There Will Be Gas

An Assessment of US Natural Gas Supply in a Low Oil Price Environment

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ENERGY POLICY RESEARCH FOUNDATION INC.
EPRINC
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ABOUT THIS REPORT

The North American petroleum renaissance has yielded a rapid and massive expansion of crude oil and natural gas output from unconventional petroleum resources throughout the United States. This swift growth in crude oil production, especially from the Permian Basin, has been accompanied by substantial volumes of associated gas, a by-product of oil production. These large volumes of associated gas have contributed to an expansion of U.S. natural gas output that has risen from 60 billion cubic feet per day (BCF/d) in 2008 to over 100 BCF/d currently. As a result, the U.S. has become the largest natural gas producer in the world. These large supplies of natural gas were accompanied by very low prices placing the U.S. in a highly competitive position for exports of several value-added commodities, including natural gas liquids (NGLs), petrochemicals, and liquefied natural gas (LNG).

In November 2017, Japan and the United States jointly announced the formation of the Japan-United States Strategic Energy Partnership (JUSEP). In its fourth year, the partnership promotes energy security across the Indo-Pacific region as well as sub-Saharan Africa. Among the objectives of the joint effort is the development of a global natural gas market, including high-quality energy infrastructure that includes the expansion of LNG markets.[1]

With the addition of U.S. LNG exports into the world market, energy security has been strengthened through the increase of the diversity of supply sources and routes. Regional energy security is further enhanced because U.S. LNG exports generally lack destination restrictions and refrain from oil-indexed pricing in their contractual arrangements. While U.S. exporters must often compete in more distant markets than their competitors, the plentiful natural gas supplies and the less restrictive characteristics of U.S. LNG contracts are attractive for purchasers seeking to diversify contract terms and geographic supply sources.

With the advent of the COVID-19 pandemic in early 2020, world and U.S. crude oil prices collapsed. Price recovery is underway but it will take time before prices recover to $40-$50/bbl. These low prices are resulting in large reductions in U.S. crude oil production and its associated gas output. However, the U.S. resource base for natural gas, both dedicated (non-associated) and associated, remains vast. Companies may go bankrupt, but the geologic formations remain. A central question for policy makers and the U.S. petroleum industry is whether the current downturn in crude oil prices, particularly if it persists for a considerable period of time, will substantially alter the outlook for large and competitively priced natural gas supplies as a feedstock for LNG. This EPRINC report evaluates the potential for the U.S. to remain competitive as a major provider of LNG to the world market in a low oil price environment and what policies, if any, should be implemented to sustain the competitive outlook for the U.S.

[1]EPRINC has jointly published three extensive studies with the IEEJ (Institute for Energy Economics, Japan):
The Future of Asian LNG: Challenges and Opportunities for Policy Makers (September 2017),
The Future of Asian LNG: The Road to Nagoya (October 2018)
Asian LNG: U.S. and Japan Efforts to Expand Market Opportunities (March 2020)

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ABOUT EPRINC

The Energy Policy Research Foundation, Inc. (EPRINC) was founded in 1944 and is a not-for-profit, non-partisan organization that studies energy economics and government policy initiatives with special emphasis on oil, natural gas, and petroleum product markets. EPRINC is routinely called upon to testify before Congress as well to provide briefings for government officials and legislators. Its research and presentations are circulated widely without charge through posts on its website. EPRINC's popular Embassy Series convenes periodic meetings and discussions with the Washington diplomatic community, industry experts, and policy makers on topical issues in energy policy.

EPRINC has been a source of expertise for numerous government studies, and both its chairman and president have participated in major assessments undertaken by the National Petroleum Council. In recent years, EPRINC has undertaken long-term assessments of the economic and strategic implications of the North American petroleum renaissance, reviews of the role of renewable fuels in the transportation sector, and evaluations of the economic contribution of petroleum infrastructure to the national economy. Most recently, EPRINC has been engaged on an assessment of the future of U.S. LNG exports to Asia and the growing importance of Mexico in sustaining the productivity and growth of the North American petroleum production platform.

EPRINC receives undirected research support from the private sector and foundations, and it has undertaken directed research from the U.S. government from both the U.S. Department of Energy and the U.S. Department of Defense. EPRINC publications can be found on its website: www.eprinc.org.

EXECUTIVE SUMMARY

At the beginning of 2020 several forces disrupted world oil and gas markets. An unexpected and massive loss in demand for petroleum products and natural gas accompanied government lockdowns worldwide in response to the global pandemic from the COVID-19 virus. Having no vaccine or treatments, many national governments undertook measures to curtail the disease through massive social distancing measures in the form of school and business closures, prohibition of mass public social activities, and international travel bans. In many places, any sort of commercial or government activity has been limited to workers classified as "essential." Global oil markets have been adversely affected as mobility, in the form of air travel, shipping, and motor vehicle usage, has dropped by half. The demand collapse was exacerbated by additional supplies from a market-share feud between Russia and Saudi Arabia. In April 2020, world oil demand fell by more than 25 percent (about 25 MMB/D) while at the same time the Russian-Saudi market share feud added an additional 3 - 4 MMB/D of crude oil into the market.

In response to the price collapse, an agreement was reached on April 12th under the auspices of the G20 that called for twenty-three producing countries to withhold 9.7 MB/d from the oil market, a total of 13 percent, of global crude oil production. A U.S. delegation participated in the agreement and committed to a reduction of 300 thousand barrels per day (TB/d), but this reduction in output does not require any direct action by U.S. regulatory agencies as it can be easily achieved as companies curtail oil and gas output in response to lower prices.

With associated natural gas representing 16 percent of total U.S. marketed natural gas production, any adjustments/shut-ins to shale crude oil basins will have impacts not just on the total U.S. natural gas and NGLs (natural gas liquids) markets, but also on their outsized role in global ones.

Analysts generally rely on two indicators to assess oil and gas production prospects: company guidance, usually in the form of capital expenditure (CapEx) announcements, and rig counts. CapEx announcements foreshadow intent on the part of producers whether to increase or decrease production. Similarly, rig counts give another account of ongoing activity. However, as shale production has become more efficient and production rates per rig have increased, rig counts have become less reliable. Nevertheless, they do offer a sense of trend.

A more severe and immediate company announcement is a bankruptcy, whether to reorganize or to liquidate. Already there have been several announcements of producers in the shale oil-producing plays of this intent.

We evaluated an outlook of a 50 percent cutback in the shale oil plays. A simple calculation shows the potential removal of 5.6 BCF/d, about 5 percent of total U.S. natural gas production, and about 515 TB/d of NGLs. Neither is trivial, but the potential NGL reduction is formidable, representing over 10 percent of current production. Petroleum prices are now recovering but the pace and extent of the recovery remains to be seen.

A projected 5 percent reduction in total U.S. natural gas production, especially with multiple alternative sources for gas available along with ample inventories, should exert minimal upward pressure on prevalent prices. Except for a few recent strong cold spells in North America where Henry Hub natural gas prices spiked as high as $4.5/MMBtu in recent years, they have been declining from $3/MMBtu in late 2018 to under $2/MMBtu in 2020.

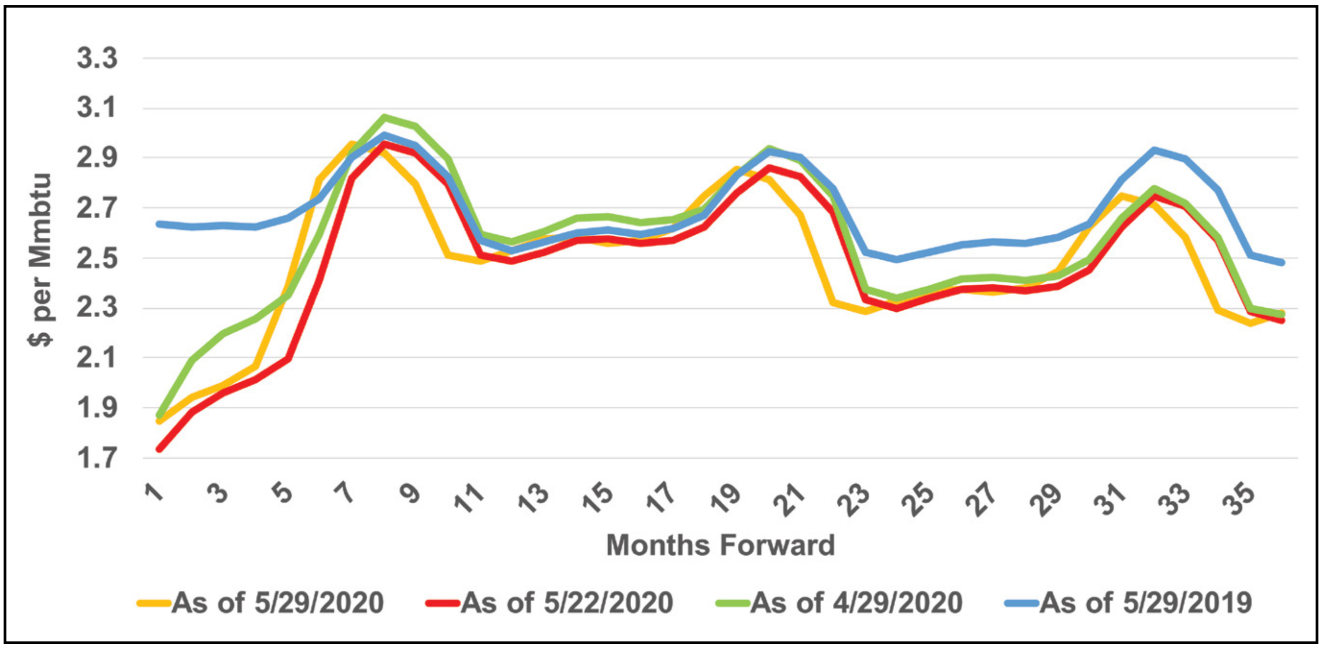
As with associated natural gas, so too with NGLs, a substantial portion of NGL production is a by-product of crude oil production; it is therefore little responsive to NGL price dynamics alone. Because of the relative strength of crude oil prices during 2019, NGL production rose considerably, outpacing domestic demand. In addition, there have been ongoing delays in the expansion of export infrastructure. Combined, they have caused NGL prices to decline substantially.

