Outlook for Natural Gas Supply and Demand for 2017-2018 Winter

Energy Ventures Analysis, Inc. (EVA)

Executive Summary

While the forthcoming winter weather is expected to be close to normal, total consumption, which is the combination of demand and exports, will be at a record high and even exceed the total consumption that occurred for the polar vortex winter of 2013/2014. A key reason for this occurrence is the increase in both LNG exports and pipeline exports to Mexico that has occurred over the last two years. Nevertheless, natural gas supplies are expected to be adequate to meet this expected record consumption level. The latter occurs primarily because of increases in domestic consumption, as storage withdrawals are close to normal for recent times and net Canadian imports are flat. Projected changes from last winter for each of the major components of consumption and supply are summarized in Exhibit 1.

Exhibit 1. Outlook For Winter Supply and Demand[1]

	Coming Winter (2017/2018)		Last Winter (2016/2017)		Change	
Sector	BCF	Average BCFD	BCF	Average BCFD	BCF	Average BCFD
I. Natural Gas Consumption						
Residential	3,437	22.8	3,186	21.1	251	1.7
Commercial	2,128	14.1	1,956	13.0	172	1.1
Industrial	3,502	23.2	3,462	22.9	40	0.3
Electric	3,426	22.7	3,189	21.1	237	1.5
Lease, Plant and Pipeline Fuel	1,020	6.7	947	6.3	73	0.5
Subtotal	*13,513*	*89.5*	*12,740*	*84.4*	*773*	*5.1*
Net Exports[2]	1,098	7.3	775	5.1	323	2.1
Total	**14,611**	**96.8**	**13,515**	**89.5**	**1,096**	**7.2**
II. Lower-48 Supply						
Lower-48 Production[3]	11,533	76.4	10,668	70.7	865	5.7
Net Canadian Imports	840	5.5	834	5.5	6	0.0
Storage Withdrawals	2,127	14.1	1,935	12.8	192	1.3
Total	**14,500**	**96.0**	**13,437**	**89.0**	**1,063**	**7.0**

(1) Figures may not add due to rounding. Source: EIA and EVA.
(2) Exports include net exports to Mexico (i.e., pipeline exports less the very small imports from Mexico) and net LNG exports (i.e., LNG exports less the small amount of LNG imports).
(3) Excludes Alaska production, which is approximately 136 BCF, or 0.9 BCFD, for both 2016/2017 and 2017/2018.

As noted in Table 1, demand this winter is expected to be higher than it was last winter. A key reason for this is the forthcoming winter weather, while close to normal, will be colder than last winter, when weather was very mild.[1] As a result, approximately 60 percent of the anticipated increase in demand for the forthcoming winter will occur in the residential and commercial sectors. In addition, electricity sector demand will be higher for the forthcoming winter. The latter, which represents about 34 percent of the net increase in demand for the forthcoming winter, is primarily due to structural changes within the power industry which are partially offset by reduced levels of coal-to-gas fuel switching.

Additive to the overall increase in demand is a net increase in exports of 2.1 BCFD. While pipeline exports to Mexico are still larger than net LNG exports, LNG exports account for about 75% of the overall increase in exports this winter.

With respect to the projected increase in total supply, domestic production should be approximately 8.1 percent higher than last winter, while net Canadian imports are nearly the same as last winter. While storage withdrawals will be higher than last winter, they are within the typical range for winter storage withdrawals for recent times.

Lastly, incorporated in this report are estimates of the impacts of Hurricanes Harvey and Irma on both production and demand. Unlike the oil industry, there was not any significant damage to natural gas infrastructure. Furthermore, for the most part, the recovery in natural gas production has been faster than initially anticipated. However, there is still some uncertainty over the full impact of the demand destruction caused by these hurricanes, which could have some impact on season ending storage levels.[2]

Exhibit 1 provides both cumulative demand and supply for the winter season in BCF and average daily demand for the winter period in BCFD. The latter is a common unit in the industry and will be the primary unit throughout this report. Also, the primary focus for supply is on the Lower-48, with Alaskan production footnoted for completeness.

Outlook For Winter Demand

Overview

The outlook for colder weather this winter results in approximately an eight percent increase in demand for the weather sensitive residential and commercial sectors. In addition, there is an increase for the electric sector, as structural changes within the power industry more than offset the expected reduction in coal-to-gas fuel switching. The latter occurs because gas prices are expected to be higher than last winter. The result is that this winter's total gas demand is projected to be 5.1 BCFD, or 6.1 percent, greater than the demand for the prior winter (see Exhibit 2).

By far the greatest area of uncertainty is the outlook for the winter weather. However, determining the net impact in variances in the winter weather can be very challenging.

[1] The forthcoming winter is projected by NOAA to be 1.2% milder than normal, while last winter was 12.5% milder than normal (i.e., overall 396 more heating degree days (HDD).

[2] This report does not include an estimate of the impact of Hurricane Maria on either production or demand.

Exhibit 2. Outlook For Winter Gas Demand[1]

Sector	Coming Winter (2017/2018) BCF	Coming Winter (2017/2018) Average BCFD	Last Winter (2016/2017) BCF	Last Winter (2016/2017) Average BCFD	Change BCF	Change Average BCFD
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Total	**13,513**	**89.5**	**12,740**	**84.4**	**773**	**5.1**

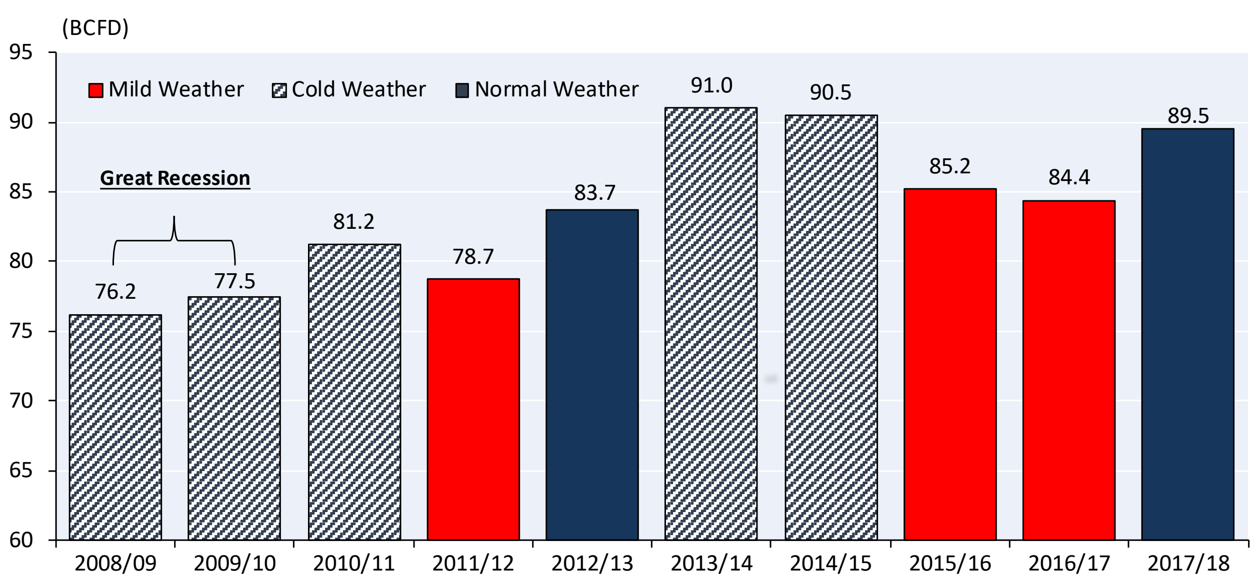
(1) Figures may not add due to rounding.
(2) Demand only; excludes exports.

Source: EIA and EVA.

Nevertheless, if the winter were to turn out to be very cold, or similar to the 2014/2015 winter,[3] winter gas demand could be about 2.6 BCFD higher than projected. If this were to happen, storage inventories likely still would be adequate, however season ending storage levels (March 31, 2018) would be reduced and end the season at relatively low levels for recent times (i.e., above 2014 levels, but below 2015 levels). Alternatively, a very warm winter could reduce storage withdrawals about 2.8 BCFD, which would result in season ending storage levels being higher but below prior records.

Lastly, Exhibit 3 compares and contrasts the current winter outlook with actual results over the last decade.

Exhibit 3. Winter Natural Gas Demand For All Sectors[1]



1. Demand only, which excludes exports.

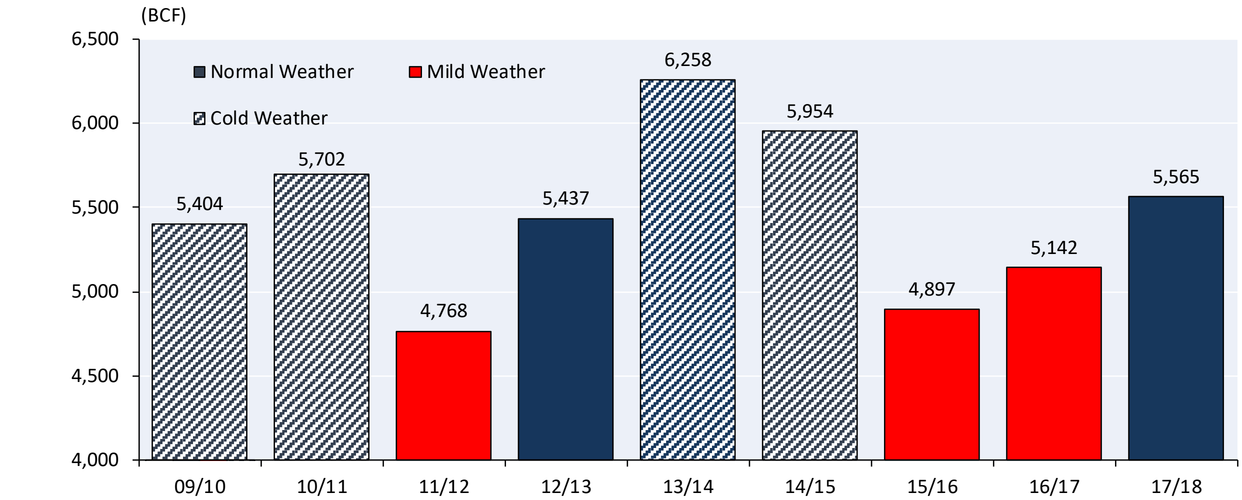
Source: EIA and EVA

[3] While the winter of 2014/2015 was only the sixth coldest in the last 20 years, the underlying increase in structural demand resulted in record winter gas demand.

Residential And Commercial Sectors

As illustrated in Exhibit 4, changes in the winter weather can have a significant impact on gas demand within these two sectors. For example, the difference in gas demand for the winters of 2013/2014 and 2015/2016 (i.e., 1,271 BCF, or 20 percent) is a classic example.

Exhibit 4. Comparison Of Winter Gas Demand For Residential And Commercial Sectors



HDDs	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18
vs Norm	3.2%	6.5%	-14.9%	-1.2%	10.0%	4.9%	-13.4%	-12.5%	-1.2%

Note: 2017/2018 is forecasted.

Source: EIA and EVA

With respect to the forthcoming winter, it is projected to be about 13 percent colder than last winter, which was very mild. More specifically, the weather this winter is projected to be approximately 1.2% milder than normal, whereas last winter was the third mildest winter on record for the last 20 years (i.e., 12.5% milder than normal). The difference in HDD between the two winters is 396 days.

Within the residential sector the three basic drivers of winter gas demand are (1) the severity of the winter weather, (2) customer growth and (3) conservation, or intensity of use. Concerning the latter two factors, over the recent past, the annual increases in the number of residential customers have been offset by decreases in the intensity of use. With respect to the former, the growth rate in the number of residential customers has been declining for most of the last decade, with the annual growth rate since the Great Recession being about 0.6 percent per annum.

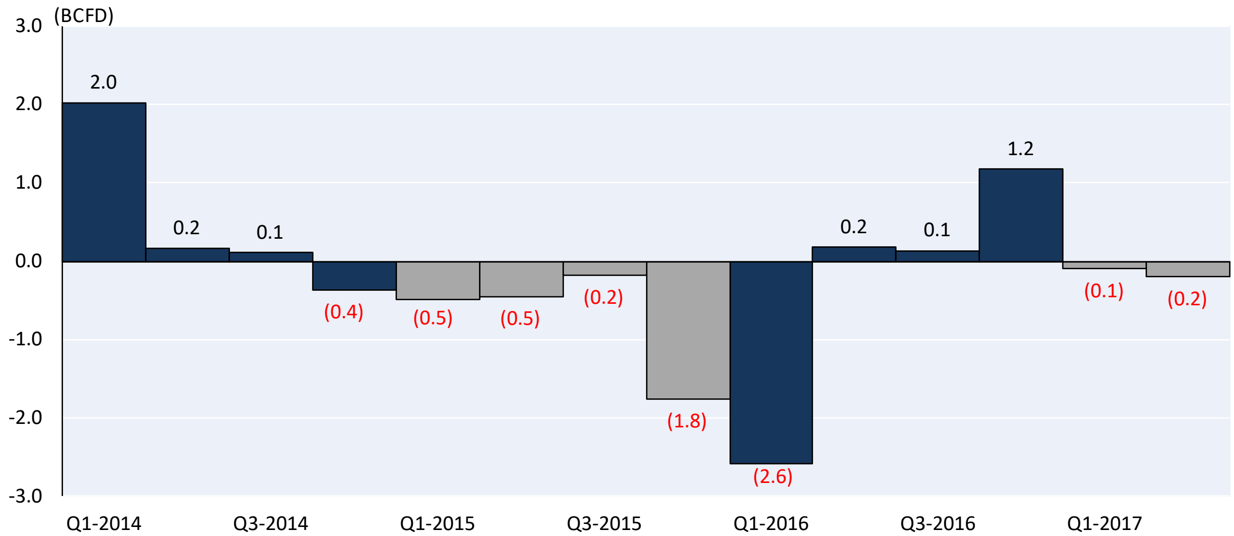
With respect to the average home, its consumption has been declining. While seasonal factors, such as a severe winter, can have an impact on this metric, the general trend over the last 20 years, with rare exception, has been a decline in consumption per customer. For example, since 1995 this metric has declined about 89 to 68 MCF, or about 24 percent.[4] There are a series of factors behind this decline, which include (1) higher energy efficiency in space heating equipment, (2) the turnover of U.S. housing stock with more energy efficiency equipment, and (3) population migration to warmer winter climates. By far the most significant of these factors is

[4] Some of the decline over this period is attributed to the recent mild winters. A 10-year trend for the same metric is a 12 percent decline.

the higher energy efficiency in space heating equipment, which has occurred primarily as a result of governmental regulations on new appliances. This factor accounts for over half of the decline in the intensity of use per customer.

While winter gas demand within the commercial sector is impacted heavily by the severity of the winter weather, the other factor affecting changes in gas demand within the sector is the overall growth in the economy, which has not been particularly robust over the last several years. Exhibit 5 presents the year-over-year changes in commercial sector gas demand for the last several years. While seasonal factors can have a significant impact on the year-to-year comparisons noted in Exhibit 5, summer demand (i.e., April through October) for the commercial sector over the last four years has declined modestly (i.e., about 0.8 percent per annum).

Exhibit 5. Quarterly Change In Natural Gas Demand For The Commercial Sector From Previous Year



Source: EIA

With respect to the regional nature of gas demand for these two sectors, a graphic in the appendix highlights the gas demand for the residential and commercial sectors by census region for the winter season.

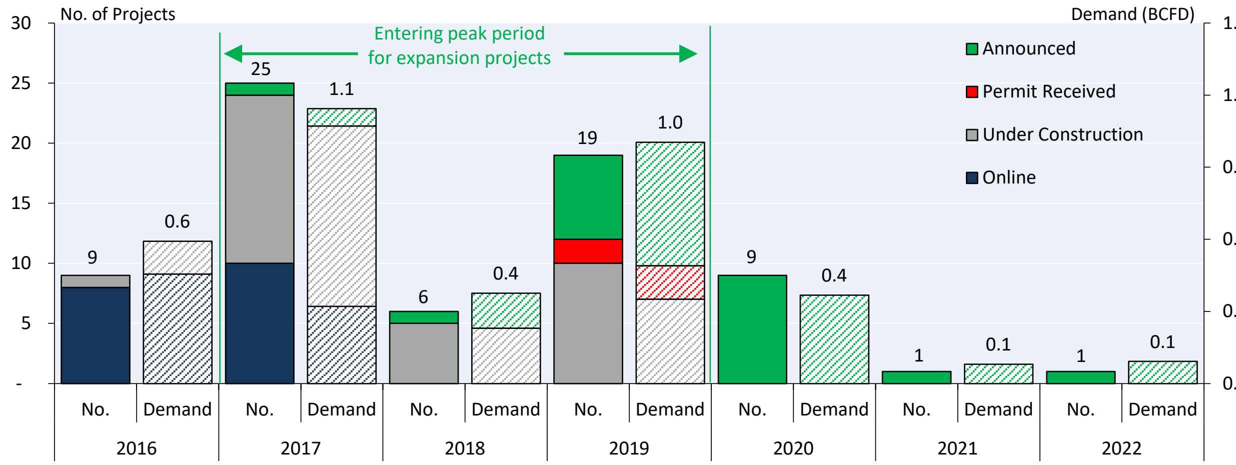
Industrial Sector

Industrial sector gas demand this winter is projected to increase only 0.3 BCFD, or 1.2 percent, over last winter's results, which is slightly over the 0.5 percent per annum growth observed over the last three years. The latter is due to offsetting factors driving industrial sector gas demand. More specifically, increased gas demand due to new capacity expansion projects coming online is being partially offset by declines in demand for existing industrial facilities, which has occurred because the past economic growth within the manufacturing sector has been limited.

Capacity Expansions

With respect to the series of capacity expansions occurring within the industrial sector, in 2017 the industrial sector started into the peak period for the annual additions of these projects. This is illustrated in Exhibit 6. For the most part these projects are expanding capacity in selected industries, in order to use relatively inexpensive U.S. natural gas to produce products (e.g., petrochemicals, methanol and fertilizer) that either increase U.S. exports or alternatively reduce U.S. imports.

Exhibit 6. Industrial Capacity Expansion Projects(1)



1. For period 2010-2015, 48 projects came online (1.6 BCFD); cost approximately $28 billion
2. For period 2016-2022, 70 projects to come online (4.3 BCFD); cost approximately $135 billion

Source: EVA and trade press.

While there have been some additions and deletions to the list of industrial capacity expansion projects, at present for the period 2016 to 2022 there are 70 likely capacity addition projects in the fertilizer, petrochemical and methanol industries. In addition to these 70 projects, 48 projects came online in the 2010 to 2015 period.

With respect to the 70 projects scheduled to come online between 2016 and 2022, Exhibit 7 provides a summary of these projects by both (1) type of expansion (e.g., new facility or expansion of an existing facility) and (2) type of industry. Similarly, Exhibit 8 summarizes the incremental gas demand associated with these 70 projects.

With respect to 2017, this year will receive the benefit of the full year impact of the nine projects that came online in 2016, plus the partial year impact of 25 additional projects that came online in 2017. The net result is that gas demand within the industrial sector is expected to increase approximately 0.87 BCFD in 2017,[5] as a result of these capacity expansion projects coming online. However, this increase has been partially offset by the lack of economic growth for the industrial sector, which has caused gas demand for existing plants to decline.

This list of 70 projects, which separates some projects into phases in order to better assess the timing of new capacity coming online, is a fully vetted list. Key to this vetting process is the tracking of project milestones, which is a continuous process at EVA. This enables one to eliminate projects that are merely 'paper announcements' that never proceed beyond that stage.

[5] Assumes an average 85 percent capacity factor.

