

Outlook for Natural Gas Supply and Demand for 2016-2017 Winter

Energy Ventures Analysis, Inc. (EVA)

Executive Summary

Natural gas supplies will be adequate to meet expected demand this winter. This is the net result of the higher storage withdrawals offsetting (1) increased demand; (2) reduced imports; and (3) nearly flat domestic production. Concerning the former, a key factor enabling the higher storage withdrawals is the high level of storage inventories entering the winter season. Projected changes in each of the major components of demand and supply for this winter are summarized in Exhibit 1.

Exhibit 1. Outlook For Winter Supply and Demand^{(1),(2)}

Sector	Coming Winter (2016/2017)		Last Winter (2015/2016)		Change	
	BCF	Average BCFD	BCF	Average BCFD	BCF	Average BCFD
I. Natural Gas Demand						
Residential	3,438	22.8	3,037	20.0	401	2.8
Commercial	2,030	13.4	1,856	12.2	174	1.2
Industrial	3,456	22.9	3,376	22.2	80	0.7
Electric	3,202	21.2	3,717	24.5	(515)	(3.3)
Lease, Plant and Pipeline Fuel	1,083	7.2	1,068	7.0	15	0.2
Total	13,209	87.5	13,054	85.9	155	1.6
II. Lower-48 Supply						
Lower-48 Production ⁽³⁾	11,020	73.0	11,177	73.5	(157)	(0.5)
Net Imports	116	0.8	368	2.4	(252)	(1.6)
Storage Withdrawals	2,008	13.3	1,468	9.7	540	3.6
Total	13,144	87.1	13,014	85.6	130	1.5

(1) Figures may not add due to rounding.

(2) The winter of 2016/2017 has 151 days, whereas the winter of 2015/2016 had 152 days, which complicates comparisons of the two winter seasons.

(3) Excludes Alaska production, which is approximately 130 BCF, or 0.9 BCFD, for both 2015/2016 and 2016/2017.

With respect to the anticipated increase in demand this winter, the increase in seasonal demand for the residential and commercial sectors because of the anticipated colder winter is partially offset by a decline in demand within the electric sector. The latter occurs because of reduced coal-to-gas fuel switching, which, in turn, is the result of the projected higher gas prices this winter.

With respect to the outlook for the weather this winter, the weather is projected to be about 12% colder than the prior relatively mild winter.¹ Lastly, there is a modest increase in demand for the industrial sector.

With respect to the projected increase in total supply, domestic production is forecasted to be below production levels attained last winter. This results in the need for higher storage withdrawals, because net imports also are expected to decline. The latter occurs because of steady increases that have occurred throughout 2016 for both LNG exports and pipeline exports to Mexico and are expected to continue during the forthcoming winter. With respect to the increase in storage withdrawals, while they are higher than last winter's relatively low level of withdrawals, they are still about 18 percent below the average level of storage withdrawals for the three winters prior to the 2015/2016 winter.

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 versus the prior winter results in an increase in demand for the weather sensitive residential and commercial sectors. In addition, a modest increase in consumption is projected for the industrial sector. Partially offsetting these increases will be a reduction in electric sector gas demand, as the projection for higher gas prices this winter will result in a reduction in coal-to-gas fuel switching within the sector. The net result is that this winter's total natural gas demand is projected to be 1.6 BCFD, or 1.9 percent, greater than the demand for the prior winter (see Exhibit 2).

Exhibit 2. Outlook For Winter Gas Demand^{(1),(2)}

Sector	Coming Winter (2016/2017)		Last Winter (2015/2016)		Change	
	BCF	Average BCFD	BCF	Average BCFD	BCF	Average BCFD
Residential	3,438	22.8	3,037	20.0	401	2.8
Commercial	2,030	13.4	1,856	12.2	174	1.2
Industrial	3,456	22.9	3,376	22.2	80	0.7
Electric	3,202	21.2	3,717	24.5	(515)	(3.3)
Lease, Plant and Pipeline Fuel	1,083	7.2	1,068	7.0	15	0.2
Total	13,209	87.5	13,054	85.9	155	1.6

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(2) The winter of 2016/2017 has 151 days, whereas the winter of 2015/2016 had 152 days, which complicates comparisons of the two winter seasons.

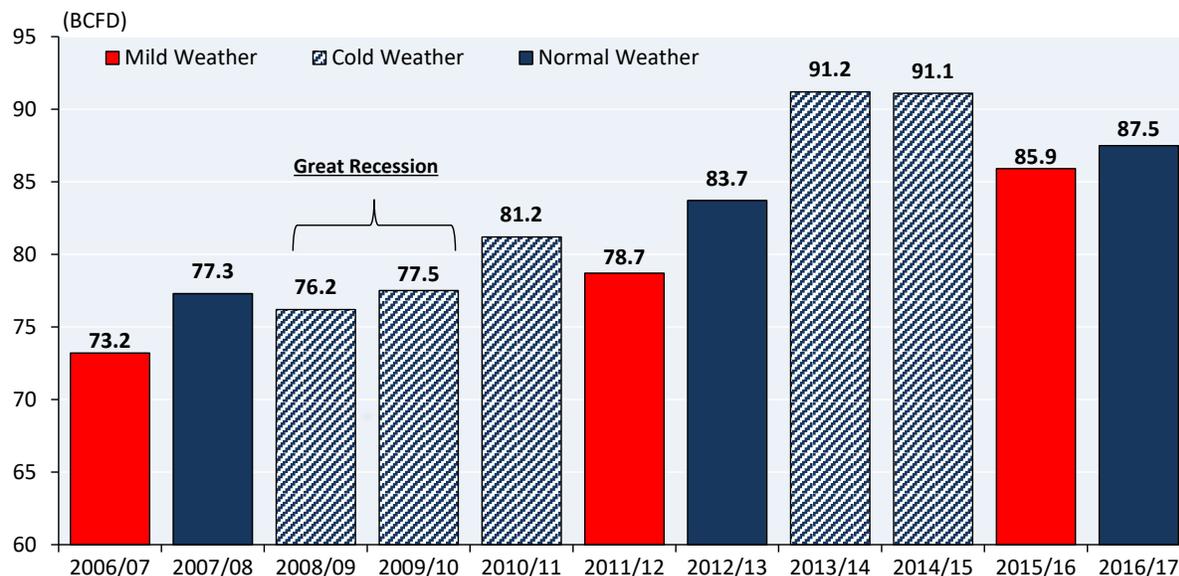
¹ The forthcoming winter is projected by NOAA to be about 12.0 percent colder than last winter (i.e., 366 more heating degree days (HDD)), but overall still about 3.0% warmer than the 30-year average.

Exhibit 2 provides both cumulative demand 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 focus of this report, because of the ease of comparing BCFD to other industry statistics.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. 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 3.6 BCFD higher than projected, when the additional structural demand for the industrial sector is included. If this were to happen, storage inventories likely still would be adequate, however season ending storage levels (March 31, 2017) would be reduced and end the season closer to 2015 levels. Alternatively, a very warm winter could reduce storage withdrawals about 1.9 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



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 2011/2012 (i.e., 1,855 BCF, or 16 percent) is a classic example, as are the three winters at the beginning of the last decade (i.e., about 937 BCF, or 16 percent).⁴

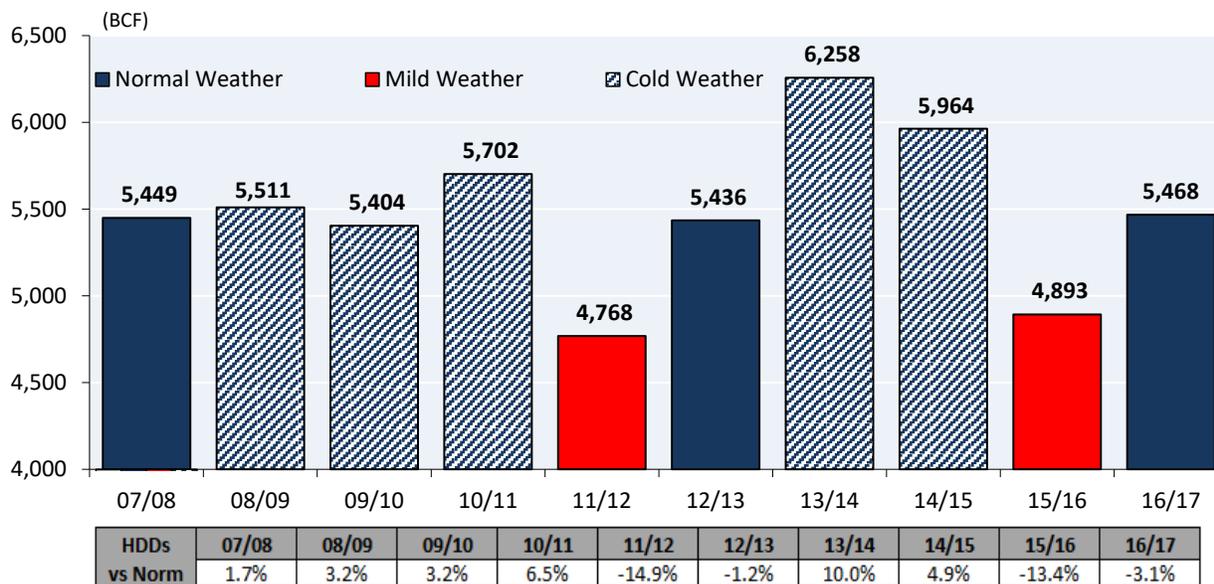
² The winter of 2014/2015 had 151 days, while the winter of 2015/2016 will have the more normal 152 days.

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.

⁴ Not included in Exhibit 3.

With respect to the forthcoming winter, it is projected to be about 12 percent colder than last winter. Nevertheless, the forthcoming winter is projected to be a relatively mild one in that it is forecasted to be about 3.0 percent warmer than the 30-year average. More specifically, last winter was the second warmest on record with only 3,042 HDDs, which is 13.4 percent below a 30-year average, while the forthcoming winter is expected to have 3,408 HDDs, or 3.0 percent below a 30-year average.

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



Note: 2016/2017 is forecasted.

Source: EIA and EVA.

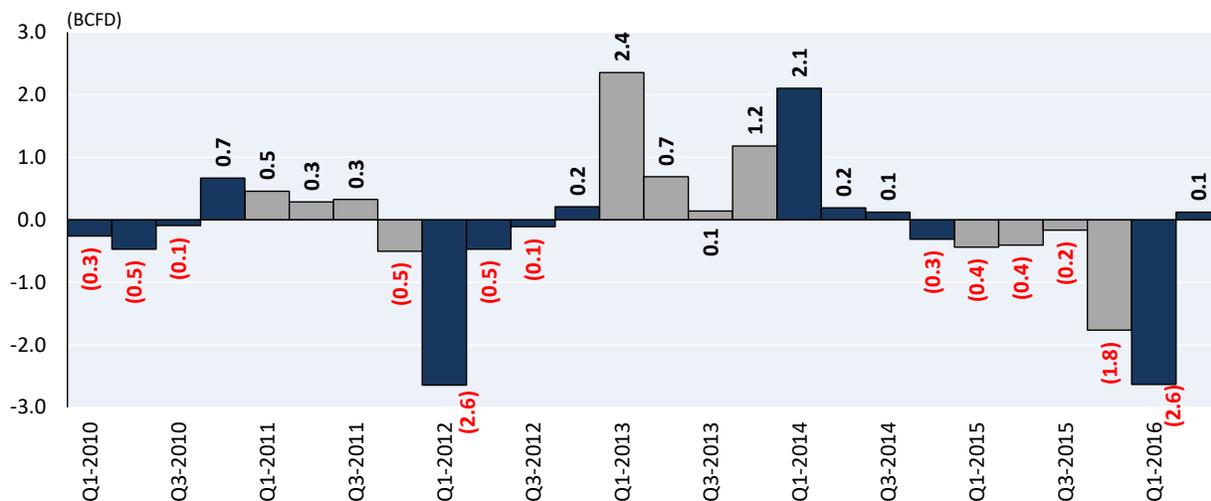
Within the residential sector the three basic drivers of winter gas demand are (1) the severity of the winter weather, (2) customer growth and (3) conservation, or intensity of use. Concerning the latter two factors, over the recent past, the annual increases in the number of residential customers have 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 0.5 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 69 MCF, or about 23 percent. 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 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. With respect to behavioral conservation (e.g., setting the thermostat lower and wearing a sweater) that initially occurred during the era of high gas prices

(e.g., 2008) and then continued both during and for a while after the Great Recession, because of the impairment to the financial well-being of many families caused by the Great Recession.

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 since the Great Recession. 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 (i.e., about 0.3 percent per annum), however the pattern has been rather erratic.

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

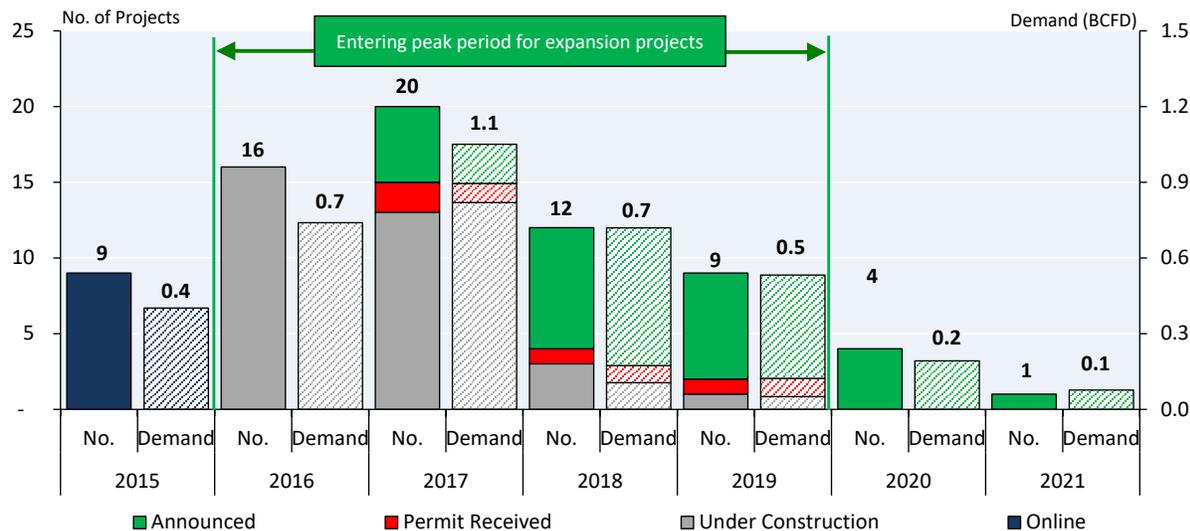
While industrial sector gas demand is projected to increase 0.7 BCFD, or 2.4 percent, this winter, over the recent past demand growth within this sector has been flat to declining. The latter is due to offsetting factors driving industrial sector gas demand. More specifically, increased gas demand due to new capacity expansion projects coming online is being offset by declines in demand for existing industrial facilities, 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 2016 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 2010-2014, 38 projects came online (1.1 BCFD), which cost approximately \$19 billion.
2. For period 2015-2021, 71 projects to come online (3.7 BCFD), which have an estimated cost of \$121 billion.

While there have been some additions and deletions to the list of industrial capacity expansion projects, at present for the period 2015 to 2021 there are 71 likely capacity addition projects in the fertilizer, petrochemical and methanol industries. In addition to these 71 projects, 38 projects came online in the 2010 to 2014 period.

With respect to the 71 projects scheduled to come online between 2015 and 2021, 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 71 projects.

With respect to 2016, this year will receive the benefit of the full year impact of the 9 projects that came online in 2015, plus the partial year impact of 16 additional projects scheduled to come online in 2016. The net result is that gas demand within the industrial sector is expected to increase approximately 0.55 BCFD in 2016,⁵ as a result of these capacity expansion projects coming online. However, this increase has been largely offset by the lack of economic growth for the industrial sector, which has caused gas demand for existing plants to decline.

This list of 71 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 (2015 to 2021)

Comparison of Project Type Count for Various Industries

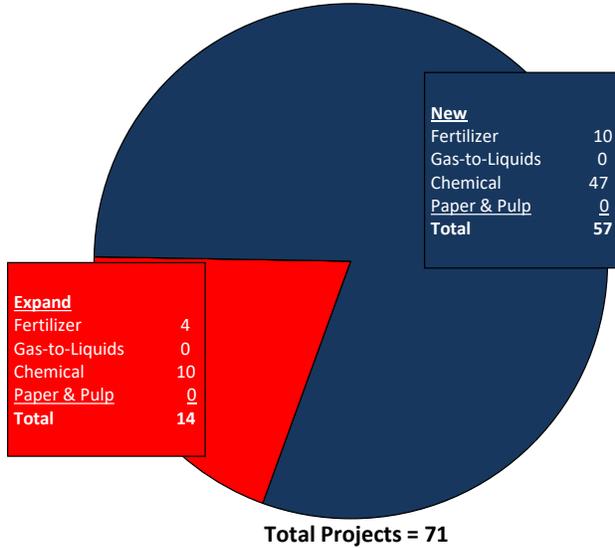
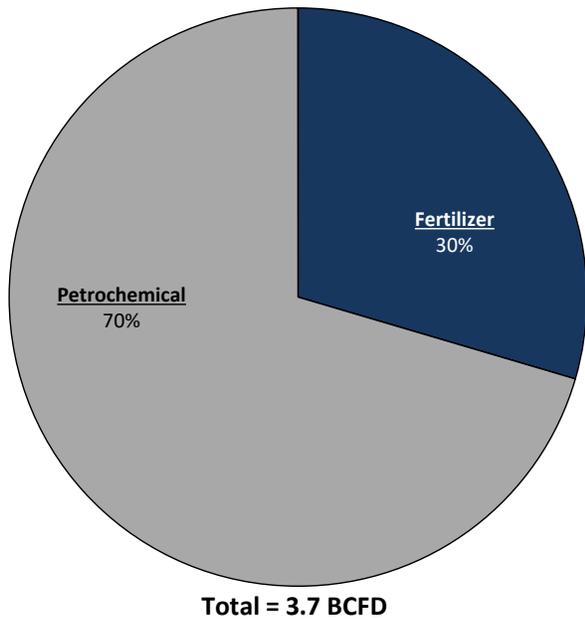


Exhibit 8. Impact of Capacity Expansion On Industrial Gas Demand (2015 to 2021)

Impact of Capacity Expansion on Industrial Gas Demand



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 71 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

For most of the last 10 months the manufacturing index has been declining, as nearly every manufacturing sector has exhibited declining to stagnant growth, with automobiles being the primary exception. This overall decline is the net result of (1) limited prospects for the global economy; (2) the strong U.S. dollar; and (3) the sharp downturn in the oil field and mining equipment sectors.

This basic phenomenon, which is impacting existing industrial facilities, is further illustrated in Exhibit 9, which summarizes the recent history for the industrial production indices for the six energy intensive industries. As illustrated, during 2016 the general trend for four of these indices has been downward. The production index for the food sector is close to flat, while the primary metals index is showing signs of recovery after an extended period of decline.

