US SHALE GAS

The Road Ahead

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August 2016

ENERGY POLICY RESEARCH FOUNDATION INC.
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NOTE ON EPRINC'S UPSTREAM RESEARCH PROGRAM

The following report on US natural gas supply was undertaken by Ben Montalbano and Trisha Curtis and is part of EPRINC's multi-year research program to provide a thorough understanding of the scale and scope of the North American petroleum renaissance. Ben Montalbano is a Trustee at EPRINC and co-founder of PetroNerds, a Denver based consultancy. Trisha Curtis is a non-resident fellow at EPRINC and also a co-founder of PetroNerds.

This assessment examines the capacity of the domestic unconventional natural gas reserve base to expand output to meet potential growth in domestic and international demand for US gas supplies. Although low natural gas prices present an array of challenges, the authors show that given the massive size of the US natural gas reserve base, domestic gas production is likely to grow substantially in the coming years and remains capable of meeting a broad range of possible demand scenarios given existing and likely improvements in extraction technologies. Although government policies could restrain supply growth, most uncertainties on the future of natural gas are on the demand side. This assessment is in many ways a companion analysis to the report published by EPRINC in December 2015 entitled US Shale Oil Dynamics in a Low Price Environment which can be downloaded at this link from the EPRINC website.

This report and all of EPRINC's publications are available, without charge, on our website.

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- The growth in US natural gas supply is supported by a growing reserve base which has seen sustained additions since 2004. The remarkable and rapid growth in US gas reserves is the direct result of advances in horizontal drilling and hydraulic fracturing which permitted access to reserves in so-called unconventional formations. The US has seen average annual additions to the natural gas reserve base over the last 10 years from 20-60 tcf and official estimates from the US government place recoverable natural gas reserves in excess of 388 trillion cubic feet.

- Shale gas currently accounts for approximately half of US natural gas production. It has raised US natural gas production growth of 30 bcf/d since 2006 and has offset over 10 bcf/d of declines from legacy sources such as the offshore Gulf of Mexico and conventional onshore gas production. Today gas production from Pennsylvania and Ohio, the Marcellus and its liquids rich neighbor the Utica play, is responsible for nearly all shale gas production growth since 2010.

- Although low oil prices have brought about a decline in oil production from unconventional reserves, associated gas production has declined at a slower rate than either oil and liquids production or gas production from primary gas wells. In North Dakota (Williston Basin) gas production increased as oil production stagnated in 2014 and has held steady since the start of 2015 whereas oil production has declined by 15% during that same period. Total gas production from the Permian Basin has grown by almost 3 bcf/d since 2010.

- Natural gas consumers across all sectors have adjusted quickly to the newfound abundance of gas and the lower prices it has ushered in. US Demand for natural gas increased by 16 bcf/d from 2006 through 2015, a 27% increase. The power sector in particular has rapidly accelerated its use of natural gas. Gas deliveries to electric power consumers (gas-fired power plants), rose by almost 10 bcf/d to 26.5 bcf/d over the 2006-2015 period, a 68% increase.

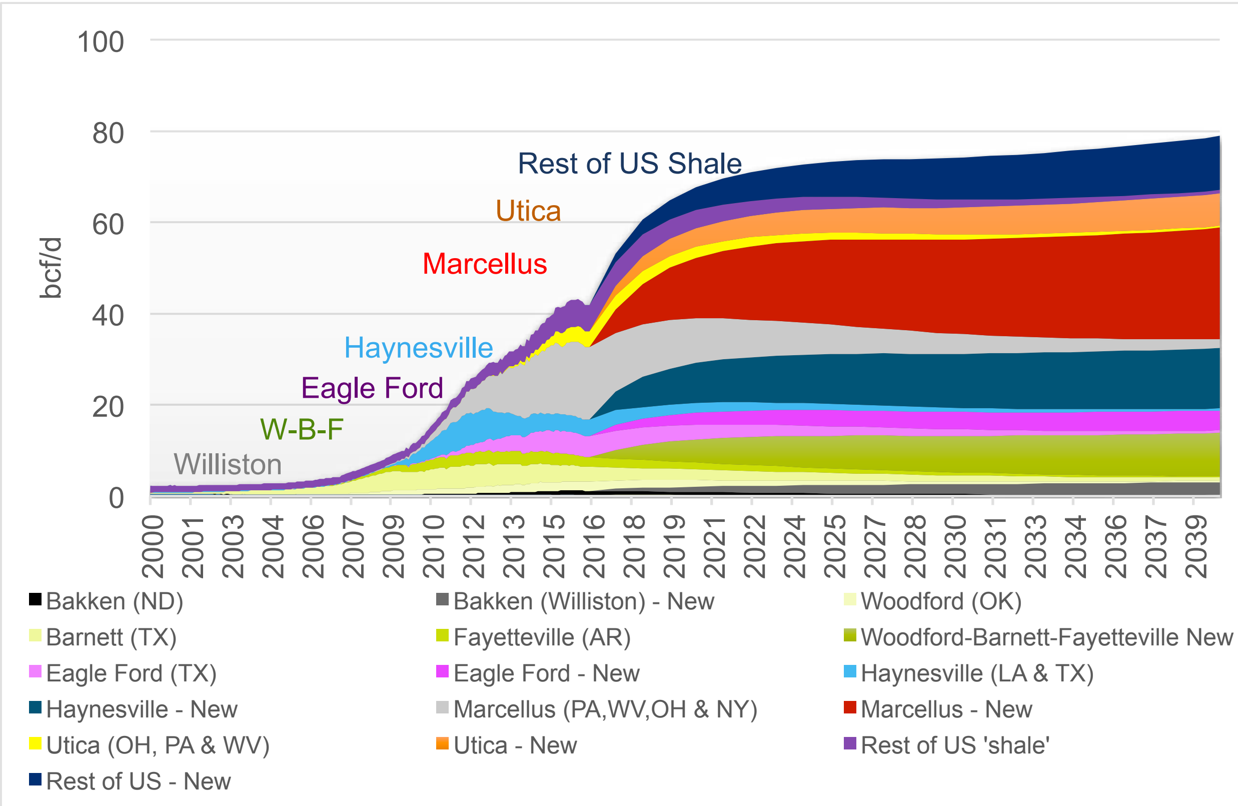
- A combination of improved drilling efficiencies, advances in extraction technology, and rising reserve additions all point to the prospects that large volumes of domestic natural gas can be produced at costs below $4 mcf .

- There are several market-based factors that will escalate demand for natural gas over the next several decades. These factors include ongoing additions of natural gas fired power generation capacity, rising LNG exports, increasing industrial use of gas, and growing demand for gas in Mexico. On the policy side, the proposed Clean Power Plan (CPP) to lower the emission of greenhouse gases (GHGs) into the atmosphere could increase demand growth for natural gas in the power sector as well as accelerate the timeline for uptake. Initial reviews of the CPP, now held up in the courts, suggest it will have a modest impact on the natural gas demand. The long-term implications of the CPP on natural gas demand remain uncertain.

- Given rising domestic demand and likely growth in LNG and pipeline exports, US production would have to add over 1.6 bcf/d per year between 2015 and 2040 to meet demand. This is far less than the 2.5 bcf/d that was added annually between 2006 and 2015. US has more than adequate reserves to sustain 1.6 bcf/d per year growth over the next 25 years.

- The authors evaluated the performance of horizontal drilling rigs between 2010-2015 and developed a forecast model evaluating rig deployment, drilling times, completion and production schedules, and decline curves aggregated across each play or plays. These decline curves, depending on the play, are generally indicative of wells brought online in 2014 or 2015, yielding a forecast that is likely conservative. This model's results are shown in the figure below.

Base Case Shale Gas Forecast by Play



Source: PetroNerds calculations, EIA and DrillingInfo Data

- The size of the unconventional natural gas resource base combined with continuing emergence of new extraction technologies and improved efficiencies in drilling operations all point to significant production growth in the coming decades. An expansion of 40 bcf/d by 2040, or 50 percent above current production is well within the potential of the US petroleum industry.

- US shale supplies can meet large volumes of incremental demand even without major advances in extraction technology. Shale producers have shown that they can expand production at $6/mcf, $4/mcf, and even $2/mcf (under certain conditions). Continued evolution of shale extraction technology and ever-improving knowledge of the rocks will enable shale gas production growth for years to come.

- There are always uncertainties in any production forecast, but uncertainties regarding the future of US shale gas supply are largely relegated to uncertainties in demand and whether future government policies regulating gas development will remain cost-effective.

INTRODUCTION

United States shale gas production has grown continuously, with scarcely a stumble, since 2006. Production has climbed through a major recession, two commodity cycles, the prolonged fall of natural gas prices from $10/mcf to $2 mcf, an oil boom and bust, and even the scrutiny of Hollywood. It is the 2014 collapse of oil prices, and corresponding fall in the value of liquids produced in shale gas plays, that has finally, and temporarily, reigned in the growth of shale gas production.

The pause and now emerging decline of US shale gas production arrives at a noteworthy time. Industry observers and participants alike have for many years described shale gas, and in turn natural gas, as a major potential export product, a low-cost feedstock that could facilitate a manufacturing renaissance, and as a bridge fuel or transition fuel, a fuel that provides a lower carbon alternative to coal and oil while carbon-free renewables continue to evolve and work themselves into the market. Natural gas is expected to wear many hats, so to speak. It appears that the time for natural gas to fill these economically critical roles, which could require 40 billion cubic feet per day of additional production between now and 2040, is upon us.

The first cargoes of a new wave of LNG exports departed the Gulf of Mexico this year. Mexico is expected to continue taking increasing volumes of pipeline gas from the United States. Nearly 20 GW (gigawatt) of natural gas fired power generation is anticipated to come online between 2016 and 2018, largely at the expense of coal fired power generation. The controversial Clean Power Plan could further accelerate the retirement of coal plants, thus providing a boost to natural gas power generation. The fortunes of a vast sector of the economy and numerous government policies and desires are riding on the ability of natural gas producers to increase shale gas production in the coming years and yet all of this culminates at a time when the economics constrain the expansion of shale gas production volumes.

This report examines future natural gas market supply and demand expectations and the ability for shale gas production to meet future market needs.

US natural gas production has been remarkably resilient in recent years, despite a prolonged period of exceedingly low prices for natural gas and scant drilling activity. This growth occurred on the back of shale and tight gas production, which has increased to over 43 bcf/d (billion cubic feet per day) from just 3 bcf/d at the start of 2006 and now accounts for half of US natural gas production. Much of this growth occurred during a period of pricing for natural gas below $4/mcf (per thousand cubic feet), and often less than $3/mcf.[1]

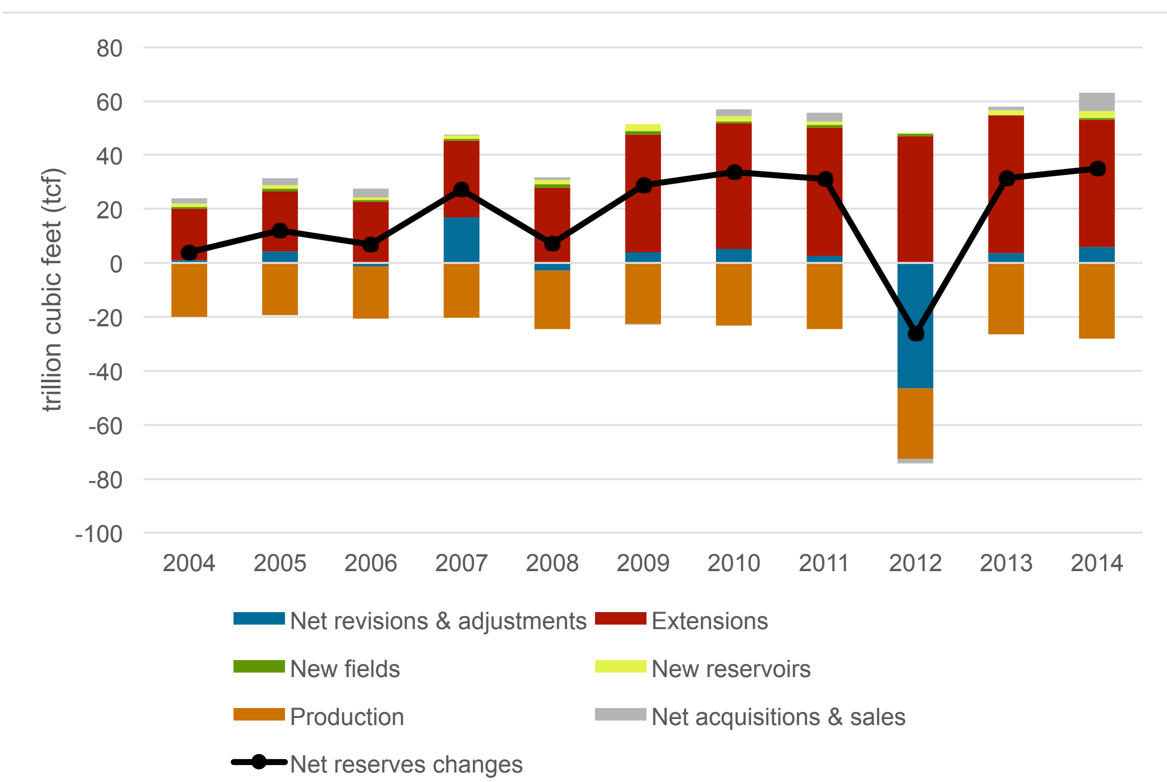
The growth in US natural gas supply is supported by a growing reserve base which has seen sustained additions since 2004. The remarkable and rapid growth in US gas reserves is the direct resultof advances in horizontal drilling and hydraulic fracturing which permitted access to reserves in so-called unconventional formations. As shown in Figure 1 the US has seen average annual additions to the natural gas reserve base over the last 10 years of 20-60 tcf a year. EIA estimates that the US has 388 trillion cubic feet of recoverable reserves. Although the EIA estimate is a massive volume by any measure, improvements in technology and efficiencies in extraction of natural gas will likely see the reserve gas grow in the coming years.

