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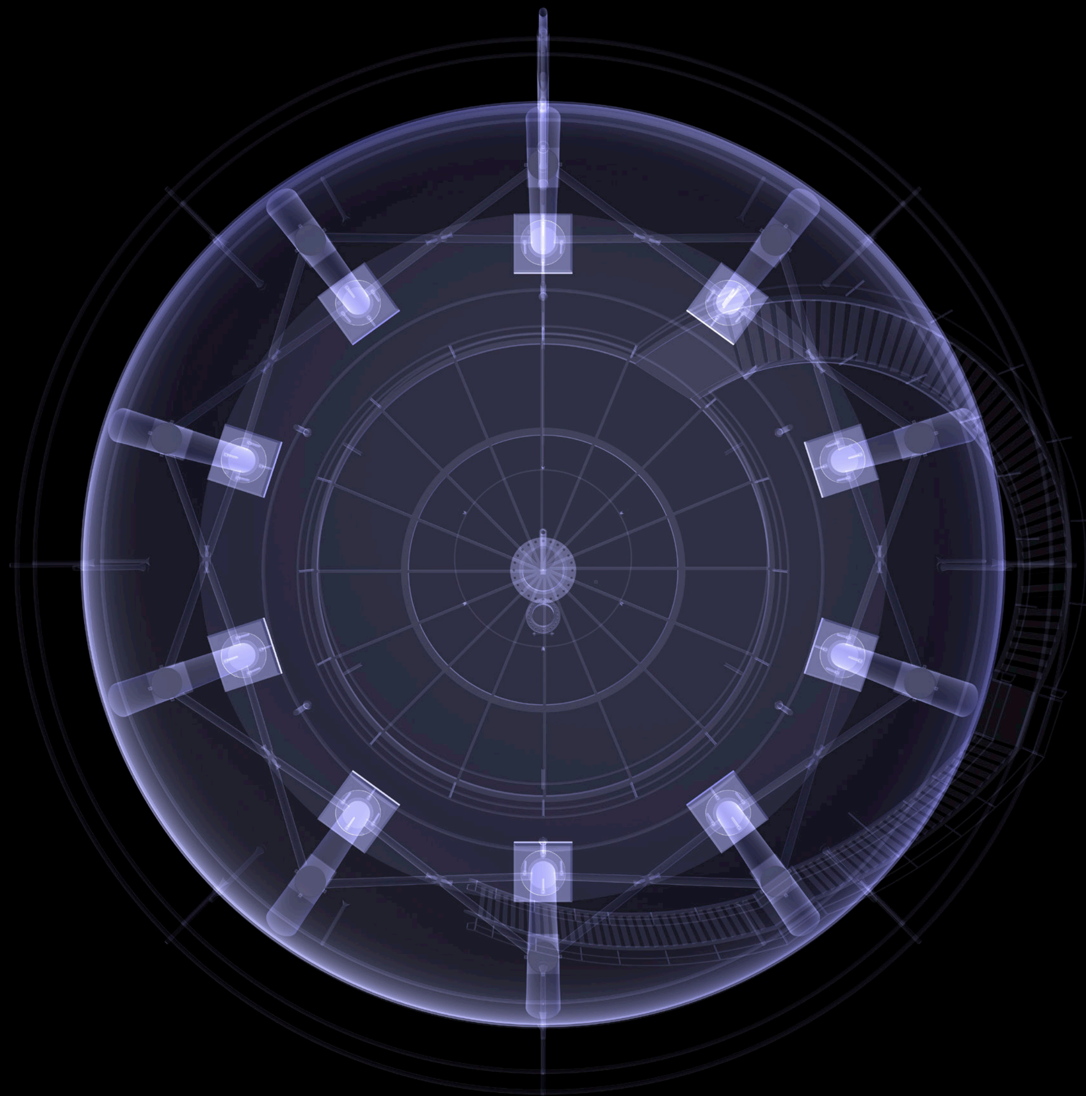

Building an industry:
Can the United States sustainably export LNG at competitive prices?

Deloitte Center *for* Energy Solutions

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Executive summary

The US natural gas industry has dramatically changed over the last ten years, with prices halving as production grew by almost 50 percent.[1] The key driver to the current energy renaissance is the largely unpredicted success of unconventional gas extraction, most notably in the Marcellus and Utica shales in Appalachia. At the same time, the global liquefied natural gas industry (LNG) has grown considerably as a result of new sources of both supply and demand. In February 2016, the first LNG cargo left the Sabine Pass liquefaction facility in Louisiana for Brazil, beginning the transformation of the United States from a net natural gas importer to an exporter. Several other liquefaction facilities are expected to come online within the next five years. In order for the export market to develop, it is paramount that producers grow production profitably at prices that are competitive in the global market.

