SUMMER 2019

ENERGY VENTURES ANALYSIS

NATURAL GAS MARKET SUMMER OUTLOOK 2019

MAY 2019

Prepared for:

NATURAL GAS SUPPLY ASSOCIATION

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I. OVERVIEW

Summer 2019[1] began with a 1.13 TCF end-of-March natural gas storage inventory level, 505 BCF lower than the five-year average. Summer season-to-date, injections have been extremely strong, about 5.8 BCFD higher than the five-year average.

The high injections thus far in the season are a result of robust production levels, which are 9.7 BCFD higher year-on-year (YoY) as of April 2019. Production is forecast to grow further in the summer, given spare pipeline takeaway capacity in the Northeast as well as new pipelines coming online in the Permian and SCOOP&STACK. In fact, high production this year will result in the second highest injection season on record, injecting 2.6 TCF to reach 3.75 TCF by the end of October. Production growth in the U.S. is also crowding out imports from Canada as Northeast and Bakken gas battle West Canadian supply. Net imports from Canada are forecast to decline by 0.8 BCFD summer-over-summer.

BCFD	Summer 2019	Summer 2018	Summer-over-Summer Changes
Dry Production	89.4	82.6	6.8
Net Canadian Imports	4.7	5.4	-0.8
LNG Imports	0.1	0.1	0.0
Total Supply	94.2	88.1	6.0
Power Burn	31.3	32.1	-0.7
Industrial	22.1	21.5	0.6
Residential & Commercial	11.0	11.9	-0.9
Pipeline Loss and Other	6.3	6.2	0.1
Pipeline Exports to Mexico	5.5	4.7	0.8
LNG Exports	6.0	3.3	2.7
Total Demand	82.1	79.6	2.5
Injections	12.1	8.6	3.5
CDDs	1272	1477	-205

Source: EVA

On the demand side, power burn is forecast to decline 0.7 BCFD YoY mainly due to the assumption of normal weather compared to last summer's above normal temperatures. Power sector demand for natural gas will continue to grow when adjusted for weather factors. However, record renewable capacity additions will limit the upside for gas burn both in the short and long term.

Summer industrial demand has been growing 0.5 BCFD per year on average since 2013, and 2019 is no exception. Better performance of the whole sector in general, and significant growth in gas[2] feedstock demand in particular, have propelled gas consumption growth at industrial facilities. 2019 will see another sizable methanol plant come online, multiple steel and aluminum plants restart, and a slew of petrochemical projects begin operation.

LNG trains that were delayed last year will enter service this summer including Freeport Train 1 (T1), Cameron T1, and Elba Island Phase I. Corpus Christi T2 is on schedule and will begin operations this summer as well. Pipeline infrastructure was completed ahead of time and is ready to serve these terminals with diversified supply from the Northeast, Midcontinent, Southeast, and the Gulf. However, global demand for LNG appears to be subdued, which could force some facilities to operate below full capacity. Therefore, exports are forecast

[1]For the purposes of this report, summer refers to April through October which is, in general, the gas injection season.

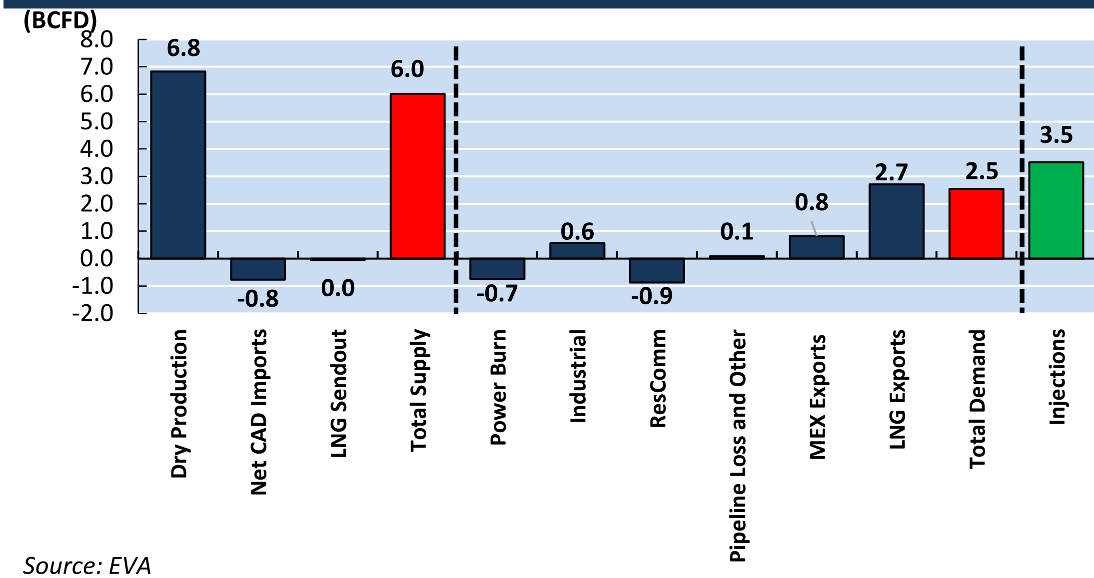
[2] Gas is the short form for natural gas in this report.

to grow by only 2.7 BCFD summer-over-summer compared to the 3.7 BCFD of additional capacity since last summer.

Two important pipeline projects are poised to begin operation in Mexico, which will boost exports to Mexico by 0.8 BCFD summer-over-summer. Sur de Texas-Tuxpan and "Wahalajara" will complete pipeline connections within Mexico, displacing LNG imports at the Altamira terminal and tapping demand in the central part of the country. However, if the past can be of reference, delays to the pipeline projects could limit export growth.

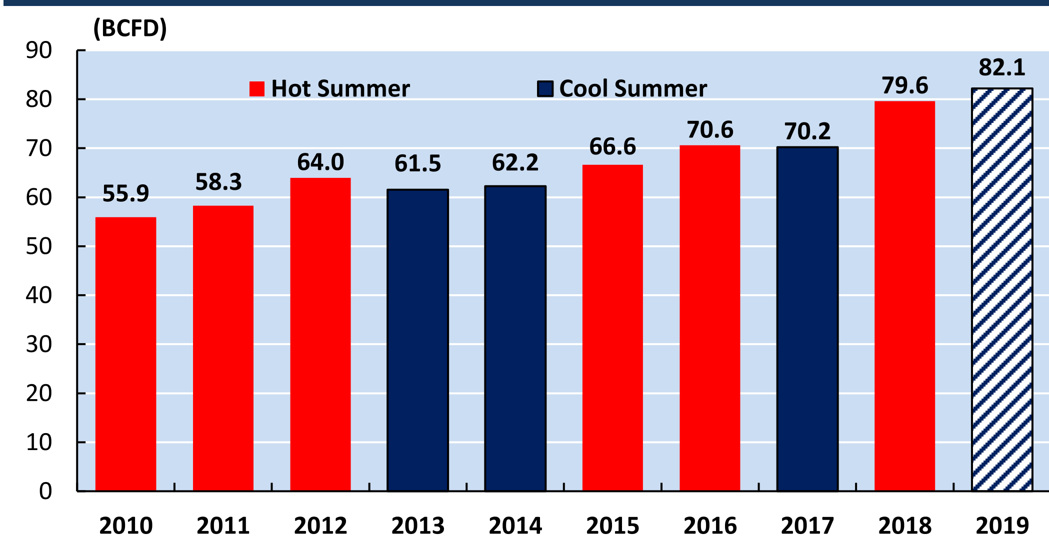
Season-ending storage inventories are forecast to reach 3,745 BCF, very close to the five-year average. Risks exist on both sides as power burn can swing storage levels up or down given different price levels (see discussion in Chapter IV) and renewable generation uncertainties (see the feature on page 9). Production could also come out lower than the forecast since a large number of gas wells began production in 2018 and are likely to experience the typical declines that follow initial production.