The remarkable and rapid growth in US gas reserves is the direct result of advances in horizontal drilling and hydraulic fracturing

Figure 1

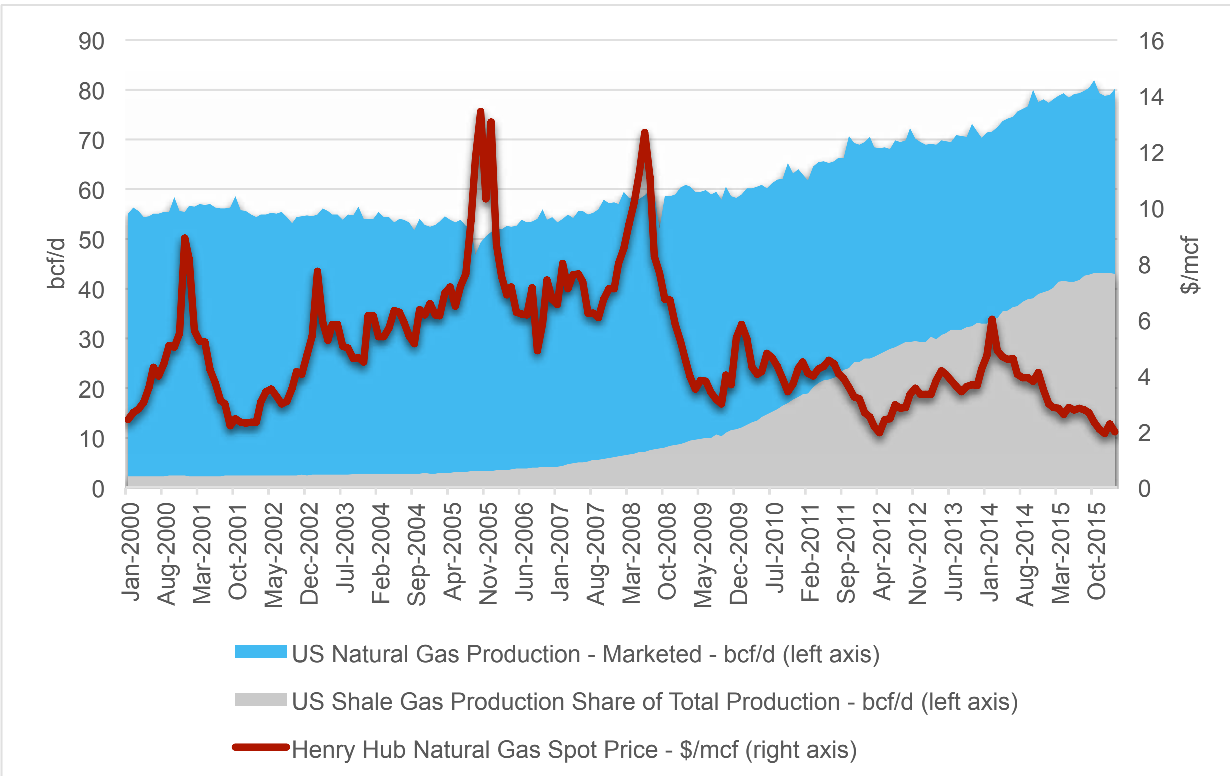
Changes in Proved Reserves of the United States, 2004-2014

(trillions of cubic feet of natural gas)



Production volumes have grown rapidly from 2010 through 2015 despite an average spot price $3.65/mcf over that time period. Prices averaged nearly $7 per mcf from 2004 through 2009. Total shale and unconventional tight gas production has grown to over 43 bcf (billion cubic feet) from just 3 bcf per day at the start of 2006 and accounts for half of US natural gas production[2]. This growth has been led by shale and tight gas production, with the Marcellus reservoir being the primary driver in recent years. However, after more than a decade of rapid growth, shale and tight gas production is taking its first prolonged breather. Nationwide shale gas production growth halted in late 2015 and began to reverse at the start of 2016, as shown in Figure 2 below.

Figure 2
U.S. Natural Gas and Shale Gas Production with Henry Hub Prices

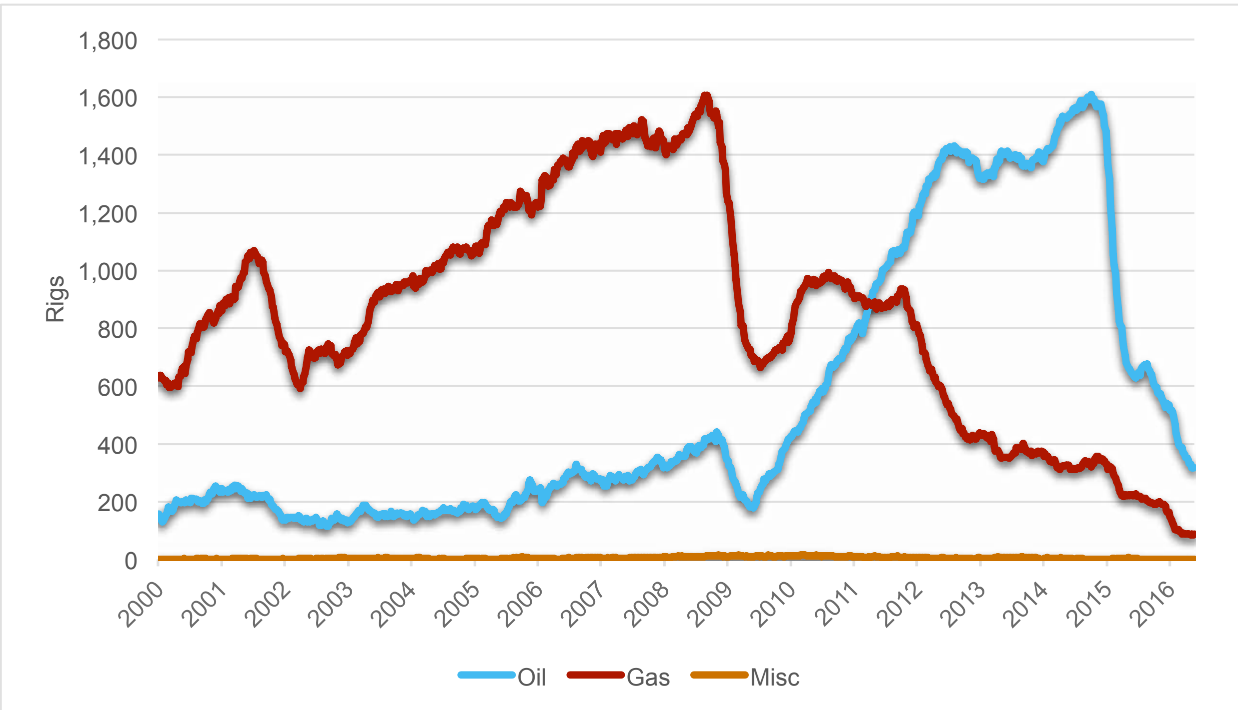


Source: EIA Data, EPRINC/PetroNerds Calculations

Fewer than 90 gas directed drilling rigs were active in the US as of May, 2016, as indicated in Figure 3. From late 2012 through 2014, the gas directed rig count remained relatively stable at about 400 rigs. This represents only one fourth of the 1,600 gas directed rigs that were active in 2008 prior to the oil and gas price collapse, and half of the 800-1,000 rigs that were active from 2009 to 2011 when Henry Hub prices hovered in the $4-$6 mcf range. However, 400 rigs, largely of horizontal trajectory, in combination with improvements in drilling and completion practices, a move to the Marcellus shale, $100 per barrel oil prices, and strong values for associated liquids and NGLs (natural gas liquids) proved sufficient to keep shale gas growth expanding at its post-2009 pace.

Many so-called gas wells produce significant volumes of associated liquids. These liquids provide additional revenue to producers and are often the difference between a well delivering positive or negative returns. As certain associated liquids, particularly condensate, are often tied to the price of oil, a drop in oil prices will also reduce the economic viability of a 'wet' gas well. So when oil prices began to collapse in the fall of 2014, the economics of drilling for natural gas deteriorated too. This removed one of the few remaining incentives for operators to continue drilling for natural gas and, in combination with $2/mcf gas prices, accelerated the reduction in the gas rig count from 400 rigs to less than 100. Similarly, natural gas drilling activity has also declined with oil prices as some oil producing companies have significant natural gas producing assets and paired back capital expenditures across their asset portfolio to preserve cash.

Figure 3
U.S. Oil and Gas Rig Count

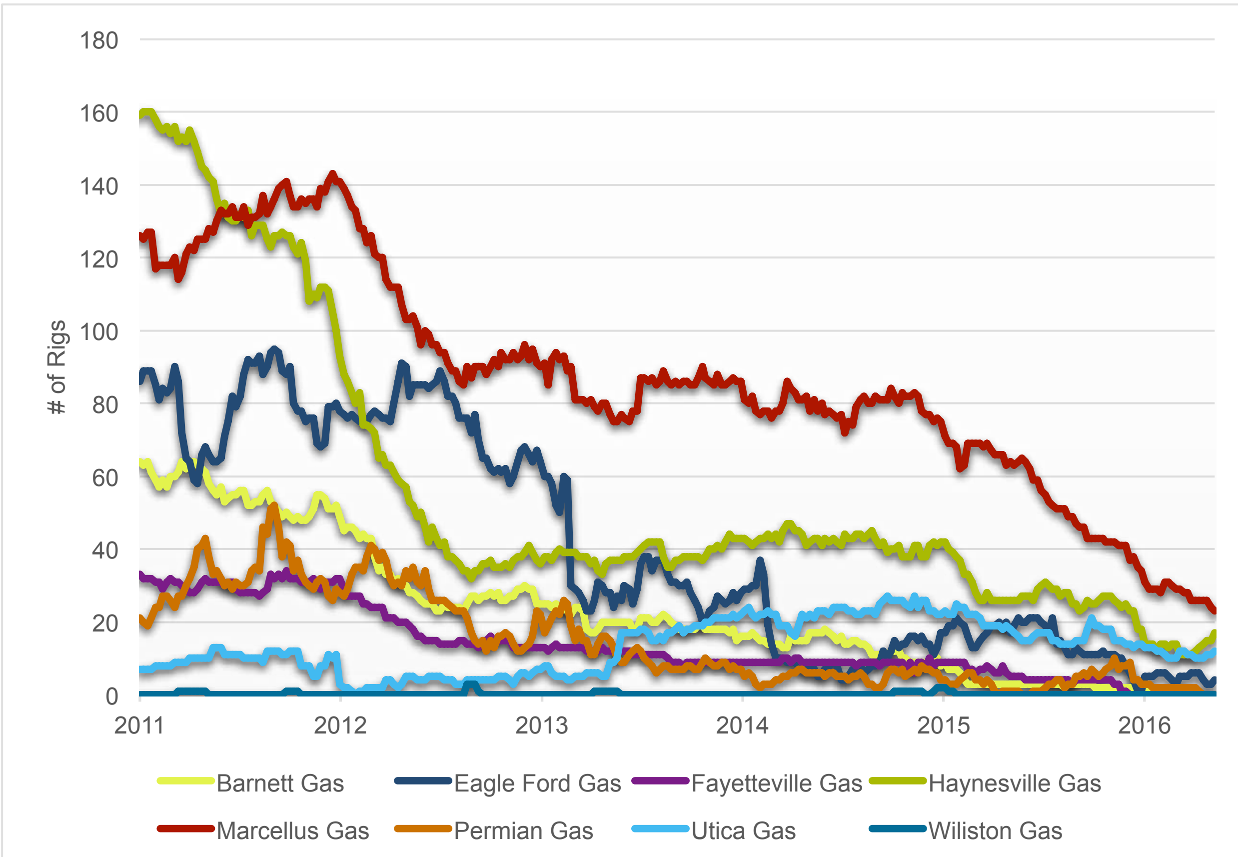


Source: BakerHughes Data

Many so-called gas wells produce significant volumes of associated liquids. These liquids provide additional revenue to producers and are often the difference between a well delivering positive or negative returns.

