Natural Gas Market Study

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Executive Summary

The rapid increase in shale gas production in the last decade profoundly affected the U.S. natural gas industry. This report examines the various factors affecting the natural gas industry, including supply, prices, demand, and the risk factors that could significantly affect natural gas prices in the future.   The report is done in fulfillment of Indiana Senate Enrolled Act 494 (2013) that directs the Indiana Utility Regulatory Commission to

> **(**1) conduct a study of the natural gas market, including:
>> (A) natural gas prices on both the open and captive markets; and
>> (B) the effect of the availability of substitute natural gas and shale gas on natural gas prices

<u>(A) Natural gas prices on both the open and captive markets</u>[1]

The period of time from 2000 through 2008 is characterized by both high average prices and shorter instances of extremely high prices. The price spikes of the winter of 2000/2001 and February 2003 resulted from a combination of low natural gas storage levels and high demand from cold weather. The price spikes of 2006 and 2008 were associated with supply disruptions in the Gulf of Mexico due to hurricane activity. The average price of natural gas dropped considerably in the latter half of 2008 and has stayed low since. The mean Henry Hub spot price for 1997-2008 was $5.09 per million British Thermal Units (mmBtu), while it was only $3.75/mmBtu from 2009 through October 18, 2013.

Price volatility has dropped considerably since 2009. A depiction of the reduced volatility in the recent period is provided in Figure ES-1. For each year, a line indicates the range between the minimum and maximum prices experienced in that year and a triangle indicates the average price. The high prices in the winter of 2000/2001 impact the spread for both years. The price spikes of 2003, 2005, and 2008 are also evident.   Starting in 2009, both the average price and the spread are smaller, with the spread in 2011 and 2012 being very tight (judgment should be reserved on 2013 until the year is complete).

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[1] The terms "open" and "captive" were used in Senate Enrolled Act 494 but were not defined. For purposes of this report, an open market refers to the wholesale market for natural gas and captive markets represent customers who purchase their natural gas through a local distribution company.
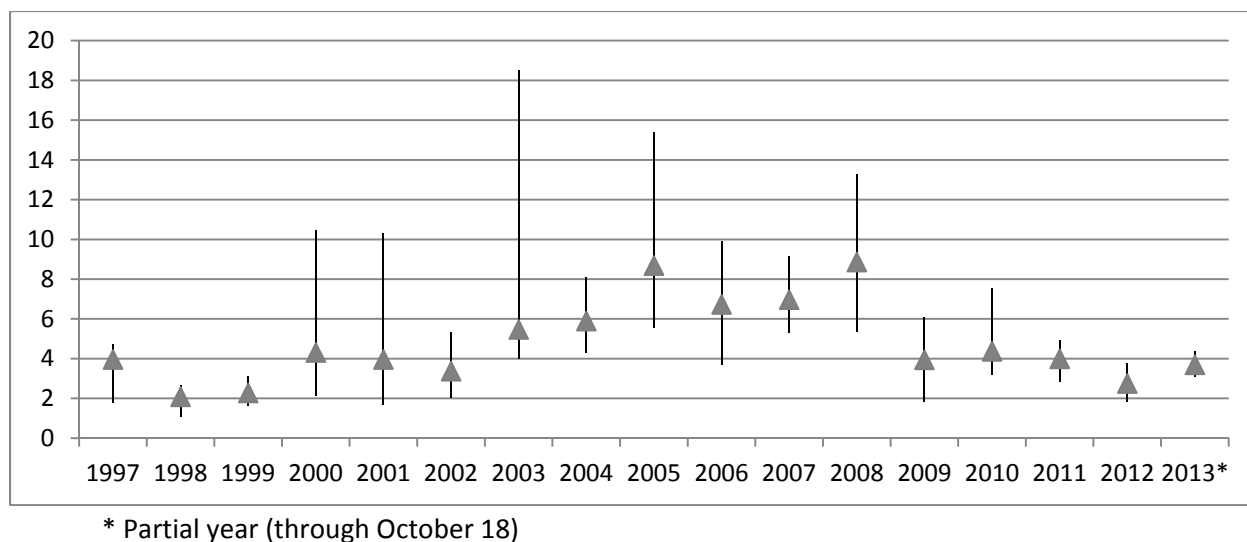
* Partial year (through October 18)

Figure ES-1. Annual Natural Gas Price Spreads with Average Price (nominal $/mmBtu) [Data source: Energy Information Administration]

From the customer perspective, the commodity price accounts for approximately 62 percent of the average residential bill in Indiana, with the remainder stemming from costs associated with the distribution system and trackers. Since the cost of procuring the natural gas in the open market is passed directly to the customer in the captive market with no profit to the utility, there is a direct dollar for dollar impact of changes in natural gas prices to changes in a customer's bill. Thus, if natural gas prices increase (or decrease) by $1/mmBtu, a customer's bill will increase (decrease) by $1 for every mmBtu of natural gas consumed.   To put this in perspective, consider a customer who consumes 200 therms in a month (10 therms equal one mmBtu). For every $1/mmBtu change in the natural gas price, the customer's bill will change by $20.

(B) The effect of the availability of substitute natural gas and shale gas on natural gas prices

The past five years have been marked by steady natural gas production, without any major disruptions. While this is in large part due to the fortuitous lack of hurricane activity in the Gulf of Mexico region, the increasing geographic diversity of supply from shale gas is likely to mitigate the impact of future events. Another factor that limits price volatility is the ability to drill new wells rapidly using current technology. If prices climb rapidly, new wells can be producing in a matter of days in response to the price increase. Thus, production is more responsive than it was previously. A third factor keeping price volatility down is fuel switching for electricity generation, which has the effect of dampening changes in natural gas price. If natural gas prices increase, less natural gas is used and the reduced demand limits the natural gas price increase. Similarly, decreasing natural gas prices result in increased gas-fired generation and the natural gas price decrease is limited. It should be noted that fuel switching does not necessarily result in lower natural gas prices, just in lower price volatility. Additionally, it should be noted that this phenomenon exists because of the current generation capacity surplus. Expected coal retirements due to U.S. Environmental Protection Agency (EPA) regulations, plant age, and economics could mitigate this price volatility dampening effect.

Substitute natural gas (SNG) is expected to exhibit low price volatility. Once a SNG plant becomes operational, the largest source of cost uncertainty is the price of the feedstock fuel, generally coal. Coal prices have historically been fairly stable and the ability to substitute petroleum coke as a feedstock provides additional price stability.

Historically, natural gas and oil prices have tended to move together as they acted as substitutes for each other for various energy demands, such as space heating, electricity generation, and industrial processes. With the development of wet gas plays (natural gas mixed with oil or petroleum liquids), that relationship has changed. When oil prices are high, they provide an incentive to develop wet gas sites, even if natural gas prices are low. The natural gas that is produced increases the total supply and drives prices downward. Thus, the relationship between natural gas and oil prices has not only weakened, it has reversed.   This means that developers can make a profit when natural gas prices are low through sales of the higher priced oil.

Despite the recent stability in natural gas prices, there is still uncertainty regarding future prices. This uncertainty includes the high level of price volatility prior to 2009, the relatively recent changes in the major factors affecting natural gas prices, the unknown future demand for natural gas and natural gas exports, and the uncertainty over potential regulations for hydraulic fracturing. The report shows natural gas price forecasts from four different sources (American Electric Power (AEP), the Energy Information Administration (EIA), Bentek, and Wood Mackenzie), covering nine different scenarios. The forecasts all follow similar paths of a steady increase in prices, but the growth is obviously higher in some cases than in others. In general, the EIA Reference case has the lowest prices of the four base forecasts, while the AEP Base case is among the highest. With one exception, the alternate forecasts generally fall between the EIA Reference and AEP Base forecasts. The AEP High forecast has the highest prices through 2033 and exceeds the next highest forecast by at least $0.80/mmBtu from 2016 to 2030. The forecast values for the base forecasts for selected years are provided in Table ES-1.

Year	AEP	Bentek	EIA	Wood Mackenzie
2015	5.47	4.80	3.32	4.03
2020	6.43	6.18	4.77	6.29
2025	7.75	6.85	6.14	7.58
2030	8.52	8.42	7.45	8.35

Table ES-1. Henry Hub Natural Gas Price Base Forecasts for Selected Years (nominal $/mmBtu)

The expected price for SNG is higher than most of the natural gas price forecasts in the early years, but grows at a slower rate. The AEP Base forecast is close to the SNG price in 2021 and the Wood Mackenzie forecast is close in 2022. The Bentek and EIA Reference forecasts are less than the SNG price until 2030 or later. One of the alternate forecasts, the AEP High price projection, has natural gas prices at or above the SNG price throughout the time period, while the AEP Low price forecast has prices below the SNG price at all times. The three alternate EIA projections are below the SNG price until 2029 (Low Growth), 2031 (High Oil), and 2034 (High Growth). The expected SNG price comparison to the base and alternate forecasts is discussed in Section 2F of this report and is shown in Figures 2-14 and 2-15.

This report uses the comparison of SNG prices to the various forecasts, under the characteristics of the purchase agreement between Indiana Gasification and the Indiana Finance Authority, to calculate the impact of the SNG purchase on an individual customer (200 therms of gas usage per month per household) if an individual forecast happened to be correct. It is important to understand that natural gas price forecasts have historically been quite inaccurate. Thus, a number of different price forecasts are used to show the impacts of different projections. Of the four base cases, the AEP Base forecast results in a slight reduction (up to 50 cents per monthly bill) between 2025 and 2035. The other base forecasts show bill increases in the earlier years (over $8 per bill in 2020 for the EIA Reference forecast). These bill increases decline over time and turn into bill decreases late in the forecast periods as natural gas prices rise while SNG prices remain flat. Of the alternate forecasts, the AEP High price forecast indicates bill reductions of 2 - 3 dollars per bill beginning in 2025. The three alternate EIA forecasts follow a similar path as the EIA Reference forecast with greater deviation in the later years. The AEP Low price forecast indicates a bill increase beginning in 2020 through the end of the forecast.

Risk Factors

This report identifies three factors that could significantly impact natural gas prices: environmental regulations, increased demand for natural gas, and falling petroleum prices.

There are several environmental issues concerning the hydraulic fracturing industry. These concerns include that a breach in the well or fracture gone too far could cause the fracturing fluid to leak into and contaminate fresh water aquifers; that the large amounts of waste water containing harmful chemicals, if not properly handled and disposed, could contaminate surface water; that the injection of waste water into deep wells for disposal has the potential to induce earthquakes; the large amounts of water that it takes to fracture a well; and methane leakage from wells associated with hydraulic fracturing.

There is considerable uncertainty as to what future environmental regulations will be in this area. For the most part, EPA has yet to act and regulation has occurred at the local level. Regulations that standardize drilling practices, monitoring, and reporting may have a small impact on natural gas prices. Regulations that impose a significant barrier to hydraulic fracturing would have a dramatic effect on natural gas prices. Given the tremendous impact of shale gas development on the U.S. economy, there is a significant economic incentive to avoid enacting prohibitive regulations.

Significant increases in demand could have a major impact on natural gas prices. Areas that could see a demand increase include the transportation sector, electricity generation, and the use of natural gas in an industrial process or as an industrial feedstock. The area that has the greatest potential to affect natural gas prices, and also has the greatest level of uncertainty, is LNG exports. The export capacity of the facilities that have currently been proposed to FERC would represent over 23 percent of the current production and a number of other potential sites have been identified (see Section 3F for more information on proposed and potential LNG export terminals). While current U.S. and overseas natural gas prices indicate that LNG exports are viable, significant development of shale gas in other regions of the world could reduce the price in Europe and Asia. A significant increase in domestic demand or

exports would likely change the pricing paradigm for natural gas, moving the price above the current levels seen under wet gas drilling and toward the level required to support dry gas production.

Since the current low natural gas prices are largely a function of high oil prices, a drop in oil prices would likely result in higher natural gas prices. The recession of 2008 saw a dramatic decrease in oil prices, from a spot market high of $145/barrel in July 2008 to $30/barrel in December for West Texas Intermediate crude. It is conceivable that the production of natural gas liquids will reduce the price for those products, thus reducing the profitability of wet gas development. Furthermore, increases in domestic production of light crude oil found in associated gas could limit refinery production, since refinery production efficiency is lower with light crude. This could result in lower light crude prices with mid and heavy crude prices remaining high, thus making associated gas development less attractive.

1. Natural Gas Supply

1A. Hydraulic Fracturing and Horizontal Drilling

The rapid increase in shale gas production in the last decade has had profound effects on the U.S. natural gas industry, turning natural gas from a high-priced commodity with the potential for imports from overseas to one with an abundant domestic supply with export potential. Two technological developments, hydraulic fracturing and horizontal drilling, have combined to greatly lower the cost of extracting natural gas (and oil) from these otherwise impervious shale rock formations. These technological advancements have also allowed for new wells to be brought online more quickly than was previously possible.

Hydraulic fracturing, also known as hydrofracking or fracking, involves the pumping of a fracturing liquid under high pressure into a shale formation to generate cracks through which hydrocarbons trapped in these impervious rock formations can flow into the well bore. According to the Kansas Geological Survey, hydraulic fracturing technology has been around since the late 1940s with the first experimental fracturing treatment having been done in a gas field in Kansas in 1947.[i] Prior to the current shale drilling boom, hydraulic fracturing was used in conventional wells to stimulate oil and gas production.

The drilling of a horizontal well starts off as a vertical well through the rock layers above the hydrocarbon-bearing shale formation. At the appropriate depth, the well is turned gradually horizontal such that the borehole can be extended a long distance through the hydrocarbon-bearing rock layer. According to a 2009 shale gas development report by the Ground Water Protection Council and ALL Consulting, the lateral portion of a horizontal well typically extends between 1,000 to over 5,000 feet.[ii] Figure 1-1 illustrates a horizontal well that has been hydraulically fractured 6,000 feet below the surface.
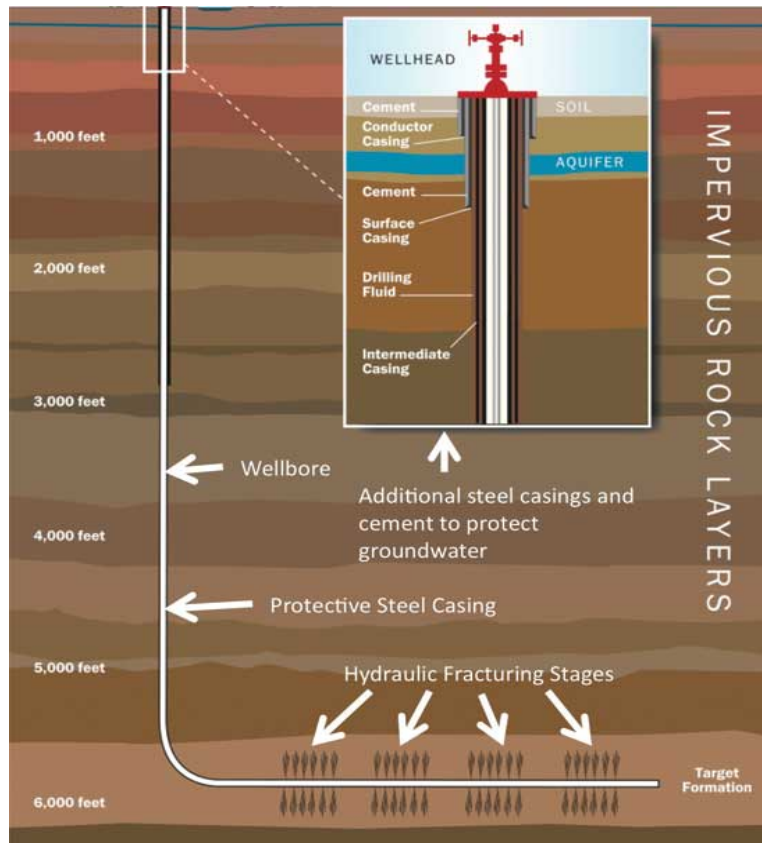
Figure 1-1. Horizontal Drilling with Hydraulic Fracturing [Source: Kansas Geological Survey][iii]

1B. Wet Gas vs. Dry Gas

The economics of gas production are also supported by natural gas occurring in conjunction with oil and natural gas liquids in differing proportions in hydrocarbon-bearing rocks. Natural gas liquids, also referred to as petroleum liquids, include ethane, propane, butane, and natural gasoline. The proportion varies from natural gas only in "dry gas" wells through a mix of natural gas and natural gas liquids in "wet gas" wells, all the way to "associated gas" that occurs together with crude oil.