SUMMER OVER SUMMER CHANGES



Source: EVA

TOTAL SUMMER GAS DEMAND ALL SECTORS



Source: EVA

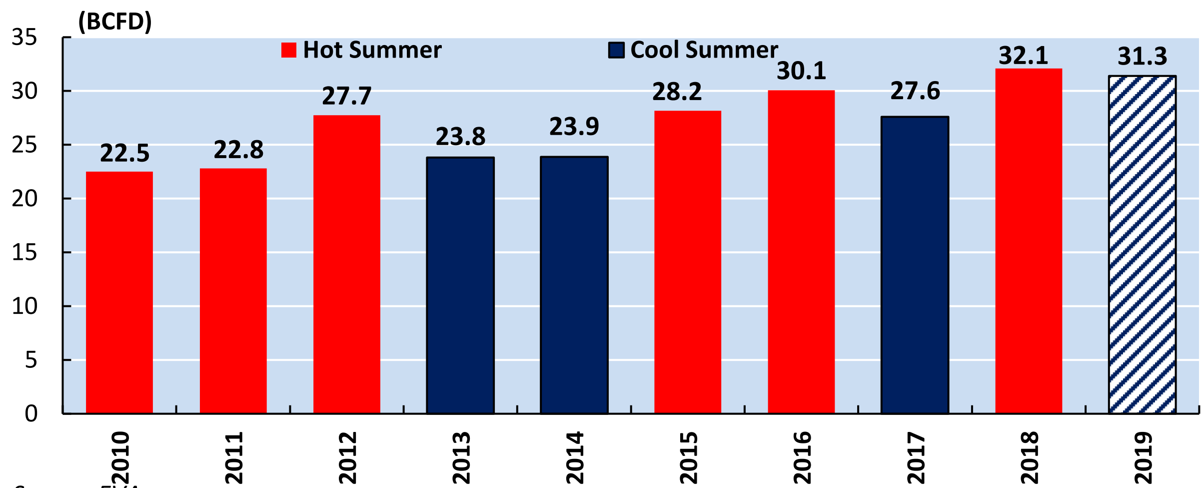
II. OUTLOOK FOR DEMAND

Power demand

Power demand for natural gas in 2019 summer is forecast to be 31.3 BCFD assuming normal weather, 0.7 BCFD or 2% lower summer-over-summer (see figure below). The decline is mostly driven by the normal weather assumption. Last year's power burn was boosted by high temperatures, with CDDs 11% above the 10-year normal. Renewable generation growth will also contribute to the decline.

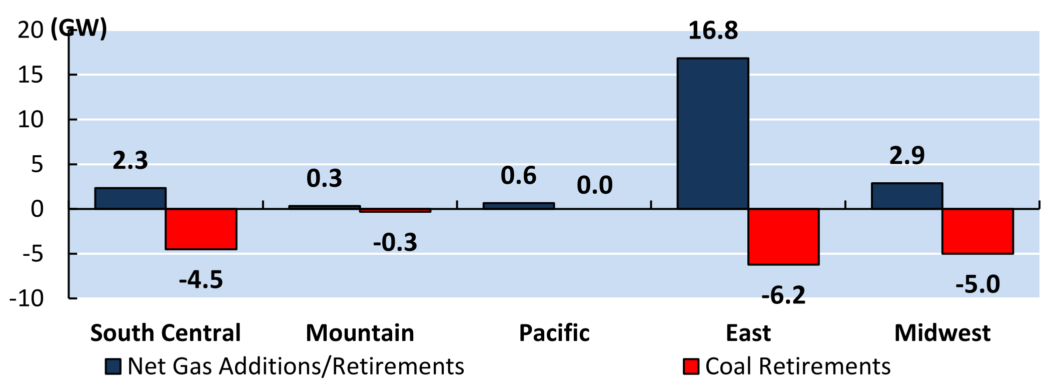
From a regional perspective, most of the summer-over-summer growth is anticipated in the East region (see map next page), where 16.8 GW of new gas-fired generating capacity was added since last April (see figure below). The growth in power burn in the East region will be offset by declines in the Midwest and Pacific regions due to a robust renewable and hydroelectric generation forecast. By sensitizing prices up and down 20 cents from our base case assumptions, power burns in the East and South Central regions are the most price-sensitive. Despite significant coal retirements in these regions, significant switching potential still exist given the operating coal and gas fleet. In addition, delivered coal prices in these regions remain competitive to regional gas prices.

TOTAL SUMMER ELECTRIC GAS DEMAND



Source: EVA

GENERATION CAPACITY CHANGES FROM APR 2018 TO APR 19

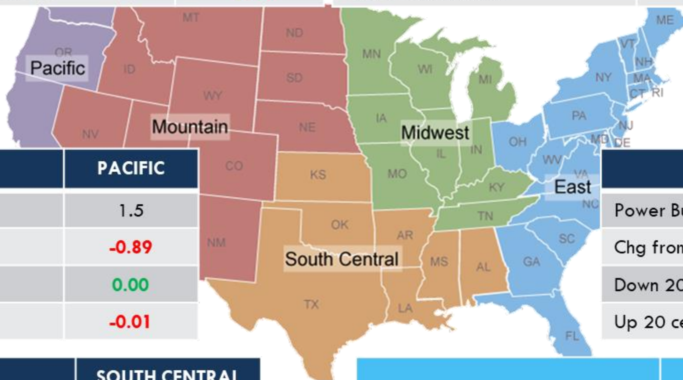


Source: EVA

2019 SUMMER POWER BURN BY REGION AND PRICE SENSITIVITY

	MOUNTAIN
Power Burn	2.8
Chg from 2018	0.25
Down 20 cents/MMBtu	0.03
Up 20 cents/MMBtu	-0.02

	MIDWEST
Power Burn	2.8
Chg from 2018	-0.60
Down 20 cents/MMBtu	0.04
Up 20 cents/MMBtu	-0.02



	PACIFIC
Power Burn	1.5
Chg from 2018	-0.89
Down 20 cents/MMBtu	0.00
Up 20 cents/MMBtu	-0.01

	EAST
Power Burn	14.2
Chg from 2018	0.43
Down 20 cents/MMBtu	0.20
Up 20 cents/MMBtu	-0.24

	SOUTH CENTRAL
Power Burn	10.0
Chg from 2018	0.07
Down 20 cents/MMBtu	0.17
Up 20 cents/MMBtu	-0.16

	U.S. TOTAL
Power Burn	31.3
Chg from 2018	-0.74
Down 20 cents/MMBtu	0.44
Up 20 cents/MMBtu	-0.45

