A STUDY OF SHALE GAS PRODUCTION AND ITS SUPPLY CHAIN

by

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Over the last few years, shale gas has become one of the most important energy sources in the United States, and advances in related technologies have led to an unprecedented economic boom in several parts of the country. On the other hand, the shale gas sector and its unique extraction technologies are still relatively young, and there are a number of concerns from the public about several aspects of the shale gas industry such as hydraulic fracturing, methane emission and waste management. The objective of this thesis is to present a comprehensive and objective study of shale gas and its entire supply chain, including the various material flows within it, in order to motivate safety, cost-savings and operational efficiency improvement.

The study begins with an introduction to the basic background of the petroleum, natural gas and shale gas industry and goes on to describe the process of shale gas production and map its supply chain, starting with initial exploration to identify a potential drilling location and ending with the delivery of the natural gas to end-use customers. We present detailed flow of various materials and when possible, costs in the shale gas supply chain as a first step toward planning for its efficient operation. We also span a wide range of topics including environmental effects and safety, public health implications of unconventional gas extraction, the upgraded equipment and techniques to reduce environmental pollution, the use pattern of shale gas, fluctuations in its price, and its implications on sustainable energy. We end with a detailed case

study of distributed power generation from Marcellus shale, and discuss how natural gas can play a key role in bridging the gap between coal/petroleum based energy and renewable energy. As a more reliable and cheaper alternative to renewable energy today, and as a more environmentally friendly alternative to other fossil fuels such as coal and petroleum, shale gas has the potential to be a solution to the energy gap in the near future.

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PREFACE

To my parents

This thesis started with some initial work on the merits of utilizing shale gas locally by using it to generate electricity and supply customers in the vicinity of the well. Pittsburgh is located in the heart of the Marcellus shale formation and there is an extremely active shale gas industrial community in this region; since the demise of steel, shale gas is the first industrial sector that has seen a significant economic boom in the Western Pennsylvania region. Subsequently, the scope of the work was therefore extended to studying shale gas production in more detail and to mapping its entire supply chain. In the process of writing this thesis I have learned a lot and our initial conceptions of an integrated shale gas industry have certainly changed. We have had several rig and facility visits, and have interviewed and met with numerous individuals in the local shale gas sector. These activities have offered us lots of invaluable information.

I would like to thank my committee, Dr. Jayant Rajgopal, Dr. William E. Hefley, and Dr. Bopaya Bidanda, for their excellent guidance and support during this process, especially my advisor, Dr. Rajgopal, who gave me myriad help and advice (even on writing).Without him I would still be suffering in writing the first chapter of the thesis. He was the instructor of my first Operations Research course, and without him I would not be fond of industrial engineering, be on board to conduct research and have the courage and enthusiasm to challenge myself to join the doctoral program. It is really my pleasure to be his student for another few years.

I would like to acknowledge the Center for Industry Studies at the University of Pittsburgh for providing me financial support through a grant to Drs. Rajgopal and Hefley. I also wish to thank Seneca Resources, and specifically, Julianne Heins for offering me invaluable advice and information; Ms. Heins also facilitated all of our site visits. I thank Rob Boulware, Alyson Joyce and Bryan Cooley for the wonderful rig visit during heavy snow, along with Marcus Heller, Barry Guenther, Justin Harsany, Dave Suski and Justin Shultz for the information and feedback that they provided. Without their cooperation I would not have been able to complete this study.

I would like to thank Christopher Wissel-Tysonfrom IMG Midstream for supporting us with technical data and market information and Kenneth Frederick for introducing us to this relatively new field. I thank the Marcellus Shale Coalition for making information available to the study team. I also thank my friends, Mamoru Iketani and John Fitzgerald, who were my colleagues during the summer project.

Finally, I thank my friends for encouraging me and everyone who helped me during the process.

1.0 INTRODUCTION

The goal of this thesis is to describe the process of shale gas production and to study its supply chain, starting with the exploration of a potential drilling location and ending with the delivery of the natural gas to end-use customers. The thesis overviews the process and details the flow of various materials in the shale gas supply chain as a step toward planning for its efficient operation. It also discusses how natural gas plays a key role in bridging the gap between coal/petroleum based energy and renewable energy.

1.1 PETROLEUM AND NATURAL GAS

Petroleum is a yellow to black liquid that develops naturally over millennia in geological formations beneath the surface of the earth. It is extracted and typically, then refined into various types of fuels. The term "petroleum" often covers naturally occurring unprocessed crude oil as well as products obtained from it. Crude oil is a mixture of hydrocarbons generated over centuries from dead plants and animals that lived millions of years ago. It is a fossil fuel that exists in liquid form in underground pools or reservoirs, within sedimentary rocks, or near the surface in tar (or oil) sands. Although petroleum products can be obtained from coal or biomass as well, they are primarily classified as fuels and other products that are made from crude oil as well as natural gas (EIA, Oil and Petroleum Products, 2015). After crude oil is collected from the ground, it is transported to a refinery where it is processed and separated into different kinds of useable petroleum products such as gasoline, diesel fuel, heating oil, jet fuel, petrochemical feedstock, waxes, lubricating oils, and asphalt.

Petroleum products have been used since ancient times. According to Herodotus and Diodorus Siculus, asphalt was used in the construction of the towers and walls of Babylon more than 4000 years ago. In addition, oil pits were found near Ardericca (near Babylon), and a pitch spring was discovered on Zacynthus. There are many allusions to the use of natural gas as alighting and heating resource in ancient China and Japan. The first mention of petroleum in America was by Sir Walter Raleigh in 1595, while the first important commercial exploitation of oil was at Alfreton, Derbyshire by James Young in 1850, when he patented his process for the manufacture of paraffin. Starting from around the middle of the nineteenth century, the petroleum industry in the United States began to grow rapidly. The reported crude petroleum production in the United States was "2000 barrels in 1859; 4,215,000 barrels in 1869; 19,914,146 barrels in 1879; 35,163,513 barrels in 1889; 57,084,428 barrels in 1899; and 126,493,936 barrels in 1906" (Chisholm, 1910). In 2015, around 3.44 billion barrels of crude oil were produced in the United States (EIA, Crude Oil Production, 2016).

Natural gas is currently one of the major sources for petroleum-based fuels. It was naturally formed from the carbon and hydrogen molecules of ancient organic matter millions of years ago and is currently trapped inside geological formations as a combustible mixture of various hydrocarbon gases (NaturalGas.org, Overview of Natural Gas, 2013). The appearance of natural gas started in the Middle East in ancient times when it was viewed as a supernatural manifestation. It gave the impression of a mysterious fire bursting from fissures in the ground when it was ignited. Seeping natural gas was found in Iran between 6000 and 2000 BC, and its applications started 2500 years ago in China, where people collected it from natural seeps using bamboo pipes and used it to boil ocean water to get salt. Natural gas was first known in Europe when it was discovered in England in 1659. In 1815, natural gas was found in the United States in Charleston, West Virginia when a salt-brine well was being dug. The first natural gas well was drilled six years later in 1821, and in 1858, the first natural gas company in the United States was established in New York. The 19th century was the starting point of the gas industry, and huge amounts of natural gas were found in Texas and Oklahoma in the early 1900s. After World War II, the natural gas industry grew rapidly because of the development of natural gas infrastructure. It also started to replace oil due to the shortages of crude oil in the late 1960s and early 1970s. Today, natural gas is considered as one of the cleanest, safest, and most efficient sources of energy (Mokhatab, Poe, & Mak, 2015)

As shown in Table 1, the composition of natural gas in different wells can vary widely before it is refined, but it typically includes methane, ethane, propane, butane and pentane. As gas is removed from a reservoir, the compositions might vary even in the same well.

Table 1. Typical Composition of Natural Gas

Methane	CH_4	70-90%
Ethane	C_2H_6	0-20%
Propane	C_3H_8	
Butane	C_4H_{10}	
Pentane	C_5H_{12}	
Carbon Dioxide	CO_2	0-8%
Oxygen	O_2	0-0.2%
Nitrogen	N_2	0-5%
Hydrogen sulfide	H_2S	0-5%
Rare gases	A, He, Ne, Xe	trace

The primary component of natural gas is methane. Methane is a colorless, odorless gas-form molecule at room temperature (approximately 70°F/21°C) and standard pressure (an absolute pressure of exactly 100 kPa) made up of one carbon atom and four hydrogen atoms, i.e., CH_4. Methane is combustible and the reaction between methane and oxygen when methane is burnt is as follows:

$$CH_4[g] + 2\ O_2[g] \rightarrow CO_2[g] + 2\ H_2O[l] + 891\ kJ$$

Every molecule of methane (CH_4) reacts with two molecules of oxygen (O_2) in gas form and produces one molecule of carbon dioxide (CO_2) in gas form and a unit of water (H_2O) in liquid form. The reaction also releases a great deal of energy (891 kJ per unit).

Natural gas is referred to as "wet" gas when other hydrocarbons are present along with methane in significant quantities. After these other hydrocarbons are removed, i.e., when it is almost pure methane, it is referred to as dry gas. To get to the final customer, gas must be processed into uniform quality gas that has specific quality measures so that it can be transported via pipelines, which constitute the main mode of transportation for natural gas.

Characteristics of natural gas are measured in many different ways. As gas, its quantity can be measured by the volume in cubic feet when it is at standard temperature and pressure. Production and distribution enterprises usually measure natural gas in thousands of cubic feet (Mcf), millions of cubic feet (MMcf), or trillions of cubic feet (Tcf). As a supply of energy, natural gas can also be measured by potential energy output. It is commonly expressed in British thermal units (Btu): one Btu is the energy required to increase the temperature of one pound of water at or around 39.2 degrees Fahrenheit by one degree Fahrenheit at normal pressure. When used to measure gas it corresponds to the amount of natural gas that will produce this exact amount of energy. Typically, one cubic foot of natural gas corresponds to 1,027 Btus. Finally, for billing purposes natural gas is measured by gas utilities in ‘therms’ when delivered to a residence. A therm is equivalent to 100,000 Btu, or approximately 97 cubic feet. In addition to residential use, the natural gas is also commonly used for electric power generation, and as industrial, commercial, and vehicle fuel.

We present a detailed description of natural gas production in Section 2.2.1, and describe the processing of natural gas from wellhead gas to dry gas in Section 2.2.2.We then discuss the distribution and storage of natural gas in Sections 2.2.3 and 2.2.4, respectively. Additionally, in Chapter 4 we discuss the use and price fluctuation of natural gas and how natural gas can bridge the gap between coal/petroleum based energy and renewable energy.

1.2 SHALE GAS

As shown in Figure 1, oil and natural gas can be classified as either conventional or unconventional. This depends upon the geological formations from which it is extracted. Conventional natural gas can be found in carbonates, sandstones, and siltstones and is typically located in deep reservoirs and is associated with crude oil. It is generally easier to produce by releasing gas from several small porous zones in naturally developed rock formations. Unconventional gas on the other hand, comes from coal (also known as coal-bed methane), tight gas sands, gas hydrates and shale. The different types of unconventional gas all contain large amounts of natural gas. However, when compared to conventional reservoir rocks, it is usually more difficult to extract. In particular, shale gas is the kind of unconventional natural gas produced from shale, a “fine-grained sedimentary rock that forms from the compaction of silt and clay-size mineral particles" (EIA, Energy in Brief, 2015). Black shale often contains organic material, and the pores in it can trap the oil and natural gas developed from the organic material.

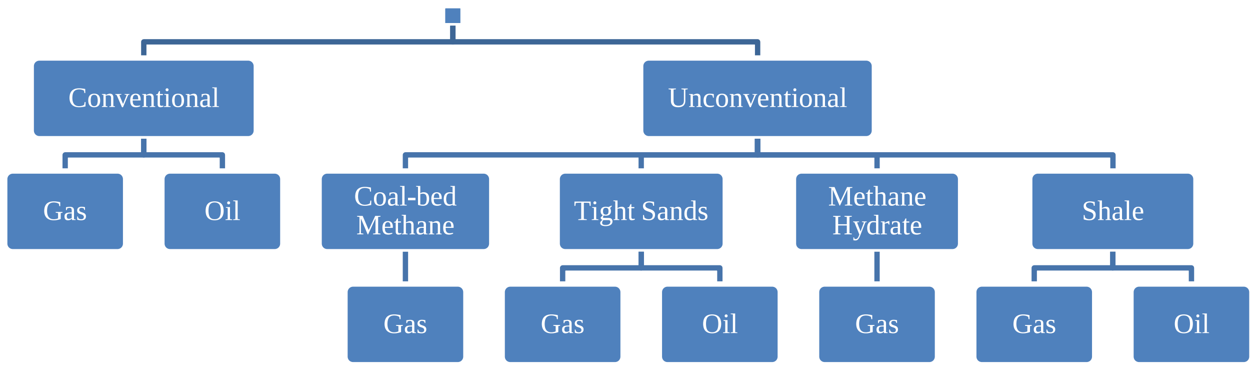
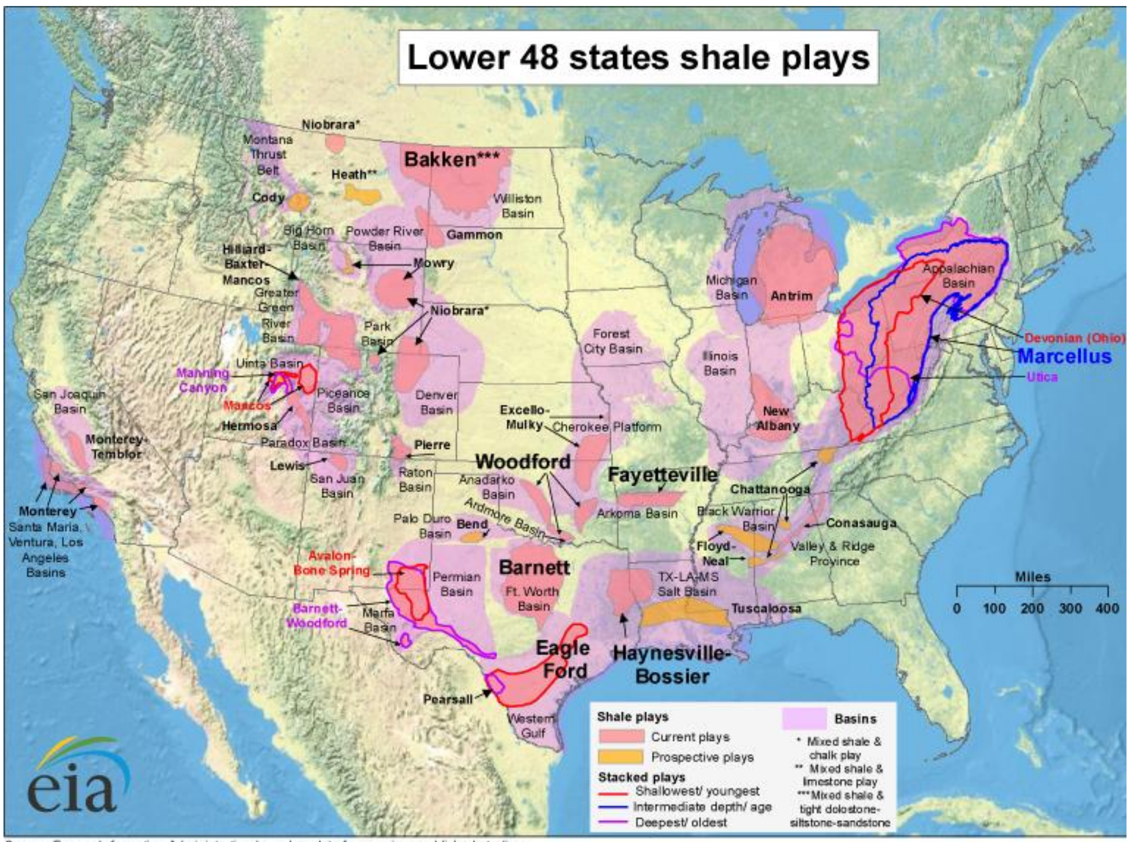


Figure 1. Range of Conventional and Unconventional Hydrocarbons

Around the year 2000, natural gas started to be produced on a large scale from shale in the Barnett Shale in north-central Texas. This was pioneered by the Mitchell Energy and Development Corporation (EIA, Energy in Brief, 2015). During the 1980s and 1990s, Mitchell Energy experimented with alternative methods of hydraulic fracturing in the Barnett Shale, and by2000, the firm had developed a hydraulic fracturing technique that could produce commercial natural gas from the shale. Following Mitchell, other companies began to drill wells in the Barnett Shale, as a result of which it was producing almost half a trillion cubic feet (Tcf) of natural gas per year in 2005. As companies developed their confidence in profitable natural gas production in the Barnett Shale, they started to expand to other shale locations such as Fayetteville in northern Arkansas, Haynesville in eastern Texas and northern Louisiana, Woodford in Oklahoma, Eagle Ford in southern Texas, and the Marcellus and Utica Shales in Ohio, Pennsylvania, West Virginia and New York. Figures 2 and 3 illustrate the distribution of shale gas plays in the lower forty-eight states and the dry gas production from each kind of shale between 2000 and 2016. Today, advanced technologies are able to provide more accurate estimates of reservoir capacities and are making production of unconventional natural gas much easier and more efficient. In particular, hydraulic fracturing is playing the most important role in shale gas production.



Source: Energy Information Administration based on data from various published studies.
Updated: May 9, 2011

Figure 2. Lower 48 States Shale Plays

(EIA, Energy in Brief, 2015)

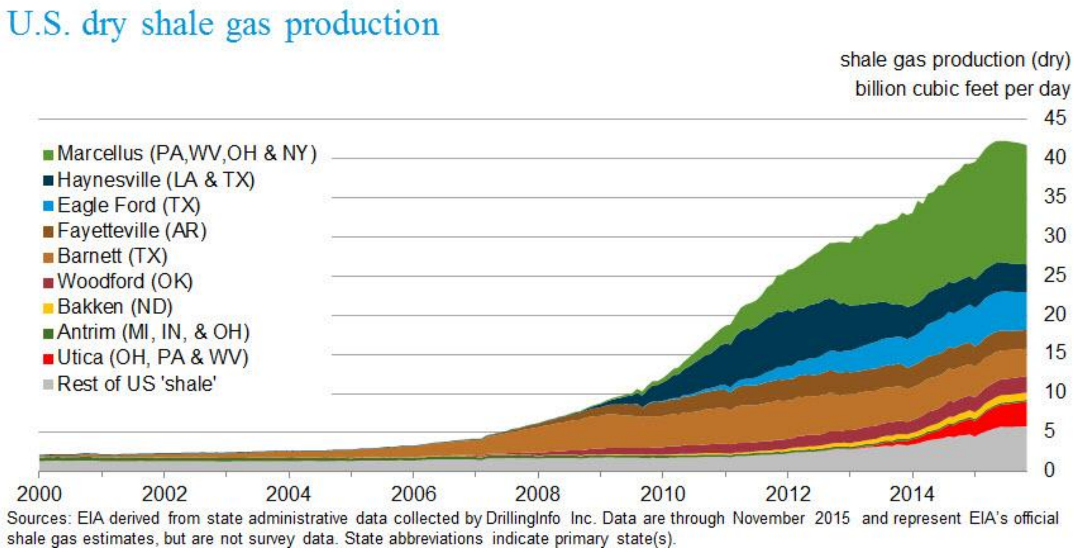


Figure 3. U.S. Dry Shale Gas Production

(EIA, Energy in Brief, 2015)

1.3 HYDRAULIC FRACTURING

Hydraulic fracturing (also called hydrofracturing, hydrofracking, fracking or frac'ing) is a reservoir stimulation technique that uses pressurized liquid to fracture the rock. As shown in Figure 4, the processes involved in hydraulic fracturing include the high-pressure injection of hydraulic fracturing fluid - primarily water, along with a mixture of sand or ceramic beads to serve as a propping agent, and chemicals that mainly serve to reduce friction -through a wellbore, and a horizontal casing that is perforated to allow the fluid to flow through the perforations and create deep cracks in the rock formations that contains natural gas. After the hydraulic pressure is removed from the wellhead, natural gas begins to flow up to the well (Gandossi, 2013).

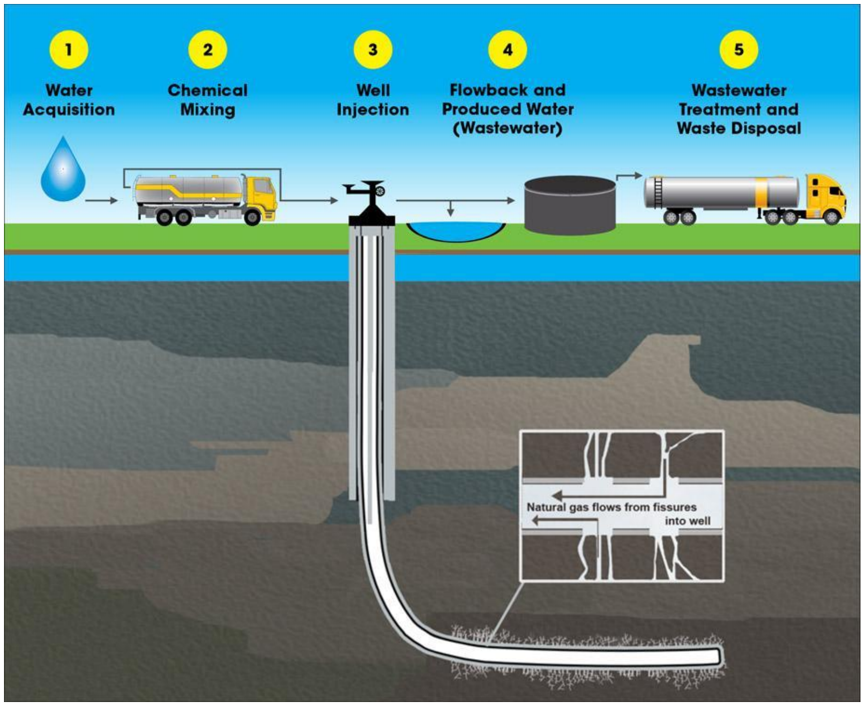


Figure 4. Hydraulic Fracturing

(EPA, The Hydraulic Fracturing Water Cycle, 2016)

Although the term "hydraulic fracturing" started to become more common around 2000, when this process began to be used to produce commercial natural gas in the Barnett Shale in north-central Texas, the technique itself is not totally new. Hydraulic fracturing has been a well-established technique for more than 6 decades. The first use of hydraulic fracturing as a stimulation technique was in 1949 by Stanolind Oil. Since then, close to 2.5 million fracture treatments have been used worldwide in approximately 60% of all wells drilled today, increasing the production rate and adding to the US recoverable reserves of oil by at least 30% and to the recoverable reserves of gas by 90%.

Fracturing can be traced back to the 1860s when liquid (and subsequently, solidified) nitroglycerin (NG) was used to stimulate hard and shallow rock wells in Pennsylvania, New

York, Kentucky, and West Virginia (Watson, 1910).Although NG was extremely hazardous, it was spectacularly successful for oil well shooting, where the objective was to separate the oil-bearing formation to increase both initial flow and subsequent oil recovery. The same fracturing principle was soon used with similar effectiveness to water and gas wells. In the 1930s, people started to try to inject fluids (acid) that were not explosive into the ground to stimulate a well and leave a flow channel to the well, thus enhancing its productivity (Montgomery & Smith, 2010).

In 1947, Floyd Farris of Stanolind Oil and Gas Corporation (Amoco) performed in-depth research to establish a relationship between observed well performance and treatment pressures. Based on this study, Farris came up with the idea of hydraulically fracturing a formation (rock, for example) to promote production from oil and gas wells. In 1948, the hydraulic fracturing process was broadly recognized by the oil and gas industry, thanks to the paper written by J.B. Clark of Stanolind Oil. A year later, in 1949, a patent was issued with an exclusive license granted to the Halliburton Oil Well Cementing Company (HOWCO) to use the new hydraulic fracturing technique. HOWCO performed the first two commercial fracturing treatments. The first treatment cost $900 and was in Stephens County, Oklahoma, and the second cost $1,000 and was performed in Archer County, Texas on March 17, 1949, using lease crude oil and a mixture of gasoline, crude, and 100 to 150 lbm of sand. Soon after that, 332 wells were treated, and the average production was increased by 75%. Applications of the fracturing process rose rapidly and increased the oil supply in the United States. During the middle 1950s, treatments were used in more than 3,000 wells within a month for stretches. In 2008, more than 50,000 hydraulic fracturing stages were completed at a cost of between $10,000 and $6 million around the world. In addition, a single well usually has from 8 to more than 40 different stages (Montgomery & Smith, 2010).

However, although hydraulic fracturing is not totally new, the technique is constantly evolving and expanding at an unprecedented rate, so that the industry is larger than ever. Directional drilling and new additional chemicals are being applied and the amount of water used is much larger (Crawford, 2013).In the past, the average fracture treatment only contained approximately 750 gal of fluid and 400 lbm of sand, while average fracture treatment today use nearly 60,000 gal of fluid and 100,000 lbm of propping agent. Some of the largest treatments even exceed 1 million gal of fluid and 5 million lbm of propping agent. Similarly, hydraulic horsepower (hhp) per treatment has increased from approximately 75 hhp to more than 1,500 hhp, and in some cases it is even around 15,000 hhp (Montgomery & Smith, 2010).

We provide a detailed description of hydraulic fracturing technologies and treatment in Section 2.1.4.

1.4 THE SHALE GAS INDUSTRY

Shale gas has become an important natural gas resource in a booming expansion within the United States due to the application of new techniques such as horizontal drilling and hydra-fracking. The development of the industry has had a huge impact on the US economy and society, and its future expansion is expected to be rapid.

As shown in Figure 5, in 2007, when shale gas was first considered as a supply of natural gas by EIA, only 8.07% of natural gas gross withdrawals were from shale gas wells, but by 2014, the proportion had rapidly risen to 43.88%. This was matched by a decrease in natural gas gross withdrawals from traditional gas wells from 60.79% to 33.13% (EIA, Natural Gas Gross Withdrawals and Production, 2016).