Exhibit 7. Comparison Of Project Type Count For Various Industries (2016 to 2022)

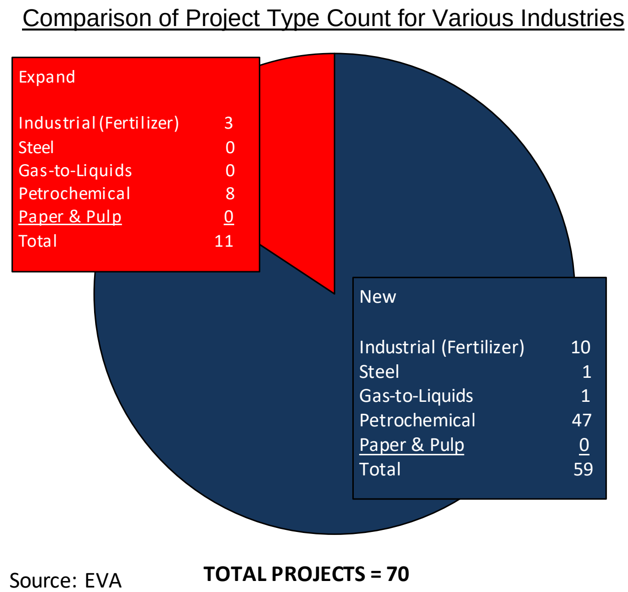
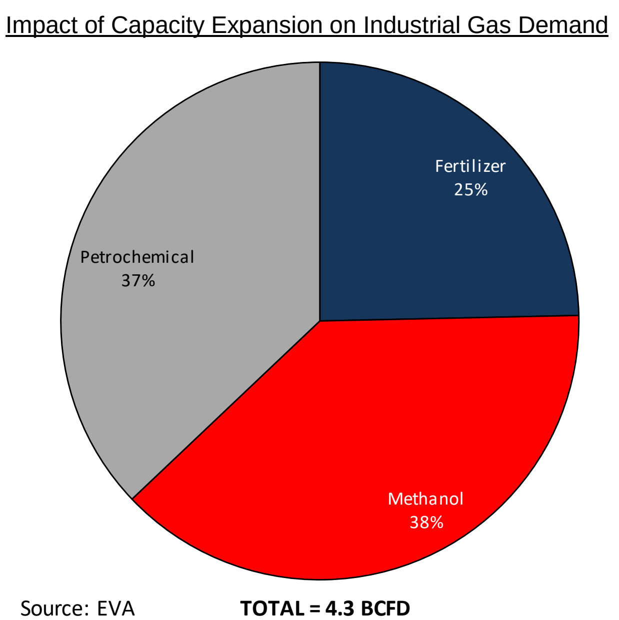


Exhibit 8. Impact of Capacity Expansion On Industrial Gas Demand (2016 to 2022)



The latter phenomenon is readily apparent within the fertilizer industry, as there are several announcements of new facilities by co-ops or small firms that merely disappear after one of the major fertilizer producers announces and proceeds with a large expansion of an existing plant. In essence, the sponsors of these smaller projects know they cannot compete with the economies of scale that exist for the larger facilities. In addition, this list of 70 projects focuses upon projects that are major consumers of natural gas (e.g., use gas as a feedstock or use significant quantities of gas as an energy source).[6]

Industrial Sector Growth

While there has been growth in 2017 for the manufacturing index versus the 2016 index, it is still below its February 2017 peak. While there has been strong growth within the chemical sector, some of which is due to new capacity coming online, the production indices for several of the six energy intensive industries (see Exhibit 9) have been flat to declining (e.g., paper and primary metals). Furthermore, the two areas that had exhibited significant growth in the past, namely petroleum drilling activity and automobiles, appear to have reached a plateau. Two factors behind this dismal outlook for existing industrial facilities are (1) the still relatively strong U.S. dollar, which impairs any growth in exports, and (2) the limited prospects for strong global economic growth.

Summary

With respect to the integrated outlook for industrial sector gas demand this winter, it is expected to increase 0.3 BCFD, or 1.2 percent, over last winter's level. Exhibit 10 compares and contrasts the expected outlook for this winter's industrial sector gas demand with the consumption levels for the years since 2007. As illustrated, with the exception of 2014/2015 and 2015/2016, there has been relatively steady growth for industrial sector demand since 2008/2009, which is when the Great Recession occurred.

As an added point of perspective, Exhibit 11 compares and contrasts, on an annual basis, the expected outlook for 2017 and 2018 industrial sector gas demand with the consumption levels for the sector since 2000. As illustrated, during the prior decade the dominant trend for industrial sector gas demand was decline, as the sector initially experienced significant price elasticity during the era of high gas prices that occurred during the first half of the decade. This was compounded by the impact of the Great Recession during the second half of the decade. However, currently with the ratio of oil-to-gas prices at about 16:1 U.S. industrial gas demand is not nearly as sensitive to changes in gas prices as in the past, when the ratio of oil-to-gas prices was closer to 6:1.

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[6] As a result, the number of capacity expansion projects summarized in Exhibit 7 is significantly below other lists circulating within the industry. While some of these lists contain over 120 projects, many of these projects are either mere 'paper announcements' or projects that are not significant consumers of natural gas - for example, assembly plants.

Exhibit 9. Performance Of The Six Key Energy Intensive Industries

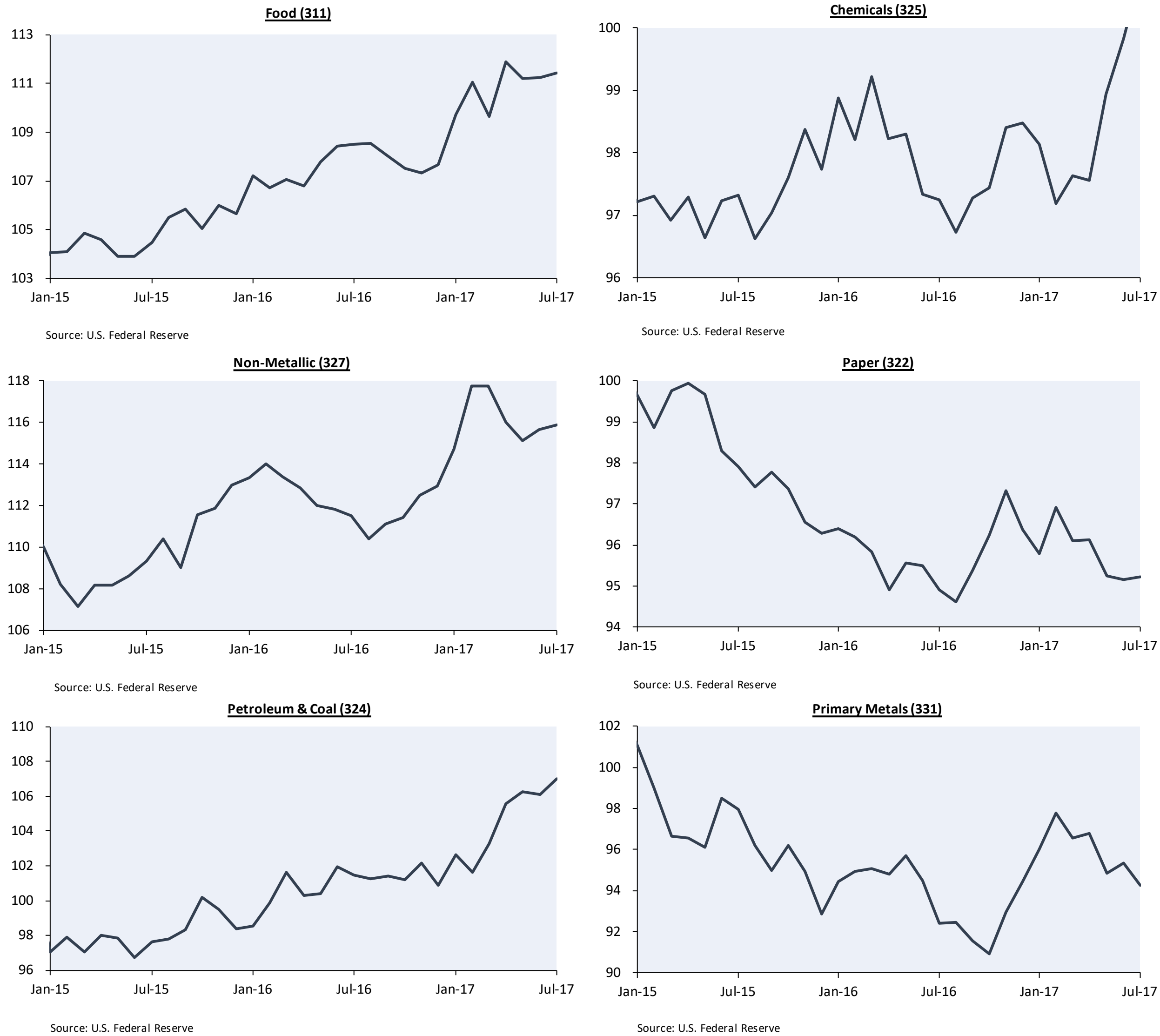
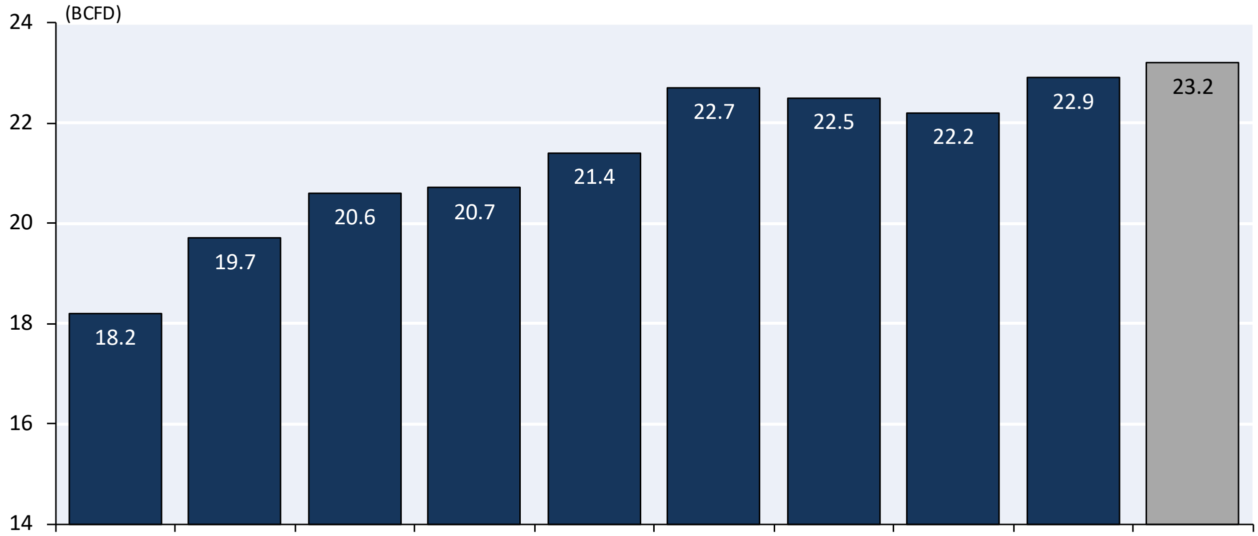
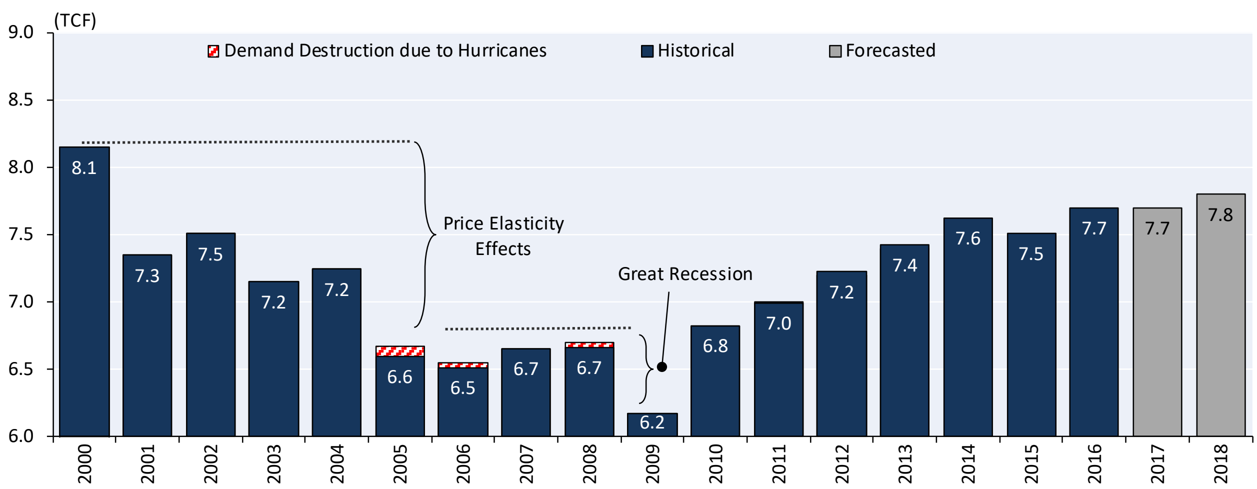


Exhibit 10. Winter Natural Gas Demand For The Industrial And Transportation Sectors



Source: EIA and EVA.

Exhibit 11. Industrial Sector Natural Gas Demand On An Annual Basis



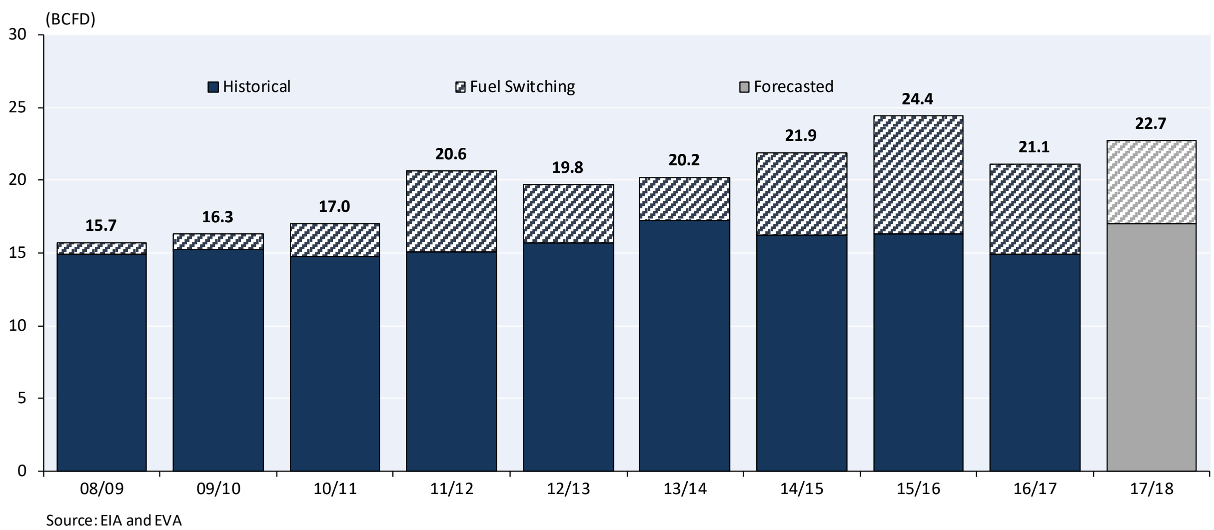
Note: Includes LNG feedstocks used for operations.

Source: EIA and EVA

Electric Sector

Based upon recent NYMEX future prices, which remain volatile, natural gas prices for the forthcoming winter are expected to be about 7.5 percent higher than gas prices for the prior winter. This change in gas prices will result in a reduction in coal-to-gas fuel switching, which, in turn, will cause electric sector gas demand for the winter to decline. However, offsetting this phenomenon are structural changes within the electric sector, such as the continuing retirements of coal-fired capacity and the additions of new gas-fired capacity. This net result is that electric sector gas demand this winter is expected to increase 1.57 BCFD, or about 7.4 percent, which is illustrated in Exhibit 12.

Exhibit 12. Winter Natural Gas Demand For The Electric Sector



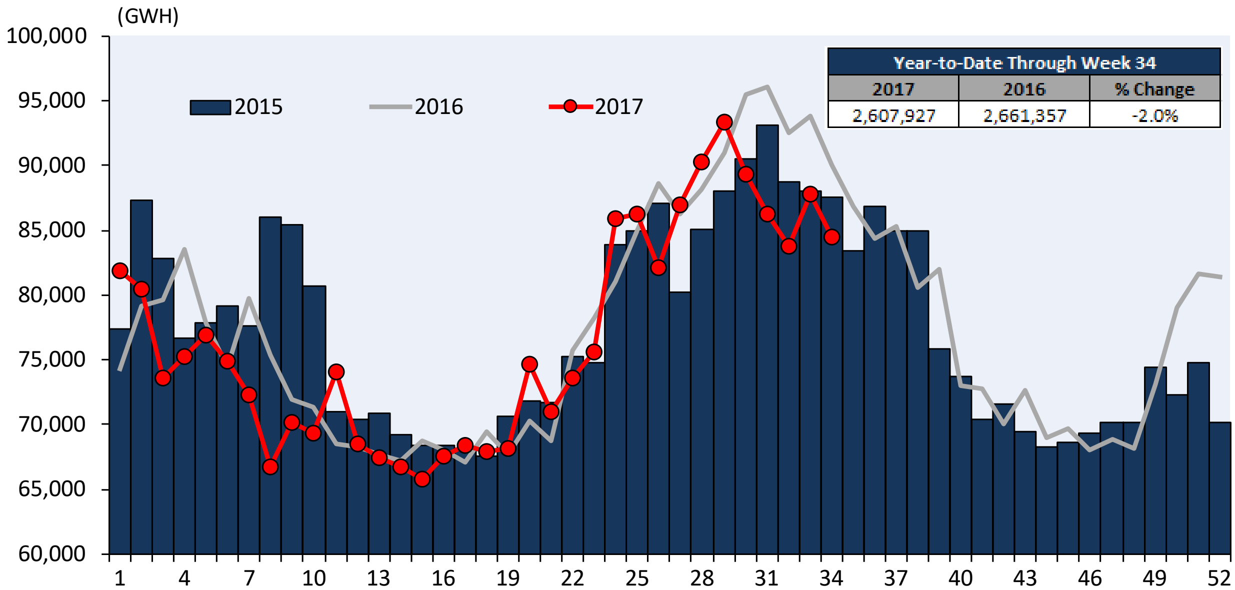
Fuel Switching

Primarily because of the mild weather last winter and resulting gas prices, fuel switching last winter was relatively high. However, with the anticipated increase in gas prices for the forthcoming winter, which is in part due to the anticipated colder weather, fuel switching is expected to be lower (i.e., in round terms about nine percent lower).

Electricity Sales

Since 2014, electricity sales provided by the grid have been in steady decline (i.e., about 0.6 percent per annum). Since gas-fired power tends to be at the margin, this factor tends to dampen overall growth in gas-fired generation. A key factor driving this phenomenon, which is in sharp contrast to historical trends prior to 2007, is the continuing growth in distribution generation (e.g., solar) in some regions. With respect to year-to-date 2017 electricity sales provided by the grid have declined about two percent, as noted in Exhibit 13.

Exhibit 13. Total Weekly Electric Output (L48-States)



Source: EEI.

Capacity Additions

Finally, while it is unlikely that the addition of new gas-fired capacity will have a significant impact on this winter's electric sector gas demand, trends in new gas-fired additions are meaningful for assessing the intermediate-term outlook for gas demand within this sector and thus, provide an additional point of perspective. Exhibit 14 summarizes recent historical capacity additions, as well as the current outlook for capacity additions for 2017 and 2018. In addition to gas-fired capacity additions, capacity additions are included for wind and solar units, which are the two key competitors to gas-fired generation. Also, noted are the retirements for coal-fired and nuclear capacity.

Exhibit 14. New U.S. Generation Capacity

					Projected	
(MW)	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Coal	**1,357**	**99**	**-**	**-**	**-**	**-**
Solar	**2,627**	**3,291**	**3,314**	**7,867**	**5,405**	5,023
Wind(1)	**824**	**4,831**	**8,188**	**8,691**	**6,986**	**7,325**
Gas Combined Cycle	3,456	8,032	4,591	5,429	11,630	15,660
Gas Peaking	3,518	285	1,245	3,200	438	1,777
Total Gas-Fired	**6,974**	**8,317**	**5,835**	**8,629**	**12,068**	**17,437**
Grand Total	**11,782**	**16,538**	**17,337**	**25,187**	**24,459**	**29,785**
Retirements - Coal	7,120	5,568	20,354	10,978	7,761	8,725
Retirements - Nuclear	2,724	628	-	479	-	789

Source: EIA and EVA.

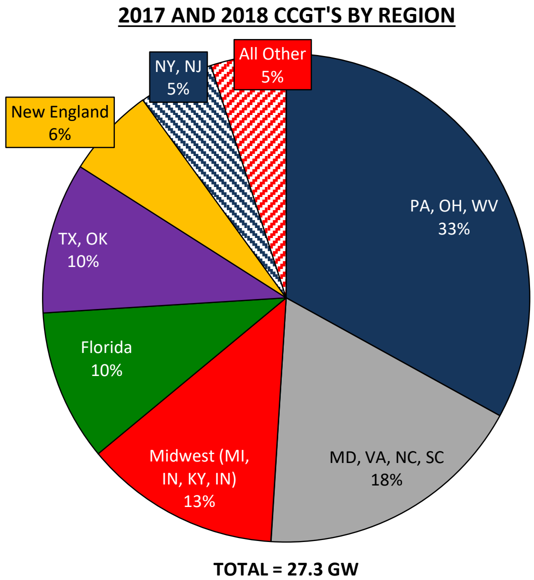
Key factors driving the recent and expected retirements of coal-fired units are a series of pending EPA regulations and the recent relatively low gas prices, which as a result of the associated coal-to-gas fuel switching, have impaired the overall profitability of many coal units.

With respect to on-the-grid wind and solar capacity additions, they represent a significant competitor to gas units for new capacity requirements, particularly over the 2017 to 2018 timeframe. When excluding the gas peaking units, which have a unique role within the power industry, the combination of (1) new CCGT units and (2) new wind and solar units account for all of the capacity additions within the industry. More specifically, new CCGT units over the 2017 to 2018 timeframe are expected to account for 51 percent of the total base load capacity additions.

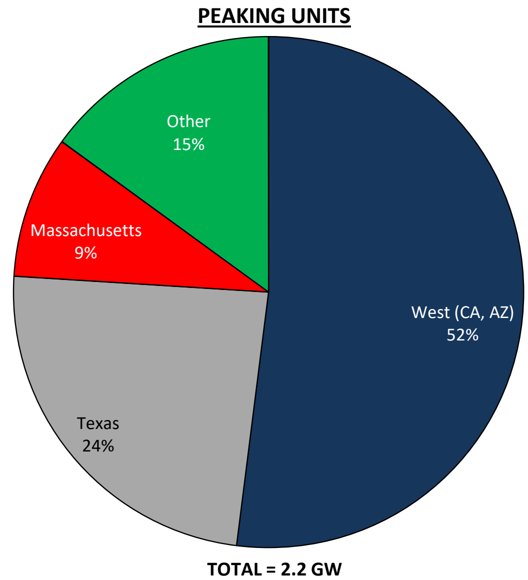
With respect to the historical competition between coal and gas, over the last several years coal-fired capacity has been declining, while gas-fired capacity has been increasing, with the net result being increased market share for gas-fired generation. Exhibit 14 provides specifics for this phenomenon over the last several years. As illustrated, on a net basis, coal-fired capacity has declined about 44 GW over the last four years, while combined cycle (CCGT) gas-fired capacity has increased about 22 GW. Going forward it is anticipated this trend will continue, as during 2017 and 2018 another 16.5 GW of coal-fired capacity is expected to retire on a net basis, while new build CCGT units will total about 27.3 GW.