This report analyzes a range of consumption and production of natural gas in relation to historical corporate and well-level economics and concludes:

- Shale gas wells will need to generate positive return at $3.75-4.35 Henry Hub prices or lower to sustain exports that are competitive with oil-indexed LNG contracts.
- Roughly $130-160 billion in additional investment in shale gas will be needed to produce the 84 billion cubic feet per day (bcfd) projected to be needed in 2020 for both domestic and export markets.
- Current low prices challenge companies' bottom lines, but the supply curve for US natural gas is long and flat providing opportunity for future development.
- Many wells may be marginal at $3 per thousand cubic foot (mcf), but will generate strong returns at $4, which can support the burgeoning export industry for the foreseeable future.

Based on these factors and the current expectations of likely costs and volumes, the United States is well positioned to sustainably export LNG at globally competitive prices

Building an industry from the ground up

Over the last 10 years, natural gas production in the United States has grown by 50 percent as operators shifted from conventional reservoirs to shale. In fact, US shale has increased from 10 percent of US natural gas production to 58 percent and will likely exceed 60 percent by 2017 if the current trend holds.[2, 3] Initial success in the Barnett shale play in Texas spread rapidly to other plays, including Haynesville and Fayetteville. However, the focus of current production has shifted to the Marcellus, Eagle Ford, and Utica plays. This creates an opportunity to build a new industry for the Lower 48: natural gas exports.

The sheer size of shale's productivity and its impact on the market is impressive. In 2005, monthly Henry Hub prices exceeded $13 per million British thermal units (Btu).[4] Prices averaged close to $7 in 2006 and 2007, before rising sharply again in 2008. In fact, the National Petroleum Council published a report in 2007, *Facing the hard truths about energy*, that discusses many of the challenges and energy constraints the United States would likely face, saying the country "will be increasingly reliant on LNG imports to satisfy domestic natural gas demand." It noted unconventional gas would play a potentially important role, but the cited projections underestimated shale's productive potential by an order of magnitude.[5]

Because of this largely unpredicted surge in productivity, average monthly natural gas prices in 2016 have fallen to 17-year lows,[6] and companies face a completely different challenge than those highlighted just ten years prior. They will need to either adapt their projects to the new economic headwinds or pull back development spend in line with current cash flows. It appears operators are pursuing both. Gas-focused operators have reduced capital and focused operations on the most productive wells. For example, in the Marcellus, high initial production rates, as well as large increases in estimated recovery, have improved economics despite lower realized prices. In 2008, an average well in the region would peak at 43 million cubic feet (mmcf) per month or roughly 1.4 mmcf per day. By 2013, it was closer to 5.7 mmcf per day.[7] Looking at rig productivity tells a similar story with monthly production growing ten-fold over the same period of time. Growth, in fact, did not stop, with current rates 50 percent above those in 2013.[8] However, profitability remains challenged, and expanding these productivity efforts to other more marginal wells and plays may prove difficult.

One question stands out in its impact on US exploration and production companies (E&P), LNG exporters, and consumers of natural gas domestically and internationally. Can US natural gas prices be high enough to incentivize ongoing shale drilling while remaining low enough to be sustainably competitive on a global basis?

The short answer is yes, but with several caveats. Low global gas prices indicate an excess of supply in multiple regional markets, primarily due to lower than expected demand and a surfeit of liquefaction capacity. In the short term, this situation is unlikely to change. LNG companies, both in the United States and internationally, will likely find it difficult to ship cargoes profitably at globally competitive prices. US liquefaction companies are well positioned to compete, with flexible delivery contracts and direct access to