Despite the severity of these curtailments, we expect natural gas and NGL supplies to meet demand. If anything, the production reductions will provide something of a price floor for both natural gas and NGLs. For the duration of the crisis, there might be some logistical reconfigurations that may take place in order to offset the loss of some gas and NGL production from the shale oil plays. As mentioned, this could include more from the shale gas plays such as the Utica/Marcellus, Haynesville, Fayetteville ones; also, more natural gas could be sourced from Canada, depending on demand requirements as well as take-away capacity. But U.S. LNG producers and consumers should expect ample gas availability to build and market cargos.

Although we cannot fully rely upon futures prices as an accurate predictor of supply and demand conditions over the next 2 - 3 years, settlement prices for contracts traded on the CME show no indications of concern on supply availability. Contract settlements for gas delivery at Henry Hub remain well below $3/MMBtu through 2024 (see **Figure 1**). Natural gas can also be purchased at other regional hubs for low prices.

Shale resources, whether natural gas or oil, are short-cycled. So resumption of production will not be constrained much operationally. But ahead of this crisis, producers were prioritizing growth over profitability (whether robust or just occasional) subject to contractual arrangements with respective landowners. Any sort of resumption of production to previous levels will probably be required to seek greater fiscal discipline than before the crisis demanding improvements to both the quality of capital retention as well as profitability.

Figure 1
Forward Curves for Natural Gas through 05/29/2020

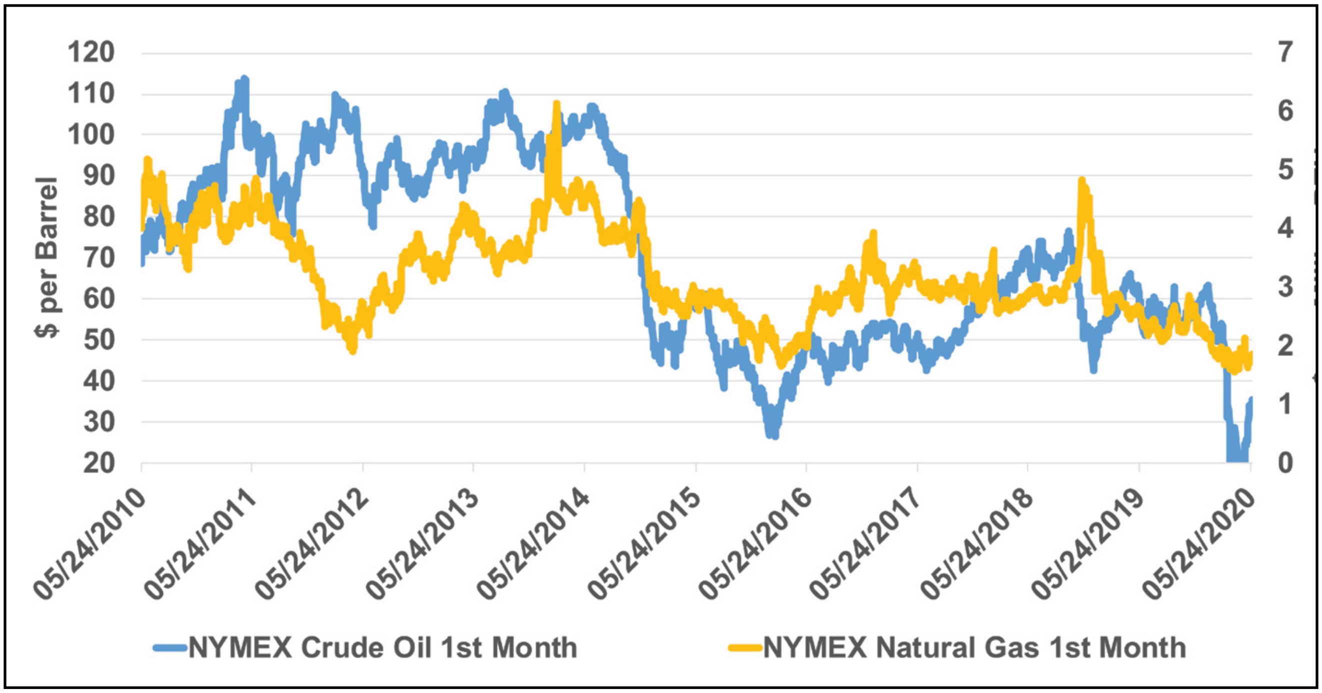


Analysis based on CME data EPRINC

INTRODUCTION

Since the last oil price collapse, which took place in mid-2014, global oil and natural gas markets have recovered and have adjusted to a lower price regimen. It is not one where key benchmarks oscillate around $100 per barrel, but rather one that has been range-bound between $40 and $70. More recently during 2019, this range has been between $50 and $65. These price dynamics can be seen in **Figure 2**.

Figure 2
NYMEX Crude Oil 1st Month vs NYMEX Natural Gas 1st Month: 05/22/2010 to 05/29/2020



Analysis based on CME data EPRINC

The 2014 oil price collapse was brought on by a surge in new production coming from North American shale formations. The combination of recently proved production technologies — hydrofracturing (fracking) along with laterally drilled wells - enabled the extraction of oil and natural gas from geological basins that were, until then, commercially unrecoverable. This new production swelled from 2008 to 2014, creating an abundance of affordable fuel as well as challenging the hegemony of OPEC and key producing countries such as Russia.

Beginning at the end of 2016, OPEC+ (the combination of OPEC along with Russia) agreed to a one-year output cut in order to bolster global oil prices. This agreement has been extended three times in the period through 2019. However during this span of time, North American shale production continued to improve technologically and thereby increase, more than offsetting any OPEC+ reductions and damping price increases.

In late 2019 and early 2020 a highly contagious respiratory pandemic that was particularly, but not singularly, lethal to the elderly, began spreading globally. Caused by SARS CoV 2 (severe acute respiratory syndrome coronavirus 2), a virus that originated in China having no vaccine or treatments, the only effective means of curtailing its spread have been massive social distancing measures in the form of school and business closures, prohibition of mass public social activities, and international travel bans. In many places, any sort of commercial or government activity has been limited to workers classified as "essential."

The distancing measures have arrested the rate of the spread of the disease. But they have also brought on a massive negative economic demand shock. Global oil markets have been adversely affected as mobility, in the form of air travel, shipping, and motor vehicle usage, has dropped by half.

Faced with this demand shock, OPEC+, rather than adjust production downward for the duration of the demand shock, raised it considerably at the beginning of March, notably due to an escalating market-share feud between Russia and Saudi Arabia, the largest producers within the de facto expanded cartel. Prices had already declined considerably; but these actions caused them to collapse.

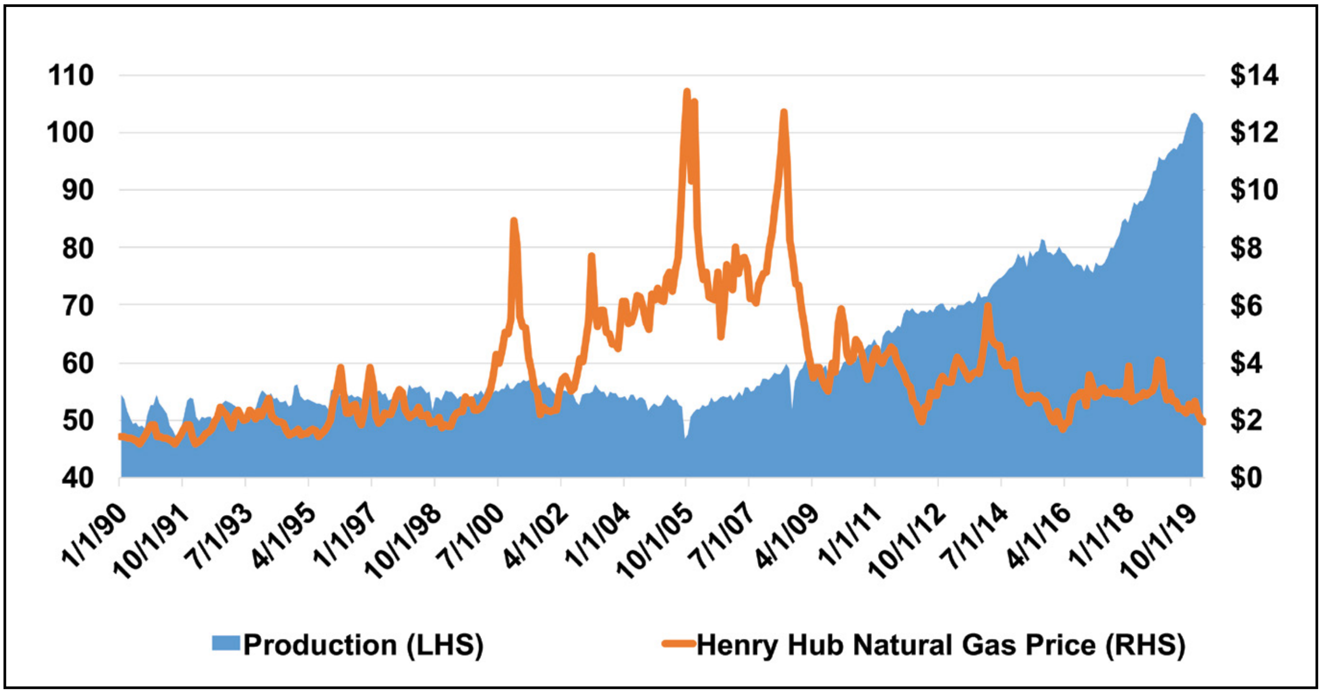
In early April, as the mismatch of the global crude oil glut combined with the massive negative demand shock became overwhelming, several crude oil producers meetings were convened and subsequently expanded. These meetings not only included the OPEC+ constituency, but also other producing countries such as Mexico and Brazil along with the G20 countries (to form a de facto OPEC++). An agreement was reached on April 12th that called for twenty-three producing countries to withhold 9.7 MB/d, or 13 percent, of global crude oil production. The U.S. delegation agreed to a 300 thousand barrel per day (TB/d) reduction, but enactment is controversial if not enforceable. A more likely outcome will be declarations and actions by individual U.S. producers to lower or even stop their production contingent on the commercial viability of their respective franchises; or in some more difficult cases, to go into bankruptcy.

