KIMMERIDGE
Energy

Feed Me Seymour

The Insatiable Growth in U.S. Gas Demand

August 2014

Introduction

The United States has seen a revolution in its natural gas supply dynamics since the beginning of the shale gas revolution. The sudden increase in domestic supply caused natural gas prices to collapse and led to the belief that it will be easy to meet demand for domestic uses and gas export. We believe that the resources are in place to allow this to happen but that the drilling and infrastructure needs required over the next eight years to match the production of the previous eight years will put upward pressure on the marginal cost of supply, which should result in an increase in gas prices over the period. The landscape change brought forth by such a dramatic shift in the domestic supply has been covered at length, but the question that is now being underestimated or overlooked is "Can we do it again?"

Much of the increase in demand (and reduction in imports) was driven by historically low prices, but headwinds have emerged to make demand "sticky" and less elastic to future increases in price than it was to the reductions in two main areas: electric power generation and exports. Electric power generation as an industry is facing regulatory changes from the EPA that could limit emissions and render it more expensive to produce electricity with coal, raising the price of natural gas which will still be economic as an input fuel. That some of the sources of new demand are less elastic to price is crucial, because many have argued that gas prices will be low for years to come, relying on a belief that if gas supply declines, the excess demand will just disappear. In this note we will argue that this is highly unlikely and that in fact there are strong secular forces that will drive U.S. natural gas demand much higher over the next eight years, from 73 billion cubic feet per day (Bcfd) in 2013 to 96 Bcfd in 2021.

We believe that 11.3 Bcfd of that increase will be from electricity production demand offset by a 2.4 Bcfd reduction in industrial demand. However, in addition to the traditional demand sources, we will consider how the trade balance for gas will increase the need for more U.S. supply. Low prices of the past five years spurred import demands from Mexico and resulted in a national Mexican policy initiative to construct gas-fired industrial and power generation capacity in the northern regions. As Mexico shifts existing petroleum generation to gas-fired generation and ramps up its industrial activity, it will increasingly be fueled by American natural gas, and since Mexico's main alternative for power is oil-based fuels, U.S. gas is likely to be price competitive even at prices much higher than today's. We believe that Mexican demand for U.S. gas will increase by 3.2 Bcfd by 2021, at an annual growth rate of 3.5%.

An even larger source of demand for export will come from LNG. LNG export facilities are currently under construction at Sabine Pass and multiple other facilities have received export approval, have signed up offtake partners, and are nearing final investment decisions. As it stands today, by 2021 there are firm commitments to export 8.5 Bcfd, which is all incremental demand for domestic supply, since currently there are no LNG exports.

This increased need for exports is unlikely to be met by imports of gas from Canada, as Canada has also approved LNG export terminals on its west coast and more Canadian gas is being used domestically in the energy-intensive process of harvesting the heavy Albertan oil sands. In addition, U.S. domestic production from conventional sources has been in decline and is unlikely to contribute significantly to growth. Therefore, the required increase in natural gas supply will need to come from domestic shale plays.[1]

Looking forward, the combination of these factors suggests that a supply deficit will emerge from additional "sticky" demand and permanent reductions in gas imports combined with the declines in conventional gas. To meet this deficit, prices will need to rise in order to: a) keep a lid on price-elastic demand (industrial, residential, commercial, vehicle fuel), and b) stimulate supply growth from shale gas sources due to rising marginal costs. To that end, this research note will investigate two primary questions that support a thesis of higher future gas prices:

1. How much incremental demand will there be, and in what segments?
2. What would the increase in shale gas supply have to look like, relative to the growth to date, in order to satisfy these projected changes in the supply/demand balance?

[1] We discussed this base decline and what this means in terms of continuing to increase supply in shale plays in our previous research piece "When Will the Hamster Fall from the Wheel".

Sources of Demand

The EIA places natural gas demand into three categories: gas used in production and transport, gas delivered to consumers, and gas exports.

(See Figure 1)

Gas used in production and transport has historically had a direct relationship with the amount of dry gas produced. We project this relationship to remain constant for purposes of this analysis, and as such, its impact on the outlook is minimal. Breaking down the consumers of natural gas, they can be split into five categories: residential, commercial, industrial, vehicle fuel, and electric power generation. Residential consumption is gas used in private dwellings for heating, air-conditioning, cooking, water heating and other household uses. Commercial consumption is gas used by nonmanufacturing establishments primarily engaged in the sale of goods and services, e.g. hotels, restaurants, retail stores, and others. Industrial consumption is gas used for heat, power, or chemical feedstock in the manufacturing and mining sectors. Vehicle fuel is gas used as fuel for transport, and electric power generation is gas used as the input fuel for plants that produce electricity.

Broadly speaking, consumer gas demand falls into three categories, heating and cooking (where residential and commercial are roughly equivalent), industry, and electricity.

