Outlook for Natural Gas Demand for the Summer of 2016

Prepared by Energy Ventures Analysis, Inc.

Overview

Summer period gas demand is expected to increase approximately 4.1 BCFD, or 6.3 percent, with most of this increase occurring because of the combination of structural changes within the electric sector and increased coal-to-gas fuel switching (see Exhibit 1). Offsetting this increase in demand will be about a 50 percent decline in storage injections this year (i.e., 5.2 BCFD lower), which largely is due to storage levels at the beginning of the summer season (April 1, 2016) being at record levels.[1] The net result will be season ending storage levels (October 31, 2016) being at about 3,875 BCF, which, while below last year's season ending levels, is above season ending levels for 2014.

As noted in Exhibit 1, approximately 85 percent of the expected increase in summer demand (i.e., primary demand) will occur within the electric sector. This increase in electric sector demand is due to the combination of (1) structural changes within the electric industry that have occurred over the last several years and have caused reductions in coal-fired capacity and increases in gas-fired capacity; and (2) near record coal-to-gas fuel switching which is occurring because of the current low gas prices. Additive to this are relatively small increases in the industrial, residential and commercial sectors.

Exhibit 1. Projected Gas Demand for April Through October 2016[(1)]

	2016		2015		Change	
Sector	**BCF**	**Average BCFD**	**BCF**	**Average BCFD**	**BCF**	**Average BCFD**
Residential	1,196	5.6	1,148	5.4	48	0.2
Commercial	1,146	5.4	1,135	5.3	11	0.1
Industrial	4,237	19.8	4,181	19.5	56	0.3
Electric	6,761	31.6	6,089	28.5	672	3.1
Lease, Plant & Pipeline Fuel	1,454	6.8	1,368	6.4	86	0.4
Subtotal	**14,794**	**69.2**	**13,921**	**65.1**	**873**	**4.1**
Net Storage Injections	1,357	6.3	2,475	11.5	(1,118)	(5.2)
Source: EIA and EVA.				(1) Figures may not add due to rounding.		

[1] For purposes of this report, summer refers to the period April through October, even though technically this period includes part of the spring and fall seasons. This terminology is used in order to simplify the discussion contained in this report.

With respect to significant risk factors for this outlook, there are two noteworthy items, namely (1) the summer weather and (2) the potential for declining domestic production. Concerning the former, the NOAA forecast is for a slightly warmer than normal summer (i.e., 7.6 percent warmer than normal), which is below last year's very warm summer (i.e., 10.3 percent warmer than normal), but above the relatively normal summer in 2014 (i.e., 0.2 percent warmer than normal). The key concern is that if this summer turns out to be a hot summer then electric gas demand could be higher, while a cooler summer would lower projected electric sector demand.[2]

With respect to domestic production, production for nearly every onshore play is declining because of the 75 percent decrease in gas-directed drilling activity since peak levels in late 2014.[3] However, offshore production is expected to increase as a result of the bringing online of a series of legacy offshore projects in 2015 and 2016, which take time to ramp up to full production (i.e., 14 projects in 2015 and 10 projects in 2016). As a result, there is some uncertainty as to the net decline in domestic production this summer. This, in turn, impacts the level of storage injections during the summer, with high production levels from a lower rate of decline causing storage injections to increase and vice-a-versa.

Exhibit 2 provides a longer term overview of historical trends for summer gas demand. As illustrated, 2016 summer gas demand will exceed the record set last year, when a combination of very hot weather and record fuel switching caused summer demand to soar.

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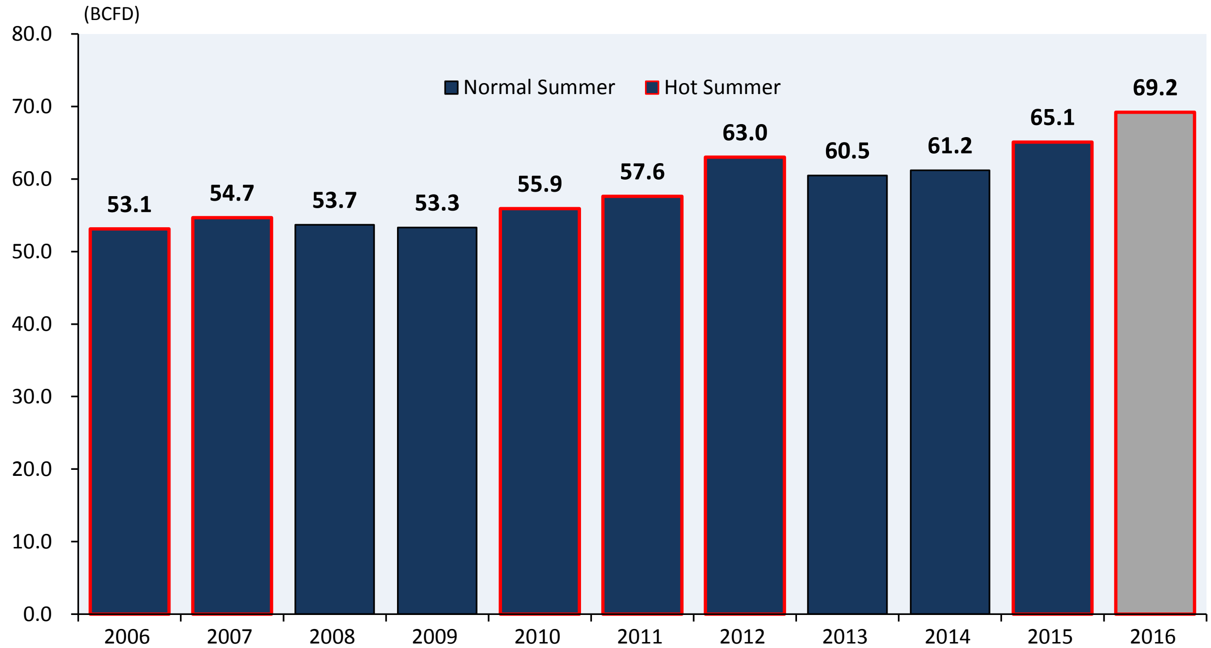
[2] Cooling degree days for periods noted are as follows: 30-yr average = 1,245; 2016 = 1,339; 2015 = 1,373; 2014 = 1,247; 2013 = 1,293; 2012 = 1,382; 2011 = 1,340; 2010 = 1,430; and 2009 = 1,174.
[3] The gas-directed rig count in early November 2014 was 356 rigs, while the current rig count is 88 rigs. In April 2015 (i.e., one year ago) the gas-directed rig count was 217.

Exhibit 2. Summer Natural Gas Demand for All Sectors



Note: 2016 natural gas demand is forecasted.
2006, 2007, 2010, 2011, 2012, 2015, and 2016 denote hot summers.

Outlook for Demand

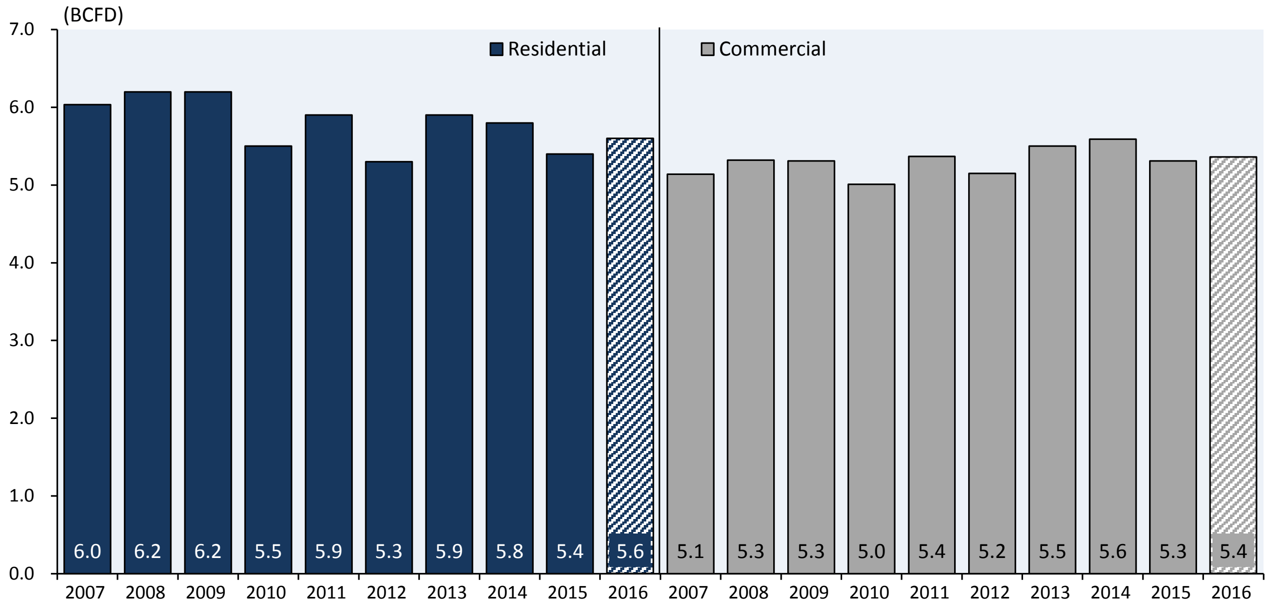
Overview

The following discussion provides an assessment of summer demand for each of the four major sectors. The impact of storage injections is addressed in a subsequent section.

Residential and Commercial

Residential and commercial sector gas demand for the forthcoming summer is, in essence, expected to be slightly higher than the prior summer's demand levels, which happen to represent a low point for the last three summers. These two winter weather-sensitive sectors usually are not affected significantly by changes in the summer weather. Finally, Exhibit 3 summarizes the longer term trends for summer gas demand within both sectors.

Exhibit 3. Summer Natural Gas Demand for the Residential and Commercial Sectors



Note: 2016 residential and commercial sector natural gas demand is forecasted.
Source: EIA and EVA

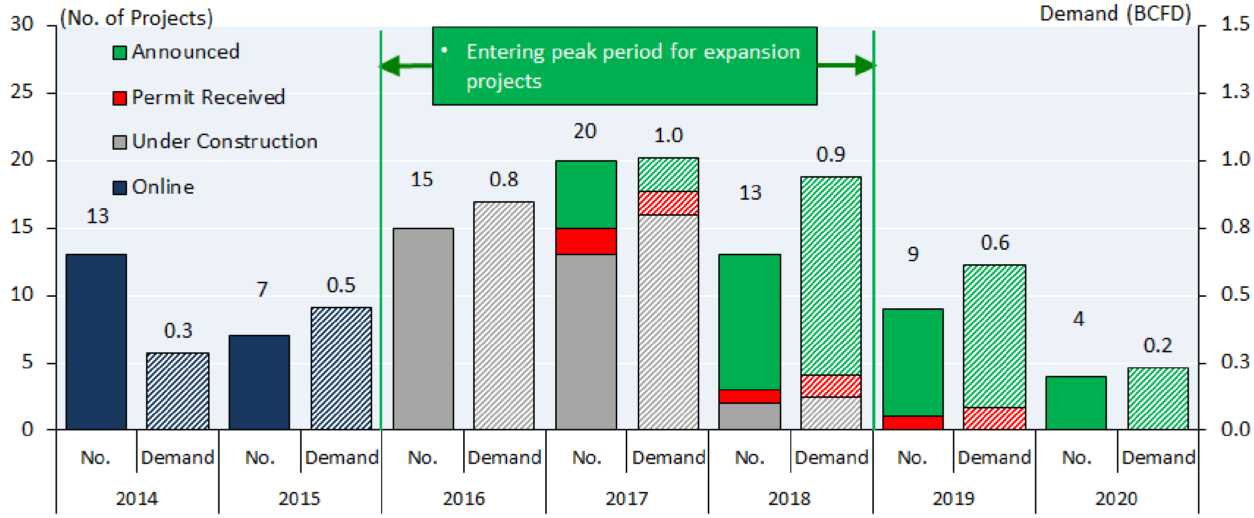
Industrial Sector

The change in industrial sector gas demand for this summer is complex, as industrial demand for existing industrial facilities is declining; however, this decline is being offset by a series of capacity expansions in a few key industries. The net result is an expected 1.3 percent, or 0.3 BCFD, increase over last summer's results.

Capacity Expansions

With respect to the series of capacity expansions occurring within the industrial sector, which are being built to take advantage of the relatively low cost gas in the U.S. The 2016 to 2018 period will mark the peak period for the annual additions of these projects. This is illustrated in Exhibit 4. 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., petrochemical and fertilizer) that either increase U.S. exports or alternatively reduce U.S. imports.

Exhibit 4. Industrial Capacity Expansion Projects[(1),(2)]



1. For period 2010-2015, 45 projects came online (1.5 BCFD)
2. For period 2016-2020, 61 projects to come online (3.6 BCFD)

While there have been some additions and deletions to the list of industrial capacity expansion projects, at present there are 106 likely capacity addition projects in the fertilizer, petrochemical, methanol, steel and paper and pulp industries. Of these 106 projects 38 came online in the 2010 to 2014 period and an additional seven came online in 2015. The remaining 61 projects are projected to come online in the 2016 to 2020 timeframe.

With respect to 2016, this year will receive the benefit of the full year impact of the seven projects that came online in 2015, plus the partial year impact of 15 additional projects scheduled to come online in 2016. The net result is that summer gas demand within the industrial sector is expected to increase approximately 0.65 BCFD, as a result of just these capacity expansion projects coming online.

Existing Facilities

While there has been modest growth in the U.S. economy (see Exhibit 5), this growth has not been even across all sectors of the economy. More specifically, for most of the last seven months there has been a decline within the manufacturing sector of the economy. This decline is occurring within every industry except automobiles and is particularly acute within the oil field services and mining sector, which is down sharply. Other factors adversely impacting the manufacturing sector are (1) the limited growth prospects for the global economy and (2) the relatively strong U.S. dollar.

