WATER VALUE AND ENVIRONMENTAL IMPLICATIONS OF HYDRAULIC FRACTURING: EAGLE FORD SHALE

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by

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ABSTRACT

Water Value and Environmental Implications of Hydraulic Fracturing: Eagle Ford Shale. (May 2014)

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Shale gas has emerged as one of the leading energy developments in the United States. Production has risen from roughly 0.9 trillion cubic feet (TCF) in 2006 to 4.8 TCF in 2010. Shale gas now encompasses 23% of U.S. natural gas production and is expected to be at 46% by 2035. Shale gas is considered to be one of the answers to the energy crisis. In this thesis, the goal is to address several issues related to the efficacy of hydraulic fracturing of shale in deep formations to capture oil and gas. In recent years, controversy has risen over the safety of hydraulic fracturing, the amount of water used, the environmental implications, and if the action is economically efficient in the water resources used. This research applies economic principles to develop implications based on industry, government and institutional data, and draw conclusions relative to impacts on the environment, realized amount of water, and value of water used for a typical well in the Eagle Ford development, a water-scarce region. The imputed value of water used for fracturing is severalfold greater than for in other uses. The results are useful to the industry, landowners, policy makers, and other stakeholders.

DEDICATION

I would like to dedicate this report to Dr. Ronald D. Lacewell and Dustin Bryant. I would not be here without their leadership, support, and belief in me as an individual to accomplish this task. Without Dustin, I would not have found the opportunity to work under Dr. Lacewell as a research assistant. Without Dr. Lacewell, I would never have completed this project. I am especially grateful for Dr. Lacewell's assistance in developing the residuals and crop enterprise budgets that made comparison of the values in this report possible. Furthermore, I would like to thank all who have supported me along this several-month journey as there have been plenty of hiccups along the way along with several opportunities to quit. I am excited to say I completed this project and am proud to present it today.

ACKNOWLEDGEMENTS

This report relative to water use and value related to hydraulic fracturing of the Eagle Ford Shale is mostly based on literature and information from the energy industry as well as its institutions. An extensive array of materials covering hydraulic fracturing was used and references were provided to identify any sources that led to the conclusions of this paper. The limitation of this report is that information comes from both the industry and institutions. Both of these sources tend to take a hard position making it difficult to pinpoint a singular conclusion. Most of the economic theory discussed in this thesis was obtained from the lectures of Dr. Richard Dunn of the Department of Agricultural Economics at Texas A&M University. The Bureau of Economic Geology, the Energy Information Administration, the Texas Water Development Board, the Railroad Commission of Texas, the Texas Municipal League, the Environmental Protection Agency, the U.S. Bureau of Labor Statistics, and the Texas A&M AgriLife Extension Service provided exceptional information relative to water and other factors related to hydraulic fracturing in the Eagle Ford Shale and several surrounding regions. Dr. Steven Holditch, formerly of the Texas A&M University Energy Institute, provided values concerning operational costs to fracking. For environmental implications, the Texas Department of State Health Services provided excellent assistance. The author of this report is working in coordination with Texas A&M AgriLife Research and has no relationships with any companies or industry related to any part of hydraulic fracturing of shale or any other form of hydrocarbon recovery.

NOMENCLATURE

One acre foot = 325,851.4 US gallons

One Mgal = One million gallons

One Mcf = One thousand cubic feet

One Million British Thermal Units (MMBTU) = 1 Mcf

One Bbl = One barrel (42 gallons)

One Tcf = One trillion cubic feet

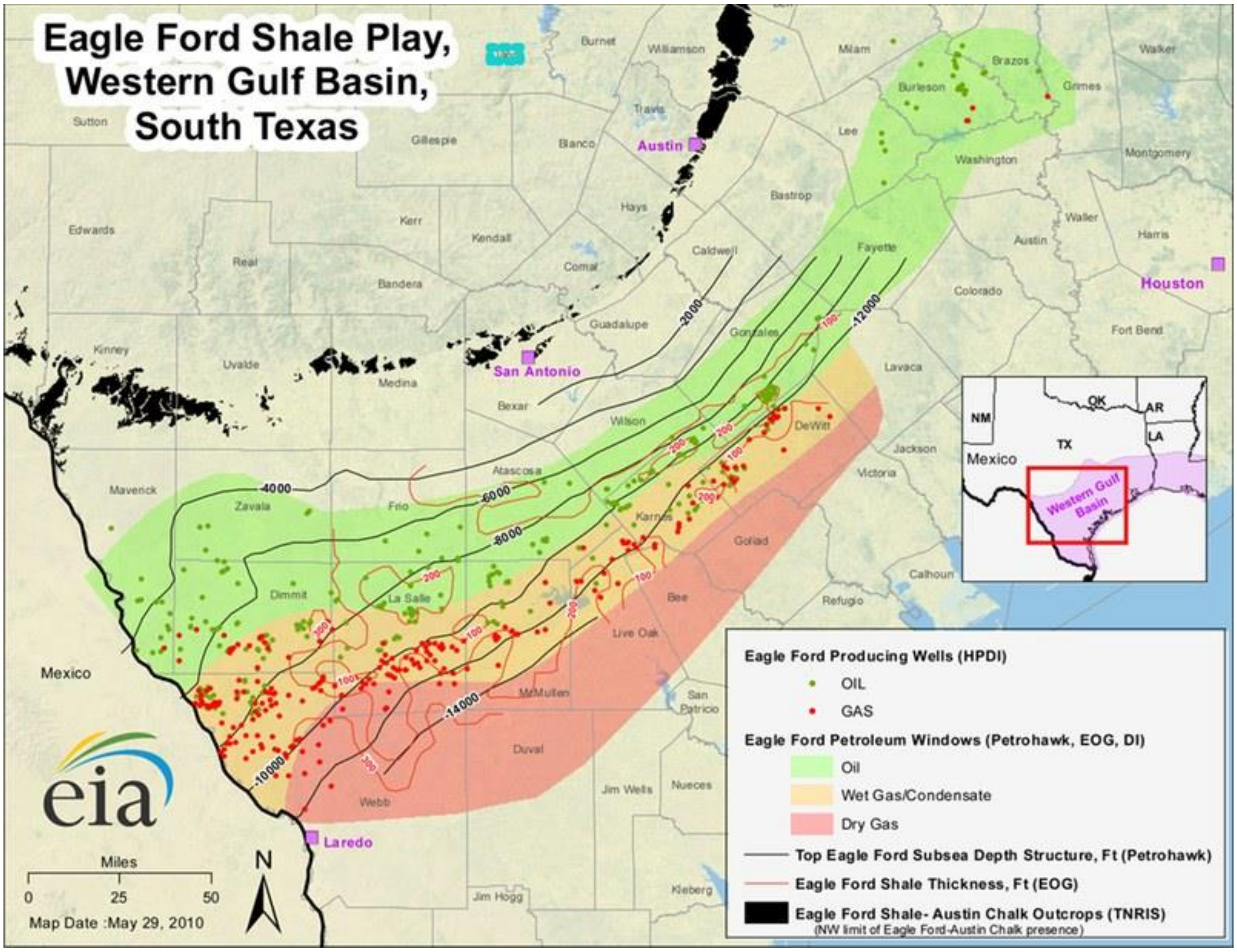
One acre = 43,560 square feet

CHAPTER I

INTRODUCTION[1]

Energy and water are intrinsically linked. Improved technology for releasing natural gas and oil from shale uses water in the hydraulic fracturing process. For Texas, such water use can be problematic as the state is already and will continue to be exposed to severe drought, and, as a result, will continue to face issues in the future related to the availability of water for industry, agriculture, a rapidly-increasing population, and the eco-system including recreational uses. Due to these anomalies, there has been significant attention directed towards the use of water in energy development. This is true across the United States and is certainly so within the Eagle Ford Shale in South Texas. An objective of this project is an analysis of the implications of the amount of water used, the relative values of the water in alternative uses, and the potential long-term health effects that arise from the hydraulic fracturing process and well operations. Although these results are confined to the Eagle Ford Region of Texas, they are applicable to other regions across the state of Texas and even the U.S. Illustrated in Figure 1-1 is a map of the Eagle Ford Shale. Also presented are the locations where oil and gas are being extracted. Note that the denser areas of oil and gas extraction are where this study's focus is.

[1] This thesis follows the style of the *American Journal of Agricultural Economics.*



Source: Eagle Ford Shale Map (2011).

Figure 1-1. Eagle Ford Shale Map

Water is a critical resource used in the hydraulic fracturing of deep formations to release hydrocarbons. In the case of the Eagle Ford Shale, these hydrocarbons come in the form of natural gas and some amounts of oil. Hydraulic fracturing involves drilling deep, horizontal wells that branch throughout many acres. The idea of horizontal drilling is to maximize the potential of energy extraction through elongating the surface area for extracting energy from the earth. Additionally, different angles of drilling ensure that multiple facets of energy can be reached simultaneously, and, finally, horizontal wells allow companies to drill without moving to multiple locations and disturbing large surface land areas. Once drilling is complete, water under high pressure, usually containing a mixture of proppants (sand and glass beads) as well as chemicals (Uhlman, et al. 2012), is injected into the well to hold open the formation to release the natural gas and oil. For the Barnett Shale, the average amount of water use per well is an estimated 6.3 million gallons (Mgal) (Cowan 2011). Hundreds of chemicals are considered for the cocktail[2] to be added to the water including friction reducer, acid, stabilizer, gelling agent, corrosion inhibitor, fluid viscosity, surfactant and many others (*Frac Focus: Chemical Disclosure Registry* 2012).

The type and amounts of chemical mixtures that are used in the oil and gas extraction process are dependent on the company, the well, and the shale formation. Once a well is completed, a significant percentage of water and chemicals that have been used in the process flow back and either have to be deep-well injected or, in some cases, treated and recycled, i.e., used again. Such reused water is termed "produced water."

Throughout the nation, issues have arisen over the amount of water and potential contamination of drinking water related to the fracturing process. While certainly not the leading user of water (agriculture and municipal use tend to be the frontrunners), hydraulic fracturing is a substantial beneficiary of water. As such, slight changes in fracturing processes and locations have the potential to cause changes in how water is allocated and how much can be depended upon for other uses. In addition, related wastewater, known as flowback or produced water, has the potential to harm the surrounding environment through contamination of aquifers, streams,

[2] The mixture of chemicals, sand, and glass beads that is added to the water for the hydraulic fracturing process

plants, and animals. Flowback can either be disposed of as per the regulations of the Railroad Commission of Texas (found in section 3.8) (Texas Railroad Commission, Texas Oil and Gas Divisions 2013a) and the Texas Commission on Water Quality (Corken 2013), or the water may be treated for reuse depending on the company and the amount of wastewater returned from the process. The amount and value of the water used and the opportunity costs of water geared towards fracturing are topics of interest to local communities, regionally, and nationally.

At the heart of the issue of water use in fracturing is the need for and demand for energy. An ever-increasing demand for energy is putting pressure on known supplies. The implications of hydraulic fracturing to open up previously unrecoverable sources of energy are evident in meeting needs. To put matters in perspective, despite improvements in renewable fuel sources and standards, oil and gas still provide 60 percent of America's needs alone (*Energy: Fueling our Way of Life* 2013). Traditional gas deposits and oil refineries alone simply cannot sustain this level of demand (*Energy: Fueling our Way of Life* 2013).

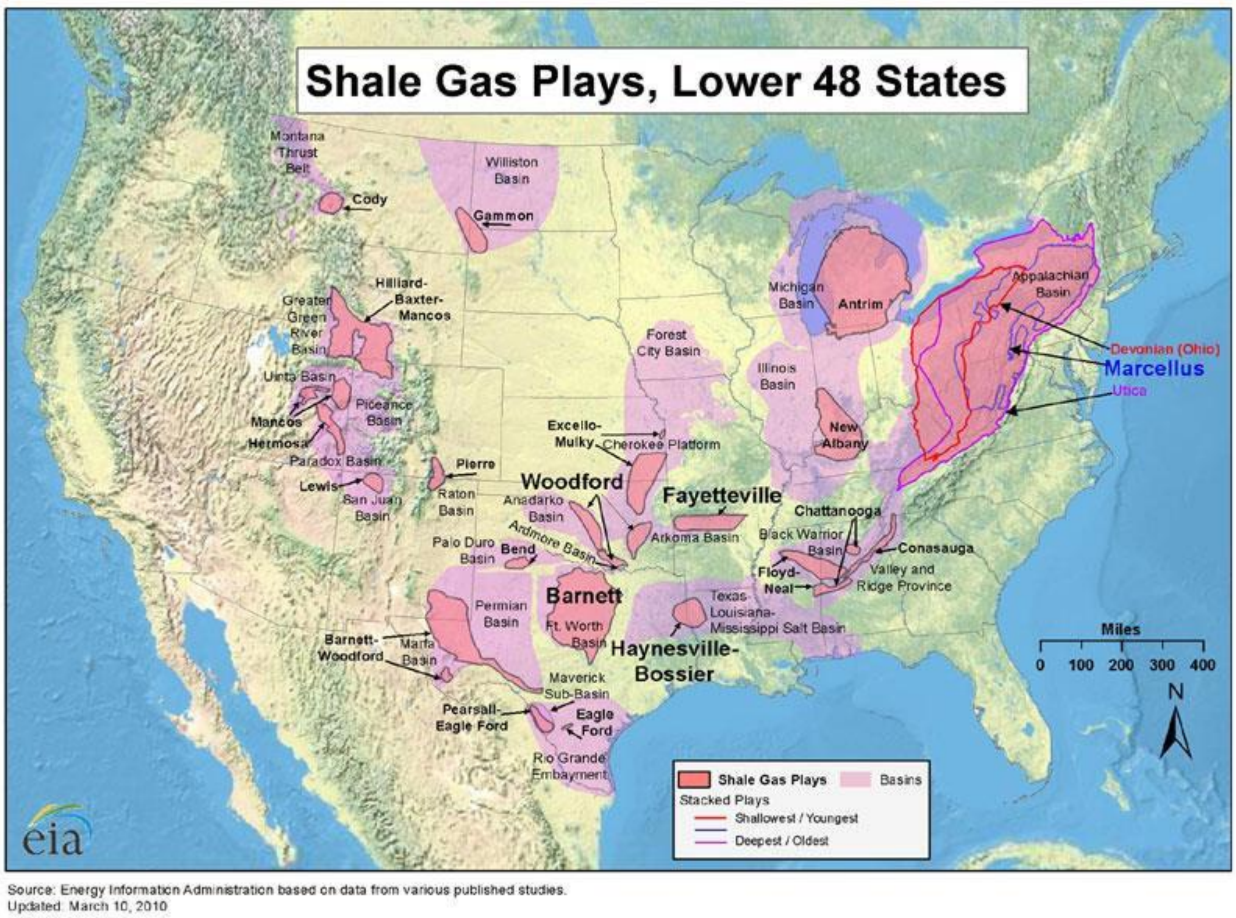
On another positive side, in addition to providing a valuable source of energy is the economic impact on landowners, mineral rights owners, communities, and states. Landowners see windfall gains, businesses flourish, and local and state revenues increase. The U.S. oil and natural gas industry has provided a boost to the national economy by creating 9.2 million jobs, generating more than $100 billion in governmental revenue (rents, royalties, lease payments, etc.), and more than $35 billion is distributed to American households in the form of dividends since 2000 (*Oil and Natural Gas Power America's Economy* 2013). The breadth of geographical regions with hydraulic fracturing are expected to increase over time as companies expand across the U.S. and the world (*Oil and Natural Gas Power America's Economy* 2013). It is important to note, however, that some states do not allow hydraulic fracturing at this point[3].

The expansion of hydraulic fracturing suggests that there is a technology that enhances the supply of energy at a competitive price but the technology is a relatively large user of water with potential issues of negative externalities. The goal of this research is to estimate the level of water use (per well and total), value of the water per unit, implications for the environment, and potential health impacts of the Eagle Ford Shale Play.

Geographic location

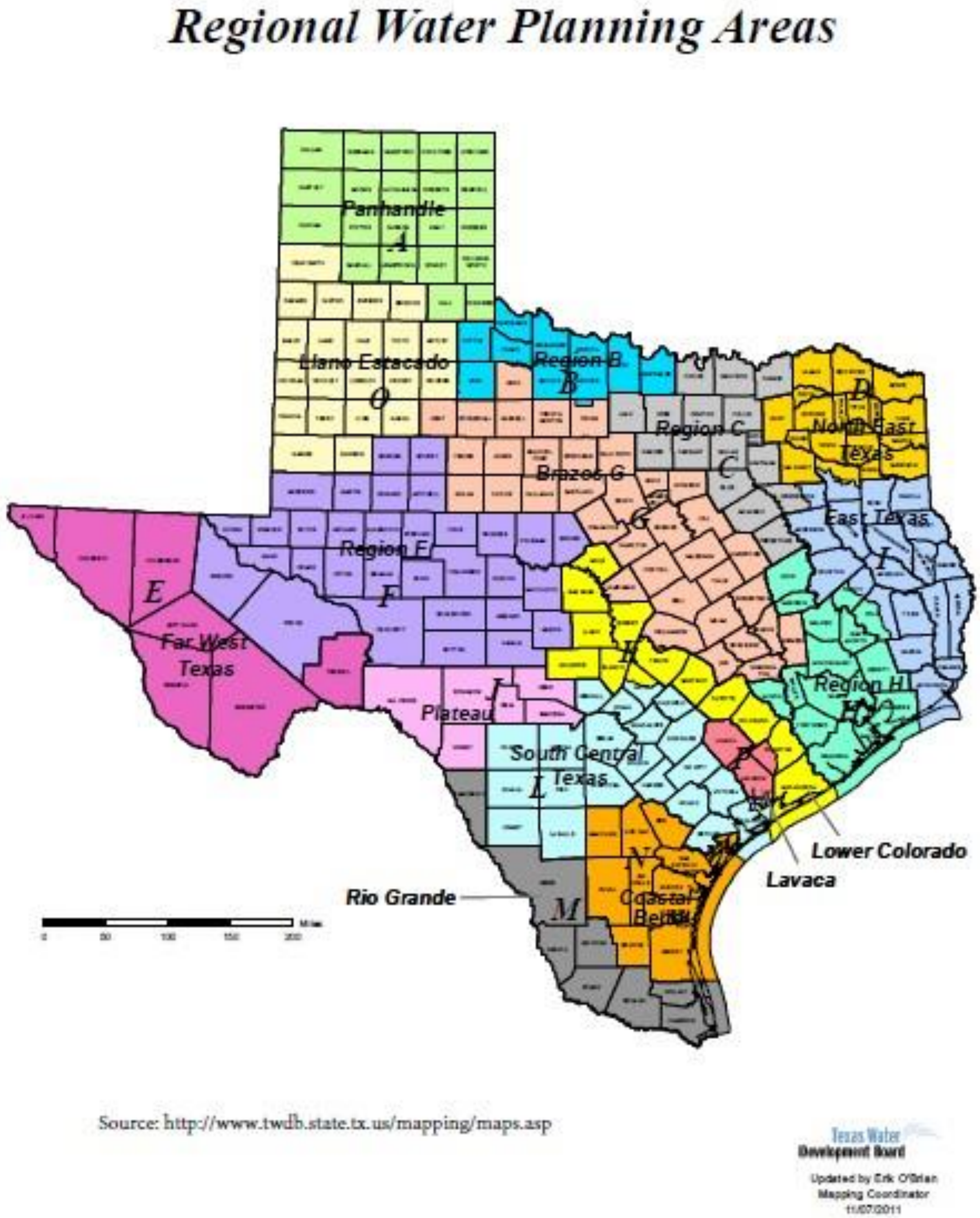
The Eagle Ford shale encompasses a large region consisting of 30 total counties in Texas (Eagle Ford Shale Play 2012). This paper is focused on a sub-region identified by the University of Texas's Bureau of Economic Geology (2013) as well as guidance from the Texas Railroad Commission (2013a). The study-area counties include Maverick, Zavala, Frio, Dimmit, La Salle and Webb. These six counties belong to regions "one" and "four" of the Texas Oil and Gas divisions (Texas Railroad Commission, Texas Oil and Gas Divisions 2012), and regions "L" and "M" of the Texas Regional Water planning areas (Texas Water Development Board 2013a). Displayed in Figure 1-2 are the major shale plays across the United States including that of the Eagle Ford Shale. Illustrated in Figure 1-3 are the Texas regional water planning areas, Figure 1-4 is a similar portrayal of the Texas oil and gas district boundaries. Represented in Figure 1-5 are the six Texas counties that are the focus of this study as well as a few other counties with substantial drilling and economic development activity.

[3] New York and the majority of Hawaii



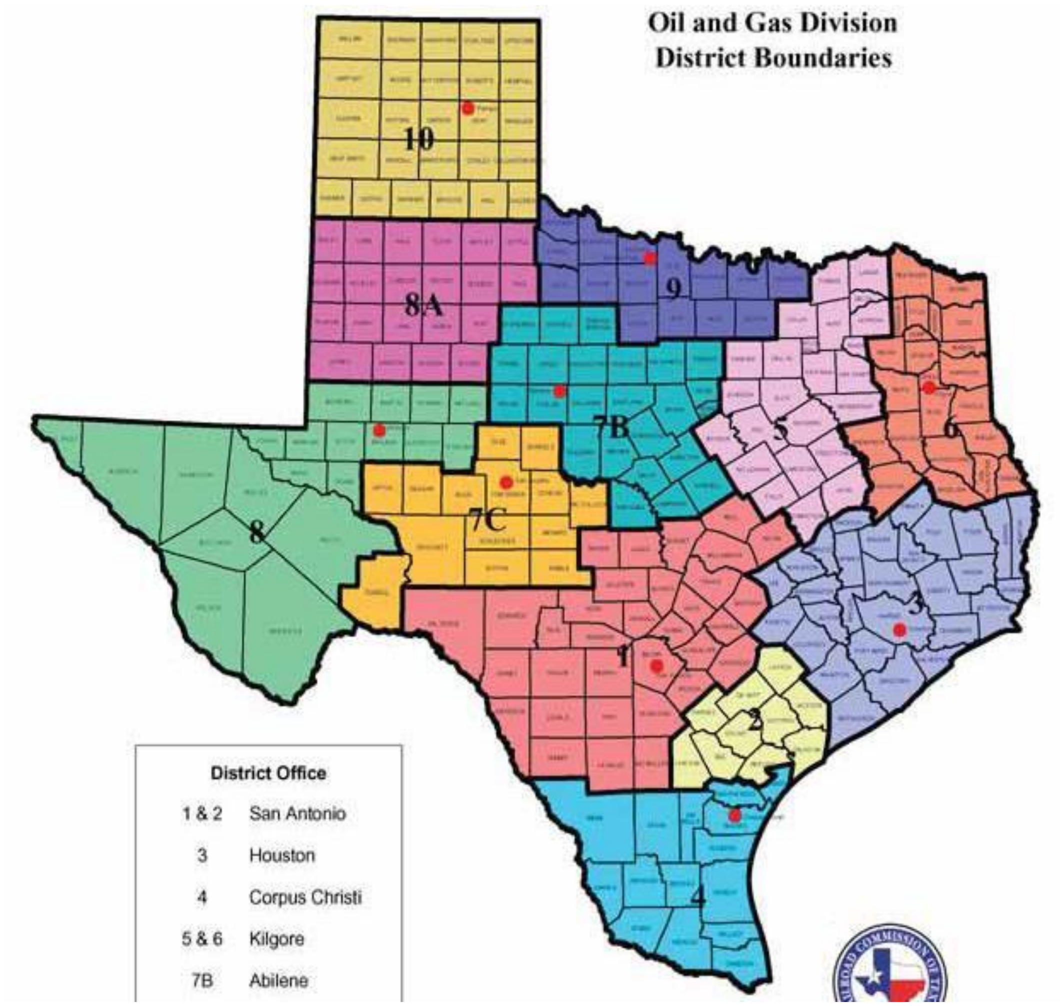
Source: Energy Information Administration (2010a).

Figure 1-2. General Location of the Major Shale Gas Plays across the United States



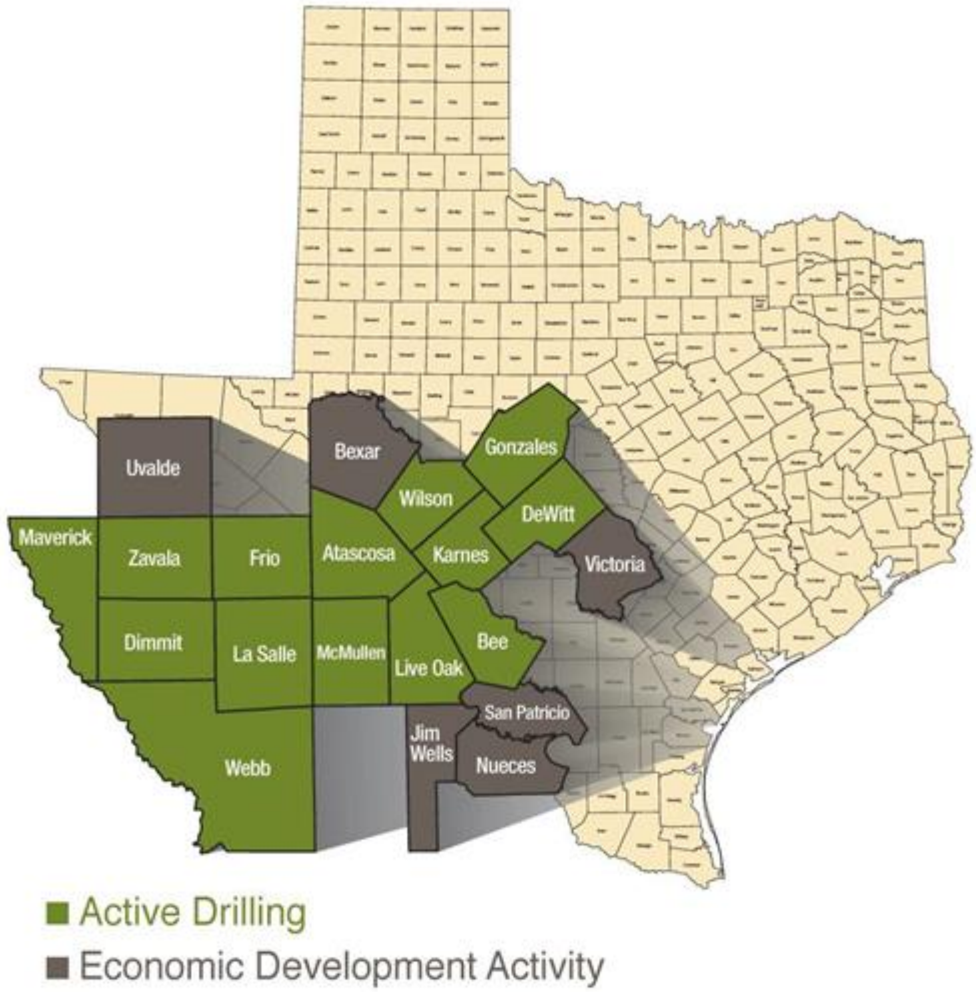
Source: Texas Water Development Board (2013a).

Figure 1-3. Texas Water Planning Regions



Source: Texas Railroad Commission (2013a).

Figure 1-4. Texas Oil and Gas Divisions



Source: *Steer: South Texas Energy & Economic Round Table* (2013).

Figure 1-5. Eagle Ford Study Area

In Figure 1-4, the counties in blue are designated as economic development activity do not include active drilling because the shale play does not extend to these counties.

Objectives

The primary goals of this thesis are to define the water situation in the Eagle Ford region relative to supply and demand for 2010-2060, expected agriculture water use, municipal and industrial water use, and fracturing water estimated use per natural gas well. In addition, the value of water used for fracking is compared to value in other uses. Lastly, emissions from the fracturing of a gas well are defined to the extent possible. The first null hypothesis of the study is that water value is less in hydraulic fracturing than in alternative uses. The alternative hypothesis is that the value of water in hydraulic fracturing is greater than in alternative uses. A second hypothesis is that hydraulic fracturing emits harmful and dangerous gases to the environment causing health problems to the citizens in the region. The alternative hypothesis in this case is that there are no environmental anomalies connected to hydraulic fracturing. Presented in table 1-1 are the hypotheses of this report.

Table 1-1. Value and Health Hypotheses

Water Value Hypothesis	
H_O	Fracturing water value < value in alternative uses
H_A	Fracturing water value > value in alternative uses
Emissions Hypothesis	
H_O	Fracturing emissions are linked to health issues
H_A	Fracturing emissions are not linked to health issues

Methodology

To estimate values associated with hydraulic fracturing of shale, a series of economic techniques are applied. These approaches include crop budgeting, budgeting analyses, capital budgeting, and sensitivity analyses.

Crop enterprise budgets

Effectively, crop enterprise budgets allow managers to analyze different costs and returns of various crops in order to determine the best technology, resources, and practices needed to achieve optimum efficiency (Kay, Edwards, and Duffy 2003). An enterprise is a unit of measurement useful in business functions with its primary purpose being to evaluate the risks and returns in various enterprises (Kay, Edwards, and Duffy 2003). Developing crop enterprise budgets is beneficial in this study in order to delve into the economic effects or value of water related to crop production. The crop enterprise budgets developed by Texas A&M AgriLife Extension Service for the study region are the basis for this analysis (Texas A&M AgriLife Extension Service 2012).

Budgeting analysis

Budgeting analysis is a comparison of budgets. Such comparisons might be across irrigated crops, municipal uses, and fracturing. Like crop enterprise budgeting, budget analyses assist in analyzing the differences in water values among agriculture, municipal and industrial, and fracturing use. In order to gain an appropriate knowledge of crop, municipal and industrial, and fracturing budgets, published municipal rates and local prices of water are used.

Capital budgeting

A capital project is best evaluated by identifying the life-cycle costs for capital investments (Penson and Lins 1980). Thus, capital budgeting is used in order to estimate the net cash flows throughout the entire life of the capital investment (plants, property and equipment) (Penson and Lins 1980). Analyzing an investment requires a prior knowledge of several features, including the initial cost of the investment, the annual net cash revenues and expenses realized, the expected life of the initial investment, the reinvestment time frame, the salvage value, and, finally, the discount rate (Penson and Lins, 1980).

Sensitivity analyses

Because there are highly variable values reported as to water use, gas production, operation costs, gas price, etc., this study conducts a series of analyses across alternative scenarios. Using budgeting analysis, various features of the economy (including discount rates and inflation) as well as several other factors are varied to demonstrate the effects that differing scenarios have on the returns to water. This study incorporates alternative sensitivity analyses in order to evaluate worst-case, expected, and best-case scenarios.

Outline

Independent, third-party data concerning fracturing, drilling and operation of gas wells in the Eagle Ford Shale region (or within other shale plays) is very limited. Therefore, much of the data used in this analysis comes from industry reports as well as governmental and institutional reports. A challenge in the analyses presented in this report is to resolve differences in industry pro-fracturing reports and environmental anti-fracturing reports. Also, due to a wide range of estimates on several topics and factors, a significant portion of this work focuses on sensitivity analyses. A review of literature provides insight on many characteristics of hydraulic fracturing for the Eagle Ford Shale and across the U.S. Following the review of literature are theoretical concepts relevant to the study.

A brief background of hydraulic fracturing activity in the Eagle Ford Shale follows the theoretical concepts. This chapter focuses on the history of the shale as well as the projected production of the shale until 2060. The concept of production decline rates is introduced in this chapter. Most importantly, this chapter provides a base for the water-value analysis in the following chapter.

As mentioned, the fracturing-activity chapter introduces the next chapter which discusses the value of water in alternative uses. This discussion is the main subject of this report. The value of water is addressed through (1) municipal and industrial water rates in the region, (2) the value in irrigated agriculture measured as the added net returns above dryland (non-irrigated) returns (defined as a residual return to water after all costs for factors of production are subtracted), and lastly, (3) in fracturing. The value of water for fracturing is estimated as residual returns after all other factors of production have been subtracted. The cost of groundwater for fracturing is estimated as the cost to pump while surface water cost is based on sales prices (cost per acre foot). The estimate of value of water includes application of capital budgeting techniques since costs and revenues extend over many years.

Impacts on health from wells are then addressed, primarily based on studies in the other regions.

Clinical studies are very limited, suggesting a need to go beyond the current state of knowledge.

The last sections of the report are summary, conclusions, and limitations.

CHAPTER II

REVIEW OF LITERATURE

The question of a sustainable energy supply is one that remains a reality across the United States. As the population increases at an exponential rate, it becomes concerning that there may not be enough energy sources to meet the coinciding increase in demand. Though there are increases in renewable fuels and plenty of incentives for producers of these fuels to produce, further life-cycle analyses and lack of efficiency are suggestive these fuels may not be able to fully replace fossil fuels as a form of energy in the near future. Thus, the question arises as to the source of a viable supply of energy? One such answer is through the use of hydraulic fracturing of shale. Though relatively new as a process, hydraulic fracturing is steadily on the rise and providing energy while also consuming resources that are otherwise demanded by society. As such, it is a point of interest to discern to what extent hydraulic fracturing affects the use of resources such as water and to determine the associated externalities' impacts on the environment. Due to a lack of third-party reports, most of the literature used in this report comes from industry or environmental-group data. There are a few exceptions; e.g., some information is sourced from regulatory agencies.

