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Outlook for Natural Gas Supply and Demand for 2014-2015 Winter

Energy Ventures Analysis, Inc. (EVA)

Executive Summary

Natural gas supplies will be adequate to meet natural gas demand this winter, which eliminates a major concern of the market that has persisted for much of the year. This assessment is based upon a combination of factors, including that (1) demand will be less this winter, (2) domestic production has increased, and (3) storage inventories at the beginning of the winter season (November 1, 2014) will be adequate. More specifically, average storage withdrawals this winter are projected to be only 12.9 BCFD, which is 6.8 BCFD, or 35 percent, below last winter's record storage withdrawal (19.7 BCFD).

With regards to winter gas demand structural demand within the industrial sector will be offset by the reduced weather-related demand within the residential and commercial sectors.[1] The latter is primarily due to the fact that the forthcoming winter currently is projected to be relatively mild (i.e., 11 percent below last winter and 2.3 percent below normal).

With respect to the electric sector there are offsetting variances, namely reduced weather related demand but increased coal-to-gas fuel switching, which is due to the reduction in gas prices. The net result is that winter gas demand is projected to be about 3.4 BCFD, or 3.8 percent, less than last winter's record demand levels (see Exhibit 1).

With respect to gas supplies, domestic production has been increasing steadily all year long, as a result of both drilling activity and infrastructure events.[2] The net result is that domestic production, absent well freeze-offs, should be about 3.6 BCFD, or 5.3 percent, above production for last year, while net imports likely will be about 0.8 BCFD, or 20 percent, below last winter's level. This will result in storage withdrawals representing only about 15 percent of total supplies, whereas last winter they represented 22 percent.

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 focus throughout this report. Also, the primary focus for supply is on the Lower-48, with Alaskan production footnoted for completeness.

[1] Annual increases in demand within the gas industry typically are categorized as either (1) increases due to weather events (i.e., weather-related) or (2) increases due to structural changes within the industry (e.g., increased capacity), which are permanent in nature and are referred to as structural demand changes.

[2] The bringing online of new pipeline capacity (i.e., an infrastructure event) can provide takeaway capacity for previously stranded gas supplies, which would increase overall flowing gas supplies.

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

Sector	Coming Winter (2014/2015)		Last Winter (2013/2014)		Change	
	BCF	Average BCFD	BCF	Average BCFD	BCF	Average BCFD
I. <u>Natural Gas Demand</u>						
Residential	3,498	23.2	3,976	26.3	(478)	(3.2)
Commercial	2,072	13.7	2,299	15.2	(227)	(1.5)
Industrial	3,675	24.3	3,451	22.9	224	1.4
Electric	3,046	20.2	3,033	20.1	13	0.1
Lease, Plant and Pipeline Fuel	956	6.3	991	6.6	(35)	(0.2)
Total	**13,247**	**87.7**	**13,750**	**91.1**	**(503)**	**(3.4)**
II. <u>Lower-48 Supply</u>						
Lower-48 Production[2]	10,694	70.8	10,156	67.2	538	3.6
Net Imports	491	3.2	613	4.1	(122)	(0.8)
Storage Withdrawals	1,946	12.9	2,978	19.7	(1,032)	(6.8)
Total	**13,131**	**87.0**	**13,747**	**91.0**	**(616)**	**(4.0)**

(1) Figures may not add due to rounding.
(2) Excludes Alaska production, which is approximately 166 BCF, or 1.1 BCFD in 2014/2015 and 144 BC, or 0.95 BCFD in 2013/2014.

Outlook For Winter Demand

Overview

This winter currently is projected to be a relatively mild winter,[3] as a result of reduced weather-related demand within the residential and commercial sectors which will offset the increase in structural demand within the industrial sector. With respect to the electric sector there are offsetting variances, namely (1) reduced weather-related demand, and (2) increased levels of coal-to-gas fuel switching which occurs because of the outlook for lower gas prices this winter. The net result is that this winter's total natural gas demand is projected to be 3.4 BCFD, or 3.8 percent, less than last winter's record demand levels of 91.1 BCFD (see Exhibit 2).

Exhibit 2. Outlook For Winter Gas Demand[1]

Sector	Coming Winter (2014/2015)		Last Winter (2013/2014)		Change	
	BCF	Average BCFD	BCF	Average BCFD	BCF	Average BCFD
Residential	3,498	23.2	3,976	26.3	(478)	(3.2)
Commercial	2,072	13.7	2,299	15.2	(227)	(1.5)
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Electric	3,046	20.2	3,033	20.1	13	0.1
Lease, Plant and Pipeline Fuel	955	6.3	991	6.6	(35)	(0.2)
Total	**13,247**	**87.7**	**13,750**	**91.1**	**(503)**	**(3.4)**

(1) Figures may not add due to rounding.

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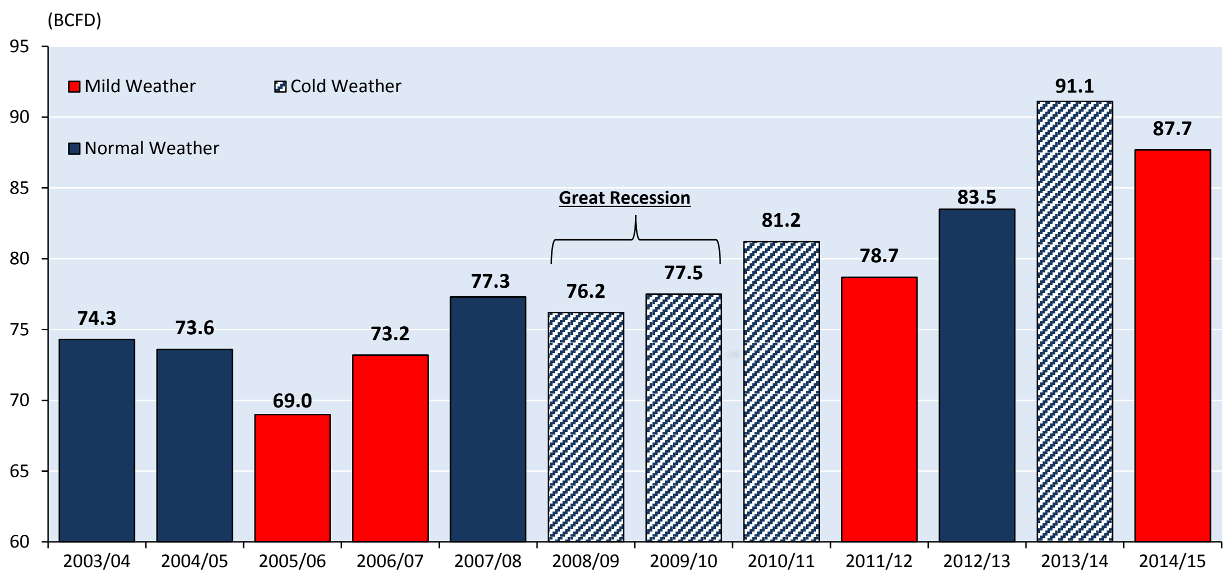
[3] The forthcoming winter is projected by NOAA to be about 11 percent milder than last winter (i.e., 415 fewer heating degree days (HDD)) and overall 2.3 percent lower than the 30-year average.

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.

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 a very cold, or similar to last winter, which was the third coldest winter on record,[4] winter gas demand would be about five BCFD higher, when the additional structural demand for the industrial sector is included. If this were to happen, storage inventories likely would be adequate, however season ending storage levels (March 31, 2015) likely would be below this year's record low for recent times.

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

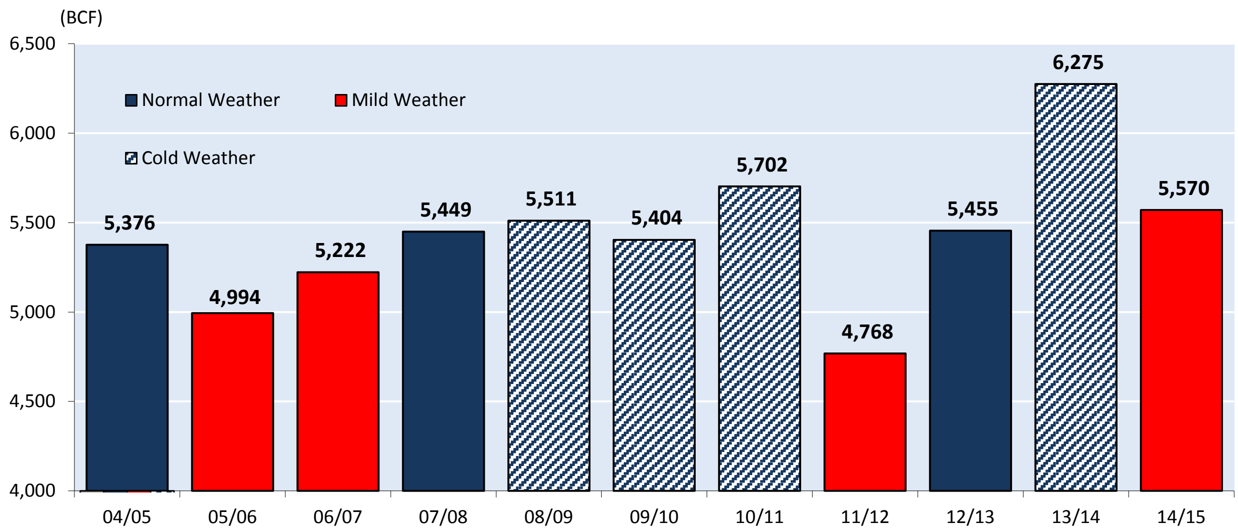


Residential And Commercial Sectors

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., 1,507 BCF, or 32 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).[5]

[4] The winter of 2013/2014 is one of only three winter's since 1931/1932 that have had heating degree days (HDD) greater than 3,800 (i.e., 1995/1996 with 3,892; 2001/2002 with 3,883 and 2013/2014 with 3,865).
[5] Not included in Exhibit 3.

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



HDDs	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15
vs Norm	-1.7%	-5.2%	-5.1%	1.1%	2.7%	2.7%	5.9%	-15.3%	-1.8%	9.4%	-2.3%

Note: 2014/2015 is forecasted. Source: EIA and EVA.

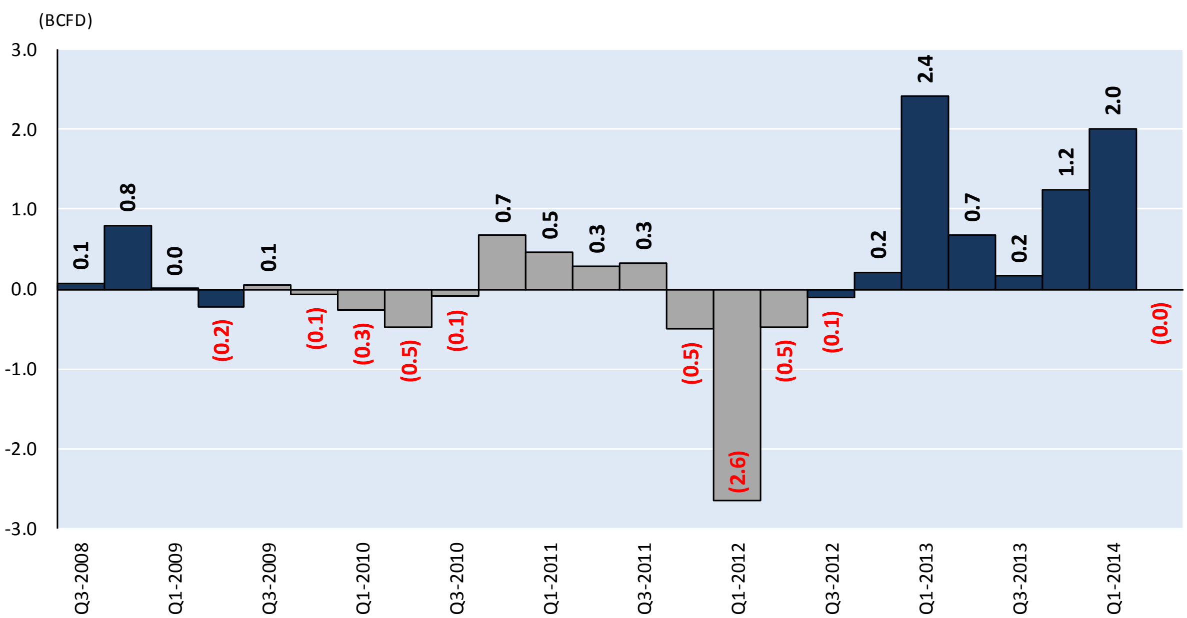
With respect to the forthcoming winter, it is projected to be about 11 percent milder than last winter, or 2.3 percent below normal. Last winter was characterized as an early, long and cold winter with the weather for individual months being approximately three to 17 percent colder than normal. The current outlook for this winter is almost the opposite with the weather for each month projected to be warmer than normal (i.e., between 1.9 and 3.7 percent warmer).

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 2005 being the sole exception. One factor in this decline has been the impact of the Great Recession on new housing completions, which are still well below 2005 levels.

With respect to the average home, its consumption has been declining. While last winter may have been an exception, because of the severe winter weather, the general trend over the last 20 years, with rare exception, has been a decline in consumption per customer on a weather-adjusted basis, with current consumption per customer near an all-time low (i.e., from 95 to 73 MCF per customer, 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, (3) population migration to warmer winter climates, and (4) the elasticity of demand effects due to high gas prices, which tends to result in more behavioral conservation rather than structural conservation. 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 during and 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 recovery from the recent recession. Exhibit 5 presents the year-over-year changes in commercial sector gas demand for the last several years. While commercial sector demand underwent a decline in 2009, which primarily was caused by the impact of the Great Recession, it has began to respond to the rebound in economic growth in 2013 and continues to do such, albeit at a modest rate.

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

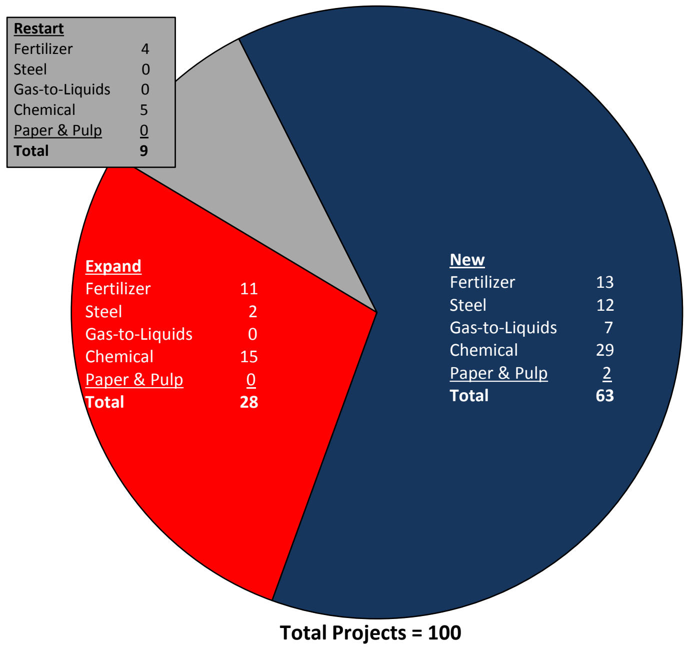
Currently the industrial sector is the fastest growing sector within the natural gas industry. Two factors are driving this growth, namely (1) a series of capacity expansions by a few key industries and (2) the impact of the slow recovery of economic growth for the U.S.

Capacity Expansions

Five key industries, namely the fertilizer, chemicals, steel, paper and pulp and gas-to-liquids industries, are expanding capacity in order to take advantage of the current era of low U.S.

natural gas prices, which is a key result of the 'game changing' shales.[6] The investment of capital by these industries to expand capacity is significant. As illustrated in Exhibit 6, to date there have been 100 announced capacity expansion projects, which include (a) the restart of previously mothballed units; (b) the expansion of existing facilities; and (c) the construction of new plants.

Exhibit 6. Comparison Of Project Type Count For Various Industries



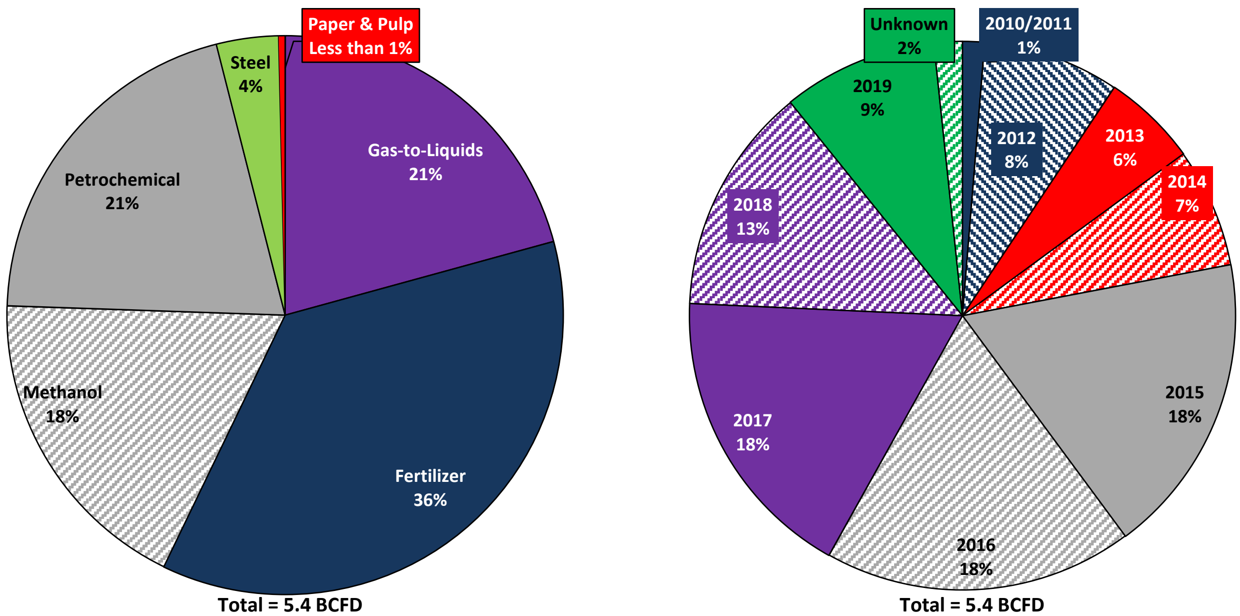
This list of 100 projects, which separates some projects into phases in order to better assess the timing of new capacity coming online, is a fully vetted list. Key to this vetting process is the tracking of project milestones, which is a continuous process at EVA. This enables one to eliminate projects that are merely 'paper announcements' that never proceed beyond that stage. 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 100 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).[7]

With respect to the longer term impact of these 100 projects on industrial sector natural gas consumption, Exhibit 7 summarizes for each major industry the anticipated increase in gas consumption, with the total for all projects being approximately 5.4 BCFD. In order to provide additional insight, the chemical industry has been subdivided into the petrochemical and methanol segments of the overall chemical industry. However, as illustrated in the right hand

[6] The addendum to this report provides highlights for expansions of each of these key industries.
[7] As a result, the number of capacity expansion projects summarized in Exhibit 5 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.

graphic contained in Exhibit 7, not all of this projected growth in industrial sector gas demand occurs in the near-term. Instead, this demand growth is spread out over a nine year period.

Exhibit 7. Impact Of Capacity Expansion On Industrial Gas Demand



With respect to those capacity expansion projects that could have an impact on industrial demand for the forthcoming winter, the number of new projects in 2013, 2014 and 2015 is 11, 17 and 19 projects, respectively, with the full year impact gas demand for each group being approximately 0.3, 0.35 and 0.85 BCFD, respectively.[8]

Economic Growth

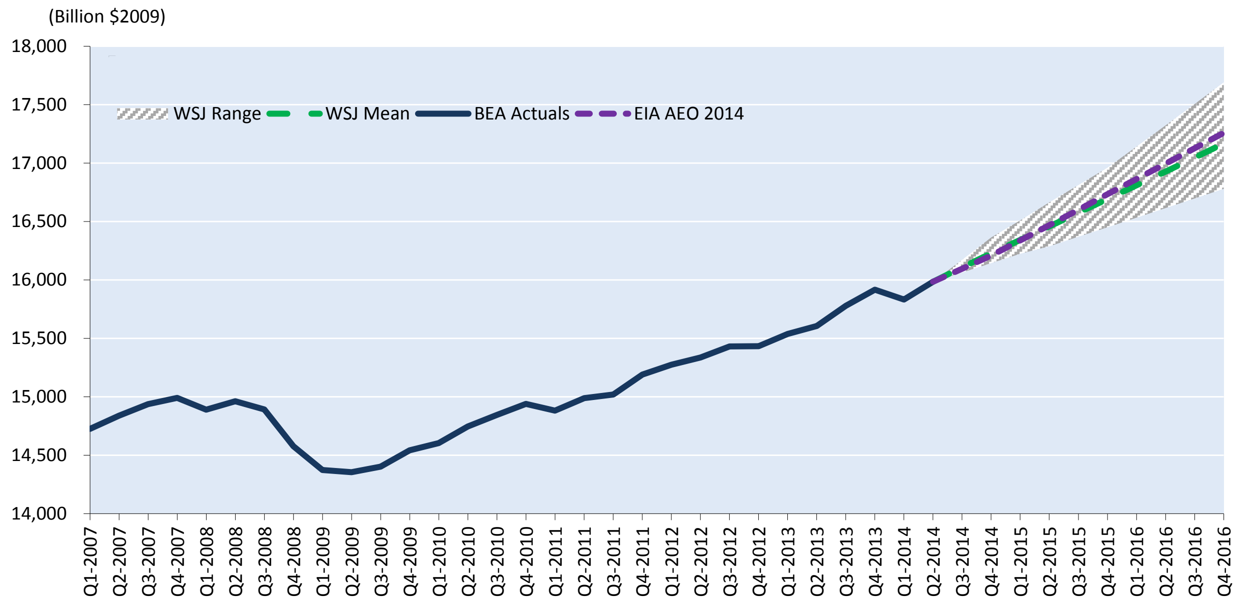
The remainder of the industrial sector is benefitting from the modest recovery in U.S. economic growth. Exhibit 8 summarizes the current range of views for U.S. economic growth, with the average expectation for the fourth and first quarters of the year being 3.0 and 2.9 percent per annum, respectively.[9]

The impact of recent economic growth on the production indices for the six major energy intensive industries is summarized in Exhibit 9. As illustrated, these production indices are increasing for four of these key industries, while for two of the remaining industries these production indices are declining.

[8] Assumes an average 90 percent capacity factor.

[9] Range in GDP projections for the fourth and first quarters is 2.0 to 4.8 percent and 2.0 to 3.6 percent, respectively.

Exhibit 8. U.S. Real GDP Short-Term Forecast Comparison

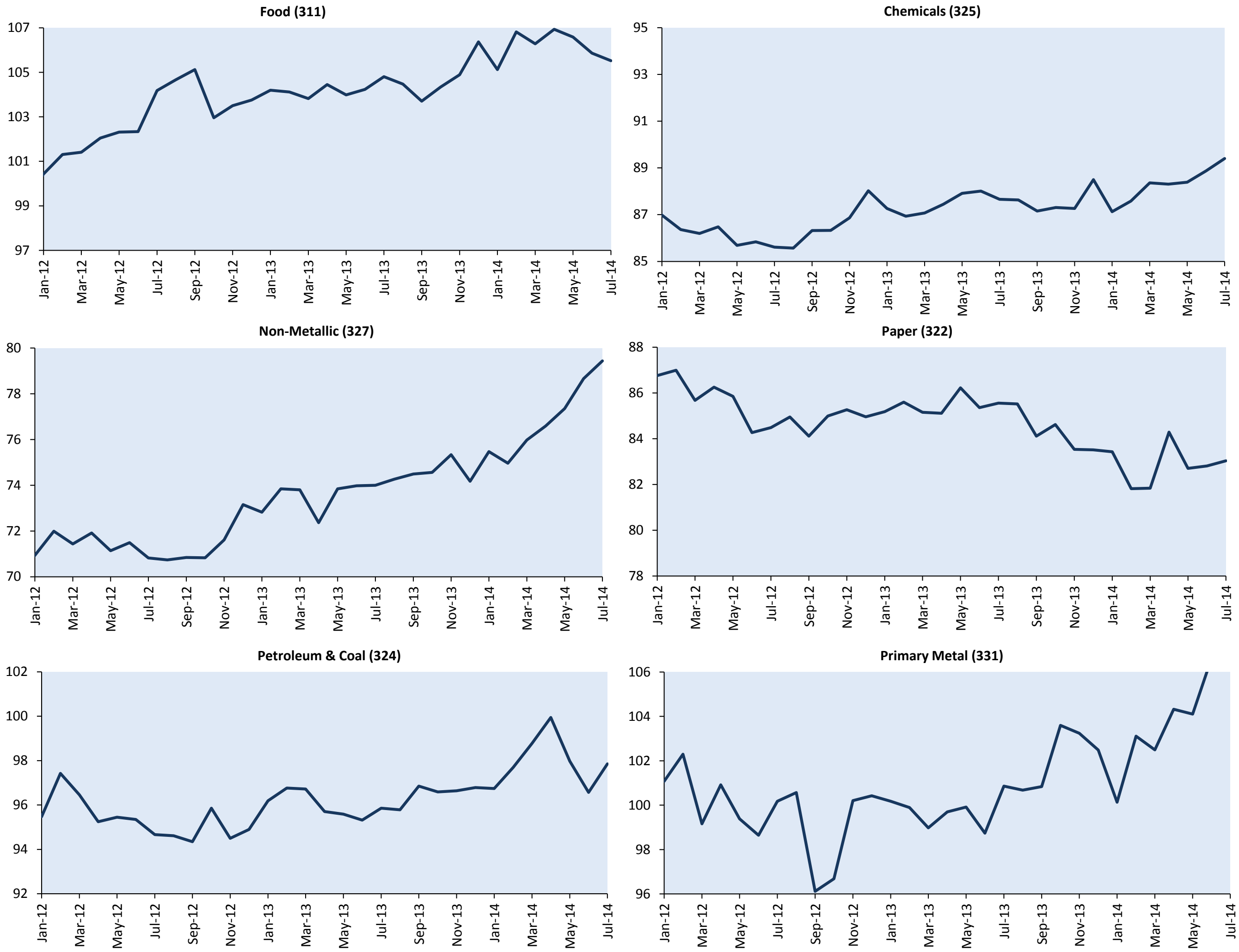


Summary

With respect to the integrated outlook for industrial sector gas demand this winter, it is expected to increase 1.4 BCFD, or 6.5 percent, over last year's level. As an added point of perspective, Exhibit 10 compares and contrasts, on an annual basis, the expected outlook for this winter's industrial sector gas demand with the consumption levels for the sector for selected years 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.