Thirty-seven of the 87 active gas rigs are located in the Utica and Marcellus and in the wet gas plays in the Appalachian basin. An additional 15 rigs are located in the Haynesville shale play in East Texas and West Louisiana. Figure 4 shows all active gas directed drilling rigs by basin.

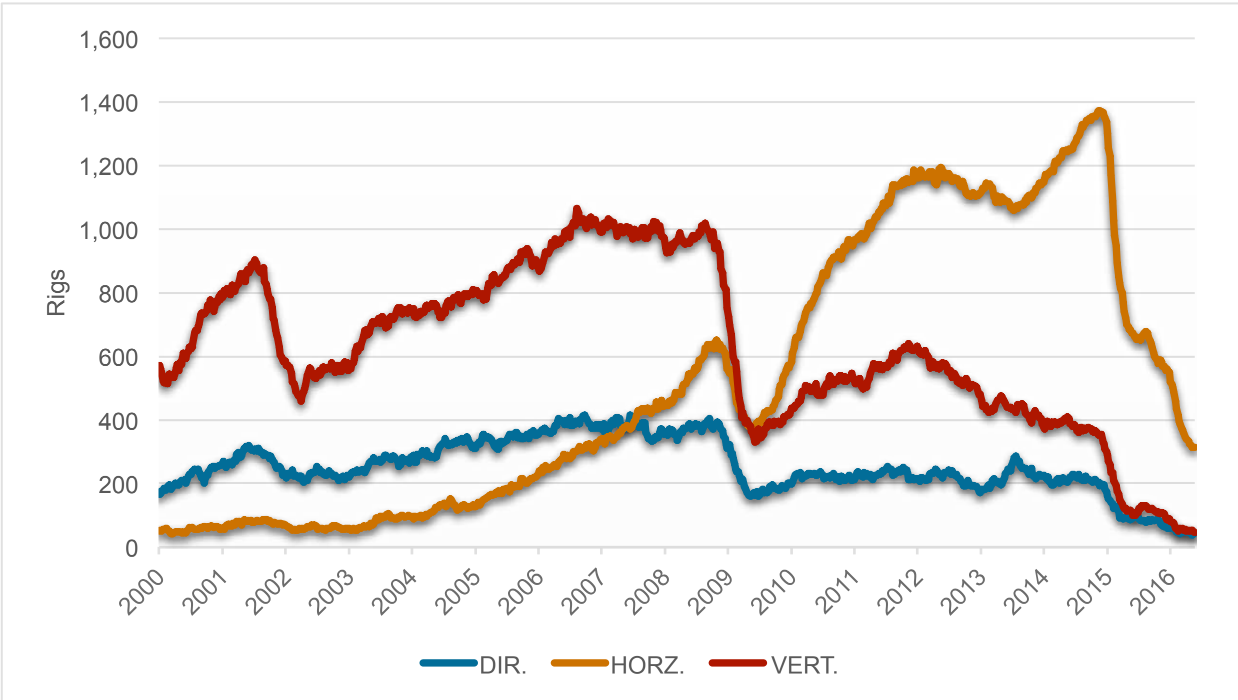
Figure 4
U.S. Gas Rig Count by Basin



Source: BakerHughes Data

Horizontal drilling has played a key role in the shale gas revolution, but it was not until after the 2009 financial crisis and commodity collapse that horizontal drilling came to dominate the drilling scene. Horizontal and directional drilling rigs represented a minority of the total US rig count until the commodity price crash in 2008. The vertical rig count never recouped its losses during the economic recovery as horizontal drilling dominated most shale plays during the recovery (Figure 5). The move to horizontal drilling is a key component of the productivity gains that enabled producers to more than double shale gas production from 2010 to 2015, despite a gas directed rig count that was, at most, half of its pre-crisis peak.

Figure 5
Rig Count by Trajectory



Source: BakerHughes Data

Several factors remain in place to encourage operators to continue drilling for oil and gas despite low wellhead values. Drilling and completion costs have come down across the country due to the surplus of rigs, completion crews, and other services. This helps to offset the impact of lower revenues from oil and gas production. Depending on the operator and geology, some shale plays therefore remain economic as certain well EUR (estimated ultimate recovery) factors enable producers to generate a positive return on investment over the life of a well, even in the current price environment. A typical 2015 Marcellus well will have a 10-year gas EUR of 5.73 bcf. This gas is worth $14.3 million at a price of $2.50/mcf, far greater than the estimated $6 million cost to drill and complete a Marcellus well in 2015, and does not account for the thousands of barrels of liquids that will be produced (nor does this calculation account for costs such as acreage acquisition, royalties, operating expenses, and overhead).

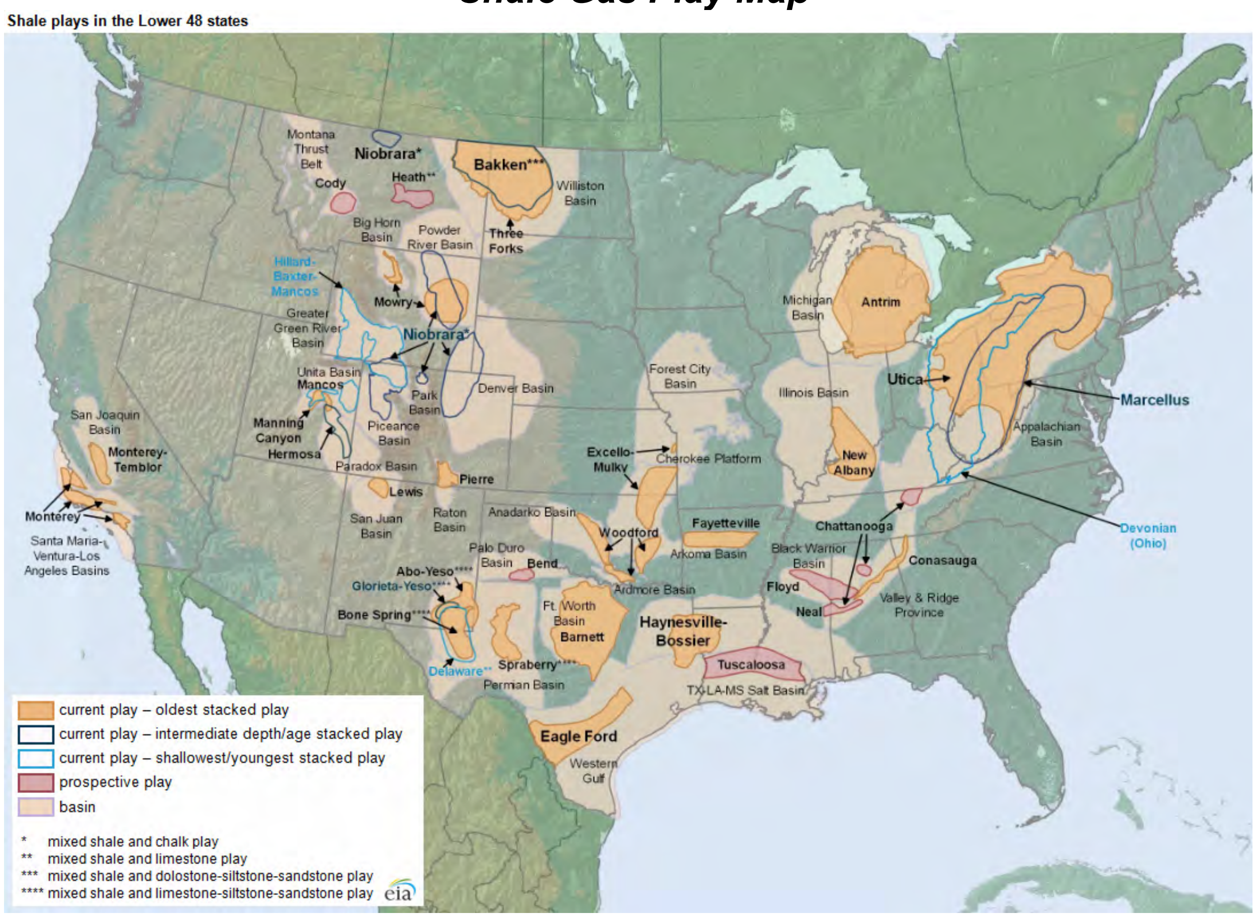
Additionally, certain operators remain hedged at a higher price point than prevailing spot prices, meaning they effectively sell their products for above market price. In many cases, operators are required to drill a lease within a certain time period in order to prevent that lease from expiring. Operators could be inclined to drill a lease in order to retain it. The well may have a poor economic performance in the near term, but its value may be substantial over a longer time period. Given that the Marcellus has been active since 2010 and well economics have been positive for most of the time period, we expect most operators to continue producing to hold their acreage position.

Many well-capitalized producers are using the current commodity collapse to reassess their operations, practices, and technologies. As a result, it is likely companies will return from the price collapse with a renewed focus and shrewder approach, even if nothing is as game-changing as the switch from vertical to horizontal drilling appears on the horizon.

THE MAJOR SHALE GAS PLAYS

Shale gas currently accounts for approximately half of US natural gas production (Figure 6). It has not only powered overall US natural gas production growth of 30 bcf/d since 2006, or 60%, but it has also offset over 10 bcf/d of declines from legacy sources such as the offshore Gulf of Mexico and conventional onshore gas production. The Barnett shale in Texas was the first shale gas play to emerge and did so in earnest in 2006. It was soon followed by the Haynesville, the Fayetteville shale in Arkansas, and the Woodford shale in Oklahoma. These plays are largely languishing now as capital shifted towards oil and more liquids rich gas plays after oil prices began to recover in 2009 and gas prices stagnated. Among the most recent shale gas plays to emerge was the Marcellus in 2010. The Marcellus, along with its neighbor, the liquids rich Utica play, is responsible for nearly all shale gas production growth since 2010 and is the current workhorse of the shale gas revolution.