History

Hydraulic fracturing, also known as "fracking," is a process that involves drilling both vertically and then horizontally into a shale formation followed by injecting water and chemicals at high pressure causing the surrounding areas to fracture and release the hydrocarbons (*A Brief History of Hydraulic Fracturing* 2010). The process is known for retrieving natural gas, but in many cases, oil is also extracted (*A Brief History of Hydraulic Fracturing* 2010). Hydraulic fracturing was first introduced by Stanolind Oil in 1949 in Stephens County, Oklahoma, and in Archer County, Texas (Montgomery and Smith 2010). Though these were the first wells, the beginnings of the process now known as hydraulic fracturing can be traced back even further to the 1860s (Montgomery and Smith 2010). In those days, liquid and, soon thereafter, nitroglycerine was used very haphazardly, and sometimes illegally, to penetrate shallow rock wells found in Pennsylvania, New York, Kentucky, and in West Virginia (Montgomery and Smith 2010). From there, the fracking industry began to develop to the point of millions of shale wells being drilled across the United States. Illustrated in Figure 1-1 of the previous chapter are the major shale formations in North America.

Total gas recovered

The total amount of gas and oil recovered in Texas, including the Eagle Ford Shale, via wells in 2012 was 417,412,664 thousand cubic feet (Mcf) of gas and 87,461,399 barrels (Bbl) of oil for District 1 and 724,228,802 Mcf of gas and 3,389,802 Bbl of oil for District 4 (Texas Railroad Commission 2013d). Displayed in Table 2-1 are monthly data for wells in Districts 1 and 4 of the Texas Oil and Gas Divisions (Texas Railroad Commission 2013d). In the table, GW stands for gas well. Shown in Figures 2-1 and 2-2 are charts indicating the magnitude of Eagle Ford Shale oil and gas production compared to total oil and gas production in Texas.

Table 2-1. Texas Shale Well Gas and Oil Produced on a Monthly Basis, 2012

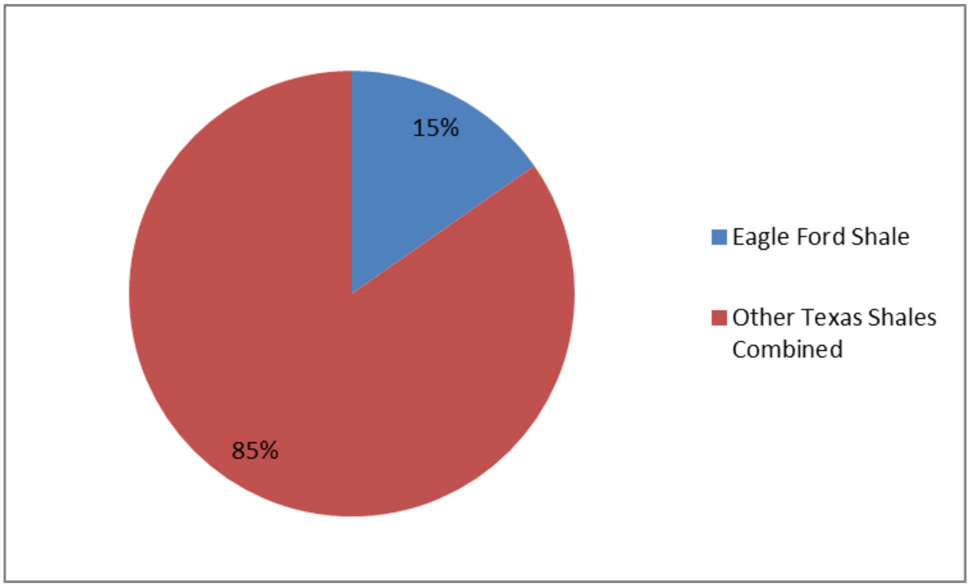
	District 1[a]		District 4[b]	
Months	**GW[c] Gas (Mcf)**	**Oil (Bbl)**	**GW Gas (Mcf)**	**Oil (Bbl)**
January	36,790,403	5,023,232	69,824,052	295,929
February	34,344,864	4,995,300	63,673,048	289,074
March	37,023,501	5,968,707	65,905,207	304,198
April	34,196,785	6,593,608	62,857,534	287,829
May	36,834,881	7,442,219	64,007,302	292,090
June	34,877,774	7,313,492	59,375,325	269,577
July	35,624,729	7,978,355	60,307,263	278,749
August	36,017,072	8,339,541	59,155,655	281,129
September	33,615,000	7,713,083	56,738,911	260,118
October	34,308,292	8,635,545	55,781,464	276,967
November	31,885,991	8,292,256	53,618,183	272,390
December	31,893,372	9,166,061	52,984,858	281,439
Total	417,412,664	87,461,399	724,228,802	3,389,489

Source: Texas Railroad Commission, Texas Oil and Gas Divisions (2013b).

[a] See Figure 1-3

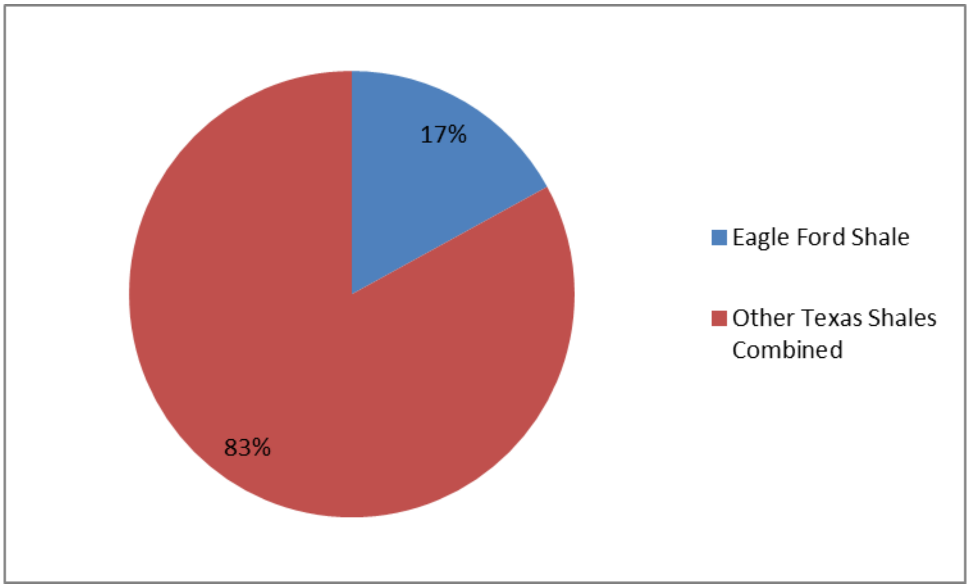
[b] See Figure 1-3

[c] GW refers to gas well as posted by the Texas Railroad Commission



Source: Texas Railroad Commission, Texas Oil and Gas Divisions (2013b).

Figure 2-1. Comparison of Eagle Ford Shale Oil Production and Other Texas Shale Oil Production, 2012



Source: Texas Railroad Commission, Texas Oil and Gas Divisions (2013b).

Figure 2-2. Comparison of Eagle Ford Shale Gas Production and Other Texas Shale Gas Production, 2012

Table 2-2 is a presentation of some of the drilling statistics in Texas since 1960 (Texas Railroad Commission 2013d). Indicated in the table, every aspect, from wells completed to drilling permits issued, has fluctuated during the past fifty years (Texas Railroad Commission 2013d). Figures for the year 2012 are neither at their highest point nor at their lowest point (Texas Railroad Commission 2013d).

Table 2-2. Texas Oil and Gas Drilling Statistics, 1960-2012

Year	Drilling Permits Issued	Oil Wells Completed	Gas Wells Completed	Total Holes Drilled[a]	Total Holes Plugged	Average Rotary Rig Count
1960	15,601	9,666	2,011	17,342	8,889	604
1965	14,227	7,207	2,383	14,433	8,836	425
1970	11,034	4,987	1,796	9,438	8,310	302
1975	20,293	7,004	3,396	14,393	10,960	638
1976	22,693	7,348	4,108	15,378	8,232	653
1977	25,189	8,121	4,399	16,577	8,129	778
1978	26,050	8,132	5,383	17,189	7,396	855
1979	29,241	8,487	5,319	17,509	6,658	770
1980	39,442	12,322	5,331	21,427	6,673	989
1981	47,940	15,627	5,454	26,209	9,054	1,318
1982	41,224	16,296	6,273	27,648	10,435	990
1983	45,550	15,941	5,027	26,882	11,661	796
1984	37,507	18,716	5,489	30,898	13,393	849
1985	30,878	16,543	4,605	27,124	14,479	677
1986	15,894	10,373	3,034	18,707	15,451	311
1987	15,297	7,327	2,542	13,121	13,186	293
1988	13,493	6,441	2,665	12,262	12,566	277
1989	12,756	4,914	2,760	10,054	11,229	206
1990	14,033	5,593	2,894	11,231	10,290	348
1991	12,494	6,025	2,755	11,295	13,089	315
1992	12,089	5,031	2,537	9,498	11,423	251
1993	11,612	4,646	3,295	9,969	11,552	263
1994	11,248	3,962	3,553	9,299	13,657	274
1995	11,244	4,334	3,778	9,785	11,081	251
1996	12,669	4,061	4,060	9,747	10,901	283
1997	13,933	4,482	4,594	10,778	9,336	358
1998	9,385	4,509	4,907	11,057	8,951	302
1999	8,430	2,049	3,566	6,658	7,011	226
2000	12,021	3,111	4,580	8,854	7,219	343
2001	12,227	3,082	5,787	10,005	8,023	462
2002	9,716	3,268	5,474	9,877	8,343	338
2003	12,664	3,111	6,336	10,420	8,720	448
2004	14,700	3,446	7,118	11,587	8,391	506
2005	16,914	3,454	7,197	12,664	7,191	662
2006	18,952	4,761	8,534	13,854	7,504	746
2007	19,994	5,084	8,643	20,619	6,892	834
2008	24,073	6,208	10,361	22,615	6,046	898
2009	12,212	5,860	8,706	20,956	6,390	432
2010	18,029	5,392	4,071	9,477	6,028	659
2011	22,480	5,380	3,008	8,391	5,564	910
2012	22,479	10,936	3,580	15,060	8,395	899

[a] Includes oil wells, gas wells, and dry holes

Source: Texas Railroad Commission, Texas Oil and Gas Divisions (2013d).

Displayed in Table 2-3 are statistics of the table shown in Table 2-2. Total holes drilled, total holes plugged, and gas wells completed were relatively more stable throughout the fifty year period than drilling permits issued, oil wells completed, and average rotary rig count (Texas Railroad Commission 2013d). In Table 2-3, the coefficient of variation is the measure of the variability and the lower the value, the more stable the set of values. The purpose of conveying this information is to show the level of stability in the industry. Knowing this information gives an idea of the degree of confidence able to be held in the projected results of this report.

Table 2-3. Summary of Texas Oil and Gas Drilling Statistics, 1960-2012

	Drilling Permits Issued	Oil Wells Completed	Gas Wells Completed	Total Holes Drilled	Total Holes Plugged	Average Rotary Rig Count
Mean	19,461	7,152	4,666	14,885	9,452	555
Standard Deviation	10,120	4,220	1,960	6,252	2,552	278
Coefficient of Variation	52%	59%	42%	42%	27%	50%

Source: Texas Railroad Commission, Texas Oil and Gas Divisions (2013d).

Water requirements and flowback

The process of hydraulic fracturing uses water with a cocktail of other chemicals. After the process, the high pressure results in flow back[4] of much of the water, chemicals and other material in the shale.

[4] After the fracking process is complete, flow back is the water that returns to the surface and is able to be used by the drillers.

Water volume usage

The volume of water used in the fracturing process as well as the amount of flow back is an important issue among those that study fracking and industry officials. Generally, both the industry and the institutions are able to provide similar statistics in this field. In fact, Chesapeake Energy (2012) claims that the total water use in the Eagle Ford region was approximately 64.8 billion gallons in 2008. In addition, according to Chesapeake Energy (2012), fracturing a typical deep well in the Eagle Ford Shale requires 4.8 million gallons (14.73 acre feet) of water. Chesapeake Energy (2012) also provides a useful breakdown of their estimated water usage in drilling for different sources of energy (Table 2-4).

Table 2-4. Water Used per Million British Thermal Units (MMBTU) of Energy Produced

Energy Resource	**Range of Gallons of Water Used per MMBTU[a] of Energy Produced**
Eagle Ford Shale Natural Gas	1.25
Conventional Natural Gas	1-3
Coal (no slurry transport) Coal (with slurry transport)	2-8 13-32
Nuclear (uranium ready to use in a power plant)	8-14
Chesapeake Deep Shale Oil	7.96-19.25
Conventional Oil	8-20
Synfuel-Coal Gasification	11-26
Oil Shale Petroleum	22-56
Oil Sands Petroleum	27-68
Synfuel-Fisher Tropsch (from coal)	41-60
Enhanced Oil Recovery (EOR)	21-2,500
Biofuels (Irrigated Corn Ethanol, Irrigated Soy Biodiesel)	>2,500

[a] One MMBTU is equal to one thousand cubic feet (Mcf).

Source: Chesapeake Energy (2012).

The values in Table 2-4 simply compare the water volume necessary to produce a given level of energy. Of all the energy sources listed, natural gas from the Eagle Ford Shale requires the least amount of water volume to produce an MMBTU.

According to Chesapeake Energy (2013), drilling a typical well requires water in the amount of 65,000 to 600,000 gallons and fracturing those same wells requires nearly 5 million gallons. These estimates are very similar to those presented by Mattson, Palmer, and Cafferty (2011) (Table 2-5).

Table 2-5. Hydraulic Fracturing Water Consumption Estimates of Different Shale Formations in the United States

Shale Formation	Volume of Drilling Water per Well (gal)	Volumeof Fracturing Water per Well (gal)	Total Volume of Water per Well (gal)
Barnett	400,000	2,300,000	2,700,000
Fayetteville	60,000	2,900,000	2,960,000
Haynesville	1,000,000	2,700,000	3,700,000
Marcellus	80,000	3,800,000	3,880,000

Source: Mattson, Palmer, and Cafferty (2011).

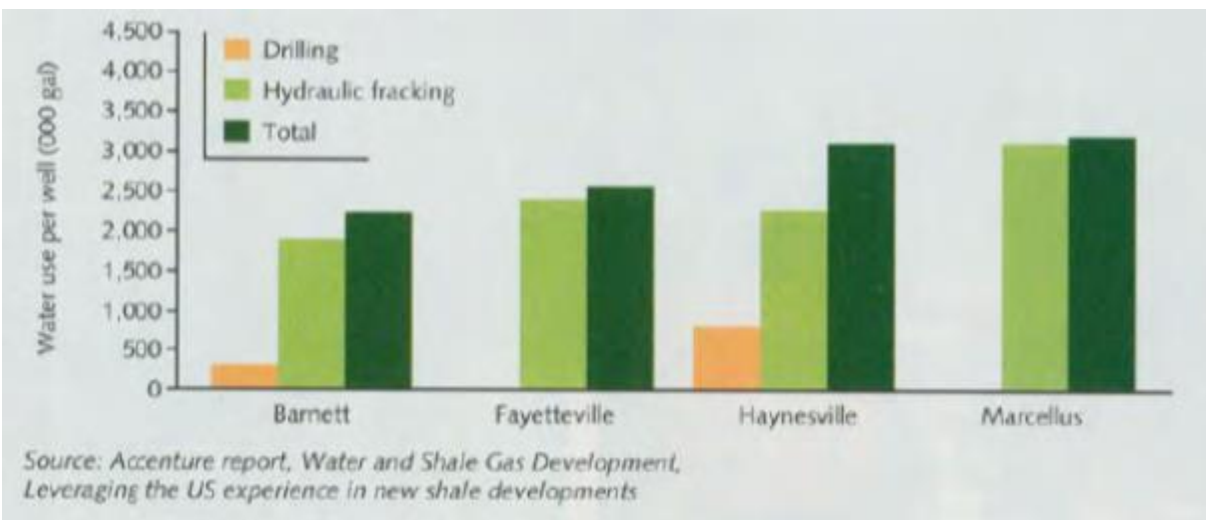
Although Chesapeake Energy (2013) indicates 5 million gallons of water is needed for fracturing, Mattson, Palmer, and Cafferty (2011) suggest a water volume range from 2.3 million to 3.8 million gallons of water, depending on the shale play. Nicot et al. (2011) present estimates of volume of water needed to fracture a well, with the Eagle Ford Shale requiring more water than both the Barnett and Haynesville Shale Plays, i.e., 1 to greater than 13 million gallons of water per well. They also note that the reported total water use in the Eagle Ford Shale (including drilling, proppants, etc.) was 977 million gallons of water as of 2010. Using other information to fill in some unaccounted-for information, they estimate that the actual water use in 2010 was closer to 1.43 billion gallons of water in the Eagle Ford Shale. Nicot et al.'s (2011) total-water-use estimates for the counties focused on in this study are shown in Table 2-6 and projected to 2060 based on 2010 levels.

Table 2-6. Total Projected Water use by County in the Eagle Ford, 2010-2060

County	2010	2020	2030	2040	2050	2060
	Million Gallons					
Dimmit	532	1,517	1,068	787	506	225
Frio	-	351	250	187	125	62
La Salle	193	1,700	1,203	894	586	278
Maverick	68	674	708	527	345	164
Webb	526	605	421	304	187	70
Zavala	-	929	661	496	330	165
Total	1,319	5,776	4,311	3,195	2,079	964

Source: Nicot et al. (2011).

Note that while drilling was mentioned a few times in the previous discussion among of the uses for water, it comprises a relatively small segment of the total process of drilling and fracturing a well. Figure 2-3 is a comparison of four shale plays and their respective total use of water.



Source: *Stark (2013).*

Figure 2-3. Comparison of Water use in Drilling and Hydraulic Fracturing

Chemical composition of fracturing materials

Proppant[5] and fluids must also be mixed in with water during the fracking process[6]. Based on the average of estimates provided by Chesapeake Energy (2013), Mattson, Palmer, and Cafferty (2011), and Nicot et al. (2011), the indication is that there is an average of 4.8 million pounds of proppant per well being added to the fracturing mixture (*Frac Focus: Chemical Disclosure Registry* 2013). For example, in each gallon of water (8.3 lbs), there is an average of 0.8 pounds of proppant, usually in the form of sand or glass beads designed to hold the shale open after fracturing (*Frac Focus: Chemical Disclosure Registry* 2013). Considering the average of five million gallons of water per well necessary to fracture the Eagle Ford Shale (Chesapeake Energy 2013), the implications are that four million pounds of proppant would need to be added for each well. This is compared to 41.5 million pounds of water being used.

In addition to proppant and fluids, chemicals are also an essential part of the mixture being used to fracture the wells. In fact, while 98% of the mixture contains water, sand, and glass beads, chemicals comprise a full two percent which proves to be a significant amount when considering the amount of water and sand being used in the process (*Frac Focus: Chemical Disclosure Registry* 2013). Acid, friction reducer, gelling agent, stabilizer, corrosion inhibitor, fluid viscosity, iron control, non-emulsifier and surfactant are a few of the compounds that are used in the propellant (*Frac Focus: Chemical Disclosure Registry* 2013).

[5] Proppant is another term for sand and glass beads.
[6] This mixture can also be known as propellant.

Flowback disposal

Flowback from drilling operations is generally expected to be 20% of the water, sand, and chemicals placed into the ground over the life of the well (Nicot et al. 2012). The flowback comes out of the well head and becomes increasingly contaminated as time passes; thus, companies tend to contract the waste to be shipped to a deep-well injection point or, if cheaper, simply treat the water on site (Holditch 2012). Cost to dispose of water in this manner depends on the location and trucking costs which range from $2.00 to $3.00 per barrel, with disposal costs at $0.50 per barrel (Holditch 2012). These figures are included in the operational costs (discussed in Chapter V) of drilling for and producing oil which is $20 to $30 per Bbl (Energy Information Administration 2012b).

Holditch (2013) indicated that operational costs for natural gas are $0.75 to $1.50 per Mcf (also discussed in Chapter V). Disposal costs per are listed at 10% of the operational costs per Bbl of oil. For this analysis it is assumed that disposal costs will be the same percentage of operational cost as that per Mcf of natural gas. Therefore, the disposal costs are $0.08 to $0.15 per Mcf of natural gas.

Flowback composition and treatment

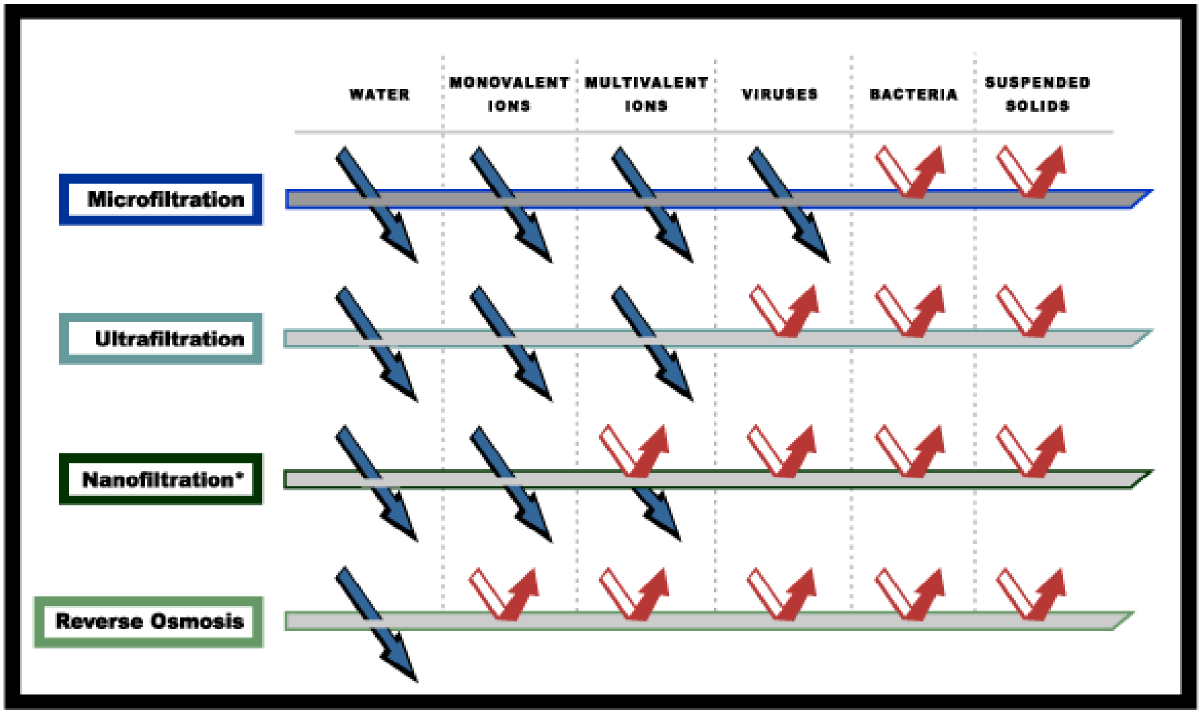
Christopher Impellitteri of the U.S. Environmental Protection Agency: Office of Research and Development (2013) recently did a study on the composition of flowback water. The results indicate that the flowback water included brine, radioactive material that occurs naturally (including radium, thorium and uranium), methane, hydrogen sulfide, polycyclic aromatic hydrocarbons, volatile organic compounds (VOC's), and semi-volatile organic compounds

(SVOC's) (Impellitteri 2013). There are an increasing number of cases where the flowback water is purified through treatment plants (Impellitteri 2013). However, sometimes compounds are unable to be removed through the normal processes due to the fact that they are either too small or polar[7], making them soluble in water (*Application of Nanofiltration for the Removal of Carbamazepine, Diclofenac and Ibuprofen from Drinking Water Sources* 2013). Thus, new methods capable of removing these compounds are going through extensive processes to test their efficacy (Impellitteri 2013).

One such flowback water treatment method is known as membrane filtration (*Application of Nanofiltration for the Removal of Carbamazepine, Diclofenac and Ibuprofen from Drinking Water Sources* 2013). Broken down further, membrane filtration can be taken to several different levels, including microfiltration (MF), nanofiltration (NF), ultrafiltration (UF) and reverse osmosis (RO) (*Application of Nanofiltration for the Removal of Carbamazepine, Diclofenac and Ibuprofen from Drinking Water Sources* 2013). These treatment methods involve moving the water across a very fine membrane that essentially acts as a filter for small compounds *(Ultrafiltration, Nanofiltration and Reverse Osmosis* 2007). The ability of each treatment method depends on the size of their membranes' pores, which are generally measured in microns (*Ultrafiltration, Nanofiltration and Reverse Osmosis* 2007). A typical MF filter has a pore size that is roughly 1.0 micron, a UF filter is usually 0.01 microns, a NF filter is at 0.001 microns and RO filters have a pore size of 0.0001 microns (*Ultrafiltration, Nanofiltration and Reverse Osmosis* 2007). Smaller pore sizes indicate a more effective filter and once water passes through the RO filter, it is considered pure water (*Ultrafiltration, Nanofiltration and Reverse Osmosis*

[7] Polar compounds include both positive and negative charges. These charges align with the opposite charges in water molecules and, as a result, are able to be combined into the water molecules.

2007). Shown in Figure 2-4 is a basic breakdown of the type of material(s) each membrane filter is intended to block in the water.



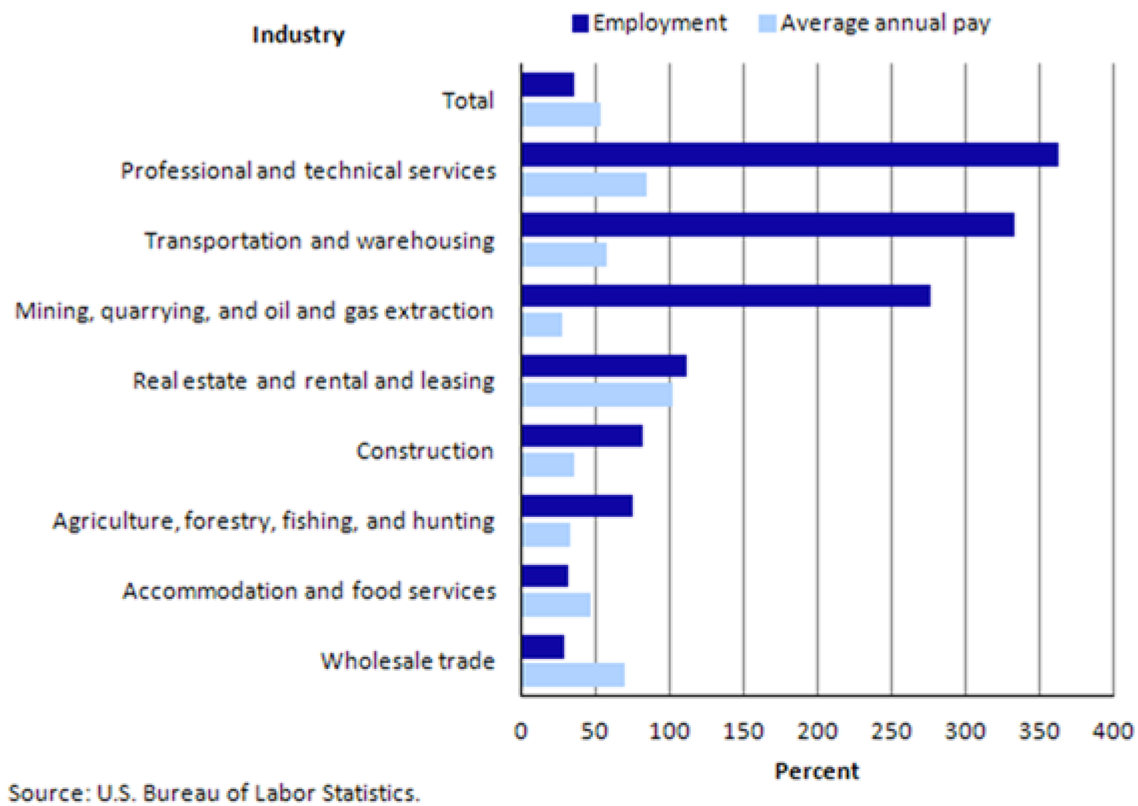
Source: *Ultrafiltration, Nanofiltration and Reverse Osmosis* (2007).
Figure 2-4. Different Levels of Membrane Filtration in Water Purification

The ability of these treatment methods and others to remove all of the compounds from flowback water remains under scrutiny and evaluation from administrative agencies such as EPA (Impellitteri 2013).

Positive impacts of hydraulic fracturing

Hydraulic fracturing has a tremendous economic impact on communities across the United States. Due to difficulties in pinpointing statistics specifically from the Eagle Ford region, reports from surrounding plays will be used to paint a general picture of the shale development/product related labor statistics across the United States. According to the U.S. Bureau of Labor, counties that contain wells in the Bakken shale formation have realized employment increases of 27,954 jobs from 2007 to 2011 (Ferree and Smith 2013). Total wages paid in these counties has more than doubled in the same amount of time from $2.6 billion in 2007 to $5.4 billion in 2011 (Ferree and Smith 2013). The average annual pay per employee has also increased, from $35,940 in 2007 to $72,355 in 2011 (Ferree and Smith 2013). Overall, total employment growth in the Bakken shale region has increased approximately 40% while annual pay has increased approximately 50% from 2007 to 2011 (Ferree and Smith 2013).

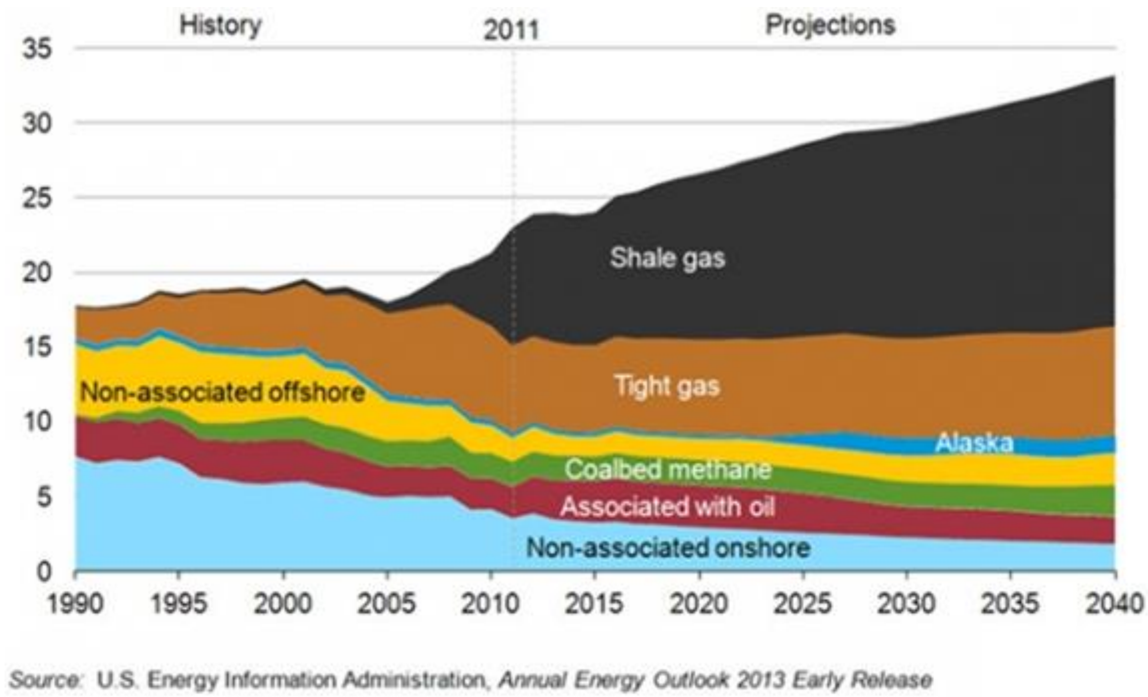
Some businesses that contribute to the fracturing process have realized employment increases of more than double during the four year period (Ferree and Smith 2013). Examples of professional and technical complimentary services include transportation and warehousing, and mining, quarrying and oil and gas extraction (Ferree and Smith 2013). While these aspects of the fracturing process have not realized increases in wages matching the employment growth, they have had substantial increases, ranging from approximately 35% to approximately 80% (Ferree and Smith 2013). Other input businesses realizing substantial growth in this region include construction, accommodation, and food services (Ferree and Smith 2013). Interestingly, real estate, rental, and leasing have realized almost equal growth in wages and in employment with both approximately doubling (Ferree and Smith 2013). Displayed in Figure 2-5 are the economic statistics of labor for Bakken Shale fracking activities from 2007 to 2011.



Source: Ferree and Smith (2013).