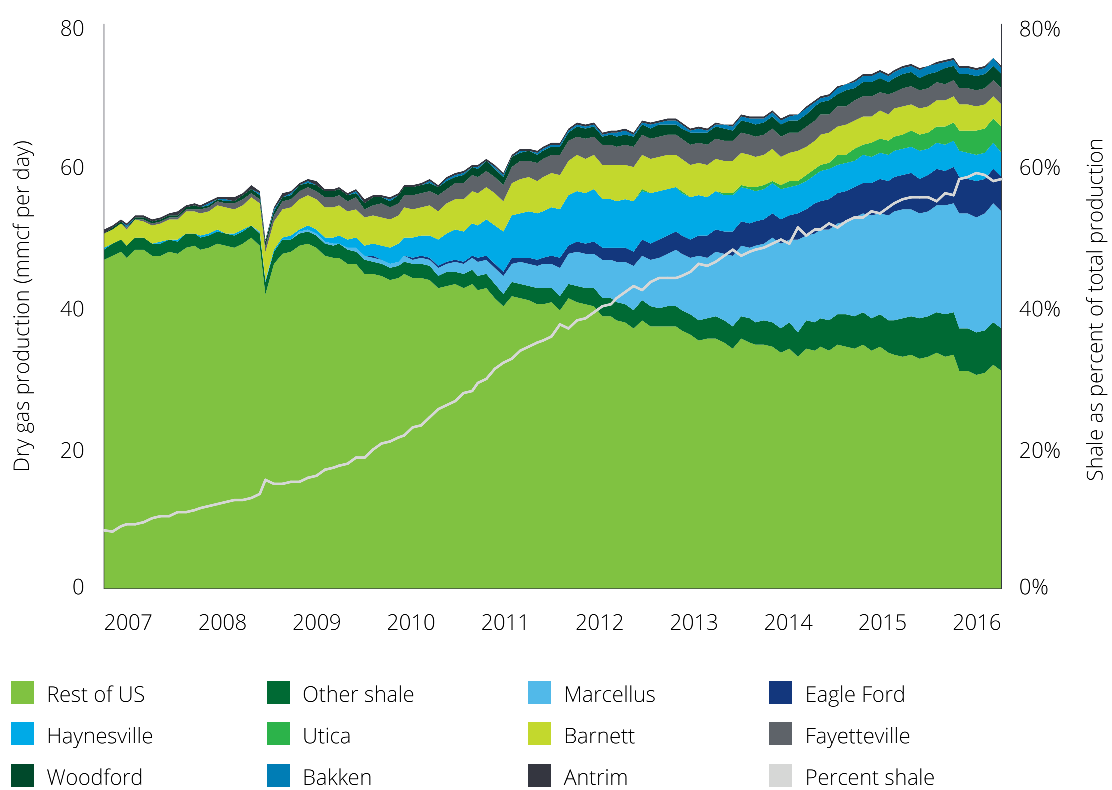
European markets along with increased access to Asia via the expansion of the Panama Canal. A recent Deloitte report, *Five years on: The outlook and impact of American LNG exports*, discusses the regional outlook and comparative positioning of the United States in greater detail.

Just as low global prices negatively impact exporters margins, low domestic prices affect US producers as well. And, in fact, low domestic prices that fuel export demand have already reduced upstream development activity and minimized investment in future resource development, though reduced costs have blunted the impact.

Much of the activity and costs trends are cyclical, as operators have pared down operations to target their core acreage. But, it masks longer-term structural changes, including using longer laterals, more completion stages, and better understanding of geological conditions to minimize costs and maximize production. Striking a balance between export competitiveness and upstream returns will be key as the LNG industry continues to develop.

To find that balance, this report breaks down the elements that comprise the continued US natural gas renaissance: the competiveness of US LNG exports, the sources of domestic consumption, and how production will be able to continue growing to meet those needs.

Figure 1. Total US dry gas production by year and source



Source: US Energy Information Administration (EIA)

Making the math work

Prices in the natural gas market are set by a number of factors. In the case of Henry Hub in the US Gulf Coast or the National Balancing Point in the United Kingdom, prices are based on regional supply and demand. Prices for the majority of LNG cargoes, however, are tied to another commodity such as Brent or Japanese Customs Cleared crude oil. Unlike other commodities, the properties of natural gas make it difficult to trade over long distances. Pipeline reach is limited by challenging terrain and geopolitical risk. LNG can be costly, with a regional differential of several dollars required to spur investment. However, over the last decade, there has been substantial growth in natural gas demand worldwide, leading to high prices in much of Europe and Asia. Subsequently, there has been a large expansion in liquefaction capacity in multiple countries, including the United States. Unlike other projects in Australia, the Middle East, and Africa, LNG exporters in the United States will not rely on large stranded gas fields for supply, but instead will actually procure it directly from the market. This is made possible by the low cost and abundant unconventional gas resources found across several plays, including the highly prolific Marcellus and Utica shales. Changing that business model leads to a very important question—Can the US LNG industry compete on a global basis? If so, how will the industry balance domestic production, consumption, and exports?

To answer that question, this study analyzes a handful of key considerations shaping the supply and demand outlook:

- Total domestic consumption and potentially exportable volumes
- The effective "net-back" price for US natural gas considering global LNG pricing
- The current level of production, likely decline rates, and cost of development
- The resource potential and profitability of future drilling at expected prices