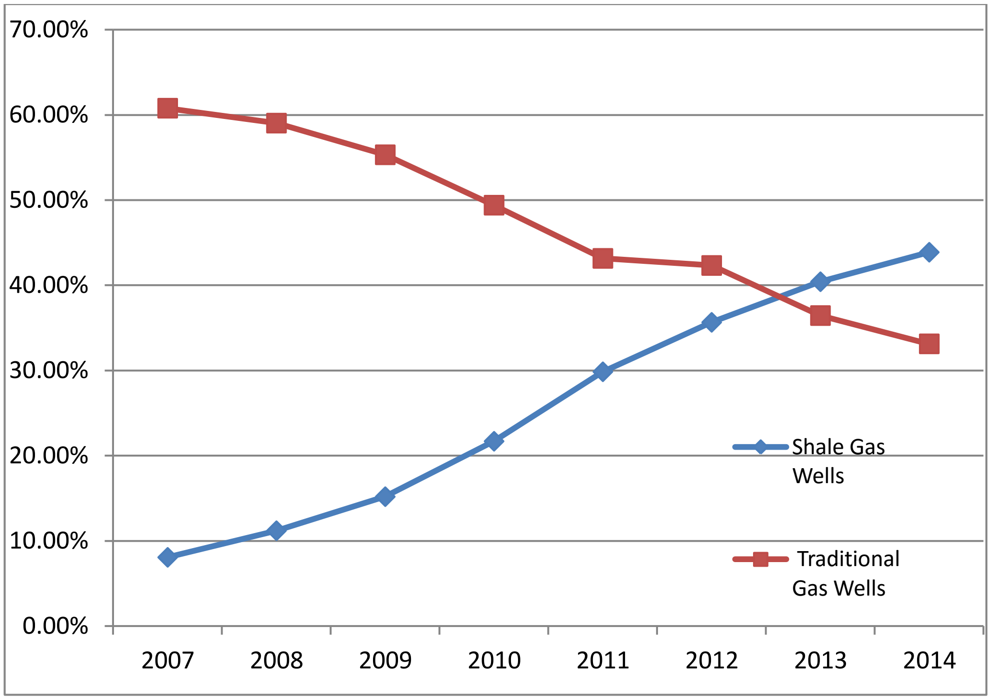


Figure 5. Natural Gas Gross Withdrawals Shares from Shale Gas Wells and Gas Wells

Data Source: (EIA, Natural Gas Gross Withdrawals and Production, 2016)

The shale gas industry has resulted insignificant direct and indirect economic effects in the form of major enhancements to opportunities in job creation, fiscal recovery, infrastructure optimization, economic sustainability and viability (Seydor, et al., 2012). Due to this fact and its environmental advantages over coal and to a lesser extent, over petroleum, a long-term increase in shale gas development is predicted for the future. Capital of nearly $1.9 trillion is expected to be invested in shale gas, leading the share of shale gas to reach an expected 60% of total natural gas production, and to the support of nearly 1.6 million jobs by 2035 (IHS Global Insight, 2011).

However, the industry is also now witnessing a different set of forecasts for the future from some sources because of the trend of declining natural gas prices since 2007, when shale well drilling started to expand on a major scale. According to the U.S. Energy Information

Administration (EIA, Natural Gas Prices, 2016), the wellhead price, before it discontinued being estimated in January 2013, had dropped by nearly 60% from $6.25 to $2.66. From 2007 to 2015, the average residential price in a calendar year had dropped from $13.08 to $10.38; the yearly commercial price had decreased from $11.34 to $7.89; the yearly industrial price had dropped from $7.68 to $3.84; and the price of gas used for electric power generation had fallen from $7.31 to $3.37, respectively. In particular, the monthly average prices in 2015were consistently trending lower than those in the same month in 2014, as illustrated in Figure 6. From the viewpoint of profitability, the aforementioned fact is increasing the interest in cost-savings and operational efficiency improvement, which requires a comprehensive understanding of the shale gas supply chain from the extraction at the gas well to the distribution of final product to the end customer.

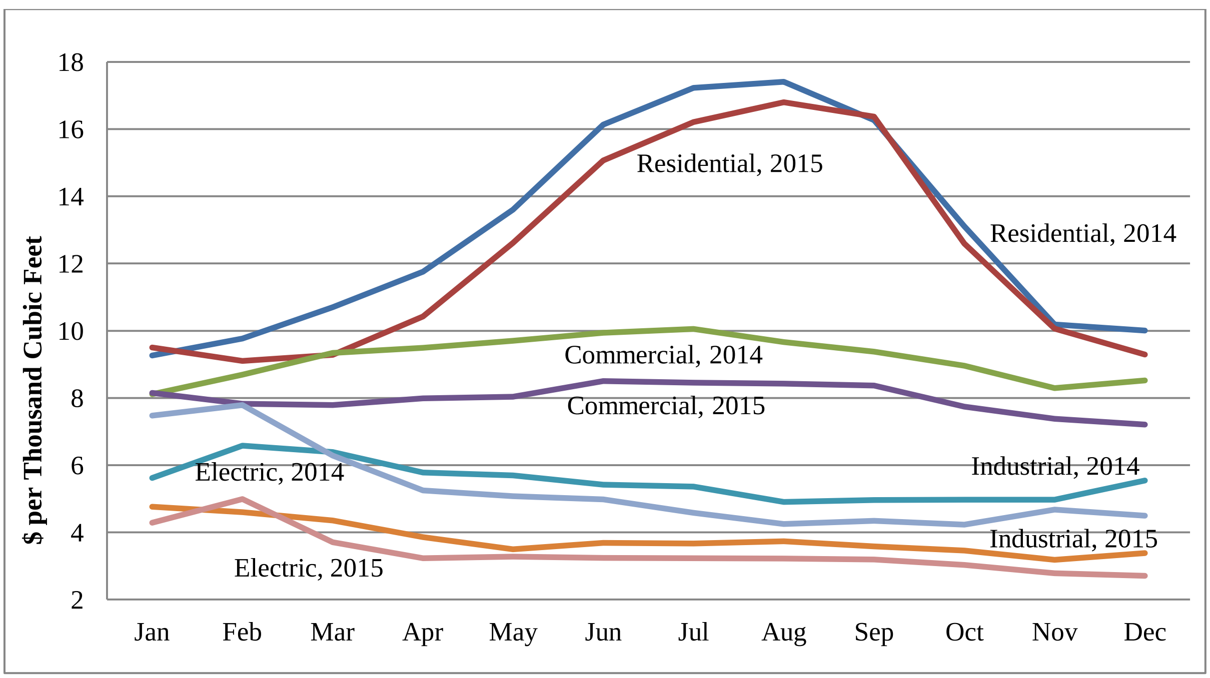


Figure 6. Monthly Natural Gas Price in 2015 and 2014

Data Source: (EIA, Natural Gas Prices, 2016)

Prior research has explored the direct economic impact of the shale gas value chain at the well. This work was based on extensive field research, including a site visit and interviews with industry participants in Pennsylvania, which has the majority of Marcellus Shale gas reserves (Hefley, et al., 2011). In other work the major supply chain components, supplier resources and characteristics were identified and analyzed from the leasing, acquisition and permitting of a shale gas well to the natural gas distribution and marketing stages (Seydor, et al., 2012). This work also mainly focused on Pennsylvania and its neighborhood area. Cafaro & Grossmann use a case study with actual data to analyze the supply chain strategy related to new facilities location and capacity, determining the number of shale gas wells to run, and water management during drilling (Cafaro & Grossmann, 2014). While these studies have focused on various stages or aspects of the supply chain, there is no comprehensive work on the entire supply chain, including the various material, information and financial flows within it, a mapping of the value stream from source to customer, and the linking of the supply chain to the external environment in order to reach cost-savings and operational efficiency improvement. Addressing some of these issues is one of the goals of this research.

The basic concepts behind a supply chain –and the shale gas supply chain in particular – are introduced at the beginning of Chapter 2. We consider the supply chain in two separate stages – a transient one and a stable one – and a detailed description of each is provided in the rest of this chapter. Their associated material flows are discussed in Chapter 3. Finally, methane emission, usage patterns and price fluctuations of natural gas, and how natural gas plays a key role in bridging the gap between coal/petroleum based energy and renewable energy are discussed in Chapter 4.

2.0 SHALE GAS SUPPLY CHAIN

A supply chain is defined as the network of operations performed by companies or organizations, which connect the suppliers to the end-use customers; it requires the management of material, information and financial flows across all the players involved in the network (Nahmias & Olsen, 2015). Traditionally called logistics, the aforementioned management issues emerged with the industrial revolution; however, the term supply chain management is relatively recent and dates to the late 1980s. The goal of supply chain management is to achieve a balance between low operational costs and a high level of service, since in most cases simultaneously optimizing both of these is not feasible. Common topics in supply chain management include sourcing, inventory control, production planning, distribution, and sales.

A supply chain is typically identified as three segments. First, the upstream segment is where we source and procure raw materials, components, and subcomponents from external suppliers. Second, the midstream segment is where actual manufacturing and assembly take place. Finally, the downstream segment is where distribution and sales to the customer take place.

As shown in Figure 7, the uniqueness of the shale gas supply chain makes it necessary to further divide it into two separate supply chains according to the status of gas wells, and each of these two chains is studied in more detail in the following sections.

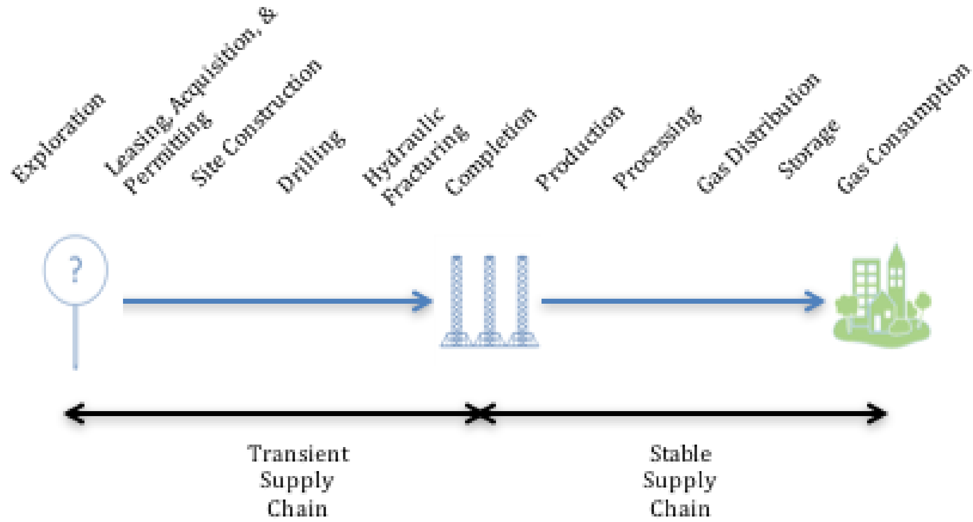


Figure 7. Shale Gas Supply Chain

1) The former, or transient supply chain, describes the segments from the exploration of a potential drilling location until the completion of well construction and the beginning of production. Although this supply chain exists only for a limited amount of time for a given well, it is replicated at multiple locations over time and is significant because this is the specific aspect in which shale gas with its unique drilling approach is different from conventionally produced natural gas. Critical environmental issues, pad location planning, and water and chemicals management during hydraulic fracturing are examples of important issues in this supply chain.

2) The latter, or stable supply chain, corresponds to the production of gas in steady state and its sales to the end customers. This is largely similar to the supply chain for conventional gas wells, but the boom in shale gas production and the large quantities of gas being injected into the market presents significant opportunities in locations such as the Marcellus Shale region. Figure 8 depicts the facilities involved in the stable supply chain. The upstream segment of the stable supply chain corresponds to the production section at the

wellhead. The midstream segment involves the processing and storage sections. The downstream segment corresponds to the distribution to different types of gas consumers. While our focus is not on this supply chain because it is not specific to shale gas, we do study the downstream portion a little further because of the effect that the increased production of shale gas is having on consumption by the end user.

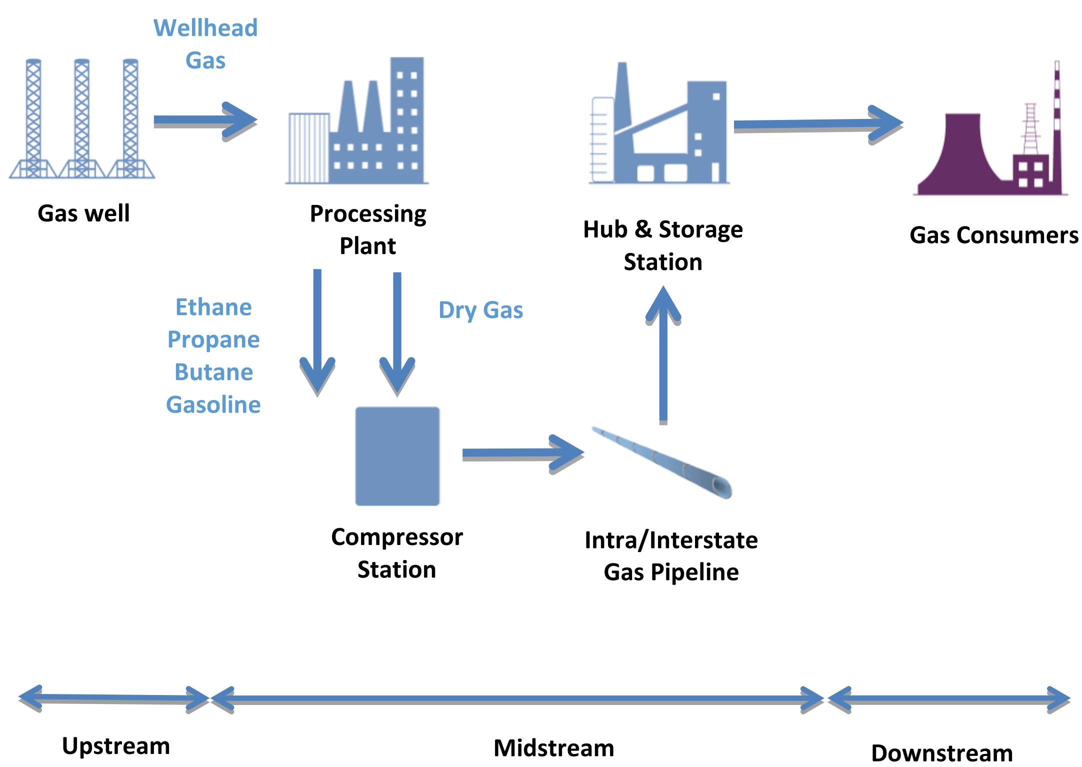


Figure 8. Stable Shale Gas Supply Chain

2.1 THE TRANSIENT SUPPLY CHAIN

The transient supply chain refers to the supply chain that exists for the duration from when exploration commences to when construction and fracking of the well are completed and steady gas flow commences. It is distinct from other natural gas supply chains because of the unique characteristics of horizontal drilling and hydraulic fracturing. The typical transient supply chain for shale gas starts with the exploration phase where potential well locations are evaluated. After the geological evaluation and the identification of the well site, the next steps are leasing, acquisition and permitting. Once a permit is issued, site preparation and construction can be started. After the site has been prepared and the well pad has been completed we come to the two key parts of the transient supply chain: (horizontal) drilling and hydraulic fracturing. With the latter, issues such as the volume of water usage, quality of produced water, and disposal and reuse of water need to be considered carefully. When hydraulic fracturing is done, and the completion of the site is accomplished, the well is ready to produce gas at a steady rate.

The average time from the exploration of a potential gas well site to its completion normally ranges from approximately 18 months to 2 years. The initial stages of exploration, leasing and permitting, and site construction take up a majority of this time. Once the drilling of the well begins, the time needed to finish drilling is relatively small and this time has continued to decrease with improvements in technology. It used to take as much as 20 to 30 days on average to drill one well, so that drilling a multi-well pad with eight wells for example, could take several months. While there are variations that depend on the geology of the site, the time to drill a well has been decreasing and today it could be as low as7 days. A pad usually has 6 to 15 wells depending upon the geological features of its location. Fracturing and completion both takes several weeks.

2.1.1 Leasing, Acquisition, and Permitting

The first stage in the transient chain corresponds to the identification of a potential site at which to drill a gas well, when geologists determine which locations might contain a gas reservoir. Once a location is identified, the shale gas well operator must obtain top land access and mineral rights. A fixed percentage of revenues from produced gas are paid to the land-owner as royalty and this royalty is also negotiated as part of the mineral lease agreement. The royalty might range from 12.5% to 25% and does not get paid until production begins.

Once land rights are successfully obtained, techniques such as 3D seismic operations are used to study the surface. Reservoir engineers and geologists then study the potential amount of gas in the area. The well pad is strategically located while ensuring proper distances from water sources and designated environmental areas.

Operators are typically required to post collateral in the form of a bond for all activities in the pre-drilling, drilling, and post-drilling stages as per drilling regulations. The operator’s permit application is usually required to include details of the location and nearby locations that could be considered as being environmentally sensitive; this includes biodiversity hotspots, coal seams, and watersheds. Once the application is reviewed and approved, the operator can begin to organize the site construction.

2.1.2 Site Construction

Once all the paperwork is completed, the process of site construction begins, when civil engineers and construction workers begin to prepare the surface. The site construction typically includes activities related to erosion control, road construction, and infrastructure and facilities construction. At first, erosion control is installed for the purpose of protecting nearby highways and water resources (such as streams and creeks) from any potential damage that could be caused by the distribution of sediments and soil. The type of silt protection to be utilized is determined and could be in the form of either silt socks or silt fences. Silt socks are plastic mesh “socks” that are typically filled with wood chips. On the other hand, silt fences are usually black fabric fences that are held up by wooden stakes, or alternatively, they could be chain link fences with black fabric liners. However, the latter would generally cost much more than the former in terms of both materials and installation.

The next step is road construction, where an important goal is to minimize driving time to the pad while allowing ready access for heavy equipment. These are often private roads owned by the well operator. Once the road is built, equipment such as backhoes, bulldozers, blades, tractors, and rollers are moved to the site by a hauling company using heavy-duty trucks. This equipment is typically used to create the foundation for the pad.

After all equipment arrives on site, it is typically stripped and grubbed. The stripping process cuts down any trees on the land; trees thicker than six inches in diameter are usually sold for lumber. Smaller trees can usually be used for wood chips. Grubbing removes brush and tree stumps. After this stage the location can be leveled. The soil on the top of the site that is stripped can be saved and reserved for replenishment of the same location after well-closure. The area is cleared, and the ground is covered with several protective layers. Typically, there is a first layer of stone, followed by a layer of protective liner made from a combination of a geotextile fabric interwoven with a spray polyurea coating, and finally a mat made of advanced composites that serve to further protect against spills while also stabilizing the drilling rig that eventually goes on top of it. The protective liner creates a film barrier and serves as a secondary containment structure to hold any spills, such as chemicals, drilling mud, and drill cuttings that are generated during later steps. It also helps to absorb materials such as nuisance leaks, drips, and spills from mud tanks and frack tanks on contact, and prevents them from reaching the ground.

Once the earthwork is done, the base of the pad is typically constructed using rock and stone that is usually 8 to 12 inches thick. A finer aggregate material that is often 3 to 4 inches in size is then installed on top of this and makes the pad look similar to a parking lot. Housing for workers to live and sleep in, infrastructure for cell phone, Internet and satellite TV connections, and other temporary infrastructure are built to support the well site for when operations will begin. A power generator is also set up to offer power throughout the later stages.

2.1.3 Drilling

Once the well pad is constructed, extensive site setup steps are completed prior to actual drilling. This includes construction of security fencing, tanks for mud, brine storage tanks, an onsite office, restroom accommodations, and of course, the actual drilling rig. Many specific products and services are required in each of these steps.

A number of storage tanks are used to hold the lubricant (or "mud" as it is called) used in drilling and that is stored on site. This mud is a combination of water and bentonite clay. The specific number of storage tanks can be increased depending on the amount of fluid needed. The mud is used to lubricate the pipe and improve drilling rates when it is passed using hydraulic force generated by the circulating section. On a drilling rig, mud pumps are also used to circulate the mud, and air compressors are used to blow the air into the drill pipe to blow back the mud to the surface into a water bath along with soil cuttings. The soil cuttings are subsequently tested and separated from the mud, and either stored for reuse as ground-fill later on after the well is completed, or as is the more common case with Marcellus wells, disposed of in landfills or other disposal sites.

In traditional drilling, a mud pond is normally a trench lined with plastic that is used to store the water and cutting produced from drilling. It is constructed during site construction. In the mud pond, the cuttings and other heavy matter usually settle at the bottom during the treatment of the water. With horizontal wells the mud is separated from the other materials in specially designed separation tanks and moved into so-called roll-off boxes. Mud ponds and storage tanks must be designed to meet minimum standards that are specified for them.

As one of the major components of the drilling phase, the drill rig itself is designed and set up to meet the requirements of vertical and horizontal drilling. Rigging is usually either portable or reusable across manufacturers and drilling companies. Various sizes of drill heads, pipes and casings are used. The holes that are drilled have diameters that are reduced with depth so that each drill bit is replaced by a smaller one sequentially in the drilling process. As illustrated in Figure 9, once the well is drilled to a depth of around 5000 to 7000 feet it reaches the kickoff point where the change of direction occurs. The drill-head then turns and follows a lateral layer of shale horizontally for several thousand feet; the lateral layer to be fractured is often about 100 feet thick. The bore is normally around 4″ to 6″ in diameter. Directional motors with bend angles of 2 to 3 degrees are used to change the direction of the pipe; the length along which such a change in direction happens can be as much as 1000 feet. Each well has a single bore so that each well has its own vertical and horizontal drilling sections. The well is then drilled horizontally to approximately two miles or less, depending on the surrounding geology. Typically, a pad could contain as many as 15 wells depending upon its location and geological features, making the pad take the shape of a “spider”. It could take as few as 7 days to drill a single well.

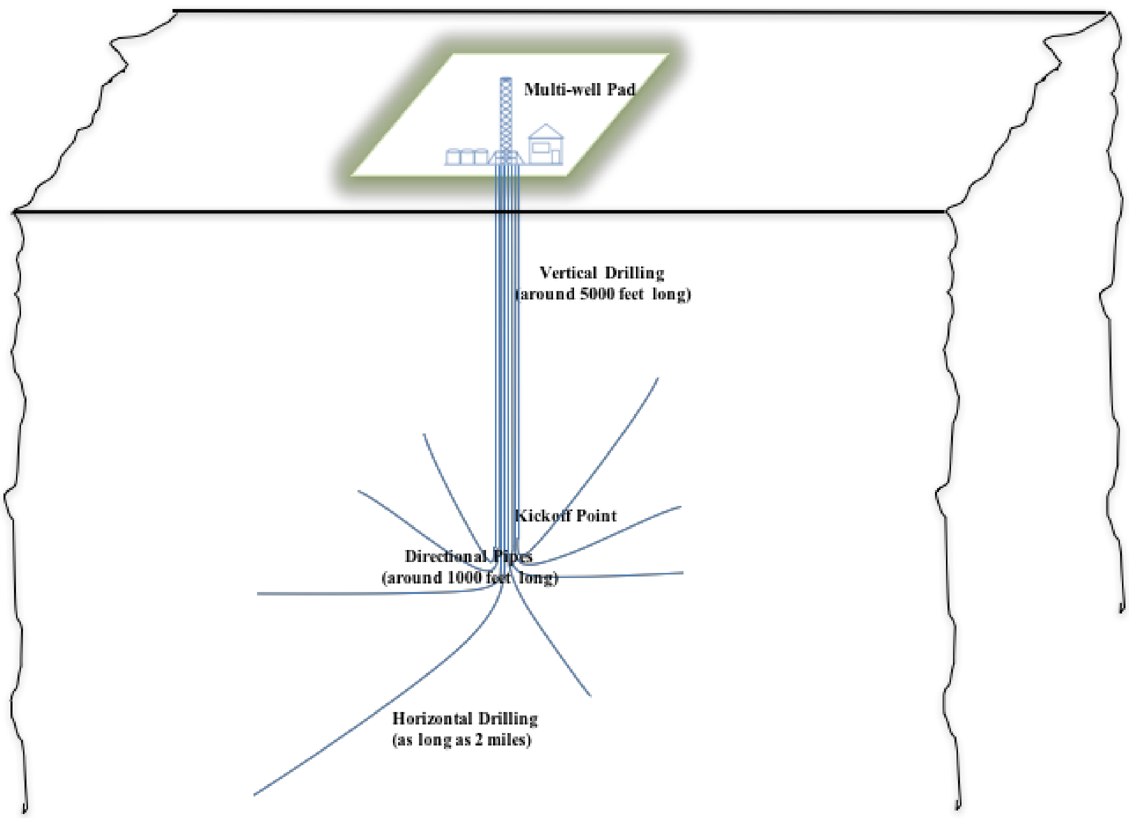


Figure 9. A Multi-Well Pad with 8 Wells

During the process of drilling the well, the integrity of the bore is maintained by sinking steel pipes (known as casing) and surrounding these with concrete to protect ground water from contamination. As shown in Figure 10, several layers of protective casing and cementing are required as protection. A conductor hole is drilled into the ground with a pile driver for a shallow depth of up to approximately 50 feet before erecting the drill rig so as to prevent the caving of soft rock. The conductor hole can also conduct mud from the bottom to the surface when drilling is conducted. A conductor casing is then cemented into place. Next drilling continues deeper and the surface casing is then cemented in place starting from about 100 to 500 feet below the earth's surface to protect fresh water reservoirs from being contaminated when the wellbore is drilled. A blow-out preventer is installed to protect against unexpected flows from deeper down, and as the drill goes deeper, intermediate casings are installed along the bore. Finally, the production casing is installed in the production zone along with a number of sophisticated geophysical tools used to gather various types of information; these are removed from the well once hydraulic fracturing is done. When drilling is completed the well is capped and after all wells in the pad are drilled the drilling rig is removed in preparation for fracking. At the same time, the gathering pipeline is laid out for when production will begin.