Figure 2-5. Percent Growth in Employment and Wages in the Bakken Shale Region from 2007 to 2011

As noted initially in this report, the United States, and the rest of the world, is experiencing an energy crisis. Fossil fuels are being utilized at an accelerating rate and they are finite in supply. As a result, among the highest priorities of the new millennium is to identify alternative sustainable sources of energy. Potential alternatives include biofuels, solar, and energy cells. However, problems in efficiency and life-cycle analyses have limited the world’s dependence on these sources. Energy from shale formations, however, has provided to provide significant relief to this problem in the last several years. According to the U.S. Department of Energy (2013), natural gas coming from shales has the ability to increase energy security, lower greenhouse emissions, and lower costs to consumers. Currently, shale gas is known to account for 16 percent of U.S. natural gas production and is expected to continue growing in importance as more and more regions are developed (U.S. Department of Energy 2013). Displayed in Figure 2-6 is the expected growth of U.S. shale gas production to 2040.



Source: *U.S. Energy Information Administration (2013a).*

Figure 2-6. U.S. Natural Gas Production, 1990-2040

In addition to being a boost to the economy and a reliable energy source, natural gas is known to be environmentally cleaner compared to oil and coal in several aspects. First of all, greenhouse gases are essentially alleviated with the use of natural gas (*Natural Gas: Earth and Sky Friendly* 2013). While the byproducts of natural gas are carbon dioxide and water, natural gas produces much less of these compounds than oil and coal (*Natural Gas: Earth and Sky Friendly* 2013). In fact, it is estimated that natural gas produces up to 45 percent less carbon dioxide than electricity generated from coal and up to 30 percent less than oil (*Natural Gas: Earth and Sky Friendly*

2013). Using natural gas from hydraulically fracturing shale has allowed the United States to lead the world in carbon reductions (7.7 percent) since 2006, which can be compared to removing 84 million cars from highways (*Natural Gas: Earth and Sky Friendly* 2013). Natural gas also emits fewer compounds that can be damaging to the environment and property. For instance, natural gas contains less nitrogen oxides and sulfur dioxide as well as less particulate matter (*Natural Gas: Earth and Sky Friendly* 2013). The statistics in Table 2-7 provide comparisons of some of the similar substances found in natural gas, coal and oil, in terms of the quantities of the values of those substances released into the atmosphere during use. Natural gas also tends to be more efficient than other sources of energy (*Natural Gas: Earth and Sky Friendly* 2013).

Table 2-7. Pollutant Comparison of Natural Gas, Oil, and Coal

Fossil Fuel Emission Levels
- Pounds per Billion Btu of Energy Input

Pollutant	Natural Gas	Oil	Coal
Carbon Dioxide	117,000	164,000	208,000
Carbon Monoxide	40	33	208
Nitrogen Oxides	92	448	457
Sulfur Dioxide	1	1,122	2,591
Particulates	7	84	2,744
Mercury	0.000	0.007	0.016

Source: EIA - Natural Gas Issues and Trends 1998

Source: *Natural Gas and the Environment* (2011).

Public response to hydraulic fracturing

While hydraulic fracturing is certainly a rising force in any energy discussion, it is still a relatively new process of which the U.S. population is beginning to become aware. Clearly, in an age that fosters a public review to anything that would help mitigate the use of fossil fuels as well as greenhouse gases, the notion of shale gas would seem to be welcome (Kasperson and Ram, 2013). According to Kasperson and Ram (2013), however, the public's acceptance of hydraulic fracturing remains uncertain due to the youth of the process and lack of full information regarding net benefits, casts, and possibilities of externalities.

Deloitte (2013) recently completed a study of public opinion in Texas, Louisiana, Arkansas, New York and Pennsylvania. The results yielded several positive reactions from the citizens. According to the survey, the industry has done a remarkable job of helping the citizens connect their energy with what is environmentally clean (Deloitte 2013). In fact, the survey indicated that 6 of 10 individuals were able to associate "hydraulic fracturing" with the term "clean." Additionally, the survey participants signaled enjoyment of the large number of jobs that the industry has created. The public also seems to understand that hydraulic fracturing is symbolic of energy independence as many of those interviewed ranked that as the top benefit of the process. Though there is a part of the public that believe the process is harmful to human and animal health, the majority of the survey participants believe the benefits of hydraulic fracturing outweigh the risks (Deloitte 2013).

A Louisiana State University master's thesis includes results similar to the Deloitte study (White 2012). According to White, 75% of 63 subjects in the Haynesville shale area said that they did not perceive any extra risks to fracturing that would not be experienced by other pollutant agents in every-day life (i.e. second-hand smoke). Many of the subjects reported they invest in natural gas companies. In fact, 40% of those same subjects said that they had leased their land to an oil and gas company (White 2012).

Despite generally a high level of public acceptance of hydraulic fracturing, however, there are some questions that the public is interested in knowing more about that may have an effect on the overall public opinion (U.S. Environmental Protection Agency 2010). As a result, groups and individuals are petitioning EPA to include in a study: climate change (including a full life-cycle analysis), whether health hazards and problems arise from hydraulic fracturing or from other factors, and the overall affect that the fracturing process will have on water in the ecosystem (U.S. Environmental Protection Agency 2010).

Chapter summary

The extraction of natural gas and oil through hydraulic fracturing is a relatively new and highly debated topic. Several arguments can be made the natural gas is relatively efficient compared to other forms of energy, and utilizing hydraulic fracturing can take away some of the reliance on foreign nations to provide the United States with energy. There are some opponents, however, who believe that hydraulic fracturing is hazardous to human and animal health and will continue to encourage pollution of the atmosphere. Future studies of hydraulic fracturing are critical if people are to grasp more fully what the implications of hydraulic fracturing are.

CHAPTER III

THEORY

The global objective of this study is to estimate the water and economic implications related to hydraulic fracturing of the Eagle Ford Shale in Texas. Because of the economic nature of this report, and wide range of interested stakeholders, it is appropriate to provide a background on basic economic theory. The economics behind water supply, values, and water rights are also addressed. Therefore, this chapter is devoted to providing an overview of the basic theoretical economics approach used in the analysis and the applicable theory applied to water economics and water rights. Furthermore, due to the focus of this study on a particular industry in one specific region, it is deemed most appropriate to observe this theory from a microeconomic standpoint as opposed to that of a macroeconomic view.

Production characteristics

To begin, it is important to understand the physical concepts underlying economic principles. Managers must make decisions involving what will be produced, how much will be produced, and what inputs as well as how many will be used. The base of discussion is a production function. A production function is the relationship between inputs and the resulting outputs (Wilbourn 2012).

Presented in Table 3-1 are the hypothetical statistics used to develop graphical examples.

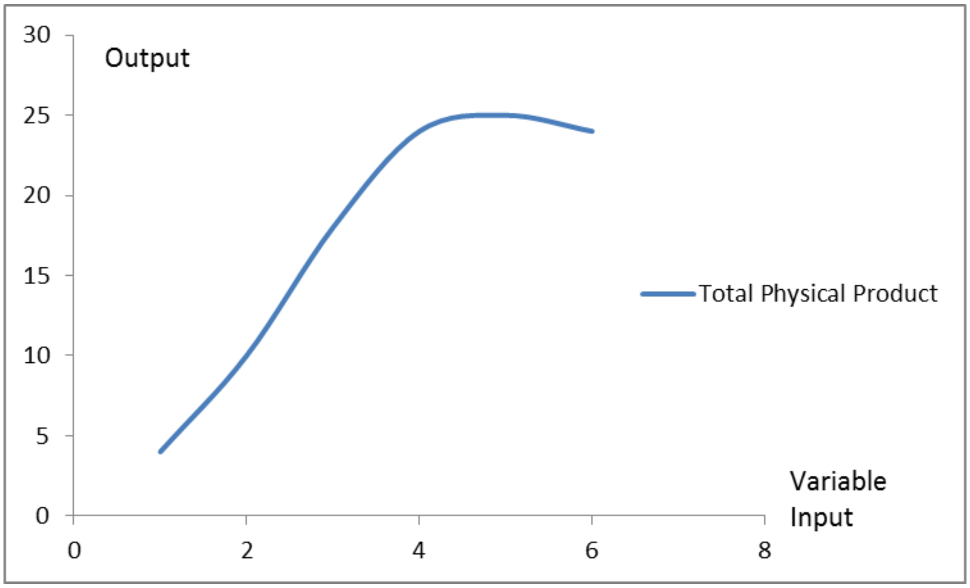
Table 3-1. Hypothetical Statistics to Support a Production Function

Input X_1[a]	Total Physical Product	Average Physical Product	Marginal Physical Product
0	0	0	-
1	4	4	4
2	10	5	6
3	18	6	8
4	24	6	6
5	25	5	1
6	24	4	-1

[a] A second input, X_2, is assumed to be held at a fixed level.
Source: Dunn (2012).

Total physical product

Total physical product (TPP) represents the total output of a firm as a function of the level of inputs (Dunn 2012). For simplicity, this discussion is based on one variable input (X_1) and the resulting output of a product. Underlying this discussion is the assumption of a fixed input (X_2), such as one acre of land. Represented in Figure 3-1 is a hypothetical TPP function. In this chart, the X axis represents the amount of variable units of input being used. The Y axis represents the total amount of output and the chart gives an example of the relationship, first increasing at an increasing rate, then at a decreasing rate, and finally leveling off and beginning to decrease. The assumption is that, at first, additional units of input help the production process greatly (Dunn 2012). However, as the amount of input increase, the impact of additional input units declines eventually, becoming counterproductive for various reasons until production eventually starts to decline (Dunn 2012).

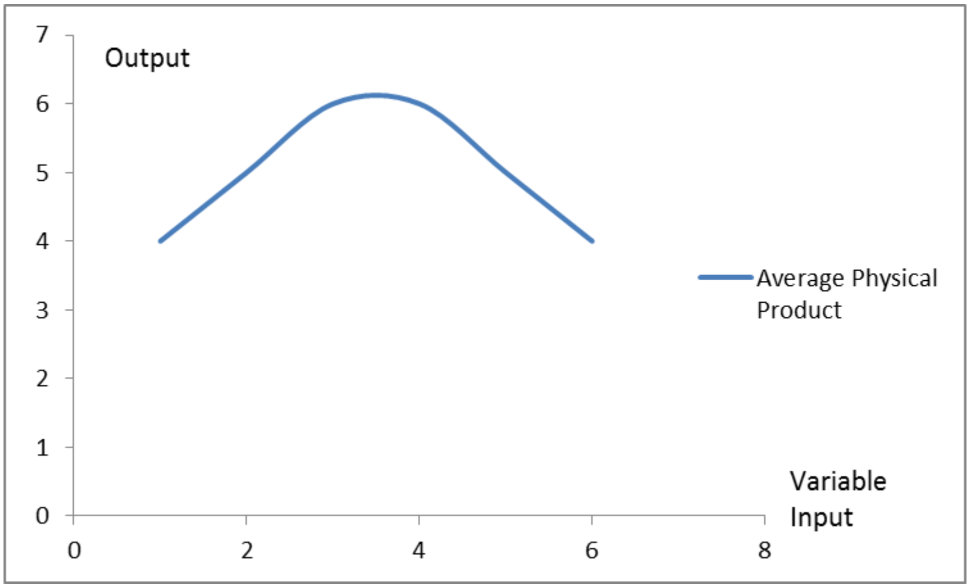


Source: Dunn (2012).

Figure 3-1. Total Physical Product

Average physical product

Average physical product (APP) represents the average level of output per unit of input (Dunn 2012). Input in this instance can be anything that is used to convert raw materials into output as well as the raw materials itself. Incorporated in Figure 3-2 are the same statistics as used in Figure 3-1 above, but with the hypothetical graphical version of APP illustrated.



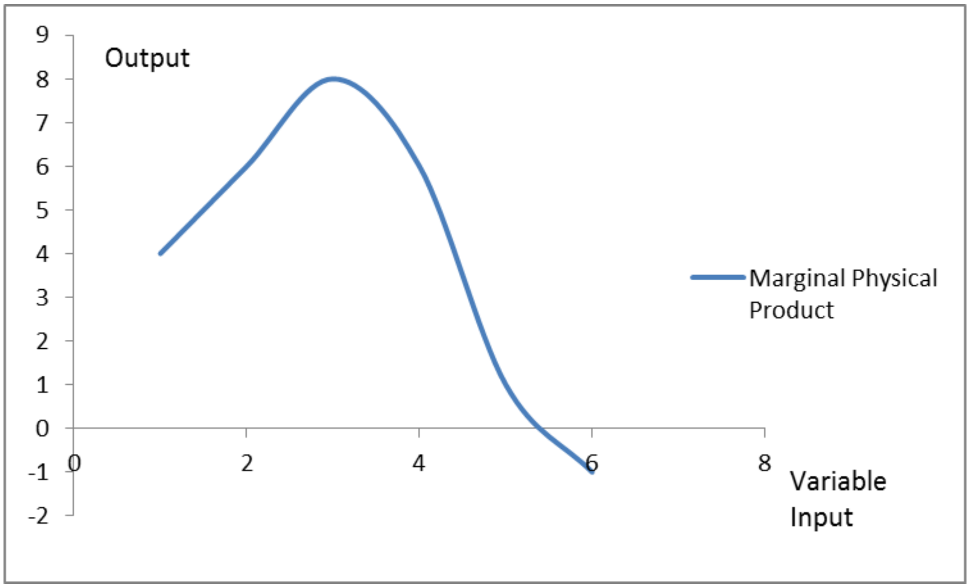
Source: Dunn (2012).

Figure 3-2. Average Physical Product

In Figure 3-2, the X axis represents the amount of inputs being used while the Y axis indicates the average amount of output that is being produced per unit of input. Similar to the graph of TPP, the graph indicates that additional inputs add greatly to production in the beginning. However, after a certain point (in this case, between 3 to 4 units of input), additional input starts to slow average production increases, resulting in eventual declines in average production. The mathematical formula for APP is TPP/Input Quantity (Dunn 2012).

Marginal physical product

Marginal physical product (MPP) represents the additional amount of output that each additional unit of input produces (Dunn 2012). Using the same statistics as before, an example graphical version of MPP is illustrated in Figure 3-3.

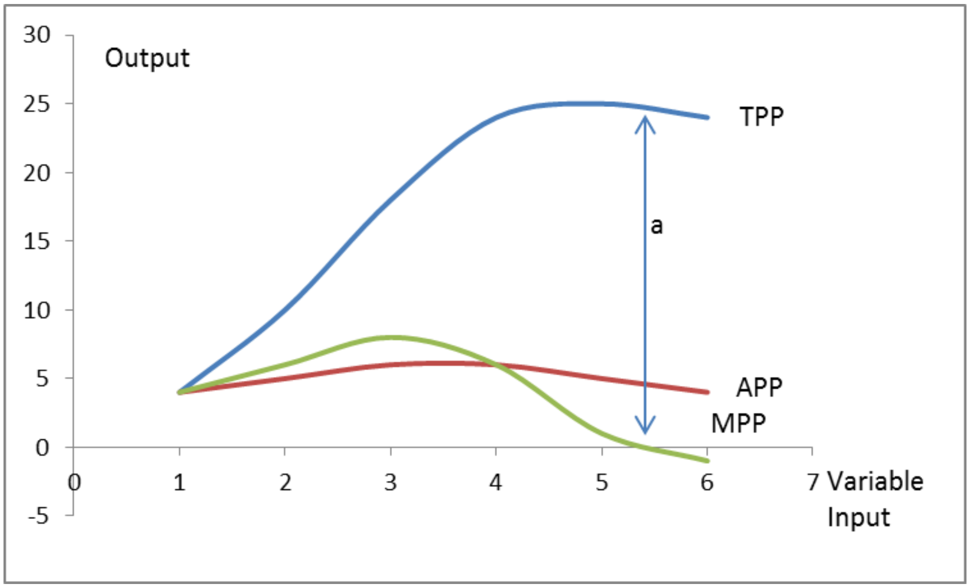


Source: Dunn (2012).

Figure 3-3. Marginal Physical Product

Again, the X axis represents input while the Y axis represents marginal output. Notice that the graph resembles the shape of TPP and APP. This is because each unit of input is only able to produce a smaller level of output than the previous unit of input after three units in this scenario (Dunn 2012). The mathematical formula for MPP is ΔTPP/ΔInput Quantity, where Δ refers to the change (Dunn 2012).

The composite relationships that TPP, APP, and MPP have from a theoretical standpoint are illustrated in Figure 3-4.



[a] Theoretically, TPP is at its peak when MPP=0.
Source: Dunn (2012).

Figure 3-4. Relationship among TPP, APP, and MPP

As before, output is listed on the Y axis with inputs being listed on the X axis. The relationship between TPP and MPP illustrated example of what causes the diminishing returns shown in the TPP function (Dunn 2012). MPP hits its peak at three units of input and starts to decline (Dunn 2012). At the same time, three units is where the TPP begins to increase at a decreasing rate until it hits its peak at five units of input and then TPP begins to decrease (Dunn 2012). The point where TPP shifts from increasing at an increasing rate to increasing at a decreasing rate is termed the point of inflection. This example shows that as each unit of input produces less MPP, the TPP begins to reciprocate that information as it starts to present less increase in total output as more units of input are added (Dunn 2012).

Another relationship worth noting is that between APP and MPP. As shown, MPP intersects the APP function at the APP function's highest point of five units. This phenomenon occurs because as MPP is increasing, each additional unit of input is allowing the firm to produce more additional output per input unit than the previous unit of input (Dunn 2012). Invariably, the APP will also be increasing as each unit of input is able to bring in more additional output than the unit of input prior (Dunn 2012). However, as each unit of input is limited to less additional output than the prior unit of input, the APP begins to peak and then decline (Dunn 2012).

Cost analysis

Using the production function, costs and returns can be applied to generate basic economic principles of costs, revenues, and profit. This can be done for an input perspective or an output perspective. Displayed in Table 3-2 are the hypothetical data used to generate the statistics for the following cost graphs. In Table 3-3 are additional data to facilitate discussion on average variable costs and average fixed costs.

Table 3-2. Hypothetical Cost Statistics Displaying the Relationship among Different Costs

Quantity	Input	Input Unit Cost	Total Variable Cost	Total Fixed Cost	Total Cost	Average Total Cost	Marginal Cost
0	0	$ 5	$ -	$ 20	$ 20	$ -	$ -
4	1	5	5	20	25	6.25	1.25
10	2	5	10	20	30	3	0.83
18	3	5	15	20	35	1.94	0.63
24	4	5	20	20	40	1.67	0.83
25	5	5	25	20	45	1.8	5
24	6	5	30	20	50	2.08	-

Source: Dunn (2012).

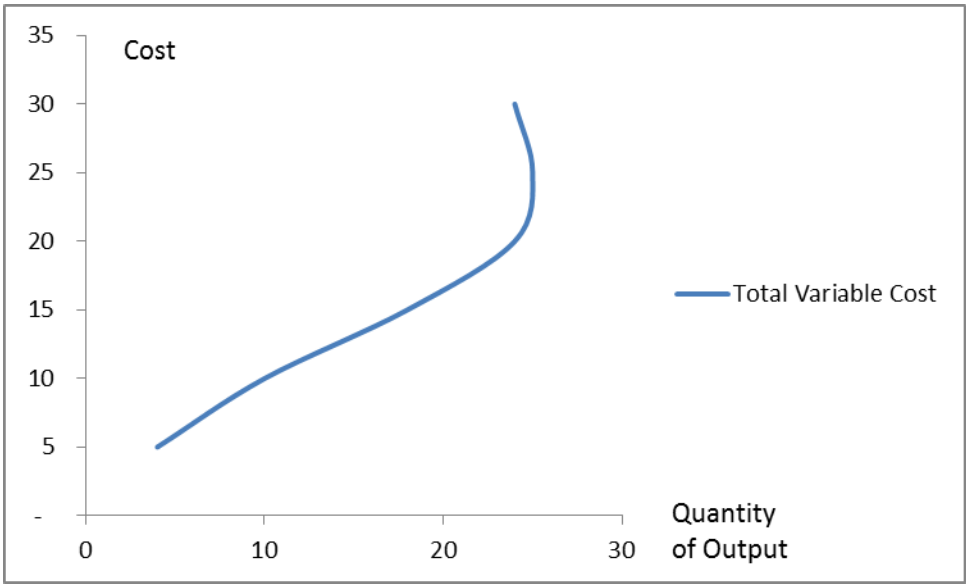
Table 3-3. Hypothetical Cost Statistics to Facilitate Average Fixed and Average Variable Cost Discussion

Quantity	Input	Input Unit Cost	Total Variable Cost	Average Variable Cost	Total Fixed Cost	Average Fixed Cost
0	0	$ 5	$ -	$ -	$ 20	$ -
4	1	5	5	1.25	20	5
10	2	5	10	1	20	2
18	3	5	15	0.83	20	1.11
24	4	5	20	0.83	20	0.83
25	5	5	25	1	20	0.8

Source: Dunn (2012).

Total variable cost

Total variable cost (TVC) represents the cost related to the amount of input being used (Dunn 2012). For example, in Table 3-2, a cost per unit of input of five dollars is assumed. To produce more output requires more inputs. Illustrated in Figure 3-5 is the relationship between quantity produced and TVC.



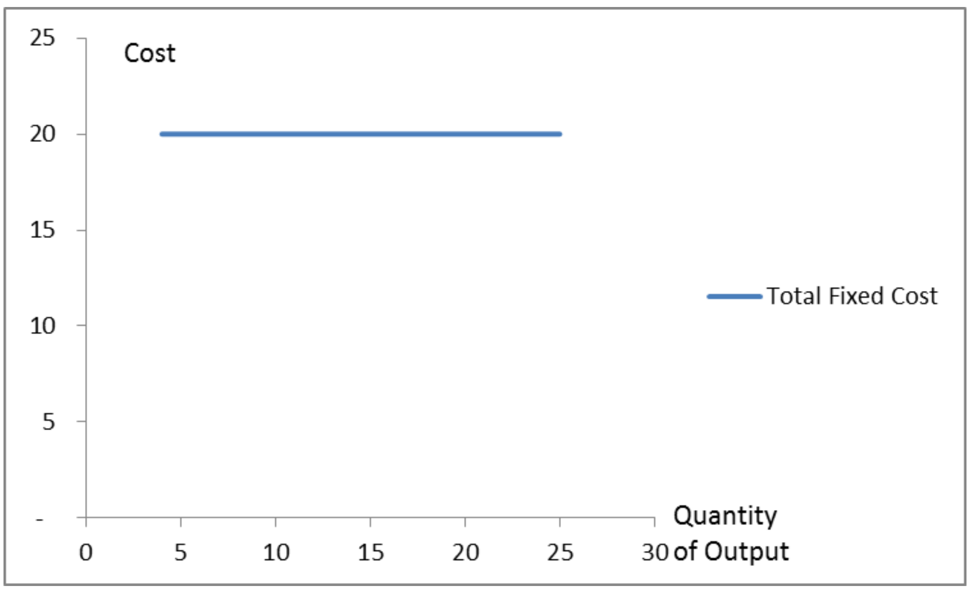
Source: Dunn (2012).

Figure 3-5. Total Variable Cost of Producing 25 Units of Output

In the graph above, quantity (output) produced is listed on the X axis and TVC is listed on the Y axis. The TVC is actually a mirror image of the TPP production function. This is the case because the costs vary directly with the number of inputs. As the number of outputs per unit of input increase, the variable costs become spread out over the increased number of outputs causing the graph to become flatter. In the case of TPP, as the quantity of outputs per unit of input increase, the graph becomes steeper in the same area where it would go flatter in the TVC function. In the TVC function, note that as the amount of inputs increases, the output quantity actually begins to decrease causing the graph to loop backwards after 25 units have been produced. This carries the implication that producers are not going to produce more than 25 units.

Total fixed costs

Total fixed costs (TFC) are those costs that do not change regardless of the quantity of output that is produced (Dunn, 2012). For instance, in this example it is assumed there is a cost of $20 regardless producing at capacity or not producing anything. The flat cost of $20 causes the graph to have a horizontal appearance. Presented in Figure 3-6 is an example of the relationship between TFC and quantity produced. TFC, in Figure 3-6, is shown on the Y axis and quantity of output produced is shown on the X axis.

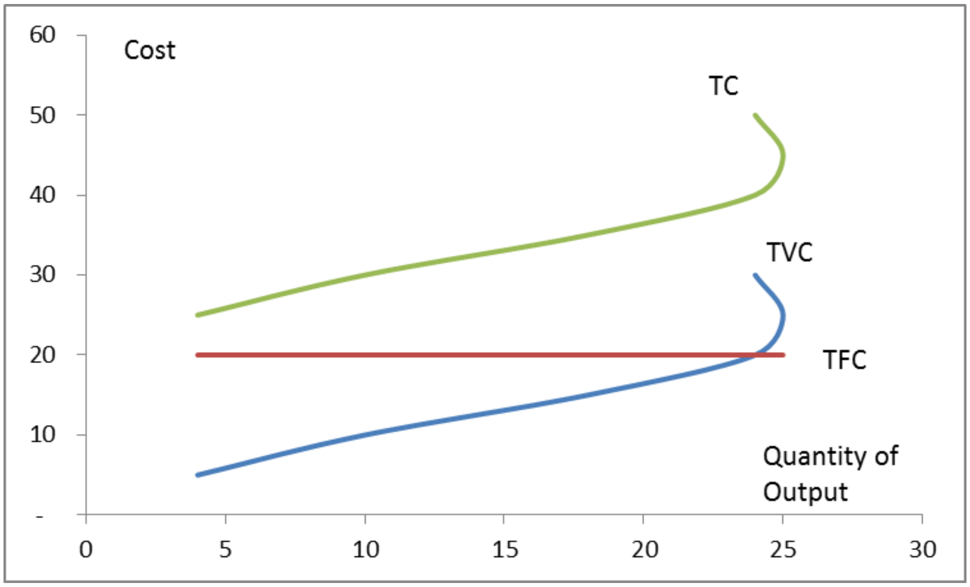


Source: Dunn (2012).

Figure 3-6. Total Fixed Cost for 25 Units of Output

Total costs

Total costs (TC) are simply the sum of TFC and TVC (Dunn 2012). On the occasion that a company may not have any fixed costs, TC would equal the TVC (Dunn 2012). A situation such as this would occur if there was only a variable input and no fixed input. Remember, however, that this example assumes a fixed input that is not shown in Table 3-2. Illustrated in Figure 3-7 is the relationship between quantity produced (X axis) and TC (Y axis).



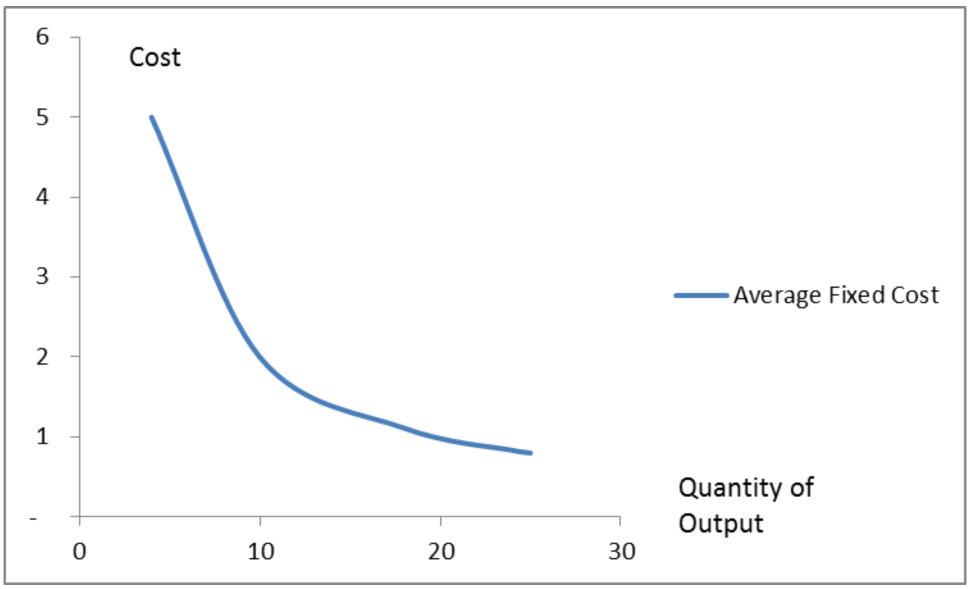
Source: Dunn (2012).

Figure 3-7. Total Cost of Producing 25 Units of Output

Average fixed and variable costs

As observed, TFC is horizontal to represent the fact that fixed costs are constant despite the level of production, and TVC (also TC) form the mirror image of the MPP because of the marginal increases (and decreases) in output per unit of input. While these paint an intricate image of how basic costs work, they do not do an adequate job of displaying what a producer is looking for to determine the most efficient level of output. To help determine that level of output, average fixed costs (AFC) and average variable costs (AVC) are next observed.

AFC is the total fixed costs divided by the total level of output. This fact is important because it gives the best explanation of the concept of economies of scale[8]. A visual example of AFC is shown in Figure 3-8. Notice that, unlike TFC, the AFC actually decreases as the level of production increases. This represents the notion that the fixed costs per unit of output decrease as the level of output increases. A company can accomplish this phenomenon by finding more efficient ways to utilize the fixed inputs without requiring more fixed inputs to increase production. For simplicity, in this example it is assumed that the same amount of fixed inputs is used across all levels of production.



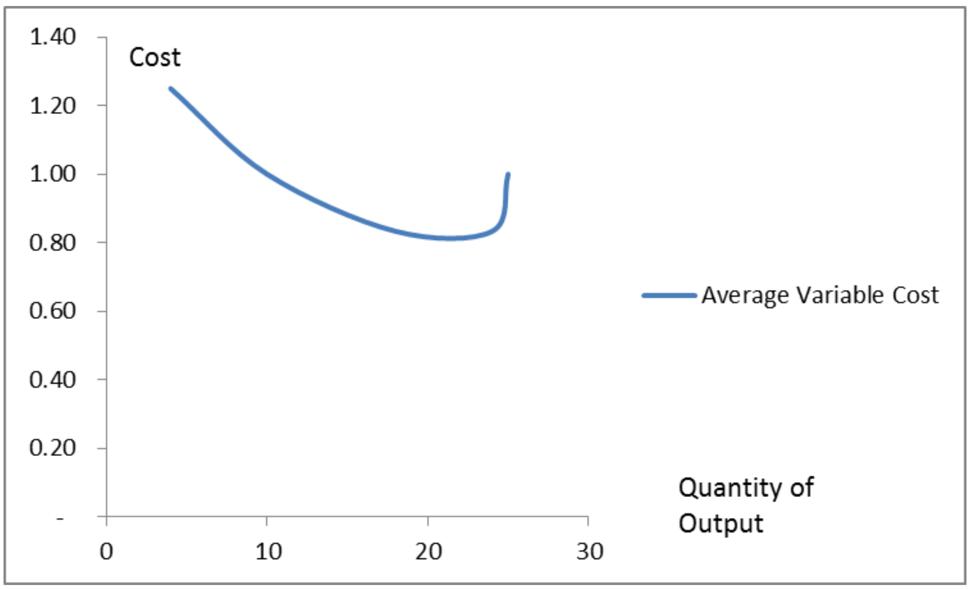
Source: Dunn (2012).

Figure 3-8. Average Fixed Cost per Unit of Output

AVC is the total variable costs divided by the level of output. Because variable costs vary directly with the level of production, the AVC graph does not always decrease as the level of production increases. In fact, the AVC graph would form a "u" shape as the level of production

[8] Economies of scale is the notion that a company can make more profit with a higher level of output to a certain point. This is possible because that same company can spread the fixed costs over more output to reduce the fixed costs per unit (Dunn 2012).

increases. The lowest level of the graph would be at the point that the MC curve would interest the AVC curve. As a company is able to produce more output per unit of input the AVC decreases. However, as soon as the company's inputs start becoming less productive, the marginal cost for each unit of output begins to increase eventually causing the AVC per unit of output to increase (Figure 3-9).

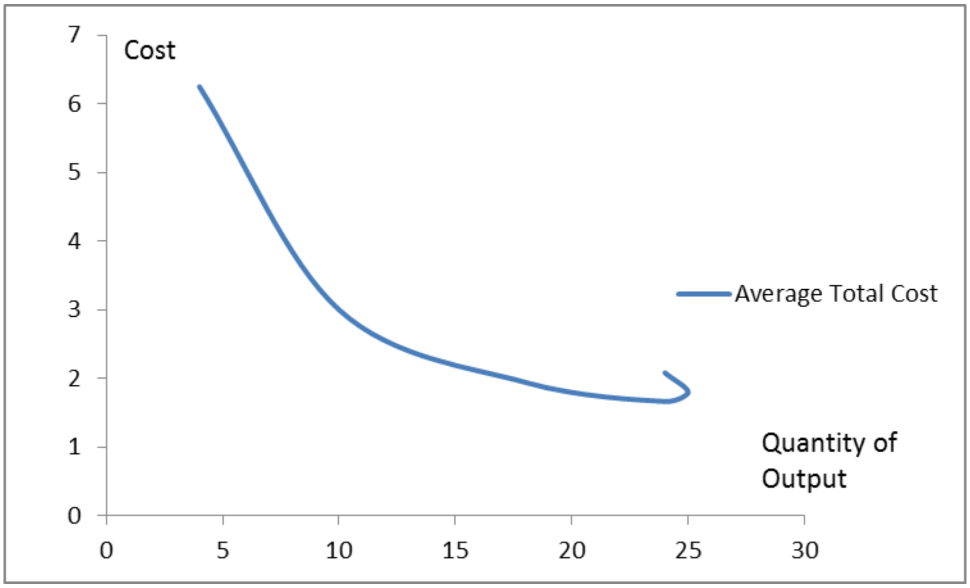


Source: Dunn (2012).