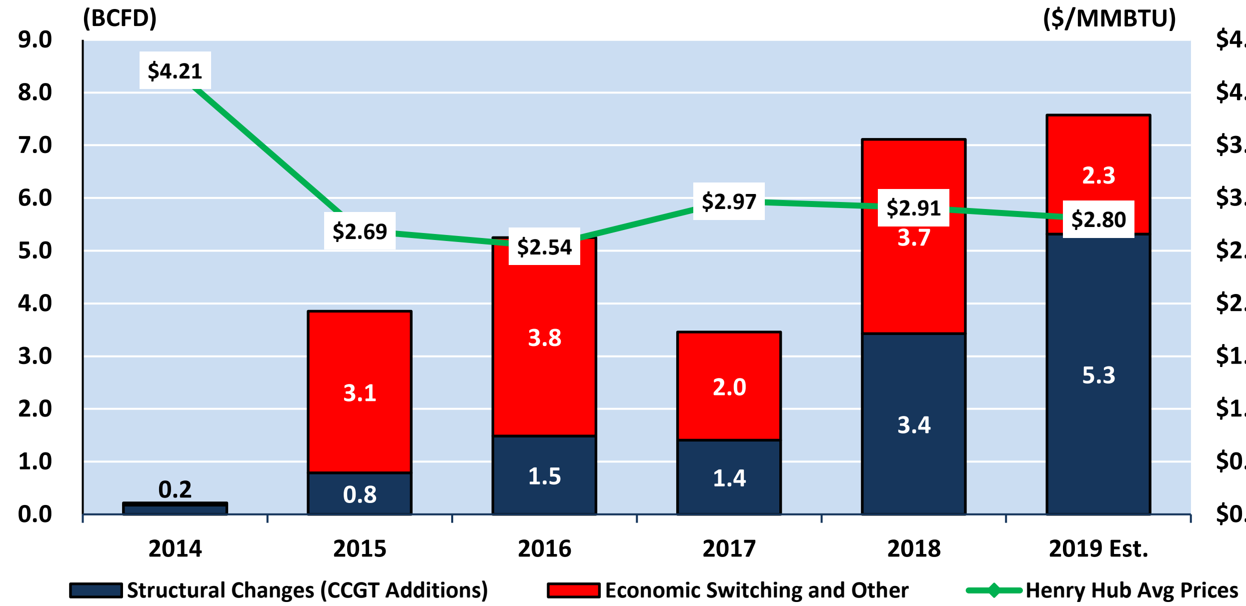
**Numbers are in BCFD*

Source: EVA, units are in BCFD

This summer we expect to see coal-to-gas switching continue. Power burn has grown on a weather-adjusted basis over the last five years (see figure next page, 2013 is the base year). This growth in power burn is driven by structural growth from new CCGT additions and economic switching from other fuels to natural gas (see blue and red bars in the figure next page). The structural growth portion represents increased gas generation from units that have been built since 2013. The economic switching portion represents switching at existing fleets given dispatch economics among different fuel types.

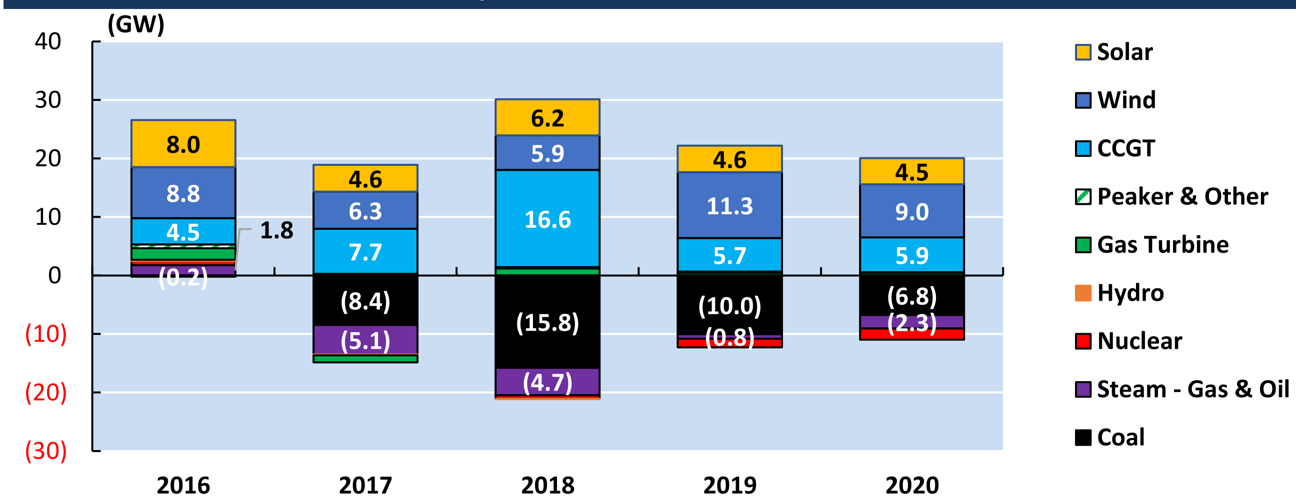
From 2014 to 2017, the increase in summer burn was largely driven by economic fuel switching. During the summer of 2014, Henry Hub prices averaged $4.21/MMBTU. The high fuel costs reduced the profitability of gas-fired power plants and resulted in minimal economic switching from coal to gas. However, as gas prices declined in 2015 and 2016, economic switching from coal to gas returned to prominence and partially contributed to a wave of coal plant retirements.

WEATHER ADJUSTED SUMMER POWER BURN INCREASE FROM 2013 BASE YEAR



In the summer of 2018, lower-48 power gas burn reached a new high at 32 BCFD. Compared to the 2013 base year, almost half of the increase came from structural growth as 16.6 GW of new CCGTs were added in 2018 (see figure below). With prices holding just below $3.00/MMBTU, economic switching contributed to 3.7 BCFD in incremental power burn in summer 2018. The high level of economic switching to gas is a result of gas price competitiveness and regional gas pipeline infrastructure development.

NET POWER CAPACITY ADDITIONS/RETIREMENTS



Source: EVA

YEARLY NET CAPACITY ADDITIONS AND RETIREMENTS (GW)

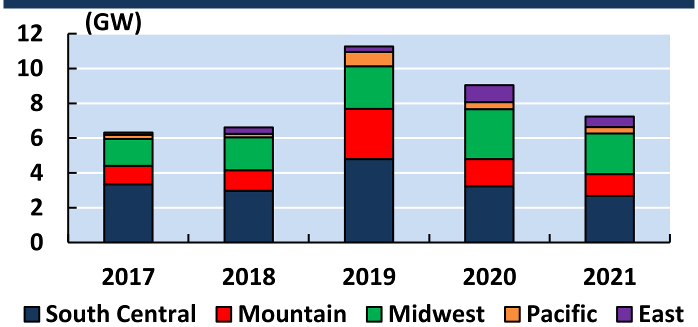
	Coal	CCGT	Gas Turbine	Steam – Gas & Oil	Nuclear	Hydro	Peaker & Other	Wind	Solar
2016	(0.22)	4.45	1.97	1.75	0.70	0.27	0.64	8.75	8.03
2017	(8.45)	7.71	(1.24)	(5.06)	-	(0.12)	0.30	6.30	4.59
2018	(15.75)	16.61	1.19	(4.69)	(0.61)	(0.01)	0.25	5.91	6.18
2019	(10.02)	5.71	0.42	(0.77)	(1.48)	0.03	0.25	11.26	4.55
2020	(6.77)	5.94	0.46	(2.30)	(1.90)	-	0.11	9.05	4.50