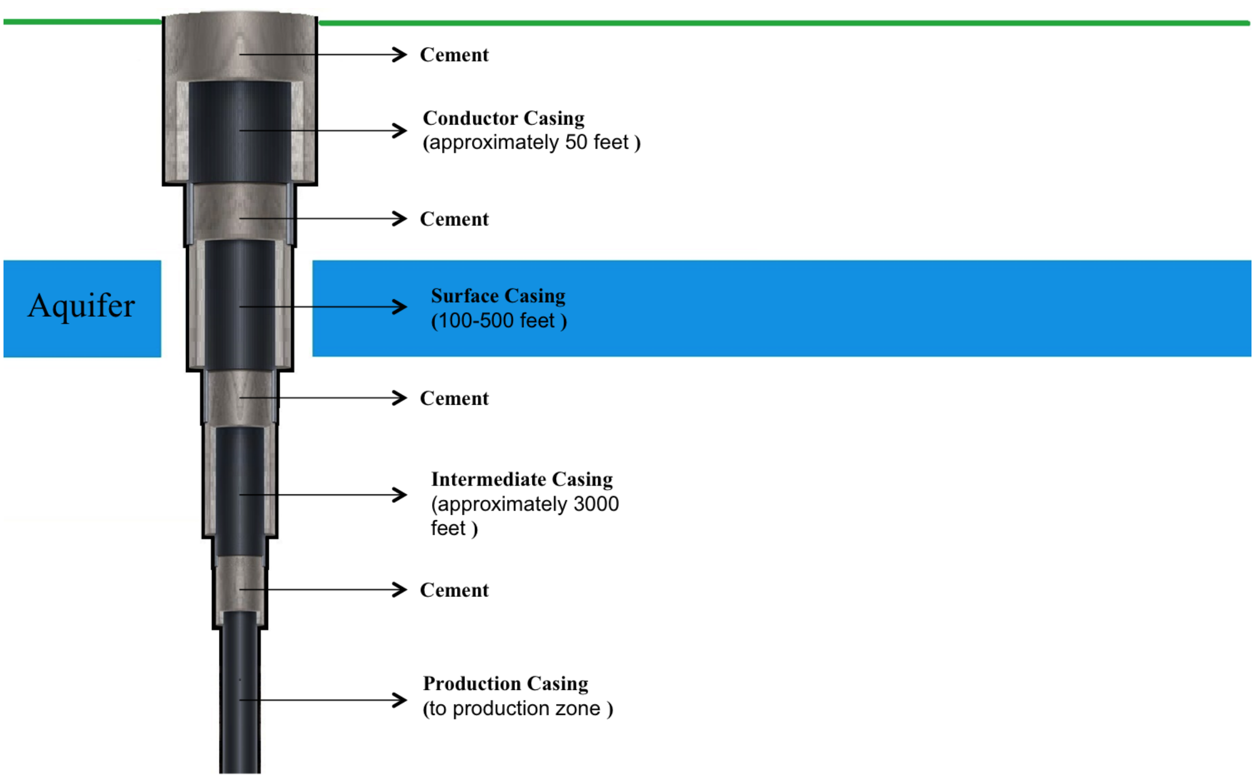


Figure 10. Casing and Cement

2.1.4 Hydraulic Fracturing

After drilling is done, the well operator can begin the shale gas well stimulation. If the market price for natural gas price is too low for a reasonable profit, well operators may choose to postpone fracking until a point in time when they think it would be profitable to get the gas flowing. Once the decision is made to start the gas flow, wells are prepared for hydraulic fracturing. In this process, fluid under high pressure is utilized to break up the shale rock formations in order to release the natural gas trapped inside the rock. Explosive charges are assigned to the designed location in the production casing to perforate the casing in order to move high-pressure fluid into the surrounding rock. Fracturing fluid -primarily a mixture of water and sand, with a small amount of chemicals – is then injected at high pressure into rock formations that are deep underground to fracture them so that gas is released from the rocks and flows upwards under pressure.

A major issue at this stage is the treatment of the flow back (the portion of the fracturing fluid that flows back). This can be reused in another fracturing job with or without pre-treatment depending on the fracturing fluid design, since the component content of the fluid is highly sensitive with respect to individual compositions. We present a detailed discussion about flow back treatment in Section 3.1.4.

Fracturing was used as a stimulation technique approximately 60 years ago, and how it is done today and equipment used is similar today. However, technological advances in hydraulic fracturing have enabled higher levels of efficiency, productivity and safety today, and the technology continues to devlop rapidly. Examples include modifications made to accommodate higher pressures, long lateral lengths, more frack stages that are closer to each other, better silica control, better air quality with lower emissions, dissolving balls instead of plugs to avoid plug drillouts, and sliding sleeves which do not require perforation prior to fracking. Somesignificant differences include (Crawford, 2013):

- *Directional Drilling*

  Figure 11 depicts the difference between a traditional vertical well and a directional well. With fracking of traditional wells there was only a vertical section and only the area surrounding the well could be fractured. With directional drilling the area that can be exploited is greatly increased and with multiple wells on the same pad this can be increased by an order of magnitude for a roughly similar surface footprint.

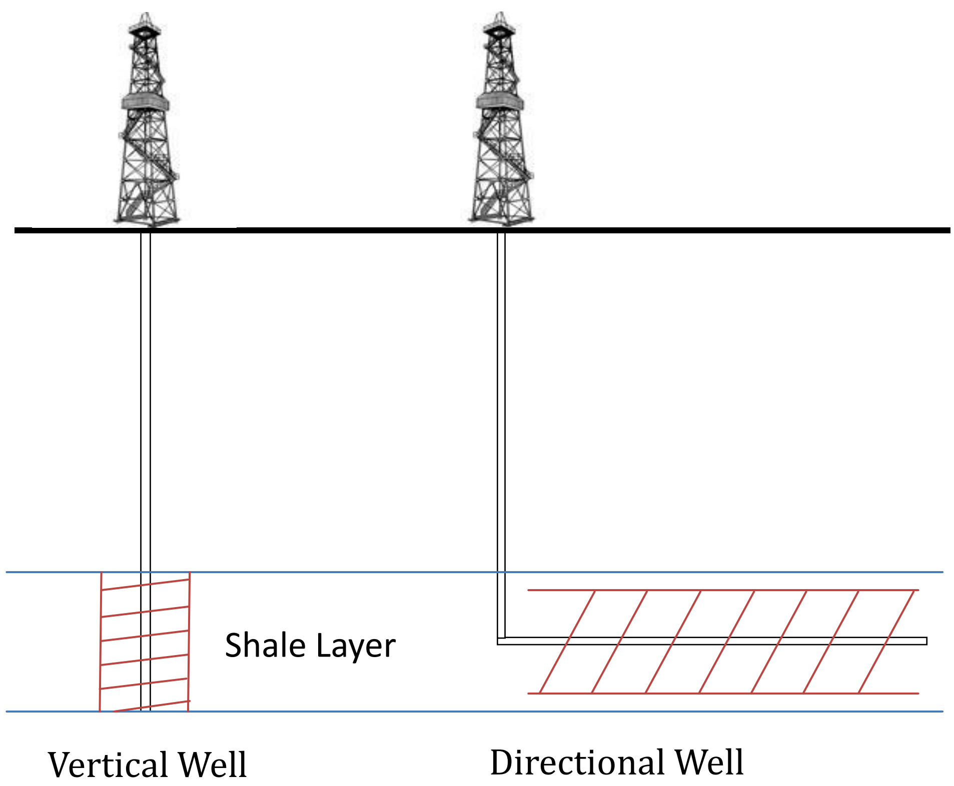


Figure 11. Vertical Well and Directional Well

- *High Volumes of Water*

A conventional (only vertical) gas well might typically use about 100,000 gallons of fracking water. On the other hand, millions of gallons of water are used in a well that uses hydraulic fracturing over a horizontal segment that could run for over a mile. Relative to environmental concerns, high volumes of fracking water are accompanied by challenges of higher environmental risks at each of the stages including water storage, transportation, disposal and recycling.

- *Fracking Fluid*

The main goal of the fluid in hydraulic fracturing is to penetrate and crack the shale surrounding the horizontal pipe, and to push sand into the cracks to keep them open so that natural gas can seep through the sand and run into the bore. The fluid used in this process is called hydraulic fracturing fluid and is mostly water with sand and some chemicals to lubricate the fracking water. These chemicals are added to make the fluid easier to pump down this very long and narrow bore and to maintain the required high pressure of around 6,000-10,000 psi until the end of the bore; this type of fracking fluid is also sometimes called slick water. Without the lubricant the fluid will lose pressure due to friction as it flows through a pipe with a small diameter. After fracking is completed the fracking fluid is flowed back and stored in on-site tanks and then transported to points where it can be recycled or disposed. Generally speaking, anywhere between 15 and 50%of fracking fluid flows back before gas production or returns later as produced water, the rest remain underground permanently(Marcellus-shale.us, 2016).

- *Multi-pad Fracking Wells*

  When fracking conventional wells, there is a single well per pad. With modern hydraulic fracturing today, multi-pad wells and directional drilling are commonplace, where a number of different wells (typically, ten or so each with its own horizontal section) are drilled from the same well pad. The surface footprint of a multi-pad well is not that much more than that of a single well in absolute terms, but a single multi-pad well with directional drilling has the potential to replace a number of single-bore conventional wells to generate the same amount of gas. The Marcellus Shale area was constructing about 4-5 wells per day, ramping up to 3,000-5,000 per year with the expected total number of wells to be roughly 40,000(Crawford, 2013).

The types of fracturing fluid commonly being used include slick water, linear gel and cross linked gel (Momentive, 2012). A fluid such as gelled propane may also be used. Slick water is the most commonly used fracturing fluid in shale gas wells because of its low cost, low treating pressure, and lower risk. We present a more detailed description of slick water in Section 3.1.3.

Compression equipment is usually rented to increase the hydraulic pressure of the fracking fluid to between 10,000 and 15,000 psi in order to fracture the rock. This is sometimes referred to as the "iron" and comprises a series of tractor trailers with compressors. The fracking is done in horizontal stages. Each stage is approximately 200feet long, and a well can have 30 to 60 horizontal stages. When fracking is completed sometimes tubing is placed inside the casing to stimulate the production (as it starts to drop off), and submersible pumping equipment can also be installed inside the tubing to further increase the flow of gas (this is also referred to as "artificial lift").

2.1.5 Completion

Once hydraulic fracturing is completed, the flow back water (water, sand, soil, chemicals) has to be processed and the well is flowed up until enough water is removed so that it can start production operations. The gathering pipeline is laid out in order to collect the natural gas that flows out after the flow back of fracturing fluid; sometimes the laying of the gathering pipeline will be done during pad construction. Trees and vegetation are removed from where the operator plans to dig pipeline trenches. Individual joints of pipe are placed on pipe skids above the soil and then installed into the trenches. After all joints of pipeline are installed, the trenches are carefully backfilled. The layout of pipelines usually involves two separate trenches where two different types of pipelines are installed. The high-pressure pipeline is used to transport the initial, strong gas flow under high pressure, while the low-pressure pipeline is utilized for the later, weaker flow.

After that, a "Christmas tree," which is a combination of equipment containing multiple components of tubing head and casing head, is installed at the wellhead. Because the gases and liquids flow back at a high pressure, the "Christmas tree" must be able to withstand 2,000 to 20,000 psi of pressure to protect the natural gas extraction from leaking and preventing blowouts at these high pressures. In addition, because of weather conditions and corrosive matter that might be present in the flow back, the "Christmas tree" must be made using corrosion-resistant materials that can operate in temperatures between-50°C (-58°F)and 150°C (302°F).

Once the wellhead and the gathering pipelines are complete, the ground is then refilled, in large part by using soil removed during the drilling process; the ground is usually covered in layers to avoid any potential pollution. Sometimes, the ground at a site is covered only with soil obtained from that same site in order to avoid environmental and ecological problems. The well can actually start production at any time after flow back is completed, and site remediation can occur later. The gas that is produced is sent to processing plants as required, and then transported along interstate or intrastate pipelines.

2.2 THE STABLESUPPLY CHAIN

The stable chain refers to the chain from the production of gas to the delivery of final product to the end customer. Unlike the transient supply chain, the stable one is similar to traditional natural gas supply chains, as shown in Figure 12. However, the boom in the shale gas industry does have an impact on the economy in terms of factors such as infrastructure renewal and interfaces with existing industries.

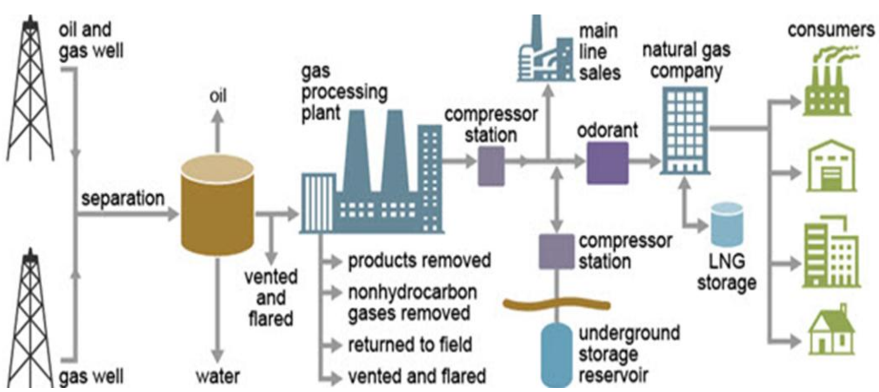


Figure 12. Natural Gas Production and Delivery

(EIA, Delivery and Storage of Natural Gas, 2014)

2.2.1 Production

After hydraulic fracturing and completion, gas starts to flow up to the ground and is fed into a gathering pipeline through which it is transported to a processing plant, other pipelines, or an end user. In the initial stages the flow of shale gas is automatic due the natural pressure inside the shale, making the production of natural gas over time continuous. However, the production rate changes over time. As shown in Figure 13, initially hydraulic fracturing releases the gas suddenly from the natural fracture networks and pores, thus causing a peak in gas production rate. After that peak, the shale rock's naturally low permeability and gradual pressure loss combine to make the rate decline during the life span of the well, and eventually the gas needs to be compressed and pumped (artificial lift).

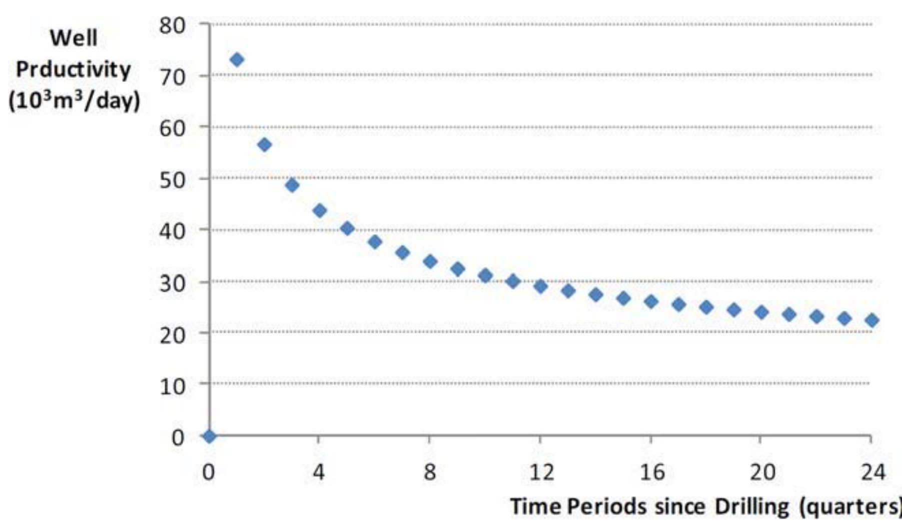


Figure 13. Discrete-time Well Productivity Profile

(Cafaro & Grossmann, 2014)

In summary, the gas production rate at a single well is a decreasing function of the age of the well. Generally speaking, the production rate of an unconventional natural gas well typically begins with a flush at the initial stage, then decreases exponentially and then flattens out after 3-5 years. In the following decades, the well continues to produce gas at a relatively low rate, for over 20 years in some cases. The recovery rate is lower than conventional gas but technology advances will likely increase this (Bahadori, 2014). Research based on gas production in the Barnett Shale has also shown that the production rate of shale gas follows a simple scaling rule: in the early stages (typically 5 years), it declines as 1 over the square root of time; in the later stages the rate declines exponentially. The same study generated an accurate descriptive model for shale gas production that was consistent with 8,294 older wells in the Barnett Shale. Another 2,057 younger wells showed the exponentially declining trend that is predicted by the scaling theory, while the remaining 6,237 wells in the analysis were "too young to predict when exponential decline will set in, but the model can nevertheless be used to establish lower and upper bounds on well lifetime."(Patzek, Male, & Marder, 2013).However, a new round of hydraulic fracturing can enhance permeability and thus increase the production rate. The extra hydraulic fracturing when the production rate begins declining is called "refracking" or "refracturing" and can be expected to enable wells to increase production flow rates.

In addition, there are other things that change over the life cycle of a gas well. As the reservoir of a well is depleted, although the composition of gas produced from the well is typically consistent, the quantities of different constituents may vary over time. The primary composition of shale gas is methane (CH_4), but it also includes large quantities of ethane (C_2H_6), propane (C_3H_8), butane (C_4H_{10}), and pentane (C_5H_{12}). Hexane (C_6H_{14}) and heavier hydrocarbons might also be present. Many gases also have nitrogen (N_2), carbon dioxide (CO_2), hydrogen sulfide (H_2S), and other sulfur components such as mercaptans (R-SH), carbonyl sulfide (COS), and carbon disulfide (CS_2). There are three types of natural gas in the reservoirs: dry gas, which is almost pure methane; wet gas, which is gas with other hydrocarbons and exists in liquid phase at surface conditions; and condensate gas, which is gas with a high content of hydrocarbon liquids. The primary product of natural gas after processing is dry gas (methane), and the byproducts are normally ethane and other natural gas liquids or NGLs (Mokhatab, Poe, & Mak, 2015).

Besides methane and common byproducts, gas reservoirs often contain water and hydrocarbons, thus gas wells produce water along with the production of gas, such water is called produced water, "brine", "saltwater", or "formation water." It is distinct from the initial flow back because it comes out with gas even after flow back stops, as long as the well is generating gas. This produced water must be removed and often there is dehydration equipment on site to handle this processing. If the gas being produced is wet gas, then further processing is required to handle the heavier natural gas liquids. Because the water was mixed with the hydrocarbon in the shale formation for a long time, it may have similar chemical characteristics of the shale formation and hydrocarbon. However, its chemical and physical properties vary significantly according to the type of hydrocarbon, geographic location, and formation of the shale. The properties and volume may even change through the lifetime of a reservoir. In general, the major constituents include dissolved salt and solids, various naturally organic or inorganic chemicals, and chemical additives utilized during hydraulic fracturing and drilling. Some produced water obtained in shale formations may also hold low level of natural radioactivity. The produced water needs to be treated in facilities designed for this purpose, transported, and then either reused or disposed. The total cost of managing produced water, including the construction and operation cost of facilities, permitting, monitoring and transportation, range from 1 cent per barrel to $5 per barrel depending on its properties and location. By one estimate, approximately 21 billion barrels (882 billion U.S. gallons) of produced water are generated from about 900,000 wells in the United States per year (Colorado School of Mines, 2013).

2.2.2 Processing

To get to the final customer, gas may need to be processed into uniform quality gas, which has specific quality measures. Oil, water, natural gas liquids, and other impurities such as sulfur, helium, nitrogen, hydrogen sulfide, and carbon dioxide are typically removed during processing at either the well site or a processing plant (Mokhatab, Poe, & Mak, 2015). The processes to transform wellhead natural gas to pipeline-quality dry natural gas include (EIA, Delivery and Storage of Natural Gas, 2014):

- *Gas-oil-water separators*

  In a one-stage separator, pressure relief separates gas from oil. However, a multiple stage separation process is necessary to separate different fluid streams in some cases.

- *Condensate separator*

  Condensates are often removed from the gas stream directly from the wellhead by using separators much like the gas-oil-water separator. Extracted condensate is stored in tanks.

- *Dehydration*

  To avoid condensation and hydrates in the pipeline, dehydration is applied to eliminate water.

- *Contaminant removal*

Contaminant removal includes the elimination of hydrogen sulfide, carbon dioxide, water vapor, helium, nitrogen, and oxygen to acceptable levels typically using techniques to direct the flow in a tower containing an amine solution. Hydrogen sulfide and carbon dioxide are absorbed by amines from natural gas. Amines can be recycled and reused.

- *Nitrogen extraction*

Molecular sieve beds are used to dehydrate Nitrogen in a Nitrogen Rejection Unit (NRU).

- *Methane separation*

To separate methane from natural gas liquids, cryogenic processing and absorption methods are applied in the gas plant or in the NRU operation.

- *Fractionation*

Fractionation is the process of separating various components of the NGL stream by using different boiling points of the individual hydrocarbons and temperature control.

In the year 2014, there were 19,754,802million cubic feet of natural gas processed in over 500 operational natural gas processing plants with combined operating capacities of approximately 77 billion cubic feet (Bcf) per day(over trillion cubic feet annually) in the United States(EIA, Natural Gas Processing Plants in the United States, 2011) (EIA, Natural Gas Plant Processing, 2015). However, the specific stages and techniques in each processing plant are highly sensitive to the composition of the wellhead natural gas; stages may be integrated into one unit, and operated in a different order or at different locations. In a specific gas well, some stages can even be skipped. The various qualities of wellhead gas make the features and capacities of their nearby processing plants different, as shown in Figure 14, and the capacity of a natural gas processing plant can range from 0~50 mmcf/d to 8500mmcf/d in the United States.

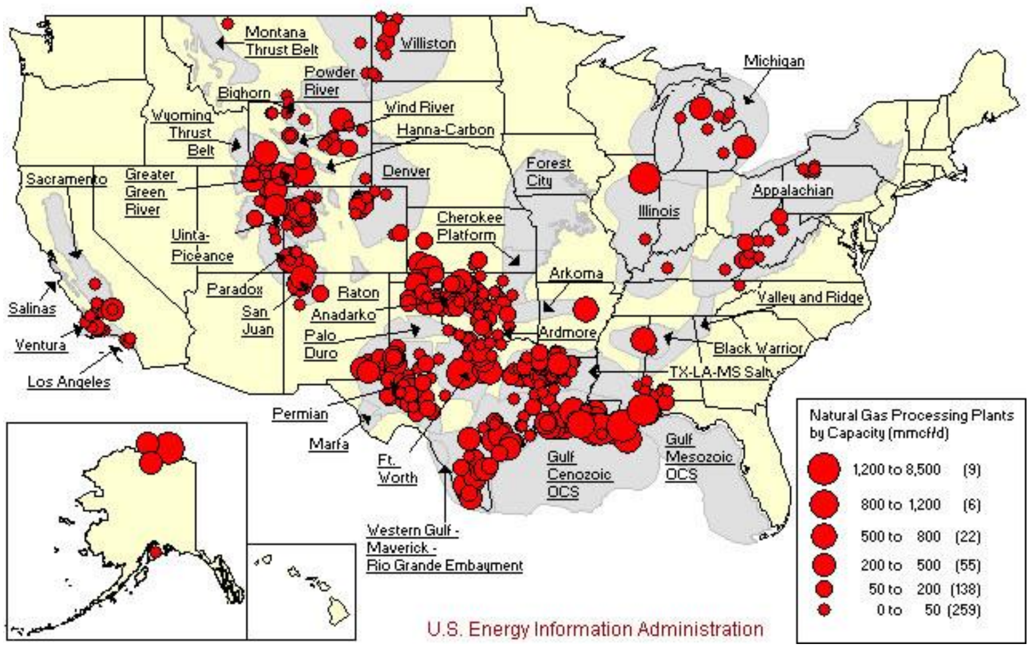


Figure 14. Natural Gas Processing Plants and Production Basins, 2009

(EIA, Natural Gas Processing Plants in the United States, 2011)

2.2.3 Gas Distribution

After shale gas is processed into the standard quality, it needs to be brought to the market area via transmission pipes. In order to maintain the standard quality and monitor its condition, facilities such as compressor stations, metering stations, valves, and control stations are involved. Finally, a gas market hub is where natural gas is priced and sold to customers in an open market.

- Transmission Pipes

Natural gas pipeline systems run from the gas well, through the processing plant and different receipt points, and finally to the principal customer areas. The natural gas transmission pipeline is used as the major mode for natural gas distribution. Pipelines can vary widely in diameter and distance depending on their types. The common types of transmission pipelines include (EIA, Delivery and Storage of Natural Gas, 2014):

1) Intrastate natural gas pipelines, which operate and transport natural gas within a state.

2) Interstate natural gas pipelines, which operate and transport natural gas across state lines.

3) Hinshaw natural gas pipelines, which receive natural gas from interstate or intrastate pipelines and deliver it to consumers.

After the natural gas is delivered to the consumption communities, it flows into smaller-scale pipelines named mains. Service lines, which are the smallest lines, connect the mains to the facilities where the natural gas is used.

- *Compressor Stations*

In order to maintain standard quality, especially the required high pressure, compression stations (also called pumping stations) are required at regular intervals along the pipelines, and are usually located 40 to 100 miles apart. Figure 15 provides a view of the distribution of natural gas compressor station. The pressures required for different pipelines can varying hugely: natural gas flows in interstate pipelines are compressed up to 1,500 pounds per square inch (psi), while natural gas flows in the distribution network may have as little as 3 psi of pressurization or ¼ psi at the customer's area(NaturalGas.org, Natural Gas Distribution, 2013). The size of compressor stations and the number of compressor engines (pumps) vary based on the diameters and types of the pipe and the volumes of gas flow.

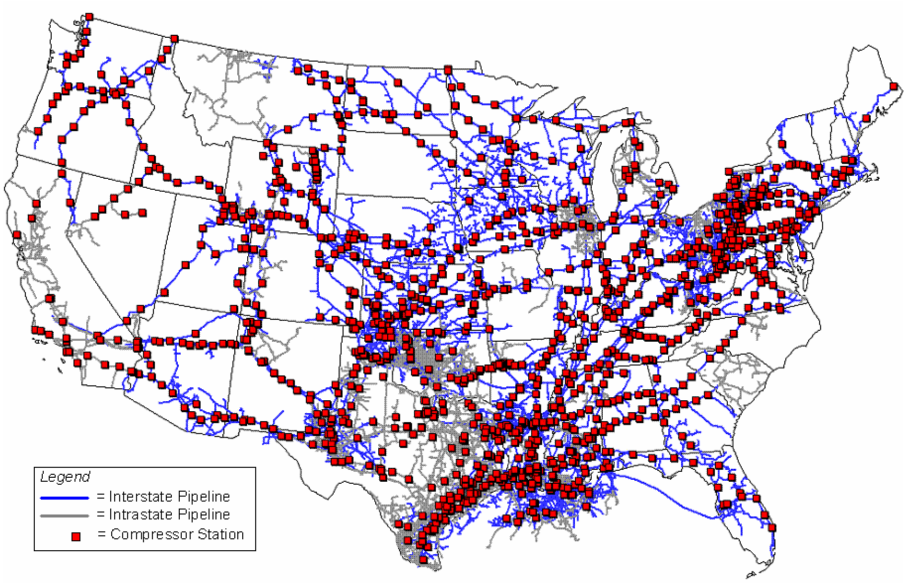


Figure 15. Natural Gas Compressors

(EIA, U.S. Natural Gas Pipeline Compressor Stations Illustration, 2008)

Generally speaking, there are three types of compression engines (INGAA, 2015):

1) Turbine/Centrifugal Compressor

The Turbine/Centrifugal Compressor uses a large fan inside a case to pump the gas as the fan is running. In order to power the turbine, a small part of natural gas in the pipeline is burned to run the natural gas-fired turbine.