Figure 6
Shale Gas Play Map

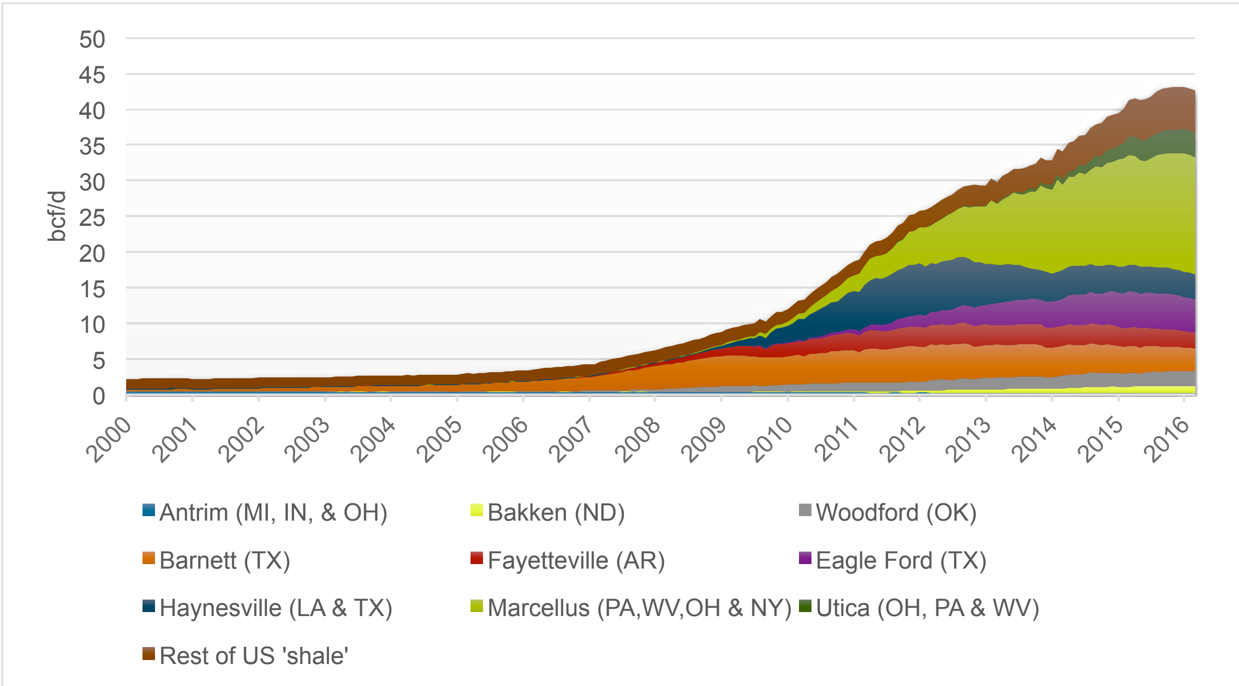


Source: EIA

The Marcellus, shown along with other shale gas plays in the map above, currently produces over 16 bcf/d of gas and the Utica adds an additional 3.5 bcf/d of gas. These two Appalachian Basin shale plays, located primarily in Pennsylvania, West Virginia, and Ohio, account for about 48% of US shale production and one quarter of all US gas production. They also produce a combined 120,000 to 130,000 b/d of liquid (mostly condensate from the Utica).

Figure 7 shows natural gas production broken down by major shale play and includes gas production, largely associated gas, from the Bakken and Eagle Ford oil plays.

Figure 7
Gas Production by Major Shale Play



Source: EIA data, PetroNerds calculations

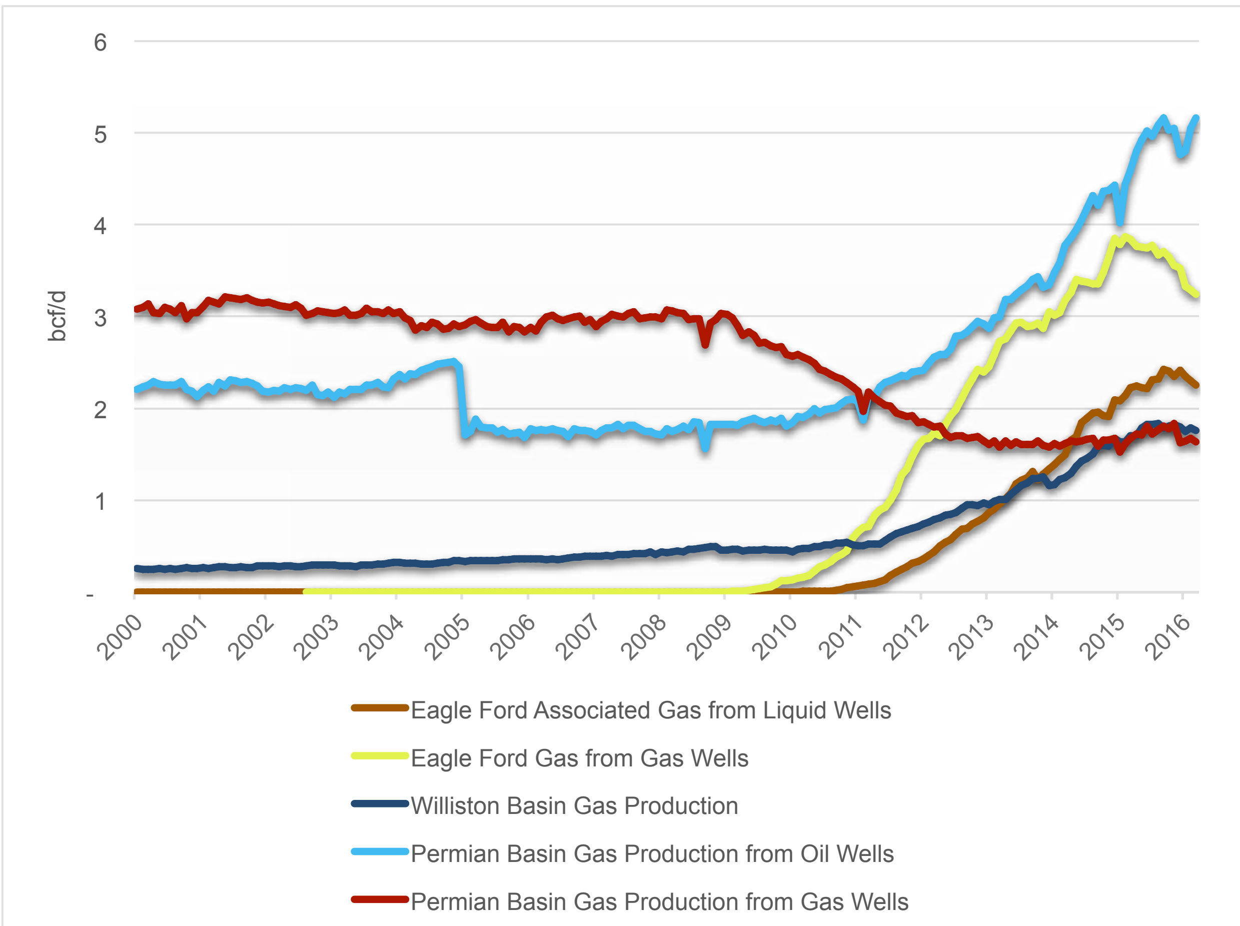
Also as shown in Figure 7 above, the Marcellus, Utica and "Rest of US 'shale" have offset the declines afflicting nearly every other shale gas play. "Rest of US 'shale'" includes oil and liquids plays such as the Anadarko Basin, portions of the Permian Basin, and the Denver-Julesburg Basin, among others. This raises an important and often controversial point. The shale gas plays in decline such as the Haynesville and Barnett are not necessarily on a permanent downwards trajectory, nor are they are 'tapped out' or at 'peak gas.' Rather, the prevailing economics of these and other shale plays, particularly those in Texas and the greater Gulf of Mexico region, are poorer than nearby liquids plays and shale plays in the Appalachian and Williston Basins. Capital has accordingly chased those more lucrative plays in recent years, as indicated by the current rig count. These plays are simply not attracting the capital required to add wells and offset declines. But this situation could change if and when either or both the price environment improves and/or cost saving extraction technologies are deployed.

The plays depicted in Figure 7 are, in aggregate, experiencing their first prolonged volumetric production declines since the beginning of the shale revolution in 2006. Shale gas production growth is taking its first pause, albeit years later than many would have expected given the poor price environment. Few would have predicted several years ago that production volumes would grow throughout much of 2015 given years of sub-$4/mcf gas and an oil price collapse in 2014. This speaks volumes to the resiliency of these plays, the ability of producers to cope with a low price environment, and the application of new and more cost effective technologies. Conversely, there is certainly evidence of cost-cutting that favors near-term cash flow generation, something many companies need to survive the current downturn and service debt, at the expense of long-term productivity. This has served to boost production in certain areas despite economics that might otherwise be considered marginable.

Associated Gas

In both the Williston Basin (Bakken) and Eagle Ford, associated gas production[3] has declined at a slower rate than either oil and liquids production or gas production from primary gas wells. Williston Basin gas production actually increased as oil production stagnated in 2014 and has held steady since the start of 2015 whereas oil production has declined by 15% during that same period. Eagle Ford associated gas production grew throughout 2015 while Eagle Ford liquids production dropped by about 20% and has far outperformed the dry gas portion of the play. Permian Basin associated gas production has more than doubled since 2010 as oil drilling activity reinvigorated the Permian. Total gas production from the Permian Basin has grown by almost 3 bcf/d since 2010. Figure 8 below shows associated gas production, and where applicable primary gas production, in the Eagle Ford, Permian Basin, and Williston Basin.

Figure 8
Primary and Associated Gas Production in Selected Oil Plays



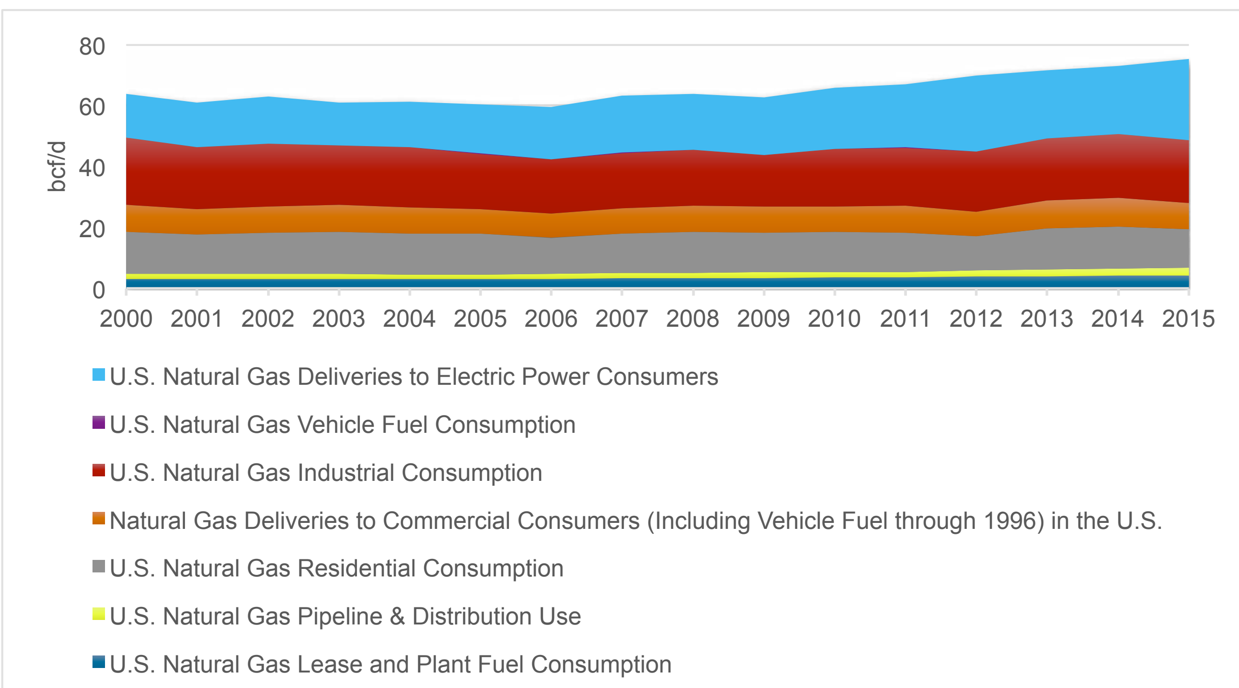
Source: DrillingInfo raw data

Several factors have contributed to the growth and relative stability of associated gas production. For one, there has been greater drilling activity in areas with higher gas to oil (GOR) ratios in recent years. A second factor is the bubblepoint. As oil wells mature and pressure drops, they reach a bubblepoint. This is the point at which gas that has been contained in the oil solution are now able to escape the solution due to the decrease in pressure. This leads to increased gas production relative to oil production. Above ground management (and measurement) of gas production has improved as well. Gathering and processing capacity has grown, particularly in the Williston Basin, and more gas is being captured and sold rather than flared.

Demand for natural gas in the US stagnated prior to the emergence of shale gas in 2006, in large part due to high prices and slowing production. Daily demand declined from 63 bcf/d in 2000 to 59 bcf/d in 2006. Henry Hub prices traded in the $6-$8 range (in nominal dollars) during much of this period. The monthly average price occasionally spiked above $8/mcf. Imports were rising to offset declining domestic production. The expectation at the time was that the US would be short natural gas and gas prices would remain elevated. Billions of dollars of investments were made to construct LNG receiving terminals in the Gulf of Mexico. Some of these terminals are now being reversed to export LNG to the global market.

