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An Analysis of Horizontal Gas Drilling and its Impact on Spot Market Pricing: A Focus on the Marcellus Shale Production Potential

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Union College, Schenectady, New York

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Abstract

This paper attempts to quantify how the rapid increase in shale gas production in the past fifteen years has impacted regional natural gas spot prices. This method of natural gas extraction-pumping water mixed with sand and clay first vertically and then horizontally, with clay and sand particulates holding fractures open to allow the flow of natural gas-has a shorter well lifespan and faster decline rate than conventional wells. Through analyzing the degree of market integration between shale gas production and spot prices, we can quantify what impact different shale plays have had on the regional pricing of natural gas. With this information, we can then discuss how the exploitation of the Marcellus Shale, a relatively untapped shale play in the Northeast, could impact different natural gas price regions.

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Chapter I. Introduction

1.1 Natural Gas and America's Energy Future

As the human population grows exponentially, energy demand grows along with it in an even greater exponential fashion. The great industrial revolutions and technological advances have snowballed into a growing addiction to a consistent and abundant supply of energy to power our innovations. Through a combination of the convenience of fossil fuel power and a daunting understanding of the global threats that these resources hold, management of the American energy supply has been an emotional debate in recent years and two distinct perspectives have arisen.

One perspective is offered in Al Gore's documentary *The Inconceivable Truth,* which brought global warming to the national spotlight. Leaders of the 'smart grid,' an innovative electrical grid that would allow for greater diversity in energy sources and would change the way in which power is transmitted, also pride themselves within this perspective. They argue that as the earth continues to rise in temperature, to levels as high as our society has ever known, we must find ways to use energy efficiently, altering our fuel structure to harness power from renewable sources that can produce clean and consistent fuel, which will guarantee America a secure resource base and a healthy planet.

Another perspective is voiced by leaders of petroleum companies and the many large businesses that thrive on the accessibility of the current electrical grid. This group argues that our current grid, supporting cheap and abundant fuel, has rarely failed our energy needs and large capital investments into new energy infrastructure will sacrifice technological progress. These two perspectives must come together and understand an adequate solution to both ensure our stable energy structure while promoting continued economic growth. The two groups will likely find a middle ground through the use of a flexible supply of both renewable and non-renewable fuel generation.

Natural Gas is one of the many fossil fuels we use today, and it has been rising since 1996 as a fuel source for electricity generation (Figure 1-1). This rise has driven coal use down to its lowest share of electricity generation since 1995. Coal and natural gas essentially compete for the same consumer base: utilities that generate electricity, industry that can use either fuel for heat, and homeowners and commercial businesses that buy electricity packages from local

suppliers based on prices. As natural gas use has gone up at the expense of coal, the price of natural gas has recently gone down relative to coal. This counterintuitive drop in the price of natural gas is due to the increasingly large supply of natural gas due to the rise in unconventional gas production.

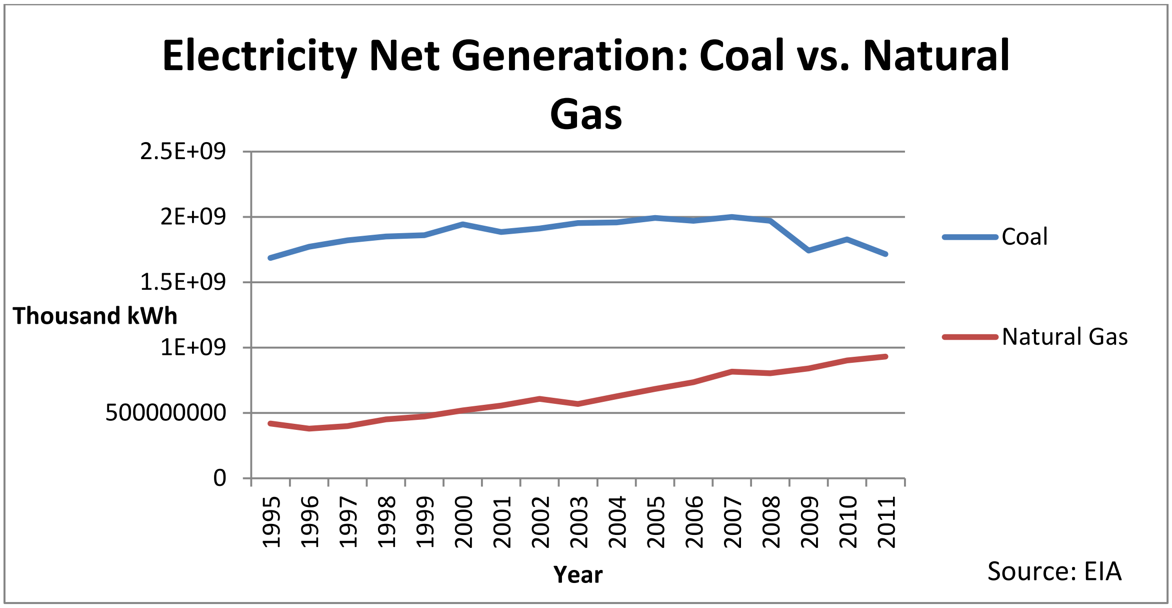
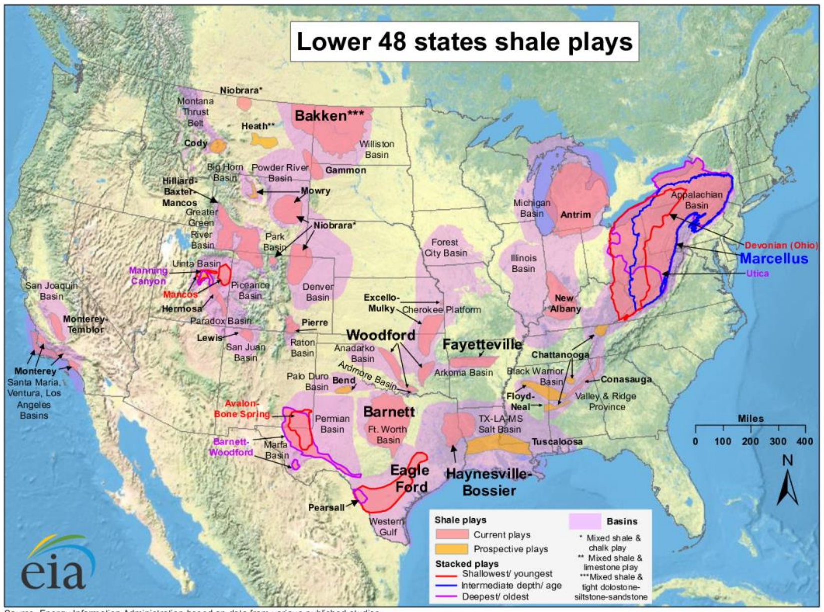


Figure 1-1. Electricity Generation; Coal vs. Natural Gas (Energy Information Administration, 2013)

1.2 Unconventional Gas

The rise in supply of natural gas comes from so-called “unconventional gas,” predominantly found in the form of shale gas using a relatively new technology known as hydraulic fracturing, which utilizes horizontal well drilling to extract the natural gas embedded within layers of shale rock. For years geologists have known of gas reserves in tight, deep shale rock layers, but have deemed it too deep to get to and not economically viable to extract. The recent sentiment is that the new technology can not only extract the gas, but at a capital cost that it makes economic sense for producers to extract the reserves.

Shale gas plays have been notable in many different regions of the United States, most notably the Barnett Shale in North-central Texas, the Fayetteville Shale in Arkansas, the Haynesville Shale in East Texas and West Louisiana, the Woodford Shale in Oklahoma, the Eagle Ford Shale in South Texas, and the Bakken Shale in East Montana and West North Dakota (Figure 1-2).



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

Figure 1-2. Notable Shale Plays in the United States (Energy Information Administration, 2013c)

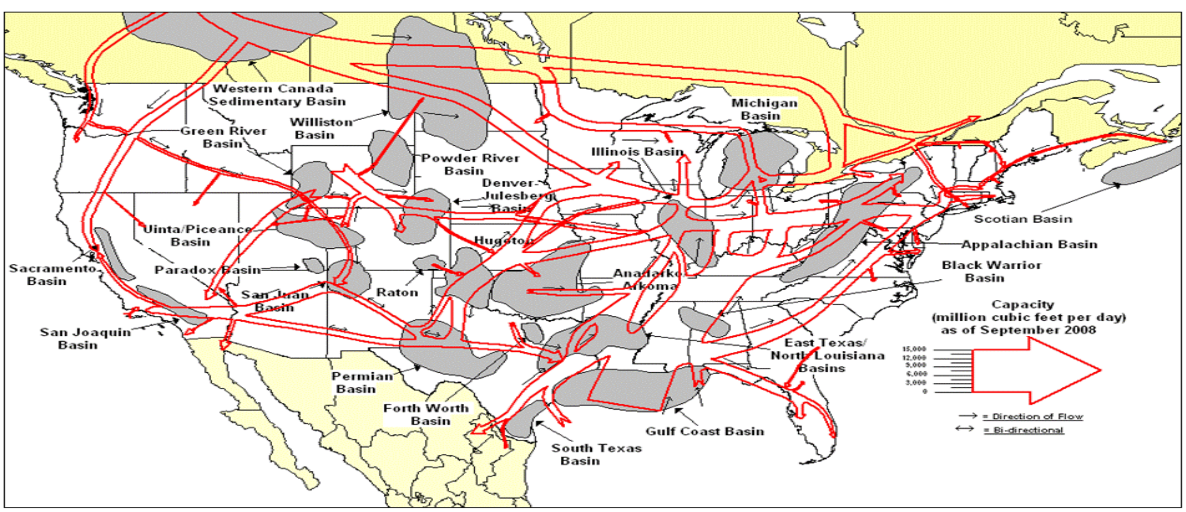
With unconventional natural gas plays becoming a larger part of the picture, the Marcellus Shale, the most recent shale gas play, lying in South-central New York and hitting chunks of Pennsylvania, Ohio, and West Virginia, has come into the bright lights of the local Northeast governments, as they debate whether or not the environmental risk of shale gas extraction is worth the reward. Environmental advocates urge that fracking creates a flow of wastewater that alters natural landscapes, decreases mined property values, produces a great degree of pollution, and increases exposure to dangerous chemicals.

Despite some exploitation and production, the Marcellus shale has been largely untouched, as a recent survey “estimated a mean undiscovered natural gas resource of 84,198 Billion Cubic Feet (BCF) of undiscovered, technically recovered natural gas,” (USGS 2011a). This is 82,000 BCF larger than the previous assessment in 2002, claiming the area only contained roughly 2 BCF of undiscovered natural gas (USGS 2011b). To put this number in perspective, the United States used 24,285 BCF of natural gas in the year of 2011. Hypothetically all the technically recoverable, undiscovered amount of natural gas in the Marcellus Shale could fuel over three years of the demand of natural gas in 2011, assuming the estimate to be accurate. This of course is impossible, but nonetheless points to the unutilized, large supply of natural gas embedded within the Marcellus formation. This has undoubtedly

sparked the interest of investors and gas exploration companies, but this curiosity has been met with formidable opposition from environmental cohorts.

The exploitation of the Marcellus Shale has been hotly contested. The recent deregulation of the Natural Gas industry has given open access to any producer to exploit a gas resource. Exploration companies have used this freedom to lease out lands rich in Marcellus shale gas, only to be thwarted by local governments claiming they cannot drill due to incomplete studies into whether potential environmental hazards of shale gas fracturing can be mitigated. ‘Hydrofracking,’ or fracking for short, has raised concerns in regards to pollution and local environments. These environmental dangers are legitimate, but if producers can mitigate the damage done to the environment and human health then there will be noted positives from the standpoint of both consumer and producer surplus.

A natural gas pipeline map shows that without a local supply the Northeast is dependent on the Midwest and the Gulf of Mexico for natural gas (Figure 1-3). The exploitation of reservoirs in the Appalachian Basin can give the northeast independence with a local supply to help prices here become more stable. However, this may not be enough to qualm the strong contingent of environmentalists and regulation in this region. Analyzing how the Marcellus and other, greater developed shale plays have moved from wellhead production to regional spot price will lend insight into how the exploitation of the Marcellus Shale could move through regional gas markets. This knowledge could help give useful answers in a hotly contested debate.



Source: Energy Information Administration, Office of Oil and Gas, Natural Gas Division, GasTran Gas Transportation Information System.

The EIA has determined that the informational map displays here do not raise security concerns, based on the application of the Federal Geographic Data Committee's *Guidelines for Providing Appropriate Access to Geospatial Data in Response to Security Concerns*.

Figure 1-3. Natural Gas Pipeline Infrastructure in America and Canada (Energy Information Administration 2013d)

1.2 Plan of the Research

The next four chapters will go as follows. Chapter 2 analyzes the previous literature on the history of regulation and subsequent deregulation of the natural gas market, the determination of the price of natural gas, the unconventional natural gas industry, and the environmental costs of extracting natural gas from tight shale beds. Chapter 3 outlines the data series used, the methods of determining causality between regional natural gas shale production and prices, and offers hypotheses regarding the analysis. Chapter 4 presents the results of the cointegration analysis and discusses inferences drawn from different levels of significance found within the analysis. Lastly, chapter 5 ends the study with a conclusion and suggestions for further research.

Chapter II. Literature Review

II. 1. A Brief History and Overview of the Natural Gas Industry

The natural gas industry has a long history of regulation within the market, mainly to benefit the consumers. Beginning in the 1930s during the Great Depression and President Franklin D. Roosevelt's New Deal included the establishment of the Federal Power Commission (FPC) as a regulatory agency, with the power to control electric power and natural gas companies to the benefit of the public interest. The Federal Power Act of 1935 gave the agency the job of assuring an abundant energy supply with the goal of securing 'just and reasonable' prices for buyers of natural gas to be handed down to residential and commercial markets. Thus, natural gas was regulated at both the pipeline, and city-gates. (MacAvoy 2000)

At the pipeline, regulations were set based on tariffs that ensured sufficient profits covered capital and operational costs, interest and depreciation rates. A 1954 Supreme Court case, *Phillips Petroleum Company vs. Wisconsin*, extended the jurisdiction of the FPC to control prices at the wellhead (Doane and Spulber 1994, p.480). These regulations consisted of price ceilings to ensure prices were no greater than the costs of exploration and production. The FPC created an intricate process of creating a price contract that gave the well a specific price ceiling based on the expected supply in that well. Many natural gas companies argued the ceilings given to them, resulting in backlogging and suspensions for natural gas sellers. These problems continued through the 1970s, and gas shortages sprang up everywhere. Breyer and MacAvoy explain the phenomenon.

> In sum, as a result of regulation in the 1960s, buyers for interstate consumption obtained fewer reserves than they wished. For the most part, those buyers were pipelines ultimately serving primarily residential customers. The short reserve supplies were bid away from these buyers by interstate gas users…regulation led to a virtually inevitable gas shortage. It brought about a variety of economically wasteful results, and it ended up hurting those whom it was designed to benefit (Breyer and MacAvoy 1973, pp. 979, 987).

These residential buyers, whom regulation was primarily aimed at helping, inevitably lost because their sellers could not outbid other gas users for the shortage brought on by the price controls. A graph is constructed to show how regulatory price ceilings can accrue producer and consumer losses (Figure 2-1). It is estimated that through the FPC price controls, buyers and producers both lost more than a combined $20 billion from 1968-1977 (MacAvoy 2000).