2) Electric Motor/Centrifugal Compressor

The Electric Motor/Centrifugal Compressor is driven by high-voltage electric motors. No air emission permit is required for this type of compressor since no hydrocarbons are burned as the fuel to start the engine. However, the supply of electric power should be reliable enough to make these units feasible; such electric power supply must also usually be close to the compressor to lower the energy lost in electricity distribution.

3) Reciprocating Engine/Reciprocating Compressor

Reciprocating Engine/Reciprocating Compressors, also known as "recips," are generally larger than any other type of compressor. Natural gas from the pipeline is used to start these automobile engines. In a cylinder case on the side of the unit, natural gas is compressed by reciprocating pistons, which are connected to the power pistons along a common crankshaft. One of the advantages of reciprocating compressors is that the gas volume pushed in the pipeline can be adjusted incrementally to meet changes in gas demand.

- *Metering Stations*

Along the interstate natural gas pipelines in which standard natural gas is transported over thousands of miles, metering stations are positioned periodically to allow enterprises to monitor the status and volume of the natural gas that is transported. The metering stations use specialized meters to measure the natural gas flow through the pipeline without impeding the movement and pressure of the gas flow (Seydor, et al., 2012). To measure the gas flow, the meters used in metering stations may include orifice meters, turbine meters, ultrasonic meters, or positive displacement meters (INGAA, 2016).

- *Control Stations*

Sophisticated control systems are used to monitor and manage the gas through all sections along the transportation pipeline network. The control station can manage the natural gas entering into the pipeline and ensure the timely delivery of this gas to the customer. Data received from compressor stations and their monitoring systems are collected, assimilated and analyzed in the control station to accomplish the task of monitoring and controlling. Typically, this data is provided by the Supervisory Control and Data Acquisition (SCADA) system, which is a real-time system that can centralize the data measuring the flow rate, operational status, temperature and pressure in order to enable quick reactions to unusual activity such as equipment malfunctions or leaks, and even remote operation (Seydor, et al., 2012).

- *Valves*

Pipeline companies also install valves along the interstate natural gas pipeline system to offer a standard controlled flow. Regulations stemming from appropriate safety codes specify the distance between two valves and this normally ranges from 5 miles to 20 miles. The valves are usually open except when a section of pipeline needs replacement or maintenance, at which time the valves are closed by operational engineers to isolate that section of pipeline. Once the section is isolated, the gas inside is normally vented to make sure that the maintenance crew can finish the maintenance work (INGAA, 2016).

- *Hubs and Citygate*

Natural gas is normally traded and priced at more than 30 major market hubs throughout the United States at the intersection of the major pipeline system, as illustrated in Figure 16. The price of natural gas that is traded through the major hubs varies based on supply and demand. Traditionally, the price at the Henry Hub in Louisiana is considered as a measure of price for gas traded on the New York Mercantile Exchange (NYMEX) for physical delivery. In addition, the price difference between another hub and the Henry Hub is called the location differential. Figure 17 provides the price difference at key trading hubs from 2014 to 2015; generally speaking, the prices are roughly at the same level, but could occasionally be significantly different. A detailed discussion of natural gas prices is presented in Section 4.2.

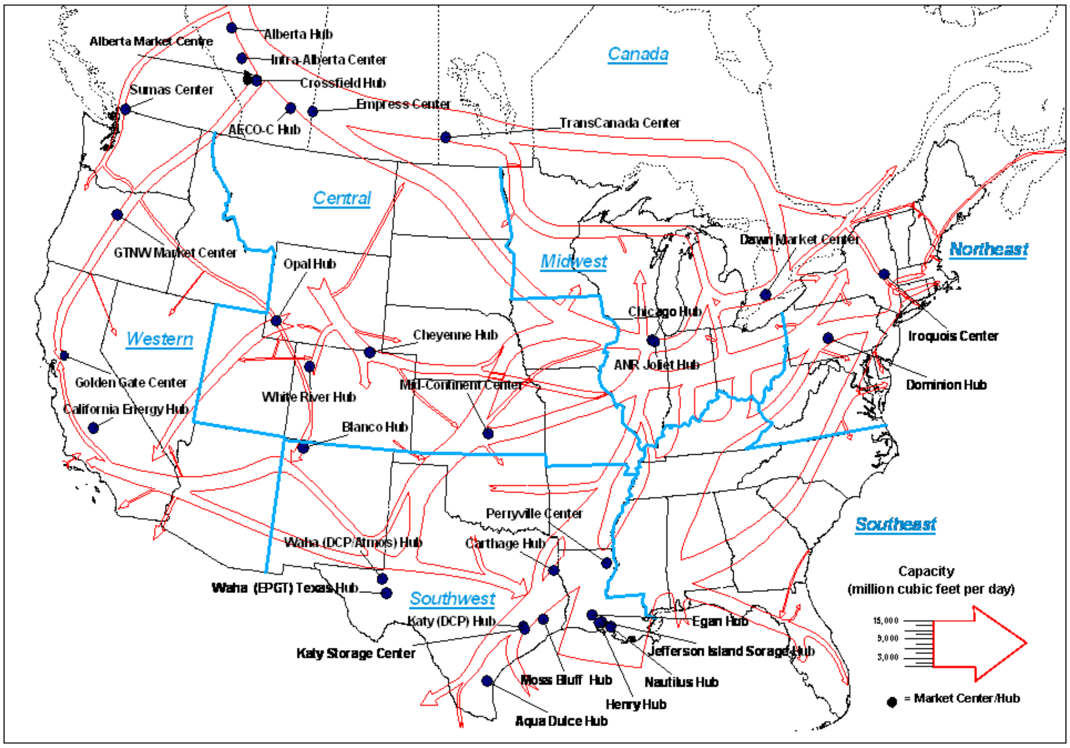


Figure 16. Natural Gas Market Centers and Hubs

(EIA, Market Centers and Hubs, 2009)

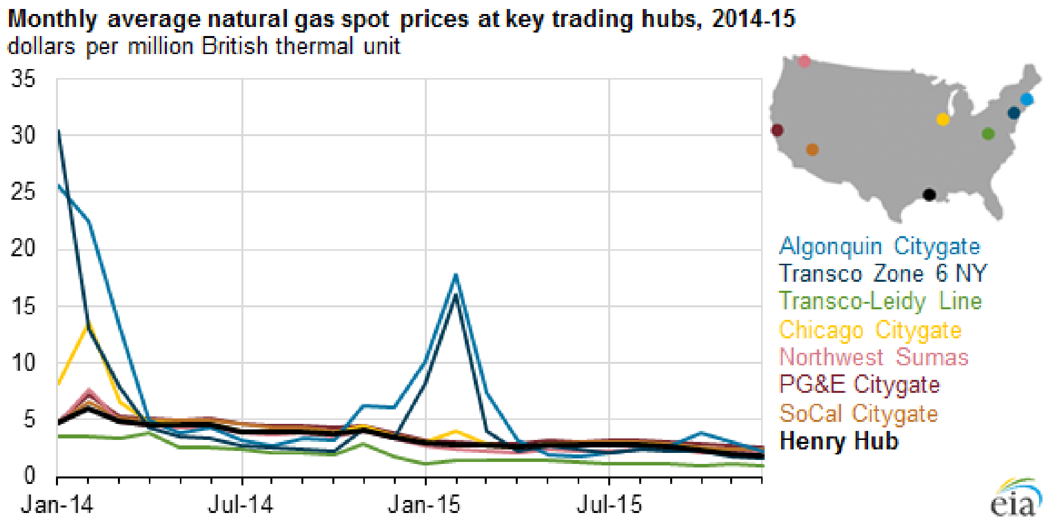


Figure 17. Monthly Average Natural Gas Spot Price at Key Trading Hubs

(EIA, Average annual natural gas spot price in 2015 was at lowest level since 1999, 2016)

On the other hand, natural gas can also be priced at the citygate, which is where a local distribution company receives gas from the pipeline. The citygate at a major metropolitan center offers another point for the natural gas delivery price.

2.2.4 Storage

Natural gas inventory is usually stored underground and used as a seasonal supply backup to deal with price fluctuations and supply shortages. There are three types of natural gas underground storage facilities usually used, as shown in Figure 18 (EIA, Delivery and Storage of Natural Gas, 2014):

- *Depleted natural gas or oil fields*

  Depleted natural gas or oil fields are the most common way to store natural gas as well as oil in the United States. They are usually close to consumption centers.

- *Salt caverns*

  Salt caverns are widely used in the Gulf Coast states in the form of salt domes, while in the Midwest, Northeast, and Southwest, they are usually leached from bedded salt formations. Salt caverns offer large quantities of withdrawal and injection rates, compared to their working gas capacity.

- *Aquifers*

  In the Midwest, aquifers are converted to gas storage reservoirs in the case that the impermeable cap rock overlays the water-bearing sedimentary rock.

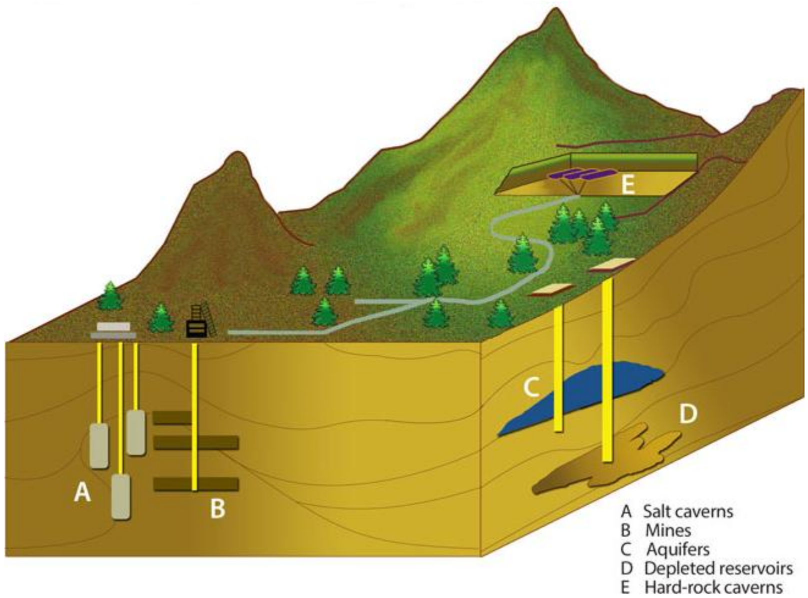


Figure 18. Natural Gas Underground Storage Facilities

(EIA, Delivery and Storage of Natural Gas, 2014)

The purpose of natural gas storage is to accommodate natural gas price fluctuation as well as fluctuations in supply and demand. Figure 19 provides the relationship between natural gas price and storage volumes from 2000 to 2015. Generally speaking, a high price tends to lead to low storage and vice-versa, but there are occasional periods when the price and storage are both at high levels (e.g., summer of 2005). A detailed description of the influence of storage on price is presented in Section 4.2.

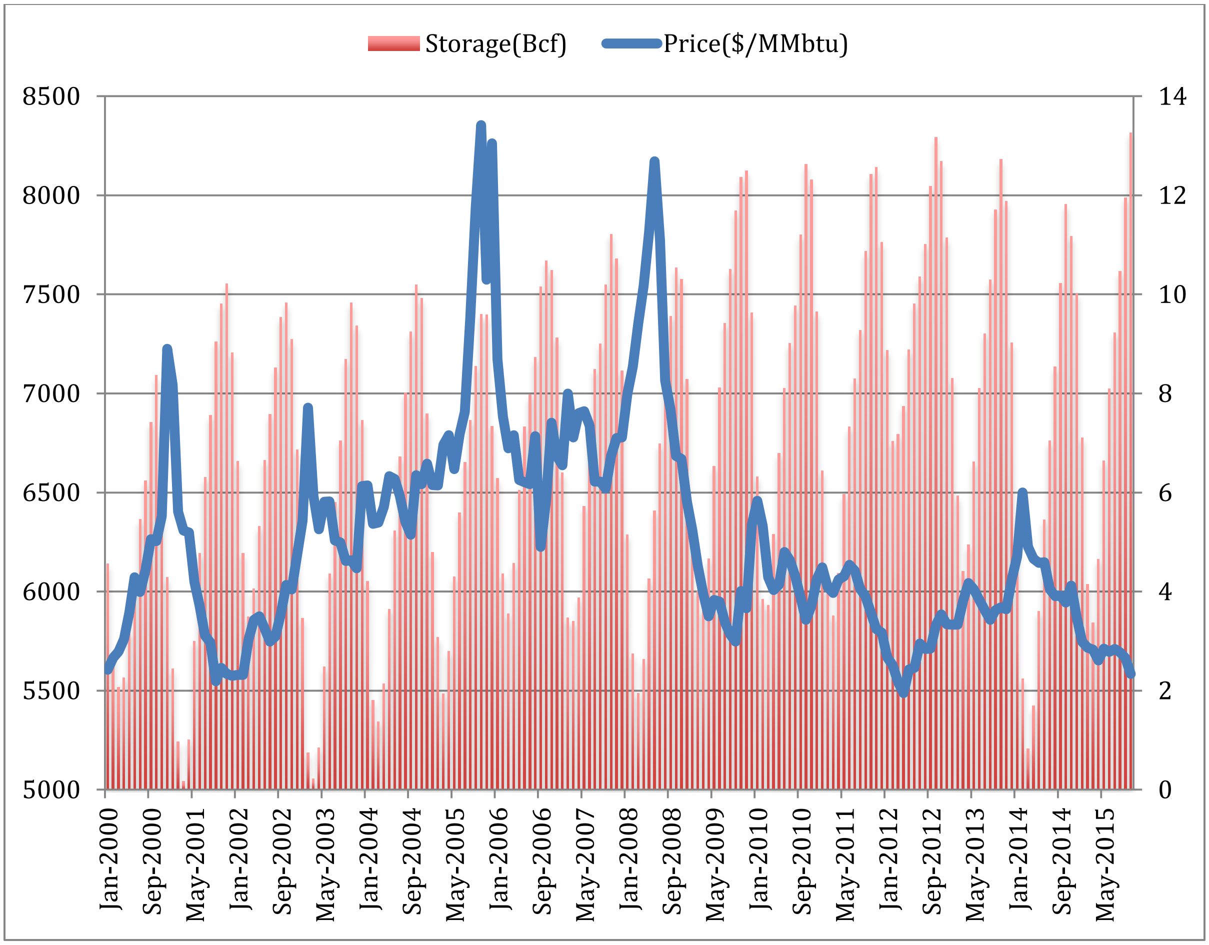


Figure 19. Natural Gas Storage Levels and Corresponding Prices

Data Source: (EIA, Weekly Natural Gas Storage Report, 2016)

3.0 FLOWS IN THE SUPPLY CHAIN

As discussed in Chapter 2, we divide the shale gas supply chain into two parts: the transient supply chain, which is before production, and the stable supply chain that is after production. Once the well starts to produce gas, it is similar to traditional natural gas in terms of flows. However, the unique drilling and extraction approach has made the material and financial flows in the transient supply chain distinct from the traditional one. In this work, we focus primarily on the flows in the transient supply chain.

While there are many arrangements possible for who does the work, ranging from well operators to their subcontractors and providers, the transient supply chain of shale gas is often highly subcontracted, i.e., the functions in this chain are typically spread across a number of different enterprises. Once the well operator completes the early steps of exploration, leasing, acquisition, and permitting, the later steps or large parts of the later steps are typically subcontracted to other companies with the well operator serving as an overall coordinator. In each such step, the well operator will typically pay another company a total price that is negotiated beforehand to do the specialty work that it has been employed to do. This arrangement applies to entities such as construction companies, a drilling company, pipeline providers, a perforation company, and a fracking company. Typically, the subcontractor will provide most of the materials involved as part of service. However, the well operator might also provide some of the components and materials such as drill pipe, drill bits, and small equipment such as electrical, safety, metering and other such devices; these might be rented or purchased by the well operator.

While subcontracting is common, there are also some operators (typically, large players like Shell and Exxon) who can be vertically integrated, and there are also a few companies (e.g., Halliburton) that provide comprehensive services. However, to minimize cost and risk, vertical integration tends to not be the norm, especially for smaller players. Due to the instability and unpredictability of natural gas prices, the well operator might drill or frack many wells in a relatively short interval of time when the market price of natural gas is considered to be attractive, or shut in the well and stop drilling and fracking for a relatively long period when natural gas prices are at a lower level. The variation in operational demand and high specificity in different steps could result in huge labor costs and carry potential risks of mismatches between labor required and labor available. Thus, well operators, and especially smaller players in the gas exploration and production sector, tend to focus on organizing, negotiating and contracting with their subcontractors, and leave the specialized work to the specialist companies.

The planning of the supply chain to support each of the stages in gas production can also be difficult because wells are typically located near small communities that might object to unusual disruptions such as heavy truck traffic. There are other complications as well; for example, even if the well itself is located in a remote location, trucks might not be allowed during the hunting season, so that all materials need to be delivered before this time. In addition, it is often hard to guarantee delivery times and quantities; so well operators tend to sign multi-source contracts.

3.1 MATERIAL FLOWS

The material flows in the transient supply chain of upstream natural gas usually have two characteristics. First, most of the large equipment on site is often rented. Such equipment is commonly provided, transported and maintained by the subcontractors. Second, a large portion of the materials and components used on site are on consignment. Thus, these items are transported and stored on site but the operator is charged only when they are actually used. This kind of a business model is popular in the shale industry because it allows well operators to eliminate inventory holding costs and reduce risks. On the other hand, the manufacturers also benefit because of the increased possibility of their product being used on account of it being conveniently available to the operator on site.

The lead-times of the materials and devices that are purchased by the well operator are relatively short, given the fact that these are almost small devices such as electrical devices, safety devices, metering devices, and automatic devices. The normal lead-times are around one month, for some of the smaller and more common devices these could even be as short as 2 to 3 days. A small portion of them could also have lead times as long as two months. In general, the lead-times of other materials are not an issue in planning since the early steps of exploration and permitting often take a sufficient amount of time to schedule the necessary reorder and compensate the lead-times.

3.1.1 Site Construction

Once all the paperwork is done, the well operator organizes the site construction. Table 2 lists the materials, components and equipment typically required during site construction. Each specific operation might be the responsibility of a different company. The subcontractors often provide and rent out the equipment related to their work. These different kinds of equipment are usually transported to the site by a hauling company using heavy-duty trucks. However, items such as stone, rock, silt protection and protective layers are typically purchased by the well operator. In addition, Table 3 shows the by-products in construction. Typical by-products include wood chips and lumber as described in Section 2.1.2.

Table 2. Material Flows in Site Construction

No.	Operation	Material/Component /Equipment	Buy/ Lease	Transportation	Purpose
1	Erosion control	Erosion controls / Silt protection	Buy	Organized by operator using trucks	To protect water resources
2	Road Construction and Surface Preparation	Backhoes, dozers, blades, tractors, grubbing, and rollers	Lease	By a hauling company using heavy-duty trucks	To create the foundation for the pad
		Protective layers / liners	Buy	Organized by operator using trucks	To protect the surface
		Stone and rock	Buy	Organized by operator using trucks	To construct the pad
3	Facility Construction	Infrastructure for housing, cellphone and satellite TV connection	Buy	Trucks	To support the well site when operations begin
		Communication tower and its components	Buy	Trucks	To transmit and receive data
		Power generation	Buy	Trucks	To offer power

Table 3. By-product in Site Construction

Operations	By-product	Transportation	Purpose
Road Construction and Surface Preparation	Trees smaller than six inches in diameter	Trucks	To be used for wood chips
	Trees thicker than six inches in diameter	Trucks	To be sold for lumber

3.1.2 Drilling

The drilling step is usually subcontracted to a drilling company, which is responsible for all aspects of the drilling operation and the required equipment; these are listed in Table 4. Materials such as water and drilling mud are also purchased and transported to the drilling rig by the subcontractor. However, some components and devices such as drill pipe and drill heads are often leased or purchased by the well operator and stored on site for use by the drilling company. While these components are utilized by the drilling company the well operator is responsible for any item damage or loss. The well operator also purchases materials such as casing, cementing and geophysical tools on consignment.

Table 4. Material Flows in Drilling

No.	Operation	Material/Component /Equipment	Buy/ Lease	Transportation	Purpose
1	Site setup	Drillers Cabin	Lease	By drilling operator using trucks	To provide interface controls, information system
		Drilling Mud	Buy	By drilling operator using trucks	To lubricate the pipe and improve drilling efficiency

Table 4 (continued)

		Water	Buy	By drilling operator using trucks or pipes	To lubricate
		Storage tanks	Lease /Buy	By drilling operator using trucks	To hold the mud and water to be used
		Shaker, desander, desilter, degasser, agitator	Lease	By drilling operator using trucks	On site mud preparation
		Mud pumps	Lease	By drilling operator using trucks	To circulate the mud
		Air compressors	Lease	By drilling operator using trucks	To blow back the mud
		Mud pond	Lease	By drilling operator using trucks	Tostore the water and cuttings produced from drilling
		Mud gas separator	Lease	By drilling operator using trucks	To separate mud and gas
2	Drilling	Rig Mover	Lease	By drilling operator using trucks	To move the rig and pipe
		Drill pipe, drill collars	Lease	By well operator using trucks	To conduct the drill head and change drilling direction
		Drill bits	Lease	By well operator using trucks	To penetrate the soil
		Casing and Cementing	Buy	By well operator using trucks	To stay as a seal for well integrity, safety and provision of a barrier to isolate production from groundwater
		Geophysical tools	Buy	By well operator using trucks	To gather various types of information required during drilling

As shown in Table 5, common by-products include used water, mud and soil cutting. Water and mud may be treated in a treating plant and are either reused in another well when feasible or alternatively, transported for disposal. Soil cuttings are first tested for radiation, and then reused as ground-fill later or transported for disposal.

Table 5. By-product in Site Construction

Operations	By-product	Transportation	Action
Drilling	Soil cuttings	Trucks	To be tested, then reused as ground-fill or to be transported for disposal
	Used Mud	Trucks	To be treated and reused
	Water	Trucks or pipes	To be reused in another well, to a treatment plant, or to be transported for disposal

3.1.3 Hydraulic Fracturing

The step of hydraulic fracturing is also usually subcontracted to a fracking company that provides and transports water, sand, chemicals and other required equipment such as tanks and pumps to generate fracturing fluid on site as part of its service.

Slick water is the most commonly used fracturing fluid in shale gas wells. It is a water-based fluid with a low viscosity of 2 – 3 cP (centipoise, which corresponds to 0.01 poise.) Solid materials, typically sand or man-made ceramic materials, are added to slick water as a proppant, whose task is to keep an induced hydraulic fracture open during or following a fracturing treatment. Certain chemicals may also be added to the fluid as other common additives. Slick water was first used in the Barnett shale as a fracturing fluid containing 800,000 gallons of water and 200,000 lb. of sand. It is typically composed of:

- Water

  Just like its name implies, the largest percentage (over 90%) of slick water is made up of water. Typically, water is provided by the well operators and transported by trucks making thousands of trips, or via temporary pipelines that are installed below or above the ground before fracturing. Most of the water (roughly 65%) is transported from lakes, rivers, and creeks, while the remainder is purchased from municipalities (Seydor, et al., 2012). The amount of water used in slick water today is typically much more than in earlier fracturing fluids, and consumption is usually between one and five million gallons of water per fracturing operation. However, not all of the water is lost when fracturing is complete. When gas begins to flow out, the natural pressure inside of the shale can bring roughly 15% to 40% of the water used in fracturing back to the surface. This water is called *flow back*, and is treated during the completion stage and possibly reused as discussed in Section 3.1.4. Furthermore, operators are now finding more ways to treat and reuse flow back water in order to minimize overall water consumption.

- Sand

  Sand, at 10%, makes up the second largest component in slick water. The sand is specialized to the task and its large density, special shape, and its strength against crushing keep the fracture in the shale rock open, so that the fissures in rock that is thousands of feet under the surface will not be blocked once it is fractured by slick water, and gas can thus flow out continuously. The sand used in slick water comes from different places. For instance, it could be brown sand from Texas, or Ottawa sand that is transported from the northeastern part of the United States or imported from Canada. For the Marcellus shale, much of the sand used is Northern White sand from Wisconsin.

- Chemicals

Chemicals or additives usually represent less than 1% of slick water. Some chemicals such as polyacrylamide are usually injected into slick water as friction reducers to speed up the mixture of water, sand, and other chemicals on-site. Biocides, surfactants and scale inhibitors are also normally found in slick water. Biocides, such as bromine, methanol and naphthalene, are used to kill organisms and prevent clogging the fissures and the long pipeline inside the well. Surfactants, such as butanol and ethylene glycol monobutyl ether (2-BE), can keep the sand suspended in the fluid. Scale inhibitors, typically containing hydrochloric acid and ethylene glycol, are added to control and prevent scale deposition.

Other chemicals including benzene and chromium may also be used. Many of these chemicals are considered to be toxic and thus raise public concern about potential water pollution issues. However, reports of actual contamination in drinking water are quite rare since hydraulic fracturing activities are heavily regulated by governments and state agencies (Wikimarcellus, 2010). In addition, improved well designs that utilize multiple layers of steel pipe and cement through the water table also help prevent any contamination and pollution of the ground water from occurring.

Table 6 concludes the materials included in the fracturing fluid. A detailed list of chemicals used in slick water, along with their Hazard Rating, may be found in Table 21 in Appendix.

Table 6. Materials used in Slick Water

Component	Percentage	Purpose	Examples
Water	More than 90%	Base of fracturing fluid	Water from lakes, rivers or creeks.
Sand	Nearly 10%	To keep fractures in the shale open	Ottawa sand, Texas sand, Brady sand.
Friction Reducers	Less than 1%	To speed up the mixing process	Polyacrylamide
Biocides		To kill biological organisms	Bromine, methanol and naphthalene
Surfactants		To keep the sand suspended in the fluid	Butanol, 2-BE
Scale inhibitors		To control and prevent scale deposition	Hydrochloric acid, ethylene glycol

As shown in Table 7, water is commonly transported from lakes, rivers, creeks, and/or nearby municipalities by trucks or pipeline. Sand is often transported via trucks or rail over long distances from Texas, Minnesota, Wisconsin, and the northeastern part of the United States or even imported from Canada; thus the lead-time of sand can be quite high. Water, sand, and chemicals are stored on site and mixed in tanks.