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. Lastly, as illustrated, demand levels for the winter of 2014/2015 now are well above the peak levels for industrial sector gas demand in the prior decade.

Exhibit 9. Performance Of The Six-Key Energy Intensive Industries



Source: Federal Reserve.

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

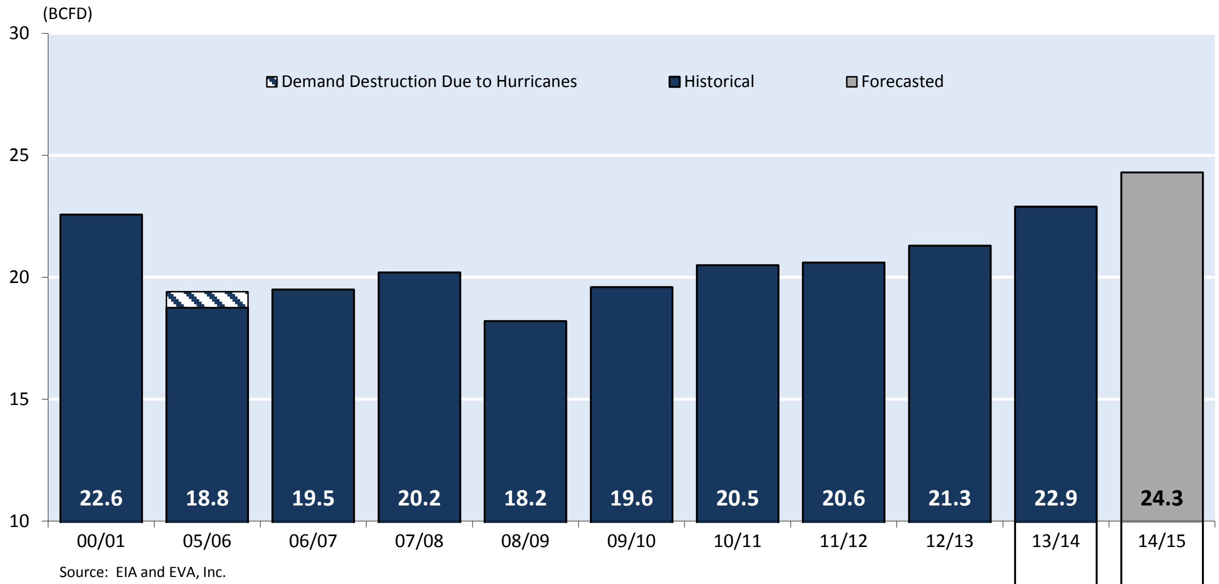
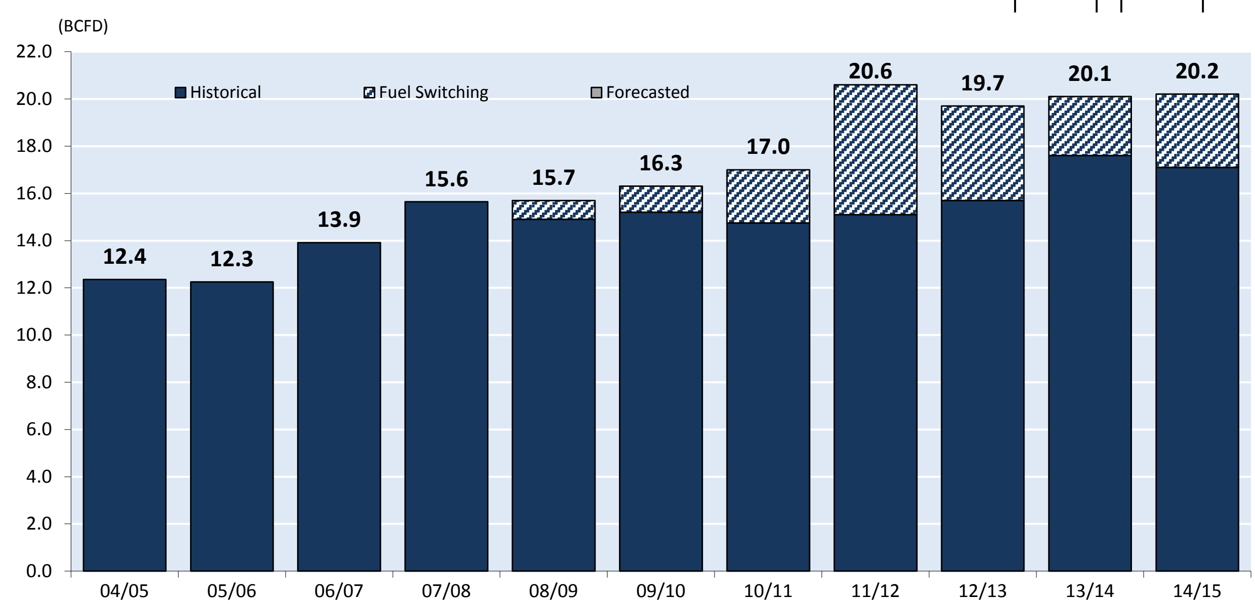


Exhibit 11. Winter Natural Gas Demand For The Electric Sector



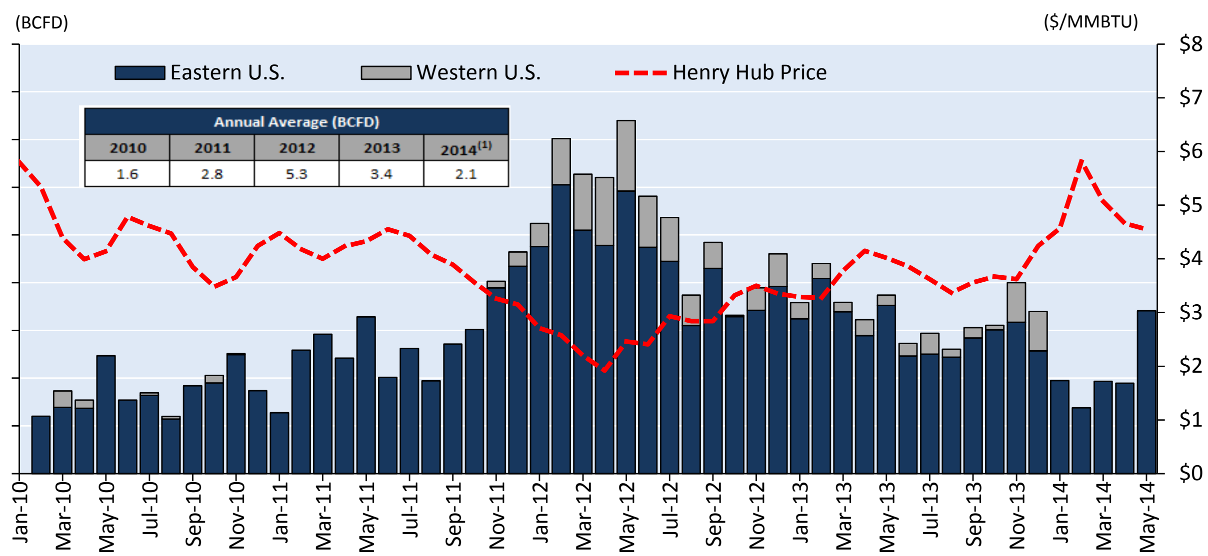
Electric Sector

While electric sector gas demand this winter is expected to be very close to the consumption levels last winter (i.e., within 0.4 percent), this is the net result of a series of offsetting factors (see Exhibit 11). During the past winter, electric sector gas demand had a weather-related component, which likely will not occur this year. However, coal-to-gas fuel switching will be greater this winter, primarily as a result of the expected lower gas prices this winter. A third factor in this assessment is the projected overall growth in electricity sales, although this appears to be a secondary factor in the overall assessment of the sector.

Fuel Switching

Last winter coal-to-gas fuel switching declined to about 2.5 BCFD (i.e., average for the winter), because of the increase in gas prices. This figure was well below the fuel switching levels for either of the prior two winters (i.e., winter of 2011/2012 and 2012/2013), as illustrated in Exhibits 11 and 12. However, with gas prices for the forthcoming winter expected to be about 10 percent below last winter's gas prices, fuel switching for the forthcoming winter is expected to increase and average about 3.1 BCFD (i.e., an increase of 24 percent).[10] Exhibit 12 summarizes the longer term trend for coal-to-gas fuel switching, with 2012 being the peak year when gas prices averaged $2.74 per MMBTU.

Exhibit 12. Coal-To-Gas Fuel Switching



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. However, for 2014 there has been only limited growth in electricity sales as noted in Exhibit 13.

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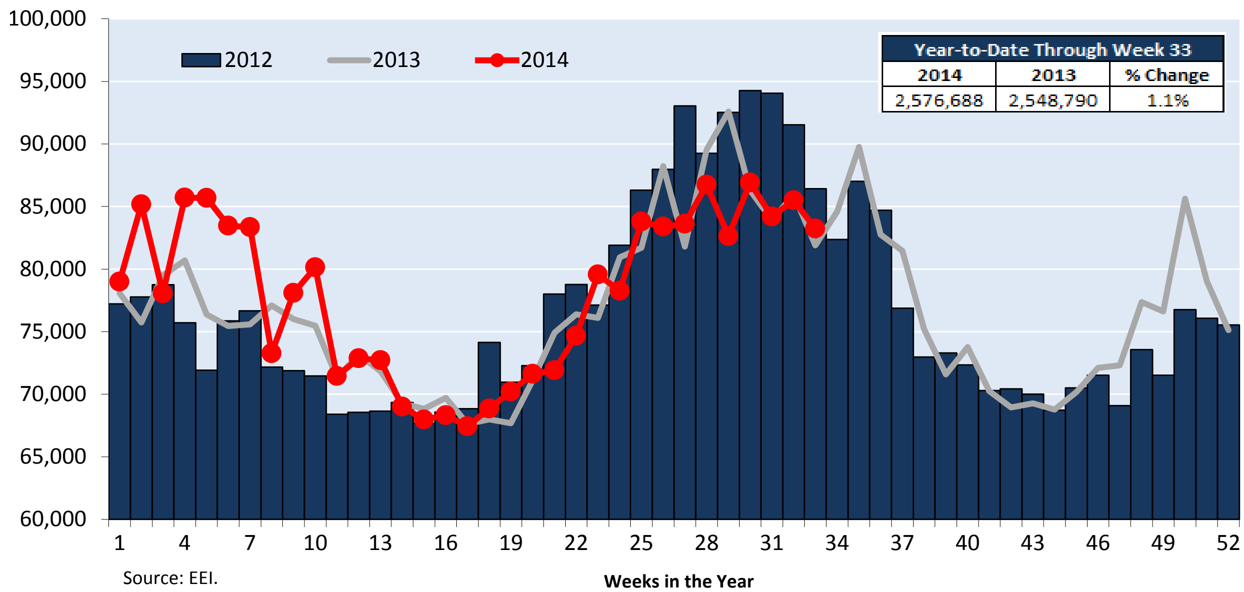
[10] Based upon current NYMEX futures.

As illustrated in Exhibit 13, electricity sales in 2013 were basically flat, while year-to-date results for 2014 have increased about 1.1 percent. However, this pattern of growth has been asymmetrical among the major seasons. More specifically, last winter electricity sales increased 4.1 percent, with almost all of this growth being due to weather-related phenomenon, rather than structural increases.[11] For the forthcoming winter the prior weather-related increase is expected to disappear and any structural increase will be minimal. As a result, electricity sales for the forthcoming winter are expected to be less than last winter, which should reduce electric sector gas demand about 0.5 BCFD.

Exhibit 13. Total Weekly Electric Output (48-States)



Capacity Additions

Finally, while it is unlikely that the addition of new gas-fired capacity will have a significant impact on this winter's electric sector gas demand, trends in new gas-fired additions are meaningful for assessing the intermediate-term outlook for gas demand within this sector and thus, provide an additional point of perspective. Exhibit 14 summarizes recent historical capacity additions, as well as the current outlook for capacity additions for 2014 and 2015. In addition to gas-fired capacity additions, capacity additions for coal-fired units and wind units, which are the two key competitors to gas-fired generation. Also, noted are the retirements for coal-fired and nuclear capacity.

[11] Electricity sales during the non-winter period in 2013 declined 2.2 percent, while in 2014 the decline has been 0.9 percent.

Exhibit 14. New U.S. Generation Capacity

(MW)	2010	2011	2012	2013	Projected 2014	Projected 2015
Coal-Fired	**5,935**	**4,594**	**4,168**	**936**	**593**	0
Wind(1)	**4,661**	**6,788**	**13,136**	**1,281**	**3,295**	**6,233**
Gas Combined Cycle	4,487	7,654	6,713	3,511	6,560	3,792
Gas Peaking	1,572	1,526	2,334	3,332	358	653
Total Gas-Fired	6,059	9,180	9,047	6,843	6,918	4,445
Grand Total	**16,655**	**20,562**	**26,351**	**9,060**	**10,806**	**10,678**
Retirements (Coal)	1,418	2,591	10,380	5,659	6,158	20,126
Retirements (Nuclear)	0	0	0	2,716	620	0

(1) Wind capacity for 2014 and 2015 estimated, as proposed projects significantly exceed these estimates.

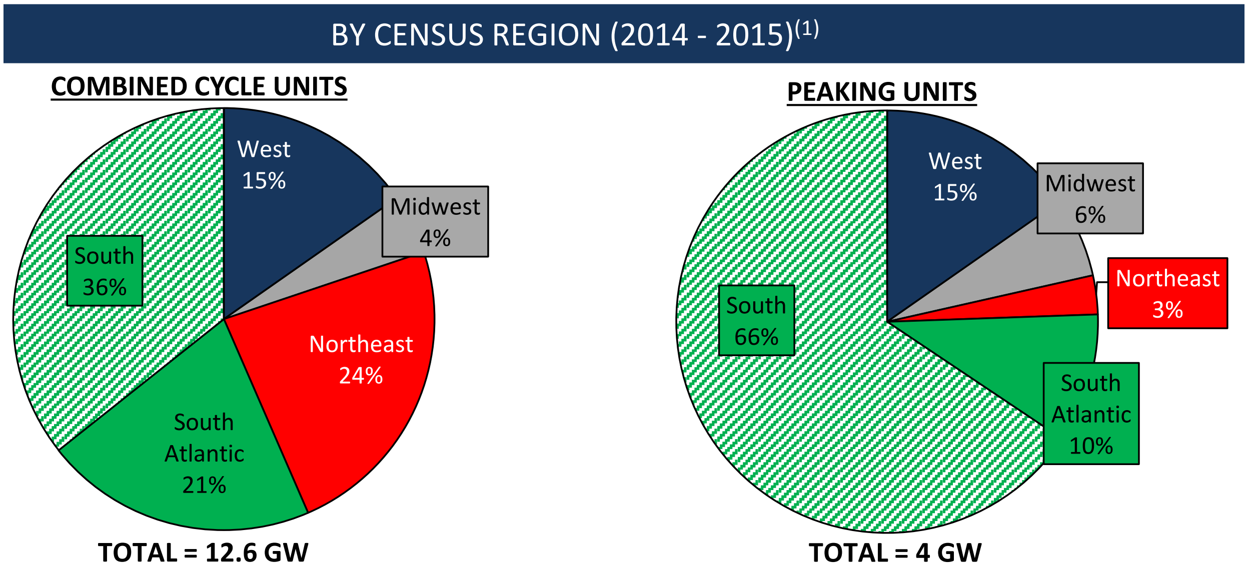
With respect to the 2015 coal retirements, the sharp increase is the net result of the April 2015 implementation of the EPA's MATS[12] regulations. As a point of perspective, it is difficult to estimate the forthcoming addition in wind capacity, because of the uncertainty over federal wind subsidies. At present there is uncertainty over whether the current federal wind subsidies, which in effect expire at year-end 2015, will be renewed. When a similar situation occurred in 2013, there was a rush to complete wind projects in the fourth quarter 2012 and a sharp reduction in the financing for these projects in 2013. A similar situation is likely to occur in 2015, if the uncertainty over the possibility of renewing these subsidies persists.

As illustrated in Exhibit 14, gas-fired combined cycle (CCGT) capacity continues to increase, which has been a consistent pattern over the recent past. Since 2010 gas-fired CCGT units and wind have accounted for over 80 percent of the capacity additions, when the peaking units are excluded, with CCGT units and wind each accounting for about 40 percent of the increase in non-peaking capacity.

Finally, with respect to the regionality of gas-fired capacity additions over the 2014 to 2015 timeframe, it is summarized in Exhibit 15. 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.

[12] Mercury Air Toxic Standards.

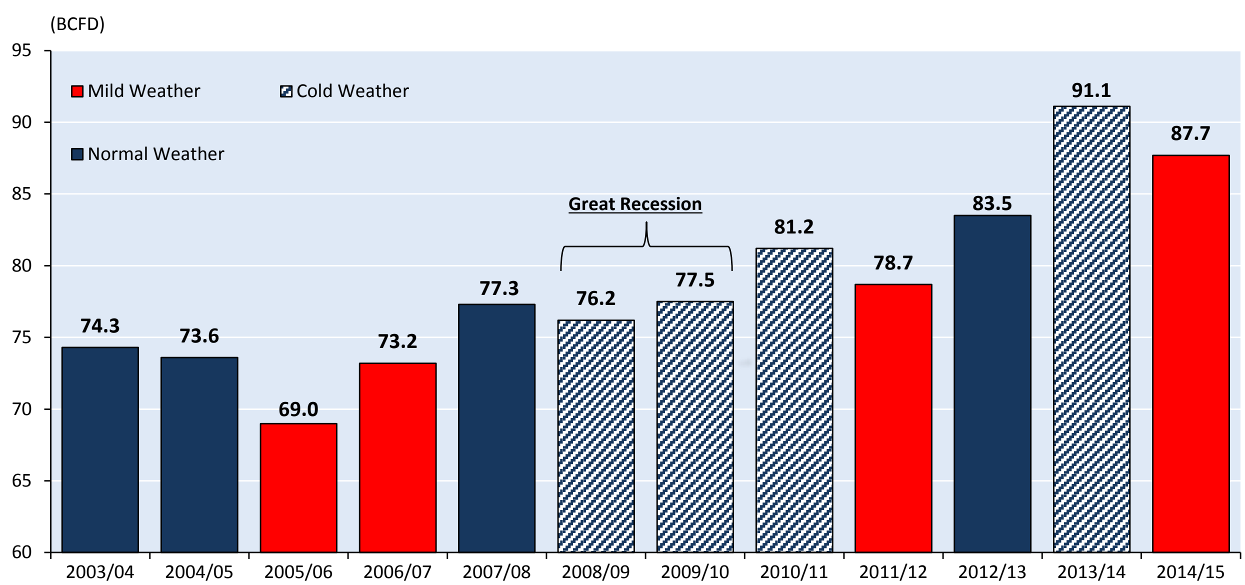
Exhibit 15. Gas-Fired Capacity Additions By Census Region (2014-2015)



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 16 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 below last winter's record demand (i.e., 3.4 BCFD, or 3.8 percent, below last winter's results).

Exhibit 16. Winter Natural Gas Demand For All Sectors



Outlook For Winter Supply

Overview

Total natural gas supply for the forthcoming winter will be less than for last winter, because of the expected reduction in winter gas consumption. Almost all of this decline will be the result of reduced requirements for storage withdrawals (i.e., 6.8 BCFD less), as illustrated in Exhibit 17. However, probably the most significant attribute to the outlook for this winter's gas supply is the expected increase in domestic production levels (i.e., 3.6 BCFD, or 5.3 percent), which is due to both (1) drilling activity, and (2) infrastructure events[13] increasing flowing gas supplies. Concerning imports, they are expected to decline about 0.8 BCFD, which is the net result of a modest increase in Mexican exports and a modest decline in Canadian imports.

Exhibit 17. Outlook For Winter Supply[(2)]

	Coming Winter (2014/2015)		Last Winter (2013/2014)		Change	
Supply Component	**BCF**	**Average BCFD**	**BCF**	**Average BCFD**	**BCF**	**Average BCFD**
Lower-48 Production[(1)]	10,694	70.8	10,156	67.2	538	3.6
Net Imports	491	3.2	613	4.1	(122)	(0.8)
Storage Withdrawals	1,946	12.9	2,978	19.7	(1,032)	(6.8)
Total	**13,131**	**87.0**	**13,747**	**91.0**	**(616)**	**4.0**

(1) Excludes Alaska production, which is approximately 166 BCF, or 1.1 BCFD in 2014/2015 and 144 BCF, or 0.95 BCFD in 2013/2014.

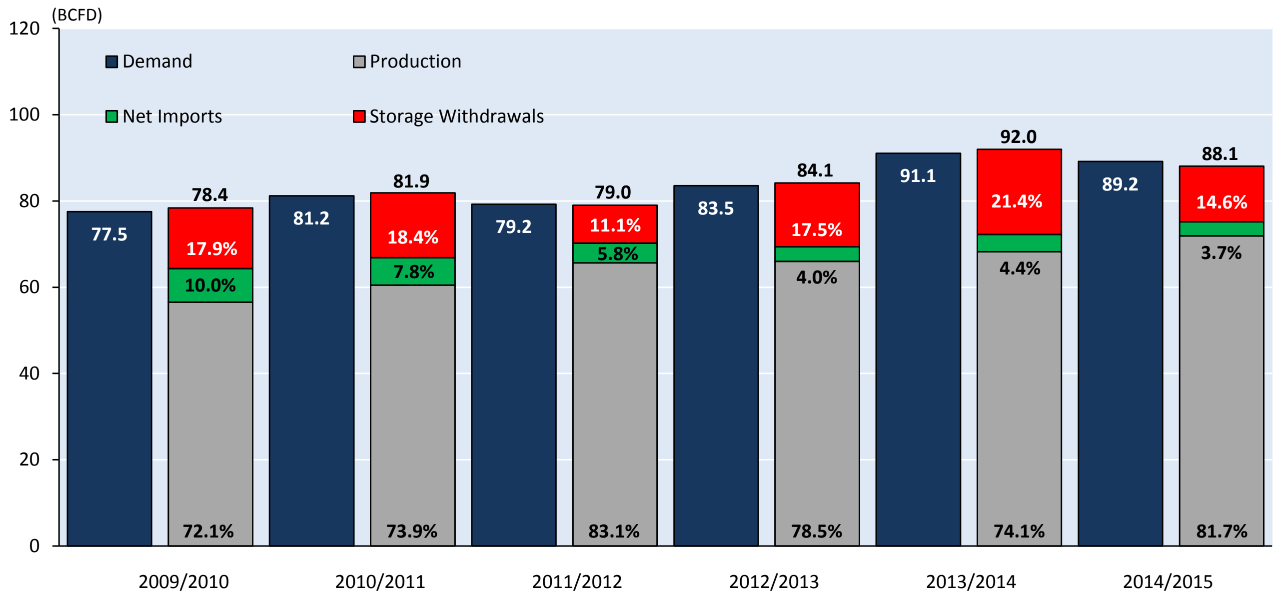
(2) Figures may not add due to rounding.

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 in early November as a result of new pipeline capacity coming online and providing takeaway capacity for stranded gas supplies (i.e., an infrastructure event). As discussed in subsequent sections of this report, the current assumption is that this infrastructure event will increase flowing gas supplies about one BCFD, however this assessment is debatable because of the minimal data available concerning the current stranded gas supplies.

In order to provide the reader with an additional perspective on the supply outlook for the forthcoming winter, Exhibit 18 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 18, namely (1) the growth in U.S. production (i.e., approximately 15.4 BCFD over the five year period); and (2) the decline in net imports (i.e., approximately 4.6 BCFD over the five year period). With respect to the former trend, the increase in domestic production is entirely due to increasing shale gas production, which has both increased in response to demand increases and increased to offset declines in conventional production. Lastly, the sharp increase in the reliance on storage withdrawals for the winter of 2013/2014 was due to the near record cold weather.

[13] 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.

Exhibit 18. Summary Of Winter Supply



Note: 2014/2015 is estimated.

U.S. Production

Overview

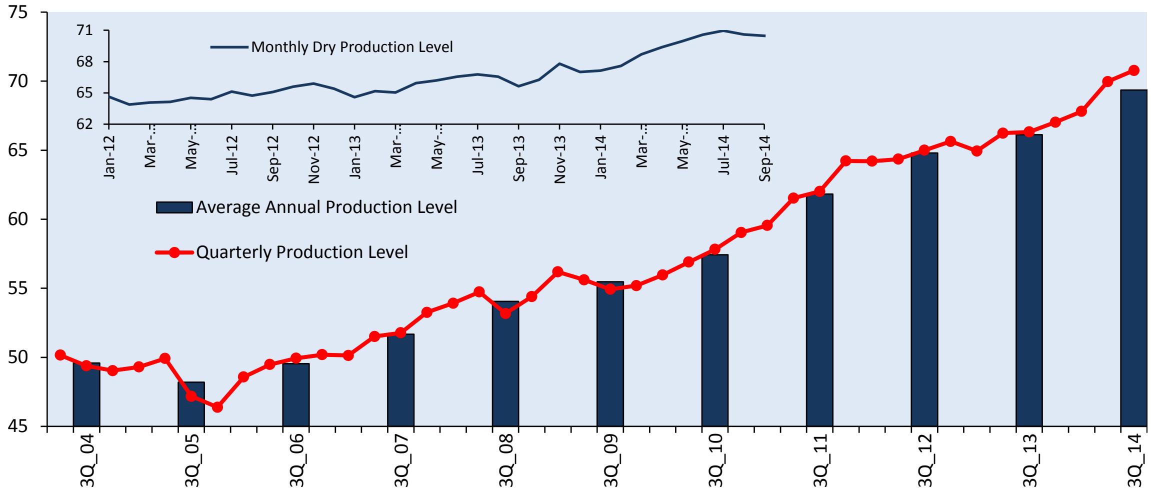
Currently increases in flowing gas supplies can occur via two different mechanisms, namely (1) directly from drilling activity and (2) from infrastructure events, which provide additional takeaway capacity for previously stranded gas supplies. The impact of both the outlook for the forthcoming winter's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

Current Assessment

With respect to current domestic production levels, Exhibits 19 and 20 summarize recent trends. Included in Exhibit 19 are annual and quarterly production levels for the Lower-48 (L-48) plus monthly trends for the last two years in the inset. In addition, Exhibit 20 provides daily production trends for the L-48 since November 2013, which represents the peak for 2013 production levels. The latter occurred because of the significant increase in flowing gas production levels that occurred as a result of the November 2013 infrastructure event.