Figure 3-9. Average Variable Cost per Unit of Output

Average total cost

Average total cost (ATC) represents the estimated cost per unit of output (Dunn 2012). Provided in Figure 3-10 is an example of the relationship between quantity produced (X axis) and ATC (Y axis). The mathematical formula for ATC is TC/Quantity Produced (Dunn 2012).

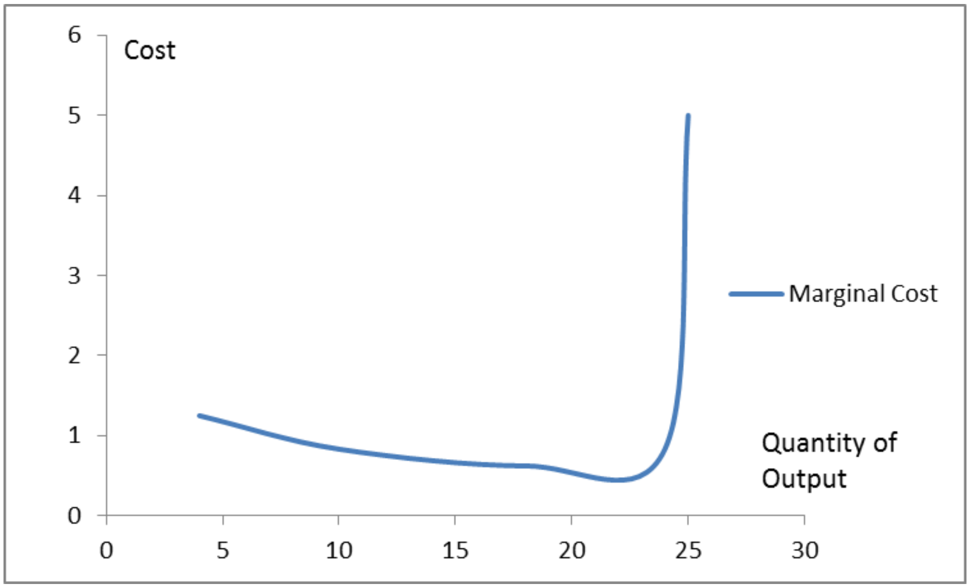


Source: Dunn (2012).

Figure 3-10. Average Cost of Each Unit of Output

Marginal cost

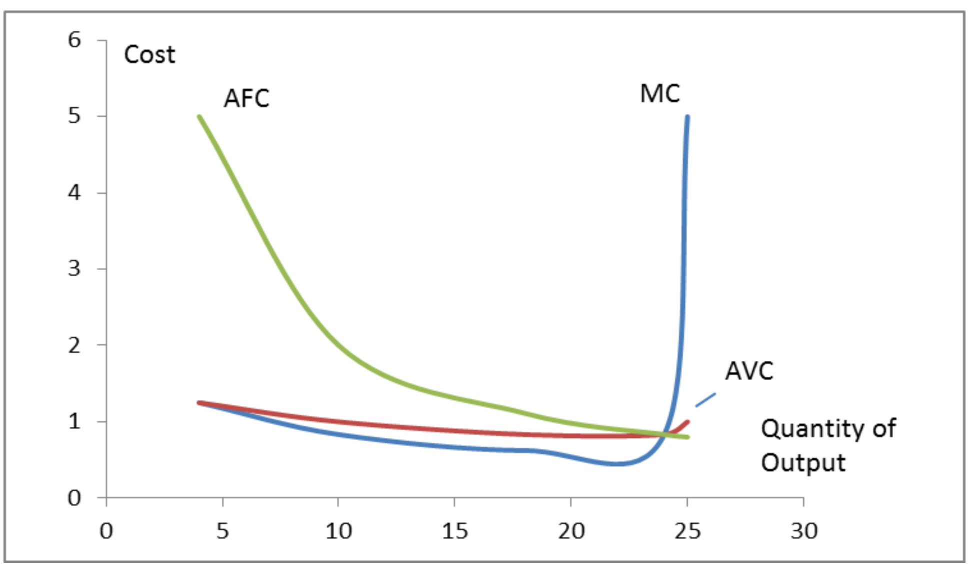
Marginal cost (MC) represents the additional cost that each additional quantity of output incurs (Dunn 2012). Shown in Figure 3-11 is the relationship between quantity produced (X axis) and MC (Y axis). The mathematical formula for MC is ΔTC/ΔQuantity Produced where Δ is change (Dunn 2012).



Source: Dunn (2012).

Figure 3-11. Marginal Cost of Each Unit of Output

Figure 3-12 is a comparison of AVC, AFC, and MC and how they are related to one another. ATC is intentionally left out because it is simply an accumulation of AFC and AVC.



Source: Dunn (2012).

Figure 3-12. Cost Comparison

Returns

With production quantified and costs established, the returns are addressed in Table 3-4. In Table 3-4, it is also important to understand that marginal revenue is equal to price in a perfectly competitive firm (Dunn 2012). Marginal revenue (MR) is equal to the change in total revenue divided by the change in quantity sold (Dunn 2012).

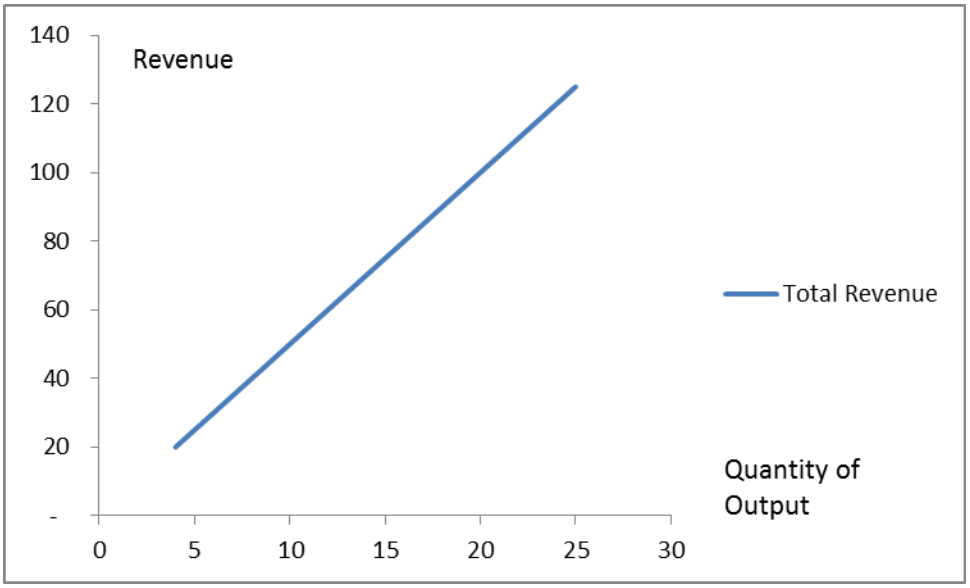
Table 3-4. Hypothetical Revenue and Profit Data to Facilitate Graphical Discussion

Quantity	Price per Unit	Total Revenue	Marginal Revenue	Total Cost	Profit[a]
0	$ 5	$ -	$ -	$ 20	$ (20)
4	5	20	5	25	(5)
10	5	50	5	30	20
18	5	90	5	35	55
24	5	120	5	40	80
25	5	125	5	45	80

[a] Parentheses indicate negative values.
Source: Dunn (2012).

Total revenue

Total revenue (TR) is the total amount of income that a firm realizes through its operations and related sales (Dunn 2012). Revenue is found through multiplying the quantity produced by the price per unit (Dunn 2012). Illustrated in Figure 3-13 is a graphical representation of total revenue.



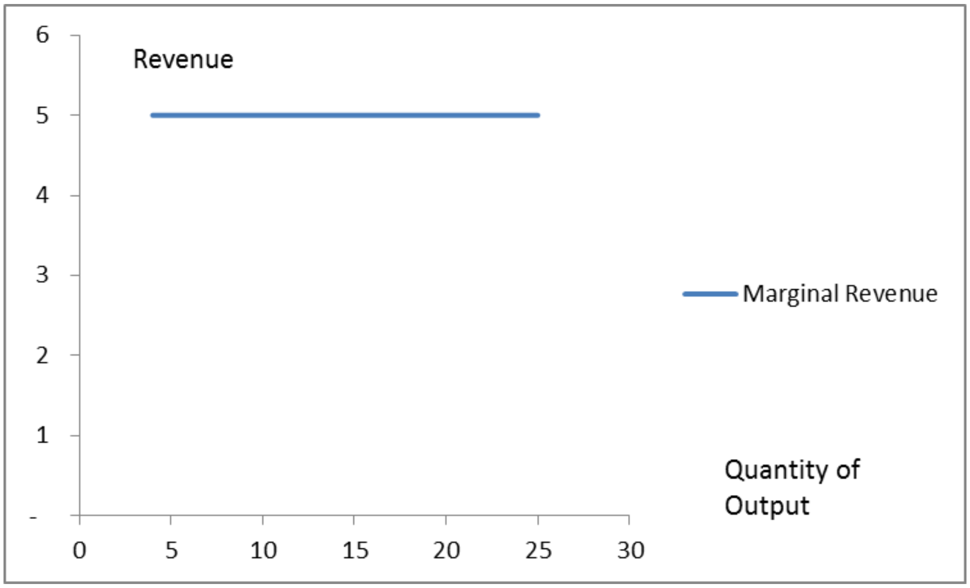
Source: Dunn (2012).

Figure 3-13. Total Revenue at Each Level of Production

Marginal revenue

Marginal revenue (MR) is found through the formula ΔTotal Revenue/ΔQuantity where Δ denotes change in (Dunn 2012). As mentioned, a producer in a perfectly competitive market would find it ideal to produce where the MR equals the MC (Dunn 2012). Also, MR is equal to the price in a perfectly competitive market (Dunn 2012). This is because producers in this type of market are known as price-takers rather than price-makers[9] (Dunn 2012). Shown in Figure 3-14 is a graphical representation of marginal revenue.

[9] No one producer can affect price by his/her level of output.



Source: Dunn (2012).

Figure 3-14. Marginal Revenue of Each Additional Unit of Output[10]

Profit

Profit is the difference between the revenue and the costs that a firm incurs while producing its output (Dunn 2012). An important question that needs consideration in any production situation is what amount to produce, given revenue and costs at each level of production. The answer lies in the comparison between MR and MC (Dunn 2012). Ideally, a firm would have incentives to produce at the level where the MR equals the MC and the firm should stay in production as long as it can cover its entire variable costs in the short run and all costs over time (Dunn 2012). Unlike MC, MR can take several different forms depending on the type of competitive environment in which it exists[11] (Dunn 2012).

[10] In a perfectly-competitive market, marginal revenue forms the same pattern as average revenue.

[11] If the industry is perfectly competitive, producers will always receive the same revenue for each product making the MR constant. In other types of competition, MR will decrease as the demand for a differentiated product decreases.

Average revenue (AR) represents the standard amount of revenue of each unit of product and is typically the price of output in a perfectly competitive industry (Dunn 2012). Mathematically, TR can be found by multiplying quantity produced by price, AR can be found by TR/quantity produced, and MR can be found by ΔTR/Δquantity produced where Δ is change in (Dunn 2012). There can be several different competitive environments such as a monopoly[12] and an oligopoly[13], but this study is focused on perfect competition.

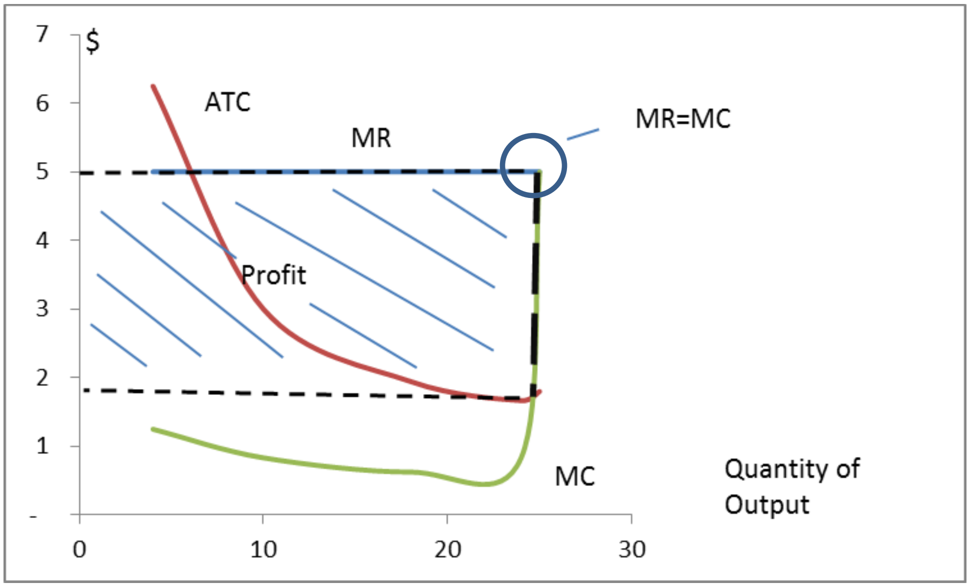
Perfectly-competitive markets

Perfectly-competitive markets are characterized by a very large number of firms, undifferentiated products, no price control for the firms, and very little barriers to entry for other firms (Dunn 2012). Perfectly-competitive markets are unique in that the firms have no price control, and, unlike monopoly and oligopoly markets, the managers of perfectly-competitive firms are price-takers based on markets. As a result, they only need to be concerned with determining if production is economical and, if so, the quantity to produce (Dunn 2012). Generally, perfectly-competitive firms are found in the agriculture industry (Dunn 2012). Note that in a perfectly competitive market, MR is equal to price and to average revenue which is also a unique property of this market (Dunn 2012).

Illustrated in Figure 3-15 is a graphical example of a perfectly-competitive market. Note that, in the graph, MR=MC at a point above the ATC. This indicates that the firm is able to operate with

[12] A monopoly is a competitive environment that has only one seller. This type of market is almost always highly regulated by federal and state governments.
[13] An oligopoly consists of several different sellers of similar products. Examples include the automobile industry and the airline industry.

economic profit[14]. While there is economic profit to be gained in this example, it is important to understand that competitors will continue to enter the market until there is zero economic profit. This particular pattern of entry is common in all perfectly-competitive markets. When the market reaches this point of zero economic profit, MR will equal MC and ATC.



Source: Dunn (2012).

Figure 3-15. Perfectly-Competitive Market Operating with Economic Profit

Externalities

Externalities represent unaccounted costs imposed on society based on the actions of an individual or group (Dunn 2012). For example, a company can produce at a highly efficient level of costs to benefits; however, it may do so using equipment that operates in a manner that can harm the surrounding environment (Dunn 2012). The harmful features of the equipment used is what is known as an externality. In the case of hydraulic fracturing, externalities are the

[14] Economic profit is revenue that covers all variable, fixed, and opportunity costs of doing business. An opportunity cost is the revenue foregone by choosing a different alternative.

pollutants and potential health effects that affect society because of the fracking process. These consequences are not monetarily incurred by the industry but are suffered by the surrounding environment. Thus, this section is directed to providing insights on the opinion of a few experts as to the externality effects of hydraulic fracturing.

Experts from the State University of New York (SUNY) at New Paltz were questioned as to their stance on hydraulic fracturing and its lasting effects on the surrounding environments (*A Big Fracking Problem* 2012). Professor Alexander Bartholomew of the SUNY Geology Department claimed that improper casing could allow gas to escape (*A Big Fracking Problem* 2012). Gas leaks can be both inefficient and hazardous to plants, animals, and people living in the area. Fluids from the fracturing process also have the tendency to leak into surrounding water sources with poor casing, potentially releasing radium, radon, and uranium into the water (*A Big Fracking Problem* 2012). Professor Shafiul Chowdhury, also of the SUNY Geology Department, indicates that once these chemicals get into the water supply, they can remain there for up to two years (*A Big Fracking Problem* 2012). He did not indicate where the chemicals went after that point (*A Big Fracking Problem* 2012).

As beneficial as hydraulic fracturing can be to the national energy initiative, there are still those, such as Professor Brian Obach of the SUNY Sociology Department, that believe that hydraulic fracturing is taking society further away from renewable energy (*A Big Fracking Problem* 2012). Obach believes that there are several health risks involved with the process and that burning these fossil fuels has a detrimental effect on the earth's atmosphere (*A Big Fracking Problem*, 2012).

Still many others believe that hydraulic fracturing is a cheaper, more efficient method of harvesting energy and will be able to sustain the United States for many years and even decades. To negate the concept that hydraulic fracturing his harmful to plants, animals, and humans, Energy Secretary, Ernest Moniz, does not believe that there is any conclusive evidence that fracking is contaminating groundwater (Geman 2013). Even former EPA Administer, Lisa Jackson, does not believe there is definitive evidence supporting the theory that fracking causes chemicals to enter groundwater (*EPA's Lisa Jackson on Safe Hydraulic Fracturing* 2012). Arguing for the efficiency of the hydraulic fracturing process is Energy Consultant and Professional Engineer, John Miller (2013). According to him, shutting down shale production in the United States will cause a substantial price increase in natural gas as well as an equally ominous decrease in energy supply (Miller 2013).

Water rights

Prior to any actions taken in the Texas Water Code (discussed next), circumstances where water demand exceeded the amount that is supplied/available were governed by the Doctrine of Priority (Yarbrough 1969). The Doctrine of Priority first came about in the Irrigation Act of 1889 arising from the notion that those who gained access to a source of water first should have the right to continue with that access (Yarbrough 1969). This belief arose from settlers that first came to the Texas region prior to 1889 (Yarbrough 1969). The idea was to prevent other settlers from benefiting from and usurping the success of early settlers who discovered a source of water and had found a use for that water (Yarbrough 1969). This doctrine is still a basic principle taken into consideration when promulgating water legislation today (Yarbrough 1969).

Today, Water rights represent a basis for access to water. In Texas, groundwater and surface water are governed differently regarding their ownership (Texas Water Development Board 1999). Texas (as frequently cited from the case, Houston & Texas Central Railway Co. v. East 98 Tex. 146, 81 S.W. 279 (1904)) treats groundwater with an "absolute ownership" philosophy (Texas Water Development Board 1999). According to the Texas Water Development Board (1999), "Pursuant to the 'absolute ownership' rule, percolating groundwater is the property of the owner of the surface who may, in the absence of malice, appropriate such water and make whatever use of it as he pleases." There are two boundaries to this law: (1) "the owner may not maliciously take water for the sole purpose of injuring his neighbor;" and (2) "the owner may not wantonly or willfully waste the water" (Texas Water Development Board 1999).

According to Castleberry (2010), "Texas State water is the water of the ordinary flow, underflow, and tides of every flowing river, natural stream, and lake, and of every bay or arm of the Gulf of Mexico, and the storm water, floodwater, and rainwater of every river, natural stream, canyon, ravine, depression, and watershed in the state is the property of the state." This definition is used in Texas to give guidelines as to what surface water is and who has ownership (Castleberry 2010). Currently, the law dictates that the usufructuary[15] rights of normal and flood waters belong to the State of Texas, and, through the use of permitting, the rights to these waters can be granted by the State or exemptions can be recognized (Castleberry 2010). Some of the exemptions subject to recognition include domestic and livestock use, agriculture land and wildlife farming, the Gulf of Mexico, and surface mining (Castleberry 2010). Special

[15] Usufructuary rights are rights that allow an individual access to the benefits of property that are owned by another individual or organization. In this case, the Texas government is the owner of the state's surface waters, and permit holders enjoy the benefits of the respective surface waters.

exemptions also exist for waters deemed private (Castleberry 2010). Percolating groundwater, diffuse surface rainfall runoff, groundwater seepage, and springwater before it reaches a watercourse (a definite channel of a stream where water flows within a defined bed and banks, originating from a definite source or sources) are all excluded from State control (Castleberry 2010). The diffused surface water is in the possession of the landowner as long as it remains on that land before passing to the natural watercourse (Castleberry 2010). Un-natural watercourses (i.e., a canal or an aqueduct) are not defined anywhere by law; however, some factors of these watercourses are under consideration (Castleberry 2010).

Section 11.024 of the Texas Water Code dictates the order of preferences to which surface water shall be allocated in times of shortages. The order of rights follows this priority, respectively: (1) domestic and municipal uses (including water necessary for human life and for domestic animals), (2) agricultural and industrial uses, (3) mining and recovery of minerals, (4) hydroelectric power, (5) navigation, and (6) recreation and pleasure; other beneficial uses come after all of the "needs" are fulfilled (Texas Water Development Board 2011b).

Chapter summary

This chapter discusses three major points that are important to understand when observing water economics in hydraulic fracturing. First discussed is basic perfectly-competitive market theory. This theory helps explain that there is an efficient level for fracking companies to produce and how that level is determined. Also, the different costs (i.e., fixed and variable) will be covered in Chapter V so it is important to understand how these costs work in a basic environment. Externalities were the second point discussed and provide a segway into the topics discussed in

Chapter VI. Water rights were discussed last to give an idea of how limited water is allocated to users.

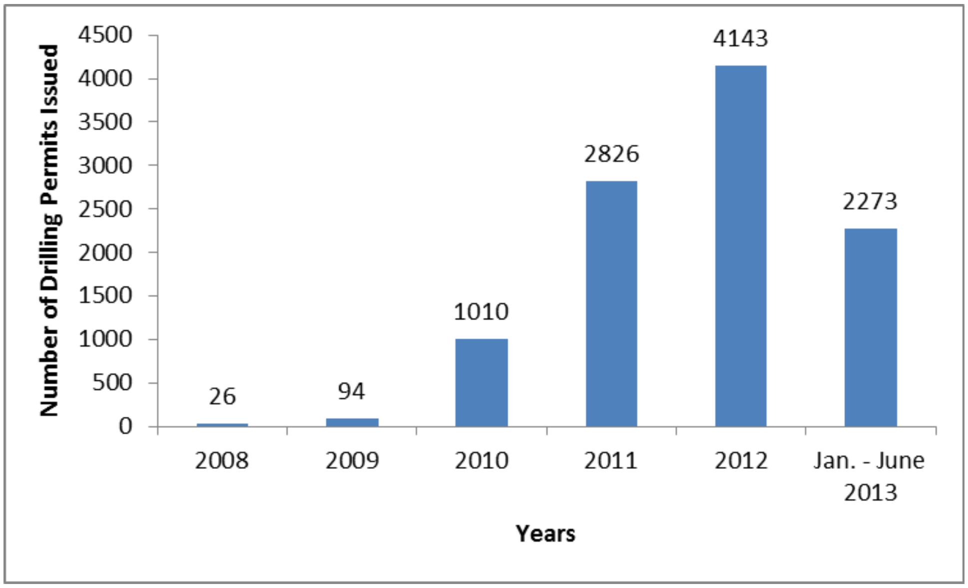
CHAPTER IV

HYDRAULIC FRACTURING ACTIVITY

The Eagle Ford Shale presents the ability for production of both gas and oil (Texas Railroad Commission 2013d). In South Texas, the EF Shale contains a 70% carbonate shale percentage which makes it brittle and fracable (Texas Railroad Commission 2013d). The shale is approximately 50 miles wide and 400 miles long extending from Maverick and Webb Counties (located on the Rio Grande) to Brazos County in Central Texas (Figure 1-1). On average, the EF Shale formation is 250 feet deep (Texas Railroad Commission 2013d). As one of the youngest shales in the United States, industrial wells in the EF shale have only been produced since 2008 (Texas Railroad Commission 2013d). Since then, the shale has experienced tremendous growth in drilling activity and it appears that energy production in the region will be prosperous for many years (Texas Railroad Commission 2013d). This section is comprised of discussion of the fracturing activity for the EF Shale in recent years and that which is projected for the future.

Drilling permits issued

In 2008, the year the first well was completed in the Eagle Ford Shale, there were 26 drilling permits issued (Texas Railroad Commission 2013d). That number has steadily grown to more than 4,000 being issued in 2012 (Texas Railroad Commission 2013d).



Source: Texas Railroad Commission (2013b).

Figure 4-1. Texas Eagle Ford Shale Drilling Permits Issued 2008 through June 2013

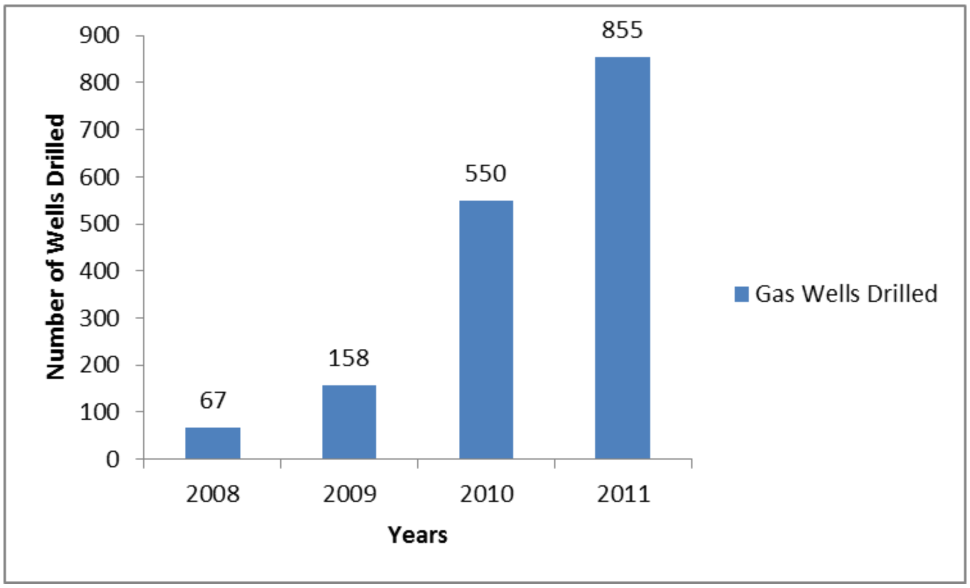
Number of wells by year

As a result of the dramatic drilling permit increase, the number of gas wells in the region has experienced substantial growth. Beginning in 2008, 67 wells were drilled, and, by 2011, the total number of wells drilled per year in the region equaled 855 (Table 4-1) (Texas Railroad Commission 2013b). The number of wells in the area increased by nearly 250% from 2009 to 2010 (i.e. 158 wells per year to 550 wells per year) (Table 4-1) (Texas Railroad Commission 2013b). Shown in Figure 4-2 is a visual of the number of wells drilled from 2008 to 2011.

Table 4-1. Producing Gas Wells: Eagle Ford Shale-Number of Wells Drilled per Year, 2008-2011

Year	Gas Wells Drilled
2008	67
2009	158
2010	550
2011	855

Source: Texas Railroad Commission (2013b).



Source: Texas Railroad Commission (2013b).

Figure 4-2. Producing Gas Wells: Eagle Ford Shale-Number of Wells Drilled per Year, 2008-2011

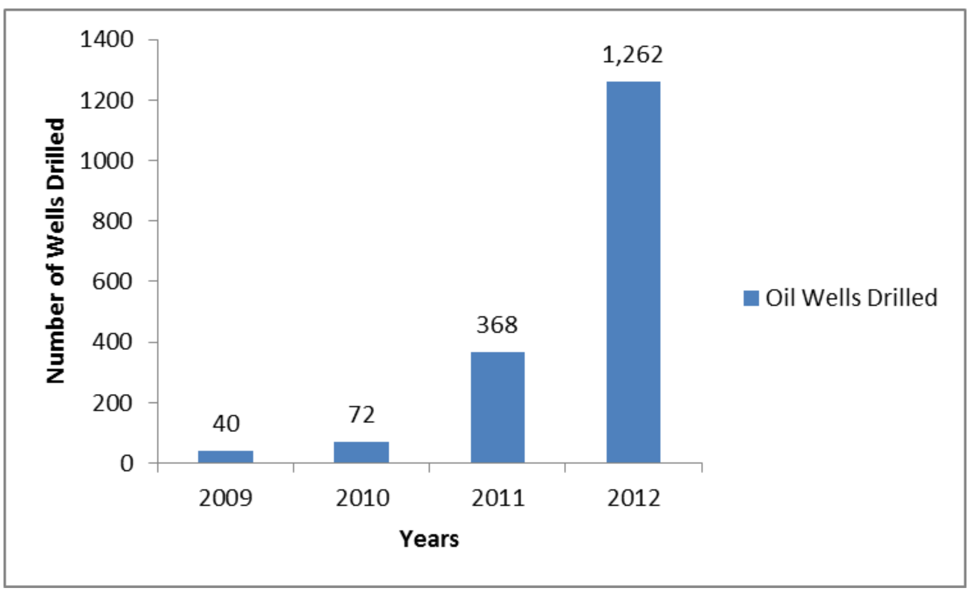
The number of oil wells drilled per year has also increased since 2009 (Texas Railroad Commission 2013b). For this assumption, the Texas Railroad Commission (2013b) starts recordings in 2009 even though oil extraction had begun in 2008. In 2009, there were approximately 40 wells drilled compared to the amount of wells drilled in 2012, which was

1,262 (Texas Railroad Commission 2013b). 2011 alone realized a growth of 411 percent from 2010 (i.e. 72 wells drilled per year in 2010 to 368 wells drilled per year in 2011) (Table 4-2) (Texas Railroad Commission 2013b). Shown in Figure 4-3 is a visual of the number of oil wells drilled from 2009 to 2012.

Table 4-2. Producing Oil Wells: Eagle Ford Shale-Number of Wells Drilled per Year, 2009-2012

Year	Oil Wells Drilled
2009	40
2010	72
2011	368
2012	1,262

Source: Texas Railroad Commission (2013b).

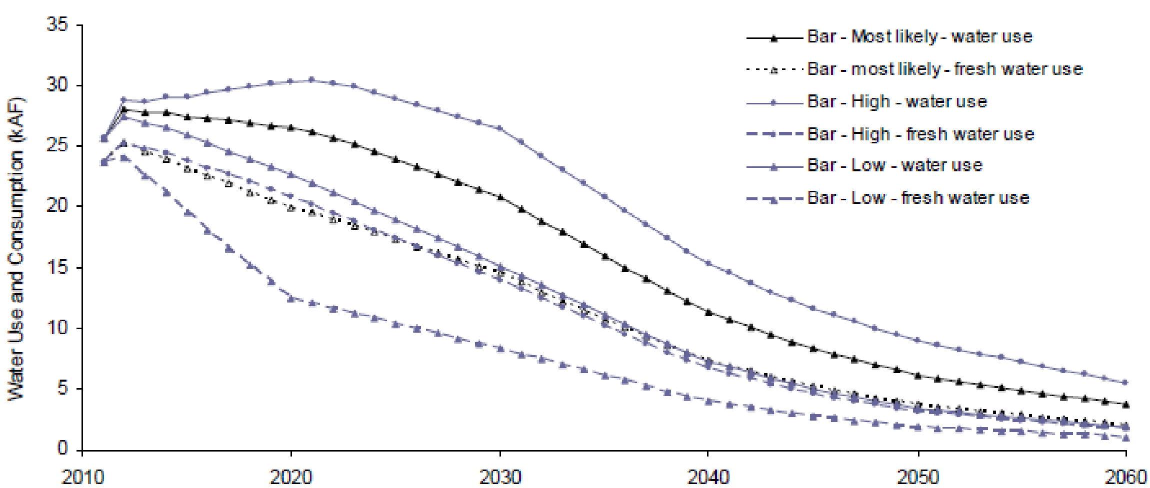


Source: Texas Railroad Commission (2013b).

Figure 4-3. Producing Oil Wells: Eagle Ford Shale-Number of Wells Drilled per Year, 2009-2012

Water use

Water used for fracturing in the Eagle Ford Shale is greater than its similar use in both the Barnett and Haynesville Shales (Nicot et al. 2011). Nicot et al. (2011) estimate that the range of water use in the EF Shale is between 1 and 13 million gallons per well. Based on estimates by the Texas Oil and Gas Divisions of the Texas Railroad Commission (2012), the total water use for the year 2011 was approximately 102,500 acre-feet with 80 percent of that amount being used for hydraulically fracturing wells. Nicot et al. (2012) project that water use for fracturing in the EF Shale will increase until approximately 2020, at which time it will begin to decrease because of more water recycling and newer technology requiring less water to be needed for fracturing wells (Figure 4-4).