Table 7. Material Flows in Hydraulic Fracturing

Operation	**Material/Component/ Equipment**	**Buy/ Lease**	**Transportation**	**Purpose**
Hydraulic Fracturing	Water	Buy	By fracking operator using trucks or pipeline	Base of fracturing fluid
	Sand	Buy	By fracking operator using trucks or rail	To keep fracture open
	Chemicals	Buy	By fracking operator using trucks	To speed the mixture, kill organisms, keep sand suspended, control and prevent scale deposition
	Tanks	Lease /Buy	By fracking operator using trucks	To hold and mix the fluid
	Pumps and compressors	Lease	By fracking operator using trucks	To inject fracturing fluid at a high pressure
	Tubing	Buy	By fracking operator using trucks	To be placed inside the casing to stimulate the production

3.1.4 Completion

The well operator often organizes the completion, and may subcontract some of the operations involved to its subcontractors. As illustrated in Table 8, protective and monitoring devices such as the "Christmas tree" and metering devices are often purchased and transported by the well operator. Soil cuttings generated during the drilling process are usually treated and either disposed of during drilling or used later as ground refill, and pipe skids used in the gathering pipeline layout could be from wood obtained during site construction. After site completion, the operator typically continues to collaborate with the metering system regularly and is responsible for maintaining and replacing it if necessary.

Table 8. Material Flows in Completion

No.	Operation	Material/Component /Equipment	Buy/ Lease	Transportation	Purpose
1	Flow back processing	Tank	Lease	Trucks	To hold the flow back
2	Gathering pipeline layout	Pipe Skids	Made from wood	Trucks	To place the pipeline
		Trencher	Lease	Trucks	To dig trenches where pipelines are installed
		High-pressure Pipeline	Buy	Trucks	To transport initial strong gas flow
		Low- pressure Pipeline	Buy	Trucks	To transport the later weaker flow
		Monitoring and Metering devices	Buy	By well operator using trucks	To monitor and meter gas flow

Table 8 (continued)

3	"Christmas tree" installation	"Christmas tree"	Buy	By well operator using trucks	Multiple components of tubing head and casing head to control and monitor the gas flow out
4	Ground refill	Soil	From soil cutting		To refill the ground
		Layers	Buy	By well operator using trucks	To avoid any potential pollution

As shown in Table 9, the by-products in site completion is primarily flow back containing water, sand and chemicals. Flow back is often transported by trucks and/or pipes for disposal or to be reused in another fracturing job with or without pre-treatment depending on the fracturing fluid design, since the component content of the fluid is highly sensitive with respect to individual compositions. Generally speaking, the initial fluid that flows back is relatively clean so that it can be blended with just fresh water for use in another well without pre-treatment. The later flow back is treated in a conventional brine plant or a new dedicated treatment facility, to discharge to surface water. The processes involved include the removal of salts, metals, and oils. The flow back fluid needs to be temporarily stored in a pond and transported – usually at a significant cost – by trucks, to get to the new well or the treatment facility. In some places, wastewater may be disposed deep underground by using deep injection wells (drilling another well to store the water). However, this process might be problematic. Small earthquakes in several parts of the U.S. are suspected to have been induced by deep injection of drilling wastewater in the vicinity (Water & Wastewater International, 2016).

Table 9. By-product in Completion

Operations	**By-product**	**Transportation**	**Purpose**
Flow back Processing	Flow back water (containing water, sand and chemicals)	Trucks or pipes	To be reused in another well, to be treated in a treating plant, or, to be transported for disposal

3.2 FINANCIAL FLOWS

In 2011, Hefley et al.explored the value chain of shale gas wells in Western Pennsylvania. Rather than focusing on the perceived benefits and regional impacts, the study emphasized the direct economic impacts based on extensive field research including site visits and interviews with industry participants (Hefley, et al., 2011). The study provided the direct cost in the steps involved in the creation of a Marcellus Shale well. These steps correspond to stages in our transient supply chain as well as the production stage in our stable supply chain, as defined in Chapter 2. Table 10, provides estimates of the total cost of a Marcellus Shale well in Western Pennsylvania in 2011. The stages of fracturing (32.67%), early preparation prior to site construction (28.77%), and drilling (24.55%) are the major contributors to total cost.

Table 10. Estimated Total Cost of a Marcellus Shale Well

Data Source: (Hefley, et al., 2011)

Stages		**Costs**	**Share**
Leasing, Acquisition & Permitting		$2,201,200	28.77%
Site Construction		$400,000	5.23%
Drilling	Vertical	$663,275	8.67%
	Horizontal	$1,214,850	15.88%
Hydraulic Fracturing		$2,500,000	32.67%
Completion		$200,000	2.61%
Production		$472,500	6.17%
Total		$7,651,825	100%

However, these costs and the impact of the well on the local economy can change over time depending on costs associated with regulation and compliance, inflation, material and labor costs, learning curves, and process improvements.

4.0 DISCUSSION AND SUMMARY

In this chapter we discuss some topics relevant to shale gas that have not been detailed in the previous chapters. Specifically, we study methane emission in the transient supply chain, discuss the usage patterns and price fluctuations of natural gas, compare natural gas with other energy sources, and discuss how natural gas plays a key role in bridging the gap between coal/petroleum based energy and renewable energy by presenting a real world case study.

4.1 METHANE EMISSION

In the United States, methane (CH_4) is the second most common greenhouse gas emitted as a result of human activities, and constitutes approximately 10.6% of all U.S. greenhouse gas emissions. In general, over 60% of global methane emissions are from human activities (EPA, Methane and Nitrous Oxide Emissions from Natural Sources, 2010). Common activities that cause methane to be emitted to the atmospheric layer include the raising of livestock and natural gas leakage. Methane could also be generated naturally from natural sources such as wetlands. At the same time, chemical reactions in the atmosphere and natural process in the soil can help to remove or reduce methane. This fact has made the lifetime of methane in the atmosphere (typically 12 years) much shorter than that of carbon dioxide (CO_2); however, the properties of methane are such that it can trap radiation with an efficiency that is much higher that of CO_2. As a result, the comparative impact of CH_4 on climate change over a 100-year period is roughly more than 25 times greater than that of carbon dioxide (EPA, Overview of Greenhouse Gases, 2016).

Oil and gas wells are often criticized for increasing methane emissions and their induced environmental pollution (D'Annunzio, 2016). But as Figure 20 shows, methane is also emitted from various other sources including agriculture, waste management, and mining. From 1990 to 2014, about 33% of total methane emissions were from natural gas and petroleum systems.

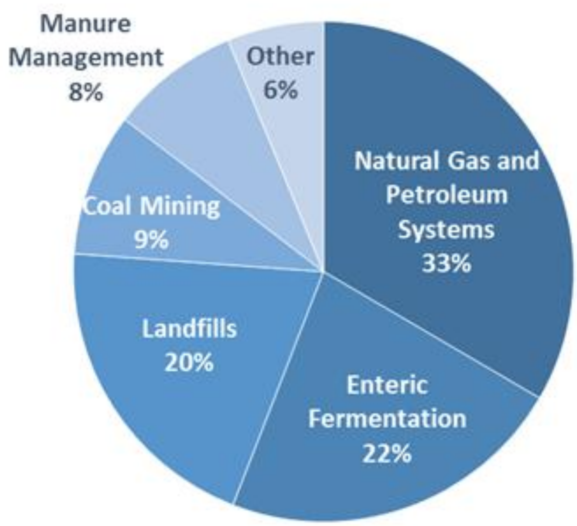


Figure 20. U.S. Methane Emissions by Source, 1990 – 2014

(EPA, U.S. Greenhouse Gas Inventory Report: 1990-2014, 2016)

The shale industry has been upgrading the equipment and techniques applied to the production, storage, and transportation of natural gas in order to reduce leaks that could contribute to methane emissions. This approach includes but is not limited to the utilization of multiple layers of liners to protect against pollution during site construction and completion (as described in Section 2.1.2 and Section 2.1.5), various casings and cement used to prevent gas leakage during drilling (as described in Section 2.1.3), several types of advanced geophysical, thermodynamic tools and devices installed inside the tubing or on the wellhead to monitor gas flow and prevent leakage (see Section 2.1.4 and Section 2.1.5 for detail), valves, monitoring and control stations along with the distribution pipelines and storage facilities to control and monitor the temperature, velocity, pressure of gas flow and discover and stop gas leakage (as detailed in Section 2.2.3). Figure 21 depicts the trend of Methane emissions from 1990 to 2014, and there is no direct evidence that the growth of the shale gas industry since 2007 has had a significant impact in terms of increased methane emissions.

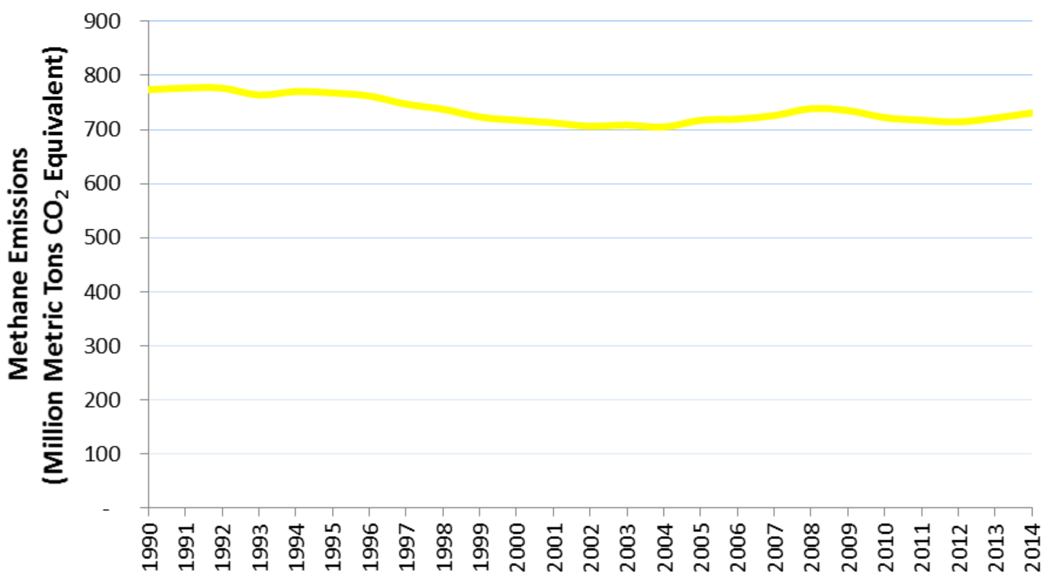


Figure 21. U.S. Methane Emissions, 1990-2014

(EPA, Overview of Greenhouse Gases, 2016)

Recent research has measured Volatile Organic Compounds (VOCs) emissions from compressor stations and production well pads in the, Uintah Basin, Marcellus Shale region, and Denver-Julesburg Basin (Li, et al., 2015). At the same time, the methane and ethane concentrations were also measured, and it was found that the sample variance of VOC emissions from individual natural gas facilities is large, but the average VOC emissions rate is very small. In most sites, the VOC concentration levels are no more than 1% higher compared to the normal VOC level in the atmosphere. Another data driven approach to the analysis of environmental impacts of shale gas development in hydraulic fracturing has shown that in over 1,600 samples near shale gas wells, only 3 samples process significantly higher levels of methane concentration, and further investigation revealed that these three locations were near a well that may be uncased and uncemented (Li, et al., 2016).Moreover, there is no data on methane concentration levels before the development of shale gas in those areas, and it is possible that the higher levels of methane might also be due to causes unrelated to drilling.

In summary, the industry has in general utilized technological advances to maintain methane emissions at acceptable levels under today's more stringent regulations and in the face of strong public opinion. However, any shortcut or violation of these regulations could result in potentially high emission rates. It would appear that a combination of government regulations, social opinion, and technological advances compliance by shale companies is required to ensure that methane emissions are kept in check.

4.2 USAGE AND PRICE FLUCTUATIONS OF NATURAL GAS

In this section we first discuss the volumes and types of natural gas usage and then follow up with a discussion of how gas prices are affected by supply and demand. The annual consumption of natural gas from 2000 to 2015 is illustrated in Figure 22. As the graph shows, from 2000 to 2009, consumption fluctuated around roughly the same level, but after 2009, the consumption has increased at a steady rate. In 2009, the total consumption was 22,910,078 MMcf; however, in 2015, the total annual consumption rose to 27,472,867 MMcf. This is probably because of the huge amount of Marcellus Shale gas flowing into the market, thus reducing natural gas prices from 2008. The upper line in the figure refers to the total consumption of natural gas, while the lower line corresponds to the volumes of natural gas that were finally delivered to consumers. The difference between the two lines indicates the amount of gas used in the supply chain for other purposes prior to final delivery; this quantity typically includes lease fuel, plant fuel, and pipeline and distribution use. Here lease fuel (an estimated 3.6% of the total consumption of natural gas) refers to the gas that is used at the well site and lease operations; it usually includes the natural gas used in heaters, on-site electricity generators, drilling operations, dehydrators, and field compressors. Plant fuel includes the natural gas used as fuel in processing plants, and is approximately 1.6% of the total consumption. Pipeline and distribution use is defined as the gas used in pipeline operations, which is primarily gas consumed to support compressors and in distribution. The amount of pipeline fuel and distribution use is an estimated 2.8% of the total consumption (EIA, Natural Gas Consumption by End Use, 2016). In conclusion, the above four types of natural gas consumption is in support of natural gas production and transportation and represent roughly 8% of the total consumption of natural gas.

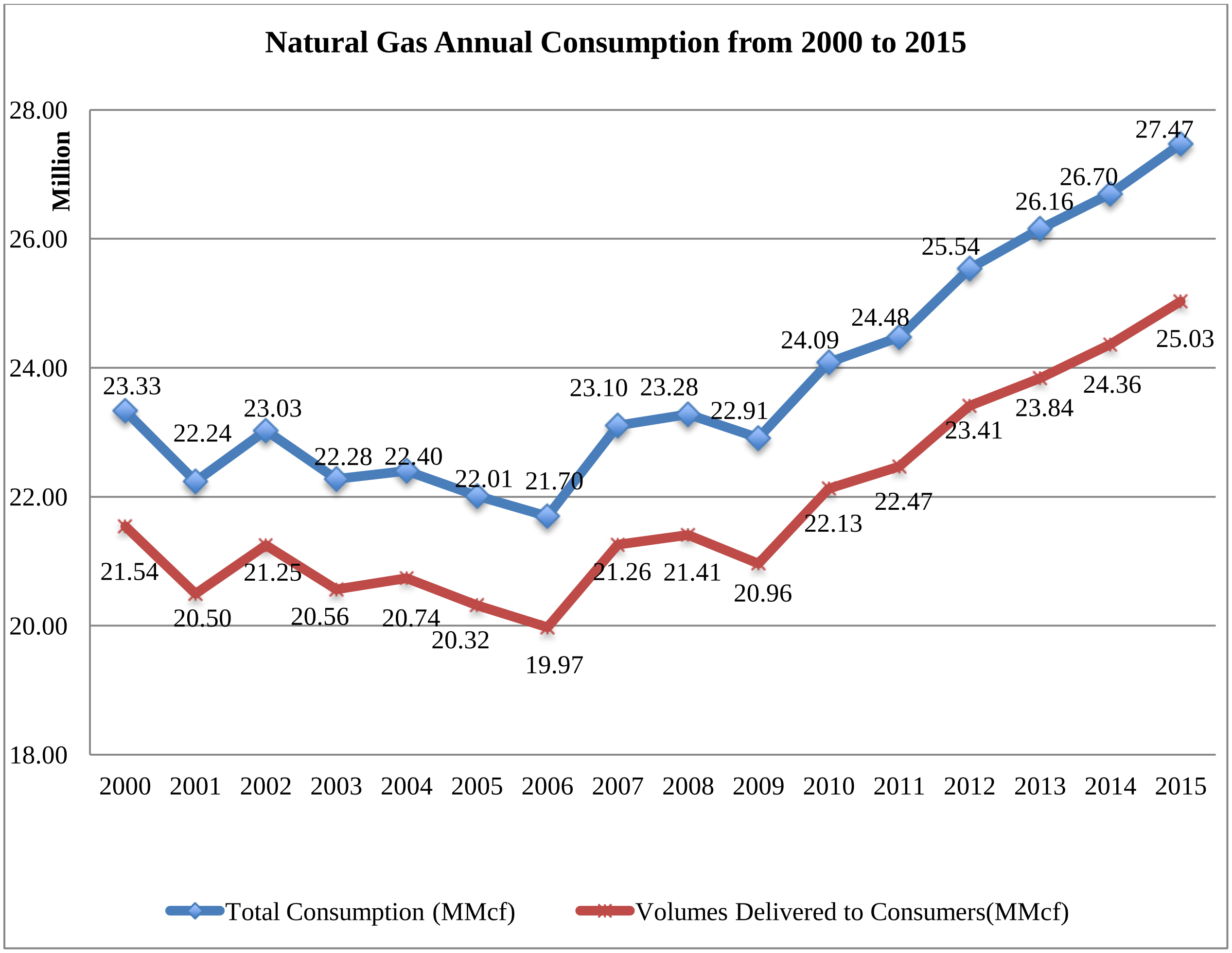


Figure 22. Natural Gas Annual Consumption from 2000 to 2015

Data Source: (EIA, Natural Gas Consumption by End Use, 2016)

The usage of natural gas encompasses (EIA, Natural Gas Consumption by End Use, 2016):

1) Electric Power: Natural gas used in the electric power generation sector as fuel.

2) Residential: Natural gas used for household use such as heating, air-conditioning, cooking and water heating in private dwellings, including apartments.

3) Industrial: Natural gas used for power, heat, and chemical feedstock in manufacturing establishments, in mining or other mineral extraction, and in fisheries,

forestry and agriculture. Natural gas used for electricity and heating to support industrial activities is also included.

4) Commercial: Gas used for sales and service by nonmanufacturing establishments or agencies such as hotels, restaurants, wholesale and retail stores and other service enterprises; gas used by local, state, and federal agencies engaged in nonmanufacturing activities.

5) Vehicle Fuel: Natural gas used by vehicles as fuel; vehicle fuel consumption is computed as the total number of vehicle miles traveled divided by fuel efficiency in miles per gallon (MPG). The latter is derived by collecting the actual vehicle fuel mileage and assigning the MPGs obtained from EPA certification files adjusted for on-road driving.

As shown in Table 11 and Figure 23, in 2015, most of the natural gas used was in electric power (9,671,095 MMcf, 38.64%) and industrial use (7,508,093 MMcf, 29.99%). Furthermore, natural gas consumption for electric power increased 40.72% from 2009 and the consumption for industrial use increased 21.74%, higher than the overall rate of 19.40%.

Table 11. Natural Gas Consumptions by End Use in 2009 and 2015

Data Source: (EIA, Natural Gas Consumption by End Use, 2016)

Annul Amount	**Electric Power**	**Industrial**	**Residential**	**Commercial**	**Vehicle Fuel**	**Total**
2009 (MMcf)	6,872,533	6,167,371	4,778,907	3,118,592	27,262	20,964,665
2015 (MMcf)	9,671,095	7,508,093	4,612,455	3,205,756	34,459	25,031,858
Increase Rate	40.72%	21.74%	-3.48%	2.79%	26.40%	19.40%

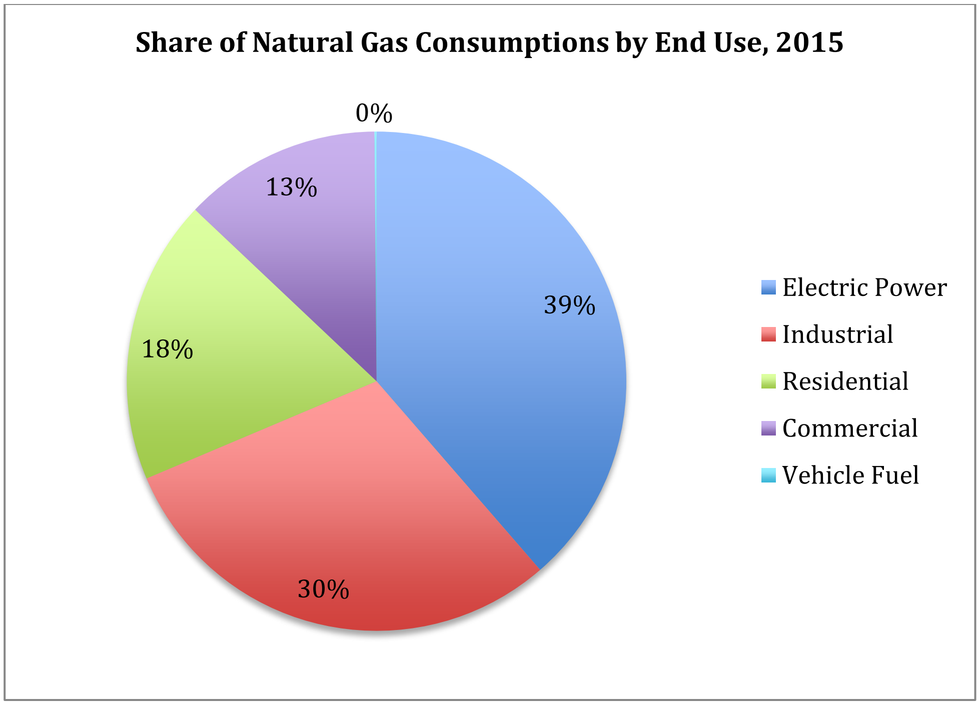


Figure 23. Share of Natural Gas Consumptions by End Use in 2015

Data Source: (EIA, Natural Gas Consumption by End Use, 2016)

The price of natural gas is a function of market supply and market demand: even a tiny change in supply or demand in a very short time period can cause huge fluctuations in the price of natural gas due to the restricted alternative recourses and the consumption of natural gas in the short term. Price changes resulting from supply and demand variations usually feed backwards and influence supply and demand, eventually bringing them back into balance. Generally speaking, an insufficient supply and higher demand tend to push the price higher, while a sufficient supply and lower demand tend to reduce the price.

The supply side factors that may affect price include (EIA, Factors Affecting Natural Gas Prices, 2015):

- *Variations in the volume of natural gas production*

Domestic natural gas prices are determined mainly by supply, most of which comes from domestic natural gas production. Higher natural gas supply tends to lead to lower prices. The dry gas production of the United States has increased from 2006 to 2014, and reached its highest recorded annual total in 2014. The increases in dry gas production during this period were primarily the result of “more efficient, cost-effective drilling and completion techniques, notably in shale and other tight geologic formations” (EIA, Delivery and Storage of Natural Gas, 2014). For instance, in 2012, average wholesale (spot) prices dropped considerably throughout the United States compared to 2011. The natural gas price during the mild 2011-12 winter was relatively low as a result of increased production and high levels of natural gas inventories in the Eagle Ford and Marcellus regions.

- *The amount of gas inventory in storage facilities*

The amount of gas inventory in underground storage fields plays a key role in meeting peak natural gas demand, especially when domestic production and any natural gas imports are not able to meet seasonal or sudden increases in demand. When the demand and price are low, the excess domestic production and potential low price ofany imports are absorbed by storage, which can also support hub services and pipeline operations. As shown in Figure 24 and Figure 25, the amount of natural gas inventory in storage facilities generally increases from April to October, when the demand for natural gas is relatively low. It decreases from November to March, when the demand is high in order to support winter heating.

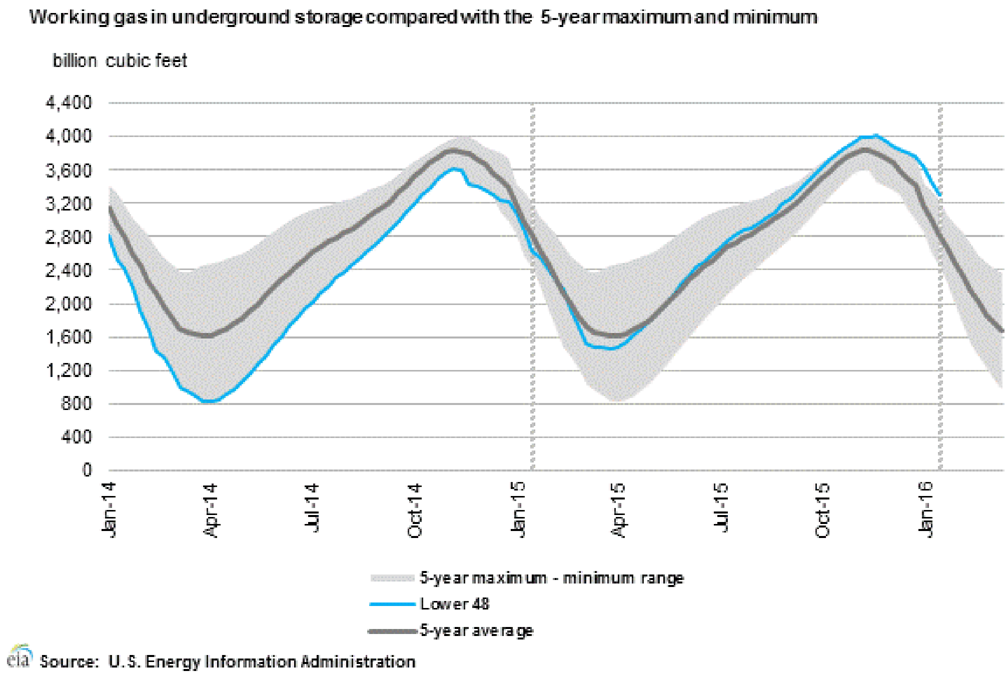


Figure 24. Working Gas in Underground Storage

(EIA, Weekly Natural Gas Storage Report, 2016)

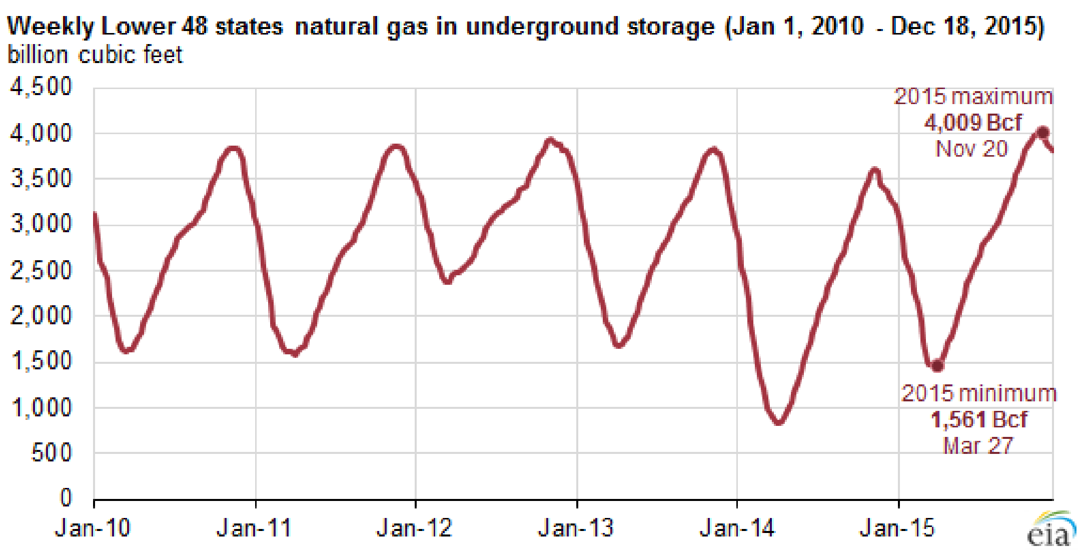


Figure 25. Weekly Lower 48 States Natural Gas in Underground Storage

(EIA, Weekly Natural Gas Storage Report, 2016)

- *The volume of natural gas being imported and/or exported*

Natural gas prices can be influenced by the import and export of natural gas. When international natural gas prices are low, more natural gas is imported, and the increased supply decreases the price of domestic natural gas. Conversely, when international prices are high enough, gas suppliers tend to export the gas that they produce which tends to increase domestic natural gas price.