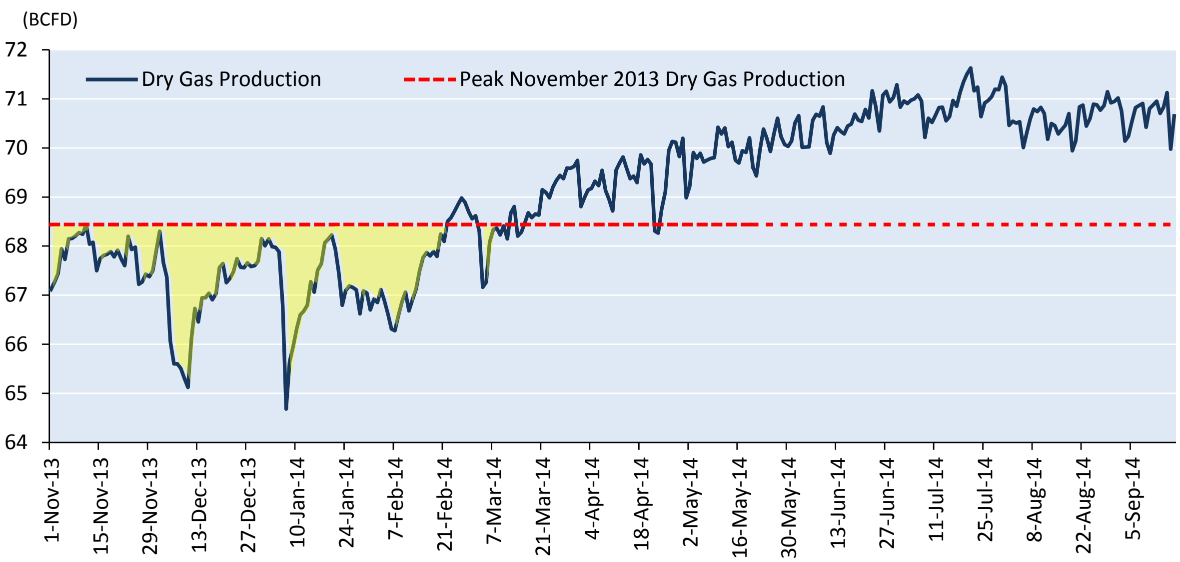
As noted in Exhibit 20, since the November 2013 peak, production levels have increased approximately 3.1 BCFD. As a point of perspective, the declines in production from November 2013 through March 2014 are a reasonable approximation of the well-freeze offs that occurred during the last winter (i.e., the area under the red dotted line, which is colored yellow). With respect to that the 3.1 BCFD increase in production since November 2013, this has occurred due to both (1) infrastructure events that have occurred during 2014 (e.g., the bringing online of Phase I of the Seneca Lateral and the Tioga Processing Plant) and (2) drilling activity throughout the course of the year. Furthermore, the infrastructure events to date account for about 20 percent of the increase, while drilling activity accounts for about 80 percent. Lastly, it is also noteworthy that since about mid-July domestic production levels have started to decline (0.8 BCFD). Some of this decline is likely due to seasonal maintenance.

Exhibit 19. Lower-48 Natural Gas Wellhead Production



Note: Bars represent average annual production levels, while dots on the line graphs represent quarterly production levels.
Source: Lippman Consulting, EVA.

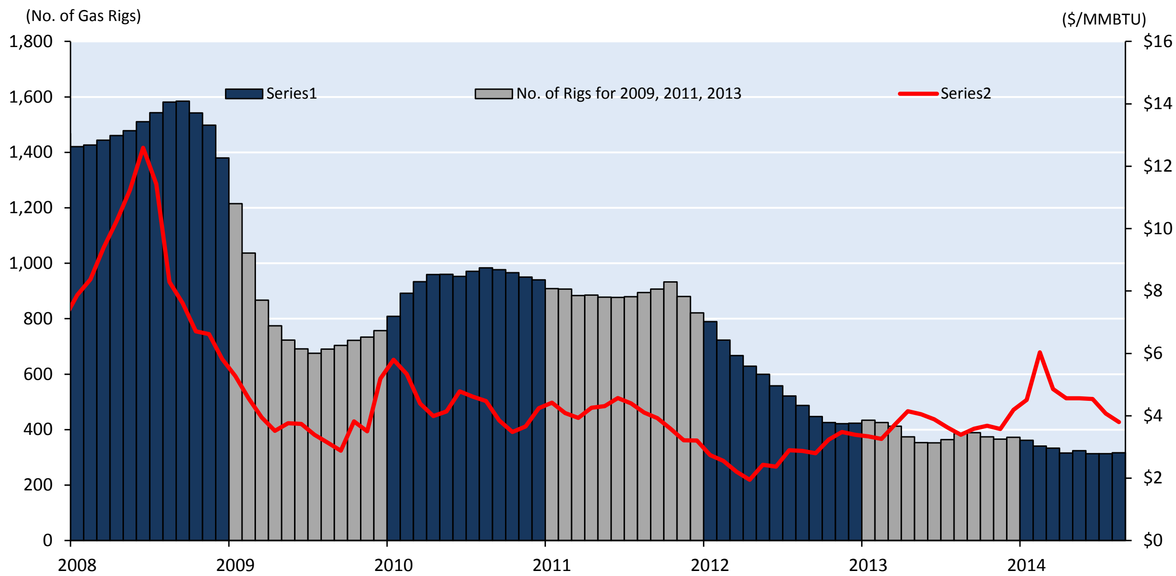
Exhibit 20. Lower-48 Daily Gas Production



Drilling Activity

At present gas-directed drilling activity is near an all-time low (see Exhibit 21) and is expected to stay near this level throughout the winter. The primary reason for the latter assessment is that many E&P firms have noted that they will not commence dry gas drilling programs until the return on these programs are at least equal to the returns for the other alternatives in their drilling portfolios, namely oil and liquids rich wells.

Exhibit 21. Rig Count For Gas Wells



Source: NGW.

A key component of the rig count noted in Exhibit 21 is the horizontal rig count for the major shale plays. When the Eagle Ford shale play is excluded,[14] the horizontal rig count for the remaining six major shale plays basically has been flat for 2014 and is discussed in more depth in the material below.

Infrastructure Events[15]

The other means of increasing flowing gas supplies is infrastructure events, which provides takeaway capacity for previously stranded gas supplies. While there have been a couple of these in the past, the most significant was in early November 2013 when flowing gas supplies increased about 1.5 BCFD within approximately three days, as a result of new pipeline capacity coming online. Furthermore, it is likely that a similar infrastructure event will occur in November 2014. Exhibit 22 compares and contrasts the pipeline capacity additions that occurred for the prior November with those that are scheduled to occur this November. As illustrated, the number of pipeline projects and capacity expected to come online this November are greater than that for last November. Concerning the latter, the cumulative capacity addition is not always a good measure, because it does not indicate the net capacity of a single transmission flow path.[16] Perhaps the most insightful comparison is the number and capacity of the major pipeline projects, which is about the same as last year.

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[14] The horizontal rig count for the Eagle Ford shale play, which includes many oil wells, has increased five rigs, or 2.2 percent, since the end of 2013.

[15] An addendum to this report provides additional discussion on both past and expected infrastructure events.

[16] 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.

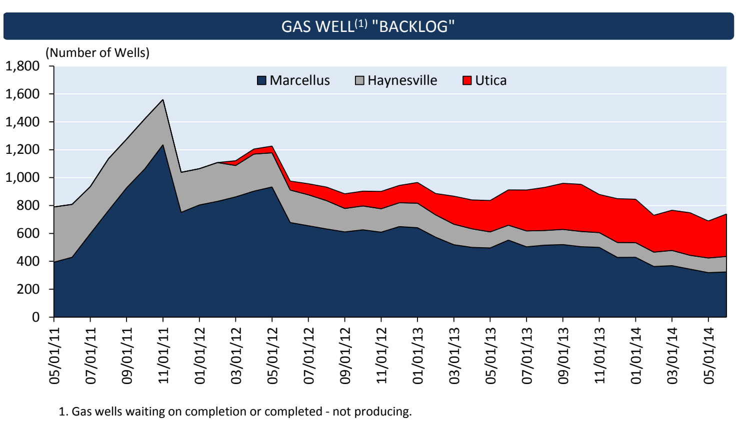
Exhibit 22. Comparison Of Pipeline Projects In 2013 And 2014 (September-November)

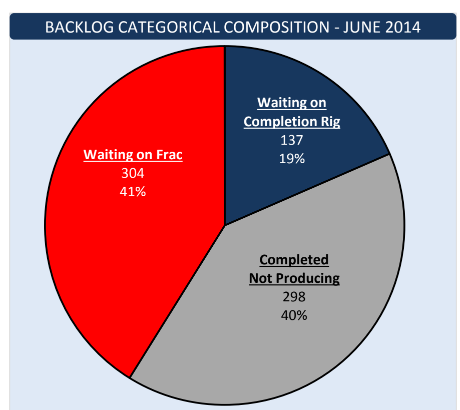
	2013	2014
Number of Pipeline Projects Online	13	14
Capacity of New Pipeline Projects (BCFD)	3.2	4.8
Number of Major Pipeline Projects Online	4	4
Capacity of Major Pipeline Projects (BCFD)	1.95	2.0

While it is known that there will be significant additions of pipeline projects in November 2014, 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 drilling but not yet connected wells. Exhibit 23 summarizes the history of the inventory of such wells for the three most significant shale plays affected by this phenomenon. As illustrated, the inventory of such wells has declined for both the Haynesville and Marcellus shale plays, while the inventory has increased for the relatively young Utica shale play. At present approximately 41 percent of the drilled but not yet connected wells are in the Utica shale play, which is significant because most of the scheduled new pipeline projects for November 2014 do not provide direct access to the Utica shale play.

Lastly, the pie graph contained in Exhibit 23 categorizes the composition of this inventory of wells. Some of these categories represent better candidates for connecting to the new pipeline projects than others. For example, the best category to have an immediate impact is the 'completed but not producing' category (40 percent), while the least likely category to have a significant impact is the 'waiting on a completion rig' category (19 percent), with the other category somewhere in between.

Exhibit 23. Inventory of Drilled But Not Yet Connected Wells





Integrating all of the above information, even though some of it is imprecise, yields an estimate of the impact of the forthcoming November 2014 infrastructure event which is that it will increase flowing gas supplies about 1.0 BCFD, which will improve the outlook for gas supplies for this winter.

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.

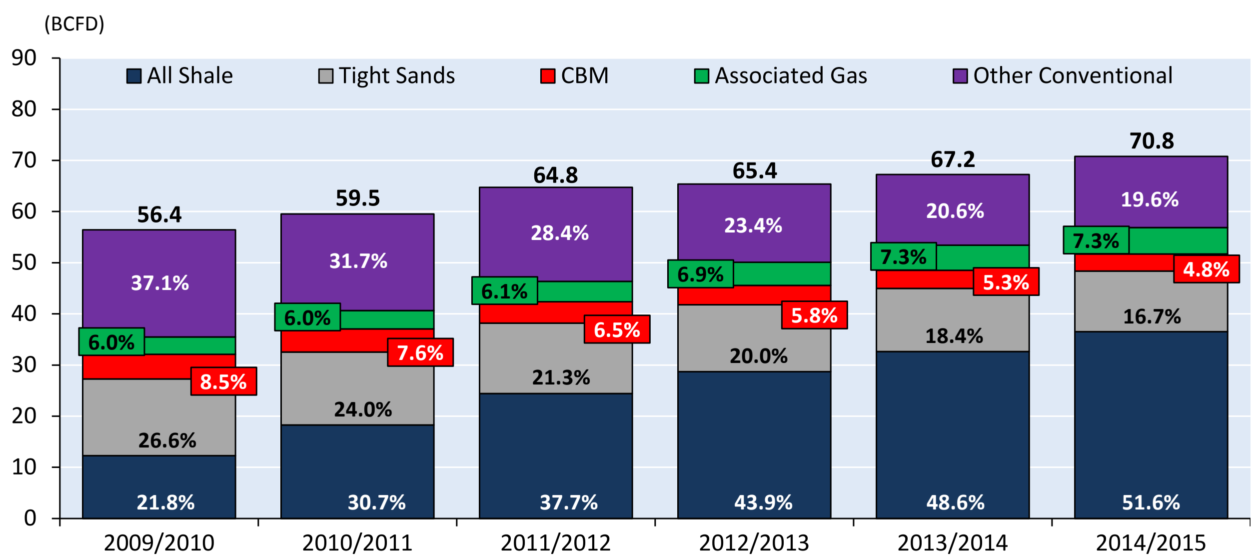
Several key trends are readily apparent in Exhibit 24 and include the following:

- **Increasing Production:** Over the last five winters domestic production has increased about 15.4 BCFD, which equates to about a 4.9 percent per annum growth rate.

- **Shale Production Surges:** All of this increase in domestic production is due to increases in shale production, which has met increases in demand, as well as offset declines in other forms of production. Overall shale production has increased approximately 24 BCFD, which equates to about a 24 percent per annum growth rate over the last five winters, with shale production now accounting for over 50 percent of total production.

- **Associated Gas**, which is gas production from oil wells, has increased about 1.1 BCFD, which equates to about a 43 percent per annum growth rate. However, this figure excludes the Eagle Ford shale play, which has an oil zone, a liquids zone and a dry gas zone, because the Eagle Ford play is already incorporated in the above assessment of shale production.[17]

Exhibit 24. Lower-48 Production Outlook For Winter



Note: 2014/2015 is estimated.

[17] Including Eagle Ford gas production within the associated gas category would result in a significantly higher growth rate for this category of gas.

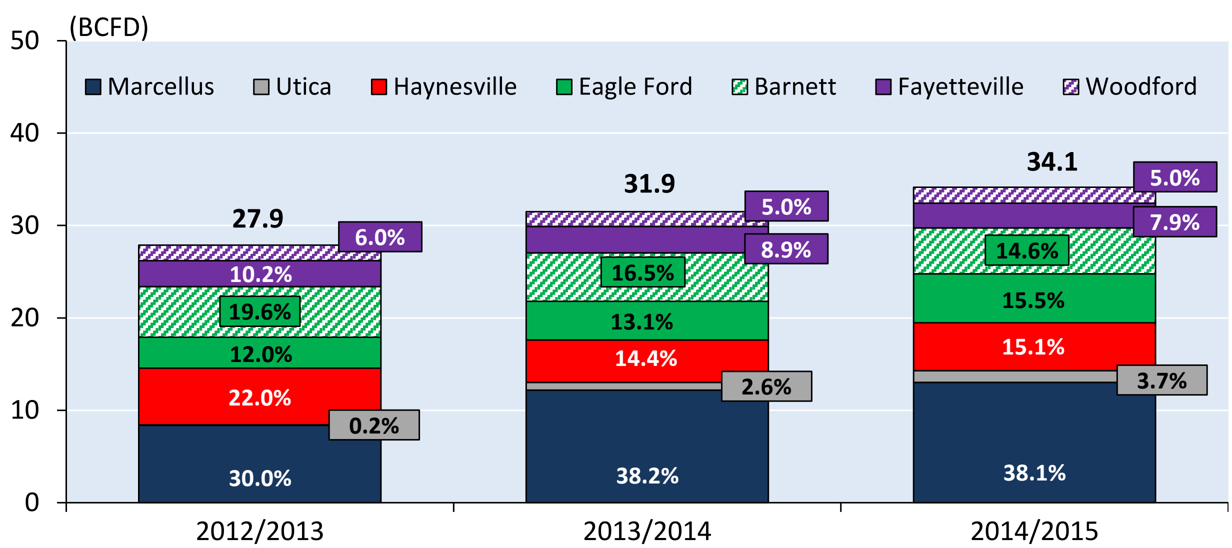
- **<u>Other Categories Declining</u>:** Gas production from conventional resources, as well as tight sands and coalbed methane (CBM), has been declining – 6.9 BCFD (9.1 percent per annum); 3.1 BCFD (4.7 percent per annum); and 1.5 BCFD (7.6 percent per annum), respectively. As a point of perspective, the one apparent bright spot for conventional production is the ongoing recovery in offshore production, following the de facto moratorium on offshore drilling following the BP Macondo oil spill (e.g., 22 offshore development projects are expected to come online in 2014, whereas in the three prior years only six, 15 and six offshore projects came online, respectively).

Shale Production

Exhibit 25 provides additional granularity on the increases in shale production during winter periods. As noted in Exhibit 25 the greatest growth among the major seven shale plays has occurred for the Marcellus shale, which now accounts for about 38 percent of the shale production from the major shale plays. Also, increasing over the last three winters is the Eagle Ford, which now represents the second largest contributor of shale production, and the still evolving Utica shale play.

As to the other shale plays, production from the Haynesville, Barnett and Fayetteville shale plays have been declining, although the production decline for Fayetteville has been rather limited. Lastly, production for the Woodford shale play has, in essence, been flat.

Exhibit 25. Winter Shale Production For The Seven Major Shale Plays



Note: 2014/2015 is estimated.

With respect to the overall trends for the seven major shale plays over the last several years, Exhibit 26 provides an overview of (1) production trends, (2) drilling activity, and (3) a few highlights for each play.

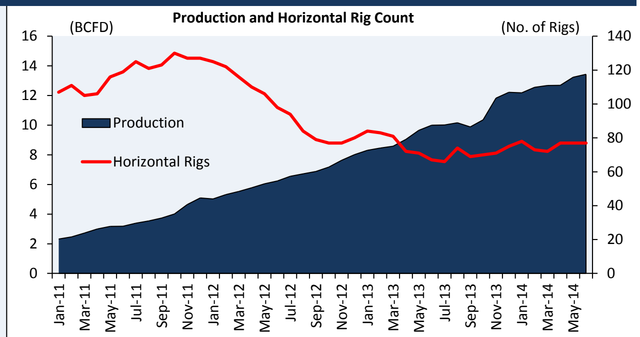
Exhibit 26. Overview Of Seven Major Shale Plays

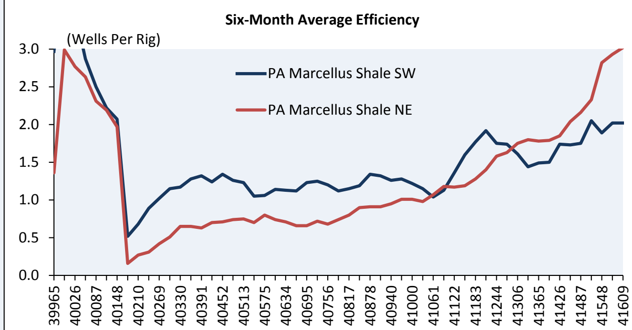
MARCELLUS SHALE PROFILE

The Marcellus Shale is the largest gas field in North America and has significant long-term potential. However, after five years of incredible growth that witnessed production doubling each year and annual increases of 3 BCFD, production for the Marcellus shale has begun to slow. For example, between November 2013 and November 2014 Marcellus production likely will only increase 10%, or 1.2 BCFD and projected gains for 2015 versus 2014, absent an infrastructure event, are for 7.5%, or 0.9 BCFD. This is in sharp contrast to increases in 2013, which were 28%, or 3.3 BCFD.

This flattening in the growth rate is attributable to the decline in drilling activity for the play (i.e., the rig count has declined from a peak of 130 rigs to 77 rigs, or 40%), which in turn is in response to the overall decline in gas prices and the need to generate returns competitive with new oil wells.

At present the Big Six in the Marcellus shale play, namely, Range, Antero Resources and EQT in the liquids rich area of southwest PA and Cabot and Chesapeake in the very thick dry gas area in northern PA. plus Southwestern Energy. Account for about 43 percent of incremental production additions. Many of the other producers (e.g., Chevron, Carrizo O&G, Hess, Newfield Exp and Anadarko), have reduced significantly their drilling activity in order to concentrate on higher returns in other plays.



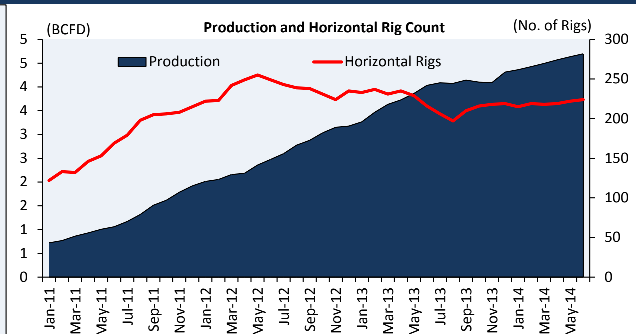


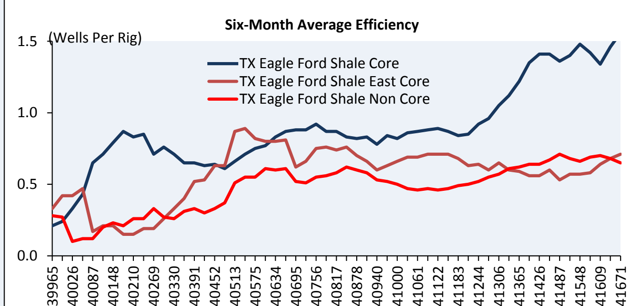
Source: Lippman Consulting

EAGLE FORD SHALE PROFILE

Eagle Ford gas production continues to increase, as does oil production from the Eagle Ford play (i.e., in 2014 Eagle Ford oil production is projected to average 1.2 MMBD, which is greater than the Bakken). As indicated, while drilling activity is slightly below prior peak levels, overall drilling activity in the play remains strong, with approximately 222 horizontal rigs currently active in the play. For 2013 about 80 percent of the 1.3 BCFD increase in Eagle Ford production was produced from the Core area of the play, which is oil prone.

Complementing this increase in associated gas was a 0.3 BCFD increase from the non-core area, which for the most part has a significant NGL component. Well economics for the latter, because of the liquids credit, can be viable at $1.00 per MMBTU gas prices.   Drilling activity for the play is very diverse, with the top 10 producers (e.g., EOG Resources, Conoco, BHP/Petrohawk, Chesapeake) accounting for less than 60% of the drilling activity.





Source: Lippman Consulting

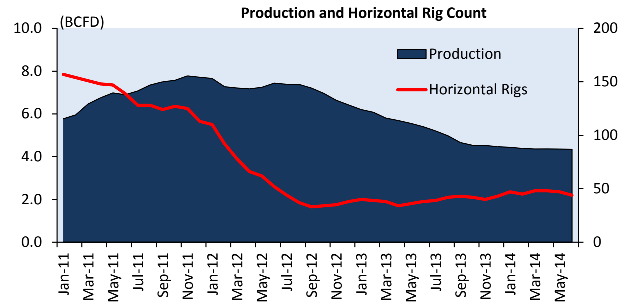
Exhibit 26. Overview Of Seven Major Shale Plays

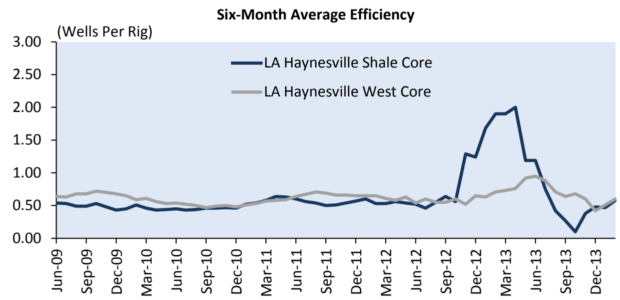
HAYNESVILLE SHALE PROFILE

The Haynesville shale play, which is a dry gas play, on average declined about 1.5 BCFD in 2013, with year end production levels being 3.1 BCFD below prior peak levels. Further declines of about 0.5 BCFD, or 9%, are expected in 2014. This decline is the net result of the decline in drilling activity, as the current horizontal rig count for the play (i.e., 47 rigs) is about 140 rigs below prior peak levels.

While parts of the play appear economic at sub -$4.00 per MMBTU gas prices, sustained gas prices at just above $5.00 per MMBTU are required to attain a 40% ROR in core areas, which would be required to compete with oil projects.

At present about 65% of the production in the play is controlled by five firms (Chesapeake, Exco, BHP/Petrohawk, Encana, and Southwestern). Chesapeake, in particular, has been able to attain returns >50% at current gas prices in its Core area acreage using its improved drilling techniques.



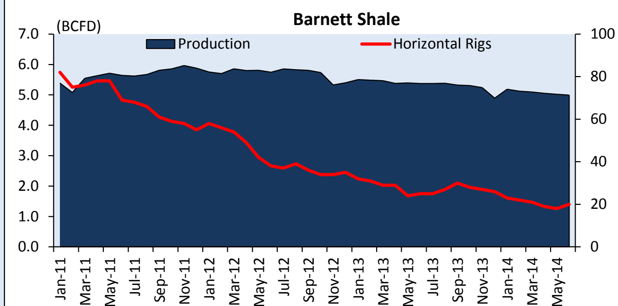


Source: Lippman Consulting

BARNETT SHALE PROFILE

Production from the Barnett shale play, which is the most mature of the seven major shale plays, declined 0.4 BCFD in 2013, with almost all of this decline occurring in the mature Core area of the play. Similar declines are expected in both 2014 and 2015. Drilling activity for the play has been in steady decline for the last nine months, despite the attractiveness of the Barnett Combo play, which has a significant liquids component. Expect drilling activity to continue to decline until gas prices on a sustained level reach $5.00 per MMBTU.