Natural gas consumers across all sectors have adjusted rather quickly to the newfound abundance of gas and the lower prices it has ushered in. US demand for natural gas increased by 16 bcf/d from 2006 through 2015, a 27% increase. The power sector in particular has rapidly accelerated its use of natural gas. Gas deliveries to electric power consumers (gas-fired power plants) rose by almost 10 bcf/d to 26.5 bcf/d over the 2006-2015 period, a 68% increase. Much of the growth has come at the expense of coal fired power generation, which has struggled to compete with sub $4/mcf natural gas, let alone $2/mcf gas. US coal production is at its lowest levels since the 1980s. Industrial consumption of natural gas, the second largest growth sector in the gas market over the past decade, rose from 17.9 bcf/d to 20.57 bcf/d. Residential consumption grew from 12 bcf/d to 12.6 bcf/d during this same period. Figure 9 below shows natural gas consumption by sector since 2000.

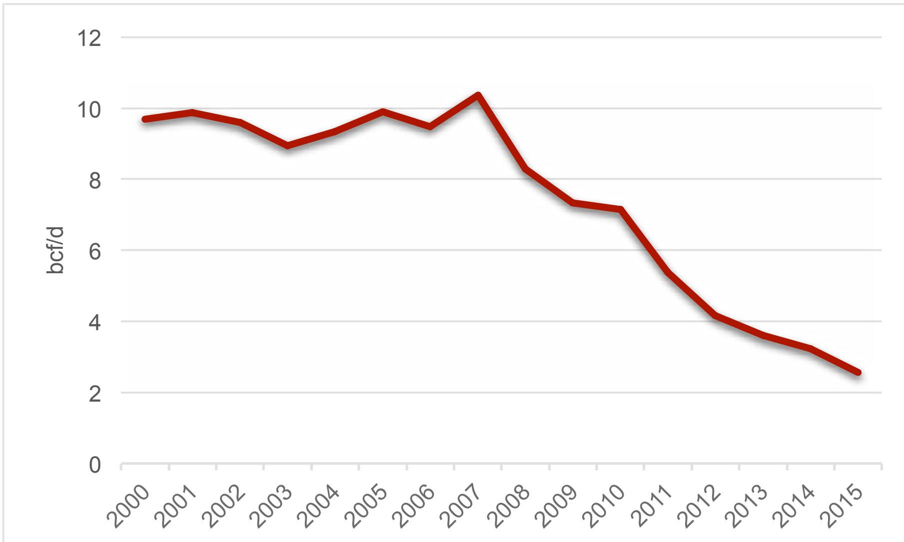
Figure 9
U.S. Natural Gas Consumption by Sector



Source: EIA Data

The US has nearly eliminated net gas imports (Figure 10) despite also soaking up the robust demand growth of the past decade. Net imports dropped to just 2.6 bcf/d in 2015 from a peak of 10.4 bcf/d in 2007, a continuation of the downward trend that began with the arrival of shale gas. The US had previously imported between 8 bcf/d and 10 bcf/d net.

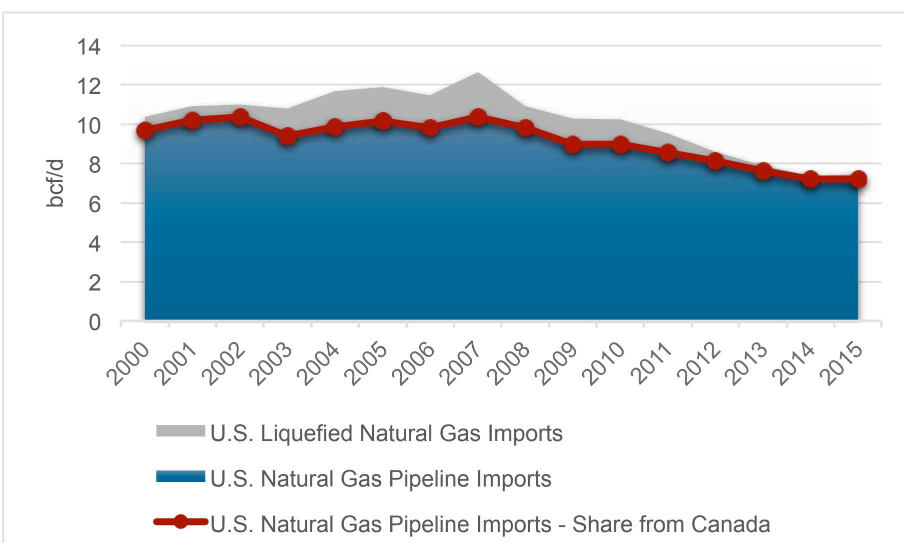
Figure 10
U.S. Net Natural Gas Imports



Source: EIA Data, PetroNerds calculations

The vast majority of US gas imports (Figure 11), over 95%, originate from Canada. The US imports over 7 bcf/d of natural gas, primarily from Canada's Western provinces. This gas serves US markets in the central and western US along the Canadian border, areas far removed from US gas sources, making Canadian gas a more accessible source of supply. The US also supplies regions of Canada with natural gas where Canadian infrastructure is lacking and better served by the United States.

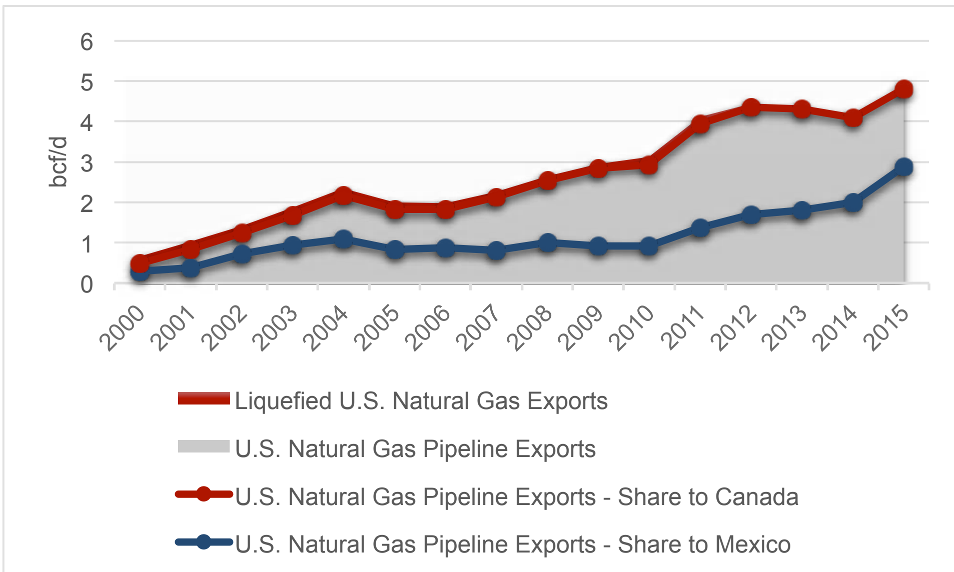
Figure 11
U.S. Natural Gas Imports by Type



Source: EIA Data

Whereas certain regions of the US along the Canadian border are short of domestically produced natural gas and turn to Canada for supplies, the Gulf of Mexico region has a surplus of gas that finds its way to Mexico. In recent years, increasing volumes of US natural gas produced in the Gulf of Mexico region have been piped across the border to feed Mexico's growing appetite for natural gas, primarily for the country's expanding power sector. Figure 12 below shows US natural gas exports by type, along with the share of US pipeline exports to Mexico. Note that exports to Mexico, 3 bcf/d at the end of 2015, have tripled since 2010 and could soon surpass 4 bcf/d. The remaining volumes of pipeline exports are shipped to Canada.

Figure 12
U.S. Natural Gas Exports by Type, Share to Mexico



Source: EIA Data

Whereas certain regions of the US along the Canadian border are short of domestically produced natural gas and turn to Canada for supplies, the Gulf of Mexico region has a surplus of gas that finds its way to Mexico.

A combination of improved drilling efficiencies, advances in extraction technology, and rising reserve additions all point to the prospects that large volumes of domestic natural gas can be produced at costs below a $4 mcf . There are several primary *market-based* factors that will escalate demand for natural gas over the next several decades. These factors include ongoing additions of natural gas fired power generation capacity, rising LNG exports, increasing industrial use of gas, and growing demand for gas in Mexico. On the policy side, the proposed Clean Power Plan (CPP) could increase demand growth for natural gas in the power sector as well as accelerate the timeline for uptake, should it become law. However, substantial uncertainties remain on how the new law will be implemented and the subsequent consequences for natural gas demand growth.

The Clean Power Plan

The final CPP rule was unveiled by the Obama Administration in August of 2015. The plan seeks a reduction of greenhouse gas (GHG) emissions from the electricity sector of 32% from 2005 levels by 2030. It does so by authorizing the Environmental Protection Agency (EPA) to use its (allegedly) existing authority under the Clean Air Act. Under the CPP, EPA would require states to meet certain power-sector emission requirements through energy efficiency measures and by replacing the current generation mix with less carbon intensive sources. The CPP utilizes a controversial methodology of enforcement that would effectively require power plant companies to replace existing coal-fired power generation capacity with renewables at a rapid pace.

The CPP is being challenged on several fronts. Over two dozen US states joined the lawsuit against the EPA in challenging the CPP. They argue that the plan unevenly applies emissions reductions targets on a state by state basis in order to achieve a national reduction figure. Not only are the targets far more strenuous in the final rule than they were in the proposed rule, but many states would face a more difficult path to compliance than other states. Numerous electric utilities are opposed to the rule as well. The CPP does allow for emissions reductions through greater energy efficiency at coal and gas fired power plants. However, the emissions reductions to be had in the CPP from improving energy efficiency are quite a small piece of the pie and, as it stands, power companies are already incentivized to run efficiently in order to maximize profit margins.

At a fundamental level, it is unclear whether or not EPA has the authority under the Clean Air Act to regulate power plants using the specific methods proposed under the CPP. There are numerous questions regarding the assumptions made by EPA in its rulemaking and whether or not it is legally justified in its compliance and enforcement methodologies. Environmental law professor Jonathan Adler described one of the core challenges as:

> "about the extent to which the EPA can look at so-called 'outside the fenceline' measures — such as the substitution of renewables for coal generation — to set a standard for emission reductions at coal-fired power plants. This is important because there is not much to be gained from increasing the efficiency of coal-fired plants, and the greatest potential for GHG emission reductions comes from the displacement of coal generation."[4]

What the CPP effectively requires for compliance goals is that power companies shut-in exiting coal-fired, and to a lesser extent gas-fired, generating capacity and make investments in renewables. These new investments are what is being referred to as "outside the fenceline" measures. The essence of the CPP is that EPA will regulate a coal plant by making its owner replace it, a controversial concept to say the least.

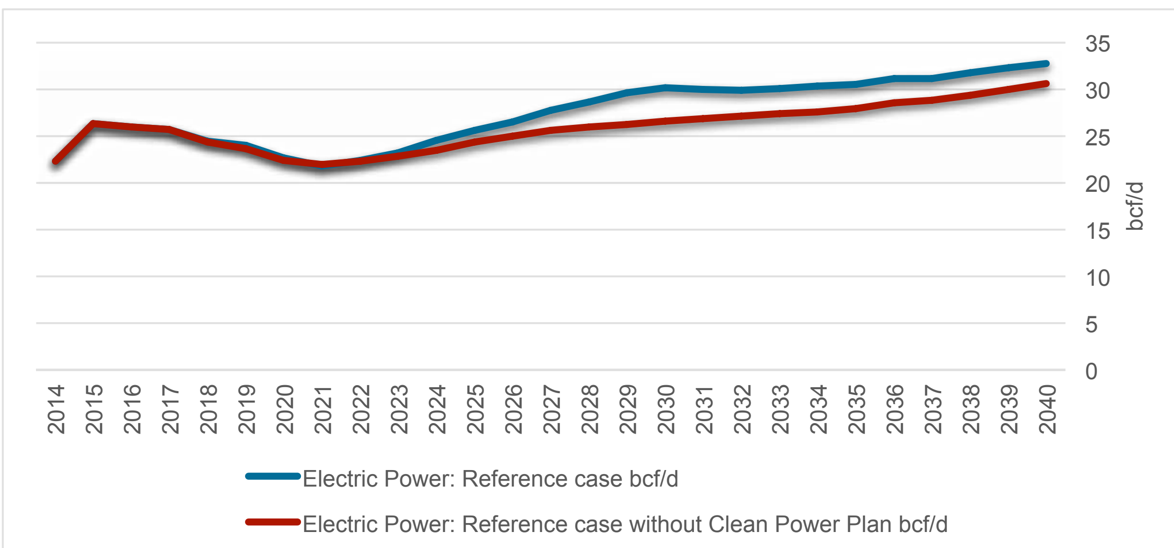
On February 9, 2016 the US Supreme Court halted implementation of the CPP until a lawsuit in lower courts regarding the CPP is resolved. As a result of the ongoing legal disputes related to the CPP, EIA includes the CPP in its 2016 Annual Energy Outlook (AEO) reference case scenarios and runs an additional policy case excluding the impact of the CPP (the no-CPP case). The differences in these two scenarios as they relate to the natural gas market are addressed in the following discussions of the future call on natural gas supplies.