The demand side factors that may affect prices are (EIA, Factors Affecting Natural Gas Prices, 2015):

- *The rate of economic growth*

Economic growth can stimulate natural gas price by promoting natural gas market demand. When the rate of economic growth is relatively high, the increased industrial and commercial demand for products and services generates a boom in the demand for natural gas, leading to the growth of production and prices. In particular, this is more obvious for the industrial sector, which uses natural gas as fuel and feedstock for many products such as pharmaceuticals and fertilizers (EIA, The Annual Energy Outlook 2015, 2015). Conversely, a weak economy tends to result in the opposite effect.

- *Variations in winter and summer weather*

Natural gas prices are also influenced by seasonal variations in weather. The weather in winter strongly influences commercial and residential demand and the price of natural gas. During the cold months, commercial and residential end consumers use more natural gas for heating. As demand increases, the pressure to raise prices also increases. Furthermore, severe or unexpected weather exacerbates the effect on prices because supply is often unable to react speedily to increased demand in the short term. In addition, when the transportation system is running at full capacity, the effects of weather on natural gas prices may be intensified. In such cases, prices tend to increase rapidly in a short time. As a result, natural gas storage during inclement weather is often used to modify the impact of high demand.

On the other hand, hot summer weather can also increase natural gas prices by increasing the demand for power. In 2014, about 27% of electric power was generated using natural gas. When the temperature is hotter than normal, the use of air-conditioning increases demand for electricity, and this in turn raises the demand for natural gas required for electric power generation. Even during the cooler season, temperatures can change natural gas prices in a similar fashion.

- *Prices of competing fuels*

The competition between natural gas and other fuels also has an effect on natural gas prices. Depending on the energy price, electricity generators, mills for producing iron, steel, paper, etc., and other large-volume fuel consumers sometimes switch their energy source between natural gas, petroleum and coal. When costs of competing fuels drop, the demand for natural gas generally decreases, thereby lowering the price of natural gas. Conversely, when the prices of alternative fuels are at relatively high levels, fuel consumers usually revert from these fuels to natural gas, thus facilitating its demand and driving up the price of natural gas price.

4.3 BRIDGING THE GAP

Although renewable energy technologies are being rapidly developed, it will be a significant amount of time before they constitute a viable replacement for fossil fuel based sources. This fact has led to a gap between current coal/petroleum based energy and renewable energy in the future. With growing concerns about climate change and global warming, few people would dispute the fact that renewable energy sources represent the best path to environmentally friendly and sustainable energy generation in the world. However, while the power obtained from solar, wind, and nuclear resources are developing, there is still a significant energy gap that needs to be bridged before renewable energy can satisfy the current large-scale demand from every-day use.

Solar power, which is highly dependent on a sunny climate, is not suitable for areas like western Pennsylvania where the number of sunny days per year is relatively low. Besides, large demands for energy require large land areas to gather sufficient energy from the sun. In addition, demand for energy in rainy weather and during the night has led to the requirement to develop efficient energy conversion and storage technologies beyond what exist today, which generally means a lower efficiency and higher cost in terms of the energy supply chain.

Similarly, wind energy, while being one of the fastest growing sources of electricity in the world, still has its limitations. First, a significant level of noise is generated by wind energy facilities, restricting their location to places that are often far away from residential areas. This leads to a significant amount of energy being lost during transportation since the energy lost is positively correlated with distance. Second, wind energy is not necessarily as environmentally friendly as it might be thought of. For instance, wind turbines often threaten the migration routes of birds. In addition, wind turbines usually have a large surface footprint. A critical consideration is that incoming wind flows are not accurately predictable as a long-term solution to the problem of energy supply. In Pennsylvania, the annual number of operational days for wind turbines could be as low as 100 days (PennFuture, 2016). Finally, like solar power, wind energy also induces significant energy losses in transportation, conversion, and storage.

Analogously, although hydroelectric power generates considerably lower level of greenhouse emission, it is limited to locations with nearby hydropower that can be feasibly harnessed. In addition, hydroelectric power station sat some locations have resulted in extensive submersion upstream from the dams/reservoirs. This phenomenon can cause devastation to biologically rich in riverine valley forests (forests near the banks of rivers), productive lowland, marshland, and grasslands. Hydropower plants could also exacerbate land loss of surrounding areas by habitat fragmentation (Robbins, 2007), and dams may also have a serious impact on the ecosystem by raising water temperatures, inundating spawning areas, and blocking and changing historic migration flows for animals such as salmon and steelhead (USFWS, 2016)(Harrison, 2008).Changes in the water flow utilized for electricity generation may also induce water siltation on dams and flow shortage in downstream areas. These could further result in exacerbating climate change.

Nuclear power, as one of the solutions to bridge the aforementioned energy gap in many developed countries, is attracting considerable public attention since the Fukushima disaster in Japan in 2011. This tragedy "has intensified the perception of the nuclear reactor as a risky proposition, and the result is a resurgence in coal and gas-burning power plants as a cost-effective, but environmentally damaging, stopgap on the way to renewables" (Lo, 2012). Immediately following the Fukushima incident, the amount of coal used for power generation rose by 5.4% in the world, making its share higher than any year since 1969.Currently, new nuclear plant projects are facing increased difficulties in being approved due to this negative public sentiment and the resultant stringent regulations. Nations such as South Korea and Taiwan are even debating the closedown or suspension of nuclear power facilities. In addition, the high initial capital investment along with the falling price of fossil fuels has made launching a nuclear plant less profitable. Finally, although nuclear energy has no harmful emissions, one fact is often being ignored: there is still no satisfactory solution to the problem of nuclear waste disposal that is feasible and sufficiently sustainable.

In summary, non-fossil fuel based technologies for energy are also not without their own problems and the most promising ones are still years away from being adequate to meet the world's ever-growing energy needs. Meanwhile, natural gas, a close relative of crude oil, is attracting interest and headlines since it produces less greenhouse gases and burns far cleaner than coal. Furthermore, natural gas has been found in the United States in abundant quantities and sophisticated technologies for its extraction have become commonplace. Energy analysts and environmentalists have thus begun considering natural gas as a bridge between coal/petroleum based fuels and renewable, low-carbon energy sources (Campbell, 2015). Table 12 summarizes the emissions impacts of natural gas, oil, and coal. In summary, natural gas produces only 50.47% of the Carbon Dioxide, 0.77% of the Sulfur Dioxides, and 28.33% of the Nitrogen Oxides as compared to coal. The potential environmental benefits in switching from oil and coal to gas could be tremendous, given that more than 50% of total U.S. energy consumption in the next 20 years is still expected to be from oil and coal, as shown in Figure 26. The potential benefits accrue not only from the usage of natural gas, but also from the improvement of the existing natural gas supply chain.

Table 12. Average Fossil Fuel Power Plant Emission Rates

Data Source: (EPA, 2012)

Emission Pollutants (lbs./MWh)	Natural Gas	Oil	Coal
Carbon Dioxide	1,135	1,672	2,249
Sulfur Dioxides	0.1	12.0	13.0
Nitrogen Oxides	1.7	4.0	6.0

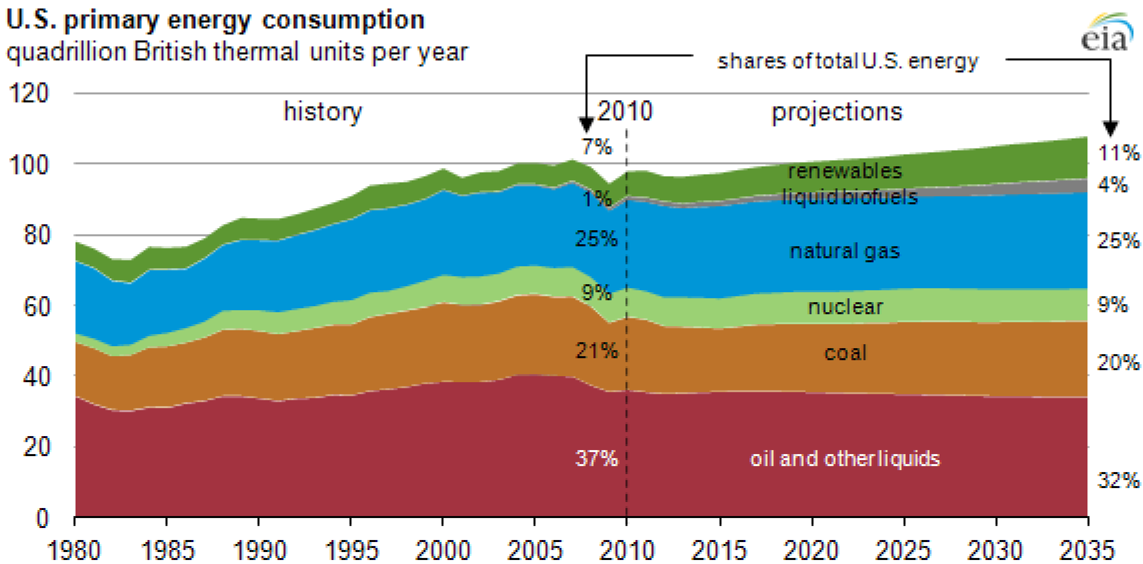


Figure 26. U.S. Primary Energy Consumption and Projection

(EIA, U.S. energy use projected to grow slowly and become less carbon-intensive, 2012)

The remainder of Section 4.3 is based on a real-world case study conducted by the author and his colleagues (Fitzgerald, Iketani, Yang, Hefley, & Rajgopal, 2015).

4.3.1 Background

The purpose of this case study is to evaluate the benefits of distributed power generation fueled by natural gas extracted from deposits such as the Marcellus Shale. With this approach an electricity generating company would be inserted into the midstream supply chain and use a series of small, natural gas based power generation units to profitably supply electric power (up to 20MW) to one or more dedicated customers and/or back into the traditional electric grid. This is in contrast to a large-scale, centralized power generation scheme.

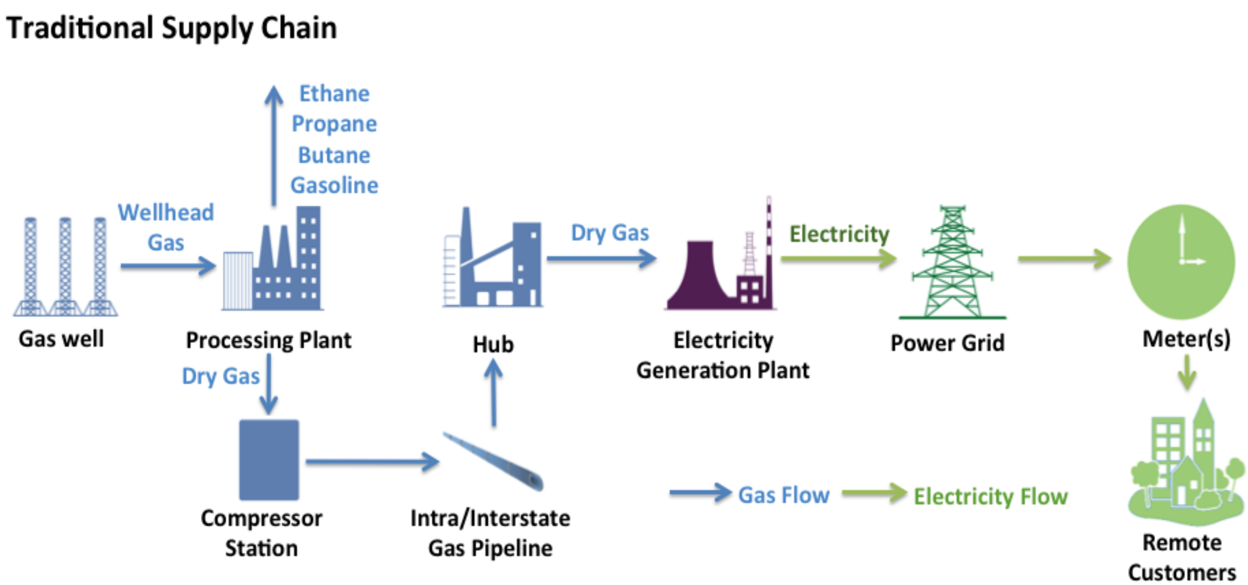
The defining characteristics of this kind of distributed power generation scheme are that (1) the power generation facility is close to the natural gas source; (2) the end users or customers are close to the power generation facility; (3) electricity generated by the power generation facility for dedicated customers is distributed through a separate transmission/distribution system from the main electricity distribution grid (i.e., sold behind the meter) or distributed to the purchasing customer through the existing grid, typically though a power purchase agreement (PPA) or other contractual mechanism; and (4) any additional electricity that is produced (beyond the amount demanded by dedicated customers) are supplied directly into the electric distribution grid. These characteristics represent significant differences in the value chain of a distributed power producer (DPP) from that of a traditional power producer and could possibly result in significant economic benefits for all three parties in the chain: the gas supplier, the electricity producer, and the end customer. Gas companies may receive higher profit for gas extracted and sold to the DPP because of reduced transportation costs and line losses. The DPP could benefit from lower gas prices and higher revenues from electricity that is priced higher than the wholesale prices charged when selling to the grid. Power customers could potentially purchase power at lower off-grid prices and will pay nothing or substantially reduced amounts for distribution. In addition, there are potential benefits to other parties as well. Communities close to where the gas source and power generation company are located could see benefits such as local use of natural gas, job creation, reduced regional electricity prices and the economic advantages that come along with it, as well as non-tangible benefits such as a reduced carbon footprint of electricity consumed, lower emissions, and increased energy security.

The feasibility of this business case hinges on several key challenges. The main challenge is identifying the efficiencies along the distributed power supply chain and benefits to the community. Economic models and forecasts based on these efficiencies are critical for a DPP to choose suppliers and customers, and to develop appropriate pricing structures and contracts that would result in the net increase in supply chain value being shared among the three parties in this value chain (the shale gas producer, the DPP, and the electricity customer). The overall value proposition has to be one where all three parties realize economic benefits; otherwise this model would be infeasible. By understanding the benefits of the business case, companies should be better able to articulate them to governments and industries and develop strategies for the future of the natural gas industry.

We show in the following sections that there are potential cost savings of 41% to 56% for electricity users, and a potential increase in profits of 12% to 35% for a natural gas supplier by locating a midstream company's facilities within the natural gas supply chain and localizing its energy distribution. This study also indicates a significant potential reduction in greenhouse gas emissions compared to traditional coal-based power plants.

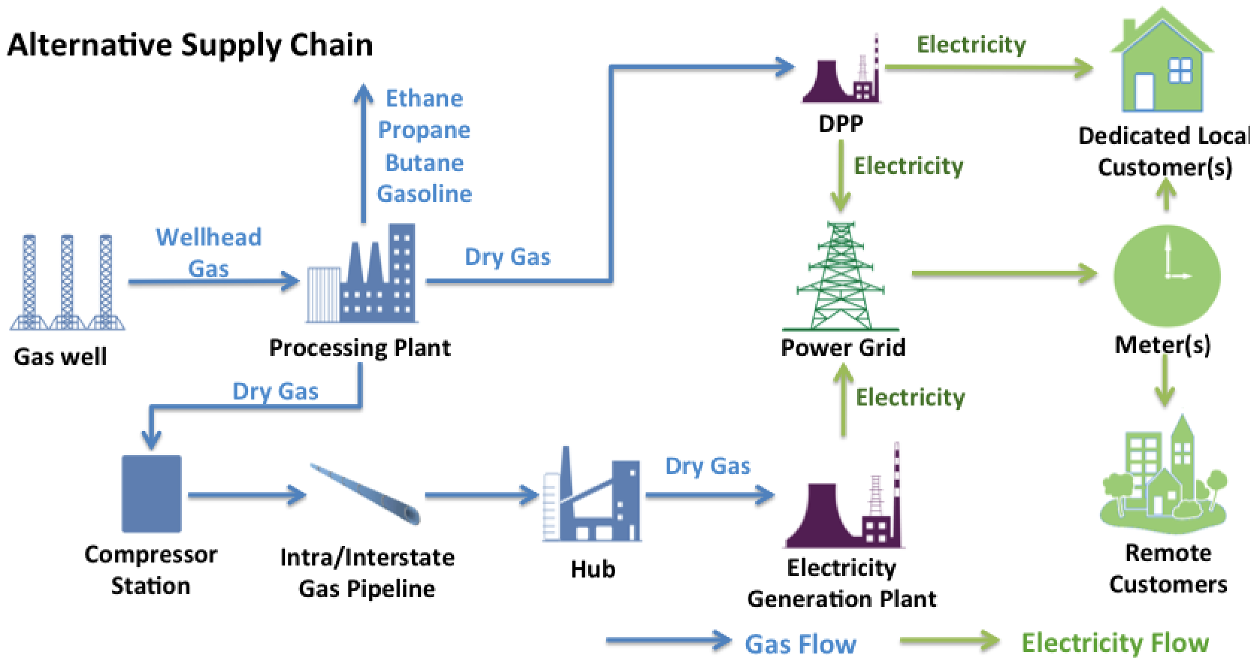
4.3.2 The Supply Chains with Distributed Power Generation

Figure 27 displays where the DPP fits into the overall distribution system. Traditionally (Figure 27a), shale gas is transported via pipelines and sold to a power plant at the hub; the electricity generated by the power plant is then distributed by the grid and sold to customer. In the proposed alternative (Figure 27b), a portion of the gas produced is sold locally to the DPP who produces electricity for dedicated customers and puts any excess back on the grid. The processed gas used by the DPP does not need to be compressed or transported long distances. We present a detailed analysis of the two supply chains in the next section.



(a) The Traditional Midstream Sector

Figure 27. Midstream Gas Sector



(b)The Alternative Midstream Sector with a DPP

Figure 27 (continued)

The market or index price of natural gas is different from the price at the wellhead because of the value adding processes and price markups between the two. Figure 28 illustrates these additive cost components that contribute to the index price. Because getting gas from the ground to the end customer is labor and technology intensive, there is about a 50/50 split between well head price and the value adding processes and how much each contributes to the index price. Because transportation cost is shared between extractor and the property owner, they both have an incentive to shorten the process or be as efficient as possible wherever they can (Cowden, 2015).

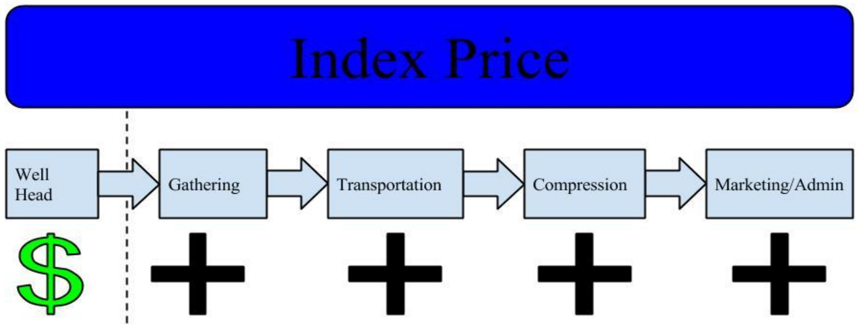


Figure 28. Natural Gas Cost Components

4.3.3 Economics of Distributed Power Generation

Distributed power generation has the potential to eliminate much of the transportation and compression required by a traditional midstream gas model for the portion of the gas that is sold locally. The gas producer can sell at a lower price than the index and still make the same (or higher) profit per unit of gas sold to the DPP. By engaging a *dedicated local customer* (DLC) for electric power generated close to a natural gas source, the DPP in turn benefits by virtue of (potentially cheaper) gas and selling behind the meter at rates higher than market wholesale. This cost saving can then be shared with the end electricity customer in the form of electricity rates that are lower than retail.

To demonstrate this business case, Figure 29 depicts a basic version of the model showing the essential cost elements. Table 13 explains the notations in the figure. We divide the supply chain of distributed power generation into two sections, the first one links the Gas Supplier and the Power Producer while the second links the Power Producer and the final Electricity Customer:

1) The Gas Supplier / Power Producer section, is defined from the production of shale gas until its delivery to the DPP (or Traditional Power Plant). In the most general case, the potential players that exist within this section include:

- The Well Operator, who operates the well, gathers the gas and normally sells the gas to a gas supply company at a price P_{GH} (Gas Price at well-head)
- The Gas Supplier, who obtains the gas from the Well Operator, processes and transports it, and resells it to the customer, or to a potential gas retail company at a price P_{GW}(Gas Wholesale Price)
- The Gas Retail Company, which buys the gas from the Gas Wholesale Company at a hub and then resells it to the customer at a price P_{GR}(Gas Retail Price)
- The Traditional Power Plant, which purchases the gas from the Gas Supplier at a price P_{GW} or the Gas Retail Company at a price P_{GR} and utilizes it to generate electricity
- The DPP, which intends to purchase U_G units of natural gas directly from the Gas Supplier at a unit price of P_{GN} (Negotiated Gas Price) after gas is processed by the supplier but before it is transported to the hub.

2) The Power Producer/Electricity Customer section corresponds to the generation of electricity in the DPP (or Traditional Power Plant) and its sale to the end customers. In the general case, this section includes

- The Traditional Power Plant, which generates electricity and sells it to an electricity retailer at a price P_{EW}(Electricity Wholesale Price)

- The Electricity Retail Company, which purchases electricity from the Traditional Power Plant and in turn distributes it through the grid and resells it to the customer at a price P_{ER} (Electricity Retail Price)
- The Dedicated Local Customer (DLC), who currently purchases electricity across the meter from the Electricity Retail Company
- The DPP, who intends to sell U_E units of electricity directly to the DLC behind the meter at P_{EN} (Negotiated Electricity Price), but could also sell it to the Electricity Retail Company at price P_{EW}

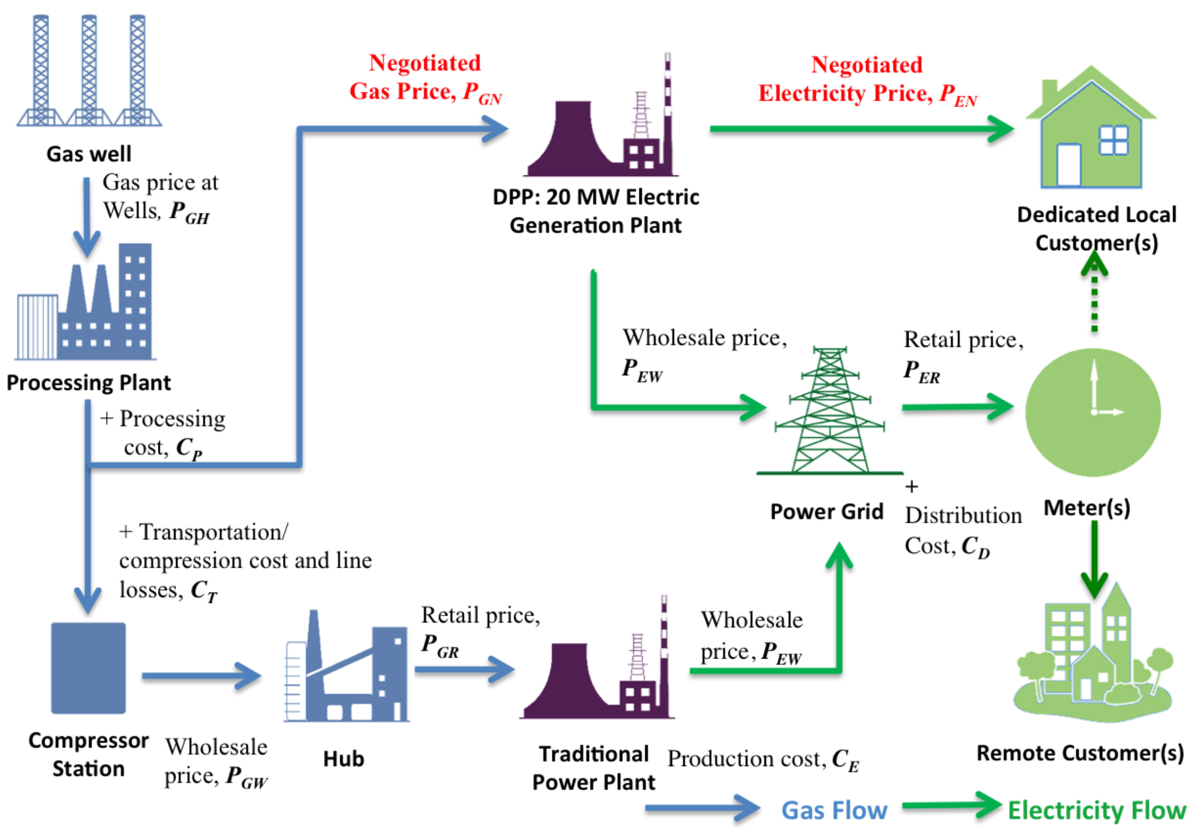


Figure 29. Distributed Power Generation Model

Table 13. List of Notations

(a) The Gas Supplier/Power Producer Section

Notation	Unit	Meaning
U_G	MMBTU	Amount of Gas Required by the DPP
P_{GH}	\$/MMBTU	Gas Price at Well-head
C_P	\$/MMBTU	Gas Processing Cost
C_T	\$/MMBTU	Gas Transportation & Line Costs
C_G	\$/MMBTU	Total Cost for Gas Supplier
M_{GW}	\$/MMBTU	Gas Wholesale Markup
P_{GW}	\$/MMBTU	Gas Wholesale Price
M_{GR}	\$/MMBTU	Gas Retail Markup
P_{GR}	\$/MMBTU	Gas Retail Price
P_{GN}	\$/MMBTU	Negotiated Gas Price for DPP
Z_G	\$/MMBTU	Profit for the Gas Supplier
$TVA(G)$	\$	Total Value Added in the Gas Supplier/Power Producer section

(b) The Power Producer/Electricity Customer Section

Notation	Unit	Meaning
U_E	MW·hr	Amount of Electricity Required by DLC
C_E	\$/MW·hr	Electricity Production Cost
M_{EW}	\$/MW·hr	Electricity Wholesale Markup
P_{EW}	\$/MW·hr	Electricity Wholesale Price
M_{ER}	\$/MW·hr	Electricity Retail Markup

Table 13 (continued)

P_{ER}	\$/MW·hr	Electricity Retail Price
C_D	\$/MW·hr	Electricity Distribution Costs
$\mathscr{P}_E$	\$/MW·hr	Electricity Cost for Customer
P_{EN}	\$/MW·hr	Negotiated Electricity Price for DLC
Z_E	\$/MMBTU	Profit for the Power Plant
$TVA(E)$	\$	Total Value Added in the Power Producer/ Electricity Customer section

We will refer to Figure 29 and Table 13 for the remainder of the discussion in this section.