Finally, with respect to the regionality of gas-fired capacity additions over the 2017 to 2018 timeframe, it is summarized in Exhibit 15. As illustrated, while the new CCGT units are being built throughout the U.S., one-third of the new capacity is built in the Northeast (i.e., Pennsylvania, Ohio and West Virginia), with an additional 28 percent of the capacity being built in the Southeast (i.e., from Maryland and Florida). With respect to the peaking units most of the capacity is being built in the West.

Exhibit 15. Gas-Fired Capacity Additions By Census Region (2017-2018)



Source: EIA and EVA.



Source: EIA and EVA.

Outlook For Exports

Overview

The other component to total consumption is exports, which includes the rapidly growing LNG exports and pipeline exports to Mexico, which are larger, but experiencing more modest growth. For the forthcoming winter exports are expected to be 2.1 BCFD, or 42 percent, greater than the exports that occurred last winter.

LNG

By the end of the forthcoming winter the U.S. should have five operable liquefaction trains (i.e., four at Sabine Pass and one a Cove Point). While these projects, for the most part, are under long-term contract, the combination of these projects coming online before contract start dates and commissioning cargoes, has resulted in the U.S. being very active in the global spot market for LNG. To date about 180 LNG cargoes have been exported with the most significant destination to date being Mexico, which has accounted for 21 percent of the cargoes exported in 2017.

Going forward the component of U.S. LNG exports that are under long-term contracts seems fairly certain, however the competition with the rest of the world for spot LNG cargoes is becoming increasingly keen. As a result, there is some uncertainty in the outlook for U.S. LNG exports, which could be higher or lower than the base case scenario noted in this report. For the forthcoming winter LNG exports are projected to average approximately 3.1 BCFD, which is more than double the 1.5 BCFD that occurred during the prior winter.

In addition to exporting LNG, the U.S. imports LNG during the winter in order to meet the peak demand requirements in New England. At present it is projected that LNG imports at the Everett, Massachusetts regasification terminal will be about the same as last year (i.e., about 0.3 BCFD).

Addendum I to this report provides a more complete assessment of the outlook for U.S. LNG exports and highlights the growth prospects beyond this winter.

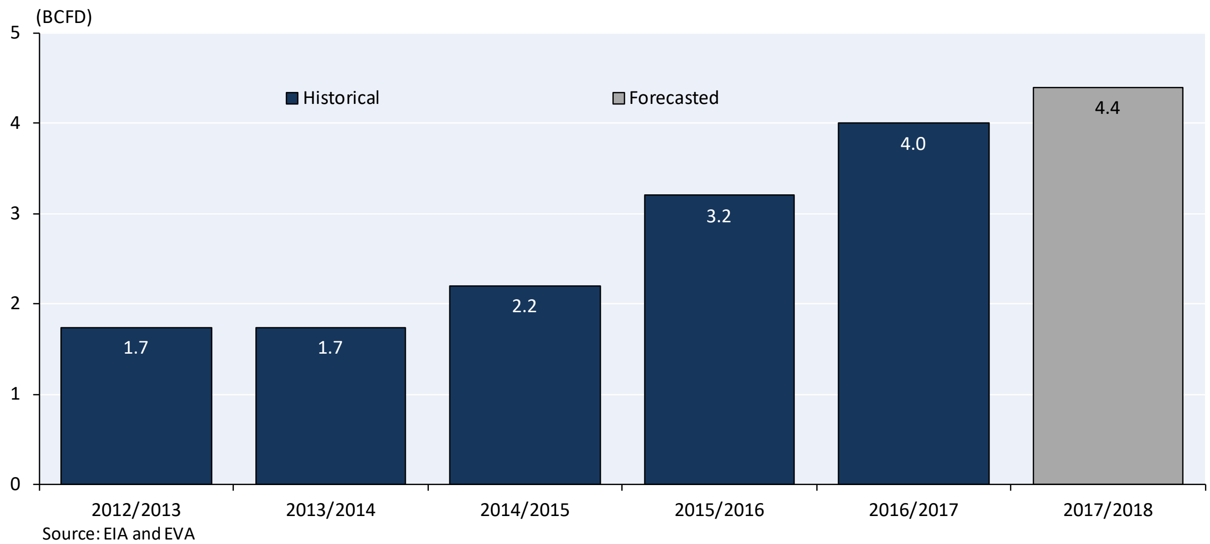
Mexico

As illustrated in Exhibit 16, net exports to Mexico have been increasing and are expected to continue this trend during the forthcoming winter.

The primary factors facilitating this increase in exports to Mexico are (1) the major expansion in Mexico's gas pipeline infrastructure; and (2) the shale gas revolution within the U.S., and in particular, the increased production from the Eagle Ford shale play and the Permian Basin. This infrastructure is enabling Mexico to meet pockets of unmet demand for its industrial sector and to focus on building more gas-fired generating units for power. In addition, as new pipeline projects are completed higher cost LNG imports at Mexico's two operating regasification terminals will be reduced.

With respect to the expansion of Mexico's pipeline infrastructure, which is being supported by a large number of pipeline projects on the U.S. side of the border, Mexico is now in the second phase of its expansion of natural gas infrastructure. The first phase of Mexico's expansion effort included three major systems, namely the Northwest Pipeline System, the Chihuahua Pipeline System and the Los Ramones Pipeline System, which had a combined capacity of approximately 4.8 BCFD.

Exhibit 16. Outlook For Winter Mexican Exports



With respect to the current or Phase II effort, Exhibit 17 highlights several of the pipeline projects expected to come online in 2017 and 2018, with most of these projects already under construction or already online. While this expansion of Mexico's pipeline infrastructure will facilitate additional exports to Mexico, they are only one of the key components driving higher levels of exports over the intermediate term. Among the other critical components are the rate of growth for natural gas demand in Mexico and when Mexico's domestic production will begin to recover. With respect to the former, several entities have noted that the time table laid out by Mexico's agencies for new gas-fired power facilities is on the aggressive side. Exhibit 18 presents an integrated assessment of all the factors driving future exports to Mexico. This assessment has exports to Mexico reaching 6.1 BCFD in 2020, which is above estimates by other entities.[7]

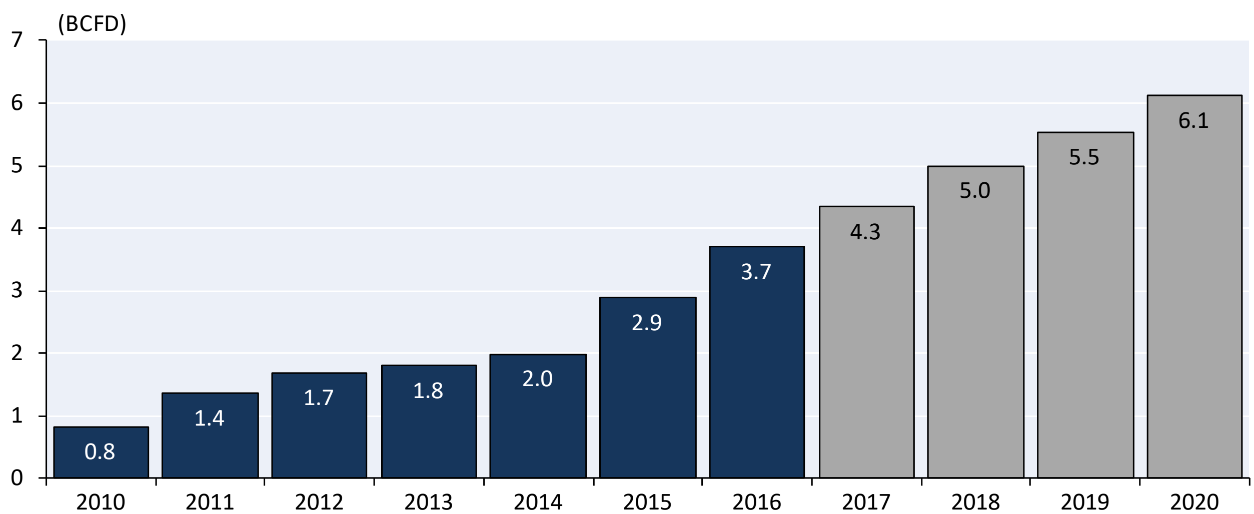
[7] Platt's Analytics projects exports to Mexico in 2020 will be 5.5 BCFD. Inside FERC's Gas Market Report, "Pipeline, LNG operators bullish on expansion", June 30, 2017, p. 9 and "Mexican gas demand growth faces challenge", June 30, 2017, p. 13 and 14.

Exhibit 17. Phase II Mexican Pipeline Systems

Project	Capacity (BCFD)	Cost ($MM)	In Service Date
El Encino-Topolobampo	0.67	$1,000	Oct 17
Ramal Tula Pipeline	0.49	$58	Jan 17
Tuxpan Tula Pipeline	0.89	$500	Dec 17
Mier-Monterrey PL Compressor Sta	0.20	$38	Dec 17
Mier-Monterrey Expansion	0.70	$38	Dec 17
Sonora Puerto Libertad-El Ore	0.55	$459	Oct 17
El Encino-La Laguna	1.50	$650	Dec 17
Ojinaga-El Encino Pipeline	1.36	$300	Jul 17
La Laguna-Aguascalientes Gas PL	1.15	$1,000	Jan 18
Villa de Reyes-Aguascalientes-Guadalajra	0.89	$555	Mar 18
Salina Cruz-Tapachula		$442	Jun 18
Lazaro Cardenas-Acapulco		$446	Dec 18
Sur de Texas-Tuxpan Pipeline (Underwater)	2.60	$3,100	Jan 18
Tula-Villa de Reyes	0.55	$550	Feb 18
Chihuahua Header	3.50	$108	Mar 17
Empalme Pipeline	0.24	$35	Jun 17
Colombia-Escobedo Pipeline		$336	Jun 18

Source: Trade press.

Exhibit 18. Intermediate-Term Outlook For Exports To Mexico

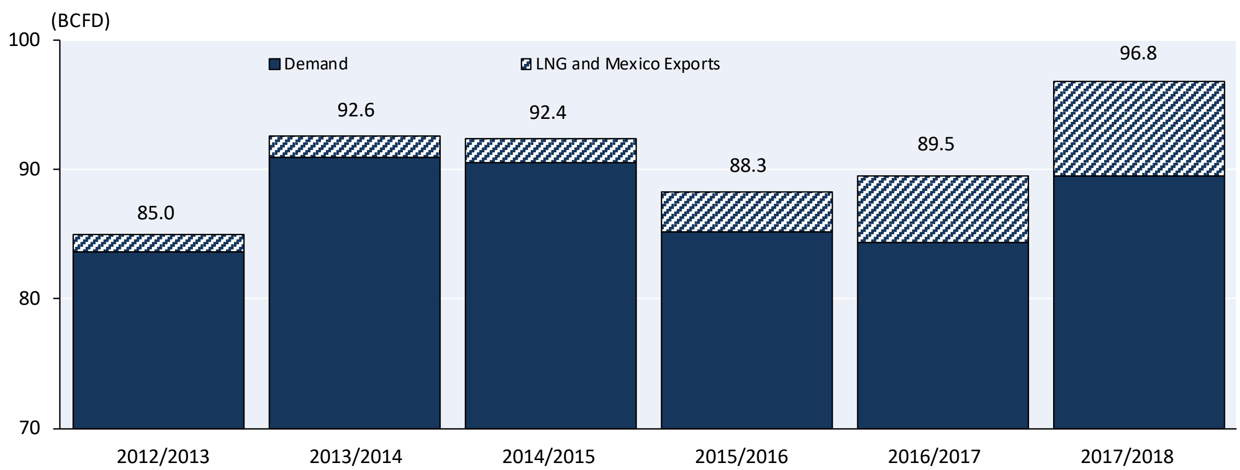


Note: Net exports.
Source: EVA and EIA.

Outlook For Total Consumption

Total consumption (i.e., demand plus exports) in the forthcoming winter is expected to reach 96.8 BCFD, which is 7.2 BCFD, or 8.1 percent, greater than the consumption level for last year (see Exhibit 19). Also, the 96.8 BCFD represents a record for total consumption and will even exceed the prior record which occurred during the polar vortex winter of 2013/2014. The primary reason for this new record is that exports for the forthcoming winter will be 5.7 BCFD greater than they were during the winter of 2013/2014.

Exhibit 19. Total Consumption For Winter(1)



1. Consumption includes both demand and exports. 2017/2018 is estimated.

Source: EIA and EVA

Outlook For Winter Supply

Overview

Total natural gas supply for the forthcoming winter will be about 7.0 BCFD, or 7.9 percent, greater than the supply for last winter. As noted in Exhibit 20, 80 percent of this increase in supply comes from higher levels of domestic production, as the increase in storage withdrawals is modest, while net Canadian imports are flat. However, the increase in the forthcoming winter's domestic production is dependent upon the occurrence of a fourth quarter infrastructure event.

There are two areas of uncertainty concerning the outlook for gas supplies this winter, with the area of greatest uncertainty being the level of storage withdrawals. The latter is dependent heavily on the winter weather outlook varying from current projections and its impact on demand. The other area of significant uncertainty is the level of increase in flowing gas supplies that will occur over the November to March period, as a result of new pipeline capacity coming online and providing takeaway capacity for stranded gas supplies (i.e., an infrastructure event).[8]

Exhibit 20. Outlook For Winter Supply(1)

	Coming Winter (2017/2018)		Last Winter (2016/2017)		Change	
Supply Component	**BCF**	**Average BCFD**	**BCF**	**Average BCFD**	**BCF**	**Average BCFD**
Lower-48 Production(2)	11,533	76.4	10,668	70.7	865	5.7
Net Canadian Imports	840	5.5	834	5.5	6	0.0
Storage Withdrawals	2,127	14.1	1,935	12.8	192	1.3
Total	**14,500**	**96.0**	**13,437**	**89.0**	**1,063**	**7.0**

(1) Figures may not add due to rounding. Source: EIA and EVA.
(2) Excludes Alaska production, which is approximately 136 BCF, or 0.9 BCFD, for both 2016/2017 and 2017/2018.

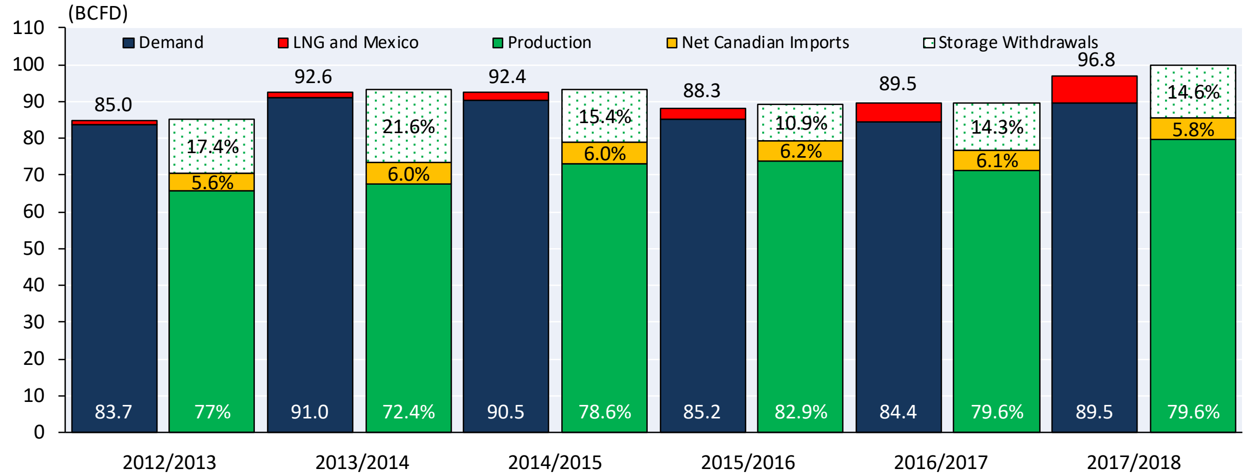
As discussed in subsequent sections of this report, the current assumption is that this infrastructure event will increase flowing gas supplies about 2.5 BCFD, however this assessment is debatable because of the possibility that there will be delays for scheduled new pipeline projects and the limited data available concerning the current stranded gas supplies.[9]

In order to provide the reader with an additional perspective on the supply outlook for the forthcoming winter, Exhibit 21 compares and contrasts these supply projections with actual results over the last several winters. There are a few very apparent trends in the data summarized in Exhibit 21, namely (1) the steady increase in domestic production for the last five years, except for last winter when drilling activity declined sharply; (2) the level of net Canadian imports have been relatively constant, while (3) the contribution of storage withdrawals has

[8] The bringing online of new pipeline capacity (i.e., an infrastructure event) can provide takeaway capacity for previously stranded gas supplies, which would increase overall flowing gas supplies.
[9] In the fourth quarter of 2013 infrastructure events increased production 1.55 BCFD, whereas in the fourth quarter of 2014 these events increased production 2.2 BCFD. For a variety of reasons the infrastructure event for the 4Q 2015 was delayed to the 1Q 2016, but resulted in a 1.3 BCFD increase in production. Similarly, a portion of the infrastructure event for the 4Q 2016 was delayed until 1Q 2017.

varied significantly from year-to-year, primarily because of changes in weather and its impact on demand.

Exhibit 21. Summary Of Winter Supply



Note: 2017/2018 is estimated.
Source: EIA, Point Logic and EVA

U.S. Production

Overview

Currently changes in flowing gas supplies can occur via two different mechanisms, namely (1) directly from drilling activity and (2) from infrastructure events, which provide additional takeaway capacity for previously stranded gas supplies. The impact that both have on the outlook for the forthcoming winter's gas supplies is discussed below.

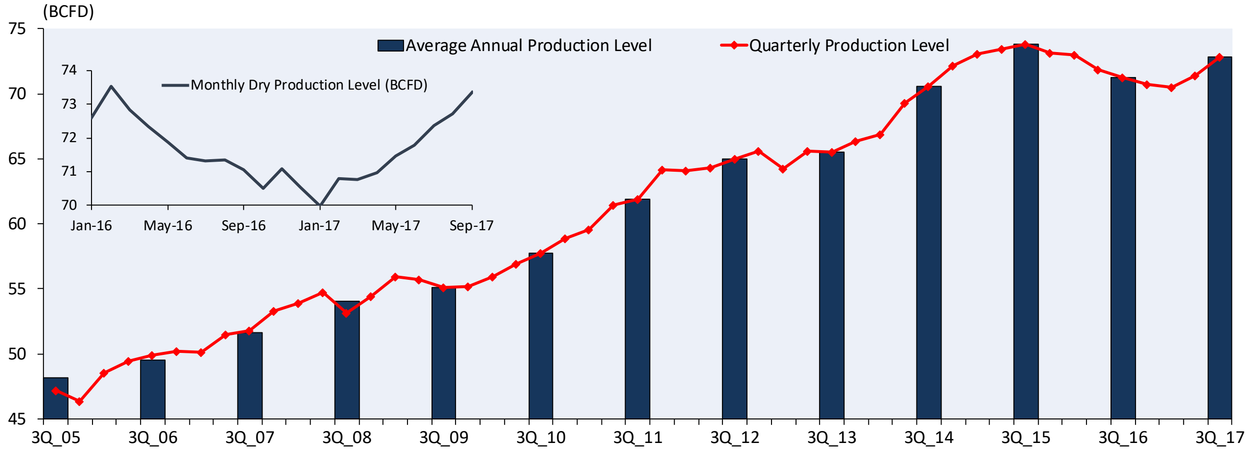
Current Assessment

With respect to current domestic production levels, Exhibits 22 and 23 summarize recent trends. Included in Exhibit 22 are annual and quarterly production levels for the Lower-48 (L-48) plus monthly trends for the last few years in the inset. In addition, Exhibit 22 provides daily production trends for the L-48 since October 2015 with the impact of winter well freeze-offs noted.[10]

As noted in Exhibit 23, the sharp decline in domestic production that began about October 2015 began to level out in February 2017, and since about May 2017 has been increasing at a relatively steady rate. This reversal in trends is the net result in the recovery of both gas-directed and oil-directed (i.e., associated gas) drilling activity.

