weld County, Colorado Home Values Compared to Well Index

6.4 Initial Conclusions

After examining the effects that oil and gas drilling has on the real estate market of the three sample counties, it appears that the extent of the impact is related to the population size of the community. There is an inverse relationship between the size of the community and the net effect that oil and gas drilling has on the real estate market. Small rural communities are much more susceptible to dramatic "boom town" growth. As the community size increases, the effects on the real estate market decreases dramatically. The series of index measures show that a relationship between home values and drilling activity is especially hard to determine in higher populated counties. El Paso County is significantly larger than Weld County. The population of El Paso is currently estimated at 626,929. Future drilling will not have a significant influence on housing demand because El Paso County is a developed metropolitan area that can absorb hundreds, if not thousands of new residents in any given year. An examination of the demographics and workforce trends provides additional insight into housing demand.

6.5 Demographics and housing trends

When assessing the impacts of net migration from drilling operations, it is important to consider the housing trends that have been observable in other counties. The typical pattern follows a large initial migration of temporary drilling employees followed by a slightly smaller reduction of personnel as wells enter into their productive life phases. This has created a migratory pattern where a large sudden influx of people enter a town to take part in the initial drilling phase, but may or may not reside within the community unless they are continually drilling new wells in the area. This migratory workforce will typically reside in man camps, RVs, hotels, and rental apartments or homes.

Garfield county and Sublette county have had increased demand to house temporary workers. In Sublette County, there were an estimated 3,000 temporary workers in 2007. Half of the workers are believed to have permanent residences outside of the county. The remaining portion occupied hotels, apartments, RVs and man camps.[363] Trends in Garfield County follow a similar path where an estimated twenty to thirty percent of all hotel rooms and campsites are occupied with oil and gas workers at any given time.[364]

There is evidence that a portion of temporary workers would move into the community as full time residents. However, most workers are prohibited by high costs and limited availability. A survey of temporary workers in Sublette County revealed the following information about temporary worker preferences.[365]

Half of temporary workers revealed they were not considering relocation. The remaining half was considering relocating to become home owners or renters. The thirty percent of workers wanting to purchase a home cited they were prohibited by home availability and high prices. The price sensitivity of temporary workers in Sublette County revealed the following price points for home purchases and rental rates.

363 (Jacquet 2007)
364 (BBC Research & Consulting 2007)
365 (Jacquet 2007)

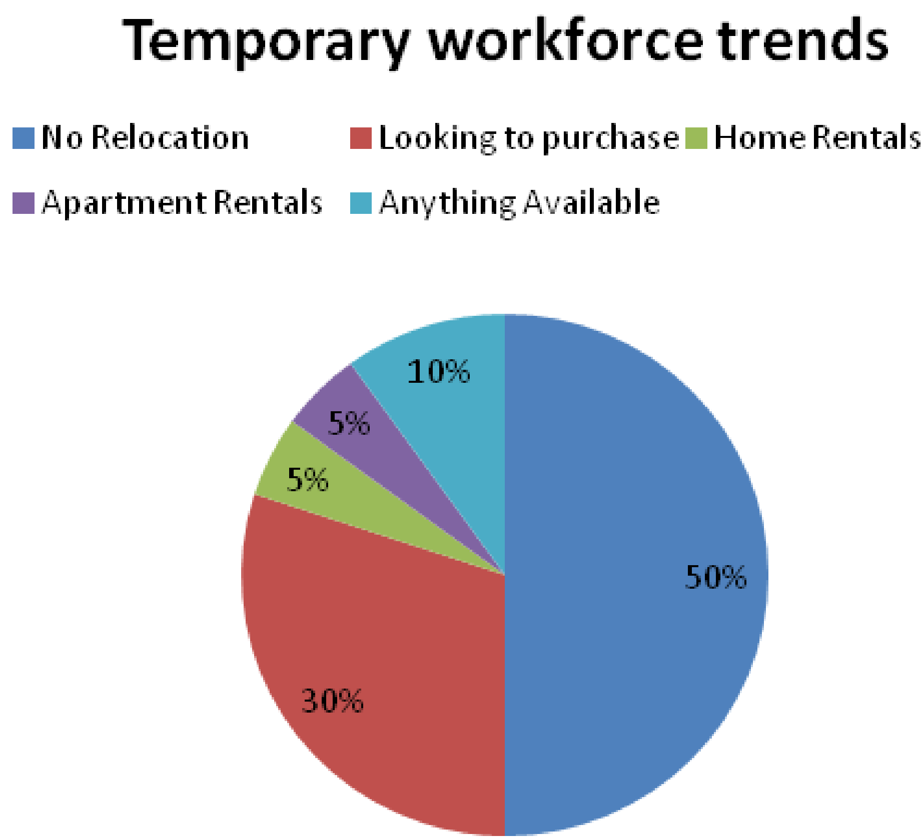

Figure 88. Temporary Workforce Housing Trends

Roughly half of survey respondents said their limits were in the range of $500 to $750 per month. Twenty one percent indicated they would require costs below $500 per month. The remaining 32 percent indicated that they would be willing to pay from $750 to $1,250 per month.

A projection for housing demand in Colorado Springs was based on these same survey results. Colorado Springs has a large real estate market that could accommodate the needs of a temporary workforce. The large majority of workers that require living expenses below $750 would find many options with apartment rentals. The remaining 32 percent of workers may find single family and townhomes priced from $140,000 to $250,000. This range is based on the observed median wage of $86,177 in the oil and gas sector. Three scenarios summarize the results of the housing demand forecast in Table 27. Demand includes both direct permanent employment and an estimate of temporary workers who may relocate to the community.

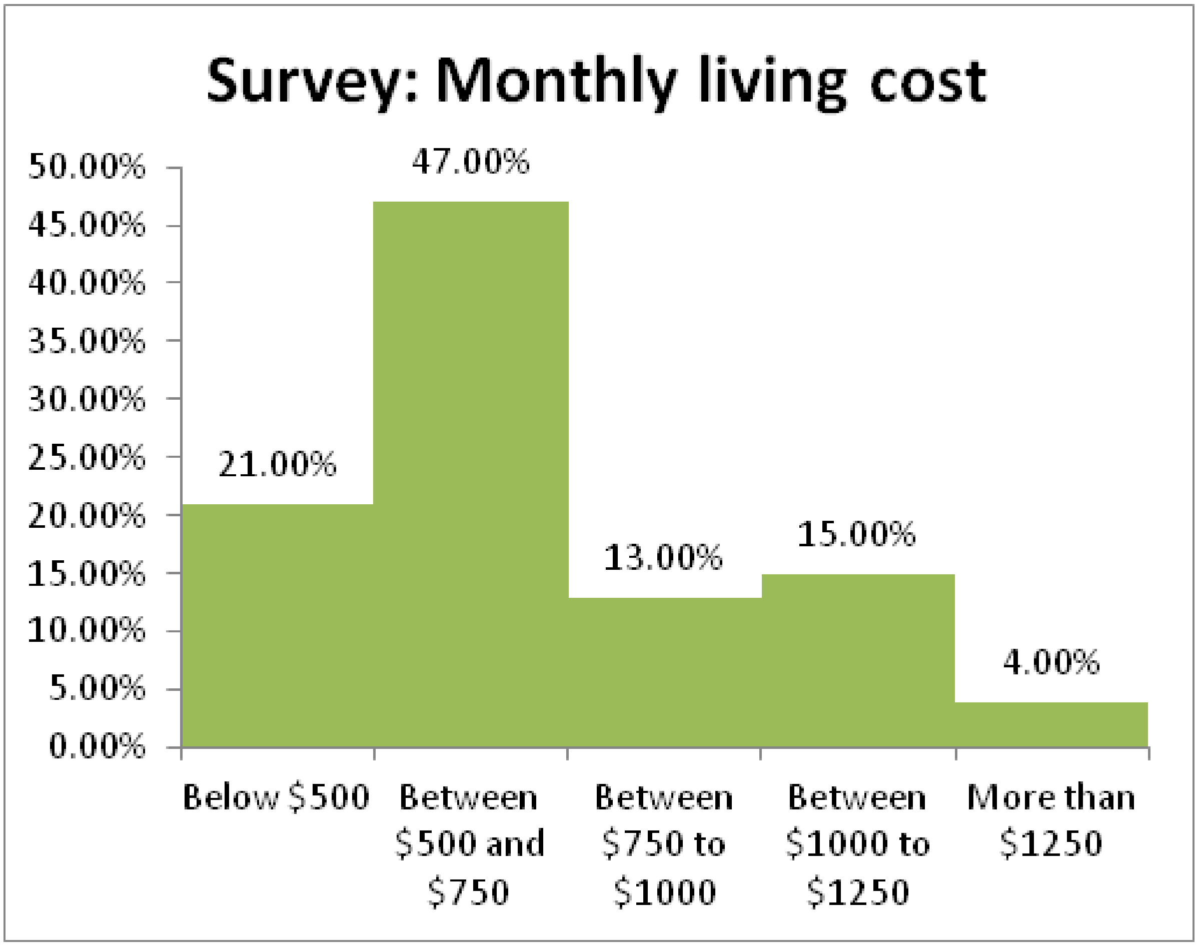

Figure 89. Sublette Co. Monthly Housing Costs

Table 27. Projected Housing Demand in El Paso County

	Permanent Jobs	Temporary Jobs	New Residents	Single Family Homes	Apartment Units
Low (5 rigs)	143	1,098	692	221	471
Mid (10 rigs)	429	2,344	1,601	512	1,089
High (15 rigs)	858	3,739	2,727.5	873	1,855

6.6 Housing Demand Conclusions

New residents will find many options in the Colorado Springs housing market. A larger demand on apartment rentals is to be expected over home purchases. The current inventory of available and apartments is large enough to accommodate the migration associated with these levels of production. The Colorado Springs MLS shows there are 3,118 single family homes actively listed in Colorado Springs as of February 2012. While this is a 22.48 percent reduction in the number of active listings from this time last year, it is still believed to be more than adequate to meet the demands created by oil and gas drilling operations. As of Q4 2011, the vacancy rate for multifamily rentals in Colorado Springs was 6.7 percent. While this is a relatively low vacancy rate which reflects a tight rental market, it is not expected to create any problems accommodating the population of migratory and permanent drill workers.

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1 Financial Feasibility Criteria

In this section, the financial feasibility of drilling for oil and gas on the Banning Lewis Ranch in El Paso County, CO is analyzed. Additional scenarios for various levels of activity in El Paso County as a whole are also considered. The only differences in these scenarios are the number of wells and the pace at which they are drilled.

As with any project that involves an investment in capital assets, capital budgeting criteria need to assess expected profitability before the investment should be made. The financial feasibility section is designed to inform the reader in making the choice to accept or reject this project.

To facilitate this process, a decision framework model was created using various financial analysis techniques that leverage a variety of inputs. Net Present Value (NPV), the technique used most often in these types of decisions, was employed with other techniques used to complement it. While the model enables the user to manipulate variable values as needed, a base case was created by researching various sources. This base case scenario assigns values (default values) to each variable.

The scenario result provides an "Accept" decision based on the NPV of slightly over $700M. This result is based on conservative input values, which include the following:

Table 23. Base Case – Based on the Conservative Input Values

Wells Necessary	112
Horizontal Well Failure Rate	22.00%
Horizontal Dry Well Cost	$3,800,000
Horizontal Productive Well Cost (to production)	$4,700,000
Vertical Dry Well Cost	$300,000
Vertical Productive Well Cost	$750,000
Vertical Well Failure Rate	30.00%
WACC	11.27%
Operating Expenses (percentage of Revenue)	39.37%
Vertical Initial Oil Flow Rate Per Well	111.17
Horizontal Initial Oil Flow Rate Per Well	152.10
Rate of Decline of Oil Flow	8.00%
Initial Price of Oil (Per Barrel)	$106.00
Percent Change in Oil Price (requested from viewer)	2.30%

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2 Financial Feasibility Introduction

Is it financially feasible to drill for oil and gas in El Paso County, primarily at the Banning Lewis Ranch? This feasibility study attempts to answer this question by developing a capital budgeting model to assess expected profitability of drilling for oil in Banning Lewis Ranch and El Paso County. The model used data collected from various industry standard and non-industry sources. Where appropriate, industry sources verified the inputs used in the feasibility model when an independently verifiable source was not available. This analysis considers oil and natural gas flows sold when they have reached a market and are of tariff quality. No proprietary data were used. All data are available for public access

2.1 Background

Oil and gas exploration and production have existed in the resource-rich west for generations. While exploration and production is new to the area, El Paso County sits on the edge of a known oil field. With the advent of new drilling technologies and recovery methods, new plans to extract oil and gas from the ground in and around El Paso County are gaining steam. Ultra Petroleum purchased the Banning Lewis Ranch property along with lease rights to a much larger portion of El Paso County. Permit requests have been filed by Ultra Petroleum to drill several exploratory wells, which will then be followed by horizontal wells intended to produce oil from the Niobrara shale formation approximately 6,000 feet below the surface of El Paso County.

2.2 Study Purpose and Goals

This feasibility study takes the approach of creating a financial model based on capital budgeting techniques. This financial model projects a set of cash flows for the drilling project in El Paso County and Banning Lewis Ranch, determines the present value of these flows, and provides a recommendation (if and only if the present value of the future expected cash flows exceeds the investment cost). This scenario is more complicated than a typical capital budgeting project since cash outflows are made over time as drilling progresses and revenues begin to flow concurrently as the earlier wells come on line.

There are several tools generally accepted in the industry for deciding whether or not to invest in a project. NPV is generally accepted as the best capital budgeting criterion because it evaluates an investment decision relative to the goal of a firm – maximize shareholder wealth. The other criteria are also useful, depending on management’s objective.

All data used in the report are public information, or released for public exposure to the Ad Rem Team with permission to publish and reference the source. Oil and gas industry 10-K numbers are difficult to narrow down to a specific well or field. Therefore, every effort was made to provide an accurate assessment of operating costs and drilling expenses.

The overall economic feasibility of the project is largely dependent upon the future commodity prices and well production volume. Certain assumptions are necessary to reflect the properties of the wells in similar regions. Additionally, forward prices were used from the U.S. Energy Information Administration (EIA), which is less prone to bias than a producer or an end-user's price forecasts.

Table 24. Capital Budgeting Standards

Term*	Explanation
Weighted Average Cost of Capital (WACC)	The weighted average of the after-tax component costs of capital – debt, preferred stock, and common equity
Net Present Value (NPV)	The present value of a project's expected future cash flows, discounted at the appropriate cost of capital
Internal Rate of Return (IRR)	The discount rate that equates the present value of the expected future cash inflows and outflows, i.e. the break-even rate of return on the investment
Modified Internal Rate of Return (MIRR)	Rate of return on investment when all cash flows are reinvested at WACC
Payback period	The number of years it takes a firm to recover its project investment

*For a complete list of glossary terms please refer to Appendix A.

2.3 Study Scope and Approach

The feasibility study sought to obtain relevant and reliable information, use a consistent set of realistic assumptions, and produce unbiased information for the user. For capital budgeting purposes, expected cash flows were discounted to determine the expected economic value in the present.

The scope of this study is the financial feasibility of drilling for and producing oil and natural gas in El Paso County, primarily in Banning Lewis Ranch. The fundamental and yet most difficult step involved in capital budgeting is estimating project cash flows. Data were collected from various sources. The sources are cited throughout this report.

Due to a lack of available public records on specific well drilling, operation, and maintenance costs, an operating expense model is used where processing, transport, severance taxes, and ad valorem taxes were treated as part of an aggregate "operating expense" and are not itemized. The data and calculations presented in the report represent the best data available at the time of the report.

3 Ultra Petroleum Financial Overview

3.1 Ultra Petroleum Financials

The financial feasibility is not a financial analysis of Ultra Petroleum Corporation (UPC). However, a brief overview of UPC will prove insightful to establish the context of the discussion to follow. The following tables summarize financial conditions for Ultra:

Table 25. UPC Financial Condition[366]

INDUSTRY: Independent Oil & Gas

FINANCIAL CONDITION	COMPANY	INDUSTRY	S&P 500
Debt/Equity Ratio	1.19	0.50	2.04
Current Ratio	0.60	1.50	1.40
Quick Ratio	0.60	1.00	0.90
Interest Coverage	NA	10.00	28.90
Leverage Ratio	3.10	2.10	5.70
Book Value/Share	10.45	35.93	27.26

Table 26. UPC Profit Margins[367]

INDUSTRY: Independent Oil & Gas

PROFIT MARGINS %	COMPANY	INDUSTRY	S&P 500
Gross Margin	81.36	63.74	39.31
Pre-Tax Margin	64.52	6.82	17.77
Net Profit Margin	41.13	12.70	13.02
5Yr Avg., Gross Margin	80.50	58.00	39.60
5Yr Avg., Pre Tax Margin	38.20	-60.20	15.80
5Yr Avg., Net Profit Margin	24.10	-66.70	11.40

Table27. UPC Investment Returns[368]

INDUSTRY: Independent Oil & Gas

INVESTMENT RETURNS %	COMPANY	INDUSTRY	S&P 500
Return On Equity	33.17	25.48	28.33
Return On Assets	10.70	8.60	8.80
Return On Capital	12.30	19.30	11.60
5Yr Avg., Return On Equity	21.90	20.40	24.70
5Yr Avg., Return On Assets	8.10	7.90	8.10
5Yr Avg., Return On Capital	9.40	17.30	11.0

[366] (MSN Money 2012)
[367] (MSN Money 2012)
[368] (MSN Money 2012)

3.2 Ultra Petroleum in El-Paso County

UPC owns approximately 18,000 acres of land in the Banning Lewis Ranch east of Colorado Springs. It also owns land or mineral rights for 116,000 acres outside of Banning Lewis Ranch but within El-Paso County. The following information was obtained from Kelley Whitley, director of investor Relations with UPC.

As of the writing of this report, UPC has not decided on the number of wells it will drill on the Banning Lewis Ranch and elsewhere in El Paso County. The company anticipates the pace and scope of drilling operations would be dependent on how much capital it is willing to allocate toward the project annually.