In fact, as early as February when energy demand began to drop, U.S. oil and natural gas producers already began signaling intentions of lowering their output by providing investor guidance of cuts to their respective future capital expenditures (CapEx). However with the March OPEC+ production dispute and the tenuous April agreement, U.S. producers have been scrambling to shut-in supply, especially from the shale basins. In addition, they have been trying to find storage wherever possible, including on tanker vessels.

There have been numerous discussions and speculation on the nature and trajectory of an economic recovery and its effect on world petroleum markets. However, there has been less focus on the prospects for natural gas, and even less on the size and implications of U.S. associated natural gas production ("associated" natural gas is that natural gas produced concurrently or alongside crude oil, as distinguished from "non-associated" natural gas). With associated natural gas representing 16 percent of total U.S. marketed natural gas production, any adjustments/shut-ins to shale crude oil basins will have impacts not just on the total U.S. natural gas and NGLs (natural gas liquids) markets, but also on their outsized role in global ones.

This briefing presents a short background of relevant developments, enumerates possible volumetric scenarios, and highlights key issues and policy considerations.

Figure 3
Monthly U.S. Natural Gas Production (LHS) vs Henry Hub Price (RHS): to 01/31/2020



Analysis based on EIA data — EPRINC

As shown in **Figure 3**, U.S. natural gas output has experienced a massive surge in output since 2008. These large volumes brought about an initial stabilization in gas prices followed by large declines, which have for the most part remained well below $4 per MMbtu (million btus) since 2013.

The key distinguishing feature of associated natural gas is that it is a by-product; associated production is driven by the commercial considerations of crude oil production: if the latter is not economically viable, then the former does not get produced.

Like crude oil, natural gas that is extracted at the wellhead is a complex raw material that

About Natural Gas Liquids (NGLs)

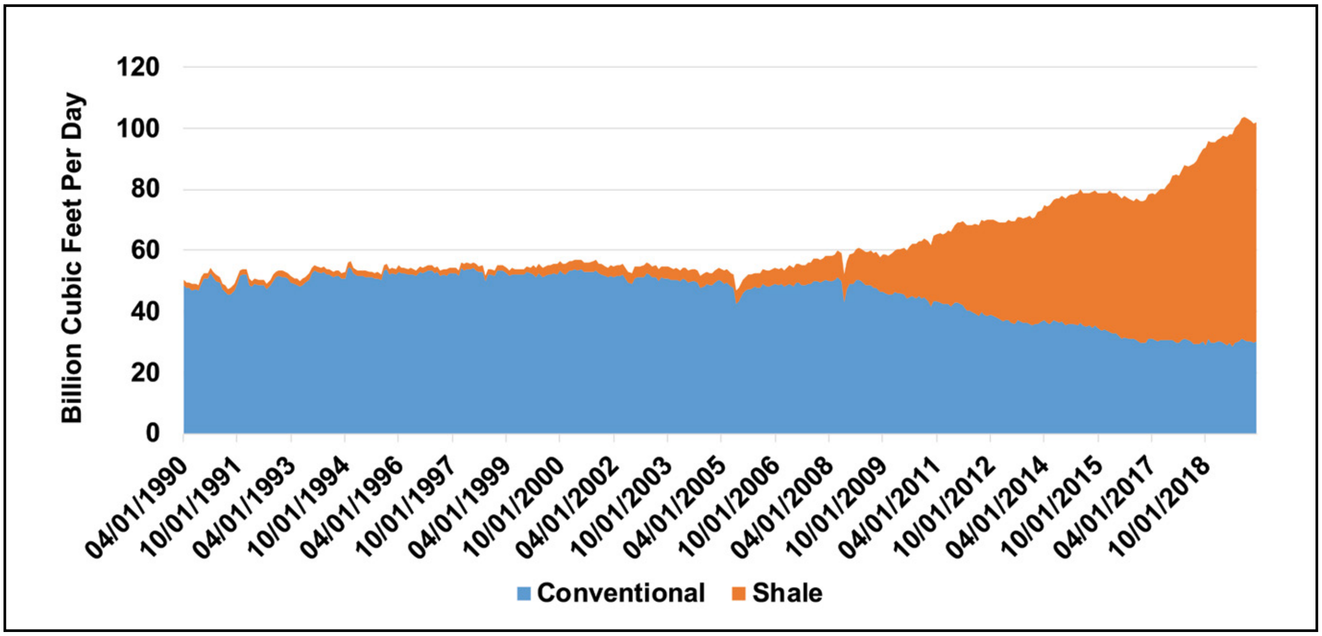
Basic natural gas processing plants remove impurities and separate wet gas into two components: methane and the NGL stream (in jargon known as “Y-grade”). Slightly more complex natural gas processing plants are known as “fractionators” doing not only the work of basic plants, but also separating (or “fractionating) the NGLs into their distinct components. The technology in both of these instances is a basic separation process similar to that of distillation that takes place in an oil refinery.

NGLs have four general application areas: fuel, petrochemical feedstock, gasoline blending components, and diluent. As fuel they are used for residential (heating, hot water, cooking) and agricultural (harvest drying and equipment fuel) requirements; as feedstock they are transformed into the intermediate components for the production of plastics, synthetic rubber, coolants, and detergents, among a myriad of other things; as blending components, especially butane during winter months, they are used to raise octane; and as diluent, in particular plant condensate, which is used to dilute heavy crude oils so that they can flow through pipelines.

requires further processing. In jargon, it is often referred to as "wet gas," comprised not only of methane (the foundational component of marketed natural gas) but also "liquid" components of ethane, propane, butane, and plant condensate (the last being a real fluid and sometimes known as "natural gasoline"), and impurities like water and sand. Together, the "liquids" components are known as "natural gas liquids" (NGLs) (alternatively, but much less often, as "hydrocarbon gas liquids" — HGLs). In addition, the composition of wet gas — the proportion of NGLs to methane — varies basin-by-basin, well-by-well.

Over the last ten years, these newly developed resources have transformed the profile of U.S. natural gas and NGL balances and logistics. Shale-sourced natural gas has grown from less than 5 percent to almost 70 percent of the total U.S. natural gas production. It has also boosted total U.S. natural gas production from just under 60 BCF/d to over 100 BCF/d (see **Figure 4**).

Figure 4
Monthly U.S. Natural Gas Production — Conventional vs. Shale:: 04/01/1990 through 03/31/2020



Analysis based on EIA data EPRINC

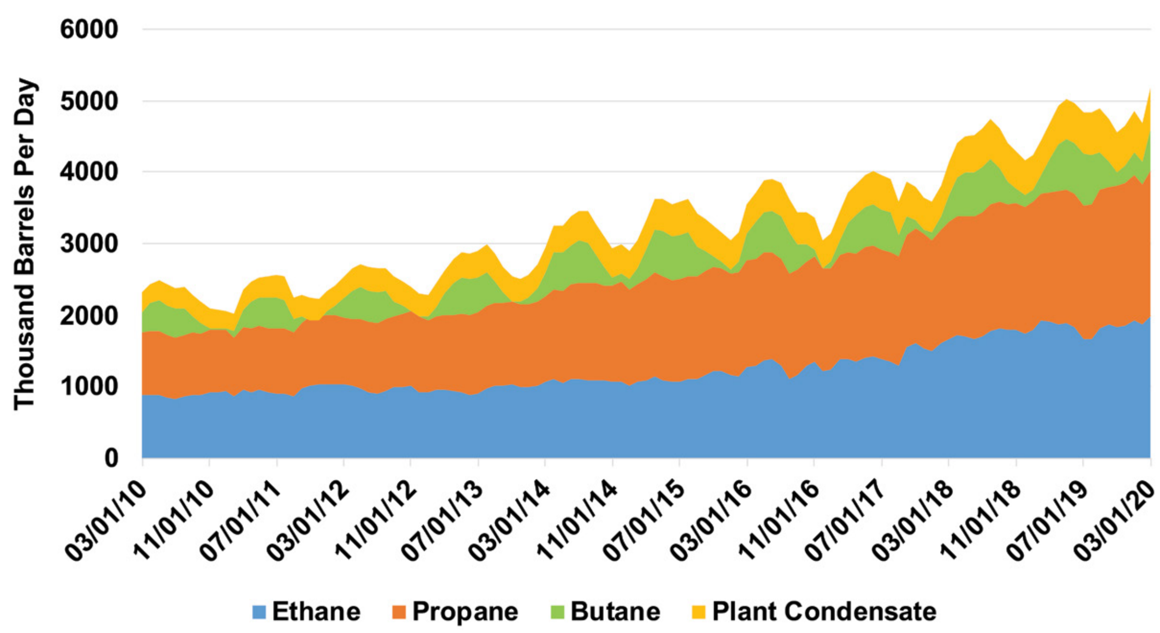
Similarly, total U.S. NGL production has grown from 2.2 MB/d in 2010 to over 5 MB/d in 2019. Extrapolating from that trend, U.S. exports have increased from 0.2 MB/d to over 2 MB/d in ten years (see **Figure 5**).