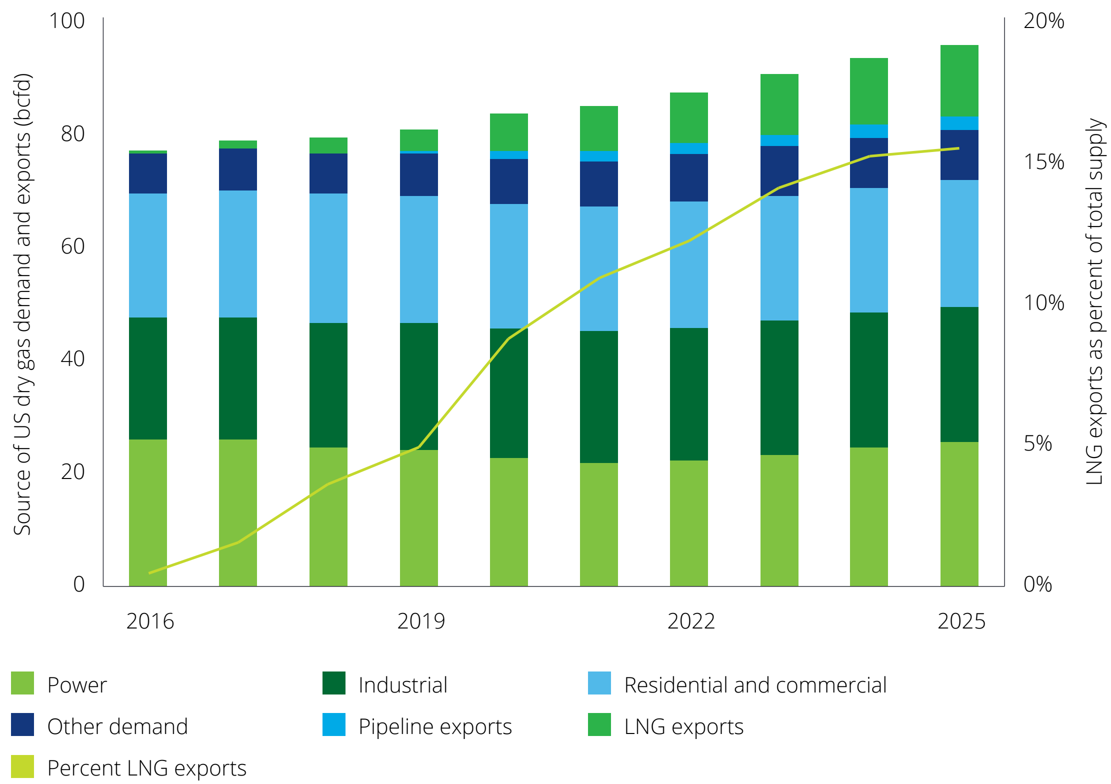
Figure 2 illustrates the outlook for US consumption through 2025. Domestic consumption is split roughly into thirds: one-third used for power generation, one-third consumed by industry, and the balance comprised of all other uses, including commercial, residential, and transport, as well as oil and gas operations. Overall, consumption for these sectors is expected to remain more or less flat over the next ten years, although year-to-year weather variations can change this picture.

Despite expectation for limited domestic demand growth, the EIA projects domestic production will grow close to 84 bcfd in 2020 and 95 bcfd by 2025. Much of this surplus will be exported—roughly three quarters via LNG and the balance primarily by pipeline to Mexico. Limited consumption growth, mainly in the industrial sector, means LNG will likely have little competition for the marginal cubic foot. With inelastic demand, the cost of supply will be the driving factor, and that cost of supply needs to be competitive on a world-wide basis.

Historically, LNG contracts were long-term and indexed to oil on 12-15 percent basis, with exact weighting, additional fees, and adjustments varying from contract to contract. Even today, the majority of LNG is traded via these indexed contracts and will likely shift only on the margins in the near-term. In *The balancing act: A look at oil market fundamentals over the next five years*, Deloitte MarketPoint projects oil will be above $65 by 2020, equivalent to roughly $8-10 per million Btu.[9]

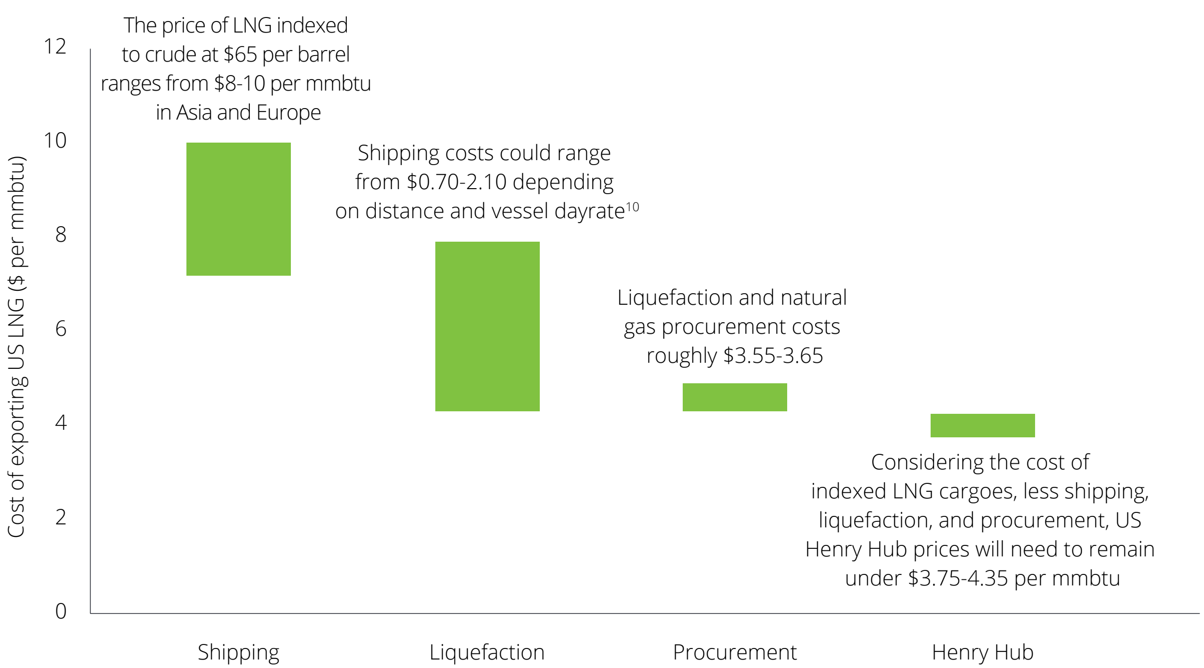
Considering a range of global gas prices, Henry Hub levels will likely need to remain at or below $3.75-4.35 per million Btu to remain globally competitive with other LNG sources. This is roughly double today's price and 30 percent above the current futures price for natural gas in 2020.