Natural Gas Fired Power Generation Capacity

The Energy Information Administration (EIA) counts 18.7 GW of natural gas fired power generation capacity additions to come online from 2016 through 2018. Many of these new facilities are being constructed near shale plays to capitalize on transportation economics afforded by close proximity to supply sources. The combined additions of 18.7 GW of capacity additions will consume up to 3.14 bcf/d of natural gas, assuming a heat rate of 7,000 Btu per kWh (British thermal units per kilowatt hour). However, in its 2016 Annual Energy Outlook, EIA actually projects a short-term decline in natural gas power generation due to forecasted rising prices caused by the ramp up of LNG exports and slowing gas production. But longer term, natural gas demand in the power sector increases by 25% in the Reference case and by 17% in the no-CPP case from 2015 to 2040 as natural gas continues to displace coal.

The following chart (Figure 13) shows EIA's natural gas consumption forecast for the electric power sector under the reference case and no-CPP case scenarios.

Figure 13
EIA 2016 AEO Forecast of Natural Gas Consumption by the Electricity Sector

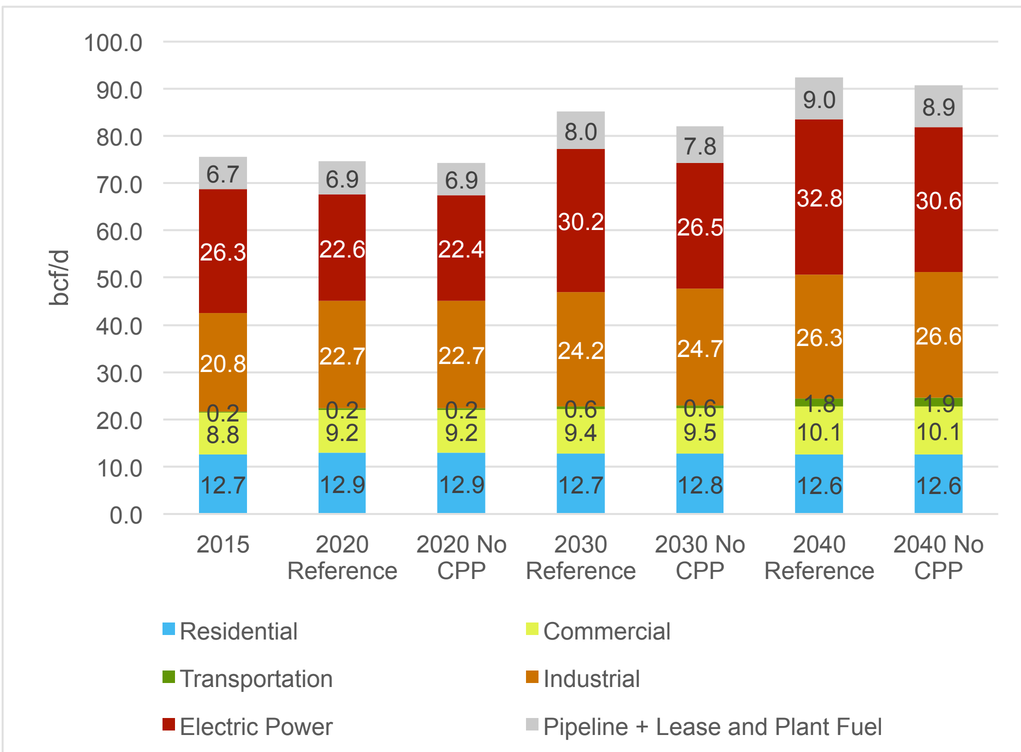


Source: EIA Data

Industrial Use and Other Sectors

The second largest growth sector for natural gas in EIA's 2016 AEO is the industrial sector (Figure 14). The industrial sector includes manufacturing, bulk chemicals, and agricultural chemicals. Industrial demand for gas grows by approximately 5.5 bcf/d from 2015 to 2040. The chart below comes from the early release of EIA's 2016 AEO and shows the changes in dry gas consumption for the five primary sectors covered by the report. Total US natural gas consumption increases by 19.4 bcf, or 26%, in the reference case and by 17.5 bcf, or 23%, in the no-CPP case from 2015 to 2040.

Figure 14
Forecasted Natural Gas Consumption by Sector



Source: EIA Data

Imports, Exports, and LNG

The first shipment of LNG from Cheniere's Sabine Pass facility on February 24, 2016 to Brazil marks the beginning of a new era of US LNG exports. The US Department of Energy has granted approval for a number of LNG export facilities, many located in the Gulf of Mexico. Cheniere's Sabine Pass facility was the first to launch and did so in February 2016. Several more trains[5] will be added in the coming years. The US will soon be sending large quantities of LNG around the globe, a sharp departure from expectations just a few years ago that the US would now be importing large volumes of LNG.

The table below (Figure 15) lists all LNG export facilities that are active or under construction. Note that these facilities represent a fraction of the 20 or so facilities that have been proposed in recent years. There is one additional facility that has been approved by FERC but is not yet under construction. The total approved volumes of the facilities listed in Figure 14 represent about half of EIA's peak LNG export forecast of 18 bcf/d in 2040. As more facilities enter the construction phase, more and more proposed facilities will pull out of the race. It remains unclear as to how many additional facilities will be constructed after this initial tranche. EIA expects LNG exports to consume 1.3 bcf/d of gas in 2017.

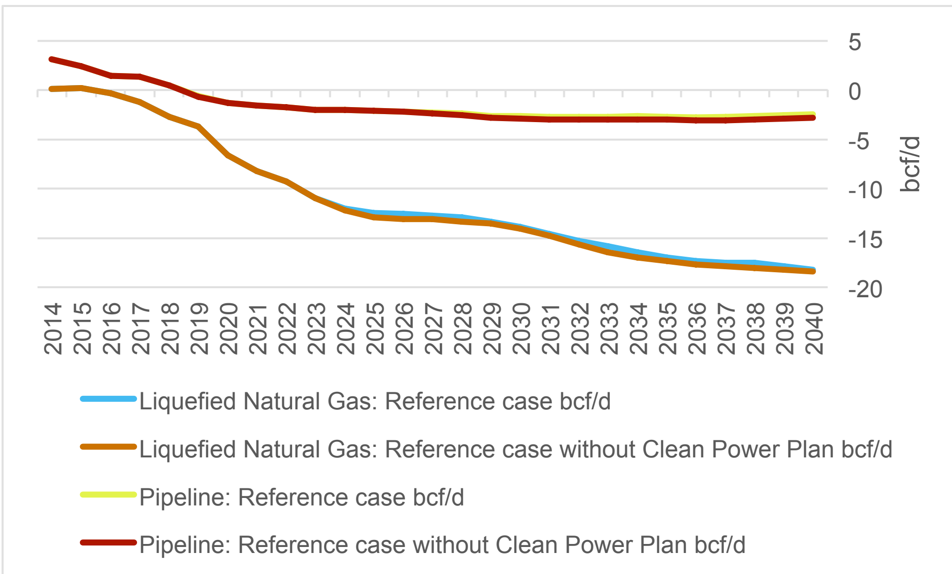
Figure 15
LNG Export Facilities Operating and Under Construction

Company/Facility	State	Gas Consumption (bcf/d)	Completion Date
Cheniere – Sabine Pass	LA	2.2 to 4.16	Partially Launched
Dominion Energy – Cove Point	MD	0.82	2017
Cheniere – Corpus Christi LNG	TX	2.14	2018
Sempra Energy – Cameron LNG	LA	1.7	2018
Freeport LNG	TX	1.8	2019
Total		***8.26 to 10.62***	

Source: EIA Data

The following chart (Figure 16) depicts EIA's 2016 AEO forecast for US LNG and pipeline exports of natural gas with and without the CPP in place. Unlike the power sector, which would be directly regulated by the CPP, natural gas imports and exports are not significantly impacted by the CPP.

Figure 16
EIA AEO 2016 Forecast for U.S. Net Natural Gas Imports
(negative figures denote net exports)



Source: EIA Data

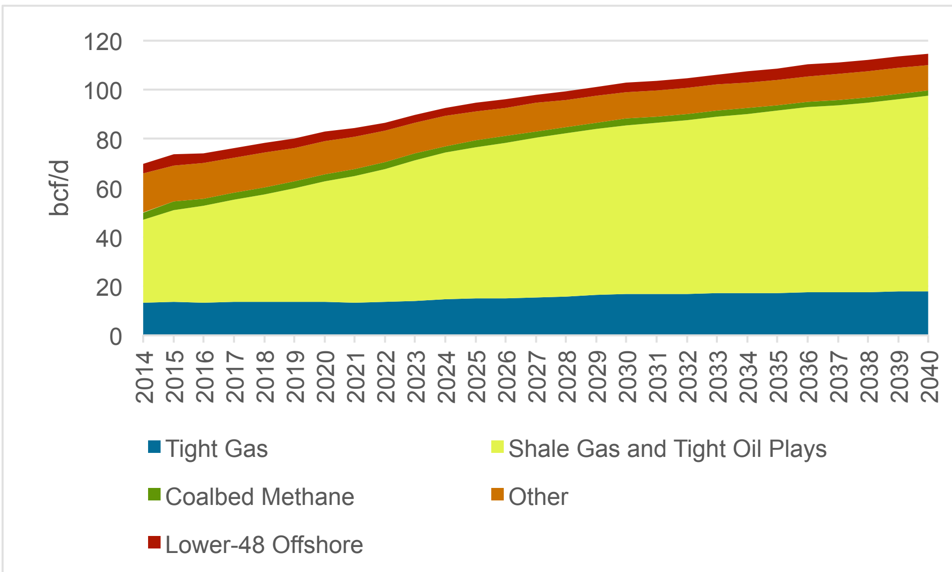
EIA projects that by 2018 the US will be a net exporter of natural gas. In AEO 2016, the US gradually reduces pipeline imports of Canadian gas while pipeline exports to Mexico ramp up to about 4 bcf/d. LNG exports to the world accelerate rapidly after 2017/2018 when additional facilities are brought online to complement Sabine Pass. In 2040, US net exports by pipeline are 3 bcf/d and 18 bcf/d by LNG. This represents a net swing of 23.5 bcf/d from 2015 levels.

Future Demand for Gas – Conclusions

In both the reference case and no-CPP case, EIA expects the total call on natural gas in the form of domestic consumption and exports to grow between 41 bcf/d to 43 bcf/d by 2040, more than 50% of current production. US production would have to add over 1.6 bcf/d per year between 2015 and 2040 to meet demand. This is far less than the 2.5 bcf/d that was added annually between 2006 and 2015, and the US clearly has more than adequate reserves to sustain 1.6 bcf/d per year growth over the next 25 years.Shale gas is expected to turn the US from an importer to a large-scale net exporter of gas, serve as a low-cost and low-carbon bridge fuel for the power sector, and provide the industrial sector with a competitive cost advantage upon which it can expand and create economic growth, all while offsetting declines of conventional and offshore gas production. This begs the question, from where and how exactly will these supplies be sourced, particularly when shale gas production growth has halted and prices sit in the $2/mcf range?

EIA projects nearly all future natural gas supply growth to emanate from shale gas. Figure 17 shows EIA's 2016 natural gas supply forecast, with total supplies approaching nearly 120 bcf/d. EIA projects non-shale gas supplies, such as offshore, coalbed methane, and conventional tight gas to decline until about 2030 before stabilizing and showing slight growth to 2040. Non-shale supplies remain under the 40 bcf/d level throughout the period. Shale gas and associated gas shale oil plays provide the entirety of growth from 2015 to 2040, rising from approximately 40 bcf/d to 80 bcf/d, and by 2040 account for 69% of the US gas supply.