Looking at associated gas, from 2006 to 2019, gross *associated* natural gas production (with NGLs) increased overall from 4.3 BCF/d to 21 BCF/d, or 8 percent to 16 percent of total U.S. volumes. In crude oil shale basins alone, gross *associated* natural gas production increased from 1.1 BCF/d to 18 BCF/d, or 8 percent to 37 percent of natural gas extracted there (see **Table 1** on p. 10).

Domestically, this abundance has led to lower prices across all consuming sectors. Notably, key industrial users such as cement, paper, and refining plants have been and continue to be some of the beneficiaries of this surge. Access to low-cost fuel has helped the U.S. refining industry not only transform into a major global petroleum product producer, but also exporter.

Internationally, this growing natural gas abundance has reshaped global natural gas logistics allowing the U.S. to go from being a net importer

Figure 5
U.S. Production — Ethane, Propane, Butane, Plant Condensate: 03/31/2010 to03/31/2020



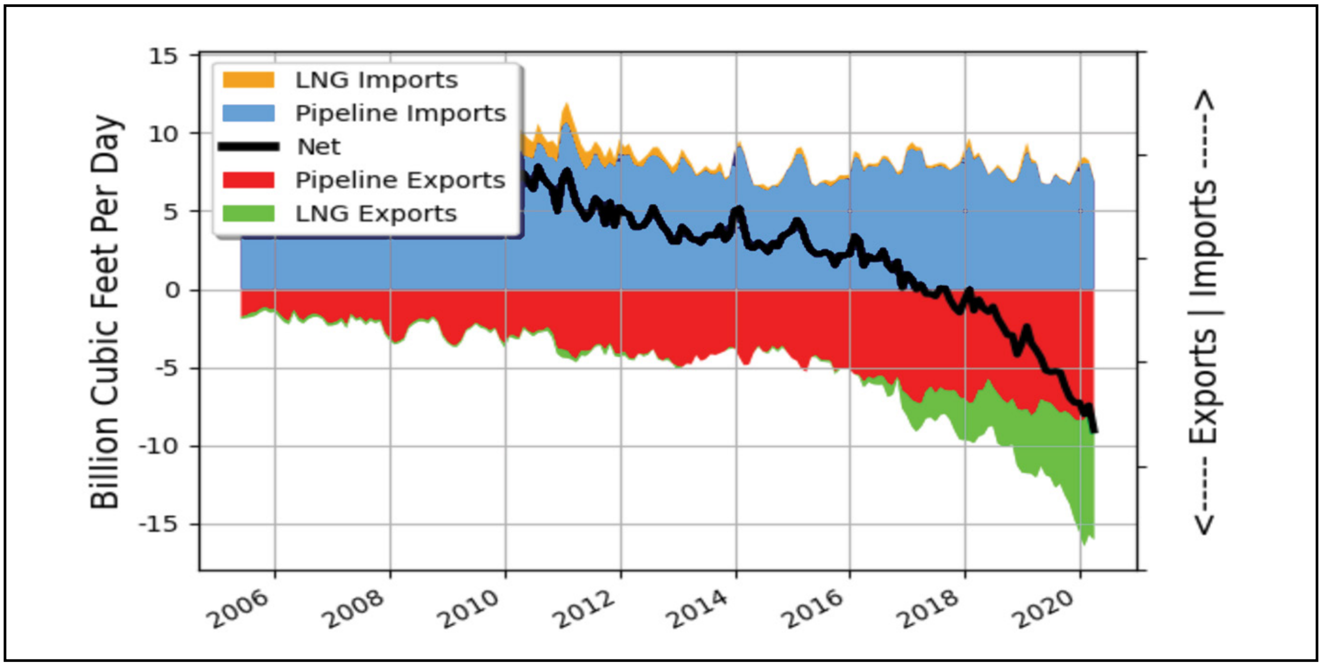
Analysis based on monthly EIA data EPRINC

of natural gas (9 BCF/d in 2005) to a net exporter beginning in 2017 (currently close to 8 BCF/d). This has challenged and even undermined the hegemony of natural gas exporters such as Russia and Qatar.

As early as 2010, companies saw the opportunity for LNG (liquefied natural gas), and began building and commissioning LNG liquefaction facilities, mostly on the U.S. Gulf Coast. Currently, there is about 9 BCF/d of commissioned LNG export capacity; another 35 BCF/d are in various stages of planning and development. Of the almost gross 15 BCF/d that the U.S. exports, 6 BCF/d now is in the form of LNG exports, making the U.S. third in LNG exports after Qatar and Australia (**Figure 6**).

During this expansionary production/low-price period, U.S. natural gas consumption has risen overall from 58 BCF/d in 2007 to 77.5 BCF/d in 2019; this represents incremental growth of 33 percent, or an annualized rate of 2.4 percent. All consuming sectors have shown increases; but the largest increase has been the power generation sector rising 12.3 BCF/d, or 4.3 percent annualized, from 18.7 BCF/d to 31 BCF/d. A large portion of this has been natural gas displacing coal-fired generation. A complete view can be seen in **Figure 7**.

Figure 6
U.S. Natural Gas Trade:
05/31/2005 to 03/31/2020



Analysis based on monthly EIA data

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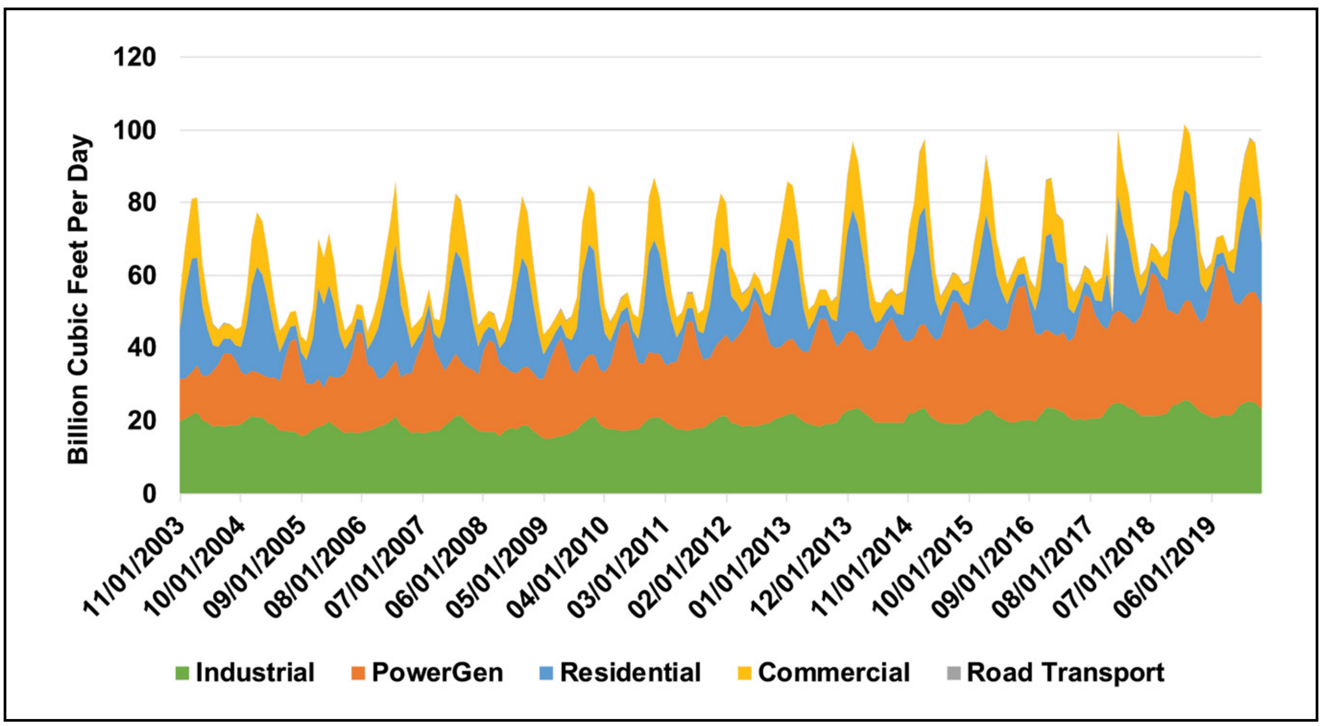
Figure 7
Natural Gas United States:
11/02/2003 to 03/31/2020