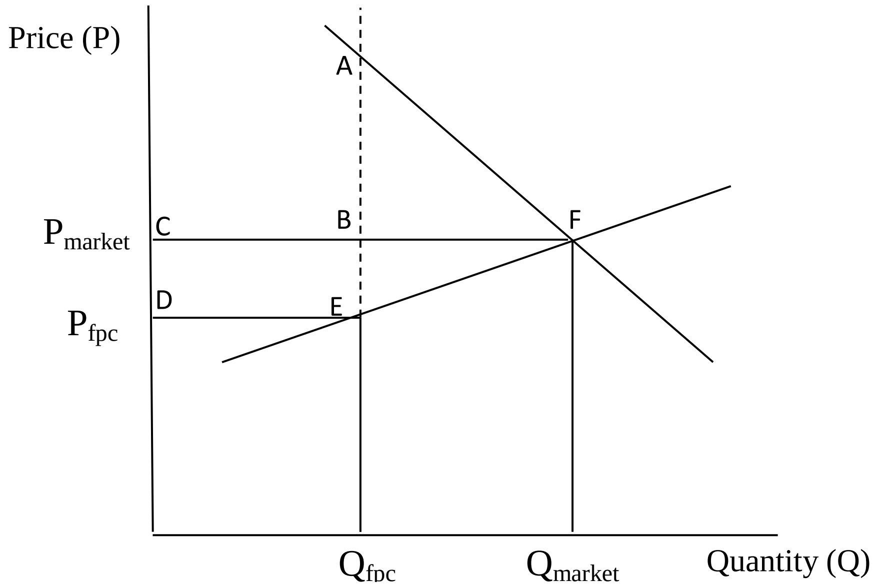


Figure 2-1. Price Regulations and Consumer loss as a result of 1954 Supreme Court Case *Phillips Petroleum Company vs. Wisconsin*. P_{market} = Market price of gas; P_{fpc} = Price with FPC regulations; Q_{market} = Market quantity of gas supplied; Q_{fpc} = Quantity of Gas supplied under FPC regulations. Triangle ABF represents Consumer Loss; Triangle BEF represents Deadweight loss. Rectangle CBDE represents Producer Loss.

The Natural Gas Policy Act of 1978 attempted to move in the opposite regulatory way, hoping to restore supply-and-demand markets by creating price floors. The NGPA regulatory scheme worked to create gradual deregulation with three different categories of gas. The first category classified a tiny portion of gas as ‘High-cost gas,’ which narrowly defined the amount of gas that was completely deregulated. The second category consisted of a lot more gas and was subjected to a price floor of $2.42/MMBtu in 1980. Lastly, “old gas,” had various different price floors averaging out to $1.75/MMBtu. New gas and most intrastate gas were scheduled for deregulation between 1985 and 1988 (Pierce Jr., 1982, pp. 89-90). Overall, this half-deregulation technique created different inefficiencies and the market was not yet fully deregulated when the FPC was finally dismantled in the mid-1980s

The Federal Energy Regulatory Commission (FERC) replaced the FPC to rejuvenate the industry and restore simple buying and selling relationships that producers and buyers had lost for about 50 years. In 1985, the commission ordered open access for pipelines to become active transporters for gas bought directly from producers, and were able to set their own rates to compete in their given market. Open access finally took full effect in 1992, with FERC Order 636.

> The Commission's primary aim in adopting [Order No.636] is to improve the competitive structure of the natural gas industry and at the same time maintain an adequate and reliable service. The Commission will do this by regulating pipelines as merchants and as open access transporters…The first goal is to ensure that all shippers have meaningful access to the pipeline transportation grid so that willing buyers and sellers can meet in a competitive, national market to transact the most efficient deals possible. As the House Committee Report to the Decontrol Act stated, 'All sellers must be able to reasonably reach the highest-bidding buyer in an increasingly national market. All buyers must be free to reach the lowest-selling producer, and obtain shipment of its gas to them on even terms with other supplies (FERC, 1992, p.7)

The reform stands today, as the act implied a network of integrated natural gas spot markets in which any seller or buyer can enter the market, hence the 'open access.' These reforms have now given natural gas the ability to adjust freely to market conditions, allowing movement from producers to consumers in a relatively hands-off approach. Residential customers now have greater choice and service options. This approach has given the price of natural gas the ability to drift to a set market price. However, this newfound market-driven industry brought price volatility. With little regulation, natural gas prices have been more susceptible to shocks than it was during regulation. This is shown through the national average natural gas wellhead price, which starts to experience these sorts of mini-shocks in late 1987, about a year and a half after open access and deregulation was ordered upon gas pipelines (Figure 2-2).

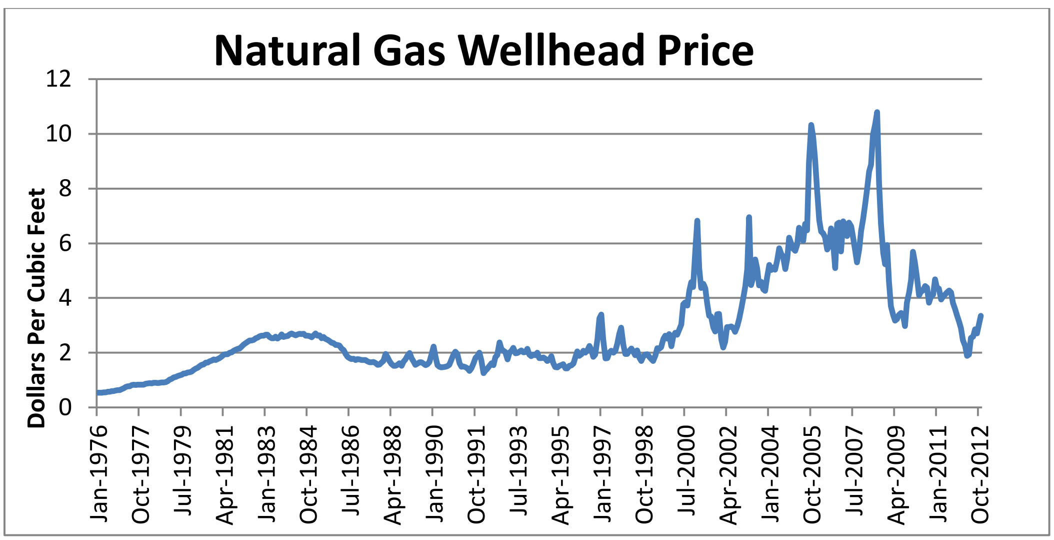


Figure 2-2. Natural Gas Wellhead price from Jan-1976 to Nov-2012. (Energy Information Administration, 2013a)

Meanwhile, deregulation within the gas industry decreased volatility in domestic production, as production rises and falls consistently during the 1980s (Figure 2-3). After

complete deregulation in the early 1990s, these peaks and valleys flatten and production is more consistent, mainly due to open access laws promoting competition between many exploration companies.

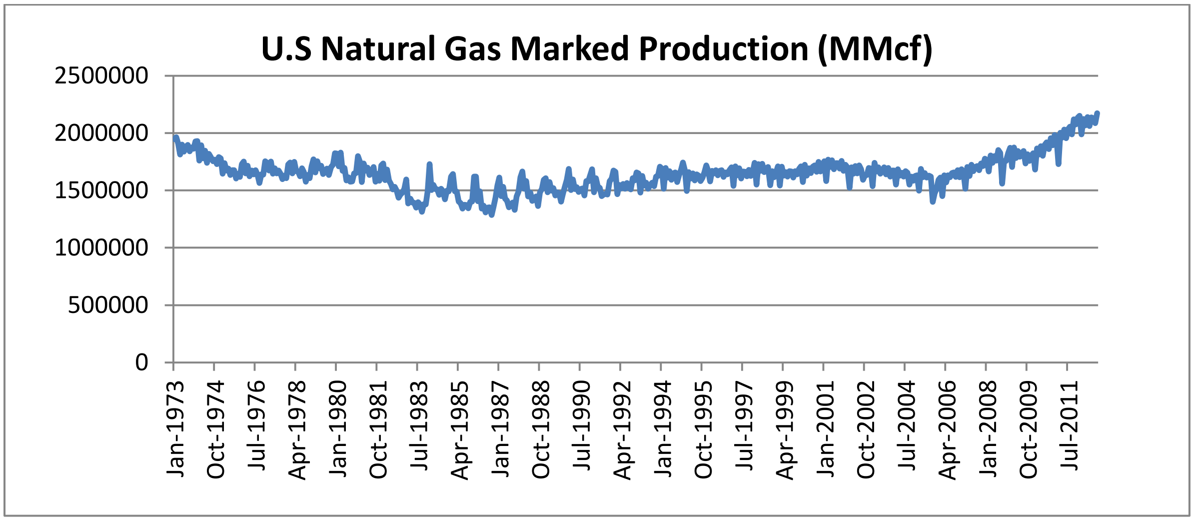


Figure 2-3. Natural gas domestic production from Jan-1973 to Oct-2012 (Energy Administration, 2013b)

In 2011, natural gas consumption flows consisted of 24.37 TCF shipped for consumption, while 22.38 TCF was produced by natural gas wells. Consumption mainly went to industrial companies, electric power utilities, residential districts, and commercial establishments, while exports accounted for 1.51 TCF. Withdrawals and additions to storage nearly cancelled each other out.

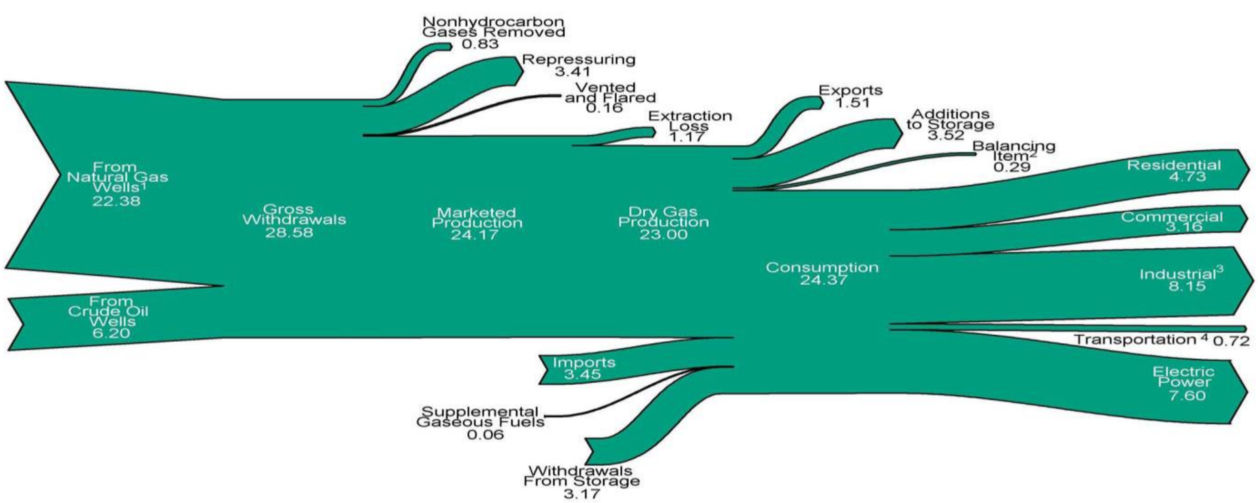


Figure 2-4. Natural Gas Production Flows in Trillion Cubic Feet (TCF). (Energy Information Administration 2011)

The natural gas industry now has three parties on the supply side and four parties on the demand side. The supply side consists of producers, pipeline operators, and local distribution companies (LDCs), and the demand side includes residential, commercial, industrial, and electrical demand. First, natural gas wellheads are bought and leased by producers, where the gas they pump is sent to the pipelines. The gas is then purchased at the city-gate by pipeline operators or independent traders, where they sell it to three parties: electrical utilities, industrial companies, and local distribution companies (LDCs). The LDCs buy the gas using long-term contracts with the pipelines and redistribute their gas to residential and commercial markets using a distribution charge, coming with a high markup from the city-gate price (Mohammadi 2011). While residential and commercial markets must go through LDCs, electrical and industrial companies can buy straight from the pipeline and do not have to go through the markup that residential and commercial customers are susceptible to. Industrial and electrical companies can typically change fuels depending on prices, while residential and commercial markets are typically tied to a single fuel, as switching between fuels is time-consuming and requires collaboration with another LDC, and most locations only have one in their area. With regulation firmly out the window, natural gas market players now act on prices set by market demand and the supply of natural gas.

II. 2. Economic Analyses of Natural Gas Pricing: Determining the Price of Natural Gas

The demand for natural gas comes at the previously mentioned four levels-industrial, electrical, commercial, and residential demands. Many studies analyze residential and commercial demand together, because both segments respond to weather changes in similar ways, with greater use in the winter months and less use in the summer months depending on heating demands. There is also a fuel substitution effect, as there has been an observed historical correlation between natural gas and oil prices. This would make sense, as both fuels can be used for the same function and could match each other’s price movements.

The historical trend between oil and natural gas prices has been called either the 10-to-1 rule or the 6-to-1 rule (Brown and Yucel 2008). The 10-to-1 rule is where the Henry Hub natural gas price per million BTU is equal to one-tenth the price per barrel of WTI (West Texas Intermediate) Crude Oil. The 6-to-1 rule holds the same concept, just as one-sixth the price instead of one-tenth. The historical trend is relatively accurate; however after 2000 the

relationship falls out because the natural gas price series begins to get too volatile, most likely due to the formation of a spot market for natural gas. Tests on whether oil and natural gas prices decoupled during the period 1997-2009 have found “temporary shifts” but that the prices return to a relationship after the volatility in natural gas prices is statistically accounted for. When taking into account “crude oil, weather, seasonality, storage, and production disruptions explain natural gas prices quite well,” (Brown and Yucel 2008) and when controlling for volatility, these factors can help to determine the price of natural gas.

There is an obvious price elasticity effect, as many different studies have been used to ask whether the demand for natural gas is elastic or inelastic. The long-run demand for natural gas has been shown relatively elastic. Different studies show a large variation of -0.17 to -2.42, with a mean long-run elasticity at -1.11 (Bohi 1981). Regional demand elasticities have also been analyzed, with specific price elasticity effects analyzed in the Northeastern parts of USA (Beierlein et al. 1981), which conclude to find natural gas demand inelastic in the short run and elastic in the long run. Meanwhile, another study uses a two-stage least squares model to test for price elasticities through regions in the United States and concludes that price elasticity for demand of natural gas varies heavily from region to region.

> Natural Gas demand by sector by region is found to be highly elastic; seven of the 30 equations showed own-price elasticities greater than -2.0. This finding coincides with what Beierlein et. al have concluded about the size of own-price elasticities of electricity and natural gas in Northeastern USA, i.e. demand is price elastic in the long run and inelastic in the short run (Liu 1983)

This study is significant because it shows how the spot market has created regional differences across the USA. Conclusions have also been made regarding how residential and commercial sectors are more price sensitive than the industrial sector, as the industrial sectors have flexibility to buy directly from different pipeline operators with little markup while residential consumers typically go to one LDC and pay a large markup. When analyzing price elasticity and natural gas demand on a state level with the use of an Autoregressive Lag Model, one study found residential natural gas prices, electricity prices and heating degree days as significant while disposable income, fuel oil prices, and industrial gas prices are insignificant, and estimate relatively inelastic price (Payen and Loomis, 2011). Further research needs to be done on different regions to analyze whether or not price elasticities vary from region to region in the spot market. The regional market has caused regional variations within the natural gas demand,

and the Northeast market has proven to be elastic in the long-run. Meanwhile, one study found residential and commercial prices to respond in a more extreme fashion to an increase in the wellhead price than industrial or electrical demand would, due to the fashion of the markups and the development of the spot market (Mohammadi 2011).