Historically, residential and commercial consumption have been mostly flat (excluding short-term weather effects which average out on an annual basis) representing two thematic trends: economic growth, which leads to square footage growth and increased consumption, and gains in efficiency, which have offset that growth. The EIA projects changes in residential and commercial gas demand to be minimal in the near-term, and we also believe demand in those segments will be broadly flat. Vehicle fuel has also been held flat at 2013 levels, as any increase in price relative to crude oil is likely to dis-incentivize fuel switching; it could be argued that this should be considered as another source of demand growth given widespread attempts by industry to diversify the end user population of natural gas, especially in the transportation (specifically fleet vehicle) sector, but we have not included such growth in our forecasts.

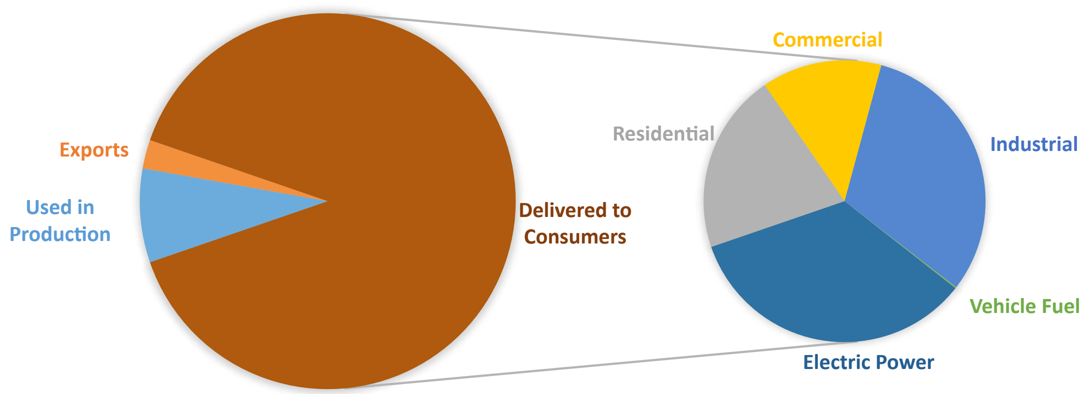

Figure 1: 2013 Gas Demand by Category (EIA)

Industrial demand has historically been inversely related to the price of gas as the input fuel – higher input prices have resulted in less demand and vice versa. Since 2001, the trailing 12-month averages of the price of gas paid by industrial users and industrial consumption has been inversely correlated with a correlation coefficient of -0.64 (resulting in an r-squared of 0.41) with a beta of -0.39. Conversely, industrial consumption only has an r-squared of 0.06 and beta of 0.00 with monthly GDP (in billions of today's dollars) over the same time frame *(see Figure 2).*

Industrial demand increased at an annual rate of 1.55% from 2005-2013 as prices fell, but maintaining that growth rate is unlikely if prices rise. If we look back between January 2006 and December 2007, gas prices were relatively stable between the peaks of 2005 and 2008. The monthly average Henry Hub price was $6.86 with a monthly standard deviation of $0.80 or 12% of the average. If gas prices return to around that level by 2021, we can estimate that industrial demand will follow. The average annual industrial consumption of natural gas in 2006-07 was 18 Bcfd, compared to 20.5 Bcfd in 2013. A reduction in consumption back to this level would require an annual decrease of 1.54% per year. This is much lower than the EIA's projection of 1.6% annual growth in industrial demand to 2021. [2]