Figure 17
EIA's AEO 2016 Natural Gas Production Forecast

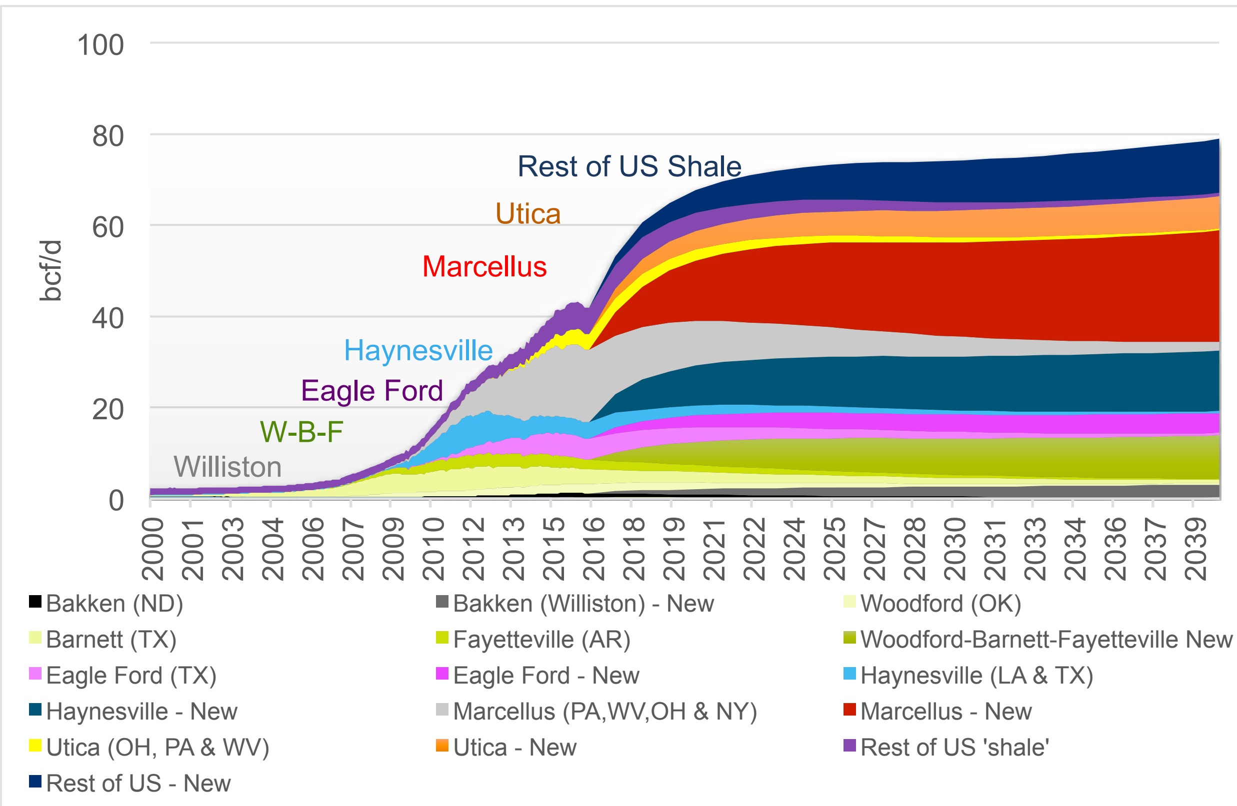


Source: EIA Data

EIA projects nearly all future natural gas supply growth to emanate from shale gas.

Although this forecast may appear aspirational at first glance, a play-by-play forecast using actual decline curves and modest drilling rates demonstrates that it is achievable. The PetroNerds/EPRINC base case shale gas forecast below (Figure 18) projects existing (i.e., the decline of present production) and new gas production (incremental volumes) for the plays covered in Figure 7 of this report from 2016 through 2040. The Woodford, Barnett, and Fayetteville shale plays have been aggregated into a single play (W-B-F). It should also be noted the PetroNerds/EPRINC forecast includes the entire Williston Basin and is not limited to the Bakken formation. The Antrim play in Michigan provides negligible supplies and is left out of the forecast.

Figure 18
Base Case Shale Gas Forecast by Play

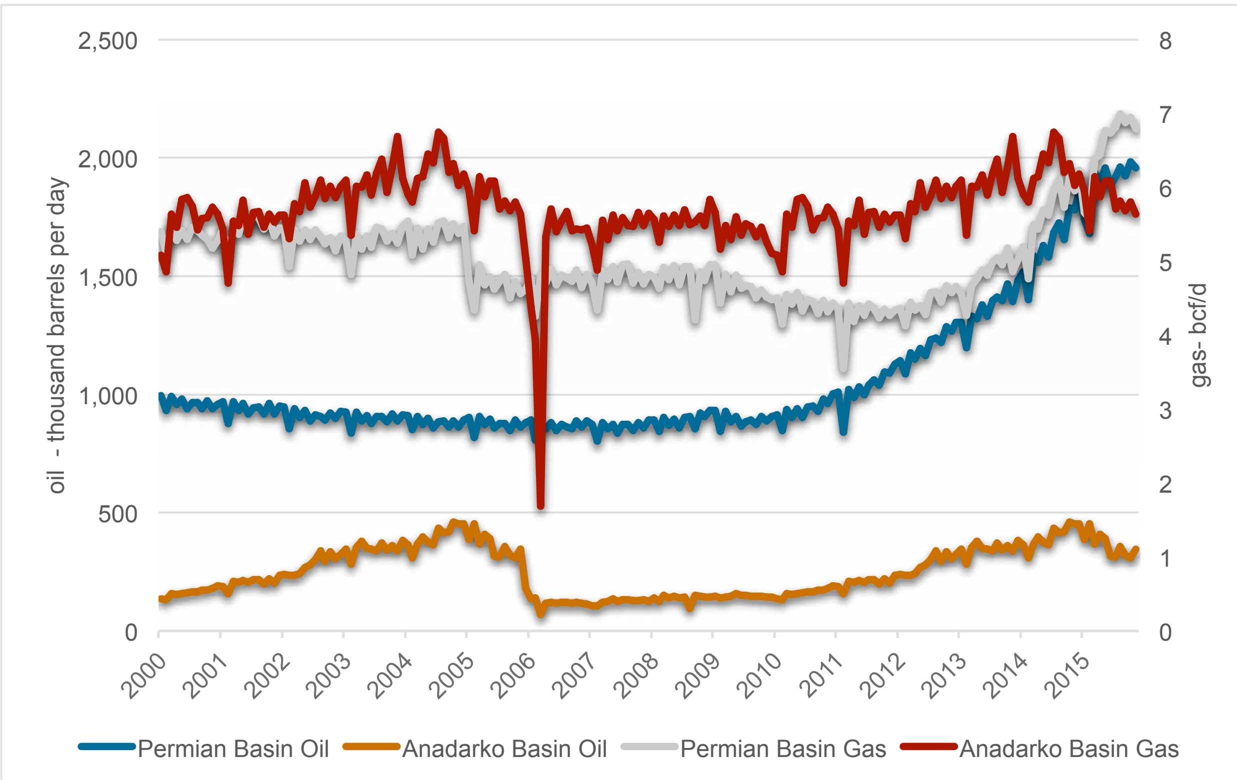


Source: PetroNerds calculations, EIA and DrillingInfo Data

The PetroNerds/EPRINC forecast (Figure 18) is largely in line with EIA's total 2040 forecast for shale gas production (EIA does not break out its forecast by play). Total shale gas production rises from 42 bcf/d in 2016 to 79 bcf/d in 2040, a gain of 37 bcf/d and nearly enough to cover all of EIA's projected demand growth over the 2015-2040 period. The Marcellus and Haynesville provide an outsized share of production growth relative to other plays in the PetroNerds/EPRINC forecast. The Marcellus tops out at 24 bcf/d, 50 percent growth from current volumes, in 2040 and the Haynesville comes in at about 14 bcf/d, twice its 2011 peak.

The "Rest of US 'shale'" category is a key contributor to the forecast. In the PetroNerds/EPRINC forecast, this category includes both pure shale plays as well as shale and other formations within existing oil plays that are accessible with unconventional drilling and production techniques. For example, the Permian Basin is a massive stacked formation and has been producing oil and gas for decades. Although it is not a pure shale play, the application of unconventional production techniques has unlocked new oil bearing reservoirs and lifted production after many years of stagnation and decline. The Anadarko Basin is a less prolific basin centered in Oklahoma but it too has benefited from the application of unconventional techniques and has experienced a post-2006 recover. The Anadarko Basin is home to the burgeoning (and much-hyped) SCOOP and STACK plays. The lesson here and shown in Figure 19 is that many mature oil and gas plays there is much room for shale and unconventional hydrocarbon production from new oil bearing layers within both shale and conventional plays that had been written off.

Figure 19
Permian and Anadarko Basin Oil and Gas Production



Source: DrillingInfo raw data

The Forecast:
How does shale get to 80 bcf/d?

The base case forecast depicted in Figure 18 is based loosely upon activity levels similar to those of 2010-2012, when 800-900, mostly horizontal trajectory, gas directed rigs were active (about half of the 2008 count of 1,600 gas directed rigs, mostly vertical). During that period, gas prices traded in a range of $4-$6/mcf and oil was about $100/b, meaning associated liquids carried a high value and incentivized drilling in wet gas plays. The PetroNerds/EPRINC forecast allocates 685 rigs in shale gas and unconventional plays as well as an additional 240 rigs targeting oil in the Williston Basin and Eagle Ford.

It is assumed that for each active rig one well per month is drilled, completed and brought online. In reality, this figure varies vastly because a rig can drill more than one well a month, but it may take several months to complete the well. EIA's May 2016 drilling activity report implies two wells are being added per month per active rig in the Marcellus. Actual spud to total depth drilling times have fallen to less than one week in some plays and just days according to some companies. But completions are often carried out several months after a well has been drilled and the rig has moved to another location. Well additions therefore more closely reflect a rig count from months earlier. Further complicating matters, many companies across the shale oil and gas sector are drilling but not completing wells. These wells are referred to as DUCs (Drilled but Uncompleted wells) or WOCs (wells Waiting on Completion) and are often kept in a company's uncompleted well inventory so that they may be brought online in a more favorable price environment.[6] The prevalence of DUCs, somewhat unique to the shale sector of the industry, further distorts the relationship between rig counts and well additions. DUCs are not included in this forecast. In any case, an assumption of one well per rig per month is conservative, particularly given the emergence of multi-well pad drilling, batch drilling, the availability of completion crews in the low-price environment, and a number of other efficiency improvements that have shaped the market in recent years.

"Rigs" and annual well addition estimates are allocated (Figure 20) as follows in the above forecast. A three year ramp up period for each play is built into the forecast before a given play reaches the peak well additions rate.