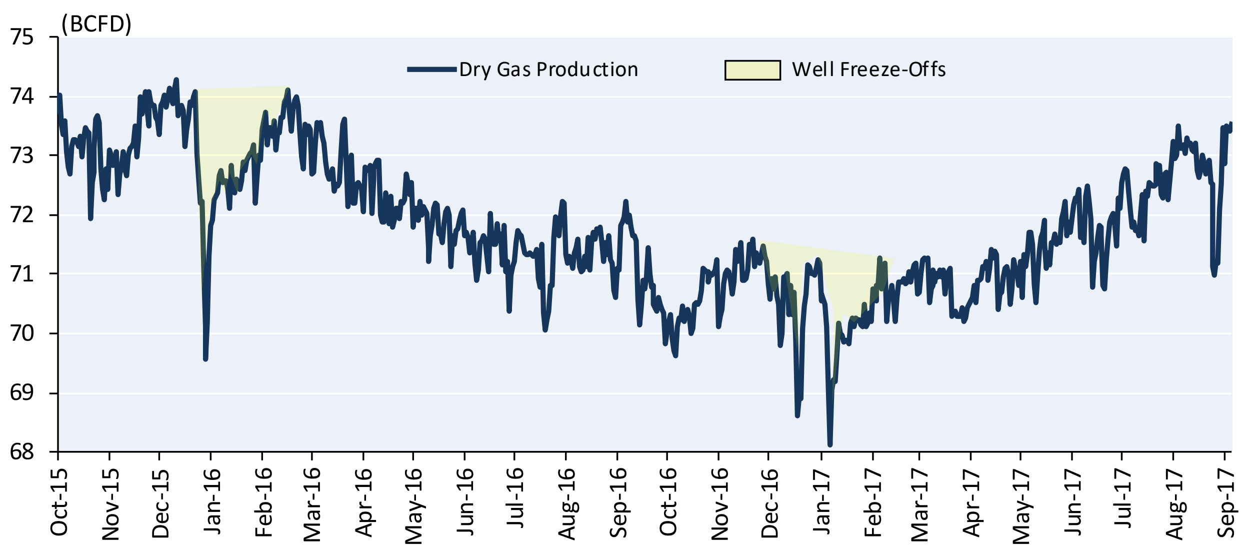
[10] The forecast for the winter 2017/2018 assumes that the impact of well freeze-offs will be similar to that for the prior winter (i.e., about 40 BCF).

Exhibit 22. Lower-48 Natural Gas Wellhead Production



Source: EVA, Point Logic

Exhibit 23. Lower-48 Daily Dry Gas Production

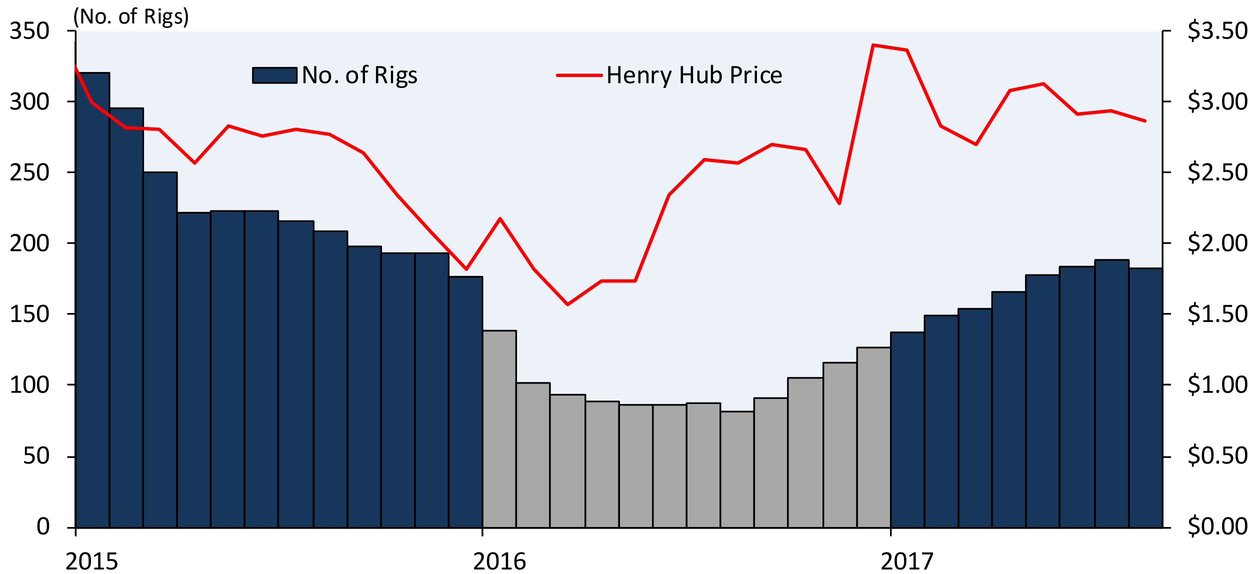


Source: Point Logic and EVA

Drilling Activity

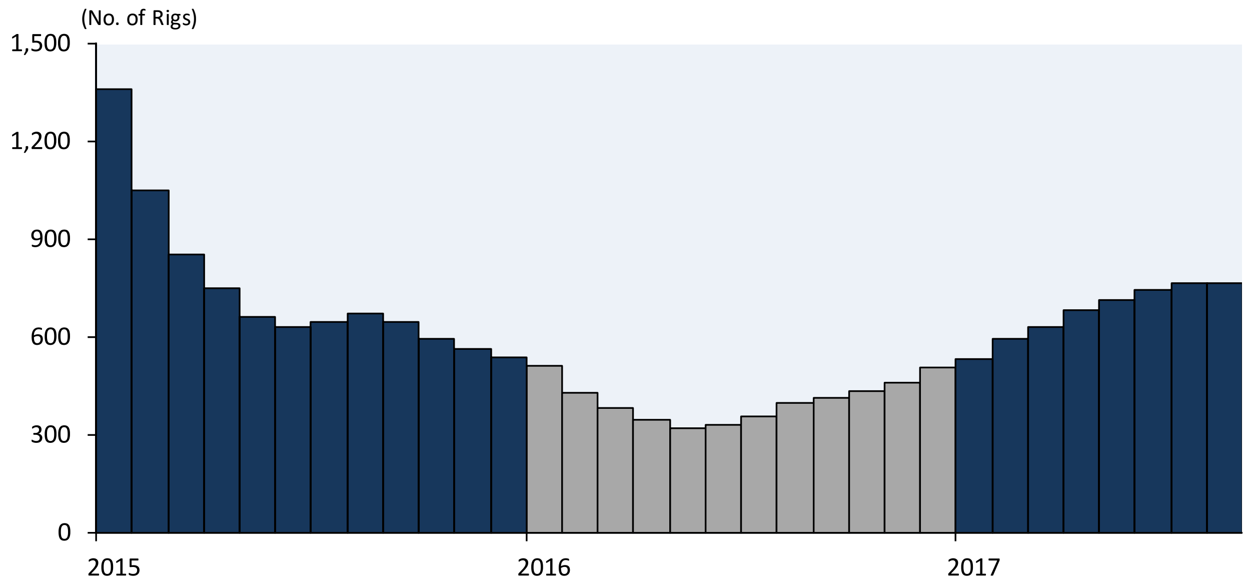
There has been a sharp contrast in the rate of recovery between gas-directed drilling activity and oil-directed drilling activity, as illustrated in Exhibits 24 and 25. In the case of oil-directed drilling activity, which yields significant associated gas, since late May 2016 it has surged and is now 140 percent above its recent low point (i.e., a net increase of approximately 445 rigs). Furthermore, approximately 55 percent of this increase in activity has occurred in the Permian Basins, which now accounts for nearly 50 percent of all oil drilling activity.

Exhibit 24. Rig Count For Gas Wells And Henry Hub Price



Source: NGW.

Exhibit 25. Rig Count For Oil Wells



Source: NGW.

With respect to gas-directed drilling activity it's increase has been closer to a slow creep. More specifically, the gas rig count has increased about 100 rigs since it's August 2016 low point, with drilling activity since mid-May 2017 being relatively flat. About 65 percemt of this increase in gas-directed drilling activity has been concentrated in the Haynesville, Marcellus and Utica shale plays.

Infrastructure Events

The other means of increasing flowing gas supplies is infrastructure events, which provide takeaway capacity for previously stranded gas supplies. There have been several of these in the past, including the fourth quarter 2013 and 2014 and the first quarters of 2016 and 2017, which increased flowing gas supplies about 1.5, 2.2, 1.3 and 0.7 BCFD, respectively, as a result of new pipeline capacity coming online. Furthermore, it is likely that a similar infrastructure event will occur in the fourth quarter of 2017. Exhibit 26 compares and contrasts the pipeline capacity additions that occurred for the prior Northeast infrastructure events with those that are scheduled to occur in the fourth quarter of 2017. As illustrated, the number of pipeline projects and capacity expected to come online this forthcoming winter is greater than that for prior infrastructure events. However, the cumulative capacity additions is not necessarily always a good measure, because it does not indicate the net capacity of a single transmission flow path.[11] Perhaps the most insightful comparison is the number and capacity of the major pipeline projects.

Exhibit 26. Comparison Of New Pipeline Projects For Winter Infrastructure Events In The Northeast

	2013	**2014**	**2015**	**2016**	**2017**
Number of Pipeline Projects Online	13	15	14	10	22
Capacity of New Pipeline Projects (BCFD)	3.3	3.2	5.1	4.8	7.3
Number of Major Pipeline Projects Online	4	5	7	5	6
Capacity of Major Pipeline Projects (BCFD)	2.2	2.0	4.7	2.5	4.3
Source: EVA and trade press.					

Estimating the net impact for the forthcoming winter's production for the Rover Pipeline is particularly challenging. The Rover Pipeline (3.25 BCFD) can be divided into three segments, namely (1) Phase 1A (1.17 BCFD), which is a 42'' pipeline with four compressor stations and four gathering system laterals, (2) Phase 1B (1.17 BCFD), which is a parallel 42'' pipeline that also has four compressor stations and four laterals; and (3) Phase 2 (0.9 BCFD), which extends the overall system to an interconnect with the Vector pipeline in Michigan. Both Phase 1A and Phase 1B segments move gas from southeast Ohio to Defiance, Ohio where they interconnect with other pipeline systems.

Phase 1A of the Rover pipeline went into service at the beginning of September and is delivering about 0.57 BCFD to Defiance, even though the four compressors for this segment are not yet in

[11] For example, a major gathering system plus a pipeline project could connect to another pipeline project, which would form a single transmission path. The cumulative capacity of the three projects would be greater than the capacity of the single net transmission path.

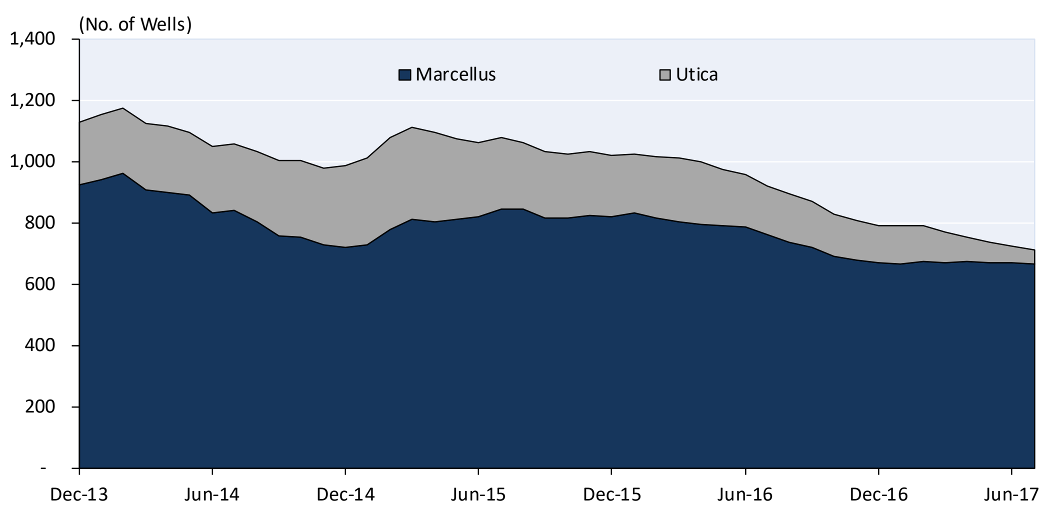
operation (i.e., lack authorization to operate).[12] However, going forward there is uncertainty over how fast the volumes for Phase 1A will ramp up. In addition, while Phase 1B and Phase 2 are scheduled to be in service by December 2017 and January 2018, respectively, several industry observers have opined that this may be optimistic. This report assumed that the online dates for the various segments of the Rover Pipeline will be close to what has been announced, but that the initial capacity factors for each segment will be relatively low.

While it is known that there will be significant additions of pipeline projects during the forthcoming winter, the key dilemma in estimating the impact of this new pipeline capacity on flowing gas supplies is that there is not any data on either the level of stranded gas supplies or how much of these stranded gas supplies will be affected by the new pipeline capacity.

Nevertheless, some insight can be obtained by analyzing the inventory, or backlog, of drilled but not yet connected wells. Exhibit 27 summarizes the inventory of such wells for the two most significant gas shale plays affected by this phenomenon. As illustrated, the well inventory for the Marcellus and Utica shales recently has been recovering from the sharp decline that started in September 2015. Concerning the latter, this decline was attributable to a reduction in drilling activity that started in late 2014 and continued through about August 2016 (i.e., the gas rig count declined 275 rigs during this period). However, with the previously discussed recovery in drilling activity since August this inventory started to recover.

Lastly, the data presented in Exhibit 27 can be divided into two categories, namely (1) those wells that are completed but not yet producing and (2) those wells that are waiting to be fracked[13]. The former category, which represents about 84 percent of the total inventory, represents those wells that are most likely to come online during this year's infrastructure event.

Exhibit 27. Inventory of Drilled But Not Yet Connected Wells



Source: EIA

[12] Phase 1A of the Rover Pipeline interconnects with the high-pressure Ohio River Gathering System. This enables Phase 1A to transport some gas even though the four compressors associated with this segment are not yet in operation.

[13] EIA data for drilled but not completed wells (DUCs), which use a catch up methodology, does not fully comport with state level data for DUCs (e.g., for example for July 2017 for the Utica shale state level data indicates 267 DUCs, while the EIA data indicates 43 DUCs.

With respect to associated gas and, in particular, the Permian Basin, the inventory of DUCs appears to be increasing. The latter is the result of the surge in drilling activity in the basin, which has caused the demand for fracking crews[14] within the basin to exceed supply by a significant margin. At present, producers have to wait months before a crew is available. In addition, there are reports of poaching fracking crews from one producer by another. When this occurs producers offer the fracking crew a premium and agree to pay the contractual penalties of the crew to withdraw from its current engagement. This is similar to what was a frequent practice during the period of peak drilling activity in 2014 and early 2015. With respect to the exact level of DUCs it is nearly impossible to provide a quality estimate because of the fluid nature of the current environment. However, the trend is upwards.

Integrating all of the above information, even though some of it is imprecise, yields an estimate of the impact that the forthcoming fourth quarter of 2017 infrastructure event will increase flowing gas supplies about 2.5 BCFD. This estimate is at the high end of the range for the last four major infrastructure events.

Another type of infrastructure that can facilitate sudden increases in flowing gas supplies is the addition of new NGL processing capacity. For 2017 it is expected that about 16 new NGL plants or expansions will be brought online (2.7 BCFD), which is about 40 percent less than the number brought online in 2016 (3.4 BCFD). Also, both the 2016 and 2017 NGL capacity additions are well below the amount of capacity brought online during the peak period for NGL plant additions during 2013 to 2015. At that time the annual average for new NGL capacity was approximately 36 new units with a capacity of 5.8 BCFD. As an additional point of perspective, there has been a significant shift in the regions where new capacity is being added. For example, during the peak period about 30% of the new units were installed to facilitate new Marcellus and Utica production, whereas in 2017 nearly 70 percent of the new units are located in the Permian Basin, while none are in the Marcellus/Utica production area.

Lower-48 Production

Exhibit 28 summarizes the outlook for L-48 production for the forthcoming winter, which includes both the impact of drilling activity and infrastructure events. This exhibit also compares and contrasts the outlook for domestic production with that for previous winters.

Several key trends are readily apparent in Exhibit 28 and include the following:

- **Production Increases:** While production last winter broke the 10-year trend of increasing production during the winter period, production for the forthcoming winter is projected to return to this historical trend and be 5.7 BCFD, or 8.1 percent, above last winter's level. This higher level of production primarily is due to the increase in drilling activity for both gas and oil (i.e., associated gas) that started about mid-2016.

- **Shale Production Growth Rebounds:** Last winter the increases in shale gas production were minimal. However, with the rebound in drilling activity the net increase in shale

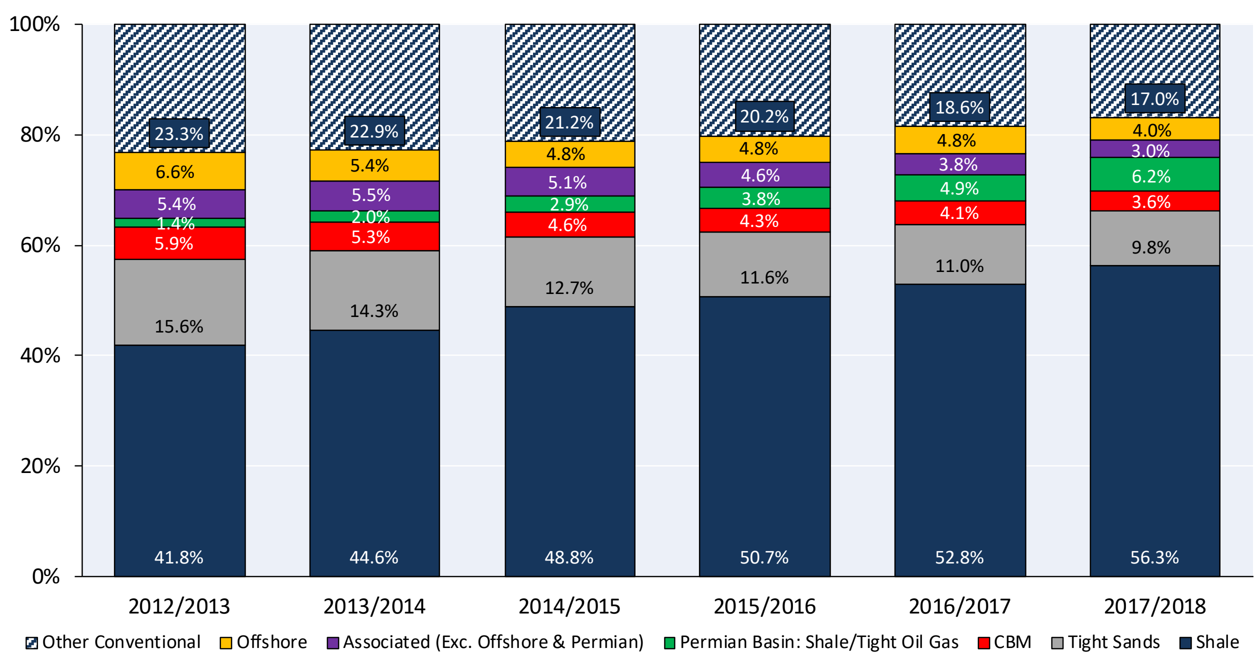
[14] A typical fracking crew consists of 25 to 30 workers, with individual workers making $29,000 to $72,000 per year plus overtime. However, specifics vary by region.

production for the forthcoming winter will return to the growth levels observed prior to the winter of 2015/2016.

- **<u>Permian Basin</u>:** Within the broad category of onshore associated gas production, one region stands out, namely the Permian Basin, which represents a world-class oil province. As previously discussed, drilling activity in the Permian Basin has surged in the recent past and is expected to continue to remain at elevated levels. For the forthcoming winter this heightened drilling activity is estimated to add about 1.3 BCFD of incremental supply over what was provided last winter, or nearly 25 percent of the expected overall increase in this winter's production. As a point of perspective, the Permian Basin gas production noted in Exhibit 28 is only that produced from the shale/tight oil formations (e.g., Wolfcamp, Bone Springs and Sprayberry) in the basin. Additive to this production is the legacy gas production from the shallower formations, which is declining.

- **<u>Offshore</u>:** Over the last several winters offshore production has been relatively flat, which is a sharp reversal from the historical trend for the preceding six years when offshore production was declining sharply (i.e., about 12 percent per annum). The key factor driving this sharp change in trends is a series of projects approved during the era of $100/BBL oil prices, which take years to complete. While in 2015 and 2016 about 14 of these legacy projects came online in each year, in 2017 that figure declined to nine legacy projects – many of which were smaller in size. As a result, offshore production for the forthcoming winter is expected to be lower than last winter's level.

Exhibit 28. Lower-48 Production Outlook For Winter



Source: EIA, PointLogic and EVA.