Summary

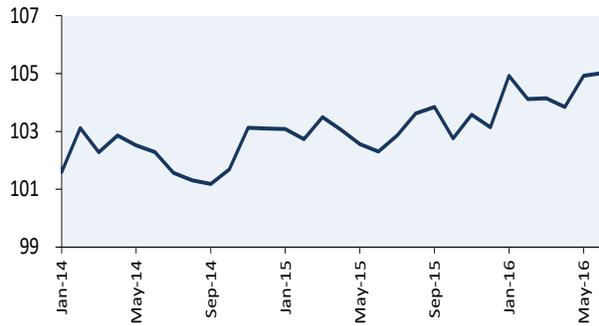
With respect to the integrated outlook for industrial sector gas demand this winter, it is expected to increase 0.7 BCFD, or 2.4 percent, over last winter's level. Exhibit 10 compares and contrasts the expected outlook for this winter's industrial sector gas demand with the consumption levels for the years since 2006. 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 2016 and 2017 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.

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.

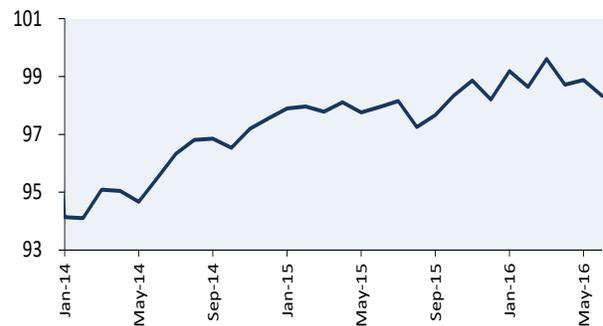
Exhibit 9. Performance Of The Six Key Energy Intensive Industries

Food (311)



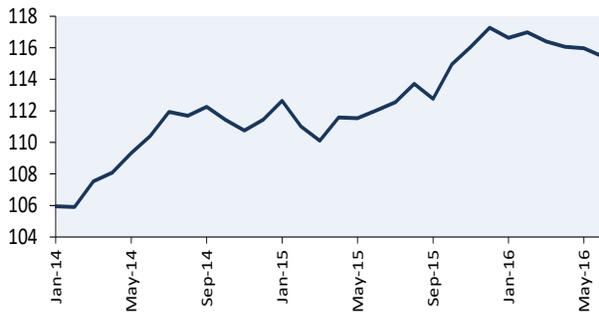
Source: U.S. Federal Reserve.

Chemicals (325)



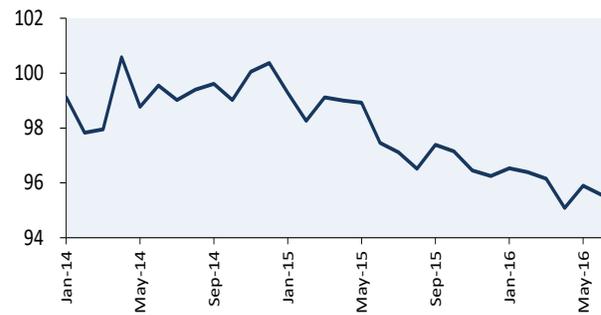
Source: U.S. Federal Reserve.

Non-Metallic (327)



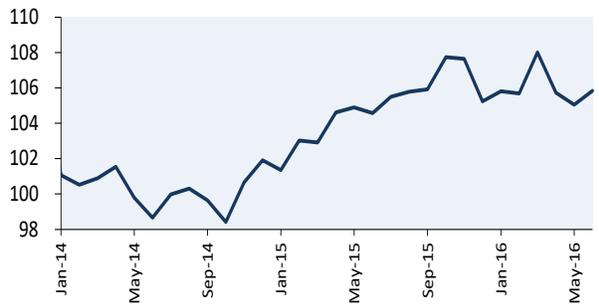
Source: U.S. Federal Reserve.

Paper (322)



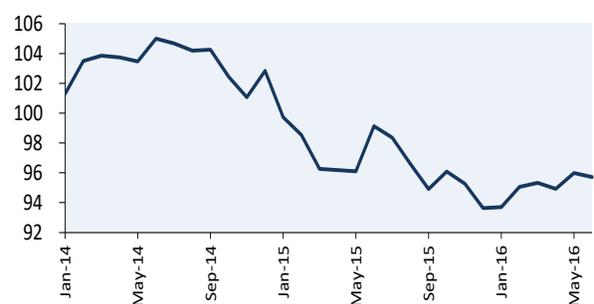
Source: U.S. Federal Reserve.

Petroleum & Coke (324)



Source: U.S. Federal Reserve.

Primary Metal (331)

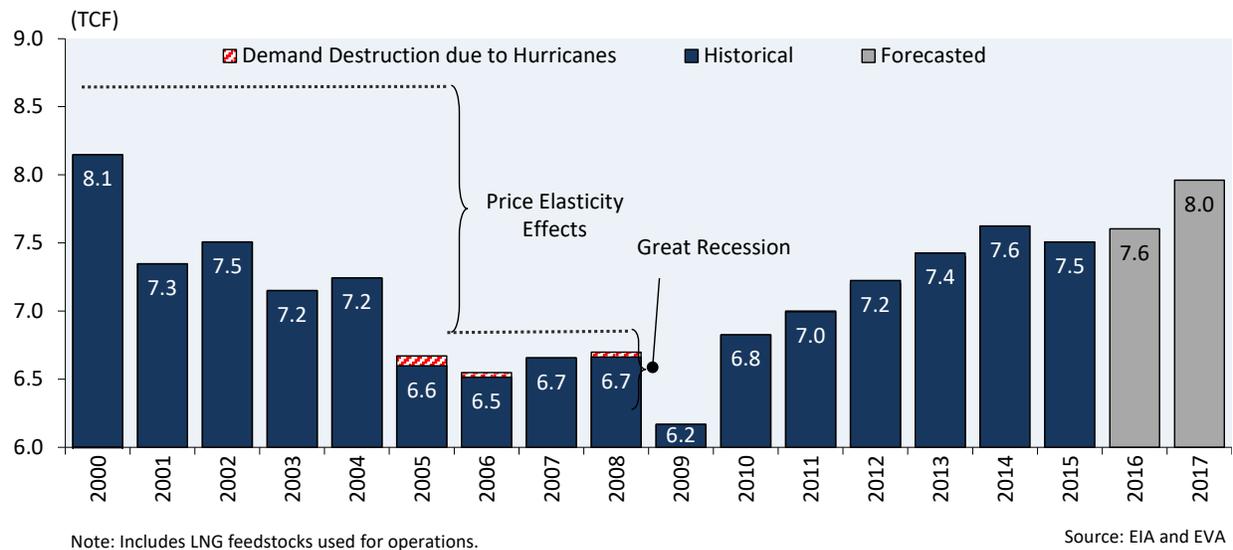


Source: U.S. Federal Reserve.

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



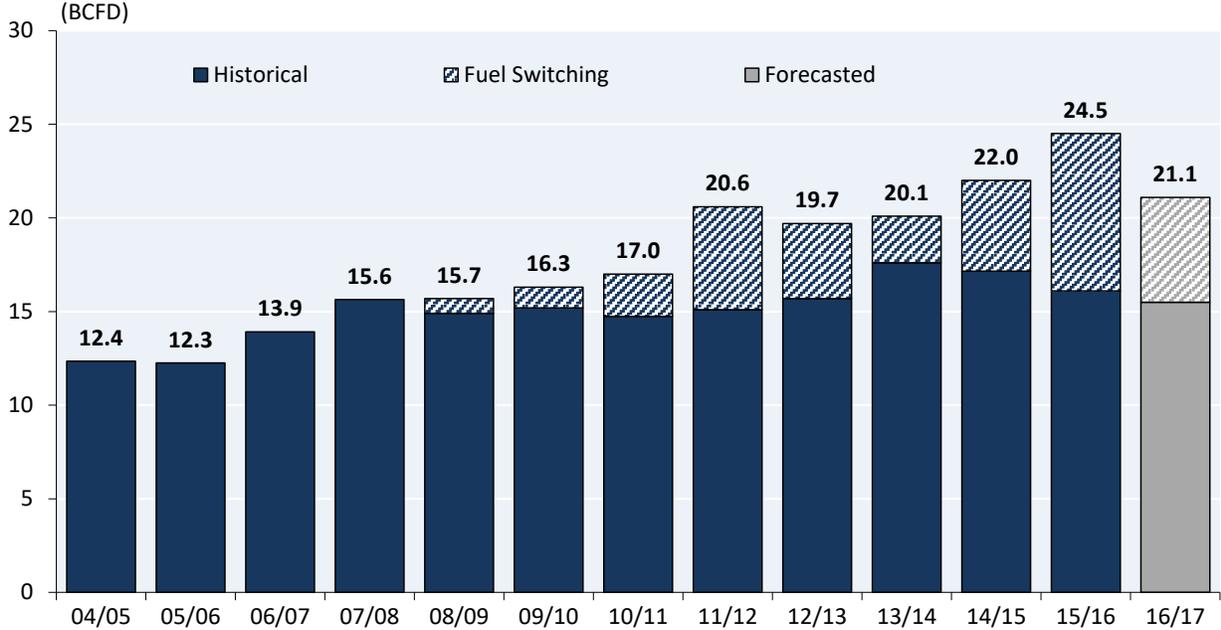
Exhibit 11. Industrial Sector Natural Gas Demand On An Annual Basis



Electric Sector

Based upon recent NYMEX future prices, which remain volatile, natural gas prices for the forthcoming winter are expected to be over 50 percent higher than gas prices for the prior winter. This change in gas prices will result in a significant reduction in coal-to-gas fuel switching, which, in turn, will cause electric sector gas demand for the winter to decline. Partially offsetting this phenomenon are structural changes within the electric sector, such as the continuing retirements of coal-fired capacity. This net result is that electric sector gas demand this winter is expected to decline 3.3 BCFD, or about 13 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 at an all-time record for the winter season. 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 substantially lower (i.e., in round terms about 50 percent lower). Exhibit 13 provides a summary of recent coal-to-gas fuel switching results.

Electricity Sales

Among the other factors that historically have influenced power sector gas demand is the overall growth in electricity sales. During periods of significant sales growth, this can be a significant factor in determining overall power sector gas demand, because gas-fired generation tends to be at the margin in most regions. Similarly, during periods of decline the opposite occurs, because gas is still at the margin. For 2016 electricity sales have declined, as noted in Exhibit 14.

Exhibit 13. Estimated Impact of Coal-To-Gas Fuel Switching On Natural Gas Consumption

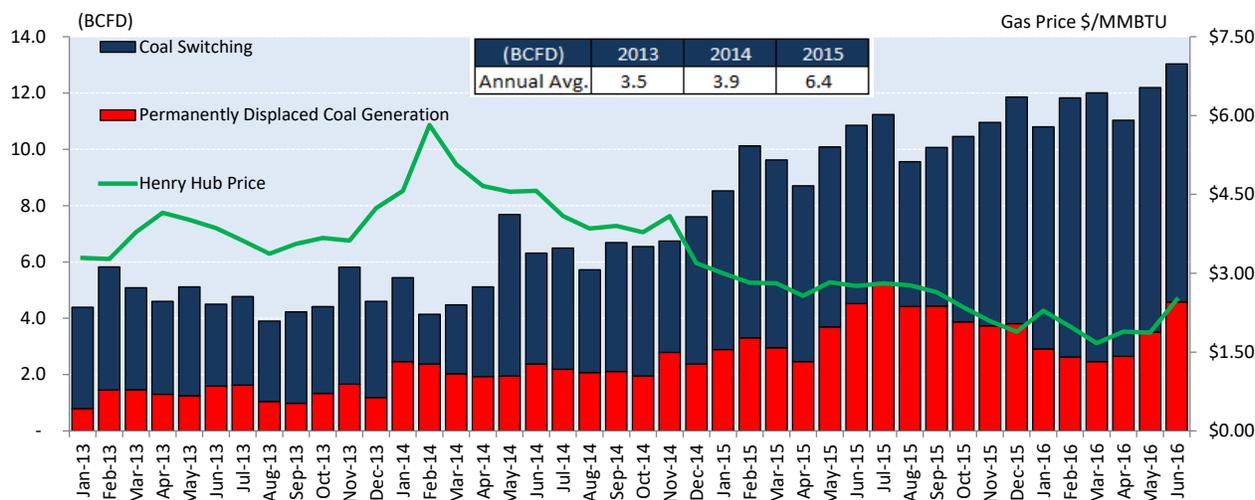
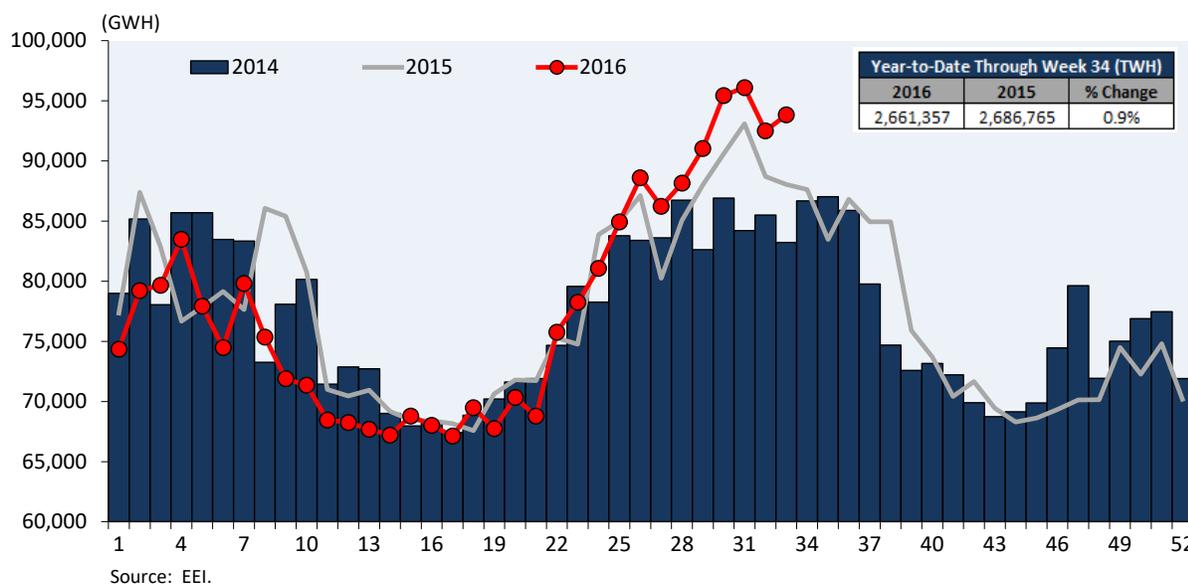


Exhibit 14. Total Weekly Electric Output (L48-States)



As illustrated in Exhibit 14, the general trend for electric sales for both 2015 and 2016 has been flat to declining (i.e., 0.3 percent growth in 2015 and a 2.2% decline year-to-date for 2016). One factor behind this decline in on-the-grid electricity sales is the continuing growth in distributive generation (e.g., solar) in some regions.

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 15 summarizes recent historical capacity additions, as well as the current outlook for capacity additions for 2016 and 2017. 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 15. New U.S. Generation Capacity

(MW)	2012	2013	2014	2015	Projected	
					2016	2017
Coal-Fired	3,748	1,357	99	-	593	-
Solar	1,527	3,573	3,478	2,231	3,851	2,629
Wind⁽¹⁾	13,134	1,034	5,156	7,099	3,898	6,052
Gas Combined Cycle	6,713	3,511	7,121	4,539	6,504	11,293
Gas Peaking	2,334	3,332	250	1,074	2,006	991
Total Gas-Fired	9,047	6,842	7,371	5,613	8,510	12,284
Grand Total	27,455	12,805	16,104	14,943	16,852	20,964
Retirements (Coal)	11,561	7,387	5,050	19,210	10,839	7,456
Retirements (Nuclear)	-	2,716	620	-	479	1,647

(1) Wind capacity for 2016 and 2017 estimated, as proposed projects significantly exceed these estimates.

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.

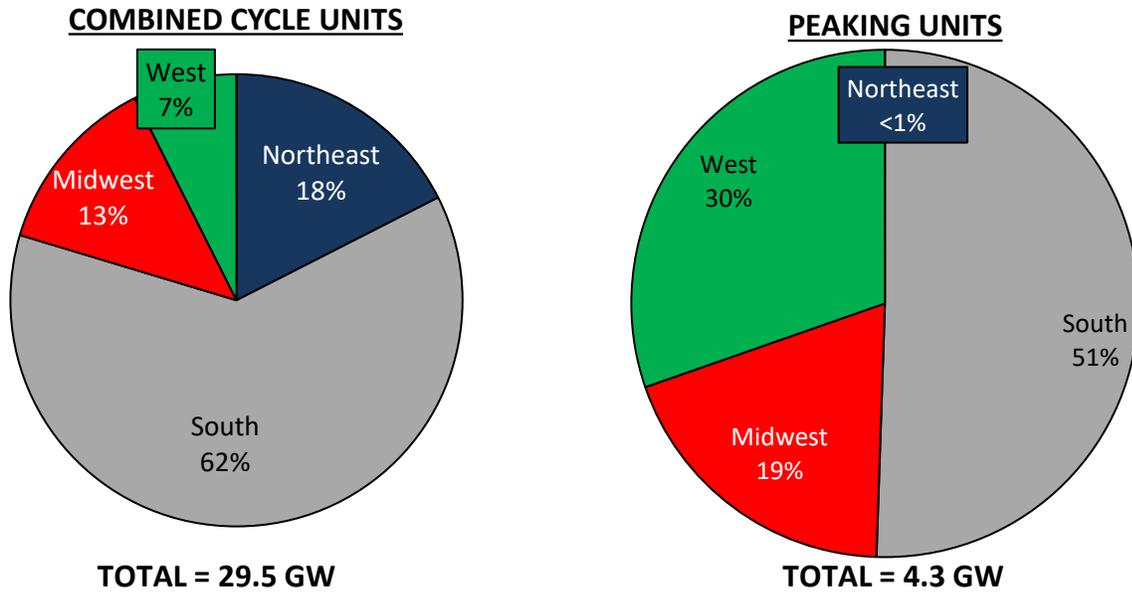
With respect to on-the-grid wind and solar capacity additions, they represent a significant competitor to gas units for new capacity requirements, particularly over the 2016 to 2017 timeframe. When excluding the gas peaking units, which have a unique role within the power industry, the combination of (1) new CCGT units and (2) new wind and solar units account for nearly all the capacity additions within the industry. More specifically, new CCGT units over the 2016 to 2017 timeframe have accounted 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 15 provides specifics for this phenomenon over the last several years. As illustrated, on a net basis, coal-fired capacity has declined about 38 GW over the last several years, while combined cycle (CCGT) gas-fired capacity has increased about 22 GW. Going forward it is anticipated this trend will continue, as during 2016 and 2017 another 20.2 GW of coal-fired capacity is expected to retire on a net basis, while new build CCGT units will total about 17.8 GW.