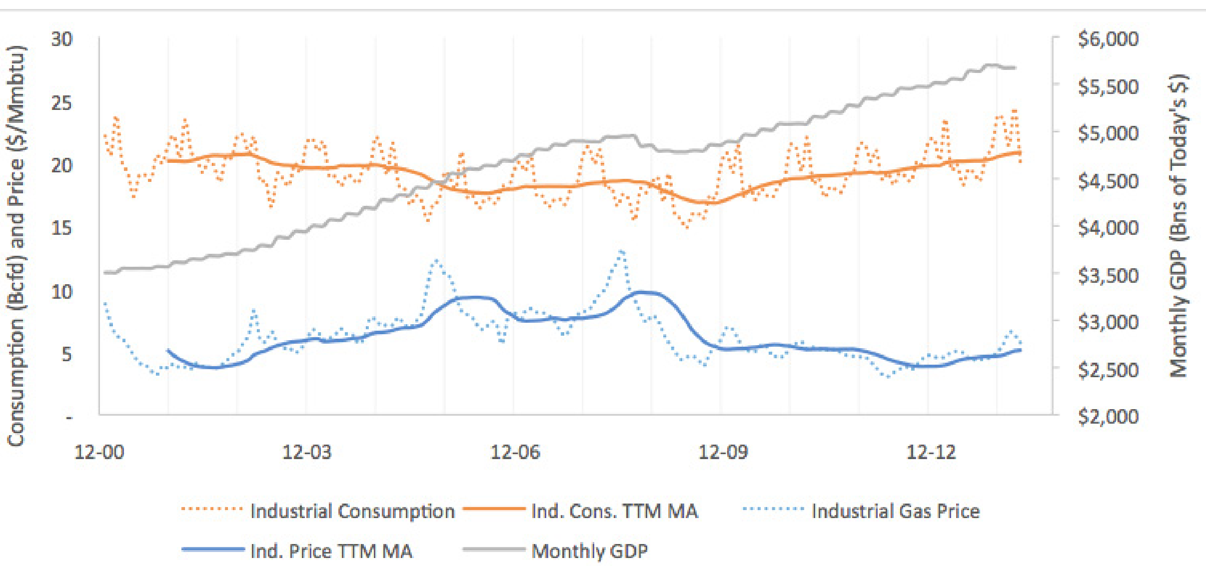

Figure 2: Industrial Gas Consumption vs. Price and Monthly GDP

[2] 2014 Annual Energy Outlook, 7 May 2014

Electricity Generation

As the price of natural gas (Henry Hub) fell from an average of $8.69/Mcf in 2005 to $3.73/Mcf in 2013, electricity generation from natural gas increased from 761,000 GWh to over 1,113,000 GWh (EIA), an annual growth rate of 4.9%. Over the same period, coal-fired generation fell from just over 2 million GWh to just under 1.6 million GWh, contracting just under 3% per year. However, as prices bottomed out in 2012 below $2.00/Mcf and began to increase again, natural gas used for power generation actually fell slightly from 2012 levels.

Any further increases in the price of natural gas relative to coal would appear to discourage any further switching; however, the EPA and the current administration are implementing a number of rule changes to reduce emissions, and if current proposals go through, the emissions reductions targets are expected to provide a regulatory incentive to switch generating capacity from coal-fired to gas-fired. Sanford C. Bernstein estimates that in order to meet the current EPA proposals on emissions, there will have to be a 25% reduction in coal-fired generation, offset by a 35% increase in gas-fired generation by 2020. [3] This would mean an annual growth rate in gas demand for electricity generation of 3.8%. If this indeed occurs, gas demand in the power generation sector would increase from 22.3 Bcfd in 2013 to 33.6 Bcfd in 2021, incremental demand of 11.3 Bcfd.

[3] U.S. Utilities: EPA's Proposed CO2 Regulations Assume a 25% Cut in Coal and a 35% Increase in Gas Fired Generation, Hugh Wynne, BernsteinResearch, 3 June 2014

LNG Exports

As U.S. gas prices have fallen and international gas prices have remained high, the economics of exporting LNG have also become more attractive. This has led to a wave of export development. DOE and FERC approvals for LNG exports currently total around 9.2 Bcfd of LNG by 2019. Binding offtake agreements have currently been signed for around 8.5 Bcfd of that total approved capacity. Currently, Cheniere Energy's Sabine Pass is on pace to be the first facility to actually export LNG loads, in 2016. When Sabine Pass's four LNG trains are complete, it will have liquefaction name plate capacity of 18 million tonnes per annum (Mtpa), or around 2.5 Bcfd.

Other LNG exports to 2021 are expected from Freeport LNG, Lake Charles LNG, Dominion's Cove Point, and Cameron LNG. Veresen's Jordan Cove has received FERC approval, but no offtake agreements have been signed as of this moment, so its capacity has conservatively not been considered in our projections. Other facilities under consideration by FERC at the moment include (but are not limited to) Oregon LNG, Golden Pass LNG, and Cheniere's extra trains at Sabine Pass, as well as Corpus Christi. *(See Table 1 and Figure 3 for a summary of LNG facilities expected to contribute to U.S. LNG exports by 2021.)*

Facility Name	Owner	State	Offtake Signed (Bcfd)	Expected In Service
Sabine Pass Trains 1-2	Cheniere	Louisiana	1.10	2016
Sabine Pass Trains 3-4	Cheniere	Louisiana	1.10	2017
Freeport LNG T1	ConocoPhillips et al.	Texas	0.60	2017
Freeport LNG T2	ConocoPhillips et al.	Texas	0.60	2018
Freeport LNG T3	ConocoPhillips et al.	Texas	0.60	2019
Cove Point	Dominion	Maryland	0.77	2018
Lake Charles LNG	BG Group	Louisiana	2.00	2019
Cameron LNG	Sempra et al.	Louisiana	1.70	2019
Jordan Cove	Veresen	Oregon	-	N/A