Exhibit 5. U.S. Real GDP Short-Term Forecast Comparison

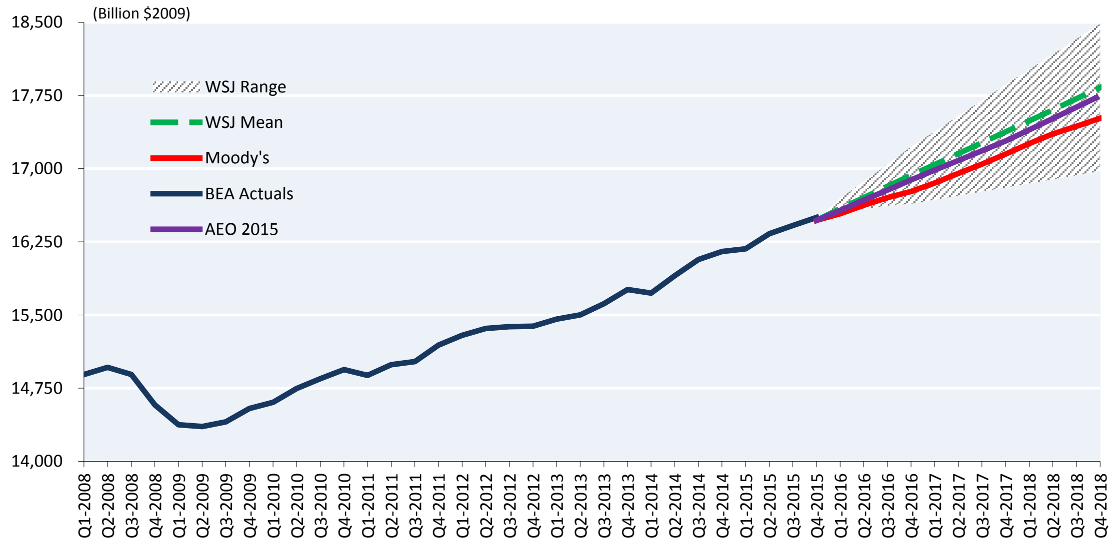
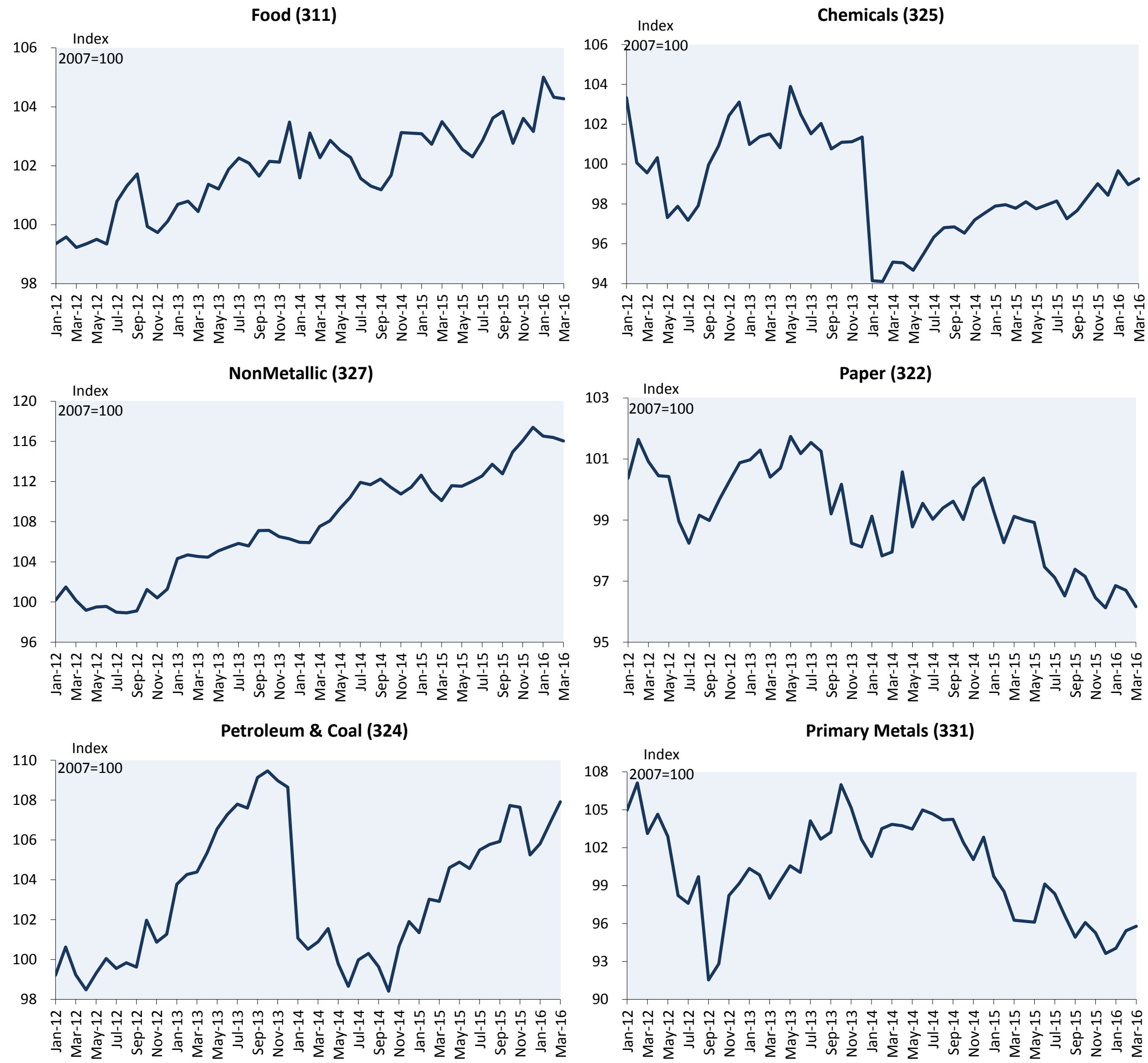


Exhibit 6 summarizes the production indices for the six major energy intensive industries. While there are month to month variations in these indices, three of the six industries, namely non-metallic, paper and primary metals, are exhibiting downward trends for their production indices. In addition, two of these energy intensive industries, namely food and chemicals, recently have had relatively flat indices. With respect to the sixth index, namely petroleum and coal, lately it has shown some signs of recovery after an earlier decline. The net result of this assessment is that gas demand for existing industrial facilities is expected to decline this summer by about 0.35 BCFD, or 1.5 percent.

Summary

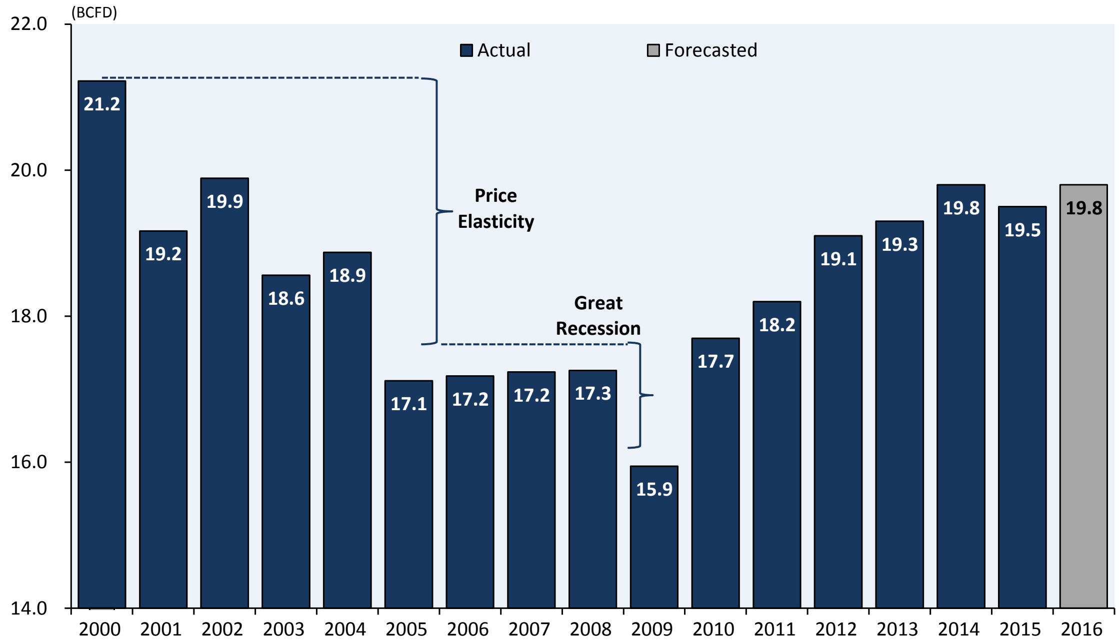
With respect to the integrated outlook for industrial sector gas demand this summer, it is expected to increase 0.3 BCFD, or 1.3 percent, over last year's level. As an added point of perspective, Exhibit 7 compares and contrasts, on an annual basis, the expected outlook for 2016 industrial sector gas 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 21:1 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.

Exhibit 6. Performance of the Six-Key Energy Intensive Industries



Source: Federal Reserve.

Exhibit 7. Summer Natural Gas Demand for the Industrial and Transportation Sectors



Source: EIA and EVA.

Starting in 2010, however, this basic downward trend for industrial sector gas demand reversed itself, as the country began to emerge from the Great Recession and the sector benefitted from the initial impact of the previously noted series of capacity additions.

Electric Sector

The primary factors driving the 11 percent, or 3.1 BCFD, increase in electric sector summer demand are (1) the structural changes that have occurred within the industry over the last several years and (2) the increase in coal-to-gas fuel switching because of the current relatively low gas prices.[4] The major uncertainty factor for this assessment is the peak summer weather (i.e., July and August), as the difference in electric sector gas burn between a mild and very hot summer can be approximately 300 BCF (i.e., equivalent to 1.4 BCFD) over the summer period.

Exhibit 8 summarizes summer gas demand for the electric sector over the last 10 years and highlights both the impact of very warm summer weather and coal-to-gas fuel switching.

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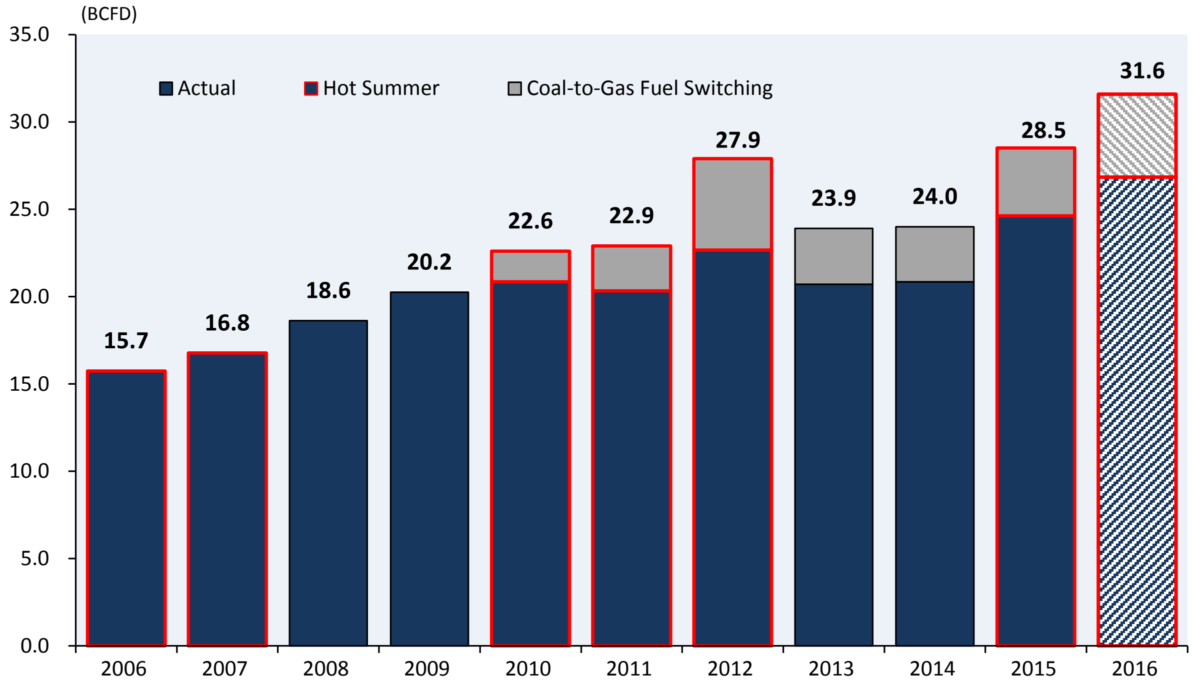
[4] Another factor that has, in the past, influenced summer electric sector gas burn has been changes in hydroelectric generation for California and the Northwest, as gas-fired generation is the primary alternative to hydroelectric generation. While the influence of this factor has been significant over the last couple of years, because of the drought conditions in California, that will not be the case for 2016.

Exhibit 8. Summer Natural Gas Demand for the Electric Sector



Note: 2006, 2007, 2010-2012, and 2015-2016 denote hot summers.
Demand and coal-to-gas fuel switching for 2016 is forecasted.

Structural Changes

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 9 provides specifics for this phenomenon over the last five years. As illustrated, on a net basis, coal-fired capacity has declined about 38.2 GW over the last five years, while combined cycle (CCGT) gas-fired capacity has increased about 27.3 GW, with most of this transition occurring within the last two years. Going forward it is anticipated this trend will accelerate, as during 2016 and 2017 another 19.2 GW of coal-fired capacity is expected to retire, while new build CCGT units will total about 19.4 GW.

For summer gas demand the net effect of this structural change within the electric industry is an estimated increase in electric sector gas consumption of approximately 2.2 BCFD (i.e., about 70 percent of the overall increase in electric sector gas consumption).

Exhibit 9. New U.S. Generation Capacity

(MW)	2011	2012	2013	2014	2015	Projected 2016	Projected 2017
Coal-Fired	**2,665**	**3,760**	**1,507**	**580**	**-**	**-**	**-**
Solar	**534**	**1,702**	**2,959**	**1,724**	**2,231**	**3,851**	**2,629**
Wind(1)	**6,800**	**12,885**	**1,032**	**2,028**	**7,099**	**3,898**	**6,052**
Gas Combined Cycle	7,259	6,713	3,511	6,383	3,384	7,145	12,289
Gas Peaking	1,752	2,334	3,332	250	1,212	2,175	1,716
Total Gas-Fired	9,011	9,047	6,842	6,633	4,596	9,320	14,005
Grand Total	**19,010**	**27,394**	**12,340**	**10,965**	**13,926**	**17,069**	**22,685**
Retirements (Coal)	3,280	10,891	6,951	5,568	20,049	12,565	6,657
Retirements (Nuclear)(2)	-	-	2,716	563	-	-	1,496

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

(2) EVA assumes that the James A Fitspatrick and R E Ginna nuclear plants will shut down in 2017.

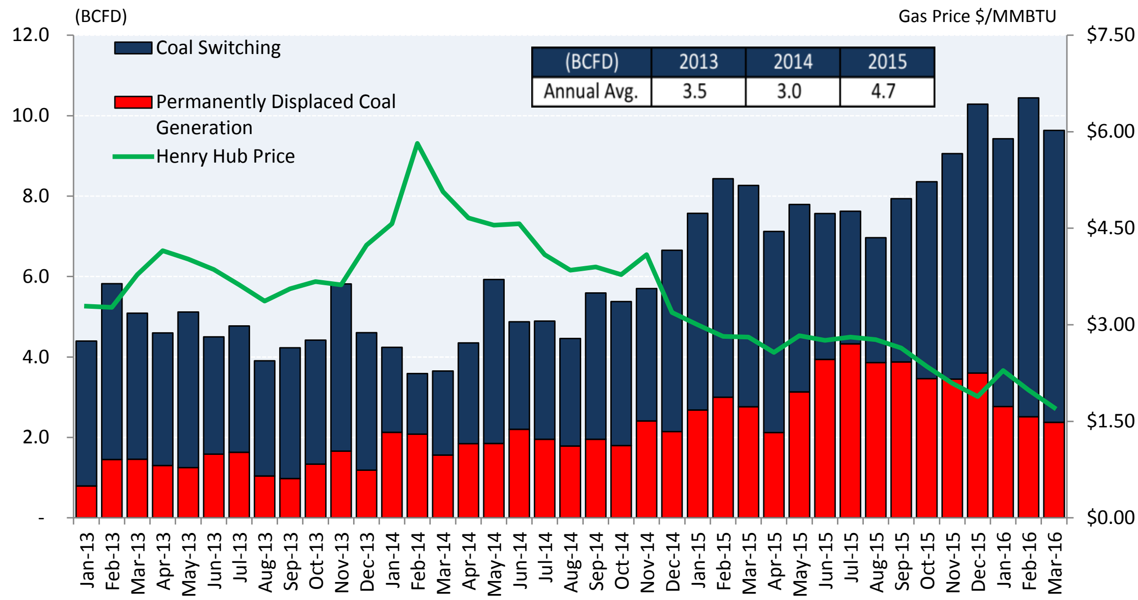
Fuel Switching

Coal-to-gas fuel switching during this summer is estimated to be about 0.9 BCFD greater than last summer's fuel switching. This is occurring because of the anticipated lower gas prices this summer versus the last summer (i.e., $2.29 versus $2.68 per MMBTU). As a point of perspective, fuel switching for this summer is expected to be only second to the levels attained in 2012, when fuel switching capacity was much higher (i.e., about 10 percent less).