The top three producers (Devon, Chesapeake and Exxon/XTO) control slightly less than 50% of the production in the play. After that production and drilling activity is very diverse.



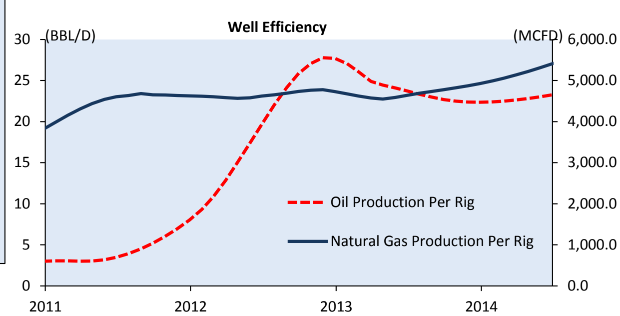
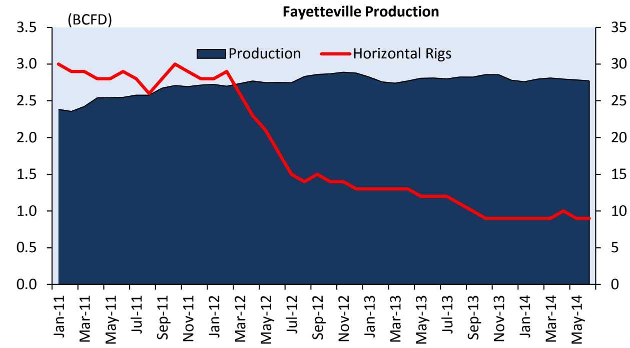


Exhibit 26. Overview Of Seven Major Shale Plays

FAYETTEVILLE SHALE PROFILE

After reaching a peak in late 2012 Fayetteville production has begun to decline and is expected to continue to decline moderately in both 2014 and 2015. This is occurring despite the success of Southwestern, which is the play's leader and controls about 900,000 acres in the Core area of the play, and improving well economics. The decline in production is the net result of a decline in drilling activity, as the rig count for the play has been in steady decline for about two years and currently is at only nine rigs.

Southwestern accounts for about 65% of the production in the play. The next largest players are BHP and Exxon/XTO, which controls about 28% of the production and significant amounts of acreage in the non-Core area.

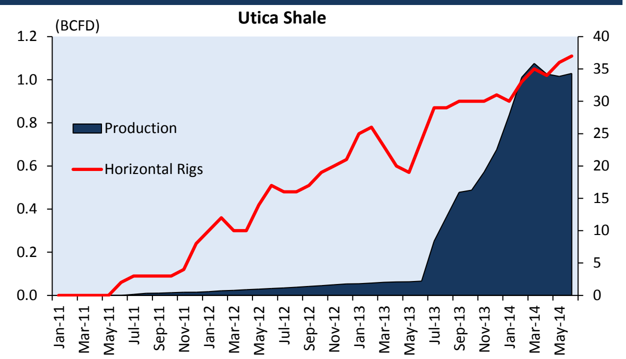


UTICA SHALE PROFILE

The Utica shale play, which is still in its infancy, remains a wild card. While several firms (e.g., BP, Shell, Hess, Carrizo O&G and EQT) have left the play, others (e.g., Chesapeake, Rice Energy, AEP, Rex and Magnum Hunter) continue to be active.

In addition, while it initially was thought that the attractive part of the play would be the oil prone area to the north, it has turned out that the Core area is likely the gas prone area to the south (Carrol and Columbia countries in OH) and the area to the north will be abandoned. While results to date have been mixed, there have been some monster wells with Rice Energy reporting a well with an IP of 40 MMCFD.

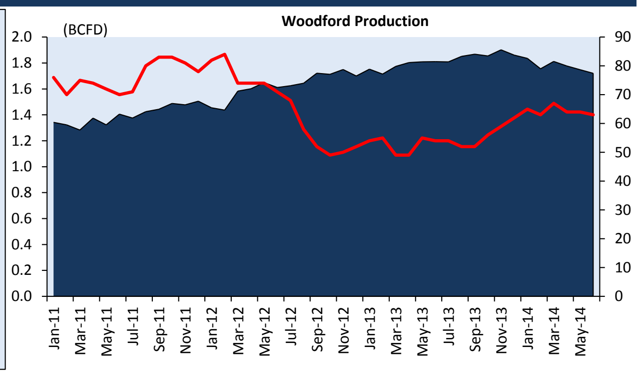
Drilling activity in the play has increased over the last year to the current 36 rigs. With respect to production it is projected to increase between 0.6 and 0.8 BCFD in 2014.



WOODFORD SHALE PROFILE

Production for the Woodford shale, which consists of three segments, has been relatively flat for the last year and likely will continue this trend in 2014. The current rig count for the play, which has some liquids rich areas, is 64 rigs, which is about 10 rigs above year ago levels.

Activity in the play is fairly diverse with the top five firms (Chesapeake, Devon, BP, Newfield and Exxon/XTO) accounting for slightly more than 40% of the play's production.



Gas Well Completions

Another indicator of overall gas-directed drilling activity is the number of gas well completions. These are illustrated on both a monthly and annual basis in Exhibit 27.[18] As an added point of perspective the inset table in Exhibit 27 notes for the years 2012, 2013 and 2014 the average number of shale well completions per month.[19] As illustrated the average number over the three years has been relatively flat.

While there is a time lag between changes in the gas-directed rig count and gas well completions, the basic pattern for both metrics for gas-directed drilling activity is very similar. More specifically, monthly gas well completions have been declining since late 2010 and appear to have reached a low point. With respect to annual gas well completions they have been declining since the 2006 to 2007 timeframe. There are several factors driving these trends towards fewer gas well completions, included in these are the following:

- **Shift in Industry Focus:** Initially this decline was attributable to the industry switching from developing conventional gas resources to developing shale gas resources. The well productivity of shale gas resources is much higher than that for conventional gas resources, which resulted in the need for fewer gas wells.

- **End of an Era:** The era of over drilling, when E&P firms were focused primarily on preserving their acreage positions, has come to an end. At present the industry as a whole seems to be much more judicious about when to develop gas wells, particularly for those plays without significant liquids credits. The latter occurs because in most cases gas prices at present are inadequate of and by themselves to yield acceptable returns.

- **Additional Improvements in Technology:** More recently the industry has begun to adopt further improvements in drilling and completion technology, which improves overall efficiency and thus, further reduces the need for additional gas wells. Examples of such improvements in technology include the use of mega-pads, particularly for the development for stacked plays.[20]

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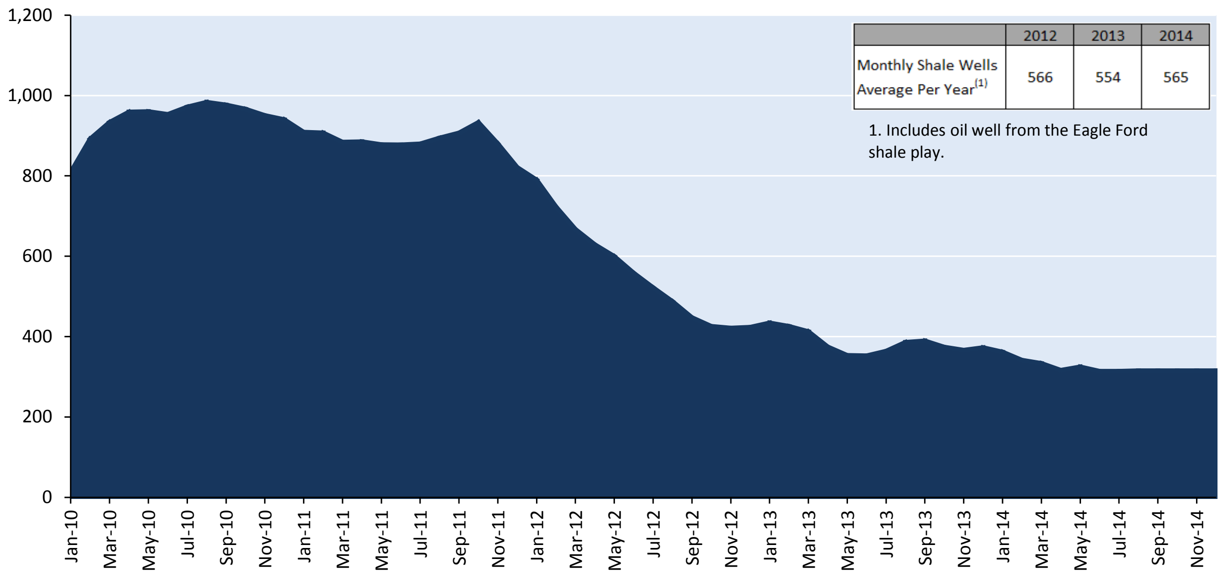
[18] See the Appendix for a tabular presentation of the data.

[19] This data is not directly comparable to the other data contained in Exhibit 17 in that it includes the oil wells from the Eagle Ford shale play. Nevertheless, it does provide an added perspective.

[20] The industry has started to adopt the practice of drilling stacked plays, which can significantly lower well economics. In the case of the southwest region for the Marcellus it is possible to develop three different formations (Upper Devonian, Marcellus and Utica) from the same well pad, or mega-pad. While the EUR for least attractive formations likely will be well below that for the most attractive formation, the reduction in costs to drill the additional well from the same pad is substantial, since there are no additional acreage costs, plus roads, water management, gas lines and compressor stations already are installed and rig movement and downtime is minimal. This approach can cut the cost of the incremental two wells by two-thirds. At present the industry is testing drilling up to 30 wells from a single mega-pad.

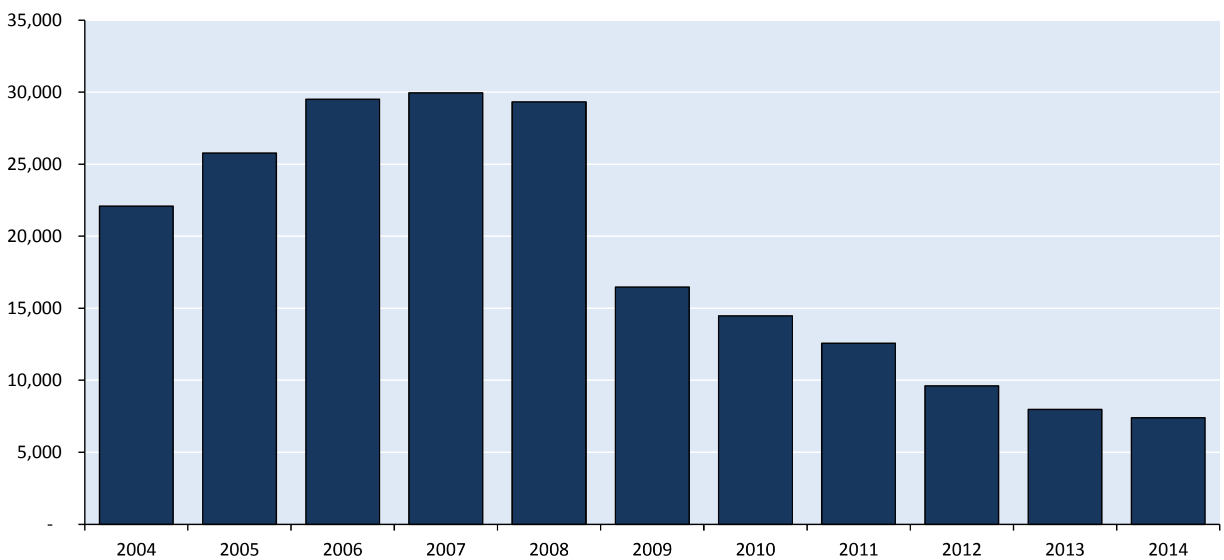
Exhibit 27. Natural Gas Well Completions

Monthly Natural Gas Well Completions



Note: API.

Annual Natural Gas Well Completions



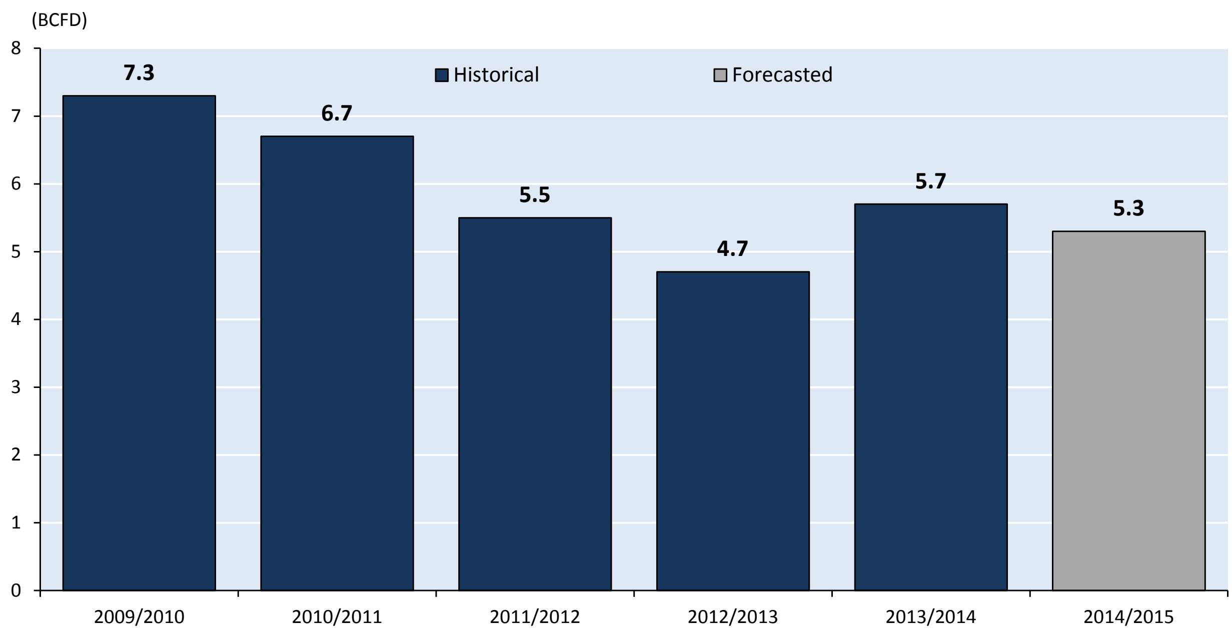
Note: API.

Imports/Exports

Canadian Imports

Net Canadian imports this winter likely will be below the very high levels of Canadian imports last winter (see Exhibit 28). As a practical matter, last winter's imports, which were driven by the severe winter weather and the associated gas prices, likely represented a temporary peak in Canadian imports. For the forthcoming winter Canadian imports will be close to the average for the winters of 2011/2012 and 2012/2013.

Exhibit 28. Outlook For Net Winter Canadian Imports

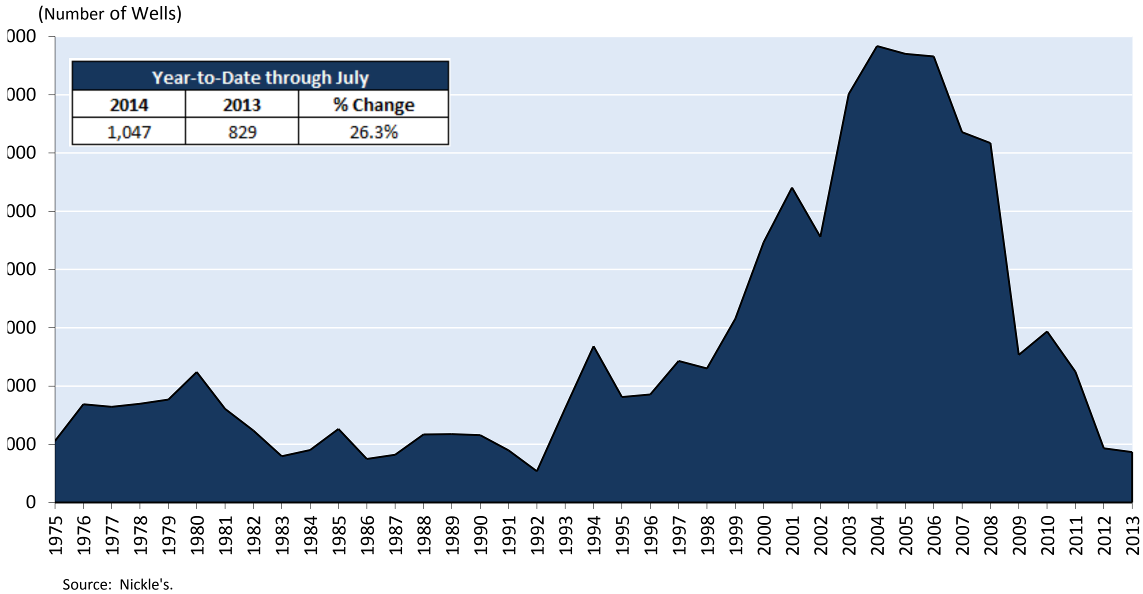


With respect to the longer term trends for Canadian imports, which on an annual basis have been declining for the last eight years, the overall decline in Canadian production appears to be flattening out after seven years of steady decline. While conventional production, particularly in Alberta, still represents one of the major marginal sources of supply for the North American market, recently its steady annual decline has been offset by increases in the level of (1) associated gas from Canada's shale/tight oil plays and (2) Canadian shale gas production. Concerning the latter, Canada has five very prolific and economic shale plays that it is just starting to develop.[21]

Underlying this modest growth in Canadian production is a reversal in the trend for declining gas well completions in Canada. As illustrated in Exhibit 29, after seven years of relatively steady decline Canadian gas well completions flatten out in 2013 and began increasing – albeit moderately – in 2014.

[21] Canada has five very prolific and economically viable shale plays, namely the Montney, Horn River, Cordova Embayment, Duvernay and Laird Basin plays.

Exhibit 29. Canadian Gas Well Completions (Number of Wells)

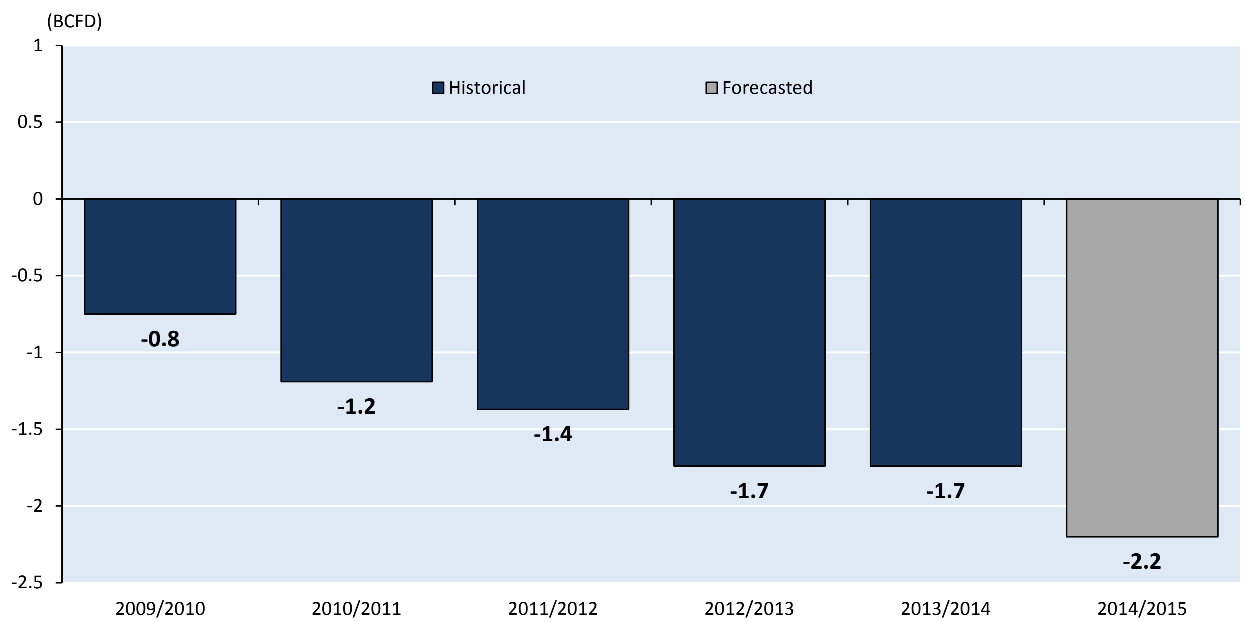


The net result of an integrated assessment of the above is that the sharp decline in Canadian imports in the past is likely over and future imports over the next few years likely will be relatively flat, although seasonal factors could result in some variances.

Mexican Exports

As illustrated in Exhibit 30, net exports to Mexico have been increasing and are expected to continue this trend during the forthcoming winter.

Exhibit 30. Outlook For Winter Net Mexican Exports



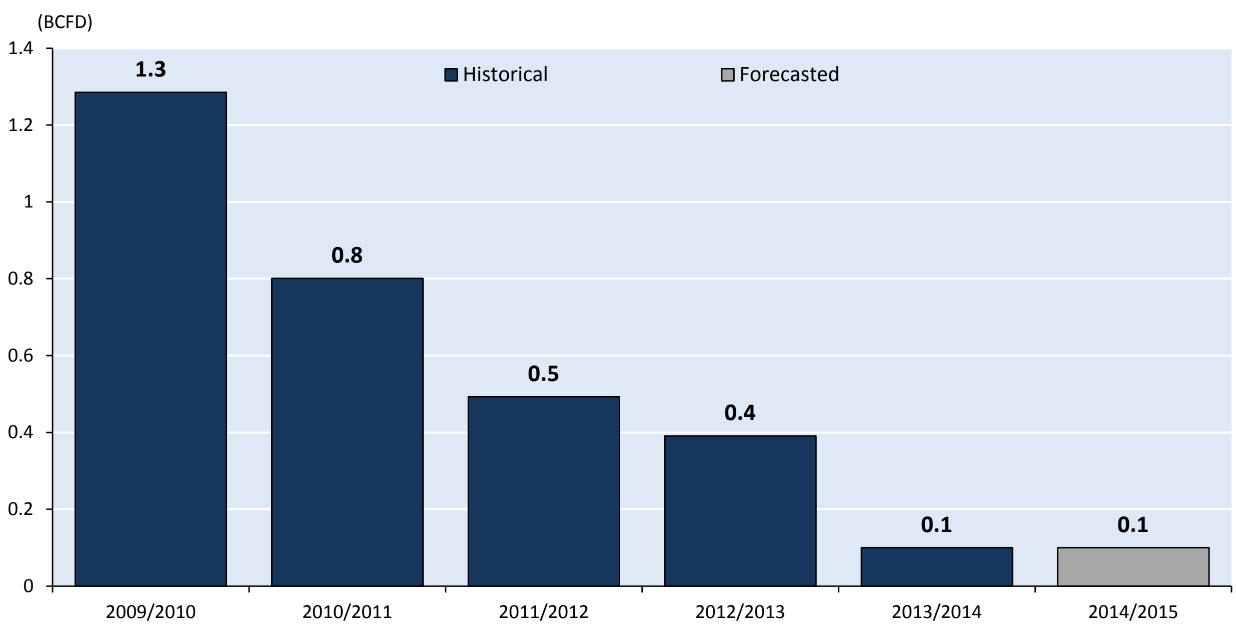
The primary reason for this increase in Mexican exports is that the Mexican economy is fairly robust, which has caused gas demand within the country to grow. At the same time Mexico's domestic production is flat to declining and LNG imports are declining, because of their high cost. While these fundamentals within Mexico create a need for more imports from the U.S., the key elements facilitating this increase in imports are (1) a major expansion in Mexico's pipeline infrastructure and (2) the shale gas revolution within the U.S. and, in particular, in the Eagle Ford shale play.

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. As discussed in an addendum to this report, Mexico is in the process of relieving this bottleneck with the construction of three new pipeline systems, which are scheduled to come online between 2013 and 2016 and in total represent 4.8 BCFD of new pipeline capacity.

LNG Imports

The U.S. no longer requires LNG imports, except for specific regional requirements. This has been the major factor in the decline of U.S. LNG net imports over the last several years (i.e., see Exhibit 31). With respect to the forthcoming winter, U.S. LNG net imports are expected to, in essence, be the same as last winter, with almost all the imported supply going to the Everett, MA terminal to supply the New England market and thus, help that region meet its winter gas requirements. As an added point of perspective, winter LNG imports have been less than LNG imports during the non-winter period, primarily because the increase in global LNG prices during the winter often results in cargoes being diverted to more attractive markets.

Exhibit 31. Outlook For Winter Net LNG Imports

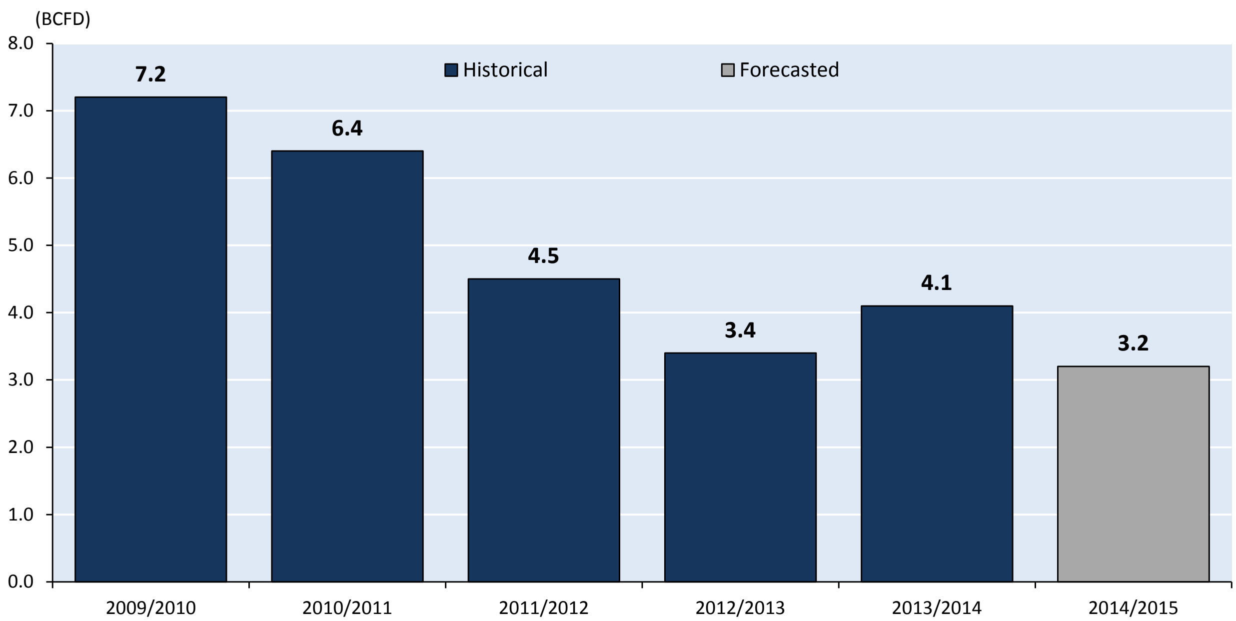


With respect to the possibility U.S. LNG exports, this likely will not occur until 2016. At present there is only one L-48 liquefaction facility under construction, however two others have received the required FERC and non-free trade (non-FTA) permits and are expected to commence construction in the near future. Addendum IV to this report provides an overview of all 45 of the proposed North American liquefaction projects, and the intense competition between these projects, as well as their competition with other viable liquefaction projects elsewhere in the world for a growing, but still limited, global market for LNG.