Figure 2. Total US natural gas supply, consumption, and exports



Source: EIA Annual Energy Outlook 2016

Figure 3. Cost and price basis for competitive US LNG exports versus oil-indexed cargoes at $65 per barrel



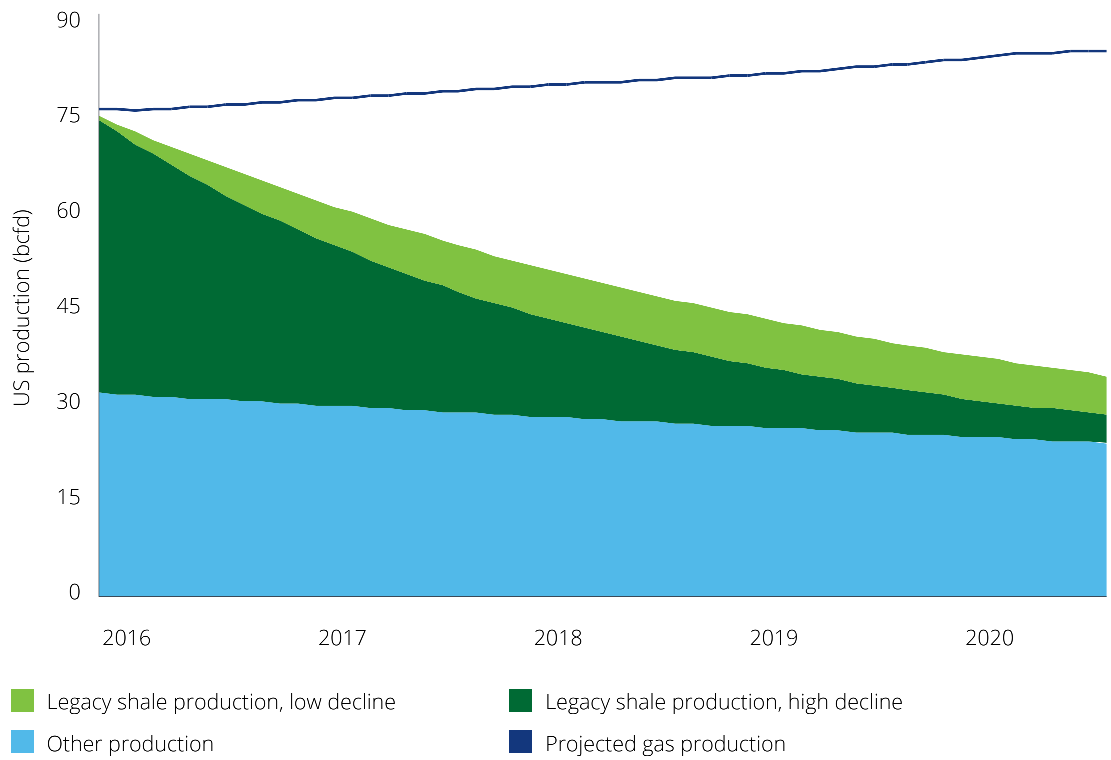
Source: Deloitte analysis, company presentations

Between future demand growth and continued depletion, new investment will be needed to keep production levels stable. For example, production from existing wells is expected to fall from over 75 bcf per day to under 35 by 2020. To meet the EIA's forecasted natural gas consumption and net exports in 2020 of 84 bcf per day,[11] roughly 47-54 of production from new wells will likely be needed. This equates to about 50-60 trillion cubic feet (tcf) in total needed between now and then.