Exhibit 10 provides a summary of monthly fuel switching over approximately the last three years in billion cubic feet per day (BCFD) of natural gas demand. Highlighted in Exhibit 10, by the red portions of the bars, is the amount of prior fuel switching that has been converted to permanent gas-fired generation because of the retirement of coal-fired units. The blue bars indicate the amount of fuel switching that still remains and is a function of the relative regional prices of coal and gas-fired generation.[5]

[5] These generation data convert to the following natural gas outcomes, all in BCFD: 2012 permanently displaced (PD) 0.8, coal switching (CS) 5.3, total 6.1; 2013 PD 1.3, CS 3.5 total 4.8; 2014 PD 2.0, CS 3.0, total 4.9; 2015 PD 3.4, CS 4.7, total 8.1.

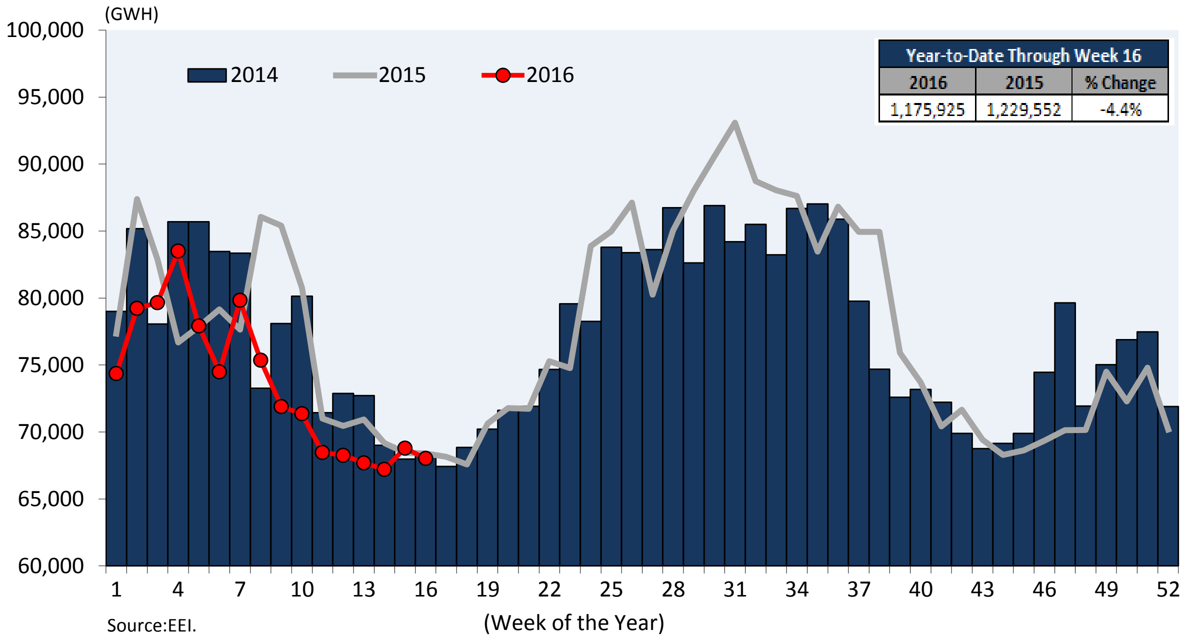
Exhibit 10. Coal-to-Gas Fuel Switching



Electric Sales

Among the other factors that historically have influenced electric 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 electric sector gas demand, because gas-fired generation tends to be at the margin in most regions. Exhibit 11 summarizes the year-to-date growth in electricity sales. As illustrated, on a year-to-date basis electricity sales figures for 2016 are below those for 2015. This year-to-date comparison primarily is due to the warm winter this year. For the summer it is anticipated that electricity sales will be flat to slightly below last year's results. The net result is that changes in electricity sales this summer are expected to have a rather limited impact on electric sector gas demand.

Exhibit 11. Total Weekly Electric Output (48-States)

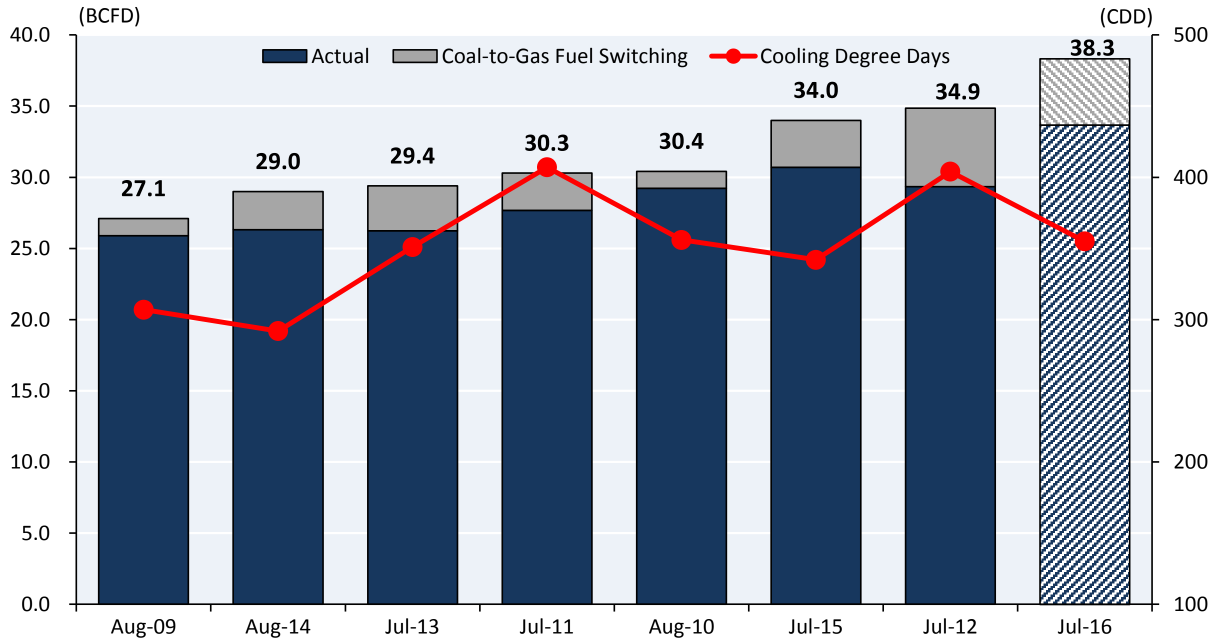


Summer Weather

With respect to the influence of summer weather, Exhibit 12 compares and contrasts peak month electric sector gas demand for each of the last seven years with the outlook for the peak month in 2016. Also, included in this graphic is the CDD for each month. The data in this exhibit presents the lowest to highest peak demand levels for the selected years. While there is not a perfect correlation between peak electric gas consumption levels and CDD,[6] the general trend is readily apparent. With July 2016 it is impacted by structural changes within the industry, as well as warm summer weather.

[6] In addition to differences in the warmth of the summer weather, gas-fired generation in a specific month can be affected by a number of factors (e.g., unplanned outages of nuclear and coal units, availability of renewable capacity, etc.).

Exhibit 12. Comparison of Summer Peak Period Natural Gas Demand for the Electric Sector and Cooling Degree Days



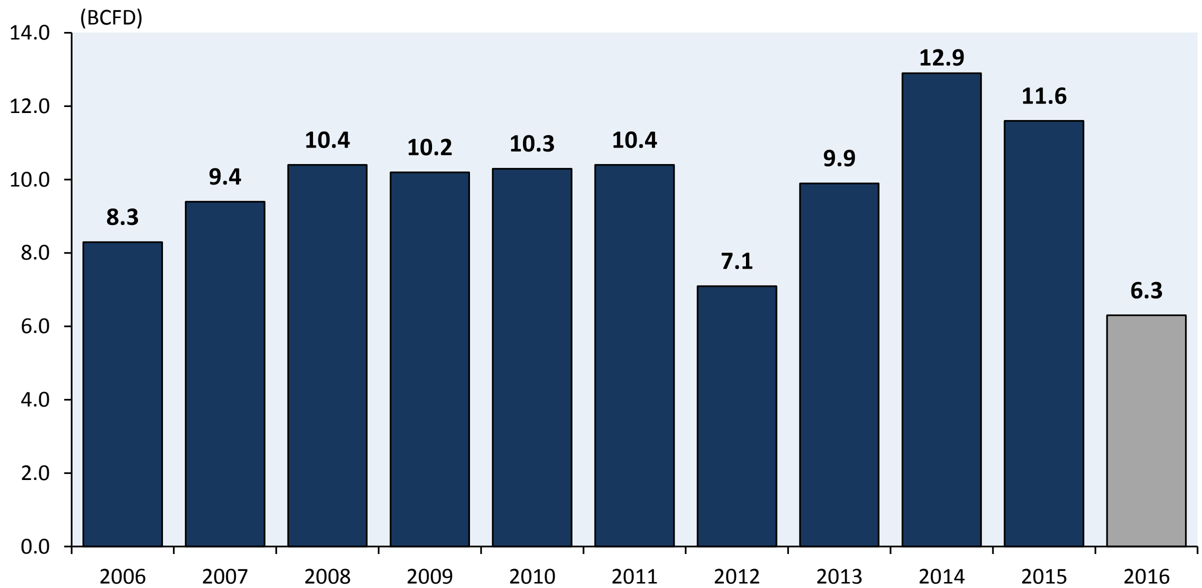
Note: 2016 demand, fuel switching, and cooling degree days for are forecasted.
Source: EIA and NOAA.

Storage Injections

Probably the most difficult element to project in this assessment of 2016 summer gas demand is the final component of the demand picture, namely 2016 storage injections. The current outlook for storage injections for this summer is that they will be relatively low, primarily because storage levels at the end of the winter season (March 31, 2016) were at record levels. As a result, injections do not need to be high in order to have adequate storage levels at the beginning of the next winter. The primary factor in ensuring the storage injections are at relatively low levels is increased levels of coal-to-gas fuel switching, and fuel switching in 2016 is expected to be the second highest level ever recorded.

Exhibit 13 compares and contrast storage injections for this summer with those over the last 10 years. As illustrated, storage injections, while below the last two years, are likely to be on a par with injections for 2012, when storage levels at end of the winter season also were at record levels. The net results that season ending storage levels for 2016 (October 31, 2016) are expected to be about 3,875 BCF, which is below 2015 levels but above 2014 levels.

Exhibit 13. U.S. Storage Injections



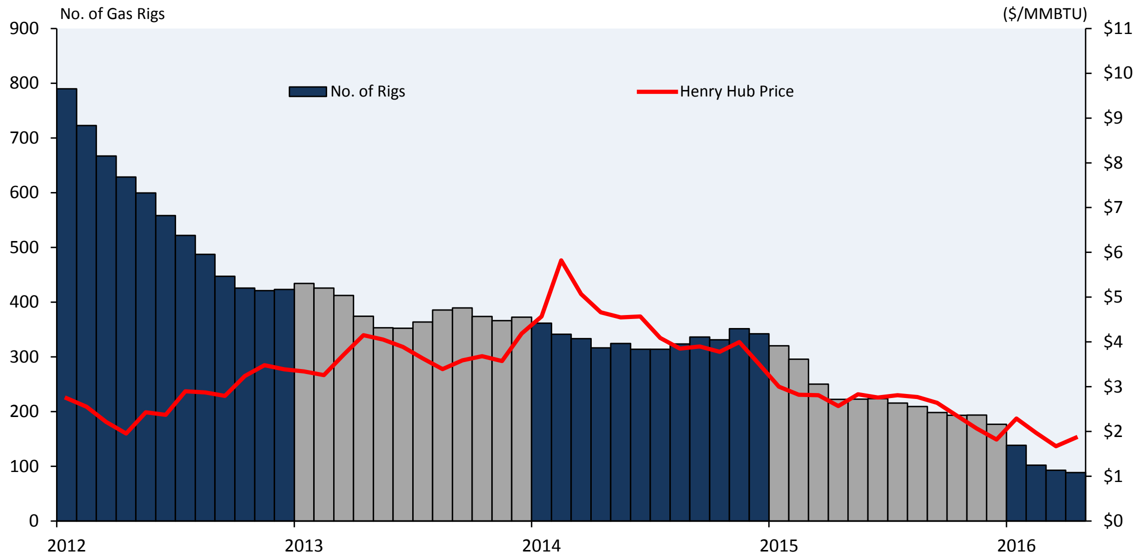
Note: 2016 is estimated.
Source: EIA.

There are two factors that could alter this assessment – potentially significantly – namely the summer weather and the current decline in onshore production – both of which are discussed below. Additionally, a brief review of the impact of the timely, but primarily regionally-significant closure of the Aliso Canyon storage facility in Southern California is provided.

- **Summer Weather:** While the summer weather is projected to be about 7.6 percent warmer than normal, the summers of 2011, 2012 and 2015 were greater than 10 percent warmer than normal. If the latter where to occur in 2016, then electric sector burn could be 150 to 200 BCF higher, with storage levels being lower. There likely is not a perfect correlation between these two elements, as fuel switching during later part of summer likely would decline. Nevertheless, the net result likely would be lower storage levels at the end of the summer season. Conversely, if this summer's weather turns out to be relatively mild, like the summers of 2008 and 2009, storage levels would be higher.

- **Domestic Production:** At present nearly every onshore gas play is declining, because of the overall decline in drilling activity (i.e., see Exhibit 14, which summarizes the 75 percent decline in the gas-directed rig count). Offsetting this decline in onshore production is the anticipated increase in offshore production, as a result of the ramping up of production for a series of legacy offshore projects (i.e., 14 projects in 2015 and 10 projects in 2016).

Exhibit 14. Rig Count for Gas Wells



Note: Blue bars represent the number of gas rigs on even years while gray bars represent odd years.
Source: NGW.

If the overall decline in domestic production is less than anticipated, then season ending storage levels could be higher. However, if the opposite occurs, they could be lower.

Lastly, Exhibit 15 compares and contrasts season ending storage levels for the last several years with that expected for October 31, 2016.

Exhibit 15. Comparison of Storage Capacity and Season-Ending (November 1) Storage Levels

	Actual									Est.
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Total Working Gas Capacity - Start of Injection Season[1]	3,593	3,665	3,754	3,925	4,049	4,103	4,265	4,333	4,336	4,343
Annual Capacity Additions	72	89	171	124	54	162	68	3	7	-
Total Working Gas Capacity - End of Injection Season	3,665	3,754	3,925	4,049	4,103	4,265	4,333	4,336	4,343	4,343
Storage Level at Start of Winter	3,567	3,399	3,810	3,847	3,804	3,929	3,817	3,587	3,953	3,875
Percent of Capacity	97%	91%	97%	95%	93%	93%	88%	83%	91%	89%

1. Effective maximum usable working capacity.

- **<u>Aliso Canyon</u>:** In October 2015, a leak was discovered at an injection well within Southern California Gas Company's (SoCal) largest storage field and would become the largest singular methane leak in U.S. history. As a result, the 86.2 Bcf of working-gas storage capacity[7] at Aliso Canyon is non-operational and

[7] Aliso Canyon's 86.2 Bcf is the largest storage facility in California, with 22.9% of the state's capacity and 63.7% of Southern California's 135.3 Bcf of capacity. However, it represents only 1.9% of total lower-48 capacity.

unavailable to the Southern California natural gas markets until further notice. This presents an operational challenge for the region's gas markets as the removal of Aliso Canyon impacts the ability for the Southern California gas market to absorb daily imbalances. However, the region's wide array of gas infrastructure, including 1.82 BCFD of working storage withdrawal capacity at SoCal's three remaining storage fields[8] and over 4 BCFD of regional import capacity with large interstate pipelines[9] present powerful tools to manage SoCal's average and peak summer demand of 2.5 and 3.6 BCFD, respectively. The ultimate impact of this event will be greatly determined by the summer weather Southern California receives.

Exports

While technically part of the supply components for natural gas, exports of natural gas does represent another draw on domestic production. As a result, recent events concerning the 2016 exports are reviewed briefly in the following material.