Shale Production

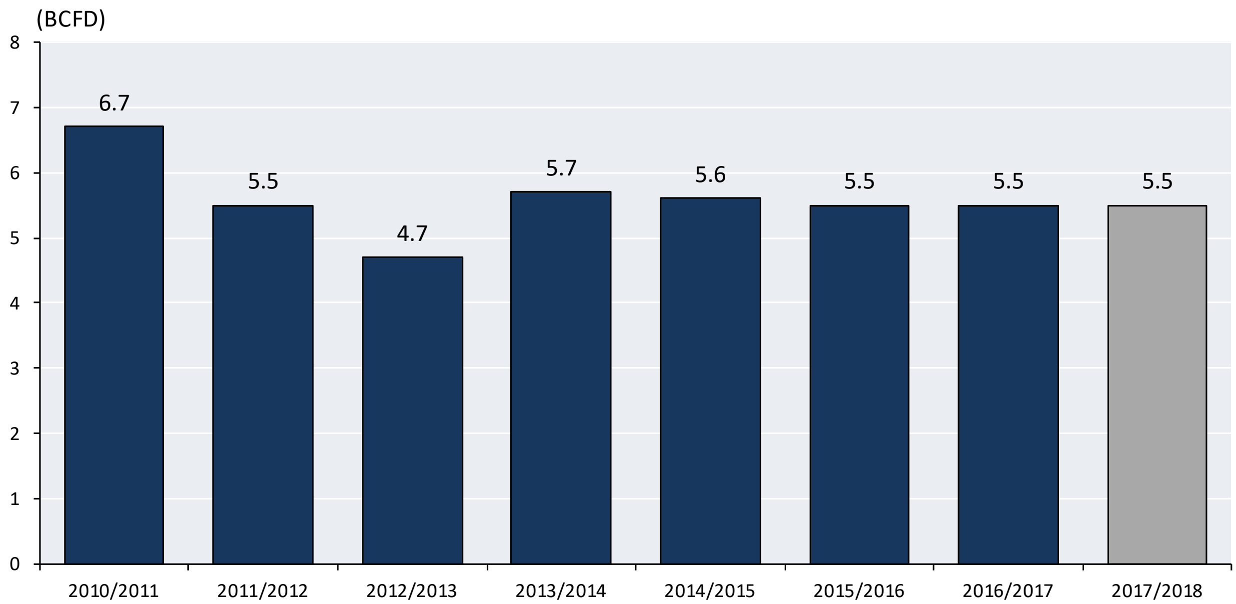
Within the seven major producing areas, there is not a uniform trend. More specifically, the Marcellus, Utica and Haynesville shale plays, like the Permian Basin, are continuing to grow, while the Haynesville play reversed its historical declining trend at about the beginning of 2017. Offsetting these increases are declines for the Barnett and Fayetteville shale plays, while the Eagle Ford production recently has been close to flat.

Net Canadian Imports

It is anticipated that net Canadian imports this winter will, in essence, be the same as those for the prior winter, as illustrated in Exhibit 29. During the period 2007 to 2013 net Canadian imports to the U.S. declined approximately 40 percent, as conventional Canadian production became the marginal source of supply for North America. However, over the last few years Canadian production has begun to increase, albeit modestly, as a result of Canada's development of its prolific unconventional shale plays (i.e., in particular the Montney and Duvernay plays).[15] The net result is that net Canadian imports have increased from their low point and have been relatively flat for the last five winters, including the forthcoming winter.

With respect to the intermediate-term outlook for net Canadian imports, the significant increase in gas-directed Canadian drilling activity likely will result in modest increases in exports to the U.S. More specifically, the Canadian gas rig count in 2017 is 56 percent higher than it was in 2016, as the core areas for the Montney and Duvernay plays have some of the best well economics in North America.

Exhibit 29. Outlook For Winter Net Canadian Imports



Source: EIA and EVA.

[15] The Canadian firms, in essence, use the same drilling and completion techniques to develop their shale plays, as those used in the U.S.

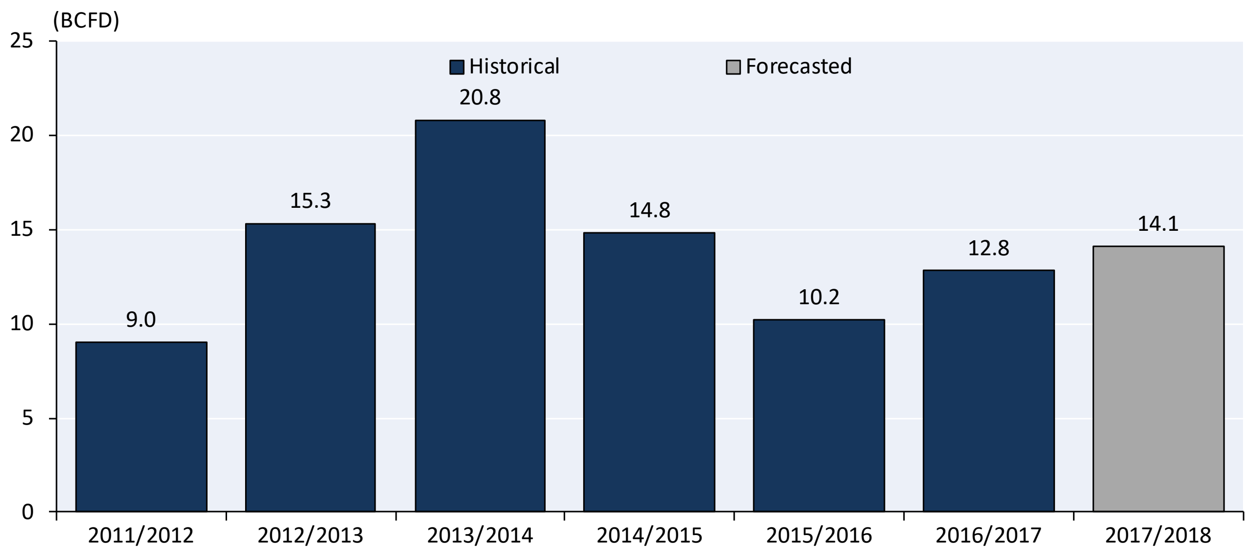
This increase in relatively economic Canadian production recently has enabled Canadian gas to displace Rockies gas that was earmarked for the Northwest and California gas markets at the Stanfield hub in Oregon. In addition, Canadian gas has made inroads into serving the Midwest power market. While Canadian imports into the Northeast markets will continue to be challenged by Marcellus and Utica production, going forward Canada appears to be capable of making some inroads into the western U.S. gas markets.

Storage Withdrawals

Storage withdrawals are the supply component that will be most affected by changes in the outlook for winter weather. As a result, there is more uncertainty about this supply component than any of the other supply components. Assuming close to normal winter weather, storage withdrawals this winter are expected to be about 1.3 BCFD, or 9.9 percent, greater than last winter in storage withdrawals.

As noted in Exhibit 30, there have been considerable variations in storage withdrawals over the last several winters, with most of this variance attributable to the difference in the severity of the winter weather.

Exhibit 30. Outlook For Storage Withdrawals

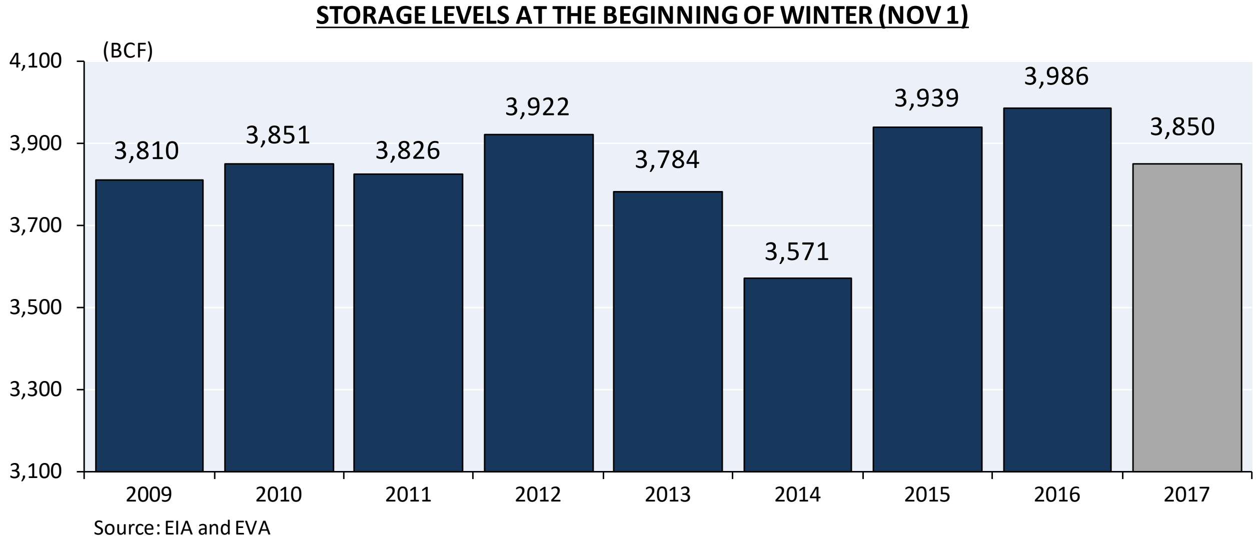


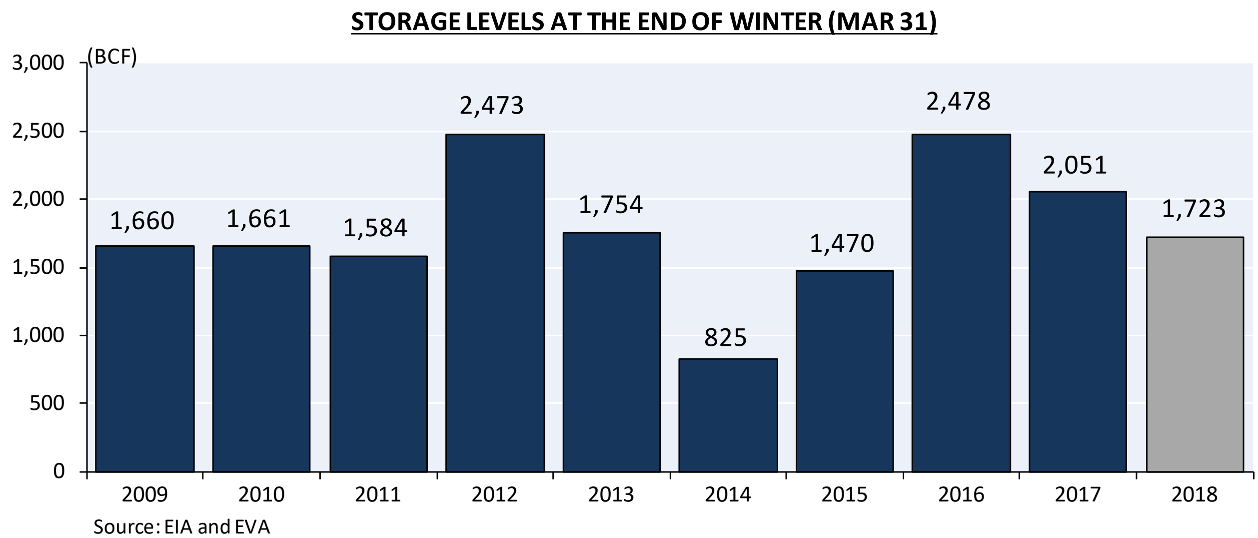
Source: EIA and EVA.

With respect to the outlook for storage levels at the beginning of the winter season (November 1st), they are expected to be less than last winter's record levels, but similar to the average level for the preceding seven winters (see Exhibit 31). In addition, storage inventories currently are expected to increase, albeit moderately, during the first two weeks of November, which would be consistent with the trend over the last several years. However, this does assume the start of the winter season is relatively mild.

With respect to storage levels at the end of the winter season (i.e., March 31st), which are noted in Exhibits 31 and 32, they are projected to be below the levels that occurred for March 31, 2017.

Exhibit 31. Projected U.S. Natural Gas Storage Levels





Nevertheless, the outlook for March 31, 2018 would be above the March 31 levels for five out of the last nine years.

Also, noted in Exhibit 32 are the very limited additions to storage capacity over the last four years. Two factors can explain at least in part the relatively few new storage projects over the last several years. Overall the underlying economics have declined because of the reduction of both seasonal spreads and price volatility over the last several years. In addition, it appears that both pipelines and LDCs currently have enough storage capacity available to them to adequately meet fluctuations in their demand requirements.

Exhibit 32. Projected U.S. Natural Gas Storage Levels

	Actual							Est
	2010	2011	2012	2013	2014	2015	2016	2017
Total Working Gas Capacity at Start of Injection Season(1)	3,925	4,049	4,103	4,265	4,333	4,336	4,342	4,373
Annual Capacity Additions	124	54	162	68	3	6	31	0
Total Working Gas Capacity at End of Injection Season	4,049	4,103	4,265	4,333	4,336	4,342	4,373	4,373
Storage Level at the Start of Winter (Nov 1)	3,851	3,826	3,922	3,784	3,571	3,939	3,986	3,850
Percent of Capacity	95%	93%	92%	87%	82%	91%	91%	88%

(1) Effective maximum usable working capacity.

B. Projected U.S. Natural Gas Storage Capacity and Beginning of Spring Storage Levels

	Actual							Est
	2011	2012	2013	2014	2015	2016	2017	2018
Total Working Gas Capacity at Start of Injection Season(1)	4,049	4,103	4,265	4,333	4,336	4,342	4,373	4,373
Annual Capacity Additions	54	162	68	3	6	31	0	0
Total Working Gas Capacity at End of Injection Season	4,103	4,265	4,333	4,336	4,342	4,373	4,373	4,373
Storage Level at the Start of Spring (April 1)	1,584	2,473	1,754	825	1,470	2,478	2,051	1,723
Percent of Capacity	39%	58%	41%	19%	34%	57%	47%	39%

(1) Effective maximum usable working capacity.

Source: EIA and EVA.

However, while the confidence level for the November 1st storage levels is fairly high, the same cannot be noted for the projection for the storage levels noted in Exhibits 31 and 32 for the end of the winter season (March 31, 2017). This projection for the March 31st storage level is dependent upon assumptions for two critical factors, namely (1) the severity of the winter weather and (2) the impact of the fourth quarter infrastructure event on domestic production. Concerning the former, a shift from the forecasted close to normal winter weather to a severe winter, potentially could increase storage withdrawals about 2.6 BCFD, which would reduce March 31st storage levels about 390 BCF. The opposite effect would occur if the winter weather turned out to be very mild.

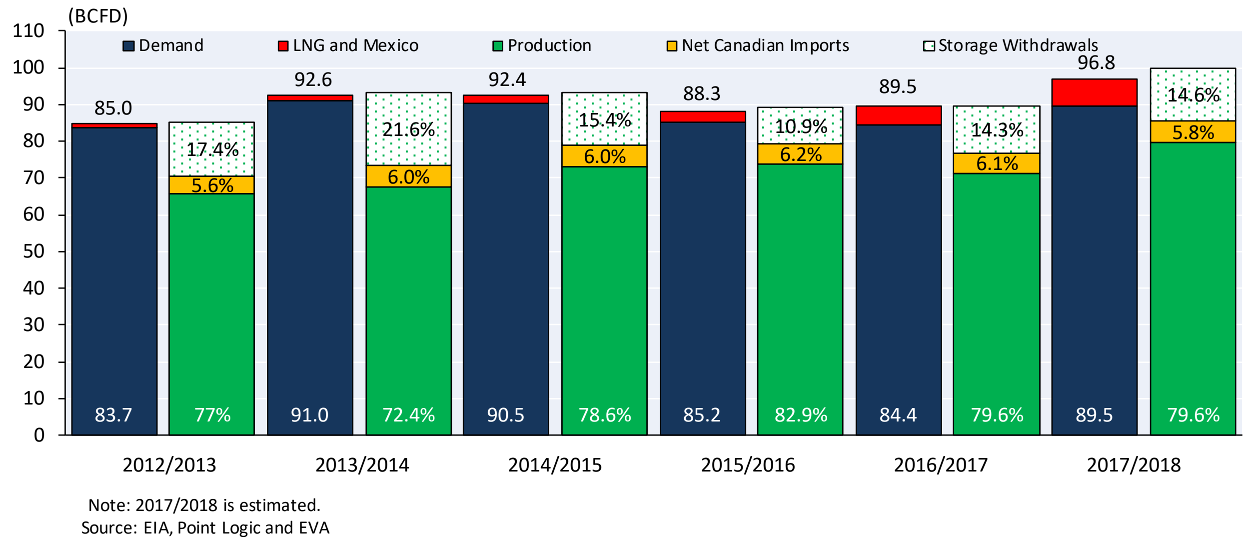
With respect to the second factor, namely the impact of the fourth quarter infrastructure event, the potential impact likely is lower. For example, if the infrastructure event is either below what is projected or is delayed, as was the case for last winter, storage levels for March 31st could be reduced about 160 BCF. As a result, the combined impact of these two areas of uncertainty could reduce March 31st storage levels about 550 BCF. This would reduce the storage levels noted in Exhibit 31 from about 1,723 to about 1,175 BCF, which would be about 20 percent below the level recorded for March 31, 2015, but still above the level attained for March 31, 2014.

With respect to the much discussed Aliso Canyon storage field in southern California, it is now back online. However, the utilization of the field is limited to 28 percent of its original capacity, or 23.6 BCF. In addition, the operating pressure for the field has been reduced 19 percent (i.e., from 3,600 to 2,926 psi), even though the field was tested at 115 percent of maximum allowable operating pressure (MAOP). Key to setting the limit of useable capacity at 23.6 BCF is allowing only those wells for which new steel tubing and packers were installed to be used (i.e., about 40 percent of the 114 wells in the field). Lastly, future operations include, among other things, 24/7 pressure monitoring and daily inspections.

Conclusions

Assuming close to normal winter weather, total natural gas supplies should be adequate to meet the record consumption levels projected for this winter (see Exhibit 33). This is the net result of increases in domestic production levels, and a reasonable increase in storage withdrawals. As previously discussed, the increase in production levels primarily is due to increases in Marcellus, Haynesville and Utica shale production, as well as associated gas from the Permian Basin.

Exhibit 33. Summary Of Winter Supply



ADDENDUM I:

U.S. LNG EXPORTS

U.S. LNG Exports

Overview

Having started in February 2016, U.S. L-48 LNG exports have increased steadily through 2016 and the first half of 2017. To date, Cheniere's Sabine Pass LNG project on the Gulf Coast of Louisiana remains the only U.S. export project in operation and now has three trains, totaling 1.8 BCFD of capacity, fully online. The project has two additional trains, totaling 1.2 BCFD of capacity, under construction, which will come online in late-2017 and early-2019, respectively.[16]

Beyond Sabine Pass, five other U.S. LNG export projects are under construction. Dominion's 0.7 BCFD Cove Point project in Maryland, which is scheduled to commence exports in late-2017, will be the next project online. The remaining projects are progressing on schedule but will not begin exports until 2018 and 2019. By 2020, total U.S. L-48 LNG export capacity will reach 8.6 BCFD.[17]

Many other U.S. LNG projects remain at various stages of proposal. With the global LNG market in the early stages of a considerable multi-year oversupply, few additional export projects are likely to be sanctioned in the U.S. (or elsewhere) through 2017 and much of 2018. However, the market is expected to balance in 2022-2023, after which a large amount of new capacity will be needed to meet steadily rising global demand. Because the U.S. offers several critical advantages over many competing supply regions, a second wave of U.S. LNG projects is expected to reach final investment decision (FID) between 2018-2020 in order to come online by 2023 and beyond. Indeed, incremental capacity additions are expected throughout the 2020s. By 2030, total U.S. LNG export capacity is expected to reach 15.5 BCFD, establishing the U.S. as the world's largest second largest LNG exporter, behind only Qatar.

Current U.S. LNG Export Dynamics

After beginning exports in February 2016, the first train at Sabine Pass reached full commercial operations in May followed by the second train in September. Train 3 subsequently achieved commercial operations in April 2017, while Train 4 is expected fully online by October.

Construction on the other five projects is progressing and while modest delays have been announced at a few (e.g., Cameron LNG), all trains are expected to come online mostly as scheduled (see Exhibit Add I-1). With the exception of Corpus Christi LNG, all of the under construction projects are brownfield developments associated with existing regasification facilities. The presence of on-site infrastructure (especially the large storage tanks) greatly reduces project cost, complexity and risk of delay.

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[16] Cheniere took Train 3 offline for maintenance in late-August. Train 4 is currently in the commissioning phase and is expected to reach commercial operations in October.

[17] Through this Addendum, discussion of LNG exports refers only the U.S. L-48 and excludes Alaska.

Exhibit Add I-1. U.S. Liquefaction Projects Online in the First Phase for U.S. Exports

Project	Train	Capacity (MMCFD)	EVA Estimated Start Date	Lead Developer	Primary Offtakers (most likely destination)
Sabine Pass LNG	1	600	May-16	Cheniere Energy	Shell (Global)
	2	600	Sep-16		GNF (Europe/S. America)
	3	600	Apr-17		KOGAS (Korea)
	4	600	Aug-17		GAIL (India)
	5	600	Aug-19		TOTAL (global) Centrica (UK)
Cameron LNG	1	533	Feb-19	Sempra Energy	Engie (Europe)
	2	533	Jul-19		Mitsubishi (Japan)
	3	533	Sep-19		Mitsui (Japan)
Freeport LNG	1	587	Sep-18	Freeport LNG	Osaka Gas, Chubu Electric (Japan)
	2	587	Feb-19		BP (Global)
	3	587	Aug-19		Toshiba (Japan)
Cove Point	1	700	Dec-17	Dominion	GAIL (India), Sumitomo (Japan)
Corpus Christi LNG	1	600	Mar-19	Cheniere Energy	EDF, Iberdrola, Endesa, GNF (Europe)
	2	600	Aug-19		Pertamina, Woodside (Asia)
Elba Island	1-6	200	Dec-18	Kinder Morgan, Shell	Shell (Global)
	7-10	133	Jun-19		

Source: Company websites and the trade press.