Composite Summary

Net imports for the forthcoming winter are expected to be approximately 3.2 BCFD, which is 0.8 BCFD, or about 20 percent, less than the net imports for the last winter (i.e., see Exhibit 32). As previously discussed, this decline is due to an increase in Mexican exports and a decline in Canadian imports.

Exhibit 32. Outlook For Winter Net Imports

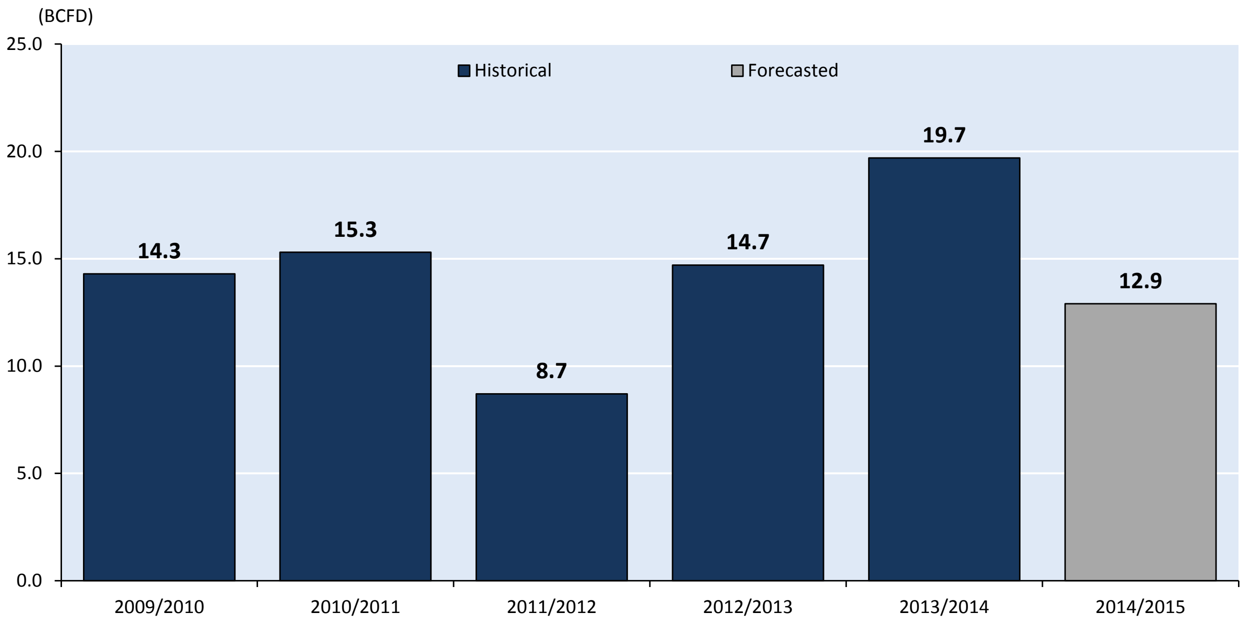


Storage Withdrawals

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 below storage withdrawals for the prior winter.

More specifically, the current projections are for about a 6.8 BCFD, or 35 percent, decline in storage withdrawals. As noted in Exhibit 33, 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 33. Outlook For Storage Withdrawals



With respect to the outlook for storage levels at both the beginning and the end of the forthcoming winter season, these are summarized in Exhibit 34. The estimate for storage levels at the beginning of winter (November 1, 2014) is for storage inventories to be well below any of the last five years and likely will be on a par with 2008 (i.e., 2014 estimate is 3,440 BCF). While this only represents a 79 percent of total existing working gas storage capacity, the reduced levels of withdrawals this winter will result in season-ending March 31, 2015 storage inventories being about 1,600 BCF. The latter is about 85 percent above storage inventories at the beginning of this season, which represents a significant change for the industry.[22]

Conclusions

Assuming slightly warmer than normal weather for the forthcoming winter, natural gas supply should be below the record supply levels that existed for the prior winter (i.e., see Exhibit 35). More specifically, there will be significant increases in L-48 production levels that are offset by a sharp decline in storage withdrawals.

[22] March 31, 2015 estimated storage inventories are still below 2009, 2010, 2011, 2012 and 2013 levels.

Exhibit 34. Projected U.S. Natural Gas Storage Levels

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

	Actual							Est
	2007	2008	2009	2010	2011	2012	2013	2014
Total Working Gas Capacity at Start of Injection Season(1)	3,593	3,665	3,754	3,925	4,049	4,188	4,264	4,332
Annual Capacity Additions	72	89	171	124	139	76	68	5
Total Working Gas Capacity at End of Injection Season	3,665	3,754	3,925	4,049	4,188	4,264	4,332	4,337
Storage Level at the Start of Winter (Nov 1)	3,567	3,399	3,810	3,851	3,804	3,929	3,816	3,440
Percent of Capacity	97%	91%	97%	95%	92%	92%	88%	79%

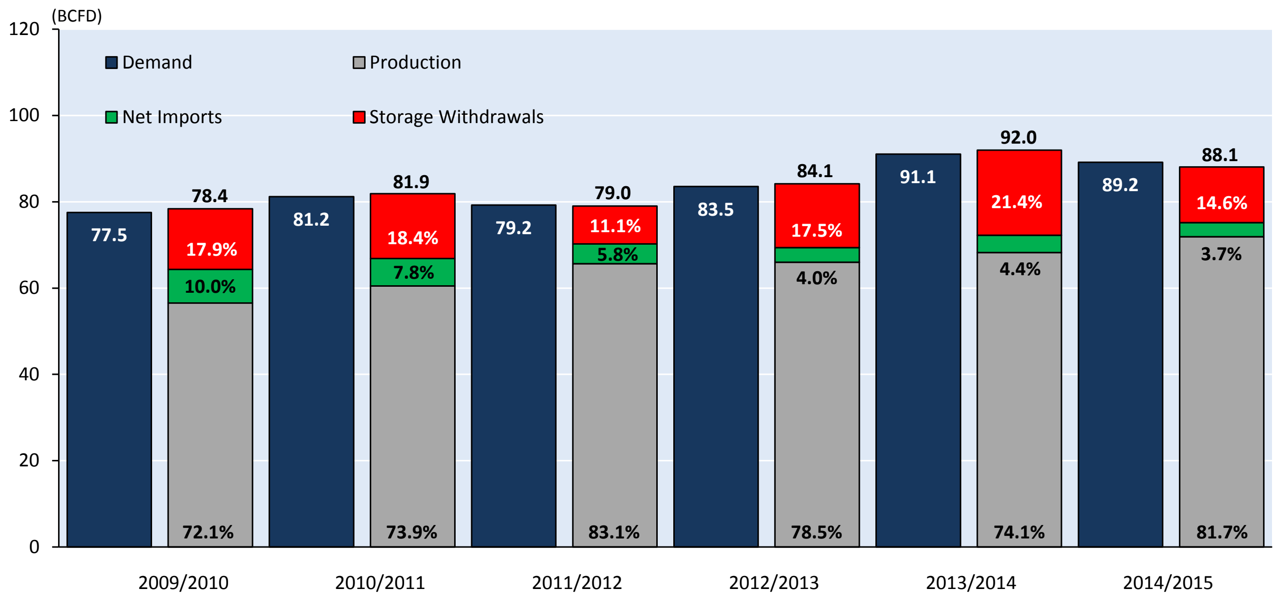
(1) Effective maximum usable working capacity.

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

	Actual							Est
	2008	2009	2010	2011	2012	2013	2014	2015
Total Working Gas Capacity at Start of Injection Season(1)	3,665	3,754	3,925	4,049	4,188	4,264	4,332	4,337
Annual Capacity Additions	89	171	124	139	76	68	5	0
Total Working Gas Capacity at End of Injection Season	3,754	3,925	4,049	4,188	4,264	4,332	4,337	4,337
Storage Level at the Start of Spring (April 1)	1,234	1,675	1,652	1,577	2,473	1,723	857	1,600
Percent of Capacity	34%	45%	42%	39%	59%	40%	20%	37%

(1) Effective maximum usable working capacity.

Exhibit 35. Summary Of Winter Supply



Note: 2014/2015 is estimated.

ADDENDUM I

OVERVIEW OF INDUSTRIES BUILDING NEW FACILITIES

Overview of Industries Building New Facilities

Overview

As noted in the body of the report, five key industries are expanding capacity primarily because they foresee an era of sustained relatively low gas prices. The following is a brief overview of these industries and their planned 100 restarts of previously shuttered facilities, expansions and new plants.[23]

Prolonged low gas prices have begun to usher in a resurgence of U.S. industrial growth, led by new investments in a number of sectors, including fertilizer and petrochemicals. With over 100 projects being tracked by EVA (with an even greater number announced and unlikely to proceed), EVA projects these projects alone will add more than 5.4 BCFD of new natural gas demand through 2020 – an increase of industrial sector demand of more than 25 percent.

This rapid growth is no less than a complete reversal of the trend seen since the beginning of the last decade. High gas prices compounded by the Great Recession resulted in a drop of more than 5.2 BCFD from 2000 through 2009. While there has been growth as the country has emerged from the Great Recession, much of the future growth will come from new sources of demand, namely the 100 projects. Sixty-three (63) of the 100 projects represent new, greenfield projects, while the remainder are expansions and restarts of existing facilities. With respect to the increase in gas demand for the sector, it is fairly well balanced between the various industries, except for the steel and the paper and pulp industries which make relatively small contributions. More specifically, the expansions in the chemical, fertilizer and gas-to-liquids (GTL) industries individually will result in excess of one BCFD of additional gas demand.

Gas-To-Liquids

Of all the assorted project types in the industrial space, none offers larger potential point load demand than gas-to-liquids. At present there is one major GTL project (i.e., Sasol's two train project) and five micro-GTL projects.

Petrochemicals And Methanol

As a result of the combination of low-cost natural gas and the associated low-cost petrochemical feedstocks, the U.S. petrochemical market is seeing a resurgence once thought of as impossible. Throughout much of the early 2000s, declining plastics and polymer demand combined with high gas prices made for a challenging environment for the historically gas-based petrochemicals in the U.S. With many global petrochemical plants using lower cost naphtha and liquefied petroleum gases (LPG), like propane and butane, as feedstocks for petrochemicals, many industry analysts speculated that the U.S. would not be able to compete within the global petrochemical market. The latter was reinforced by petrochemical investments in the Middle

[23] Prior Demand Outlooks by NGSA contained a longer and more complete assessment of the capacity expansions with the industrial sector. This assessment is a more abbreviated version of the prior one, with some updates.

East, as countries, such as Saudi Arabia and Qatar, positioned themselves to capitalize on the low cost ethane in their countries to rapidly expand global petrochemical capacity.

What has happened since the birth of the shale revolution has been just the opposite, as the Middle East continues to underperform in meeting their aggressive downstream/ petrochemical plans, while the U.S. has laid the foundation to continue to grow itself as the world's largest producer of olefins and aromatics-based petrochemicals. This competitiveness extends well beyond the Middle East, as Europe and Asia historically have produced their petrochemicals such as ethylene and propylene, from higher cost liquids-based feedstocks.

In addition to increased ethane consumption, EVA forecasts that there will be 1.2 BCFD of incremental natural gas demand required to meet increased energy requirements at new and expanded petrochemical facilities. This growth will manifest itself in the form of 33 new petrochemical projects across the U.S. Gulf and Northeast. Twenty-six (26) of these projects are dedicated to creating ethylene (primarily sourced from ethane), while the remaining seven (7) are focused further downstream on producing ethylene/propylene derivatives. The owners and operators of these new plants represent a diverse set of global petrochemical players, and are outlined in Exhibit Add I-1.

In addition to petrochemical facilities, EVA has been tracking the rapid growth in what was once a niche industry – methanol. At the beginning of 2011, U.S. methanol capacity was 0.78 MMTPY. Since then, a number of previously idled facilities have been restarted, such as LyondellBasell's Channelview, TX plant, along with an additional 7.5 MMTPY of new capacity by 2020. These new plants, along with the forecasted restarts, are expected to add about 1.0 BCFD of new gas demand by 2020.

Steel

Natural gas demand also likely will grow within the steel industry, albeit at a relatively slow rate. This growth will occur because at projected gas prices it is more economical to use natural gas for the energy component (i.e., not the raw material component) of steel making than it is to use coking coal. This displacement of coking coal by natural gas for the energy component likely will occur via two different mechanisms. One mechanism will be the use of natural gas injection in blast furnaces.[24]

With respect to the second mechanism, this involves the use of natural gas to fuel direct reduction iron (DRI) operations, which is an alternative and less energy intensive process of producing iron. The sponge iron from DRI operations can be used as a feedstock for either an electric arc furnace, or potentially a blast furnace.[25]

[24] Currently about 40 percent of U.S. steel is made in blast furnaces, while the remainder is made via electric arc furnaces.

[25] Electronic arc furnaces primarily use scrap steel for feedstock, but there is a limited supply of scrap steel.

Exhibit Add I-1. Industrial Project List by Type

This chart excluded from this report because it contains Energy Ventures Analysis proprietary data.

Contact EVA for more information:
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At present, Nucor has announced plans to build a new DRI plant in St. James Parish, Louisiana that will use natural gas, while the French firm Vallourec and Mannesmann Holding, Inc. plans to build a new steel plant in Youngstown, Ohio that will use natural gas. Similarly, U.S. Steel is evaluating the use of natural gas at some of its operations. U.S. Steel noted the use of natural gas would reduce raw steel costs between $6 and $7 per ton. Furthermore, U.S. Steel indicated that the cost to increase their ability to inject greater quantities of natural gas into their blast furnaces would be minimal.

Fertilizer

As the world's largest importer of fertilizer, reduced natural gas prices have created an enormous opportunity for lower cost domestic producers to push out production from other countries. As a result, a series of projects to expand U.S. fertilizer capacity have been announced. The projects making up this new capacity are expected to be divided into demand-located versus supply-located facilities, with the former located in the Midwest and then later on and around the U.S. Gulf. The largest projects will consist of a greenfield fertilizer plant in Weaver, IA by Egyptian manufacturer Orascom, as well as large expansions by CF industries in Donaldsonville, LA and Deerfield, Illinois. In total there are 28 fertilizer projects that have accomplished at least one milestone in a path towards a completed project. If all of these projects are completed industrial sector gas demand would increase approximately 1.9 BCFD.

Timeline

As illustrated in Exhibit Add I-2, over the 2014 to 2015 timeframe, 36 industrial capacity expansion projects are expected to come online that will have the net effect of increasing industrial sector gas demand approximately 0.9 BCFD, assuming mid-year timing and an average 90 percent capacity factor.

Exhibit Add I-2. Timeline For Industrial Capacity Expansion Projects

	2012	2013	2014	2015	2016	2017	2018	2019
Number of Projects Online	10	11	17	19	15	13	7	2
Increase in Industry-Side Gas Demand (BCFD)	0.20	0.33	0.31	0.60	0.87	0.87	0.75	0.55

ADDENDUM II

INFRASTRUCTURE EVENTS

Infrastructure Events

Background

In November 2013 flowing gas supplies increased 1.55 BCFD within a period of a few days because a series of new pipeline projects were brought online that provided take away capacity for previously stranded gas supplies. Furthermore, this is not the first time in the recent past that an infrastructure event has caused an increase in flowing gas supplies. For example, in November 2011 when Tennessee expanded its 300 Line (0.35 BCFD) the line was full within two to three days.

Outlook For November 2014

There is a reasonable likelihood that a similar infrastructure event will occur in November 2014, as 10 new pipeline projects with a cumulative capacity of 2.8 BCFD are scheduled to come online. Additive to this are two pipeline projects that are scheduled to come online in September (1.0 BCFD). While the cumulative capacity figures are one metric, they do not fully reflect that amount of new gas supplies that could come online, as it often takes several pipeline projects to form a single transmission path (e.g., a new gathering system and pipeline expansion project).

With respect to potential forthcoming infrastructure events, Exhibit Add II-1 compares and contrasts the pipeline projects scheduled to come online in the September to November 2014 timeframe with those pipeline projects that came online last September to November. As illustrated, the two infrastructure events from the perspective of the number of pipeline projects coming online and the associated capacity are similar.

Exhibit Add II-1. Comparison Of Pipeline Expansion Projects In 2013 And 2014 (September-November)

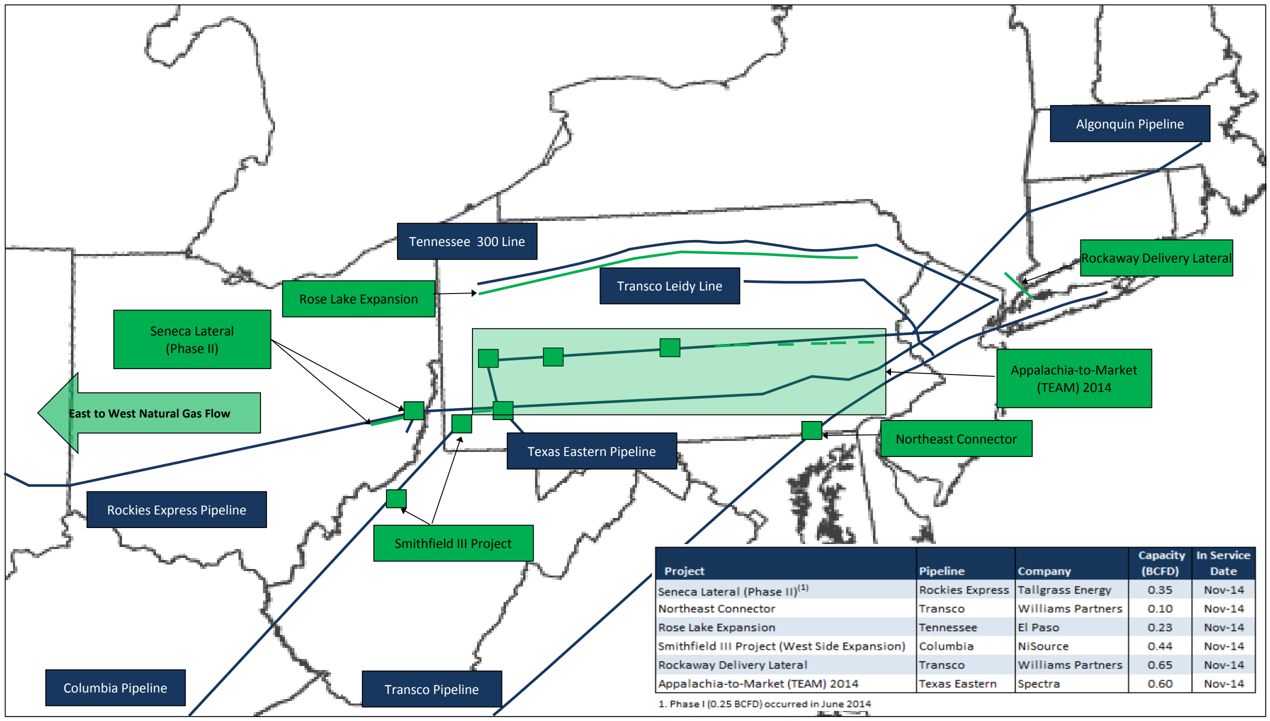
	2014	2013
Number of Pipeline Projects Online	14[1]	13
Capacity of New Pipeline Projects (BCFD)	4.8	3.2
Number of Major Pipeline Projects Online	4	4
Capacity of Major Pipeline Projects (BCFD)	2.0	1.95

1. Two of these pipeline projects (1.0 BCFD) are in Arizona.

With respect to the location of several of the major important pipeline projects scheduled to come online in November 2014, Exhibit Add II-2 provides a simplified map.

Lastly, as discussed in the body of the report it is estimated that the November 2014 infra-structure report will increase flowing gas supplies about one BCFD.

Exhibit Add II-2. Scheduled Additions To Northeast Infrastructure In November 2014



Project	Pipeline	Company	Capacity (BCFD)	In Service Date
Seneca Lateral (Phase II)[1]	Rockies Express	Tallgrass Energy	0.35	Nov-14
Northeast Connector	Transco	Williams Partners	0.10	Nov-14
Rose Lake Expansion	Tennessee	El Paso	0.23	Nov-14
Smithfield III Project (West Side Expansion)	Columbia	NiSource	0.44	Nov-14
Rockaway Delivery Lateral	Transco	Williams Partners	0.65	Nov-14
Appalachia-to-Market (TEAM) 2014	Texas Eastern	Spectra	0.60	Nov-14

1. Phase I (0.25 BCFD) occurred in June 2014

ADDENDUM III

EXPORTS TO MEXICO

Exports To Mexico

Mexican Exports

Since 2010 U.S. exports to Mexico have been increasing and likely will approach 5.0 BCFD by 2020. The primary reason for this increase in Mexican exports is that the Mexican economy is fairly robust, which has caused gas demand within the country to grow. At the same time Mexico's domestic production is flat to declining and LNG imports are declining, because of their high cost. While these fundamentals within Mexico create a need for more imports from the U.S., the key elements facilitating this increase in imports are (1) a major expansion in Mexico's pipeline infrastructure and (2) the shale gas revolution within the U.S. and, in particular, in the Eagle Ford shale play.

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. As illustrated in Exhibit App III-1, Mexico is in the process of relieving this bottleneck with the construction of three new pipeline systems, which are scheduled to come online between 2013 and 2016 and in total represent 4.8 BCFD of new pipeline capacity. Importantly, Mexico for the first time is using foreign contractors (i.e., Sempra and TransCanada) to build a significant portion of this new infrastructure.

In addition, as illustrated in Exhibit Add III-2, the U.S. is expanding its export capability at both new and existing locations.

As illustrated in Exhibit Add III-3, the combination of this expansion in pipeline infrastructure and the growing gas demand within Mexico's industrial and electrical sectors will increase exports to Mexico to close to 4.9 BCFD in 2020. After that the pace of the growth in exports to Mexico likely will slow to about 0.05 BCFD per annum, as the combination of increasing gas prices and the development of Mexico's own gas resources begins to occur.

With respect to the latter, to date PEMEX has a dismal record in developing the countries gas resources due to the combination of (1) a lack of capital, (2) a lack of technical expertise to drill gas shale resources and (3) domestic laws inhibiting the use of foreign firms. However, Mexico is making significant strides in overcoming the latter obstacle, as illustrated by the recent contracts with foreign firms to build new gas pipeline infrastructure within the country, and the reforms currently being implemented by Mexico's president. It is anticipated that further steps in this area will allow the use of foreign firms, with their superior drilling and completion technology, to develop the country's own shale and offshore gas reserves. In addition, joint ventures with these firms will help resolve their dilemma of inadequate capital. While the true impact of these events will take some time, in the post-2020 timeframe it is likely that Mexico will start expanding its own production, with the most likely candidate for onshore reserves being the Eagle Ford shale that extends across the Rio Grande River.