LNG Exports

In late February the first export of L-48 LNG occurred from Train 1 of Cheniere's Sabine Pass liquefaction facilities. This shipment is part of eight commissioning cargoes (i.e., about 32 BCF) for Train 1, with the first seven cargoes already having occurred.[10] These initial exports represent spot cargoes into a very competitive global market. Contracted cargoes using Sabine Pass tolling contract approach are scheduled to begin in November, which is when Sabine Pass' contract with Shell/BG begins. While these initial shipments likely will result in only 0.5 BCFD of LNG exports for the summer of 2016, by year-end 2018 L-48 LNG exports are projected to reach about 3.8 BCFD, as eight additional trains from various projects are projected to come online.

Exports To Mexico

Exports to Mexico have been increasing steadily over the last five years and are expected to also increase in 2016. With respect specifically to the summer of 2016, exports to Mexico are projected to increase approximately 0.95 BCFD.

The primary factor behind this steady increase in exports to Mexico is the building of new pipeline capacity on both sides of the border and, in particular, on the Mexican side of the border, which historically has been the limiting factor for exports to Mexico.

[8] Honor Rancho and Playa del Ray in Los Angeles County and La Goleta in Santa Barbara County.
[9] Pipelines include El Paso Natural Gas, Transwestern, Kern River Gas Transmission, Mojave Pipeline and Southern Trails Pipeline
[10] The first seven cargoes were sent to various destinations, including Brazil (twice), Argentina, Portugal, India and Dubai.

Addendum I of this report provides a detailed assessment of these pipeline projects and the longer term expectations for exports to Mexico.

Ethane

While technically not part of the natural gas supply and demand, ethane is a key component of raw gas volumes at the wellhead. Recently, the U.S. initiated its first exports of ethane, which represents a significant milestone in that the U.S. currently has significant excess supplies of ethane, as a result of the surge in unconventional drilling for the shale plays.

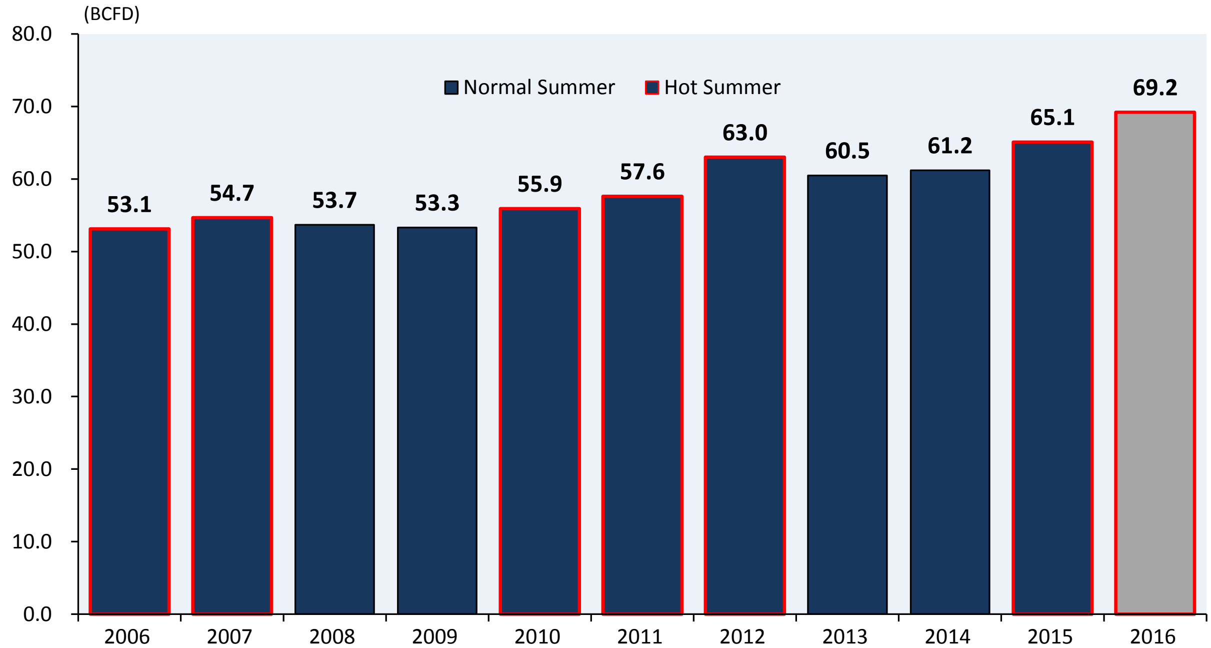
More specifically, on March 9th the first U.S. shipment of ethane left the Marcus Hook terminal near Philadelphia. This ethane shipment, which is part of a 15-year contract between Range Resources and Ineos went to the Ineos petrochemical in Rafnes, Norway. The ethane was delivered to Sunoco's Marcus Hook terminal via the recently completed Mariner East 1 pipeline, which originates near Pittsburgh. An expansion of this pipeline, namely the Marine East 2 pipeline, is under construction. Finally, a second ethane export terminal at Morgan's Point, Texas is scheduled to be completed by Enterprise Product Partners in the 3Q 2016.

Conclusions

As illustrated in Exhibit 16 summer gas demand this year should be approximately 4.1 BCFD, or 6.3 percent, greater than demand last summer. Furthermore, gas demand this summer will set a new record, as it will exceed the prior records set in 2012 and 2015. Approximately 85 percent of projected increase in summer demand (i.e., primary demand) will occur within the electric sector, as a result of both (1) recent structural changes within the industry and (2) increased levels of fuel switching.

Offsetting this increase in demand will be about a 50 percent decline in storage injections this year. However, since storage levels at the start of the summer season (April 1, 2016) were at record levels, season ending (October 31, 2016) storage levels should be adequate to meet storage withdrawal requirements this winter.

Exhibit 16. Summer Natural Gas Demand for All Sectors



Note: 2016 natural gas demand is forecasted.
2006, 2007, 2010, 2011, 2012, 2015, and 2016 denote hot summers.

ADDENDUM I:

OUTLOOK FOR U.S. NATURAL GAS EXPORTS TO MEXICO

Overview for U.S. Gas Exports to Mexico

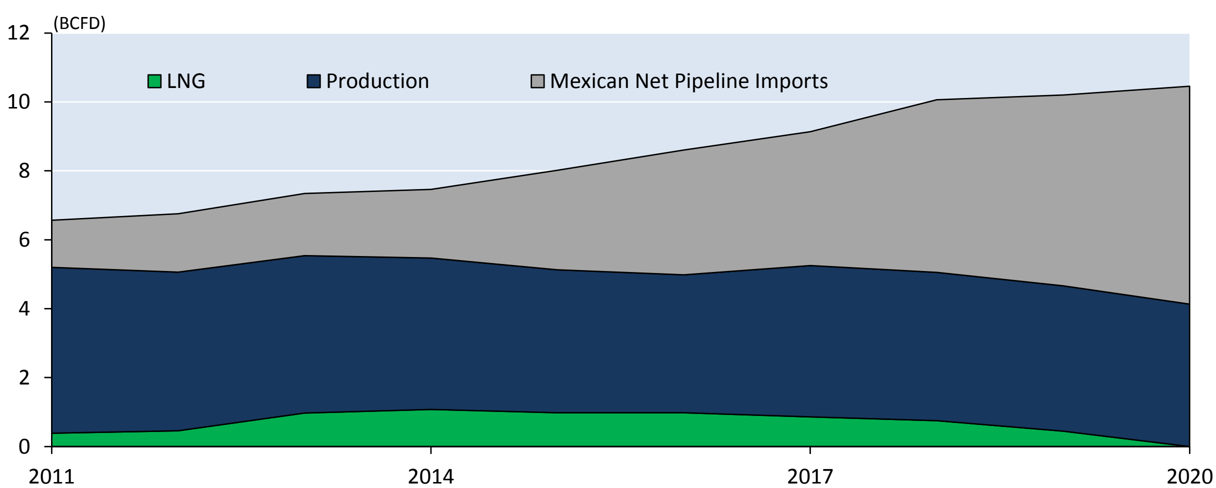
Overview

Cheap U.S. natural gas is driving a natural gas renaissance in Mexico. Mexican regulators have made significant strides to continue to grow the import capacity of natural gas to Mexico to allow both its power sector and its industrial sector to enjoy the benefits of cheap U.S. natural gas. It is forecasted as illustrated in **Exhibit Add I-1**, that the Mexican pipeline imports from the U.S. will double between 2015 and 2020.

Two key drivers behind this renaissance have been (1) the U.S. shale gas revolution and the resulting low natural gas prices, and (2) the 2013 Mexican Energy Reform which opened up investment opportunities for private companies. Private companies will continue to push Mexico away from fuel-oil in power generation, which has been Mexico's leading fuel source, and towards cheaper and greener natural gas.

This has led to the development of a series of pipeline projects both within Mexico, and on the U.S. side. There are currently 13 pipeline projects being developed to supply U.S. natural gas to Mexico and another 15 pipeline projects being developed in Mexico to more efficiently transport this natural gas. There is about 5 BCFD of direct export capacity currently being developed and scheduled to be operational before 2018. By 2019 Mexico will have the capacity to import 9 BCFD. EVA expects that this high level of investment and continued expansion will double exports by 2020, up from 3 BCFD to 6 BCFD

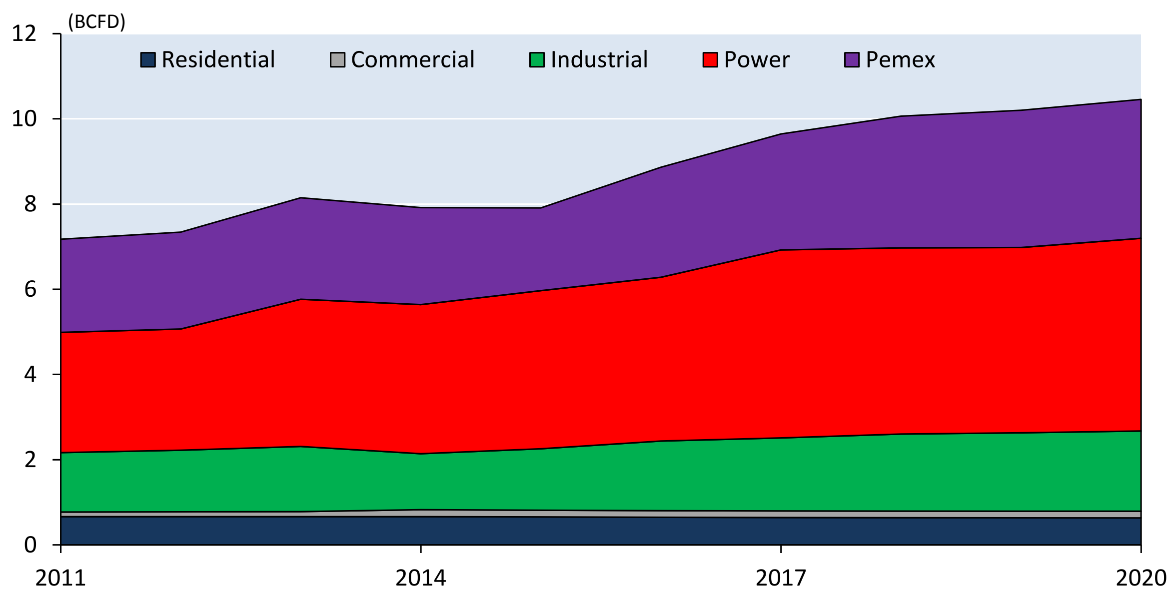
Exhibit Add I-1.   Mexico Natural Gas Supply



Mexico’s Growing Gas Demand

Mexico's need for imported energy has never been greater. As can be observed in **Exhibit Add 1-2,** the major source of new natural gas demand will come from the power sector. The Mexican power sector's natural gas demand is projected to grow by 0.8 BCFD between 2015 and 2020, a third of the projected demand growth in Mexico during that time. CFE, the governmental electricity commission, is the major producer of electricity, as well as transporter and retailer in Mexico. Historically, the CFE has used fuel oil as a feedstock for power generation. However, in recent years the CFE has started a diversification program and will switch its fleet to natural gas in the coming years. An increased private participation in the power sector also has led to an increase in natural gas powered combined-cycle turbines and a move away from fuel oil.

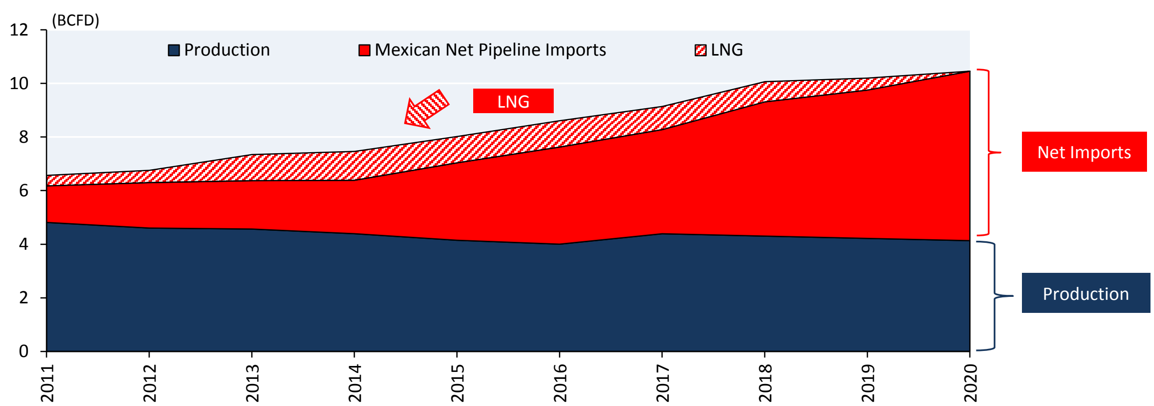
Exhibit Add I-2. Mexico Natural Gas Demand



Mexican electricity prices already have seen a decrease in recent years as a result of the switch from fuel oil to natural gas and the increasing imports of cheap U.S. natural gas, as can be observed in **Exhibit Add I-3.** Prices may not track this trend in the future as the Mexican government may end its generous electricity rate subsidies. However, it is likely that power prices will continue to drop as more U.S. natural gas becomes available, more generators enter the market, and more generators switch to gas.

Another major reason for Mexico's increased natural gas imports is the on-going manufacturing boom in Mexico. The industrial sector represents ~20% (0.45 BCFD) of the expected growth in Mexico's natural gas demand 2015-2020. The Dollar-Peso exchange rates have meant that producing goods in Mexico is very attractive, and more and more companies are choosing to locate their factories south of the U.S. Mexico border. The center of this growth is located in the north central part of Mexico, in an area called the Bajío, which has become the country's industrial heartland. A significant amount of the existing and proposed pipelines now lead to this area, which incorporates the states of Guanajuato, Querétaro, Aguascalientes and Jalisco. As a result the manufacturing sectors, as well as the steel and chemical sectors, are demanding more and more natural gas.

Exhibit Add I-3. Mexico Natural Gas Supply



Source: BP Statistical Review, SENER, EVA.

Another large source of natural gas demand comes from Mexico's continued reliance on natural gas as a feedstock for Enhanced Oil Recovery (EOR). As several large scale projects come online in the coming years, Mexico's use of natural gas as a feedstock for EOR will continue to increase, before plateauing around 2020. In the coming five years Mexico likely will increase natural gas demand for EOR by 1.3 BCFD, which is a majority of the increase during that time.

Mexico’s Stagnant Domestic Production

Mexican gas production has been decreasing slightly since 2012 but is for the most part stagnant. PEMEX has invested in natural gas production in recent years, and these investments, as well as a growing share of gas in the oil stream, have offset the natural decline and also somewhat increased production. However the current and future production levels are nowhere near sufficient to keep up with the growing demand.