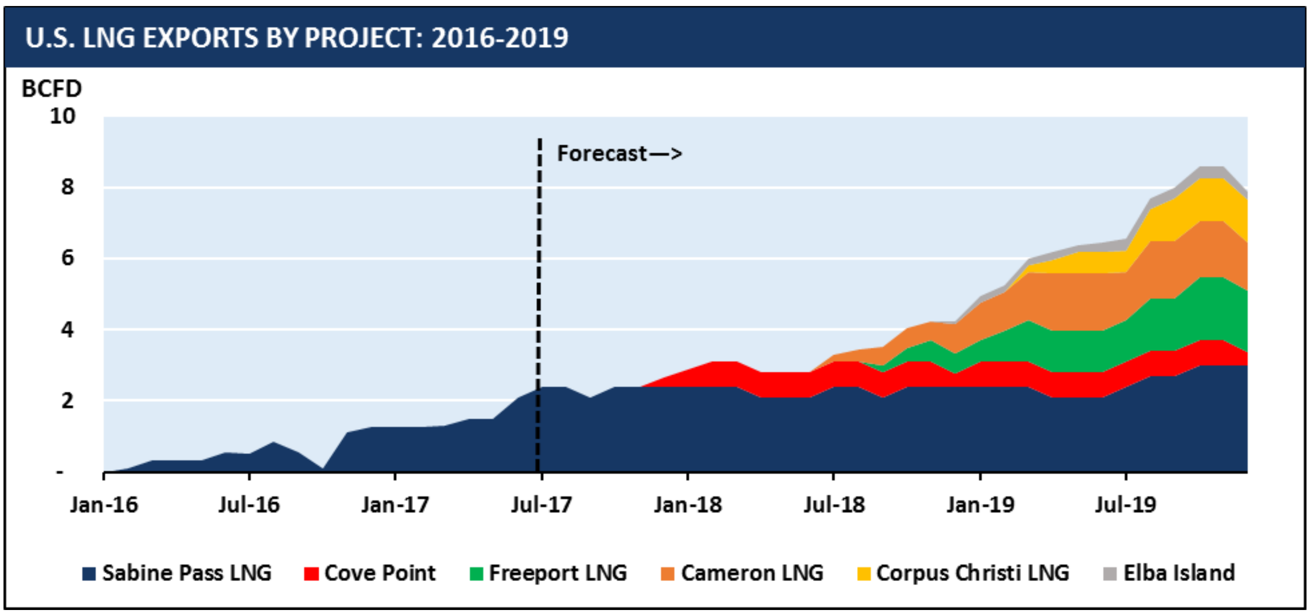
Through early July, more than 170 LNG cargoes have been exported from Sabine Pass, with the project now averaging 15 cargoes/month, the equivalent of ~1.8 BCFD. The cargoes have been directed to at least 24 different countries, covering every region of the world. Somewhat surprisingly, Mexico has been the single largest recipient of U.S. LNG cargoes (38 cargoes as of late August), followed by Chile (16 cargoes) and South Korea (16 cargoes). The remaining cargoes have been split largely equally between Asia and South America, and to a lesser extent, the Middle East and Europe.

Output from Sabine Pass has generally remained high. Exports declined precipitously, but briefly, in October 2016 due to planned maintenance. More recently, Train 3 was taken offline in late-August for an undisclosed length of time. Otherwise, the project's trains have otherwise ramped-up quickly and operated near or just below nameplate capacity. The cargoes have flowed despite a global LNG market moving quickly toward oversupply, with global gas prices—including European hubs, spot LNG and oil-linked LNG—all hovering just below $6/MMBTU.

The prospect of persistently low global gas prices has called into question the value proposition of U.S. LNG and led to concerns that a certain portion of the capacity may be shut-in or under-utilized. So far at least, this outcome has been avoided, as the structure of the contracts at Sabine Pass (as well as other under construction U.S. LNG projects) greatly reduces the likelihood of meaningful export curtailment. More specifically, LNG offtakers appear to view the take-or-pay tolling fee as a sunk cost, and thus make offtake decisions based on variable costs alone. With Henry Hub prices holding near $3/MMBTU, and shipping costs at multi-year lows, U.S. LNG cargoes are still in the money even as global prices fall between $4-$5/MMBTU. Europe, with ample import capacity and several liquid hubs, is available as a market of last resort and will effectively set the basement price for LNG. Thus far, relatively few U.S. cargoes have been directed to European markets, but it may become a more common destination going forward.

As at Sabine Pass, substantially all of the remaining capacity under construction has been contracted to LNG buyers on a long-term basis, including a flat, take-or-pay tolling fee. In contrast to Sabine Pass, the LNG buyers at the other projects (excluding Cheniere's second project, Corpus Christi) are responsible for supplying feedstock to the facility.[18] Regardless, the slight difference in contract structure is unlikely to impact offtake decisions and for all projects, contracts are void of any destination restrictions. As a result, exports from all U.S. LNG projects are expected to effectively match contracted levels, though there may be some slight curtailment during the peak of the global oversupply in 2019-2020. LNG exports (including 10% feedstock requirement) are expected to average 2.1 BCFD in 2017 and 3.5 BCFD in 2018 before rising to 7.1 BCFD in 2019 (see Exhibit Add I-3).[19]

Exhibit Add I-3. U.S. LNG Exports by Project: 2016-2019



So far, most U.S. LNG cargoes have been traded on the spot market. However, for the winter of 2017/2018 this metric is expected to decline to about 75 percent, as the long-term Sabine Pass contracts with GAIL and KOGAS commence. For the winter of 2018/2019, more cargoes may go to buyers' home markets, as additional trains come online and additional long-term contracts commence.

[18] Cheniere has structured its contracts in a slightly different manner. At both Sabine Pass and Corpus Christi, Cheniere will supply the feedstock and charge the LNG buyer 115% of Henry Hub.
[19] Note, exports differ from nameplate capacity and likely will be lower due to maintenance and because a few projects are not 100% contracted.

Global Oversupply Slows Development of Second Wave

The U.S. LNG projects currently under construction will come online over the next few years amid a heavily oversupplied global LNG market. Early signs of the impending glut are already apparent, with spot LNG prices falling to multi-year lows.[20] The oversupply is cyclical, driven by a tremendous amount of new liquefaction capacity that has and continues to come online in Australia, followed thereafter by capacity in the U.S. and to a lesser extent, Russia. Supply will still meet demand, but the market will clear at prices much lower than those experienced over the past several years and buyers will look to take advantage by meeting a larger proportion of their demand on the spot market.

The combined result is that few LNG buyers are interested in signing the types of long-term offtake contracts historically required to underpin new LNG export projects. This dynamic has held for the past few years, with relatively few new contracts announced since early-2015 and is likely to persist through the end of 2017. However, global LNG demand continues to rise and the consensus is that the market will balance in 2022 then shift, rather abruptly, to shortage. Thus, there will be considerable demand for new LNG projects to come online in that timeframe, which in turn will require new projects to reach FID in the next few years (LNG projects typically require 4-5 years of construction).

A large number of projects in several regions have been proposed to meet this demand. Among them are Qatar, Western Canada, Russia, East Africa and offshore Australia, all of which offer enormous gas reserves and close proximity to premium Asian markets. However, each region also suffers from large obstacles, including high costs, geopolitical uncertainty or environmental opposition. In contrast, the U.S. projects offer several enduring advantages, such as lower construction costs, access to the highly-liquid U.S. gas grid, plentiful financing options, and a well-established environmental permitting process. Given these benefits, a second phase of U.S. LNG export capacity is expected to move forward to meet the tightening global supply/demand balance in the early-2020s.

The magnitude of the second wave of U.S. LNG is difficult to predict and is largely dependent on the rate of LNG demand growth in China, India and multiple emerging markets, as well as supply development in competing regions. The latter issue recently has become more acute, as Qatar (already the world's largest LNG exporter) announced plans to increase its capacity from 10.3 BCFD to 13.3 BCFD by the mid-2020s. Qatar sources gas from the North Field, which is not only massive, but also offers development costs far below any other competing supply region, including the U.S. The Middle Eastern country's proximity to growing importers such as India, Pakistan, Bangladesh and others, is also an advantage and should facilitate successful marketing of the new capacity. In short, Qatar's ability to quickly add a considerable amount of low-cost export capacity reduces the magnitude of opportunity for other exporters in the 2020s, including the U.S.

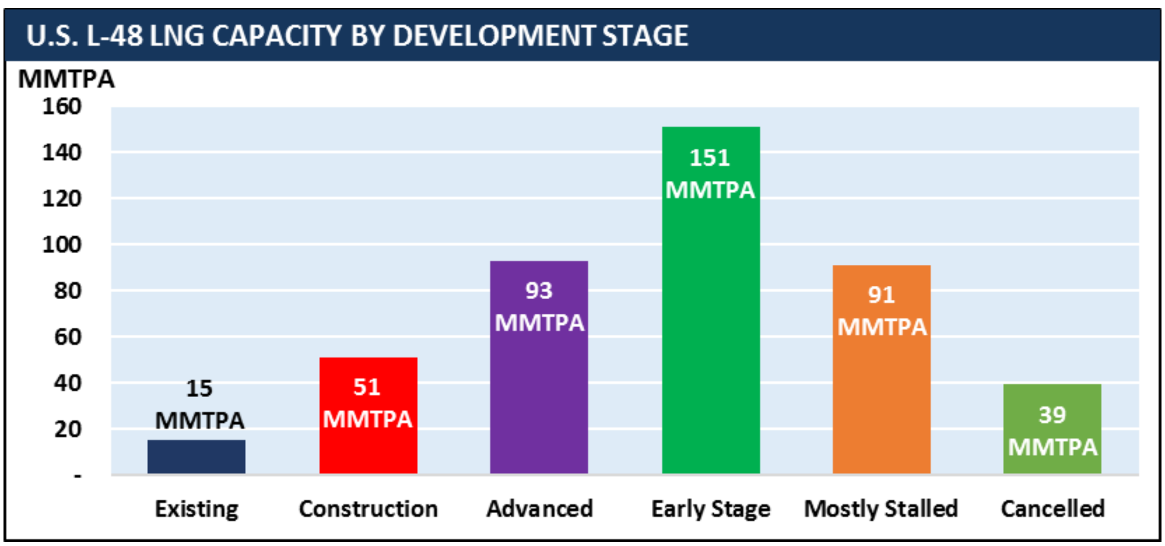
Still, LNG demand, especially in the new paradigm of lower prices, will increase rapidly enough to ensure additional U.S. projects fill a substantial portion of new demand. More than 30 additional U.S. projects—totaling 44.6 BCFD—have been proposed (see Exhibit Add I-3).

[20] In contrast, the price of long-term, oil-linked contracts does not reflect LNG supply/demand dynamics, but are instead driven (predictably) by oil price fluctuations.

Regulatory concerns at both FERC and DOE have largely been eliminated, as several projects have already completed the process. Further, the Trump administration has been quite vocal about its strong support for U.S. LNG exports, suggesting that the regulatory timeline may even be expedited.

The bigger challenge for proposed LNG projects is marketing. Only a few have generated any meaningful commercial momentum in the current environment, though interest among buyers seems to be trending slightly upward. A few projects (Rio Grande LNG, Delfin FLNG, Magnolia LNG, among others) have announced non-binding offtake contracts, but these are unlikely to be finalized until 2018. Potential buyers may show a preference for experienced developers. Brownfield projects, or expansions at brownfield projects already under construction, would offer particularly low construction costs and accelerated development schedules. Several small scale projects (i.e., less than 0.25 BCFD in capacity) also have been proposed and could emerge as good options for buyers unwilling to commit to large volume deals.

Exhibit Add I-3. Summary of Proposed U.S. Liquefaction Projects[21]



While it is a crowded field filled with some uncertainty for each proposed project, Exhibit Add I-4 summarizes EVA's base case for this second phase. As illustrated, it is anticipated that several projects, totaling (7.2 BCFD) will come online between 2023 and 2028. Nearly all the capacity is associated with expansions (Sabine Pass, Cameron LNG) or brownfield developments (Lake Charles, Golden Pass). A few additional projects also may move forward post-2030. The forecast excludes the massive Alaskan LNG project (2.6 BCFD), which is unlikely to move forward due to extraordinary project costs and complexity.[22]

[21] Status and category distinctions are based on EVA's assessment, which is driven by a project's commercial progress, regulatory status and ownership structure, among other factors.
[22] Further, the Kenai LNG project, which has been operating in Alaska since 1969, will soon be mothballed by owner ConocoPhillips. The project had shipped only a handful of cargoes over the past few years and is not expected to be restarted.

The combination of the first and second phase expansions would bring total U.S. liquefaction capacity to 15.5 BCFD by 2030, with actual exports averaging 13.2 BCFD. While this would establish the U.S. as the world's largest LNG exporter based on current capacity, the likelihood of significant capacity expansions in Qatar suggests the U.S. will reach only the number two position.

Exhibit Add I-4. U.S. Liquefaction Projects Online in the Second Phase for U.S. LNG Exports

Project	Train	Nominal Capacity (MMCFD)	Status	EVA Estimated Start Date	Lead Developer(s)
Golden Pass LNG	1	693	Approved, Not Contracted	Jun-23	ExxonMobil, Qatar Petroleum
	2	693	Approved, Not Contracted	Dec-23	
	3	693	Approved, Not Contracted	May-24	
Lake Charles LNG	1	667	Approved, Contracted	Jun-25	Energy Transfer, Shell
	2	667	Approved, Contracted	Mar-26	
	3	667	Approved, Contracted	Dec-26	
Sabine Pass LNG	6	600	Approved, Not Contracted	Jan-25	Cheniere Energy
Cameron LNG	4	533	Not Approved or Contracted	Sep-25	Sempra Energy
	5	533	Not Approved or Contracted	Jan-27	
Corpus Christi LNG	3	600	Approved, Part Contracted	Jan-25	Cheniere Energy
Magnolia LNG	1	267	Approved, Part Contracted	Jan-27	LNG Limited
	2	267	Approved, Part Contracted	Jan-28	

ADDENDUM II

TRANSPORTATION SECTOR

Transportation Sector

Overview

During the era of high oil prices, many industry observers opined that natural gas would make significant inroads into the transportation sector. The two driving forces behind this assessment were (1) the economic advantage of natural gas and (2) current and pending regulations to reduce emissions from the transportation sector. With the sharp decline in oil prices, the natural gas option has lost its economic advantage, which is at least in part borne out by the observation of Washington Gas, which notes that for the last year, on a gasoline equivalent basis, CNG was more expensive than gasoline for their fleet of vehicles.[23] With respect to the regulations factor, while the emphasis on emissions reduction continues, natural gas now has competition, at least in some segments of the transportation sector, from the emerging electric vehicles.

As a result, the expected growth for natural gas within the transportation sector is expected to be minimal and likely will not become a significant component for the outlook for natural gas demand, as previously opined by some industry observers. Nevertheless, there are some segments of the overall transportation sector where natural gas has, and will continue to make, substantial inroads, albeit small volumes when compared to total U.S. natural gas demand.

The material below briefly reviews the outlook for several of the 11 subsegments to the transportation sector, as the transportation sector in its entirely is far from being a homogeneous entity.

Outlook For Transportation Sector

There are five major segments of the transportation sector and 11 subsegments within them. Each of these subsegments has its own unique characteristics, which makes developing a composite assessment of the penetration of CNG/LNG within the transportation sector rather complex. While there is significant momentum within certain subsegments, primarily because of commitments made two years ago, for many subsegments this momentum is declining because of the reduced economic incentives. Exhibit Add II-1 provides a simplified summary of CNG/LNG within most of the transportation subsegments.

As noted, only the refuse truck segment still has a significant economic incentive to convert to CNG/LNG. This occurs primarily because of the high mileage associated with waste management trucks (i.e., 150,000 miles/year versus the more typical 60,000 miles/year for heavy duty Class 8 trucks) and the fact that they are fleet vehicles that return to a common staging area each night (i.e., the need for a single CNG/LNG refueling location). In addition, the introduction in late 2014 of the Cummins-Westport 15X-12G 11.9 liter engine represented a significant step forward for heavy duty trucks.

[23] Comparative economics of the two fuels vary by region. "Even Gas Utilities Having Trouble Finding Cars for Their NGV Fleet", *Natural Gas Week*, October 3, 2016, p. 1 ff.

Exhibit Add II-1. Overview Of Emerging Transportation Markets

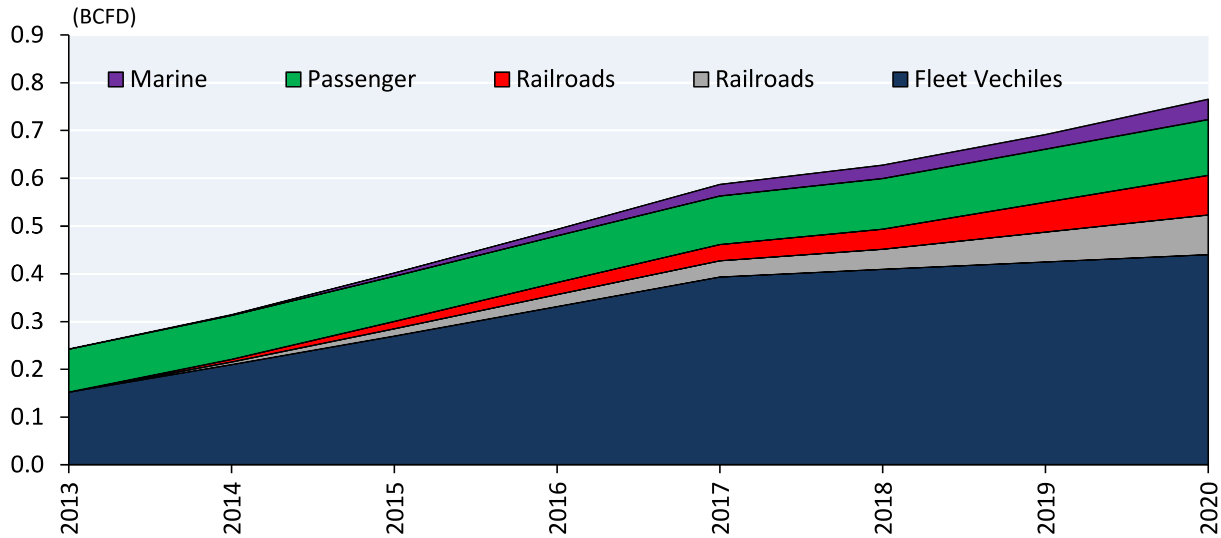
Transportation	Potential For Penetration High: Economic	Potential For Penetration High: Environmental	Potential For Penetration Low
Maritime			
• Ocean Going Vessels		X(B)	
• Ferries		X(A)	
• Other			X
Trucks/Bus			
• Refuse Trucks	X(C)		
• Mining			X
• Fleet Vehicles			X(D)
• Transit Buses		X(F)	
Field E&P			
• North Dakota		X	
• Other Areas			X
Railroads			X(G)
Passenger Cars			X(E)

A. 17 LNG ferries in U.S. commissioned since 2013. Source: EVA and trade press.
B. Worldwide there are 57 LNG supply locations for ships with 36 more planned. At year end 2016 there were 88 LNG-fueled ships in operation and 98 on order. Norway is the world's leader for LNG-fueled ships.
C. Approximately 50% of the fleet of refuse trucks are fueled by CNG, with approximately 60% of new orders being for CNG-fueled ships.
D. Sales of medium duty trucks in 2014 increased 24% to 2,700 trucks.
E. New sales of NGV represents about 0.3% of total light duty vehicle sales. If the bi-fuel NGV category is included, this metric is still <0.5%.
F. Approximately 20% of the transit buses use natural gas, while about 30% of the new orders for transit buses are fueled by natural gas.
G. To date only the Indiana Harbor Belt (IHB) railroad, which basically operates as a switching yard, makes use of LNG powered locomotives. IHB has two dual-fuel (i.e., diesel and CNG) short-haul locomotives in operation with plans for 29 more. Since IHB is near an urban area, the reduction in emissions was a significant factor.

Furthermore, there are four other segments in which environmental factors are continuing to drive the industry to convert away from diesel consumption to CNG/LNG use. Other than these highlighted segments, there has been a significant loss in the momentum, because of the decline in the economic incentive, for an increased market share for CNG/LNG.

With respect to a composite view of the intermediate-term outlook for the increased penetration of CNG/LNG within the transportation sector, this is summarized in Exhibit Add II-2. Furthermore, according to the EIA the current gas consumption within the transportation sector is approximately 0.1 BCFD, however it is not clear that the EIA is capturing all of the natural gas use with the transportation sector, as there are now about 1,763 CNG/LNG refueling stations of which about 60 percent are open to the public. It is assumed that any missing gas consumption levels for the transportation sector have been captured within the much larger industrial sector consumption data. Nevertheless, using the EIA metric the current outlook for the transportation sector represents a high percentage growth rate, but a relatively small overall increase in total gas demand by 2020 (i.e., about 0.6 BCFD).

Exhibit II-2. Outlook For Gas Demand Within The Transportation Sector



Source: EVA.

Marine Sector

Overview

As noted in Exhibit Add II-1, there is still significant momentum within the marine segment of the transportation sector for the use of CNG/LNG to replace fuel oil, with the primary driver being changing environmental regulations. However, while the above is, in general, true for the marine segment, there are unique attributes and differences within the four subsegments or categories of the marine segment.

Background

The marine segment of the U.S. transportation sector consumes about 645 MBD of oil-derived fuel per year, however roughly 80 to 85% of this is high-sulfur residual fuel oil with the remainder, or about 125 MBD, being diesel. Primarily because the cost of residual fuel oil is so low (i.e., about $1.00 per gallon), the potential use of LNG as a substitute for most categories of the marine segment is unlikely on a purely economic basis. However, with the recent enactment of regulations to invoke more stringent emissions requirements the use of LNG as a substitute likely still will occur in many areas of the overall marine transportation segment.

In addition, there is a significant international perspective to use LNG within the shipping industry. More specifically, within certain segments of the international market the use of LNG has been growing rapidly and likely will continue to grow. The latter is particularly true of Europe and especially Norway. However, the same cannot be noted for the U.S., even though progress is being made.