The majority of the natural gas is produced offshore in the Gulf of Mexico, Texas, Louisiana, New Mexico, Oklahoma, Western Canada, and the Rocky Mountains. The northeast states account for 2.4% of the share of natural gas production. Market centers provide services to ease gas trading and transportation costs, while pipeline expansion has increased the integration of the national network, all giving gas producers and sellers more choices. By analyzing spot markets with an autoregressive regression model from 1993-1997, the early years under deregulation, studies find the East and Central regions form a highly integrated market, but that this market is quite segmented from the morel loosely integrated Western market (Cuddington and Wang 2006). Another analysis of spot market integration concluded that deregulation has integrated separate, even distant gas markets into one market (DeVany and Walls 1993). By now, it seems as though the Law of One Price (LOOP) for the natural gas market is in full effect, with little to no barrier of integration.

Studies have been performed to analyze competition and the elasticity of substitution between coal, natural gas, and petroleum for electricity generation and industrial use. One report took nine studies done previously on American industrial fuel substitution to analyze average substitution elasticities. They found these elasticities to be low except for the coal-natural gas substitution which was -0.7185 (Stern 2009). One study uses a locally flexible translog form to investigate interfuel substitution, to which they find all elasticities relatively low, suggesting interfuel substitution as limited in the near term (Serletis et al. 2010). Lastly, the EIA conducted their own study of fuel substitution within power generation, and found elasticities to be relatively low with the exception of substitution between petroleum and natural gas (Energy Information Administration, 2012). Historically, this kind of substitution effect between oil and natural gas is expected, as it is easier to convert a natural gas plant to and from an oil plant than to convert a natural gas plant to and from a coal plant.

In conclusion, many studies attempt to quantify residential and commercial demand into determinants of different factors, the most important being income and price effects, weather and seasonality, storage conditions, and fuel substitution effects (mainly oil). There have been many

different studies analyzing regional demand for natural gas, as analysts hold views that aggregate demand studies cannot test for regional variations in market conditions, especially with the recently deregulated natural gas market where regional variations are quite high. The few analyses of the spot market have shown the entire market as almost fully integrated, with the West as slightly separated from the Central and Eastern parts of America.

II. 3. The Unconventional Natural Gas Industry

Unconventional natural gas resources are abundant in North America. According to an assessment of the technically recoverable unconventional resources in North America, mainly USA and Canada, there are 274 TCF (Trillion Cubic Feet) of recoverable natural gas from shale reservoirs in North America (Pickering and Smead 2008). The number is large, showing that the resource is clearly there, yet the economic nature of unconventional natural gas plays makes it difficult for investment and adequate rates of return, problems that are necessary to address as we continue to exploit these reserves in the coming decades.

According to the EIA, there are six types of unconventional natural gas plays, with some being recently discovered. Deep natural gas is natural gas found deeper than conventional drilling depths, requiring greater force and pressure in order to extract the natural gas. Tight natural gas is gas stuck in a very tight geologic formation, more so than the average conventional well. Tight natural gas is similar to shale gas in that both trap natural gas in rock that is highly impermeable. Coalbed Methane (CBM) is natural gas trapped in coalbeds, in the fractures and on the surface of coal. Known as a hazard to coal miners, capturing the natural gas within coal was originally done to keep coal miners safe, but now commercial production has taken-off to the point where it accounts for 10% of total natural gas production. Geopressurized Zones are another unconventional natural gas resource, as natural gas is formed through underground formations with high pressure rates. Natural gas is formed through the compression of clay compress on top of porous material deep underground. Lastly, methane hydrates form natural gas through pseudo-ice solids that form a mixture of natural gas and water. The exploration of this type of natural gas reserve is still in the research phase, with reserves thought to be significant but extraction processes quite unknown.

Unconventional gas plays are generally characterized by low geologic risk and higher commercial risk. The low geologic risk is due to the smaller chance of a ‘dry hole,’ which is an

unsuccessful well that produces no gas resources, than conventional wells. Shale gas wells deplete much faster than conventional wells, as they exhibit an early peak followed by steady decline. Shale wells experience a life of 8-12 years, while conventional wells have a life of 30-40 years (Stevens 2010).

The commercial risk is high because the wells typically require large capital costs, larger than conventional wells, and investors typically need to wait some years after production to get to a break-even stage and start to see profits. One study attempts to project production, capital costs, and subsequent cash flow in a time series of shale gas plays, and concludes that there is a wait of almost nine years until the average well breaks even and cash flow turns positive. The average shale well in the study experienced a steep increase from year 2 through year 4, where it hits the peak and then declines all the way through the rest of the life of the well. Lastly, the analysis concludes an estimated 85% chance that shale gas plays would break even, portraying a considerable amount of risk (Gray et al. 2007). With high capital costs and commercial uncertainty from well to well, the total investment risk is decently large. The commercial risk associated with these shale plays may be forcing natural gas operators into a bind.

> …natural gas production from unconventional sources has become largely sub-economic over the past three years for a large portion of the US natural gas operators. A majority of gas operators continues to outspend their net earnings on CAPEX (Capital Expenditure) programs. They must do so, because of the short-life cycle of unconventional gas wells. If they were to stop CAPEX (Capital Expenditure) for new wells, free cash flow would dry up quickly. Low well productivity data, together with high cost of recovery (well completion cost and frac-jobs), low gas prices and drying up of access to new capital are the underlying causes for lagging cash flow from unconventional wells (Weijermars 2011).

The analysis here notes that if there is a drop in projected net earnings, the burden will fall on natural gas operators to cover this drop. With recent low prices, shale gas operators are having a tough time finding investors, and analysts have gone as far to question whether a price-floor policy is necessary to bail out the unconventional natural gas industry (Weijermars 2011).

These problems with the natural gas industry and unconventional commercial risk have garnered recent pessimism with the projected rising shale gas industry. One analysis portrayed the industry as “after the gold rush” (Berman 2012). Berman notes the large declining rates of the biggest shale reserves, with the average Haynesville Shale well declining at 48%. Meanwhile, standard conventional wells have declining rates of up to 20%. For the shale gas

industry to meet projected growth expectations in the coming decades, the industry needs higher gas prices. When comparing shale and conventional wells, there are clear differences in lifespan, profiles, and declining rates. There are also geologic differences, mainly in terms of Estimated Ultimate Recovery (EUR), where it is by and large well known that shale wells offers higher EURs than conventional wells (Bahily 2011).

II. 4. Environmental Costs of Shale Gas Extraction

Despite the large amount of natural gas estimated in shale gas reservoirs, horizontal well technology is a new technique. Environmentalists are quick to point out serious environmental hazards, which have proven worrisome. Understanding the geologic nature of shale gas source rock formations and the process of horizontal hydraulic fracturing will allow quantifications on environmental costs.

Formations containing reserves of shale gas have been loosely called shale rock, though many observe the formation as a mixture of organic, low-permeability rock material. Shale gas that results from the formation is typically dry, although some do produce gas and water mixtures that need to be separated. The rock is typically comprised of consolidated clay-sized particles that were deposited as muds in low-energy depositional environments and are deposited with rich organic matter, such as algae, plant and animal derived organic debris (Arthur 2008). Clay sediments accumulate and compact as mud layers gradually become pressurized to form shale rock.

The process of hydraulic fracturing creates permeability within the formation. The fracturing can facilitate the flow of fluids through the source rock to extract natural gas. The process involves first drilling vertically between 5000 and 12000 ft., and then drilling for a few thousand feet (Rahm 2011). Steel casings are cemented into place to protect freshwater aquifers that typically lie above the shale rock. High pressure pumping of the liquid mixture causes fractures and cracks, to which clay and sand particulates act as “propping” agents, flowing in and holding the fractures open. Once pumping of the fluids stops, the gas flows back through the horizontal portion and then through the vertical portion of the well (Arthur 2008).

In a study of 68 private drinking water wells in northern Pennsylvania and New York, high amounts of methane were claimed to be found within fracking sites (Holzman 2011). The amounts of water needed for shale gas plays is immense and is estimated at up to 5 million

gallons per well (EPA 2010). An estimated 15%-80% of wastewater is flown back through the well, and proper disposal of this 'flowback' is crucial to mitigating effects of hydraulic fracturing on local lands and water supplies. Pennsylvania passed the Marcellus Shale Bill in May of 2010, enforcing a three year ban on hydraulic fracturing until more research has been done into shale wastewater mitigation, and New York has taken a similar stance. Understanding the damage to local water supplies and degrees of mitigation will be essential for future exploration of the Marcellus Shale.

The additives to the water-sand mixture pumped into the ground makes up a majority of the worry associated with hydraulic fracturing, most of which are essential for successful shale gas plays. A Hydrochloric acid mixture is utilized at the beginning of the shale gas play to clean up the area. Corrosion inhibitors are also used in engineering simulations that test wells for productivity. Biocides are used to make sure bacterial corrosion does not happen in the wellbore, because fracture fluids are typically containing organic materials that provide a nice medium for bacteria growth. Fracking fluids are known to contain more than 99% water, however drilling companies are not required to disclose the other chemicals they use during the process. Other chemicals that have been used are said to be potassium chloride, guar gum, ethylene glycol, sodium carbonate, potassium carbonate, sodium chloride, borate salts, citric acid, glutaraldehyde, or isopropanol (Rahm 2011). Although these added chemicals are mostly noted as non-toxic by proponents of hydraulic fracturing (Vaugn and Pursell 2010), it is vital to mitigate the potential for chemicals to leak into local grounds.

Disposal of wastewater can be done directly into land or involve deep-injection into surface waters, depending on the location of the wellhead (Rahm 2011). Improper mitigation has caused serious environmental opposition in Pennsylvania, most notably in Clearfield County, Dunkard Creek, Monongahala River, Hopewell Township, and Dimcock (Vaughn and Pursell 2010). As a global leader in oil and natural gas production, it is obvious to turn to Texas to understand exactly how they have handled water issues surrounding hydraulic fracturing. A case study on shale gas production in Texas shows little environmental regulation here.

> Texas…does not have centralized administrative structure for managing environmental regulation. Multiple commissions and authorities have a role to play in jurisdiction over mineral, water, air, and land regulation. But…Texas does not have a strong ethos of environmental protectionism. Moreover, under the leadership of Governor Rick Perry, Texas has taken a decidedly anti-EPA and anti-federal regulation position (Rahm 2011).

The Texas Railroad Commission regulates the oil and gas industry and has conflicted with the EPA due to relaxed enforcement of the Safe Drinking Water Act. The Railroad Commission allows drilling companies to use as much groundwater as they want (Texas Railroad Commission, 2013) and the state thrives from the industry. In general, wastewater control has shown itself as a problem in Texas. For example, when finding flammables present in drinking water, the EPA declared an Imminent and Substantial Endangerment Order in December 2010 to protect waters in Southern Parker County, located next to Barnett shale wellheads. The federal government will most likely continue to clash with local authorities in Texas.

Costs to mitigate flowback brought by hydraulic fracturing are essential to understanding the possible exploration of the Marcellus Shale. The Marcellus Shale is noted as a large shale gas basin that has barely been explored and extracted. In the near future this will likely change, as the emergence of successful plays around the United States and the ever-growing demand of energy will put pressure on local Northeast leaders to drill. Responsible price scenarios for extraction and environmental mitigation of flowback wastewater will be imperative to analyzing whether to drill in certain Marcellus areas.

Chapter III. Data Description and Methodology

In this chapter, data series and methodologies are explained in detail. The data is two-fold with shale gas production and gas spot price data gathered. For shale production, raw datasets of shale production according to lease number was extracted from the *Drilling Info* database and was aggregated to form three variables for each shale play: the total gas produced in a month, the count of flowing wells in each month, and the average gas produced per lease number in each month. Meanwhile, weekly spot price data was accessed through the *Intelligence Press*. Through developing ARDL (Autoregressive Distributed Lag) Models, granger causality tests were analyzed between production and prices in both causality directions.

III. 1. Data Series

III. 1 Shale Gas Production

Monthly, aggregated shale gas production for seven major shale plays from the *Drilling Info* database was gathered. Each shale play has three different measures of production: the average gas produced by lease per month, the number of flowing wells per month, and the total gas produced by month. A lease refers to a number of flowing wells that a specific company may hold at a given time. The seven shale plays were the Barnett Shale in north-central Texas, the Fayetteville Shale in Arkansas, the Woodford Shale in Oklahoma, the Eagle Ford Shale in southern Texas, the Bakken Shale in west North Dakota and east Montana, the Haynesville Shale in east Texas and west Louisiana, and the Marcellus Shale in New York, Pennsylvania, West Virginia, and Ohio. The monthly data starts when horizontal drilling begins for that particular shale play, which is different for each shale play.

Total gas produced per month is compiled and shown in a scatter-plot (Figure 3-1). The Barnett Shale is denoted *BAR Sum* starts with exploratory wells in 1996. Consistent increases pick up in late 2003, where it rises consistently until mid-2008. The rate of increase slows to the end of the series and reaches the highest point in December of 2011, at roughly 168.5 million MCF. The Barnett is clearly the most developed shale reservoir in the country. Meanwhile, the Fayetteville is denoted *FAY Sum* in the key and starts production in September 2004, increasing consistently in January 2006 through 2012. Woodford shale plays start in 2005 and are denoted *Wood Sum*. This series increases in 2008 through 2010, where it gradually increases to a high of about 21.8 million MCF (almost 13 times less than the highest total in the Barnett shale). The

Bakken shale is barely visible when plotting with the Barnett play and is denoted *BAK sum*. We see its movement more clearly in the Appendix, as in March 2006 wellheads increase production fairly rapidly until late 2007, where production remains relatively steady until another increases in June 2011 through 2012, reaching a high of roughly 0.913 million MCF in August 2012. The Haynesville shale starts production in 2008, denoted *HAY sum*, and starts a steady increase in February 2009, reaching a high of 63.51 million MCF in May 2012 before starting to taper off. The Eagle Ford shale gets similarly dwarfed as the Bakken shale, denoted as *EF Sum*. This series can be viewed in the Appendix, and starts production in June 2008, with a steady increase starting in October 2009, until reaching a maximum of 13.69 million MCF in October 2011 and tailing off into 2012. Lastly, the Marcellus shale, denoted *Mar Sum*, starts production in November 2008 and increases exponentially through the end of the series in June 2012. Unlike other shale plays, the Marcellus did not taper off, as wells were simply halted in June.