PEMEX has neglected to invest in natural gas production for years. This primarily is due to poor management and political influence which geared much of the CAPEX budget towards EOR, which is a low risk high short-term reward investment. This affected natural gas not only because it limited the investments in production, but also because the natural gas was and is used heavily in EOR. At the current market price, influenced by

U.S. imports, it is likely that much of the natural gas reserves in Mexico will be left in the ground for years or even decades.

Mexico has 17 TCF of proven natural gas reserves, and could in the future produce heavily from both conventional and unconventional sources. The southern Texas shale basins extend far into the northern border areas of Mexico. The Mexican Burgos region alone contains 393 TCF of technically recoverable gas. Here, the keyword is ‘technically recoverable’, because at the current level of insecurity in the area, with the current natural gas prices and with lack of access to large volumes of water, there are very few companies that would be willing to invest. It also would take time to build up a large enough supporting take-away infrastructure to transport a sufficient amount of water to this arid desert region.

Mexican LNG imports are forecasted to stop by 2020. Previously, LNG imports were seen as the new source of natural gas for Mexico for the same reason the U.S. was investing in LNG import terminals just five years ago. However, the shale gas revolution changed that and LNG imports can no longer compete economically with pipeline imports. Mexican LNG imports surged in 2013 due to pipeline constraints. Mexico currently has two operational LNG import terminals, Altamira and Manzanillo. The 2014 utilization rate for these terminals was 40%,. This is expected to be reduced drastically in 2015 and beyond. Mexico also has a third LNG import terminal, Energia Costa Azul, that has been considered as an export terminal. This facility is currently not receiving gas.

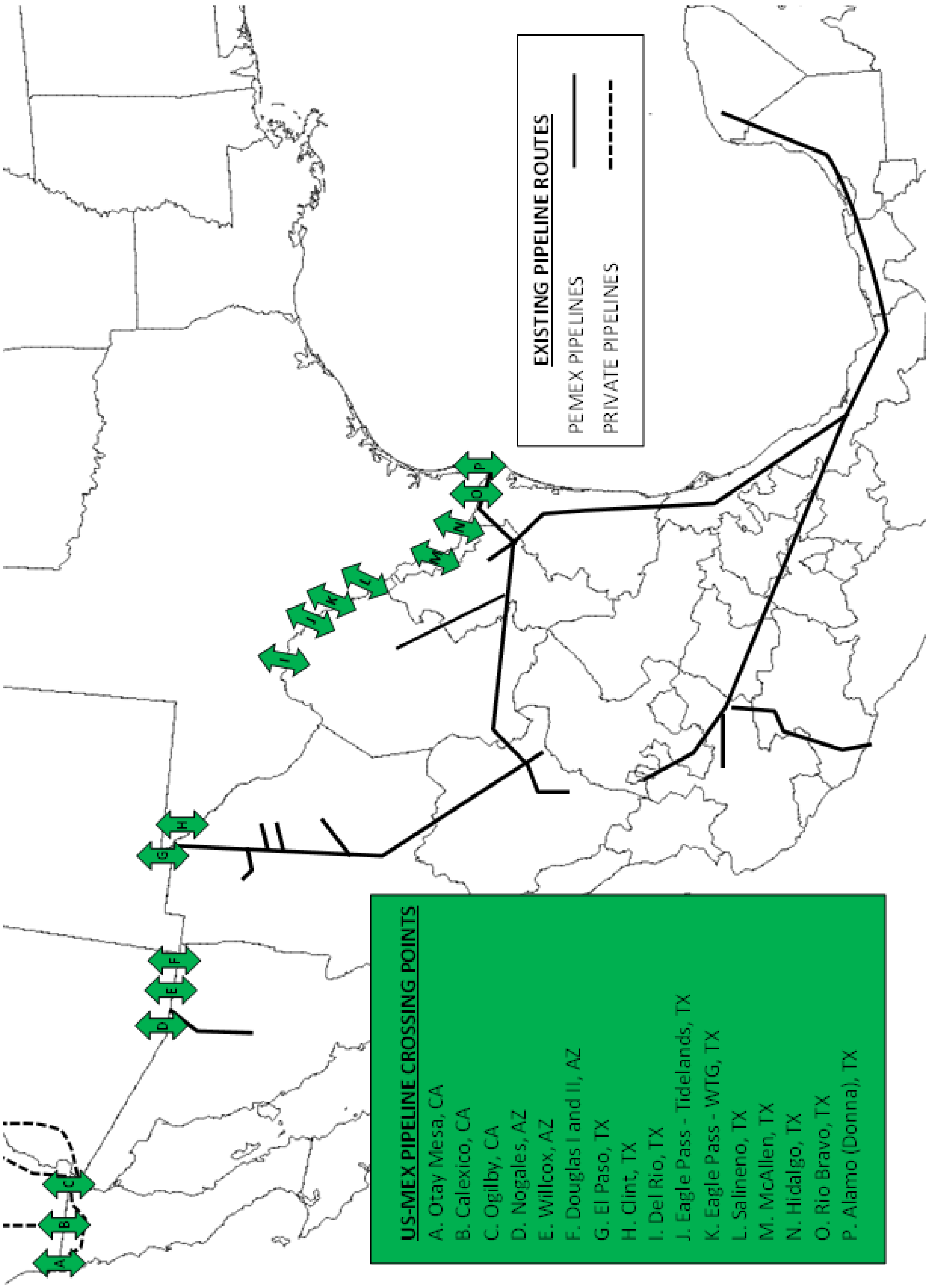
In order to fuel the growing exports a significant amount of natural gas pipeline capacity has been built and will be built in the coming years. Interest from both sides of the border has been strong, as indicated by the large investments by companies, such as Kinder Morgan, Oneok, Energy Transfer Partners, etc. Key to allowing these companies to invest though has been the reform which allows private sector participation in the natural gas. This solves a key concern for the Mexican government, namely funding. At least $10 B currently is being invested in the expansion of the pipeline system.[11]

The most notable change in infrastructure in recent years occurred in December of 2014 with the opening of the NET Midstream's Net Mexico pipeline. This pipeline, which has a capacity of 2.1 BCFD, has been ramping up its capacity factor from a first full month in January 2015, when it ran at 24% capacity factor, to October 2015, when it ran at a 48% capacity factor.

As can be observed from **Exhibit Add I-4** below, most of the U.S. sourced gas will come from Texas, and specifically the Eagle Ford and Permian basins in South and West Texas.

[11] Based on available data. The estimated cost for all current pipelines could be twice that cost.

Exhibit Add I-4. Existing Major Mexican Pipeline Infrastructure



Texas Crossing

There are currently 12 projects being developed to transport gas from the U.S. directly to a destination in Mexico or to a border crossing. The most significant additions to the export capacity of the U.S. will happen around the Clint crossing, south east of El Paso and Ciudad Juarez, where the Samalayuca pipeline is being expanded. The Clint crossing used to be the single largest border crossing in terms of volume until it was overtaken by Kinder Morgan's Texas Pipeline in Roma, TX and most recently by NET Midstream's NET Mexico pipeline in Rio Grande. The total supporting pipelines and additions to the Samalayuca pipeline on the U.S. side of the border have a capacity to transport 4 BCFD.

Exhibit Add I-5. Planned U.S.-Mexican Pipeline Infrastructure

Component	From	To	Capacity (BCFD)	Distance (Miles)	Online	Contractor
Roadrunner Gas Transmission (Phase I)	Coyanosa, TX	San Elizario, TX	0.17	200	Mar-16	Oneok/Fermaca
Waha-San Elizario	Waha, TX	Chihuahua, MX	1.14	200	Jan-17	ETP/Carso/Mastec
San Elizario Crossing	Waha Hub, TX	San Elizario, TX	1.10	195	Jan-17	Energy Transfer
Roadrunner Gas Transmission (Phase II)	Coyanosa, TX	San Elizario, TX	0.40		Mar-17	Oneok/Fermaca
Waha-Presidio	Waha, TX	Ojinaga-El Encino, MX	1.35		Mar-17	Carso/Energy Transfer/MasTec
Trans-Peco Pipeline	Stockton, TX	Presidio, TX	1.40		Mar-17	Energy Transfer
San Isidro - Samalayuca	Permian Basin, TX	Norte III Plant, MX	0.15		Jul-17	Abengoa
Nueva Era Pipeline	Webb Co., TX	Escobedo, MX	1.12	200	Jul-17	Howard Midstream/Grupo Clisa
Samalayuca Sasabe	Waha, TX	Chihuahua&Sonora, MX	0.55	400	Nov-17	CFE
Nueces – Brownsville Gas Pipeline	Nueces, TX	Brownsville, TX	2.60	155	Jun-18	Transcanada
Roadrunner Gas Transmission (Phase III)	Coyanosa, TX	San Elizario, TX	0.07		Jan-19	Oneok/Fermaca
Texas Pipeline Expansion	Starr County, TX	Monterrey, MX	0.28		TBD	Kinder Morgan
Guayamas-El Oro Section- Phase II	Guayamas, TX	El Oro, Sinaloa, MX	0.51	200	Sep-16	Sempra Energy

Domestic Mexican Pipelines

On the eastern side of Mexico closer to the Gulf of Mexico, Mexico is working on increasing the compression of the Los Ramones Pipeline, which extends from the Agua Dulce gas hub in South Texas to Guanajuato, Mexico. As noted in **Exhibit Add 1-6**, this system will consist of several sections that will be completed between 2014 and 2019. This system, which will extend approximately 825 miles when the U.S. segment to the Agua Dulce hub is included, is being built by a subsidiary of Pemex (i.e., NET Mexico Pipeline) and will have a capacity of 2.1 BCFD. It is a high pressure system (i.e., a MAOP of 1,480 psi) and cost about $2.8 billion, including the U.S. segment. The pipeline's capacity is contracted fully to Pemex.

Exhibit Add I-6. Planned Mexican Pipeline Infrastructure

Component	From	To	Capacity (BCFD)	Distance (Miles)	Online	Contractor
Ramal Tula	El Pedregal	Tula, Hidalgo	0.49		Aug-15	ATCO
Los Ramones	Nuevo Leon	Villa Hildalgo, San Luis Potosi	1.43	280	Dec-15	PEMEX/Sempra International
Los Ramones	Villa Hildalgo, San Luis Potosi	Apaseo Del Alto, San Luis Potosi	1.42	180	Jun-16	PEMEX/Sempra International
Northwest/ TransCanada	El Encino	Topolobampo	0.67	329	Jul-16	TransCanada
Mazaltan Pipeline	El Oro	Mazaltan	0.20	257	Oct-16	TransCanada
Jáltipan - Salina Cruz	Jáltipan	Salina Cruz		153	Jan-17	
El Encino - La Laguna	El Encino, Chihuahua	La Laguna, Durango	1.60		Mar-17	Fermaca
Ojinaga-El Encino Pipeline	Ojinaga	Chihuahua	1.40		Jun-17	Sempra
Tuxpan Tula	Veracruz	Hidalgo, Puebla	0.89	155	Oct-17	Transcanada
Mier-Monterrey	Pesquería, Nuevo León	Escobedo, Nuevo León	1.34		Oct-17	Kinder Morgan
La Laguna – Aguascalientes	Durango	Aguascalientes	1.15	373	Dec-17	CFE
Villa de Reyes-Aguascalientes-Guadalajara	Villa de Reyes	Guadalajara	1.00	221	Dec-17	
Tula-Villa de Reyes	Villa de Reyes	Tula	0.55	183	Dec-17	
Salina Cruz - Tapachula	Salina Cruz	Tapachula		273	Jan-18	
Guayamas-El Oro Section- Phase II	Guayama: Guayamas	Acapulco	0.51	200	Sep-16	Sempra Energy
Sur de Texas-Tuxpan	Brownsville	Tuxpan, Veracruz	2.60	497	Jun-18	Transcanada
Los Ramones		Cempoala		531	Jan-19	PEMEX/Sempra International

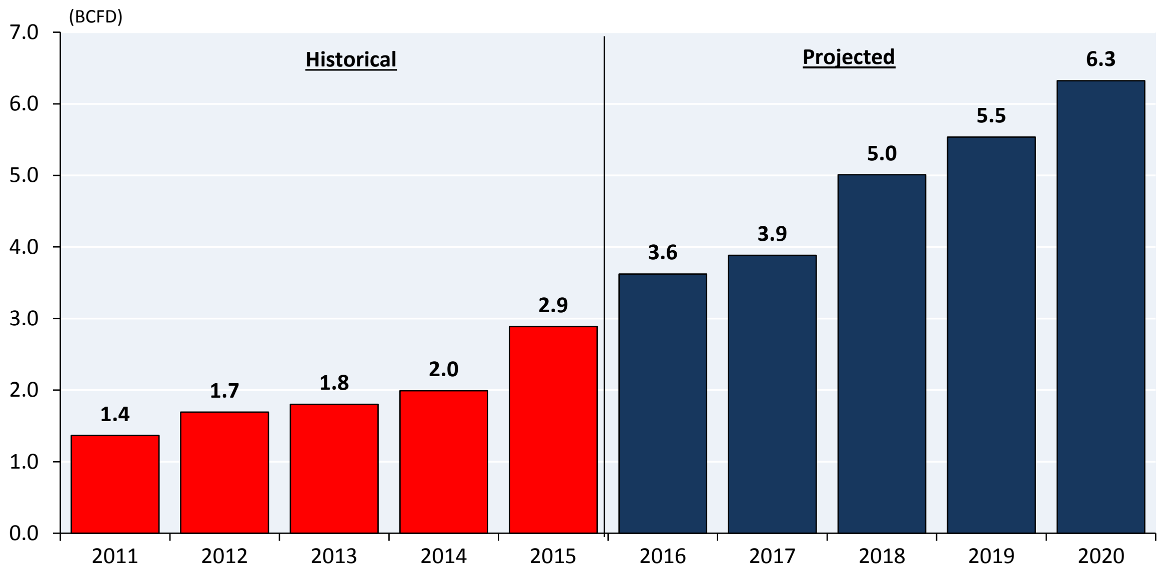
Exports To Mexico Likely Will Reach 6 BCFD By 2020

Over the six year period of 2005 to 2010, net exports to Mexico were between 0.8 and 0.9 BCFD. However, starting in 2011 there was a sharp break from this historical trend, as net exports increased approximately 0.6 BCFD, or 64 percent, and then increased another 0.3 BCFD, or 24 percent, in 2012. As previously noted, this increase was due to a combination of growing Mexican gas demand and flat production along with the surge in relatively low cost Permian and Eagle Ford shale gas production.

Going forward this new growth trend is expected to continue, as a result of the significant expansion in the Mexican pipeline system. As illustrated in **Exhibit Add I-7**, net exports to Mexico are expected to increase approximately 0.7 BCFD and 0.3 BCFD in 2016 and 2017, respectively, and then continue to increase for the remainder of the decade at about 0.45 BCFD per annum, as the new pipeline infrastructure comes online. This will result in net exports to Mexico reaching about 6.3 BCFD in 2020, which represents a 4.9 BCFD increase from 2011 levels.

Beyond 2020 further increases in exports to Mexico are likely as plans for additional pipeline expansions will provide for an additional six BCFD of new infrastructure which provides adequate capacity for future increases. This is likely conservative, and ultimately will be decided by the cost of U.S. gas and the rate of electricity demand growth and power plant building in Mexico.

Exhibit Add I-7. Existing Major Mexican Pipeline Infrastructure



One significant impact of this increase in Mexican imports is that it will create additional upward pressure on gas prices. While there are myriad of factors to consider, analysis indicates that this upward pressure on gas prices is on the order of $0.30 per MMBTU. In addition, there likely will be an impact on the basis differentials for South Texas gas supplies.