Table 1: LNG Facilities with FERC Approval for non-FTA Export

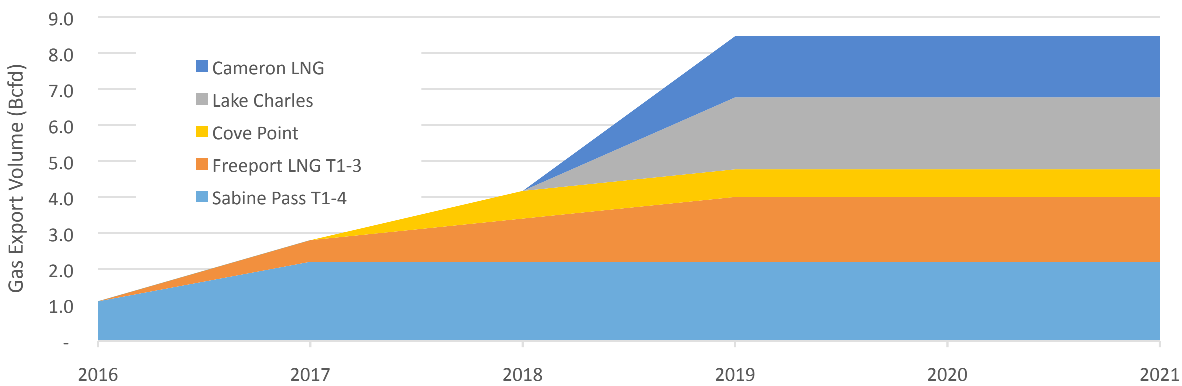

Figure 3: Schedule of LNG Export Startups – Firm Commitments to Deliver Only

Pipeline Exports to Mexico

While natural gas production in Mexico increased from 2005-2012 (the most recent data available from the EIA) from 3.7 Bcfd to 4.6 Bcfd, Mexican consumption increased even more, from 4.5 Bcfd to 6.6 Bcfd, taking Mexico's net imports up from 0.9 Bcfd in 2005 to 2.1 Bcfd in 2012. Of the 2.1 Bcfd imports in 2012, 1.7 Bcfd were via pipeline imports from the US which increased to 1.8 Bcfd in 2013 (the rest was from LNG). In all, pipeline exports have grown at a 10% annual growth rate since 2005, and a 12.5% annual rate since 2008. Expansion projects have been completed in West Texas and Arizona, and new capacity is expected to come online in South Texas and Arizona in 2015.

Mexico produces around 80% of its electricity with fossil fuels (Secretaria de Energía, SENER), with the historic majority of this provided by fuel oil and diesel-fired generation, then by natural gas and coal (Comision Federal de Electricidad, CFE). However, due to the cost and environmental advantages of natural gas, Mexico has set out on a path of switching much of its generation to natural gas, as well as building greenfield power generation plants in its northern states to fuel the industrial sector and spur economic growth in the northern regions. *See Table 2* for summary of Northern Mexico gas-fired power plants expected on-line in the next five years.

	Estimated	Name Plate	Exp. Gas Demand
Power Plant	In-Service Date	Cap (net MW)	(MMcf/d)
Baja California II	4/1/2014	276	39
Norte III	4/1/2015	954	136
El Encino	4/1/2015	600	85
Centro II	9/1/2015	660	94
Noreste (Escobedo)	4/1/2016	1,034	147
Todos Santos	4/1/2016	80	11
Topolobampo I	4/1/2016	320	45
Topolobampo II	4/1/2016	700	100
Tenaris, Ternium, Tecepetrol	9/1/2016	900	128
Guaymas II	4/1/2017	747	106
Mazatlan II 1	4/1/2017	158	22
Puerto Libertad	4/1/2017	632	90
Topolobampo III	6/1/2017	700	100
Valle de Mexico II	9/1/2017	601	85
Guaymas III	4/1/2018	747	106
Baja California IV	4/1/2018	565	80
Manzanillo II rep U1	4/1/2018	460	65
Occidental I (Bajio)	4/1/2018	470	67
Mazatlan II 2	4/1/2018	158	22
Manzanillo II rep U2	4/1/2019	460	65
Merida IV	4/1/2019	378	54
Valle de Mexico III	4/1/2019	601	85
Norte IV	4/1/2019	918	130

Table 2: Mexico Power Plant Gas Demand (Source: Bentek)

Preparations for supplying this incremental volume are already underway. Current pipeline capacity from the U.S. into Mexico is about 4.1 Bcfd, but this is scheduled to increase to around 6.4 Bcfd once the Agua Dulce Line and Sierrita Lateral are completed in 2015. Based on growth in power demand and infrastructure, we have projected gas exports to Mexico via pipeline to increase at their 2008-13 annual growth rate until the infrastructure reaches capacity. We have also projected the Agua Dulce Line (in dark green below) and Sierrita Lateral (AZ – Sasabe) to begin at 50% capacity in 2015, 75% in 2016, and 100% thereafter. These assumptions result in Mexican exports increasing from 1.8 Bcfd in 2013 to 5.0 Bcfd in 2021. By 2021, 60% of the 3.2 Bcfd of incremental gas exports to Mexico is expected to be consumed by currently planned gas-fired power plants *(see schedule in Table 2)*, with the balance expected to be consumed by increases in industrial demand, displacing LNG imports, and other users who will arise once the supply becomes available (residential, commercial, etc.). *(See Figure 4 for historical and projected pipeline exports to Mexico, with the incremental demand from planned power plants shown.)*