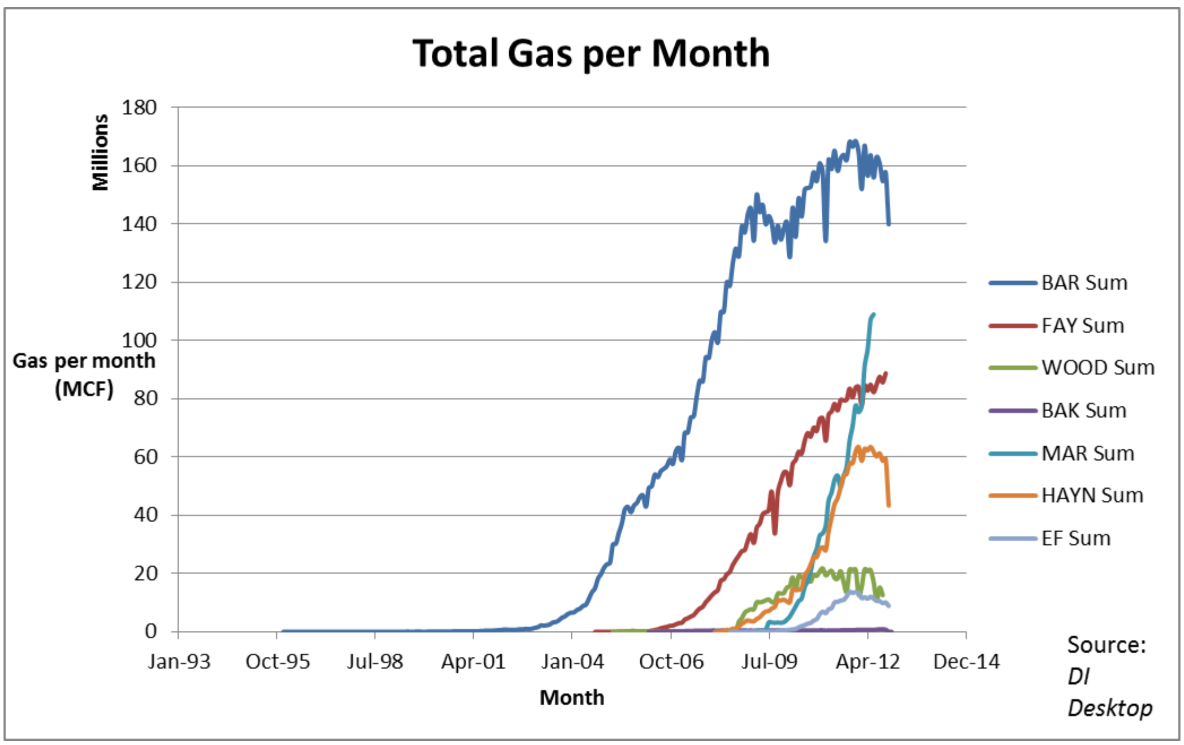


Figure 3-1. Total Gas per Month for all seven shale plays. Note *BAR Sum* = Barnett total production by month; *FAY Sum* = Fayetteville total production by month; *WOOD Sum* = Woodford total production by month; *BAK Sum* = Bakken total production by month; *MAR Sum* = Marcellus total production by month; *HAYN Sum* = Haynesville total production by month; *EF Sum* = Eagle Ford total production by month

A logarithmic scatter plot of well count shows exactly when the seven shale series increased, and the various shale plays follow a similar profile to the total gas per month series

(Figure 3-2). The logarithmic scale, with a base of 20 depicts when each play started production and wells sprang up. Without the log scale, the Barnett series dwarfs all aggregated well counts, as this reservoir hits highs over 13000 flowing wells per month, while the next-highest Fayetteville hits highs to over 4000, and the other plays fail to get higher than 1000 flowing wells per month.

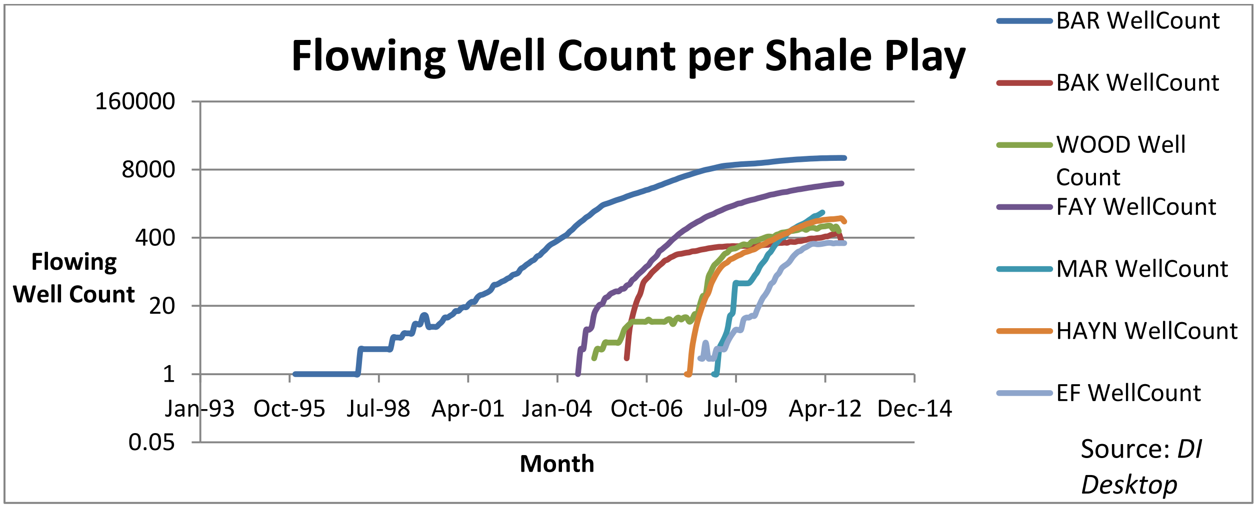


Figure 3-2. Flowing Well Count per shale play. Note *BAR WellCount* = Barnett flowing wells per month; *FAY WellCount* = Fayetteville flowing wells per month; *WOOD WellCount* = Woodford flowing wells per month; *BAK WellCount* = Bakken flowing wells per month; *MAR WellCount* = Marcellus flowing wells per month; *HAYN WellCount* = Haynesville flowing wells per month; *EF WellCount* = Eagle Ford flowing wells per month

Average gas per lease number per month is compiled in an XY scatter plot (Figure 3-3). The Barnett and Fayetteville are some of the lowest because these reservoirs have high well counts, while the Haynesville, Marcellus, and Eagle Ford plays are some of the highest because they have low well counts. Barnett averages increases in 2005-2006 and taper off through the series, reaching a high in July 2005 with 24.3 thousand MCF per aggregated lease. Average Fayetteville leases increase rapidly in 2006 and slowly decline in 2009, after a high of 26.2 thousand MCF. Average Woodford leases are erratic, but increase to a high of roughly 57 thousand MCF in November 2008 where it then declines through temporal spikes. Bakken averages are consistently low but see a one month increase to 913 thousand MCF, where a few leases were very successful. Marcellus averages hit the highest of any shale play, with an average of roughly 83439 MCF per lease in October 2010. Haynesville averages are high as well, hitting a high of roughly 78590 MCF per lease number in August 2011. Lastly, the Eagle

Ford shale averages hit highs in June 2010 and January 2011, where average lease production hits at least 63000 MCF.

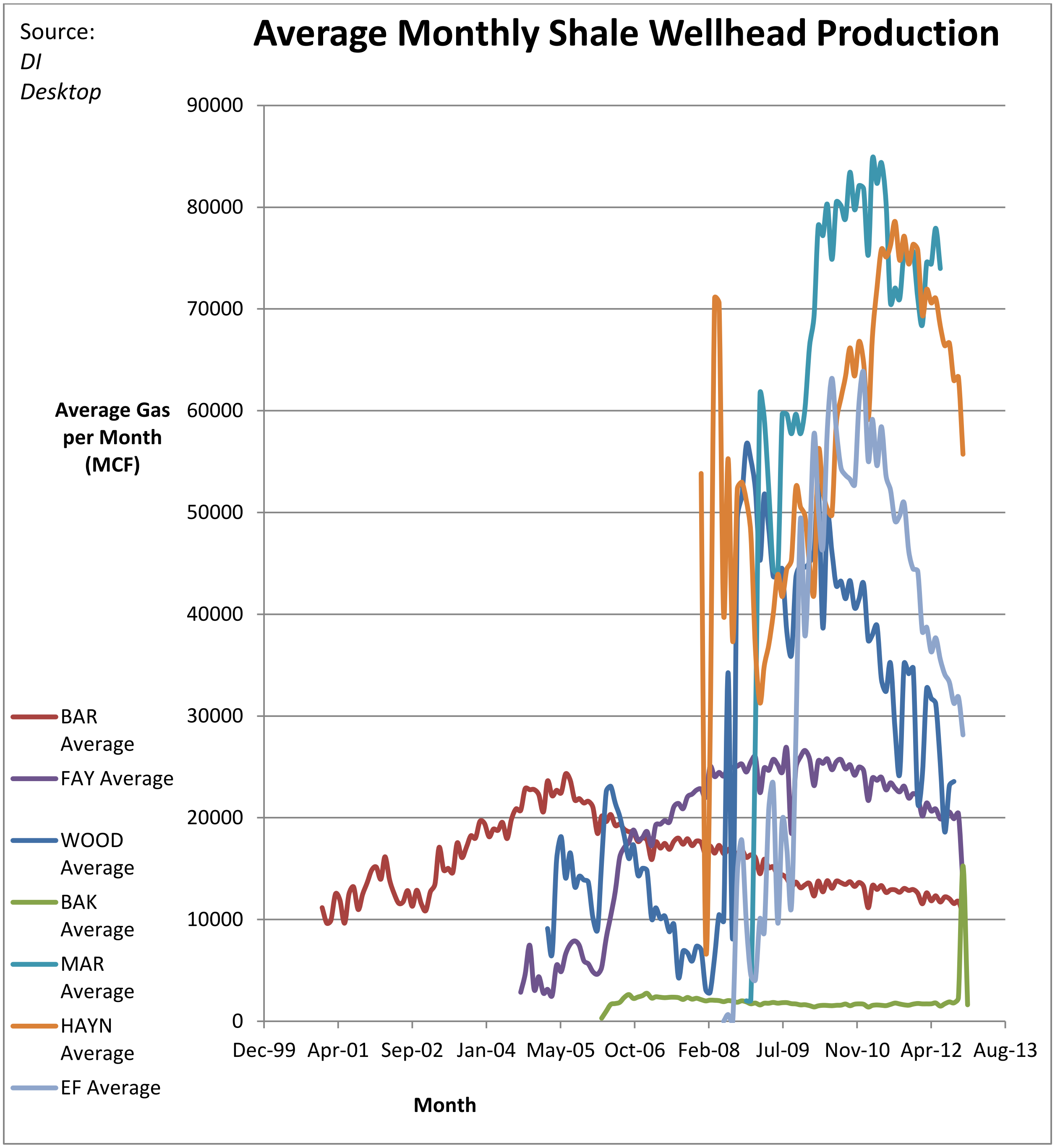


Figure 3-3. Average production per lease number per month. Note *BAR Average* = Barnett average lease production per month; *FAY Average* = Fayetteville average lease production per month; *WOOD Average* = Woodford average lease production per month; *BAK Average* = Bakken average lease production per month; *MAR Average* = Marcellus average lease production per month; *HAYN Average* = Haynesville average lease production per month; *EF Average* = Eagle Ford average lease production per month

III. 1. 2. Regional Gas Prices

The second data series that was used is the weekly spot price data series for seven different spot locations from the *Intelligence Press National Gas Index* (NGI). All seven series start on July 7, 2003 and end on January 21, 2013. These seven different spots are the Henry Hub spot in southern Louisiana, the El Paso Permian spot in east Texas, the Rocky Mountain spot price, also known as Opal, in north Wyoming, the Pacific Gas & Electric (PG&E) city-gate in west California, the SoCal spot price located in southern California, the Transco Zone 6 New York spot price located in New York City, and the Algonquin city-gate located in Massachusetts. The seven spots are dispersed well enough to hit three regions in the United States, with the east and west coast represented, and the South, the heart of domestic natural gas production, is well represented with two spots, while the Opal is the lone Midwest spot.

Seven spots and their price movements through the monthly time series is shown in a line graph (Figure 3-4). The Opal price series reaches lows in 2007 and falls significantly away from the rest of the series for about ten months before coming back. Other than this hiccup, these price series seem to be integrated and could be used to loosely test the Law of One Price rule. However, this test would be weak as there are only seven spots and the geographic market is not well represented throughout.

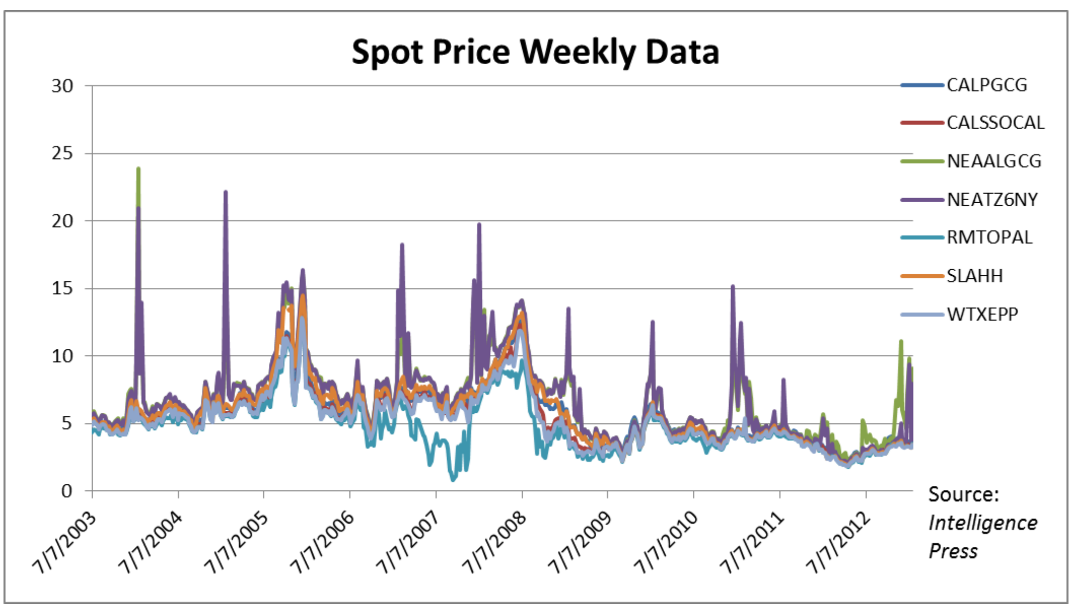


Figure 3-4. Weekly Spot Location Price Series. Note: *CALPGCC* = California PG&E spot; *CALSSOCAL* = Southern California spot; *NEAALGCG* = New England Algonquin spot; *NEATZ6NY* = Transco Zone 6 New York; *RMTOPAL* = Rocky Mountain Opal spot; *SLAHH* = Southern Louisiana Henry Hub spot; *WTXEPP* = West Texas El Paso Permian spot

III. 2. Methodology

The analysis attempts to quantify the geographic downstream market for natural gas and the ways in which wellhead production from horizontal drilling influences prices. Cointegration is used to describe two or more series that have similar linear movements. Cointegration occurs when two or more series generates a linear combination such that there is a stationary process in which the said series drifts in a similar way. Furthermore, tests for causality can observe which series drifts first and causes the other series to move similarly. The specific degree of causality that a spot price would have on a shale gas production level, or that a shale gas production level would have on a spot price will let us analyze how different regions of supply and demand affect each other within a time series. The rationale could be made for both price to significantly influence quantity and quantity to significantly influence price. An increase in price would make investing in gas production more favorable, and an increase in gas production might cause prices to drop, although the recent economic recession could be at play as well. This level of thought is the basis for the test, with the goal to quantify the degree of market integration between regions of gas production and prices.

Significant causality relationships between time-series data can be analyzed through the use of an Autoregressive Distributed Lag (ARDL) model. The model runs an Ordinary Least Squares (OLS) regression with time lags on the variables in the estimation. Based on the *Koyck Lag Structure* to quantify geometric effects of past on current events, Figure 3-5 shows an example of the derivation of an ARDL model from a distributed lag model.