Based on a survey of gas-focused companies' expenditures and production, this growth will require in excess of 130 billion dollars in new investment through 2020 based on 2015 capital intensity.[12] This should be attainable considering the decline in capital costs and slowing production growth compared to the prior five year period. However, with the current low prices reducing profitability in shale gas, funding future developments with existing cash flow will be difficult for many companies, and securing debt will be a challenge at the current price strip.

To meet that growth, costs will need to continue to be reduced and natural gas prices will need to increase. If current spend rates are maintained, Henry Hub prices moving from the 2015 average of $2.60-4 would make headway in mending balance sheets. Of course, future consumption is dependent on pricing, with exports being the most sensitive. Will the market support the higher prices necessary to grow production?

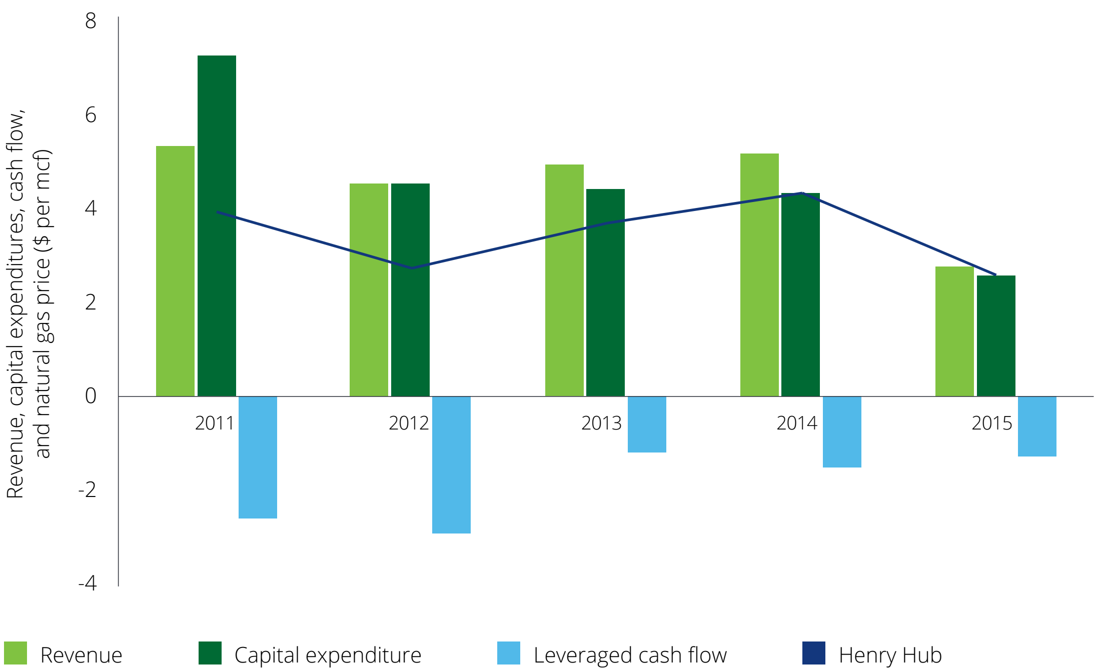
Figure 4. Legacy well production versus forecasted consumption 2016-2020



Source: Deloitte analysis, EIA

Shale gas resource potential likely to meet projected demand

Figure 5. Median revenue, capital expenditure, and free cash flow per thousand cubic feet produced 2011-2015



Source: Deloitte analysis, S&P Global Market Intelligence Capital IQ database

Production growth will be partially determined by future capital intensity—how much money is required per cubic foot produced. Based on the analysis of 32 North American, gas-focused companies,* Deloitte projects that achieving sustained profitability may be a challenge at current strip prices, but it is attainable particularly if prices rise. Figure 5 illustrates the peer groups' revenues, capital expenditures, and leveraged cash flow along with Henry Hub natural gas prices.

Companies, on average, have been unprofitable, with high levels of capital investment limiting free cash flow. More notable is not just the high level of capital intensity but the fact companies have been effective at reducing costs to stay in line with prices. Generally speaking, capital spend is needed to increase production and reserves, and it is a testament to shale's resiliency that the capital pull back did not negatively impact either.

Between 2011 and 2015, the median company in the peer group increased production by 80 percent. It also added 160 bcf and 7.5 million barrels of liquids in reserves each year, more than triple production over the same period of time. This indicates that companies should be capable of maintaining lower levels of capital expenditures even as production (and revenue) grows.

The potential stems from shale's increasing productivity, which has significant running room. The consultancy IHS estimated in a February 2016 report that there is 1,400 tcf of North American natural gas that is economic at $4 per million Btu, which is more than enough to satisfy demand growth over the next 30 to 40 years.[13] So, even as companies continue to produce gas, the sheer quantity of resource will provide sufficient volumes for both domestic consumption and exports.

*The peer group included 32 public E&P companies based in the United States and Canada with natural gas making up over 80 percent of their production on an energy equivalent basis. For more information on the companies included, see the peer selection criteria (Appendix 1).