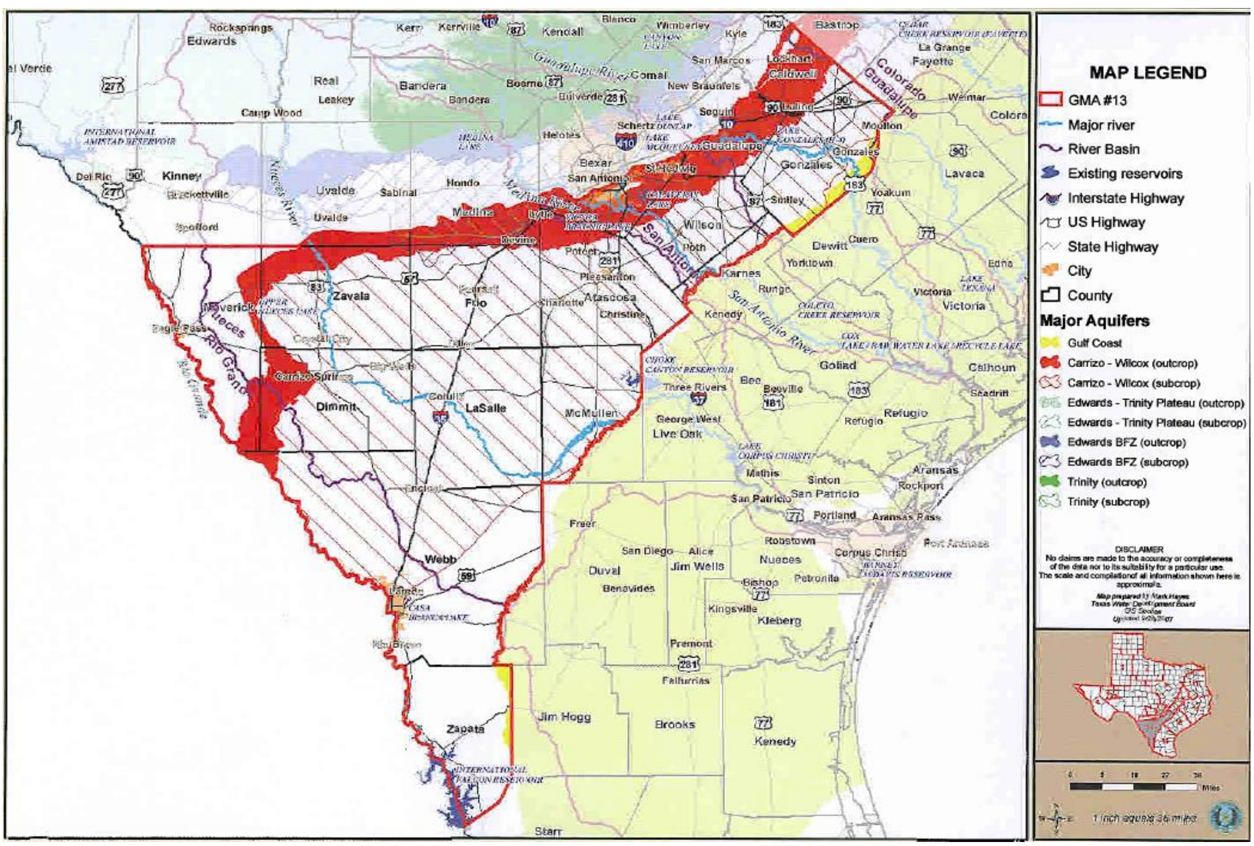


Source: Nicot et al. (2012).

Figure 4-4. Water-use Projections for the Eagle Ford Shale, 2010-2060

Water sources

Nicot et al. (2012) estimate that 95% of water for drilling and fracturing originates as groundwater sources while the remaining 5% comes from surface. In the six-county Texas study region, the Carrizo-Wilcox aquifer (both the outcrop and the subcrop parts of the aquifer) is the main source of groundwater (Texas Water Development Board 2013b). The study region sits on top of this aquifer and this source covers most of the Eagle-Ford-Shale region (Texas Water Development Board 2013b). Surrounding aquifers include the Gulf Coast Aquifer, the Edwards Aquifer, the Edwards-Trinity Plateau Aquifer, and the Trinity Aquifer (Figure 4-5) (Texas Water Development Board 2013b). There is no strong evidence that these surrounding aquifers are significant water sources for fracturing in the study area; however, there may be some drilling activity that utilizes water from these locations.



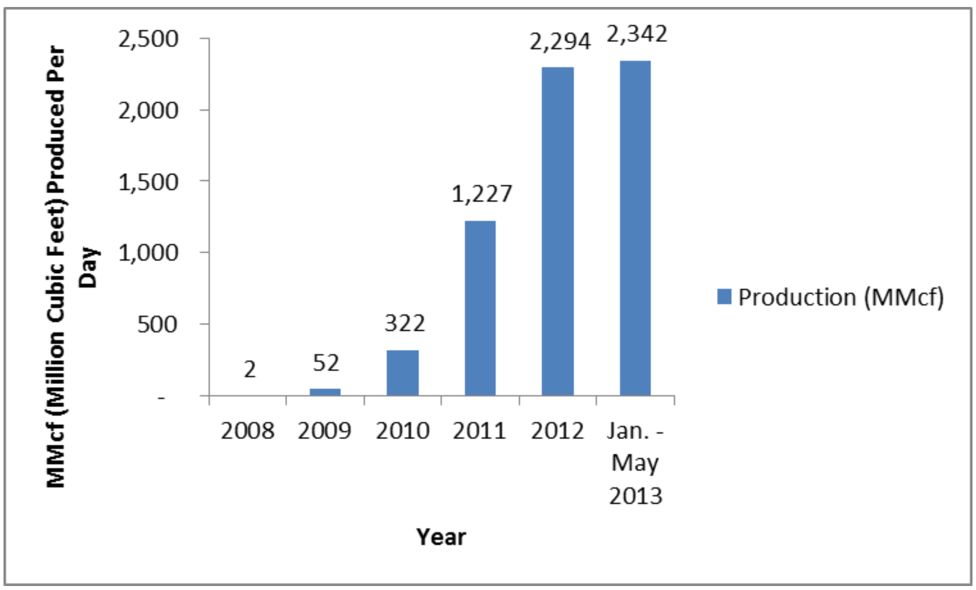
Source: Texas Water Development Board (2013).

Figure 4-5. Groundwater Sources for the Six-County Texas Study Area of the Eagle Ford Shale

Surface water sources in the study area include the Rio Grande, the Nueces River, and the Nueces Rio Grande (Figure 4-5) (Texas Water Development Board, 2013b).

Gas production

Total gas production in the Eagle Ford Shale started at two million cubic feet per day when drilling began in 2008. By the end of 2012, companies were able to produce almost 2,500 million cubic feet per day. Illustrated in Figure 4-6 is the total gas production from the Eagle Ford Shale for 2008 through May, 2013.



Source: Texas Railroad Commission (2013c).

Figure 4-6. Texas Eagle Ford Shale-Total Natural Gas Production per Day 2008 through May 2013 (MMCF)

Gas production projections

This section is a discussion of total natural gas production within the entire Eagle Ford region and then in the study-area Texas counties. The total gas production statistics for the six-county Texas study region are reported in Table 4-3 for the study area from 2008 to 2012. Generally, each county shows an increase each year corresponding to the general trend presented in Figure 4-6. The production suggests that Webb, Dimmit and La Salle are the largest with Webb being much greater than others. Zavala and Frio counties are the only two that do not follow the general trend displayed in Figure 4-6.

Table 4-3. GW Gas Production in the Six-County Texas Study Region, 2008-2012

	Thousand Cubic Feet (Mcf)					
Year	**Dimmit**	**Frio**	**La Salle**	**Maverick**	**Webb**	**Zavala**
2008	2,767,248	1,162,643	13,885,440	2,866,576	215,580,133	703,350
2009	2,979,786	1,236,933	23,363,584	2,298,235	202,794,822	678,875
2010	11,635,313	1,272,894	39,447,278	2,945,941	232,843,001	688,270
2011	39,685,234	1,418,184	61,119,419	3,346,719	360,363,906	586,853
2012	80,287,682	1,267,848	85,510,479	3,050,152	428,362,936	499,789
Total Production	137,355,263	6,358,502	223,326,200	14,507,623	1,439,944,798	3,157,137

Source: Texas Railroad Commission, Texas Oil and Gas Divisions (2013b).

The goal of this section is to identify the characteristics of an “average” well and associated production followed by what that well can be expected to produce over a 20-year period. Certainly, there is a wide range in well character, and sensitivity analyses will provide insight to this range. An average well in the Eagle Ford Shale is estimated to have a total first-year production of 853,967 Mcf (Swindell 2012). Only 347 days are used for the annual scale to account for days that the well is down for maintenance and repair (Swindell 2012). After the first year, a typical well will encounter a production decline of anywhere from 65% to 78%

(*Production of a Natural Gas Well* 2013). In other words, in the second year, that a well will produce only 22% to 35% of what it was able to produce when it was first drilled (*Production of a Natural Gas Well* 2013). Annual production will decrease at slower rates during the next five to six years before it declines at a steady rate *(Production of a Natural Gas Well* 2013). For this analysis, a 20-year period of production is used for the average gas well.

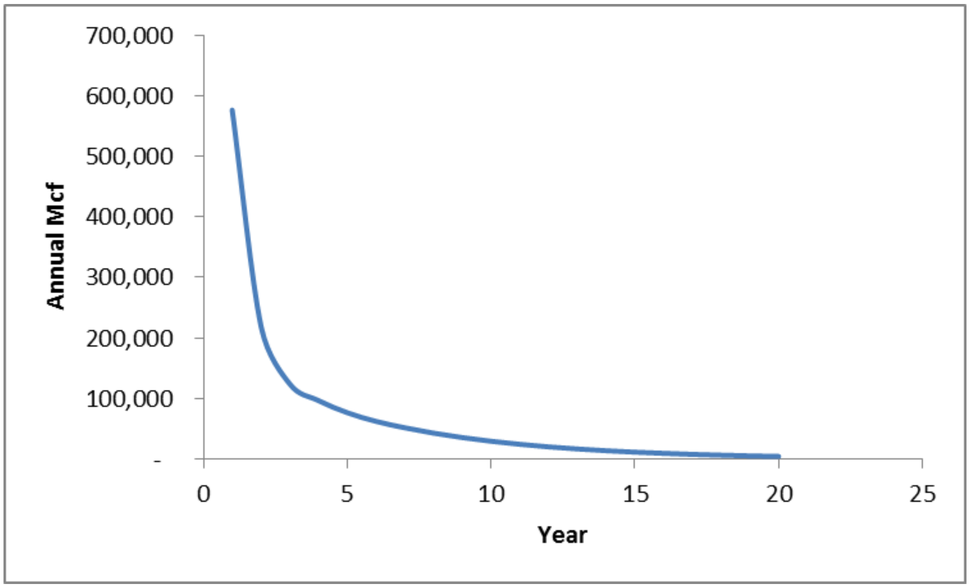
Provided in Tables 4-4 and 4-5, along with Figures 4-7 and 4-8, are production projections for a typical gas well in the Eagle Ford Shale based on two sets of assumptions of decline in production over time. Both assumptions imply decreasing rates of production. Assumption "A" decreases at a slightly slower rate than assumption "B," however. On the other hand, assumption "B" assumes that production is higher at the end of the 20-year period than the production level estimated in assumption "A." Note that all initial levels of production in this circumstance are assumed to be 853,967 Mcf. All reduced production levels are derived from this point. In the tables, each year listed signifies the end of the production year for the well (i.e. year one implies that the well has been producing for one year and year two implies that the well has been producing for two years).

Table 4-4. Production Projection for an Eagle Ford Gas Well, Assumption A[16]

Year	Reduced Production Percentage	Daily Average Mcf	Annual Mcf
1	65	1,661	576,428
2	53	633	219,683
3	23	358	124,323
4	21	279	96,810
5	20	222	76,907
6	17	180	62,551
7	17	150	51,918
8	17	124	43,092
9	17	103	35,766
10	17	86	29,686
11	17	71	24,639
12	17	59	20,451
13	17	49	16,974
14	17	41	14,088
15	17	34	11,693
16	17	28	9,705
17	17	23	8,056
18	17	19	6,686
19	17	16	5,549
20	17	13	4,606

Source: Swindell (2012); U.S. Energy Information Administration (2011).

[16] Assumption “A” estimates a slower initial decline in production than assumption “B.” However, the production levels estimated in assumption “A” are lower at the end of the 20-year production period than estimated in assumption “B.”



Source: Swindell (2012); U.S. Energy Information Administration (2011).

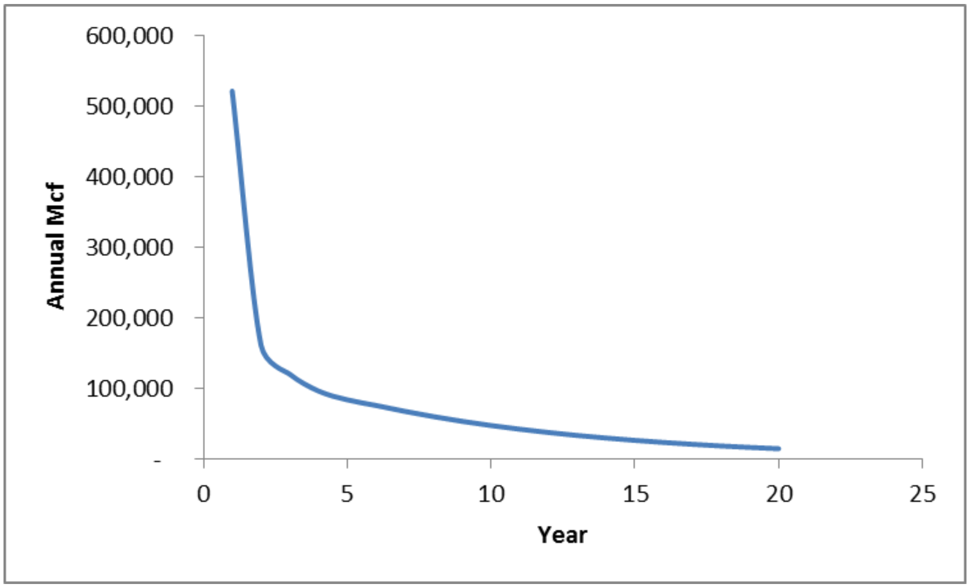
Figure 4-7. Production Projection for an Eagle Ford Gas Well, Assumption A

Table 4-5. Production Projection for an Eagle Ford Gas Well, Assumption B[17]

Year	Reduced Production Percentage	Daily Average Mcf	Annual Mcf
1	78	1,501	520,920
2	28	466	161,571
3	22	347	120,389
4	17	278	96,541
5	8	242	84,070
6	11	219	76,136
7	11	195	67,761
8	11	174	60,307
9	11	155	53,673
10	11	138	47,769
11	11	123	42,515
12	11	109	37,838
13	11	97	33,676
14	11	86	29,972
15	11	77	26,675
16	11	68	23,740
17	11	61	21,129
18	11	54	18,805
19	11	48	16,736
20	11	43	14,895

Source: *Production Decline of a Natural Gas Well over Time* (2013); U.S. Energy Information Administration (2011).

[17] Assumption "B" estimates a higher initial decrease in production than estimated in assumption "A." However, assumption "B" estimates higher production levels at the end of the 20-year production period than estimated in assumption "A."

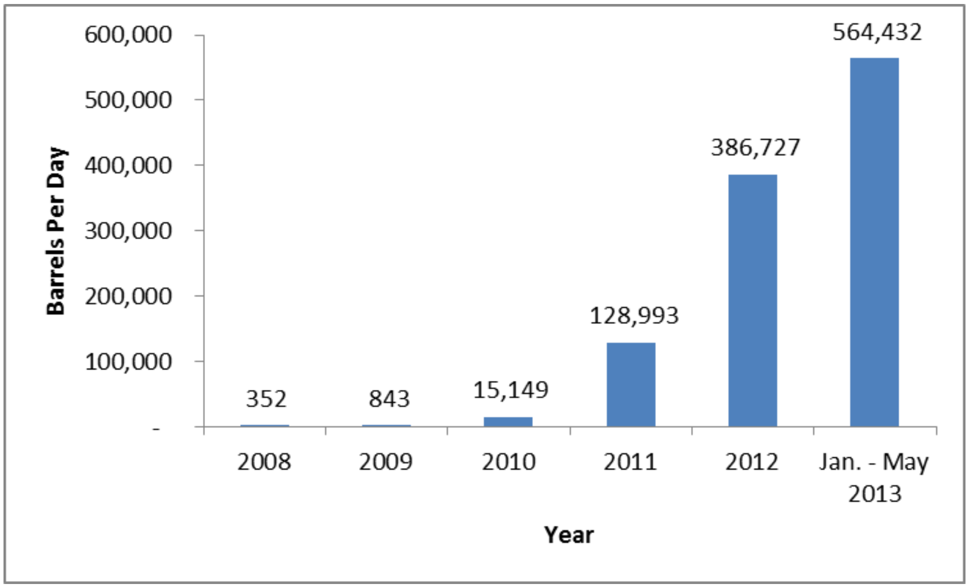


Source: *Production Decline of a Natural Gas Well over Time* (2013); U.S. Energy Information Administration (2011).

Figure 4-8. Production Projection for an Eagle Ford Gas Well, Assumption B

Oil production

In the Eagle Ford formation, a typical well produces both gas and oil. Oil, like gas, has seen dramatic production increases in the Eagle Ford Shale since drilling commenced in 2008 (Texas Railroad Commission 2013b). In 2008, production throughout the EF Shale was 352 barrels (Bbl) per day and, at the end of 2012, was 386,727 Bbl per day (Texas Railroad Commission 2013b). Displayed in Figure 4-9 is the daily oil-production growth in the region during 2008 – 2013.



Source: Texas Railroad Commission (2013b).

Figure 4-9. Texas Eagle Ford Shale Daily Oil Production: 2008 through May 2013

Presented in Table 4-6 is oil production during the last five years in the EF Shale study region. For 2012, the data are monthly oil production statistics in barrels (Bbl). In most cases, the annual production of oil decreases after 2008 for a couple of years, but increases every year after 2009. There are many instances where the growth is rather rapid in a county.

Table 4-6. Oil Production in the Six-County Texas Study Region, 2008-2012

			Barrels (Bbl)			
Year	**Dimmit**	**Frio**	**La Salle**	**Maverick**	**Webb**	**Zavala**
2008	935,954	6,085,100	165,351	1,952,546	123,443	721,072
2009	808,082	547,793	117,298	1,477,017	116,787	463,360
2010	1,621,748	851,479	675,206	1,091,572	113,782	432,201
2011	4,389,014	2,125,927	6,354,932	1,032,974	124,346	818,081
2012	11,893,958	3,352,850	21,141,829	888,819	210,384	2,294,332
Total Production	19,648,756	12,963,149	28,454,616	6,442,928	688,742	4,729,046

Source: Texas Railroad Commission; Texas Oil and Gas Divisions (2013c).

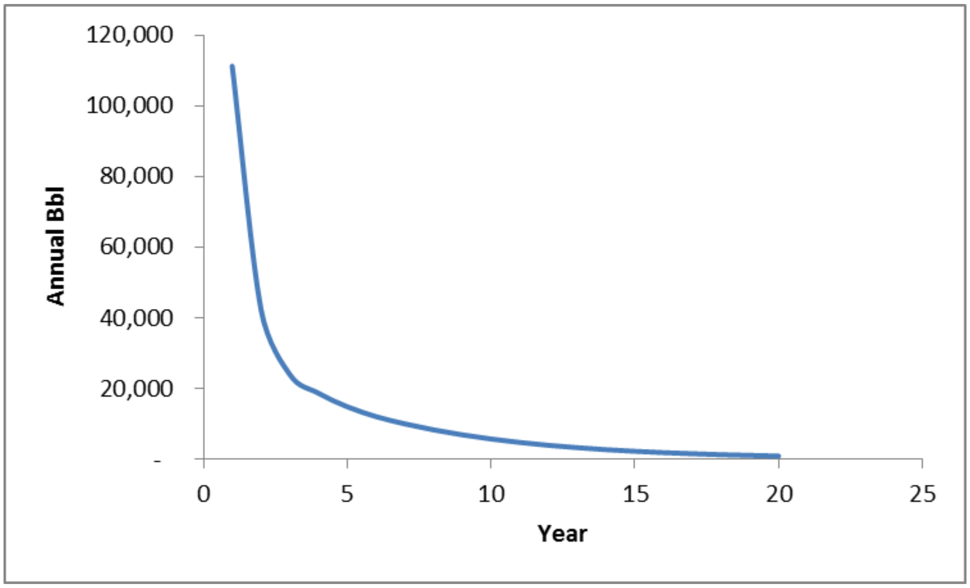
Oil production projections

This section focuses on the projected production of a single well over a 20-year period. Most sources indicate that oil well decline is highly similar to natural gas well decline, and, therefore, the same percentage decline rates as natural gas wells are considered *(Oilfield Decline Rates* 2009). It is assumed an average well is able to produce a total of 164,825 Bbl for the first year (Texas Railroad Commission 2013b). Displayed in Tables 4-7 and 4-8, along with Figures 4-10 and 4-11, are the projections for oil production in a typical well in the Eagle Ford Shale based on two assumptions regarding decline in production over time. These assumptions are listed as assumptions "A" and "B" and are the same estimates that were discussed with gas production. Note that all initial levels of production in this circumstance are assumed to be 164,825 Bbl. All reduced production levels are derived from this point. In the tables, each year listed signifies the end of the production year for the well (i.e. year one implies that the well has been producing for one year and year two implies that the well has been producing for two years).

Table 4-7. Production Projection for an Eagle Ford Oil Well, Assumption A

Year	Reduced Production Percentage	Daily Average Bbl	Annual Bbl
1	65	321	111,257
2	53	122	42,401
3	23	69	23,996
4	21	54	18,685
5	20	43	14,844
6	17	35	12,073
7	17	29	10,021
8	17	24	8,317
9	17	20	6,903
10	17	17	5,730
11	17	14	4,756
12	17	11	3,947
13	17	9	3,276
14	17	8	2,719
15	17	7	2,257
16	17	5	1,873
17	17	4	1,555
18	17	4	1,290
19	17	3	1,071
20	17	3	889

Source: Swindell (2012); U.S. Energy Information Administration (2011).



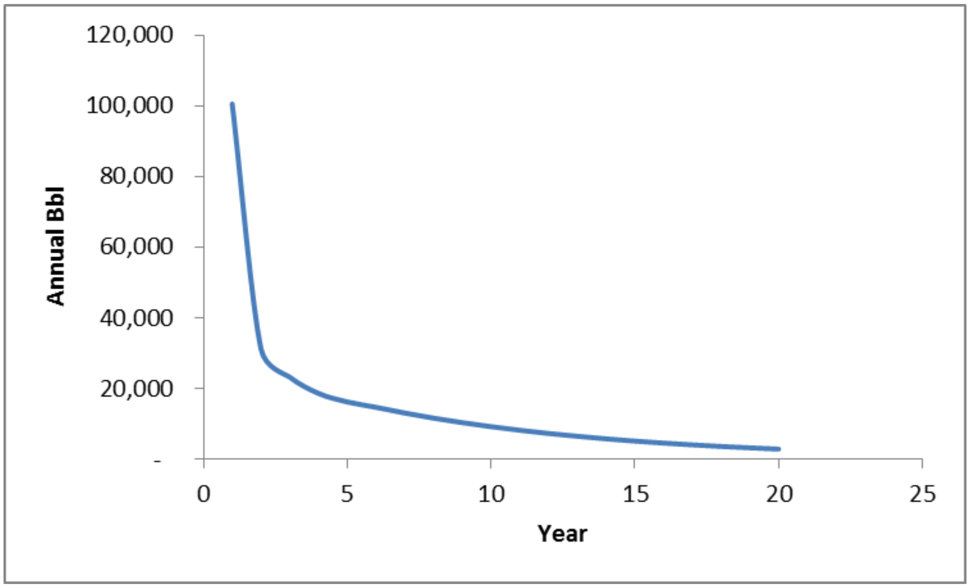
Source: Swindell (2012); U.S. Energy Information Administration (2011).

Figure 4-10. Production Projection for an Eagle Ford Oil Well, Assumption A

Table 4-8. Production Projection for an Eagle Ford Oil Well, Assumption B

Year	Reduced Production Percentage	Daily Average Bbl	Annual Bbl
1	78	290	100,543
2	28	90	31,185
3	22	67	23,236
4	17	54	18,633
5	8	47	16,226
6	11	42	14,695
7	11	38	13,079
8	11	34	11,640
9	11	30	10,360
10	11	27	9,220
11	11	24	8,206
12	11	21	7,303
13	11	19	6,500
14	11	17	5,785
15	11	15	5,148
16	11	13	4,582
17	11	12	4,078
18	11	10	3,630
19	11	9	3,230
20	11	8	2,875

Source: *Production Decline of a Natural Gas Well over Time* (2013); U.S. Energy Information Administration (2013b).



Source: *Production Decline of a Natural Gas Well over Time* (2013); U.S. Energy Information Administration (2013b).

Figure 4-11. Production Projection for an Eagle Ford Oil Well, Assumption B

Chapter summary

This chapter summarized oil and gas production statistics in the EF Shale from 2008 to the beginning months of 2013. In most cases, both oil and gas extraction has realized increases since drilling in the EF Shale began, though some counties do not follow the trend. The typical production cycle of a well was also discussed to give an idea of what a well is expected to produce during the 20 years that it is projected to be operating.

CHAPTER V

WATER SUPPLY AND DEMAND

The Eagle Ford Shale region is characterized by areas of water scarcity, but there is surface water (such as the Rio Grande) and groundwater (such as the Carrizo-Wilcox Aquifer). There are a few relatively-large communities in the region, including Eagle Pass, Pearsall, and Crystal City that are concerned about sufficient long-term water supplies. However, major issues dealing with water use will more than likely occur in the agriculture sector of the region. This section reviews water use and projections from 2010 to 2060 by economic sector along with water supply availability for the six counties that comprise the study region. A primary data source is the Texas Water Development Board (2012). Uses presented include municipal and industrial, mining, steam electric, livestock, and irrigation. In addition, this section delves into the water value of alternative uses, including that of agriculture, municipal and industrial (M&I), and hydraulic fracturing. The primary sources for water values are the Texas A&M Extension Service "Crop and Livestock Enterprise Budgets" (2012) for agriculture, published municipal and industrial water rates (Texas Municipal League 2013), and the calculated residual value of water used in fracking after all other components of production are compensated.

Water sources

As the current drought and outlook for climate change persist, available water becomes scarcer, especially in the southern region of Texas. Water supplies are quickly becoming depleted to the point that considerations for water transfer into the region are under consideration (Texas Water Development Board, Texas State Water Plan 2012). Due to visibility of water required for hydraulic fracturing, such use is being scrutinized by various stakeholders. The primary groundwater suppliers of the Texas Water Plan in region “L” (containing a portion of the Eagle Ford Shale) (Figure 1-2) are the Edwards Aquifer (sitting directly north of the EF Shale region), the Carrizo-Wilcox Aquifer, the Trinity Aquifer, the Gulf Coast Aquifer, and the Edwards-Trinity (Plateau) Aquifer (Texas Water Development Board 2012).

One-half of the total groundwater supply available to the EF Shale is provided by the Edwards Aquifer, followed closely by the Carrizo-Wilcox Aquifer which provides approximately 40% of the groundwater supply (Texas Water Development Board 2012). The other three aquifers plus two minor aquifers, Sparta and Queen City, comprise the additional ten percent of groundwater available to region “L” (Texas Water Development Board 2012).

The primary surface water suppliers of region “L” are the San Antonio, Guadalupe, Lavaca and Nueces Rivers (Texas Water Development Board 2012). In region “M” of the Texas Water Plan (Figure 1-2), surface water provides over 90% of the water supply, with the primary source being the Rio Grande (Texas Water Development Board 2012). However, the lower Rio Grande Valley is the major demand center for this water, rather than the Eagle Ford Shale. The two major groundwater suppliers in this region are the Gulf Coast Aquifer, which is primarily brackish water, and the Carrizo-Wilcox aquifer (Texas Water Development Board 2012). As mentioned in the theory section, strict guidelines must be followed (as per the Texas Water Code) regarding who has the rights to these waters.

Water uses

According to the Texas State Water Plan, each of the 16 regions is responsible for developing a recurring 50-year projection of water demand by sector (type) and associated available water supply (Texas Water Development Board, Texas State Water Plan 2012). The Eagle Ford region extends across two State Water Planning regions, “L” and “M,” with each region working independently on its own horizons of water supply and demand. Representatives of each water demand sector, water management agencies, and public and environmental interests serve on the regional planning groups. At the State level, all of the regional plans are integrated into the state water plan.

For this report, county data reported in the State Water Plan for the six-county study area is accumulated across the two water planning regions to provide totals on water use (demand) and supply (Texas Water Development Board, Texas State Water Plan 2012). Projected shortages or surpluses are listed as the difference or “balance” between demand and supply. However, for the state planning process, alternative water sources or management strategies are required to be identified to offset shortages. For example, water conservation practices and developing new water resources are options to offset any deficit.

Presented in Table 5-1 are projected water demands by sector, available ground and surface water supplies and the net difference by decade for the period 2010 through 2060. Note that the available water supplies are not average supplies, but represent rather the supply available during drought of record conditions, (i.e. the most severe drought on record which occurred during the 1950’s). Across all of the six decades (2010-2060) there is a projected shortfall in water for the study area suggestive of L&M regions.

The deficit in water supply increases over the 50-year period, going from more than 100,000 acre feet in 2010 to more than 161,000 acre feet in 2060. The majority of water available is groundwater at more than 263,000 acre feet compared to only 5,466 acre feet from surface sources. The major projected increase in demand comes from M&I[18] while agriculture declines. Regardless, the take away is that this region is facing a serious water supply issue and, at the same time, the fracturing is adding to demand for water.

Table 5-1. Six-County Texas Study Area 50-Year Water Availability and use Projections in Acre-Feet [a]

Water Demand					Water Supply			
Year	**Mining**	**M&I**	**Agricultural**	**Total**	**Groundwater**	**Surface-Water**	**Total**	**Balance (-)[b]**
2010	2,594	76,272	290,743	369,609	263,753	5,467	269,220	(100,389)
2020	2,617	92,772	280,255	375,644	263,753	5,466	269,219	(106,425)
2030	2,635	111,109	269,759	383,503	263,753	5,466	269,219	(114,284)
2040	2,651	130,992	263,916	397,559	263,753	5,466	269,219	(128,340)
2050	2,666	152,364	258,284	413,314	263,753	5,466	269,219	(144,095)
2060	2,676	175,239	252,862	430,777	263,753	5,466	269,219	(161,558)

Source: Texas Water Development Board, Texas State Water Plan (2012).
[a] See Appendix A for detailed water supply and demand data for each county.
[b] Parentheses indicate negative values.

Water value in alternative uses

This section addresses values of water in alternative uses. The goals of this study include developing estimates of water value ($/ac-ft) for M&I activities, irrigated agricultural production, and for hydraulic fracturing. For M&I, the published rate per unit (Texas Municipal

[18] M&I does not include hydraulic fracturing.

League 2013) serves as a proxy of value while agriculture and fracking are estimated as a residual return to water after all other factors of production are paid (Lacewell 2013).

Estimating the value of water in any given use is a challenge. There are many reasons for such difficulties, including imperfect markets for water resulting from the heterogeneous nature of water (quantity, quality, and timing differ by use, location, and over time), different treatment and transportation costs, regulations and other restrictions, public good characteristics (common access issues – how do you identify and protect "your" water, public and other environmental issues), water rights and regulations, lack of information (e.g., undisclosed/proprietary information), and other factors. It is also important to remember that where prices are available, price (cost) is usually not equivalent to value. However, prices, where they are available, can provide an indication of the minimum monetary amount of a good (e.g., water). In estimating the value of water used in hydraulic fracturing, an important factor relates to the value (price) of water in other uses in the region. This is to both benchmark the results of the value of water in hydraulic fracturing and to see if there could be any implications as to where water owners will want to sell their water. To gain access to water, a company can (a) purchase surface water and/or groundwater or (b) drill a well with cost for drilling, equipping and pumping the water.

Water demand includes both municipal and industrial users as reported above. Other users include mining, where fracturing is included, and agriculture, primarily irrigation. Not included among these identified demands are water quantities and values for ecosystem services, other environmental values, and in-stream flow. In the Eagle Ford Shale region, the major users (demand) for water are agriculture users.

A variety of economic approaches are applied to develop three different sets of estimates of water value in alternative uses in the study region. They are: (1) water prices (rates) charged to municipal and industrial users; (2) the differential returns in irrigated and dryland agricultural production for the major crops in the region representing the value water adds to production; and (3) the residual value related to production of natural gas (and oil), after all other factors of production are paid. To use these economic approaches requires application of capital budgeting methods and, for this analysis, assumes a typical energy-production well for the region.