UPC believes conventional plays and wildcat wells typically yield some level of success for an exploratory effort. UPC’s target in the Niobrara (and the Banning Lewis Ranch or the greater El-Paso County) is an unconventional play. This means that at the time of creating this report, it is unknown exactly how successful the exploration would be in the Banning Lewis Ranch and/or the greater El-Paso County area.

Additionally, UPC feels it will find oil in the area, but is uncertain if it would be economical to develop the project as a whole. UPC does not anticipate collecting or marketing natural gas products. UPC is approaching the project as purely an oil play.

4 General Model Framework

A financial feasibility model was developed in Microsoft Excel™. It was used to evaluate the expected benefits and costs to drill for oil in Banning Lewis Ranch. While hypothetical, the analysis can be applied to UPC. The model allows a user to conduct a sensitivity analysis on any of the inputs to the model.

This section of the report focuses specifically on how the framework was developed. The model outputs are discussed in sections five and six. Further, the model only evaluates the project's viability for the corporation and does not evaluate the economic impact to El Paso County or the potential environmental consequences. Those items are evaluated in earlier sections of the report. It is important to note that while Ultra Resources Inc. and its intentions are germane to this report, the model and the resulting feasibility study are independent of what firm actually engages in oil and gas development in this area. It is quite likely, depending on the level of success, that multiple oil and gas firms would be involved in the development in the local area.

The model has two data sets – a base case and a variable case. The base case used data developed from collected research and evaluates the project based on that data. The variable case operates as a "what if" scenario that allows for the manipulation of the input data and shows the corresponding changes in output. Either set of data can be scaled to various levels of activity. Four levels of activity are analyzed later in this report.

4.1 Model Objectives

When creating the model, a number of primary objectives designed to make the model both unbiased and reproducible were considered. These include only utilizing data that is externally verifiable, easily reproducible, incorporates project risk, and is adaptable to scenario changes.

4.1.1 Determine Profitability of Project Using Externally Verifiable Sources

The evaluation of the project was meant to be applicable to any natural gas and oil company, not specifically UPC, and was intended to show the project's benefit regardless if UPC decides to invest. To do this, all research was obtained from externally verifiable sources. A full list of sources and calculations is available in the appendix.

While it might have been possible to gain a certain level of proprietary data, it was determined that only publically available data should be used. Additionally, executives from both Anadarko and UPC evaluated and verified the data as being reasonable, giving the project a greater level of credibility.

4.1.2 Use of Conservative Estimates Due to the Riskiness of the Project

There is a great deal of risk associated with this project. While natural gas and oil have been collected in the Wattenberg Field region near Denver, Colorado, there have been few drilling attempts in the Banning Lewis Ranch and greater El Paso County region to date.

There is no guarantee oil or gas will be found, much less how long potential reserves will last. A single horizontal well is projected to cost an average of $4.7M if successful or $3.8M if unproductive. This represents an initial cash outlay and does not include the daily operating costs associated with running the well or the resources spent analyzing the project's potential payoff. This uncertainty is a significant risk factor.

Several steps were taken in model development to keep the results conservative: Extrapolated data for oil and gas revenues were taken based on conservative estimates, and higher expense estimates were used to avoid underreporting any costs. These items will be discussed in detail within this section of the report.

4.1.3 Methods of Project Evaluation

The project was evaluated using standard capital budgeting techniques. To find these values the annual net operating incomes for the project were calculated in the model. Once these calculations were complete, the project was evaluated using the formulas for net present value (NPV), internal rate of return (IRR), modified internal rate of return (MIRR), payback period, and discounted payback period. A weighted average cost of capital (WACC) was determined for use as the discount rate. The results of NPV, IRR and, MIRR are show in the following chart (Based on 112 Wells).

Method	Accept/Reject Criteria	Determined Value	Yes/No
NPV	>0	$715M	Yes
IRR	>WACC (11.27%)	54.24%	Yes
MIRR	>WACC (11.27%)	14.63%	Yes

4.1.4 Net Operating Income

The Net Operating Income is determined, to a large degree, based on the number of producing wells. First, annual oil revenues are determined. Annual operating expenses for the well are subtracted to find the operating income before taxes.

The means by which these costs are estimated will be discussed in part 6. The annual taxes are then subtracted from the operating income before taxes based on an annual corporate tax rate of 39.63 percent. From the resulting operating income, several non-cash expenses such as depreciation and interest expense are added back to find annual incremental cash inflow.

4.1.5 Net Present Value

The first capital budgeting technique used was Net Present Value (NPV). NPV is calculated by subtracting the initial cash outlay (cost) of a project from the present value of all future cash flows of the project. A positive NPV indicates the investment is expected to generate an economic profit. A negative NPV indicates the project is expected to have an economic loss. NPV requires taking the present value of the future cash flows at the risk adjusted cost of financing the project (WACC).

The WACC is the weighted average of the cost of financing a project. Normally, three components are considered. These are the costs of debt, common stock and preferred stock. The first step used to determine this project's WACC required estimating the typical proportional mix of capital used in the oil and gas industry.[369] This was done by reviewing industry data in the Value Line Investment Survey[370] from 1995 through 2010. The results showed virtually no preferred stock was issued. The remaining capital structure was 35 percent debt and 65 percent common stock.

The cost of common stock was obtained by applying the formula for the required rate of return. This is called the Capital Asset Pricing Model (CAPM). CAPM is a market based estimate of required return to risk. The model evaluates what return an investor should receive absent any risk, the premium on this return offered by the market, and the industry's risk compared to the market as whole to create a return an investor should expect to receive based on the level of risk. This value is called the required rate of return. The required rate of return for the industry was found to be 9.61 percent.

The debt portion was determined based on average corporate yield to maturity on publicly held bonds for the industry. Since debt is an expense that reduces tax expense, the cost of debt to the company is calculated to be the after-tax cost of debt. The before cost of debt was calculated to be 5.77 percent. The after tax cost of debt was determined to be 3.69 percent.

Based on these weights, the industry-wide WACC was found to be 7.51 percent. However, this is the rate of return that the company should require of itself as a whole. To keep conservative estimates and to evaluate the riskiness of the specific project, this number was then increased by 50 percent to create a project WACC of 11.27 percent.

4.1.6 Internal Rate of Return and Modified Internal Rate of Return

The second capital budgeting calculations used were the internal rate of return (IRR) and the Modified Internal Rate of Return (MIRR). These are used to determine what rate of return a project is expected to receive. Ultimately, the desire is for these numbers to be greater than the WACC. The IRR and/or MIRR need to be greater than the WACC to recommend a project. An accept/reject rule simplifies to this. If the WACC is greater than the IRR or MIRR, the project should not be undertaken.

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[369] Please refer to Appendix B for a detailed explanation
[370] (ValueLine Issue 12 2011)

The IRR solves for an unknown rate of return that produces a NPV of "0." The IRR assumes net cash flows are reinvested at the IRR. This can lead to optimistic estimates. A more conservative approach would use the MIRR. It assumes net cash flows are reinvested at the cost of financing (WACC). The rate of return that produces a NPV of "0" for this situation is the MIRR.

4.1.7 Payback period and Discounted Payback Period

The final capital budgeting techniques used in this analysis are payback period and discounted payback (Present Value Payback). Payback period is a measure of how many years the project takes to return the initial costs. It is obtained by keeping a cumulative cash flow. Payback takes place when the cumulative cash flow is equal to the cost. Discounted payback uses present value of cash flows to accumulate. Discounted payback takes place when the cumulative discounted cash flow is equal to the cost of the project. The cash flows are discounted at the WACC.

4.2 Revenue and Expense Formats

The model was developed with the intention to create a revenue and expense estimate that is both reasonable and externally verifiable. Much of the revenue data collected comes from oil and natural gas returns from the Wattenberg Field near Denver, Colorado. The industry costs were taken from cost percentages provided by the Risk Management Association (RMA) website.

4.2.1 Revenues Extrapolated from Oil and Gas Production Data

To create a reliable estimate of oil and gas flow, daily average flow rates where extrapolated from the Wattenberg Field oil and gas wells. To adjust for the statistical errors that might occur with a small sample size of wells, sample size was augmented with the bootstrap method. For oil, daily flow rates averaged 111.17 barrels of oil for a vertical well and 152.10 for a horizontal. To account for the steady decline of oil production from a functioning well over time, these production levels were reduced by 8 percent annually for oil and 6 percent annually for gas.

As of this writing (April 2012), the price for a barrel of oil is $106. A million cubic feet (MMcf) of natural gas is selling for $2. Since the current price of oil is expected to rise over time, the current price was then increased at an annual rate of 2.3 percent, a number lower than the expected rate of inflation. The estimated annual production level was multiplied by the projected yearly prices of oil to obtain projected annual revenues.

4.2.2 Expense percentages of revenue taken from RMA Data

To determine a reasonable operating expense estimate for each year, an average historic cost for the industry was taken from the RMA website. This data were represented as a function of revenue. The average operating expense of 39.37 percent was taken from the RMA site. A 12.5 percent royalty rate, payable to the land owner, was added to the RMA value for a total expense of 51.87 percent. It was multiplied by revenue to determine a dollar cost per year.

4.3 Model Calibration

The model is designed to allow for easy alteration. As previously mentioned, it has two aspects, a base case and a sensitivity (variable) case. The base case applies the capital budgeting techniques based on the independently verifiable data used in this report. This creates a realistic valuation of the Banning Lewis Ranch project. It can also be scaled to any level of activity. The data collected is based on industry wide averages, meaning this model serves as a reasonable model for any oil and gas company. The variable case works identically with the exception of allowing for a sensitivity analysis by altering any combination of the input variables. This allows the model to be calibrated for a change in the underlying assumptions or as a means of creating “what if” scenarios. The results of these changes are easily viewable through graphs that show the capital budgeting results from each case. A real-time spreadsheet is also available.

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5 Detailed Model Design

5.1 Model Inputs

The financial model design to evaluate the feasibility of the project uses the following inputs.

Initial Year	2012
Effective Tax Rate	39.63%
WACC	11.27%
Operating Expenses (percentage of Revenue)	39.37%
Interest Expense (percentage of revenue)	6.50%
Depletion Rate	15.00%
Royalties Rate	12.50%
Wells Necessary	112
Horizontal Well Failure Rate	22.00%
Horizontal Dry Well Cost	$ 3,800,000.00
Horizontal Productive Well Cost (to production)	$ 4,700,000.00
Vertical Dry Well Cost	$ 300,000.00
Vertical Productive Well Cost	$ 750,000.00
Vertical Well Failure Rate	30%
% of Productive Well Cost Attributed to Intangible Cost	80%
Building Cost Index	2.70%
Vertical Initial Oil Flow Rate Per Well	111.17
Horizontal Initial Oil Flow Rate Per Well	152.10
Rate of Decline of Oil Flow	8.00%
Initial Price of Oil (Per Barrel)	$ 106.00
% Change in Oil Price (requested from viewer)	2.30%
Will Gas Be Found/Harvested and Sold	YES
Vertical Initial Gas Flow Rate Per Well	26.60
Horizontal Initial Gas Flow Rate Per Well	162.97
Rate of Decline of Gas Flow	6.00%
Initial Price of Gas (Per MMcf)	$ 2.00
% Change in Gas Price (requested from viewer)	2.30%
Gas Gathering Line Required (miles)	8.00
Gas Gathering Line Cost (per mile)	$ 1,000,000.00
Interstate Pipeline Connection Cost	$ 1,500,000.00
Gas Refinement Infrastructure Cost	$ 10,000,000.00
Expected Economic Life of a Well	45.00

Figure 90. Model Input Variables with Default Values

These costs and percentages represent extensive research. All measures are available to the public and can be verified independently. The model attempts to answer the question of NPV using a present value series of future cash flows.

The WACC, or discount rate, represents the industry standard using appropriate values of debt and equity financing and a risk premium due to a field of unproven reserves. Costs for drilling a vertical and horizontal well were obtained from investor relations materials and validated with a separate entity in the industry. Much of the initial well costs are expensed as intangible drilling expenses while the balance of these costs are depreciated using the modified accelerated cost recovery system (MACRS). The price of oil and gas at the wellhead was established using Energy Information Administration (EIA) forward curves, corrected to the current price of oil and natural gas.

Based on the inputs in Figure 90, the model calculated the NPV, Payback, modified Payback, IRR and MIRR for the project. The model also allows the user to modify parameters in real-time to view their expected effect on the project's financial viability. This dynamic analysis tool allows the validity of the results to be challenged with different production values and commodity prices, as well as inflation rates and a changing cost of capital.

Tracing the model from the drilling and well finishing stages into the production years, the NPV quickly becomes positive. Strong rate of return values are well in excess of the WACC. The number of wells can be modified. The base assumption has been made that the exploratory wells will yield oil and the remaining wells to be drilled will be horizontal production wells.

Environmental reclamation is also included as an end of life cost for the well; the assumption is made that the well site will be restored to its original condition or better.

While obtaining data inputs for potential drilling in El Paso County, it was found that the target for this area is oil, due to a higher commodity price. Drilling for oil will likely result in some gas production, this production will require an additional infrastructure cost for processing and gathering. Accurate infrastructure costs were difficult to obtain. The most accurate estimates are represented in the inputs. The model recognizes an option that the producers may choose not to harvest this natural gas and flare it at the well head. The option to produce gas and interconnect with an intrastate pipeline is designed for in the model, and the user may turn it on or off as desired.

The model produces seven graphs:

1. Incremental Cash Flows
2. Cumulative Cash Flows
3. Oil and Gas Revenues
4. Discounted Oil and Gas Revenues
5. Discounted Cash Flows

6. NPV as a Function of Year
7. Net Present Value

These graphs have static and dynamic components. The base case is derived from the inputs in Figure 90. The dynamic component can be changed at the request of the user to demonstrate the impact of a requested change. Each of the 30 input variables has this functionality; once a variable is changed the graph will show 2 data series, the original base case, and the variable manipulated data. The model also has a reset button that restores all values to their original numbers.

5.2 Production Volume Forecast

Assumptions, based upon logical and timely values defined during the research period, have been made with regard to the production values that are included in this analysis. They are believed to be conservative to realistic.

First, comparative production areas were identified to develop the analysis. The areas included locations in Pennsylvania, North and South Dakota, Wyoming, Canada and northern Colorado. All of these areas have current production utilizing the "fracking" technique.

After evaluating each of these areas, the northern Colorado production field became the basis for production assumptions. This area is known as the Niobrara/Codell production area in the Wattenberg field. This area had many similarities with the potential drilling sites in eastern El Paso County that might explain potential oil production in El Paso County.

The geographic and geological similarities made sense to utilize this area as a comparison. The potential site in eastern El Paso County lies on the southern edge of the same geological formation that is in production in northern Colorado. Being within the same formation does not equate to the same production values, but does allow the assumption that a similar depth and breadth of each well as well as a basis for potential production.

Production values for existing wells in northern Colorado were obtained from the Colorado Oil and Gas Conservation Commission website.[371] Research showed that the production values can vary dramatically. The decision was made to utilize an average production value of newer wells to give base flow rates for oil and any potential gas production. Historical production decay rates would be applied to the base. The flow rate used is for newer wells only and does not take into account any re-fracking or re-drilling of existing wells. Flow rate information was gathered from areas within Weld County and utilized the statistical process of re-sampling to verify the findings.[372]

Resampling provides a relevant representation of potential flow rates. A "bootstrapping" effect was applied upon the data to find the mean production rate of a much larger sample to eliminate some of the issues with having a smaller sample size. This

[371] (Colorado Oil and Gas Conservation Commission Public Announcements 2011)
[372] Bootstrap resampling performed, based upon the Central Limit Theorem.

methodology takes the initial flow rates per well and extrapolates the findings multiple times to produce a normalized curve. The bootstrapping data analysis is in Appendix G.

The variable rate of yearly decline was initially set at a minimum of 8 percent for oil flow and at 6 percent for gas production. This was based upon findings within the United States Geological Survey report.[373]

5.3 Variable Values and Relevant Ranges

Some inputs such as commodity prices, WACC, well failure rate, and inflation are beyond the control of all parties and are an exposed risk. In the analysis, an attempt was made to consider a range where each variable could be considered "relevant."

For example, the price of oil is not expected to go below $50 or exceed $150 in the next 5 years. However, it could. The sensitivity analysis capability of the model eliminates this limitation. Each of the base values used for variables are addressed below.

5.3.1 Horizontal Well Failure Rate

(22 percent) This number was calculated from a township in Weld County, CO by counting all wells drilled and calculating a percentage of "dry" wells. This number was deemed to be very conservative when verified with industry experts.

5.3.2 Horizontal Dry Well Cost

In this analysis, the estimated horizontal dry well cost is $3.8 million per well. This was obtained from the Independent Petroleum Association of America (IPAA) and verified by Anadarko. The cost for a producing a horizontal well in 2010 was $3,284,944, according to the "2010-2011 Oil and Gas Producing Industry in Your State" report by IPAA. In a conversation on March 28, 2012, Tommy Thompson, GM – Rockies Drilling and Completions for Anadarko, verified the current cost to drill a horizontal dry well at $3.8 million.

5.3.3 Horizontal Well Cost

The value for the estimated horizontal well cost variable was set at $4.7 million per well. This cost was originally obtained from the Independent Petroleum Association of America (IPAA) and verified as a reasonable estimate by Ultra Petroleum and Anadarko as reasonable. Actual drilling costs will obviously vary depending on a number of technical factors. The $4.7 million cost was verified with several other sources.

In the IPAA "2010-2011 Oil and Gas Producing Industry in Your State", the cost for a producing horizontal well is cited as $4,640,903. At the CapitalOne Southcoast Energy

[373] (Oil and Gas Exploration and Development Along the Front Range In The Denver Basin of Colorado, Nebraska and Wyoming pgs 18-19 n.d.)

Conference, Ultra Petroleum estimated the cost for a producing horizontal well at $4.8 million for a well in Pinedale, WY.

Kelly Whitley, Director Investor Relations for Ultra Petroleum, confirmed this cost. He stated it includes "all costs associated with drilling and completing a single well in Pinedale, WY."

In addition, Tommy Thompson, GM – Rockies Drilling and Completions for Anadarko, verified this assumed horizontal well cost at $4.7 million in a conversation with Ad Rem team member Nick Pagano on March 28, 2012.