Source: EVA

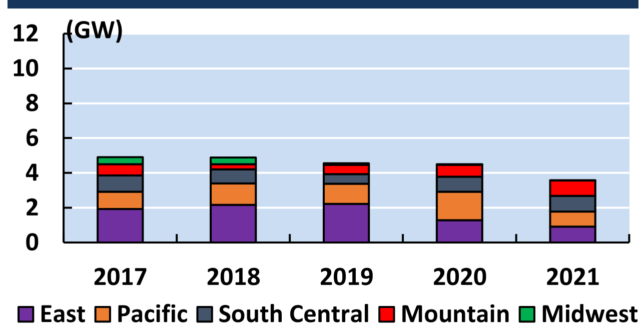
Looking ahead to summer 2019, structural growth will continue to drive increases in power burn with another 6 GW of new CCGTs coming online. However, economic switching to gas will be 1.4 BCFD lower than economic switching in 2018 given the three main reasons discussed below:

- Newer gas-fired units are more efficient and therefore could displace generation from older gas units, resulting in gas-on-gas competition.
- Over the last few years, the U.S. retired many less efficient and price-sensitive coal plants from the fleet. The remaining coal units are more efficient and have lower operating costs. They tend to dispatch more price-competitively regardless of natural gas prices. Furthermore, as global coal demand remains robust, more of U.S. coal production is committed to export rather than responding to marginal increases in domestic demand. This has reduced the flexibility of switching to coal when gas prices fluctuate.
- The addition of wind and solar capacity will limit the upside for power burn. In 2019, another 11.3 of wind and 4.6 GW of solar capacity are expected to enter service, with the South Central region seeing the largest additions (see figures below).

WIND CAPACITY ADDITIONS



SOLAR CAPACITY ADDITIONS



Source: EVA

As rapid renewable development has become a central topic when discussing electric sector gas demand, EVA developed the features below to discuss the short-term as well as long-term impacts of renewable energy development.

Impacts of Wind Generation on Summer Power Burn

In 2019, more than 11 GW of new wind capacity is expected to enter service, which will surpass gas to become the leading source of capacity additions. Because wind generation is less predictable, and is growing most rapidly in certain key markets, EVA conducted a sensitivity analysis of 15% higher and lower wind output to quantify the impact on power burn for the U.S. as a whole.

In our base case, U.S. wind capacity factors average roughly 31% for the summer. Adjusting the output up and down by 15% yields capacity factors of 35.7% and 26.4%, respectively. According to EVA's dispatch modeling results, a 15% change in national wind capacity factor will yield **a 0.8 BCFD change in summer power burns**. Assuming other supply and demand sectors remain unchanged, a high wind scenario would reduce summer gas demand by 184 BCF, loosening end-of-season storage to nearly 4 TCF (see table below).

2019 Summer Power Burn under Three Wind Scenarios

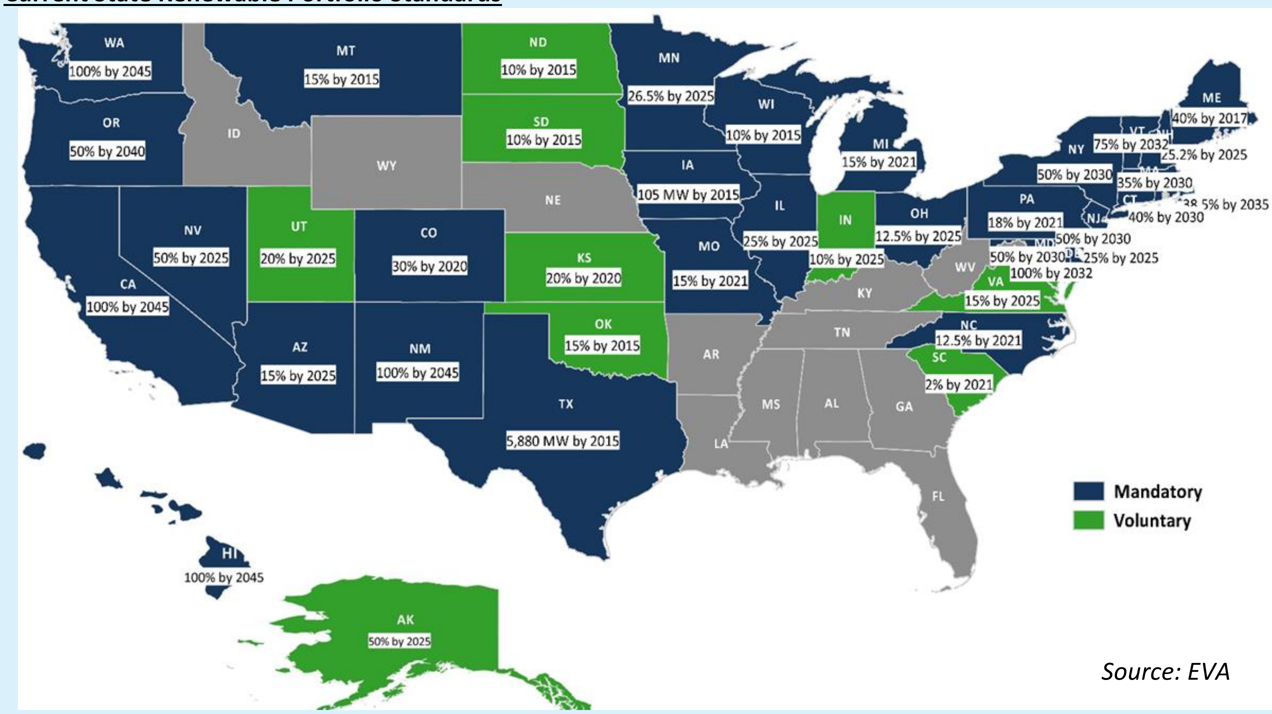
	Power Burn (BCFD) Under Different Wind Generation Scenarios		
(	15% lower wind generation	Normal wind generation	15% higher wind generation
Apr-2019	24.4	23.6	22.9
May-2019	27.2	26.4	25.5
Jun-2019	31.9	31.2	30.4
Jul-2019	40.4	39.4	38.4
Aug-2019	39.5	38.7	37.9
Sep-2019	33.9	33.0	32.2
Oct-2019	28.2	26.9	25.8
Average	32.2	31.3	30.4
Difference from Base (BCF) for the Injection Season	193	0	(184)
End of Season (BCF)	3,552	3,745	3,929

Source: EVA

The Emergence of 100% RPS

In recent years, states have been actively revising their Renewable Portfolio Standards (RPS), policies that typically dictate what percentage of utilities' electric sales must come from renewables, nuclear or hydro generation (see map below). In the context of RPS, clean energy typically refers to generation that has zero emissions. As of May 2019, Hawaii, California, New Mexico and Washington (as well as Washington D.C. and Puerto Rico) passed legislation to achieve 100% clean energy, while states like New York, Massachusetts, Illinois could join the next wave of 100% clean energy legislation. Additionally, states that currently have high gas penetration such as Nevada have also set aggressive RPS targets. To address the intermittent nature of renewable resources, states like Massachusetts, California, and Arizona have also discussed Clean Peaking Standards (CPS), which gives credits to clean energy delivered during specific peak demand hours. The CPS could enable the acceleration of the "renewable plus storage" business model as energy storage units can discharge to meet peak demand. In the longer term, state-level policies will steer the direction of renewable energy development.