A. The Gas Supplier/Power Producer Section

The gas company earns money from a customer who buys the gas. However, the gas company not only spends money to gather the gas, but also incurs the cost of transportation and compression. This is the most common way to buy and sell gas in the natural gas industry. Research shows that transmission and distribution costs are large components in gas prices, and according to EIA's data, it accounted for 42% to 49% of natural gas prices from 2003 to 2009 (Seydor, et al., 2012).

The gas price that the electricity producer pays is either a wholesale price at the hub or a retail price to a reseller who buys at the hub at wholesale and sells to many customers. We use an estimate of P_{GW} = \$3.416 per MMBTU for the wholesale price by analyzing the NYMEX gas wholesale price based on ten years of past prices (EIA, Natural Gas Spot and Futures Prices (NYMEX), 2015) and forecasting for the next 5 years. The wholesale price at the hub includes gas wellhead price, transportation cost, and profit of the gas wholesale company. For example, suppose the Gas Supplier pays P_{GH}= \$0.95 per MMBTU to the Well Operator as the gathering cost at wellhead and spends C_P=\$0.05 per MMBTU for the gas processing, the transportation cost and other costs are C_T=\$1.00 per MMBTU. So the total unit cost to the gas company is C_G= 0.95+0.05+1.00=\$2.00, and if the gas is sold to the wholesale market at \$3.416 per MMBTU, then the markup M_{GW}(the profit made) by the Gas Supplier is \$1.416 per MMBTU. There is possibly, a further retail markup before it is sold to the final customer.

The Gas Supplier has two options to consider when selling gas to a customer:

1) OPTION 1: Through a traditional hub

The cost to the Gas Supplier per MMBTU is:

$$C_G = P_{GH} + C_P + C_T \tag{1}$$

i.e., the total cost for the Gas Supplier (C_G) is equivalent to the gas price at the wellhead (P_{GH}) plus gas processing cost (C_P) and transportation and line costs (C_T).

The markup (profit) of the Gas Supplier per MMBTU (M_{GW}) is represented by the difference between Wholesale Price (P_{GW}) and total cost (C_G):

$$M_{GW} = P_{GW} - C_G = P_{GW} - (P_{GH} + C_P + C_T) \tag{2}$$

Note that with a possible retail markup (M_{GR}), the gas costs to the customer (P_{GR}) per MMBTU are:

$$P_{GR} = P_{GW} + M_{GR} \tag{3}$$

So if the gas customer (DPP) is currently purchasing U_G units of natural gas at the retail price), the total gas cost it is:

$$\textit{Total Gas Costs (\$)} = U_G \times P_{GR} \tag{4}$$

2) OPTION 2: To a distributed power producer (DPP) at a negotiated price

Alternatively, the Gas Supplier can sell gas directly to a local distributed power producer (DPP). By selling gas to the DPP, the Gas Supplier could eliminate or incur vastly lower transportation, compression and other line costs (C_P). Suppose the gas is sold right after it is processed to the DPP and is priced at a Negotiated Gas Price (P_{GN}).

For the Gas Supplier, the profit Z_G is given by:

$$Z_G = P_{GN} - (P_{GH} + C_P) \quad (5)$$

For the DPP, the total gas cost is given by

$$\textit{Total Gas Cost (\$)} = U_G \times P_{NG} \quad (6)$$

Then for the Gas Supplier/Power Producer decision makers:

a) The Gas Supplier should sell gas at a *Negotiated Gas Price* (P_{GN})such that the profit is at least as much as the traditional wholesale markup M_{GW}, as given by (2), so that:

$$Z_G \geq M_{GW} \quad (7)$$

Applying (2) and (5) we have,

$$P_{GN} - (P_{GH} + C_P) \geq P_{GW} - (P_{GH} + C_P + C_T) \quad (8)$$

This is equivalent to

$$P_{GN} \geq P_{GW} - C_T \quad (9)$$

b) In order to incentivize the DPP, the Negotiated Gas Price (P_{GN}) should be lower than Retail Gas Price (P_{GR}) currently being paid:

$$P_{GN} \leq P_{GR} \quad (10)$$

In summary, (9) and (10) imply that:

$$P_{GW} - C_T \leq P_{GN} \leq P_{GR} \tag{11}$$

The gas producer now has a profit of Z_G per MMBTU (as opposed to M_{GW} with the first option), thus the additional profit (say, ΔZ_G) for the gas producer from this arrangement is equal to:

$$\Delta Z_G = Z_G - M_{GW} \tag{12}$$

Using Equations (2) and (5):

$$\Delta Z_G = [\, P_{GN} - (\, P_{GH} + C_P\,) \,] - [\, P_{GW} - (\, P_{GH} + C_P + C_T\,) \,]$$

$$= P_{GN} - P_{GW} + C_T \tag{13}$$

For the DPP the reduction in unit costs (say ΔC_G) from the lower prices paid amount to:

$$\Delta C_G = P_{GR} - P_{GN} \tag{14}$$

Thus the Total Value Added (*TVA(G)*) from this arrangement that can be shared between both parties is:

$$TVA(G) = U_G \times (\, \Delta Z_G + \Delta C_G) \tag{15}$$

Applying Equation (13) and (14):

$$TVA(G) = U_G \times [\, (\, P_{GN} - P_{GW} + C_T\,) + (\, P_{GR} - P_{GN}) \,]$$

i.e.,

$$\boldsymbol{TVA(G) = U_G \times (\, P_{GR} - P_{GW} + C_T\,)} \tag{16}$$

In the case where the DPP is directly buying gas at the Wholesale Gas Price (P_{GW}) as opposed to retail, one just need to apply $M_{GR} = 0$, i.e., $P_{GR} = P_{GW}$ and the *total value added* = $U_G \times C_T$.

The exact share of the benefits for each party will be determined by the value of P_{GN} (higher values favor the gas seller and lower values the DPP) as negotiated between the two parties.

B. The Power Producer/Electricity Customer Section

Now consider the Power Producer/Electricity Customer part of the value chain.

The electricity customer has two options when buying electricity:

1) OPTION 1: From the grid across the meter.

If a customer is buying electricity from the grid, the total cost includes the cost of the electricity generation and transmission, and the cost of electricity distribution. The cost of electricity generation and transmission that the customer is based on buying from the grid at a retail price (P_{ER}). There is typically a trader between the customer and the electricity generation companies who will buy the electricity at a unit wholesale price (P_{EW}) from the electricity companies that includes a markup per unit (M_{EW}) above the cost to produce and transmit the electricity (\$$C_E$ per unit). The trader then resells it to the customer at the unit retail price (P_{ER}); the difference or retail markup (M_{ER}) between wholesale and retail cost represents the profit per unit to the retailer. The distribution costs incurred by the customer are in addition to this and the rates differ slightly according to the specific type of account that it applies to (based on average and/or maximum/peak consumption). For simplicity, we assume that this can be stated as \$$C_D$ per unit of electricity. In summary, for a customer, Electricity Cost per MW·hr includes Electricity Generation and Transmission Retail Price (P_{ER}) and Distribution Cost (C_D):

$$\mathscr{P}_E = P_{ER} + C_D \tag{17}$$

Where Electricity Generation and Transmission Retail Price (P_{ER}) is equal to Electricity Wholesale Cost (P_{EW}) plus Electricity Retail Markup (M_{ER}), i.e.:

$$P_{ER} = P_{EW} + M_{ER} \tag{18}$$

So total customer costs are

$$\begin{aligned} \textit{Total Electricity Costs} &= U_E \times \mathscr{P}_E \\ &= U_E \times (P_{ER} + C_D) \\ &= U_E \times (P_{EW} + M_{ER} + C_D) \end{aligned} \tag{19}$$

For the electricity power generator, the Wholesale Markup (M_{EW}) per MW·hr is the difference between Wholesale Price (P_{EW}) and generation and transmission cost (C_E):

$$M_{EW} = P_{EW} - C_E \tag{20}$$

2) OPTION 2: Act as a dedicated local customer (DLC) and buy from the distributed power producer (DPP), behind the meter.

On the other hand, suppose electricity is sold behind the meter to a dedicated customer at a Negotiated Electricity Price per MW·hr (P_{EN}). We assume that the customer would only pay for the electricity generation and transmission while the cost of distribution (C_D) is eliminated or vastly reduced and included in the negotiated price. Because the reseller/trader does not exist anymore, the markup added between wholesale and retail as the revenue of the trader is also eliminated. We also assume the customer does not need to pay for a standby service fee for the privilege of backup electricity, because the distributed power generator would provide that service as part of their obligation to provide power to the customer (presumably, via the grid).

Thus, for the DPP, the profit (say, Z_E) is now given by:

$$Z_E\,(\$/MMBTU) = P_{EN} - C_E \tag{21}$$

For the DLC, the total electricity cost is:

$$Total\ Electricity\ Costs = U_E \times P_{EN} \quad (22)$$

So for the DPP/DLC decision makers:

a) The DPP should sell electricity at a *Negotiated Electricity Price* (P_{EN}) that can ensure that the profit (say Z_E) is greater than the wholesale markup (M_{EW}) so as to make more money compared to the traditional way (Option 1):

$$Z_E \geq M_{EW} \quad (23)$$

Applying (20) and (21) this yields:

$$P_{EN} - C_E \geq P_{EW} - C_E$$

i.e.,

$$P_{EN} \geq P_{EW} \quad (24)$$

b) In order to incentivize the DLC, the Negotiated Electricity Price (P_{EN}) should be lower than the customer's regular Electricity Cost ($\mathscr{P}_E$):

$$P_{EN} \leq \mathscr{P}_E \quad (25)$$

Applying (17) this yields:

$$P_{EN} \leq P_{ER} + C_D \quad (26)$$

This (25) and (26) imply that:

$$P_{EW} \leq P_{EN} \leq P_{ER} + C_D \quad (27)$$

Note that the DPP now has additional unit profits (ΔZ_E) given by:

$$\Delta Z_E = Z_E - M_{WE} \quad (28)$$

From (20), (21) and (28) it follows that:

$\Delta Z_E = (P_{EN} - C_E) - (P_{EW} - C_E)$

$= P_{EN} - P_{EW}$ (29)

While the unit cost reduction for the customer (say, ΔC_E) is:

$\Delta C_E = \mathscr{P}_E - P_{EN}$

$= P_{ER} + C_D - P_{EN}$ (30)

Thus the Total Value Added (*TVA(E)*) of this arrangement that can be shared between both parties is:

$TVA(E) = U_E \times (\Delta Z_E + \Delta C_E)$ (31)

Applying (29) and (30) yields:

$TVA(E) = U_E \times [(P_{EN} - P_{EW}) + (P_{ER} + C_D - P_{EN})]$

$= U_E \times (P_{ER} + C_D - P_{EW})$ (32)

Since $P_{ER} - P_{EW}$ is equal to the retail markup M_{ER}, we have

$\boldsymbol{TVA(E) = U_E \times (M_{ER} + C_D)}$ (33)

The exact share of the benefits that each party obtains will be determined by the value of P_{EN} (higher values favor the DPP and lower values the customer) as negotiated between the two parties.

4.3.4 A Case Study

We now use the model proposed in the previous section with a real-world example of a potential dedicated local customer and a potential distributed power producer (because of confidentiality agreements we designate this customer as DLC and the power producer as DPP), using estimates of market prices for gas and electricity, estimates of various costs in the model, and actual electricity consumption history at DLC.

A. The Gas Supplier/Power Producer Section

Based upon interviews with the Marcellus Shale Coalition (Cowden, 2015), the cost during transportation from the gas well to the distribution hub is estimated to be between \$0.50 and \$1.00 per MMBTU in Pennsylvania. We use the mid-point of this range (\$0.75) as an estimate of transportation costs, along with a wholesale gas price forecast of $P_{GW} = 3.416$ per MMBTU, and assume that the DPP buys at this price without a retail markup, so that $P_{GR} = P_{GW} = 3.416$. The scenario for the decision makers is as follow:

1. Assuming a transport and line loss cost (C_T) of \$0.75 per MMBTU, the well price (P_{GH}), processing cost (C_P) and the wholesale markup (M_{GW}) thus add up to \$3.416 - \$0.75 = \$2.666 per MMBTU. With the savings in transport and line costs, any price higher than this will enable the gas company to make more money compared to the traditional way.
2. For the DPP, if the gas company is selling gas at a price lower than \$3.416 per MMBTU, then it is less expensive than paying what it currently does.

Therefore the negotiated gas price per MMBTU (P_{GN}) must satisfy condition (11) in the previous section: $\boldsymbol{P_{GW} - C_T \leq P_{GN} \leq P_{GR}}$. Substituting $P_{GR} = P_{GW} = 3.416$ and $C_T = 0.75$, we have:

$$\mathbf{2.666 \leq P_{GN} \leq 3.416} \qquad (34)$$

We consider two options over the lifetime of the DPP's power plant (say, 20 years) : (1) the DPP runs its facility 11 hours on-peak per day; and (2) also runs off-peak hours. However, it is assumed that the total daily running time cannot exceed 22.8 hours in order to match a 95% capacity goal to account for reserve time for maintenance, etc. The engine efficiency of the facility is assumed to be 8,300 BTU/KW·hr. As shown below, if the DPP runs its facility for as much time as possible, the DPP and its gas partner could share a total saving of between \$13,814,520 and \$27,629,040 over twenty years. If the facility only runs at on-peak time, a total saving of \$6,664,900 to \$13,329,800 could be shared by the two. From Equation (16) and since $P_{GR} = P_{GW} = 3.416$ by assumption, we have:

$$TVA_G = U_G \times (P_{GR} - P_{GW} + C_T) = U_G \times C_T \tag{35}$$

We compute three estimates of potential supply chain value based on three possible values of C_T over its assumed range: 0.50, 0.75, and 1.00.

First, note that

$$\textit{Daily Amount of Gas Used (MMBTU)} = \textit{Engine Efficiency (BTU/KW}\cdot\textit{hr)} \times 10^{-6}\,\textit{MMBTU/BTU} \times 10^{3}\,\textit{KW}\cdot\textit{hr/MW}\cdot\textit{hr} \times \textit{Capacity of total Electricity Generation (MW)} \times \textit{Operating Hours per day (hour)} \tag{36}$$

$$= 8300 \times 10^{-6} \times 10^{3} \times 20 \times \textit{Operating Hours per day} = 166 \times \textit{Operating Hours per day}$$

Consider a 20-year period of $20 \times 365 = 7300$ days. From (35) and (36):

$$\boldsymbol{TVA_G = U_G \times C_T}$$

$$\boldsymbol{= 7300 \times \textit{Daily Amount of Gas Used} \times C_T}$$

$$\boldsymbol{= 7300 \times 166 \times \textit{Operating Hours per day} \times C_T}$$

$$\boldsymbol{= 1{,}211{,}800 \times \textit{Daily Operating Hours} \times C_T} \tag{37}$$

<u>Case (i)</u>: Power generator only runs on-peak:

$$\textit{Lowest TVA(G) On Peak} = 1{,}211{,}800 \times 11 \times 0.50 = \$6{,}664{,}900 \tag{38}$$

$$\textit{Average TVA(G) On Peak} = 1{,}211{,}800 \times 11 \times 0.75 = \$9{,}997{,}350 \tag{39}$$

$$\textit{Highest TVA(G) On Peak} = 1{,}211{,}800 \times 11 \times 1.00 = \$13{,}329{,}800 \tag{40}$$

Case (ii): Power generator runs on-peak time as well as off-peak:

$$\textit{Lowest TVA(G) On \& Off Peak} = 1{,}211{,}800 \times 22.8 \times 0.50 = \$13{,}814{,}520 \quad (41)$$

$$\textit{Average TVA(G) On \& Off Peak} = 1{,}211{,}800 \times 22.8 \times 0.50 = \$20{,}721{,}780 \quad (42)$$

$$\textit{Highest TVA(G) On \& Off Peak} = 1{,}211{,}800 \times 22.8 \times 0.50 = \$27{,}629{,}040 \quad (43)$$

While the dollar amount of increase in supply chain value above only depends on the transportation and line loss costs per MMBTU, the *percentage* saving in the overall supply chain cost also depends on the actual gas prices (since we need to find the current value of the chain). This percentage saving in supply chain cost is given by (*total dollar value of savings*) ÷ (*total current value*) = $(C_T \times U_G) \div (P_{GR} \times U_G) = C_T / P_{GR}$.

Since gas prices are uncertain we also examine how these estimates might change with different gas prices. We consider two additional scenarios using two different gas prices of \$3.42±0.60 around the mean estimate. To come up with the widest range of estimates, the extreme case 1(pessimistic) estimate of the percentage saving in supply chain cost would be when gas price (P_{GR}) is highest and transport costs (C_T) are lowest, while the extreme case 2 (optimistic) would be the opposite one. Table 14 displays the percentage saving along with the actual dollar values computed earlier for three scenarios. Based on the extremes considered herein the supply chain saving resulting from the local gas contract ranges from 12.44% to 35.46%.

Table 14. The Gas Supplier/DPP Interface Efficiency

Case	**Nominal Case**	**Extreme Case 1**	**Extreme Case 2**
Transportation Costs $/MMBTU (A)	0.5	0.75	1
Saving if power generator only runs On-peak	$9,997,350	$6,664,900	$13,329,800
Saving if power generator runs On & Off-peak	$20,721,780	$13,814,520	$27,629,040
Gas Price $/MMBTU (B)	3.416	4.02	2.82
% Saving in Supply Chain Cost (A/B)	21.96%	12.44%	35.46%

Additionally, there might be other benefits due to a shorter distance between extraction and the end user that are not directly quantifiable; these are outlined later in the next section.

B. The DPP/DLC Section

Here we use actual data from a potential dedicated local customer (**DLC**). Currently, this entity is paying P_{ER} = *$68.20* per MW·hr for the electricity itself. The distribution costs are more difficult to estimate because there are several different accounts that are all charged differently according to tariff rates established by the distribution company (Strah, 2015) as follows:

Account type 1: GENERAL SERVICE – PRIMARY

$90.73 per month (Customer Charge), plus

$2.60 per kW for all billed kW

$.20 for each rkVA of Reactive Demand Billed

Account type 2: GENERAL SERVICE - MEDIUM

$19.11 per month (Customer Charge), plus Demand

$2.62 per kW for all billing demand as measured in kW

$0.20 for each rkVA of Reactive Demand Billed

Account type 3: GENERAL SERVICE - SMALL

$19.24 per month (Customer Charge), plus

$0.01926 per kWh for all kWh

Account type 4: RESIDENTIAL SERVICE

$10.85 per month (Customer Charge), plus

$0.03135 per kWh for all kWh

Based on an analysis of detailed billing and usage information provided by DLC, the average demand is around 1,100 kW, while the on-peak demand is around 1,800 kW, and the percentages of the totals attributable to each of the above four rate types were estimated as follows and are summarized in Table 15:

1) 60% of the demand, i.e., 660 kW of average and 1,080 kW of on-peak demand is estimated as being charged the General Service Primary rate, and is charged by on-peak demand;

2) 30% of the demand, the 330 kW of average and 540 kW of on-peak demand is estimated as being charged the General Service – Medium rate, and is charged by on-peak demand;

3) 5% of the demand, the 55 kW of average and 90 kW on-peak demand is estimated as being charged the General Service – Small rate, and is charged by average demand;

4) 5% of the demand, the 55 kW of average and 90 kW on-peak demand is estimated as being charged the Residential rate, and is charged by average demand.

Table 15. Electricity Demand Estimates at DLC

Demand	**Average Demand**	**On-peak Demand**	**Percentage**
Total	1,100 kW	1,800 kW	100%
Primary	660 kW	1,080 kW	60%
Medium	330 kW	540 kW	30%
Small	55 kW	90 kW	5%
Residential	55 kW	90 kW	5%

Ignoring the relatively small amount from the reactive demand in the bill, the distribution cost component is calculated as follows:

1) The General Service Primary rate applies to 60% of the demand, the 660 kW of average and 1,080 kW of on-peak demand, and is charged based upon on-peak demand, so the related distribution cost is \$90.73 per month (Customer Charge) plus \$2.60 per kW for all billed kW (On-peak Demand), which is \$2,898.73:

   Monthly Primary Distribution Cost (\$) = Customer Charge (\$) + Rate per kW (\$/kW) × All billed kW (kW)

   $$= \$90.73 + 2.60\ \$/kW \times 1{,}080\ kW = \$2{,}898.73 \qquad (44)$$

2) The General Service Medium rate applies to 30% of the demand, the 330 kW of average and 540 kW of on-peak demand, and is charged based upon on-peak demand.

The cost related to this is \$19.11 per month (Total Customer Charge) plus \$2.62 per kW for all billing demand as measured in kW (On-peak Demand), which is \$1,433.91:

$$\textit{Monthly General Service Medium Distribution Cost (\$)} = \textit{Customer Charge (\$)} + \textit{Rate per kW (\$/kW)} \times \textit{All billed kW (kW)}$$

$$= \$19.11 + 2.62\ \$/kW \times 540\ kW = \$1,433.91 \qquad (45)$$

3) The General Service Small rate applies to 5% of the demand, the 55 kW of average and 90 kW on-peak demand, and is charged based upon average demand. Therefore, the cost of this account is \$19.24 per month plus \$0.01926 per kWh for all kWh, which is \$781.94:

$$\textit{Monthly General Service Small Distribution Cost (\$)} = \textit{Total Customer Charge (\$)} + \textit{Rate per kWh (\$/kW)} \times \textit{All billed kWh (kW·hr)}$$

$$= \$19.24 + 0.01926\ \$/kW{\cdot}hr \times 55\ kW \times 30 \times 24\ hours = \$781.94 \qquad (46)$$

Since *All billed kWh (kW·hr) = Average Demand (kW) × Time (hours)*

4) The Residential rate applies to 5% of the demand, the 55 kW of average and 90 kW on-peak demand is applied to Residential rate, and is charged based upon average demand. The cost is \$10.85 per month plus \$0.03135 per kWh for all kWh, which is \$1,252.31:

$$\textit{Monthly Residential Distribution Cost (\$)} = \textit{Total Customer Charge (\$)} + \textit{Rate per kWh (\$/kW)} \times \textit{All billed kWh (kW·hr)}$$

$$= \$10.85 + 0.03135\ \$/kW{\cdot}hr \times 55\ kW \times 30 \times 24\ hour = \$1,252.31 \qquad (47)$$

Therefore, the Total Monthly Distribution Cost is the sum of these four components:

Monthly Total Distribution Cost = \$2,898.73 + \$1,433.91 + \$781.94 + \$1,252.31

= \$6,366.89 (48)

Now consider the monthly electricity generation and transmission retail costs which are

= Electricity Retail Price (\$$P_{ER}$/MW·hr) × Average Demand (MW) × hours per month

Hence

Monthly Electricity Generation and Transmission Retail Price Paid = 68.20 \$/MW·hr× 1.1 MW × 30 × 24 hour = \$54,014.40 (49)

The Total Cost is:

Current Average Monthly Electricity Cost (\$) = Monthly Electricity Generation and Transmission Retail Price Paid (\$) + Monthly Distribution Cost (\$)

= \$54,014.40 + \$6,366.89 = \$60,381.29 (50)

For the purpose of validation, the actual electricity bills from DCX were analyzed by each account. The generation and transmission cost, and the distribution cost of each account was calculated separately. The average amounts of usage or demand related to all billed kW or kWh were obtained, and the average rate of each component was computed. If we compare each component of average monthly electricity cost to actual electricity billing as shown in Table 16, it can be seen that the estimates are very close to the actual values. This validates the adequacy of the assumptions made in our cost calculations. In addition, we ignored taxes, which could also account for the fact that the actual cost of 0.0725 is a little higher than the assumed value of 0.0682.