At present, of the 16 export points to Mexico, the largest are in (1) South Texas (i.e., Tennessee at Alamo, TX, and Rio Bravo, TX, plus a few Kinder Morgan intrastate systems); (2) West Texas (i.e., EPNG at Clint, TX) and (3) Southern California (i.e., North Baja at Ogilby, CA).

With the addition of the 2.1 BCFD Los Ramones Pipeline and the 0.4 BCFD expansion of the KM Texas Pipeline, which will source their gas supplies from Agua Dulce, the focus on gas supplies from South Texas likely will increase. This will have the net effect over time of pulling gas away from the Henry Hub and likely result in several of the key South Texas gas hubs being priced at a premium to the Henry Hub. While it is likely that the Tenn Zone 0 pricing point in South Texas will be the pricing point that is most affected, increasing basis differentials for the Houston Ship Channel and Katy hubs also may occur. In time it is possible that the Tenn Zone 0 pricing point could reach a $0.10 to $0.20 per MMBTU premium over the Henry Hub.

While the net impact should be less, a similar phenomenon could occur for the Waha hub (i.e., West Texas), which will be the primary source of gas for the smaller 0.8 BCFD Northwest Pipeline System.

Appendix

Exhibit A-1. Natural Gas Consumption (BCF)

	Annual								
	2008	2009	2010	2011	2012	2013	2014	2015	2016
Residential	4,890	4,777	4,783	4,715	4,149	4,898	5,088	4,614	4,380
Commercial	3,153	3,119	3,102	3,155	2,895	3,295	3,467	3,207	3,053
Industrial	6,662	6,168	6,825	6,995	7,227	7,426	7,625	7,508	7,562
Electric	6,668	6,871	7,388	7,574	9,112	8,191	8,150	9,671	10,524
Other	1,868	1,946	1,962	2,010	2,127	2,316	2,335	2,442	2,511
Transport	26	27	29	30	30	30	35	34	35
Total	**23,267**	**22,908**	**24,089**	**24,479**	**25,540**	**26,156**	**26,700**	**27,476**	**28,064**

	Summer (April-October)								
	2008	2009	2010	2011	2012	2013	2014	2015	2016
Residential	1,327	1,333	1,182	1,254	1,138	1,248	1,237	1,148	1,196
Commercial	1,138	1,136	1,071	1,148	1,101	1,175	1,195	1,135	1,146
Industrial	3,679	3,396	3,770	3,884	4,062	4,115	4,221	4,161	4,217
Electric	4,303	4,454	4,844	4,911	5,964	5,117	5,142	6,089	6,761
Other	1,025	1,072	1,083	1,117	1,200	1,281	1,289	1,368	1,454
Transport	14	16	17	17	18	17	19	20	20
Total	**11,486**	**11,407**	**11,967**	**12,331**	**13,483**	**12,953**	**13,103**	**13,921**	**14,794**

Note: 2016 natural gas consumption is forecasted.

Source: EIA and EVA..

Exhibit A-2. Industrial Production Growth Rate

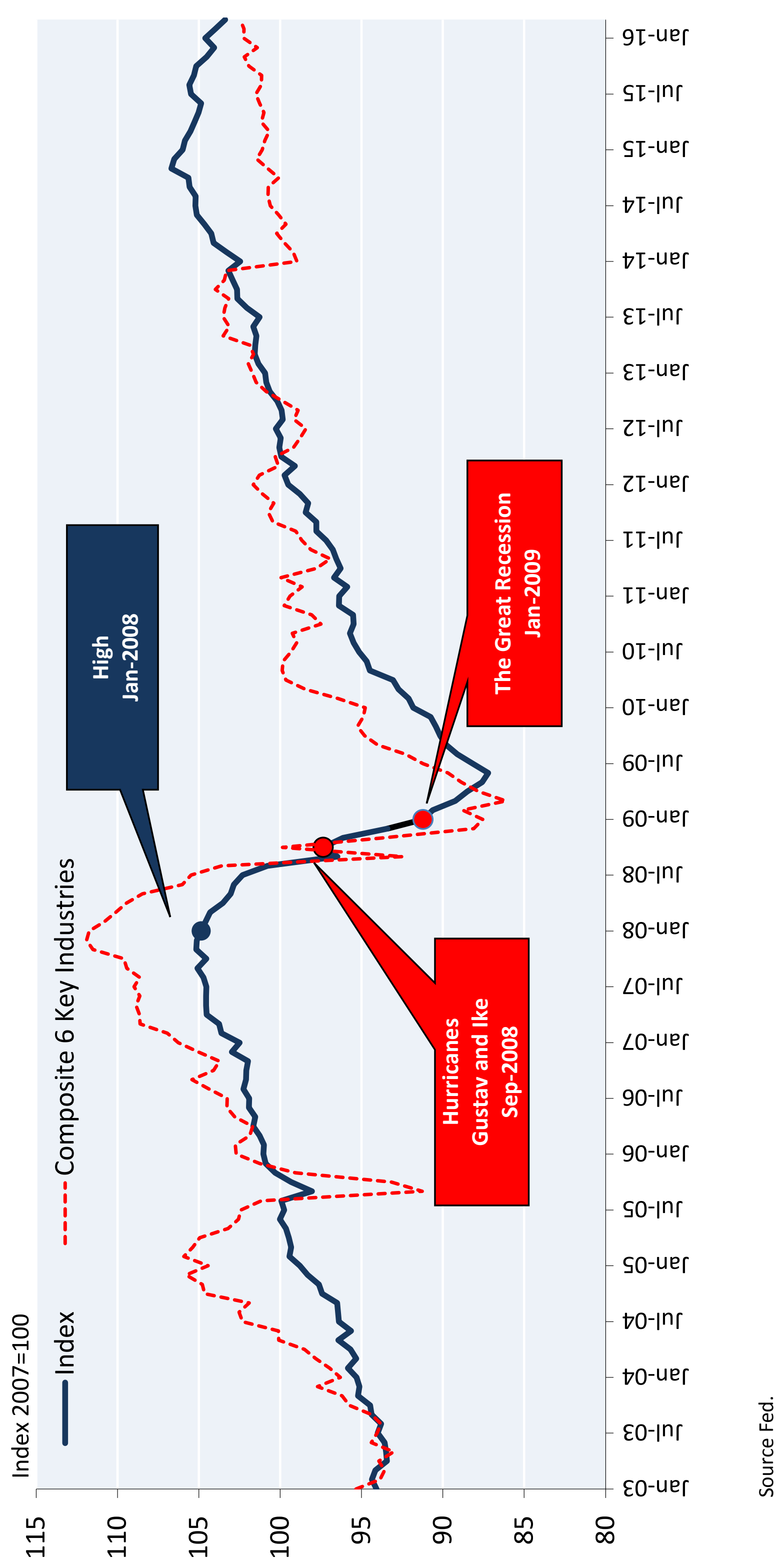
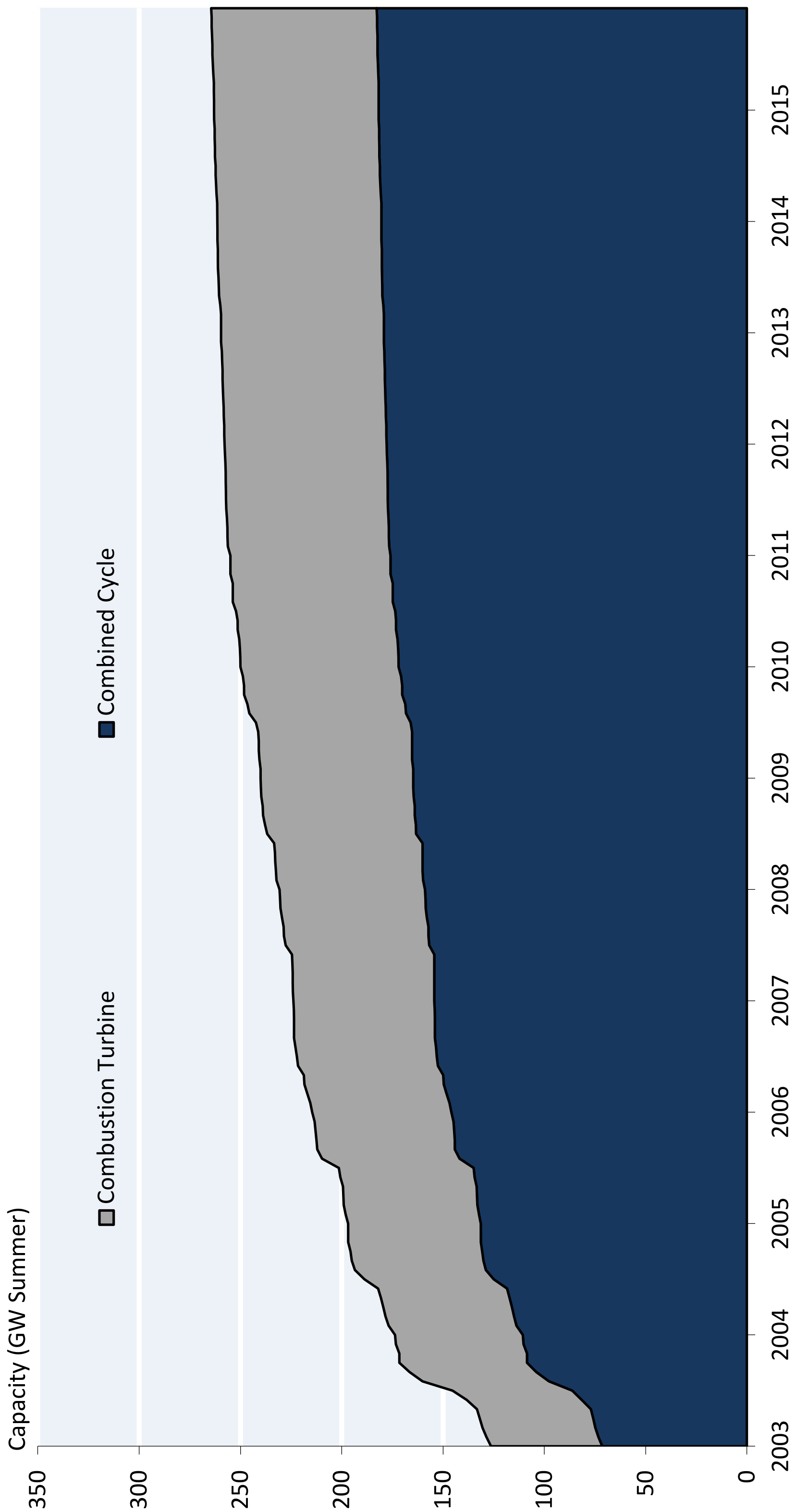


Exhibit A-3. New Gas-Fired Capacity



Source: EIA and EVA.

Exhibit A-4. Annual Additions of Gas-Fired Capacity (2003-2016)