Analysis based on EIA data

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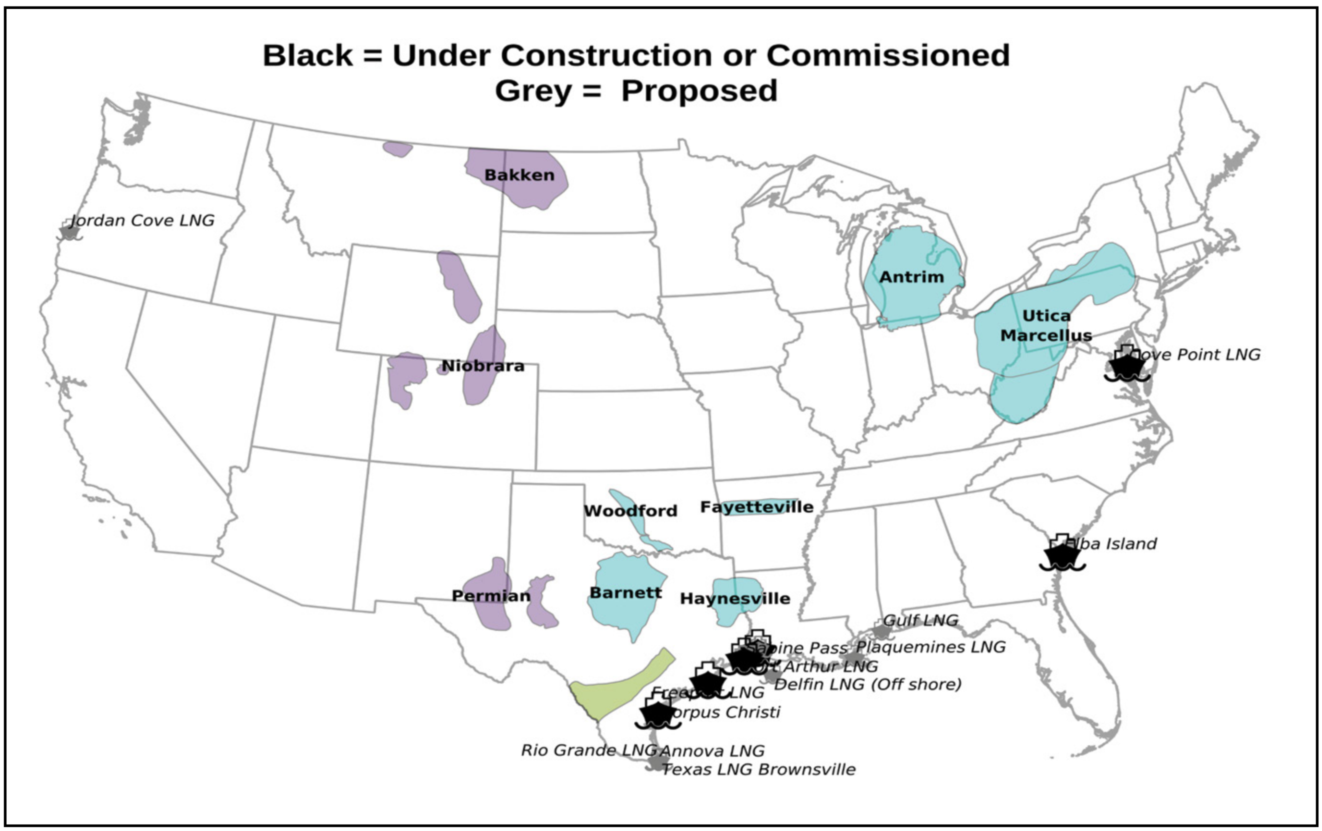
MAIN OIL-PRODUCING SHALE FORMATIONS WITH ASSOCIATED NATURAL GAS PRODUCTION

From 1997 through 2010, the first key U.S. shale basins were found and developed. Subsequently, additional ones have been commissioned as they have been geologically identified and economically proven. Many are located along either the eastern slopes of the Rocky Mountains or western slopes of the Appalachians, close to where conventional oil and gas production in North America was first developed. The primary natural gas producing ones (i.e. "non-associated" natural gas) are the Marcellus and Utica formations straddling the tri-state region of western Pennsylvania, eastern Ohio, and West Virginia. Other, natural gas-producing basins are found in central Texas, Oklahoma, and Arkansas (Barnett, Haynesville, and Fayetteville, respectively — **Figure 8**).

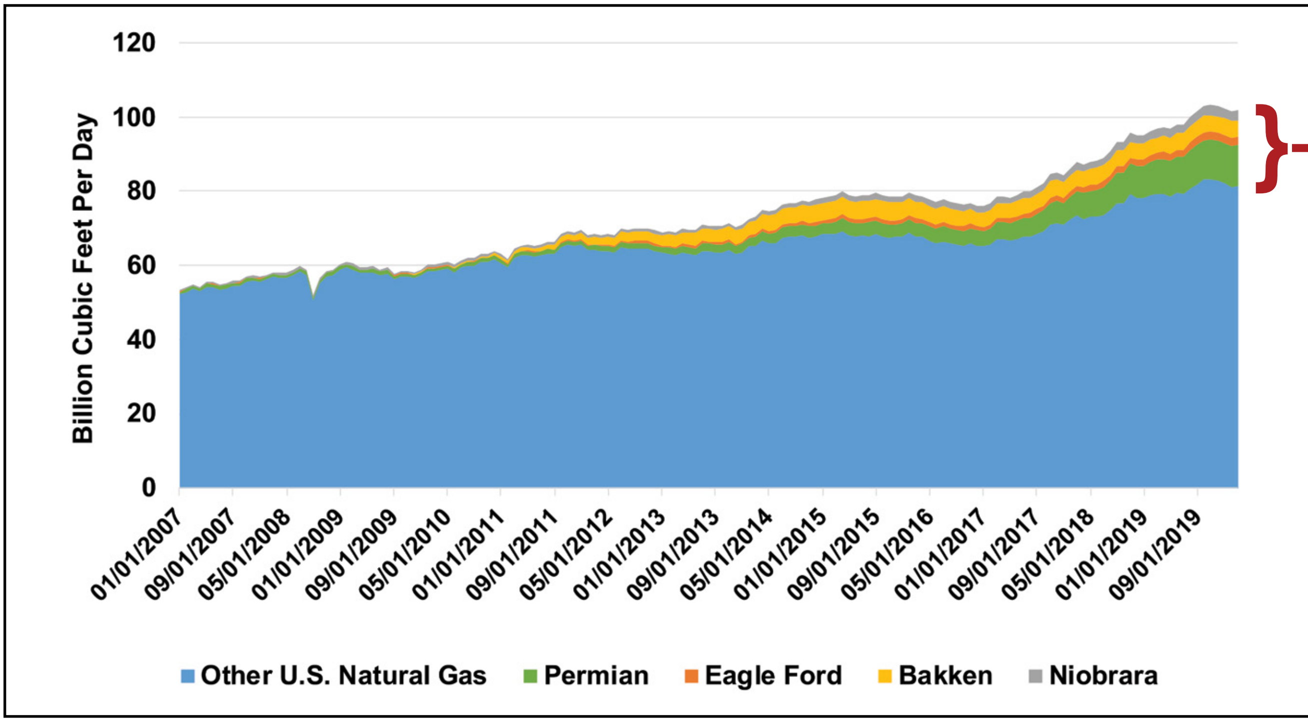
Of the oil-producing plays, the most prolific are the Permian, the Eagle Ford, and the Bakken. The first two are in the western part of Texas (with part of the Permian also in New Mexico), while the Bakken spreads from western North Dakota to eastern Montana. Other oil-producing shale plays that are less prolific are the Niobrara straddling Wyoming, Colorado, and western Nebraska, and the SCOOP/STACK (South Central Oklahoma Oil Province/Sooner Trend, Anadarko, Canadian, Kingfisher plays) essentially all within the Anadarko basin in Oklahoma. Data for these shale oil plays can be found in **Table 1** and **Figure 9** (located on next page) summarizing their natural gas, crude oil, and NGL production, along with their associated natural gas output.

Figure 8
U.S. Shale Plays & LNG Plants



Analysis based on EIA, USDA and RFA data EPRINC

Figure 9
Monthly U.S. Natural Gas Production — Mayor Oil Shale Plays Natural Gas Production vs. Other U.S. Natural Gas Production: 04/30/2004 through 03/31/2020



Anaylysis based on EIA data EPRINC

Table 1[2]

2019 Averages	Associated Natural Gas Calculations				NGL Estimates		
Gas in BCF/d; Liquids in TB/d	Dry Gas Production	Gross Gas Production	Associated Gas From Gross Production	Dry Gas From Associated Production	Total NGLs – TB/	From Associated Production	Crude Oil Production
Permian	9.9	14.9	7.6	5.0	939.2	479.0	4,310.2
Bakken	1.9	2.9	2.7	1.8	276.4	254.2	1,442.9
Eagle Ford	4.4	6.8	3.2	2.1	466.1	220.4	1,377.3
Niobrara	2.5	5.4	1.8	0.8	76.4	25.0	729.1
Anadarko	4.8	7.8	2.5	1.6	149.2	48.8	567.9
Totals	23.5		17.8	11.3	1,907.2	1,027.4	8,427.4

Analysis based on Industry Reports and EIA data EPRINC

This 11.3 BCF/d is about half of the Natural Gas Production in the Oil Shale Basins.

[2]Assumptions in Table 1 on NGL output and associated gas percentage per basin were taken from the following EIA Today In Energy series:
EIA tracks oil and natural gas production by both surface location and geologic formation (November 10, 2014)
EIA adds new play production data to shale gas and tight oil reports (February 15, 2019)
U.S. natural gas plant liquid production continues to hit record highs (March 22, 2019)
Associated gas contributes to growth in U.S. natural gas production (November 4, 2019)
North Dakota flared 19% of its natural gas production in 2019 (April 22, 2020)

CAPEX AND RIG COUNT CUTS, AND BANKRUPTCIES

With the onset of the epidemic and the resulting negative demand shock to global oil and gas markets, coupled with the OPEC+ production disputes, analysts have been attempting to quantify the impacts, determine the duration and effect on producers, as well as predict possible recovery scenarios. The goal here is to evaluate potential impact on U.S. and global natural gas and NGL markets and logistics.

Over the course of the last ten years, the increase in U.S. associated natural gas production as a proportion of shale crude oil production has not been linear. We are likely to see the same nonlinear response as production is curtailed.

Analysts generally rely on two indicators to assess oil and gas production prospects: company guidance, usually in the form of capital expenditure (CapEx) announcements, and rig counts. CapEx announcements foreshadow intent on the part of producers whether to increase or decrease production. Similarly, rig counts give another account of ongoing activity. However, as shale production has become more efficient and production rates per rig have increased, rig counts have become less reliable. Nevertheless, they do offer a sense of trend.

A more severe and immediate company announcement is a bankruptcy, whether to reorganize or liquidate. Already there have been several announcements of producers in the shale oil-producing plays of this intent.