Current State Renewable Portfolio Standards

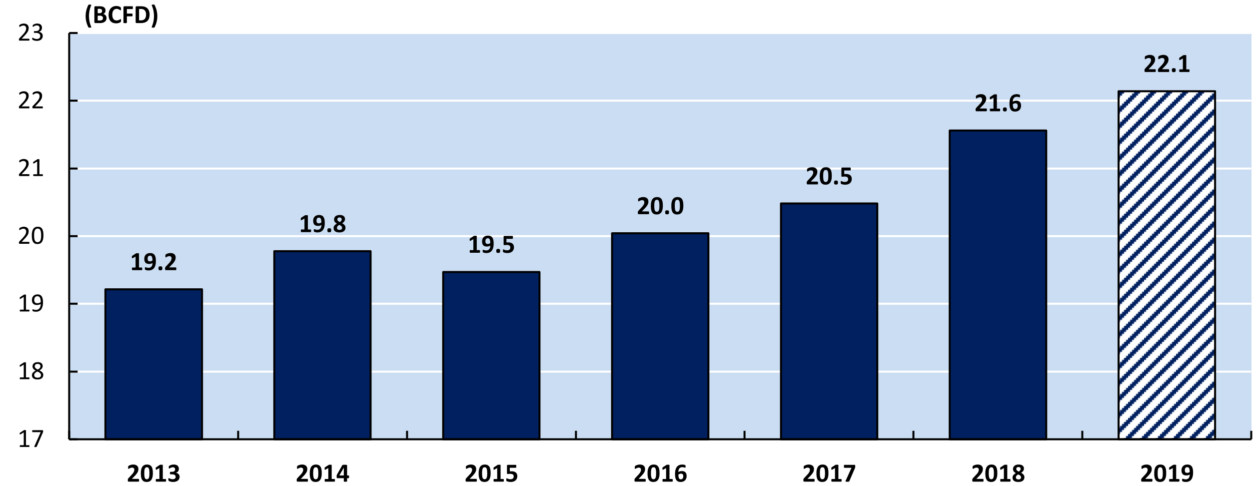


The potential impacts of 100% RPS are two-fold if followed through by states. First, driven by state policy and falling capital costs, utilities will accelerate the buildout of renewable energy in the coming years, which will gradually reduce power burn. Secondly, the resulting reduction in electric gas demand might affect future investment on gas infrastructure such as power plants and pipelines. Regulatory uncertainty over gas infrastructure will likely grow in certain states, e.g. New York blocking the Constitution Pipeline. The gas industry will have to innovate and adapt to the era of high renewable penetration and demonstrate the benefits of diversifying the supply mix as well as its role in providing flexibility.

Industrial demand

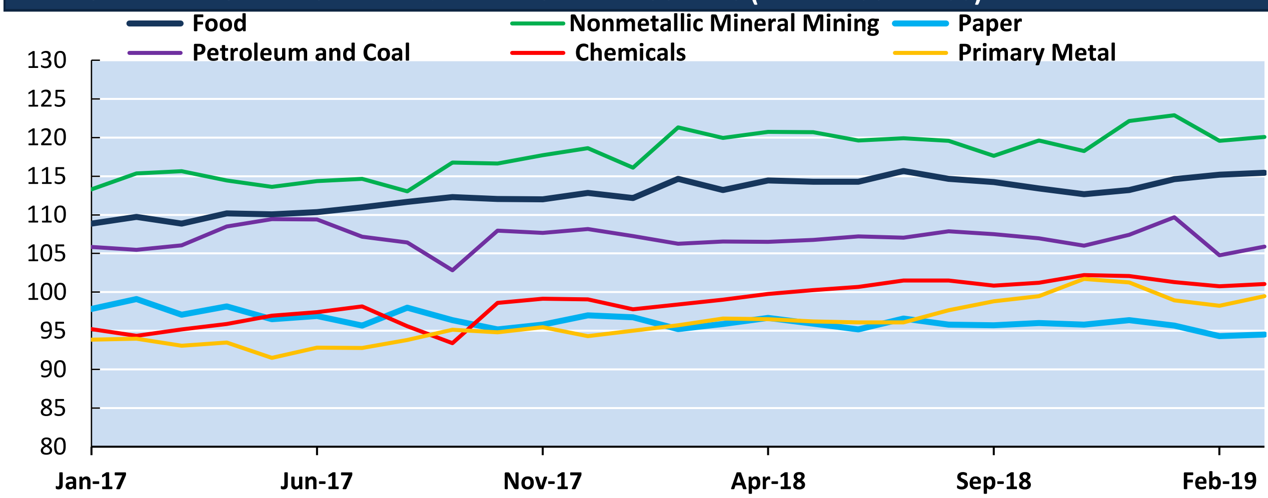
Summer industrial demand has grown by 0.5 BCFD per year on average since 2013 (see figure below). Demand in summer at industrial facilities is less affected by weather and thus could be indicative of real structural growth. A stronger economy contributed to the growth as evidenced by the climbing indices for the performance of the six energy-intensive industries and higher overall capacity utilization at industrial facilities (see figures below).

INDUSTRIAL SUMMER GAS DEMAND



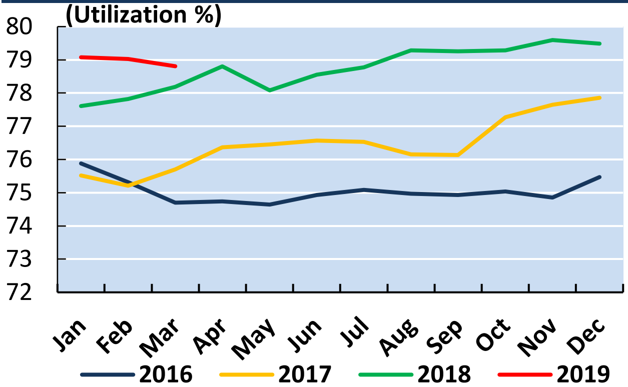
Source: EVA

PERFORMANCE OF THE SIX ENERGY INTENSIVE INDUSTRIES (INDEX 2007 = 100)



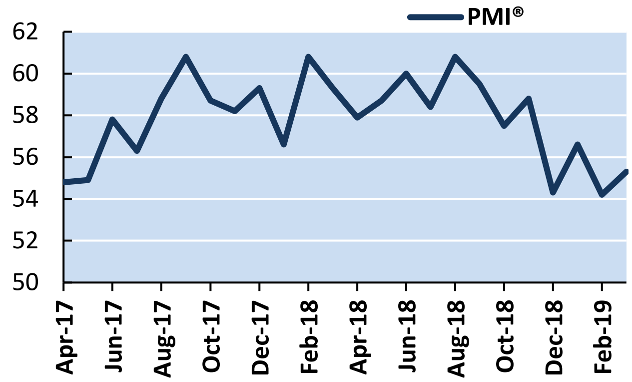
Source: U.S. Federal Reserve

INDUSTRIAL CAPACITY UTILIZATION



Source: U.S. Federal Reserve

PURCHASING MANAGERS' INDEX



Source: ISM. A reading above 50 percent indicates that the manufacturing economy is generally expanding.

The primary metal sector has benefited from the import tariffs that were imposed on steel and aluminum in 2018. Plant-restarts as well as new facilities were announced domestically in response to declining imports. In 2018, U.S. steel production increased by 6.2% while imports dropped by 11.5%. However, as imports dropped, steel prices rose, leading to high costs for industries that use steel as a key input. For example, the auto manufacturing industry has blamed tariffs for cost increases and worker layoffs. Therefore, the long-term impact of the steel tariff could be a mixed bag. The Purchasing Managers' Index, a measure of the prevailing direction of economic trends in manufacturing, has begun softening in 2019 (see figure above), signaling a potential contraction.