(1) $\mathrm{BAR\_AVERAGE}_t = c + \beta_0 CALPGCC_t + \beta_0\lambda CALPGCC_{t-1} + \beta_1 CALSSOCAL_t + \beta_1\lambda CALSSOCAL_{t-1} + u_t$

(2) $\mathrm{BAR\_AVERAGE}_{t-1} = c + \beta_0\lambda CALPGCC_{t-1} + \beta_0\lambda^2 CALPGCC_{t-2} + \beta_1\lambda CALSSOCAL_{t-1} + \beta_1\lambda^2 CALSSOCAL_{t-2}$

(3) $\lambda\mathrm{BAR\_AVERAGE}_{t-1} = c\lambda + \beta_0\lambda^2 CALPGCC_{t-1} + \beta_0\lambda^3 CALPGCC_{t-2} + \beta_1\lambda^2 CALSSOCAL_{t-1} + \beta_1\lambda^3 CALSSOCAL_{t-2}$

(4) $\mathrm{BAR\_AVERAGE}_t - \lambda\mathrm{BAR\_AVERAGE}_{t-1} = c(1-\lambda) + \beta_0 CALPGCC_t + \beta CALSSOCAL_t + (u_t - \lambda u_{t-1})$

(5) $\mathrm{BAR\_AVERAGE}_t = c(1-\lambda) + \lambda\mathrm{BAR\_AVERAGE}_{t-1} + \beta_0 CALPGCC_t + \beta CALSSOCAL_t + (u_t - \lambda u_{t-1})$

Figure 3-5. Example of the derivation of an ARDL model

For simplicity, this ARDL model only used one lag and one lag interval. The analysis performed in the next chapter uses 12 lags as recommended for monthly data, and anywhere from one to four intervals. The ARDL model in Figure 3-5 is run with the dependent variable

$BAR\_AVERAGE_t$, the average Barnett shale gas production per lease number series, and independent variables *$CALPGCC_t$*, the California PG&C price series, and *$CALSSOCAL_t$*, the California SoCal price series, with β_0 and β_1 as coefficients, c as a constant, and λ as the geometric rate of decline. The steps taken to generate equation (5) was to start with equation (1) as a distributed lag model with rate of decline λ substituted in, to then lag the model by one period to get equation (2), to multiply both sides of equation (2) by rate of decline λ, and then subtracting equation (3) from (1) to get the ARDL model (4). Equation (5) is equal to equation (4) but is rewritten to have dependent variable $BAR\_AVERAGE_t$ alone on the right-side. The analysis uses up to four lag intervals, and the number of intervals was selected with the use of optimal lag-length criteria, selected with a combination of the Hannon-Quinn, Akaike Information Criterion, and Schwartz criterion methods, which take collinearity and other statistical problems with estimators into account when choosing the optimal lag structure for a given ARDL model specification (Hacker and Hatemi-J 2008; Lütkepohl 1985).

Through the constructing of many different ARDL models, similar to the one shown in equation (5), the analysis matched a shale production series with all price series to test for causation. Granger causality tests are cointegration tests that prove significant causality within a geographic market. These tests analyze whether a variable *X* can cause another variable *Y* when forecasting of current value of *Y* can be improved by using information on past values of *X*. Granger causality tests involves using lagged values of *X* to explain movement in the current value of *Y*, and when Y_t can be predicted better by using past values of *X*, there is Granger causality. Furthermore, when bidirectional Granger causality exists there is said to be feedback between the two variables (Doane and Spulber 1994; Granger 1969).

Testing for Granger causality with shale gas production data requires two adjustments to the price series. The first adjustment is required because the natural gas production data series was monthly while the spot price series was weekly. Statistical analyses for causality cannot be done if all variables do not have the same period. The spot price series was converted from weekly to monthly to match the time series of the production data. This conversion involved taking the average of three or four weekly data points in one given month and using this average as a monthly series. The second adjustment was made because the price data was dependent on the season, as prices consistently peaked in the winter and dipped during the summer. Meanwhile, the production data is not seasonal, and thus taking away this effect was necessary to

match the two databases. The seasonal adjustment used is known as the X-11-ARIMA seasonal adjustment method. This method is known to reduce about 30% in the bias of 20% in the absolute value of the total error in the seasonal factor forecasts for the 12 months, and when corresponding to peaks and troughs this reduction is larger (Dagum 2005).

Residual tests for ARDL estimators were performed to check if the estimators represented were the best linear, unbiased estimators. The Portmanteau and Lagrange Multiplier tests were used to check for autocorrelations, with the desire to accept null hypothesis that the estimator residuals had no serial correlation up to lag *k*. Autocorrelations result in the estimated coefficients not having the minimum variance among all estimates and are inefficient. Significance in these tests suggests that the error terms, also known as residuals, are closely related (Hosking 1980; Peña and Rodríguez 2002). Meanwhile, the White test was used to test for heteroskedasticity, which tests for patterns and whether or not degrees of finite variance exist or the estimators are completely random (White 1980). Lastly, Jarque-Bera normality tests were used, testing kurtosis and skewness to check whether data matches that of a normal distribution (Thadewad and Büning 2004).

III. 3. Hypotheses

The hypotheses prior to the analysis were based on two key factors. Firstly, the natural gas pipeline network infrastructure relative to shale play and spot price locations was taken into account. Recall Figure 1-3, which showed the national gas pipeline layout. Observations pertaining to this map will lend an idea as to how wellheads from certain regions can affect the spot price in another region. A specific shale play should require more lag intervals to affect a price series geographically farther away as opposed to one that is geographically closer. Secondly, a specific shale play's amount of gas and length of production time will likely have an impact on how significant it reacts with regional price series.

The Barnett Shale has been a leading gas source for America in recent years and this fact alone should allow Barnett production to cause feedback (granger causality both ways) with most spot prices. El Paso Permian and the Henry Hub spot prices are particularly good bets for causality because of their close proximity to the Barnett shale. The pipelines to the California spots-PG&C and SoCal-to Texas seem direct and cointegration could come here as well. Production from the Woodford shale in Oklahoma is also extensive and causality could be seen

for most spot prices. The El Paso Permian spot is very close is the best bet for feedback, while pipelines out of Oklahoma seem relatively direct to the Northeast and the West so cointegration could be expected here. The Henry Hub and Opal spots do not seem directly connected through pipelines with the Woodford and causality is not expected here. The Haynesville shale has been developed considerably in the past few years and feedback could be expected with multiple spots. The Henry Hub is the best bet for causality based upon close location to these shale plays, however the Northeast spots and the Opal could see integration with relatively direct lines to these regions.

The Fayetteville shale has been developed considerably, and the Henry Hub is the closest and should have causality. The northeast spots are also good candidates, as the piping from Arkansas to New York seems adequate. Bakken shale production has not reached high levels, and thus the expectation is that no causality will occur with spot prices. The Opal price series is the closest to these shale plays and has the best chance at causality, but just based off sheer lack of production, this is unlikely. The Eagle Ford shale production in south Texas has been steady in recent years and could interact with the El Paso Permian and Henry Hub spots, which are both close to these wellheads. Piping infrastructure shows itself relatively direct from south Texas to the Northeast and West, and given more lag intervals, significant causality could show here as well. The Opal spot seems a bit too far to feel an effect from the Eagle Ford. The Marcellus production was relatively extensive for a year and a half, and despite a short time series it should exhibit causality with the two Northeast spots with one or two lag intervals. As stated previously, spot prices tend to move in a similar fashion with the exception of the Opal spot price which drifts lower than other price series in 2007. Through observing significant causality relationships with different shale plays, we may be able to discuss how supply altered this price series with respect to the others.

The question of which type of aggregated shale data series will Granger cause prices and which types will be Granger caused by prices is interesting to note. The count of flowing wells and total production in a given month should be Granger caused by prices more often. Prices dictate whether or not it is feasible to invest and build more wells and get subsequent more production. These two data series matched the movements of one another and it would be expected for them to test significant and insignificant in a somewhat similar fashion. Meanwhile, the average natural gas per lease number is a bit more complex category and may granger cause

prices. This variable depicts good and bad performance of natural gas wellheads in a particular month, which could bleed through the gas market with more efficiency than the other two production variables.

Chapter IV. Results and Discussion

ARDL models are generated for a specific shale play series variable (i.e. Woodford Average), and different spot price series. Results showed a large degree of causality with both shale production to spot prices and spot prices to shale production, although the former relationship was found significant more often than the latter. Two-way granger causality, known as feedback, was found for sixteen different relationships. With regards to the hypothesis, some significance hit where it was expected while other times significance hit where it wasn't expected.

IV. 1. Results

Granger tests for causality were run from various ARDL models, and significant relationships are summarized in Table 1. Note that the table has two variables in every row, the first being the dependent variable and the second being a variable that was said to Granger cause the dependent variable given a certain number of lags and intervals. In total, there were 100 significant Granger causalities among 278 different combinations of Granger directions between a given spot price series and a given shale production series, a 36% chance of significance.

Table 4-1. Summary of granger causality tests with 12 lags chosen. Note the direction of granger causality "Dependent variable is GRANGER CAUSED by other variable." Number of lag intervals and P-values showing significance listed.

Dependent Variable	**Granger Causing Variable**	**Number of Lag Intervals**	**P-Value**
Wyoming Opal	Haynesville Average	4	0.0000***
Eagle Ford Sum	Transco Zone 6 NY	3	0.0000***
Eagle Ford Sum	Algonquin Citygate MA	3	0.0001***
PG&C CA	Haynesville Average	3	0.0002***
Transco Zone 6 NY	Haynesville Average	4	0.0006***
SoCal CA	Haynesville Average	3	0.0012***
Transco Zone 6 NY	Marcellus Average	1	0.0014***
Haynesville Average	PG&C CA	3	0.0014***
Transco Zone 6 NY	Fayetteville Well Count	1	0.0018***
Haynesville Average	SoCal CA	3	0.0019***
Transco Zone 6 NY	Fayetteville Sum	1	0.0020***
SoCal CA	Woodford Average	1	0.0021***
Transco Zone 6 NY	Eagle Ford Well Count	4	0.0023***
Algonquin Citygate MA	Haynesville Average	4	0.0036***
PG&C CA	Woodford Well Count	1	0.0036***

Dependent Variable	**Granger Causing Variable**	**Number of Lag Intervals**	**P-Value**
West Texas El Paso Permian	Fayetteville Well Count	1	0.0042***
West Texas El Paso Permian	Woodford Well Count	1	0.0043***
PG&C CA	Woodford Sum	1	0.0045***
Fayetteville Average	PG&C CA	3	0.0049***
Wyoming Opal	Barnett Well Count	4	0.0057***
Algonquin Citygate MA	Marcellus Average	1	0.0063***
Woodford Average	SoCal CA	1	0.0070***
Barnett Average	West Texas El Paso Permian	3	0.0072***
Barnett Average	Southern Louisiana Henry Hub	3	0.0075***
Southern Louisiana Henry Hub	Woodford Well Count	1	0.0080***
West Texas El Paso Permian	Fayetteville Sum	1	0.0087***
SoCal CA	Woodford Sum	1	0.0087***
SoCal CA	Woodford Well Count	1	0.0092***
Algonquin Citygate MA	Bakken Average	2	0.0093***
Transco Zone 6 NY	Woodford Well Count	1	0.0098***
Southern Louisiana Henry Hub	Fayetteville Well Count	1	0.0102**
Fayetteville Average	SoCal CA	3	0.0107**
Transco Zone 6 NY	Barnett Average	1	0.0108**
Algonquin Citygate MA	Woodford Average	1	0.0112**
Eagle Ford Well Count	Transco Zone 6 NY	4	0.0130**
Fayetteville Average	Southern Louisiana Henry Hub	3	0.0134**
Algonquin Citygate MA	Fayetteville Sum	1	0.0138**
PG&C CA	Woodford Average	1	0.0141**
West Texas El Paso Permian	Eagle Ford Well Count	2	0.0144**
West Texas El Paso Permian	Barnett Average	3	0.0145**
Algonquin Citygate MA	Woodford Sum	1	0.0150**
PG&C CA	Fayetteville Sum	1	0.0156**
West Texas El Paso Permian	Bakken Average	3	0.0157**
Woodford Average	PG&C CA	1	0.0158**
Wyoming Opal	Barnett Average	2	0.0170**
Algonquin Citygate MA	Woodford Well Count	1	0.0173**
Southern Louisiana Henry Hub	Fayetteville Sum	1	0.0177**

Dependent Variable	Granger Causing Variable	Number of Lag Intervals	P-Value
Transco Zone 6 NY	Woodford Sum	1	0.0181**
West Texas El Paso Permian	Barnett Sum	3	0.0191**
SoCal CA	Barnett Average	1	0.0201**
Algonquin Citygate MA	Fayetteville Well Count	1	0.0212**
Southern Louisiana Henry Hub	Haynesville Well Count	1	0.0227**
Southern Louisiana Henry Hub	Barnett Average	3	0.0237**
SoCal CA	Fayetteville Sum	1	0.0238**
PG&C CA	Eagle Ford Well Count	2	0.0251**
Eagle Ford Well Count	Algonquin Citygate MA	4	0.0267**
PG&C CA	Fayetteville Well Count	1	0.0268**
Haynesville Average	Transco Zone 6 NY	4	0.0275**
Transco Zone 6 NY	Marcellus Well Count	1	0.0277**
Southern Louisiana Henry Hub	Woodford Sum	3	0.0277**
Haynesville Average	Algonquin Citygate MA	4	0.0279**
Algonquin Citygate MA	Barnett Average	1	0.0287**
Southern Louisiana Henry Hub	Eagle Ford Well Count	2	0.0293**
Transco Zone 6 NY	Bakken Average	2	0.0294**
Transco Zone 6 NY	Marcellus Sum	1	0.0323**
SoCal CA	Bakken Average	3	0.0352**
Transco Zone 6 NY	Woodford Average	1	0.0363**
West Texas El Paso Permian	Haynesville Well Count	1	0.0376**
Fayetteville Average	West Texas El Paso Permian	3	0.0444**
Haynesville Average	West Texas El Paso Permian	1	0.0458**
Algonquin Citygate MA	Eagle Ford Sum	3	0.0475**
SoCal CA	Fayetteville Well Count	1	0.0487**
Haynesville Well Count	Algonquin Citygate MA	1	0.0492**
Woodford Average	Wyoming Opal	4	0.0518*
Southern Louisiana Henry Hub	Bakken Average	3	0.0546*
Marcellus Well Count	PG&C CA	1	0.0562*
Southern Louisiana Henry Hub	Haynesville Well Count	2	0.0609*
Eagle Ford Sum	West Texas El Paso Permian	1	0.0613*
Haynesville Well Count	Transco Zone 6 NY	1	0.0623*
Eagle Ford Sum	SoCal CA	1	0.0637*

Dependent Variable	Granger Causing Variable	Number of Lag Intervals	P-Value
Algonquin Citygate MA	Barnett Well Count	2	0.0662*
West Texas El Paso Permian	Woodford Average	2	0.0674*
Transco Zone 6 NY	Haynesville Sum	1	0.0677*
SoCal CA	Eagle Ford Well Count	2	0.0678*
Haynesville Sum	Algonquin Citygate MA	1	0.0686*
Woodford Average	West Texas El Paso Permian	2	0.0704*
PG&C CA	Barnett Well Count	2	0.0705*
Eagle Ford Sum	PG&C CA	1	0.0726*
Transco Zone 6 NY	Haynesville Well Count	1	0.0728*
West Texas El Paso Permian	Woodford Sum	3	0.0732*
Haynesville Sum	Transco Zone 6 NY	1	0.0754*
Southern Louisiana Henry Hub	Eagle Ford Sum	1	0.0765*
West Texas El Paso Permian	Eagle Ford Sum	1	0.0793*
Haynesville Average	Southern Louisiana Henry Hub	1	0.0803*
Woodford Well Count	SoCal CA	1	0.0819*
Wyoming Opal	Fayetteville Sum	1	0.0820*
Eagle Ford Sum	Southern Louisiana Henry Hub	1	0.0827*
PG&C CA	Barnett Average	1	0.0860*
SoCal CA	Barnett Sum	1	0.0949*
Wyoming Opal	Fayetteville Well Count	1	0.0951*

Note: *=statistically significant at the 10% level **=statistically significant at the 5% level; *** = Statistically significant at the 1% level.