For example, according to the EIA, the number of gas-directed wells in the Appalachian basin has been steadily shifting from the northeastern corner of Pennsylvania, where the dry gas production in the Marcellus Shale is concentrated, to the West Virginia / southwest Pennsylvania region where the wet gas in the Marcellus and Utica shale formations is produced.[iv] Another example of gas production being supported by co-occurring products is in North Dakota from the Bakken Shale where associated natural gas, found together with crude oil, has experienced rapidly increasing production, not because it was economical on its own, but as a byproduct of crude oil production. The rate of natural gas output in North Dakota wells has been such that, according to EIA, over 35 percent of the gas was flared in 2011 because there was no infrastructure to move it to the market.[v]

The distinction between wet gas and dry gas is important because it can dramatically affect the natural gas price that is necessary for a well to be profitable. If the prices of oil and petroleum products are high, a wet gas rig can become profitable based on the liquid production alone. In many current wet gas production regions, natural gas produces only 5 percent of the revenue for new wells.[vi] For dry gas wells, the sale of natural gas is the only source of revenue. At current prices, dry gas wells are far less profitable than wet gas wells.

1C. Geographical Supply Regions

With the rapid rise in shale gas reserves and production, the supply of natural gas is more uniformly distributed across the contiguous U.S. with some of the major shale formations, like the Marcellus, being located close to the major natural gas consuming regions of the country. Figure 1-2 shows the location of the gas containing shale formations, commonly referred in the oil and gas industry as shale "plays". Almost all of the growth in natural gas production (and nearly 90 percent of oil production growth) from 2011 to 2012 occurred in six regions: Bakken, Niobrara, Permian, Eagle Ford, Haynesville, and Marcellus.[vii] The Bakken, Eagle Ford, and Permian regions produced the largest amounts of oil, while the Marcellus and Haynesville regions produced the largest amount of natural gas.
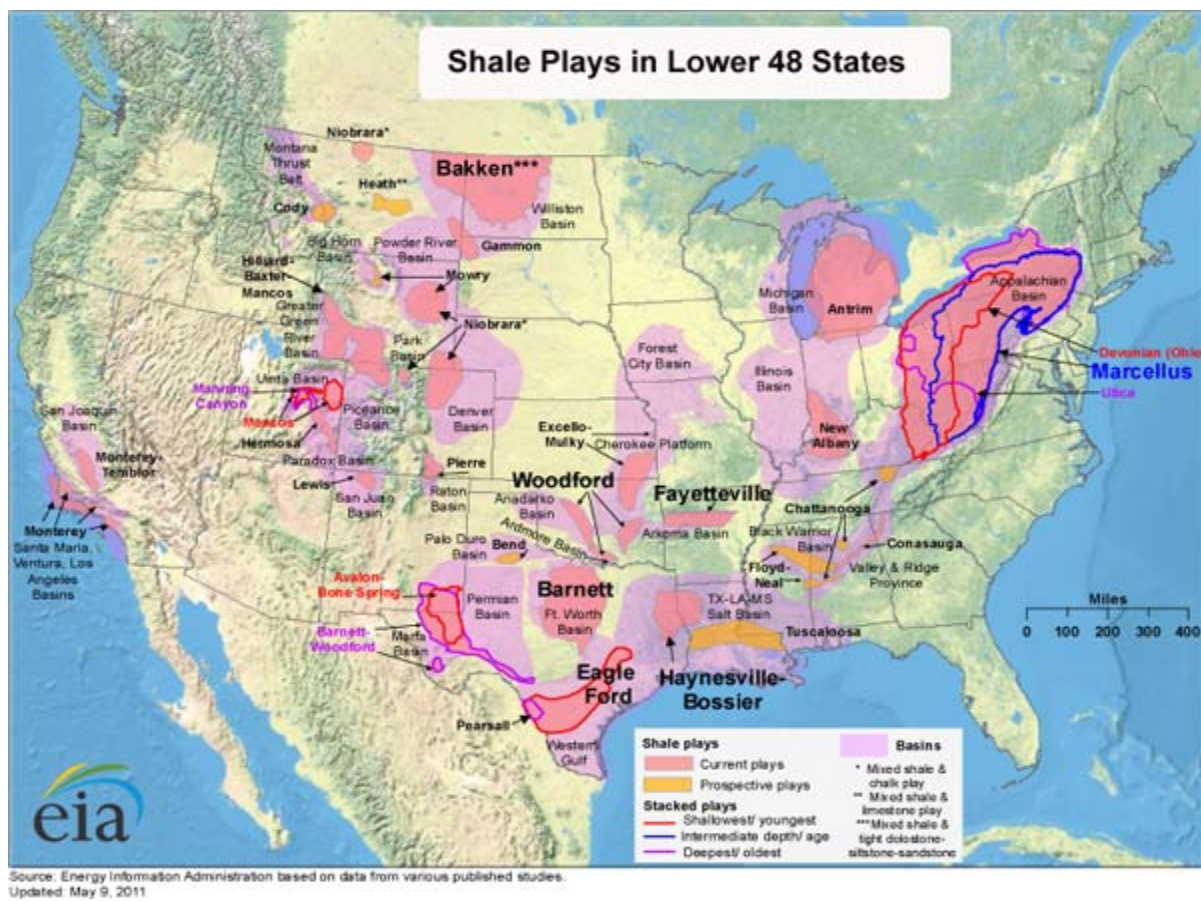

Figure 1-2. Major Shale Gas Plays in the Contiguous U.S. [EIA][viii]

According to EIA, 63 percent of the 750 trillion cubic feet (Tcf) of technically recoverable shale gas in the contiguous U.S. is located in the Northeast shale plays, most of it (410 Tcf) in the Marcellus Shale.[ix] The effect of the rising production from the Marcellus shale play is best highlighted by the large drop in the price differential between the Gulf Coast and the North East. Figure 1-3 shows the price premium between the TCO Appalachia Hub in southwestern Pennsylvania and the Henry Hub on the Gulf Coast in Louisiana. According to EIA, the gas at the TCO Appalachia hub has been priced at average $0.25/mmBtu above the Henry Hub. This premium had all but been erased by July 2012 with the forward markets pricing the TCO Appalachia Hub lower than the Henry Hub.
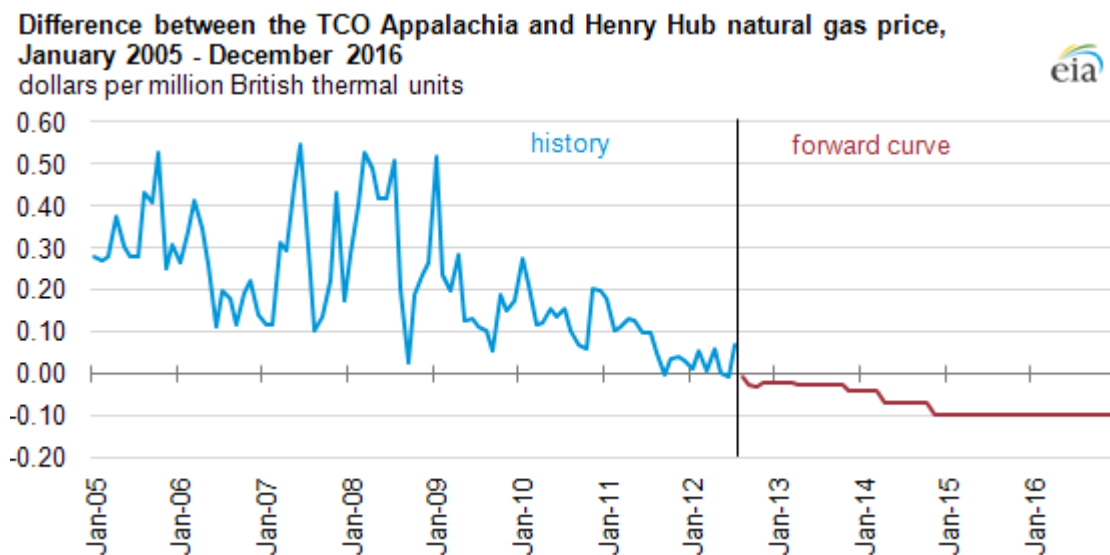

Difference between the TCO Appalachia and Henry Hub natural gas price, January 2005 - December 2016
dollars per million British thermal units

Figure 1-3. Price Difference between Henry Hub and a Hub in the Northeast [Source: EIA][x]

1D. Synthesis Gas

The production of gas from coal for use in lighting and heating is not new. Gas from coal, commonly known as fuel, town, or manufactured gas was the primary means of lighting and heating in Europe and North America in the nineteenth century and the early parts of the twentieth century. The modern gasifier is a high pressure vessel where oxygen and steam are passed through the feedstock (usually coal or petroleum coke) causing a series of chemical reactions producing a synthesis gas (syngas) composed primarily of hydrogen, carbon monoxide, and carbon dioxide.[2] The raw synthesis gas is then passed through a cleaning process to remove contaminants which include carbon dioxide, fine particulates, sulfur, ammonia, chlorides, mercury, and other trace heavy metals.[xi]

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[2] In this report, synthesis gas is used for all uses of the gas (including electrical generation and as a chemical feedstock), while substitute natural gas refers only to gas that is injected into the natural gas delivery system as a replacement for natural gas.

According to the National Energy Technologies Laboratory (NETL), the main markets for syngas, based on analysis of current and planned projects across the globe are production of chemicals and fertilizers (45 percent), liquid fuels such as diesel and gasoline (28 percent), electric power (19 percent), and gaseous fuels such as synthetic natural gas (SNG) and hydrogen (8 percent) as shown in Figure 1-4. The syngas produced at the Indiana gasification facilities, Wabash River and Duke Edwardsport, is not processed to pipeline quality SNG. The syngas from these plants has the toxic contaminants removed, but not the carbon dioxide, which is required for pipeline quality SNG. In addition, the Wabash River gasification project does not use coal as a feedstock, but rather petroleum coke, a byproduct of petroleum refining.
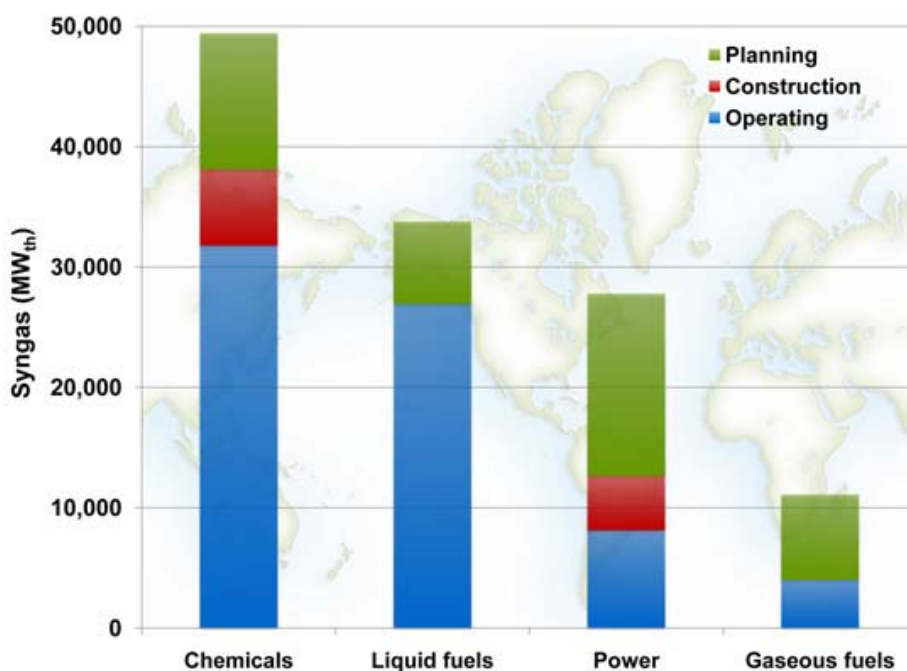

Figure 1-4. 2010 World Gasification Capacity and Planned Growth – by Product [Source: NETL][xii]

As can be seen in Figure 1-4 only a small proportion of existing and proposed gasification plants worldwide are dedicated to producing pipeline quality SNG. Currently in the U.S., the only gasification plant dedicated to converting coal to SNG is the Great Plains Synfuel plant in North Dakota. The plant is owned by Basin Electric Power Cooperative and has been in operation since 1984. Basin Electric purchased it for $2.1 billion dollars, including $1.5 billion in U.S. Department of Energy assistance. The plant produces an average of 153 million cubic feet of equivalent natural gas per day from lignite coal. The carbon dioxide from the plant is piped to Saskatchewan, Canada where it is used for enhanced oil recovery.[xiii] According to the Gasification Technologies World Gasification Database, there is only one other operating coal-to-SNG plant, the Shenhua Erdos plant in China and a total of twenty-three proposed plants world-wide, including two in the United States. The two proposed coal-to-SNG plants in the U.S. are the Indiana Gasification Plant and the South Heart Energy Development project in Wyoming.[xiv]

1E. Environmental Considerations

There are several environmental concerns that have arisen around the hydraulic fracturing industry. One of the greatest concerns is that a breach in the well or fracture gone too far could cause the fracturing fluid to leak into and contaminate a community's fresh water supply. Another concern is that the large amounts of waste water containing harmful chemicals, if not properly handled and disposed, could contaminate surface water in nearby communities when some of it flows back to the surface. In addition, when this waste water is disposed of by injection into deep wells, as it typically is, it has the potential to induce earthquakes strong enough to be felt at the surface.[xv] Yet another concern is the large amounts of water that it takes to fracture a well. According to the Groundwater Protection Council it takes between 2 million and 4 million gallons of water to fracture one horizontal well.[xvi] According to the Groundwater Protection Council, this is not a large volume when compared to other uses such as irrigation; however, there is concern that this additional large-scale use could deplete vital fresh water supply sources.

The EPA is currently conducting a study on the potential impacts of hydraulic fracturing on drinking water in response to a request from Congress. In December 2012, EPA released a preliminary report that explains research projects that were being undertaken. The research is intended to address five stages of water use in hydraulic fracturing. From the preliminary report,[xvii] they are:

- *Water acquisition: What are the possible impacts of large volume water withdrawals from ground and surface waters on drinking water resources?*

- *Chemical mixing: What are the possible impacts of hydraulic fracturing fluid surface spills on or near well pads on the drinking water resources?*

- *Well injection: What are the possible impacts of the injection and fracturing process on drinking water resources?*

- *Flowback and produced water: What are the possible impacts of flowback and produced water (collectively referred to as "hydraulic fracturing wastewater") surface spills on or near well pads on drinking water resources?*

- *Wastewater treatment and waste disposal: What are the possible impacts of inadequate treatment of hydraulic fracturing wastewater on drinking water resources?*

EPA expects to release the final report in draft version for public comment and review in 2014.

Methane leakage from wells associated with hydraulic fracturing is another concern. Recent studies of methane leakage have come to very different conclusions, often with considerable criticism. In 2011, researchers from Cornell published an evaluation of the greenhouse gas footprint of the extraction of shale gas indicating that methane emissions from shale gas was 30-100 percent higher than from conventional gas.[xviii] In 2012, the Joint Institute for Strategic Energy Analysis released a study authored by researchers from NREL, the University of Colorado, and Colorado State University that found that life cycle emissions of greenhouse gases from electricity generated from Barnett shale gas were very similar

to electricity generated from conventional gas.[xix] In a study reported in September 2013, researchers found that actual methane emissions from well sites were lower than previously estimated and similar to those from conventional sites.[xx] Furthermore, EPA finalized regulations requiring new wells to capture emissions beginning in 2015.[xxi]

These environmental concerns have resulted in strict regulations in countries outside the U.S., especially in Europe, ranging from moratoria to an outright ban in France. There is an active constituency seeking similar measures to be implemented in the U.S. To date, hydraulic fracturing bans or moratoria have been implemented on local levels. At the state level, New York instituted a moratorium on hydraulic fracturing in 2008. While the moratorium has lapsed, a de facto restriction is in place pending completion of a review of the health effects. Legislation has been introduced in other states, but these measures have yet to gain enough support to become law. A number of local governments in New York have banned or placed a moratorium on hydraulic fracturing. Similarly, Mora County, NM and the City of Bowling Green, WI have banned the practice.[xxii]

The International Energy Agency (IEA) has developed a number of suggested rules for responsible development of oil and natural gas from shale formations. IEA estimates that the implementation of these "Golden Rules" would increase the production cost of hydraulic fracturing by 7 percent.[xxiii] The rules fall under the following general categories:

- *Measure, disclose and engage: Engage with the local community; establish baselines for key environmental indicators; measure and disclose operational data on water use, air emissions and fracturing fluids; and minimize disruptions to the local community.*

- *Watch where you drill: Choose well sites to minimize impacts; survey the local geology and assess risks; and monitor to ensure fractures do not extend beyond the gas-producing region.*

- *Isolate wells and prevent leaks: Enact robust rules on well design and construction; consider minimum depth limitations; and take action to prevent and contain surface spills and ensure proper disposal of waste.*

- *Treat water responsibly: Reduce freshwater usage; store and dispose of waste water responsibly; and minimize the use of chemical additives.*

- *Eliminate venting, minimize flaring and other emissions: Target zero venting and minimal flaring during well construction and reduce fugitive emissions during operation; and minimize air pollution from vehicles and equipment.*

- *Be ready to think big: Seek to use economies of scale; and account for cumulative regional effects of multiple activities in a region.*

- *Ensure a consistently high level of environmental performance: Ensure regulatory bodies have sufficient resources; find a balance between prescriptive and performance-based regulation; have robust emergency response plans; continuously improve regulations and operations; and independently evaluate and verify environmental performance.*

It has been demonstrated that hydraulic fracturing can be done without using water as a fracturing medium. GASFRAC has used liquefied petroleum (LP) gas gel for fracturing in Texas and Canada and claims that it has better performance than using water.[xxiv] Liquid nitrogen and CO2 have also been proposed as fracturing fluids. These non-water fracturing fluids are early-stage technologies with higher costs.