Finally, with respect to the regionality of gas-fired capacity additions over the 2016 to 2017 timeframe, it is summarized in Exhibit 16. As illustrated, the South census region, which

includes Texas, accounts for over one-third of the CCGT capacity additions and nearly two-thirds of the capacity additions for peaking units.

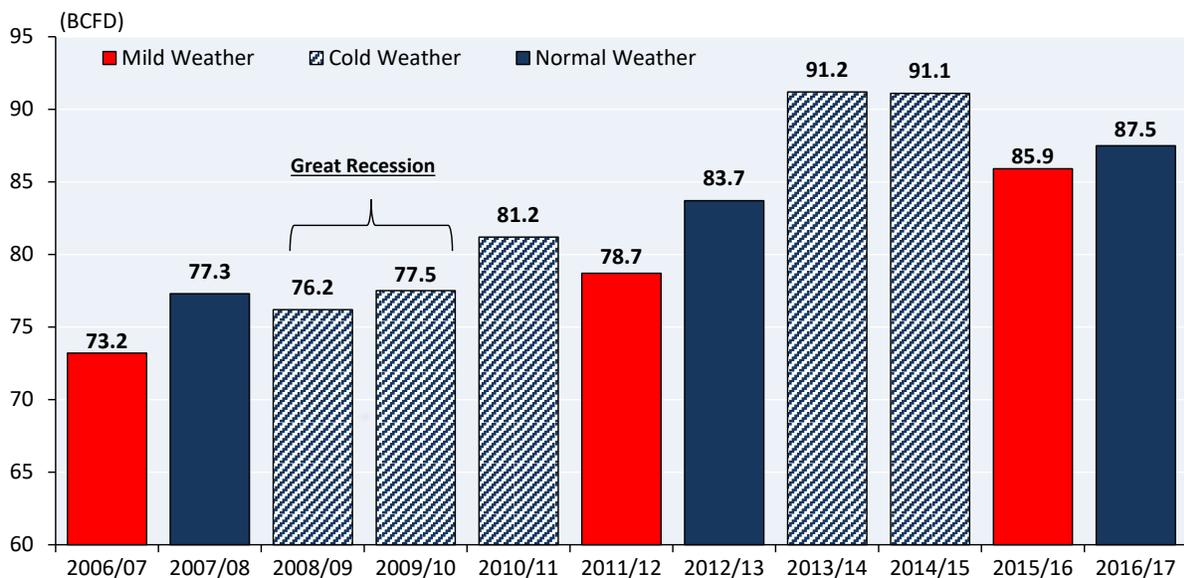
Exhibit 16. Gas-Fired Capacity Additions By Census Region (2014-2017)



Conclusions

As is the case for most projections for the winter period gas demand, the area of greatest uncertainty for the forecast of gas demand is the severity of the winter weather. Exhibit 17 compares and contrasts the outlook for gas demand for the forthcoming winter with that for a series of winters over the recent past. As illustrated, gas demand this winter is expected to be above the demand levels for last winter, which was very mild (i.e., 1.6 BCFD, or 1.9 percent).

Exhibit 17. Winter Natural Gas Demand For All Sectors



Outlook For Winter Supply

Overview

Total natural gas supply for the forthcoming winter will be about 1.5 BCFD, or 1.8 percent, greater than last winter (see Exhibit 18). This composite assessment is the net result of nearly flat production, as well as a decline in imports, being totally offset by a higher level of storage withdrawals. In simplified terms the nearly flat domestic production is due to the sharp decline in drilling activity (i.e., about a 75 percent decline from peak levels), while the decline in net imports is due to increases in LNG exports and pipeline exports to Mexico – both having occurred throughout 2016. With respect to the increase in storage withdrawals, while they are higher than last winter’s relatively low level of withdrawals, they are still about 18 percent below the average level of storage withdrawals for the three winters prior to the 2015/2016 winter.

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 January period, as a result of new pipeline capacity coming online and providing takeaway capacity for stranded gas supplies (i.e., an infrastructure event).⁷

Exhibit 18. Outlook For Winter Supply^{(2),(3)}

Supply Component	Coming Winter (2016/2017)		Last Winter (2015/2016)		Change	
	BCF	Average BCFD	BCF	Average BCFD	BCF	Average BCFD
Lower-48 Production ⁽¹⁾	11,020	73.0	11,177	73.5	(157)	(0.5)
Net Imports	116	0.8	368	2.4	(252)	(1.6)
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(1) Excludes Alaska production, which is approximately 130 BCF, or 0.9 BCFD for both 2015/2016 and 2016/2017.

(2) Figures may not add due to rounding.

(3) The winter of 2016/2017 has 151 days, whereas the winter of 2015/2016 had 152 days, which complicates the comparison of the two winters.

As discussed in subsequent sections of this report, the current assumption is that this infrastructure event will increase flowing gas supplies about 1.3 BCFD, however this assessment is debatable because of the minimal data available concerning the current stranded gas supplies.⁸

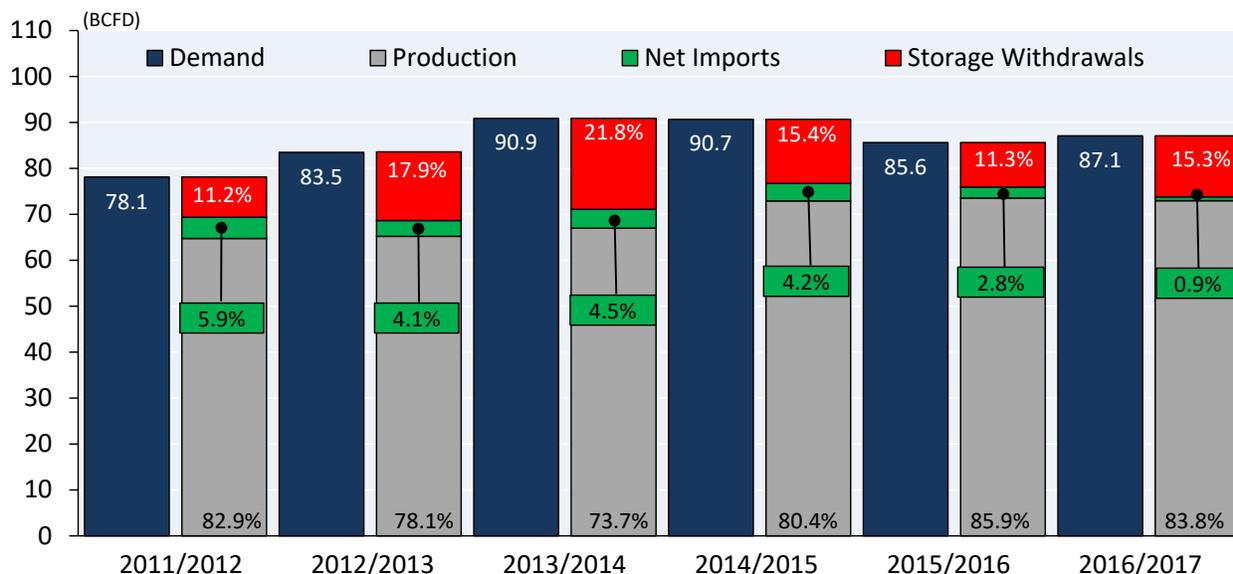
In order to provide the reader with an additional perspective on the supply outlook for the forthcoming winter, Exhibit 19 compares and contrasts these supply projections with actual results over the last several winters. There are a few very apparent trends in the data summarized in Exhibit 19, namely (1) the steady increase in domestic production for the last four years has

⁷ 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 flow gas supplies.

⁸ 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.

come to a halt, because of the aforementioned decline in drilling activity; (2) there has been a steady decline in the net contribution in net imports, because of increases in both exports to Mexico and LNG exports; and (3) the contribution of storage withdrawals has varied significantly from year-to-year, primarily because of changes in weather and its impact on demand.

Exhibit 19. Summary Of Winter Supply



Note: 2016/2017 is estimated.

U.S. Production

Overview

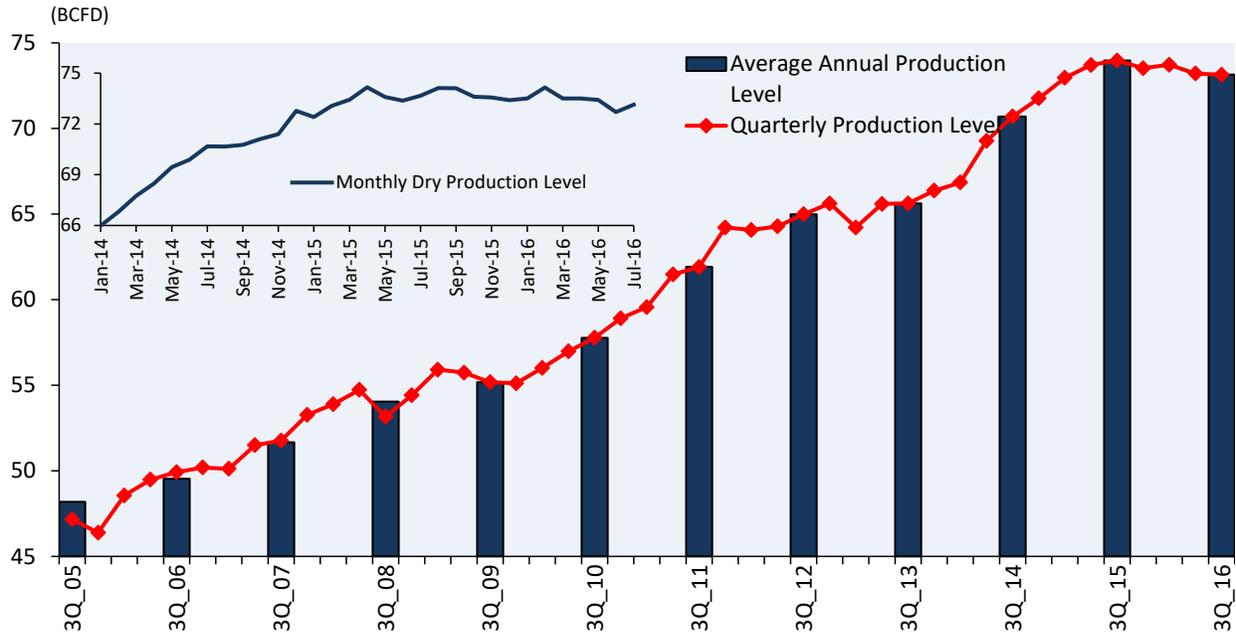
Currently changes in flowing gas supplies can occur via two different mechanisms, namely (1) directly from drilling activity and (2) from infrastructure events, which provide additional takeaway capacity for previously stranded gas supplies. The impact that both have on the outlook for the forthcoming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

Current Assessment

With respect to current domestic production levels, Exhibits 20 and 21 summarize recent trends. Included in Exhibit 20 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 21 provides daily production trends for the L-48 since November 2014.

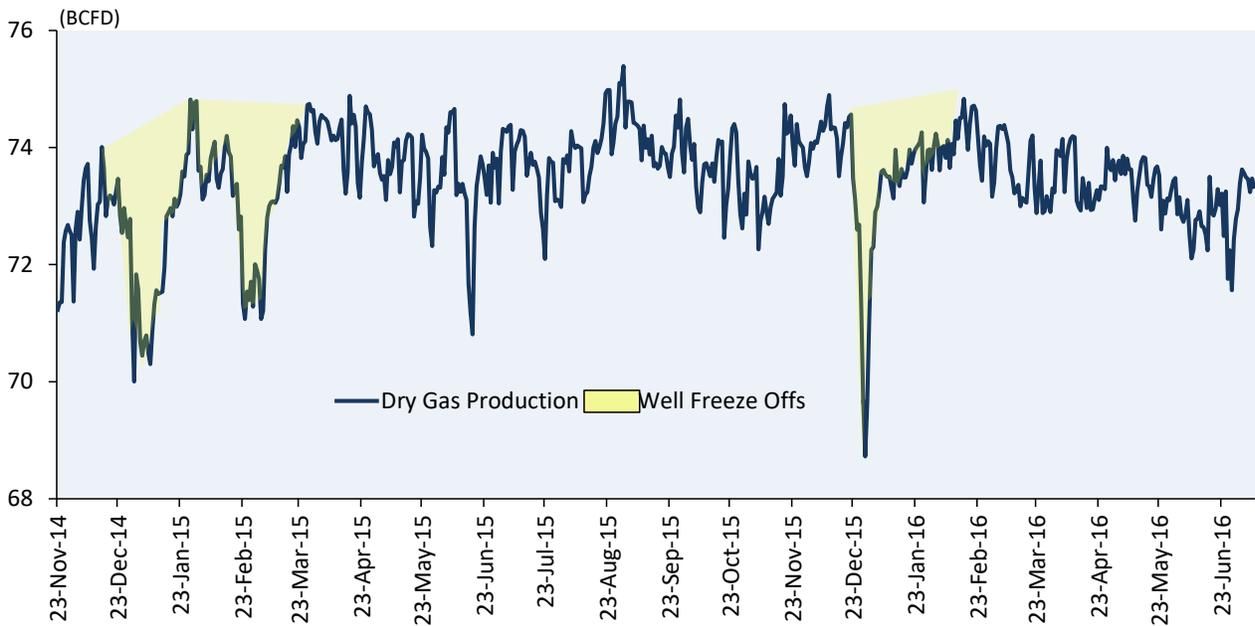
As noted in Exhibit 21, there has been a relatively steady decline in domestic production since the last infrastructure event in February 2016. This decline is due to the aforementioned decline in drilling activity, as both the gas-directed rig count and oil-directed rig count have declined about 75 percent.

Exhibit 20. Lower-48 Natural Gas Wellhead Production



Source: PointLogic Energy, Inc. and EIA.

Exhibit 21. Lower-48 Daily Dry Gas Production

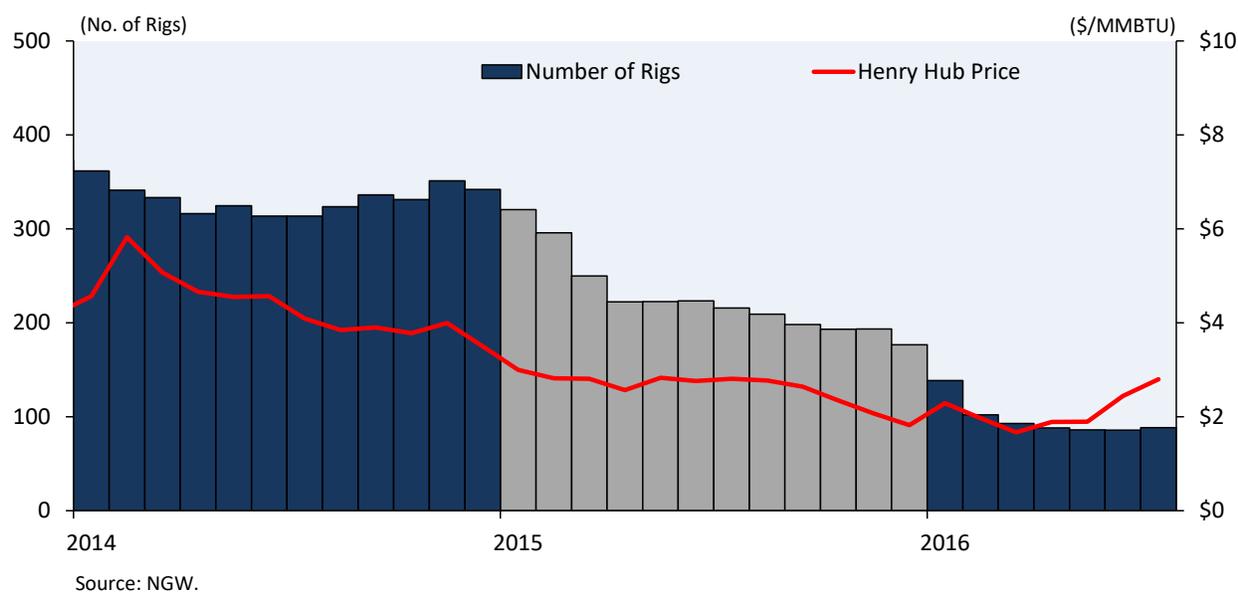


Source: PointLogic Energy, Inc. and EVA.

Drilling Activity

At present gas-directed drilling activity is at an all-time low for recent times (see Exhibit 22). More specifically, the gas-directed rig count has been at, or below, 90 rigs for the last 21 weeks. This represents about a 75 percent decline in the gas-directed rig count since peak levels in 2014, although improvements in drilling efficiency and hi-grading have offset some of the impact of this decline in drilling activity.⁹ In addition, there also has been about a 75 percent decline in the oil-directed rig count. This decline in oil drilling activity has an adverse impact on associated gas.

Exhibit 22. Rig Count For Gas Wells And Henry Hub Price



Key factors behind this decline in gas and oil drilling activity are (1) the decline in oil and gas prices, which reduced the incentive to drill new wells; and (2) the overall decline in the financial health of the industry, which has placed constraints on the level of capital spending for many firms.¹⁰

Lastly, this decline in drilling activity has affected nearly every gas play, including the seven major shales. Concerning the latter, the gas-directed rig count for three of the seven major shale plays currently is at, or near, zero, while the decline in the rig count since the last November 2014 peak for the other major shale plays ranges from 50 to 74 percent.

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, with the most significant ones occurring in the fourth quarters of 2013 and 2014 and the

⁹ See section on Shale Production on page 21 for a further discussion on hi-grading.