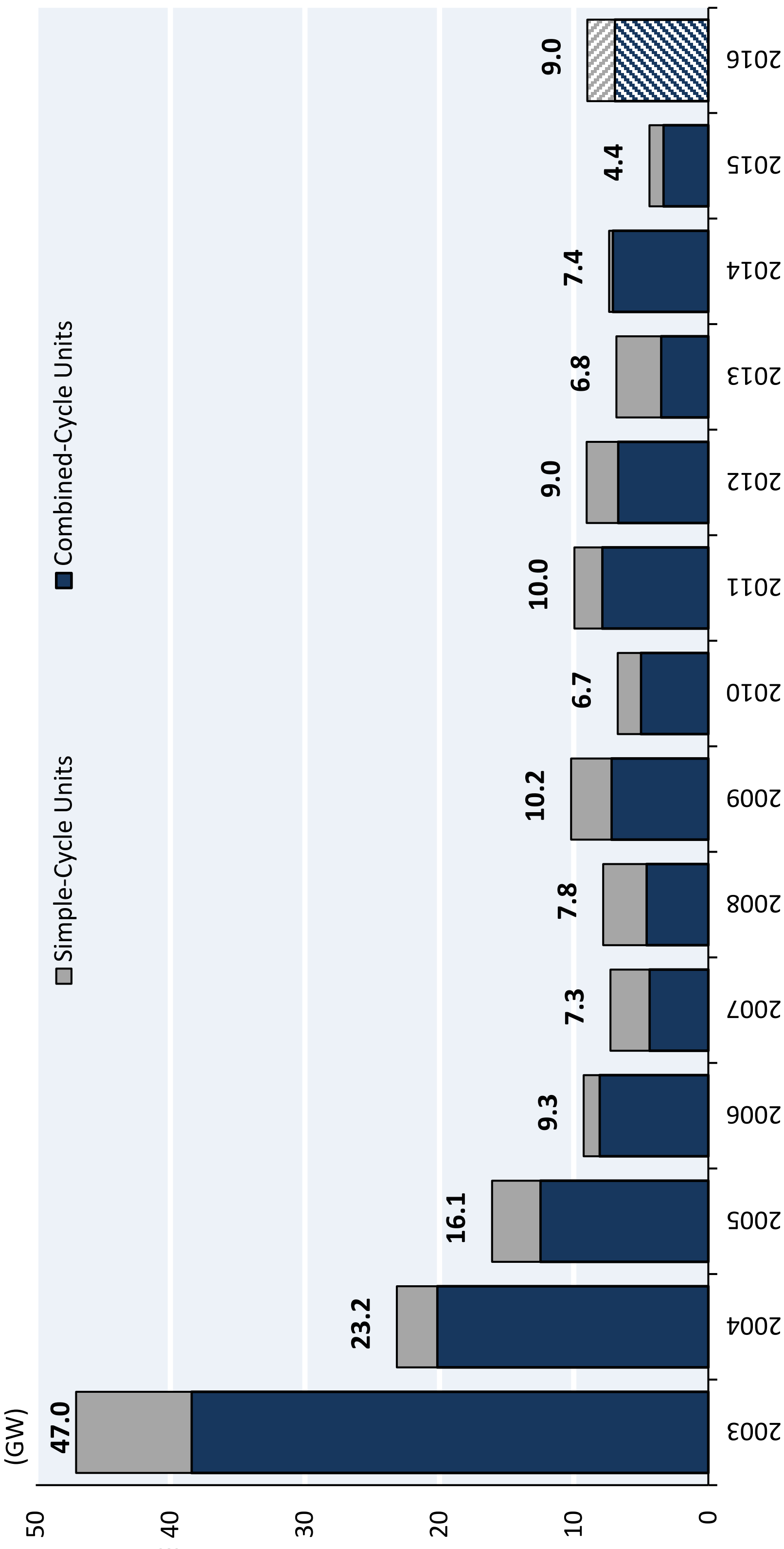


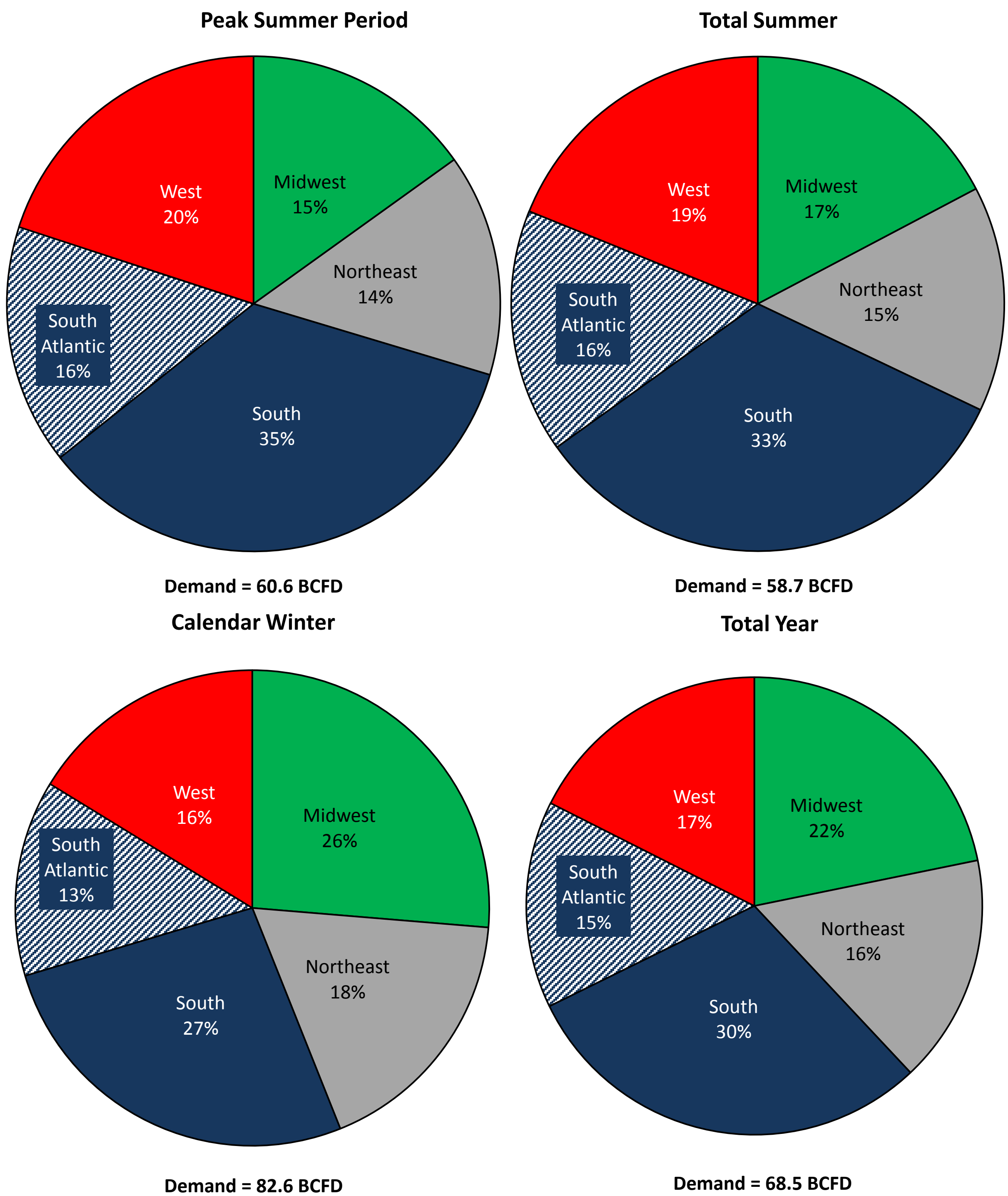
Exhibit A-5. Performance Characteristics Of Natural Gas Combined Cycle Units By Region

Census Region	Weighted Average Capacity Factor										
	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
New England	75.2%	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%	53.4%
West North Central	23.2%	19.6%	24.9%	20.2%	12.5%	17.5%	15.3%	25.2%	21.4%	16.5%	26.3%
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%	65.6%
West South Central w/o ERCO	50.4%	57.3%	33.2%	33.6%	36.4%	35.6%	36.4%	46.3%	37.5%	37.0%	49.6%
ERCOT	96.2%	96.3%	51.6%	49.5%	45.9%	45.1%	45.6%	50.0%	48.5%	46.7%	56.2%
West South Central	75.5%	78.5%	43.6%	42.5%	41.8%	41.0%	41.7%	48.4%	43.9%	42.7%	53.5%
Mountain	65.1%	70.0%	48.2%	48.0%	45.7%	40.9%	34.7%	40.4%	40.4%	38.2%	45.0%
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%**	**56.0%**

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	7,577
Middle Atlantic	7,389	7,591	7,543	7,536	7,561	7,403	7,355	7,426	7,358	7,440	7,414
East North Central	7,488	7,540	7,439	7,509	7,437	7,473	7,371	7,315	7,069	7,556	7,539
West North Central	7,794	7,720	7,605	7,635	7,731	7,648	7,665	7,412	7,247	7,574	7,380
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	7,253
Florida	7,417	7,416	7,476	7,409	7,479	7,431	7,381	7,320	7,080	7,320	7,279
South Atlantic	7,500	7,471	7,538	7,465	7,468	7,447	7,391	7,314	6,798	7,298	7,267
East South Central	7,713	7,643	7,633	7,629	7,437	7,409	7,377	7,296	7,022	7,350	7,342
West South Central w/o ERCO	8,499	8,354	8,387	8,270	7,862	8,298	8,232	9,552	8,117	7,360	7,268
ERCOT	7,339	7,334	7,374	7,473	7,369	7,356	7,358	7,337	7,305	7,334	7,255
West South Central	7,689	7,675	7,713	7,749	7,552	7,707	7,679	8,235	7,596	7,343	7,260
Mountain	7,574	7,613	7,393	7,460	7,531	7,533	7,639	7,490	7,097	7,544	7,492
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	7,368
California	7,291	7,504	7,453	7,285	7,291	7,255	7,358	7,305	6,895	7,346	7,401
Pacific Contiguous	7,270	7,458	7,422	7,261	7,247	7,239	7,331	7,291	6,989	7,344	7,392
TOTAL U.S.	**7,534**	**7,571**	**7,556**	**7,534**	**7,479**	**7,492**	**7,479**	**7,557**	**7,166**	**7,385**	**7,356**

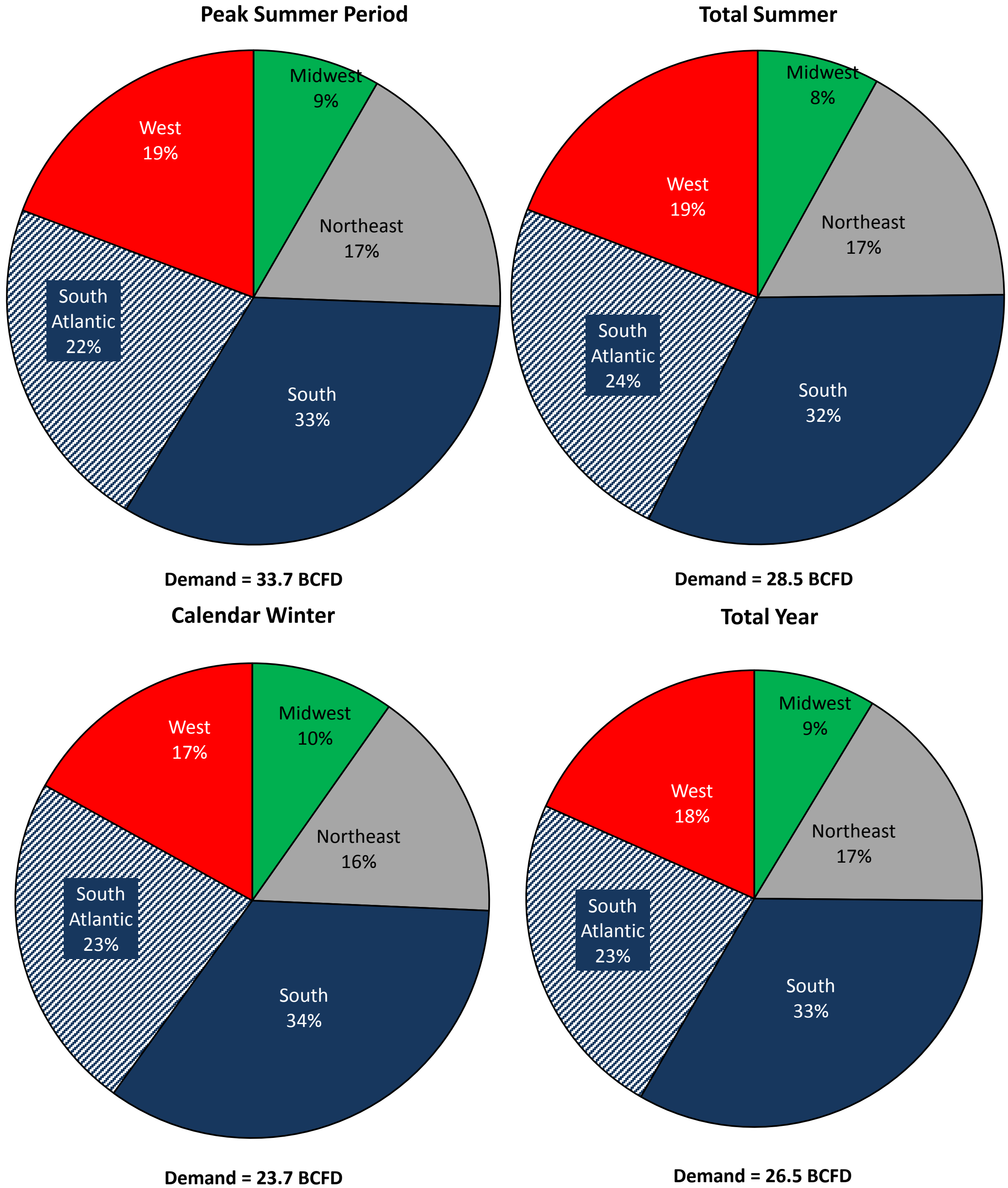
Note: 2014 is EIA-923 Preliminary Data.

Exhibit A-6. Total 2015 Primary Gas Demand By Region and Time Of Year



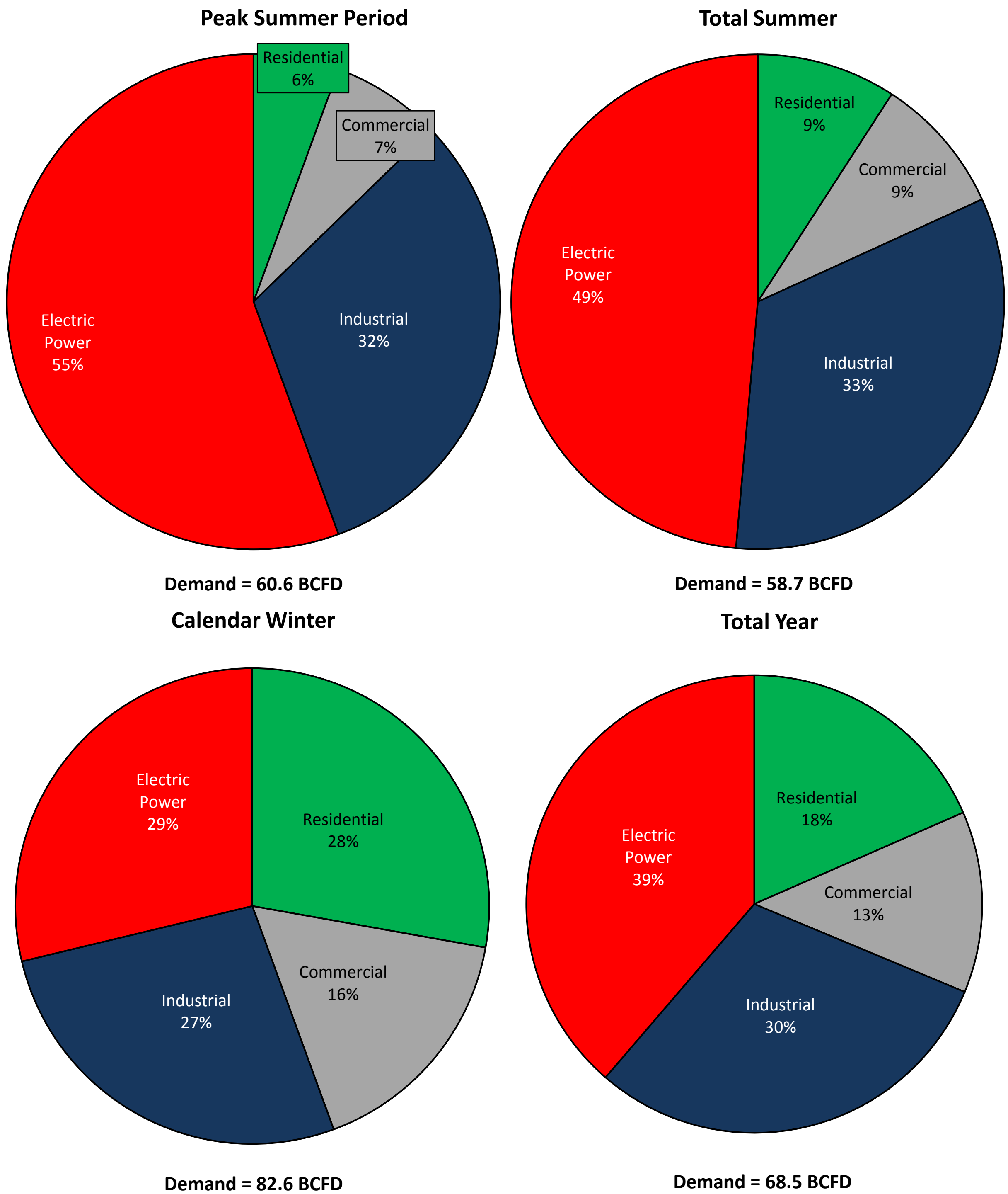
Note: Peak Summer = July & August; Total Summer = April through October; Calendar Winter = Jan, Feb, Mar, Nov, Dec.
Source: U.S. DOE, Energy Information Adminstration.

Exhibit A-7. Electric Power Sector 2015 Gas Demand by Region and Time of Year



Note: Peak Summer = July & August; Total Summer = April through October; Calendar Winter = Jan, Feb, Mar, Nov, Dec.
Source: U.S. DOE, Energy Information Adminstration.

Exhibit A-8. Total 2015 Primary Gas Demand By Sector and Time of Year



Note: Peak Summer = July & August; Total Summer = April through October; Calendar Winter = Jan, Feb, Mar, Nov, Dec.
Source: U.S. DOE, Energy Information Adminstration.

Exhibit A-9. Overview of Peak Summer Electric Sector Gas Demand

Year	Volume (BCFD)				Percent Change From Prior Year			
	Peak Summer Month (1)	Summer (2)	Winter (3)	Full Year	Peak Summer (1)	Summer (2)	Winter (3)	Full Year
2003	22.1	15.7	11.7	14.1	-9.5%	-11.9%	-4.4%	-9.4%
2004	20.2	16.8	12.3	14.9	-8.5%	6.5%	5.6%	6.1%
2005	25.5	18.6	12.4	16.1	26.4%	11.1%	1.0%	7.7%
2006	27.9	20.2	12.5	17.0	9.2%	8.7%	0.2%	6.0%
2007	31.3	21.5	14.8	18.7	12.2%	6.2%	18.8%	9.9%
2008	25.2	20.1	15.6	18.2	-19.3%	-6.5%	5.0%	-2.8%
2009	27.1	20.8	16.0	18.8	7.4%	3.5%	2.9%	3.3%
2010	30.4	22.6	16.9	20.2	12.3%	8.7%	5.3%	7.5%
2011	30.3	22.9	17.6	20.8	-0.4%	1.4%	4.6%	2.5%
2012	34.9	27.9	20.7	24.9	15.2%	21.5%	17.5%	20.0%
2013	29.4	23.9	20.4	22.4	-15.8%	-14.2%	-1.8%	-9.9%
2014	29.0	24.0	19.9	22.3	-1.3%	0.5%	-2.2%	-0.5%
2015	34.0	28.4	23.7	26.5	17.2%	18.4%	19.1%	18.7%
2016	38.3	31.6	24.8	28.8	12.7%	11.0%	4.4%	8.5%

1. Peak summer month is defined as the month with the highest demand (either July or August).
2. Summer consists of April through October.
3. Winter consists of January, February, March, November, and December.

Note: 2016 volumes are forecasted.

Source: EIA and EVA.