As is the case with shale gas, syngas production involves the use of water and the production of greenhouse gases. While the water usage in syngas production is substantial, it is less than the amount needed to produce an equivalent amount of shale gas.[xxv] Also, syngas production does not involve large amounts of wastewater or the potential for a well breach contaminating drinking water supplies.

Syngas production creates a significant amount of carbon dioxide (CO2) as a byproduct. While the quantities of CO2 are large, it is believed that a given amount of CO2 has less than 5 percent of an effect on climate than does the same amount of methane.[xxvi] Also, since the CO2 produced is in a more concentrated form than is found in the exhaust of coal combustion, it is better suited for capture. Thus, it can be converted from an environmental concern into a source of revenue as is the case with the Great Plains Synfuel plant referred to in Section 1D. The carbon dioxide from this plant is sold to oil producers in Saskatchewan for use in the enhanced oil recovery. A similar plan is envisaged for the Indiana Gasification Plant to sell the carbon dioxide for enhanced oil and gas recovery in the Gulf Coast.

The main advantage of gasification of coal compared to combustion-based technologies is the relative ease with which the pollutants in the feedstock can be captured in the gasification process. According to NETL "*gasification systems can achieve almost an order of magnitude lower criteria emissions levels than typical current U.S. permit levels and +95% mercury removal with minimal cost increase*".[xxvii] Nevertheless, as long as the cleanup process does not guarantee a hundred percent removal of pollutants, the remaining levels will be a source of some environmental concern. According to NETL, the high temperature and pressure in the gasification process turn inorganic substances, including the pollutants in the coal, into a slag as opposed to ash in the typical combustion process. This slag captures the pollutants in a form that does not allow them to leach from the material and therefore it can be sold as road construction or concrete making material. The sulfur captured from the gas-cleaning process can also be sold to the chemical industry where the U.S. is a net importer of sulfur.

2. Natural Gas Prices

2A. Average Price

As can be seen from Figure 2-1, the annual average price of natural gas has gone through a number of distinct phases. Prior to the energy crisis and Arab oil embargoes of the 1970s, natural gas prices were stable and low. From 1973 to 1983, wellhead natural gas prices increased from $0.22/mmBtu to $2.59/mmBtu. Amid curtailments of natural gas and concerns about U.S. supplies, the Powerplant and Industrial Fuel Use Act, which restricted natural gas usage by new industrial boilers and power plants, was passed in 1978. Prices dropped and stabilized in the mid-1980s, and these restrictions were removed in 1987. Wellhead prices remained relatively stable in the $1.50/mmBtu to $2.50/mmBtu range for the remainder of the century. During the 2000s, natural gas prices followed crude oil prices sharply upward, while well productivity continued the decline that had started in the late 1990s. Natural gas prices dropped dramatically in 2009 due to reduced demand and the development of shale gas sources.
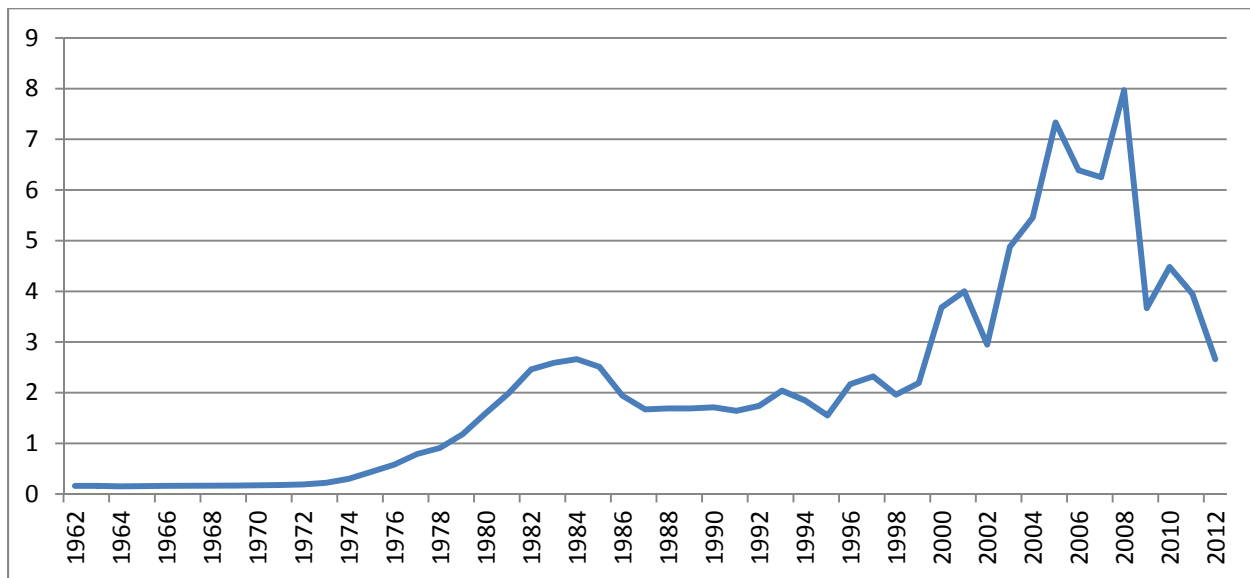

Figure 2-1. Annual Wellhead Natural Gas Prices (nominal $/mmBtu) [Data source: EIA][xxviii]

Declining well productivity played a key role in the price increases that started in the late 1990s. With the average well producing less natural gas, the natural gas price needed to support drilling increased. Figure 2-2 shows the average production from natural gas wells in Texas from 1990 to 2011.
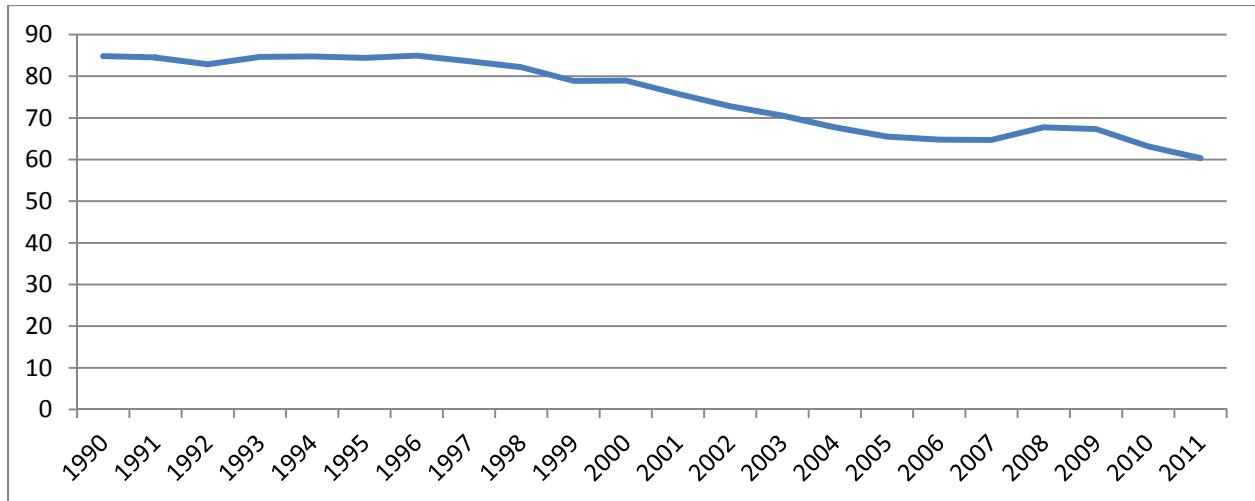
Figure 2-2. Average Production from Natural Gas Wells in Texas (million cubic feet per well) [Data source: Railroad Commission of Texas][xxix]

The average price of natural gas dropped considerably in the latter half of 2008 and has stayed low since. The mean Henry Hub spot price for 1997-2008 was $5.09/mmBtu, while it averaged only $3.75/mmBtu from 2009 through October 18, 2013. The decline would be even larger if the effect of general inflation were taken into account. As shown in Figure 2-3, natural gas prices are still exhibiting the same seasonal pattern as they did in the earlier period. Higher prices in the winter are generally driven by heating demand, while higher summer electricity demand means greater usage of natural gas from the electricity sector.
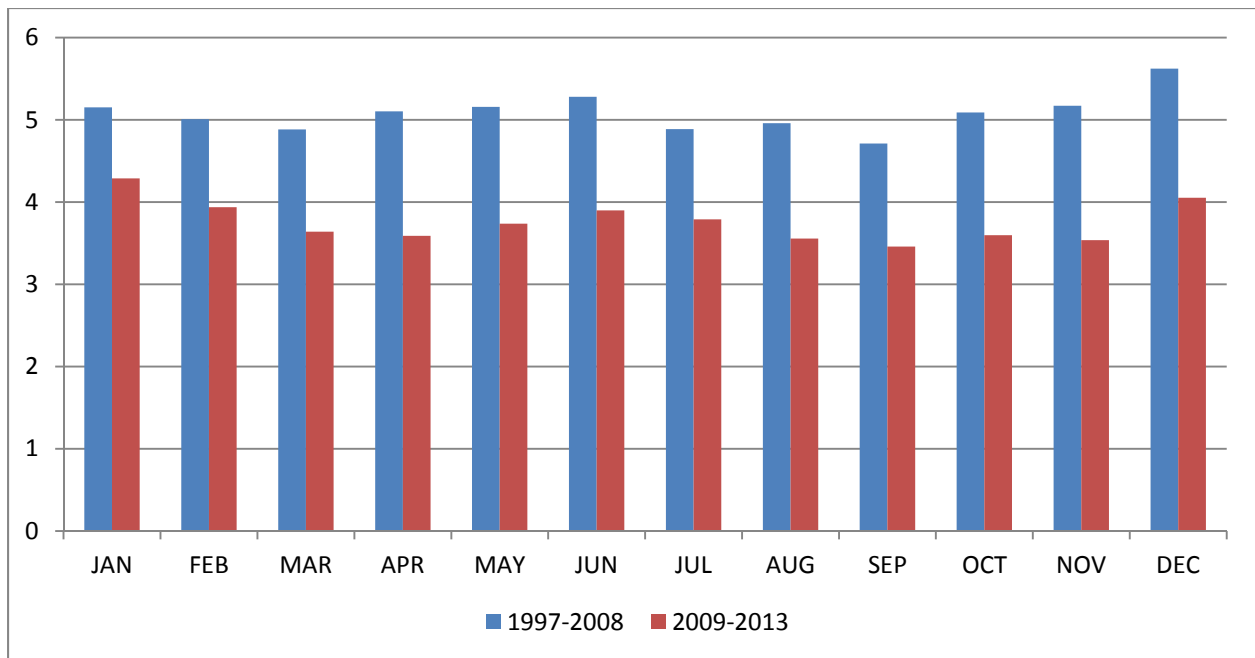

Figure 2-3. Henry Hub Natural Gas Monthly Average Price (nominal $/mmBtu) [Data source: EIA][xxx]

2B. Price Volatility

Figure 2-4 shows the daily Henry Hub spot price for natural gas from 1997 through October 2013. The period of time from 2000 through 2008 is characterized by both high average prices and shorter instances of extremely high prices. The price spikes of the winter of 2000/2001 and February 2003 resulted from a combination of low levels of natural gas storage and high demand from colder than typical weather. The U.S. entered the 2000/2001 heating season with the lowest level of storage since 1976 and by the end of March 2001, the storage was at the lowest level ever recorded by EIA[xxxi]. The February 2003 price spike was very severe but short lived. It occurred after a prolonged cold winter that depleted natural gas storage followed by a cold front that reached into the deep South, resulting in well freeze-offs. (A well freeze-off occurs when the ambient temperature drops below freezing at an unprotected well and water in the natural gas freezes, blocking the flow of gas). The combination of increased demand and restricted supply caused Henry Hub prices to rise from $8/mmBtu to over $18/mmBtu over two days before dropping back below $10/mmBtu the same week[xxxii].

The price spikes of 2006 and 2008 were associated with supply disruptions in the Gulf of Mexico due to hurricane activity. Henry Hub prices rose $2.50/mmBtu in a single day in late August 2005, as natural gas production was curtailed due to Hurricane Katrina. Production was further curtailed in September due to Hurricane Rita. Normal production levels (and sustained sub $10 prices) did not return until 2006. Hurricanes Gustav and Ike had a similar impact on natural gas prices in the late summer and fall of 2008.
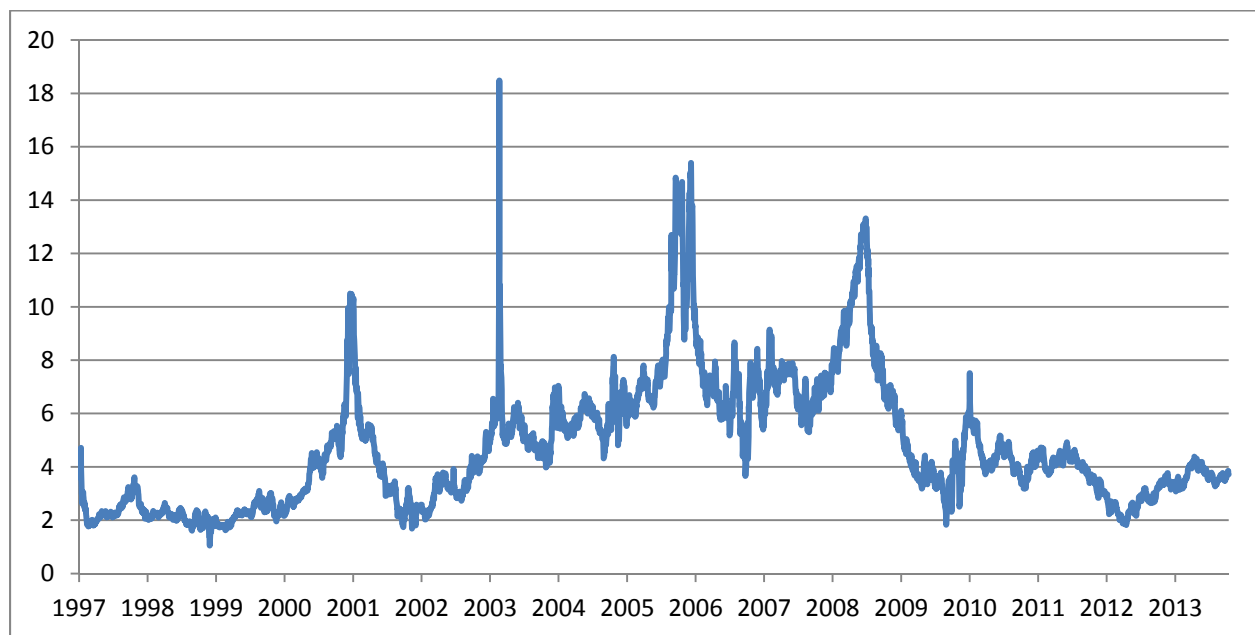

Figure 2-4. Henry Hub Spot Natural Gas Prices (nominal $/mmBtu) [Data source: EIA][xxxiii]