Regulations

Approximately 10 to 15% of all marine fuel consumption for the international market occurs in areas that are now being designated as emission control areas (ECAs). To comply with both existing and pending regulations for ECAs, ship-owners can either: (1) install scrubbers; (2) use compliant low-sulfur fuel, such as marine diesel oil (MDO); or (3) switch to alternative fuels, with LNG being the leading candidate. In each case the primary objective is to reduce NOx and SOx emissions. With respect to the relative economics of these alternatives, installing exhaust gas-after-treatment, such as either scrubbers or urea catalysts, both add to capital costs and fuel costs, as overall fuel consumption can increase two to three percent. With respect to the alternative of burning cleaner oil-derived fuels, this will increase the overall cost of fuel and there is a risk that such fuel costs will increase if either demand increases or oil markets come under stress.

One of the major drivers for the adoption of natural gas in ocean-going vessels is the adoption of new stringent sulfur regulations throughout North America. These new regulations require ships to use higher-quality expensive fuels, which will increase the oil-to-gas price ratio. This in turn will increase the attractiveness of using natural gas. The timing of these regulations is indicated in Exhibit Add II-3, which highlights the initial transition to a 100 ppm sulfur limit by 2015/2016 and then subsequent regulations requiring better after treatment.

Exhibit Add II-3. MARPOL Regulations

	> Jan 1, 2010	< Jan 1, 2010	Jan 1, 2012	Jan 1, 2015	Jan 1, 2016	Jan 1, 2020
ECA Regulations	SOx <1.5%	SOx <1%		SOx <1%		
Other ECA Regulations				New after treatment regulation.		
Global Regulations	SOx <4.5%		SOx <3.5%			SOx <0.5%*

* Subject to review in 2018. Source: Trade press.

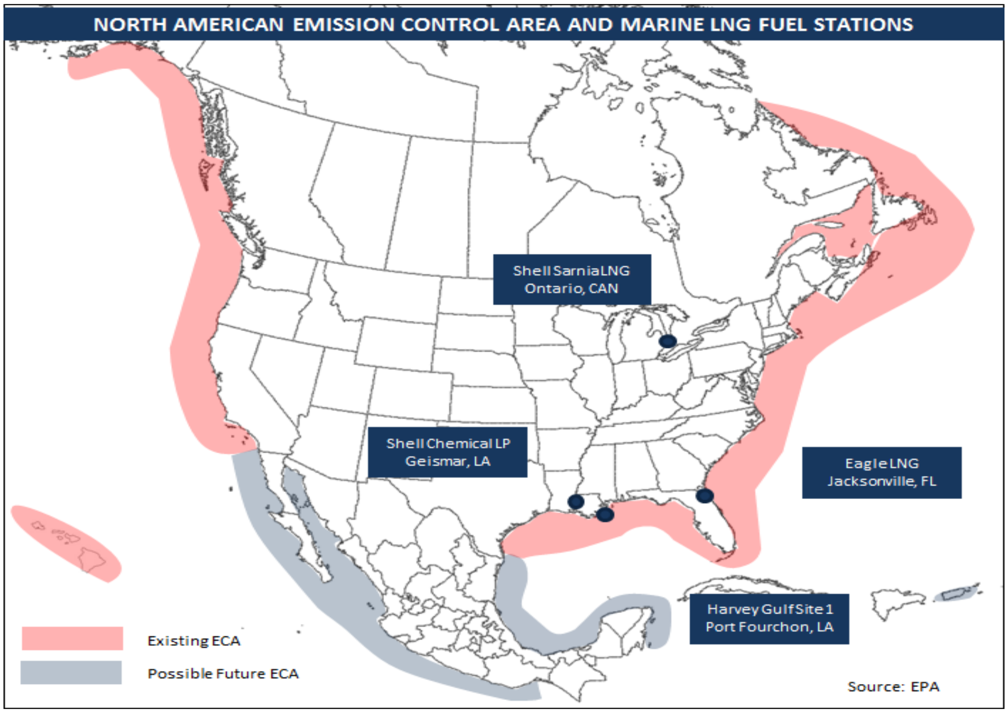
With respect to North America the existing and pending ECAs are illustrated in Exhibit Add II-4. To date the reaction to the ECA regulations has been mixed. While both Sea Star Line and Tote already have LNG powered vessels in operation in order to comply with forthcoming emissions, there is not an universal strategy within the industry.[24] For example, the LNG tanks for these vessels are large, which reduces overall cargo space, and expensive (i.e., about a 19% premium to existing ships). This reduction in overall cargo space is a significant drawback for some firms.

In the case of the cruise ship industry, 10 new LNG powered cruise ships are on order for 2017, while another 15 are on order for 2018. With respect to one of the largest cruise ship firms, namely Carnival Cruise Ships, they have chosen to pursue a bi-furcated strategy that involves (a) spending $180 MM to install sulfur scrubbers on 32 of its cruise ships and (b) ordering four new LNG powered cruise ships, which are scheduled to be delivered in 2019 and 2022.[25]

[24] The two Tote ships represent the first LNG powered container ships, with the first being delivered in the fourth quarter of 2015 for service between Jacksonville, Florida and Puerto Rico. The second was delivered in the first quarter of 2016.

[25] Two of the four new Carnival Cruise ships will be used for German-based cruises.

Exhibit Add II-4. North American Emission Control Areas And Marine LNG Fuel Stations



Source: Trade press and EVA.

Four Categories

As noted above, there are four categories to the marine segment. The unique attributes for each of these categories is reviewed briefly below, along with a general assessment of the outlook for the use of CNG/LNG within each category.

Ferries

While the use of ferries within the U.S. is rather limited, ferries likely will be one of the first areas of the U.S. marine segment to adopt the use of LNG as an alternative fuel. Ferries operate using a point-to-point system, which enables them to utilize a centralized refueling system that can be tailored to the specific needs of each fleet of ferries. This is a significant attribute that greatly enhances the economics of using LNG. In addition, ferries operate in urban environments, which in most instances have, or are in the process of, implementing stricter emission requirements.

Currently, the Washington State Ferries are retrofitting six ships to use LNG, while the Staten Island Ferries have undertaken a feasibility study for the use of LNG. A similar phenomenon is occurring in Canada, where the Quebec Ferries Company has ordered three LNG ferries, while BC Ferries in Vancouver has one LNG ferry in operation and two more on order.

Harbor Vessels

While there are several different types of harbor vessels, the most significant, and primary focus of this assessment, is the tugboat. There are three significant attributes to tugboats, namely:

(1) Many tugboats operate in major ports, which are densely populated areas that likely will enact more stringent emission requirements over time.

(2) The use of a centralized refueling station, which significantly enhances overall economics, is applicable for many of the tugboats. As a point of perspective, centralized refueling, this is more applicable to tugboats serving major ports than it is to inland tugboats (e.g., tugboats in service along the Mississippi River). For inland tugboats the lack of refueling structure is problematic.

(3) Tugboats, because of their powerful engines, are large consumers of fuel. The latter potentially results in significant annual fuel savings for those tugboats that convert to LNG. However, such savings are reduced at $50/BBL oil prices.

In addition, there could be a time delay in the rapid conversion of the U.S. tugboat fleet, because historically the manufacturing of new tugboats within the U.S. tends to occur in waves, with approximately a 20-year gap between peak building periods (i.e., the typical life of many tugboats). At present the U.S. is close to one of these peak building periods, which would imply some delay before rapid conversion occurs.

With respect to the economics for converting a tugboat to using LNG, they can be very attractive. This occurs because the typical tugboat uses about 7,000 gallons/day of diesel. Even at only $0.40 per gallon (DEQ) savings this would result in annual fuel savings of about $1.0MM, which in turn results in a payback period of about two or three years. In addition, this annual fuel savings likely will increase over time, as the trend in the shipping industry towards larger container ships (i.e., more dead weight tons (DWT)) is requiring that new tugboats have even higher horsepower engines.

Offshore O&G Supply Vessels

With respect to the current international LNG shipping fleet, a significant percentage are the various supply and transport ships used for the offshore O&G industry. At present most of these offshore field service ships are located in the North Sea and, in particular, Norway. However, it is expected over time that the U.S. offshore field service industry will follow suit. More specifically, Harvey Gulf has ordered six Marine 302' x 64' dual-fuel Offshore Supply Vessels, and the first of these launched in January 2014. Furthermore, Shell already has chartered three of these six vessels.

Ocean-Going Ships

At year-end 2016 there were 88 LNG powered ships in operation and another 98 on order (i.e., total global fleet is about 50,000 ships). Most of these LNG-powered ships will be concentrated in Europe and, in particular, Norway, because of the strict EU regulations concerning emissions within European ports, which goes beyond the MARPOL standards.[26] With respect to the U.S.,

[26] With respect to the international use of LNG for vessels, it is becoming rather widespread, and includes the following: (1) a medium range CNG ship in Indonesia; (2) a LNG bunkering vessel in the Baltic Sea (2016); (3) numerous ferries in Norway; (4) a unique CNG/Solar ferry in the Netherlands; (5) harbor patrol craft in Norway; (6) a ferry in British Columbia; and (7) a ferry in Argentina/Uruguay. Offsetting, to a degree, these advances are the cancellation of plans in the U.K. and France to use LNG powered ferries by Brittany Ferries.

where progress towards an LNG shipping fleet has been slow, Exhibit Add II-5 identifies 16 LNG ships that are currently on order. In addition, VanEnkevart Tug and Barge has plans to convert some of its vessels on the Great Lakes. While economics are important, the key driver behind this initial fleet of U.S. LNG ships are the 2016 emission regulations for the shipping industry that operate within U.S. waters (i.e., 200-mile limit).

Exhibit Add II-5. U.S. LNG Ships Currently On Order

Company	No.	Type	Areas of Operations	New/Retrofit	Delivery Date
Crowley Maritime	2	RoRo	Caribbean, FL-PR	New	2017
Interlake	10	General Cargo	Great Lakes	Retrofit	2016
TOTE Inc.	2	Container	Caribbean, FL-PR	New	2015/2016
Navigation Co.	2	Container	West Coast-Hawaii	New	2018
Source: Trade press.					

Refueling Stations

A key component for the conversion to LNG vessels for each of the above segments is the building of LNG fueling infrastructure tailored to the needs of the marine sector. At present there are four planned U.S. marine LNG fueling stations that will be capable of serving the marine sector, as well as other sectors (i.e., see Exhibit Add II-6 for a tabulation of these facilities) with the Jacksonville facility scheduled to be online in the fourth quarter of 2017. Two of these four planned LNG fueling stations have received their final investment decision (FID) by their developers (i.e., the Harvey Gulf and Eagle facilities), while Shell has announced that it is proceeding with its two facilities. With respect to the Sarnia facility, it will service ships operating in the Great Lakes.

Exhibit Add II-6. U.S. LNG Fuel Stations For The Marine Sector

Company	Location	MMCFD	Gallons
Shell Geismar	Geismar, LA	35	276,243
Shell Sarnia	Sarnia, Ontario	34	270,000
Harvey Gulf Site 1	Port Fourchon, LA	34	270,000
Eagle LNG	Jacksonville, FL	15	120,000
Puget Sound Energy	Tacoma, WA	2	12,826
Total		**120**	**936,243**
Source: Trade press.			

Outlook

The movement towards the use of CNG/LNG within the marine segment in the U.S. is much slower than that elsewhere in the world, particularly for Europe. As a result, the outlook is that by 2020 use of CNG/LNG in U.S. marine segment, while increasing, likely will be 0.1 BCFD or slightly less.

Jones Act:

The international nature of the shipping industry means American ship-owners use international registries (also known as flag states or flags of convenience) to register their vessels. There are four major flag states: Panama, Liberia, Malta and the Marshall Islands. American ship-owners primarily use the Marshall Island registry. However, if a ship only uses American ports, or if it goes from one U.S. port to another, it needs to comply with the Jones Act. The Jones Act requires that a ship be (1) built in the U.S.; (2) registered in the U.S.; (3) owned by an American; and (4) operated by an American crew. This significantly raises the price of a ship and could be a major impediment to the adoption of LNG fueling in the U.S. For example, Valero Energy estimates that it costs $5.00 to $6.00 per barrel to ship oil from the Gulf to the East Coast in a Jones Act vessel, while it only costs $2.00 per barrel to ship oil from the Gulf to Canada's East Coast in a non-Jones Act vessel.

Other Segments: Competition

While natural gas has made significant inroads in the transit bus segment of the transportation sector, going forward there likely will be some competition from electric-driven buses. At present natural gas is used for approximately 20 percent of the transit buses and about 30 percent of the new orders are for natural gas fueled buses. This significant penetration of this segment of the transportation sector primarily is due to the reduced emission levels of natural gas fueled buses, which is preferred in many urban areas. However, going forward electric-driven buses likely will begin to compete for market share in this segment, as evidenced by the recent opening of an electric-bus factory in Southern California.[27]

Similarly, for the light duty vehicle segment of the transportation sector, electric vehicles have proven to be a significant competitor and are now in the lead. While both alternatives to gasoline powered vehicles still represent a small segment of total annual light duty vehicle sales, the electric vehicles (i.e., battery and plug-in) represent about 1.8 percent of new sales, while natural gas vehicles are still less than 0.5 percent. The lack of market share for natural gas vehicles has resulted in Honda, after 17 years of limited sales, withdrawing its Honda Civic GX at the end of 2015.[28]

Even in the challenging area of infrastructure, electric vehicles currently have the advantage. More specifically, there are approximately 1,763 CNG/LNG refueling stations of which about 60 percent are open to the public. Furthermore, these stations are concentrated in select locations, as the top three states accounted for about 35 percent of the total. As a point of comparison there are approximately 16,102 electric recharging stations with 43,812 outlets. However, these also are fairly concentrated with California accounting for 24 percent of the total recharging stations.

[27] The factory is capable of producing 400 electric buses annually.
[28] The Honda Civic GX had been the most popular natural gas vehicle in the U.S.

Appendix

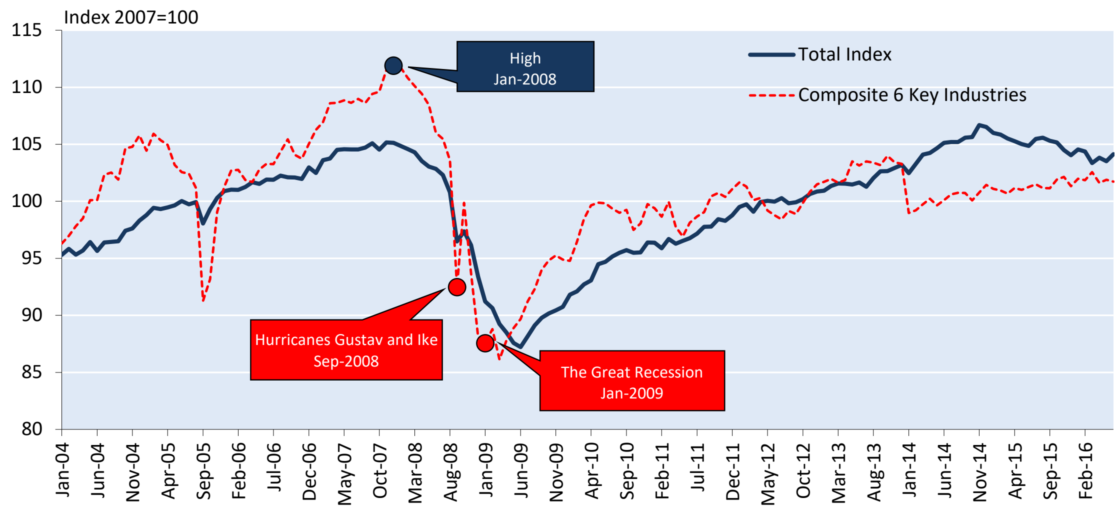
Exhibit A-1. Natural Gas Consumption (BCF)

	Annual					Winter (Nov-Mar)				
	2013	2014	2015	2016	2017	2013/2014	2014/2015	2015/2016	2016/2017	2017/2018
Residential	4,897	5,087	4,610	4,392	4,463	3,956	3,732	3,042	3,186	3,437
Commercial	3,295	3,466	3,199	3,123	3,163	2,302	2,222	1,856	1,956	2,128
Industrial	7,425	7,646	7,535	7,719	7,763	3,421	3,394	3,357	3,444	3,484
Electric	8,191	8,146	9,671	9,984	9,084	3,045	3,313	3,709	3,189	3,426
Other	2,316	2,212	2,253	2,232	2,250	1,004	994	976	947	1,020
Transportation	30	35	39	41	43	14	16	16	18	18
Total	**26,155**	**26,593**	**27,306**	**27,941**	**26,766**	**13,741**	**13,671**	**12,957**	**12,740**	**13,513**

Source: EIA and EVA

Note: Figures may not add due to rounding.

Exhibit A-2. Industrial Production Growth Rates



Source: Fed

Exhibit A-3. Cumulative U.S. Capacity By Technology, 2000-2018

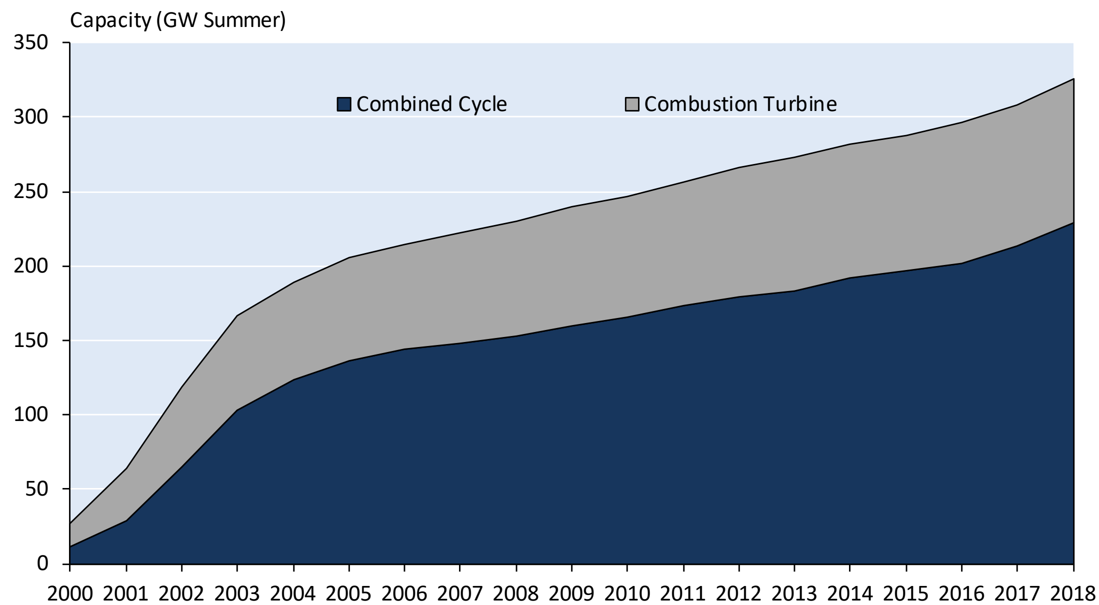
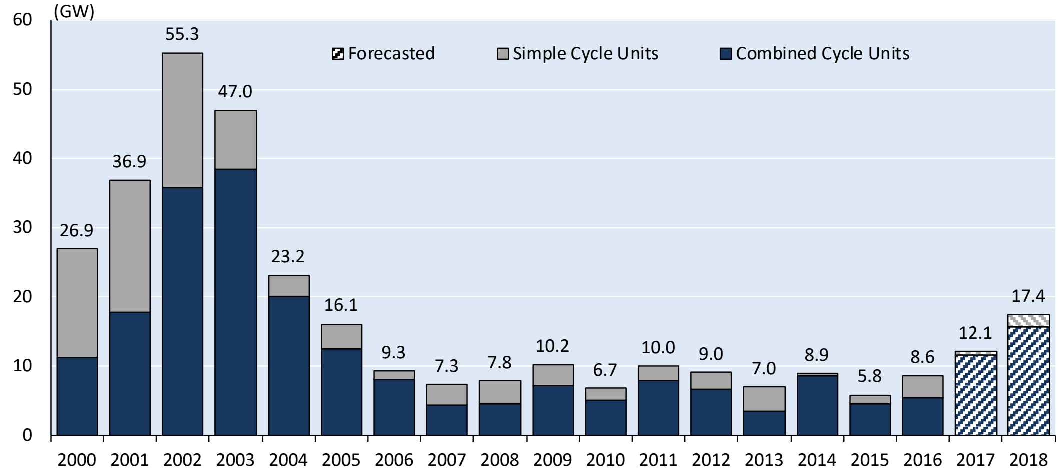


Exhibit A-4. Annual Additions Of Gas-Fired Capacity 2000-2018



Source: EIA and EVA

Exhibit A-5. Performance Characteristics Of Natural Gas Combined Cycle Units By Region