Municipal and industrial

Municipal and Industrial use represents roughly 30% of total water use in the Eagle Ford Shale region (Texas Water Development Board 2011a). As discussed above, the price paid (cost) for water in any given use is a minimum value for that use. Information on water costs[19] to residential and commercial users across the cities and waters suppliers in the six-county EF Shale study region was obtained from statewide data reported by the Texas Municipal League (2013). Water rates (prices/costs) are reported for two water use levels, including residential (5,000 and 10,000 gallons per month) and commercial (50,000 and 200,000 gallons per month) customers, without reference to average typical quantities of water consumed by those users (Texas Municipal League 2013). High and low rates from seven water suppliers in the six-county EF Shale study region are identified based on the data provided by the Texas Municipal League for 2012. Displayed in Table 5-2 are 2012 water rates for residential and commercial consumers. Listed in Appendix B are details on rates of water for municipal and industrial users across all cities in the Eagle Ford Shale study region.

[19] Note that such costs include charge for the water plus treatment and delivery.

Table 5-2. Six-County Study Area Water Rates for Residential and Commercial Consumers[20]

Classification	$ Per Thousand Gallons		$ Per Acre Foot	
Residential	**Low**	**High**	**Low**	**High**
5,000 gal	2.62	6.70	855	2,185
10,000 gal	2.17	5.05	708	1,647
Commercial				
50,000 gal	2.29	4.21	747	1,373
200,000 gal	2.31	4.05	753	1,321

Source: Texas Municipal League (2013).

Large increases in M&I demand and costs are projected until the year 2060, especially in larger urban areas. While the Texas Water Development Board (2012) has projected water demand by water planning region (for the Eagle Ford Shale area, these statistics are shown in Table 5-1 of this report), the rates are not projected, but are expected to increase as well. To keep up with a growing demand in Texas, an estimated required investment of $53 billion is projected as well as $178 billion to maintain the existing M&I infrastructure over the next 50 years (Michelson 2012).

Applying low and high rates per thousand gallons of M&I to the Texas Water Development Board demand quantities provides a range of total costs (value) for municipal and industrial users. Complicating matters is the fact that municipal and industrial uses are not presented separately, but the rates of the two are fairly comparable. M&I water use (demand) for 2010 from the Texas Water Development Board is 76,272 acre feet (2012a) and rates are presented

[20] Note that water costs are averages for two levels of use (low and high) and two groups of rates (low and high) for seven urban suppliers in the Eagle Ford Shale region. The results are from 2012 and are derived from Texas Municipal League (2012) data.

with 2012 data from the Texas Municipal League (2013). Using the high and low rates in Table 5-2 suggests that water costs/values range from $54 million to $167 million per year, with the simple average being $110 million per year for M&I use.

Note that the water that is provided for municipal and industrial use has generally been treated and delivered to the end user. Treating water implies additional costs that have not been explicitly mentioned in this study. However, the rates listed in Table 5-2 are sensitive to these unmentioned costs as these are the actual rates that consumers pay.

Agriculture

In Table 5-1, the agriculture demand represents both irrigation and livestock. Livestock is a minor factor in the Eagle Ford region, however. Therefore, the focus for water value in this section is placed on the value of water used for irrigation purposes. As in the previous section, the agriculture demand is presented for 2010 data from the Texas Water Development Board (2012) and the agriculture water values are estimated based on 2012 data from the Texas A&M AgriLife Extension Service (2012). In estimating agriculture values of water for irrigation, residual and comparative valuations are used.

Basically, the estimation procedure involves first calculating dryland net returns with a charge to all inputs including land. Then, the same approach is used to determine irrigated net returns using the same element costs except for the land charge[21] and the water itself[22]. The difference in

[21] Irrigated land is assumed to cost more because of the availability of water.
[22] Delivery costs are not included in the water charge because it is assumed that water is pumped onto the land by the landowner. In that regard, drilling costs are included in the water charge.

between the estimated irrigated and dryland net returns are the estimated returns to water for a specific crop, for the amount of water assumed in the irrigated crop budget.

Economists have used this form of residual valuation to estimate value of irrigation water in agriculture (Lacewell 2013). Residual valuation has also been used in estimating the value of water in the production of other goods and is used later in this report as a means for estimating the value of water in natural gas and oil production via hydraulic fracturing. Residual estimates of water in agriculture require detailed information on crop production costs and revenue. After all costs are accounted for except water itself, the difference in net revenue (profit) between dryland and irrigation is the maximum amount (value) that could be paid for water to produce that crop. In this study region, the capabilities exist to grow crops without the assistance of irrigation (i.e., dryland production), but generally, such dryland crops will have a lower yield as they are entirely dependent on rainfall.

To estimate the value of water for irrigation, the Texas A&M AgriLife Extension Enterprise Budgets for the region are applied (2013). Displayed in Table 5-3 is an overview from the enterprise crop budgets when there is irrigated and dryland production of the same crop. Detailed crop budgets for cotton, sorghum, and bermuda pasture are presented in Appendix C. In Table 5-3, the expected yield, revenue, land charge, water costs, level of irrigation, and returns to water are presented. To describe the contents of Table 5-3, first consider the cotton crop information. The first line is yield, then total revenue (price times yield), followed by a land charge for dryland and irrigated (note the irrigated land charge is greater), water charge for irrigation, water applied (in irrigated acre-inches), and per-acre net returns. Returns to water is the third column behind the dry and irrigated columns. First, the difference in land charges is listed as a positive value. This positive value is to indicate that the irrigated land is more valuable to the farmer and could be sold at a higher price than dry land. The added water charge for irrigated land is shown as a negative value symbolizing the additional cost that the owner of the irrigated land must pay in order to pump the water onto the land. Next, the net returns are determined by subtracting the absolute value[23] of net returns for irrigated land from the absolute value of net returns for dryland. Finally, the three values discussed are added together to determine the net returns to irrigation. This cumulative value is then divided by the irrigated inches to derive the value of water per acre-inch. Lastly, the value of water per acre-inch is multiplied by 12 to get the value of water per acre-foot.

Table 5-3. Six-County EFS Study Area Dryland Agriculture Compared to Irrigated Agriculture per Acre by Crop[24]

	Cotton			**Sorghum**			**Bermuda Pasture**		
	Dry	*Irrigated*	*Returns to Water*	*Dry*	*Irrigated*	*Returns to Water*	*Dry*	*Irrigated*	*Returns to Water*
Yield	1,320 lbs.	2,272 lbs.	-	22 cwt	43 cwt	-	140 lbs.	600 lbs.	-
Total Revenue ($)	493.00	826.00	-	187.00	366.00	-	55.00	270.00	-
Land Charge ($)	123.00	207.00	84.00	62.00	121.00	59.00	25.00	100.00	75.00
Water Charge ($)	-	16.00	(16.00)	-	8.00	(8.00)	-	84.00	(84.00)
Irrigated (ac.in.)	-	14.00	-	-	14.00	-	-	12.00	-
Net Returns ($)	(77.00)	(28.00)	49.00	(49.00)	17.00	66.00	(26.00)	(102.00)	(76.00)
Net Returns to Irrigation ($)	-	-	117.00	-	-	117.00	-	-	(85.00)
Value (ac.in.) ($)	-	-	8.36	-	-	8.36	-	-	-
Value (ac.ft.) ($)	-	-	100.29	-	-	100.29	-	-	-

Source: Texas A&M AgriLife Extension Service (2012).

The values per acre foot of water are as follows: cotton--$100 per acre-foot, sorghum--$100 per acre-foot, and bermuda pasture grass--essentially zero. Bermuda pasture was not listed in the

[23] The absolute value of an integer is determined by taking the positive value of that integer regardless if it is listed as a positive or a negative.

[24] Detailed crop budgets are located in Appendix C-1.

crop budgets for District 12 of the Texas A&M AgriLife Extension (2013) system (the six-county EFS study area). However, it is noted in the U.S. Department of Agriculture (2013) that there is an estimated 4.27 million acres of pasture in the six counties that are under observation. Therefore, the budget for Bermuda pasture was derived from District 10 which is located next to District 12 and has similar agriculture practices as District 12. Forage (pasture) acres listed in Appendix C-2 are used as a proxy for the acreage of irrigated pasture.

The above-described process provides estimates for irrigation on a per-acre and per-unit of water basis. To estimate the total value of irrigation water, the bermuda pasture is ignored. The average value per acre foot of water for cotton and sorghum (100 acres) (Table 5-3) is multiplied by total acre feet for agriculture listed in the Texas Water Development Board (2012). Presented in Table 5-4 are estimates for water value in irrigation projected by decade to 2060. The aggregate annual value of water in irrigation for 2010-2060 ranges from $25.4 million to $29.2 million.

Obviously several factors may change over the next 50 years (prices, costs, weather, etc.) and the presented information consequently has a broadening confidence interval through time. Table 5-4 is a presentation of estimates based on current prices and costs, however; as such, it represents the best practical way of determining the value of water for agriculture in this region.

Table 5-4. Estimated Value of Water used for Irrigated Agriculture in the Texas Eagle Ford Study Area by Decade, 2010-2060

Year	Ag Water Use (ac.ft.)	Value at $100/ac.ft. (million $)
2010	290,743	29.2
2020	280,255	28.1
2030	269,759	27.1
2040	263,916	26.5
2050	258,284	25.9
2060	252,862	25.4

Hydraulic fracturing

Estimating the value of water in hydraulic fracturing is a principle purpose of this research. For simplicity, a typical gas (oil) well is assumed. Nicot et al. (2011) estimate that 95% of the water used for fracking comes from groundwater sources and roughly 20% of this water is brackish (depending on the company). The Texas Water Development Board (2012) estimates 80% of the regional water supply comes from groundwater sources.

When determining the value of the water that is used for fracking, there are several factors that must be considered, including investments, operating costs, royalties, and oil and gas production over time. The analysis essentially involves appraising the value of the gas (and oil) minus all costs estimated via capital budgeting techniques, and using the residual value to represent the value of the water used.

The capital budgeting techniques include finding the net present value of all costs and revenues over the estimated 20-year life of the well. Afterwards, the costs are subtracted from the revenues to determine the residual value representing the value of the water used. Furthermore, gas and oil revenues will be separated and the respective variable costs are subtracted from each. Both of these values are considered the returns above variable costs (RAVC). Afterwards, fixed costs (sunk costs) are subtracted from the cumulative value of RAVC for both gas and oil. This value will be considered the returns above total costs (RATC). The variable costs and fixed costs to production are described with more detail later in this chapter.

Returns: The first venue that needs observance is total returns (revenue) to oil and gas production. Revenue is a function of price of energy (gas and oil) and production levels. Before the introduction of costs, it is necessary to examine the wellhead price per Mcf and Bbl.

Since revenue and operation costs are keyed to production, temporal estimates are needed. To effectively accomplish this, this section involves consideration of the entire expected 20-year life of a well and what that well is capable of producing during that time period on an annual basis. The projected production of a well was emphasized in Chapter IV; however, the projected production levels are also displayed in Table 5-5 to ease the transition into gauging total-well value.

Table 5-5. Estimated Projected Production of an Eagle-Ford Gas (Oil) Well in the Texas Eagle Ford Area, 2012

Year	Assumption A (% Decline)	Assumption B (% Decline)	Gas (Assumption A) Annual Mcf	Gas (Assumption B) Annual Mcf	Oil (Assumption A) Annual Bbl	Oil (Assumption B) Annual Bbl
1	**65**	**78**	576,428	520,920	111,257	100,543
2	**53**	**28**	219,683	161,571	42,401	31,185
3	**23**	**22**	124,323	120,389	23,996	23,236
4	**21**	**17**	86,810	96,541	18,685	18,633
5	**20**	**8**	76,907	84,070	14,844	16,226
6	**17**	**11**	62,551	76,136	12,073	14,695
7	**17**	**11**	51,918	67,761	10,021	13,079
8	**17**	**11**	43,092	60,307	8,317	11,640
9	**17**	**11**	35,766	53,673	6,903	10,360
10	**17**	**11**	29,686	47,769	5,730	9,220
11	**17**	**11**	24,639	42,515	4,756	8,206
12	**17**	**11**	20,451	37,838	3,947	7,303
13	**17**	**11**	16,974	33,676	3,276	6,500
14	**17**	**11**	14,088	29,972	2,719	5,785
15	**17**	**11**	11,693	26,675	2,257	5,149
16	**17**	**11**	9,705	23,740	1,873	4,582
17	**17**	**11**	8,056	21,129	1,555	4,078
18	**17**	**11**	6,686	18,805	1,290	3,630
19	**17**	**11**	5,549	16,736	1,071	3,230
20	**17**	**11**	4,606	14,895	889	2,875

Sources: Energy Information Administration (2011); Production Decline of a Natural Gas Well over Time (2013); Swindell (2012).

Shown in Tables 5-6 through 5-9 are the values of the range of revenues as presented by the Energy Information Administration (2012a; 2013b). Natural gas prices listed generally range from $2.5 to $7.5 per Mcf. (Energy Information Administration 2012a). Thus, they are listed in this format in the sensitivity analyses. Also, according to the U.S. Energy Information Administration (2013b), the price of oil per Bbl ranges from $55 to $95.

Table 5-6. Annual Returns for a Texas Eagle Ford Gas Well throughout its 20-Year Life, Assumption A

	Price ($ per Mcf)		
Year	**2.50**	**5.00**	**7.50**
1	$ 278,143	$ 556,285	$ 834,428
2	106,003	212,005	318,008
3	59,990	119,980	179,970
4	46,713	93,425	140,138
5	37,110	74,220	111,330
6	30,183	60,365	90,548
7	25,053	50,105	75,158
8	20,793	41,585	62,378
9	17,258	34,515	51,773
10	14,325	28,650	42,975
11	11,890	23,780	35,670
12	9,868	19,735	29,603
13	8,190	16,380	24,570
14	6,798	13,595	20,393
15	5,643	11,285	16,928
16	4,683	9,365	14,048
17	3,888	7,775	11,663
18	3,225	6,450	9,675
19	2,678	5,355	8,033
20	2,223	4,445	6,668

Table 5-7. Annual Returns for a Texas Eagle Ford Gas Well throughout its 20-Year Life, Assumption B

	Price ($ per Mcf)		
Year	**2.50**	**5.00**	**7.50**
1	$ 251,358	$ 502,715	$ 754,073
2	77,963	155,925	233,888
3	58,090	116,180	174,270
4	46,583	93,165	139,748
5	40,565	81,130	121,695
6	36,738	73,475	110,213
7	32,698	65,395	98,093
8	29,100	58,200	87,300
9	25,900	51,800	77,700
10	23,050	46,100	69,150
11	20,515	41,030	61,545
12	18,258	36,515	54,773
13	16,250	32,500	48,750
14	14,463	28,925	43,388
15	12,873	25,745	38,618
16	11,455	22,910	34,365
17	10,195	20,390	30,585
18	9,075	18,150	27,225
19	8,075	16,150	24,225
20	7,188	14,375	21,563

Table 5-8. Annual Returns for a Texas Eagle Ford Oil Well throughout its 20-Year Life, Assumption A

	Price ($ per Bbl)		
Year	**55**	**75**	**95**
1	$ 6,119,135	$ 8,344,275	$ 10,569,415
2	2,332,055	3,180,075	4,028,095
3	1,319,780	1,799,700	2,279,620
4	1,027,675	1,401,375	1,775,075
5	816,420	1,113,300	1,410,180
6	664,015	905,475	1,146,935
7	551,155	751,575	951,995
8	457,435	623,775	790,115
9	379,665	517,725	655,785
10	315,150	429,750	544,350
11	261,580	356,700	451,820
12	217,085	296,025	374,965
13	180,180	245,700	311,220
14	149,545	203,925	258,305
15	124,135	169,275	214,415
16	103,015	140,475	177,935
17	85,525	116,625	147,725
18	70,950	96,750	122,550
19	58,905	80,325	101,745
20	48,895	66,675	84,455

Table 5-9. Annual Returns for a Texas Eagle Ford Oil Well throughout its 20-Year Life, Assumption B

	Price ($ per Bbl)		
Year	**55**	**75**	**95**
1	$ 5,529,865	$ 7,540,725	$ 9,551,585
2	1,715,175	2,338,875	2,962,575
3	1,277,980	1,742,700	2,207,420
4	1,024,815	1,397,475	1,770,135
5	892,430	1,216,950	1,541,470
6	808,225	1,102,125	1,396,025
7	719,345	980,925	1,242,505
8	640,200	873,000	1,105,800
9	569,800	777,000	984,200
10	507,100	691,500	875,900
11	451,330	615,450	779,570
12	401,665	547,725	693,785
13	357,500	487,500	617,500
14	318,175	433,875	549,575
15	283,195	386,175	489,155
16	252,010	343,650	435,290
17	224,290	305,850	387,410
18	199,650	272,250	344,850
19	177,650	242,250	306,850
20	158,125	215,625	273,125

The next step is to take the net-present-value of each of the 20-year projections presented. Presented in Table 5-10 is the estimated present value of the total returns based on the U.S. Energy Information Administration (2007) price forecasts. Ranges of $2.5 to $7.5 per Mcf of gas as well as ranges of $55 to $95 per Bbl of oil are provided in the table. In addition, the net-present-value equation requires a discount rate in order to bring the future values back to the present period. According to the Office of Management and Budget (2011), the current discount rate is 1.7%. For sensitivity purposes, a range of discount rates is provided from 1.7% to 7%. The purpose is to show the value of a well by taking alternative prices and nominal discount rates over a 20-year time period and discounting back to the current (present) value via the net-present-value equation. In the table, the returns for gas and oil production are added together because, as mentioned earlier in this report, a typical well is capable of producing both gas and oil.

Table 5-10. Estimated Net Present Value of Total Returns for a Typical Texas Eagle-Ford Gas (Oil) Well ($)

	Gas (Assumption A) Price per Mcf ($)			**Gas (Assumption B) Price per Mcf ($)**		
Discount Rate (%)	**2.50**	**5.00**	**7.50**	**2.50**	**5.00**	**7.50**
1.7	3,370,380	6,740,761	10,111,141	3,540,731	7,081,462	10,622,193
5	3,029,407	6,058,814	9,088,222	3,083,919	6,267,839	9,251,758
7	2,856,201	5,712,403	8,568,604	2,855,929	5,711,857	8,567,786
	Oil (Assumption A) Price per Bbl ($)			**Oil (Assumption B) Price per Bbl ($)**		
	55	**75**	**95**	**55**	**75**	**95**
1.7	14,311,449	19,515,612	24,719,775	15,034,798	20,501,998	25,969,197
5	12,863,594	17,541,265	22,218,935	13,095,067	17,856,909	22,618,751
7	12,128,120	16,538,346	20,948,571	12,126,963	16,536,767	20,946,572
	Total Returns per Well (Gas and Oil)			**Total Returns per Well (Gas and Oil)**		
	$ per Well			**$ per Well**		
1.7	17,681,829	26,256,373	34,830,916	18,575,529	27,583,460	36,591,390
5	15,893,001	23,600,079	31,307,157	16,178,986	24,124,748	31,870,509
7	14,984,321	22,250,749	29,517,175	14,982,892	22,248,624	29,514,358

Investment: After determining returns, it is necessary to estimate the initial investment (fixed costs). For fracturing, this includes leasing mineral rights, drilling, and fracking. Gary Swindell (2012) estimates that the mineral lease cost for drilling in the Eagle Ford Shale ranges from $3,000 to $3,500 per acre. The total number of acres associated with a particular well can vary. As reported by the Department of Energy, the average acres for a well equal 116.4 (Energy Information Administration 2011). Alternatively, Nicot et al. (2012) estimate that the acreage per well is 40. This paper will assumes 40 acres to support one well, but also considers 60 and 120 acres for comparisons in sensitivity analyses. Shown in Table 5-11 are the potential leasing values for a typical well.

Table 5-11. Estimated Cost to Lease Mineral Rights per Gas (Oil) Well in the Texas Eagle Ford Study Area, 2012

	Acres/Well		
$ per Acre	**40**	**60**	**120**
3,000	$ 120,000	$ 180,000	$ 360,000
3,500	140,000	210,000	420,000

Sources: Nicot et al. (2012); U.S. Energy Information Administration (2013b).

As shown in Table 5-11, the range of leasing values is $120,000 to $420,000 with an average of $270,000 per well.

According to Trey Cowan (2011), the cost to drill a typical Eagle Ford well is approximately $2.3 million and the cost to frack a well is approximately $4 million. This brings the total cost to complete a well to $6.3 million, ignoring the leasing costs. Shown in Table 5-12 is the breakdown of the costs to drill and fracture a well. For simplicity, this paper assumes that a well will only be fractured once during its operational life.

Table 5-12. Estimated Cost to Drill and Fracture a Well in the Texas Eagle Ford Area, 2012

Typical Eagle Ford Well Budget		
Drilling		**($ Thousands)**
Set Up Costs		215
35 Rigs Days at 20k/d		700
Fluids[a], Chemicals, Transportation, & Fuel		270
Services & Rental Equipment		540
Bits, Expendable Equipment, & Misc.		60
Labor, Engineering, & Overhead		70
Casing and Other Intangibles		190
Contingencies		240
Plugging & Abandonment		100
Sub-total for Drilling	**$**	**2,385**
Fracturing		
Set Up		35
Rig and Daywork		115
Fluids, Chemicals, Transportation, & Fuel		66
Services & Rental Equipment		208
Formation Stimulation		2,760
Expendable Equipment, & Misc.		19
Casing and Other Intangibles		430
Contingencies		325
Sub-total for Fracturing	**$**	**3,958**
Total Drilling and Fracturing Budget	**$**	**6,343**

[a] Water is included in fluids.

Source: Cowan (2011).

The total investment (leasing, drilling, and fracking), which is shown in Table 5-13, for a natural gas well (where oil is also produced) in the Eagle Ford Shale ranges from $6.46 million to $6.76 million. Note that this analysis does not assume that every drilled well will be a success; however, each well that is a success is estimated to have the following range of total investments.

Table 5-13. Estimated Total Investment for Drilling, Fracturing, and Leasing for a Typical Gas (Oil) Well in the Texas Eagle Ford Area, 2012

	Acres/Well		
$ per Acre	**40**	**60**	**120**
3,000	$6,463,000	$6,523,000	$6,703,000
3,500	6,483,000	6,553,000	6,763,000

Sources: Cowan (2011); Nicot et al. (2012); U.S. Energy Information Administration (2013b).

Operating costs: Operating costs (variable costs) are recurring costs through time. While much of the cost lies in the initial investment of mineral rights and drilling, there still is the energy required to run the well, labor, materials, and an estimate of the cost for deep-well injection of the return flow/produced water. Operating costs, to a large extent, are a function of oil and gas production. Well yields (gas and oil) decline in their output by 65% (Swindell 2012) to 78% (*Production Decline of a Natural Gas Well over Time* 2012) in the first year, but the well continues to produce natural gas at a declining rate for many years. According to Dr. Steve Holditch (2013), a retired member of the Harold Vance Department of Petroleum Engineering at Texas A&M University, the estimated operating cost for a natural gas well is approximately $1.50 per Mcf. Alternatively, the operating costs per barrel of oil are set at approximately $30 (Energy Information Administration 2012b).

Shown in Tables 5-14 through 5-17 are the values of the range of operation costs as presented by Dr. Steve Holditch (2013) and the Energy Information Administration (2012b). For sensitivity purposes, an operating cost range of $0.75 to $1.50 per Mcf of gas is assumed along with an operating cost range of $20 to $30 per barrel of oil. Note that no inflation costs were incorporated into the operating costs.

Table 5-14. Annual Operating Costs for a Texas Eagle Ford Gas Well throughout its 20-Year Life, Assumption A

	Operating Cost ($ per MCF)		
Year	**0.75**	**1.00**	**1.50**
1	$ 432,321	$ 576,428	$ 864,642
2	164,762	219,683	329,525
3	93,242	124,323	186,485
4	65,108	86,810	130,215
5	57,680	76,907	115,361
6	46,913	62,551	93,827
7	38,939	51,918	77,877
8	32,319	43,092	64,638
9	26,825	35,766	53,649
10	22,265	29,686	44,529
11	18,479	24,639	36,959
12	15,338	20,451	30,677
13	12,731	16,974	25,461
14	10,566	14,088	21,132
15	8,770	11,693	17,540
16	7,279	9,705	14,558
17	6,042	8,056	12,084
18	5,015	6,686	10,029
19	4,162	5,549	8,324
20	3,455	4,606	6,909

Table 5-15. Annual Operating Costs for a Texas Eagle Ford Gas Well throughout its 20-Year Life, Assumption B

	Operating Cost ($ per MCF)		
Year	**0.75**	**1.00**	**1.50**
1	$ 390,690	$ 520,920	$ 781,380
2	121,178	161,571	242,357
3	90,292	120,389	180,584
4	72,406	96,541	144,812
5	63,053	84,070	126,105
6	57,102	76,136	114,204
7	50,821	67,761	101,642
8	45,230	60,307	90,461
9	40,255	53,673	80,510
10	35,827	47,769	71,654
11	31,886	42,515	63,773
12	28,379	37,838	56,757
13	25,257	33,676	50,514
14	22,479	29,972	44,958
15	20,006	26,675	40,013
16	17,805	23,740	35,610
17	15,847	21,129	31,694
18	14,104	18,805	28,208
19	12,552	16,736	25,104
20	11,171	14,895	22,343

Table 5-16. Annual Operating Costs for a Texas Eagle Ford Oil Well throughout its 20-Year Life, Assumption A

	Operating Cost ($ per Bbl)		
Year	**20**	**25**	**30**
1	$ 2,225,140	$ 2,781,425	$ 3,337,710
2	848,020	1,060,025	1,272,030
3	479,920	599,900	719,880
4	373,700	467,125	560,550
5	296,880	371,100	445,320
6	241,460	301,825	362,190
7	200,420	250,525	300,630
8	166,340	207,925	249,510
9	138,060	172,575	207,090
10	114,600	143,250	171,900
11	95,120	118,900	142,680
12	78,940	98,675	118,410
13	65,520	81,900	98,280
14	54,380	67,975	81,570
15	45,140	56,425	67,710
16	37,460	46,825	56,190
17	31,100	38,875	46,650
18	25,800	32,250	38,700
19	21,420	26,775	32,130
20	17,780	22,225	26,670

Table 5-17. Annual Operating Costs for a Texas Eagle Ford Oil Well throughout its 20-Year Life, Assumption B

	Operating Cost ($ per Bbl)		
Year	**20**	**25**	**30**
1	$ 2,010,860	$ 2,513,575	$ 3,016,290
2	623,700	779,625	935,550
3	464,720	580,900	697,080
4	372,660	465,825	558,990
5	324,520	405,650	486,780
6	293,900	367,375	440,850
7	261,580	326,975	392,370
8	232,800	291,000	349,200
9	207,200	259,000	310,800
10	184,400	230,500	276,600
11	164,120	205,150	246,180
12	146,060	182,575	219,090
13	130,000	162,500	195,000
14	115,700	144,625	173,550
15	102,980	128,725	154,470
16	91,640	114,550	137,460
17	81,560	101,950	122,340
18	72,600	90,750	108,900
19	64,600	80,750	96,900
20	57,500	71,875	86,250

The values in Tables 5-14 through 5-17 are next discounted back to the present time using the net-present-value equation. The results of this net-present-value analysis are shown in Table 5-18. Similar to the returns analyses, a discount rate range of 1.7% to 7% is shown in addition to the range of operating costs. Note that the table has two different assumptions based on two different decline rates.

Table 5-18. Estimated Net Present Value of Operating Costs for a Texas Eagle-Ford Gas (Oil) Well ($)

Discount Rate (%)	Gas (Assumption A) Operating Cost ($ per Mcf)			Gas (Assumption B) Operating Cost ($ per Mcf)		
	0.75	**1.00**	**1.50**	**0.75**	**1.00**	**1.50**
1.7	1,013,580	1,351,440	2,027,160	1,070,194	1,426,925	2,140,387
5	908,822	1,211,763	1,817,644	925,176	1,233,568	1,850,352
7	856,860	1,142,481	1,713,721	856,779	1,142,372	1,713,557
	Oil (Assumption A) Operating Cost ($ per Bbl)			**Oil (Assumption B) Operating Cost ($ per Bbl)**		
	20	**25**	**30**	**20**	**25**	**30**
1.7	5,216,855	6,521,069	7,825,282	5,508,243	6,885,303	8,262,364
5	4,677,671	5,847,088	7,016,506	4,761,842	5,952,303	7,142,764
7	4,410,225	5,512,782	6,615,338	4,409,805	5,512,256	6,614,707

Sources: Holditch (2013); *Production Decline of a Natural Gas Well over Time* (2013); Swindell (2012); U.S. Energy Information Administration (2013b); U.S. Energy Information Administration (2012); U.S. Energy Information Administration (2011).

Royalty payments: In addition to the above costs, there is generally an approximate 25% royalty payment to the mineral owner for the oil and gas obtained from the wells (Global Data, 2013). Royalties, similar to operational costs, are variable dependent on the amount of oil and gas production revenue. Presented in Table 5-19 are the estimated royalty payments for oil and gas from the typical well. Royalty payments are estimated by taking 25% of the total returns each year of operation. The annual royalty payments are discounted to a present value to facilitate the analysis. Note that the table has two assumptions based on two different rates of declining production. Furthermore, note that, since based on revenue, the values in the table reflect price per Mcf/Bbl instead of cost per Mcf/Bbl.

Table 5-19. Estimated Net Present Value of Royalty Payments for a Typical Texas Eagle-Ford Gas (Oil) Well ($)

Discount Rate (%)	Gas (Assumption A) Price per Mcf ($)			Gas (Assumption B) Price per Mcf ($)		
	2.50	**5.00**	**7.50**	**2.50**	**5.00**	**7.50**
1.7	842,595	1,685,190	2,527,785	885,183	1,770,365	2,655,548
5	757,352	1,514,704	2,272,055	770,980	1,541,960	2,312,940
7	714,050	1,428,101	2,142,151	713,982	1,427,964	2,312,940
	Oil (Assumption A) Price per Bbl ($)			**Oil (Assumption B) Price per Bbl ($)**		
	55	**75**	**95**	**55**	**75**	**95**
1.7	3,577,862	4,878,903	6,179,944	3,758,700	5,125,499	6,492,299
5	3,215,899	4,385,316	5,554,734	3,273,767	4,464,227	5,654,688
7	3,032,030	4,134,586	5,237,143	3,031,741	4,134,192	5,236,643

Source: Global Data (2013).

The royalty payment being set at 25% of the total revenue explains the difference based on assumed price of gas and oil. Shown in Table 5-20 is the present value of the total variable costs of a typical gas (oil) well in the Eagle Ford Shale. The values are obtained through summing the operating costs and royalty payments. Note that the columns are labeled with the price per Mcf/Bbl to give the reader an idea of the revenue levels that each variable cost is associated with.

Table 5-20. Estimated Net Present Value of Total Variable Costs for a Typical Texas Eagle-Ford Gas (Oil) Well ($)

Discount Rate (%)	Gas (Assumption A) Price per Mcf ($)			Gas (Assumption B) Price per Mcf ($)		
	2.50	5.00	7.50	2.50	5.00	7.50
1.7	1,856,175	3,036,630	4,554,945	1,955,376	3,197,290	4,795,935
5	1,666,174	2,726,466	4,089,700	1,696,156	2,775,528	4,163,291
7	1,570,911	2,570,581	3,855,872	1,570,761	2,570,336	2,855,929
	Oil (Assumption A) Price per Bbl ($)			Oil (Assumption B) Price per Bbl ($)		
	55	75	95	55	75	95
1.7	8,794,717	11,399,971	14,005,226	9,266,942	12,010,803	14,754,663
5	7,893,569	10,232,404	12,571,240	8,035,609	10,416,530	12,797,451
7	7,442,256	9,647,368	11,852,481	7,441,545	9,646,448	11,851,350
	Total Variable Cost per Well (Gas and Oil) $ per Well			Total Variable Cost per Well (Gas and Oil) $ per Well		
1.7	10,650,892	14,436,601	18,560,171	11,222,318	15,208,093	19,550,598
5	9,559,743	12,958,870	16,660,940	9,731,765	13,192,058	16,960,742
7	9,013,167	12,217,949	15,708,353	9,012,306	12,216,784	14,707,279

Sources: Cowan (2011); Global Data (2013); Holditch (2013); Nicot et al. (2012); *Production Decline of a Natural Gas Well over Time* (2013); Swindell (2012); U.S. Energy Information Administration (2013b); U.S. Energy Information Administration (2012); U.S. Energy Information Administration (2011).

Returns above variable costs: Shown in Table 5-21 are the returns above variable costs (RAVC). RAVC comes from taking the present value of the total returns and subtracting the present value of the total variable cost. This ignores costs of investment in leasing, drilling, and fracking. For oil and gas, the RAVC are impressive, ranging from a low of nearly $6 million up to over $17 million. This indicates that once a well is in place, it should be pumped. Production should occur as long as the variable costs can be covered provided the well can produce at a level enabling it to recover from a “bad” year.