¹⁰ Gas prices for 1H 2016 were about 53 percent below the average gas prices for 2014, while current oil prices are about 60 percent below the July 2014 peak levels.

first quarter 2016, when flowing gas supplies increased about 1.5, 2.2 and 1.3 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 2016. Exhibit 23 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 2016. As illustrated, the number of pipeline projects and capacity expected to come online this forthcoming fourth quarter is on a par with the prior infrastructure events. However, the cumulative capacity addition 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 23. Comparison Of New Pipeline Projects For The Fourth Quarter Infrastructure Events In The Northeast

	2013	2014	2015	2016
Number of Pipeline Projects Online	13	15	14	13
Capacity of New Pipeline Projects (BCFD)	3.3	3.2	5.1	5.2
Number of Major Pipeline Projects Online	4	5	7	4
Capacity of Major Pipeline Projects (BCFD)	2.2	2.0	4.7	1.7

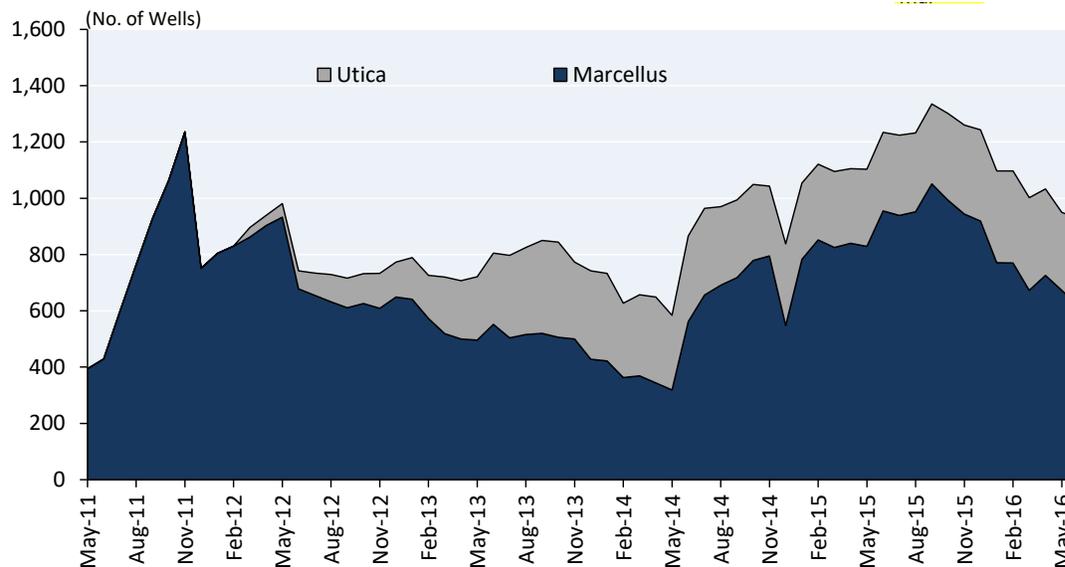
While it is known that there will be significant additions of pipeline projects in the fourth quarter of 2016, the key dilemma in estimating the impact of this new pipeline capacity on flowing gas supplies is that there is not any data on either the level of stranded gas supplies or how much of these 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 23 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 shale plays has been declining since September of last year. Two factors appear to be driving this decline, namely (1) the reduction in drilling activity has reduced the potential additions to this inventory; and (2) some firms have chosen to complete and connect these wells, because it is the low cost option for maintaining production levels, particularly when capital budgets are constrained.

Lastly, the data presented in Exhibit 24 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. 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.

Integrating all of the above information, even though some of it is imprecise, yields an estimate of the impact of the forthcoming fourth quarter of 2016 infrastructure event will increase flowing gas supplies about 1.3 BCFD. This estimate is at the low end of the range for the last three major infrastructure events.

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

Exhibit 24. Inventory of Drilled But Not Yet Connected Wells



1. Gas wells waiting on completion or completed - not producing.

Lower-48 Production

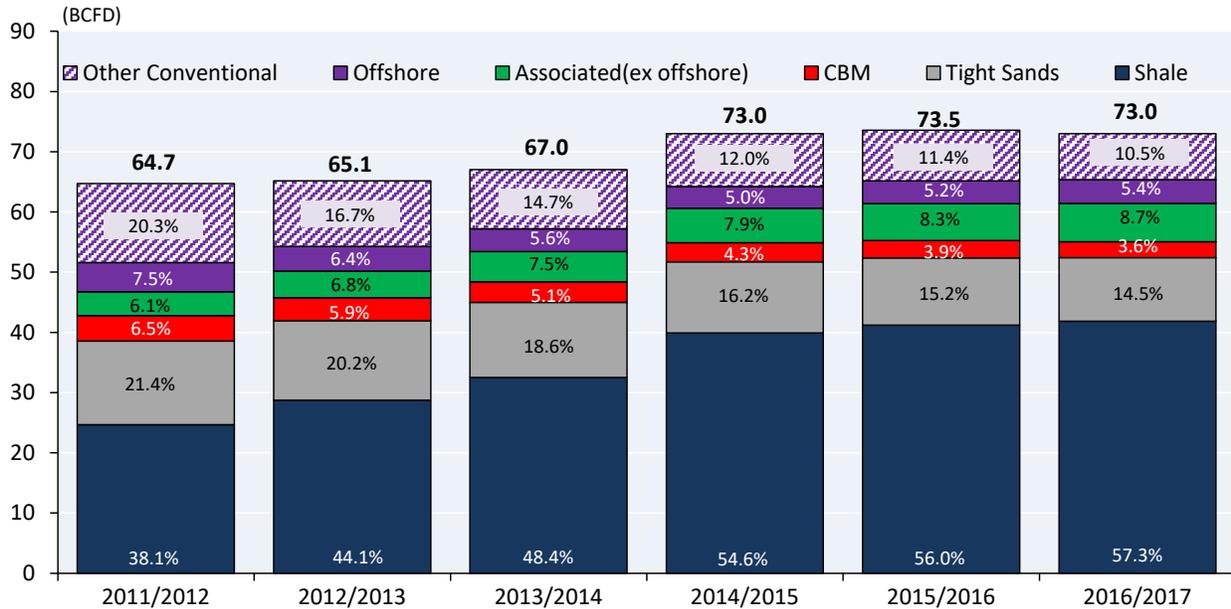
Exhibit 24 summarizes the outlook for L-48 production for the forthcoming winter, which includes both the impact of drilling activity and infrastructure events. This exhibit also compares and contrasts the outlook for domestic production with that for previous winters.

Several key trends are readily apparent in Exhibit 25 and include the following:

- Production Declines:** The significant increase in winter domestic gas production that occurred prior to the winter of 2014/2015 has come to a halt. Over the last three winters, including the forthcoming winter, domestic production has been relatively flat. As previously noted, the small decline in domestic production this winter is due to the sharp drop in drilling activity.
- Shale Production Growth Slows:** For the same reasons as noted above, the rapid growth in shale production that has occurred in the past has slowed significantly (i.e., only 2.4 percent per annum) over the last three winters. However, as a percent of total domestic production, shale production continues to grow and is expected to be about 57 percent of total domestic production for the forthcoming winter.
- Offshore Is An Exception:** While offshore production historically has been in an extended period of decline, it has reversed course and increased, albeit modestly, over the last two winters (i.e., includes the forthcoming winter). This change in trends is the net result of a series of legacy offshore projects that were approved prior to the sharp decline in oil and gas prices. In general, these offshore projects represent rather large and lumpy additions to domestic production and, as a result, it is a real challenge to predict their net impact on production at any single point in time. With respect to the 16 offshore projects

that come online in 2015, several are still in the process of ramping up to their peak production levels. For 2016 it is expected that an additional 12 projects will come online and ramp up over time.

Exhibit 25. Lower-48 Production Outlook For Winter



Shale Production

As illustrated in Exhibit 25, shale gas production is relatively flat as compared to the growth experienced between 2011/2012 and 2014/2015, which is a direct result of the decline in drilling activity. For the Barnett, Fayetteville and Woodford shale plays the current gas rig count is at, or near, zero and in the case of Fayetteville it has been that way since the beginning of the year. With respect to the more prolific Marcellus and Utica shale plays in the Northeast, drilling activity has declined 46 to 74 percent, respectively, since peak drilling levels in late 2014. Similarly, declines have occurred for the Haynesville and Eagle Ford shale plays. The result is shale gas production growth is forecast to be only 0.6 BCFD, which is only half the growth of the previous year and more than 6 BCFD less growth than that gained by shale gas during 2014/2015.

Shale gas production perhaps would have declined if “hi-grading” had not continued through 2016. Hi-grading is the process where drilling moves from being dispersed across a play to becoming concentrated in the most productive areas of a play that offer the greatest returns. These areas are also referred to as super sweet spots.

Exports/Imports

Exports

Both LNG exports and pipeline exports to Mexico are increasing and are projected to continue to do such in the future. This likely will result in the U.S. becoming a net exporter of natural gas by mid-2017, which would be a first for the U.S.

LNG Exports

The forthcoming winter will be the first winter for which LNG is exported, with Trains 1 and 2 of the Sabine Pass liquefaction terminal being the source of this LNG. Both of these trains were commissioned earlier in 2016 (i.e., February and August) and should be fully operational during the winter of 2016/2017. Furthermore, while the initial shipments from these two trains represent spot LNG cargoes into an over supplied global LNG spot market, starting in November the long-term contracts associated with these trains are expected to commence. This shift from a focus on spot LNG shipments to term LNG shipments should result in greater assurity of future U.S. LNG exports.

With respect to the outlook for U.S. LNG exports into a very dynamic global LNG market, Addendum I to this report contains a succinct overview.

Mexico

As illustrated in Exhibit 26, 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, as well as reducing higher cost LNG imports at Mexico's two operating regasification terminals.

Exhibit 26. Outlook For Winter Net Mexican Exports



With respect to the expansion of Mexico’s pipeline infrastructure, historically there has been significant export capability from the U.S. to Mexico, however inadequate takeaway capacity within Mexico has limited exports to Mexico. Mexico is now in the process of relieving this bottleneck with the construction of new pipeline systems. The infrastructure expansion within Mexico can be divided into two phases. With respect to the first phase, this involved the construction of three major pipeline systems within Mexico, namely the Northwest Pipeline System, the Chihuahua Pipeline System and the Los Ramones Pipeline System, which have a total capacity of 4.8 BCFD. All these systems are either already online or will be online by year end 2016.

With respect to the second phase of the expansion of Mexican gas pipeline capacity, Mexico has, or is, in the process of authorizing seven new systems that are scheduled to be completed over the 2017 to 2021 timeframe. These new systems are summarized in Exhibit 27.

Exhibit 27. Phase II Mexican Pipeline Systems

Pipeline System	Capacity (BCFD)	Cost (\$ Bil)	Online	Comments
Nueces to Tuxpan	2.6	\$2.1	YE2018	A two part project consisting of (1) a U.S. project from the Aqua Dulce hub in Nueces Couty, TX to Brownsville and (2) an under water pipeline in the Gulf of Mexico from Brownsville to Tuxpan.
Comanche Trail	1.1	-	Jan-17	Includes the San Elizario Crossing under the Rio Grand, which connects to the San Isidro-Samalayuca system.
Trans-Pecos	1.3	-	Mar-17	Includes the Presido Border Crossing under the Rio Grand, which connects to the Qjinaga-El Encinto system.
Tula-Ville de Reyes	0.9	\$0.55	Early 2018	-
Villa de Reyes- Aguaschlientes-Guadalajara	1.0	\$0.55	Jan 2018	-
La Laguna-Aguaschlientes	1.15	\$1.0	Dec-17	-
Roadrunner Gas Transmission	0.64	\$0.45	2019	A three phase project from Coyanosa, TX to San Elizario and will connect to the Tarahumara Gas Pipeline in Mexico.

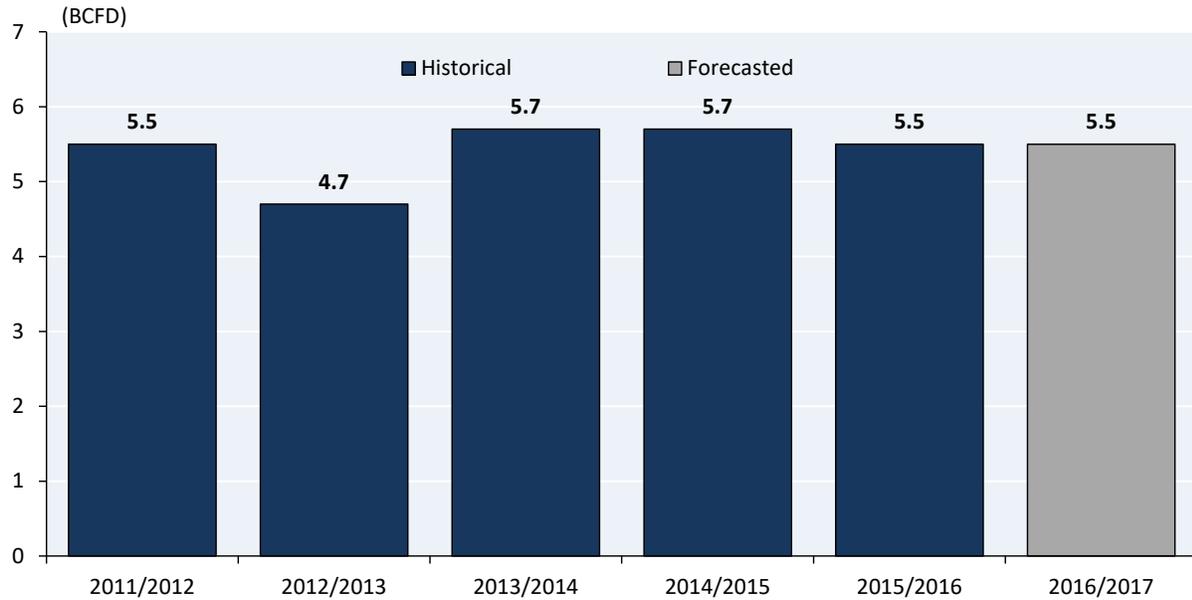
Imports

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 28. During the period from 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).¹²

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.

¹² The Canadian firms, in essence, use the same drilling and completion techniques to develop their shale plays, as those used in the U.S.

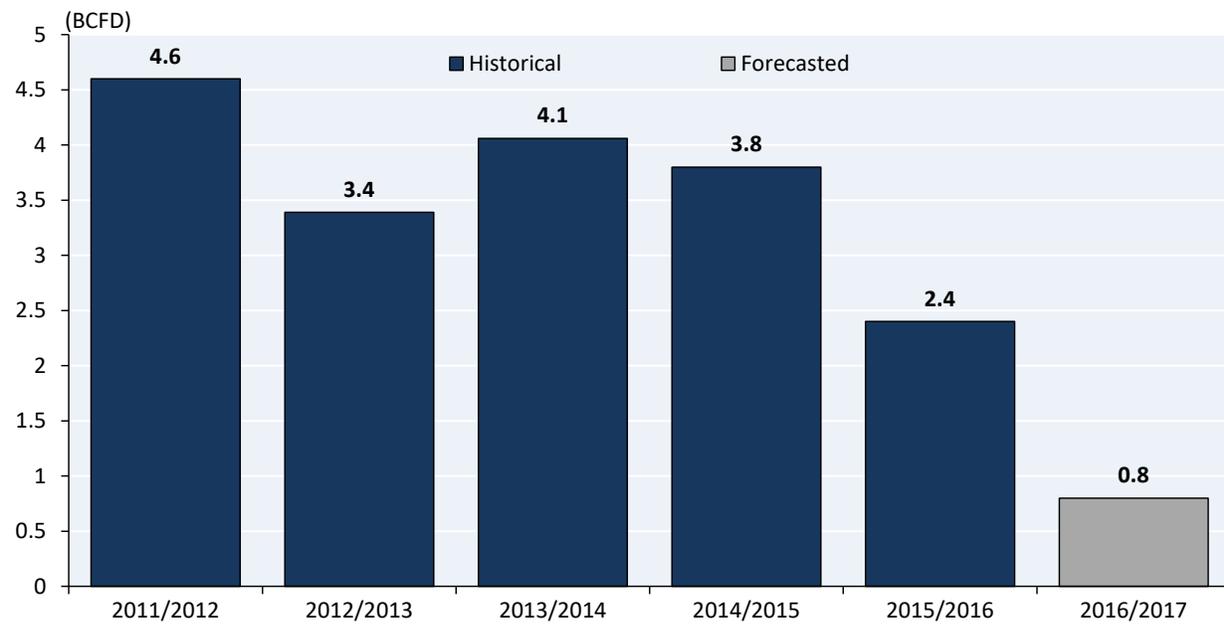
Exhibit 28. Outlook For Winter Net Canadian Imports



Composite Summary

Net imports for the forthcoming winter will decline as indicated in Exhibit 29. This decline is due to the combination of (1) increased exports to Mexico; (2) the transition from net LNG imports to net LNG exports; and (3) flat Canadian imports.

Exhibit 29. Outlook For Winter Net Imports

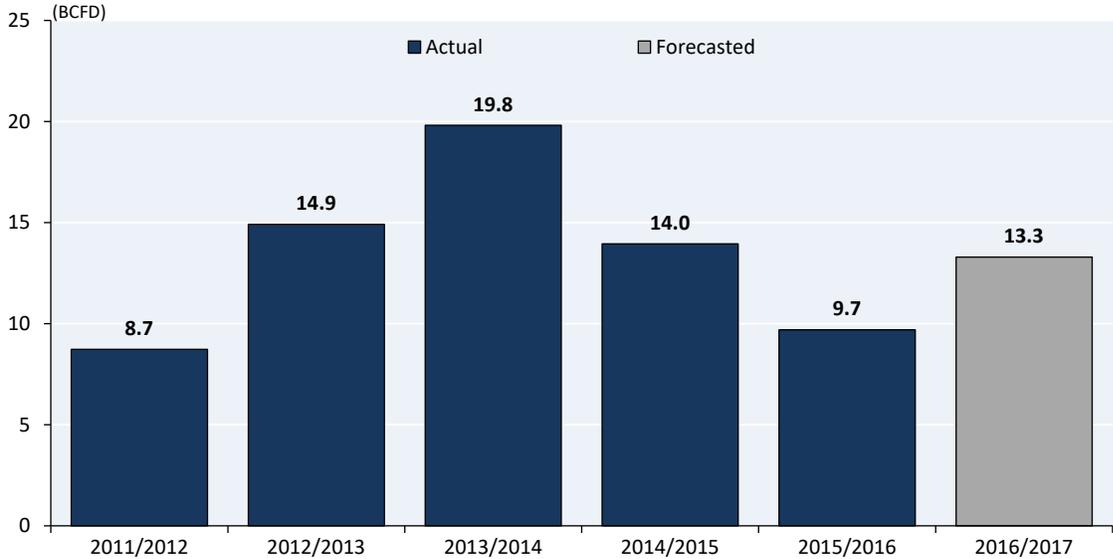


Storage Withdrawals

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 slightly warmer than normal winter weather, storage withdrawals this winter are expected to be well above storage withdrawals for the prior winter, which was the second mildest winter on record.