Table 2 shows relationships where Granger causality is found significant between two variables in both causality directions, a phenomenon known as feedback. Note that P-values are shown in either direction, showing the level of significance that each causality direction held.

Table 4-2. 16 significant feedback relationships, two-way granger causality between variables.

Dependent Variable	Granger Causing Variable	Number of Lag Intervals	P-Value
Eagle Ford Sum	Algonquin Citygate MA	3	0.0001***
Algonquin Citygate MA	Eagle Ford Sum	3	0.0475**
Haynesville Average	Algonquin Citygate MA	4	0.0279**
Algonquin Citygate MA	Haynesville Average	4	0.0036***
Barnett Average	Southern Louisiana Henry Hub	3	0.0075***

Dependent Variable	Granger Causing Variable	Number of Lag Intervals	P-Value
Southern Louisiana Henry Hub	Barnett Average	3	0.0237**
Barnett Average	West Texas El Paso Permian	3	0.0072***
West Texas El Paso Permian	Barnett Average	3	0.0145**
Eagle Ford Sum	Algonquin Citygate MA	3	0.0001***
Algonquin Citygate MA	Eagle Ford Sum	3	0.0475**
Eagle Ford Sum	Southern Louisiana Henry Hub	1	0.0827*
Southern Louisiana Henry Hub	Eagle Ford Sum	1	0.0765*
Eagle Ford Sum	West Texas El Paso Permian	1	0.0613*
West Texas El Paso Permian	Eagle Ford Sum	1	0.0793*
Eagle Ford Well Count	Transco Zone 6 NY	4	0.0130**
Transco Zone 6 NY	Eagle Ford Well Count	4	0.0023***
Haynesville Average	Algonquin Citygate MA	4	0.0279**
Algonquin Citygate MA	Haynesville Average	4	0.0036***
Haynesville Average	PG&C CA	3	0.0014***
PG&C CA	Haynesville Average	3	0.0002***
Haynesville Average	SoCal CA	3	0.0019***
SoCal CA	Haynesville Average	3	0.0012***
Haynesville Well Count	Transco Zone 6 NY	1	0.0623*
Transco Zone 6 NY	Haynesville Well Count	1	0.0728*
Haynesville Sum	Transco Zone 6 NY	1	0.0754*
Transco Zone 6 NY	Haynesville Sum	1	0.0677*
West Texas El Paso Permian	Woodford Average	2	0.0674*
Woodford Average	West Texas El Paso Permian	2	0.0704*
PG&C CA	Woodford Average	1	0.0141**
Woodford Average	PG&C CA	1	0.0158**
Woodford Average	SoCal CA	1	0.0070***
SoCal CA	Woodford Average	1	0.0021***
Woodford Well Count	SoCal CA	1	0.0819*
SoCal CA	Woodford Well Count	1	0.0092***

Table 3 summarizes the different ways that the price granger caused the three types of shale production variables-average gas, total gas, and well count-and shale production granger

caused the price. Despite shale production causing price more often more, prices did granger cause average well performance fifteen times.

Table 4-3. Summary table of Granger Causation Tests

Granger Causation	Significant relationship	Average Significance	Average Lag Intervals
Price GRANGER CAUSING Total Production	9	0.0552*	1.444444444
Price GRANGER CAUSING Average Production	15	0.0274**	2.6
Price GRANGER CAUSING Well Count	7	0.0424**	2.142857143
Total Production GRANGER CAUSING Price	19	0.0364**	1.4
Average Production GRANGER CAUSING Price	23	0.0203917**	2.125
Well Count GRANGER CAUSING Price	25	0.029353846**	1.5

Two bar graphs are shown below, with Figure 4-1 representing the number of times a shale play variables significantly granger caused a price while Figure 4-2 shows the number of times a price significantly granger caused a shale play variable.

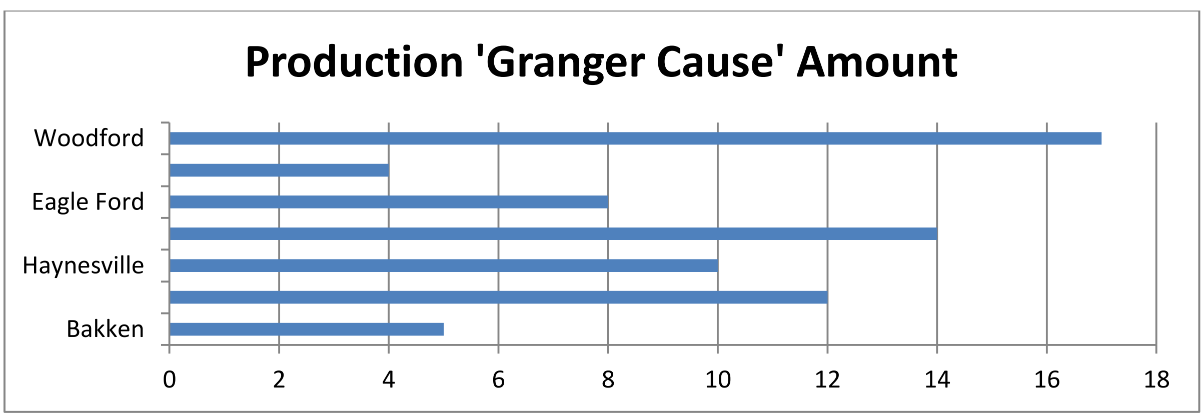


Figure 4-1. Chart outlining amount in which individual aggregated shale production data granger caused a price series.

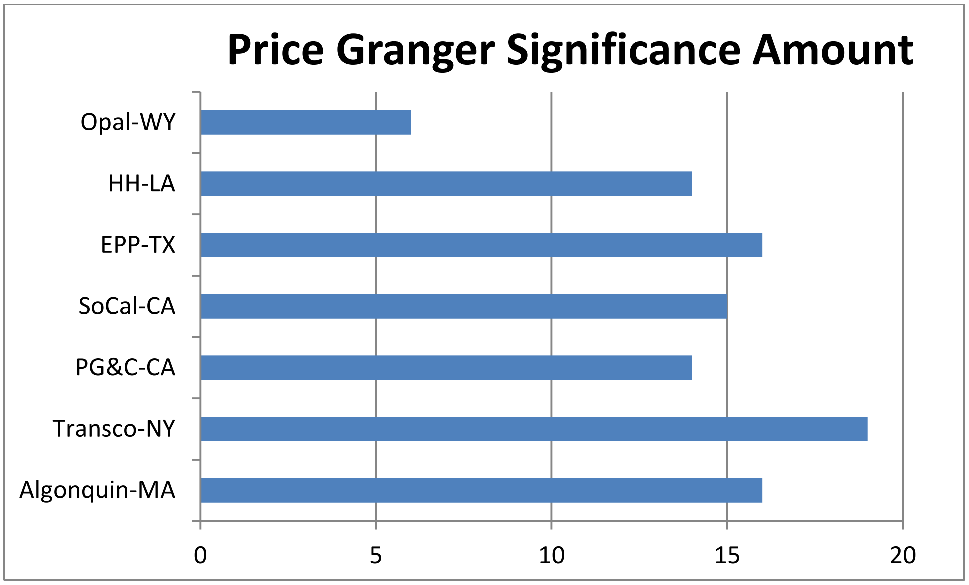


Figure 4-2. Chart outlining amount in which regional prices were found significant in a granger causality relationship, with both flow directions. Note: Opal-WY: Opal Spot; HH-LA: Henry Hub spot; EPP-TX: El Paso Permian spot; SoCal-CA: Southern California spot; PG&C-CA: PG&C California spot; Transco-NY: Transco Zone 6 NY spot; Algonquin-MA: Algonquin city-gate spot.

The Barnett average gas series Granger caused all seven spot prices at the 5-10% significance level. The series was significant with only one lag interval for east and west spot prices, two intervals with the Opal spot, and three intervals for the two south spots. Meanwhile, Barnett well count and total gas variables were less significant, Granger causing the Opal price series at 1% significance with 4 intervals, and caused the El Paso Permian series at 3% significance with 3 intervals., and three other causalities at 10%. The Fayetteville well count and total gas series data were highly significant, Granger causing NY and El Paso Permian spots at 1% significance and the Henry Hub, Massachusetts, and both California spots at 5% significance and all with just one lag interval. The Fayetteville average gas series was insignificant to Granger cause any price series, but both California and the Henry Hub spots Granger caused this series with 3 lag intervals. No feedback occurred with the Fayetteville shale. The Haynesville average gas series Granger caused the Opal and both Northeast spots with 4 lag intervals, and the two California price series with 3 lag intervals, all at 1% significance. The series exhibited feedback with California spots and Massachusetts spot series. The Southern spot prices were Granger caused by the Haynesville average series with one lag interval at 5-10% significance. Haynesville well count Granger caused the Southern spots at 5% significance with 1 lag interval. Woodford production data significantly Granger caused all price series except for the Opal. The

average gas series Granger caused both Northeast spots and both California spots with one lag interval at levels of 1-5% significance, and Granger caused the El Paso Permian spot with two intervals at 10% significance. The total gas and well count series Granger caused six out of seven spot prices, with Northeast and California spots again with one interval and at 1-5% significance, while the Henry Hub and El Paso Permian showed various significance. The Woodford average series exhibited feedback with the El Paso Permian spot at two lag intervals and the two California spots at one lag interval. Feedback also showed between the Woodford well count series and the SoCal spot price, with one lag interval.

The Bakken and Marcellus production series made the least significance in the analysis. The Bakken average shale series showed significance to Granger cause the Massachusetts and New York spot prices with 1% and 5% significance respectively with two lag intervals, the El Paso and SoCal spot prices with three lag intervals at 5% significance and the Henry Hub at 10% significance with three lag intervals as well. Well count and total gas variables failed to significantly interact with any price series. The Marcellus average shale series Granger caused both Northeast spot prices at 1% significance with one lag interval, while the total gas production and well count variables Granger caused the NY spot at 5% significance with one lag interval.

Of the 16 feedback relationships shown in Table 2, eight of them were based on the average gas production per month, five were based on the total gas production per month, and three were based off the well count per month. Table 3 summarizes how the three production variables interacted with price data, with average P-value at 5% significance for all but a price series granger causing total production series. The most significant relationships came from well count and average production Granger causing price, with total production not far behind. The summary here shows how causality mostly moved from production series on the price series, although, as described above, there were significant causality flows from prices to production as well. There were 31 relationships that had price granger cause production, while there were 67 relationships that had production granger cause prices.

Figure 4-1 shows that the Woodford was found significant 17 times in causality flows, followed by the Fayetteville at 14, the Barnett at 12, the Haynesville at 10, the Eagle Ford at 8, the Bakken at 5, and the Marcellus at 4. This is what was expected, as the most developed, oldest shale plays, the Woodford, the Fayetteville, and Barnett found the significant the most times. There were more observations with these plays compared to other, less developed shales, and

thus a more detailed, less biased dataset. Meanwhile, Figure 4-2 shows the amount individual price series were significant in Granger tests, in either causality direction. The Transco Zone 6 had the most significant Granger relationships, at 19, while the Algonquin city-gate, the El Paso Permian, the SoCal spot, the PG&C and Henry Hub were no more than 5 relationships behind. The Opal was far back with just 6 significant causality relationships, which was expected.

IV. 2. Discussion

Overall, tests for Granger causality between production and price data came back as highly significant when taking into account relatively small sample size of spot prices. The most developed shale plays in the gas production series were the Barnett, Fayetteville, Woodford, and Haynesville shale reservoirs, and it is not a coincidence that these shales were the biggest players in causality analyses between shale production and prices either. With regards to the impact of the three different production variables-well count, total production, and average-the largest statistical impact was felt with the average production per lease number in a given month. The Haynesville Barnett, Fayetteville and Woodford averages all were highly correlated with the different regional gas prices.

The lag structure had a great impact on the significance of different causality relationships. The hypothesis was made that shale plays would need more lag intervals to significantly cause spot prices geographically farther away. This theory held with some plays and didn’t for others. Average Haynesville wellhead production, in east Texas and west Louisiana, significantly caused West and Northeast spots with 3-4 lag intervals, and average Marcellus wellhead production, in Pennsylvania, West Virginia, New York, and Ohio, significantly caused Northeast spots with just one interval. However, the Arkansas Fayetteville well count and total gas variables significantly caused all price series with only one interval, disproving the theory. When lags and geography do not match up, pipeline infrastructure should be noted, as the pipelines from the Fayetteville to the Northeast and West spots seem very direct.

The Opal spot price was in an interesting geographic location. The price data was organized in a way in which there was two series from the East, two from the West, two from the South, and Opal was ‘on an island.’ As seen in Figure 3-4, Opal breaks away from the rest of the series in 2007 when prices drop to very low levels. Thus, the Opal price series was not integrated with the general price trend. The original hypothesis held that the Opal was the most likely to

hold significance with Bakken shale production, as they are close geographically. This turned out not to be the case, as the Bakken performed poorly in most causality tests. The Opal did have 1% significance as being Granger caused by the average shale production from the Haynesville shale, which potentially points to this region obtaining their gas from this reservoir, as fluctuations in aggregated well performance from the Haynesville shale lowered Opal spot prices.

The Eagle Ford shale well count and sum variables were highly significant in the analysis as well. These production series and the Northeast spot prices had significant feedback between them with 3-4 lag intervals. The relationship here is important to note, as south Texas production is shipped out to the Northeast and with adequate time lags this relationship came through very significant to affect both prices and production in these areas. Eagle Ford well count and sum also had feedback with Texas and Louisiana spot prices with one lag interval, which stresses the importance of gas production to the local regions as well. However, the average Eagle Ford series performed very poorly in causality tests, not showing significance with any price series. Looking back at the series, it shows temporal spikes and is relatively random, thus not surprising that it did not interact with price series data significantly.

Most importantly, despite relatively low levels of production from the Marcellus shale, the reservoir did significantly impact prices in both of the Northeast spots with only one lag interval, while not affecting other spots significantly. This is important because the analysis shows how during the Marcellus shale production time, gas produced went directly to Northeast regional demand and had a significant impact. As the debate as to whether or not to drill for shale gas in the Marcellus rages on, it is important to note that during its peak production times, the resource had a strong impact on regional prices and demand in the Northeast.

Chapter V. Conclusion

Horizontal drilling to extract natural gas from tight shale beds has spurred boomed wellhead natural gas production in the past fifteen years. Meanwhile, deregulation and open access laws of the early 1990s have paved the way for a spot market for natural gas, which is now predicated on regional market competition. This deregulation has opened the way for downstream pricing for natural gas from the wellhead. With a different lifespan and EUR than an average conventional gas well, shale wells have impacted the regional market in different ways.

Using ARDL models and testing production from horizontal drilling against different regional prices, we can assess cointegration within the market through Granger causality tests, which depict how knowledge of past variable values can predict future values of another variable. This technique has been noted in many different studies to test for spot market price integration (Cuddington and Wang 2006; Doane and Spulber 1994), but has seldom been used to test between natural gas production and price to observe integration.