5.3.4 Vertical Well Cost

The vertical well cost variable was set at $750,000 per well. This assumption was originally obtained from a presentation on March 16, 2012 by Reed Cagle of High Plains Energy and verified by Anadarko.[374] In a conversation on March 28, 2012, Tommy Thompson, GM – Rockies Drilling and Completions for Anadarko, verified this assumed vertical well cost at $750,000.[375]

5.3.5 Dry Well Expenses

Dry well expenses (unproductive wells) are generally 100 percent deductible in the year incurred as outlined in Internal Revenue Service (IRS) Oil and Gas publication.[376]

5.3.6 Vertical Dry Well Cost

The vertical well cost variable was set at $300,000 per well. This value was originally obtained from a presentation on March 16, 2012 to the Ad Rem team by Reed Cagle of High Plains Energy. The information was verified with Anadarko.[377] In a conversation on March 28, 2012, Tommy Thompson, GM – Rockies Drilling and Completions for Anadarko, verified a vertical well cost at $300,000.[378]

5.4 Financial Input Assumptions

5.4.1 Tax-Related Stipulations

This project uses reasonable, conservative measures to estimate cash flows for the pending oil drilling feasibility study on Banning Lewis Ranch and in unincorporated El Paso County. Project authors are not tax accountants and the tax and financial statement information provided reflects their best effort to research and represent applicable tax provisions (benefits).

[374] (Cagle 2012)
[375] (Thompson 2012)
[376] (Oil and Gas Industry n.d.)
[377] (Cagle 2012)
[378] (Thompson 2012)

5.4.2 Effective Tax Rate

Ultra Petroleum is currently taxed at the highest permitted progressive U.S. statutory rate of 35 percent; therefore, any additional earnings before taxes, resulting from this project, will be taxed at the federal flat rate of 35 percent.[379] In addition, any additional Ultra Petroleum earnings will be taxed at Colorado's flat tax rate of 4.63 percent. An effective tax of 39.63 percent (35% federal and 4.63% state) was applied to this analysis.[380]

5.4.3 Operating Expense Default Values

The Risk Management Association (RMA) publishes crude petroleum and natural gas extraction mining industry information in the RMA Financial Ratio Benchmarks Journal. The most recent financial data provided in the 2011 RMA journal was from FY 2010. Therefore, an average of the years 2006 – 2010 was used to provide an independent estimate of yearly operating expenses.

The 39.37 percent five-year average based on operating expenses as a percentage of revenues was derived from the industry average of corporations in the $100 – $250 million asset category. The following are the yearly operating expenses as a percentage of yearly operating expenses used to arrive at the five year industry average: 10/1/09 - 3/31/10: 52.6 percent, 10/1/07-3/31/08: 39.7 percent, 10/1/04 - 3/31/05: 25.8 percent.

The $100 - $250 million dollars of assets category is the largest asset category provided in the RMA Journal's crude petroleum and natural gas extraction mining industry information tables. Although UPC reported $4.869 billion of assets on its 2011 balance sheet, the assumption is used that companies with assets larger than the $100 - $250 million dollars of assets category have comparable financial characteristics.[381]

5.4.4 Depletion Rate Default Value

Depletion allowance enables a company to reduce its taxable income by accounting for the oil and gas reserves extracted from the ground. The model used the larger of the cost depletion method or the percentage depletion method. Based on conservative measures, a depletion rate of 15 percent of gross income was deducted yearly as outlined in Internal Revenue Service (IRS) publication 535 (depletion) chapter 9 (business expenses). Percentage depletion was computed as 15 percent of the gross income from the property based on average daily production of domestic crude oil, assuming daily production does not exceed the quantity of oil available.[382]

5.4.5 Building Cost Index Related Default Values

In order to adjust for the effects of inflation on UPC's drilling expenses, ENR's (Engineering News Record) Building Cost Index (BCI) was applied at an escalating annual

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[379] (Tax Rates.cc 2012)

[380] (Federation Of Tax Administrators 2012)

[381] (The Risk Managment Association 2006 - 2011 Journals)

[382] (Depletion Publication 535 n.d.)

rate of 2.7 percent per year for the life of the project. The BCI is widely used in the construction industry because it provides an escalation rate taking into consideration both materials and labor components. The labor escalation component of the BCI is based on skilled construction labor and the materials based on comparable building materials, making the BCI the most appropriate available index to apply to the project. [383]

5.4.6 Tangible Drilling Costs and Depreciation Schedule

The tangible drillings cost of an oil well generally account for 15 percent to 20 percent of the total well cost. These costs are normally capitalized and deducted as depreciation using a seven-year MACRS schedule with a half-year convention.[384] The following are the applicable MACRS depreciation rates applied to tangible drilling costs starting in the year they were paid.[385]

Year 1- 14.29%
Year 2- 24.49%
Year 3- 17.49%
Year 4- 12.49%
Year 5- 8.93%
Year 6- 8.92%
Year 7- 8.93%
Year 8- 4.46%

5.4.7 Intangible Drilling Costs

Intangible drilling costs (IDC) are generally 100 percent deductible in the year incurred or paid if an election is made to expense the IDCs. These costs account for about 80 percent to 85 percent of the total cost of drilling an oil well. IDCs include non-salvageable costs such as labor, chemicals, mud, grease repairs, drilling rig time, drilling fluids, etc.[386]

5.4.8 Interest Expense and Other Financial Default Values

When developing the capital budget, various IRS Statistics of Income (SOI) Integrated Business Datasets (IBDs) were reviewed to identify relevant business expenses that should be included in the analysis, specifically, interest expense and other items that might not be publicly available.

The IBD was assembled at the table level from the annual SOI cross-sectional studies of S and C-corporations, partnerships, and non-farm sole proprietorships. The datasets

[383] (Engineering News Record 2012)

[384] (Energy Capital Group n.d.)
[385] (Publication 946 2010)
[386] (Champ Oil Company, Inc. 2012)

combine data from these types of organizations to enable examination of changes in business composition.[387]

Since the IRS is currently aggregating and processing more current data, reports from years 2000 through 2003 were used to establish financial metrics for key elements as a percentage of sales - see Appendix B. These metrics included the following: number of returns, total receipts, business receipts, total business deductions, cost of goods sold, salaries and wages, taxes paid, interest paid, depreciation, net income (less deficit), net income, and deficit.

5.5 Limitations of the Model

It is important to recognize and account for limitations of the model and why those limitations are acceptable. The following are recognized limitations of the model:

5.5.1 Drilling is completed in the first 21 years of the project.

It is important to note that under the Weighted Average Cost of Capital of 11.27 percent, in the year 2033 when the last well would be drilled, the discount factor is 10.618 percent. This indicates that every dollar of incremental cash flow that year is equivalent to just $.10618 or just less than 11 cents in terms of NPV. For those wells drilled in 2033, their economic life expires in approximately 45 years or 2077. The discount factor that year is just .097 percent. It is clear that under these conditions, cash flows near the end of the project's long time horizon have a very small impact on the Net Present Value of the project.

5.5.2 Four levels of drilling activity are analyzed

Different drilling rates are assumed for each level of activity. For drilling to be limited to 112 wells on Banning Lewis Ranch, it is assumed that drilling is done at the rate of 26 wells per year. This requires two drilling rigs. All drilling would be complete by the ninth year. For the 500, 1500, and 3000 well levels of activity in El Paso County, drilling is completed by 5, 10, and 15 rigs respectively. Refer to Figure 92 for the levels of activity and drilling rates.

5.5.3 Oil and gas price modeling

To model the price of oil and gas, there is an initial price and a constant rate of appreciation. It would be possible, although inefficient, to use individual prices for each of the 75 years of the model. Rates of appreciation may be specified but once chosen, it is held constant over the life of the project. This method of modeling may not take into account swing of the global energy market, but has a firm foundation on current events and forecast rates of price appreciation.

[387] (SOI Tax Stats - Integrated Business Data n.d.)

5.5.4 Revenue start from productive wells

Revenues from a drilled well are assumed to start in the year after completion. This allows for time to finish the well and begin production. This is considered to be a conservative measure.

5.5.5 Project time horizon

The model is limited to 70 years. The effect of discounting future cash flows at the WACC beyond that period makes cash flows beyond year 70 inconsequential in the present time. With drilling limited to the first 21 years, and the economic life of a well estimated at 45 years, the last drilled wells will have been retired for several years by the end of the model's time limitation.

5.5.6 Gas infrastructure timeframe

Finally, all infrastructures associated with the gathering, refining, and shipping of natural gas is assumed to be built in Year "0." It is possible that the companies that develop the energy resources in this area will not market the gas but will burn it off in the process called "flaring." This has been the case with most of the mining done in Northern Colorado. Gas is maintained in the analysis but it is clear that the revenues from gas are minor compared to those from oil.

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6 Model Outputs

6.1 Levels of Activity

In determining the operating and financial performance aspect of a project, an analysis needs to be considered that answers the question of cash flows and revenues to be expected. This implies there is a degree of uncertainty about how much drilling may take place in El Paso County. To reflect this uncertainty, four levels of activity were analyzed to accommodate the range of possibilities. The rates of activity are set at 112, 500, 1,500, and 3,000 wells. The 112 number of wells represents data limited to 18,000 acres of Banning Lewis Ranch. The remaining levels simply reflect the range of levels activity for El Paso County.

The pace of drilling has important implications on the feasibility of the project. As shown in Figure 91, each respective level of activity is coupled with a pace of drilling that corresponds to a conservative to realistic number of drilling rigs operating in the area. While drilling performance varies, each rig is capable of drilling 13 wells per year with completion activities taking place after drilling is complete. Under these assumptions, the lesser levels of activity have shorter horizons for the drilling process.

The discount factor is an important aspect of the model as well. The concept of weighted average cost of capital (WACC) is addressed above. Technically, the discount factor is found by the following formula:

Equation 15.

$$Discount\ Factor = \frac{1}{(1 + WACC)^{N}}$$

N is the number of years into the project with the initial year being Year 0. Conceptually, the discount factor is used to decrease the value of future cash flows to equate them to present day dollars. This technique is used to compute the Net Present Value, the preferred method to evaluate capital investment proposals. The corresponding discount factors are summarized in figure 91.

	Wells Drilled Each Year per Level of Activity				
Rigs in Use	2 Rigs	5 Rigs	10 Rigs	15 Rigs	
Year	112 Wells	500 Wells	1500 Wells	3000 Wells	Discount Factor
2012	2	2	2	2	100.000%
2013	26	65	130	195	89.871%
2014	26	65	130	195	80.769%
2015	26	65	130	195	72.588%
2016	26	65	130	195	65.236%
2017	6	65	130	195	58.629%
2018	0	65	130	195	52.690%
2019	0	65	130	195	47.354%
2020	0	43	130	195	42.557%
2021	0	0	130	195	38.247%
2022	0	0	130	195	34.373%
2023	0	0	130	195	30.892%
2024	0	0	68	195	27.763%
2025	0	0	0	195	24.951%
2026	0	0	0	195	22.424%
2027	0	0	0	195	20.152%
2028	0	0	0	73	18.111%
2029	0	0	0	0	16.277%
…	…	…	…	…	…
2075					0.120%
2076					0.108%
2077					0.097%
2078					0.087%
2079					0.078%
2080					0.070%
2081					0.063%
2082					0.057%

Figure 91. Drilling Rates and Applicable Discount Factor

6.2 Incremental Cash Flows

Figure 92 illustrates a comparison of incremental cash flows for all levels of well activity. Each level of activity showed similar patterns in performance. Cash flows are negative for the early years, spike, and then gradually decrease over the life of the wells.

Cash flows are initially negative due to the larger capital expenditures associated with drilling. Also, while oil flow rates per well are highest initially, gross oil production for the project begins lower and climbs as additional wells come on line.

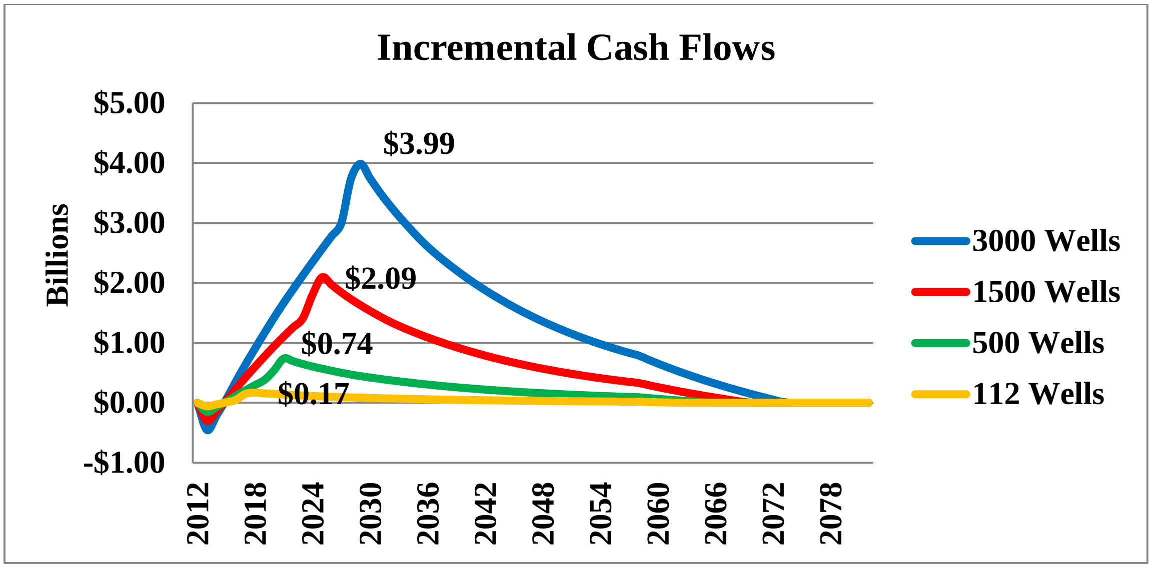

Figure 92. Incremental Cash Flows

The upward trend in cash flows is due to an increasing oil flow rate as the number of wells increase. A more dramatic upward spike was discovered before the full incremental cash flow peak is reached. This corresponds to the elimination of drilling expenses at the completion of drilling activities. This spike occurs later in the project as the level of activity increases because drilling activities persist longer. This is consistent with Figure 92. Finally, cash flows are gradually reduced over time as oil flow decreases with well age.

It's important to note that even in year 2057, after a 45 year expected economic well life, cash flows for each level of well activity are approximately $14.5 million, $75.7 million, $271.5 million, and $647.4 million, respectively.

6.2.1 Discounted Cash Flows

The incremental cash flows are discounted at the Weighted Average Cost of Capital (WACC) of 11.27 percent. This is done to give a comparison of what these future cash flows are worth in today's dollars as seen in Figure 93.

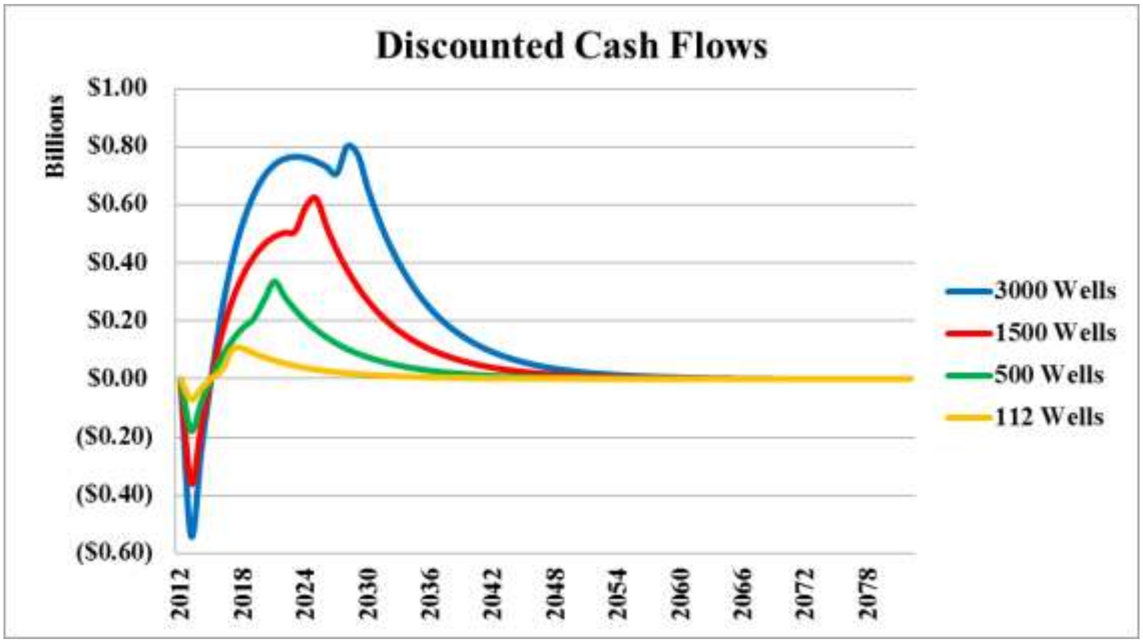

Figure 93. Discounted Cash Flows

The performance again shows the initial dip, spike, and tapering of cash flows over time similar to Figure 92. Another phenomenon seen in Figure 93 is the small decrease in discounted cash flows off of the initial peak before spiking once again. As explained earlier, this corresponds to drilling cessation.

6.2.2 Cumulative Cash Flows

Cumulative cash flow is the summation or running total of all cash flows up to that year. The result is an estimate of all the cash flows expected to be generated throughout the project's life. Figure 94 represents the cumulative cash flow throughout the life of the project based on each level of activity.