Exhibit Add III-1. Pipeline Expansion Projects Facilitating Increased U.S. Exports To Mexico

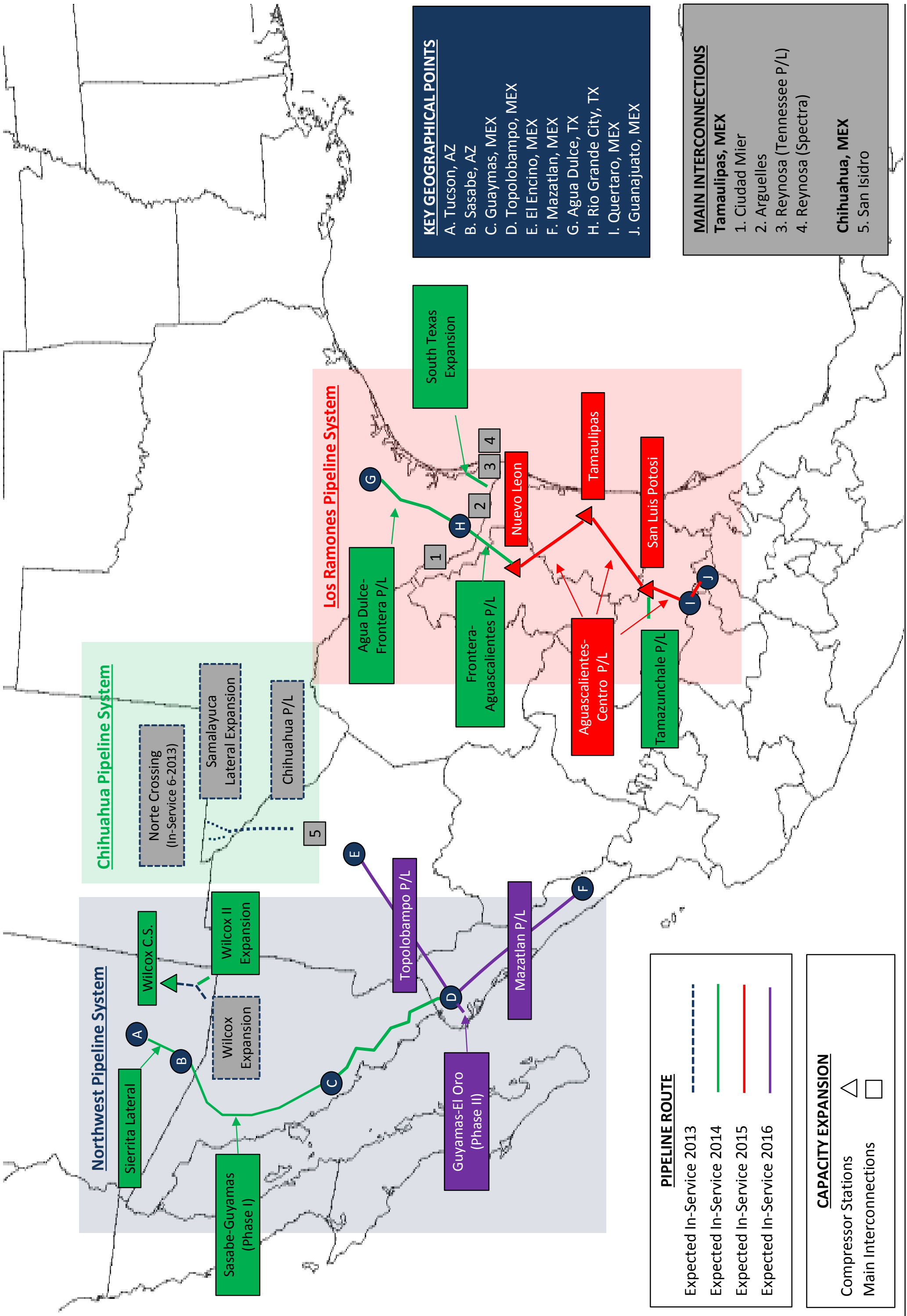
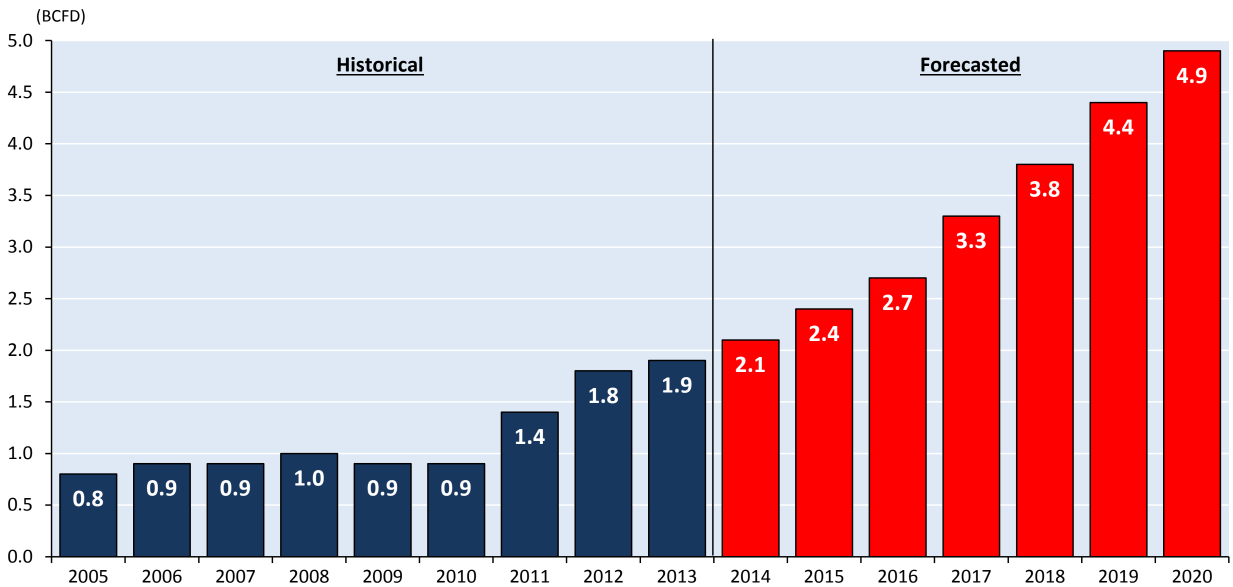


Exhibit Add III-2. U.S. Pipeline Projects Facilitating Increased Exports To Mexico

Project	Location	Capacity (BCFD)	Distance (Miles)	Online	Operator	Connects To
Wilcox Lateral Exp I	Cochise City, AZ	0.19	0	Apr-13	EPNG	Existing System
Norte Crossing	El Paso, TX	0.37	1	Jul-13	EPNG	Chihuaha Pipeline
Samalayuca Lateral Exp	El Paso, TX	0.10	1	Jul-13	EPNG	Chihuaha Pipeline
Wilcox Lateral Exp II	Cochise City, AZ	0.09	11	Jan-14	EPNG	Existing System
South Texas Exp	Texas	0.30	1	Jun-14	TETCO	Existing System
Sierrita Lateral	Sasabe, AZ	0.81	60	Oct-14	EPNG	Northwest Pipeline System
Agua Duke-Fronterra Pipeline	Rio Grande City, TX	2.10	124	Dec-14	New Midstream (Pemex)	Los Ramones Pipeline
Kinder Morgan Texas PL Phase I/II	Salineno, TX	0.33	-	2014	Kinder Morgan	Kinder Morgan Mexico Pipeline
Tucson-Sasabe Pipeline	Sasabe, AZ	0.77	60	2015	Mitsui(3)	Unknown

Exhibit Add III-3. Projected U.S. Natural Gas Exports To Mexico



ADDENDUM IV

LNG EXPORTS

LNG Exports

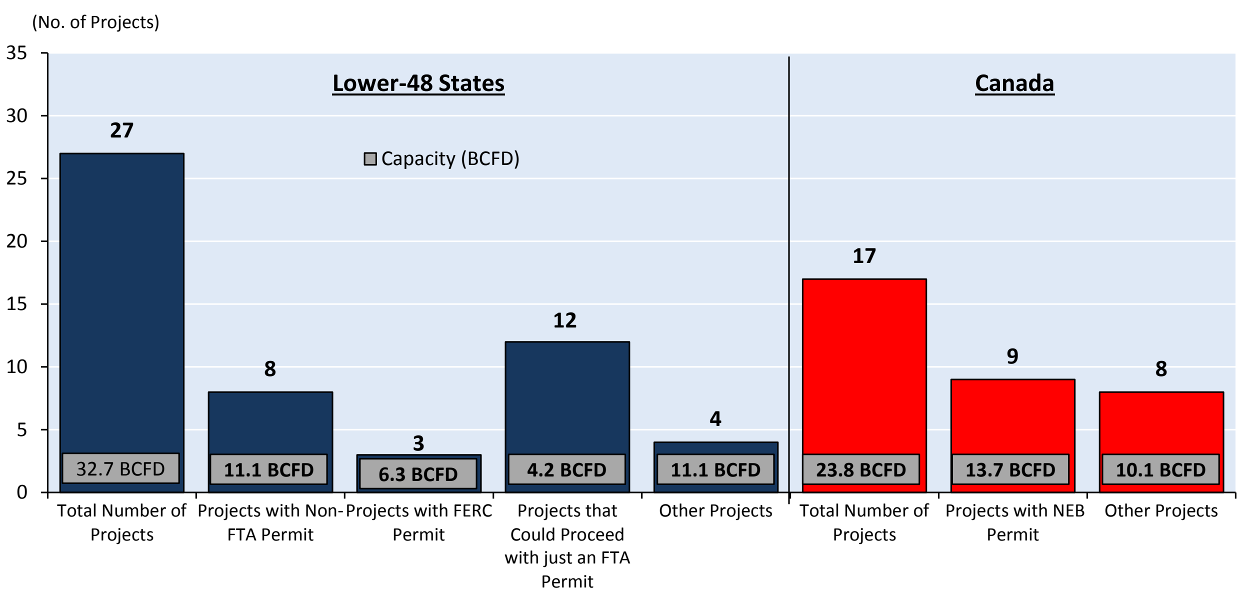
Overview

While not a factor this year, in 2016 the Lower-48 will start exporting LNG. While initial exports will be small (0.8 BCFD), they are expected to ramp up over the next six years to reach approximately 9.8 BCFD.[26] Additive to this will be LNG exports from Canada and eventually Alaska in about 2025. While this represents a credible base case, there remain a number of potential scenarios, primarily because of uncertainty over permits, competition for market share and conflicting third-party interests.

Current Status

As illustrated in Exhibit Add IV-1, at present only eight of the proposed 27 Lower-48 liquefaction projects have both free trade country (FTA) permits[27] and non-FTA permits, however only three of these seven projects have yet been able to secure the required FERC permit. At present only one of these projects is under construction, namely Trains 1-4 for the Sabine Pass project. Potentially additive to these projects with both FTA and non-FTA permits are a series of 12 smaller proposed projects that could proceed with just FTA permits. This latter group of projects is focused on serving the Caribbean and South American markets, which have several free trade countries. However, competition between these projects is keen and the market is limited.

Exhibit Add IV-1. Proposed North American Liquefaction Projects



[26] Assumes an 85 percent capacity factor.
[27] There are 20 free trade countries, namely Australia, Bahrain, Canada, Chile, Colombia, Costa Rica, Dominican Republic, El Salvador, Guatemala, Honduras, Israel, Jordan, South Korea, Mexico, Morocco, Nicaragua, Oman, Panama, Peru and Singapore.

Also, noted in Exhibit Add IV-1 is that nine of the 17 proposed Canadian liquefaction projects have obtained National Energy Board (NEB) permits. At present none of the Canadian projects are under construction, as most of Canada's larger liquefaction projects still are trying to resolve natural gas pipeline issues with the indigenous First Nations groups. The best estimate for the start of Canadian LNG exports is about 2019.

Competition/Market Share

The Lower-48 projects to date have done a superb job in securing offtake contracts, despite significant competition from liquefaction projects elsewhere in the world. As noted in Exhibit Add IV-2, to date Lower-48 projects have been able to secure offtake commitments totaling 13.8 BCFD, however some of these are non-binding commitments. Of this 13.8 BCFD in commitments approximately 72 percent, or 10 BCFD, are incorporated in the base case assessment.

Exhibit Add IV-2. U.S. LNG Commitments to Date (BCFD)

This chart excluded from this report because it contains Energy Ventures Analysis proprietary data.

Contact EVA for more information:
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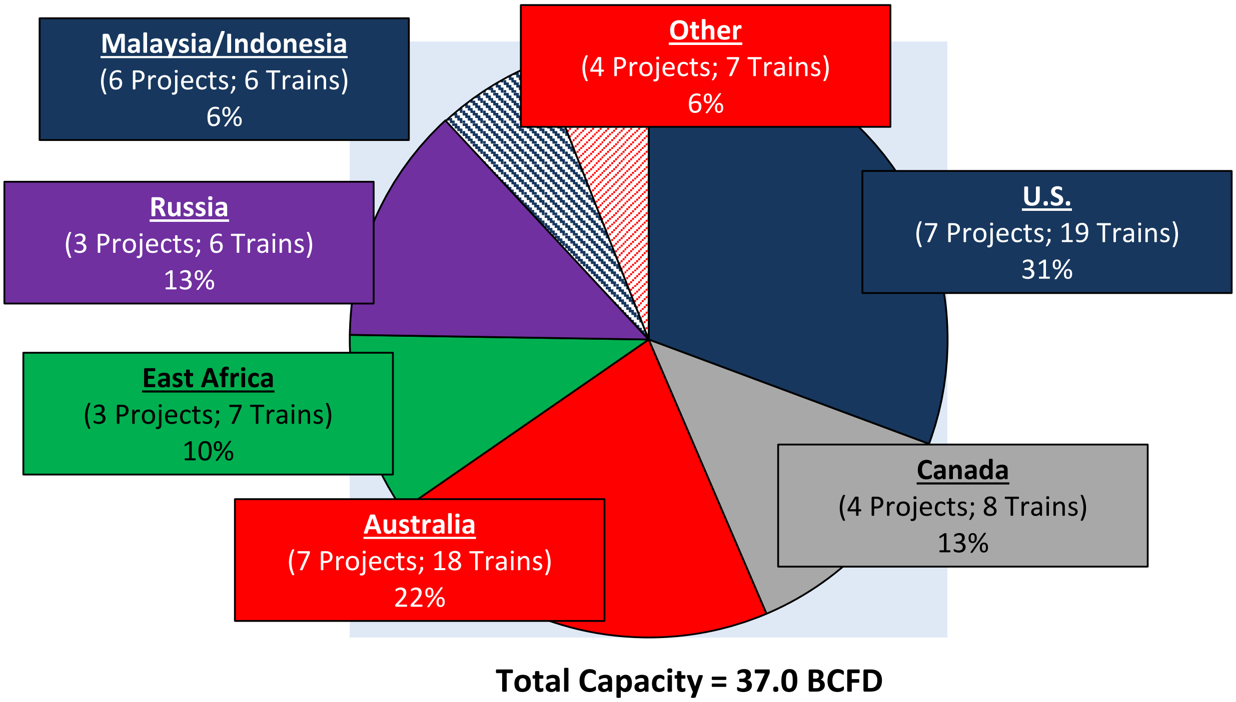
North America, excluding the small existing liquefaction plant in Alaska, was not a part of the global LNG exporting community until about 2010, when the first filings for FTA permits started to occur. In the ensuing years, both U.S. and Canada have made significant strides in becoming major participants in the global LNG exporting community. For example, while neither U.S. or Canada, excluding Alaska, have exported LNG in the past, they are projected to provide about 44 percent of the world's incremental LNG supply during the 2014 to 2020 period. This phenomenon is summarized in Exhibit Add IV-3, which identifies by country the likely liquefaction capacity to come online during the 2014 to 2020 timeframe. While there may be a few questions about the Russian projects and the exact timing of the U.S. projects, many of the projects identified in Exhibit Add IV-3 are either under construction or have reached a final investment decision (FID). As a point of perspective, the total capacity of the projects presented in Exhibit Add IV-3 is about 37 BCFD, which would, in essence, increase the current global liquefaction capacity by 120% (i.e., more than double it).

Exhibit Add IV-3. Incremental LNG Supply for 2014-2020 (BCFD)



Timeline For U.S. Liquefaction Project

The base case assessment for L-48 LNG exports is that seven projects[28] consisting of 19 trains will be built, as summarized in Exhibit Add IV-4. Furthermore, LNG exports from these seven LNG projects will ramp up over time and eventually reach 9.8 BCFD, assuming an average fleet capacity factor of 85 percent.

Exhibit Add IV-4. Timeline for L-48 Liquefaction Projects

	2016	2017	2018	2019	2020	2021	2022
Number of Trains Coming Online	3	3	5	4	3	1	0
Capacity of New Trains (BCFD)	2.2	1.7	2.7	2.5	1.9	0.5	0
Expected Avg LNG Exports (BCFD)	0.8	2.5	3.9	6.3	8.7	9.5	9.8

[28] The seven projects are Sabine Pass (Trains 1-5); Freeport (1-31), Cameron (1-3), Cove Point (1), Lake Charles (1-3), Corpus Christi (1-2) and both phases of Kinder Morgan/Shell's micro-LNG project at Elba Island.

ADDENDUM V:

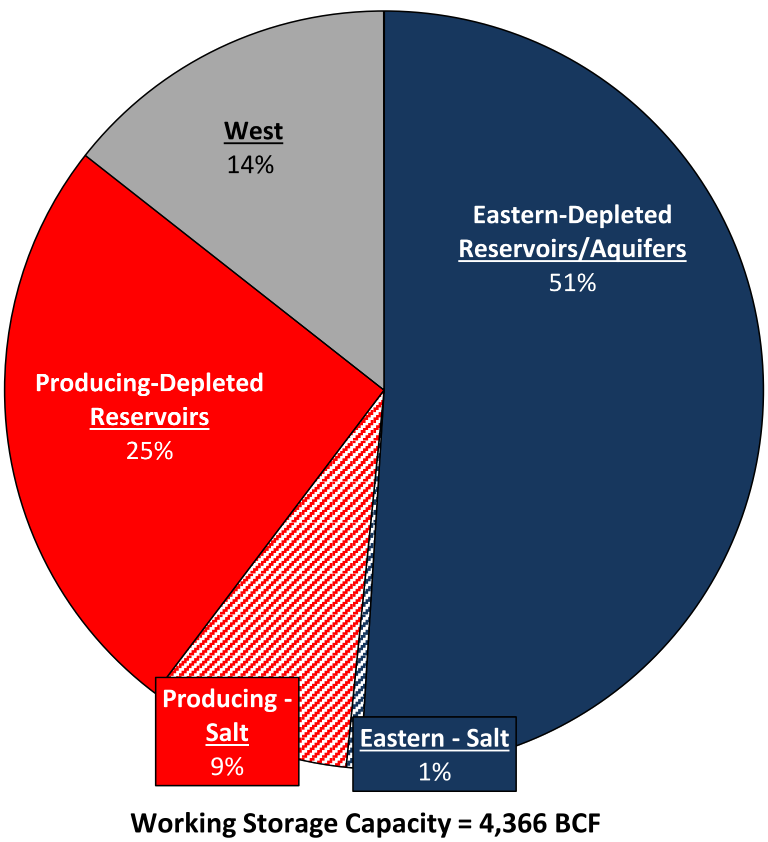
BACKGROUND FOR NATURAL GAS STORAGE

Background For Natural Gas Storage

Capacity

At the end of 2013 the working capacity for U.S. natural gas storage was approximately 4,366 BCF. This capacity can be subdivided into three regions, namely eastern, producing and west. Exhibit Add V-1 summarizes the breakdown of U.S. storage capacity by these three regions. As illustrated, the eastern region is by far the largest in terms of total working capacity.

Exhibit Add V-1. Overview of U.S. Natural Gas Storage Capacity (Working Capacity)



Source: EIA and EVA.

In addition, Exhibit Add V-1 also highlights the amount of this working capacity that is associated with salt domes (i.e., approximately 9.3 percent). Storage facilities are commonly divided into three categories because of differences in functionality. The largest category is depleted oil and gas reservoirs, which are designed to be used once a year to meet peak winter demand requirements and tend to be very large facilities. At the other end of the spectrum are the salt dome facilities, which tend to be smaller facilities but have the unique characteristic of being able to be cycled (i.e., filled, then emptied and then refilled) up to 12 times per year, although six cycles is more typical. The remaining category, which tends to be concentrated in the Midwest, is aquifers, which are similar to depleted reservoirs but can cycle about 1.5 times per year. The industry often categorizes salt dome facilities as small, high pressure bottles that are capable of multiple cycles, and depleted reservoirs and aquifers as large, low pressure bottles that can only be cycled once.

Industry Participants

In very broad terms the primary users of storage can be divided into three categories, namely consumers, traders and producers, with each of these types of users having different objectives when using storage. With respect to the first category, the local distribution companies (LDCs) by far represent the largest segment of the consumer category, with more recently the electric utilities also making use of storage. With respect to the LDCs, historically they were the dominant users of U.S. storage capacity and had the primary objective of using storage to help meet peak winter demand requirements. As a result, LDCs are very focused on using depleted reservoir storage facilities. In addition, LDCs have very rigorous procedures for filling storage in set increments throughout the storage injection season, such that storage levels entering the winter season are as close as practical to the level needed to optimize their overall winter supply portfolio. In simplified terms the primary objective of LDCs using storage is reliability of supply during the winter season.

At the opposite end of the spectrum is traders, which use storage as both a physical option to facilitate their trading book and a vehicle to arbitrage seasonal differences in gas prices. The simplest example of the latter is the difference between summer gas prices and winter gas prices. In some years, such as in 2006, this seasonal spread was over $1.00 per MMBTU and with careful use of NYMEX futures this spread could be captured with no risk. By capturing this spread on a no risk basis traders in the past have been able to cover their costs for storage capacity and staff and still make a profit. For 2014 the current spread between summer and winter gas prices is about $0.15 to $0.20 per MMBTU, which is not a particularly attractive spread. In simplified terms, the primary objective of traders in using storage is to make a profit, which is very different from the primary objective of the LDCs.

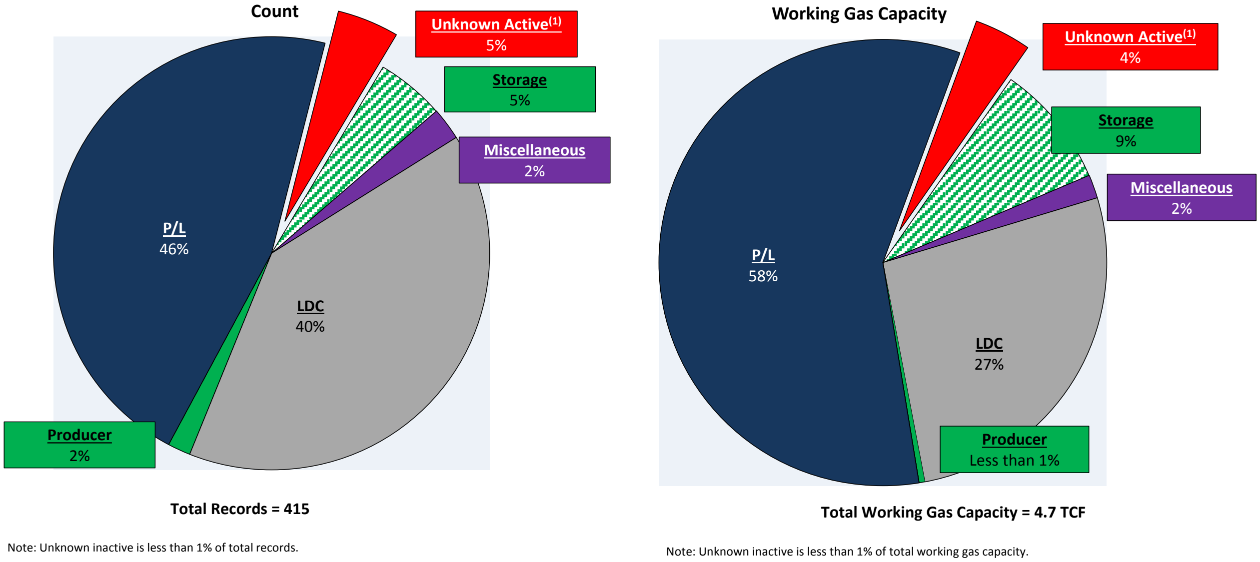
While producers have some similarities to traders, they also use storage as a vehicle to store their gas supplies during periods of low gas demand (i.e., spring, summer and fall) in order to make sure their wells continue to operate. For those producers with high liquids content gas wells, this enables them to continue to produce the associated liquids and capture the revenues associated with these liquids on a continuous basis. Also, the associated liquids revenues are much higher than the gas revenues.

Lastly, the newer segment of the consumer category is the electric utilities, which, in general, use storage to help facilitate meeting their highly variable loads. As a result of this requirement, which may require the daily use of storage, electric utilities make significant use of salt dome storage facilities, because their multiple cycle characteristic best meets their unique requirements for storage.

Ownership And Control

Exhibit V-2 summarizes an assessment of the available data on the ownership of storage capacity. As illustrated, the pipelines are the largest owner of storage capacity, with the LDCs in second place. Concerning the LDCs they own approximately 40 percent of the storage projects and about 27 percent of the working capacity. However, this assessment does not fully communicate the total control of storage capacity by the LDC, as both the pipelines and storage operators lease out some of their storage capacity to third-parties. According to the American Gas Association LDCs have long-term contracts for about one-third of the U.S. storage capacity.[29] As a result, the LDC control over storage capacity is in the range of about 60 percent, which makes them the largest entity for the control of storage capacity.

Exhibit V-2. Ownership of U.S. Storage

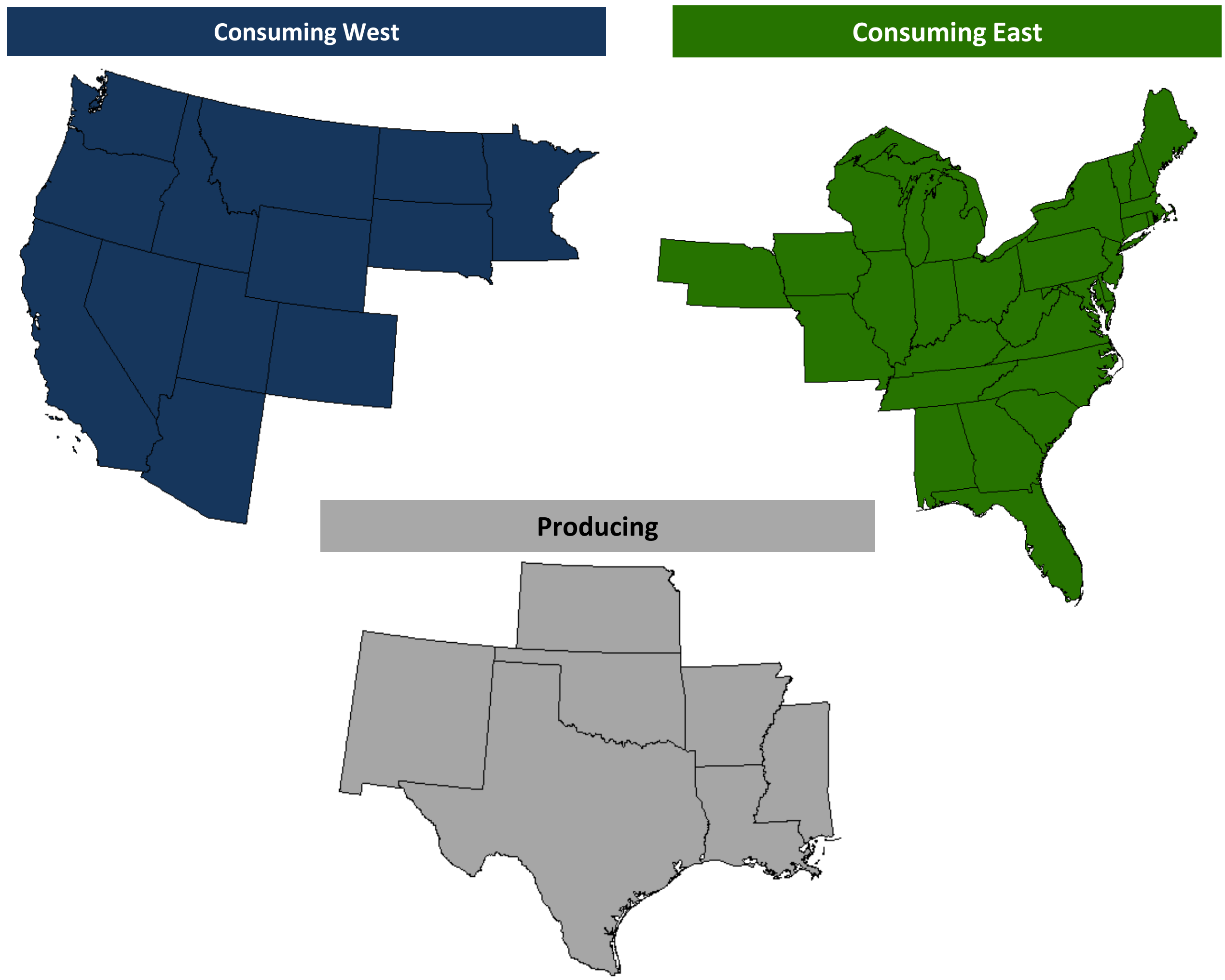


Summary

There are several different types of users of U.S. storage capacity and these users have a range of objectives for using storage capacity. The primary objective of the LDCs, which likely are the largest users of storage capacity, is reliability. Furthermore, LDCs tend to be the largest holder of storage capacity in the East and West regions (see Exhibit Add V-3). The primary objective for traders, on the other hand, is the profit motive. While traders have contracted for storage capacity throughout the U.S., they are major participants in the producing region and make heavy use of salt dome storage facilities, with the latter being a key tool to serve their electric utility clients.