Price volatility has dropped considerably since 2009. One measure of the volatility, the statistical variance, indicates how spread out the prices are from the average: a small variance indicates they are close to the average while a large variance indicates they are not. The variance for the 1997-2008

period is $7.05/mmBtu and the 2009-present variance is only $0.65/mmBtu. Another depiction of the reduced volatility in the recent period is provided in Figure 2-5. For each year, a line indicates the range between the minimum and maximum prices experienced in that year and a triangle indicates the average price. The high prices in the winter of 2000/2001 impact the spread for both years. The price spikes of 2003, 2005, and 2008 are also evident.   Starting in 2009, both the average price and the spread are smaller, with the spread in 2011 and 2012 being very tight (judgment should be reserved on 2013 until the year is complete).
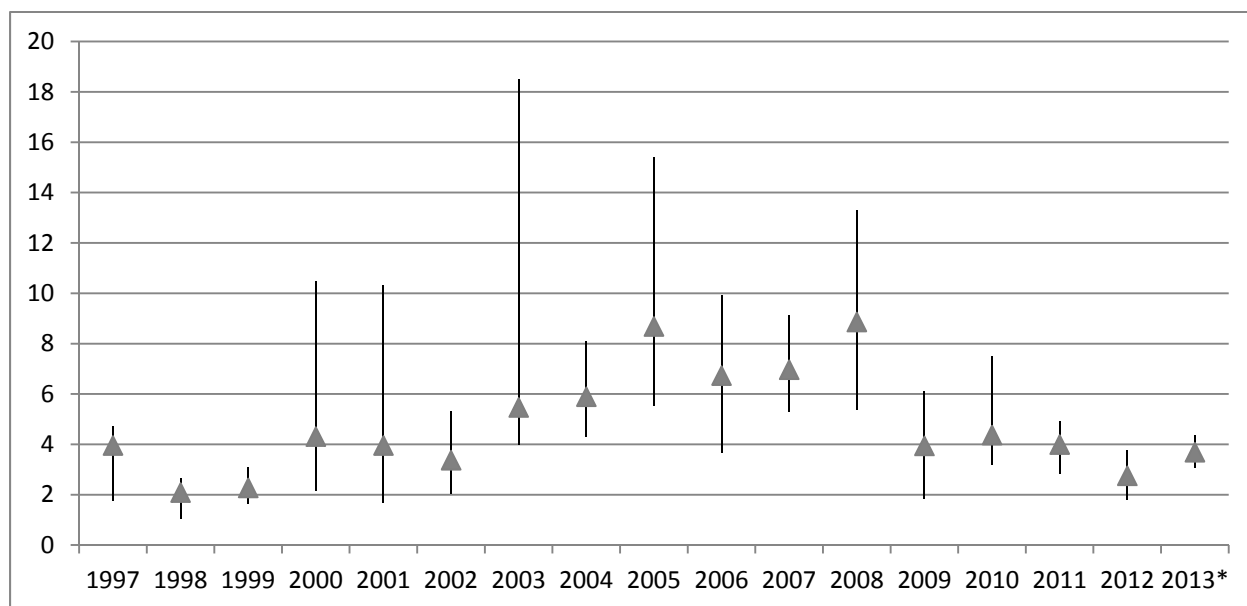
* Partial year (through October 18)

Figure 2-5. Annual Natural Gas Price Spreads with Average Price (nominal $/mmBtu) [Data source: EIA][xxxiv]

The past five years have been marked by steady natural gas production, without any major disruptions. While this is in large part due to the fortuitous lack of hurricane activity in the Gulf of Mexico region, the increasing geographic diversity of supply (see Section 1C of this report) is likely to mitigate the impact of future events. With the increased production in such geographically diverse states as Pennsylvania (where production increased by 620 percent from 2007 to 2011) to Arkansas (with an increase of 300 percent) to North Dakota (with an increase of 120 percent), it is less likely that a single event will impact U.S. natural gas production capability. In 2011, nine states each produced at least 2.5 percent of the nation's natural gas for the first time ever. Also, the U.S. has become significantly less dependent on off-shore sources of natural gas supply (see Figure 2-6); with the off-shore share of total U.S. production declining from 21.6 percent in 2003 to 8.5 percent in 2011.
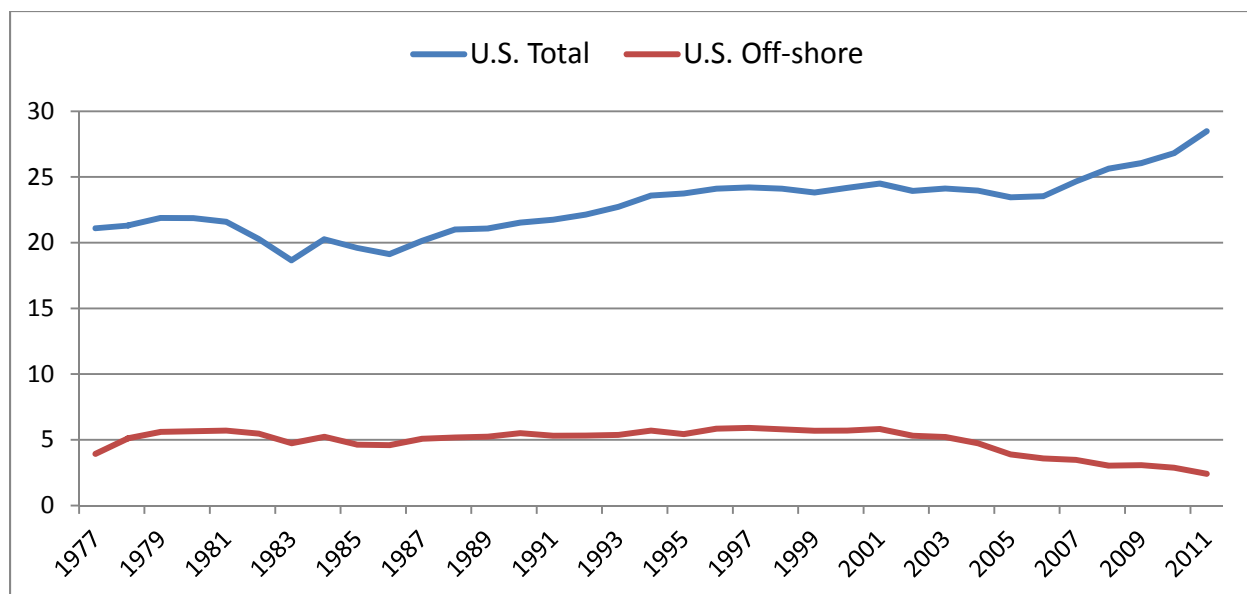
Figure 2-6. U.S. Total and Off-shore Natural Gas Production (Trillion Cubic Feet) [Data source: EIA][xxxv]

One factor that limits price volatility is the ability to drill new wells rapidly using current technology. If prices climb rapidly; new wells can be producing in a matter of days in response to the price increase. Thus, production is more responsive to increases in demand than it was previously.

Another factor keeping natural gas price volatility down is fuel switching for electricity generation. The current surplus of electricity generating capacity means that some capacity is generally idle at all times. The determination as to which plants operate and which ones are idle is largely a function of the relative price of coal and natural gas. If natural gas is relatively more expensive than coal, natural gas plants will idle and coal plants will operate. Conversely, low natural gas prices mean operating natural gas plants and idle coal plants. According to EIA data from 2012 (a year with low natural gas prices), electricity generation from natural gas increased over 30 percent from the previous year, while electricity generation from coal fell by 18 percent. Higher natural gas prices in 2013 reversed that trend, with year-to-date coal-fired generation up by 7.5 percent and natural gas-fired generation down by almost 14 percent[xxxvi].

Fuel switching for electricity generation has the effect of dampening changes in natural gas price. If natural gas prices increase, less natural gas is used and the reduced demand limits the natural gas price increase. Similarly, decreasing natural gas prices result in increased gas-fired generation and the natural gas price decrease is limited. It should be noted that since this phenomenon exists because of the current electricity generation capacity surplus; coal retirements expected due to EPA regulations, plant age, and economics could eliminate this price volatility dampening effect.

2C. Relationship between Natural Gas Prices and Other Fuels

Historically, natural gas and oil prices have tended to move together as they acted as substitutes for each other for various energy demands, such as space heating, electricity generation, and industrial processes. With the development of wet gas plays, that relationship has changed. Figure 2-7 shows how natural gas and crude oil spot prices have changed through time. The prices are normalized so that the prices on January 7, 1997 (the first date for which both prices are available) are equal to 1. The prices follow the same general trajectories, with the exceptions of the previously mentioned natural gas price spikes, until 2009, at which point they diverge.
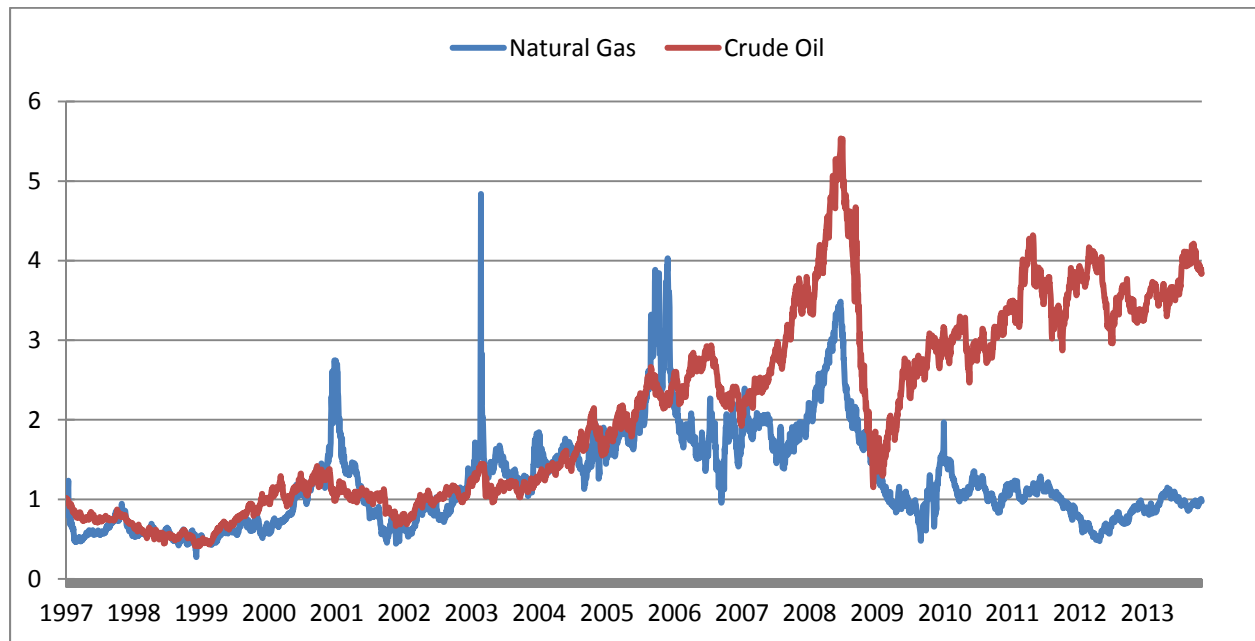

Figure 2-7. Henry Hub Natural Gas and West Texas Intermediate Crude Spot Prices (normalized) [Data source: EIA][xxxvii,xxxviii]

From the standpoint of the correlation coefficient, the relationship between natural gas and oil prices has changed dramatically in the last few years. The correlation coefficient is a statistical indicator of how two sets of data are related. It varies from perfectly positively correlated (a value of +1), where the two always move together in lockstep, to perfectly negatively correlated (a value of -1), where the two always move in the opposite direction. A correlation coefficient of 0 indicates that the two move randomly, independent of each other. From 1997 through 2008, natural gas and oil exhibited a strong positive correlation of 0.81. From 2009 to the present, the correlation is slightly negative, at -0.33. Thus, the relationship between natural gas and oil prices has not only weakened, it has reversed. This is a result of the development of wet gas. When oil prices are high, they provide an incentive to develop wet gas sites, even when natural gas prices are low. The natural gas that is produced increases the total supply and drives prices downward.

The reliance of natural gas on oil production can be seen in recent well drilling and production information. Figure 2-8 shows the production from both dry gas wells and associated gas wells (used

here to indicate extraction of gas mixed with either crude oil or petroleum liquids) and the total natural gas production (the black line, using the right-hand axis). As the figure shows, total gas production has been increasing, with wet gas more than making up for the decline in dry gas production. Similarly, Figure 2-9 shows that the dry gas rig count has been decreasing while the number of oil and wet gas rigs have increased.
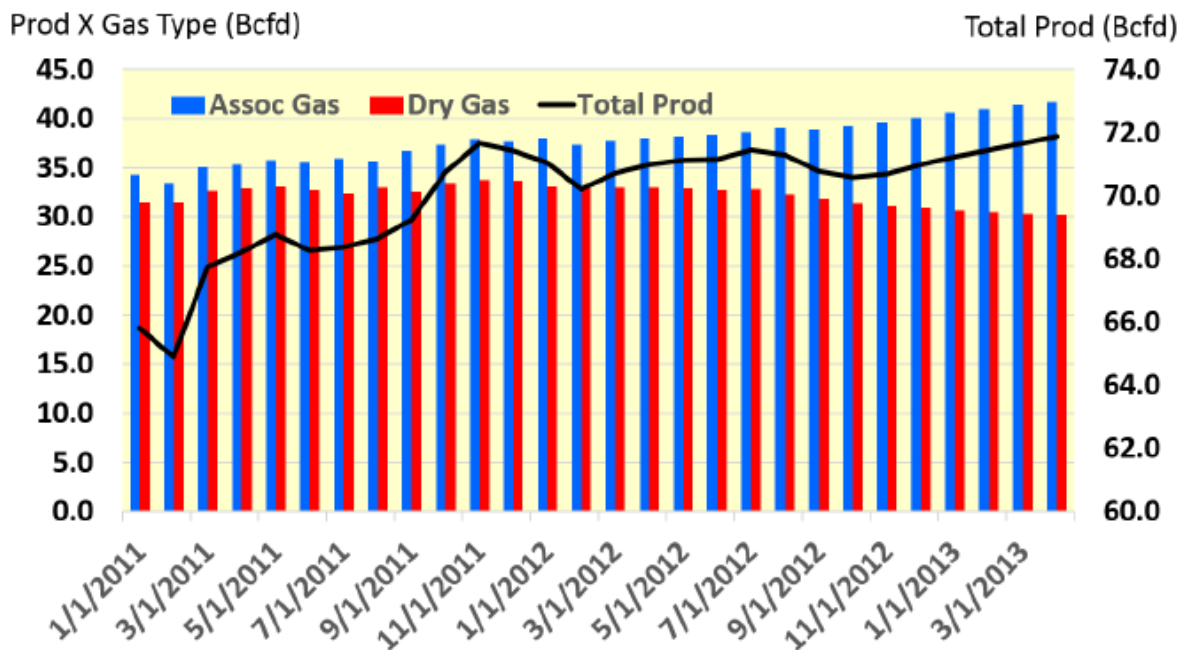

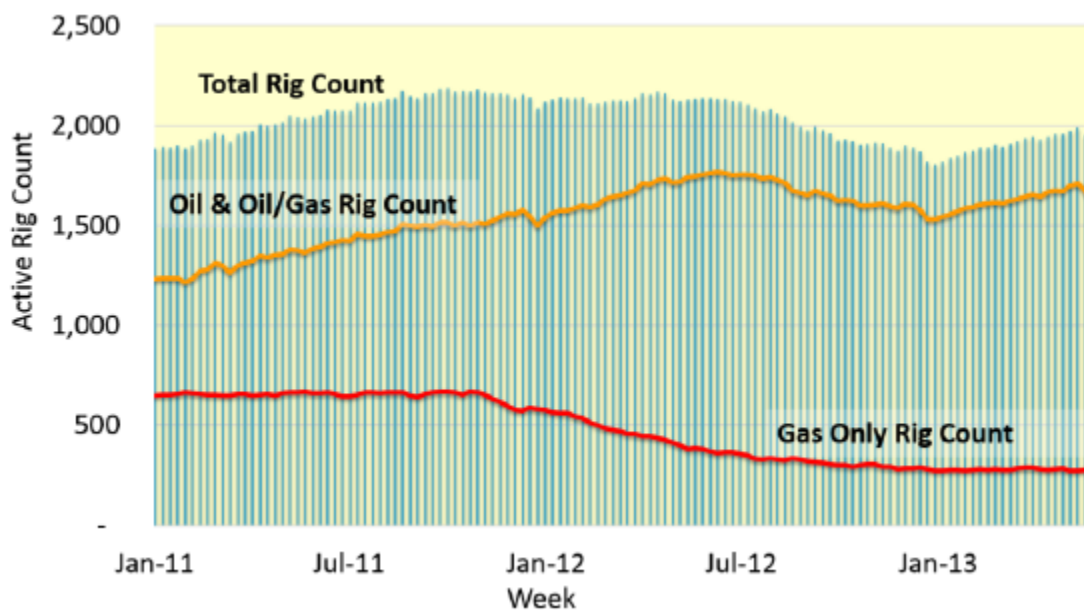Figure 2-8. U.S. Dry Gas and Associated Gas Production (Bcfd) [Source: Ponderosa Advisors][xxxix]

Figure 2-9. U.S. Weekly Active Rig Count [Source: Ponderosa Advisors][xl]

This represents a significant shift in the natural gas price paradigm. While natural gas prices are still a function of demand, the productivity and number of dry gas wells is less significant and the relationship to oil prices has shifted in the opposite direction.