Broadly speaking, a generic Marcellus well is economically marginal at current Henry Hub futures prices. Not only would it not likely earn the 15-20 percent rate of return needed to justify investment, but it might not break even on a cash basis. However, if you factor in a 30 percent uplift in natural gas prices, in line with $3.75-4.35 per mcf needed for competitive LNG exports in 2020, two thirds of the type wells would meet or exceed a typical hurdle rate.

This shift in well-level profitability over a narrow price range speaks to the flat supply curve in the United States. In this case, a less than $1 per mcf increase in gas prices over the next five years boosts the average rate of return by 20 percentage points. But there are also other factors besides Henry Hub pricing that will impact economics and need to be considered—most notably infrastructure limitations and liquids production.

As production in the Marcellus and Utica basins continues to grow, infrastructure has not kept up in the Northeast and Midwest, leading to significant regional price discounts. For example, the Leidy Hub in Pennsylvania has traded at a $1.40 discount,[14] reducing the rate of return by 30 percentage points or more as compared to an identical well in North Texas or Louisiana.

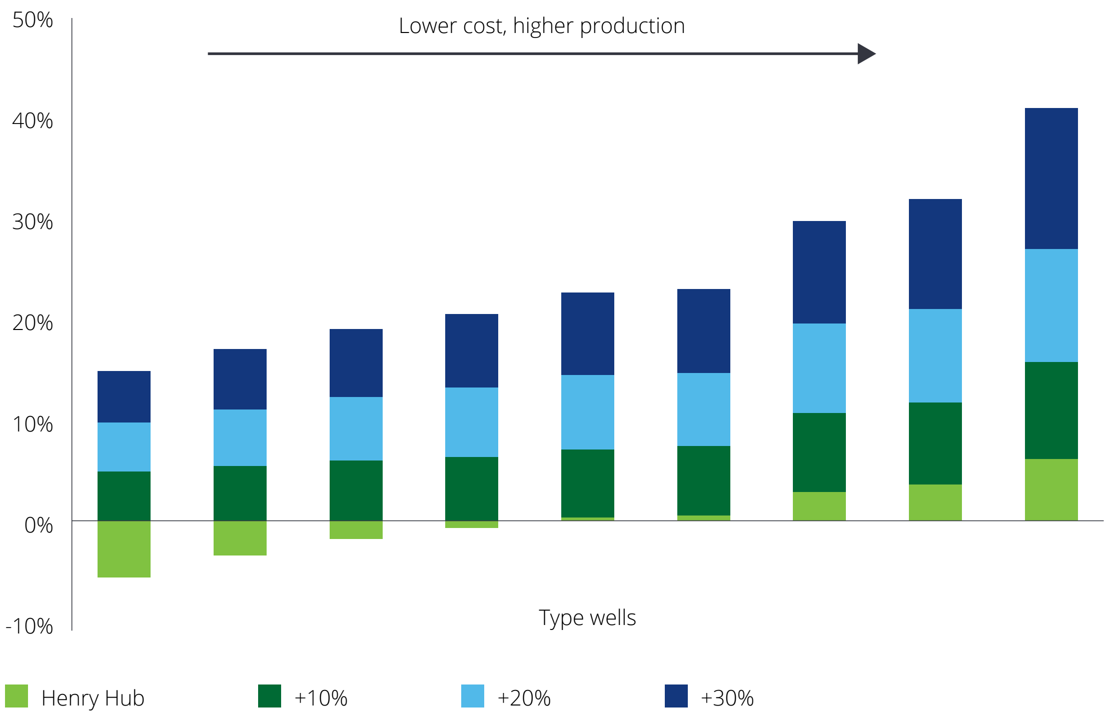
Fortunately, pipeline capacity limitations should be transient. Several key projects including expanded access to the Transco system will increase the flow of gas from the more productive regions down to the Gulf Coast, where the majority of US LNG capacity is expected to be built.[15]

Liquids production has the potential to boost value of gas wells, allowing for sustained production growth at lower prices. For example, 20 percent liquids content improves the type well rate of return by 12 percentage points, all other assumptions held constant. Based on a similar analysis of type wells from several other unconventional natural gas plays, this impact holds true for other regions as well.

The positive impact of liquids production is heavily dependent on pricing, which varies with composition and where it is traded. For example, propane currently trades at double the price of ethane on a volumetric basis.[16] And like natural gas, there are regional price differentials. The model assumes a roughly $20/bbl aggregate liquids price. Reduce this to $10 and the uplift is only 4 percentage points.

The main implication is that low oil and condensate prices decrease the number of profitable gas wells and that an increase in liquids prices will likely increase the supply of gas, all else being equal. Though expanding infrastructure capacity would likely improve gas pricing, improved liquids takeaway capacity could do much the same.