[29] *Gas Daily*, July 25, 2014, p. 8.

Exhibit Add V-3. Storage Regions

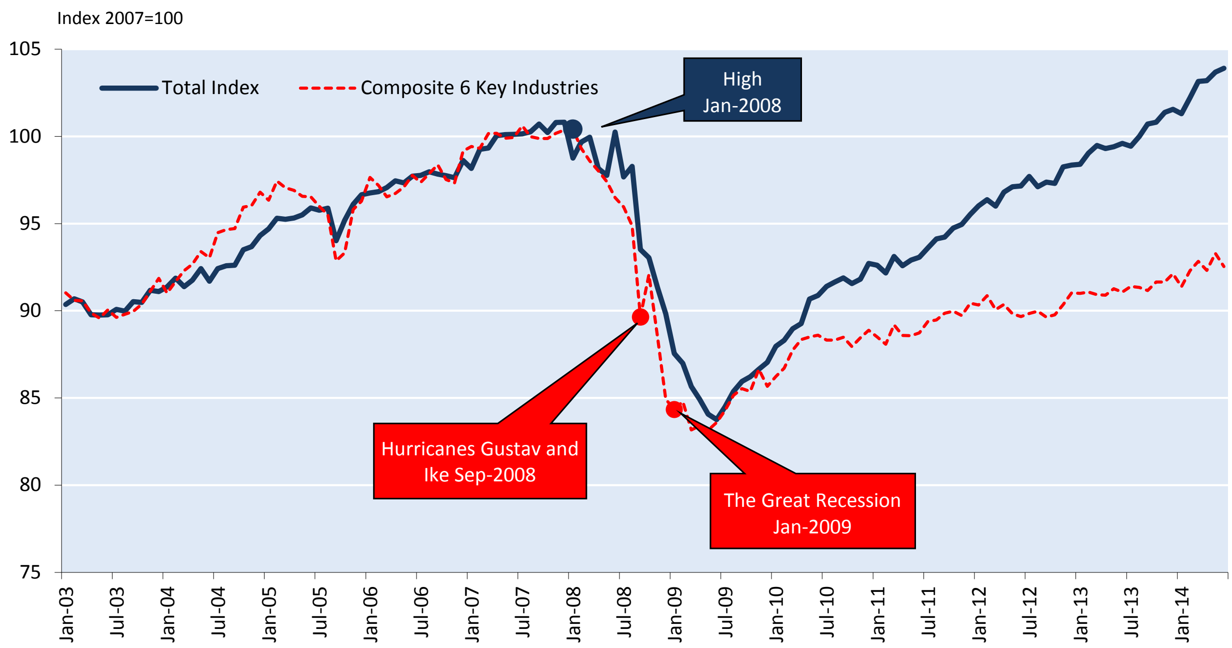


APPENDIX

Exhibit A-1. Natural Gas Consumption (BCF)

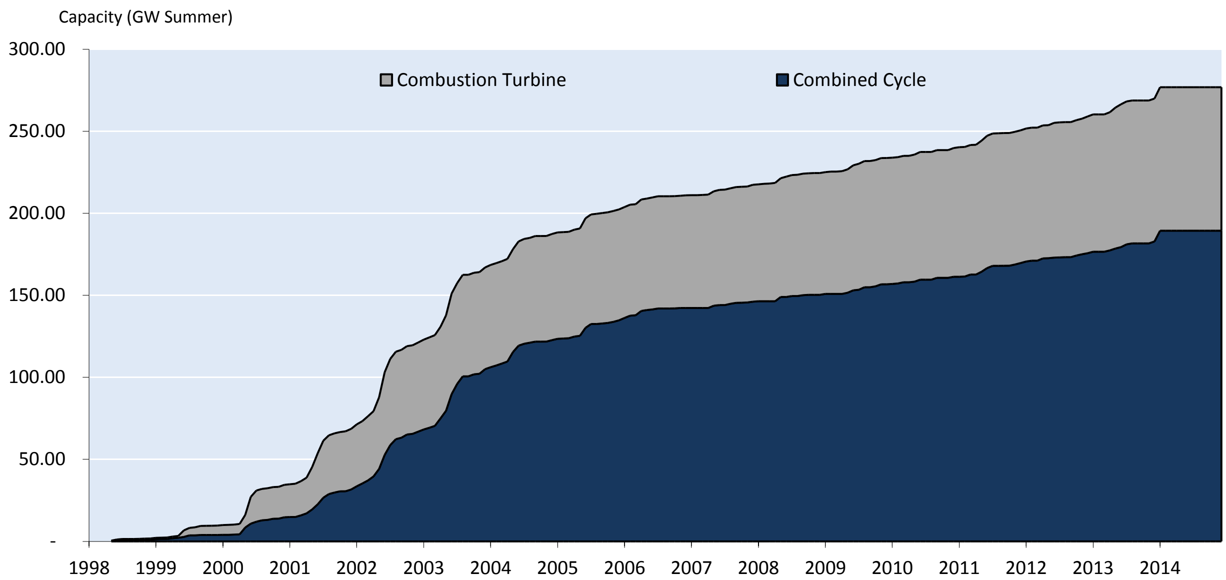
	Annual						Winter (November-March)					
	2009	2010	2011	2012	2013	2014	2009/2010	2010/2011	2011/2012	2012/2013	2013/2014	2014/2015
Residential	4,777	4,783	4,715	4,149	4,942	5,123	3,447	3,627	2,987	3,457	3,976	3,498
Commercial	3,119	3,102	3,155	2,896	3,290	3,435	1,957	2,075	1,781	1,998	2,299	2,072
Industrial	6,168	6,825	6,995	7,224	7,463	7,887	2,966	3,093	3,133	3,227	3,435	3,629
Electric	6,871	7,388	7,574	9,112	8,152	8,197	2,460	2,567	3,125	2,975	3,033	3,046
Other	1,946	1,962	2,010	2,126	2,157	2,228	861	887	924	942	991	956
Transportation	27	29	30	30	33	66	12	12	12	13	16	46
Total	**22,908**	**24,089**	**24,479**	**25,537**	**26,037**	**26,936**	**11,703**	**12,261**	**11,962**	**12,612**	**13,750**	**13,247**

Exhibit A-2. Industrial Production Growth Rates



Source: Fed

Exhibit A-3. Cumulative U.S. Capacity By Technology, 1998-2014



Source: EVA CCGT Database

Exhibit A-4. Annual Additions Of Gas-Fired Capacity 2000-2015

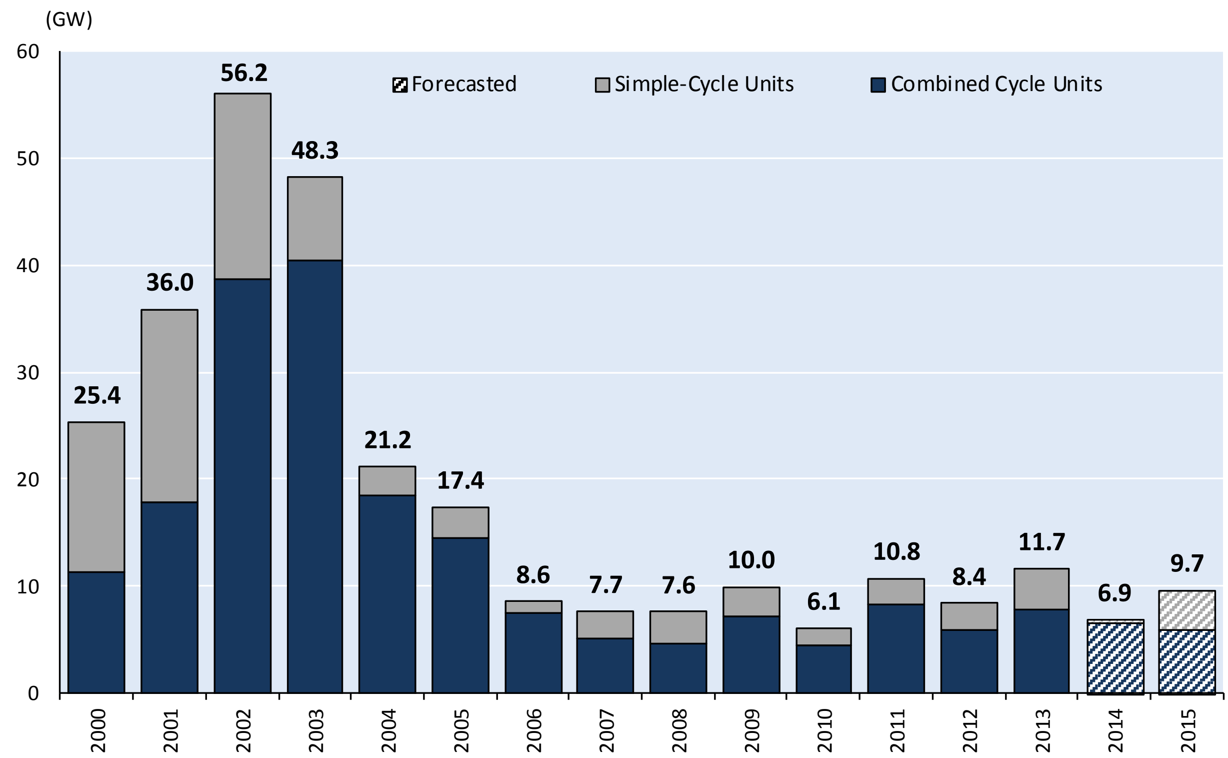


Exhibit A-5. Performance Characteristics Of Natural Gas Combined Cycle Units By Region

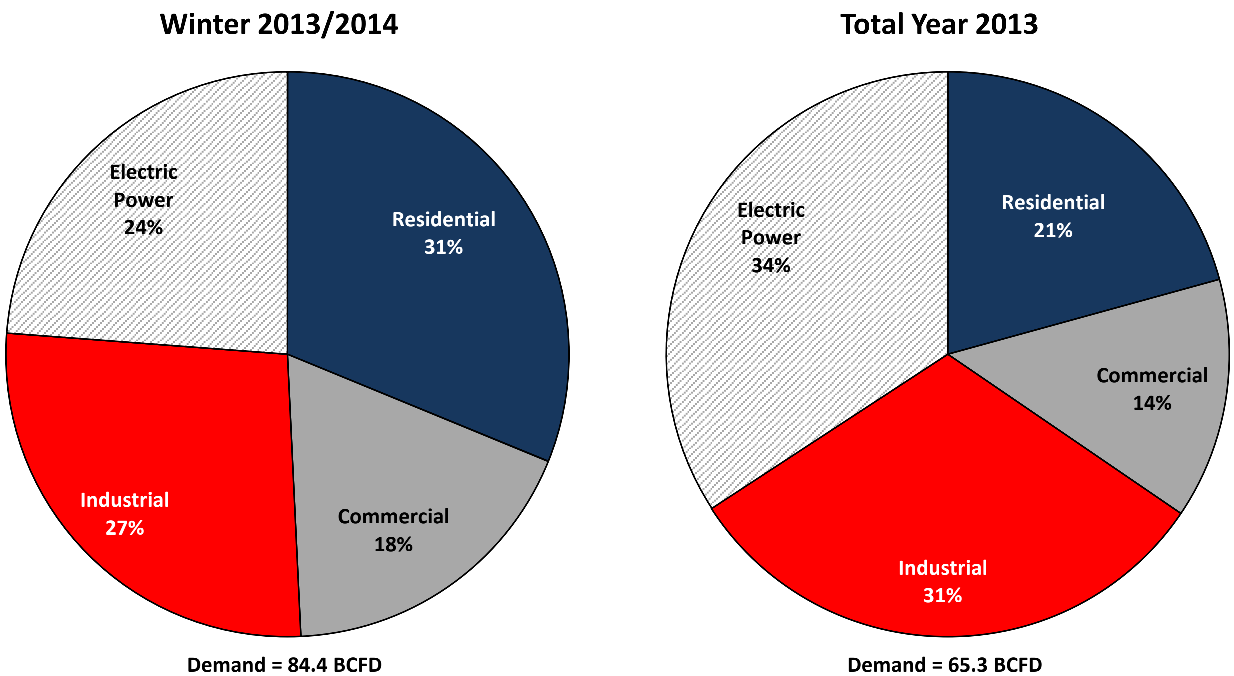
Capacity Factor %

Census Region	Weighted Average Capacity Factor								
	2005	2006	2007	2008	2009	2010	2011	2012	2013
New England	76.0%	78.5%	51.0%	48.4%	48.4%	55.4%	58.2%	52.3%	44.6%
Middle Atlantic	37.7%	42.0%	33.9%	34.1%	42.7%	46.0%	50.6%	59.7%	52.0%
East North Central	28.9%	26.7%	20.3%	14.4%	16.5%	22.1%	30.1%	50.3%	32.0%
West North Central	23.2%	19.6%	24.9%	21.2%	12.7%	16.6%	15.1%	22.5%	17.7%
South Atlantic w/o Florida	30.0%	31.4%	26.6%	23.8%	36.1%	33.9%	44.3%	53.7%	57.9%
Florida	65.6%	67.8%	54.0%	56.5%	54.3%	59.7%	59.5%	63.4%	56.8%
South Atlantic	51.2%	54.8%	42.1%	42.4%	47.2%	48.6%	53.2%	61.9%	57.3%
East South Central	12.2%	14.4%	9.8%	9.3%	12.2%	15.2%	16.6%	20.9%	16.9%
West South Central w/o ERCOT	48.5%	55.5%	32.9%	33.3%	36.0%	36.1%	36.9%	47.3%	35.1%
ERCOT	96.3%	97.4%	52.0%	50.0%	46.7%	44.6%	45.2%	50.1%	48.0%
West South Central	76.1%	78.8%	43.8%	42.8%	42.1%	41.4%	42.1%	49.2%	43.3%
Mountain	65.1%	70.0%	48.2%	48.0%	45.7%	40.9%	34.7%	40.4%	37.0%
Pacific Contiguous w/o CA	97.8%	83.9%	48.8%	49.7%	53.1%	51.1%	25.2%	36.3%	49.7%
California	64.6%	78.1%	61.5%	61.5%	52.4%	52.7%	40.1%	55.1%	48.9%
Pacific Contiguous	71.7%	79.3%	58.3%	58.3%	52.6%	52.3%	36.2%	50.8%	49.1%
TOTAL U.S.	**48.7%**	**51.6%**	**35.3%**	**34.4%**	**35.9%**	**37.5%**	**37.7%**	**45.0%**	**40.1%**

Heat Rate (BTU/kW)

Census Region	Weighted Average Heat Rate (BTU/KWH)								
	2005	2006	2007	2008	2009	2010	2011	2012	2013
New England	7,416	7,410	7,467	7,469	7,463	7,493	7,461	7,520	7,551
Middle Atlantic	7,574	7,591	7,541	7,537	7,560	7,404	7,387	7,502	7,507
East North Central	7,468	7,524	7,437	7,496	7,428	7,465	7,352	7,206	7,645
West North Central	7,795	7,720	7,606	7,572	7,739	7,676	7,689	7,481	7,665
South Atlantic w/o Florida	7,770	7,654	7,701	7,642	7,439	7,484	7,410	7,295	6,475
Florida	7,417	7,416	7,476	7,409	7,479	7,431	7,381	7,320	7,432
South Atlantic	7,500	7,471	7,538	7,465	7,467	7,447	7,391	7,314	7,349
East South Central	7,713	7,643	7,633	7,629	7,437	7,409	7,377	7,017	7,014
West South Central w/o ERCOT	7,369	7,407	7,497	7,430	7,366	7,446	7,448	9,010	7,399
ERCOT	7,342	7,331	7,369	7,462	7,349	7,347	7,350	7,328	7,610
West South Central	7,345	7,355	7,408	7,451	7,353	7,382	7,381	7,987	7,538
Mountain	7,574	7,613	7,393	7,460	7,531	7,533	7,639	7,450	7,446
Pacific Contiguous w/o CA	7,217	7,288	7,303	7,183	7,129	7,194	7,210	7,300	7,780
California	7,345	7,502	7,451	7,283	7,289	7,254	7,373	7,298	7,093
Pacific Contiguous	7,307	7,456	7,420	7,260	7,245	7,239	7,343	7,299	7,254
TOTAL U.S.	**7,446**	**7,471**	**7,465**	**7,448**	**7,423**	**7,410**	**7,408**	**7,462**	**7,268**

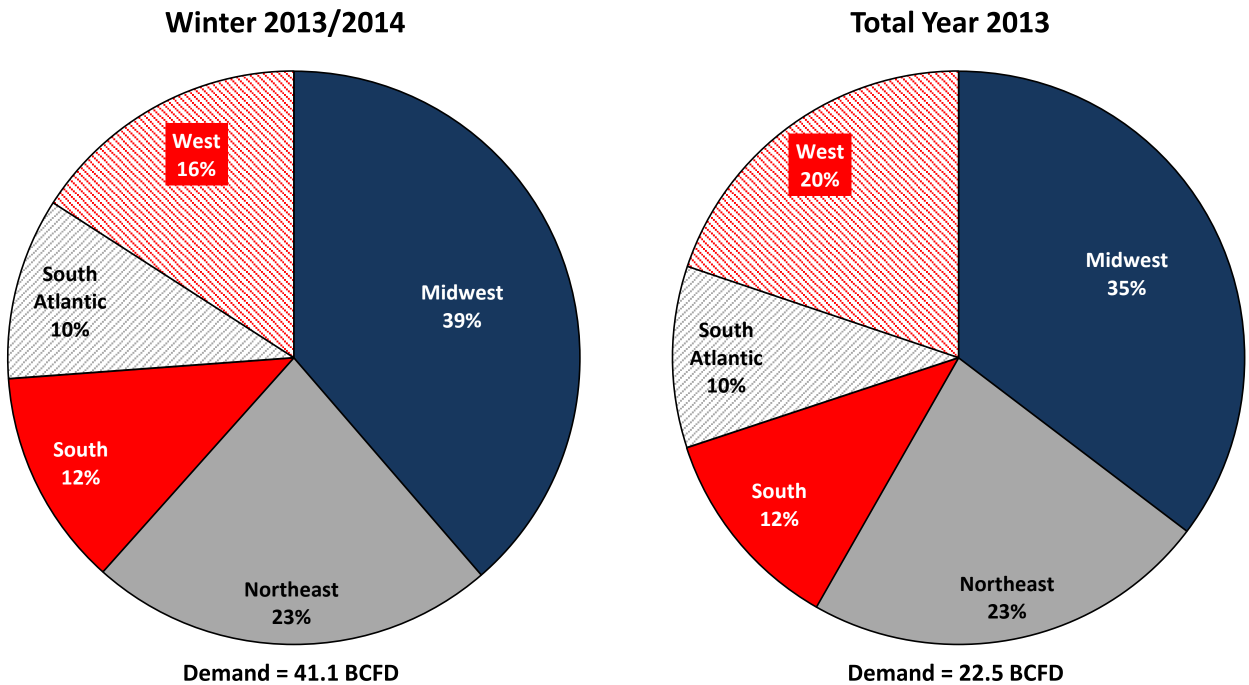
Exhibit A-6. Total Primary Gas Demand By Sector And Time Of Year



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

Source: EIA.

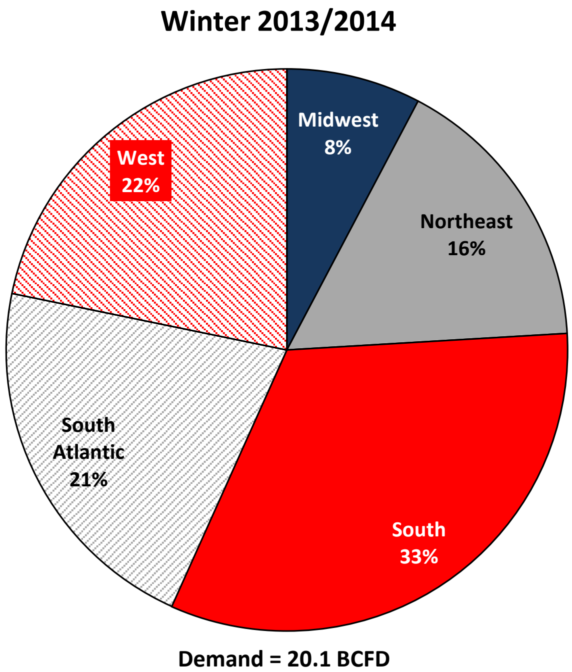
Exhibit A-7. Residential And Commercial Gas Demand By Region And Time Of Year

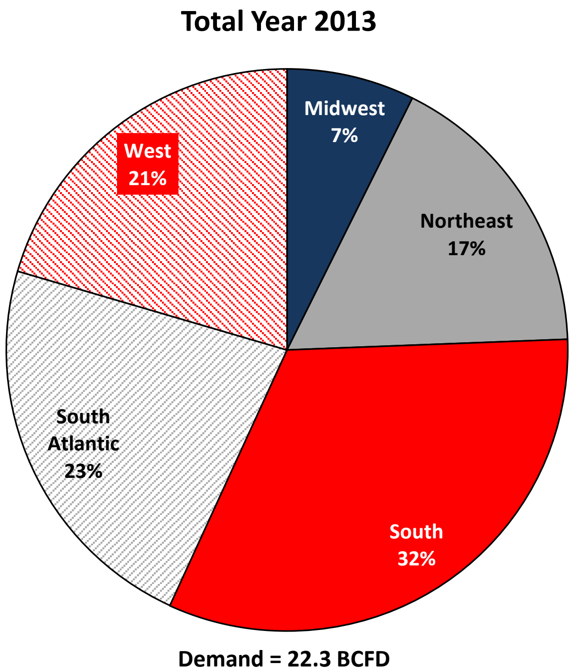


Note: Winter consists of November through March.