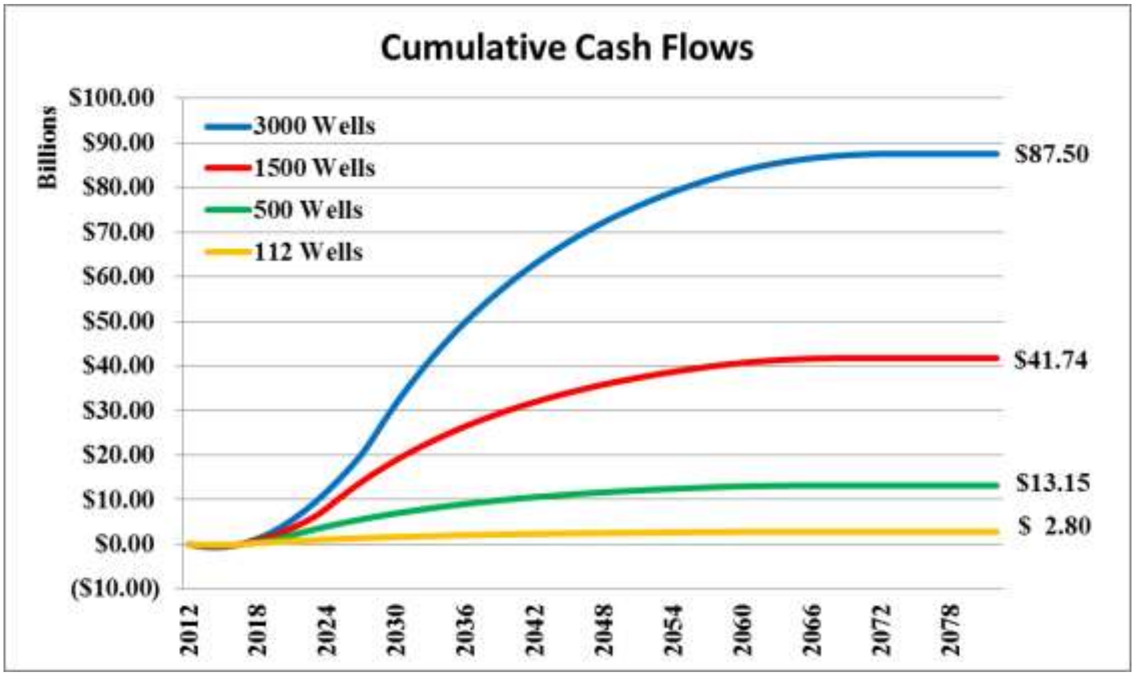

Figure 94. Cumulative Cash Flows

The cumulative cash flows dip initially, climb quickly, then level out for each respective level of activity. The leveling of each line corresponds to revenues ceasing as the economic life of the wells expire. The higher levels of activity take longer to level out because drilling activities extend cash flows into the future. It is also important to note that the cash flows in Figure 94 are nominal. They have not been discounted by the WACC over time.

6.2.3 Revenues

Research for this project indicated the most likely scenario is that all revenues will come from oil sales. Any recovered gas will likely be flared. Graphically, we see how oil revenues react over time. Similar to the cumulative cash flows, Figure 95 shows the initial spike, and then gradual decrease of revenues. This is different from Figure 94 in that it is for revenues and does not account for drilling and other operating expenses. Also, this figure represents per year revenues vice a cumulative projection as in Figure 94. Since expenses are not accounted for in Figure 95, the “dip” from previous figures is not present in the early years of the project.

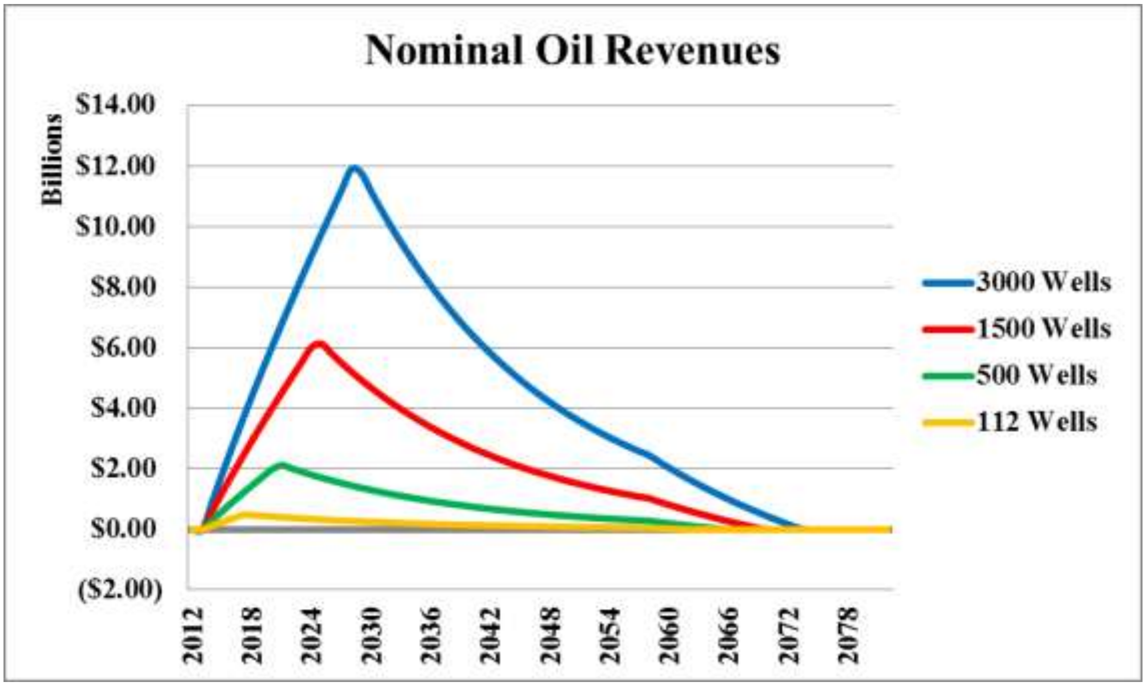

Figure 95. Nominal Oil Revenues (Per Year Basis)

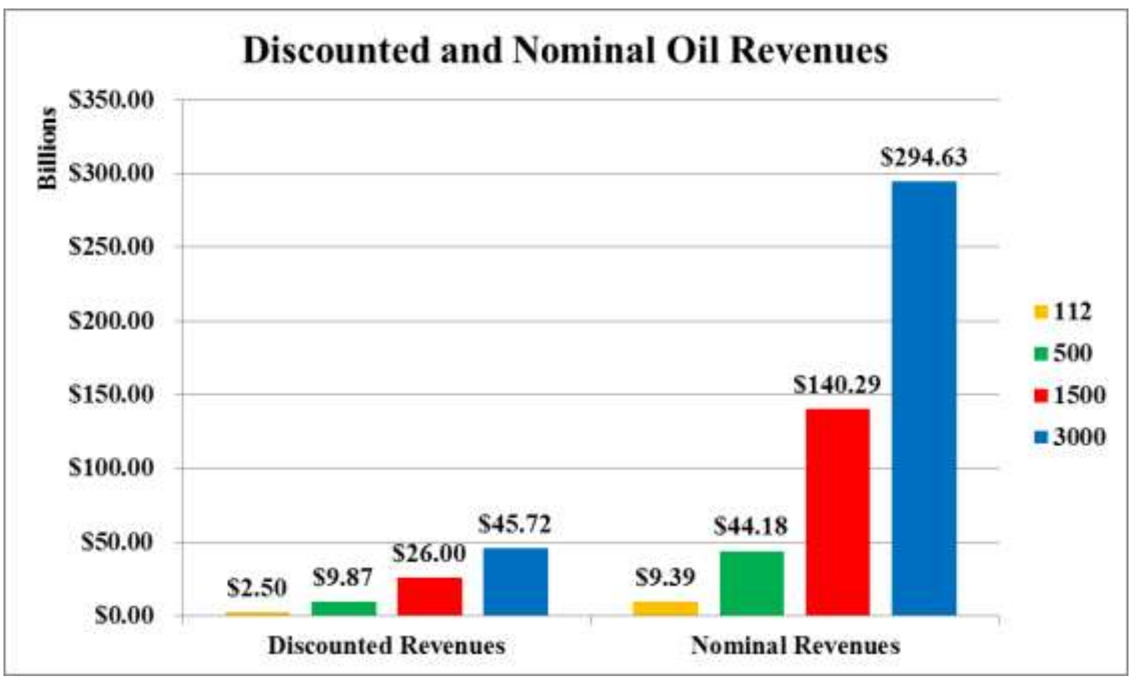

Figure 96. Discounted and Nominal Revenues (Life of the Project)

Figure 96 illustrates nominal and discounted oil revenues over the life of the project for different levels of activity. The present value of the revenues was taken at the weighted average cost of capital, 11.27 percent.

6.2.4 Royalties

It is important to remember the 12.50 percent royalty rate paid to land owners on oil and gas revenues. Royalties are paid to the land owner when an outside entity drills and sells the oil. If the oil company owns the land and the mineral rights, no royalties are paid. Ultra Resources owns the land and mineral right for Banning Lewis Ranch. If Ultra Resources does develop the oil and gas resources on that land, it will not be obligated to pay royalties on the production to a third party. Figure 97 shows the possible royalties to be paid on gross revenues.

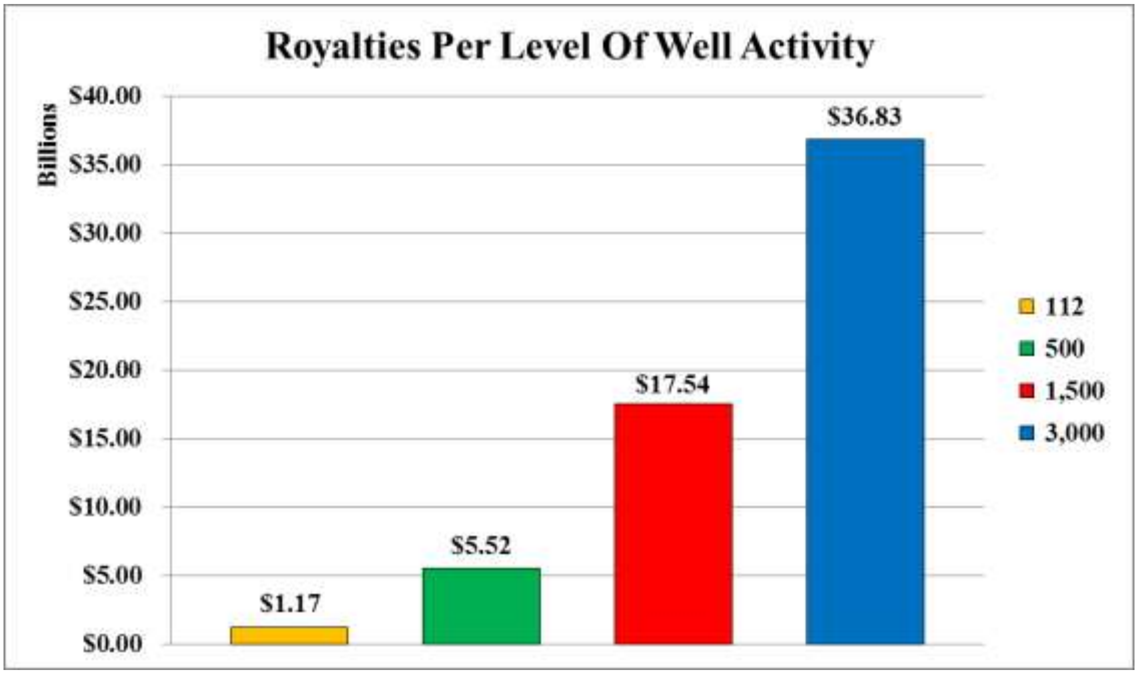

Figure 97. Estimated Royalties

6.3 Investment Analysis

Before any capital investment in a project is undertaken, a company needs to assess if it is feasible to move forward by completing an investment analysis. Any investment analysis will include a series of questions. Do the expected future cash flows, in today's dollars, exceed the initial costs? Will the expected rate of return exceed or fall below the cost of capital? How long will it take for the project to recover its cost? The investment analysis tools used to answer these questions are NPV, IRR, MIRR, Payback Period, and Discounted Payback Period. While each of the tools by themselves provide vital information, it's more advantageous to use all of them together to come to a final decision whether drilling in Banning Lewis Ranch and/or the greater El Paso County area, is a financially feasible venture.

6.3.1 Analysis of Net Present Value (NPV)

The NPV of a project is an important factor to consider when a company is considering a capital investment. As explained above it demonstrates if the future cash flows, in today's dollars, exceed the initial capital expenditures.

The projected future cash flows discounted back to 2012 dollars at the WACC. They are used to offset the project's initial capital investments. The NPV needs to be greater than zero for the project to make economic sense for the company be accepted.

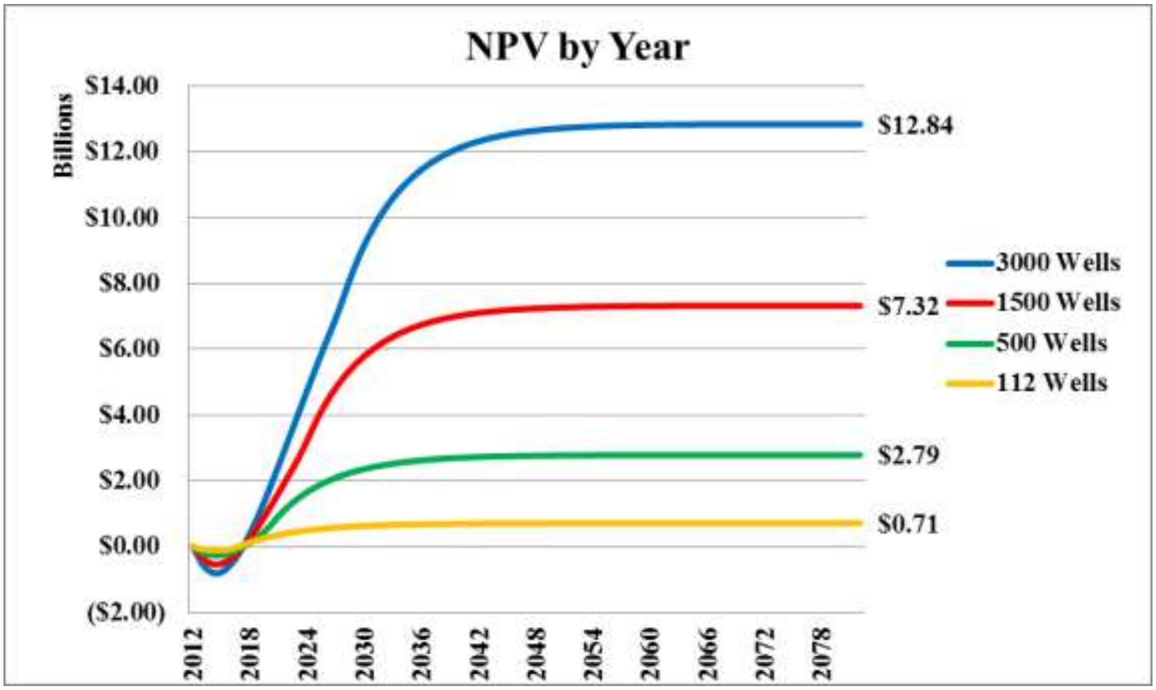

Figure 98. Net Present Value by Year

The cumulative NPV is expected to be negative for the first several years. This is attributed to higher initial costs and the fewer number of operational wells. However, as time progresses, more wells are drilled and come online, cumulative NPV rises sharply and eventually levels out at the NPV of the project as a whole. Figure 98 shows the trend in cumulative NPV for each level of activity over the life of the project.

All levels of well activity show an NPV greater than zero. In further review it is seen that NPV is extremely valuable even at the 112 well activity rate. This is evidenced by NPV exceeding the initial cost outlay by $715 million. Therefore, the company investing in drilling within the Colorado Springs area stands to benefit from this venture.

6.3.2 Analysis of Rates of Return

When making an investment decision based on rate of return, a company will require the IRR and MIRR to exceed the WACC. If this is true, the project is considered an acceptable investment.

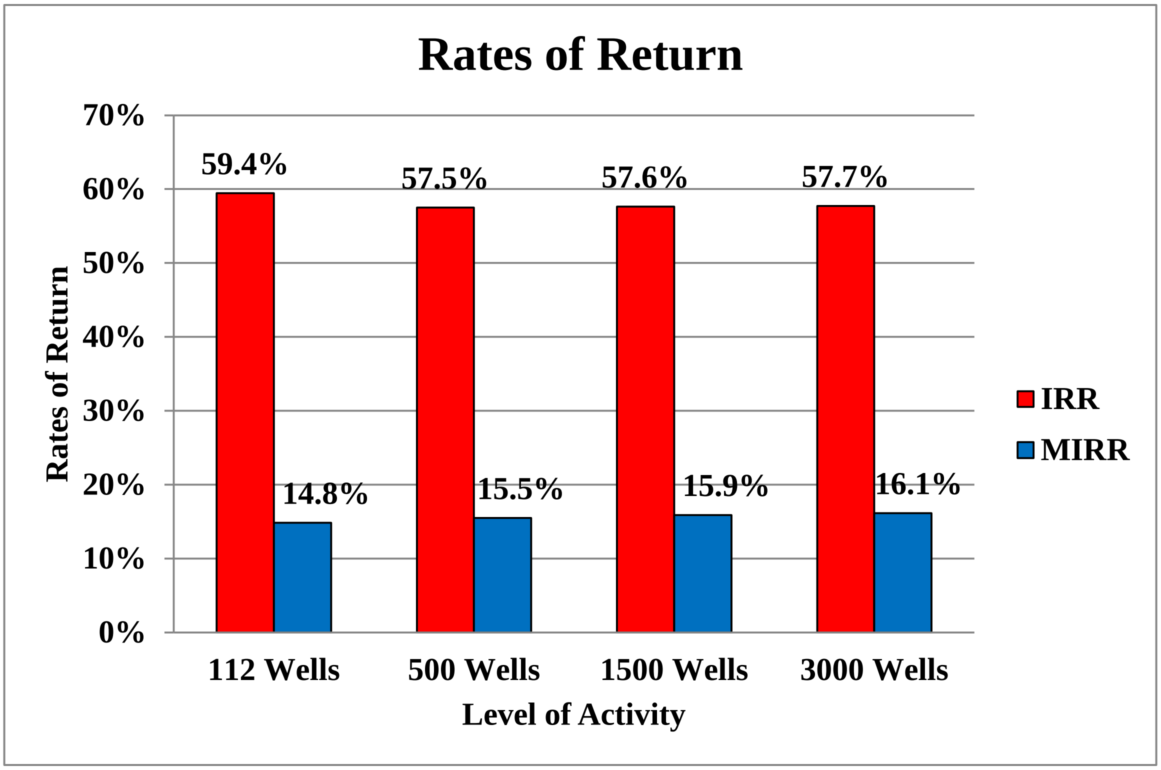

Figure 99. Rates of Return

Figure 99 shows the breakdown of IRR and MIRR based on the number of wells drilled. IRR for each well rate is 52 percent or higher. MIRR is in the 14 percent to 16 percent range.