New projects that use natural gas as a feedstock, such as fertilizer and methanol plants, have also contributed to demand growth in the industrial sector. This summer, G2X Energy's Big Lake Phase I (1.4 million metric ton per year, 0.1 BCFD of gas demand) is expected to enter service by Q3 2019 in Louisiana. A few more methanol projects are expected to come online in 2020, including Liberty One in West Virginia and Yuhuang Chemical in Louisiana.

Besides fertilizer and methanol plants, new ethylene, propylene, and olefins facilities will also boost natural gas and natural gas liquids (NGL) demand this summer. These facilities use natural gas for heat and power and can also increase electricity demand when consuming power from the grid. Projects in this category are concentrated in Texas and Louisiana.

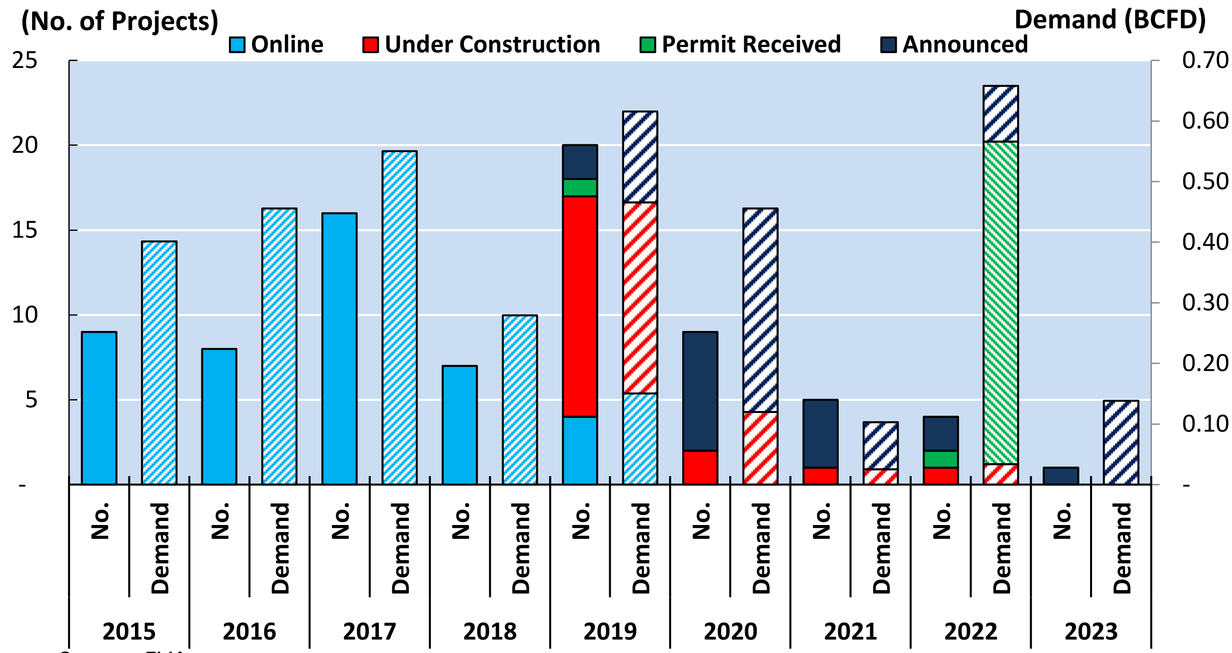
In total, industrial demand is expected to grow by 0.6 BCFD, or 2.3%, summer-over-summer.

INDUSTRIAL PROJECTS AND NATURAL GAS DEMAND

	No. of Projects	Demand (BCFD)
2015	9.0	0.4
2016	8.0	0.5
2017	16.0	0.6
2018	7.0	0.3
2019	21.0	0.6
2020	10.0	0.5
2021	3.0	0.1
2022	5.0	0.7
2023	1.0	0.1

Source: EVA

INDUSTRIAL PROJECTS AND GAS DEMAND



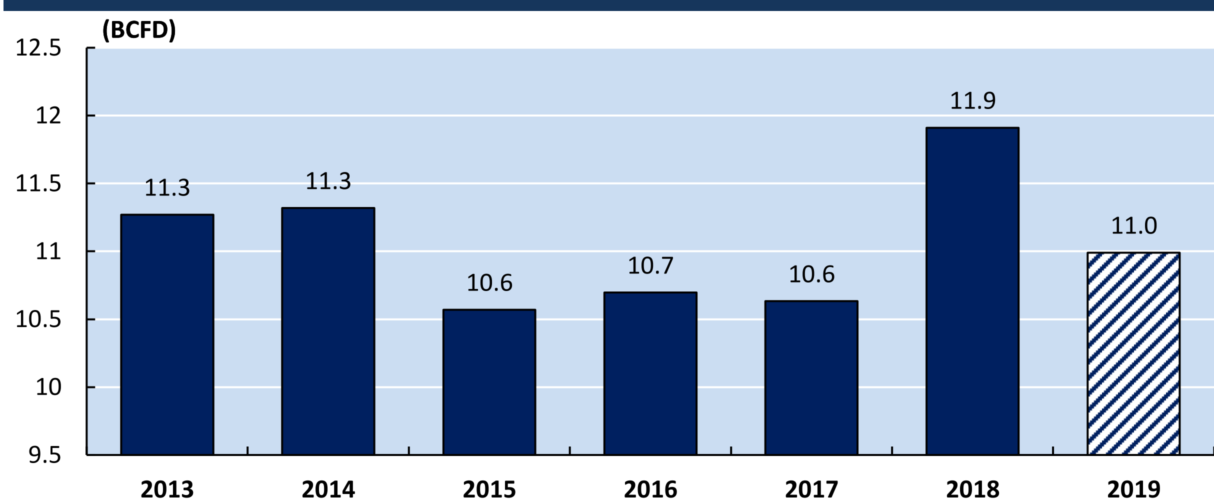
Source: EVA

40 projects (2015-2018), total natural gas demand: 1.69 BCFD
40 projects (2019-2023), total natural gas demand: 1.97 BCFD

Residential and Commercial

The decline in gas demand in the Residential and Commercial (ResComm) sectors this summer is mostly caused by the assumption of normal weather. Last April's heating degree days (HDDs) were 86 degree days higher than the 30-year normal, which elevated last summer's ResComm demand. A mild April this year and the normal weather assumption for May to October is expected to lead to a 0.9 BCFD summer-over-summer drop in the ResComm forecast.

RESIDENTIAL AND COMMERCIAL



Source: EVA

Exports

Natural gas exports will again be the biggest growth factor this summer. LNG exports and exports to Mexico are forecast to grow by 2.7 BCFD and 0.8 BCFD, respectively.

This summer's LNG exports growth is mostly driven by the addition of new LNG trains (see table below). Since last summer, 1.4 BCFD of new capacity has come online (Sabine Pass T5, Corpus Christi T1). Four more trains (Corpus T2, Freeport T1, Elba Phase I, Cameron T1), totaling 2.3 BCFD of capacity, are being commissioned and are scheduled to come online before the end of summer. Except for Corpus Christi T2, the facilities have experienced substantial delays from their original schedule. Recently, Cameron announced further delays for T2 and T3.