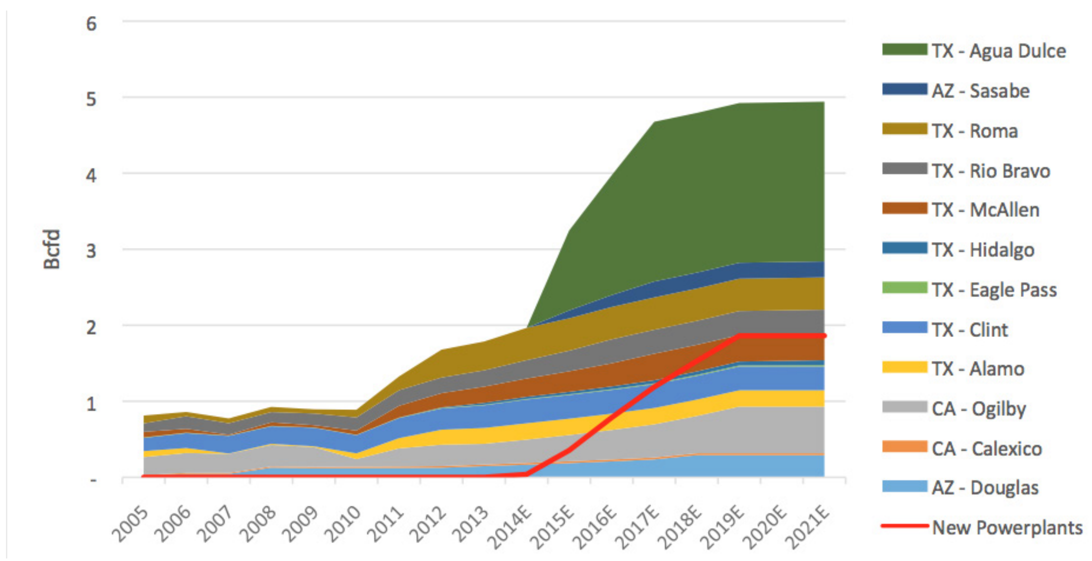

Figure 4: Pipeline Exports to Mexico, Historical and Projected (Source: EIA, Bentek and Kimmeridge)

Demand Summary

Combining these several factors, we expect to see U.S. gas demand increase significantly out to 2021 from three main areas: electric power, LNG exports, and pipeline exports to Mexico. During this period we assume industrial demand declines and residential, commercial, and vehicle fuel demand remain constant at 2013 levels (which is below EIA projections). These assumptions result in an increase in demand from 73 Bcfd in 2013 to just over 96 Bcfd in 2021, an absolute increase of 23 Bcfd which equates to a 3.5% annual growth rate, for a cumulative 31.5% *(See Figure 5)*. To put this in perspective, this would exceed by 6 Bcfd the 17 Bcfd of domestic growth delivered over an eight year period from 2005 to 2013.

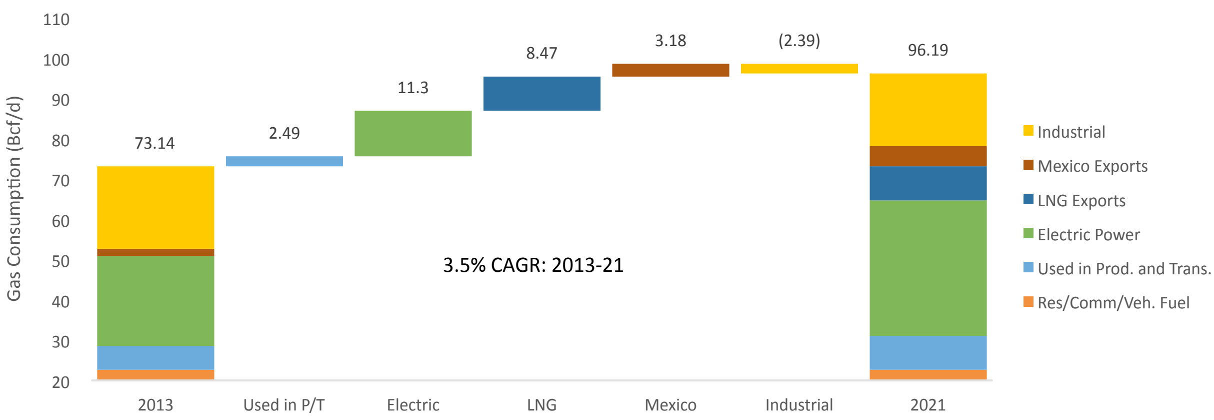

Figure 5: Natural Gas Demand, Historical and Projected Growth (EIA and Kimmeridge)