One point to note is that there is a disadvantage in using IRR by itself to estimate return on investment. While a return of 50 percent or more is impressive, it is an inflated figure since cash flows are less likely to be reinvested at the IRR rate itself. To control for this situation, MIRR is used. It assumes that cash flows are reinvested at the cost of capital of 11.27 percent. MIRR results in a much more realistic rate of return to be expected.

In conclusion, the project shows rates of return exceeding the cost of capital. Therefore, these investments are expected to provide a good return on investment and will likely increase the value of the firm.

6.3.3 Analysis of Payback Period

A payback period analysis gives a clear picture of how many years are needed to make-up the initial capital investment. Two payback periods were considered in the analysis. They are the payback period and discounted payback period. The discounted payback period discounts the cash flows at the WACC.

Figure 100 illustrates the results of the Payback and Discounted Payback. The result of the payback period analysis shows that at any well activity level, payback periods are expected within 5 to 7 years. Alternatively, all net revenue beyond payback is pure profit, having recovered investment costs.

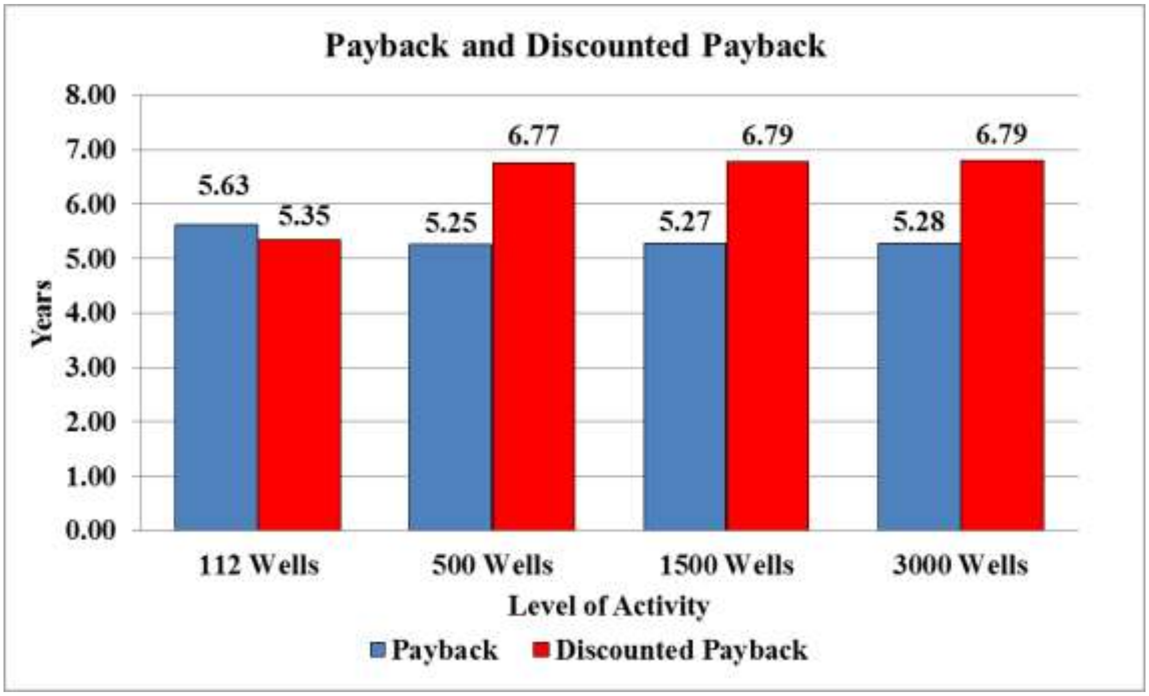

Figure 100. Payback Periods

All payback period activity showed normal results with the exception of the 112 well level. One would expect the normal payback period to be less than the discounted payback period. However, as noted by Figure 100, the nominal payback period is longer. This phenomenon is caused by the drilling expenses being concentrated in the first few years of the project. Those expenses are thus disproportionately affected by the WACC used in Discounted Payback.

It's important to note that in the findings, an industry baseline for a payback period could not be established. Each company will use its own measures in determining a time period that makes sense to recoup their costs. The more conservative discounted payback period is in the range of 5 to 7 years. Compared to the 45 year expected economic life of a well, that leaves a 38 to 40 year time frame after recouping the initial cost to generate net cash flows and realize economic profits.

7 Financial Performance Scenarios

7.1 Analysis of Level of Activity

The industry standard for well concentration is one well per 160 acres. This corresponds to approximately 112 wells on the 18,000 acres of Banning Lewis that URC owns. The other three levels of activity correspond to arbitrary levels of development throughout the balance of El Paso County.

The Ad Rem Project used 500, 1,500, and 3,000 wells to demonstrate drilling scenarios (Figure 101). As the levels of activity increase, the economic impact increases dramatically. It is important to note in this format as this part of the analysis examines the sensitivity of Net Present Value to changes in key model inputs.

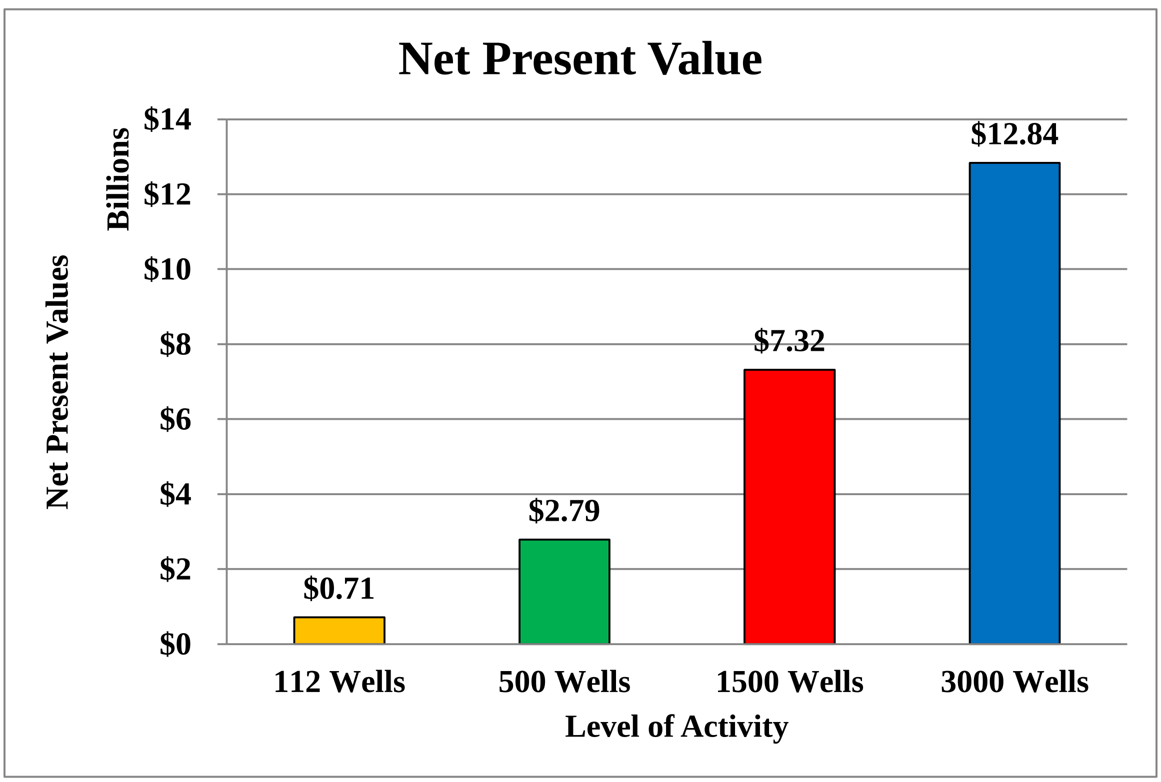

Figure 101. NPV at Different Activity (Number of Wells) Levels

Clearly, as the number of wells increases, the NPV of the project increases. If 3,000 wells were drilled and the variables held true, that would be equivalent to adding $12.8 billion to the value of the company, dramatically affecting the surrounding economy.

7.2 NPV Sensitivity to WACC

It is important to understand the sensitivity of the project's NPV to small changes in WACC. Figure 102 represents the NPV of the oil and gas drilling at the 3,000-well level of activity. From the figure, it can be seen that small changes in the WACC have dramatic effects on the NPV. The typical cost of equity is 9.61 percent while 5.77 percent represents a typical cost of debt. The industry WACC is 7.51 percent. This project used 11.27 percent as the risk adjusted WACC.

When the WACC drops from 11.27 percent to 5.77 percent, the NPV of the project nearly triples. Further, the impact of a certain percentage drop increases as the WACC decreases. The 1.5 percent decrease in WACC from 11.27 percent to 9.61 percent produced a nearly $4B increase in NPV. Drops from 9.61 percent to 7.51 percent increased NPV by over $6B. The less than 2 percent drop in WACC from 7.51 percent to 5.77 percent increased NPV by over $8B. Clearly, NPV is sensitive to changes in WACC, and more so when WACC is comparatively small.

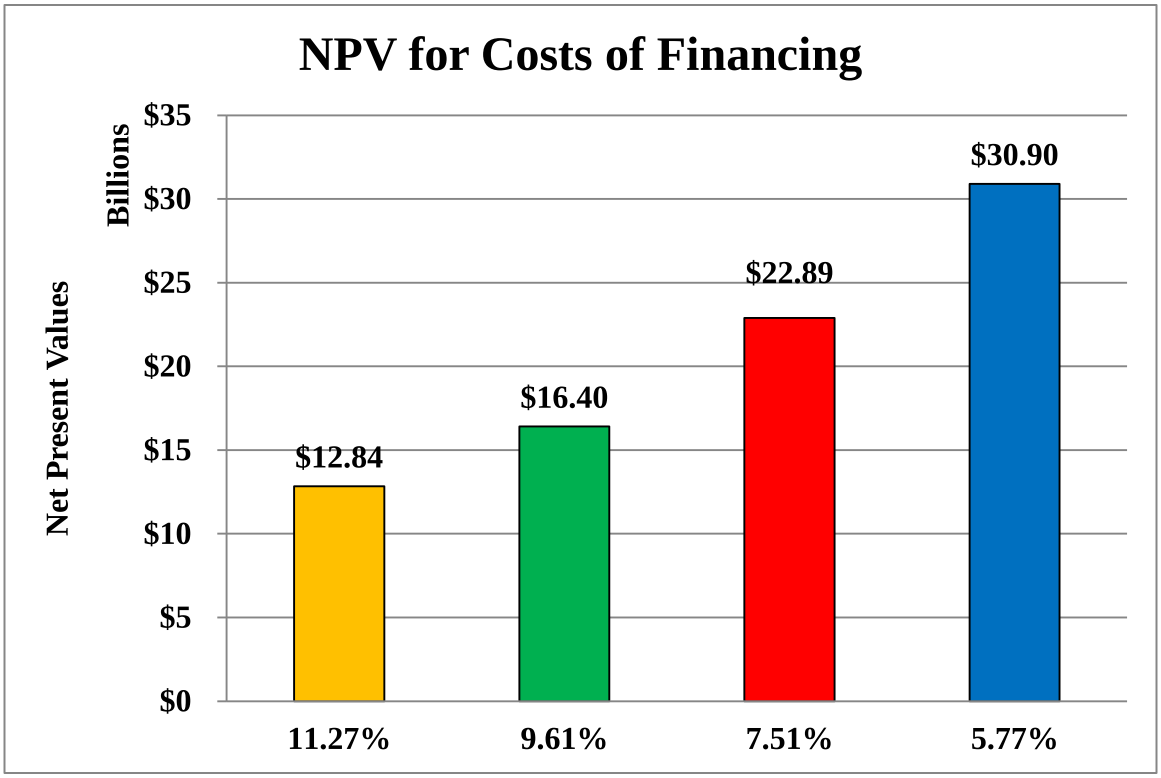

Figure 102. NPV of Cash flows from 3,000 Wells at Different WACC Rates

7.3 NPV Sensitivity to Pace of Drilling

It is interesting to note from the previous figures that the NPV decreases as the number of wells increases. This has to do with the timing of the discounted cash values for well development and production and not a decline in profits. The lowest level of activity has an NPV/well of $6.38M while the highest level of activity shown an NPV/well of just $4.28M. Again, this difference stems from the timeframes necessary to drill the wells.

The building cost index (the rate at which the cost of drilling wells is increasing) is set at 2.7 percent while the price of oil is increasing by just 2.3 percent. Also, revenues realized later in the project are met with a decreased discount factor and thus influence the NPV to a lesser extent. As with previous calculations, this is a conservative approach. See Figure 103 below:

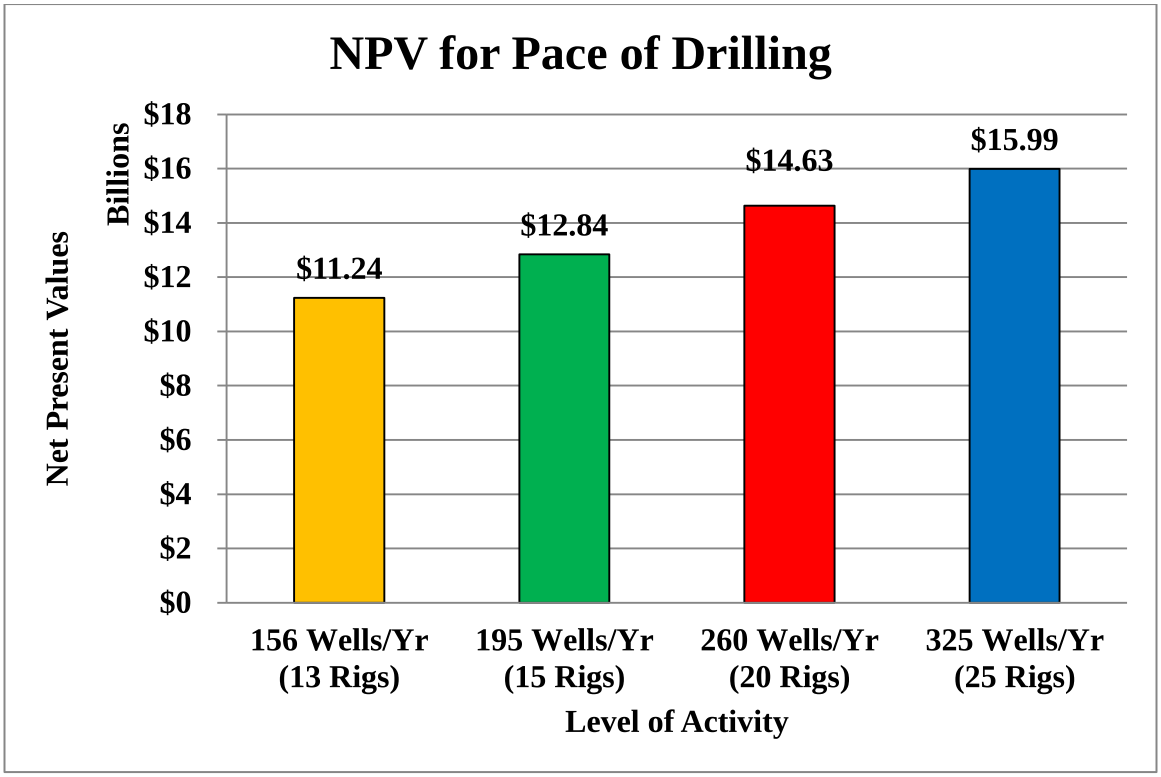

Figure 103. NPV vs. Pace of Drilling for 3,000 Wells

Figure 103 represents the different NPVs of cash flows for the 3,000-well level of activity at four difference paces of drilling. Clearly, for the reasons mentioned above, as the pace of drilling increases, the NPV increases.

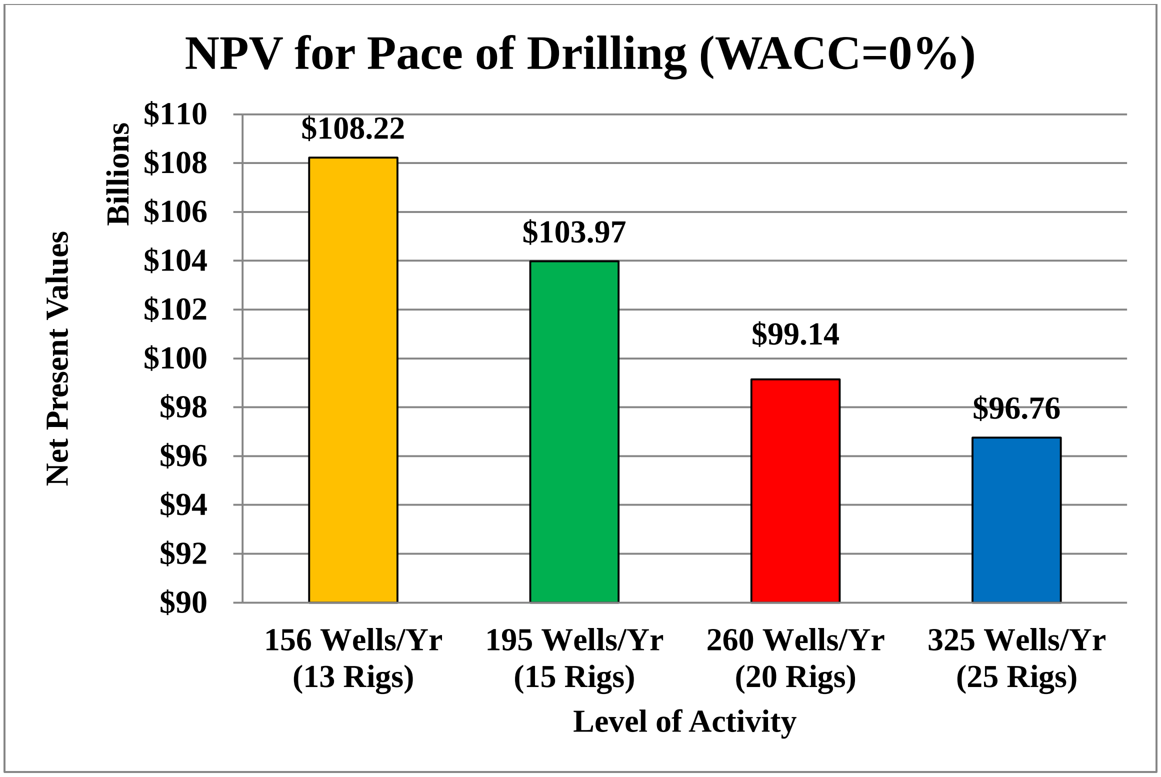

Figure 104. NPV vs. Pace of Drilling with WACC = 0 Percent

Figure 104 shows the NPV for 3,000 wells when the discount rate is "0" percent. Essentially, this is a traditional accounting approach. With that modification in the model, the slower paces of drilling actually fare better. This occurs because even though the building cost is higher than the rate of appreciation in the oil price, it only matters through Year 20. Drilling ceases by that year while the price of oil continues to escalate throughout the life of the project. Removing the discount factor brings this effect to the forefront.