U.S. LNG TRAINS

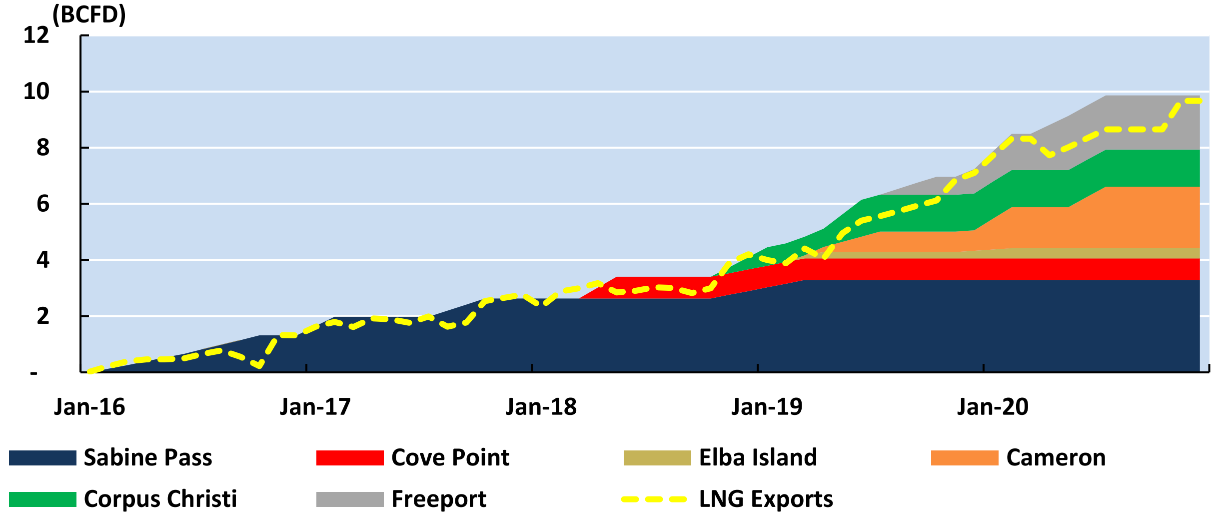
Train	Start Date	Capacity (MMtpa)	Capacity (BCFD)
Sabine Pass LNG T1	Feb-16	4.5	0.7
Sabine Pass LNG T2	Jul-16	4.5	0.7
Sabine Pass LNG T3	Jan-17	4.5	0.7
Sabine Pass LNG T4	Aug-17	4.5	0.7
Sabine Pass LNG T5	Nov-18	4.5	0.7
Cove Point T1	Mar-18	5.3	0.8
Elba Island T1-6	May-19	1.5	0.2
Elba Island T7-10	Dec-19	1.0	0.1
Freeport LNG T1	Aug-19	4.4	0.6
Freeport LNG T2	Jan-20	4.4	0.6
Freeport LNG T3	Apr-20	4.4	0.6
Cameron LNG T1	May-19	4.0	0.6
Cameron LNG T2	Mar-20	4.0	0.6
Cameron LNG T3	Aug-20	4.0	0.6
Corpus Christi LNG T1	Mar-19	4.5	0.7
Corpus Christi LNG T2	Aug-19	4.5	0.7
Corpus Christi LNG T3	Dec-21	4.5	0.7
Calcasieu Pass (9 Modular Trains)	Mar-22	10.0	1.5
Golden Pass (3 Trains)	2023-2024	15.6	2.3

Source: EVA

As seen in the figure below, LNG export capacity was not fully utilized last summer. As global demand for LNG demonstrates a seasonal shape with a winter peak and a smaller summer peak, shoulder season demand often trends below available supply, leading to under-utilization of less competitive suppliers. A mild winter 2018-2019 in Europe and Asia led to a drop in LNG prices on both continents, signaling lackluster demand. Europe's storage inventory is at a multi-year high due to strong LNG imports, unyielding pipeline imports from Russia and relatively flat demand. Asian prices are likely to recover as power demand ramps up, however, the commissioning of two Australian trains[3] early this year could help meet growing demand.

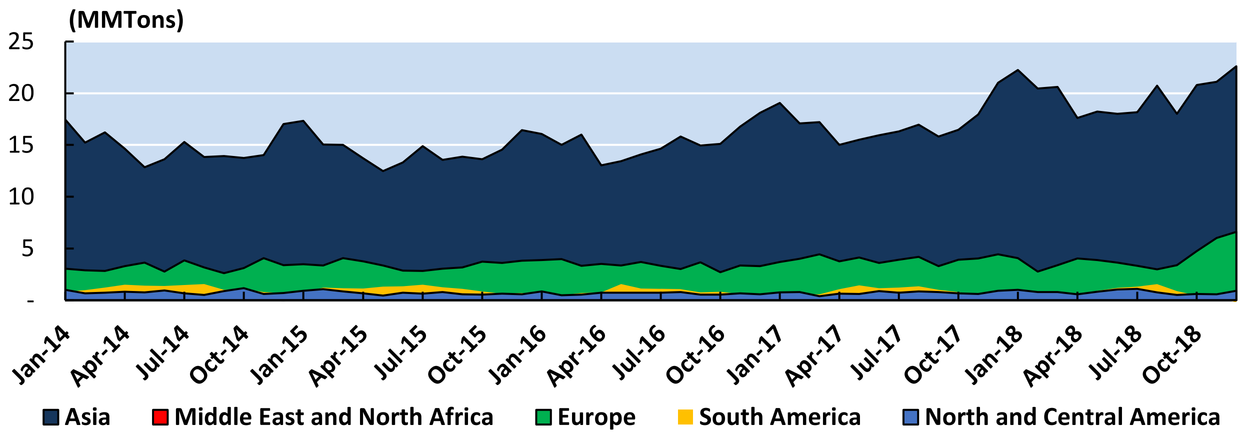
[3] Prelude, Ichthys

U.S. LNG EXPORTS - ACTUAL AND FORECAST BY PROJECT



Source: EVA

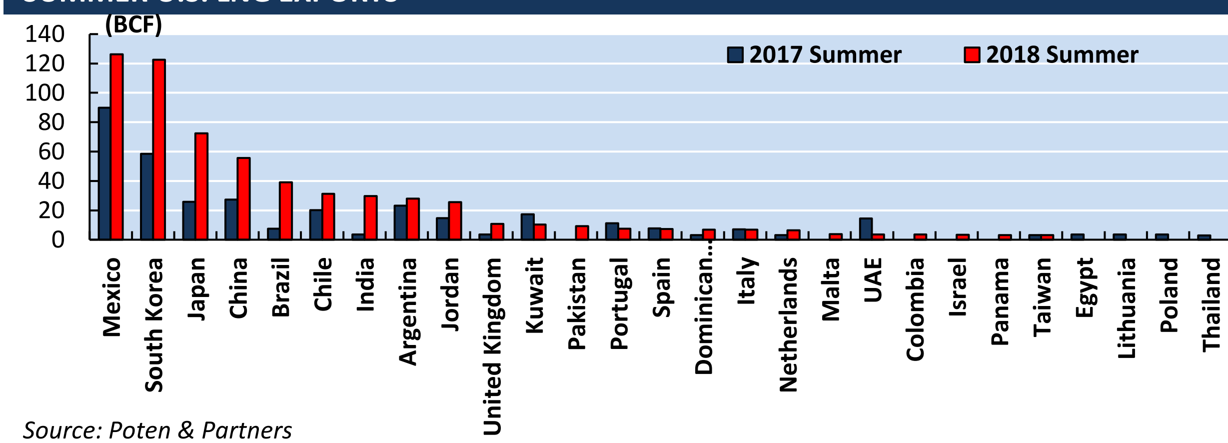
GLOBAL LNG IMPORTS SEASONALITY



Source: Poten & Partners, EVA

In addition, the U.S. could lose Mexico as an LNG export destination this summer. Last summer, the U.S. exported on average 0.5 BCFD of LNG to Mexico (see figure below). As Mexico is poised to replace LNG imports with pipeline imports, U.S. spot cargo sales could lose a source of demand.