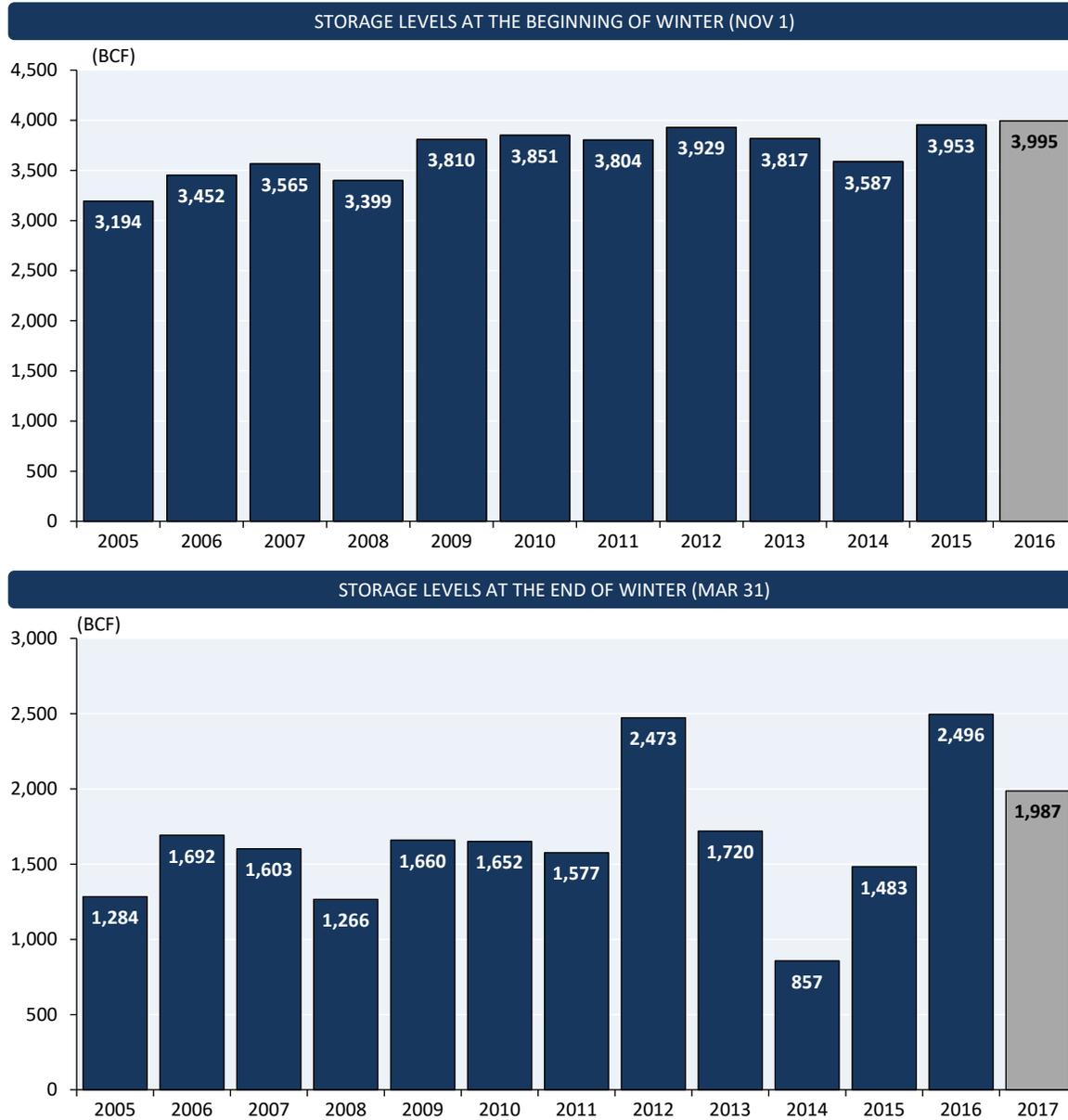
More specifically, the current projections are for about a 3.6 BCFD, or 37 percent, increase in storage withdrawals. As noted in Exhibit 30, there have been considerable variations in storage withdrawals over the last several winters, with most of this variance attributable to the difference in the severity of the winter weather.

Exhibit 30. Outlook For Storage Withdrawals



With respect to the outlook for storage levels at the beginning of the winter season (November 1st), they are expected to be slightly higher than the levels that occurred at the beginning of the last winter. In addition, they likely will be slightly higher than the near record levels set for November 1, 2012. This would be a new record, albeit marginally, as illustrated in Exhibit 31. In addition, storage inventories currently are expected to increase, albeit moderately, during the first two weeks of November. However, this does assume the start of the winter season is relatively mild.

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



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

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

A. Projected U.S. Natural Gas Storage Capacity and Beginning of Winter Storage Levels

	Actual							Est
	2009	2010	2011	2012	2013	2014	2015	2016
Total Working Gas Capacity at Start of Injection Season ⁽¹⁾	3,754	3,925	4,049	4,103	4,265	4,333	4,336	4,346
Annual Capacity Additions	171	124	54	162	68	3	10	7
Total Working Gas Capacity at End of Injection Season	3,925	4,049	4,103	4,265	4,333	4,336	4,346	4,353
Storage Level at the Start of Winter (Nov 1)	3,810	3,851	3,804	3,929	3,817	3,587	3,953	3,995
Percent of Capacity	97%	95%	93%	92%	88%	83%	91%	92%

(1) Effective maximum usable working capacity.

B. Projected U.S. Natural Gas Storage Capacity and Beginning of Spring 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	4,346	4,353
Annual Capacity Additions	124	54	162	68	3	10	7	0
Total Working Gas Capacity at End of Injection Season	4,049	4,103	4,265	4,333	4,336	4,346	4,353	4,353
Storage Level at the Start of Spring (April 1)	1,652	1,577	2,473	1,720	857	1,483	2,496	1,987
Percent of Capacity	41%	38%	58%	40%	20%	34%	57%	46%

(1) Effective maximum usable working capacity.

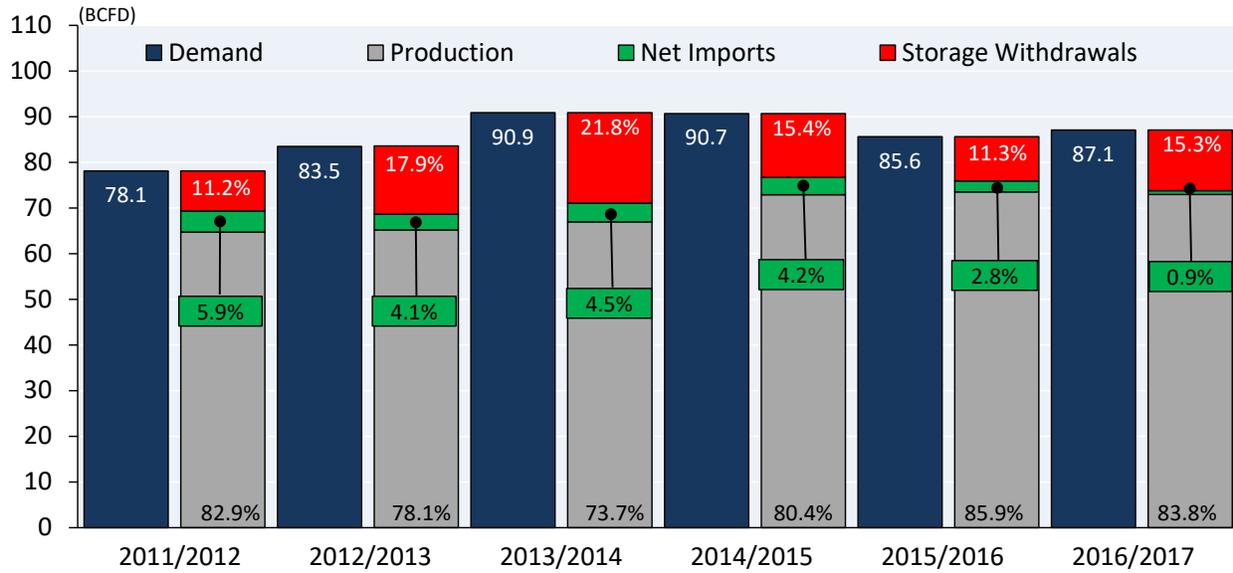
However, while the confidence level for the November 1st storage levels is fairly high, the same cannot be noted for the projection for the storage levels noted in Exhibits 31 and 32 for the end of the winter season (March 31, 2017). This projection for the March 31st storage level is dependent upon 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 milder than normal winter to a severe winter, potentially could increase storage withdrawals about 3.6 BCFD, which would reduce March 31st storage levels about 545 BCF.

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 about 100 BCF. As a result, the combined impact of these two areas of uncertainty could reduce March 31st storage levels about 645 BCF. This would reduce the relatively high storage levels noted in Exhibit 31 from about 1,987 to about 1,345 BCF, which would be about nine percent below the level recorded for March 31, 2015, but still above the level attained for March 31, 2014.

Conclusions

Assuming slightly warmer than normal weather for the forthcoming winter, total natural gas supply will be above that for the prior winter. However, it will be below the levels set for the very cold winters for 2013/2014 and 2014/2015 (i.e., see Exhibit 33). More specifically, domestic production and net imports will decline, but this will be more than offset by increases in storage withdrawals.

Exhibit 33. Summary Of Winter Supply



Note: 2016/2017 is estimated.

ADDENDUM I:
U.S. LNG EXPORTS

U.S. LNG Exports

Overview

The era of U.S. L-48 LNG exports began in February 2016, when Cheniere shipped the first cargo from its Sabine Pass facility on the Gulf Coast of Louisiana. The 2.4 BCFD project is scheduled to reach full commercial operations by late-2017. Four other projects, plus a fifth train at Sabine Pass, are also under construction but will not be completed until 2018-2019. By 2020, total U.S. LNG export capacity will reach 8.6 BCFD. In the near-term, few additional projects will be sanctioned due the oversupplied global LNG market. However, in the long-term, a second wave of U.S. LNG projects are expected to move forward post-2023. By 2030, total U.S. LNG export capacity is expected to reach 15.5 BCFD, establishing the United States as the world's largest LNG exporter.

Phase I

After beginning exports in February, the first train at Sabine Pass reached full commercial operations in May. Commissioning of the second train began in July, with Trains 3-4 expected to come online in 2017. As of August, more than 20 LNG cargoes have been exported from the project, averaging approximately 0.6 BCFD. Most of the cargoes have been directed to South American markets, with a few also shipped to the Middle East, Europe and Asia.

Construction on the other four projects is progressing and while modest delays are possible, 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.

The U.S. LNG projects will come online amid a heavily oversupplied global LNG market. The glut is driven by a tremendous amount of new liquefaction capacity coming online in Australia, followed shortly thereafter by capacity in the U.S. Weaker than expected demand growth in Asia will exacerbate the oversupply, which is expected to persist through 2024.

The oversupplied market and corresponding low global gas prices have 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. However, the structure of the U.S. LNG contracts greatly reduces the likelihood of this outcome.

Substantially all of the capacity under construction has been contracted to LNG buyers on a long-term basis. In contrast to traditional LNG contracts—which are linked to oil prices—U.S. LNG contracts are predominately tolling arrangements linked to Henry Hub. Under the tolling

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

Project	Train	Capacity (MMCFD)	EVA		Primary Offtakers (most likely destination)
			Estimated Commercial Start Date	Lead Developer	
Sabine Pass LNG	1	600	May-16	Cheniere Energy	Shell (Global)
	2	600	Sep-16		GNF (Europe)
	3	600	Apr-17		KOGAS (Korea)
	4	600	Aug-17		GAIL (India)
	5	600	Aug-19		TOTAL (global) Centrica (UK)
Cameron LNG	1	533	Dec-18	Sempra Energy	Engie (Europe)
	2	533	Sep-19		Mitsubishi (Japan)
	3	533	Mar-20		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		

structure, the LNG buyer pays a flat tolling fee to the project owner for the right to liquefy the gas. The buyer is responsible for supplying feedstock to the facility, then receives the liquefied gas on a free on board (FOB) basis.¹³

Notably, the tolling contracts associated with U.S. LNG projects are take-or-pay, meaning the offtaker is required to pay the tolling fee regardless of whether it actually lifts cargoes. For that reason, most buyers are likely to view the tolling fee as a sunk cost and take cargoes so long as the transaction covers their variable costs. Only under extreme scenarios would this not be the case. A few buyers may occasionally elect to forego shipments, especially in the peak of the oversupply in 2019-2020. Otherwise, U.S. LNG projects are expected to operate near 85% utilization rates—in line with the long-term average utilization of well-functioning international LNG projects.

Phase II

The global LNG market is likely to be oversupplied through 2024. During that period, final investment decisions (FIDs) on additional projects in the U.S. (or anywhere else) are expected to be few and far between. Yet, global gas demand will continue to increase rapidly and by 2025, the world likely will require additional LNG supply.

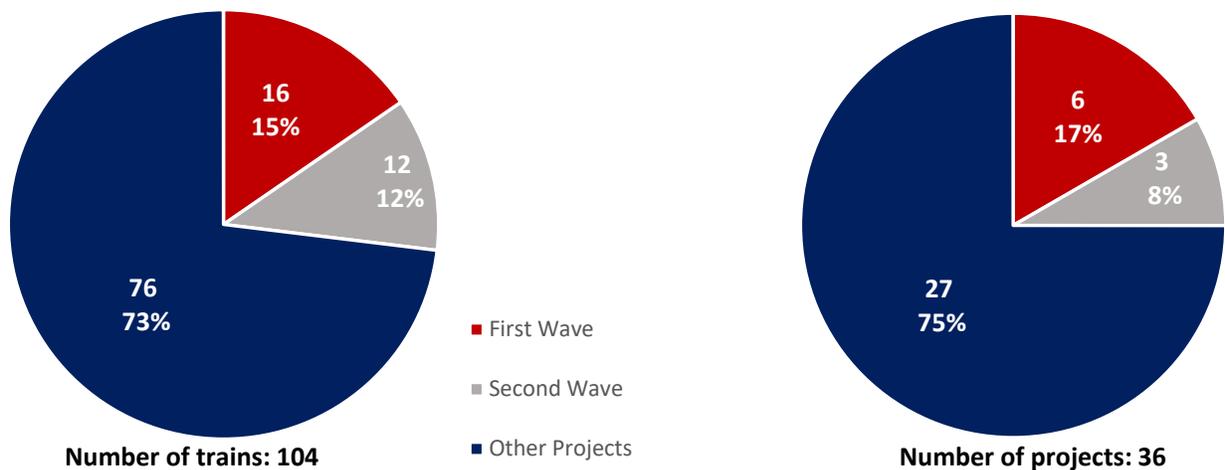
A large number of projects in several regions have been proposed to meet this demand. Among them are Western Canada, East Africa and offshore Australia, all of which offer enormous gas

¹³ 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.

reserves and close proximity to premium Asian markets. 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 once the global supply/demand balance begins to tighten (i.e., 2024-2025).

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. Global oil and coal prices also will impact LNG demand, as could potential carbon regulations. Yet, LNG demand certainly will increase in the long-term and U.S. projects will fill a substantial portion of that demand. Beyond the 8.5 BCFD of existing and under construction capacity in the U.S., more than 30 additional projects—totaling 45.8 BCFD—have been proposed (see Exhibit Add I-2). Few have generated any meaningful commercial momentum in the current environment, but many projects will be quite compelling options post-2020. 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) have also been proposed and could emerge as good options for buyers unwilling to commit to large volume deals.

Exhibit Add I-2. Summary of Proposed U.S. Liquefaction Projects



While it is a crowded field filled with some uncertainty for each proposed project, Exhibit Add I-3 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 may also 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.

The combination of the first and second phase expansions would bring total U.S. liquefaction capacity to 15.5 BCFD and establish the U.S. as the world’s largest LNG exporter—exceeding both Australia and Qatar.

Exhibit Add I-3. U.S. Liquefaction Projects Online in the Second Phase for U.S. LNG Exports

Project	Train	Nominal Capacity (MMCFD)	Status	EVA Estimated Commercial Start Date	Lead Developer(s)
Lake Charles LNG	1	667	Proposed	Jun-23	Energy Transfer, Shell
	2	667	Proposed	Dec-23	
	3	667	Proposed	May-24	
Golden Pass LNG	1	693	Proposed	Jun-25	ExxonMobil, Qatar Petroleum
	2	693	Proposed	Mar-26	
	3	693	Proposed	Dec-26	
Sabine Pass LNG	6	600	Proposed	Jan-25	Cheniere Energy
Cameron LNG	4	533	Proposed	Sep-25	Sempra Energy
	5	533	Proposed	Jan-27	
Corpus Christi LNG	3	600	Proposed	Jan-25	Cheniere Energy
Magnolia LNG	1	267	Proposed	Jan-27	LNG Limited
	2	267	Proposed	Jan-28	

U.S. LNG Exports

As illustrated in Exhibit Add I-4, U.S. LNG exports are expected to ramp up steadily from 2016 to 2020, as six projects are brought online, to about 7.2 BCFD (i.e., assuming an average 85% capacity factor). Exports are then expected to remain steady until post-2023, when the second phase of U.S. LNG starts to come online. By 2030, U.S. LNG exports are expected to reach approximately 13.2 BCFD.

Exhibit Add I-4. U.S. LNG Exports



Canada and Mexico LNG

At present there are 22 liquefaction projects (44.3 BCFD) proposed in Canada. The bulk of proposed capacity is in British Columbia, though several projects have also been proposed on the East Coast, in Nova Scotia. Further, the Costa Azul regasification plant in Western Mexico has been proposed as a brownfield liquefaction export project, as well.¹⁴

Few of these projects have achieved any meaningful commercial momentum. For those proposals in Eastern Canada and Mexico, the outcome is hardly surprising, but many projects in Western Canada actually were proposed before projects now under construction on the U.S. Gulf Coast. Yet they have been hampered by several obstacles, including high costs, the need for lengthy pipelines, upstream uncertainty and persistent environmental opposition (including from First Nations groups). The resulting delays and continuing uncertainty has made it difficult for project developers to secure LNG buyers. Even those with strong partner structures (e.g., LNG Canada and Pacific Northwest LNG) have now delayed FIDs due to the difficult market environment.

Given the impending multi-year global LNG glut, Canada likely has missed the window of opportunity for bringing on new LNG projects. A few projects, especially those with strong partnership structures, could move forward as the market begins to tighten post-2020, but high costs and environmental opposition will remain challenges (especially when compared to competing proposals in the U.S. or elsewhere). Currently, the EVA base case does not include any Canadian (or Mexican) LNG projects moving forward.

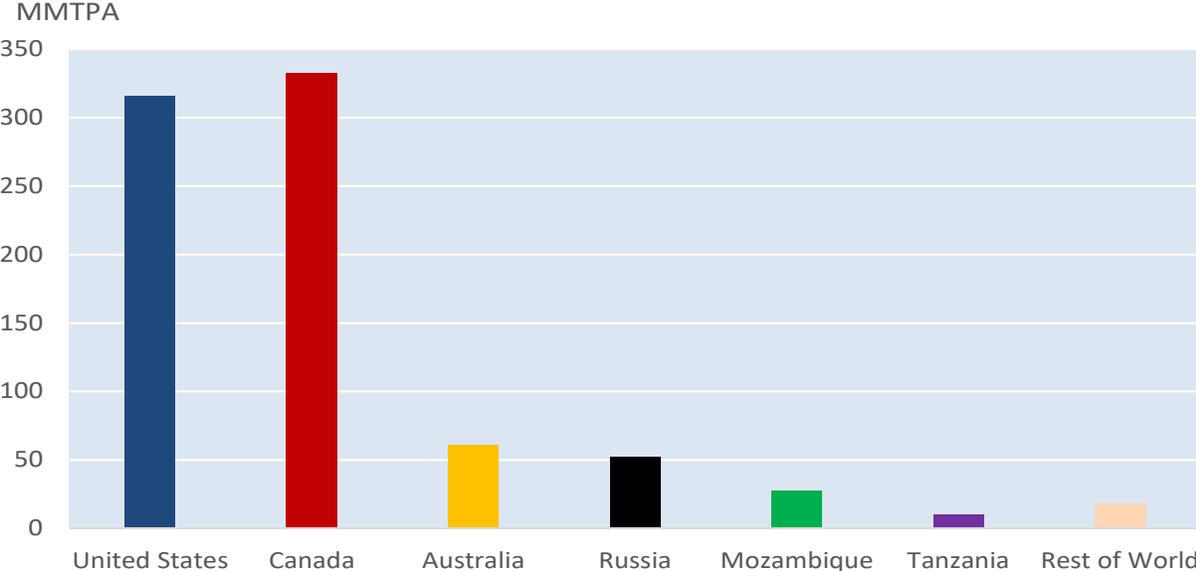
Global Overview

As previously noted, the global LNG industry is entering a period of considerable oversupply because of the significant amount of new capacity coming online first in Australia, then in the U.S. Combined, nearly 15 BCFD of new capacity will come online between 2016 and 2020, which will greatly outpace the not-inconsiderable global demand growth during that period.