Table 2 presents recent announcements of

Table 2

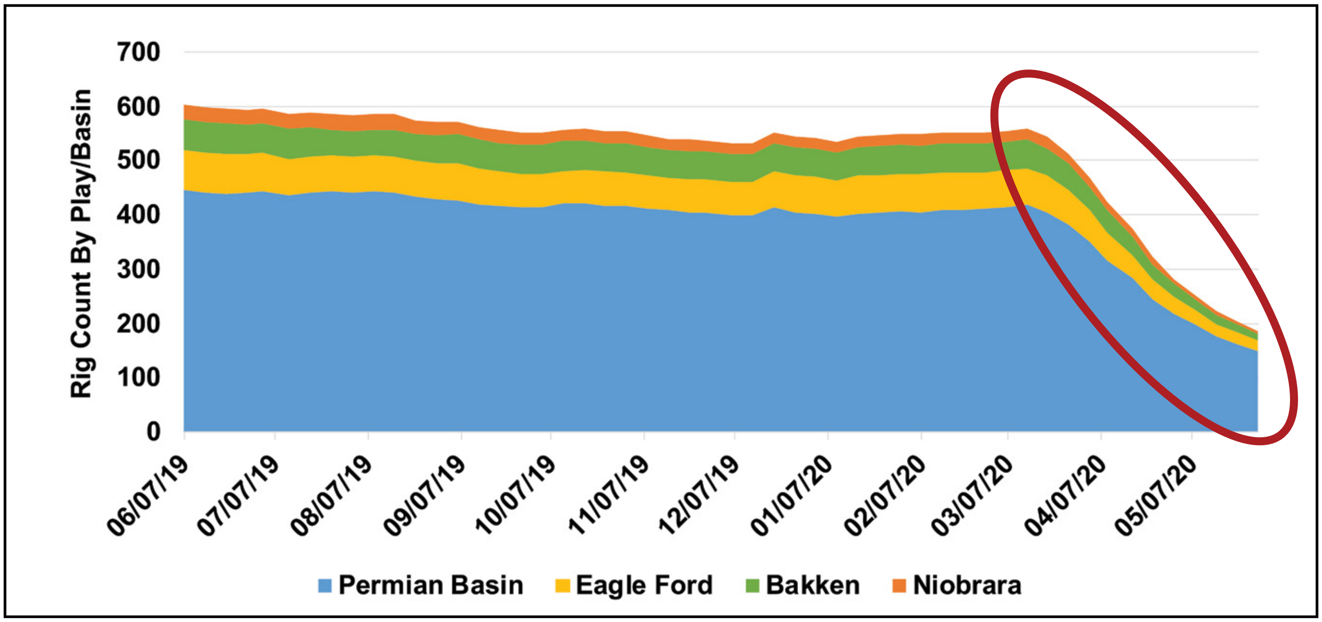
Permian Producers				
	Revised capex ($ billion)	Change (%)	Production ('000 b/d)	Change ('000 b/d)
Apache Corp.	1.1	-37.0%		
BP	12.0	-25.0%	430.0	-70.0
Callon Petroleum	0.7	-27.0%		
Centennial Resource Development	0.3	-50.0%		
Chevron	14.0	-30.0%	1,920.0	-250.0
Cimarex Energy	0.6	-58.0%	65.8	-28.2
Concho Resources	1.6	-35.0%	198.6	-10.5
ConocoPhillips	4.3	-35.0%	830.0	-420.0
Devon Energy	1.0	-44.0%		
Diamondback Energy	1.7	-41.0%	188.0	-22.0
Earthstone Energy	0.1	-67.0%	14.3	-1.8
EOG Resources	4.5	-31.0%	456.0	-62.2
Extraction Oil & Gas	0.2	-42.0%		
ExxonMobil	23.0	-31.0%	3,600.0	-400.0
Laredo Petroleum	0.3	-36.0%	81.0	-4.0
Marathon Oil	1.3	-46.0%		
Matador Resources	0.5	-35.0%		
Noble Energy	0.9	-50.0%		
Occidental Petroleum	2.8	-47.0%	1,290.0	-85.0
Ovintiv	2.2	-19.0%		
Parsley Energy	1.0	-41.0%		
PDC Energy	0.6	-48.0%	180.0	-30.0
Pioneer Natural Resources	1.8	-45.0%	211.0	-28.8
QEP Resources	0.0	-32.0%	17.5	-1.5
Ring Energy	0.0	-63.0%		
Royal Dutch Shell	20.0	-20.0%		
WPX Energy	1.3	-23.0%	150.0	-10.0
Average for Percentage; all else Totals	$97.7	-39.2%	9,632.10	-1,423.9

Analysis based on Platts data — EPRINC

capex reductions of companies that are active in the Permian. The projected decrease is almost $100 billion with a projected reduction of about 1.5 MB/d, or about 32 percent of 2019 Permian crude oil production.

Similarly, **Figure 10** and **Table 3** show that since the beginning of 2020 there has been a reduction in rig counts in the main oil producing plays of almost 50 percent, or a drop from 544 to 282. The bulk of this has been in the Permian; but in terms of percent the idled rigs in the Niobrara, Eagle Ford, and Bakken have been considerable at 65, 55, and 50 percent, respectively.

Figure 10
Weekly U.S. Rig Counts — Oil Producing Basin: 06/04/2019 to 05/29/2020



Analysis based on weekly Baker-Hughes data EPRINC

Table 3

Weekly U.S. Rig Counts - Oil Producing Basins					
	Permian	**Eagle Ford**	**Bakken**	**Niobrara**	**Total**
12/27/19	405	67	52	20	544
5/1/20	219	30	26	7	282
	-186	-37	-26	-13	-262
	-45.9%	-55.2%	-50.0%	-65.0%	-48.2%

Analysis based on Baker-Hughes data EPRINC

ASSESSING IMPACTS

Because associated natural gas production is driven by the commercial interests of crude oil production, disposition of natural gas in excess of domestic requirements becomes problematic. Natural gas prices alone do not convey the direction of demand requirements. This means that even with an over-supply of natural gas in the market, there could still be new production being commissioned. The reverse is potentially true – natural gas production is cut despite being marketable at prevailing prices - especially in the current environment of low crude oil prices brought on by depressed demand and the price feud between Russia and Saudi Arabia.

PRODUCTION SCENARIOS

Table 4 summarizes the size of reductions to associated natural gas and NGL production in the shale crude plays. This approach is a linear approximation. While more detailed, non-linear approximations can provide more nuanced discussions of the range of possibilities, this linear approximation presents a high-level direct view of the impacts on associated gas supplies brought on by cutbacks to shale oil production.

Using a range from -10 to -50 percent in increments of 10 percent, **Table 4** shows the potential declines in dry gas and NGL production. Assuming a 50 percent cutback in the shale oil plays, the same as the drop in rigs, a simple calculation shows the potential removal of 5.6 BCF/d of production and about 515 TB/d of NGLs. Neither is trivial, but the potential NGL reduction is formidable, representing over 10 percent of current production.

At 5.6 BCF/d, or about 5 percent of total U.S. natural gas production, this sort of reduction is relatively small. However as production in the shale oil basins is curtailed for the duration of crisis, and perhaps afterwards, there could be adjustments to varying degrees in the realm of logistics, LNG production, and prices.

Table 4

2019 Averages	Associated Natural Gas Calculations				NGL Estimates		
Gas in BCF/d; Liquids in TB/d	Dry Gas Production	Gross Gas Production	Associated Gas From Gross Production	Dry Gas From Associated Production	Total NGLs – TB/	From Associated Production	Crude Oil Production
Totals	23.5		17.8	11.3	1,907.2	1,027.4	8,427.4
Shut-in %tage of Associated Wells – How much comes off?							
	-10.0%			-1.1		-102.7	
	-20.0%			-2.3		-205.5	
	-30.0%			-3.4		-308.2	
	-40.0%			-4.5		-411.0	
	-50.0%			-5.6		-513.7	

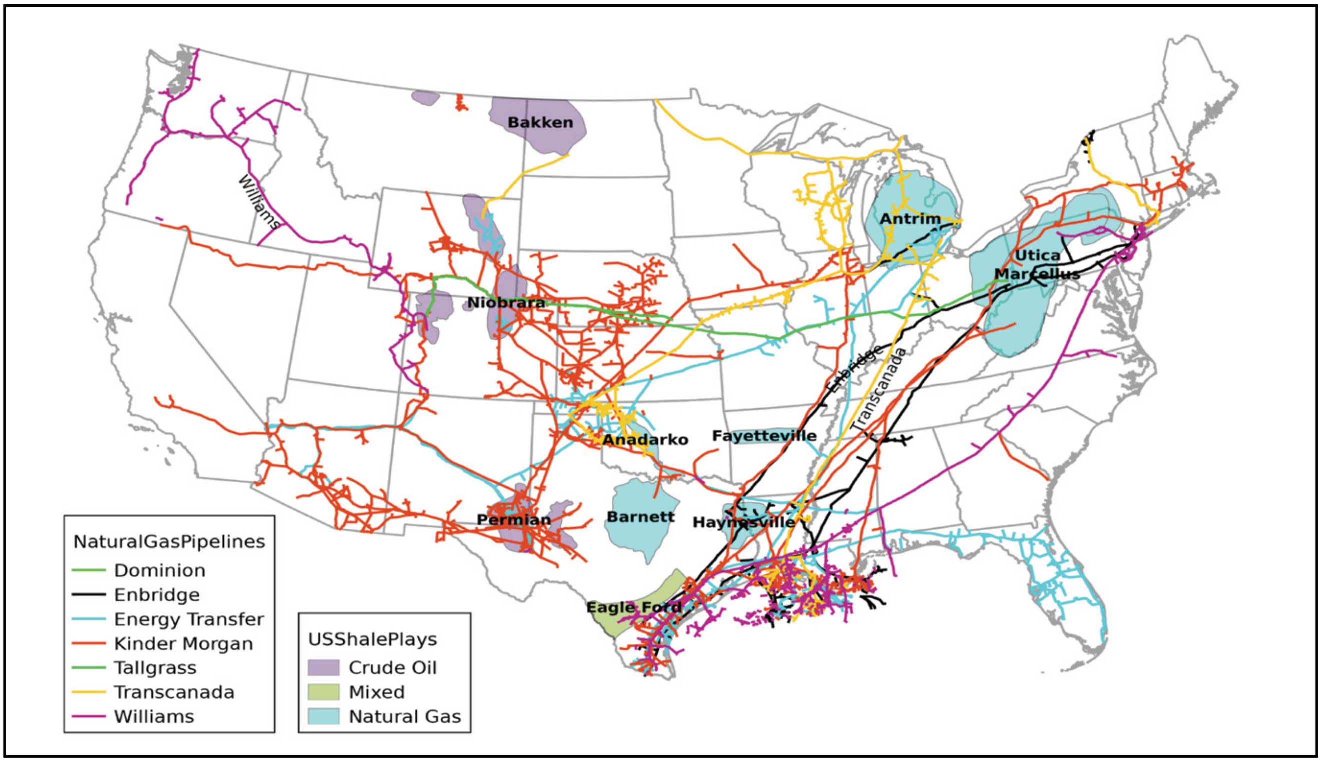
Analysis based on Industry Reports and EIA data | EPRINC