7.4 NPV Sensitivity to Price

The value of the project to the company and the community is clearly linked to the price of oil and gas. For the purposes of the analysis, the initial prices were linked to today's price of oil and then inflated over time at a rate consistent with a 20-year forecast of prices. It is interesting to see how a low price of oil can affect the project but remain economically feasible for the company executing the project. This analysis is also instructive as many may argue that the price of oil at the well head will not hit the advertised price of a barrel of sweet crude due to quality and transportation factors.

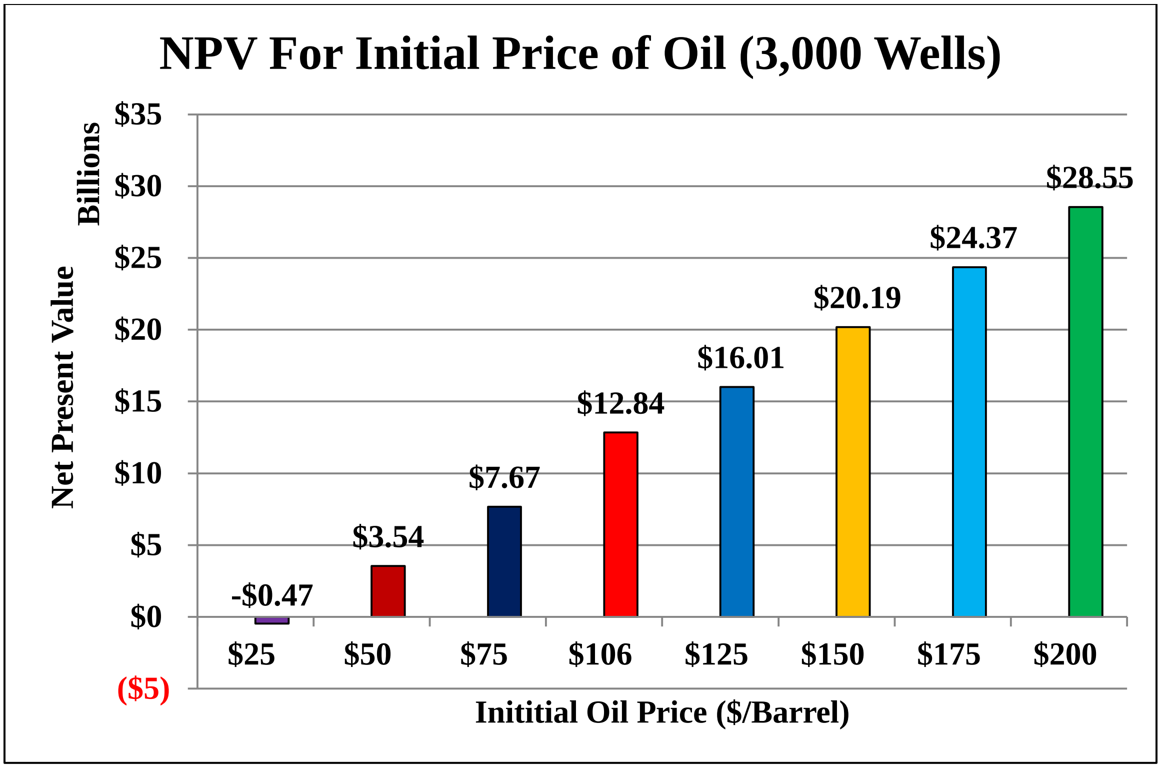

Figure 105. NPV vs. Initial Price of Oil per Barrel

The base case held the initial price of oil at $106 per barrel. Clearly, the price of oil could drop due to macroeconomics, quality of oil or local or transportation issues and still remain feasible for the company. The price would have to drop to roughly $28/barrel to turn the NPV negative.

As global geopolitics may dictate, perhaps a more likely scenario is that oil will go up in price. Much speculation has been made how an Iranian closure of the Strait of Hormuz might affect the price of oil. It is interesting to see what would happen to the NPV of this project if the price of oil did suddenly jump. Figure 105 also shows the NPV of the 3,000-well level of activity at prices ranging from $25 to $200 per barrel.

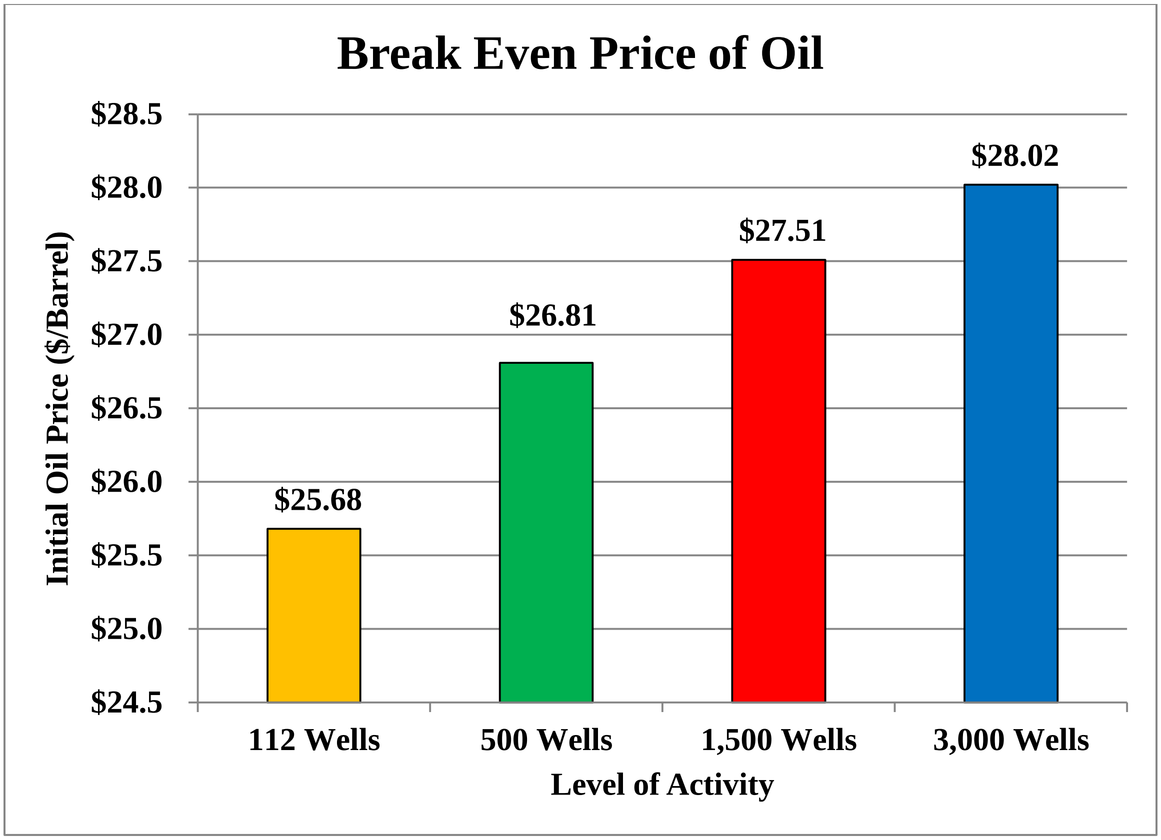

Figure 106. NPV Break-even Price of Oil per Barrel

With much speculation on where oil prices will go, it's instructive to examine how far oil prices could drop and still have this project maintain a positive NPV. Figure 106 shows the break even prices of oil per barrel. The figures are not surprising since the NPV per well was higher for the lowest level of activity. Therefore, the project could absorb a larger price hit per barrel and still maintain a positive NPV. The larger projects produce much more oil and thus their values are more highly leveraged against the price of oil.

7.5 NPV Sensitivity to Well Failure Rates

Regardless of the technology used to explore for oil and gas, there is a good deal of uncertainty on the amount and quality of oil and gas available in this region. The question on quality was addressed by analyzing the sensitivity of NPV to changes in price dictated by quality or economic reasons.

However, it is important to look what levels of well success are necessary to produce a positive NPV for the project. While the base case calls for a 22 percent failure rate on horizontal wells, the failure rate could be much higher and still produce a positive net present value for the project. An 82 percent failure is needed before the project is expected to have a negative NPV.

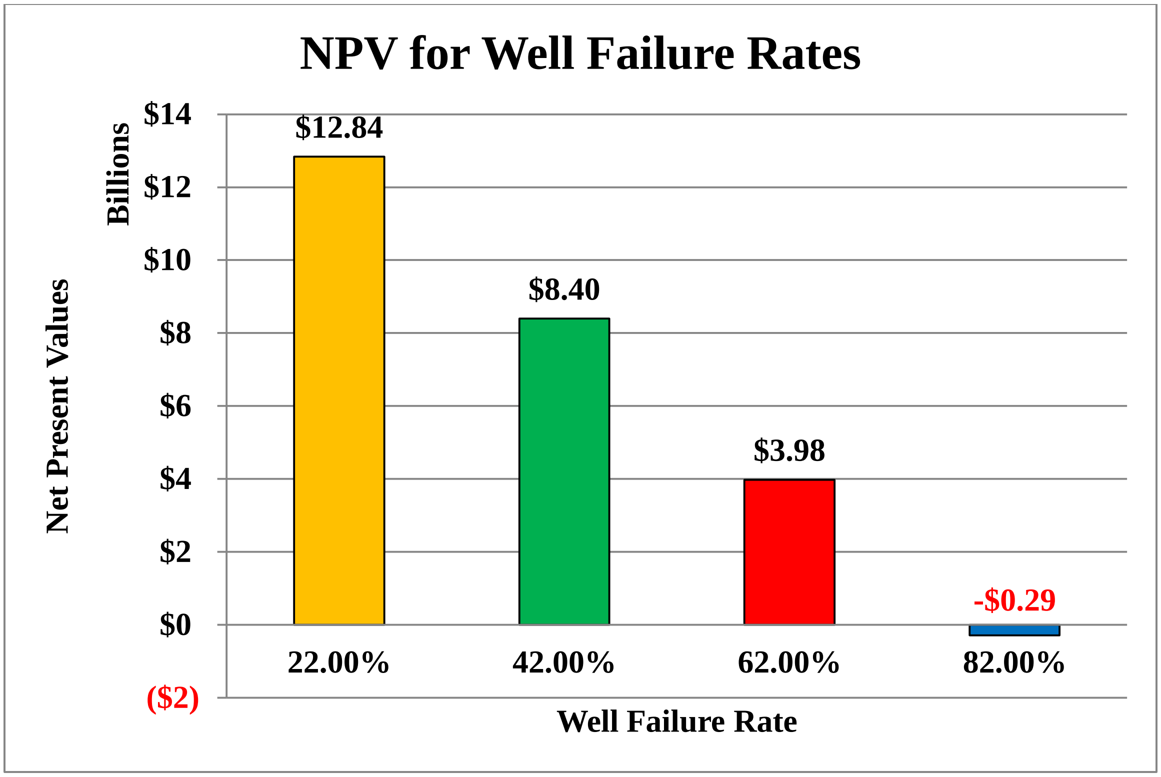

Figure 107. NPV at Different Well Failure Rates (3,000 Wells)

7.6 NPV Sensitivity to Operating Expenses as a Percent of Revenues)

One could argue that the input values used for operating expenses are misleading as they only take into account operating expenses and may not account for other expenses associated with the project. It is very difficult to accurately portray other expenses associated with the project as they are highly dependent on operating practices for each oil and gas company.

However, sensitivity to changes in operating expenses can be explored. Figure 107 demonstrates how changes in operating expenses affect NPV for 3,000 wells. The results are scalable for different levels of well activity. It is clear from the figure that operating and other expenses could escalate significantly before a negative NPV would be expected to take place.

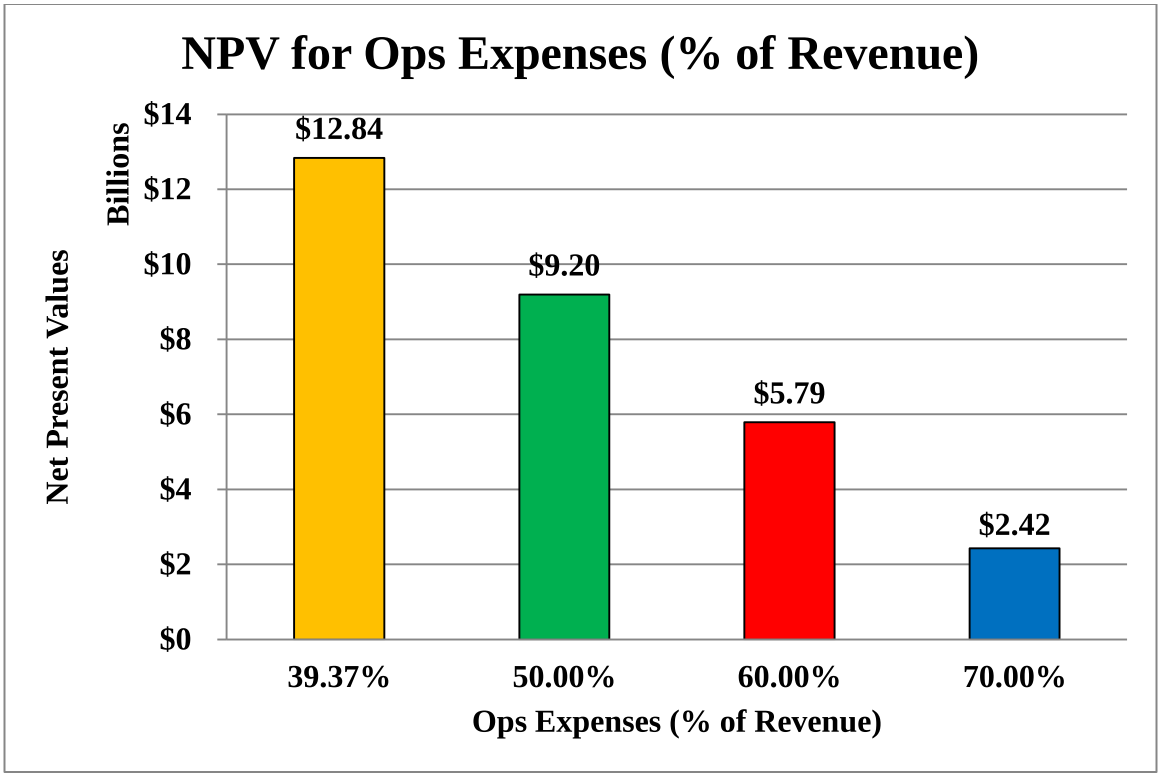

Figure 108. NPV at Various Levels of Operating Expenses (3,000 Wells)

7.7 NPV Sensitivity to Horizontal Well Failure and Initial Flow Rates

Ultimately, one must consider sensitivity to changes in multiple variables simultaneously. Thus far, the analysis has focused on only a single variable at a time. The chart below shows NPV sensitivity to both Horizontal Well Failure rate and oil initial flow rate for successful wells. These two variables address a good deal of the uncertainty in the oil drilling in the Niobrara.

The base case is highlighted in light blue with an NPV of $12.8B as seen above. However, the important note from this chart is how badly these important variables must fall short of expectations to turn the NPV negative.

Negative NPVs are highlighted in red. The well failure rate must nearly double to 42 percent and the initial flow rate on successful wells fall by 67 percent to turn the NPV negative. As seen above, only at a well failure rate of 82 percent does the NPV turn negative at the forecast initial flow rate of 152 barrels per day.

NPV for Horizontal Well Failure and Initial Flow Rates ($Billions)						
	Horizontal Well Failure Rate					
Initial Flow Rate (Barrels/Day)	5%	10%	22%	42%	62%	82%
300	$37.61	$35.32	$30.07	$21.19	$12.31	$3.52
250	$30.50	$28.60	$24.24	$16.86	$9.49	$2.20
200	$23.40	$21.89	$18.41	$12.53	$6.67	$0.91
152.1	$16.61	$15.47	$12.84	$8.40	$3.98	-$0.29
125	$12.77	$11.83	$9.69	$6.06	$2.48	-$0.94
100	$9.23	$8.49	$6.79	$3.93	$1.11	-$1.53
75	$5.71	$5.17	$3.91	$1.81	-$0.22	-$2.12
50	$2.23	$1.88	$1.08	-$0.24	-$1.48	-$2.71

Figure 109. NPV as Horizontal Well Failure Rate and Initial Flow Rate are Changed

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8 Conclusions and Recommendations

The oil and gas industry tends to be capital-intensive. There are several risk factors at play. These risks include:

- Cost of capital for oil and gas industry may increase, making investments more costly.
- Natural gas and crude oil prices fluctuate unpredictably and a decline in natural gas and crude oil prices may affect the NPV and the project choice.
- Well failure rates can vary depending on the geographical area and the oil flow rates will vary as well.
- Operating expenses tend to vary by organization in the Oil and Gas Industry.

The risks noted above are all accounted for in the model. The model makes it easier to analyze NPV sensitivity to a variety of factors. The key is to ensure that the geology of the Banning Lewis area allows for greater rewards at a later time. Any firm could test the geology of the area by drilling exploratory wells (in the Oil and Gas industry, one or two vertical wells are typically drilled). Based on the results of this exploration, more realistic and project-specific variable values can be determined. Assuming commercial volumes of oil are found, the expected profitability of drilling and developing oil fields in El Paso County indicates drilling will take place.