Figure 6. Indicative type-curve economics for Marcellus shale gas wells



Source: Deloitte analysis, company investor presentations, EIA

What does that 1,400 tcf resource curve mean in practice? Figure 6 illustrates a range of potential rates of return for drilling and completing a well in the Marcellus shale, which is broadly indicative of many shale plays. The horizontal axis includes nine different wells, representing a range of costs and production rates. As you move left to right, costs decrease, production rates increase, and the rate of return improves. The vertical axis shows how the rate of return varies based on natural gas prices, including the June 2016 Henry Hub forward strip price as well as at 10, 20, and 30 percent uplifts.

Both cost and production ranges for the type wells are based on a survey of company presentations and other aggregate sources. Operating and gathering costs, in addition to well declines, were held constant and general and administrative costs, royalties, taxes, and other associated fees have been excluded from the model.

The type wells used in the model illustrate the impact of the various assumptions on returns, but not necessarily the profitability of specific projects or sub-plays, since acreage can be heterogeneous and costs continue to evolve. See the indicative type-curve methodology and assumptions (Appendix 2) for more specific modelling assumptions.

Tying together the North American and global gas markets

Due to advances in shale gas production, the United States is in a position to meet its domestic consumption requirements, including the power, industrial, commercial, and residential sectors at historically low prices. Moreover, there is an opportunity to export gas internationally via both pipelines and LNG tankers. But, several key factors will impact how successfully companies will translate shale gas into LNG cargoes.

- **Production growth:** US production is projected to grow nearly 10 bcfd over the next five years, with LNG exports comprising more than 15 percent of the total. This is a large opportunity for E&P companies, but it will require internationally competitive LNG cargo prices.
- **Competitive prices:** Shale gas wells will need to generate positive return at $3.75-4.35 Henry Hub prices or lower to sustain exports that are competitive with oil-indexed LNG contracts at expected oil prices.
- **Continuing investment:** Between 2011 and 2015, companies were successful in increasing production and reserves even as capital investment decreased. Additional investment of roughly $130-160 will be need to grow production to 84 bcfd in 2020.
- **Resource base:** The supply curve for US natural gas is long and flat. While well-level economics are marginal at $3 per mcf, many wells generate strong returns at $4 that can support the burgeoning export industry for the foreseeable future.

Considering all five of these factors, the United States has all the elements required to sustainably export natural gas into Europe and Asia at competitive prices.

Appendix 1: Peer selection criteria

For all company peer group information, 32 companies are included with data sourced from S&P Market Intelligence's Capital IQ database. The study focused on US and Canadian E&P companies, with more than 80 percent production being gas on an energy equivalent basis.

The peer group included:

Advantage Oil & Gas, Antero Resources Corporation, Atlas Resource Partners, Bellatrix Exploration, Birchcliff Energy, Bonavista Energy Corporation, Cabot Oil & Gas Corporation, Carbon Natural Gas Company, Cequence Energy, Chesapeake Energy Corporation, Chinook Energy, Comstock Resources, Contango Oil & Gas, Crew Energy, Crown Point Energy, Eclipse Resources Corporation, EV Energy Partners, EXCO Resources, Gulfport Energy Corporation, Memorial Resource Development, Perpetual Energy, PetroQuest Energy, Peyto Exploration, Pine Cliff Energy, Questfire Energy Corporation, Range Resources Corporation, Rex Energy Corporation, Rice Energy, Sabine Oil & Gas Corporation, Southwestern Energy Company, Tourmaline Oil Corporation, and Ultra Petroleum Corporation.

Appendix 2: Indicative type-curve methodology and assumptions

Revenue and cost assumptions:

- Production for the Marcellus varies from 10 to 15 mmcfe/d with drilling and completions costs varying $5-7 million per well.
- Future pricing is based on NYMEX Henry Hub[17] and West Texas Intermediate (WTI)[18] indexes.
- Liquids prices are assumed to trade at a 60 percent discount to WTI, with a 6 bbl per 1 mmcf energy equivalency.
- Regional natural gas price discounts were assumed to be $1.40 per mmcf for northeast United States (Marcellus, Utica) and $0.20 per mmcf for northern Texas and Louisiana (Haynesville) based on two-year average price discounts for the AECO, Perryville, Carthage, and Leidy hubs.

Calculation methodology:

- Well economics, including production declines, revenues, and costs, were calculated on a monthly basis, with the illustrative rate of return annualized.
- Lease operating, gathering, and transport costs are assumed to be $1.05/mmcfe.
- All wells were assumed to have the same declines, with annualized decline rates shown in Figure 7.

Figure 7. Well annualized declines

Year	Annualized decline (%)
1	74
2	29
3	19
4	14
5	11
6	8
7	8

Endnotes

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Let's talk

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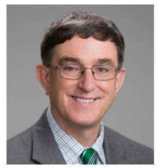

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