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

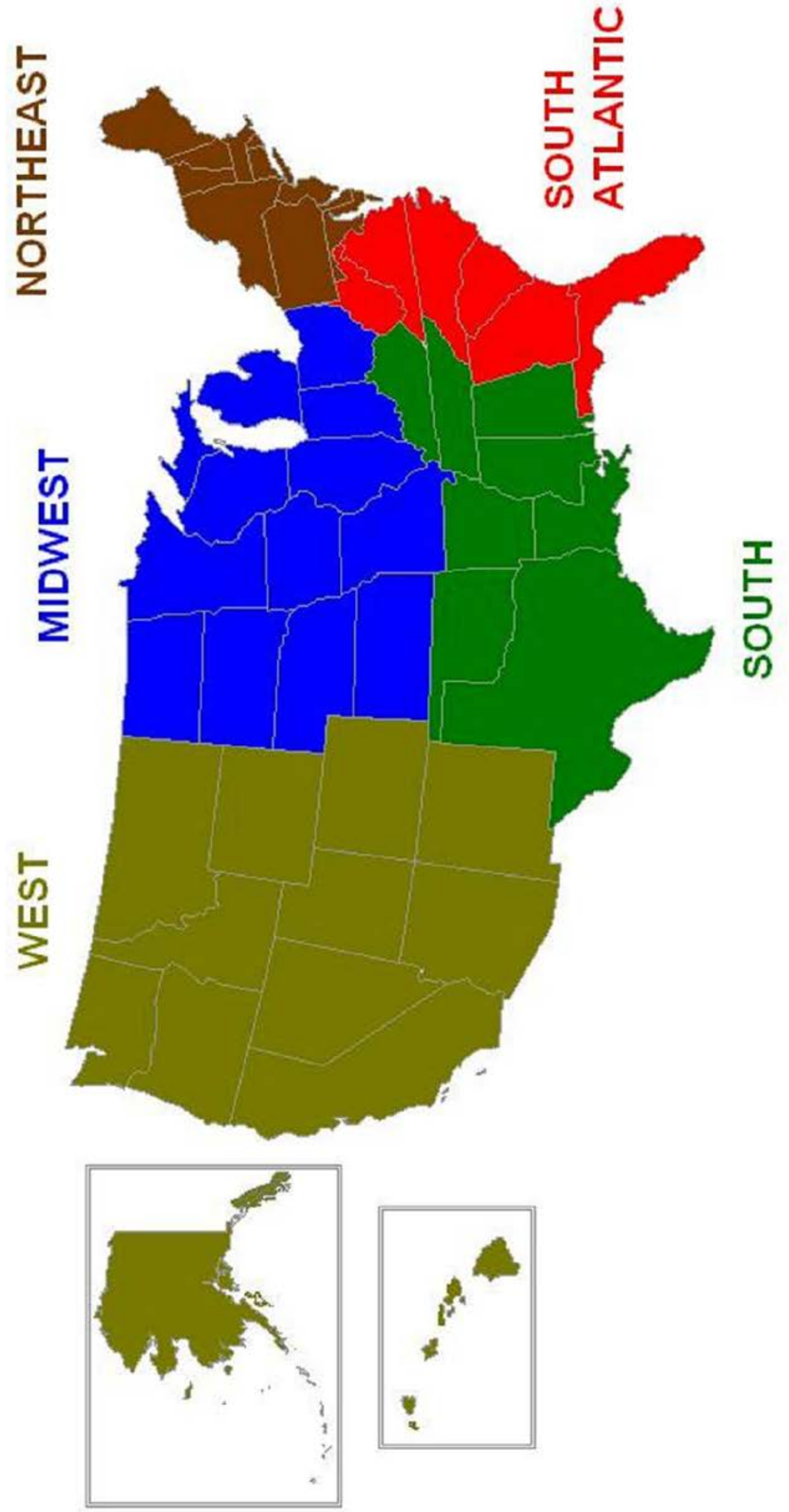


Exhibit A-10. Relevant Data

		2011	2012	2013	2014	% Diff 14/13	2010/11	2011/12	2012/13	2013/14	2014/15	14/
Residential Housing Stock	(Thousands)	117,977	118,990	120,094	121,312	1.0%	117,609	118,469	119,557	120,745	122,059	
Electric												
Weather												
Heating Degree Days (HDD)	(Degree Days)	4,257	4,496	4,562	4,457	-2.3%	3,740	2,991	3,470	3,865	3,442	
Normal HDD[1]	(Degree Days)	4,373	4,373	4,373	4,373	-	3,532	3,532	3,532	3,532	3,532	
% of Normal		97.4%	102.8%	104.3%	101.9%	-	105.9%	84.7%	98.2%	109.4%	97.4%	
New Gas-Fired Capacity[2]												
CC	(MW)	8,359	5,979	7,831	10,634	35.8%	1,995	3,069	2,329	625	1,121	
CT	(MW)	2,434	2,458	3,858	2,003	-48.1%	1,131	180	820	90	135	
Hydro and Nuclear Generation												
Hydro Generation - Pacific	(GWh)	217,404	189,803	185,059	168,016	-9.2%	82,775	67,380	67,382	59,683	66,225	
Nuclear Generation	(GWh)	790,204	769,331	810,783	784,121	-3.3%	336,921	334,268	321,133	325,022	342,472	
Industrial (Index: 2007=100)												
Food		98.5	102.8	104.5	106.7	2.1%	98.4	100.2	103.9	105.9	122.6	
Paper		87.3	85.4	85.0	82.5	-2.9%	87.8	86.7	85.2	82.8	91.6	
Chemicals		86.3	86.4	87.5	89.0	1.8%	86.5	86.4	87.2	87.8	107.2	
Petroleum		94.7	95.4	96.2	98.6	2.4%	93.1	96.6	95.8	97.3	110.0	
Non-metallic Minerals		72.7	75.5	77.6	80.2	3.3%	69.2	70.9	73.0	75.2	77.5	
Primary Metals		97.4	99.6	100.8	101.9	1.2%	94.8	101.0	99.9	102.1	95.1	
Total Industrial Production		93.6	97.1	99.9	103.2	3.3%	92.5	95.8	98.7	101.9	109.2	
Composite 6-key Ind.		89.7	90.7	91.8	93.3	1.5%	88.6	90.3	90.9	92.1	93.3	
Economy												
Real GDP	(Bill. 2009$)	15,052	15,471	15,761	16,135	2.4%	14,914	15,340	15,566	15,918	16,461	
Employment	(Thousands)	131,928	134,210	136,541	138,809	1.7%	132,404	129,845	131,346	133,627	135,894	
GDP IPD	(2005=100)	114.1	115.9	117.5	119.3	1.6%	112.9	115.0	116.8	118.4	120.6	

[1]Normal weather conditions are based upon the most recent 30 year average (i.e., 1982-2011).

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

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

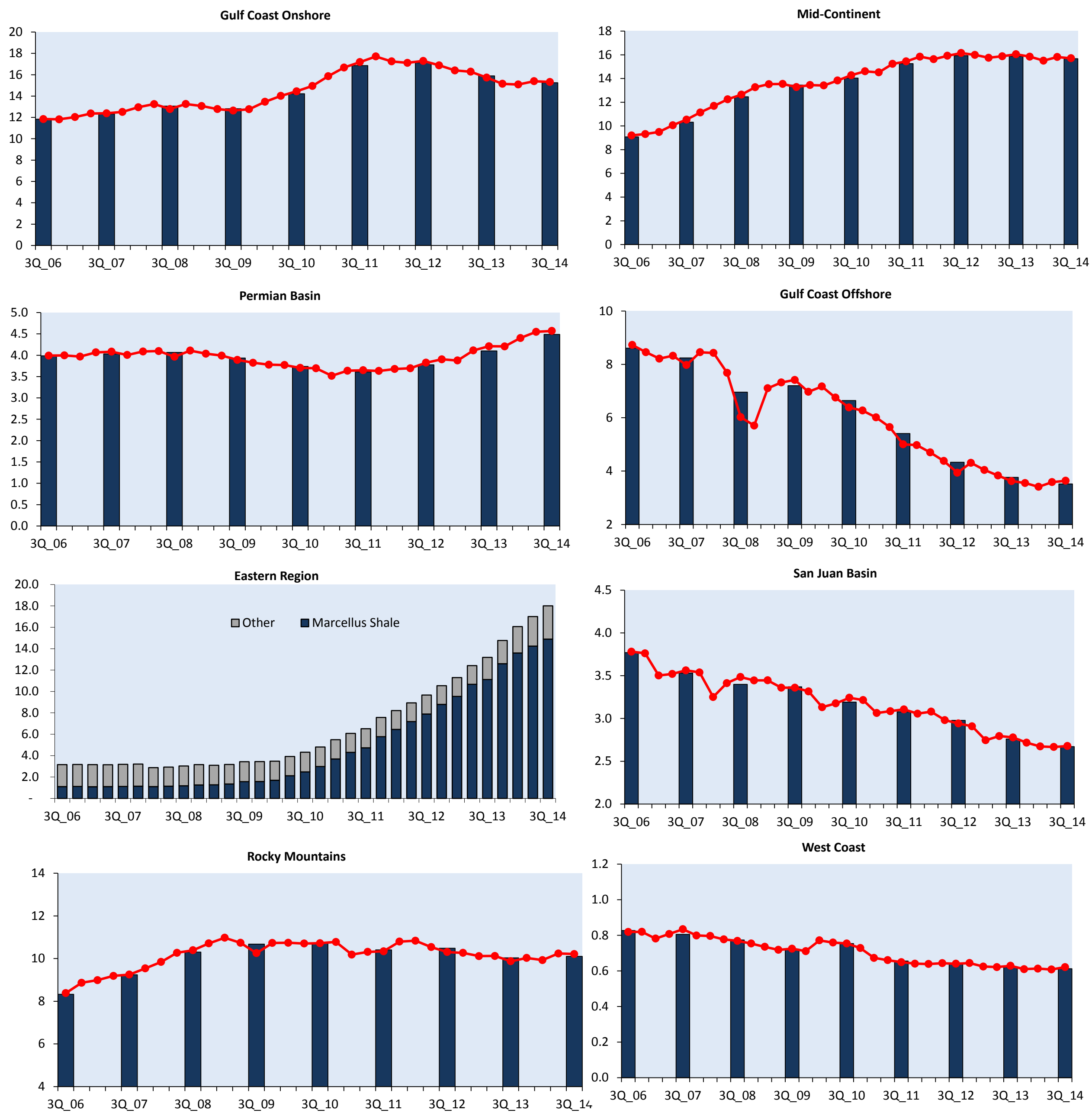


Exhibit A-12. Milestones For Proposed North American Liquefaction Projects

	Milestones For Proposed North American Liquefcation Projects												
				Capacity		FTA Permit		Non-FTA Permit			FERC or NEB Permit		Contracts
	Project	Phase	Trains	Company (MMCFD)	Type[1]	Applies	Approved	Applies	Order of DOE Review	Approved	Applies[2]	Approved	Completes
	I. US: Lower-48												
1A	Sabine Pass LNG	I	1&2	1,201	B	Aug-10	Sep-10	Sep-10		Aug-12	Jan-11	Apr-12	BG(4.2)/ Fenosa(3.5)
1B	Sabine Pass LNG	I	3&4	1,201	B	Aug-10	Sep-10	Sep-10		Aug-12	Jan-11	Apr-12	
1C	Sabine Pass LNG	II	debottleneck for 1-	560	B	Aug-10	Sep-10	Sep-10		Aug-12	Jan-11	Apr-12	BG(1.3)/Kogas(3.5)&Total(0.7)/Gail(3.5)
1D	Sabine Pass LNG	III	5	600	B	Feb-13	Jul-13	Feb-13	14		Sep-13		Total(2.0)&Centrica(1.75 MMTPY)
1E	Sabine Pass LNG	III	6	600	B	Apr-13	Jul-13	Apr-13	15		Sep-13		
2A	Freeport LNG-Phase I	I	1	587	B	Feb-11	Feb-11	Dec-10		May-13	Aug-12	expected in '14	Chubu(2.2 MMTPY; Osaka(2.2 MMTPY)
2B	Freeport LNG-Phase II	II	2	587	B	Feb-11	Feb-11	Dec-11		Nov-13	Aug-12	expected in '14	BP signs agreement for 4.4 MMTPY; no details-2/13;Interim agreement w/Shell for Trains 2&3-old
2C	Freeport LNG-Phase III	III	3	587	B	Feb-11	Feb-11	Dec-11		May-13	Aug-12	expected in '14	Toshiba(2.3 MMTPY + 0.6 MMTPY excess) & SK E&S(2.3 MMTPY) & E.on(1.5 MMTPY)
3	Lake Charles		1, 2 & 3	2,001	B	May-11	Jul-11	May-11		Aug-13	Mar-14		BG to take 100% for its own porfolio
4	Cove Point		1	774	B	Sep-11	Oct-11	Oct-11		Sep-13	Apr-13		Sumitomo(Tokyo Gas & Kansai Elec) for 0.31 BCFD; Gail 0.31BCFD
5A	Cameron LNG Terminal-Phase I	I	1&2	1,067	B	1-Nov	Jan-12	Dec-11		Feb-14	Dec-12	expected in '14	Mitsubishi & Mitsui(1.01 BCFD mkt agreement)-Toyko Elec/Mitsu(53 MMCFD)-Toho Gas/Mitsui(41 MMCFD)
5B	Cameron LNG Terminal-Phase II	II	3	534	B	1-Nov	Jan-12	Dec-11		Feb-14	Apr-12	expected in '14	GDF Suez contracts for 0.53 BCFD;
6	Jordan Cove Energy		1	801	G	Sep-11	Dec-11	Mar-12		Mar-14	May-13		
7	Oregon LNG		1&2	1,201	G	May-12	May-12	Jul-12	3		Jun-13		
8A	Corpus Christi LNG: Phase I		1&2	1,201	G	Aug-12	Oct-12	Aug-12	4		Aug-12		Pertamina 0.8 MTPY; Endesa1.5 MMTPY
8B	Corpus Christi LNG: Phase II		3	600	G	Aug-12	Oct-12	Aug-12			Aug-12		
9	Port Lavaca_Floater		1&2	587	F	Feb-12	Aug-12	Oct-12	5		Mar-14		
10	Carib		1	40	O	Jun-11	Jul-11	Oct-11	6				
11	Gulf Coast LNG Export		1,2,3&4	2,802	G	Jan-12	Oct-12	Jan-12	7				
12A	Elba Island Phase I		1,2,3,4,5&6	320	B	May-12	Jun-12	Aug-12	8		Jan-13		Shell to retain as part of its own portfolio
12B	Elba Island Phase II		7&8	124	B	May-12	Jun-12	Aug-12	8		Jan-13		
13	Gulf LNG Clean Energy		1,2&3	1,501	B	May-12	Jun-12	Aug-12	9				
14	CE LNG(floater)		1&2	1,067	F	Oct-12	Dec-12	Sep-12	10		Apr-13		
15	Golden Pass		1,2,3&4	2,081	B	Aug-12	Oct-12	Oct-12	11				Exxon/Qatar for own portfolio to UK terminal
16	South Texas LNG Export		1&2	1,067	G	Dec-12	Feb-13	Dec-12	12				
17	Main Pass Energy Hub		1,2,3,4,5&6	3,220	F	Sep-12	Feb-13	Feb-13	13		not required-		Sarwarzad(4 MMTPY) & Petronet(4 MMTPY)
18	Venture Global LNG		1	667	G	May-13	Sep-13	May-13	16				
19	Eos LNG		1	1,601	F	Sep-13	Dec-13		17				
20	Barca LNG		1	1,601	F	Sep-13	Dec-13		18				
21	SB Power Solutions		1	67	O	May-12	Jun-12	n/a					
22	Waller LNG		1	167	G	Oct-12	Dec-12	n/a					
23A	Magnolia LNG-Phase 1 (FTA only)		1&2	534	G	Dec-12	Feb-13	Oct-13					Brightstone(1.7 MMTPY; 20-yr) & interruptible 0.3 MMTPY; Gas Natural 1.7 MMTPY
23B	Magnolia LNG-Phase 2 (non-FTA)		3 &4	534	G						Apr-13		
24	Gasfin LNG		1,2&3	200	G	Jan-13	Mar-13	Jan-14					
25	Argent Marine LNG		1	27	O	Sep-13							
26	Annova LNG		1	267	F	Jan-14		Jan-14					
27	Cambridge Energy-Floater		1		F	Feb-12	withdraws -	Mar-12		withdraws -			
	II. US: Alaska												
1	Valdez, AK		1,2,&3	2,322	G	Oct-12					Oct-12		
	III. Canada												
1A	Kitimat LNG		1&2	1,334	G					Oct-11		Oct-11	Kogas(280);Gas Natural(200);Mitsubshi(200),Japex(160)
1B	Kitimat LNG		3	667	G								
2	Douglas Channel LNG-floater		1&2	93	G					Feb-12		Apr-12	LNG Partners(private) & Golar LNG for 254 MMCFD
3	Penn West LNG		1	467	G								
4	Pacific Northwest LNG		1&2	1,601	G					Dec-13		Dec-13	Japex(1.2 MMTY) equity gas; India IOC 1.2 MMTPY
5	LNG Canada		1,2,3&4	3,202	G					Feb-13	Aug-12	Dec-13	
6	Golboro LNG		1&2	1,334	G								Eon (5.0 MMTPY)
7	Triton LNG-floater		1&2	307	G						Nov-13		
8A	West Coast Canada(WCC)-Phase I		1,2 & 3	2,001	G					Dec-13	Jun-13	Dec-13	
8B	West Coast Canada(WCC)-Phase II		4,5 &6	2,001	G					Dec-13	Jun-13	Dec-13	
9	Woodfibre Natural Gas		1	280	G					Dec-13	Aug-13	Dec-13	
10	Quicksilver		1	667	G								
11	Aurora LNG		1&2	1,601	G						Nov-13		
12A	Prince Rupert LNG/BG LNG Terminial-Phas		1	961	G						Jun-13	Dec-13	
12B	Prince Rupert LNG/BG LNG Terminial-Phas		2	961	G						Jun-13	Dec-13	
12C	Prince Rupert LNG/BG LNG Terminial-Phas		3	961	G						Jun-13	Dec-13	

(1) B=brownfield; G=greenfield; F=floater
(2) Includes pre-filing dates and complete filing dates.

Permit Status For US Projects
Approved Non-FTA
Non-FTA Permit Not Yet Approved
Group I at FERC
Group II at FERC

Exhibit A-13. Natural Gas Supply

Supply Component	2010/2011	2011/2012	2012/2013	2013/2014	2014/2015
I. US Production					
Shale	18.26	24.42	28.69	32.63	36.59
Tight Sands	14.29	13.77	13.09	12.35	11.82
CBM	4.50	4.18	3.80	3.54	3.37
Associated(ex offshore)	3.60	3.98	4.49	4.93	5.16
Offshore	4.59	3.64	2.89	2.45	2.18
Other Conventional	14.29	14.76	12.14	11.36	11.69
Subtotal Lower-48	**59.53**	**64.75**	**65.10**	**67.26**	**70.82**
Footnote:					
Alaska	0.95	0.91	0.91	0.95	1.10
Total US	60.48	65.66	66.01	68.21	71.92
II. Imports					
Net Canada	6.74	5.47	4.74	5.66	5.28
Net Mexico	-1.19	-1.37	-1.74	-1.70	-2.15
Net LNG	0.80	0.49	0.39	0.10	0.12
Total Net Imports	**6.35**	**4.60**	**3.39**	**4.06**	**3.25**
III. Storage Withdrawals	**15.02**	**8.73**	**14.74**	**19.72**	**12.89**
IV. Total Lower-48 Supply	**80.90**	**78.08**	**83.23**	**91.04**	**86.96**

Supply Component	2010/2011	2011/2012	2012/2013	2013/2014	2014/2015
I. US Production					
Shale	2,757	3,712	4,332	4,927	5,526
Tight Sands	2,158	2,092	1,977	1,865	1,785
CBM	680	636	574	534	510
Associated(ex offshore)	544	605	677	745	779
Offshore	693	553	436	369	330
Other Conventional	2,157	2,243	1,833	1,715	1,764
Subtotal Lower-48	**8,989**	**9,841**	**9,829**	**10,156**	**10,694**
Footnote:					
Alaska	143	139	138	144	166
Total US	9,132	9,980	9,968	10,300	10,860
II. Imports					
Net Canada	1,018	832	715	855	797
Net Mexico	(180)	(208)	(262)	(257)	(325)
Net LNG	121	75	59	15	18
Total Net Imports	**959**	**699**	**512**	**613**	**491**
III. Storage Withdrawals	**2,268**	**1,327**	**2,226**	**2,978**	**1,946**
IV. Total Lower-48 Supply	**12,216**	**11,867**	**12,567**	**13,746**	**13,131**

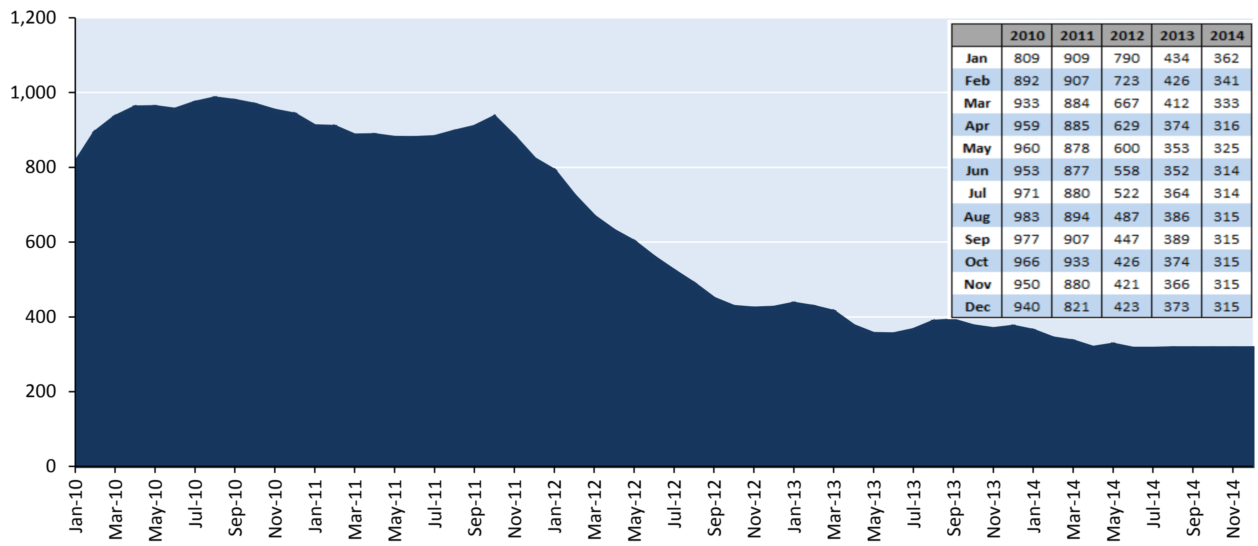
Exhibit A-13. Natural Gas Supply (Continued)

Supply Component	2010	2011	2012	2013	2014	2015
I. US Production						
Shale	14.70	21.82	27.03	30.35	34.91	38.28
Tight Sands	14.60	13.98	13.55	12.64	12.06	11.58
CBM	4.68	4.33	4.04	3.57	3.51	3.24
Associated(ex offshore)	3.46	3.75	4.22	4.76	5.11	5.22
Offshore	5.09	4.09	3.19	2.58	2.31	2.06
Other Conventional	15.07	14.02	12.98	11.85	11.58	10.61
Subtotal Lower-48	**57.60**	**61.99**	**64.99**	**65.76**	**69.47**	**70.99**
Footnote:						
Alaska	0.98	0.92	0.91	0.92	0.98	1.01
Total US	58.57	62.91	65.90	66.68	70.45	72.00
II. Imports						
Net Canada	6.96	5.97	5.44	5.14	5.28	5.01
Net Mexico	-0.83	-1.36	-1.69	-1.80	-2.11	-2.39
Net LNG	1.00	0.76	0.40	0.26	0.20	0.20
Total Net Imports	**7.13**	**5.38**	**4.15**	**3.60**	**3.37**	**2.82**
III. Net Storage Change	**0.01**	**-0.96**	**-0.02**	**1.50**	**0.25**	**1.55**
IV. Total Lower-48 Supply	**64.74**	**66.40**	**69.12**	**70.86**	**73.09**	**75.36**

Supply Component	2010	2011	2012	2013	2014	2015
I. US Production						
Shale	5,364	7,964	9,892	11,079	12,741	13,973
Tight Sands	5,327	5,104	4,958	4,614	4,403	4,227
CBM	1,708	1,580	1,477	1,303	1,279	1,184
Associated(ex offshore)	1,262	1,367	1,543	1,736	1,864	1,905
Offshore	1,859	1,493	1,167	943	842	751
Other Conventional	5,502	5,118	4,751	4,326	4,226	3,873
Subtotal Lower-48	**21,023**	**22,626**	**23,787**	**24,001**	**25,355**	
Footnote:						
Alaska	357	337	332	337	359	367
Total US	21,379	22,962	24,119	24,338	25,714	26,280
II. Imports						
Net Canada	2,541	2,180	1,992	1,876	1,927	1,829
Net Mexico	(303)	(496)	(619)	(657)	(770)	(872)
Net LNG	366	278	146	95	73	73
Total Net Imports	**2,604**	**1,962**	**1,519**	**1,314**	**1,230**	**1,029**
III. Net Storage Change	**4**	**(350)**	**(7)**	**548**	**91**	**566**
IV. Total Lower-48 Supply	**23,630**	**24,237**	**25,299**	**25,863**	**26,676**	**1,595**

Exhibit A-14. Gas Well Completions

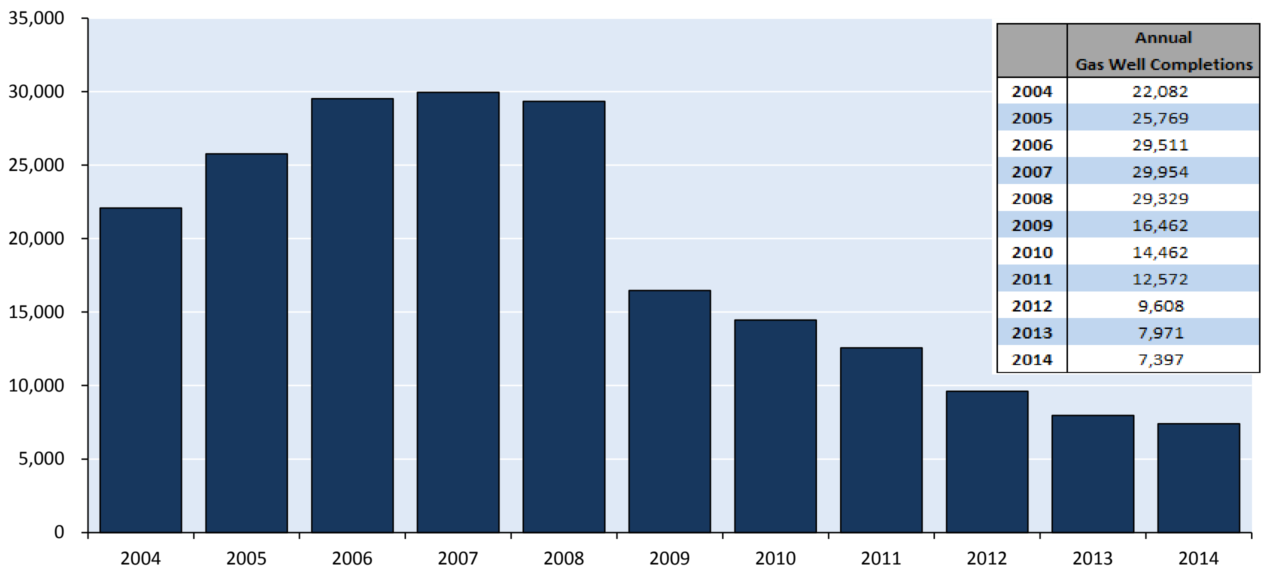
Monthly Well Completions



	2010	2011	2012	2013	2014
Jan	809	909	790	434	362
Feb	892	907	723	426	341
Mar	933	884	667	412	333
Apr	959	885	629	374	316
May	960	878	600	353	325
Jun	953	877	558	352	314
Jul	971	880	522	364	314
Aug	983	894	487	386	315
Sep	977	907	447	389	315
Oct	966	933	426	374	315
Nov	950	880	421	366	315
Dec	940	821	423	373	315

Note: API.

Annual Well Completions



	Annual Gas Well Completions
2004	22,082
2005	25,769
2006	29,511
2007	29,954
2008	29,329
2009	16,462
2010	14,462
2011	12,572
2012	9,608
2013	7,971
2014	7,397

Note: API