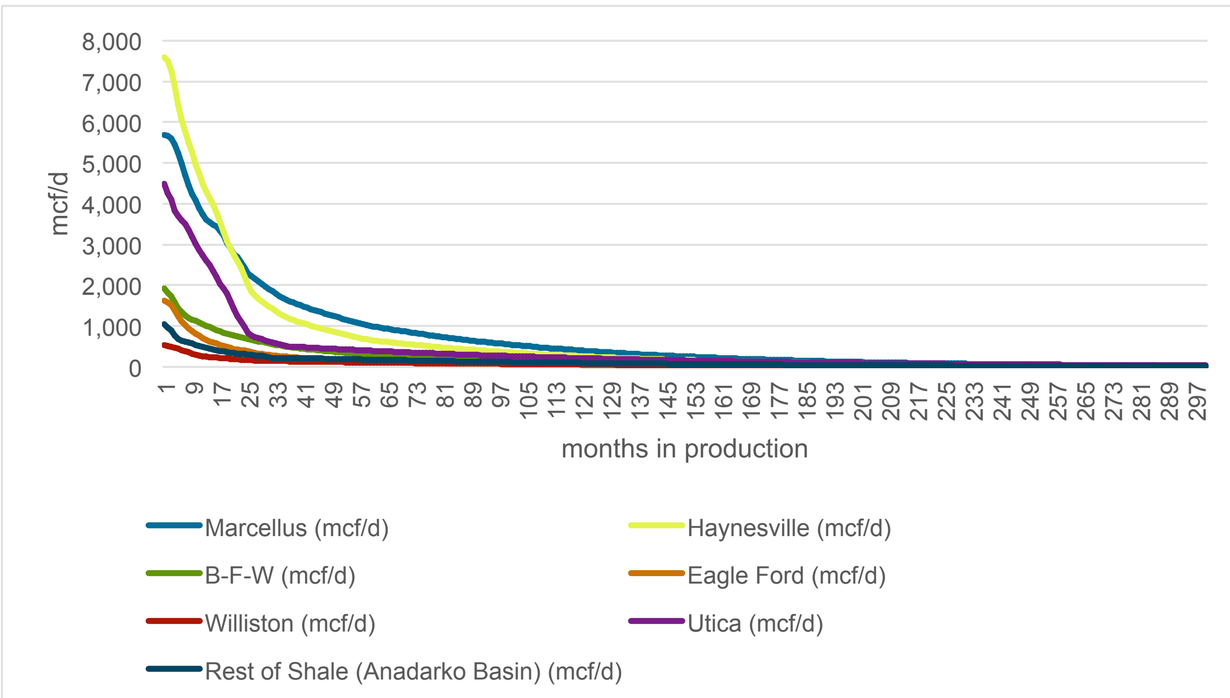
Figure 20
Activity Levels in the Base Case Forecast

Play	Gas Rigs	Oil Rigs	Peak Wells Additions Per Year
Woodford-Barnett-Fayetteville	145		1,740
EF		120	1,440
Haynesville	70		840
Marcellus	110		1,320
Utica	60		720
Williston		120	1,440
Rest	300		3,600
Total	***685***	***240***	***11,100***

Source: EPRINC/PetroNerds

The chart below (Figure 21) displays 25-year gas decline curves for the plays covered in this forecast. The decline curves are derived from actual, individual well decline curves aggregated across each play or plays. These curves, depending on the play, are generally indicative of wells brought online in 2014 or 2015. The Anadarko Basin gas decline curve is used to represent the "Rest of Shale" curve. Barnett, Fayetteville, and Woodford wells have been combined into a single play. These decline curves are held constant for the life of the forecast. Therefore, as far as individual well performance goes, this forecast is likely on the conservative side. The future economic environment and, in turn, activity levels, are among the most important wild cards.

Figure 21
Natural Gas Decline Curves for Selected Plays



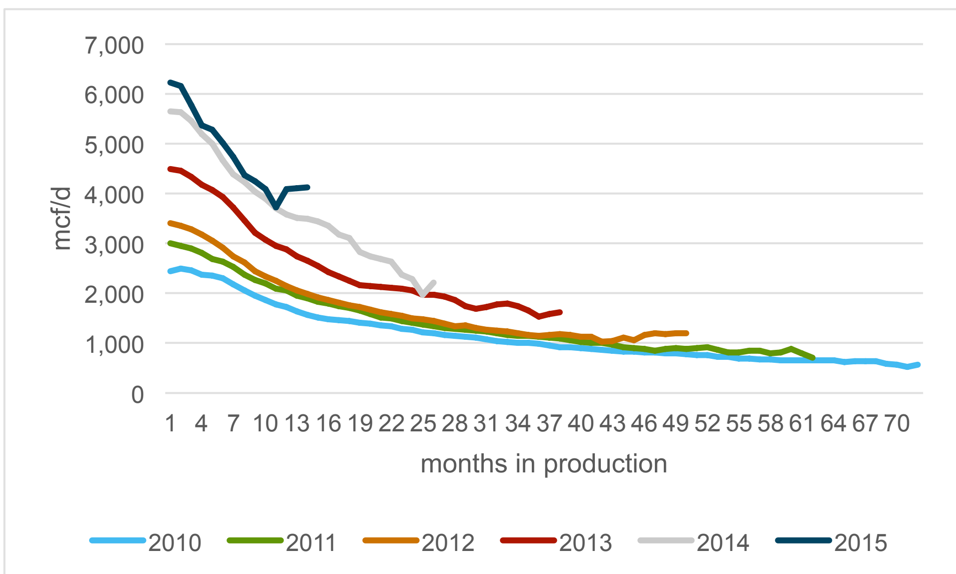
Source: DrillingInfo Raw Data, PetroNerds Calculations

The future economic environment and, in turn, activity levels, are among the most important wild cards.

Note as shown in Figure 22 below in the first few years of production, Marcellus, Haynesville, and Utica wells produce at more than double the rate of other plays. This exceptional performance and the addition of associated liquids production is largely responsible for the ability of these gas plays to attract activity with gas at $2/mcf while the others have remained idle. The Barnett, Woodford, and Fayetteville plays do not currently provide the EURs necessary to offset $6 million in drilling and completion costs. The combined B-F-W play has a 10-year gas EUR of 1.7 bcf and would require a gas price well north of $4/mcf in the historical cost environment to offset just drilling and completion costs after royalties are deducted from revenues.

This forecast holds constant several dynamics of oil and gas production that could be beneficial to both individual well production and ultimate production volumes, such as technological improvements, cost reduction, refracing and restimulation, DUCs, and infrastructure additions. As an example, Figure 20 below depicts the history of gas type curves in the Marcellus for wells added between 2010 and 2015. As production techniques evolved and operators became more accustomed to the play's geology, the Marcellus emerged as the most prolific and most improved shale gas play of the past six years.

Figure 22
Marcellus Gas Type Curves 2010-2015



Source: DrillingInfo Raw Data

Technology and geological acclimation are already allowing companies to do more with less and these factors are among the most important catalysts for future growth. These factors are important not only for improving production volumes, but also in reducing costs and mitigating environmental impacts. Each year rig efficiencies grow, completion practices improve, and operators' understanding of the underlying geology advances. Operators are only just now beginning to visualize and observe the efficacy of stimulation (fracing) techniques so that they can truly target their fractures.

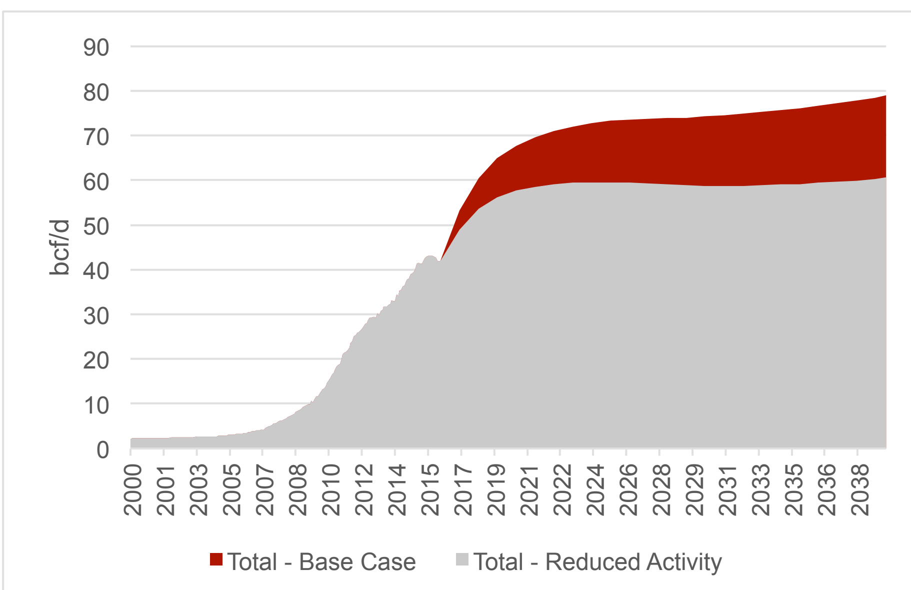
An average Marcellus well in 2015, for example, would produce more than twice as much natural gas as that of an average 2010 well. Many other shale oil and gas plays have also made great production strides in recent years and, although such improvements are subject to the law of diminishing returns, there remains great upside in many plays. Shale oil and gas producers have already discovered what 'just works', but the many companies are doing a better job of examining what works best and why. The shale sector is the least mature sector of the oil and gas industry and has much room to advance.

Furthermore, the discovery of new hydrocarbon bearing geology within existing plays and discoveries of new reservoirs or plays is not included. Therefore, the "Rest of US Shale" figure is arguably the biggest variable in this equation.

There are several potentially limiting factors that are not included in the forecast. These include the assumption of adequate drilling inventory going forward, a stable policy allowing for economic oil and gas production and hydraulic fracturing, and, of course, and a price environment that promotes the expansion of oil and gas activity.

For perspective, a "reduced activity" forecast is shown in Figure 23 below in contrast with the base PetroNerds/EPRINC shale gas forecast. The "reduced activity" reduces annual peak well additions in all plays by 25%. Shale gas production grows by about 50% to 60 bcf/d in the "reduced activity" case.

Figure 23
Shale Gas Production Under Two Scenarios



Source: PetroNerds calculations, EIA and DrillingInfo Data

CONCLUSION

What the PetroNerds/EPRINC forecast demonstrates is that with a modest level of activity, one far short of peak 2006-2008 levels, shale gas production can be expanded greatly over the coming decades. We are certainly not reserve limited. Future production will be driven by a combination of sound government policies, continued advances in extraction technologies, and a growing market for natural gas.

The capacity of the US natural gas resource base to deliver ever larger volumes of natural gas for the US economy in the coming decades is largely dependent on government policy. The size of the resource base and continuing emergence of new extraction technologies and improved efficiencies drilling operations all point to significant production growth in the coming decades, roughly 40 bcf/d by 2040, or 50 percent of current production volumes, if EIA's consumption forecast comes to pass. There are always uncertainties, but these uncertainties are largely on the demand side.

Both policy and market based developments could greatly affect the future for US natural gas demand. The scrapping of the CPP would provide a small respite for the coal industry and could reduce future natural gas consumption by as much as 4 bcf/d, according to EIA's forecast. Other variants in implementation of the CPP could even reduce long-term demand for natural gas should policies encourage even greater use of renewable forms of power generation and the expense of natural gas power generation. Regulatory policies on the use of hydraulic fracturing or control of methane emissions, if not implemented in a cost-effective manner, also pose risks to gas supply. On the market side, global LNG supplies are expected to increase by 50 percent between now and 2020. In the near term, the cost of spot cargoes in Asia have already declined by 80 percent since 2014, from $20 per million BTU (mmBTU) to just $4/mmBTU. Where longer term LNG v US LNG projects currently under development could be stalled or scrapped in the face of this expected glut, just as GOM import projects were halted as the US supply picture improved.

In any case, the US gas market will balance itself, even if in fits and starts. What is certain is that natural gas will become an even more important part of the US energy sector and economy as a whole. This report demonstrates that shale gas supplies can meet large volumes of incremental demand should the price environment improve slightly and government policy remain stable, even when technology is held constant. Shale producers have shown that they can expand production at $6/mcf, $4/mcf, and even $2/mcf when oil prices remain strong. A modest recovery in long-term prices in tandem with the continued evolution of shale technology and ever-improving knowledge of the rocks will enable shale gas production growth for years to come.

ENDNOTES

[1]Natural gas futures contracts are largely traded on the New York Mercantile Exchange (NYMEX) based on prices established at Henry Hub which is a location in Louisiana that interconnects with nine interstate and four intrastate pipelines. It has historically been viewed as the central pricing point for determining the value of natural gas, but the growth in production of gas supplies from Pennsylvania (Marcellus) hasalso led to large variations in regional pricing for natural gas. Spot and future natural gas prices set at Henry Hub are denominated in $/mmbtu (millions of British thermal units) which is nearly same price when measured in thousands of cubic feet (mcf).

[2]Heretofore, shale gas and 'unconventional' tight gas will be referred to simply as shale gas.

[3]Associated gas is gas produced as a byproduct of the production of crude oil.

[4]A discussion of the decision by the Supreme Court to stay all regulatory efforts to implement the Clean Power Plan is reported by Jonathan H. Adler in his article in the Washington Post on February 10, 2016. The article can be found here.

[5]An LNG train refers not to a conventional railroad train, but to a set of physical export infrastructure at an LNG facility that can load a predefined volume of cargoes.

[6]There are a number of factors that go into an individual company's decision making process for drilling, but not completing, a well. A primary driver for this behavior is the desire to capitalize on low drilling and completion costs by creating a well inventory at a large cost savings.