Unfortunately, historical coal spot prices are not publicly available. According to EIA, "historical data for coal commodity spot market prices are proprietary and not available for public release."[xli] Thus, annual numbers are used here rather than daily or weekly prices. Also, unlike natural gas, coal is not a homogeneous commodity. That is, different types of coal from different locations may have very different energy and chemical content. These factors make a direct comparison of the historical relationship of natural gas and coal difficult. Figure 2-10 provides annual average U.S. prices for wellhead natural gas and bituminous coal, normalized to the first data year, 1980. The two curves exhibit a slight positive correlation in that both rise in the 2000s, but coal prices have historically been much more stable. The correlation between the prices of the two commodities is likely to be stronger at the present due to fuel switching for electricity generation. If the price of natural gas increases, electricity generation shifts toward coal, thus increasing the demand and price of coal. Conversely, decreasing natural gas prices put downward pressure on coal prices.
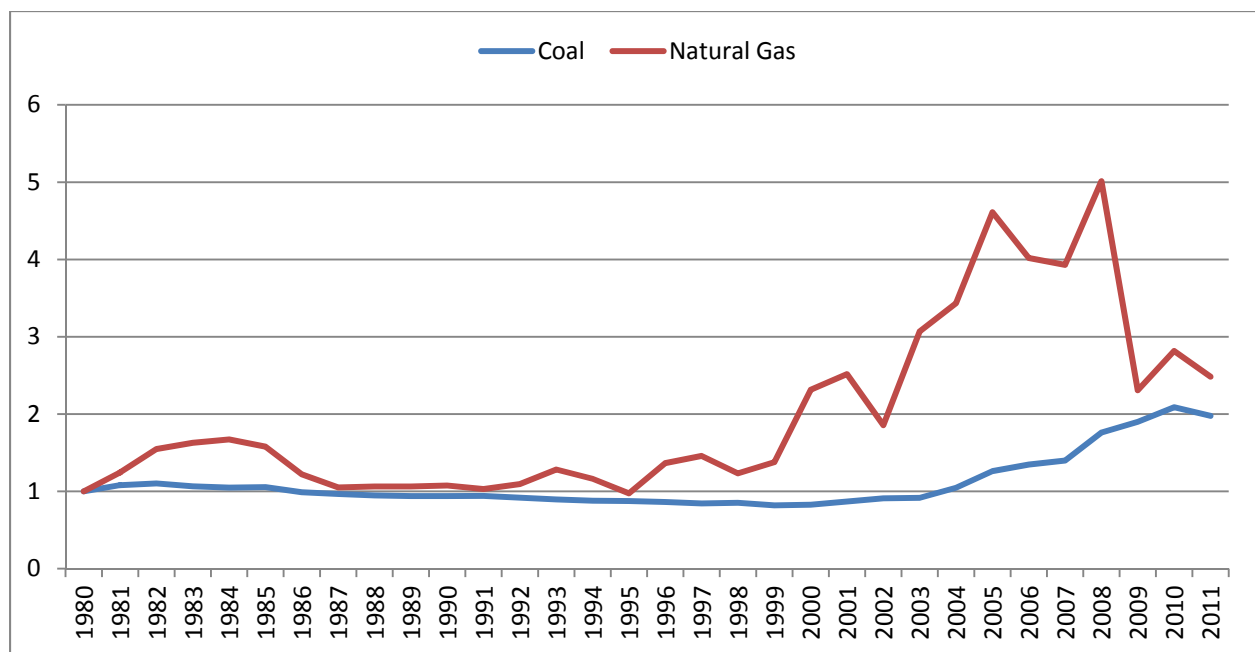

Figure 2-10. U.S. Annual Natural Gas Wellhead and Bituminous Coal Prices (normalized) [Data source: EIA][xliixliii]

2D. Price Forecasts

Despite the recent stability in natural gas prices, there is still uncertainty regarding future prices. A number of issues lead to that uncertainty, including the high level of price volatility prior to 2009, the relatively recent changes in the major factors affecting natural gas prices, the unknown future demand

for natural gas and natural gas exports, and the uncertainty over potential regulations of hydraulic fracturing. This section examines the expected prices in the open, or wholesale, market.

While a large number of entities forecast natural gas prices, most of those forecasts are proprietary and not publicly accessible. This section will present forecasts of natural gas prices that were obtained from the public domain. It will also look at natural gas futures prices as an indicator of expected prices.

Figure 2-11 shows natural gas price forecasts from four different sources, covering nine different scenarios. The projections labeled AEP Base, AEP Low, and AEP High were produced by the fundamentals forecasters at American Electric Power for use in Indiana Michigan Power's integrated resource planning process.[xliv] Four of the scenarios come from EIA's Annual Outlook 2013.[xlv] The EIA Reference case represents their base case assumptions, the EIA Low Growth and EIA High Growth cases represent alternative assumptions for national economic growth, and the EIA High Oil case includes the impact of high oil prices. The BENTEK Base forecast was estimated from the graph of BENTEK's projections used in the Phase III Gas Study of the Midcontinent Independent System Operator (MISO).[xlvi] This projection was also adjusted to account for the difference between Midwestern and Henry Hub prices. Thus, the BENTEK forecast is only an approximation of their actual projection. The Wood Mackenzie forecast is from the Wood Mackenzie North America Natural Gas Long-Term View as of June 2013.[xlvii] These forecasts are all in nominal dollars per million Btu. The forecasts all follow similar paths of a steady increase in prices, but the growth is obviously higher in some cases than in others. In 2020, the forecasts range from a low of $4.69 (EIA High Oil) to $7.40 (AEP High). In 2025, the range falls between $6.14 (EIA Reference) and $8.91 (AEP High). In 2030, the range falls between $7.45 (EIA Reference) and $9.80 (AEP High). Note that at each point in time, the low end of the range of these forecasts corresponds to an EIA case, and the high end of the range corresponds to the AEP High case, which is roughly a dollar higher than any other case except for the first and last few years of the projection.
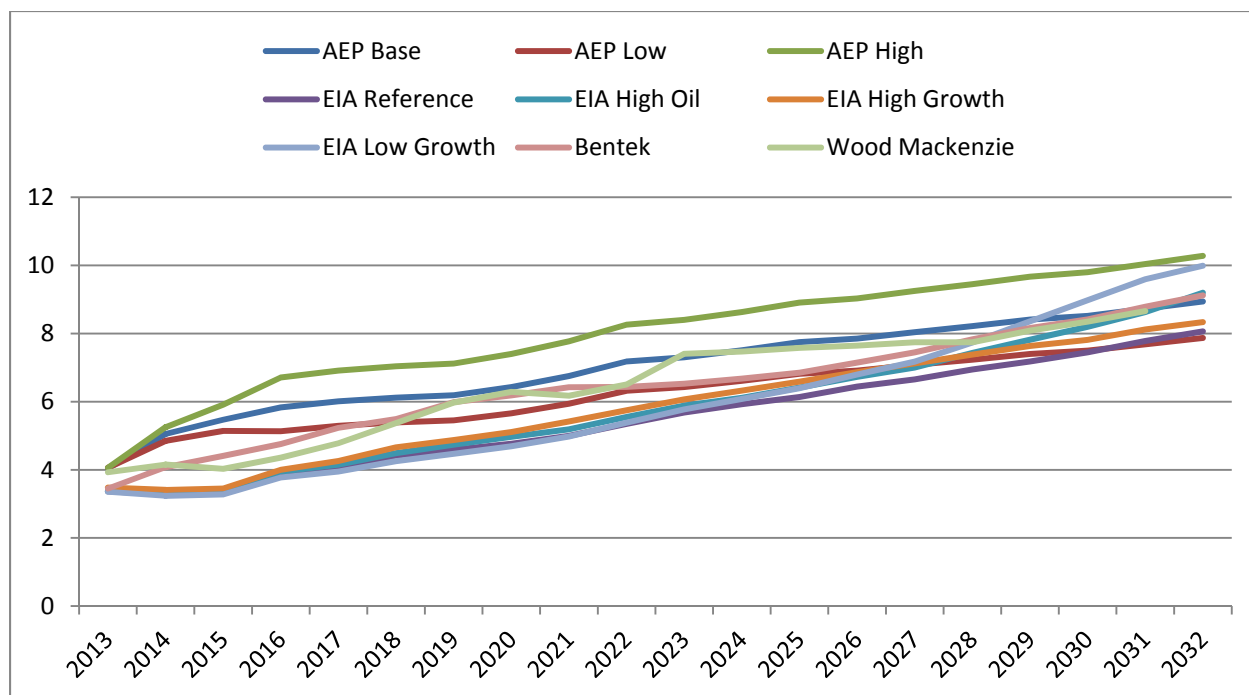
Figure 2-11. Henry Hub Natural Gas Price Forecasts (nominal $/mmBtu)

Figure 2.12 shows only the base forecasts from the four sources. In general, the AEP forecast tends to be the highest and the EIA forecast is the lowest. The forecast values for selected years are provided in Table 2-1. Again, the BENTEK forecast is approximate.
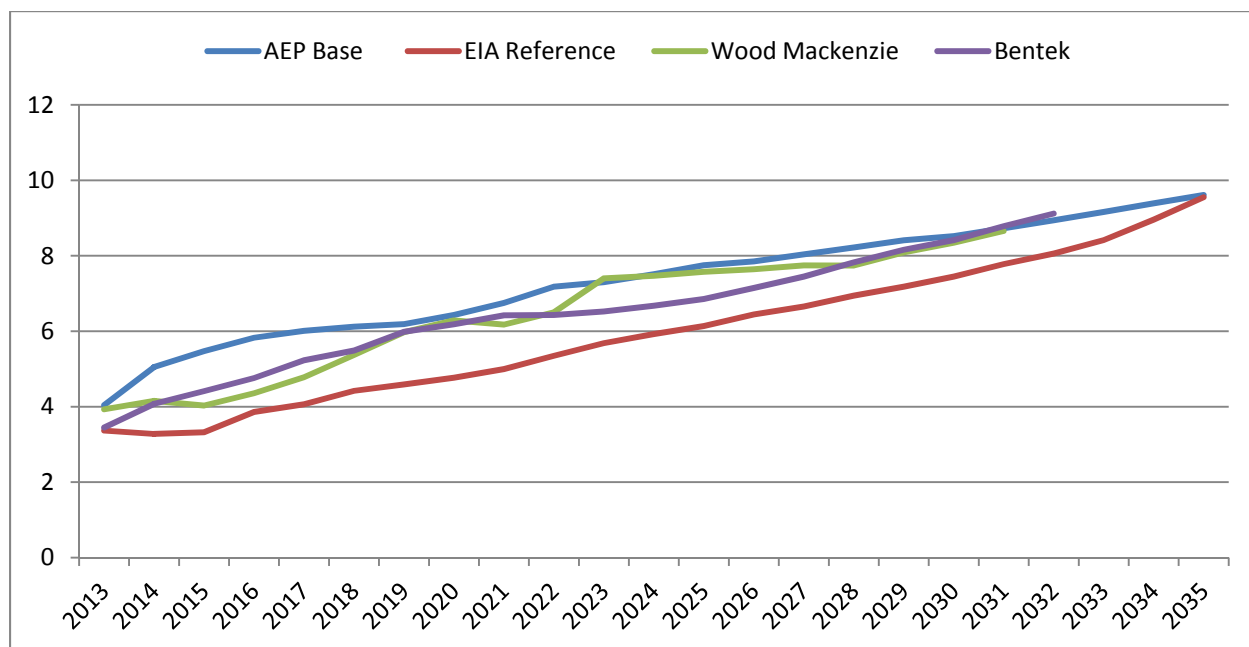

Figure 2-12. Henry Hub Natural Gas Price Base Forecasts (nominal $/mmBtu)

Year	AEP	Bentek	EIA	Wood Mackenzie
2015	5.47	4.80	3.32	4.03
2020	6.43	6.18	4.77	6.29
2025	7.75	6.85	6.14	7.58
2030	8.52	8.42	7.45	8.35

Table 2-1. Henry Hub Natural Gas Price Base Forecasts for Selected Years (nominal $/mmBtu)

In its Annual Energy Outlook 2013, EIA provides comparisons of its Reference case to projections by others for selected years. Table 2-2 provides the comparison in 2011 real (inflation-adjusted) dollars.

Year	EIA	HIS Global Insight	Energy Ventures Analysis	ICF International
2025	4.87	4.39	6.34	5.02
2035	6.32	4.98	8.00	6.21

Table 2-2. Henry Hub Natural Gas Price Forecast Comparison for Selected Years (2011$/mmBtu) [Data source: EIA][xlviii]

Futures contracts represent an agreement between two parties to buy and sell something in the future at a price agreed upon at the present time. As such, they represent a risk-adjusted expected price for both the buyer and the seller. Natural gas futures are typically traded on a monthly basis, with the heaviest volume of trade occurring in the near term (next four to six months). Intermediate-term trading (going out 6-18 months) is lighter and contracts further into the future are sparsely traded. Thus, natural gas futures prices provide an expectation of natural gas prices, with less certainty as you go further into the future. Figure 2-13 shows natural gas futures prices as of September 24, 2013, as reported on the barchart.com website. The futures prices generally fall between the EIA Reference and BENTEK base forecasts in Figure 2-12.
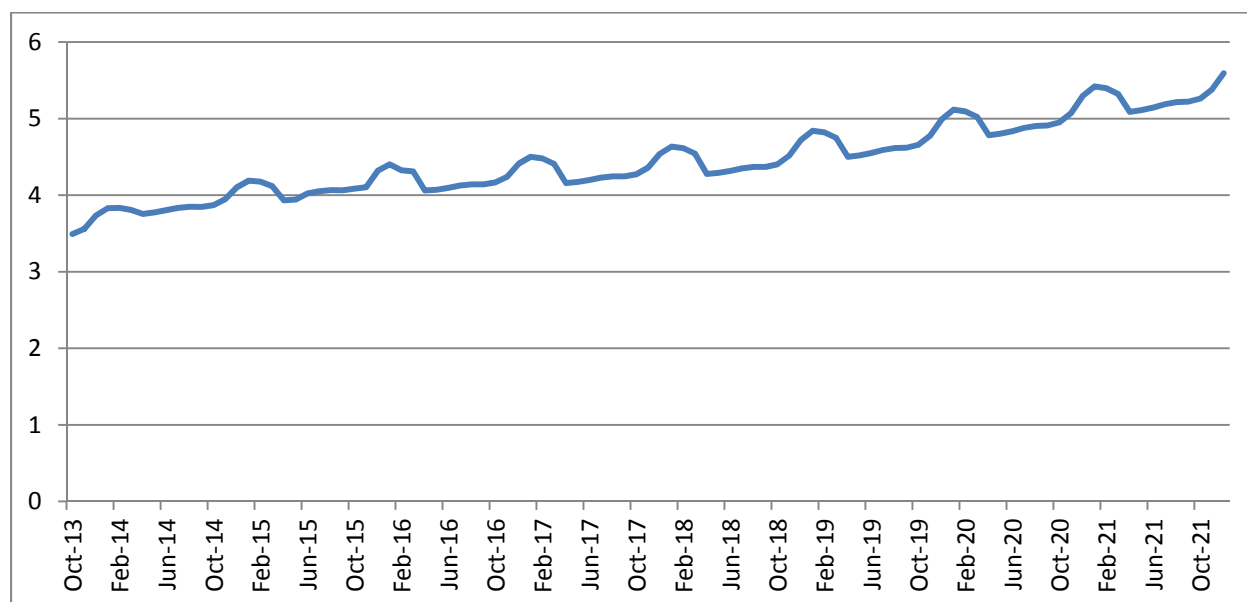

Figure 2-13. Henry Hub Natural Gas Futures Prices (nominal $/mmBtu) [Data source: barchart.com][xlix]

2E. Captive Market (Ratepayer) Impacts

A customer's natural gas bill consists of three components: the costs associated with operating the natural gas distribution system (including a return on capital investment for for-profit utilities), the commodity cost of acquiring the natural gas (known as the Gas Cost Adjustment), and Commission-approved trackers (for items like pipeline safety, energy efficiency, and adjustments for abnormal temperatures). According to the IURC, the commodity cost is the largest of the three, accounting for approximately 62 percent of the average residential bill in Indiana. The distribution cost represents about 34 percent and trackers account for less than 4 percent.[i] While the breakdown of costs for individual utilities will vary, the gas commodity cost represents the majority of costs in a customer's bill for all of the largest natural gas utilities in Indiana.

The impact of natural gas commodity prices on a customer can be examined from two different perspectives. Since the cost of procuring the natural gas is passed directly to the customer with no profit to the utility, there is a direct dollar for dollar impact of changes in natural gas prices to changes in a customer's bill. Thus, if natural gas prices increase (or decrease) by $1/mmBtu, a customer's bill will increase (decrease) by $1 for every mmBtu of natural gas consumed.   To put this in perspective, consider a customer who consumes 200 therms in a month (10 therms equal one mmBtu). For every $1/mmBtu change in the natural gas price, the customer's bill will change by $20. It should be noted that the Gas Cost Adjustment does not only include the cost of acquiring natural gas. There may be at times an over or under collection variance along with refunds included in the Gas Cost Adjustment factor.