Granger tests came back significant in levels of 1%, 5%, and 10% for anywhere from one to four lag intervals (12-lag scale). There were different insights made from the analysis. First, there was a highly significant effect of the average gas production, per lease number in a given month from the most developed shale plays in the analysis, the Haynesville, Fayetteville, Woodford, and Barnett, and it is known that these shale plays have had an important effect in most regions of the natural gas market. Well count and total production from the Eagle Ford shale in south Texas had significant feedback with the Northeast spot markets, which could speak to a significant pipeline relationship between these two areas.

The Marcellus shale has been near the top of the agenda for most New York, Pennsylvania, Ohio, and West Virginia politicians, and this study shows how production from the Marcellus significantly affected the local supply and demand structure in the Northeast. With the recent USGS survey claiming that there is over 84,000 BCF of undiscovered natural gas within the Marcellus, this analysis shows that if drilling were to commence, the Northeast would have a more reliable, local source of natural gas that could ease residential demand for natural gas and spark industrial demand in certain parts. The recent New England gas crunch is important to note, as the demand for gas in this region has increased to the point where it is considerably above the supply that the Northeast piping infrastructure can handle. Marcellus shale production would give the Northeast a steady supply of gas, independent of the long-

distance piping layout from the Gulf of Mexico, Texas, or the Midwest. The environmental concerns with regards to the water supply must be mitigated and handled appropriately, and if this is feasible then the economic benefit of investing in Marcellus unconventional wellheads would be beneficial for the local and national economy.

Research limitations were centered on the lack of spot prices. When asking whether or not spot prices were affected more by shale plays closer to them, the answer was not always clear. Regions such as southern Louisiana and west Texas, the locations of the Henry Hub and the El Paso Permian spots respectively, have a multitude of gas sources at their disposal. Meanwhile, California and Opal spot locations had little shale resources. These differences made the geographic market for supply and demand difficult to quantify in certain areas. More spot prices and areas of production would have benefited the study.

Suggestions for further research are quantifying environmental costs of hydraulic fracturing in the Northeast, which would give tools to devise a cost-benefit analysis for hydraulic fracturing in this area, as this study made insight into the economic effects of Northeast shale gas drilling . Proper research must be performed to discuss all factors of hydraulic fracturing before tapping into this vast resource. Research could also focus on how conventional gas wellheads, as opposed to unconventional wellheads, move through the natural gas industry and affect regional prices.

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Appendix

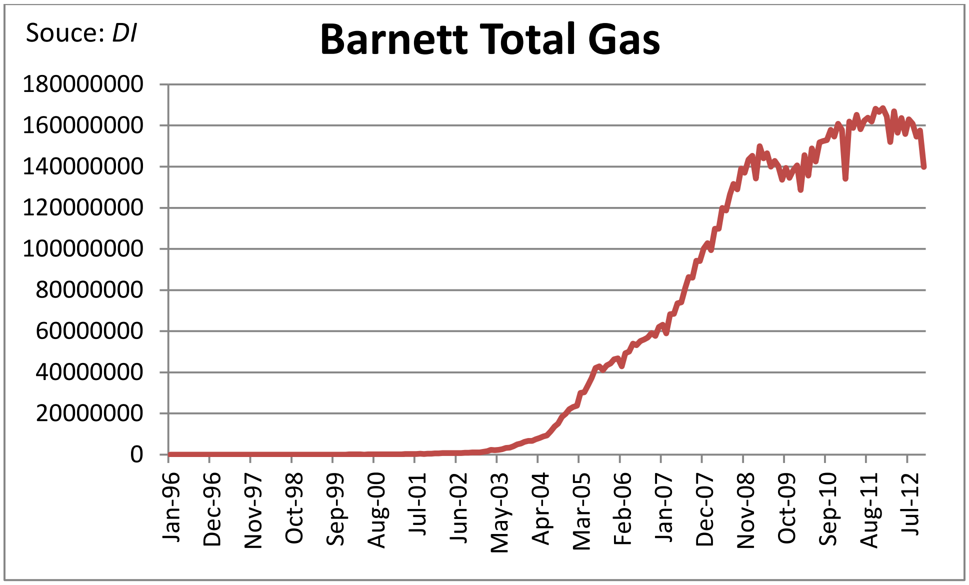

Figure 1. Barnett shale total natural gas production per month.

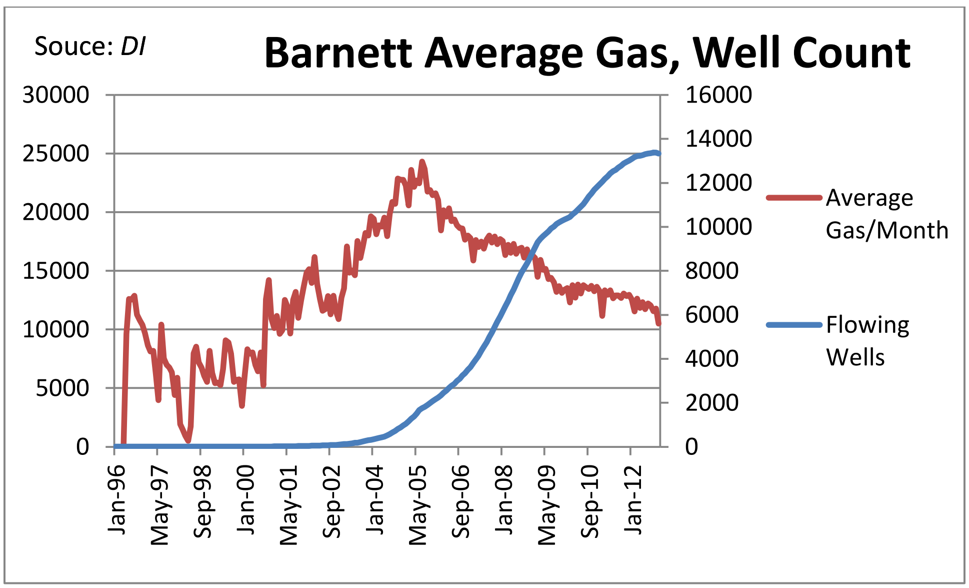

Figure 2. Barnett shale average gas per lease number per month and total flowing wells per month

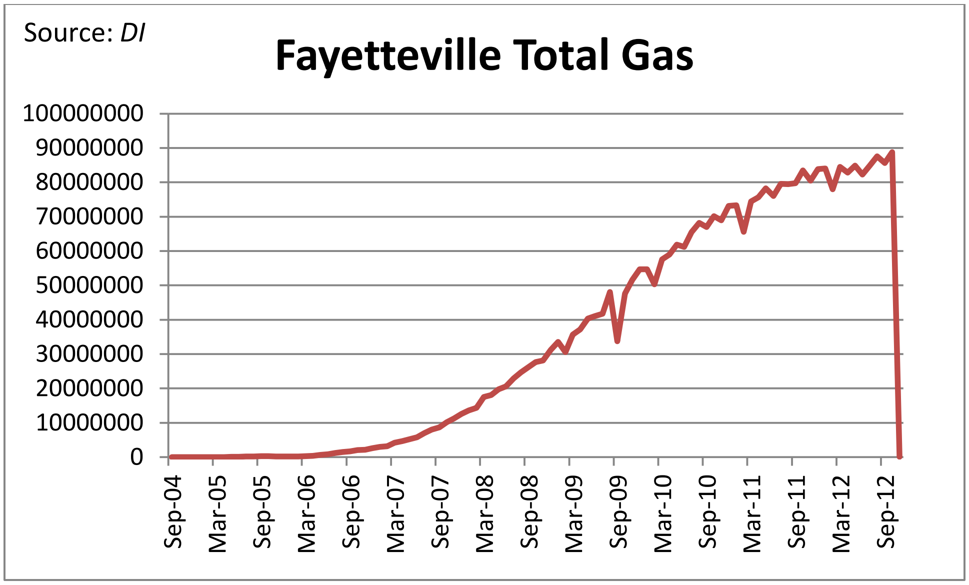

Figure 3. Fayetteville shale total natural gas production per month

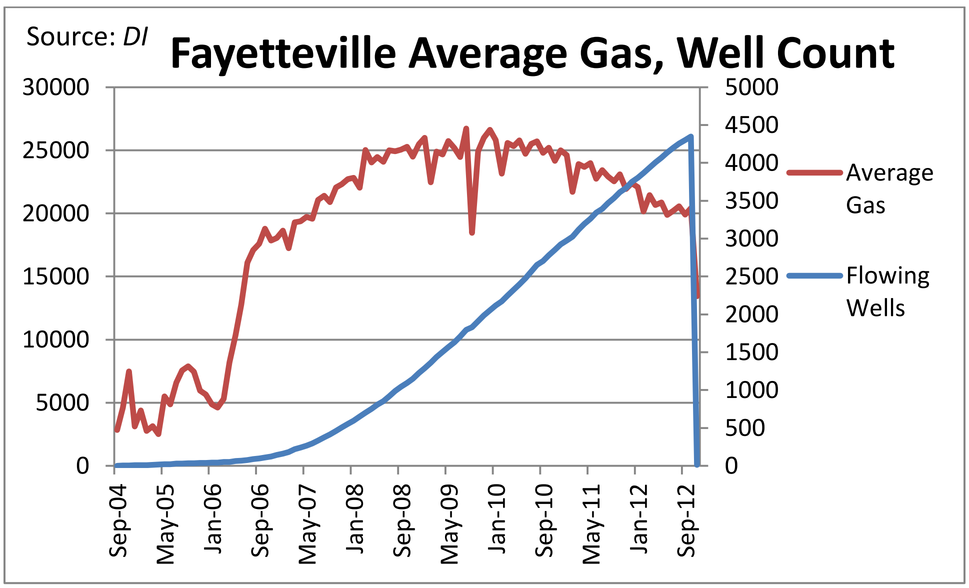

Figure 4. Fayetteville average gas per lease number and well count per month

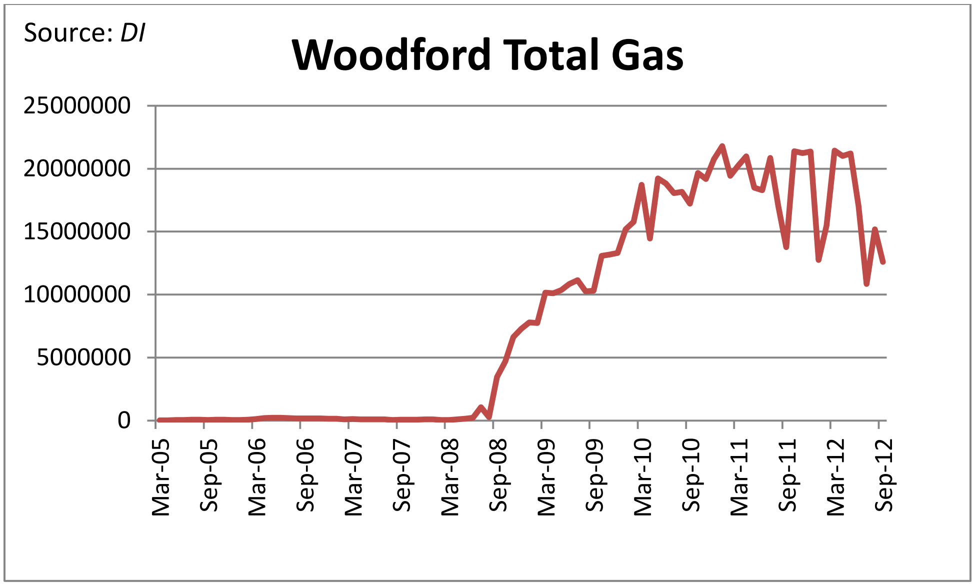

Figure 5. Woodford total natural gas per month

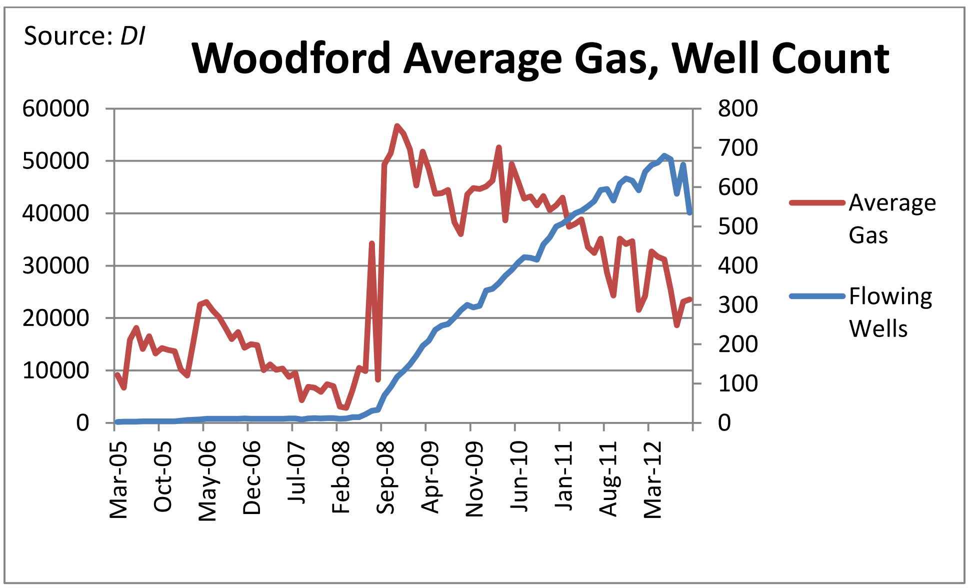

Figure 6. Woodford shale average gas per lease number and flowing well count per month

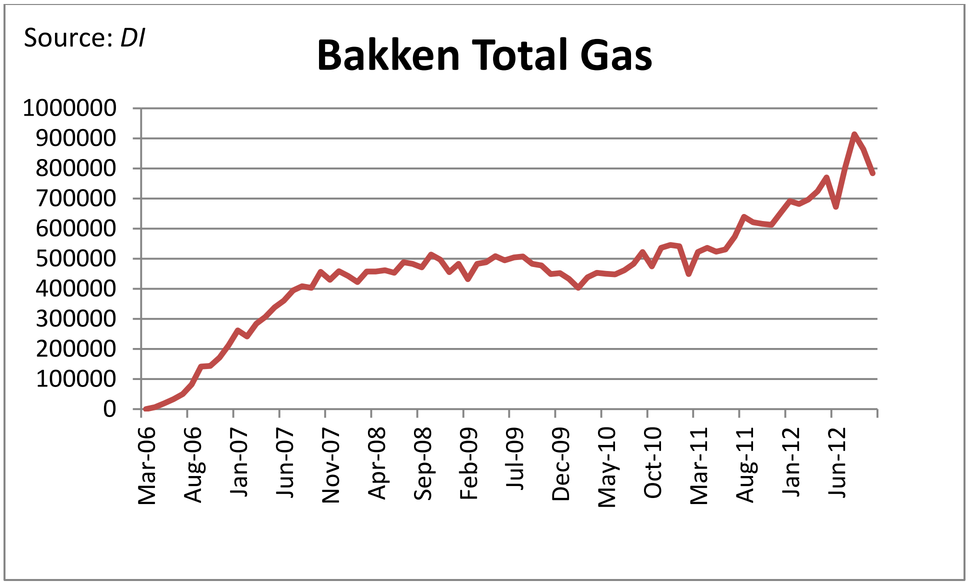

Figure 7. Bakken shale total natural gas production per month

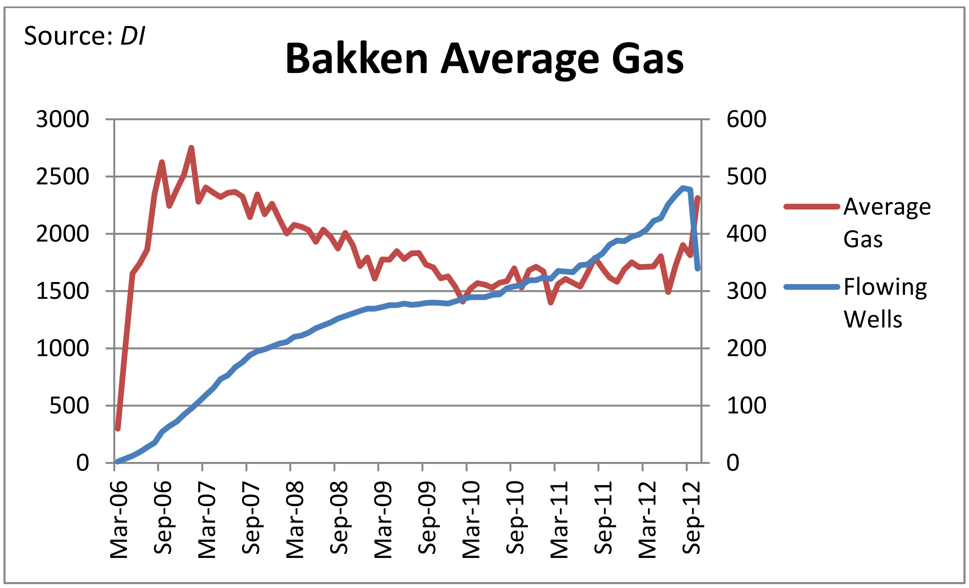

Figure 8. Bakken shale average natural gas per lease number and well count per month