Capacity Factor %

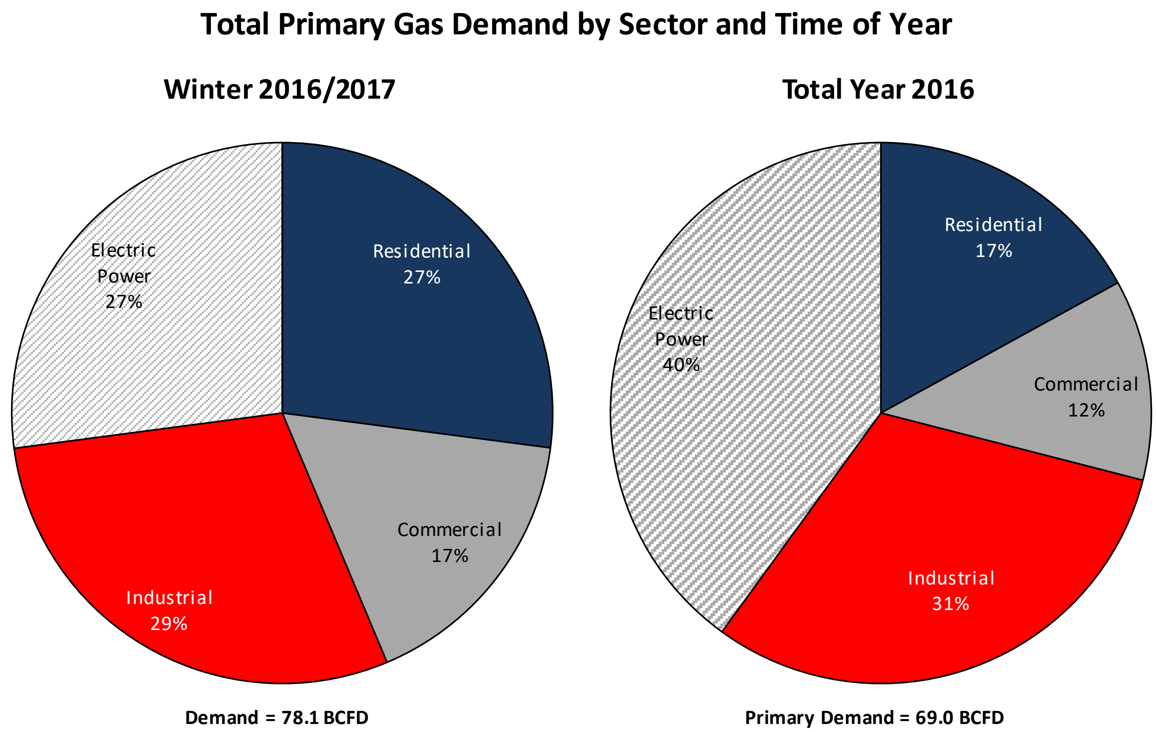
Census Region	Capacity Factor								
	2008	2009	2010	2011	2012	2013	2014	2015	2016
New England	47%	47%	53%	58%	55%	45%	43%	48%	48%
Middle Atlantic	34%	43%	47%	53%	60%	56%	58%	62%	62%
East North Central	15%	17%	23%	31%	48%	34%	35%	54%	59%
West North Central	20%	13%	18%	15%	26%	21%	17%	26%	32%
South Atlantic w/o Florida	22%	34%	43%	52%	61%	58%	56%	65%	67%
South Atlantic	41%	45%	53%	58%	62%	59%	57%	64%	64%
East South Central	27%	37%	45%	49%	60%	49%	52%	64%	70%
West South Central w/o ERCOT	38%	41%	37%	38%	47%	37%	39%	49%	53%
ERCOT	48%	46%	43%	46%	51%	49%	49%	56%	50%
West South Central	44%	44%	41%	43%	50%	45%	45%	53%	51%
Mountain	47%	46%	41%	34%	40%	43%	40%	44%	44%
Pacific Contiguous w/o CA	54%	56%	51%	26%	33%	51%	47%	47%	48%
California	62%	53%	54%	40%	57%	55%	54%	53%	44%
Total U.S.	40%	42%	44%	45%	53%	49%	48%	55%	55%

Source: EIA and EVA

Heat Rate (BTU/kW)

Census Region	Heat Rate (BTU/kWh)								
	2008	2009	2010	2011	2012	2013	2014	2015	2016
New England	7,500	7,493	7,522	7,470	7,492	7,531	7,548	7,593	7,570
Middle Atlantic	8,204	7,970	7,764	7,746	7,431	7,423	7,453	7,667	7,591
East North Central	9,400	9,096	8,718	8,275	7,437	7,561	7,517	7,838	7,834
West North Central	7,739	7,892	7,795	7,819	7,433	7,584	7,621	7,393	7,432
South Atlantic w/o Florida	7,709	7,482	7,486	7,433	7,311	7,215	7,270	7,303	7,246
South Atlantic	7,549	7,533	7,489	7,416	7,313	7,274	7,299	7,311	7,283
East South Central	7,643	7,437	7,409	7,375	7,296	7,327	7,345	7,300	7,276
West South Central w/o ERCOT	8,292	8,106	7,885	7,957	9,114	7,419	7,362	7,547	7,520
ERCOT	8,459	8,304	8,364	8,320	7,324	7,294	7,333	7,983	8,061
West South Central	8,404	8,234	8,197	8,195	8,006	7,336	7,343	7,829	7,848
Mountain	7,528	7,600	7,596	7,706	7,492	7,495	7,534	7,554	7,541
Pacific Contiguous w/o CA	7,484	7,445	7,550	7,781	7,182	7,282	7,305	7,489	7,585
California	7,458	7,490	7,441	7,595	7,308	7,276	7,346	7,514	7,644
Total U.S.	7,880	7,800	7,734	7,730	7,509	7,362	7,383	7,562	7,551

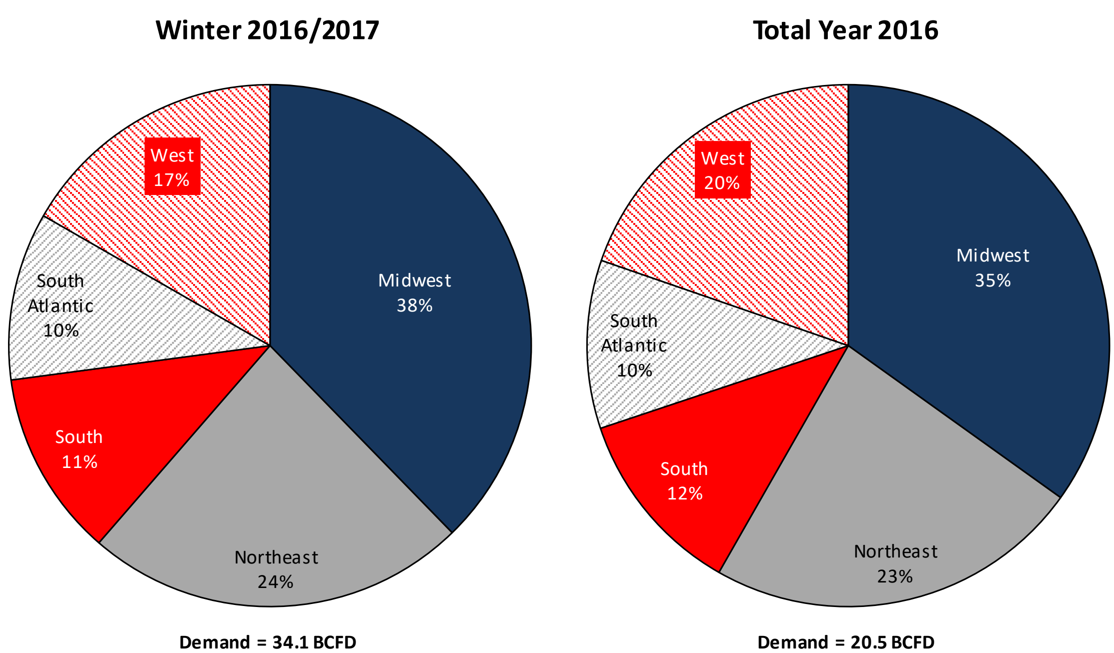
Source: EIA and EVA



1. Winter consists of November through March.
2. Excludes lease, plant, and pipeline fuel.
Source: EIA

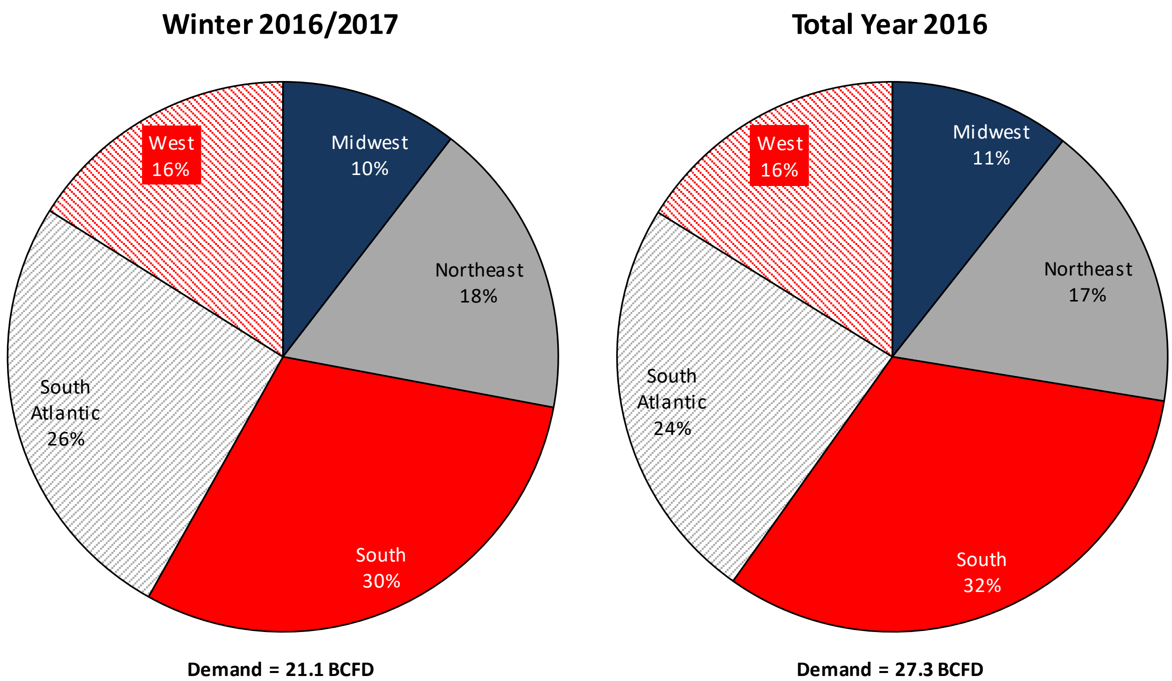
Exhibit A-6. Total Primary Gas Demand By Sector And Time Of Year

Exhibit A-7. Residential And Commercial Gas Demand By Region And Time Of Year



Note: Winter consists of November through March.
Source: EIA

Exhibit A-8   Electric Power Sector Gas Demand By Region And Time Of Year



Note: Winter consists of November through March.
Source: EIA

Exhibit A-9.   U.S. Census Regions

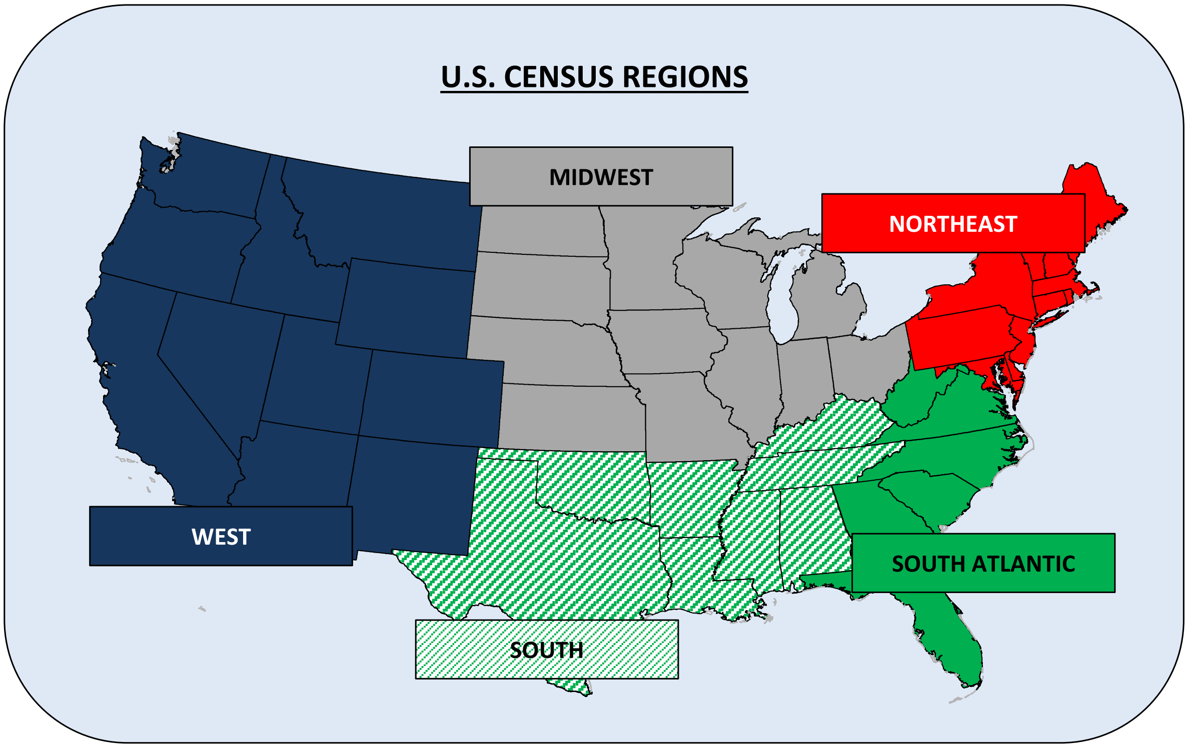


Exhibit A-10. Relevant Data

		Annual					Nov-Mar					
						% Diff						% Diff
		2014	2015	2016	2017	17/16	2013/14	2014/15	2015/16	2016/17	2017/18	17/18-16/17
Residential Housing Stock	(Thousands)	120,734	121,937	123,848	125,631	1.6%	120,496	121,140	122,992	124,809	126,620	1.5%
Electric												
Weather												
Heating Degree Days (HDD)	(Degree Days)	4,572	4,111	3,920	3,928	-4.6%	3,865	3,685	3,042	3,074	3,468	12.8%
Normal HDD[1]	(Degree Days)	4,344	4,344	4,344	4,344	-	3,513	3,513	3,513	3,513	3,513	-
% of Normal		105.3%	94.6%	90.2%	90.4%	-	110.0%	104.9%	86.6%	87.5%	98.7%	-
New Gas-Fired Capacity[2]												
CC	(MW)	7,121	4,539	6,504	11,630	78.8%	625	2,628	1,067	1,340	7,185	25.6%
CT	(MW)	250	1,074	2,006	440	86.7%	125	256	40	0	1,044	-
Hydro and Nuclear Generation												
Hydro Generation - Pacific	(GWh)	163,252	149,196	171,389	220,401	14.9%	59,577	58,770	61,132	80,710	71,771	-11.1%
Nuclear Generation	(GWh)	797,166	797,178	805,327	799,228	1.0%	325,022	342,472	332,682	337,482	408,673	21.1%
Industrial (Index: 2007=100)												
Food		102.2	104.8	107.6	126.4	2.7%	102.5	103.9	106.5	109.1	142.8	30.9%
Paper		99.3	98.3	95.8	99.7	-2.6%	98.3	99.7	96.3	96.5	103.9	7.7%
Chemicals		95.8	97.3	98.0	111.0	0.7%	97.2	97.2	98.5	98.0	124.7	27.2%
Petroleum		100.3	98.0	100.9	114.0	2.9%	104.0	98.9	99.6	102.1	124.3	21.7%
Non-metallic Minerals		116.0	115.4	114.0	121.4	-1.2%	106.4	109.5	113.1	115.1	-	
Primary Metals		103.4	96.8	93.7	96.4	-3.2%	103.3	100.1	94.4	95.5	97.7	2.3%
Total Industrial Production		104.9	104.4	103.1	109.8	-1.2%	103.2	105.9	103.1	103.5	115.6	11.6%
Composite 6-key Ind.		100.7	100.2	100.5	111.5	0.4%	100.9	100.3	100.5	101.5	-	-
Economy												
Real GDP	(Bill. 2009$)	15,982	16,397	16,662	16,873	1.6%	15,768	16,241	16,513	16,852	17,329	2.8%
Employment	(Thousands)	138,809	141,928	145,358	147,700	2.4%	133,696	135,914	138,350	141,281	143,764	1.8%
GDP IPD	(2005=100)	110.1	111.3	112.7	113.7	1.3%	109.2	110.5	112.0	113.6	115.8	2.0%

[1] Normal weather conditions are based upon the most recent 30 year average (i.e., 1986-2015).

[2] Amount of capacity brought online in the period.

Exhibit A-11. Natural Gas Supply

Supply Component (BCF)	2012/2013	2013/2014	2014/2015	2015/2016	2016/2017	2017/2018
I. US Production						
Shale	4,103	4,507	5,340	5,637	5,629	6,489
Tight Sands	1,529	1,447	1,388	1,290	1,172	1,131
CBM	583	530	500	473	441	420
Permian Basin: Shale/Tight Oil Gas	138	205	312	425	520	717
Associated(ex offshore & Permian)	527	556	556	508	404	350
Offshore	646	547	526	538	513	461
Other Conventional	2,287	2,311	2,323	2,247	1,988	1,965
Subtotal Lower-48	**9,814**	**10,102**	**10,946**	**11,118**	**10,668**	**11,533**
Footnote:						
Alaska	134	133	135	137	136	136
Total US	9,947	10,235	11,081	11,256	10,804	11,669
II. Net Canadian Imports	716	855	849	835	834	840
III. Storage Withdrawals	**2,253**	**3,041**	**2,162**	**1,479**	**1,935**	**2,127**
IV. Total Lower-48 Supply	**12,783**	**13,998**	**13,957**	**13,432**	**13,437**	**14,500**

Supply Component (BCF)	2012	2013	2014	2015	2016	2017	2018
I. US Production							
Shale	9,531	10,470	11,946	13,017	13,692	14,253	16,387
Tight Sands	3,855	3,547	3,447	3,265	2,931	2,808	2,662
CBM	1,495	1,328	1,236	1,180	1,093	1,037	995
Permian Basin: Shale/Tight Oil Gas							
Associated(ex offshore & Permian)	1,251	1,300	1,386	1,303	1,136	892	799
Offshore	1,591	1,435	1,318	1,340	1,249	1,173	1,054
Other Conventional	6,038	5,864	6,289	5,778	4,950	4,875	4,854
Subtotal Lower-48	**23,762**	**23,944**	**25,622**	**26,793**	**26,182**	**26,494**	**28,761**
Footnote:							
Alaska	330	318	327	326	334	325	334
Total US	24,092	24,262	25,949	27,119	26,516	26,819	29,095
II. Net Canadian Imports	1,992	1,874	1,865	1,925	2,140	2,063	2,083
III. Net Storage Change	**(9)**	**546**	**(254)**	**(547)**	**387**	**139**	**(145)**
IV. Total Lower-48 Supply	**25,745**	**26,365**	**27,233**	**28,171**	**28,709**	**28,696**	**30,699**

Exhibit A-11. Natural Gas Supply (Continued)

Supply Component (BCF)	2012/2013	2013/2014	2014/2015	2015/2016	2016/2017	2017/2018
I. US Production						
Shale	27.17	29.85	35.37	37.09	37.28	42.97
Tight Sands	10.13	9.58	9.19	8.49	7.76	7.49
CBM	3.86	3.51	3.31	3.11	2.92	2.78
Permian Basin: Shale/Tight Oil Gas	0.91	1.35	2.07	2.80	3.45	4.75
Associated(ex offshore & Permian)	3.49	3.68	3.68	3.34	2.68	2.32
Offshore	4.28	3.62	3.48	3.54	3.40	3.05
Other Conventional	15.15	15.30	15.39	14.78	13.17	13.01
Subtotal Lower-48	**64.99**	**66.90**	**72.49**	**73.15**	**70.65**	**76.38**
Footnote:						
Alaska	0.89	0.88	0.89	0.90	0.90	0.90
Total US	65.88	67.78	73.38	74.05	71.55	77.28
II. Net Canadian Imports	4.74	5.66	5.62	5.49	5.52	5.56
III. Storage Withdrawals	**14.92**	**20.14**	**14.32**	**9.73**	**12.82**	**14.09**
IV. Total Lower-48 Supply	**84.65**	**92.70**	**92.43**	**88.37**	**88.99**	**96.02**

Supply Component (BCF)	2012	2013	2014	2015	2016	2017	2018
I. US Production							
Shale	26.04	28.69	32.73	35.66	37.51	39.05	44.90
Tight Sands	10.53	9.72	9.44	8.95	8.03	7.69	7.29
CBM	4.08	3.64	3.39	3.23	3.00	2.84	2.73
Permian Basin: Shale/Tight Oil Gas	0.76	1.07	1.64	2.49	3.10	3.99	5.51
Associated(ex offshore & Permian)	3.42	3.56	3.80	3.57	3.11	2.45	2.19
Offshore	4.35	3.93	3.61	3.67	3.42	3.21	2.89
Other Conventional	15.74	15.00	15.59	15.83	13.56	13.36	13.30
Subtotal Lower-48	**64.92**	**65.60**	**70.20**	**73.41**	**71.73**	**72.59**	**78.80**
Footnote:							
Alaska	0.90	0.87	0.90	0.89	0.92	0.89	0.92
Total US	65.82	66.47	71.09	74.30	72.65	73.48	79.71
II. Net Canadian Imports	5.44	5.14	5.11	5.27	5.86	5.65	5.71
III. Net Storage Change	**(0.02)**	**1.50**	**(0.70)**	**(1.50)**	**1.06**	**0.38**	**(0.40)**
IV. Total Lower-48 Supply	**70.34**	**72.23**	**74.61**	**77.18**	**78.66**	**78.62**	**84.11**