While the bulk of capacity currently under construction is in Australia and the U.S., many other projects have been proposed in other regions of the world (See Exhibit Add I-5). Globally, the vast majority of projects will not move forward. However, given rising LNG demand, it is likely that a few projects from each region are eventually brought online.

¹⁴ Notably, the East Coast Canada projects, as well as Costa Azul in Mexico, would rely primarily on U.S. gas, which would be piped across the border, then liquefied and exported. The U.S. Department of Energy has approved the plans to do so, meaning the projects need only abide by their own national regulatory processes.

Exhibit Add I-5. Global Proposed Liquefaction Capacity



ADDENDUM II
TRANSPORTATION SECTOR

Transportation Sector

Overview

While not a critical component to the outlook for gas demand for the forthcoming winter, over the last few years there has been considerable discussion concerning natural gas penetrating the transportation sector and capturing market share from oil, which dominates this particular sector. While some momentum developed for this phenomenon in 2013 and 2014 when oil prices were \$100/BBL and the ratio of oil to gas prices was in the range of 20:1 to 25:1, this momentum appears to have declined sharply with the decline in oil prices to \$40/BBL and the ratio of oil to gas prices at approximately 15:1.

While this is a valid overview for the transportation sector, this assessment requires a more granular appraisal, because the transportation sector is not a homogenous entity. Instead there are approximately five major segments to the transportation sector that can be further divided into 11 subsegments, with each of the subsegments having their own unique attributes and drivers.

The material below briefly reviews the current outlook for these 11 subsegments of the transportation sector and the impact of the two key drivers, namely economics and environmental regulations, on each of these subsegments.

Outlook For Transportation Sector

There are two basic drivers for the penetration of CNG/LNG within the transportation sector, namely (1) economic and (2) environmental. Concerning the former, the recent 60 percent decline in oil prices has significantly reduced the economic incentive to use CNG/LNG as a replacement for diesel. This is illustrated in Exhibit Add II-1, which illustrates that the lifetime cost of a CNG truck was less than that to operate a diesel truck in June 2014, however in 2015 this relationship changed, as it is now cheaper to run a truck on diesel. This is because of the relative fuel economics. More specifically, in June 2014 it was \$11.53 per MMBTU less expensive to use CNG in heavy duty trucks than diesel, however by August 2015 this margin had declined to \$3.50 per MMBTU. While the margin at lower oil prices is still positive, in most cases it either is not adequate to cover the additional capital costs or it is marginal at best. With respect to the environmental driver (i.e., the industry's response to changing regulations), it is still a significant factor for some segments of the 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 in 2014, for many subsegments this momentum is declining because of the reduced economic incentives. Exhibit Add II-2 provides a simplified summary of CNG/LNG within most of the transportation subsegments.

Exhibit Add II-1. Lifetime Cost Of Heavy-Duty Trucks

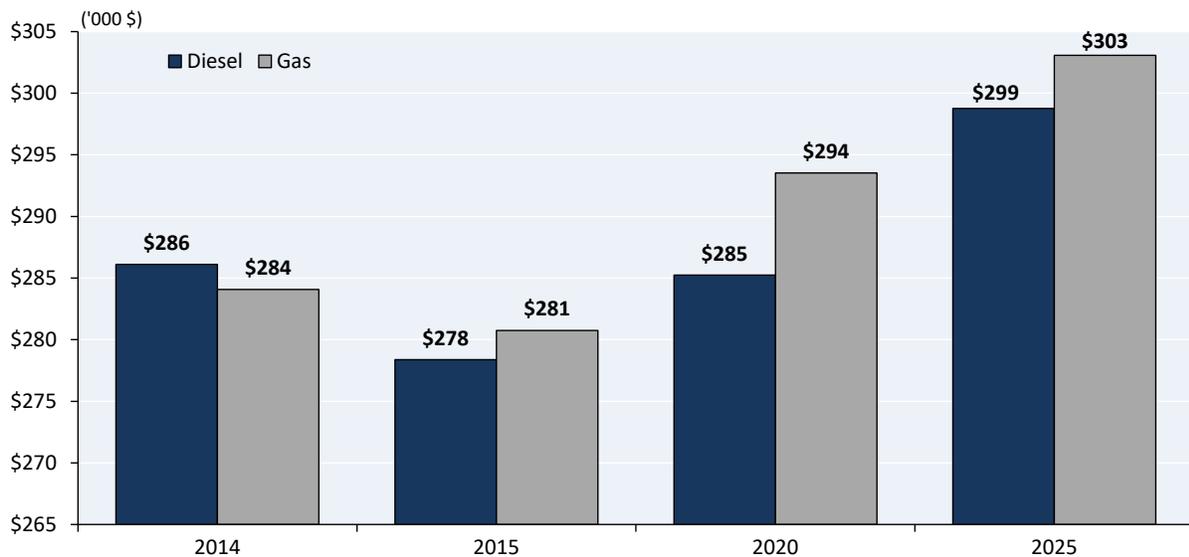


Exhibit Add II-2. Overview Of Emerging Transportation Markets

Transportation	Potential For Penetration High		Potential For Penetration Low
	Economic	Environmental	
Maritime <ul style="list-style-type: none"> ▪ Ocean Going Vessels ▪ Ferries ▪ Other 		X ^(B) X ^(A)	X
Trucks/Bus <ul style="list-style-type: none"> ▪ Refuse Trucks ▪ Mining ▪ Fleet Vehicles ▪ Transit Buses 	X ^(C)	X	X X ^(D)
Field E&P <ul style="list-style-type: none"> ▪ North Dakota ▪ Other Areas 		X	X
Railroads			X
Passenger Cars			X ^(E)

A. 17 LNG ferries in U.S. commissioned since 2013.

B. 59% of 27 major world ports have or plan to have LNG capability; 134 LNG vessels, of which most are in Norway.

C. Sales of heavy duty trucks in 2014 increased 30% to 8,300 trucks; CNG refuse trucks captured >50% of annual sales for refuse trucks; for all heavy duty trucks only 3% or 2.1 MM heavy duty trucks are CNG/LNG capable.

D. Sales of medium duty trucks in 2014 increased 24% to 2,700 trucks.

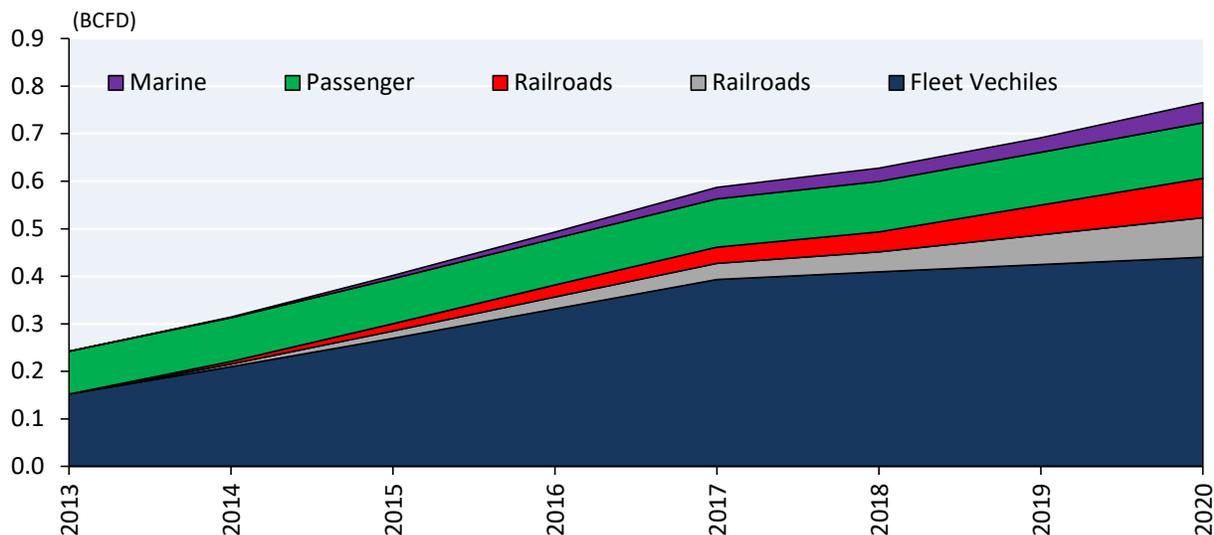
E. Light duty NGV sales in 2014 declined 34% to 3,500 cars.

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 mile/year versus the more typical 60,000 mile/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.

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-3. 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 1,029 CNG/LNG fueling stations that 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 0.5 BCFD).

Exhibit II-3. Outlook For Gas Demand Within The Transportation Sector



Marine Sector

Overview

As noted in Exhibit Add II-2, 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. These are summarized briefly in Exhibit Add II-4 and then explored in more depth in the material below.

Exhibit Add II-4. Major Categories Of The Marine Transportation Segment

Categories	Ferries	Harbor	Offshore O&G Field Services	Ocean
Driver of Change	Emissions	Emissions	Regulations	Regulations
	Economics	Economics	Emissions	Regulations

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., less than \$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 is going to 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-5, 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-5. 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.

With respect to North America the existing and pending ECAs are illustrated in Exhibit Add II-6. To date the reaction to the ECA regulations has been mixed, particularly for the cruise ship industry. In the case of Sea Star Line and Tote they have ordered four LNG powered vessels in order to comply with forthcoming emission regulations.¹ However, 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. Carnival Cruise Ships, on the other hand, has 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 2022.²

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.

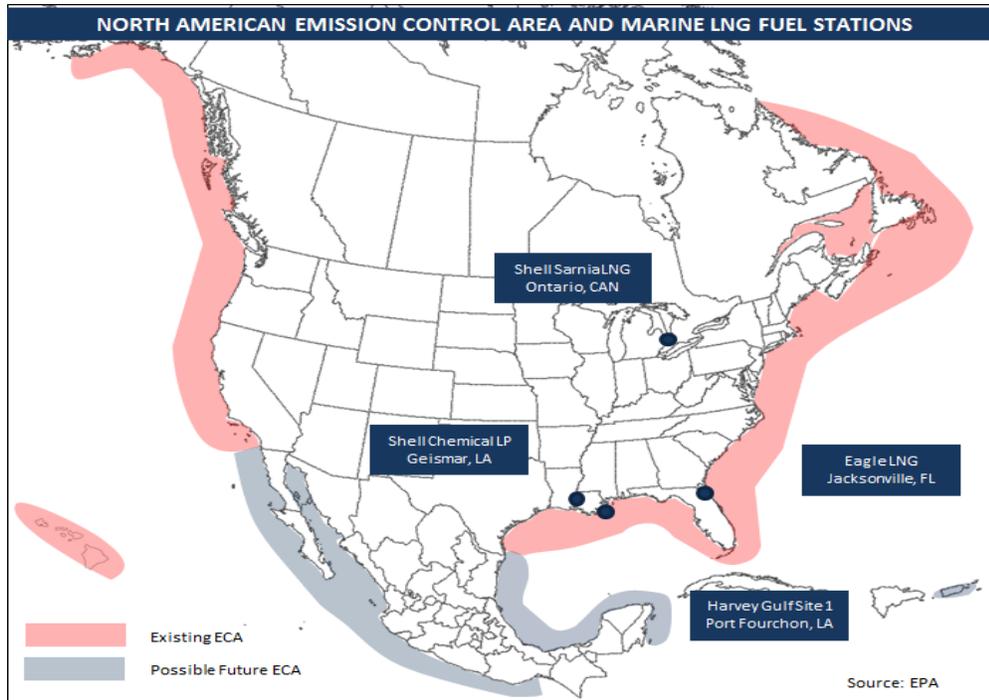
Ferries

While the use of ferries within the U.S. is rather limited, ferries likely will be one of the first area 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.

¹ 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 is scheduled to be delivered in the first quarter of 2016.

² Two of the four new Carnival Cruise ships will be used for German-based cruises.

Exhibit Add II-6. North American Emission Control Areas And Marine LNG Fuel Stations



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 undertaken a feasibility study.

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 about tugboats, namely:

- (1) Many tenders 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; and,
- (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 \$40/BBL oil prices. With respect to the second attribute, namely 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.

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

Currently there are over 80 LNG-powered ships in the world and this number is projected to increase over the next several years. 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.³ With respect to the U.S., where progress towards an LNG shipping fleet has been slow, Exhibit Add II-7 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 2015 emission regulations for the shipping industry that operate within U.S. waters (i.e., 200-mile limit).

Exhibit Add II-7. 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

³ 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; and (6) 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.

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-8 for a tabulation of these facilities and Exhibit Add II-8 for a map of their locations)). 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-8. 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	38	300,000
Total		141	1,116,243

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.

Appendix

Exhibit A-1. Natural Gas Consumption (BCF)

	Annual						Winter (November - March)					
	2011	2012	2013	2014	2015	2016	2011/2012	2012/2013	2013/2014	2014/2015	2015/2016	2016/2017
Residential	4,715	4,149	4,898	5,088	4,617	4,467	2,987	3,436	3,956	3,736	3,037	3,438
Commercial	3,155	2,895	3,295	3,467	3,208	3,063	1,781	2,000	2,302	2,228	1,856	2,030
Industrial	6,995	7,227	7,426	7,625	7,508	7,604	3,134	3,219	3,417	3,385	3,362	3,441
Electric	7,574	9,112	8,191	8,150	9,671	10,040	3,125	2,984	3,041	3,311	3,717	3,202
Other	2,010	2,127	2,316	2,335	2,438	2,486	920	986	1,044	1,077	1,068	1,083
Transportation	30	30	30	35	34	35	12	12	14	15	14	15
Total	24,479	25,540	26,156	26,700	27,476	27,694	11,959	12,637	13,774	13,752	13,054	13,209