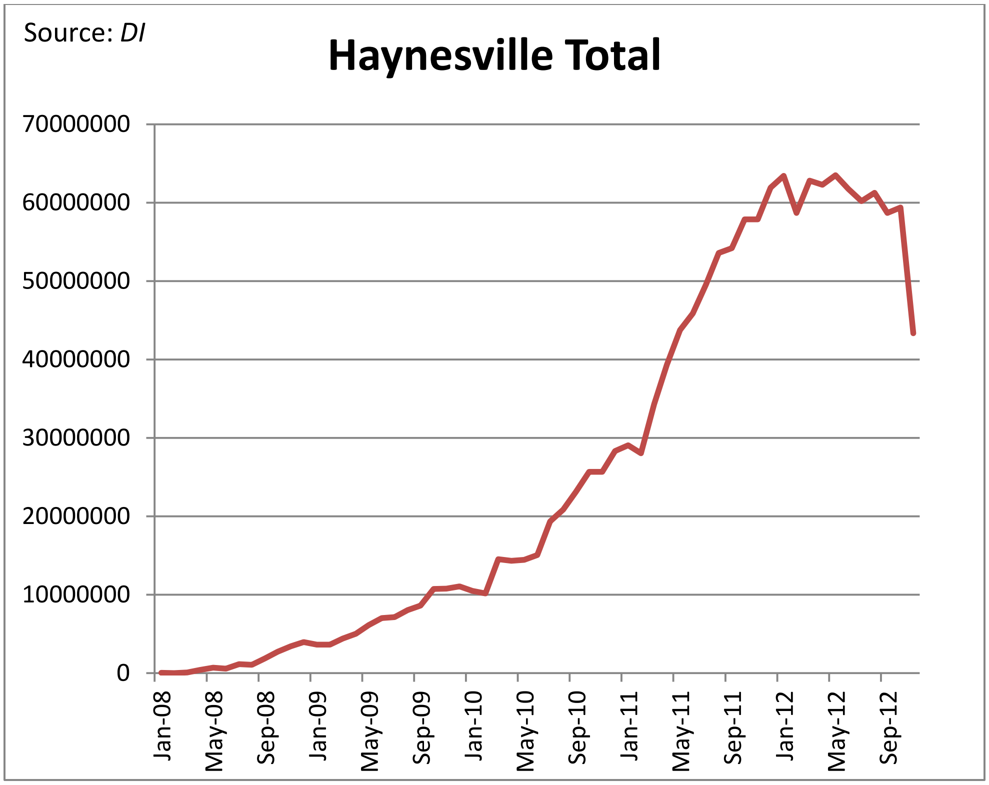

Figure 9. Haynesville shale total natural gas production per month

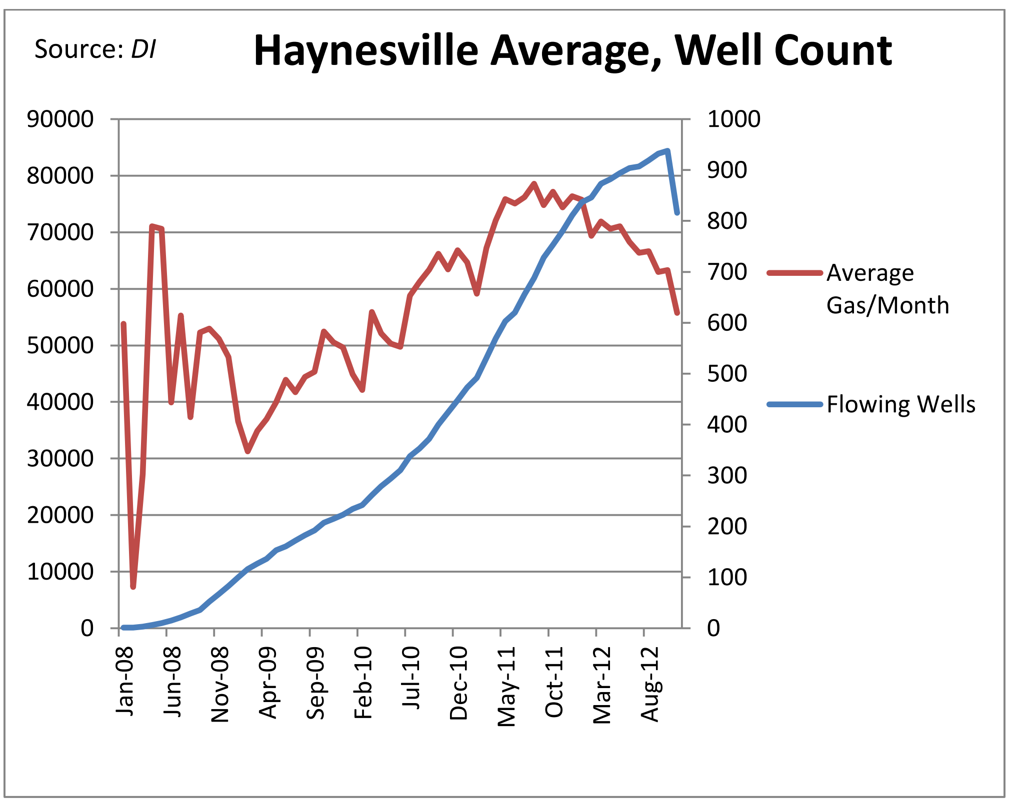

Figure 10. Haynesville average gas production per lease number and well count per month

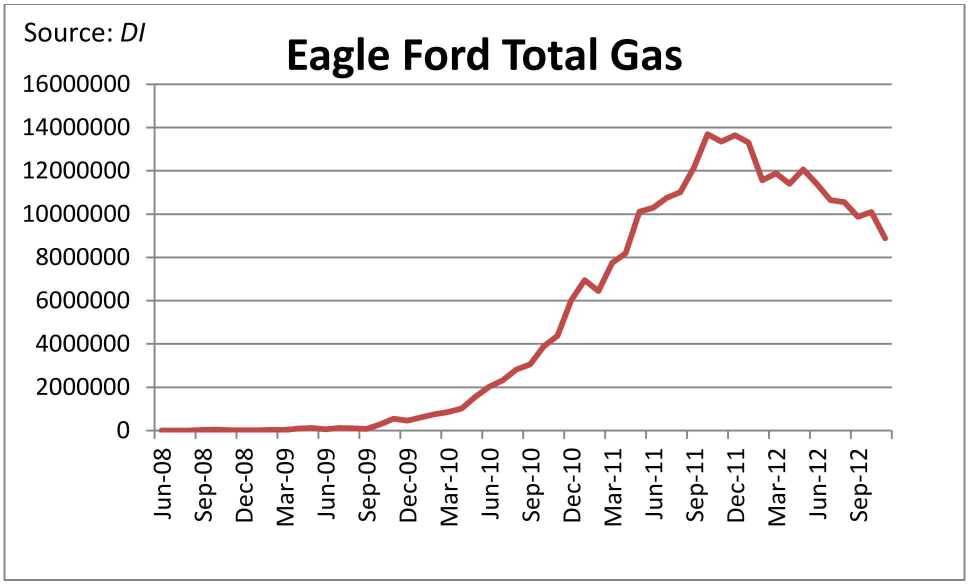

Figure 11. Eagle Ford total natural gas production per month

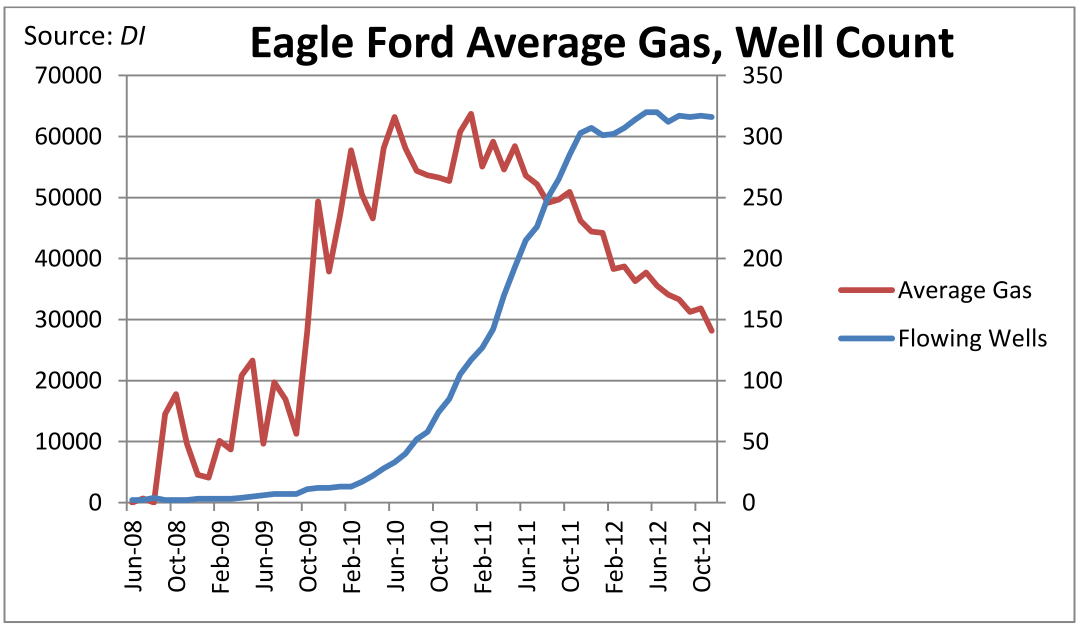

Figure 12. Eagle Ford average gas production per lease number and well count per month

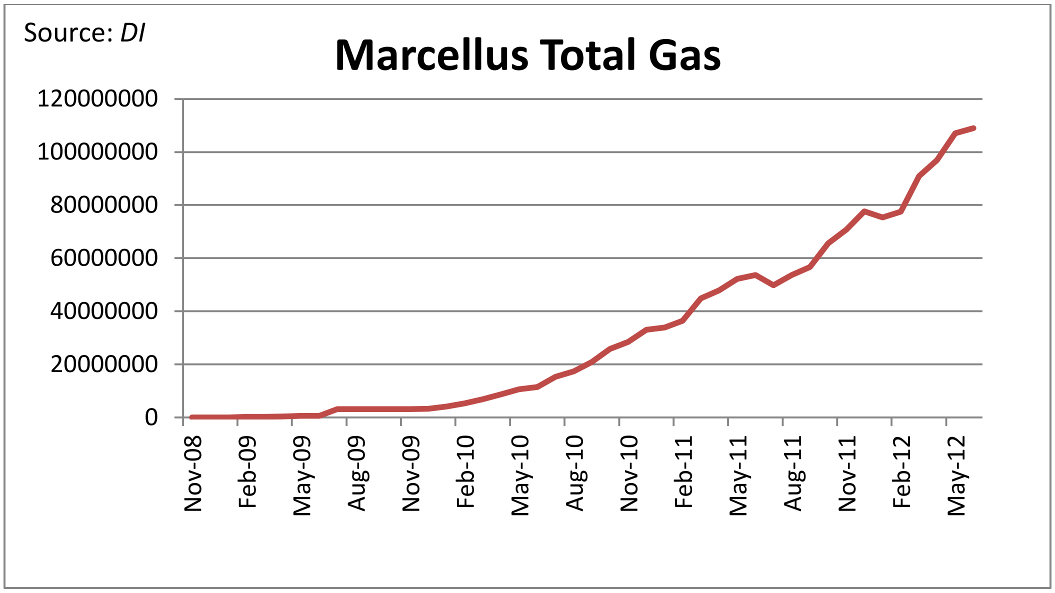

Figure 13. Marcellus total gas production per month

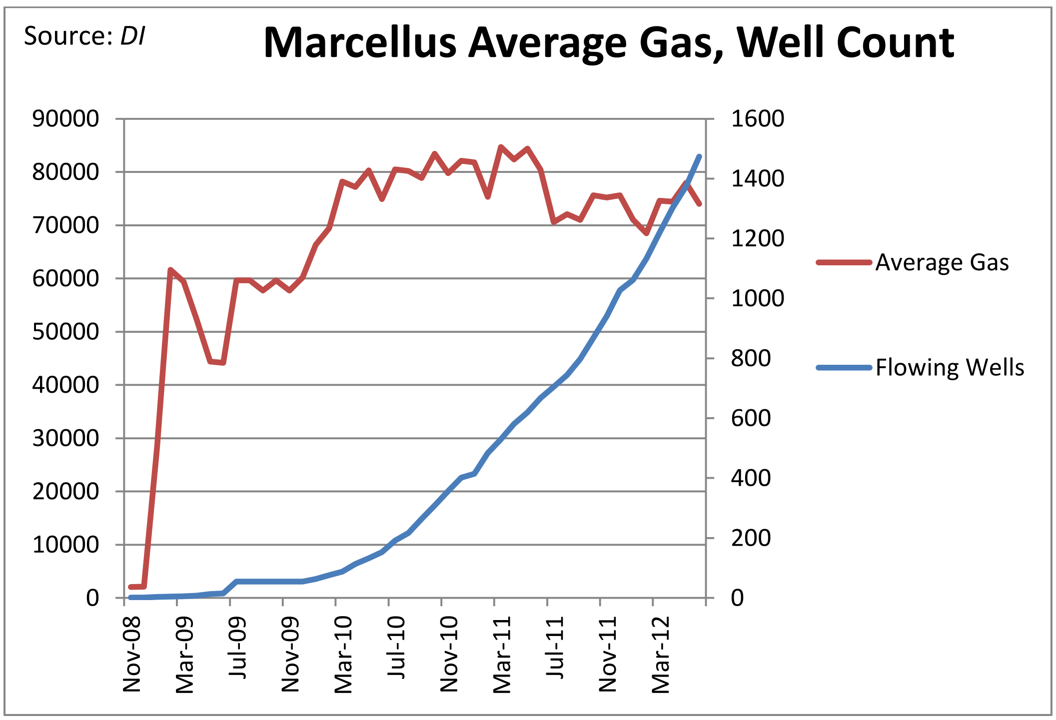

Figure 14. Marcellus average gas production per lease number and well count per month