The impact of natural gas prices on customer bills can also be viewed on a percentage basis. Assuming the distribution costs and tracker costs do not change, a 10 percent change in natural gas prices will result in a corresponding 6.2 percent (62 percent of 10 percent) change in customers' bills. It should be noted that the 62-34-4 percent breakdown of cost components is a function of the commodity cost itself. If the natural gas prices are significantly higher, the commodity cost would represent more than 62 percent of total costs. Similarly, lower natural gas prices would mean that commodity costs are a lower percentage of total costs.

2F. SNG Price Impacts

The price at which SNG can be produced depends on a number of factors. These include capital costs, which are dependent on the construction costs; the fraction of the costs covered by debt and equity; and the relative costs of debt and equity (determined by interest rates, the return to investors, and taxes). The operation and maintenance costs represent another component of the SNG price. Similarly, the cost of fuel (typically, coal) as a feedstock to the SNG process will affect the SNG price. Revenue or expenses associated with byproducts of the gasification process (such as CO_2) will also impact the SNG price. Finally, the transportation costs to ship the product via pipeline to consumers are also a factor.

The Indiana Gasification project in Rockport has an expected cost of $2.8 billion with up to 38 million mmBtu of SNG to be sold to the Indiana Finance Authority annually.[liii] According to testimony in the IURC Cause No. 43976 involving the purchase agreement between Indiana Gasification and the Indiana Finance Authority, the average base contract price for the SNG is expected to be $6.60/mmBtu in real (inflation-adjusted) terms. In order to place this on an equal footing with the natural gas price forecasts in section 2D, the real price was converted to a nominal price trajectory using the inflation level implicit in EIA's price forecasts (ranging between 1.4 and 1.9 percent per year). This price was then adjusted downward to account for the price differential between the Henry Hub (the location for the price forecasts) and Indiana using the price differential for each year between those regions in EIA's 2013 Annual Outlook. The resulting price trajectory is shown along with the four base forecasts in Figure 2-14 (it is assumed here that the SNG plant will be operational in 2018). The SNG price is above the base forecast market prices initially, but grows less slowly (the others grow faster than the rate of inflation). The AEP Base forecast is close to the SNG price in 2021 (well within the accuracy of this analysis) and the Wood Mackenzie forecast is close in 2022. The Bentek and EIA Reference forecasts are less than the SNG price until 2030 or later.
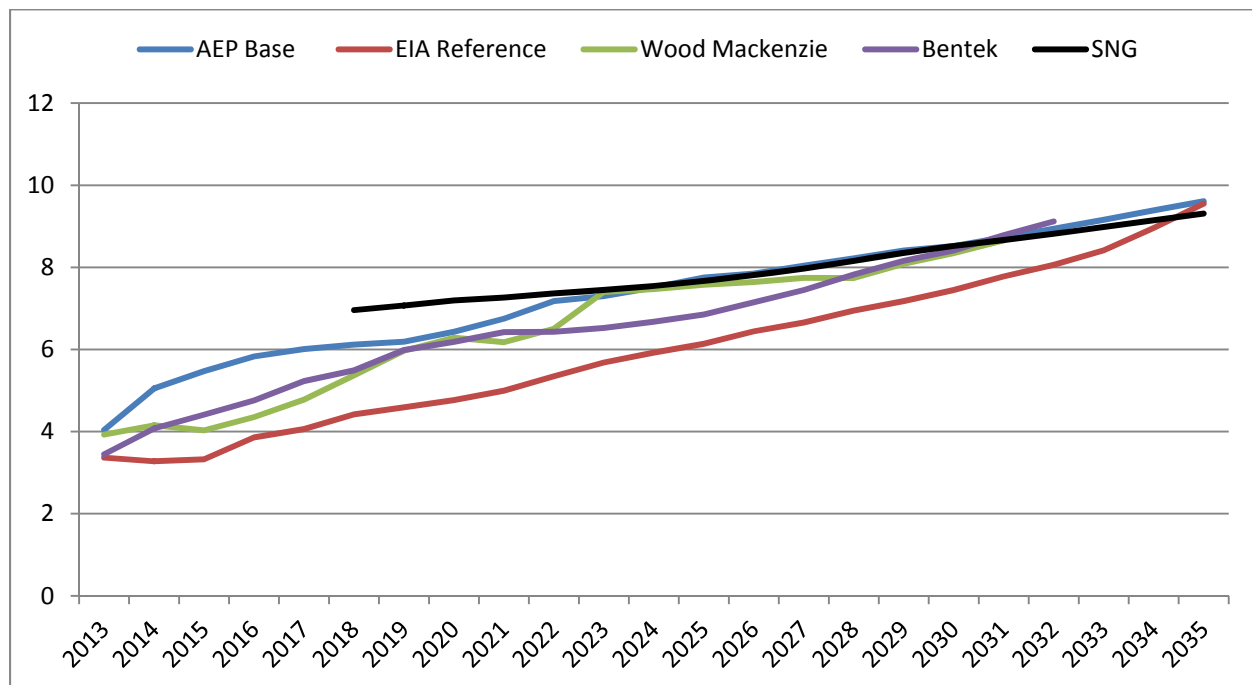

Figure 2-14. Calculated SNG Price Compared to Base Natural Gas Price Forecasts (nominal $/mmBtu)

SNG is expected to exhibit low price volatility. Once a syngas plant becomes operational, the largest source of cost uncertainty is the price of the feedstock fuel, generally coal. Coal prices have historically been fairly stable and the ability to substitute petroleum coke as a feedstock provides additional price stability.

Figure 2-15 shows the comparison of the calculated SNG price to the alternate forecasts from section 2D. Here the AEP High price forecast projects prices at or above the SNG price throughout the time

period, while the AEP Low price forecast has prices below the SNG price at all times. The three alternate EIA projections are below the SNG until 2029 (Low Growth), 2031 (High Oil), and 2034 (High Growth).
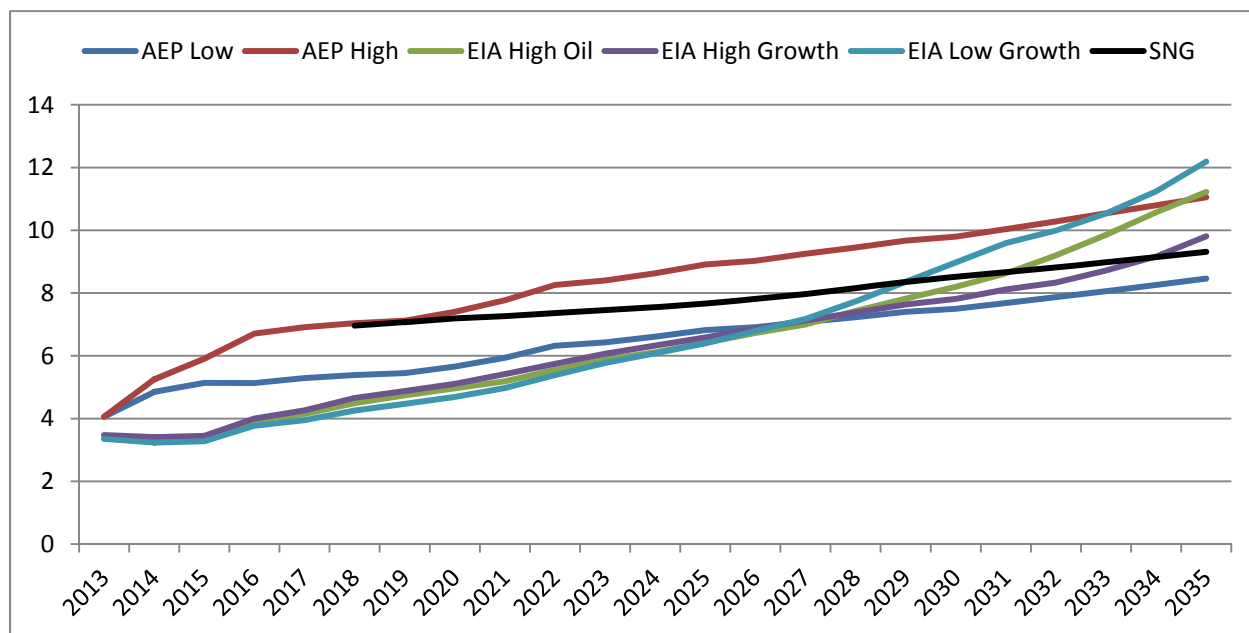

Figure 2-15. Calculated SNG Price Compared to Alternate Natural Gas Price Forecasts (nominal $/mmBtu)

Using the relative prices of the forecasts and SNG price and the characteristics of the purchase agreement, the expected impacts on a customer's bill can be calculated. The specific aspects of the purchase agreement that affect the calculation are the establishment of a Consumer Protection Reserve Account (CPRA) and the mechanism for sharing any positive differential between the SNG and market price. The CPRA is a $150 million fund that Indiana Gasification will be required to establish. The fund can be used to cover the difference between market and SNG prices if the SNG price is the higher of the two. Indiana Gasification is to be reimbursed when the SNG price is less than the market price.[3]

For these purposes, it is assumed that the SNG facility will produce an output of 38 million mmBtu per year and be online at the start of 2018. It is further assumed that the facility produces 17 percent of the residential and commercial gas consumed. The amount of cumulative savings for each of the price forecast scenarios is then calculated (essentially, this is a "what if the forecast is right" analysis). Finally, the bill impact for a customer using 200 therms is determined. It should be noted that the price forecasts (and hence, this analysis) do not go far enough into the future to address the guaranteed savings after 30 years.

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[3] The reimbursement process depends on whether cumulative savings to customers exist from the start of the purchase agreement until that time. If cumulative savings exist, Indiana Gasification will receive all positive market differentials until it has received repayment of the $150 million to fund the CPRA. After repayment, the savings are split 50/50 between Indiana Gasification and customers. If no cumulative savings exist, then Indiana Gasification and customers are allocated 50% until Indiana Gasification is paid the $150 million.

Figure 2-16 shows the change in the billed amount for the base forecasts. A positive number in a particular year indicates an increase of that many dollars to the monthly bill of a customer using 200 therms of natural gas. None of the cases have an impact in the first year, as the SNG price exceeds the market price but the CPRA makes up the difference. In the EIA reference case, the CPRA is depleted in 2019, so part of the year is at market price and part at the SNG price (the overall price is an energy weighted average of the two). The EIA reference case indicates an increase in the customer's bill from 2019 through 2034. The Bentek and Wood Mackenzie cases exhaust the CPRA in 2021 and show an increase in the customer's bill beginning in that year. The AEP base case never exhausts the CPRA, so there are no years where the customer's bill increases. In 2025 and after (except 2030), the AEP base case can be characterized by a negative cumulative savings, but a positive market price differential, with savings being shared. The EIA Reference and Bentek cases show some customer savings in the later years.
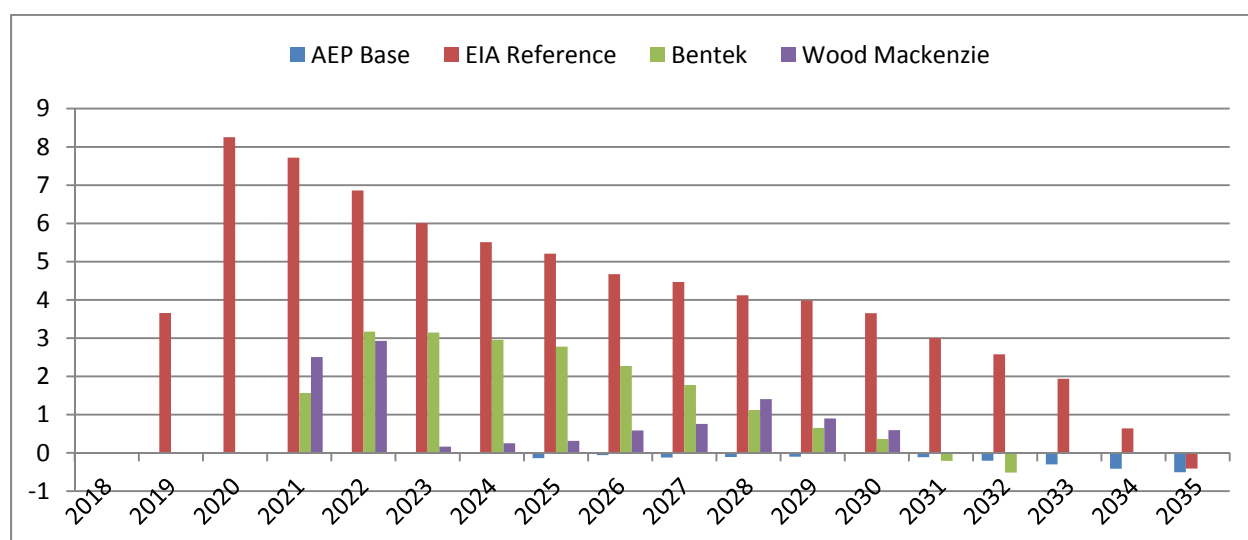

Figure 2-16. Changes in a Customer's Bill for 200 Therms of Usage - Base Forecasts (nominal dollars)

The bill impacts for the alternate price scenarios are provided in Figure 2-17. As in the EIA reference case, the alternate EIA scenarios show increases in customer costs in 2019 (the differences among the EIA scenarios are small in the early years). Two of the EIA scenarios (High Oil and Low Growth) begin to show customer savings somewhat earlier than the Reference scenario due to higher market prices. The AEP Low scenario shows an increase in the customer's bill from 2020 on, while the AEP High scenario has customer savings beginning in 2025.
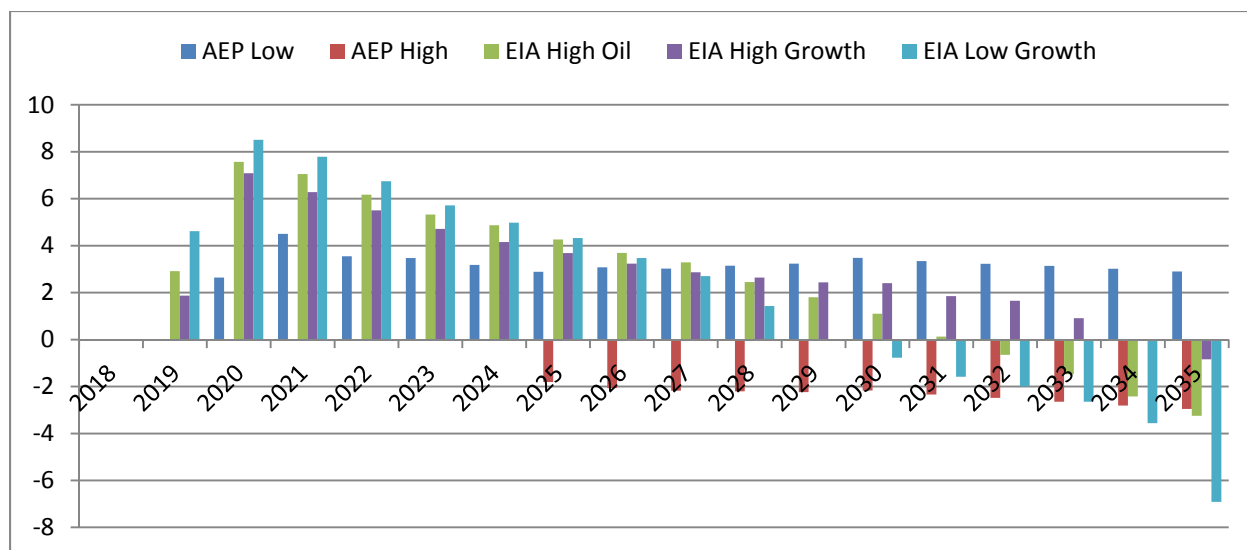
Figure 2-16. Changes in a Customer's Bill for 200 Therms of Usage - Alternate Forecasts (nominal dollars)