The Supply Story

Imports

U.S. supply of natural gas comes from three primary sources: LNG imports, pipeline imports from Canada, and domestic production. While domestic production accounted for over 80% of supply in 2005, base decline trends sparked fears of gas shortages, leading to significant LNG import capacity to be built around the country. As shale gas production has grown, the need for LNG imports has vanished and these terminals are in the process of either closing or being converted to export terminals. To restart these imports, natural gas from global sources would have to be cheap enough to undercut domestic production while adding in liquefaction and transportation costs – an unlikely scenario. As a consequence, we have projected LNG imports to fall to zero by 2016 when the U.S. is set to begin exporting LNG.

With the decline in price and associated economics, net pipeline imports from Canada have also been decreasing since 2005, from over 9.1 Bcfd to 5.1 Bcfd in 2013, an average contraction of 7% per year. This has been the result of burning the candle at both ends, as imports from Canada's western gas producing regions have decreased and exports from the Marcellus have increased to eastern Canadian cities like Toronto, displacing western Canada gas even within Canada. In addition to the reduced gas import demand from the U.S., Canadian heavy oil production is increasing from the Albertan Oil Sands, a very energy-intensive process. The power generation requirements to harvest this prolific resource have kept more Canadian gas nearby.

Canada has responded to the direct reduction in demand from its southern neighbor by looking west; no less than nine LNG export terminals have received approval from the National Energy Board (NEB) on Canada's West Coast in northern British Colombia, primarily Kitimat and Prince Rupert. While very little of this capacity has been signed up by offtake partners, and therefore final investment decisions have yet to be reached, at least a few of these projects are expected to be built and exporting LNG by 2021. The most likely candidates are probably Kitimat LNG, owned by Chevron and Apache, and Pacific Northwest LNG, owned by Petronas and Sinopec. Kitimat has a capacity of 10 Mtpa (1.4 Bcfd) and has some of this signed up for offtake by KOGAS; Pacific NW LNG has 12 Mtpa (1.7 Bcfd) capacity and has current offtake agreements for some of its volume with Indian Oil and Japan Petroleum Exploration Corp.

Given that more Canadian gas is being used in domestic heavy oil sand production, and Canada is on its way to exporting LNG to Asian buyers, it is unlikely that the cost of Canadian gas will dip low enough to displace U.S. production and spur another increase in U.S. imports. In addition, Canadian natural gas is subject to many of the same upstream costs as the U.S. in terms of competing for services and raw materials, so increases in the marginal cost of U.S. gas would, at least partially, be expected to translate to Canadian gas as well. As such, we have projected Canadian pipeline gas imports to continue to decrease at the 2005-13 average of 7% per year.

Domestic Gas Production

The main source of U.S. natural gas is domestic production. Separating this supply into the conventional and unconventional segments, it is evident that the conventional supply of natural gas has been declining from 2005 to 2013. Natural gas production from Alaska, coalbed methane, the lower 48 offshore, and lower 48 onshore conventional declined an average of 3.5% per year over that time (these are the sources we are defining as "conventional"). Of that drop, the majority was the result of production declines from offshore and conventional onshore wells. As gas production from previously drilled conventional wells declined, production from newly-drilled wells did not make up the difference, either because the new wells were not productive enough or because not enough new wells were drilled.

Countering this phenomenon was the unconventional boom that led total gas production in the U.S. to increase from 49.5 Bcfd in 2005 to 66.5 Bcfd in 2013. The replacement of this base decline as well as the entire growth over the period was provided by tight gas (1.8 Bcfd added) and shale gas production (23.6 Bcfd added), with shale gas providing 93% of these gains.

LNG Exports

Shale gas contributed 2.0 Bcfd in 2005 to domestic supply and 25.6 Bcfd in 2013 (actually less than the 26.6 Bcfd in 2012, as producers responded to the drastic drop in price by finally producing less). Shale gas production grew at an annual rate of 37.6% over the time period and added 23.6 Bcfd of incremental gas supply. In 2005, shale gas provided 4% of domestic gas production, increasing its share to about 39% by 2013. This supply came from plays like the Barnett, Haynesville, Woodford, Fayetteville, and Marcellus. By all measure, these have been prolific discoveries to date, but how much more will they need to contribute over the next eight years, and what other areas are likely to join in the contribution?