As of this writing, UPC has not disclosed its findings from its exploratory wells. This would affect the decision to drill, the number of wells it would drill and expected oil production volumes. The model (especially at the base case) nonetheless provides a reasonable estimation of the net present value of future cash flows.

With 112 total wells drilled (with 22% failure rate for horizontal and 30 percent failure rate for vertical wells), and with oil production rates similar to Weld County area wells and all other variables used, set to very conservative values (WACC of 11.27 percent etc.), the model provides a NPV of over $700M. This suggests oil exploration and development will take place.

The expected positive NPV makes this project appear to be feasible from a financial perspective. This is supported with all capital budgeting standards applied in the analysis. These included Net Present Value, Payback Period, Discounted Payback Period, Internal Rate of Return and Modified Internal Rate of Return.

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Appendix A: Glossary

Building Cost Index: The building cost index describes relative changes in the building costs of building works and buildings of essentially identical structures by monitoring developments in the prices of the basic inputs used in their construction.

Depletion Allowance/Rate: Depletion allowance enables a company to reduce its taxable income by accounting for the reduction of oil and gas reserves extracted from the ground. Depletion is determined using the larger value of the cost depletion method or the percentage depletion method.

Discounted payback period: This is the number of periods it takes a firm to recover its project investment based on discounted cash flows.

Dry well cost: Expressed in dollars, the cost to complete a well that does not produce sufficiently to be judged economically viable by the firm. These wells never reach production.

Initial flow rate: This is the rate at which oil or gas flows from a productive well. It is expressed in number of barrels (oil) or Mcfe (gas).

Internal Rate of Return (IRR): The discount rate that equates the present value of the expected future cash inflows and outflows. IRR measures the rate of return on a project. It assumes all cash flows can be reinvested at the IRR rate.

Modified Internal Rate of Return (MIRR): This assumes cash flows from all projects are reinvested at the cost of capital (WACC), not at the project's own IRR. This makes the MIRR a more conservative and reliable indicator of a project's rate of return.

Net Present Value (NPV): The present value of a project's expected future cash flows, discounted at the appropriate cost of capital.

Payback period: The number of years it takes a firm to recover its project investment. Even though payback period does not capture a project's entire cash flow stream however it does measure a project's liquidity.

Productive well cost: This is expressed in dollars. It is the cost to complete a producing well.

Weighted Average Cost of Capital (WACC): The weighted average of the after-tax component costs of capital – debt, preferred stock, and common equity. Each weighting factor is the proportion of that type of capital used to finance a project.

Well failure rate: this is the percentage of total wells drilled that fail to produce sufficient oil/gas to go into production. Failed wells are called dry wells.

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Appendix B: Weighted Average Cost of Capital (WACC)

Capital Asset Pricing Model (CAPM) model is most often used to calculate required returns on investments. During capital budgeting for this project, the following equation was used as a starting point.

Required Return on Project = Risk-Free Rate + Market Risk Premium x Beta

The Market Risk Premium is often calculated by Subtracting Risk free rate of return from Market Return. Restated, it is

Required Return on Project = Risk-Free Rate + (Market Return – Risk free rate of return) x Beta

Calculating the WACC involved creating estimates for each of the formula inputs.

The first step generated the required return for the equity portion of the company. The total market return was the first number calculated. This number was derived from annual returns from the S&P 500 for the period spanning January of 1991 to January of 2012.[388]

These annual returns were then averaged to find a market return of 8.51 percent. Next, a risk-free rate of return was calculated by taking the average return on 10-year treasury bonds for the same period. These were then averaged to find a risk-free rate of return of 5.16 percent.[389] The next step was to find the industry beta. This was accomplished by averaging the betas for a sample of 12 companies in the industry.

The beta was found to be 1.33.[390] These values were then used as the inputs for the CAPM and the resulting output was used as the required return for equity. That number was 9.61 percent.

The next step was to find the required return for debt financing. This was determined by taking samples of the effective rate of interest for bonds issued by each of the same 12 companies. The interest rate quoted was divided by the percentage difference between each bonds coupon and market rate to find the actual rate of return to the bondholder.

For consistency, the bonds with maturities closest to 10 years were used for each company.[391] These returns were then averaged to find the required return for debt financing. The resulting number was 5.77 percent.

$$WACC = Required\ Return\ on\ Equity \times \%\ of\ capital\ structure + \{Required\ Return\ on\ Debt\ X\ \%\ of\ capital\ structure \times (1 - tax\ rate)\}$$

[388] (Yahoo Finance n.d.)
[389] Board of Governors of the Federal Reserve system (http://www.federalreserve.gov)
[390] Value Line Issue 12 (Date issued November 11, 2011)
[391] (Yahoo Finance n.d.)

After the equity and debt required returns were found the next step was to apply to the WACC formula. Weights had to be established for each portion of financing. These weights were 35 percent debt financing and 65 percent capital financing.[392]

Since debt is an expense that lowers a company's tax liability, the after tax cost of debt was used. The average tax rate calculated out to 36 percent[393] and the resulting after tax cost of debt was 3.69 percent. The industry WACC was calculated at 7.51 percent. Since the project has additional risk compared to the industry as a whole, this number was increased by 50 percent. The WACC used in the analysis was 11.27 percent.

[392] (ValueLine Issue 12 2011)
[393] (ValueLine Issue 12 2011)

Appendix C: Data Inputs & Calculations for WACC

S&P 500 Prices and Rates of Return		
Date	Adj Close	Annual Return
3-Jan-12	1,312.41	2.04%
3-Jan-11	1,286.12	19.76%
4-Jan-10	1,073.87	30.03%
2-Jan-09	825.88	-40.09%
2-Jan-08	1,378.55	-4.15%
3-Jan-07	1,438.24	12.36%
3-Jan-06	1,280.08	8.36%
3-Jan-05	1,181.27	4.43%
2-Jan-04	1,131.13	0.08%
3-Jan-02	1,130.20	-17.26%
3-Jan-01	1,366.01	-2.04%
3-Jan-00	1,394.46	8.97%
4-Jan-99	1,279.64	30.54%
2-Jan-98	980.28	24.69%
2-Jan-97	786.16	23.61%
2-Jan-96	636.02	35.20%
3-Jan-95	470.42	-2.32%
3-Jan-94	481.61	9.76%
4-Jan-93	438.78	7.34%
2-Jan-92	408.78	18.86%
3-Jan-91	343.93	
Average Return		8.51%

Raw Data For WACC

**Data Taken from YahooFinance*[394]

Industry Betas	
Company	**Beta**
Anadarko Petro	1.25
Apache Corp.	1.2
Berry Petrol.	1.75
Can. Natural Res.	1.2
Denbury Res. Inc	1.6
Forest Oil Corp.	1.55
Nexen Inc.	1.15
Noble Energy	1.2
Pioneer Nat. Res.	1.45
Range Resources	1.2
Ultra Petro. Corp	1.1
Halliburton	1.3
Average Beta	1.33

** Beta Data Taken From ValueLine*[395]

[394] (Yahoo Finance n.d.)
[395] (ValueLine Issue 12 2011)

10 Year Treasury Bond Rates								Average:		5.16%	
Month	**Rate**	**Month**	**Rate**	**Month**	**Rate**	**Month**	**Rate**	**Month**	**Rate**	**Month**	**Rate**
1991-01	8.09	1994-08	7.24	1998-03	5.65	2001-10	4.57	2005-05	4.14	2008-12	2.42
1991-02	7.85	1994-09	7.46	1998-04	5.64	2001-11	4.65	2005-06	4	2009-01	2.52
1991-03	8.11	1994-10	7.74	1998-05	5.65	2001-12	5.09	2005-07	4.18	2009-02	2.87
1991-04	8.04	1994-11	7.96	1998-06	5.5	2002-01	5.04	2005-08	4.26	2009-03	2.82
1991-05	8.07	1994-12	7.81	1998-07	5.46	2002-02	4.91	2005-09	4.2	2009-04	2.93
1991-06	8.28	1995-01	7.78	1998-08	5.34	2002-03	5.28	2005-10	4.46	2009-05	3.29
1991-07	8.27	1995-02	7.47	1998-09	4.81	2002-04	5.21	2005-11	4.54	2009-06	3.72
1991-08	7.9	1995-03	7.2	1998-10	4.53	2002-05	5.16	2005-12	4.47	2009-07	3.56
1991-09	7.65	1995-04	7.06	1998-11	4.83	2002-06	4.93	2006-01	4.42	2009-08	3.59
1991-10	7.53	1995-05	6.63	1998-12	4.65	2002-07	4.65	2006-02	4.57	2009-09	3.4
1991-11	7.42	1995-06	6.17	1999-01	4.72	2002-08	4.26	2006-03	4.72	2009-10	3.39
1991-12	7.09	1995-07	6.28	1999-02	5	2002-09	3.87	2006-04	4.99	2009-11	3.4
1992-01	7.03	1995-08	6.49	1999-03	5.23	2002-10	3.94	2006-05	5.11	2009-12	3.59
1992-02	7.34	1995-09	6.2	1999-04	5.18	2002-11	4.05	2006-06	5.11	2010-01	3.73
1992-03	7.54	1995-10	6.04	1999-05	5.54	2002-12	4.03	2006-07	5.09	2010-02	3.69
1992-04	7.48	1995-11	5.93	1999-06	5.9	2003-01	4.05	2006-08	4.88	2010-03	3.73
1992-05	7.39	1995-12	5.71	1999-07	5.79	2003-02	3.9	2006-09	4.72	2010-04	3.85
1992-06	7.26	1996-01	5.65	1999-08	5.94	2003-03	3.81	2006-10	4.73	2010-05	3.42
1992-07	6.84	1996-02	5.81	1999-09	5.92	2003-04	3.96	2006-11	4.6	2010-06	3.2
1992-08	6.59	1996-03	6.27	1999-10	6.11	2003-05	3.57	2006-12	4.56	2010-07	3.01
1992-09	6.42	1996-04	6.51	1999-11	6.03	2003-06	3.33	2007-01	4.76	2010-08	2.7
1992-10	6.59	1996-05	6.74	1999-12	6.28	2003-07	3.98	2007-02	4.72	2010-09	2.65
1992-11	6.87	1996-06	6.91	2000-01	6.66	2003-08	4.45	2007-03	4.56	2010-10	2.54
1992-12	6.77	1996-07	6.87	2000-02	6.52	2003-09	4.27	2007-04	4.69	2010-11	2.76
1993-01	6.6	1996-08	6.64	2000-03	6.26	2003-10	4.29	2007-05	4.75	2010-12	3.29
1993-02	6.26	1996-09	6.83	2000-04	5.99	2003-11	4.3	2007-06	5.1	2011-01	3.39
1993-03	5.98	1996-10	6.53	2000-05	6.44	2003-12	4.27	2007-07	5	2011-02	3.58
1993-04	5.97	1996-11	6.2	2000-06	6.1	2004-01	4.15	2007-08	4.67	2011-03	3.41
1993-05	6.04	1996-12	6.3	2000-07	6.05	2004-02	4.08	2007-09	4.52	2011-04	3.46
1993-06	5.96	1997-01	6.58	2000-08	5.83	2004-03	3.83	2007-10	4.53	2011-05	3.17
1993-07	5.81	1997-02	6.42	2000-09	5.8	2004-04	4.35	2007-11	4.15	2011-06	3
1993-08	5.68	1997-03	6.69	2000-10	5.74	2004-05	4.72	2007-12	4.1	2011-07	3
1993-09	5.36	1997-04	6.89	2000-11	5.72	2004-06	4.73	2008-01	3.74	2011-08	2.3
1993-10	5.33	1997-05	6.71	2000-12	5.24	2004-07	4.5	2008-02	3.74	2011-09	1.98
1993-11	5.72	1997-06	6.49	2001-01	5.16	2004-08	4.28	2008-03	3.51	2011-10	2.15
1993-12	5.77	1997-07	6.22	2001-02	5.1	2004-09	4.13	2008-04	3.68	2011-11	2.01
1994-01	5.75	1997-08	6.3	2001-03	4.89	2004-10	4.1	2008-05	3.88	2011-12	1.98
1994-02	5.97	1997-09	6.21	2001-04	5.14	2004-11	4.19	2008-06	4.1	2012-01	1.97
1994-03	6.48	1997-10	6.03	2001-05	5.39	2004-12	4.23	2008-07	4.01		
1994-04	6.97	1997-11	5.88	2001-06	5.28	2005-01	4.22	2008-08	3.89		
1994-05	7.18	1997-12	5.81	2001-07	5.24	2005-02	4.17	2008-09	3.69		
1994-06	7.1	1998-01	5.54	2001-08	4.97	2005-03	4.5	2008-10	3.81		
1994-07	7.3	1998-02	5.57	2001-09	4.73	2005-04	4.34	2008-11	3.53		

** Data taken from Board of Governors of the Federal Reserve System*
http://www.federalreserve.gov/releases/h15/data.html[396]

[396] (Selected Interest Rates Daily H.15 Release n.d.)

Required Rate of Return (CAPM)			
Risk Free Rate of Return	Market Risk Premium	Beta	Required Rate of Return
5.16%	3.35%	1.33	**9.61%**

Cost of Debt					
Company	**Bond Discount Rate**	**Bond Market Value**	**Cost of Debt**		**Industry Pre-Tax Cost of Debt**
Anadarko Petro	7.00%	1080.0	6.48%	6/15/2019	
Apache Corp.	2.63%	979.4	2.68%	2/1/2021	
Berry Petrol.	6.75%	1062.5	6.35%	11/1/2020	
Can. Natural Res.	5.90%	1203.0	4.90%	2/1/2018	
Denbury Res. Inc	6.38%	1077.0	5.92%	8/15/2021	
Forest Oil Corp.	7.25%	1067.5	6.79%	6/15/2019	
Nexen Inc.	6.20%	1140.9	5.43%	6/30/2019	
Noble Energy	6.00%	1064.4	5.64%	3/1/2019	
Pioneer Nat. Res.	7.50%	1150.0	6.52%	1/15/2020	
Range Resources	6.75%	1095.0	6.16%	8/1/2020	
Halliburton	8.75%	1330.0	6.58%	2/15/2021	
					5.77%
** Data Taken From YahooFinance*[397]					

[397] (Yahoo Finance n.d.)

WACC										
Company	Total debt (000's)	% Debt Financing	Tax rate	P/E	Shares Outstanding	Total Equity	% Equity Financing	WACC	Project Risk Premium	Project WACC
Anadarko Petro	12,949,000	40%	39%	39.1	491,098,118	19,201,936,414	60%	**7.16%**	50.00%	**11.27%**
Apache Corp.	7,202,000	62%	42%	11.8	380,122,745	4,485,448,391	38%	**5.75%**		
Berry Petrol.	1,348,000	55%	35%	20.7	53,402,260	1,105,426,782	45%	**6.39%**		
Can. Natural Res.	8,624,000	33%	30%	15.7	1,097,205,000	17,226,118,500	67%	**7.75%**		
Denbury Res. Inc	2,296,700	17%	38%	26.9	402,508,895	10,827,489,276	83%	**8.55%**		
Forest Oil Corp.	1,872,100	48%	35%	17.6	114,368,834	2,012,891,478	52%	**6.79%**		
Nexen Inc.	4,479,000	26%	40%	18.3	714,008,956	13,066,363,895	74%	**8.04%**		
Noble Energy	3,937,000	29%	30%	17.9	526,450,126	9,423,457,255	71%	**7.97%**		
Pioneer Nat. Res.	2,571,000	38%	38%	35.5	116,243,586	4,126,647,303	62%	**7.29%**		
Range Resources	1,787,700	21%	37%	42.7	160,958,810	6,872,941,187	79%	**8.38%**		
Ultra Petro. Corp.	1,714,000	35%	35%	20.8	152,922,524	3,180,788,499	65%	**7.56%**		
Halliburton	3,824,000	21%	33%	15.9	920,165,263	14,630,627,682	79%	**8.42%**		
Industry Average	**4,383,708**	**35%**	**36%**	**23.575**	**427454593**	**8,846,678,055**	**65%**	**7.51%**		

Appendix D: Capital Budgeting Technique

This model adhered to standard guidelines for a capital budgeting design. The primary purpose is to find the value of the cash inflows less the value of all cash outflows and then used standard capital budgeting criteria to evaluate the project's viability. The model begins by determining all project costs that will be capitalized for the project. These costs are drilling costs, the cost for the gas gathering line, the cost to connect to the interstate pipeline, and gas refinement infrastructure costs. Excluding drilling costs, these costs are fixed at the beginning of the project. Drilling costs are determined on per well-installed basis. The model's base case assumes that gas will be "flared" rather than collected and sold. This is consistent with the intentions conveyed by UPC. It is also consistent with activities of similar oil operations in Weld County Colorado. Therefore, the gas infrastructure expenditures will be unnecessary and are not included in the initial capital investment.

The cost for producing a well is estimated to be \$4.7M for a producing well and \$3.8M for a nonproducing or "dry" well. These costs are then multiplied by the total number of wells projected to be installed each year to determine a yearly drilling cost. The base case scenario assumption is that two vertical wells are drilled in year 0. Twenty-six wells will be drilled in years one to four. Six wells will be drilled in Year 5. This is a total of 112 wells. Other levels of activity with their respective paces of drilling are also analyzed in the report. See section five for an outline of the levels of activity and assumed paces of drilling.

It was assumed that 30 percent of the vertical wells and 22 percent of the horizontal wells be non-producing, "dry" wells. Annual drilling costs were discounted back at the Weighted Average Cost of Capital (WACC) to find a present day dollar value for drilling costs. The WACC for this project was determined to be 11.27 percent. The present day drilling cost is then used as the effective initial cash outflow for the project.

The model then takes the estimated annual gas and oil revenues over the next 70 years and subtracts the various operating costs, much like an income statement. It is important to note that cash outflows from drilling and inflows from oil sales are occurring concurrently in the early years of the project.

These calculations produce the Net Operating Profit for the project on a year-by-year basis. Certain non-cash expenses such as depreciation are added to this number to find the incremental cash inflow/outflow each year.