Exhibit A-2. Industrial Production Growth Rates

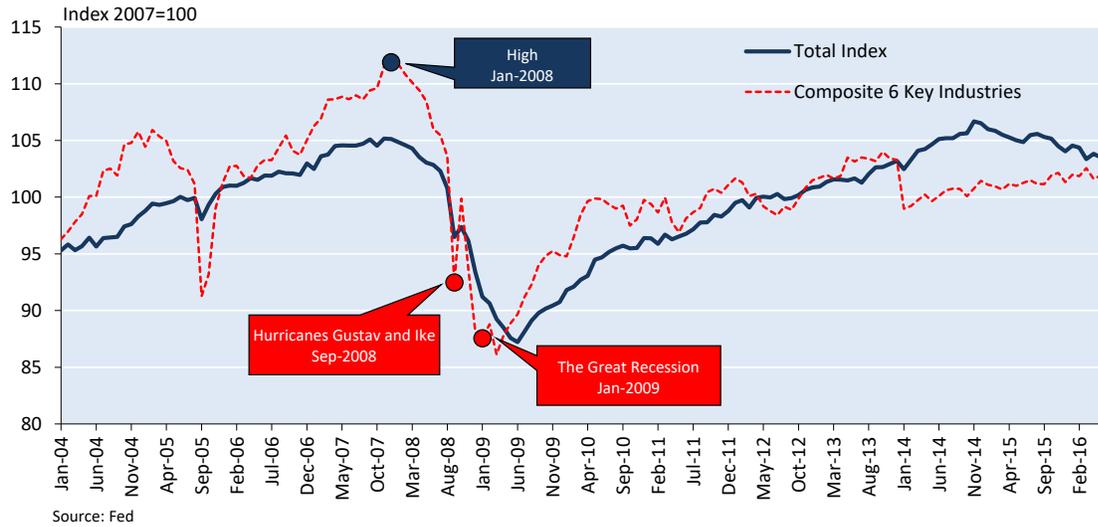


Exhibit A-3. Cumulative U.S. Capacity By Technology, 1998-2015

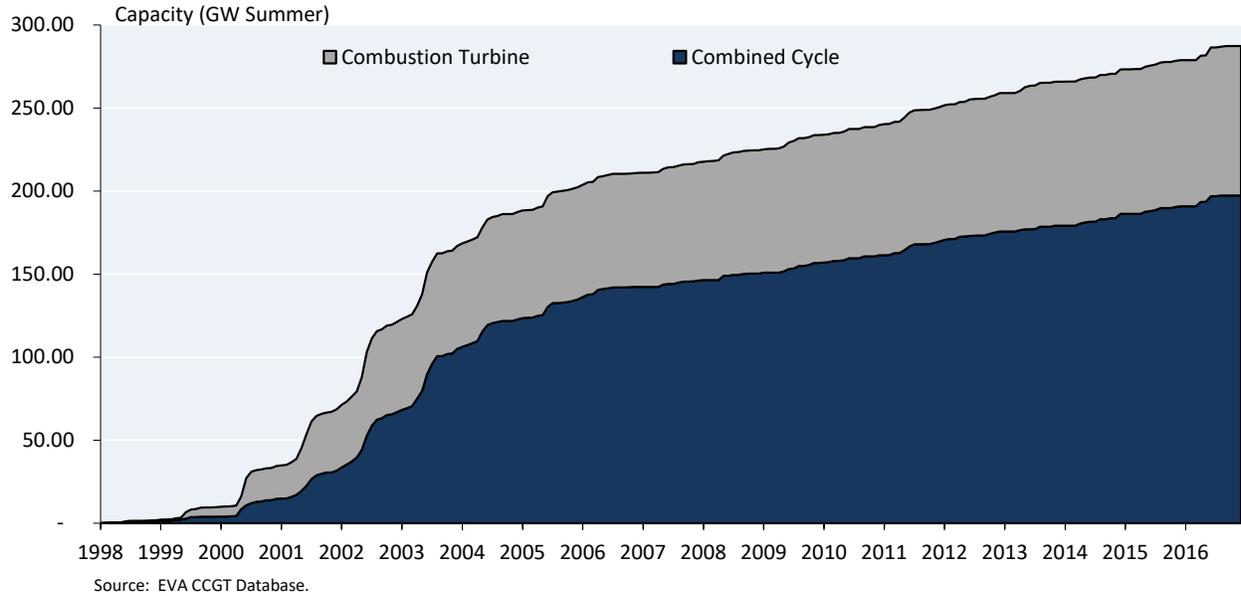


Exhibit A-4. Annual Additions Of Gas-Fired Capacity 2000-2016

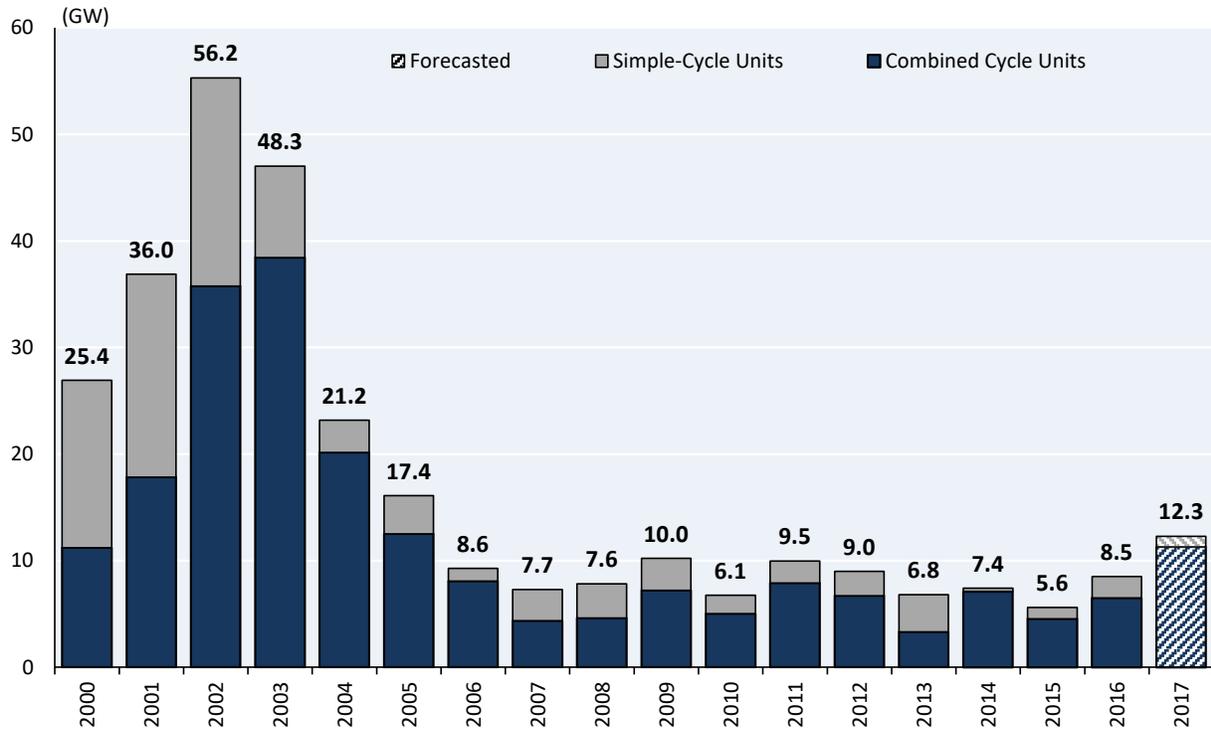


Exhibit A-5. Performance Characteristics Of Natural Gas Combined Cycle Units By Region

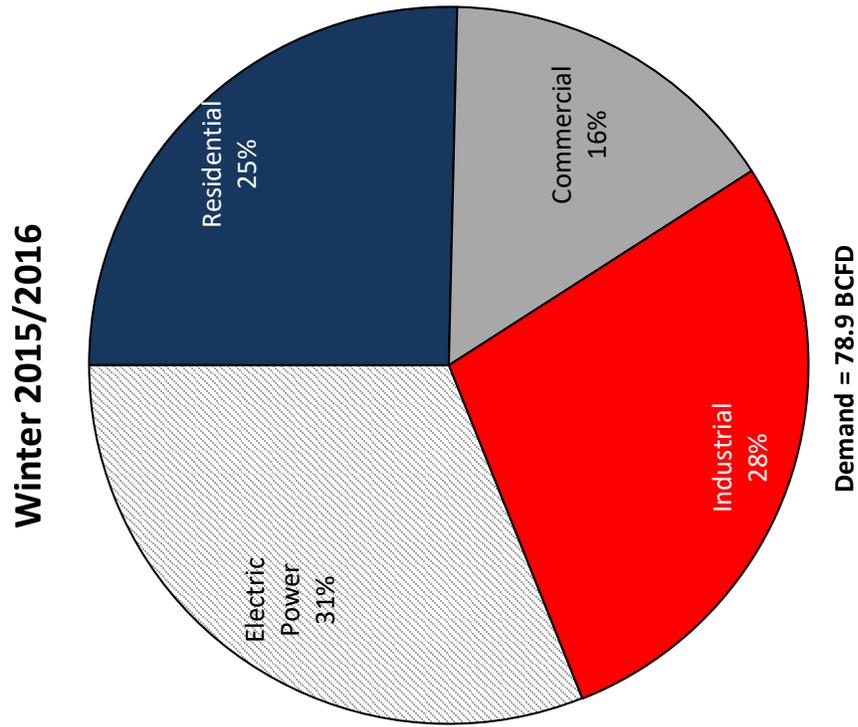
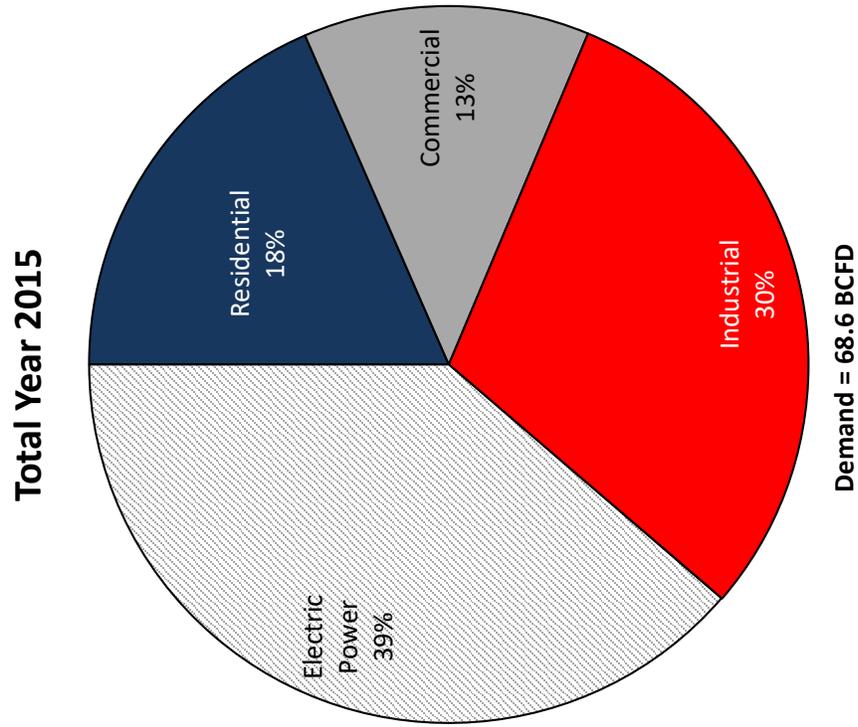
Capacity Factor %

Census Region	Weighted Average Capacity Factor										
	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
New England		77.3%	50.8%	48.2%	48.2%	55.1%	56.4%	52.8%	45.4%	42.6%	48.1%
Middle Atlantic	38.6%	42.0%	33.9%	34.1%	42.7%	46.0%	50.4%	59.8%	55.6%	56.2%	61.8%
East North Central	27.3%	25.3%	20.0%	14.2%	16.3%	21.9%	30.7%	48.0%	34.8%	35.5%	53.2%
West North Central	23.2%	19.6%	24.9%	20.2%	12.5%	17.5%	15.3%	25.2%	21.4%	16.5%	26.6%
South Atlantic w/o Florida	30.0%	31.4%	26.6%	23.8%	36.1%	33.9%	44.3%	53.7%	56.6%	52.2%	65.7%
Florida	65.6%	67.8%	54.0%	56.5%	54.3%	59.7%	59.5%	63.4%	59.7%	58.8%	63.8%
South Atlantic	51.2%	53.5%	42.1%	42.4%	47.2%	48.6%	53.2%	59.0%	58.3%	55.7%	64.7%
East South Central	31.0%	36.2%	30.7%	28.0%	38.1%	43.8%	49.7%	59.3%	49.4%	51.9%	66.5%
West South Central w/o ERCOT	50.4%	57.3%	33.2%	33.6%	36.4%	35.6%	36.4%	46.3%	37.5%	37.0%	49.7%
ERCOT	96.2%	96.3%	51.6%	49.5%	45.9%	45.1%	45.6%	50.0%	48.5%	46.7%	56.6%
West South Central	75.5%	78.5%	43.6%	42.5%	41.8%	41.0%	41.7%	48.4%	43.9%	42.7%	53.8%
Mountain	65.1%	70.0%	48.2%	48.0%	45.7%	40.9%	34.7%	40.4%	40.4%	38.2%	45.3%
Pacific Contiguous w/o CA	76.9%	66.0%	48.8%	49.7%	53.1%	51.1%	25.2%	32.9%	51.9%	48.3%	57.8%
California	65.3%	78.1%	61.4%	61.4%	52.3%	52.8%	40.0%	55.1%	52.8%	56.0%	52.9%
Pacific Contiguous	68.3%	75.1%	58.3%	58.3%	52.5%	52.3%	36.1%	49.5%	52.6%	54.2%	54.1%
TOTAL U.S.	55.0%	58.0%	41.2%	39.9%	41.6%	43.2%	43.6%	51.6%	48.0%	47.3%	56.1%

Heat Rate (BTU/kW)

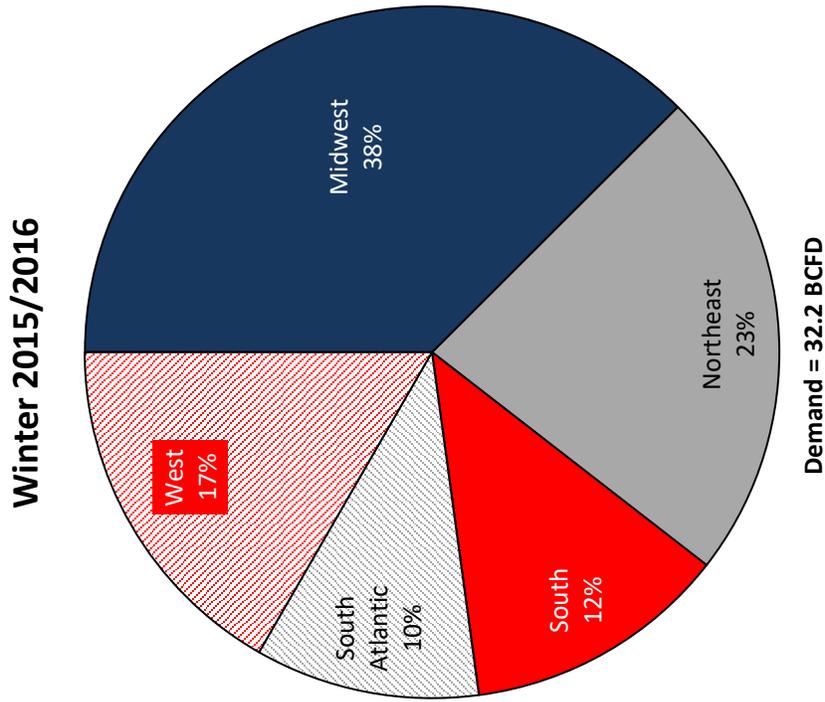
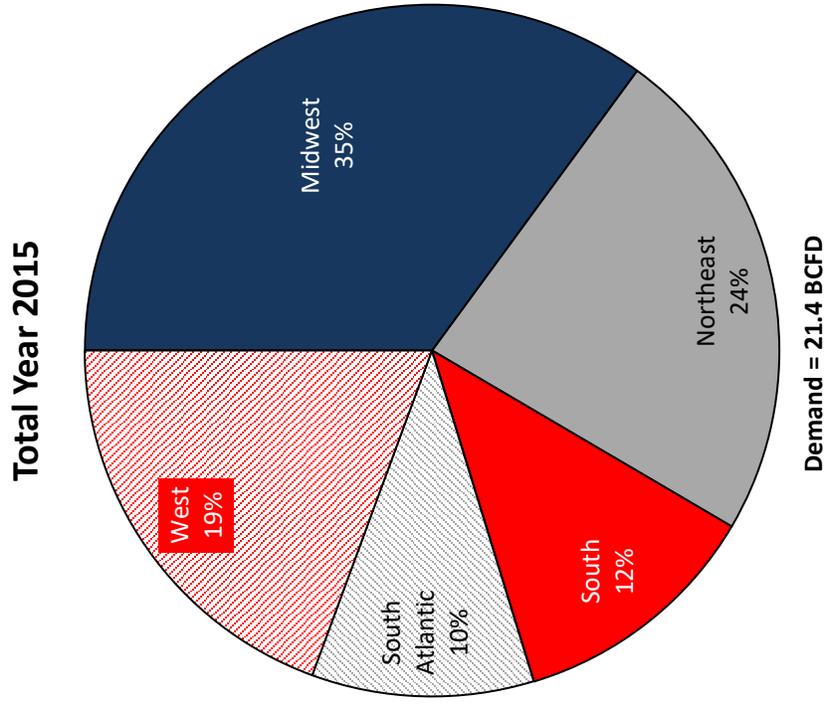
Census Region	Weighted Average Heat Rate (Btu/kWh)										
	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
New England	7,471	7,502	7,587	7,561	7,553	7,606	7,538	7,613	7,638	7,541	7,594
Middle Atlantic	7,389	7,591	7,543	7,536	7,561	7,403	7,355	7,426	7,358	7,440	7,447
East North Central	7,488	7,540	7,439	7,509	7,437	7,473	7,371	7,315	7,069	7,556	7,589
West North Central	7,794	7,720	7,605	7,635	7,731	7,648	7,665	7,412	7,247	7,574	7,345
South Atlantic w/o Florida	7,770	7,654	7,704	7,642	7,441	7,484	7,410	7,306	6,437	7,270	7,248
Florida	7,417	7,416	7,476	7,409	7,479	7,431	7,381	7,320	7,080	7,320	7,236
South Atlantic	7,500	7,471	7,538	7,465	7,468	7,447	7,391	7,314	6,798	7,298	7,242
East South Central	7,713	7,643	7,633	7,629	7,437	7,409	7,377	7,296	7,022	7,350	7,329
West South Central w/o ERCOT	8,499	8,354	8,387	8,270	7,862	8,298	8,232	9,552	8,117	7,360	7,228
ERCOT	7,339	7,334	7,374	7,473	7,369	7,356	7,358	7,337	7,305	7,334	7,307
West South Central	7,689	7,675	7,713	7,749	7,552	7,707	7,679	8,235	7,596	7,343	7,278
Mountain	7,574	7,613	7,393	7,460	7,531	7,533	7,639	7,490	7,097	7,544	7,455
Pacific Contiguous w/o CA	7,217	7,288	7,303	7,183	7,129	7,194	7,210	7,222	7,310	7,338	7,272
California	7,291	7,504	7,453	7,285	7,291	7,255	7,358	7,305	6,895	7,346	7,237
Pacific Contiguous	7,270	7,458	7,422	7,261	7,247	7,239	7,331	7,291	6,989	7,344	7,246
TOTAL U.S.	7,534	7,571	7,556	7,534	7,479	7,492	7,479	7,557	7,166	7,385	7,342

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



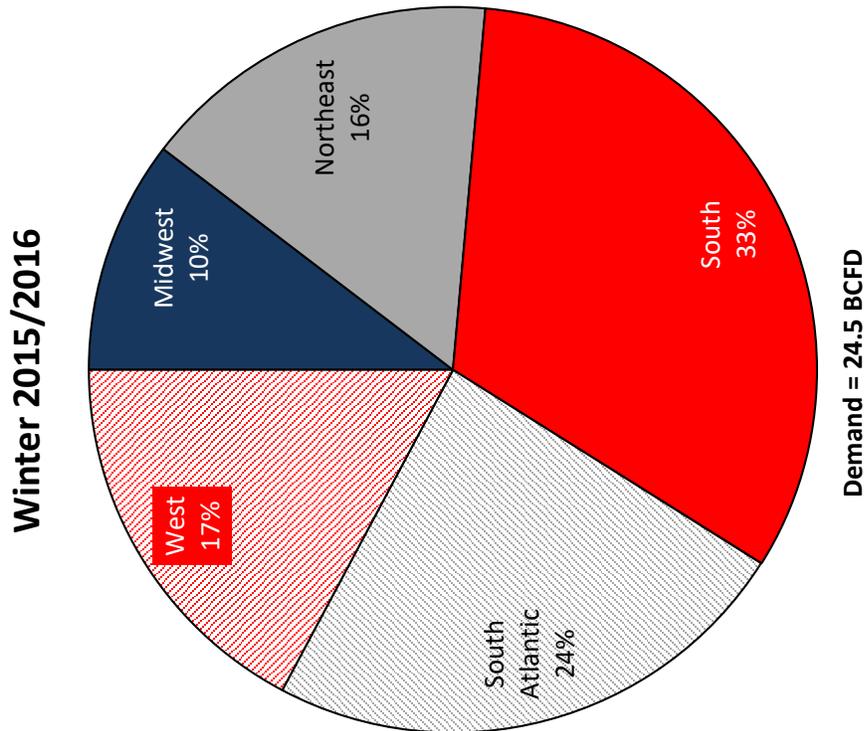
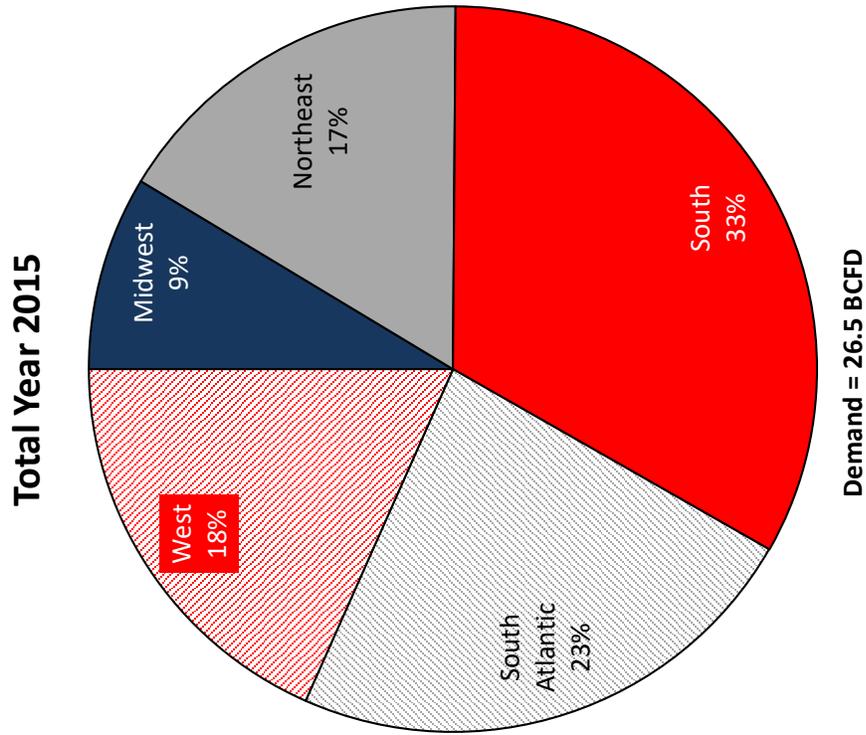
1. Winter consists of November through March.
 2. Excludes lease, plant, and pipeline fuel.
- Source: EIA.