Table 5-21. Estimated Net Present Value of Returns above Variable Costs for a Typical Gas (Oil) Well in the Eagle Ford Shale ($)

	Gas (Assumption A) Price per Mcf ($)			**Gas (Assumption B) Price per Mcf ($)**		
Discount Rate (%)	**2.50**	**5.00**	**7.50**	**2.50**	**5.00**	**7.50**
1.7	1,514,205	3,704,131	5,556,196	1,585,355	3,884,172	5,826,258
5	1,363,233	3,332,348	4,998,522	1,387,764	3,492,311	5,088,467
7	1,285,291	3,141,821	4,712,732	1,285,168	3,141,522	5,711,857
	Oil (Assumption A) Price per Bbl ($)			**Oil (Assumption B) Price per Bbl ($)**		
	55	**75**	**95**	**55**	**75**	**95**
1.7	5,516,732	8,115,640	10,714,549	5,767,856	8,491,195	11,214,534
5	4,970,025	7,308,860	9,647,696	5,059,458	7,440,379	9,821,300
7	4,685,865	6,890,977	9,096,090	4,685,417	6,890,320	9,095,222
	Total RAVC (Gas and Oil)			**Total RAVC (Gas and Oil)**		
	$ per Well			**$ per Well**		
1.7	7,030,937	11,819,771	16,270,745	7,353,211	12,375,367	17,040,792
5	6,333,258	10,641,208	14,646,218	6,447,222	10,932,690	14,909,767
7	5,971,156	10,032,798	13,808,822	5,970,585	10,031,842	14,807,079

Returns to water: Finally, to estimate the residual or returns to water it is necessary to subtract the fixed costs (leasing, drilling, and fracking) from the RAVC for an Eagle-Ford well. For this analysis, the fixed costs are subtracted from the total RAVC of oil and gas (shown in Table 5-13). Fixed costs represent a sunk cost that occurs regardless if oil or gas is being extracted. As mentioned, a single well could serve as a source for both oil and gas and, therefore, would not need to have more than one well drilled to obtain both. Shown in Table 5-22 is the total returns over costs or estimated returns to water, for an Eagle Ford well. The fixed costs per well are estimated at $6.61 million per well as presented earlier. The fixed costs are primarily encountered before drilling, hence can be considered as a present value when applying the capital budgeting techniques used in this chapter.

Table 5-22. Estimated Net Present Value of Returns over Costs for a Typical Eagle Ford Gas (Oil) Well ($)

	Total Gas and Oil (Assumption A) Price of Gas ($ per Mcf)			Total Gas and Oil (Assumption B) Price of Gas ($ per Mcf)		
	2.50	5.00	7.50	2.50	5.00	7.50
	Price of Oil ($ per Bbl)			Price of Oil ($ per Bbl)		
	55	75	95	55	75	95
Discount Rate (%)	$ per Well			$ per Well		
1.7	420,937	5,209,771	9,660,745	743,211	5,765,367	10,430,791
5	(276,742)	4,031,208	8,036,218	(162,779)	4,322,690	8,299,767
7	(638,845)	3,422,799	7,198,822	(639,415)	3,421,841	8,197,080

Hydraulic fracturing appears to be a very lucrative industry when prices are above $2.50 per Mcf for gas and $55 per Bbl for oil and/or discount rates are low. In Table 5-22, returns over costs, or returns to water used in fracturing, range from a loss of $0.64 million to a gain of $10.43 million per well.

Mentioned in the review of literature, a Chesapeake energy estimate suggests that it takes 5 million gallons (15.34 acre feet) of water to drill and fracture a typical well in the Eagle Ford Shale (Chesapeake Energy, 2013). Therefore, shown in Tables 5-23 through 5-25 are sensitivity analyses of the estimated values of water per acre foot assuming alternative amounts of water for drilling and fracturing. The values are estimated by taking the present value of net returns of natural gas, oil, and total production and dividing them by the volume of water used in fracturing measured in acre-feet. In Table 5-23, 4 million gallons (12.28 acre-feet) of water are used to determine the value of water. In Table 5-24, 5 million gallons (15.34 acre-feet) of water are used to determine the value of water. In Table 5-25, 6 million gallons (18.41 acre-feet) of water are used to determine the value of water.

Table 5-23. Estimated Returns to Water for Hydraulic Fracturing in the Eagle Ford Shale at Four Million Gallons (12.28 Acre-Feet) per Well

	Total Gas and Oil (Assumption A) Price of Gas ($ per Mcf)			**Total Gas and Oil (Assumption B) Price of Gas ($ per Mcf)**		
	2.50	**5.00**	**7.50**	**2.50**	**5.00**	**7.50**
	Price of Oil ($ per Bbl)			**Price of Oil ($ per Bbl)**		
	55	**75**	**95**	**55**	**75**	**95**
Discount Rate (%)	**$ per Well per Acre-Foot**			**$ per Well per Acre-Foot**		
1.7	34,278	424,248	786,706	60,522	469,492	849,413
5	(22,536)	328,274	654,415	(13,256)	352,011	675,877
7	(52,023)	278,730	586,223	(52,070)	278,652	667,515

As shown in Table 5-23, the total value of water per acre-foot ranges from a loss of $52 thousand per acre-foot to a gain of nearly $850 thousand per acre foot. These results depend on the wellhead price, the discount rate, and the production decline rate of a well (indicated by Assumptions "A" and "B"). With all else held constant, the lower the discount rate, the higher the value of water per acre-foot. The cause of this relationship is simply the fact that a higher discount rate causes the present value to be less. The idea is that, with a higher interest rate (opposite of a higher discount rate), a lower value today will increase at a faster rate with time. Generally speaking, the different decline-rate assumptions have little to no effect on the returns to water per acre-foot.

Table 5-24. Estimated Returns to Water for Hydraulic Fracturing in the Eagle Ford Shale at Five Million Gallons (15.34 Acre-Feet) per Well

	Total Gas and Oil (Assumption A) Price of Gas ($ per Mcf)			**Total Gas and Oil (Assumption B) Price of Gas ($ per Mcf)**		
	2.50	**5.00**	**7.50**	**2.50**	**5.00**	**7.50**
	Price of Oil ($ per Bbl)			**Price of Oil ($ per Bbl)**		
	55	**75**	**95**	**55**	**75**	**95**
Discount Rate (%)	**$ per Well per Acre-Foot**			**$ per Well per Acre-Foot**		
1.7	27,440	339,620	629,775	48,449	375,839	679,973
5	(18,041)	262,791	523,873	(10,611)	281,792	541,054
7	(41,646)	223,129	469,284	(41,683)	223,067	534,360

In Table 5-24, the range of water values goes from a loss of nearly $42 thousand to gain of $679 thousand per acre-foot. The results yield a smaller range than did Table 5-15 because of the requirement for more water to drill and fracture.

Table 5-25. Estimated Returns to Water for Hydraulic Fracturing in the Eagle Ford Shale at Six Million Gallons (18.41 Acre-Feet) per Well

	Total Gas and Oil (Assumption A) Price of Gas ($ per Mcf)			**Total Gas and Oil (Assumption B) Price of Gas ($ per Mcf)**		
	2.50	**5.00**	**7.50**	**2.50**	**5.00**	**7.50**
	Price of Oil ($ per Bbl)			**Price of Oil ($ per Bbl)**		
	55	**75**	**95**	**55**	**75**	**95**
Discount Rate (%)	**$ per Well per Acre-Foot**			**$ per Well per Acre-Foot**		
1.7	22,865	282,986	524,755	40,370	313,165	566,583
5	(15,032)	218,968	436,514	(8,842)	234,801	450,829
7	(34,701)	185,921	391,028	(34,732)	185,869	445,251

The results shown in Table 5-25 assume the greatest amount of water being required for drilling and fracturing. Here, the values of water range from a loss of nearly $35 thousand to a gain of nearly $570 thousand per acre-foot. Naturally, as the amount of water used increases the range of water value declines. Given gas and oil price and outlook, it can be concluded that water used for drilling and fracking is very valuable.

Chapter summary

Once the commitment is made and a well is drilled and successfully completed, oil and gas will be produced when the variable costs can be covered, from an economic theory perspective. This principle holds true for the scenarios in this study. Though the investment of drilling and fracking a well is substantial, these costs are considered to be a sunk cost and, therefore, not relevant in the decision to operate a well. This suggests that even at relatively low gas and oil prices, the variable costs can be covered, but only a part of the total fixed (investment) costs can be covered in one year. Shown in Appendix D is an example of the operating cost by year and discounted.

CHAPTER VI

HEALTH IMPLICATIONS

Natural gas and oil production in the Eagle Ford Shale has increased dramatically in the past few years and is expected to continue to do so into the future. Increases in drilling give rise to questioning of the potential health effects that drilling and hydraulic fracturing may have on humans, plants and animals. Therefore, this chapter addresses the potentially-hazardous substances that may be released through fracturing in the Eagle Ford Shale and the extent to which they may penetrate the surrounding community. Because drilling and fracking activities have been going on for only a few years in the Eagle Ford Shale region, much of the section will use other shale areas' experiences as examples.

Potential hazards

Methane (estimated to be 20 times more toxic than carbon dioxide), volatile organic compounds (VOC's) which contribute to smog formation, and hazardous air pollutants (HAP's) (some of which may include benzene and hexane) that can cause cancer and other serious health effects are some of the emissions potentially associated with fracking (U.S. Environmental Protection Agency 2011). The emissions that come from fracturing include those VOC's introduced during the process of fracking. Contaminants also come from gas leaking in pipelines, gas escaping from the well during the fracturing process, natural gas leaks in the wellheads, flowback water (covered more extensively in the review of literature), and from gas escaping from compressor stations (Colborn et al. 2012). Radon is another airborne element potentially linked to fracturing that can be very hazardous to humans. Radon exposure is associated with lung cancer and is a huge cause of death amongst non-smokers (U.S. Environmental Protection Agency 2013a).

Urban Issues

Operations, such as hydraulic fracturing sites, can be problematic in urban areas. Such a pressure would seem to be a big factor in much of the Barnett Shale region, but not so much in the Eagle Ford Shale region as most of the latter area is rural. Thus, there have not been many reported health effects in the Eagle Ford Shale region that could be linked to hazardous materials from fracking. Some Barnett Shale residents have reported headaches, respiratory problems, and itchy and water eyes amongst other allergy-like symptoms which can be caused by fracking activities (Texas Department of State Health Services 2010). One reported case involved the former mayor of Dish, Texas, moving his sons away from the Dish area because of frequent nosebleeds (Tillman 2011). After the family moved, the nosebleeds reportedly subsided rather quickly (Tillman 2011). Argyle residents have also been known to report school children complaining of nosebleeds, dizziness, and other illnesses that may be connected to drilling activities (Brown and Tabor 2010).

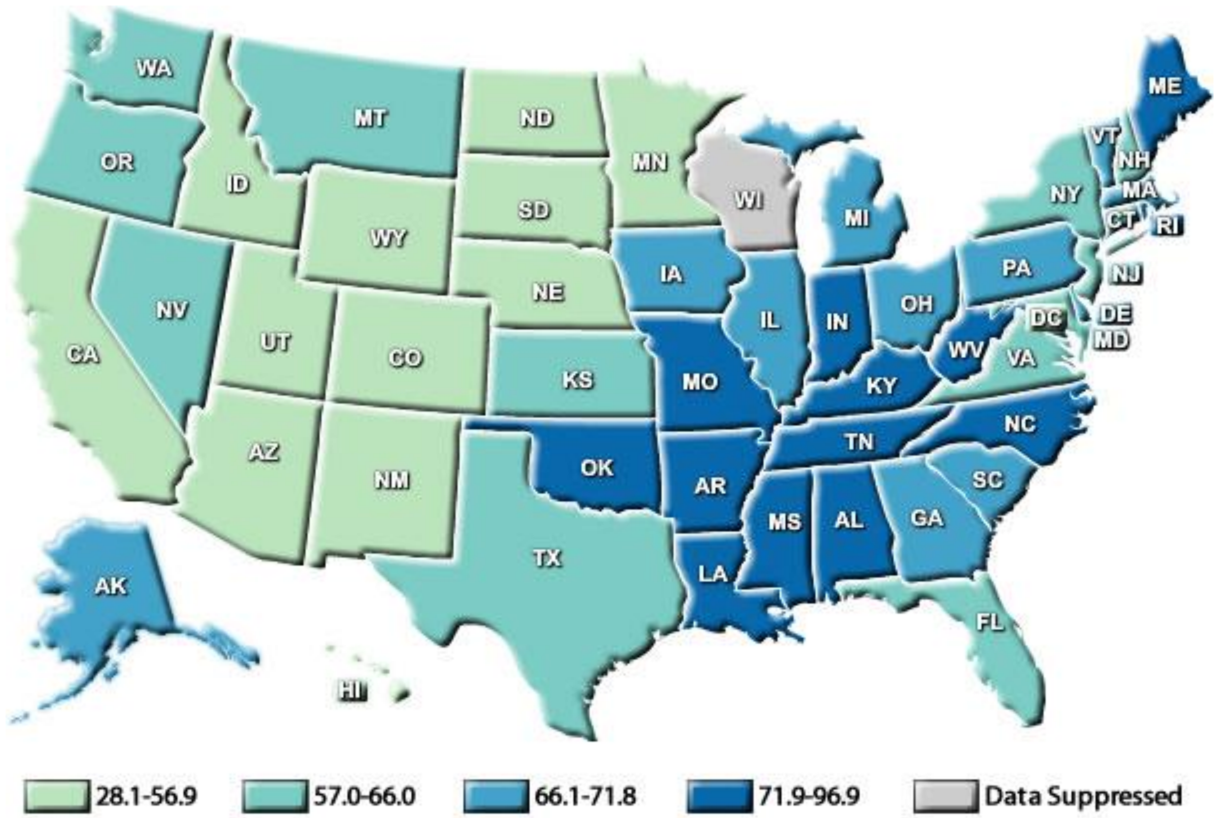
Oil spill potential

Situations occur, though infrequently, where an accident occurs on a hydraulic fracturing site that threatens the safety of the surrounding environment. Recently, a study conducted by the U.S. Geological Survey and the U.S. Fish and Wildlife Service found that a 2007 fracking spill in Kentucky may be the cause of a large fish kill (Gerken 2013). Based on lesions found on the gills of green sunfish and creek chub and consistent findings of aluminum and iron (metals often found in fracking mixtures) on these fish, conclusions have been drawn that the spill acidified the stream (Gerken 2013).

Evidence negating problems with fracking

There are numerous agents in hydraulic fracturing activities that could be harmful to human and animal health as well as the environment. It may seem reasonable to conclude that the lack of reported cases in the EFS region is simply due to the limited time that oil and gas production and related fracturing have been active. In the cases reported in the Barnett Shale, however, no proof of cause and effect has been determined (Rawlins and Paterson 2012). Furthermore, several of the agents mentioned do not come only from hydraulic fracturing, but there are other sources contributing to the difficulty in drawing cause and effect conclusions. For example, while radon is released from breaking apart rocks to release hydrocarbons, radon also is naturally released from uranium-bearing rocks as these rocks undergo radioactive decay over time (U.S. Environmental Protection Agency 2013b). Radon is at its worst when it seeps under the foundations of buildings and builds up indoors (U.S. Environmental Protection Agency 2013b). Therefore, even if hydraulic fracturing was completely stopped, there may still be a high risk of getting exposed to radon in areas of high uranium.

Methane can also just as easily be found naturally, especially in areas such as the Eagle Ford Shale where there is a large livestock industry. Most intriguingly, the claims that the VOCs produced by hydraulic fracturing are hazardous can be taken in an entirely different direction. VOCs can be caused by many sources, including vehicles and paints (U.S. Environmental Protection Agency 2013c). There have been claims of illnesses in the Barnett Shale area which could be thought of as a red flag in hydraulic fracturing activities; however, this is also a highlypopulated urban area with much vehicular activity, making it tough to pin the emission of VOCs on any one industry. Furthermore, displayed in Figure 6-1 is a lung and bronchus cancer incidence map. Looking back at Figure 1-1, it is clear that the highest areas of cancer do not tend to correlate with shale play regions. In fact, some areas which would appear to have high fracturing activity, such as Texas, actually have amongst the lowest levels of lung and bronchus cancer (Centers for Disease Control and Prevention 2013). This would indicate that there are several other factors leading to lung cancer besides the elements emitted through hydraulic fracturing.



Color on Map	Interval	States
	28.1 to 56.9	Arizona, California, Colorado, District of Columbia, Hawaii, Idaho, Minnesota, Nebraska, New Mexico, North Dakota, South Dakota, Utah, and Wyoming
	57.0 to 66.0	Connecticut, Florida, Kansas, Maryland, Montana, Nevada, New Hampshire, New Jersey, New York, Oregon, Texas, Virginia, and Washington
	66.1 to 71.8	Alaska, Delaware, Georgia, Illinois, Iowa, Massachusetts, Michigan, Ohio, Pennsylvania, South Carolina, and Vermont
	71.9 to 96.9	Alabama, Arkansas, Indiana, Kentucky, Louisiana, Maine, Mississippi, Missouri, North Carolina, Oklahoma, Rhode Island, Tennessee, and West Virginia
	Data Suppressed‡	Wisconsin

*Rates are per 100,000 and are age-adjusted to the 2000 U.S. standard population.
‡Data are suppressed at the state's request.

Source: Centers for Disease Control and Prevention (2013).

Figure 6-1. Lung and Bronchus Cancer Death Rates by State, 2009

Federal research also indicates that fracking is not responsible for contaminating drinking water. According to Begos (2013), geologists have concluded that chemical-laced fluids that are used during the fracking process remain thousands of feet below the drinking water sources.

Chapter summary

Based on these data and in recognition of the possible alternative sources of the hazardous emissions, there is reason to infer that hydraulic fracturing is not providing undue health risks to the surrounding communities in a general sense based on current information. However, there is a need for further study.

CHAPTER VII

SUMMARY AND CONCLUSIONS

As the 21st century unfolds, there still remains a large issue of what to do about the energy crisis. As it is, there would seem to not be any single answer to this conundrum. One possible response to the situation, however, lies in the viability of using hydraulic fracturing to obtain natural gas and oil from shales beneath the surface of the earth. While little is known about the industry, it continues to grow and become more of a factor in obtaining energy for public consumption.

Water value comparison

This paper addressed issues of water use and value as well as environmental implications of hydraulic fracturing. Water value in fracking compared to alternative uses was addressed. Municipal and industrial and agriculture use realize a much lower water value than hydraulic fracturing under expected prices for gas and oil. If simple averages are used, municipal and industrial use yields an average value of $1,200 per acre-foot and agriculture use yields an average of $110 per acre-foot. These values are both relative low values compared to an average value of nearly $300 thousand per acre-foot for hydraulic fracturing use. Based on these results, the null hypothesis is rejected and it is concluded that the value of water used for fracking is greater than alternative uses.

Recent reports suggest new technology has significantly reduced water required for fracking (Wythe 2013). Such developments are suggestive that the value of water in fracking is greater than estimated in this report. The reason for this conclusion is that technology is expected to make input usage decrease while increasing productivity. As a result, less water is used to frack yet more oil and gas is able to be extracted. Therefore, a similar residual analysis as the one in this report would reveal that the water is more valuable than it currently is estimated.

Environmental and health implications

After observing the comparative value of water in hydraulic fracturing, the issues of safety and health were addressed. While some health cases have been documented to potentially be linked to hydraulic fracturing, this study found that many cases could just as easily be linked to other causes that happen regardless of the act of fracking. Based on these findings, there is evidence to question the null hypothesis that fracking is linked to health issues. However, there remains a substantial amount of research that needs to be done on the subject. Furthermore, the review of material does not provide definitive evidence one way or the other.

The results of this report, although not coming up with conclusive evidence of a correlation between hydraulic fracturing and health concerns, does suggest from antidotal experiences that there is a need for further study. Similarly, the implications related to potential groundwater contamination emphasize the need to research health and environmental implications of hydraulic fracturing to a higher degree.

Implications of this report

A major implication of this research is to assist water owners in understanding the value of the water they possess and/or manage. Hydraulic fracturing is a relatively young industry and many people are not fully aware of the value of the energy (and imputed value of the water) associated with these activities. The lack of information translates into water resource owners and managers not having a basis for negotiating a price for water used in fracking. This is a form of market failure. These results and related interpretations suggest these water owners may not be fully aware of how valuable their water is to the fracking company, and thus may be susceptible to being undercompensated for the resource.

One large user of water (as discussed in this report) is agriculture. If farmers are alerted of the potential returns they could make through selling their water, then some of the agricultural industry could be affected. In this case, it is acceptable to assume that a reasonable person will seek what will benefit them and, if applicable, their families the most. As a result, farmers in the areas surrounding the Eagle Ford Shale (and other shale areas given that water value could be similar for every shale in the United States) will possibly look to sell their water to the fracking companies. In reality, if the values of this analysis are correct, then even at a marked-down oil and gas price, farmers will still make far more money selling their water than using it to grow their crops. If enough farmers start to engage in this activity, the results could slow the growth of the agricultural industry and any subsidiary productions, such as biofuels (if there is a large enough shift of farmers selling water instead of growing crops).

CHAPTER VIII

LIMITATIONS

There are several factors that could impact the production of well that were not considered in this report. One such factor is that there are opportunities for re-fracturing wells which impacts the life and production of wells (Cameron 2013). This report assumes that a typical well is only fractured once. Furthermore, through time, many factors are subject to change such as wellhead price of gas and wellhead price of oil. Constant values were assumed and sensitivity analyses were applied to consider alternative scenarios. There are also a variety of taxes that impact costs which are not included in this analysis since they vary by final destination of the gas and other factors. Inflation was also not considered in this report. While inflation affects both input and output, the results could be slightly distorted without inflation. Many sources of data with different assumptions also create problems with consistency. Even though great effort was made to achieve an unbiased and solid document, this report is still limited by the effects of using these inconsistent sources. There is an increased emphasis on use of brackish water for hydraulic fracturing, study of alternatives for fracturing, and treatment of flowback water and reuse. This report does not consider these functions in the analyses. Lastly, some of the calculations include "simple averages." Simple averages are adequate when dealing with circumstances that have normal distributions. However, it is likely that the wells in the Eagle Ford Shale come in many different sizes, depths, and productivity levels with some being more ubiquitous than others. Therefore, a simple average may not have been the best method to determine what the "average" well would be. The reason for using simple averages was that it would have been very difficult and time consuming to determine all of the parameters for every well in the Eagle Ford area.

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APPENDIX A

Table A-1. 50-Year Water Availability and Use Projections for Mining in Acre-Feet by County

Mining (Demand)							
	Dimmit	Frio	La Salle	Maverick	Webb	Zavala	Total
2010	1,003	109	-	156	1,204	122	2,594
2020	1,034	104	-	162	1,192	125	2,617
2030	1,051	102	-	166	1,189	127	2,635
2040	1,067	100	-	169	1,187	128	2,651
2050	1,082	98	-	172	1,185	129	2,666
2060	1,095	96	-	175	1,180	130	2,676

Table A-2. 50-Year Water Availability and Use Projections for M&I in Acre-Feet by County

Municipal and Industrial (M&I) (Demand)							
	Dimmit	Frio	La Salle	Maverick	Webb	Zavala	Total
2010	2,561	3,402	1,799	9,473	54,883	4,154	76,272
2020	2,692	3,668	1,946	10,628	69,432	4,406	92,772
2030	2,756	3,890	2,058	11,739	86,035	4,631	111,109
2040	2,725	4,061	2,162	12,726	104,540	4,778	130,992
2050	2,652	4,202	2,262	13,681	124,653	4,914	152,364
2060	2,523	4,287	2,350	14,561	146,462	5,056	175,239

Table A-3. 50-Year Water Availability and Use Projections for Agriculture in Acre-Feet by County

Agricultural (Demand)							
	Dimmit	Frio	La Salle	Maverick	Webb	Zavala	Total
2010	11,163	83,226	6,478	95,300	22,020	72,556	290,743
2020	10,885	80,307	6,330	91,953	21,061	69,719	280,255
2030	10,777	77,511	6,187	88,123	20,167	66,994	269,759
2040	10,365	74,836	6,048	88,123	20,167	64,377	263,916
2050	9,943	72,274	5,914	88,123	20,167	61,863	258,284
2060	9,539	69,801	5,784	88,123	20,167	59,448	252,862

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Table A-4. 50-Year Water Availability and Use Projections for Groundwater in Acre-Feet by County

Groundwater (Supply)							
	Dimmit	Frio	La Salle	Maverick	Webb	Zavala	Total
2010	23,780	140,024	28,771	12,066	35,176	23,936	263,753
2020	23,780	140,024	28,771	12,066	35,176	23,936	263,753
2030	23,780	140,024	28,771	12,066	35,176	23,936	263,753
2040	23,780	140,024	28,771	12,066	35,176	23,936	263,753
2050	23,780	140,024	28,771	12,066	35,176	23,936	263,753
2060	23,780	140,024	28,771	12,066	35,176	23,936	263,753

Table A-5. 50-Year Water Availability and Use Projections for Surface Water in Acre-Feet by County

Surface Water (Supply)							
	Dimmit	Frio	La Salle	Maverick	Webb	Zavala	Total
2010	2,539	605	1,549	243	151	380	5,467
2020	2,539	605	1,549	243	151	379	5,466
2030	2,539	605	1,549	243	151	379	5,466
2040	2,539	605	1,549	243	151	379	5,466
2050	2,539	605	1,549	243	151	379	5,466
2060	2,539	605	1,549	243	151	379	5,466

Source: Texas Water Development Board, Texas State Water Plan (2012).

APPENDIX B

Table B-1. Water Costs for Residential and Commercial Consumers

Residential and Commercial Water Costs

Details
2012

City List	City Population	Residential Water: Fee For: $ per 5,000 Gal.	Residential Water: Fee For: $ per 10,000 Gal.	Total Customers	Average Usage	Commercial Water: Fee For: $ per 50,000 Gal.	Commercial Water: Fee For: $ per 200,000 Gal.
Maverick							
Eagle Pass	27,183	14.52	26.49	15,150	9,000	157.78	560.28
Zavala							
Crystal City	7,362	17.62	29.17	2,372	7,000	114.64	461.14
Frio							
Dilley	3,894	30.50	48.10	1,240	4,500	184.10	694.10
Dimmit							
Carrizo Springs	5,681	25.88	37.31	2,080	10,000	167.08	719.15
Asherton	1,608	32.50	45.75	524	6,376	208.75	721.50
Big Wells	756	33.50	50.50	285	4,633	210.50	810.50
Webb							
Laredo	236,091	13.11	21.66	64,100	7,977	155.61	580.11

Source: Texas Municipal League (2013).
Note: The values listed below the number of gallons are based on the total value of that amount of gallons. For example, the total value of 5,000 gallons of water at Eagle Pass is $14.52. This is $2.90 per thousand gallons of water.

APPENDIX C

Appendix C-1. Dryland Compared to Irrigated Production

Projections for Planning Purposes Only
Not to be Used without Updating after February 1, 2012

Table 3.A Estimated costs and returns per acre
Cotton; Conventional Tillage, Furrow Irr.
Projected for 2012, Rio Grande Valley, For Planning Purposes

ITEM	UNIT	PRICE	QUANTITY	AMOUNT	YOUR FARM
		dollars		dollars	
INCOME					
Cotton Lint	lb	0.81	825.0000	668.25	________
Cotton Seed	ton	215.00	0.7360	158.24	________
TOTAL INCOME				826.49	________
DIRECT EXPENSES					
CUSTOM SPRAY					
App by Air (3 gal)	appl	5.75	3.0000	17.25	________
HARVEST AID					
Dropp 50 WP	lb	55.45	0.2000	11.09	________
PROCESSING					
Gin	lb	0.12	825.0000	99.00	________
FERTILIZER					
UAN (32% N)	cwt	46.00	2.5000	115.00	________
HERBICIDE					
Treflan EC	pt	4.02	2.0000	8.04	________
Surfactant	pt	1.25	1.0000	1.25	________
2,4-D Amine	pt	1.74	1.0000	1.74	________
INSECTICIDE/MITICIDE					
Vydate C-LV	oz	1.39	8.5000	11.81	________
Guthion 2L	pt	4.73	3.0000	14.19	________
Tracer	oz	7.64	2.0000	15.28	________
IRRIGATION SUPPLIES					
Irrigation Water	ac-ft	20.00	0.8000	16.00	________
SEED/PLANTS					
Cotton Seed	lb	1.95	15.0000	29.25	________
GROWTH REGULATOR					
Pix	oz	0.11	12.0000	1.32	________
SERVICE FEE					
Insect Scouting	acre	7.00	1.0000	7.00	________
CUSTOM HARVEST/HAUL					
Haul Cotton	lb	0.14	825.0000	115.50	________
OPERATOR LABOR					
Tractors	hour	7.50	1.1240	8.43	________
Self-Propelled Eq.	hour	7.50	0.4830	3.62	________
HAND LABOR					
Implements	hour	7.50	0.3310	2.48	________
IRRIGATION LABOR					
Labor (Flood)	hour	7.50	1.0000	7.50	________
Labor (Irr. Setup)	hour	7.50	0.1000	0.75	________
UNALLOCATED LABOR	hour	7.50	1.2856	9.64	________
DIESEL FUEL					
Tractors	gal	3.10	8.5300	26.44	________
Self-Propelled Eq.	gal	3.10	1.9260	5.97	________
REPAIR & MAINTENANCE					
Implements	acre	8.26	1.0000	8.26	________
Tractors	acre	6.94	1.0000	6.94	________
Self-Propelled Eq.	acre	16.05	1.0000	16.05	________
INTEREST ON OP. CAP.	acre	16.33	1.0000	16.33	________
TOTAL DIRECT EXPENSES				576.16	________
RETURNS ABOVE DIRECT EXPENSES				250.32	________
FIXED EXPENSES					
Implements	acre	21.14	1.0000	21.14	________
Tractors	acre	20.38	1.0000	20.38	________
Self-Propelled Eq.	acre	31.05	1.0000	31.05	________
TOTAL FIXED EXPENSES				72.58	________
TOTAL SPECIFIED EXPENSES				648.75	________
RETURNS ABOVE TOTAL SPECIFIED EXPENSES				177.73	________
ALLOCATED COST ITEMS					
Share Rent% of Gross	%	826.49	25.0000	206.62	________
RESIDUAL RETURNS				-28.88	________

Brand names are mentioned only as examples and imply no endorsement.

Information presented is prepared solely as a general guide & not intended to recognize or predict the costs & returns from any one operation.
Developed by Texas AgriLife Extension Service

Source: Texas A&M AgriLife Extension Service (2012).

Exhibit C-1. Estimated Costs and Returns per Acre for Irrigated Cotton, District 12

Table 3.B Estimated resource use and costs for field operations, per acre
Cotton; Conventional Tillage, Furrow Irr.
Projected for 2012, Rio Grande Valley, For Planning Purposes Only

OPERATION/ OPERATING INPUT	SIZE/ UNIT	TRACTOR SIZE	PERF RATE	TIMES OVER	MTH	TRACTOR COST DIRECT	TRACTOR COST FIXED	EQUIP COST DIRECT	EQUIP COST FIXED	ALLOC LABOR HOURS	ALLOC LABOR COST	OPERATING INPUT AMOUNT	OPERATING INPUT PRICE	OPERATING INPUT COST	TOTAL COST
						------------dollars-----------					dollars		-------dollars--------		
Heavy Disk	14'	150 hp	0.167	1.00	Sep	4.88	2.65	0.98	1.91	0.167	1.25				11.69
Heavy Disk	14'	150 hp	0.167	1.00	Oct	4.88	2.65	0.98	1.91	0.167	1.25				11.69
Lister Bedder	8R-40	190 hp	0.070	1.00	Nov	2.56	1.31	0.20	0.61	0.070	0.52				5.23
Fert Appl (Liquid)	8R-40	130 hp	0.074	1.00	Jan	2.16	1.77	0.92	2.67	0.111	0.83				8.37
UAN (32% N)	cwt											2.5000	46.00	115.00	115.00
Lilliston Cultivator	8R-40	130 hp	0.095	1.00	Jan	2.77	2.28	0.63	1.43	0.095	0.71				7.83
Treflan EC	pt											2.0000	4.02	8.04	8.04
Plant & Pre	8R-40	150 hp	0.074	1.00	Feb	2.16	1.17	1.59	3.81	0.148	1.11				9.86
Cotton Seed	lb											15.0000	1.95	29.25	29.25
Insect Scouting	acre			1.00	Mar							1.0000	7.00	7.00	7.00
Lilliston Cultivator	8R-40	130 hp	0.095	1.00	Mar	2.77	2.28	0.63	1.43	0.095	0.71				7.83
Hi-Clear Sprayer	60'		0.033	1.00	Apr			0.74	0.97	0.033	0.24				1.96
Vydate C-LV	oz											8.5000	1.39	11.81	11.81
Hi-Clear Sprayer	60'		0.033	1.00	May			0.74	0.97	0.033	0.24				1.96
Guthion 2L	pt											1.0000	4.73	4.73	4.73
Pix	oz											12.0000	0.11	1.32	1.32
Hi-Clear Sprayer	60'		0.033	1.00	May			0.74	0.97	0.033	0.24				1.96
Guthion 2L	pt											1.0000	4.73	4.73	4.73
Ditcher	standard	130 hp	0.020	1.00	Jun	0.56	0.48	0.06	0.18	0.020	0.15				1.46
Labor (Irr. Setup)	hour									0.100	0.75	0.1000			0.75
Labor (Flood)	hour			1.00	Jun					1.000	7.50	1.0000			7.50
Irrigation Water	ac-ft											0.8000	20.00	16.00	16.00
App by Air (3 gal)	appl			1.00	Jun							1.0000	5.75	5.75	5.75
Guthion 2L	pt											1.0000	4.73	4.73	4.73
App by Air (3 gal)	appl			1.00	Jun							1.0000	5.75	5.75	5.75
Tracer	oz											2.0000	7.64	15.28	15.28
App by Air (3 gal)	appl			1.00	Jul							1.0000	5.75	5.75	5.75
Dropp 50 WP	lb											0.2000	55.45	11.09	11.09
Surfactant	pt											1.0000	1.25	1.25	1.25
Cotton Picker-1st-Tr	4-Row		0.192	1.00	Aug			19.80	28.13	0.384	2.88				50.82
Module Builder	32'	150 hp	0.220	1.00	Aug	6.43	3.49	1.98	6.19	0.440	3.30				21.41
Haul Cotton	lb			1.00	Aug							825.0000	0.14	115.50	115.50
Stalk Shredder	12'	150 hp	0.142	1.00	Aug	4.15	2.25	0.24	0.95	0.142	1.06				8.67
2,4-D Amine	pt											1.0000	1.74	1.74	1.74
Gin	lb			1.00	Aug							825.0000	0.12	99.00	99.00
TOTALS						33.38	20.38	30.29	52.19	3.038	22.78			463.72	622.77
INTEREST ON OPERATING CAPITAL															16.33
UNALLOCATED LABOR															9.64
TOTAL SPECIFIED COST															648.75

Brand names are mentioned only as examples and imply no endorsement.