The cash inflows/outflows are then compared to the cash outflows using the capital budgeting techniques of net present value, internal rate of return, modified internal rate of return, payback period, and discounted payback period. The results from these calculations are used to determine the project's viability.

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Appendix E: Mining Industry -Financial Background[398]

	Mining								
	All Businesses			Corporations			C-Corporations		
	Avg	% of Sales	Population	Avg	% of Sales	Population	Avg	% of Sales	Population
Number of businesses	401			269			219		
Total receipts	539,345	100.00%	216,277,299	597,293	100.00%	160,671,914	701,410	100.00%	153,721,086
Business receipts	503,973	93.44%	202,093,342	554,164	92.78%	149,069,982	650,055	92.68%	142,466,033
Total business deductions	486,841	90.27%	195,223,116	570,518	95.52%	153,469,433	674,276	96.13%	147,774,387
Costs of goods sold	297,634	55.18%	119,351,059	322,260	53.95%	86,687,898	379,829	54.15%	83,243,232
Salaries and wages	21,518	3.99%	8,628,816	29,821	4.99%	8,021,826	35,396	5.05%	7,757,426
Taxes paid	13,067	2.42%	5,239,800	15,272	2.56%	4,108,105	17,916	2.55%	3,926,542
Interest paid	23,090	4.28%	9,259,152	31,531	5.28%	8,481,921	38,030	5.42%	8,334,584
Depreciation	33,428	6.20%	13,404,727	41,239	6.90%	11,093,363	48,760	6.95%	10,686,218
Net income (less deficit)	56,229	10.43%	22,547,917	30,645	5.13%	8,243,484	30,428	4.34%	6,668,501
Net income	67,192	12.46%	26,943,867	45,761	7.66%	12,309,749	48,884	6.97%	10,713,445
Deficit	10,962	2.03%	4,395,951	15,116	2.53%	4,066,266	18,457	2.63%	4,044,943

--not applicable.

* Estimate should be used with caution because of the small number of returns on which it is based.

** Data combined to avoid disclosure of information for specific taxpayers.

[1] Total corporation "net income (less deficit)" includes "total net income (less deficit)" from S corporations and is more comprehensive than SOI generally publishes.

[2] For this table, the data for C corporations also include 1120-RIC and 1120-REIT returns.

NOTE: Detail may not add to totals because of rounding.

Source: IRS, Statistics of Income Division, November 2007

398 (SOI Tax Stats - Integrated Business Data n.d.)

Appendix F: Industry Communications

Ultra Petroleum Corp.[399]
From: Kelly Whitley
Subject: RE: Re: Banning Lewis Ranch
To: "Nicholas Pagano"
Date: Friday, March 2, 2012, 3:33 PM
Nick
Here are the answers to your questions.
The $4.8 MM well cost refers to a Pinedale, WY well. It includes all costs associated with drilling and completing a single well in Pinedale.
We do not know how many wells we will drill on the 18,000 acres we own in the Banning Lewis Ranch as we do not know the prospectively at this time. We do have 116,000 acres outside the Banning Lewis Ranch. Most of the timing issues will be dependent upon how much capital we're willing to allocate toward the project annually.
Conventional plays and wildcat wells usually have some kind of success rate for an exploratory effort. Unconventional plays, such as our target in the Niobrara, is unconventional. We know that we will find oil in the rock. But, what we do not know is if it is economic to develop.

> The drilling cuttings will be solidified into bricks and seals before being placed in a disposal landfill. The bricks are rendered harmless. As for recovered water, it is disposed of in industrial waste sites.
>
> We do not anticipate any methane gas since this is an oil play.
>
> Cement will be poured from surface to total depth (TD).
>
> All of Ultra's drilling will be completed by a drilling contractor such as Patterson UTI as we do not own any rigs. Please contact them for details regarding the crew.

Regards,

Kelly Whitley I Director Investor Relations I Ultra Petroleum Corp. (NYSE:UPL)
400 N. Sam Houston Pky. E #1200 I Houston, Texas 77060

[399] (Whitley 2012)

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Appendix G: Production Rate Bootstrapping

The flow rates utilized in this study were gathered from ranges within Weld County Colorado. The flow rates of these wells were gathered from the Colorado Oil and Gas Conservation Commission website.[400]

Ranges in Weld County that contained a majority of the types of wells were chosen due to similarities in the geographical areas. The range that was utilized for the flow rate of the horizontal flow rates was 11N -63W and 7N -64W for the vertical flow rates. These ranges were selected due to large amount data that were available for the specific type of wells.

Each well within the studied range had been in production for a minimum of one year but no more than three. These were selected to allow the use of an average starting flow rate, as typically productive wells have much higher initial flow rates before they taper off to more representative long term production volumes.

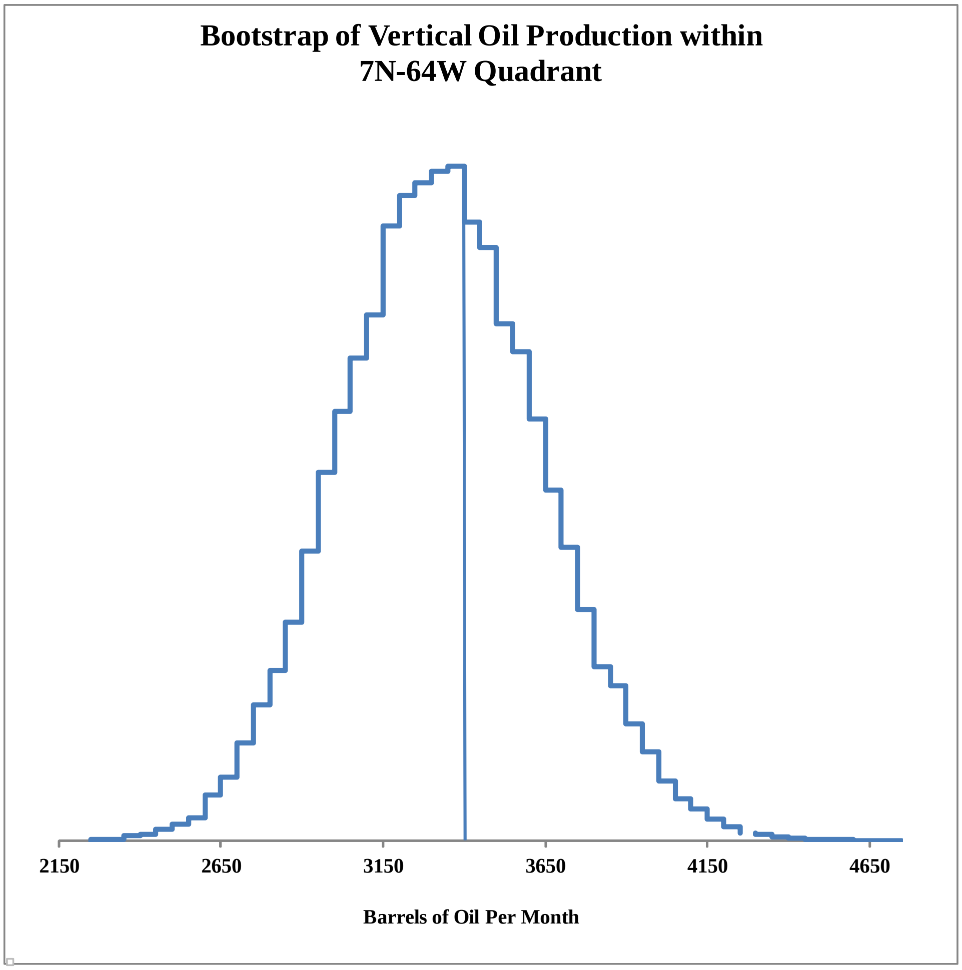
The flows were taken for each well within the given range for the initial period of study and averaged together to obtain the mean initial flow rate.

The bootstrap resampling with replacement procedure was used to establish statistical confidence for the initial average flow rate. Bootstrapping is a generally recognized resampling method used to establish an expected range of activity based on a limited sample size. Bootstrapping is based on the central limit theorem. It states that “a large number of independent observations from the same distribution have an approximate normal distribution, and this approximation improves as the number of observations increases.”

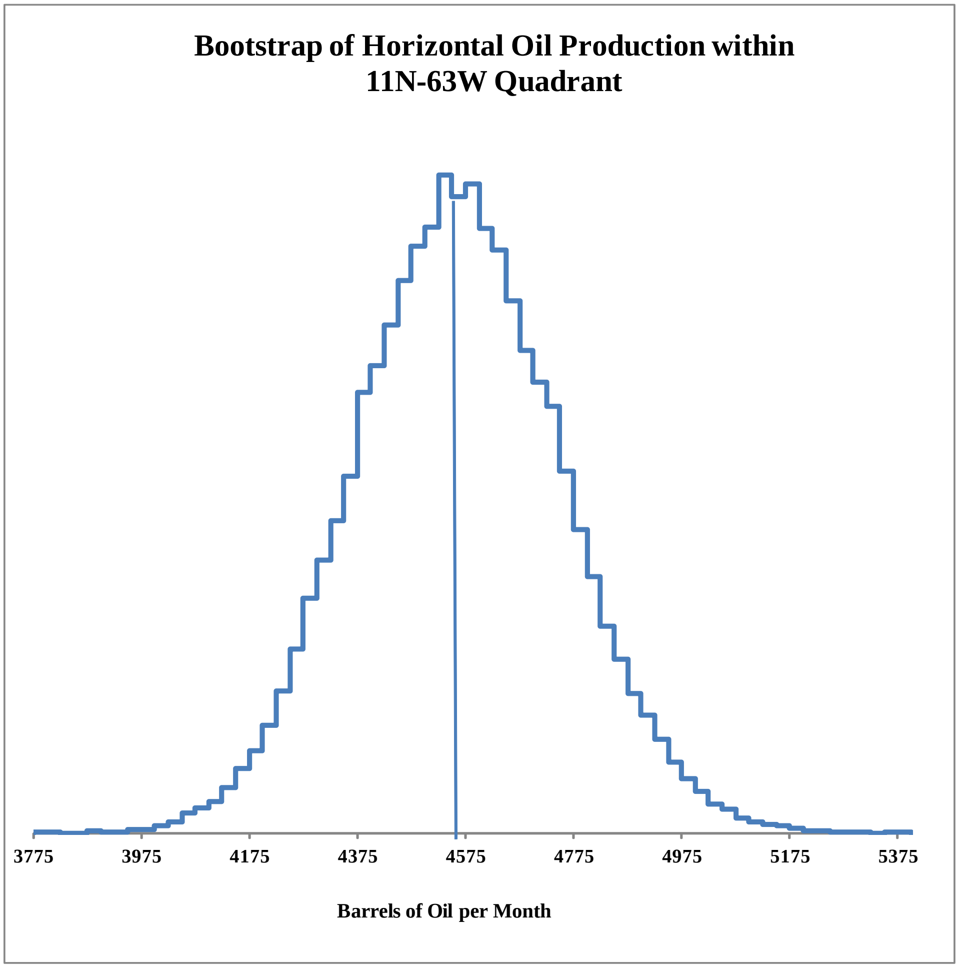
The statistical program takes the initial values found in the small sample. It then generates random distributions of possible outcomes by taking repeated samples from the data. This process is repeated until the distribution of the sampling means is normal. A total of 50,000 iterations were completed for this study. The mean for each sample was observed. The mean of the sample means was calculated. The mean of sample means is the expected flow rate that was utilized in the assessment of financial feasibility. Supporting data and charts are on the following pages:

[400] (Colorado Oil and Gas Conservation Commission Website n.d.)

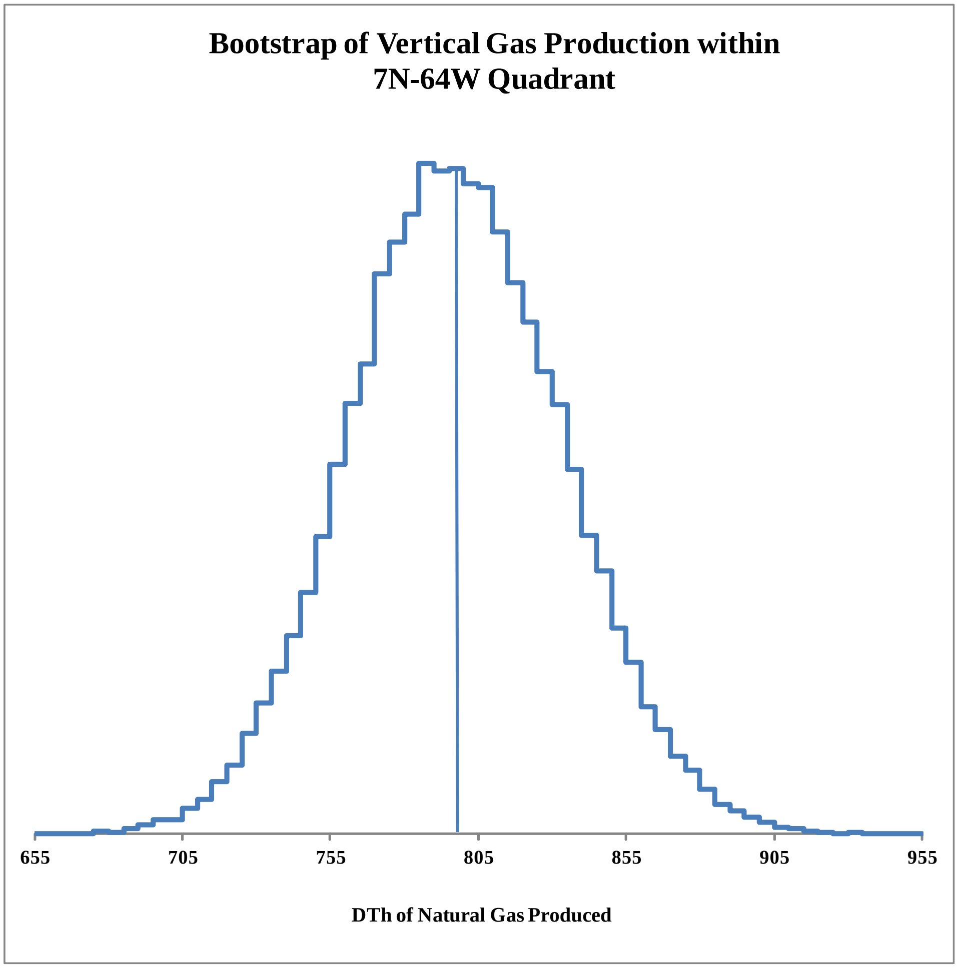
Summary Statistics			Notes
Average	3,334.97	Barrels	7N -64W (6) 50,000 Repetitions
SD	309.66	Barrels	
Max	4,748.45	Barrels	
Min	2,158.56	Barrels	



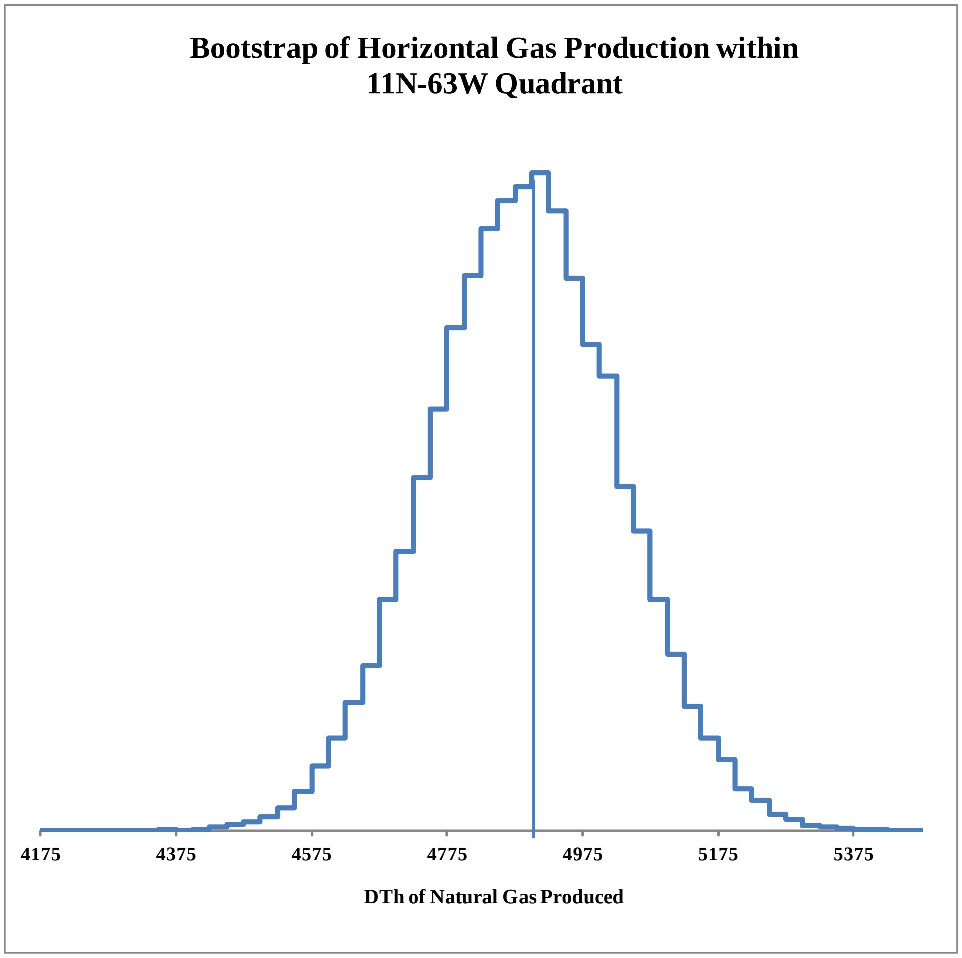
Summary Statistics			Notes
Average	4,563.24	Barrels	11N-63W 50,000 Repetitions
SD	188.77	Barrels	
Max	5,378.80	Barrels	
Min	3,779.72	Barrels	



Summary Statistics			Notes
Average	797.85	DTh	
SD	35.86	DTh	7N -64W (6)
Max	951.99	DTh	50,000 Repetitions
Min	656.50	DTh	



Summary Statistics			Notes
Average	4,889.20	DTh	11N -63W (6) 50,000 Repetitions
SD	138.52	DTh	
Max	5,465.87	DTh	
Min	4,197.68	DTh	



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