The EIA projects gas production from Alaska, coalbed methane, lower 48 offshore, and lower 48 onshore conventional sources to decline very gradually at a rate of 0.5% per year to 2021, with gains in gas production offshore offsetting most of the losses in the other areas. On the other side, the EIA only projects production gains of 4.3% per year for tight and shale gas, resulting in total gas production of just over 81 Bcfd by 2021. Placing this in context we forecast expected gas demand to be around 96 Bcfd in 2021, meaning EIA projections would leave us 15 Bcfd short of our projected required supply *(See Table 3).*

	Bcfd				
Production Source	2013	2021E	Incr. Prod.	2013-21 CAGR	Cum %
Alaska	0.87	0.75	(0.13)	-1.94%	-14%
Coalbed Methane	4.49	4.56	0.07	0.20%	2%
Lower 48 Offshore	5.16	5.72	0.56	1.30%	11%
Lower 48 Onshore Conv.	15.78	14.20	(1.58)	-1.31%	-10%
Tight Gas	14.34	18.21	3.87	3.03%	27%
Shale Gas	25.62	37.94	12.32	5.03%	48%
Total	66.26	81.37	15.11	2.60%	23%

Table 3: EIA Projections of Dry Gas Production (2014 Annual Energy Outlook)

From 2005 to 2008, Henry Hub spot prices averaged $7.85 monthly, and during this time dry gas production from conventional sources fell from 34.8 Bcfd to 33.7 Bcfd. Given this period of high prices and inability of the conventional sources to deliver growth, we have not considered them to be growth sources for purposes of our analysis. If we instead accept the EIA projections for the conventional sources and tight gas production, and assume that the difference between supply and demand will be made up by shale gas sources, a startling picture emerges. Even considering the EIA's projections that offshore and tight gas production will increase, shale gas production will need to increase from 25.6 Bcfd in 2013 to 50 Bcfd by 2021 to meet our demand forecast. On a raw basis, this will mean shale gas production will need to increase by over 24 Bcfd in the eight years leading up to 2021, an increase greater than the 23.6 Bcfd we saw from the shale boom between 2005 and 2013. This averages to an annual growth rate of 8.7% per year over the period, and by 2021, shale gas production would have a 53% share of total U.S. gas production *(see Figure 6 – note we project the balance to be made up by shale gas production).*

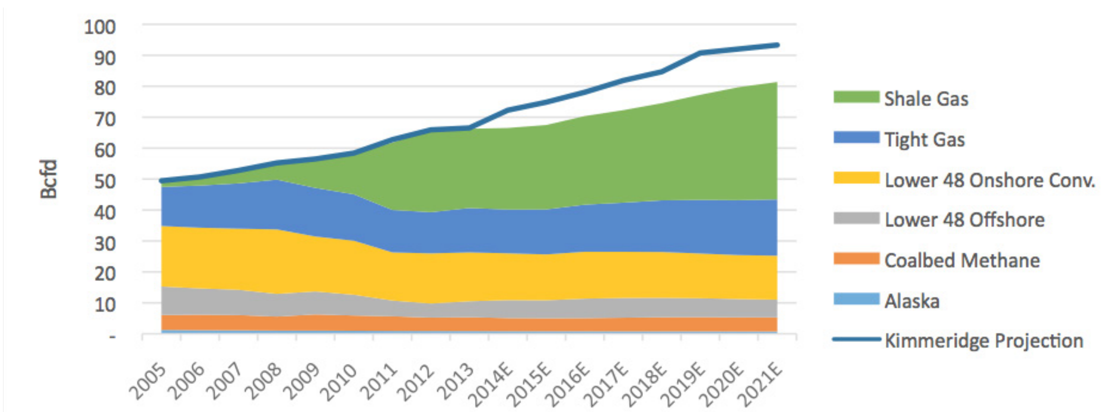

Figure 6: Kimmeridge Natural Gas Projection vs. EIA Estimates for Gas Production by Source

Feeding Seymour – Delivering the Supply Growth

There are numerous obstacles associated with meeting this supply projection. Aside from the technical challenges of discovering, proving, and extracting the resources in place, there are headwinds from replacing base decline, rig and service availability, infrastructure constraints, and the intensity of capital required.

We previously addressed the issue of replacing base decline and the effect on rig availability in our aforementioned research piece "When Will the Hamster Fall From the Wheel", which discussed the nature of the new shale wells being drilled, how and why they decline faster than the older wells they are replacing, and the subsequent need for more and more wells to be drilled per year to replace the production from the older declining wells. Figure 7 shows why this will be difficult to achieve for gas production, as rigs have been moving to oil and liquids plays. These same scarcity and cost inflation dynamics can be applied to oilfield services in general, although general services should be able to respond faster with more supply than can rigs.