Figure 2-17 shows the total cumulative savings for each of the nine scenarios in millions of dollars. The CPRA covers the first $150 million in negative savings (if applicable) and the first $150 million in positive savings go to Indiana Gasification to cover their outlay in establishing the CPRA. The AEP High price forecast shows positive savings throughout the forecast period. For the AEP Base forecast, the CPRA is never exhausted. The remaining scenarios all incur sufficient negative savings to exhaust the CPRA. The AEP Low Price scenario is the only one that does not see positive annual savings by the end of the analysis period (as seen by the upward trend in the other lines). While most scenarios demonstrate that positive annual savings are reached by the end of the analysis period, it is important to note that all scenarios, except for the AEP High case, result in a cumulative loss for ratepayers. Again, it should be noted that this analysis does not look far enough forward to address the 30-year guaranteed savings provision in the purchase agreement.
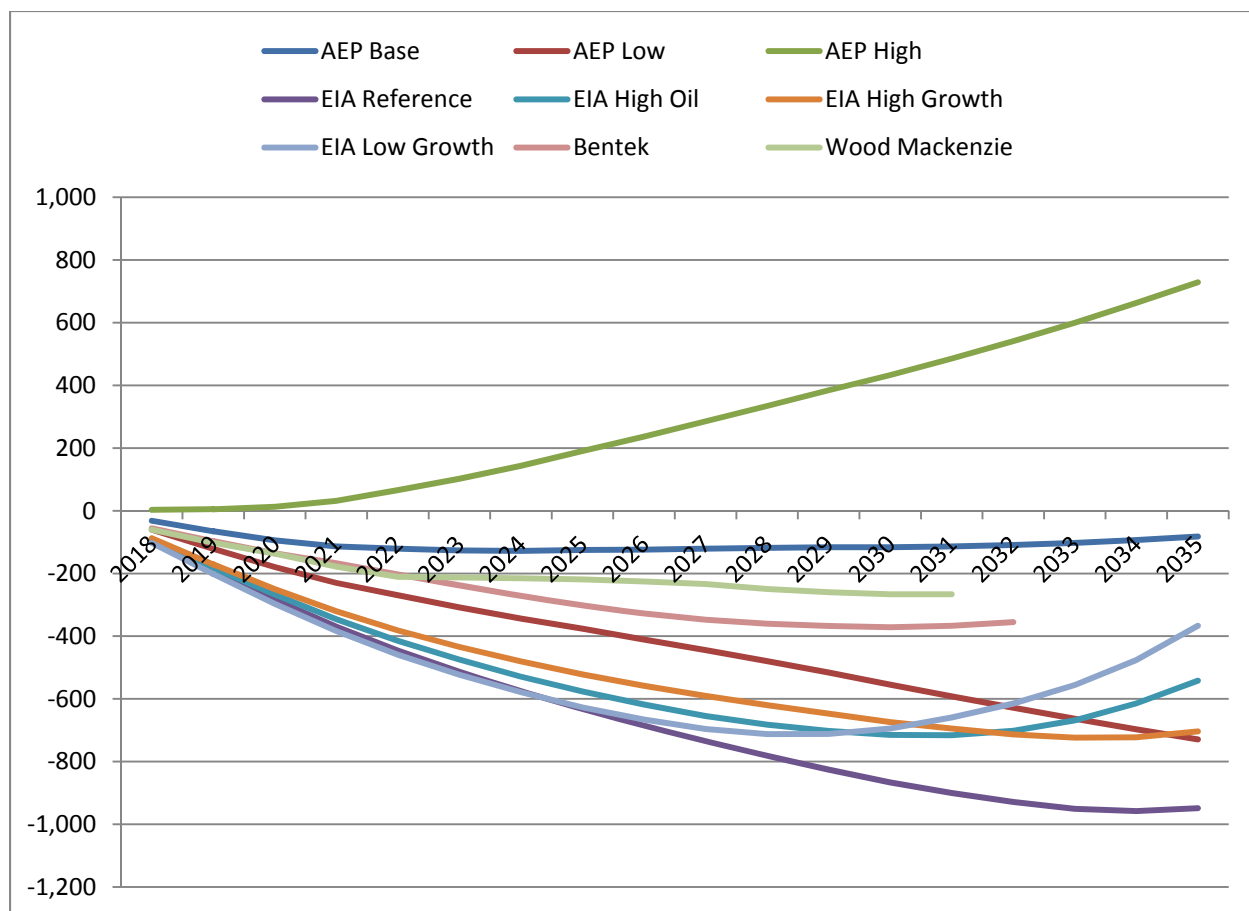
Figure 2-17. Cumulative Savings (millions of dollars)

3. Natural Gas Demand

3A. Historical Demand

Natural gas is used for a number of purposes, both as a source of energy and as an industrial feedstock. Uses in the residential and commercial sectors generally fall into the space heating, water heating, cooking, and clothes drying end uses. In the manufacturing sector, it is often used as an energy source for industrial processes and as a chemical feedstock, such as in the manufacture of ammonia for fertilizer production. It has been used to a lesser degree as a transportation fuel, particularly in metropolitan bus fleets that can use a single fueling location. The lack of a fueling infrastructure has historically been a barrier to natural gas use as a transportation fuel.

While U.S. natural gas demand has been increasing over time, the share of total energy from natural gas has varied. Figure 3-1 shows the percentage of energy in each of four sectors (residential, commercial, industrial, and electricity) that came from natural gas. Natural gas's share increased significantly prior to 1970 due to increasing availability to customers and low, stable prices. With price increases associated with the 1970s energy crisis and restrictions on natural gas usage due to the Powerplant and Industrial Fuels Act (1978), the share of energy coming from natural gas dropped in all sectors. With the removal of the prohibition on new natural gas-fired boilers and generators in 1987 and the stabilization of prices in the 1990s, natural gas regained some of its share in the industrial and electricity sectors, while the residential and commercial shares remained fairly constant (it should be noted that variations in weather can cause shifts from one year to another in these sectors). With the price increases after the turn of the century, natural gas's shares declined in all but the electricity sector, where the lower capital costs of natural gas-fired generation was more favorable than other alternatives in the face of stricter environmental regulations and de-regulation of the electricity industry in some states. Finally, recent decreases in natural gas prices, combined with increasing electricity prices has resulted in a return to stable or growing shares.
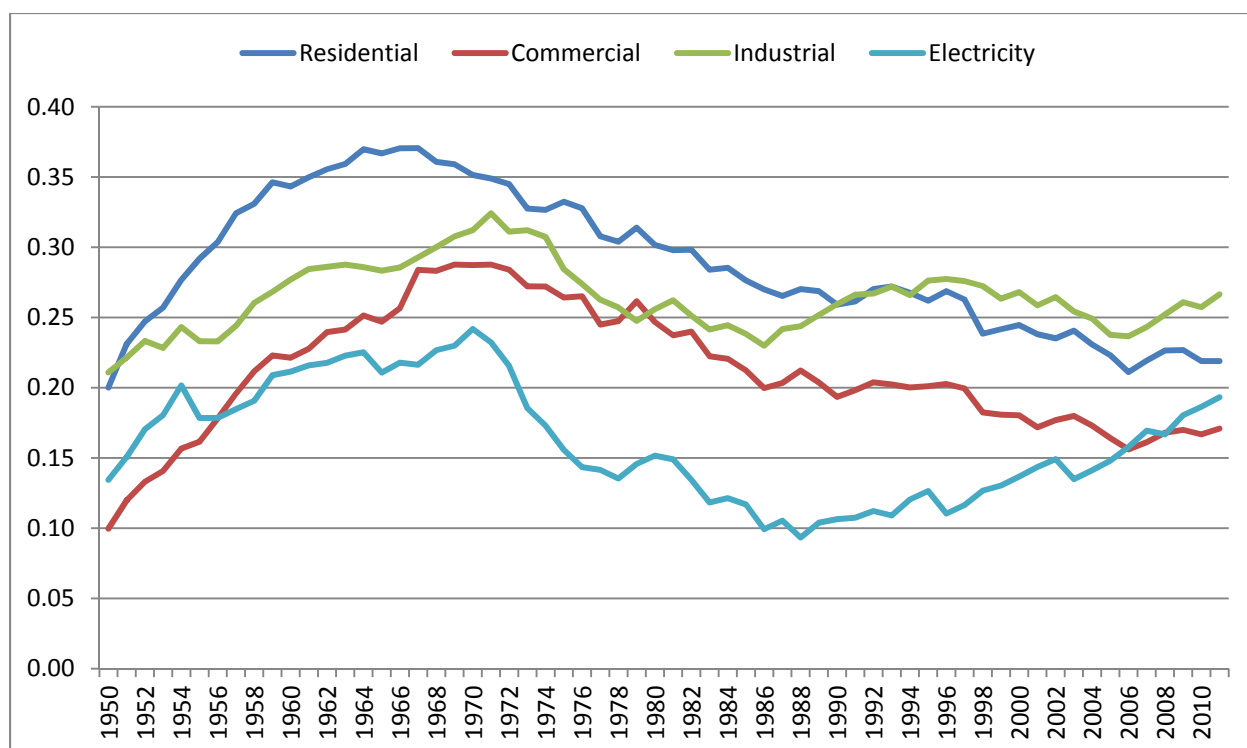
Figure 3-1. Share of U.S. Energy Provided by Natural Gas by Sector [Data source: EIA] [liii]

3B. Price Response

Price is a major factor of natural gas demand; lower natural gas prices result in increased demand and high prices curtail demand. With low prices, existing customers may switch from another energy source for some of their energy needs or they may be more likely to purchase equipment powered by natural gas. New customers are more likely to use natural gas for their processes and end uses with low natural gas prices.

Historically, the share of energy provided by natural gas is highly negatively correlated with the ratio of natural gas to electricity prices. Thus, as natural gas becomes less expensive relative to electricity (the ratio becomes smaller), the share of total energy supplied by natural gas increases. Conversely, as natural gas prices increase relative to electricity, natural gas loses share. This relationship is common among products that act as substitutes for each other. Table 3-1 lists the correlation coefficients for the three consumer sectors for natural gas energy share and natural gas to electricity price ratio.

	Residential	Commercial	Industrial
Correlation coefficient	-0.83	-0.88	-0.82

Table 3-1. Correlation between Natural Gas Energy Share and Natural Gas to Electricity Price Ratio [Data source: EIA] [liv]

If natural gas prices stay low in the future, or electricity prices increase at a faster rate than natural gas, an increase in natural gas share can be expected, especially in the industrial sector, which has been more price-sensitive. However, price projections in EIA's Annual Energy Outlook 2013 indicate that natural gas prices are expected to increase faster than electricity prices, as can be seen in Figure 3-2.
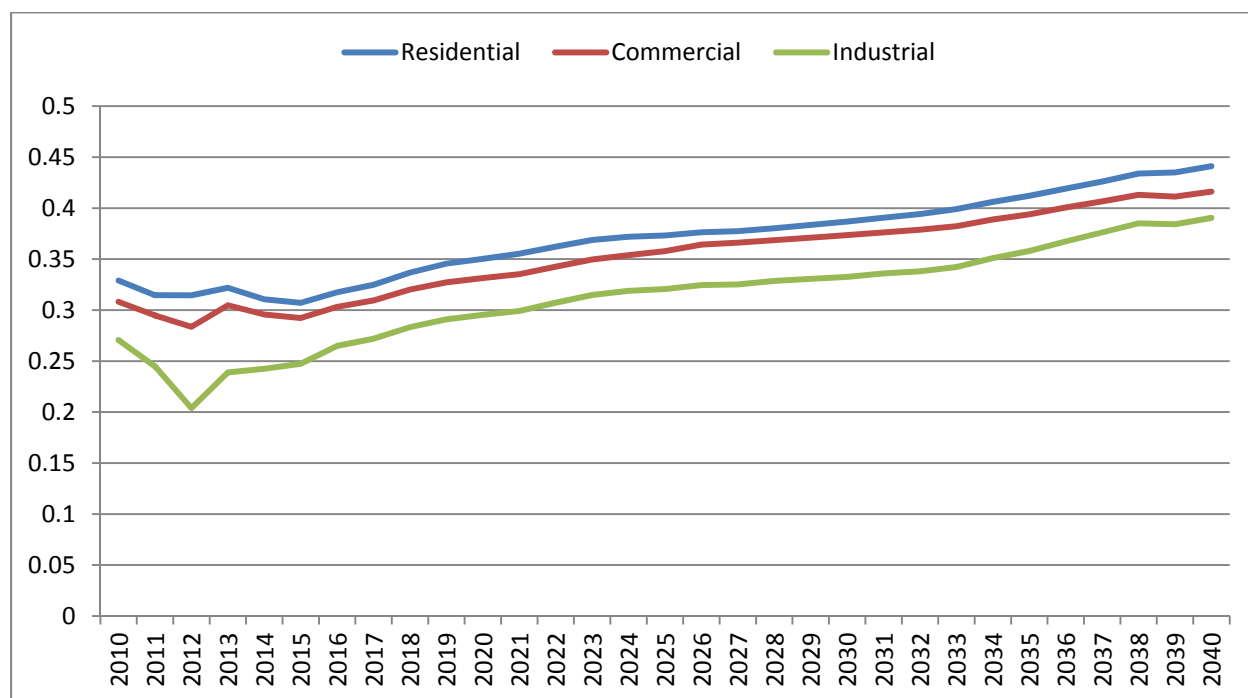

Figure 3-2. Forecast Ratio of Natural Gas to Electricity Prices (per mmBtu) in EIA's Annual Energy Outlook 2013 [Data source: EIA][lv]

3C. Demand from the Electric Power Sector

As explained in section 2B, natural gas and coal have been acting as substitutes for each other for electricity generation due to the current surplus of electricity generation capacity. This has had a significant impact on natural gas demand from the electricity sector as seen by the dramatic increase in 2012 and subsequent decline in 2013. Fuel switching is expected to decline in the next few years as the generating capacity surplus erodes due to retirements and growing demand.

3D. Future Demand

The lower natural gas prices seen recently are starting to incentivize new uses for natural gas. One example is as a transportation fuel. While natural gas has been used for some time for local uses, such as city bus fleets where they can be refilled at a single facility, natural gas fueling stations are under development. This will allow natural gas to be used for long-distance transportation. As of September 25, 2013, there were 1,242 compressed natural gas (CNG) fueling stations in the U.S., with every state except South Dakota having at least one. Indiana has 17, with three of them becoming operational in 2013. In addition, there were 74 liquefied natural gas (LNG) fueling stations in the U.S., with over half located in California.[lvi] Figure 3-3 shows the number of natural gas fueling stations (CNG and LNG) by

state in December 2012. The number of natural gas fueling stations has increased from 978 in October 2011 to 1,194 in December 2012 to 1,314 in September 2013.
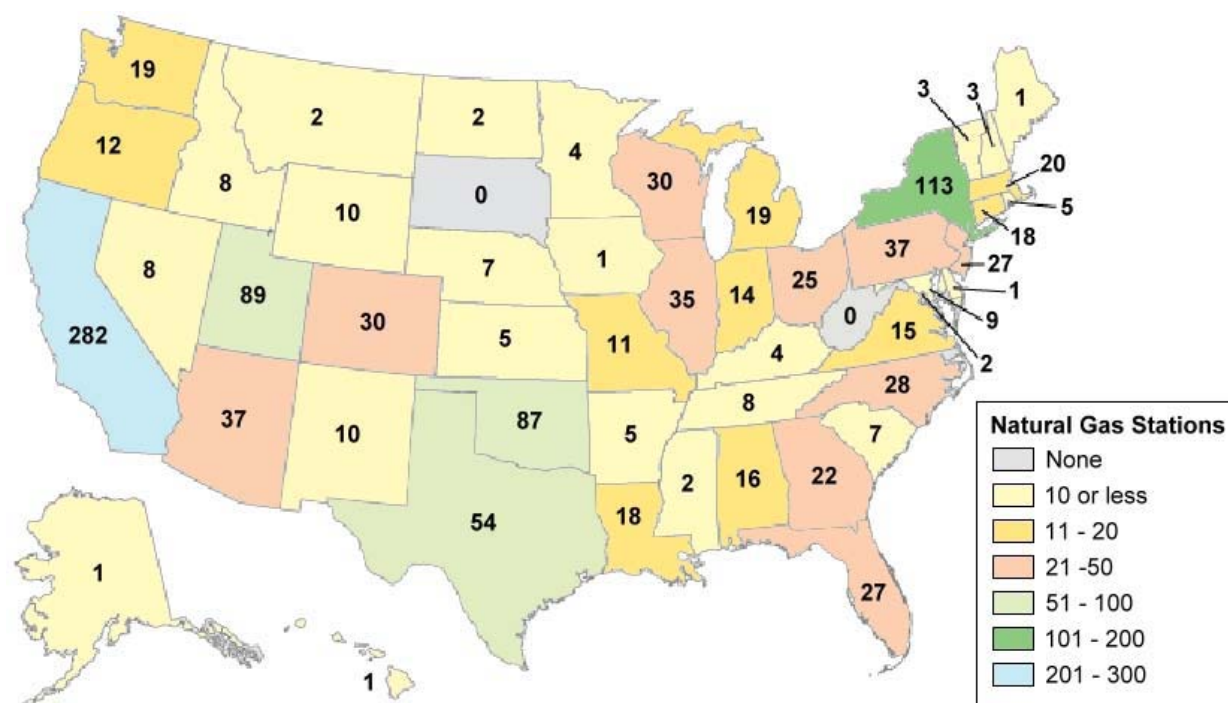