Exhibit A-10. U.S. Census Regions

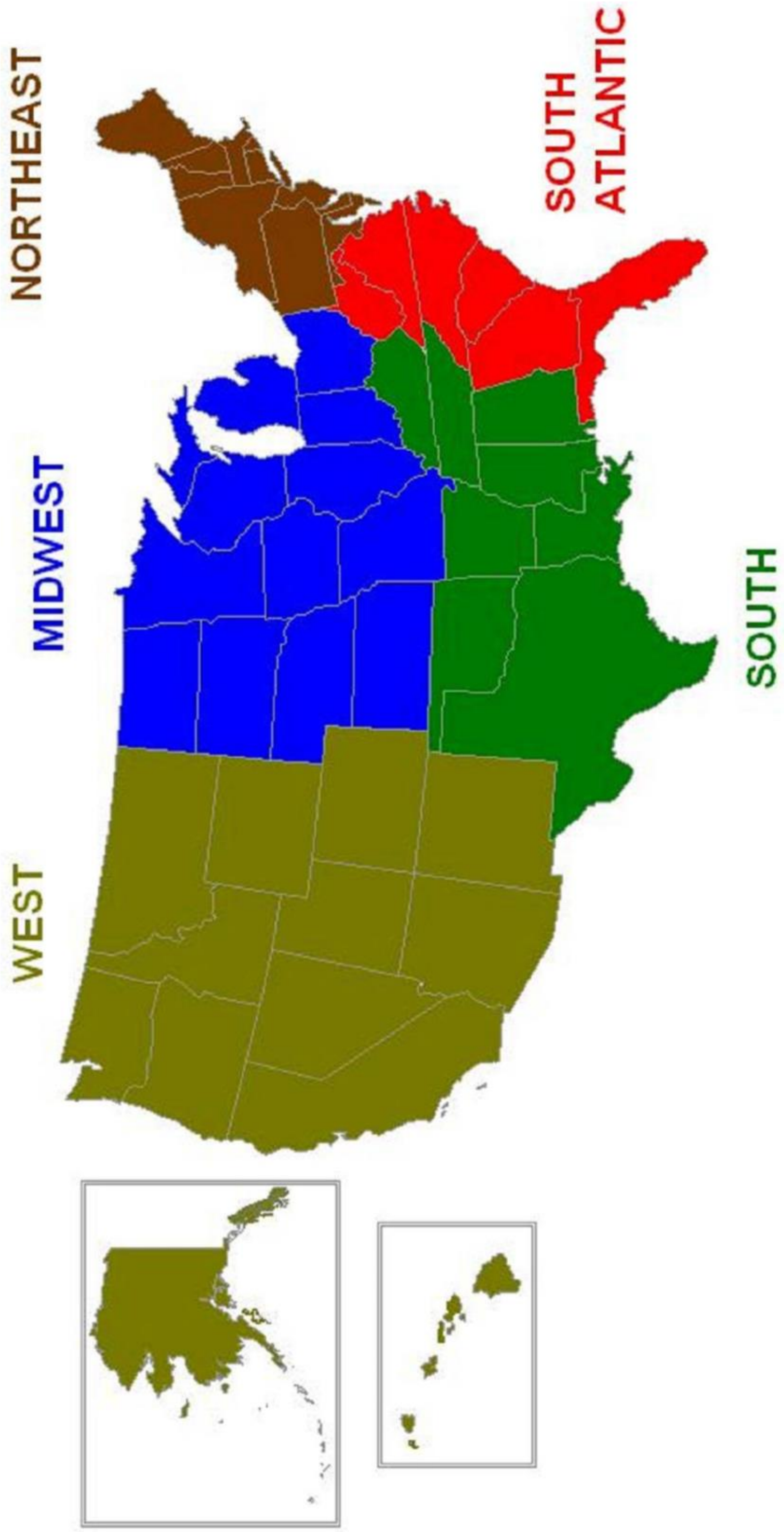


Exhibit A-11. Selected Relevant Data

		Annual						April-Oct						June - August					
		2012	2013	2014	2015	2016	% Diff 16/15	2012	2013	2014	2015	2016	% Diff 16/15	2012	2013	2014	2015	2016	% Diff 16/15
Residential Housing Stock	(Thousands)	118,955	119,999	120,746	121,954	123,920	1.6%	119,012	120,063	120,757	122,018	124,001	1.6%	119,025	120,068	120,753	122,015	123,997	1.6%
Electric																			
Weather																			
Cooling Degree Days (CDD)	(Degree Days)	1,469	1,348	1,287	1,450	1,402	12.7%	1,382	1,293	1,247	1,373	1,339	-2.5%	961	895	838	910	934	2.6%
Normal CDD[1]	(Degree Days)	1,302	1,302	1,302	1,302	1,302	-	1,245	1,245	1,245	1,245	1,245	-	878	878	878	878	878	-
% of Normal		112.8%	103.5%	98.8%	111.3%	107.6%	-	111.0%	103.9%	100.2%	110.3%	107.6%	-	109.5%	102.0%	95.5%	103.7%	106.4%	-
New Gas-Fired Capacity[2]																			
CC	(MW)	1,463	1,223	1,375	989	1,324	33.8%	902	1,015	1,112	766	800	4.5%	449	250	467	368	188	-48.9%
CT	(MW)	465	565	250	464	471	1.5%	147	565	125	336	431	28.3%	97	314	88	70	97	39.7%
Hydro and Nuclear Generation																			
Hydro Generation - Pacific	(GWh)	154,174	135,919	121,117	125,306	129,640	3.5%	96,884	84,617	84,617	77,435	70,863	-8.5%	46,476	39,177	37,072	43,612	51,306	17.6%
Nuclear Generation	(GWh)	769,331	789,016	796,875	807,657	779,243	-3.5%	446,078	456,911	460,822	462,833	473,667	2.3%	203,872	208,313	211,748	210,620	214,634	1.9%
Industrial (Index: 2007=100)																			
Food		100.0	101.7	102.2	103.1	129.6	25.7%	100.3	101.8	101.9	103.0	137.8	33.8%	100.5	102.1	101.7	102.9	138.0	34.1%
Paper		100.0	100.4	99.3	97.7	100.0	2.3%	99.4	100.8	99.4	97.7	101.0	3.4%	98.8	101.3	99.3	97.0	101.0	4.1%
Chemicals		100.0	101.6	95.8	98.0	116.1	18.4%	98.8	101.8	96.0	97.9	121.5	24.2%	97.7	102.0	96.2	97.8	121.5	24.3%
Petroleum		100.0	106.9	100.3	104.9	117.3	11.8%	99.8	107.6	99.8	105.6	120.6	14.2%	99.8	107.6	99.6	105.3	120.6	14.6%
Non-metallic Minerals		110.6	112.7	116.0	116.3	123.5	6.1%	112.6	114.7	118.3	118.5	128.5	8.5%	113.2	115.0	119.0	119.2	129.2	8.4%
Primary Metals		100.0	101.9	103.4	96.7	94.3	-2.5%	98.2	102.4	104.0	96.8	93.8	-3.0%	98.5	102.3	104.6	98.0	93.8	-4.3%
Total Industrial Production		100.0	101.9	104.9	105.2	111.7	6.1%	100.0	101.9	105.1	105.2	114.2	8.5%	100.0	101.7	105.2	105.3	114.2	8.4%
Composite 6-key Ind.		101.0	103.5	100.7	101.5	114.4	12.7%	100.5	104.1	101.0	101.7	118.6	16.5%	100.1	104.2	101.1	101.0	117.8	16.6%
Economy																			
Real GDP	(Bill. 2005$)	15,355	15,584	15,962	16,357	16,687	2.0%	15,372	15,585	16,008	16,390	16,704	1.9%	15,382	15,560	16,024	16,397	16,709	1.9%
Employment	(Thousands)	134,213	136,617	139,266	141,977	152,623	7.5%	134,247	136,675	139,387	142,058	152,718	7.5%	134,178	136,629	139,368	142,031	152,737	7.5%
GDP IPD	(2005=100)	106.0	108.0	109.8	110.8	112.2	1.2%	106.1	108.1	110.0	111.0	112.2	1.1%	106.1	108.1	110.1	111.2	112.2	0.9%

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

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

[3]2016 is estimated.

Exhibit A-12. Industrial Gas Demand(1)

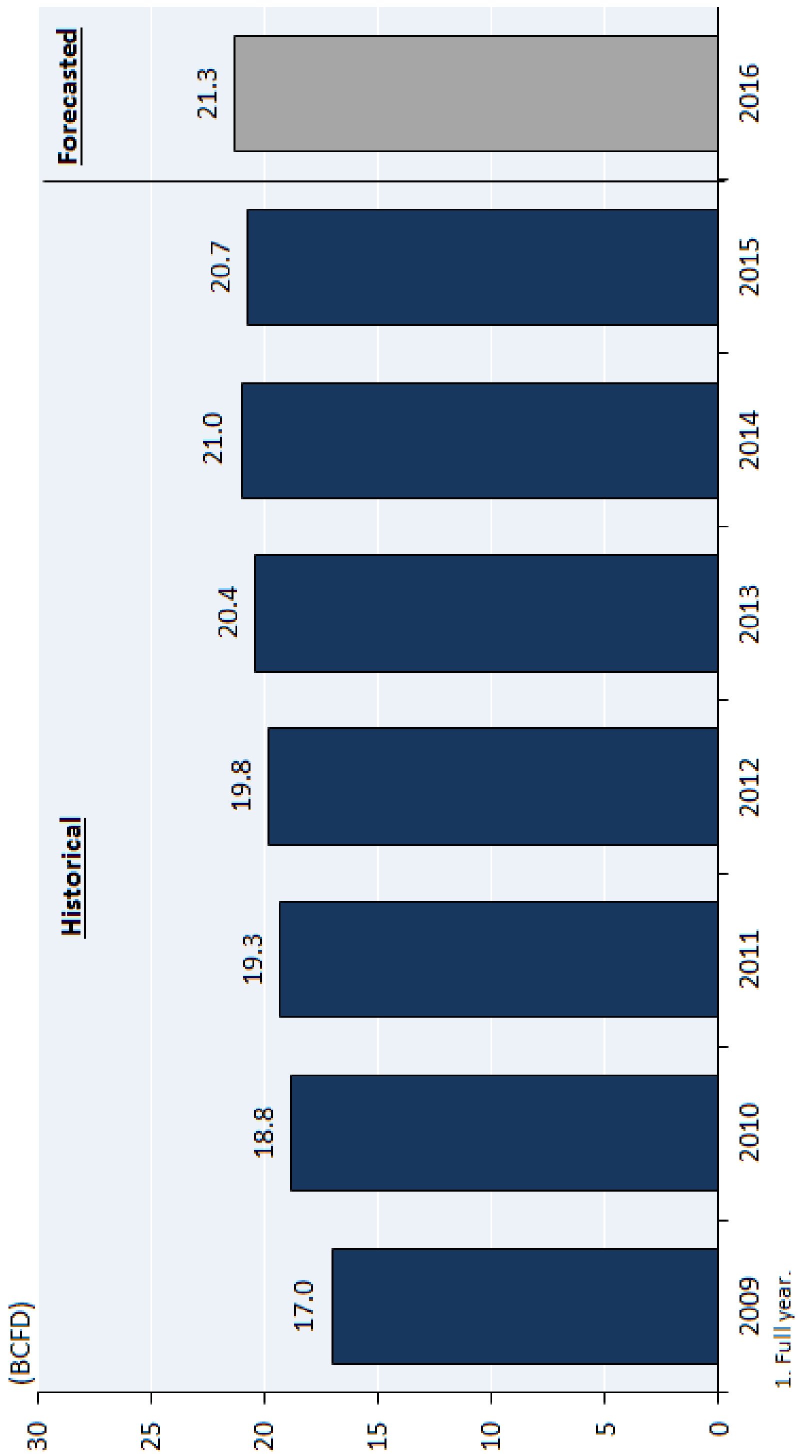


Exhibit A-13. Capital Expenditures for Plant Expansions (Cumulative)

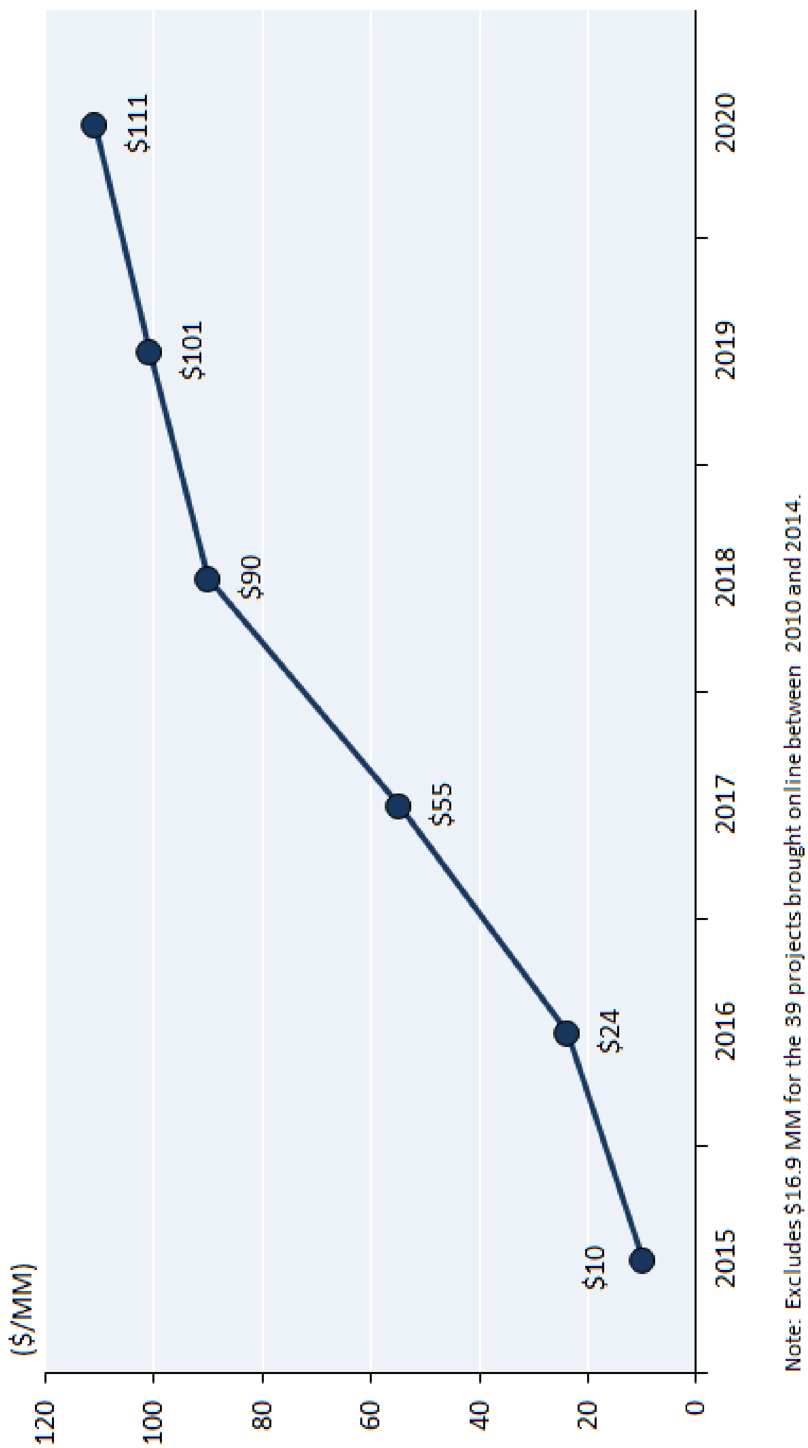


Exhibit A-14. Project Count and Impact of Capacity Expansion on Industrial Gas Demand (2015-2020)