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

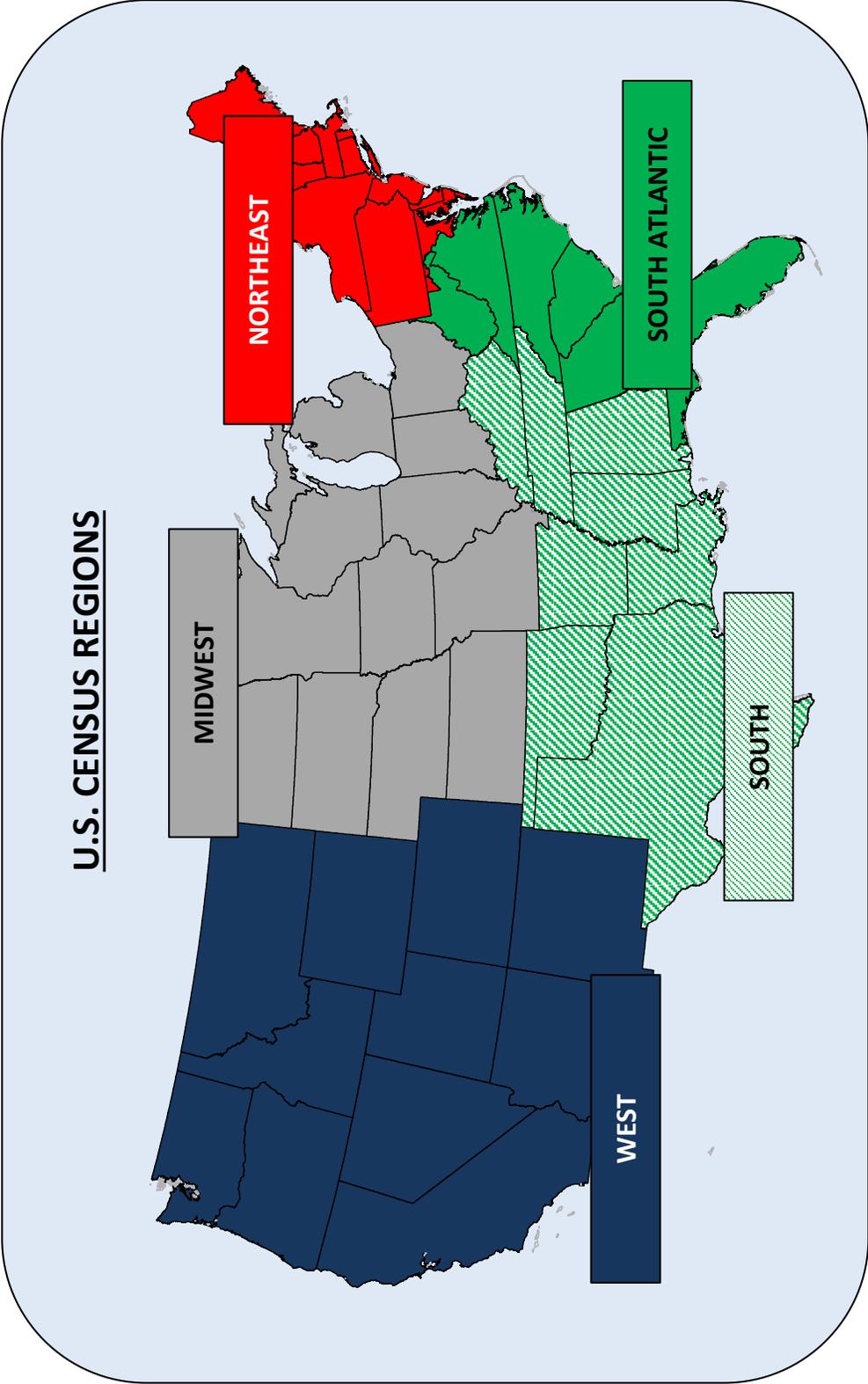


Exhibit A-10. Relevant Data

	Annual										Nov-Mar						% Diff 16/17-15/16
	2012	2013	2014	2015	2016	16/15	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	% Diff 16/17-15/16				
	118,963	120,018	120,734	121,937	123,848	1.6%	118,480	119,491	120,496	121,140	122,992	124,809					
Residential Housing Stock Electric																	
Weather																	
Heating Degree Days (HDD) (Degree Days)	3,785	4,497	4,572	4,111	4,097	-0.3%	2,991	3,470	3,865	3,685	3,042	3,408	12.0%				
Normal HDD ¹ (Degree Days)	4,357	4,357	4,357	4,357	4,357	-	3,513	3,513	3,513	3,513	3,513	3,513	-				
% of Normal	86.9%	103.2%	104.9%	94.4%	94.0%	-	85.1%	98.8%	110.0%	104.9%	86.6%	97.0%	-				
New Gas-Fired Capacity ²																	
CC (MW)	6,713	3,511	7,121	4,539	6,504	43.3%	2,901	2,319	625	2,628	1,067	1,340	25.6%				
CT (MW)	2,334	3,332	250	1,074	2,006	86.7%	180	815	125	256	40	0	-100.0%				
Hydro and Nuclear Generation																	
Hydro Generation - Pacific (GWh)	190,927	164,168	163,851	150,183	163,056	8.6%	67,380	67,382	59,577	58,770	61,132	60,451	-1.1%				
Nuclear Generation (GWh)	769,331	789,016	796,875	797,178	804,328	0.9%	334,268	321,133	325,022	342,472	332,682	333,779	0.3%				
Industrial (Index: 2007=100)																	
Food	100.0	101.7	102.2	103.1	121.4	17.8%	99.3	100.4	102.5	103.1	104.0	139.2	33.9%				
Paper	100.0	100.4	99.3	97.7	98.6	0.9%	100.9	100.8	98.3	99.4	96.4	101.8	5.7%				
Chemicals	100.0	101.6	95.8	98.0	110.4	12.7%	100.3	101.9	97.2	97.7	98.9	122.5	23.9%				
Petroleum	100.0	106.9	100.3	104.9	113.6	8.2%	100.2	102.9	104.0	102.0	106.5	121.8	14.4%				
Non-metallic Minerals	110.6	112.7	116.0	116.3	120.7	3.7%	100.9	103.0	106.4	111.2	116.7	-	-				
Primary Metals	100.0	101.9	103.4	96.7	94.7	-2.1%	105.3	99.1	103.3	99.7	94.6	95.2	0.6%				
Total Industrial Production	100.0	101.9	104.9	105.2	109.2	3.7%	99.1	101.1	103.2	106.1	104.2	-	-				
Composite 6-key Ind.	101.0	103.5	100.7	101.5	110.2	8.6%	100.9	101.5	100.9	101.0	102.0	-	-				
Economy																	
Real GDP (Bill. 2009\$)	15,355	15,584	15,962	16,349	16,685	2.1%	15,263	15,431	15,742	16,169	16,500	16,945	2.7%				
Employment (Thousands)	134,210	136,541	138,809	141,928	145,358	2.4%	129,909	131,424	133,696	135,914	138,350	141,281	2.1%				
GDP IPD (2005=100)	106.6	107.9	109.0	109.9	111.3	1.3%	106.2	107.2	108.7	109.2	110.6	112.3	1.5%				

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

²Amount of capacity brought online in the period.

Exhibit A-11. Regional Dry Natural Gas Production (BCFD)

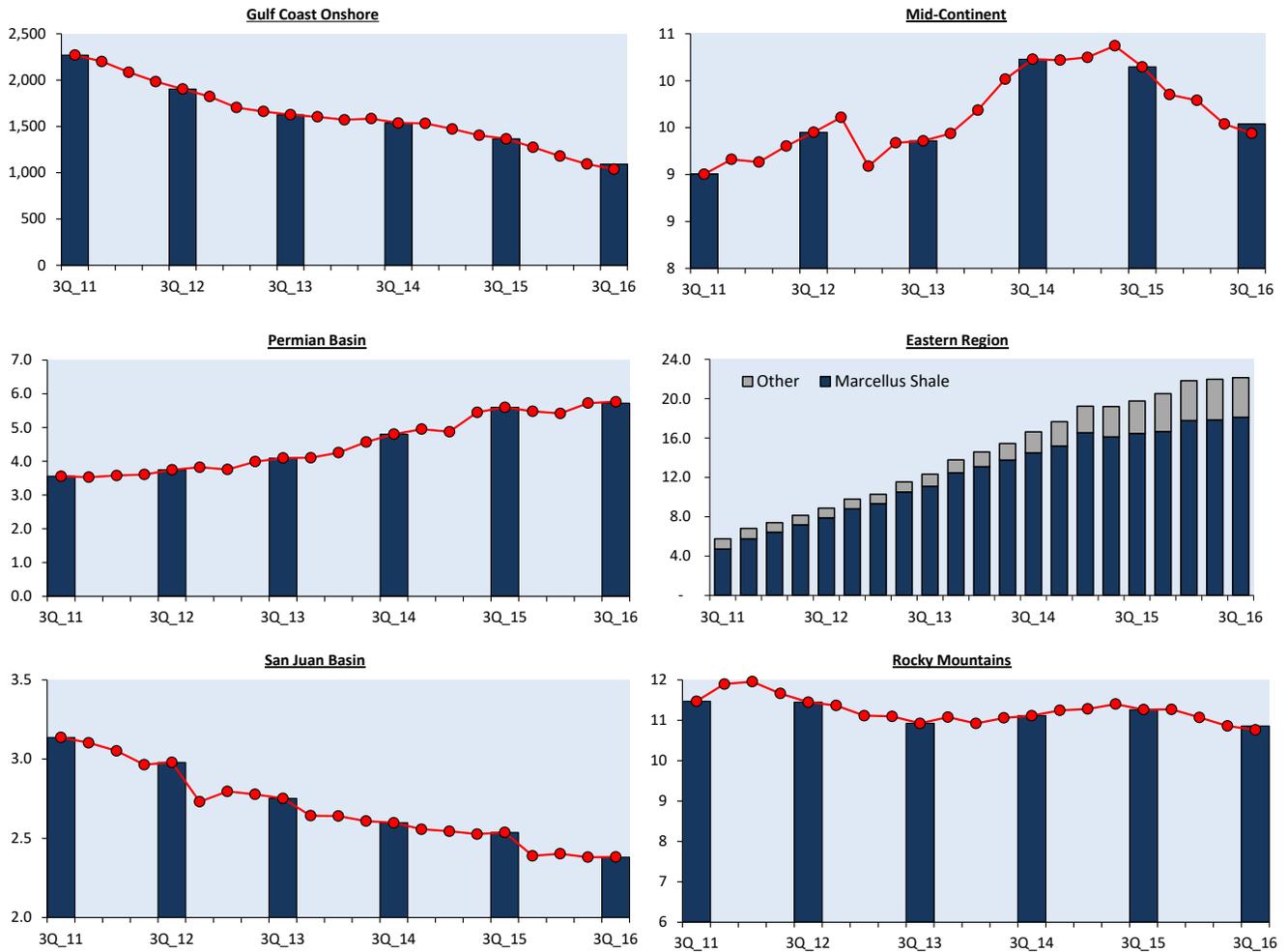


Exhibit A-12. Milestones For Proposed North American Liquefaction Projects

Note: We have removed the table from this report. Please contact Energy Ventures Analysis directly if you would like to request this proprietary information. (There is likely to be an associated fee.)

Energy Ventures Analysis, Inc.
1901 N. Moore Stree – Suite 1200
Arlington, VA 22209
www.evainc.com

Exhibit A-13. Natural Gas Supply

Supply Component	<u>2011/2012</u>	<u>2012/2013</u>	<u>2013/2014</u>	<u>2014/2015</u>	<u>2015/2016</u>	<u>2016/2017</u>
I. US Production						
Shale	3,750	4,339	4,904	6,022	6,245	6,320
Tight Sands	2,107	1,988	1,886	1,787	1,688	1,593
CBM	643	579	517	474	438	400
Associated(ex offshore)	599	665	760	868	933	955
Offshore	741	625	569	547	577	591
Other Conventional	<u>1,997</u>	<u>1,640</u>	<u>1,486</u>	<u>1,322</u>	<u>1,296</u>	<u>1,162</u>
Subtotal Lower-48	9,837	9,836	10,122	11,020	11,177	11,020
Footnote:						
Alaska	<u>139</u>	<u>134</u>	<u>131</u>	<u>133</u>	<u>137</u>	<u>140</u>
Total US	9,976	9,971	10,253	11,153	11,315	11,160
II. Imports						
Net Canada	832	715	855	861	831	827
Net Mexico	(208)	(262)	(257)	(329)	(488)	(596)
Net LNG	<u>75</u>	<u>59</u>	<u>15</u>	<u>41</u>	<u>24</u>	<u>(115)</u>
Total Net Imports	699	512	613	572	368	116
III. Storage Withdrawals	1,327	2,253	2,993	2,106	1,468	2,008
IV. Total Lower-48 Supply	11,863	12,601	13,728	13,699	13,014	13,145

Supply Component	<u>2011</u>	<u>2012</u>	<u>2013</u>	<u>2014</u>	<u>2015</u>	<u>2016</u>	<u>2017</u>
I. US Production							
Shale	7,972	10,066	10,937	12,771	14,782	15,209	15,636
Tight Sands	5,148	4,987	4,640	4,477	4,161	3,947	3,827
CBM	1,601	1,492	1,313	1,187	1,104	1,001	930
Associated(ex offshore)	1,349	1,530	1,690	1,985	2,213	2,268	2,348
Offshore	1,970	1,592	1,435	1,316	1,329	1,444	1,488
Other Conventional	<u>4,543</u>	<u>4,094</u>	<u>3,984</u>	<u>3,672</u>	<u>3,153</u>	<u>2,741</u>	<u>2,744</u>
Subtotal Lower-48	22,583	23,760	23,997	25,409	26,741	26,610	26,973
Footnote:							
Alaska	<u>336</u>	<u>331</u>	<u>319</u>	<u>314</u>	<u>326</u>	<u>334</u>	<u>343</u>
Total US	22,919	24,091	24,316	25,723	27,068	26,944	27,317
II. Imports							
Net Canada	2,180	1,992	1,876	1,865	1,925	2,108	2,092
Net Mexico	(500)	(619)	(657)	(726)	(1,054)	(1,364)	(1,602)
Net LNG	<u>278</u>	<u>146</u>	<u>95</u>	<u>44</u>	<u>63</u>	<u>(121)</u>	<u>(504)</u>
Total Net Imports	1,958	1,519	1,314	1,183	933	622	(14)
III. Net Storage Change	(350)	(7)	548	(252)	(537)	168	(64)
IV. Total Lower-48 Supply	24,191	25,272	25,858	26,339	27,138	27,401	26,895

Exhibit A-13. Natural Gas Supply (Continued)

Supply Component	<u>2011/2012</u>	<u>2012/2013</u>	<u>2013/2014</u>	<u>2014/2015</u>	<u>2015/2016</u>	<u>2016/2017</u>
I. US Production						
Shale	24.67	28.73	32.48	39.88	41.08	41.85
Tight Sands	13.87	13.17	12.49	11.83	11.11	10.55
CBM	4.23	3.84	3.42	3.14	2.88	2.65
Associated(ex offshore)	3.94	4.40	5.03	5.75	6.14	6.32
Offshore	4.87	4.14	3.77	3.62	3.80	3.92
Other Conventional	<u>13.14</u>	<u>10.86</u>	<u>9.84</u>	<u>8.75</u>	<u>8.53</u>	<u>7.69</u>
Subtotal Lower-48	64.72	65.14	67.03	72.98	73.54	72.98
Footnote:						
Alaska	<u>0.91</u>	<u>0.89</u>	<u>0.87</u>	<u>0.88</u>	<u>0.90</u>	<u>0.93</u>
Total US	65.63	66.03	67.90	73.86	74.44	73.91
II. Imports						
Net Canada	5.47	4.74	5.66	5.70	5.47	5.48
Net Mexico	-1.37	-1.74	-1.70	-2.18	-3.21	-3.95
Net LNG	<u>0.49</u>	<u>0.39</u>	<u>0.10</u>	<u>0.27</u>	<u>0.16</u>	<u>-0.76</u>
Total Net Imports	4.60	3.39	4.06	3.79	2.42	0.77
III. Storage Withdrawals						
	8.73	14.92	19.82	13.95	9.66	13.30
IV. Total Lower-48 Supply						
	78.05	83.45	90.91	90.72	85.62	87.05

Supply Component	<u>2011</u>	<u>2012</u>	<u>2013</u>	<u>2014</u>	<u>2015</u>	<u>2016</u>	<u>2017</u>
I. US Production							
Shale	21.84	27.50	29.96	34.99	40.50	41.67	42.84
Tight Sands	14.11	13.63	12.71	12.27	11.40	10.81	10.49
CBM	4.39	4.08	3.60	3.25	3.02	2.74	2.55
Associated(ex offshore)	3.70	4.18	4.63	5.44	6.06	6.21	6.43
Offshore	5.40	4.35	3.93	3.61	3.64	3.96	4.08
Other Conventional	<u>12.45</u>	<u>11.19</u>	<u>10.91</u>	<u>10.06</u>	<u>8.64</u>	<u>7.51</u>	<u>7.52</u>
Subtotal Lower-48	61.87	64.92	65.75	69.61	73.26	72.91	73.90
Footnote:							
Alaska	<u>0.92</u>	<u>0.91</u>	<u>0.87</u>	<u>0.86</u>	<u>0.89</u>	<u>0.92</u>	<u>0.94</u>
Total US	62.79	65.82	66.62	70.47	74.16	73.82	74.84
II. Imports							
Net Canada	5.97	5.44	5.14	5.11	5.27	5.77	5.73
Net Mexico	-1.37	-1.69	-1.80	-1.99	-2.89	-3.74	-4.39
Net LNG	<u>0.76</u>	<u>0.40</u>	<u>0.26</u>	0.12	0.17	-0.33	-1.38
Total Net Imports	5.37	4.15	3.60	3.24	2.56	1.70	-0.04
III. Net Storage Change							
	-0.96	-0.02	1.50	-0.69	-1.47	0.46	-0.18
IV. Total Lower-48 Supply							
	66.28	69.05	70.85	72.16	74.35	75.07	73.69