Source: Texas A&M AgriLife Extension Service (2012).

Exhibit C-2. Estimated Resource Use and Cost per Acre of Field Operations for Irrigated Cotton, District 12

Projections for Planning Purposes Only
Not to be Used without Updating after February 1, 2012

Table 5.A Estimated costs and returns per acre
Cotton; Conventional Tillage, Dryland
Projected for 2012, Rio Grande Valley, For Planning Purposes

ITEM	UNIT	PRICE	QUANTITY	AMOUNT	YOUR FARM
		dollars		dollars	
INCOME					
Cotton Lint	lb	0.81	500.0000	405.00	
Cotton Seed	ton	215.00	0.4100	88.15	
TOTAL INCOME				493.15	
DIRECT EXPENSES					
CUSTOM SPRAY					
App by Air (3 gal)	appl	5.75	2.0000	11.50	
HARVEST AID					
Dropp 50 WP	lb	55.45	0.2000	11.09	
PROCESSING					
Gin	lb	0.12	500.0000	60.00	
FERTILIZER					
UAN (32% N)	cwt	46.00	1.5000	69.00	
HERBICIDE					
Treflan EC	pt	4.02	2.0000	8.04	
Surfactant	pt	1.25	1.0000	1.25	
INSECTICIDE/MITICIDE					
Vydate C-LV	oz	1.39	8.5000	11.81	
Guthion 2L	pt	4.73	2.0000	9.46	
SEED/PLANTS					
Cotton Seed	lb	1.95	10.0000	19.50	
SERVICE FEE					
Insect Scouting	acre	7.00	1.0000	7.00	
CUSTOM HARVEST/HAUL					
Haul Cotton	lb	0.14	500.0000	70.00	
OPERATOR LABOR					
Tractors	hour	7.50	1.1040	8.28	
Self-Propelled Eq.	hour	7.50	0.4500	3.37	
HAND LABOR					
Implements	hour	7.50	0.3310	2.48	
UNALLOCATED LABOR	hour	7.50	1.2432	9.32	
DIESEL FUEL					
Tractors	gal	3.10	8.3961	26.02	
Self-Propelled Eq.	gal	3.10	1.8600	5.76	
REPAIR & MAINTENANCE					
Implements	acre	8.19	1.0000	8.19	
Tractors	acre	6.77	1.0000	6.77	
Self-Propelled Eq.	acre	15.52	1.0000	15.52	
INTEREST ON OP. CAP.	acre	11.11	1.0000	11.11	
TOTAL DIRECT EXPENSES				375.51	
RETURNS ABOVE DIRECT EXPENSES				117.63	
FIXED EXPENSES					
Implements	acre	20.96	1.0000	20.96	
Tractors	acre	19.90	1.0000	19.90	
Self-Propelled Eq.	acre	30.07	1.0000	30.07	
TOTAL FIXED EXPENSES				70.94	
TOTAL SPECIFIED EXPENSES				446.46	
RETURNS ABOVE TOTAL SPECIFIED EXPENSES				46.68	
ALLOCATED COST ITEMS					
Share Rent% of Gross	%	493.15	25.0000	123.28	
RESIDUAL RETURNS				-76.60	

Brand names are mentioned only as examples and imply no endorsement.

Source: Texas A&M AgriLife Extension Service (2012).

Exhibit C-3. Estimated Costs and Returns per Acre for Dryland Cotton, District 12

Table 5.B Estimated resource use and costs for field operations, per acre
Cotton; Conventional Tillage, Dryland
Projected for 2012, Rio Grande Valley, For Planning Purposes Only

OPERATION/ OPERATING INPUT	SIZE/ UNIT	TRACTOR SIZE	PERF RATE	TIMES OVER	MTH	TRACTOR COST DIRECT	TRACTOR COST FIXED	EQUIP COST DIRECT	EQUIP COST FIXED	ALLOC LABOR HOURS	ALLOC LABOR COST	OPERATING INPUT AMOUNT	OPERATING INPUT PRICE	OPERATING INPUT COST	TOTAL COST
						------------dollars------------					dollars		-------dollars--------		
Heavy Disk	14'	150 hp	0.167	1.00	Sep	4.88	2.65	0.98	1.91	0.167	1.25				11.69
Heavy Disk	14'	150 hp	0.167	1.00	Oct	4.88	2.65	0.98	1.91	0.167	1.25				11.69
Lister Bedder	8R-40	190 hp	0.070	1.00	Nov	2.56	1.31	0.20	0.61	0.070	0.52				5.23
Fert Appl (Liquid)	8R-40	130 hp	0.074	1.00	Jan	2.16	1.77	0.92	2.67	0.111	0.83				8.37
UAN (32% N)	cwt											1.5000	46.00	69.00	69.00
Lilliston Cultivator	8R-40	130 hp	0.095	1.00	Jan	2.77	2.28	0.63	1.43	0.095	0.71				7.83
Treflan EC	pt											2.0000	4.02	8.04	8.04
Plant & Pre	8R-40	150 hp	0.074	1.00	Feb	2.16	1.17	1.59	3.81	0.148	1.11				9.86
Cotton Seed	lb											10.0000	1.95	19.50	19.50
Insect Scouting	acre			1.00	Mar							1.0000	7.00	7.00	7.00
Lilliston Cultivator	8R-40	130 hp	0.095	1.00	Mar	2.77	2.28	0.63	1.43	0.095	0.71				7.83
Hi-Clear Sprayer	60'		0.033	1.00	Apr			0.74	0.97	0.033	0.24				1.96
Vydate C-LV	oz											8.5000	1.39	11.81	11.81
Hi-Clear Sprayer	60'		0.033	1.00	Jun			0.74	0.97	0.033	0.24				1.96
Guthion 2L	pt											1.0000	4.73	4.73	4.73
App by Air (3 gal)	appl			1.00	Jun							1.0000	5.75	5.75	5.75
Guthion 2L	pt											1.0000	4.73	4.73	4.73
App by Air (3 gal)	appl			1.00	Jul							1.0000	5.75	5.75	5.75
Dropp 50 WP	lb											0.2000	55.45	11.09	11.09
Surfactant	pt											1.0000	1.25	1.25	1.25
Cotton Picker-1st-Tr	4-Row		0.192	1.00	Aug			19.80	28.13	0.384	2.88				50.82
Module Builder	32'	150 hp	0.220	1.00	Aug	6.43	3.49	1.98	6.19	0.440	3.30				21.41
Haul Cotton	lb			1.00	Aug							500.0000	0.14	70.00	70.00
Stalk Shredder	12'	150 hp	0.142	1.00	Aug	4.15	2.25	0.24	0.95	0.142	1.06				8.67
Gin	lb			1.00	Aug							500.0000	0.12	60.00	60.00
TOTALS						32.80	19.90	29.48	51.04	1.885	14.13			278.65	426.03
INTEREST ON OPERATING CAPITAL															11.11
UNALLOCATED LABOR															9.32
TOTAL SPECIFIED COST															446.46

Brand names are mentioned only as examples and imply no endorsement.

Source: Texas A&M AgriLife Extension Service (2012).

Exhibit C-4. Estimated Resource Use and Cost per Acre of Field Operations for Dryland Cotton, District 12

Projections for Planning Purposes Only
Not to be Used without Updating after February 1, 2012

Table 6.A Estimated costs and returns per acre
Grain Sorghum; Conventional Tillage, Furrow Irr.
Projected for 2012, Rio Grande Valley, For Planning Purposes

ITEM	UNIT	PRICE	QUANTITY	AMOUNT	YOUR FARM
		dollars		dollars	
INCOME					
Grain Sorghum	cwt	8.50	43.0000	365.50	________

TOTAL INCOME				365.50	________
DIRECT EXPENSES					
FERTILIZER					
Fert 25-10-0	tons	375.00	0.2000	75.00	________
HERBICIDE					
AAtrex 4L	pt	2.60	2.0000	5.20	________
IRRIGATION SUPPLIES					
Irrigation Water	ac-ft	20.00	0.4000	8.00	________
SEED/PLANTS					
Grain Sorghum Seed	lb	3.10	6.0000	18.60	________
CUSTOM HARVEST/HAUL					
Harvest/Haul Sorghum	cwt	0.61	43.0000	26.23	________
OPERATOR LABOR					
Tractors	hour	7.50	0.9040	6.78	________
HAND LABOR					
Implements	hour	7.50	0.1110	0.83	________
IRRIGATION LABOR					
Labor (Flood)	hour	7.50	1.0000	7.50	________
Labor (Irr. Setup)	hour	7.50	0.1000	0.75	________
UNALLOCATED LABOR	hour	7.50	0.7232	5.42	________
DIESEL FUEL					
Tractors	gal	3.10	6.8313	21.17	________
REPAIR & MAINTENANCE					
Implements	acre	6.27	1.0000	6.27	________
Tractors	acre	5.77	1.0000	5.77	________
INTEREST ON OP. CAP.	acre	8.35	1.0000	8.35	________

TOTAL DIRECT EXPENSES				195.91	________
RETURNS ABOVE DIRECT EXPENSES				169.58	________
FIXED EXPENSES					
Implements	acre	14.95	1.0000	14.95	________
Tractors	acre	16.88	1.0000	16.88	________

TOTAL FIXED EXPENSES				31.83	________

TOTAL SPECIFIED EXPENSES				227.74	________
RETURNS ABOVE TOTAL SPECIFIED EXPENSES				137.75	________
ALLOCATED COST ITEMS					
Share Rent %of Gross	%	365.50	33.0000	120.61	________
RESIDUAL RETURNS				17.13	________

Brand names are mentioned only as examples and imply no endorsement.

Source: Texas A&M AgriLife Extension Service (2012).

Exhibit C-5. Estimated Costs and Returns per Acre for Irrigated Sorghum, District 12

Table 6.B Estimated resource use and costs for field operations, per acre
Grain Sorghum; Conventional Tillage, Furrow Irr.
Projected for 2012, Rio Grande Valley, For Planning Purposes Only

OPERATION/ OPERATING INPUT	SIZE/ UNIT	TRACTOR SIZE	PERF RATE	TIMES OVER	MTH	TRACTOR COST DIRECT	TRACTOR COST FIXED	EQUIP COST DIRECT	EQUIP COST FIXED	ALLOC LABOR HOURS	ALLOC LABOR COST	OPERATING INPUT AMOUNT	OPERATING INPUT PRICE	OPERATING INPUT COST	TOTAL COST
						------------dollars-----------					dollars		-------dollars--------		
Heavy Disk	14'	150 hp	0.167	1.00	Sep	4.88	2.65	0.98	1.91	0.167	1.25				11.69
Heavy Disk	14'	150 hp	0.167	1.00	Oct	4.88	2.65	0.98	1.91	0.167	1.25				11.69
Lister Bedder	8R-40	190 hp	0.070	1.00	Nov	2.56	1.31	0.20	0.61	0.070	0.52				5.23
Fert Appl (Liquid)	8R-40	130 hp	0.074	1.00	Jan	2.16	1.77	0.92	2.67	0.111	0.83				8.37
Fert 25-10-0	tons											0.2000	375.00	75.00	75.00
Lilliston Cultivator	8R-40	130 hp	0.095	1.00	Jan	2.77	2.28	0.63	1.43	0.095	0.71				7.83
Plant & Pre	8R-40	150 hp	0.074	1.00	Jan	2.16	1.17	1.59	3.81	0.148	1.11				9.86
Grain Sorghum Seed	lb											6.0000	3.10	18.60	18.60
AAtrex 4L	pt											2.0000	2.60	5.20	5.20
Lilliston Cultivator	8R-40	130 hp	0.095	1.00	Mar	2.77	2.28	0.63	1.43	0.095	0.71				7.83
Ditcher	standard	130 hp	0.020	1.00	Apr	0.58	0.48	0.06	0.18	0.020	0.15				1.46
Labor (Irr. Setup)	hour									0.100	0.75	0.1000			0.75
Labor (Flood)	hour			1.00	Apr					1.000	7.50	1.0000			7.50
Irrigation Water	ac-ft											0.4000	20.00	8.00	8.00
Harvest/Haul Sorghum	cwt			1.00	Jul							43.0000	0.61	26.23	26.23
Stalk Shredder	12'	150 hp	0.142	1.00	Aug	4.15	2.25	0.24	0.95	0.142	1.06				8.67
TOTALS						26.95	16.88	6.27	14.95	2.115	15.86			133.03	213.96
INTEREST ON OPERATING CAPITAL															8.35
UNALLOCATED LABOR															5.42
TOTAL SPECIFIED COST															227.74

Brand names are mentioned only as examples and imply no endorsement.

Source: Texas A&M AgriLife Extension Service (2012).

Exhibit C-6. Estimated Resource Use and Costs per Acre of Field Operations for Irrigated Sorghum, District 12

Table 8.A Estimated costs and returns per acre
Grain Sorghum; Conventional Tillage, Dryland
Projected for 2012, South Texas, For Planning Purposes Only

ITEM	UNIT	PRICE	QUANTITY	AMOUNT	YOUR FARM
		dollars		dollars	
INCOME					
Grain Sorghum	cwt	8.50	22.0000	187.00	________
TOTAL INCOME				187.00	________
DIRECT EXPENSES					
FERTILIZER					
Fert 25-10-0	tons	375.00	0.1200	45.00	________
HERBICIDE					
Permit & applicat	acre	18.50	1.0000	18.50	________
SEED/PLANTS					
Grain Sorghum Seed	lb	3.10	4.5000	13.95	________
CUSTOM HARVEST/HAUL					
Harvest/Haul Sorghum	cwt	0.61	22.0000	13.42	________
OPERATOR LABOR					
Tractors	hour	7.50	0.8840	6.63	________
HAND LABOR					
Implements	hour	7.50	0.1110	0.83	________
UNALLOCATED LABOR	hour	7.50	0.7072	5.30	________
DIESEL FUEL					
Tractors	gal	3.10	6.6975	20.76	________
REPAIR & MAINTENANCE					
Implements	acre	6.20	1.0000	6.20	________
Tractors	acre	5.60	1.0000	5.60	________
INTEREST ON OP. CAP.	acre	6.62	1.0000	6.62	________
TOTAL DIRECT EXPENSES				142.84	________
RETURNS ABOVE DIRECT EXPENSES				44.15	________
FIXED EXPENSES					
Implements	acre	14.76	1.0000	14.76	________
Tractors	acre	16.40	1.0000	16.40	________
TOTAL FIXED EXPENSES				31.17	________
TOTAL SPECIFIED EXPENSES				174.01	________
RETURNS ABOVE TOTAL SPECIFIED EXPENSES				12.98	________
ALLOCATED COST ITEMS					
Share Rent %of Gross	%	187.00	33.0000	61.71	________
RESIDUAL RETURNS				-48.72	________

Brand names are mentioned only as examples and imply no endorsement.

Information presented is prepared solely as a general guide & not intended to recognize or predict the costs & returns from any one operation.
Developed by Texas AgriLife Extension Service.

Source: Texas A&M AgriLife Extension Service (2012).

Exhibit C-7. Estimated Costs and Returns per Acre for Dryland Sorghum, District 12

Table 8.B Estimated resource use and costs for field operations, per acre
Grain Sorghum; Conventional Tillage, Dryland
Projected for 2012, South Texas, For Planning Purposes Only

OPERATION/ OPERATING INPUT	SIZE/ UNIT	TRACTOR SIZE	PERF RATE	TIMES OVER	MTH	TRACTOR COST DIRECT	TRACTOR COST FIXED	EQUIP COST DIRECT	EQUIP COST FIXED	ALLOC LABOR HOURS	ALLOC LABOR COST	OPERATING INPUT AMOUNT	OPERATING INPUT PRICE	OPERATING INPUT COST	TOTAL COST
						------------dollars----------					dollars		-------dollars--------		
Heavy Disk	14'	150 hp	0.167	1.00	Sep	4.88	2.65	0.98	1.91	0.167	1.25				11.69
Heavy Disk	14'	150 hp	0.167	1.00	Oct	4.88	2.65	0.98	1.91	0.167	1.25				11.69
Lister Bedder	8R-40	190 hp	0.070	1.00	Nov	2.56	1.31	0.20	0.61	0.070	0.52				5.23
Fert Appl (Liquid)	8R-40	130 hp	0.074	1.00	Jan	2.16	1.77	0.92	2.67	0.111	0.83				8.37
Fert 25-10-0	tons											0.1200	375.00	45.00	45.00
Lilliston Cultivator	8R-40	130 hp	0.095	1.00	Jan	2.77	2.28	0.63	1.43	0.095	0.71				7.83
Plant & Pre	8R-40	150 hp	0.074	1.00	Jan	2.16	1.17	1.59	3.81	0.148	1.11				9.86
Grain Sorghum Seed	lb											4.5000	3.10	13.95	13.95
Permit & applicat	acre											1.0000	18.50	18.50	18.50
Lilliston Cultivator	8R-40	130 hp	0.095	1.00	Mar	2.77	2.28	0.63	1.43	0.095	0.71				7.83
Harvest/Haul Sorghum	cwt			1.00	Jul							22.0000	0.61	13.42	13.42
Stalk Shredder	12'	150 hp	0.142	1.00	Aug	4.15	2.25	0.24	0.95	0.142	1.06				8.67
TOTALS						26.37	16.40	6.20	14.76	0.995	7.46			90.87	162.08
INTEREST ON OPERATING CAPITAL															6.62
UNALLOCATED LABOR															5.30
TOTAL SPECIFIED COST															174.01

Brand names are mentioned only as examples and imply no endorsement.

Source: Texas A&M AgriLife Extension Service (2012).

Exhibit C-8. Estimated Resource Use and Costs per Acre of Field Operations for Dryland Sorghum, District 12

Projections for Planning Purposes Only
Not to be Used without Updating after March 15, 2012

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Table 2.A Estimated costs and returns per acre
Bermuda Pasture, Irrigated
2012 Projected Costs and Returns per Acre

ITEM	UNIT	PRICE	QUANTITY	AMOUNT	YOUR FARM
		dollars		dollars	
INCOME					
pasture bermuda	lb/g	0.45	600.0000	270.00	________

TOTAL INCOME				270.00	________
DIRECT EXPENSES					
CROP INSURANCE					
rainfall insurance-p	acre	2.00	1.0000	2.00	________
FERTILIZER					
32-0-0	lb	0.14	600.0000	84.00	________
11-37-0	lb	0.24	200.0000	48.00	________
MISC ADMIN O/H					
mis admin o/h past	acre	4.00	0.2500	1.00	________
CUSTOM					
cust fert spreader	acre	4.50	2.0000	9.00	________
IRRIGATION					
irrigation costs	ac/in	7.00	12.0000	84.00	________
OPERATOR LABOR					
Tractors	hour	11.00	0.2400	2.64	________
IRRIGATION LABOR					
irr system 1	hour	11.00	0.6000	6.60	________
DIESEL FUEL					
Tractors	gal	3.30	1.2960	4.27	________
GASOLINE					
Pick-up, 3/4 ton	gal	3.20	0.4550	1.45	________
REPAIR & MAINTENANCE					
Implements	acre	2.54	1.0000	2.54	________
Tractors	acre	2.61	1.0000	2.61	________
Pick-up, 3/4 ton	acre	1.00	0.5000	0.50	________
irr system 1	ac/in	0.17	12.0000	2.04	________
INTEREST ON OP. CAP.	acre	9.53	1.0000	9.53	________

TOTAL DIRECT EXPENSES				260.20	________
RETURNS ABOVE DIRECT EXPENSES				9.79	________
FIXED EXPENSES					
Implements	acre	3.75	1.0000	3.75	________
Tractors	acre	3.88	1.0000	3.88	________
Pick-up, 3/4 ton	acre	3.60	0.5000	1.80	________
irr system 1	ac/in	0.20	12.0000	2.44	________

TOTAL FIXED EXPENSES				11.88	________

TOTAL SPECIFIED EXPENSES				272.08	________
RETURNS ABOVE TOTAL SPECIFIED EXPENSES				-2.08	________
ALLOCATED COST ITEMS					
cash rent past irr	acre	100.00	1.0000	100.00	________
RESIDUAL RETURNS				-102.08	________

Information presented is prepared solely as a general guide & not intended to recognize or predict the costs & returns from any one operation.
Developed by Texas AgriLife Extension Service.

Source: Texas A&M AgriLife Extension Service (2012).

Exhibit C-9. Estimated Costs and Returns per Acre for Irrigated Bermuda Pasture, District 10

Table 2.B Estimated resource use and costs for field operations, per acre
Bermuda Pasture, Irrigated
2012 Projected Costs and Returns per Acre

OPERATION/ OPERATING INPUT	SIZE/ UNIT	TRACTOR SIZE	PERF RATE	TIMES OVER	MTH	TRACTOR COST DIRECT	TRACTOR COST FIXED	EQUIP COST DIRECT	EQUIP COST FIXED	ALLOC LABOR HOURS	ALLOC LABOR COST	OPERATING INPUT AMOUNT	OPERATING INPUT PRICE	OPERATING INPUT COST	TOTAL COST
						------------dollars-----------					dollars		-------dollars--------		
aereator	12 ft	100	0.120	1.00	Jan	3.44	1.94	1.27	1.87	0.120	1.32				9.85
irrigation costs	ac/in			1.00	Mar							1.5000	7.00	10.50	10.50
32-0-0	lb			1.00	Apr							300.0000	0.14	42.00	42.00
cust fert spreader	acre											1.0000	4.50	4.50	4.50
11-37-0	lb											100.0000	0.24	24.00	24.00
irrigation costs	ac/in			1.00	Apr							1.5000	7.00	10.50	10.50
aereator	12 ft	100	0.120	1.00	Jun	3.44	1.94	1.27	1.87	0.120	1.32				9.85
irrigation costs	ac/in											2.0000	7.00	14.00	14.00
mis admin o/h past	acre			1.00	Jun							0.2500	4.00	1.00	1.00
32-0-0	lb			1.00	Jul							300.0000	0.14	42.00	42.00
irrigation costs	ac/in											2.5000	7.00	17.50	17.50
cust fert spreader	acre											1.0000	4.50	4.50	4.50
11-37-0	lb											100.0000	0.24	24.00	24.00
irrigation costs	ac/in			1.00	Aug							2.0000	7.00	14.00	14.00
irrigation costs	ac/in			1.00	Sep							2.5000	7.00	17.50	17.50
irr system 1	ac/in			1.00	Oct			2.04	2.44	0.600	6.60	12.0000			11.08
rainfall insurance-p	acre											1.0000	2.00	2.00	2.00
Pick-up, 3/4 ton	acre			0.50	Oct			1.95	1.80			0.5000			3.75
TOTALS						6.89	3.88	6.53	8.00	0.840	9.24			228.00	262.55
INTEREST ON OPERATING CAPITAL															9.53
UNALLOCATED LABOR															0.00
TOTAL SPECIFIED COST															272.08

Source: Texas A&M AgriLife Extension Service (2012).

Exhibit C-10. Estimated Resource Use and Costs per Acre of Field Operations for Irrigated Bermuda Pasture, District 10

Table 1.A Estimated costs and returns per acre
Bermuda Pasture, Dryland
2012 Projected Costs and Returns per Acre

ITEM	UNIT	PRICE	QUANTITY	AMOUNT	YOUR FARM
		dollars		dollars	
INCOME					
grazing bermuda	lb/g	0.39	140.0000	54.60	______

TOTAL INCOME				54.60	______
DIRECT EXPENSES					
CROP INSURANCE					
rainfall insurance-p	acre	2.00	1.0000	2.00	______
FERTILIZER					
32-0-0	lb	0.14	150.0000	21.00	______
11-37-0	lb	0.24	50.0000	12.00	______
MISC ADMIN O/H					
mis admin o/h past	acre	4.00	0.2500	1.00	______
HERBICIDES					
herb-Banvell/24D	pt	6.00	1.0000	6.00	______
CUSTOM					
cust fert spreader	acre	4.50	1.0000	4.50	______
GASOLINE					
Pick-up, 3/4 ton	gal	3.20	0.9100	2.91	______
REPAIR & MAINTENANCE					
Pick-up, 3/4 ton	acre	1.00	1.0000	1.00	______
INTEREST ON OP. CAP.	acre	1.68	1.0000	1.68	______

TOTAL DIRECT EXPENSES				52.09	______
RETURNS ABOVE DIRECT EXPENSES				2.50	______
FIXED EXPENSES					
Pick-up, 3/4 ton	acre	3.60	1.0000	3.60	______

TOTAL FIXED EXPENSES				3.60	______

TOTAL SPECIFIED EXPENSES				55.69	______
RETURNS ABOVE TOTAL SPECIFIED EXPENSES				-1.09	______
ALLOCATED COST ITEMS					
cash rent bermuda dr	acre	25.00	1.0000	25.00	______
RESIDUAL RETURNS				-26.09	______

Source: Texas A&M AgriLife Extension Service (2012).

Exhibit C-11. Estimated Costs and Returns per Acre for Dryland Bermuda Pasture, District 10

Table 1.B Estimated resource use and costs for field operations, per acre
Bermuda Pasture, Dryland
2012 Projected Costs and Returns per Acre

OPERATION/ OPERATING INPUT	SIZE/ UNIT	TRACTOR SIZE	PERF RATE	TIMES OVER	MTH	TRACTOR COST DIRECT	TRACTOR COST FIXED	EQUIP COST DIRECT	EQUIP COST FIXED	ALLOC LABOR HOURS	ALLOC LABOR COST	OPERATING INPUT AMOUNT	OPERATING INPUT PRICE	OPERATING INPUT COST	TOTAL COST
						------------dollars-----------					dollars		-------dollars--------		
32-0-0	lb			1.00	Feb							150.0000	0.14	21.00	21.00
11-37-0	lb											50.0000	0.24	12.00	12.00
cust fert spreader	acre											1.0000	4.50	4.50	4.50
herb-Banvell/24D	pt											1.0000	6.00	6.00	6.00
mis admin o/h past	acre			0.25	Jun							0.2500	4.00	1.00	1.00
Pick-up, 3/4 ton	acre			1.00	Dec			3.91	3.60			1.0000			7.51
rainfall insurance-p	acre											1.0000	2.00	2.00	2.00
TOTALS						0.00	0.00	3.91	3.60	0.000	0.00			46.50	54.01
INTEREST ON OPERATING CAPITAL															1.68
UNALLOCATED LABOR															0.00
TOTAL SPECIFIED COST															55.69

Source: Texas A&M AgriLife Extension Service (2012).

Exhibit C-12. Estimated Resource Use and Costs per Acre of Field Operations for Dryland Bermuda Pasture, District 10

Appendix C-2

Table C-1. Top 5 Agricultural Commodities by County

Top 5 Crops 2007/Pasture/2007			
	Crop	**Quantity (Acres)**	**Pasture (Acres)**
Dimmit	1. Forage	1,816	657,109
	2. Oats (Grain)	834	
	3. Sorghum (Grain)	N/A	
	4. Vegetables	N/A	
	5. Pecans	N/A	
Frio	1. Peanuts for nuts	11,626	399,391
	2. Forage	10,581	
	3. Vegetables	9,842	
	4. Sorghum (Grain)	9,760	
	5. Wheat (Grain)	7,404	
La Salle	1. Sorghum (Grain)	4,431	493,336
	2. Forage	4,032	
	3. Peanuts for nuts	N/A	
	4. Wheat (Grain)	1,569	
	5. Vegetables	1,017	
Maverick	1. Forage	6,458	392,588
	2. Pecans	N/A	
	3. Sorghum (Silage)	N/A	
	4. Oats (Grain)	N/A	
	5. Wheat (Grain)	N/A	
Webb	1. Forage	3,476	1,757,160
	2. Pecans	N/A	
	3. Oats (Grain)	N/A	
	4. Vegetables	N/A	
	5. Peppers (Except Bell)	N/A	
Zavala	1. Sorghum (Grain)	11,989	587,250
	2. Wheat (Grain)	8,251	
	3. Forage	4,316	
	4. Cotton	4,066	
	5. Vegetables	3,380	

Source: U.S. Department of Agriculture (2013).
Note: Pasture acreage was calculated by multiplying percent pastureland by land in farms.

APPENDIX D

Table D-1. Example of Discount Formulas for a Typical Gas (Oil) Well in the Eagle Ford Shale[a]

								Discount Rate		
	Reduced	Initial Daily	Daily	Annual				1.70%		
Year	Production	Mcf	Average Mcf	Mcf	Operating Cost/$ per Mcf					
	Percent	2,461.00			0.75	1.00	1.50	0.75	1.00	1.50
1	78	541.42	1,501.21	520,919.87	390,689.90	520,919.87	781,379.81	384,159.20	512,212.26	768,318.39
2	28	389.82	465.62	161,570.56	121,177.92	161,570.56	242,355.83	117,160.60	156,214.13	234,321.20
3	22	304.06	346.94	120,388.85	90,291.64	120,388.85	180,583.28	85,839.01	114,452.01	171,678.01
4	17	252.37	278.22	96,541.04	72,405.78	96,541.04	144,811.56	67,684.53	90,246.04	135,369.06
5	8	232.18	242.28	84,069.83	63,052.38	84,069.83	126,104.75	57,955.77	77,274.36	115,911.54
6	11	206.64	219.41	76,135.74	57,101.81	76,135.74	114,203.62	51,608.85	68,811.79	103,217.69
7	11	183.91	195.28	67,760.81	50,820.61	67,760.81	101,641.22	45,164.08	60,218.78	90,328.17
8	11	163.68	173.80	60,307.12	45,230.34	60,307.12	90,460.68	39,524.12	52,698.83	79,048.25
9	11	145.68	154.68	53,673.34	40,255.00	53,673.34	80,510.01	34,588.47	46,117.95	69,176.93
10	11	129.65	137.66	47,769.27	35,826.95	47,769.27	71,653.91	30,269.16	40,358.88	60,538.32
11	11	115.39	122.52	42,514.65	31,885.99	42,514.65	63,771.98	26,489.23	35,318.98	52,978.47
12	11	102.70	109.04	37,838.04	28,378.53	37,838.04	56,757.06	23,181.34	30,908.45	46,362.67
13	11	91.40	97.05	33,675.86	25,256.89	33,675.86	50,513.78	20,286.52	27,048.69	40,573.04
14	11	81.35	86.37	29,971.51	22,478.63	29,971.51	44,957.27	17,753.20	23,670.93	35,506.39
15	11	72.40	76.87	26,674.65	20,005.98	26,674.65	40,011.97	15,536.23	20,714.97	31,072.46
16	11	64.43	68.42	23,740.43	17,805.33	23,740.43	35,610.65	13,596.11	18,128.15	27,192.22
17	11	57.35	60.89	21,128.99	15,846.74	21,128.99	31,693.48	11,898.27	15,864.36	23,796.54
18	11	51.04	54.19	18,804.80	14,103.60	18,804.80	28,207.20	10,412.45	13,883.26	20,824.89
19	11	45.42	48.23	16,736.27	12,552.20	16,736.27	25,104.41	9,112.17	12,149.56	18,224.34
20	11	40.43	42.93	14,895.28	11,171.46	14,895.28	22,342.92	7,974.27	10,632.36	15,948.54
		Total Well Mcf		1,555,116.92						
							1.7%	$1,070,193.56	$1,426,924.74	$2,140,387.12
							5%	$925,175.85	$1,233,567.80	$1,850,351.70
							7%	$856,778.62	$1,142,371.50	$1,713,557.24

[a] Based on percent decline rate (Assumption B) in Table 5-5

Sources: Holditch (2013); *Production Decline of a Natural Gas Well over Time* (2013); Swindell (2012).