Table 16. Each Component of Estimated and Actual Billing

Component		Generation and Transmission				Distribution				Total
		P	M	S+R	**Total**	P	M	S+R	**Total**	
Cost	Estimated	\$32,408	\$16,204	\$5,401	**\$54,014**	\$2,899	\$1,434	\$2,034	**\$6,367**	**\$60,381**
	Actual	\$37,231	\$15,206	\$4,131	**\$56,568**	\$2,760	\$1,126	\$1,994	**\$5,880**	**\$62,448**
Demand	Estimated	475,200 kWh	237,600 kWh	79,200 kWh	**792,000 kWh**	1080 kW	540 kW	79,200 kWh		
	Actual	513,574 kWh	209,770 kWh	56,906 kWh	**780,250 kWh**	1002 kW	404 kW	56,906 kWh		
Rate	Estimated	0.0682 + Tax				2.60+ Reactive	2.62+ Reactive	0.0253		
	Actual	0.0725				2.66	2.74	0.0345		

*P: Primary, M: General Service Medium, $S+R$: General Service Small plus Residential

To calculate the added supply chain value from a distributed power model, the monthly electricity generation and transmission price paid is further divided into monthly electricity wholesale cost plus the retail markup. For each unit of electricity, recall from Equation (17): *Electricity Retail Cost* (P_{ER}) = *Electricity Wholesale Cost* (P_{EW})+ *Electricity Retail Markup* (M_{ER})

The wholesale price is determined from an analysis of the wholesale electricity market data (EIA, Wholesale Electricity and Natural Gas Market Data, 2015). The average wholesale price is estimated to be $P_{EW}= \$44.01$ per MW·hr, and given that the retail price is $M_{RE}=\$68.20$ per MW·hr, we can compute the retail markup as

$$M_{ER}= P_{ER} - P_{EW}= 68.20 - 44.01=\$24.19 \text{ per MW·hr.} \tag{51}$$

We can now compute the wholesale and retail markup components of the monthly transmission and generation charges costs (\$54,014.40that we previously computed) as follows:

Monthly Electricity Generation & Transmission Wholesale Cost (\$) = Electricity Wholesale Price (\$$P_{EW}$ per MW·hr) × ***Average Demand (MW)*** × ***hours per month***

$$= 44.01 \times 1.1 \times 720 = \$34,856 \quad (52)$$

And,

Monthly Electricity Generation & Transmission Markup Cost (\$) = Electricity Retail Markup (\$$M_{ER}$ per MW·hr) × ***Average Demand (MW)*** × ***Time (hour)***

$$= 24.19 \times 1.1 \times 720 = \$19,158 \quad (53)$$

Allocating these two totals among the four rate types using the aforementioned demand ratios:

1) *Monthly Primary Electricity Markup Cost = 60%×\$19,158.48 = \$11,495* (54)

   Monthly Primary Electricity Wholesale Cost = 60%×\$34,855.92 = \$20,914(55)

2) *Monthly Medium Electricity Markup Cost = 30%×\$19,158.48 = \$5,748* (56)

   Monthly Medium Electricity Wholesale Cost = 30%×\$34,855.92 = \$10,457 (57)

3) *Monthly Small Electricity Markup Cost = 5%×\$19,158.48 = \$958* (58)

   Monthly Small Electricity Wholesale Cost = 5%×\$34,855.92 = \$1,743 (59)

4) *Monthly Residential Electricity Markup Cost = 5%×\$19,158.48 = \$958* (60)

   Monthly Residential Electricity Wholesale Cost = 5%×\$34,855.92 = \$1,743 (61)

Now consider the scenario with a DPP providing power behind the meter. This eliminates the distribution cost (C_D) and retail markup (M_{ER}). The supply chain value for each account/rate type account and the monthly bills are illustrated in Table 17. Note that the *TVA(E)* is given by Equation (33): $\boldsymbol{TVA(E) = U_E \times (M_{ER} + C_D)}$.

Across the different account/rate types, the percentage saving in supply chain cost varies between 40.72% and 55.91%, while the overall saving is 42.27%.

Table 17. The DPP/DLC Section Saving

Account	**Primary**	**Medium**	**Small**	**Residential**	**Total**
Percentage	60%	30%	5%	5%	100%
Average Demand	660 kW	330 kW	55 kW	55 kW	1,100 kW
On-peak Demand	1,080 kW	540 kW	90 kW	90 kW	1,800 kW
Monthly Distribution Share (A)	$2,899	$1,434	$782	$1,252	$6,367
Monthly Markup Share(B=$U_E \times M_{ER}$)	$11,495	$5,748	$958	$958	$19,158
Monthly Wholesale Share(C= $U_E \times P_{EW}$)	$20,914	$10,457	$1,743	$1,743	$34,856
Monthly Total Cost (A+B+C)	$35,307	$17,638	$3,483	$3,953	$60,381
Monthly Savings (*TVA(E))* (A+B)	**$14,394**	**$7,181**	**$1,740**	**$2,210**	**$25,525**
% Saving in Supply Chain Cost(A+B)/(A+B+C)	**40.77%**	**40.72%**	**49.96%**	**55.91%**	**42.27%**
20-year Value (A+B)×12×20	**$3,454,517**	**$1,723,548**	**$417,566**	**$530,455**	**$6,126,089**

We can also compute the average distribution rate (C_D) for one unit (MW·hr) of electricity as:

$$C_D = \textit{Monthly Total Distribution Cost (\$)} \div (\textit{Average Demand (MW)} \times \textit{Time (hour)})$$

$$= \$6,367 \div (1.1\ MW \times 30 \times 24\ hour)$$

$$= 8.04\ \$/MW \cdot hr \qquad (62)$$

Therefore, for the DPP/DCX decision makers:

a) The DPP should sell electricity at a *Negotiated Electricity Price* (P_{NE}) that can make the profit greater than the wholesale markup (M_{EW}) so as to make more money compared to the traditional way. Applying Equation (24):

$$P_{EN} \geq P_{EW} = 44.02 \tag{63}$$

b) In order to incentivize the dedicated customer, the *Negotiated Electricity Price* (P_{EN}) should be lower than traditional Electricity Cost at Customer ($\mathscr{P}_E$). Plugging in Equation (25), (26) and (62):

$$P_{EN} \leq \mathscr{P}_E = P_{ER} + C_D = 68.20 + 8.04 = 76.24 \tag{64}$$

So (also refer to Equation (27) in: $P_{EW} \leq P_{EN} \leq P_{ER} + C_D$, so that)**,**

$$\boldsymbol{44.02 \leq P_{EN} \leq 76.24} \tag{65}$$

Note that the DPP now has additional profits of ($\Delta Z_E = P_{EN} - P_{EW}$) per MW·hr (by Equation (29)), while DCX saves ($\Delta C_E = P_{ER} + C_D - P_{EN}$) per MW·hr (by Equation (30)).

Generally speaking, the total savings of this arrangement that can be shared between both parties over the next 20 years is computed using Equation (32):

$$TVA(E) = U_E \times (P_{ER} + C_D - P_{EW})$$

$$= 1.1\ MW \times 20 \times 365 \times 24\ hour \times (68.20 + 8.04 - 44.02)(\$/MW \cdot hr)$$

$$= \$6{,}126{,}089 \tag{66}$$

Therefore, a value around 6 million can be shared between the DPP and DCX over the next 20 years.

4.3.5 Discussion

Levelized cost of electricity

The levelized cost of electricity (LCOE), described as a useful summary measurement of the total competiveness of different generating technologies, represents the per kilowatt-hour cost (in real dollars) of constructing and operating a generating plant over a projected financial life and duty cycle. The LCOE considers capital costs, fuel costs, fixed and variable operations and maintenance (O&M) costs, financing costs, and an assumed utilization rate. As indicated in Table 18, the LCOE of natural gas-fired power plants is lower than that of other power plants. This advantage would help generators set competitive electricity prices and pass on benefits to their end-users (EIA, Annual Energy Outlook 2015, 2015).

Table 18. Estimated Levelized Cost of Electricity for New Generation Resources

Plant Type (Dispatchable Technologies)	**Total System LCOE ($/MWh)**
Natural Gas-fired	72.6
Advanced Coal	115.7
Advanced Nuclear	95.2
Wind	73.6
Solar	114.3

While wind and solar power have an advantage in producing electricity without any fuel, there are several disadvantages as discussed earlier.

Reduction of Environmental Impact and Cost

The proposed business case eliminates some portions of the gas transportation process including some treatment and compression. In the Marcellus Shale gas region, the typical gas line utilized is large-diameter (24 to 36 inches) and the average in most cases is 120 miles in length. Based on research by the International Pipeline and Offshore Contractors Association, the carbon footprint associated with laying large-diameter pipelines is approximately 960 tons per mile. Therefore, the proposed case could reduce around 115,200 tons of CO_2 emissions over its lifetime if it obviates the need to lay such a pipeline. Of course, this might not be relevant since the gas is more than likely, transported across an existing pipeline.

The proposed business case can reduce both environmental impacts and costs. Table 19 describes the total amount of CO_2 emissions (refer to Table 12 for lbs. of emissions per KWh from gas and coal based plants) and Table 20 calculates environmental costs (refer to Table 18 for cost of electricity per MWh from gas and coal based plants), both of which can be reduced. The proposed case could save about 49.53% of carbon tax compared to a traditional coal-based power plant.

Table 19. Comparison of Total Amount of CO_2Emissions (tons)

Production Process	**Proposed Business Case (Natural Gas)**	**Traditional Case (Natural Gas)**	**Traditional Case (Coal)**
CO_2 Emissions	1,889,094[(1)]	1,889,094	3,743,235 [(2)]

NOTES:
1) 1,135 lbs. /MWh × 20 MW × 20 Years ×365 Days × 22.8 h× 0.0005 lbs./ton
2) 2,249 lbs. /MWh × 20 MW × 20 Years ×365 Days × 22.8 h × 0.0005 lbs./ton

Table 20. Comparison of Total Cost (US dollar)

Process	**Proposed Business Case (Natural Gas)**	**Traditional Case (Natural Gas)**	**Traditional Case (Coal)**
Carbon Tax [(1)]	47,227,350[(1)]	47,227,350	93,580,875
Cost of Electricity	241,670,880[(2)]	241,670,880	385,142,160[(3)]
Transmission Loss[(4)]	0	14,379,417	22,915,958
Total Cost	288,898,230	303,327,647	501,638,993

NOTES:
1) Assume the carbon tax rate is \$25/ton-CO_2emissions in Table 19 (EIA, Annual Energy Outlook 2015, 2015)

Table 20 (continued)

2) \$72.6/MWh × 20 MW× 20 Years × 365 Days × 22.8 h (US dollar per year)
3) \$115.7/MWh × 20 MW× 20 Years × 365 Days × 22.8 h (US dollar per year)
4) Average transmission loss rate in Pennsylvania is 5.95%(EIA, State Electricity Profiles, 2016)

Indirect and Induced Impact

One of the advantages of the business case described herein is that the natural gas that is produced is used locally for electricity consumption. In addition to the supply chain efficiency, one can also expect indirect economic impacts because of the creation of employment. Once employees move to areas producing natural gas to staff and maintain the distributed power generation facilities, they also drive development of restaurants, hotels, car dealerships, entertainment and any other services they might need. The additional indirect and induced impact of the Marcellus Shale industry in Pennsylvania on goods and services were \$1.56billion (indirect impact) and \$1.84 billion (induced impact) in 2009(Hefley & Seydor, 2015). It is estimated that \$1.90 of total gross output or sales is generated for every \$1 that the Marcellus industry spends in the state.(Constantine, Watson, & Blumsack, 2010).

4.3.6 Limitations

This case study does not consider the economic and environmental impacts of taxes and other related government policies. One such policy under discussion in Pennsylvania is the severance tax. These taxes or fees are in place in approximately 35 states in the United States (Rabe & Hampton, 2015). One cost component not addressed in the analyses in this study is any potential future extraction or severance taxes or fees. Such extraction, drilling taxes or fees would typically be levied on the extraction of a non-renewable natural resource, such as the extraction of natural gas from the Marcellus play. A severance tax would typically be levied on the extractor, which would change the Wholesale Gas Price (P_{GW}) in the Gas Supplier/Power Producer Section analysis by adding severance tax costs to the gas price at the well-head (P_{GH}).

These taxes or fees have served a number of purposes. They been used to create severance endowments; contribute to a state's general fund; contribute to a permanent fund, whose earned interest can help balance the state budget; or used for targeted purposes such as funding conservation and environmental cleanup projects or to provide annual allocations to local governments (National Conference of State Legislatures, 2012) (Rabe & Hampton, 2015). For example, under Pennsylvania's current system of impact fees, the state distributed $233,500,000 in impact fees to counties and municipalities in 2014 (Pennsylvania Public Utility Commission, 2015). These uses are all implements of public policy.

There are perceptions among governmental regulators and legislators that they need to suppress severance tax rates or expand exemptions in order to sustain investment (Rabe & Hampton, 2015). A policy implementation that could be used to encourage utilization of Marcellus natural gas within the state could be to waive or reduce any severance taxes or impact fees for natural gas extracted and used for distributed power generation within the state. This use of Marcellus gas potentially has not only significant economic benefits for all three parties in the chain (the gas supplier or extractor, the electricity producer operating the distributed power generation facility, and the end customer), but also the added benefit of reduced gas costs as a result of reduced or waived severance taxes. In addition to these direct economic benefits, distributed power generation may also result in other indirect and induced economic benefits and reduced environmental impacts discussed above.

4.3.7 Conclusion

The natural gas industry is in a unique situation. Due to the global glut in petroleum and gas, the price of natural gas has dropped significantly since 2015. This situation calls for innovative approaches to increase supply chain efficiency so that the natural gas industry can remain profitable. Using the distributed power production model has the potential to reduce 12% to 35% of the cost in the upstream supply chain. Our case study also shows that there could be a cost saving in the range of 41% to 56% for different kinds of electricity users. Power producers could potentially eliminate enormous amounts of environmental emissions compared to traditional coal-based power plants. Clearly, this model could not be used everywhere, but depending on the scale along which it can be implemented there is significant potential for large absolute cost savings.

In summary, the supply chain reengineering for the distributed power generation industry introduced and quantified in this case study is a new way of taking advantage of the recent boom in natural gas, rather than an optimization of the existing business process flow. It describes a revolution more than an evolution. As shown from the case study, if the natural gas supply chain can be further analyzed and optimized, there could be more potential economic benefits for the supplier and customer and environmental benefit for society at large. With the power generation supply chain efficiency as an operations strategy, this is one way of enabling increased all-around efficiencies for the near future.

4.4 SUMMARY AND CONCLUSIONS

In this thesis we introduced the basic background of the petroleum, natural gas and shale gas industry in Chapter 1. In Chapter 2 we described the process of shale gas production and mapped its supply chain, which starts with the exploration of a potential drilling location and ends with the delivery of the natural gas to end-use customers. We propose a breakdown of this supply chain into two parts: a transient one that exists until the well goes into production and a stable one that remains thereafter. In Chapter 3, we presented detailed flow of various materials and some relevant costs in the shale gas supply chain as a first step toward planning for its efficient operation. Finally, in Chapter 4 we touch upon other related issues such as methane emission, natural gas use patterns and fluctuation in its prices. Through a case study of distributed power generation from Marcellus shale we also discussed how natural gas can play a role in bridging the gap between coal/petroleum based energy and renewable energy.

Although clean renewable energy is highly desirable as a source of future power needs, technologies in this area are not mature and reliable enough to meet a majority of our energy needs today. Its environmental and cost advantages thus make natural gas an attractive bridge between fossil energy and renewable energy. It is more reliable and a cheaper alternative to renewable energy today, and as a more environmentally friendly alternative to other fossil fuels such as coal and petroleum, natural gas has the potential to be a solution to the energy gap in the near future.

On the other hand, the most common concerns about the shale gas industry are with respect to methane emissions, water management and pollution. Under today's more stringent regulations and in the face of strong public opinion, the shale industry has in general attempted to address the latter issue by utilizing technological advances with on-site or off-site water treatment for reuse of wastewater or discharge as fresh water. In addition, the industry has been upgrading the equipment and techniques applied to the production, storage, and transportation of natural gas such as various protective layers, casings and cement in order to reduce leaks that could contribute to methane emissions and environmental pollution. However, the technology and processes behind the production, distribution and delivery of natural gas from shale gas should continue to be studied and optimized.

4.5 CONTRIBUTIONS AND FUTURE WORK

The primary contributions of this thesis are to: 1)separate the shale gas supply chain into two segments based upon the unique characteristic of shale gas; 2) emphasize and study the processes in the transient supply chain along with their related critical issues; 3) map out the material flows within the transient supply chain as a first step to achieving cost savings and operations improvement; 4) establish a business model for utilizing Marcellus shale gas for distributed power generation and use a real-world case study to demonstrate how shale gas can effectively bridge the gap between other fossil fuels like coal/petroleum and renewable energy. The work is based on detailed field investigations and interviews, and collaboration with several local business players in order to conduct a comprehensive and objective study.

This research offers a better understanding of the unique characteristics of the shale gas supply chain. The stable supply chain of shale gas, which is post-production, is not particularly different from that of conventional gas since it generally follows similar processes once gas is extracted and gathered. However, the transient supply chain for shale gas is distinct, and its unique aspects and material flows are investigated and mapped in this thesis.

There are still some significant challenges that need to be addressed. Among these challenges, development and retention of the workforce is a major issue. Due to the specialized techniques and uncommon working environment, all workers must be skilled to meet labor and safety standards. This could be problematic since local workers might not be sufficiently skilled or experienced in terms of these standards. In Pennsylvania, although 250,000 jobs were projected to be supported by natural gas (Considine, Watson, & Blumsack, 2011), companies have often had to recruit workers from other states where drilling has existed long since, because the local workers "aren't trained to do the actual drilling jobs" (Toland, 2010). As a result, approximately 70% of the shale gas employees are recruited from out of state, according to one analysis, while materials and equipment could also be potentially from there (Barth, 2011).The situation is most serious for the many small and medium sized players that do not have the same resources as the relatively small number of large and more vertically integrated companies.

A related issue is that the workforce is disproportionately impacted by the cyclical nature of the oil and gas sector. Interest in the sector grows when there is a boom but any downturn has a significant impact on the number of gas and oilfield professionals as they tend to move to a different sector; the number of fresh graduates in these areas also declines. This is also true of areas like supply chain management in the shale gas sector where skills are often transferable and result in the loss of experienced personnel when there is a downturn. When the situation changes for the better there is often a big shortage of qualified personnel, and new hires can often face a significant learning curve. By one estimate, 71% of the workforce in the oil and gas industry is estimated to be over 50 years old (Randazzo, 2014). By 2018, around half of the current engineers and geophysicists in this industry will retire, according to another study (Oil & Gas IQ, 2014). This situation will lead to a serious labor shortage in the next few years, especially if the shale industry comes out of its current downturn and there is increased activity. Common immediate and growing areas of need for the shale gas sector to bridge this skills gap include (David, 2014)(Faraguna, 2013) (Low, 2013):

- Geologists, geophysicists, and geoscientists with skills in subsurface reservoir characterization
- Petroleum and reservoir engineers to determine optimal drilling locations and maximize recovery
- Drilling and fracking specialists such as petrophysicists, oil field mechanics, seismic interpreters, hydrocarbon mud loggers, and hydromechanics and hydrokinetics experts with horizontal drilling and hydraulic fracturing skills and experience to exploit and stimulate the reservoirs
- Plant managers, operations managers, project managers, and finance managers who can take responsibility for various operations, planning, budgeting and other management duties related to exploration and production of shale gas
- Transportation, shipping and maritime leaders to support downstream marketing and transportation operations

The educational methods, training lead-times and correlation and compatibility with other industrial sectors are still not clear and remain to be studied as future guidance for training local workers. In order to stimulate local employment and compensate for this labor shortage, further study of man-power and human resource issues is needed in the future.

APPENDIX A

CHEMICALS IN HYDRAULIC FRACTURING FLUIDS

Table 21. A Summary of the Various Chemicals Used to Make Hydraulic Fracturing Fluids

(Montgomery C. , 2013)

Chemical Name	**CAS Number**	**Chemical Purpose**	**Product Function**	Hazard Rating[1]
Hydrochloric Acid HCl	007647-01-0	Removes acid soluble minerals and weakens the rock to allow lower fracture iniciation pressures.	Acid	4*,8**
Glutaraldehyde $C_5H_8O_2$	000111-30-8	Eliminates bacteria in the water to prevent frac polymer premature breakdown and well souring	Biocide	3*,6**
Quaternary Ammonium Chloride Compounds	63393-96-4	Clay Control Agents	Biocides and Clay Stabilizers	3**
Tetrakis Hydroxymethyl-Phosphonium Sulfate $C_8H_{24}O_8P_2.SO_4$	055566-30-8	Eliminates bacteria in the water to prevent frac polymer premature breakdown and well souring	Biocide	NR
Ammonium Persulfate $(NH_4)_2S_2O_8$	007727-54-0	Breaks the polymer that is used to create the fracturing fluid	Breaker	4*,5**
Sodium Chloride $NaCl$	007647-14-5	Product Stabilizer	Breaker	NR
Magnesium Peroxide MgO_2	1335-26-8	Delays the breakdown of the fracturing fluid gelling agent	Breaker	5**

Table 21 (continued)

Magnesium Oxide MgO	1309-48-4	Delays the cross linking of the fracturing fluid gelling agent	Buffer	4*
Calcium Chloride $CaCl_2$	10043-52-4	Product Stabilizer and Freeze Protection	Buffer	NR
Ammonium Chloride NH_4Cl	012125-02-9	Clay Stabilizer – Compatible with Mud Acid	Clay Stabilizer	4*,9**
Choline Chloride $[HOCH_2CH_2N^+(CH_3)_3]C$	67-48-1	Prevents clays from swelling or migrating	Clay Stabilizer	5*
Potassium chloride KCl	007447-40-7	Prevents clays from swelling or migrating	Clay Stabilizer	5*,5**
Tetramethyl ammonium chloride $(CH_3)_4NCl$	000075-57-0	Prevents clays from swelling or migrating	Clay Stabilizer	3*,6**
Sodium Chloride $NaCl$	007647-14-5			NR
Isopropanol $CH_3CH(OH)CH_3$	000067-63-0	Winterizing agent	Winterizing agent and Surface Tension Reduction	3**
Methanol CH_3OH	000067-56-1	Winterizing agent	Winterizing agent	3*, 3**
Formic Acid $HCOOH$	000064-18-6	pH adjustment	pH adjustment	4*.8**
Acetaldehyde CH_3CHO	000075-07-0	Prevents the corrosion of the pipe	Corrosion Inhibitor	4*,3**

Table 21 (continued)

Hydrotreated Light Petroleum Distillate	064742-47-8	Carrier fluid for gelling agents, friction reducers and crosslinkers	Carrier fluid and fluid loss control	3**
Potassium Metaborate KBO_2	013709-94-9	Crosslinker for borate crosslinked fluids	Crosslinke r	3*
Triethanolamine (TEA) $N(CH_2CH_2OH)_3$	102-71-6	Maintains fluid viscosity as temperature increases	Fluid Stabilizer	5*,3**
Sodium Tetraborate $Na_2B_4O_7$	001330-43-4	Crosslinker for borate crosslinked fluids	Crosslinke r	4*
Boric Acid H_3BO_3	13343-35-3	Crosslinker for borate crosslinked fluids	Crosslinke r	4*
Chelated Zirconium		Crosslinker for High Temperature or low pH Fluids	Crosslinke r	
Zirconium oxychloride $ZrCl_2O$	7699-43-6	Inorganic Clay Stabilizer	Clay Stabilizer	4*
Ethylene Glycol OCH_2CH_2OH	000107-21-1	Product stabilizer and / or winterizing agent.	Winterizin g Agent	4*
Methanol CH_3OH	000067-56-1	Surface Tension Reduction and / or winterizing agent.	Fluid Recovery and Winterizin g Agent	3*,3**
Ethanol C_2H_5OH	000064-17-5	Product stabilizer and / or winterizing agent.	Fluid Recovery and Winterizin g Agent	3**
Polyacrylamide $(C_3H_5NO)_n$	009003-05-8	"Slicks" the water to minimize friction	Friction Reducer	5*

Table 21 (continued)

Guar Gum and its derivatives HPG, CMHPG	009000-30-0	Thickens the water in order to suspend the proppant and reduce friction	Gelling Agents	NR
Derivatives of cellulose - HEC, CMHEC $R(n)OCH_2COONa$	9004-34-6 9004-32-4	Thickens the water in order to suspend the proppant and reduce friction	Gelling Agents	NR
Xanthan gum	11138-66-2	Thickens Acid in order to control fluid loss	Gelling Agent	NR
Citric Acid $(HOOCCH_2)_2C(OH)COOH$	000077-92-9	Prevents precipitation of metal oxides	Iron Control	5*,8**
Acetic Acid CH_3COOH	000064-19-7	Prevents precipitation of metal oxides and pH control	Iron Control and pH Adjustment	4*,8**
Thioglycolic Acid $HSCH_2COOH$	000068-11-1	Prevents precipitation of metal oxides	Iron Control	3*,8**
Sodium Erythorbate $C_6H_7O_6$. Na	006381-77-7	Prevents precipitation of metal oxides	Iron Control	NR
Lauryl Sulfate and its Derivatives $C_{12}H_{25}OSO_2ONa$	000151-21-3	Used to prevent the formation of emulsions in the reservoir and to improve fluid recovery	Non-Emulsifier and Surfactants	4*
Sodium Hydroxide NaOH	001310-73-2	Adjusts the pH of fluid to initiate the effectiveness of other components, such as crosslinkers	pH Adjusting Agent	4*,8**
Potassium Hydroxide KOH	001310-58-3	Adjusts the pH of fluid to initiate the effectiveness of other components, such as crosslinkers	pH Adjusting Agent	2*,8**

Table 21 (continued)

Sodium Carbonate Na_2CO_3	000497-19-8	Adjusts the pH of fluid to maintains the effectiveness of other components, such as crosslinkers	pH Adjusting Agent	5*,5**
Potassium Carbonate K_2CO_3	000584-08-7	Adjusts the pH of fluid to maintains the effectiveness of other components, such as crosslinkers	pH Adjusting Agent	4*
Sodium Acrylate and Copolymers of Acrylamide $C_3H_3O_2$. Na	007446-81-3	Prevents scale deposits in the pipe or in the fracture	Scale Inhibitor	NR
Sodium Polycarboxylate	N/A	Prevents scale deposits in the pipe	Scale Inhibitor	
Phosphonic Acid Salt	N/A	Prevents scale deposits in the pipe	Scale Inhibitor	
Naphthalene $C_{10}H_8$	000091-20-3	Carrier fluid for the active surfactant ingredients	Surfactant	3*,4**
Ethylene glycol monobutyl ether - EGMBE $C_4H_9OCH_2CH_2OH$	000111-76-2	Surface Tension Reduction for Fluid Recovery	Surfactant	4*, 6**

[i] - 1 – Hazard Rating – An attempt made by the author to rate the hazard level associated with the chemicals in the list. The first number of Hazard Rating with the "*" is the Poison Hazard and the second number of Hazard Rating with "**" is the transportation Hazard. The Poison Hazard is defined by the EU/Swiss Poison Class and the transportation Hazard is defined by the US Department of Transportation (DOT). The appearance of "NR" means that no rating could be found, and if a substance is present, that chemical was normally non-hazardous.

[ii] - * EU/Swiss Poison Class

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