Logistics

Logistically, whatever gas production is removed from the oil shale plays could be replaced by other sources depending on demand requirements, relative pricing, and pipeline availability. This realignment could include increased output from the Marcellus/Utica formations depending on destination needs (Marcellus/Utica takeaway capacity is primarily available south-, west-, and north-bound; less so toward the east). Alternatively, more gas could be sourced from other U.S. gas plays such as Haynesville and Fayetteville, or even from Canada using one of several cross-border pipelines (**Figure 11**).

To note, there is some friction in shale production: companies contract parcels of land from owners. Lease terms usually require some form of development and production to take place within a certain period of time. If during that time, no production or development takes place, then the lease holder potentially forfeits their claim and whatever financial deposit they made to secure that claim. In sum, there are also considerations of operating costs, transport costs, costs of stopping and restarting production, taxes, and oil quality.

Figure 11
Main Shale Play Formations and U.S. Natural Gas Pipeline Systems



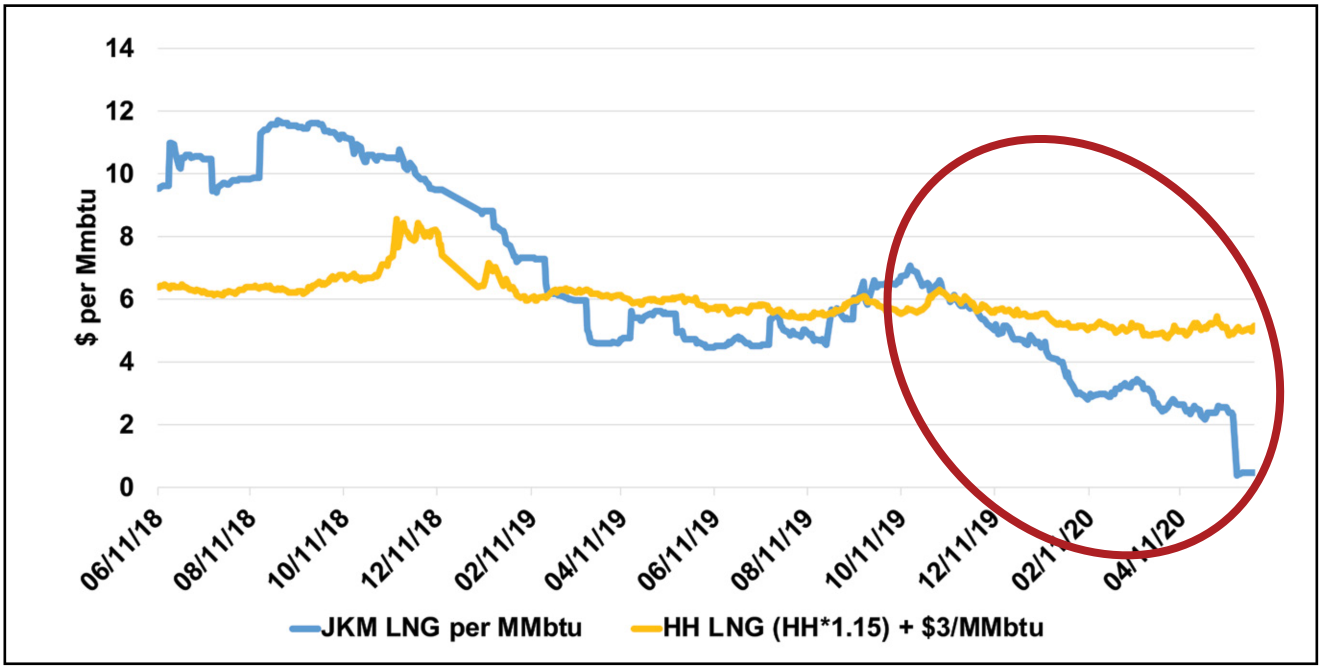
Analysis based on EIA, Company data EPRINC

Price

A projected 5 percent reduction in production, especially with multiple alternative sources for gas available along with ample inventories, should exert minimal upward pressure on prevalent prices. Except for a few strong cold spells in North America where Henry Hub natural gas prices spiked over $4.5/MMBtu, they have been declining from $3/MMBtu to under $2/MMBtu in 2020.

As can be seen in the **Figure 12**, both U.S. Henry Hub LNG as well as JKM (Japanese Korea Marker) LNG prices have been low for a considerable period of time. The current pandemic crisis along with the demand shock have pulled them back more. Any sort of rebound from a contraction in U.S. natural gas production, especially between 5 to 6 BCF/d, should be minimal, especially if those supplies can be easily substituted from production elsewhere.

Figure 12
Japan Korea Marker vs. Henry Hub LNG Contract: 06/09/2018 through 05/29/2020



Analysis based on CME and EIA data EPRINC

LNG

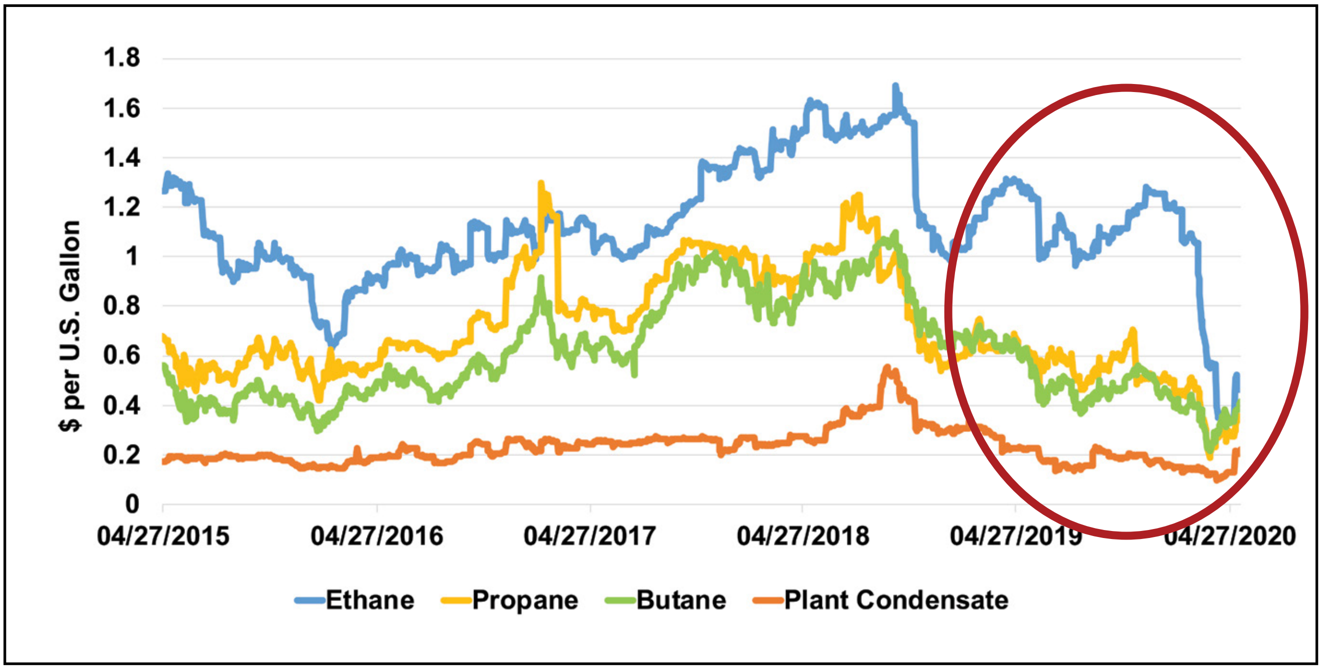
Most LNG producers use a tolling model: an LNG consumer buys natural gas from the grid, and an LNG operator liquefies the gas and builds and LNG cargo. Commodity price risk is born by the purchaser. Tellurian, one of the U.S. LNG producers that as yet has not commissioned their production plant, is one of the exceptions to the tolling model; they are vertically integrated having their own dedicated resource in the Haynesville formation. There are no alternative uses for their production other than LNG.

NGLs

As with associated natural gas, so too with NGLs, a considerable portion of NGL production is a by-product of crude oil production, little responsive to NGL price dynamics alone. Consequently, NGL production rose considerably in 2019 only to have prices drop because of a combination of limited growth in both domestic demand and export infrastructure (**Figure 13**).