Figure 3-3. Number of Natural Gas Fueling Stations by State, 2012 [Source: Oak Ridge National Laboratory][lvii]

Additionally, low natural gas prices have led to the return of industries that had previously moved to other countries. An example of this is the production of ammonia to make nitrogen-based fertilizer. According to the U.S. Bureau of Labor Statistics, between 72 and 85 percent of the cost of producing ammonia comes from natural gas.[lviii] High U.S. natural gas prices in the 2000s led to a reduction in U.S. nitrogen production and an increase in imports, as is shown in Figure 3-4. A new $1.5 billion nitrogen fertilizer facility is under construction in North Dakota, which will take advantage of the surplus of natural gas in the state.[lix]
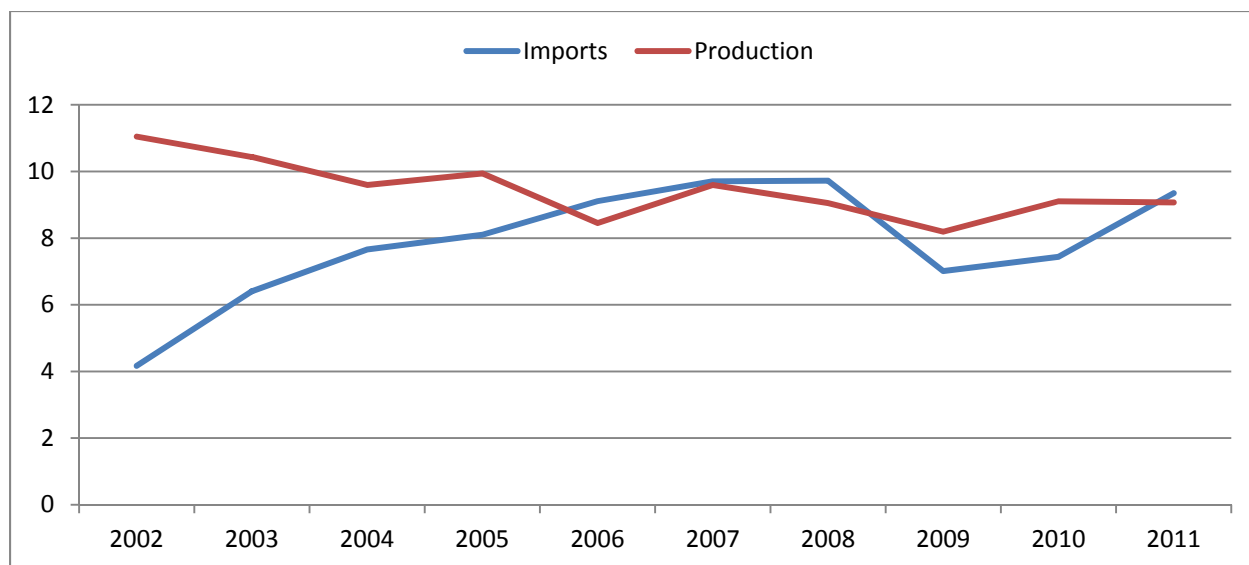
Figure 3-4. U.S. Production and Imports of Nitrogen (millions of short tons) [Data source: USDA][lx]

Figure 3-5 shows EIA's projected consumption of natural gas by sector for the Annual Energy Outlook 2013 Reference case. The transportation industry is expected to grow rapidly in the later years, but is starting from a very low base. The commercial sector grows very slightly, while residential sector usage is expected to decline slowly. The industrial sector is expected to increase in the first ten years before leveling off. The electricity sector exhibits substantial swings in the first few years (such as was experienced in 2011 through 2013) before starting to grow around 2024.
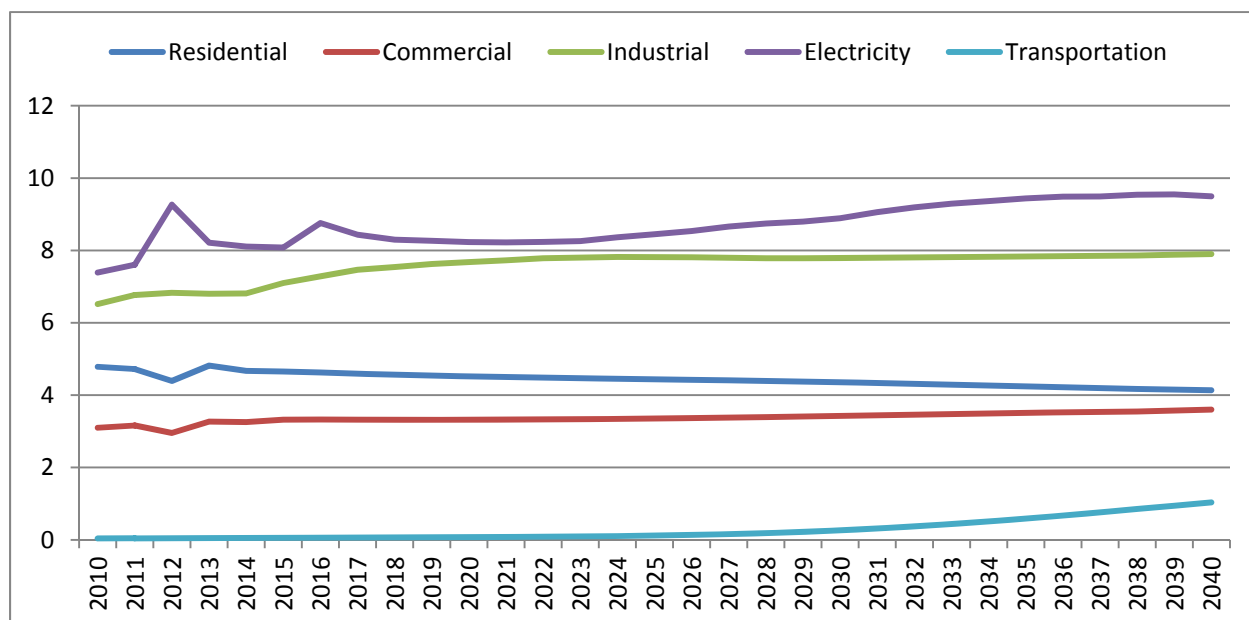

Figure 3-5. EIA Annual Energy Outlook 2013 Reference Case Projected Natural Gas Consumption by Sector (trillion cubic feet) [Data source: EIA][lxi]

The conversion of LNG import terminals to allow export to other countries, as well as the construction of new export terminals could create a significant increase in natural gas demand. Currently, there is a significant difference between natural gas prices in North America and the rest of the world. According to the International Energy Agency (IEA), 2012 industrial natural gas prices in the United Kingdom were triple those in the U.S. Prices in France and Germany were four times as high as in the U.S. and those in South Korea were five times as high.[lxii]

As of September 2013, only one LNG export terminal was approved and under construction. The facility in Sabine Pass, LA is expected to have an export capacity of 2.6 billion cubic feet per day (Bcfd) and is projected to be in service in the 4th quarter of 2015. This project is located at a currently operational LNG import terminal. Based on the project schedule, the time frame between final authorization and the in-service date is expected to be roughly 3.5 years.[lxiii]

A number of LNG export terminals have been proposed and several other sites have been identified by project sponsors. According to the Federal Energy Regulatory Commission (FERC), thirteen export terminals with a total export capacity of 19.24 Bcfd have been proposed to FERC. Of these, applications have been filed for 9.57 Bcfd of export capacity at six facilities. Additionally, eight potential sites have been identified by project sponsors with 12.84 Bcfd of capacity. Table 3-2 lists the facilities with applications that have been filed, that have been proposed, or that are considered potential sites for LNG export terminals. To put these numbers into context, average U.S. natural gas withdrawals in the U.S. for the first six months of 2013 were 82.2 Bcfd.[lxiv] Thus, the proposed LNG export facilities represent over 23 percent of current production.

In addition to FERC licensing, entities must receive permission from DOE to export natural gas. Per the Natural Gas Act of 1938, exports to free trade agreement (FTA) countries are deemed to be in the public interest and are to be approved without delay. According to DOE, almost 30 Bcfd of export capacity to FTA countries has been approved, with nearly 5 Bcfd more pending approval. Non-FTA approvals are less straightforward, allowing for participation from interveners and requiring a public interest determination. As of September 11, 2013, only 4 non-FTA applications had been approved, covering 6.6 Bcfd of capacity.[lxv]

Location	Capacity (Bcfd)
Application Filed	
Freeport, TX	1.8
Corpus Christi, TX	2.1
Coos Bay, OR	0.9
Hackberry, LA	1.7
Cove Point, MD	1.82
Astoria, OR	1.25
Proposed to FERC	
Lake Charles, LA	2.4
Lavaca Bay, TX	1.38
Elba Island, GA	0.35
Sabine Pass, LA	1.3
Lake Charles, LA	1.07
Plaquemines Parish, LA	1.07
Sabine Pass, TX	2.1
Potential Sites	
Brownsville, TX	2.8
Pascagoula, MS	1.5
Cameron Parish, LA	0.16
Ingleside, TX	1.09
Cameron Parish, LA	0.2
Cameron Parish, LA	0.67
Brownsville, TX	3.2
Gulf of Mexico	3.22

Table 3-2. Proposed and Potential LNG Export Terminals [Data source: FERC][lxvi]

Based on the Sabine Pass construction schedule, it is unlikely that additional facilities will be operational before 2017. Also, it is expected that the cost and construction time will be higher for locations that are not current LNG import facilities, since they will need to add LNG storage capacity in addition to the liquefaction plant. Current LNG import facilities exist at Cove Point, MD; Elba Island, GA; Lake Charles, LA; Jefferson County, TX; Cameron Parish, LA; Everett, MA; Pascagoula, MS; and offshore facilities in the Gulf of Mexico and off of Gloucester, MA.

While current international natural gas prices indicate that there are substantial opportunities for the export of LNG, there is considerable uncertainty over the viability of exports in the future. While the U.S. is currently the major developer of shale gas, a number of other countries have substantial shale gas resources available. Figure 3-6 shows a map of basins associated with shale oil and gas formations and Table 3-3 list the top ten countries with technically recoverable shale gas resources. It is likely that shale resources will start to be developed elsewhere before substantial U.S. LNG export capability is operational. The development of those shale plays could significantly impact the price of natural gas overseas and hamper the profitability of LNG exports.

It should also be noted that most long-term natural gas price forecasts have assumptions about LNG exports embedded in them. The EIA Reference scenario indicates that the U.S. will move from a net importer to a net exporter in 2016, with net exports exceeding 1 trillion cubic feet per year in 2025.[lxvii]
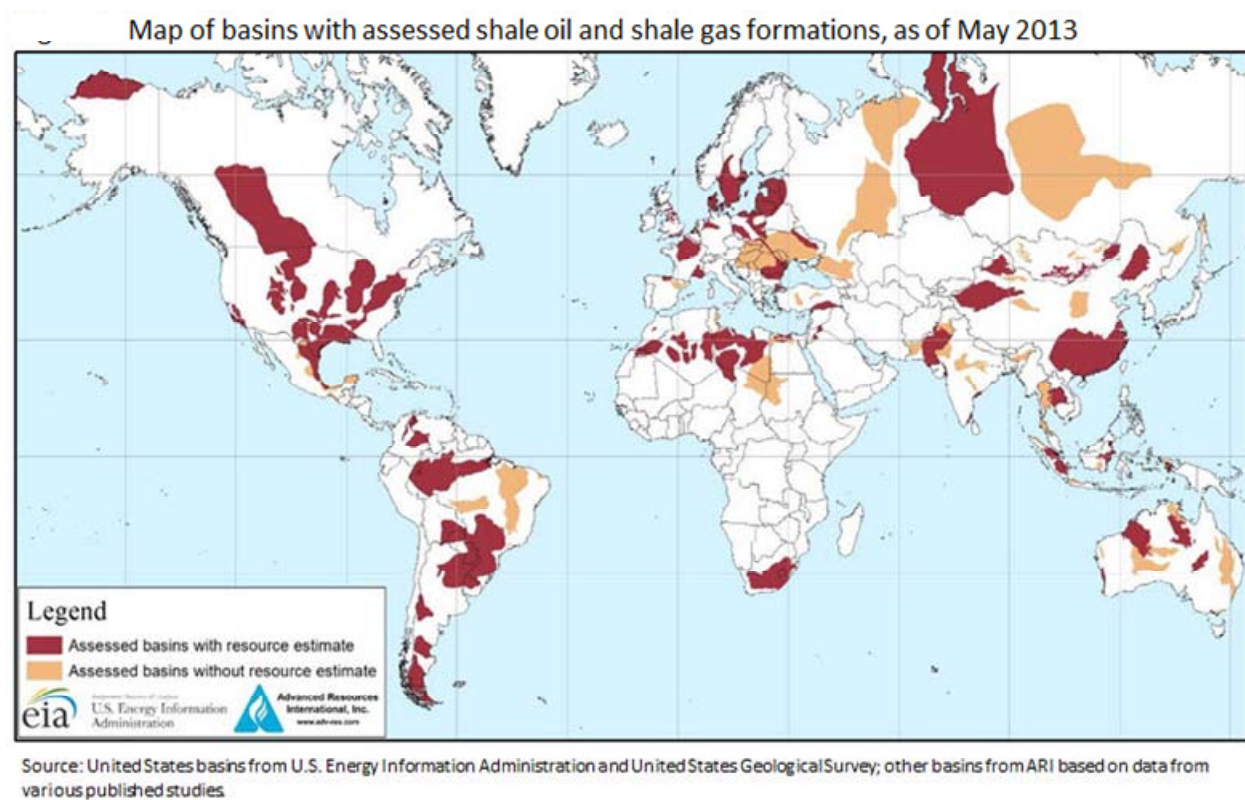

Map of basins with assessed shale oil and shale gas formations, as of May 2013

Legend
- Assessed basins with resource estimate
- Assessed basins without resource estimate

Source: United States basins from U.S. Energy Information Administration and United States Geological Survey; other basins from ARI based on data from various published studies

Figure 3-6. World Shale Oil and Gas Formations [Source: EIA][lxviii]

Rank	Country	Shale gas
1	China	1,115
2	Argentina	802
3	Algeria	707
4	U.S.	665
5	Canada	573
6	Mexico	545
7	Australia	437
8	South Africa	390
9	Russia	285
10	Brazil	245
	World total	7,299

Table 3-3. Top Ten Countries with Technically Recoverable Shale Gas Resources (trillion cubic feet) [Data source: EIA][lxix]

4. Risk Factors

4A. Environmental Regulations

There is considerable uncertainty as to what future environmental regulations will impact shale gas production (see section 1.E). For the most part, EPA has yet to act and regulation has occurred at the local level. Regulations that standardize drilling practices, monitoring and reporting (such as IEA's proposed Golden Rules) may have a small impact on natural gas prices. Regulations that impose a significant barrier to hydraulic fracturing could have a dramatic effect on natural gas prices. Given the tremendous impact of shale gas development on the U.S. economy, there is a significant incentive to avoid enacting prohibitive regulations. Researchers at Purdue University have estimated that the expansion of shale gas resources would increase U.S. gross domestic product by 3.5 percent over the 2008-2035 period.[lxx] Thus, it may take the occurrence of a hydraulic fracturing-related disaster to generate sufficient political capital to produce prohibitive regulations.

4B. Increased Demand

Significant increases in demand (see section 3) could have a major impact on natural gas prices. Areas that could see an increase include the transportation sector, electricity generation, and the use of natural gas in an industrial process or as an industrial feedstock. The area that has the greatest potential to affect natural gas prices, and also has the greatest level of uncertainty, is LNG exports. The export capacity of the facilities that have currently been proposed to FERC would represent a significant fraction of the current production and a number of other potential sites have been identified. While current U.S. and overseas natural gas prices indicate that LNG exports are viable, significant development of shale gas in other regions could reduce the price in Europe and Asia. A significant increase in domestic demand or exports would likely change the pricing paradigm for natural gas, moving the price above the current levels seen under wet gas drilling and toward the level required to support dry gas production.

4C. Petroleum prices

Since the current low natural gas prices are largely a function of high oil prices, a drop in oil prices would likely result in higher natural gas prices. The recession of 2008 saw a dramatic decrease in oil prices, from a spot market high of $145/barrel in July 2008 to $30/barrel in December for West Texas Intermediate crude.[lxxi]   While U.S. oil production is unlikely to have a major impact on global oil prices, it is conceivable that the production of natural gas liquids will reduce the price for those products, thus reducing the profitability of wet gas development. Furthermore, increases in domestic production of light crude oil found in associated gas could limit refinery production, since refinery production efficiency is lower with light crude. This could result in lower light crude prices with mid and heavy crude prices remaining high, thus making associated gas development less attractive.[lxxii]

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