(See Figure 7)

Tightness in the markets for rigs, services, and labor are expected to manifest themselves in rising input prices for drilling and completing new wells. In addition, raw materials prices and labor market tightness on the infrastructure side, combined with the requirement for massive infrastructure build-out, is expected to result in higher takeaway prices in the near-term, increasing the all-in marginal cost of supply. This will subsequently increase the price of gas required to deliver this requisite supply growth (see our 2012 report "Creeping to a Correction? Why the U.S. Gas Market may be Poised to Recover" for a more detailed discussion of the price of gas and its relation to the marginal cost of supply).

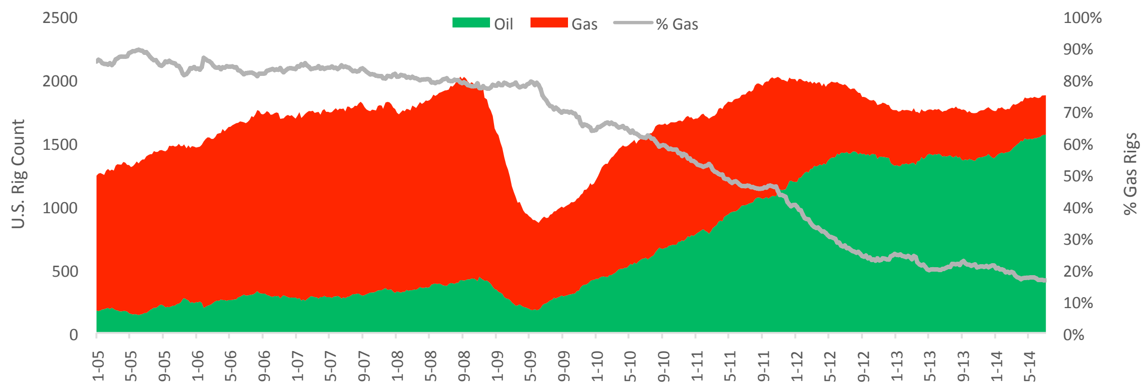

Figure 7: U.S. Rig Count Oil/Gas Mix

Conclusions and Consequences

Combining these projections, we expect gas used in production and transport to maintain their historical relationships to dry gas production. Residential, commercial, and vehicle fuel demand will continue to be flat to 2021, and industrial demand will drop to 2006-07 levels based on a gas price between \$6.50 - \$7.00 (more conservative than the EIA's 1.6% annual growth projection). We believe power generation consumption will increase by 35% to 2021 from 2012 levels, a raw increase of 11 Bcfd, based on the retained economics of gas caused by regulation making it more expensive to burn coal. We also included the impact of currently approved LNG export terminals that have roughly 8.5 Bcfd of capacity already signed up to be exporting by 2019, while ignoring potential increases in this amount that do not already have approvals and offtake agreements in place. Lastly, on the consumption side, we project pipeline exports to Mexico to rise from 1.8 Bcfd in 2013 to 5 Bcfd in 2021, largely to power northern Mexico's planned gas-fired power plants and industrial facilities, as well as general demand growth in northern Mexico as supply becomes available. **Combined these result in projected gas demand rising from 73 Bcfd in 2013 to 96 Bcfd in 2021.**

On the supply side, as traditional conventional gas sources are in decline and the current base replacement and growth has been almost entirely provided by shale gas, we project that increases in shale gas production will be required to meet the rise in demand. The entire amount of shale gas production increase from 2005-2013 was just over 23 Bcfd. The amount required to meet the increase in demand and offset decline from conventional sources is over 24 Bcfd. While this will inevitably require volume growth from multiple basins, the key contributors who "take share" are likely to be the Marcellus, Utica, Eagle Ford, Fayetteville, associated gas from the Delaware Basin (Permian), and inevitably one or two new plays. In reality this supply growth at today's economics will be extremely challenging and suggests that prices must rise to either dampen price-elastic demand or incentivize more supply (or both).

The areas to reduce gas demand would be through non-regulated gas-fired power demand, uncontracted LNG, and exports to Mexico. However, as EPA regulations would act as a barrier to power plant switching and LNG plants contract their supply through firm requirements for 20-25 years before coming to a final investment decision, it appears more likely that prices would have to rise to stimulate supply. This alone may further drive increases in price given current rig markets are very tight and increasingly levered to liquids plays, suggesting additional cost inflation on the service side and increasing the marginal cost of supply. As of this writing, the futures price of Henry Hub gas on the NYMEX in July 2021 is \$4.36/Mcf. We believe we have shown that this price level will be insufficient to meet projected demand at that time.

In conclusion, the supply of gas from U.S. shale plays that we will need to meet forecasted demand out to 2021 is on par with the entire amount of shale gas supply growth from 2005-2013. As our projections have accounted for the price elasticity of gas consumption in elastic sectors, and the growth is likely to appear in relatively price-inelastic domains, prices will need to rise to stimulate supply given the increasing marginal cost of the incremental gas.

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