With the possibility of 500 TB/d NGL production decline associated with oil shale basins shutting in (**Table 4** on p. 13), this could be supportive for NGL prices, but there still would be plenty of supply to accommodate demand.

Figure 13
Plant Condensate, Butane, Propane, Ethane:
04/26/2015 to 05/29/2020



Analysis based on CME and EIA data | EPRINC

CONCLUSIONS & POLICY CONSIDERATIONS

Because of the pandemic and the OPEC++ market-share feud, there is substantial ongoing production contraction that is taking place across the expanse of the U.S. oil, gas, and NGL production space. Not only is this causing the rationalization of production it is possibly leading to the contraction of producing entities.

Despite the severity of this curtailment, there probably will continue to be ample natural gas and NGL supplies to meet both U.S. domestic demand and export requirements. There might be some shifts in sectoral demand - perhaps an increase in residential demand offset by a decrease in commercial requirements in the event the pandemic lasts and people continue to work from home where possible.

If anything, the production reductions will provide something of a price floor for both natural gas and NGLs. For the duration of the crisis, there might be some logistical reconfigurations that may take place in order to offset the loss of some gas and NGL production from the shale oil plays. As mentioned, this could include more from the shale gas plays such as the Utica/Marcellus, Haynesville, Fayetteville ones; also, more natural gas could be sourced from Canada, depending on demand requirements as well as take-away capacity (**Figure 11** on p. 14). But U.S. LNG producers and consumers should expect ample gas availability to build and market cargos assuaging any concerns that might affect JUSEP.

Shale resources, whether natural gas or oil, are short-cycled. So resumption of production will not be constrained much operationally. But prevailing benchmark prices are key. In the first quarter 2020 Dallas Federal Reserve Energy Survey, about 130 producers responded that in order for existing shale wells to keep operating they required an average $27.50 WTI price. However in order to achieve profitability, the respondents indicated that they would need an average $49.20 WTI. **Table 5** summarizes some of the Dallas Federal Reserve Survey results by shale plays.

Lastly, ahead of this crisis, producers were prioritizing growth over profitability (whether robust or just occasional) subject to contractual arrangements with respective landowners. Any sort of resumption of production to previous levels will probably be required to seek greater fiscal discipline than before the crisis demanding improvements to both the quality of capital retention as well as profitability.

Table 5

Dallas Fed Quarterly Energy Survey - 1Q2020 Responses
Required WTI Price To* ...

	Permian	Eagle Ford	Bakken	Other U.S. Shale
... Maintain Operations	28.01	23.38	28.00	30.44
... Achieve Profitability	48.90	46.00	51.00	51.00

*These are averages based on a wide range of replies and number of respondants
Analysis based on Dallas Fed data

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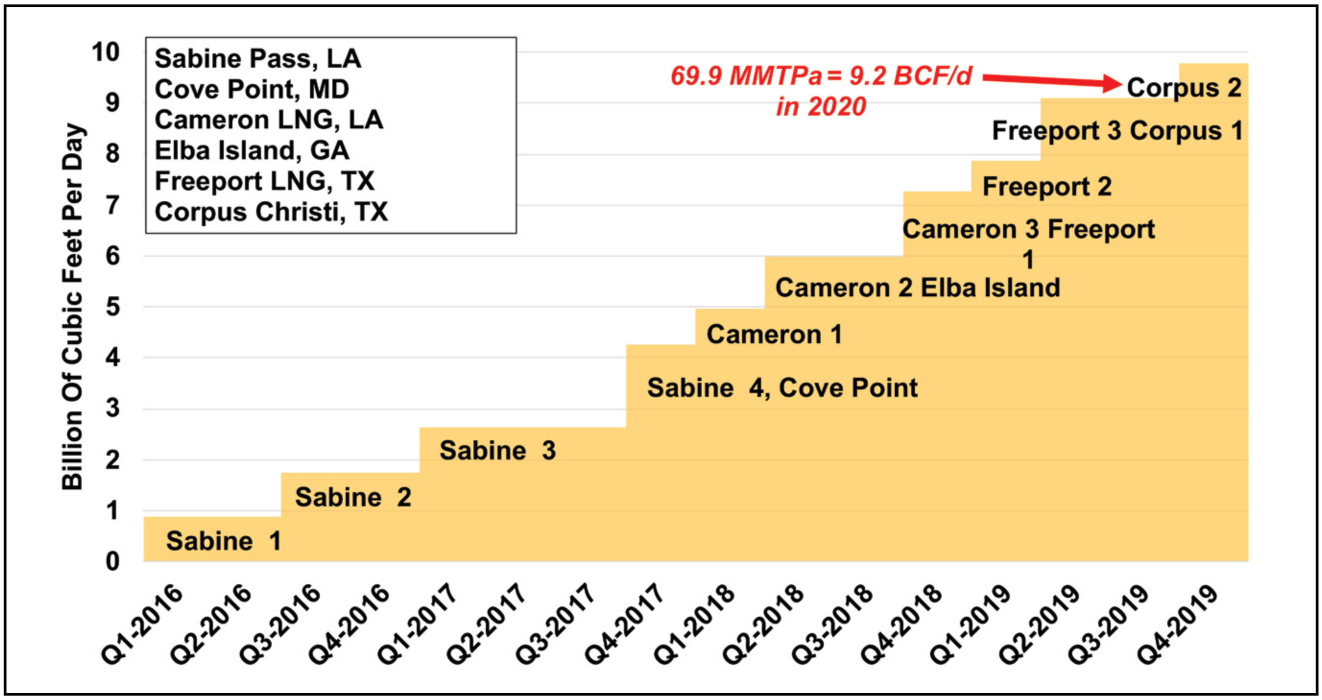
APPENDIX: U.S. LNG EXHIBITS

U.S LNG Export Projects							
LNG Export Project	Owner	State	MTP	BCF/d	Initial Export Target Date	FERC/MARAD Filing Date	Status of LNG Contracts (FS= Fully Subscribed)
Commission or Under Construction							
Sabine Pass (Trains 1-4)	Cheniere Energy	LA	20.0	2.6	Q1-2016	01/31/2011	FS
Cove Point LNG	Dominion Resources	MD	5.7	0.8	Q4-2017	04/01/2013	FS
Cameron LNG (Trains 1-3)	Sempra and Partners	LA	16.0	2.1	Q1-2018	12/07/2012	FS
Elba Island	Kinder Morgan	GA	2.5	0.3	Q2-2018	03/10/2014	FS
Freeport LNG (Trains 1-3)	Freeport LNG	TX	13.4	1.8	Q4-2018	08/31/2012	FS
Corpus Christi (Trains 1-3) 3	Cheniere Energy	TX	15.0	2.0	Q2-2019	08/31/2012	T1 & T2 FS
Sabine Pass (Trains 5-6) 3	Cheniere Energy	LA	10.0	1.3	Q3-2019	09/30/2013	T5 FS
Cameron LNG (Trains 4-5)	Sempra and Partners	LA	10.0	1.3	Q4-2019	09/28/2015	Unknown
	Cheniere Energy		45.0	5.9			
	Dominion Resources		5.7	0.8			
	Sempra and Partners		25.9	3.4			
	Kinder Morgan		2.5	0.3			
	Freeport LNG		13.4	1.8			
In Various Proposed Stages							
Driftwood LNG	Tellurian	LA	26.0	3.4	Q2-2020	05/11/2016	Unknown
Golden Pass Products	Qatar Petro., Exxon	TX	15.6	2.1	Q2-2021	07/07/2014	Unknown
Calcasieu Pass	Venture Global LNG	LA	10.8	1.4	Q2-2021	09/04/2015	Part. Sub.
G2 LNG	G2 LNG	LA	14.0	1.8	Q2-2021	12/23/2015	Unknown
Plaquemines LNG	Venture Global LNG	LA	10.0	1.3	Q2-2021	03/31/2017	Unknown
Rio Grande LNG	NextDecade	TX	27.0	3.6	Q1-2022	05/05/2016	Unknown
Annova LNG	Exelon	TX	6.0	0.8	Q1-2022	07/13/2016	Unknown
Delfin LNG (Off shore)	Fairwood LNG	LA	13.0	1.7	Q2-2022	05/08/2015	Unknown
Texas LNG Brownsville	Texas LNG	TX	2.0	0.3	Q2-2022	03/31/2016	Unknown
Port Arthur LNG	Sempra, Woodside	TX	13.5	1.8	Q2-2023	11/29/2016	Unknown
Alaska LNG	State of Alaska & Part.	AK	19.0	2.5	Q2-2024	09/12/2014	Unknown
Lake Charles LNG 4	Energy Tran., Shell (BG)	LA	16.5	2.2	Unknown	03/25/2014	Unknown
Magnolia LNG	LNG Ltd.	LA	8.0	1.1	Unknown	04/30/2014	Part. Sub.
Gulf LNG	Kinder Morgan & Part.	MS	11.0	1.4	Unknown	06/19/2015	Unknown
Eagle LNG	Eagle LNG Part. (Ferus)	FL	1.0	0.1	Unknown	01/31/2017	Unknown
Jordan Cove LNG	Veresen	OR	7.8	1.0	Unknown	02/10/2017	Unknown
SCT&E LNG	SCT&E LNG	LA	15.75	2.1	Unknown	Proposed	Unknown
Port Comfort LNG	Lloyds Energy	TX	9.6	1.3	Unknown	Proposed	Unknown
Totals							
Commission Or Under Construction			92.5	12.2			
Approved Expansions			15.0	2.0			
In Various Proposed Stages			226.5	29.8			
GRAND TOTAL			334.0	44.0			

Analysis based on Company Sources, LNG Allies data — EPRINC

U.S. LNG Exports are Growing:
Projects Approved and Commissioned or Under Construction



Analysis based on EIA data | EPRINC