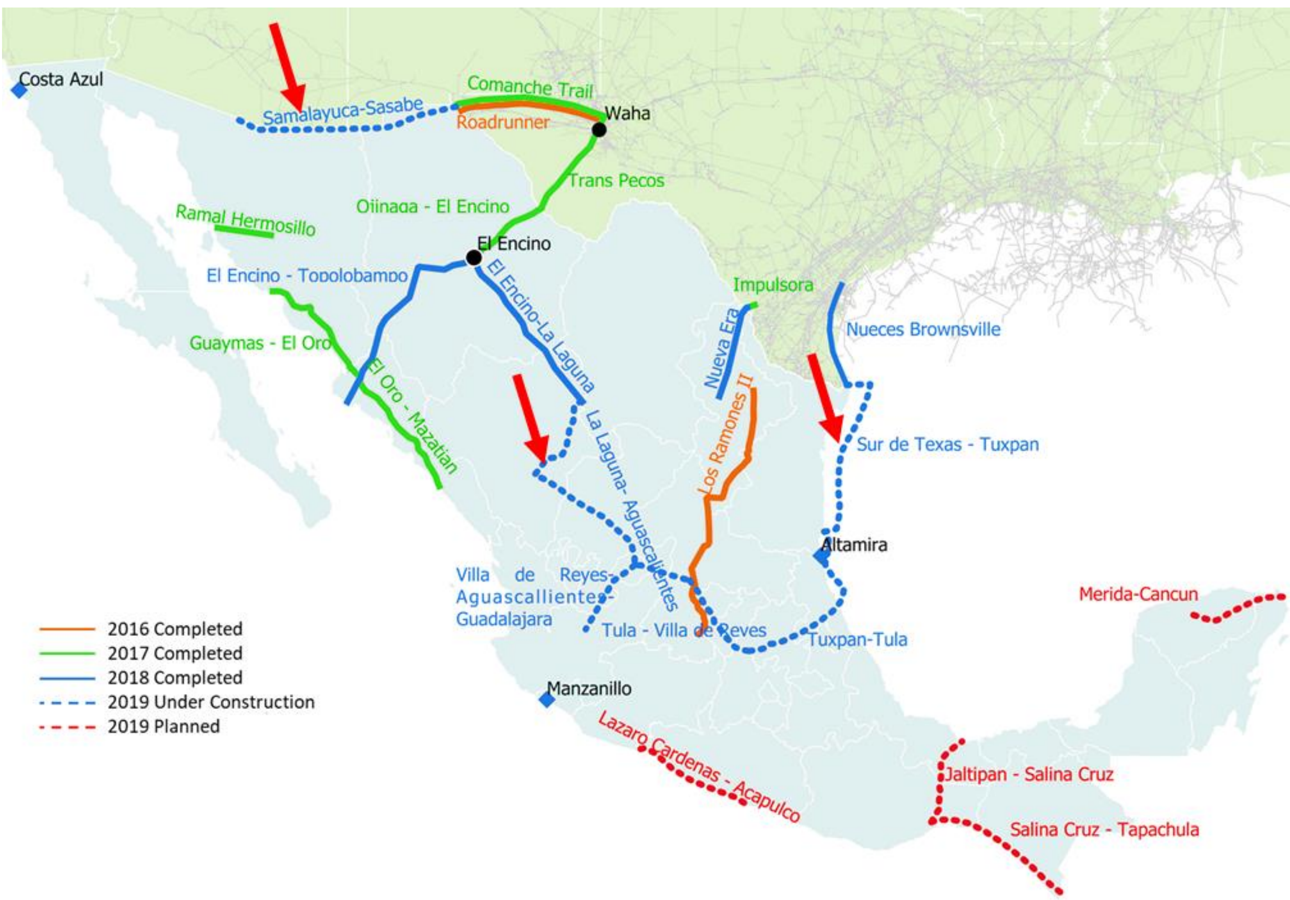
SUMMER U.S. LNG EXPORTS



Source: Poten & Partners

Pipeline exports to Mexico, on the other hand, are forecast to grow 0.8 BCFD summer-over-summer. Since last summer, more than 1.4 BCFD of pipeline capacity was added in Mexico (see table below). However, demand has only grown by 0.32 BCFD. This summer, more downstream pipeline capacity will be developed (see table below and the red arrows in the map), including Sur de Texas-Tuxpan, which has the potential to displace LNG imports as well as Wahalajara, which can connect Waha to central Mexico. While Sur de Texas-Tuxpan could potentially start in June, Wahalajara could experience delays. Therefore, only 0.8 BCFD of pipeline import growth was built into the forecast.

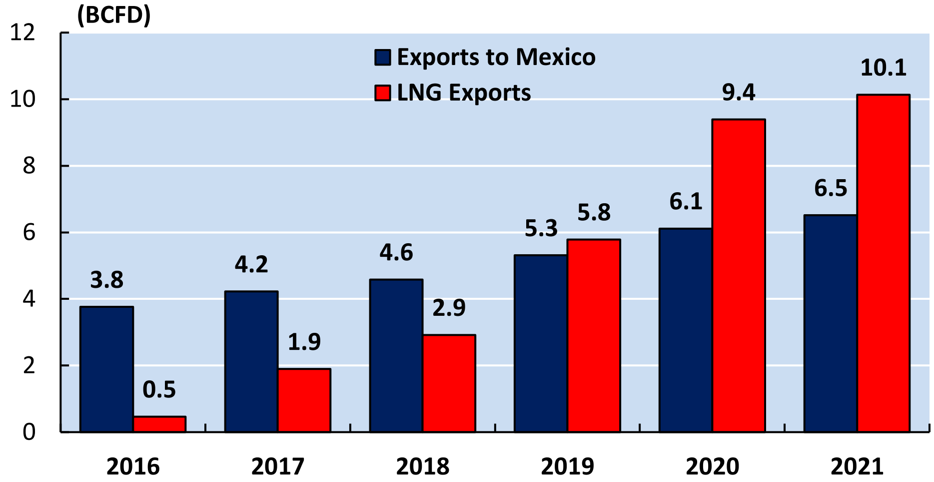
Came online since last summer	To come online this summer
▪ *Tarahumara expansion (0.2 BCFD)* ▪ *El Encino-Topolobampo (0.7 BCFD)* ▪ *Nueva Era (0.5 BCFD)* ▪ *TGP and Kinder Morgan received approvals to increase cross-border capacity.*	▪ *Sur de Texas –Tuxpan (2.6 BCFD), Q2 2019* ▪ *El Encino – La Laguna (1.67 BCFD) saw first flows on April 17.* ▪ *La Laguna-Aguascalientes (1.3 BCFD), Q3 2019* ▪ *Villa de Reyes Aguascalientes-Guadalajara (0.89 BCFD), Q3 2019* ▪ *Samalayuca-Sasabe (0.5 BCFD) – second half of 2019*



Source: EVA

In the longer term, LNG exports are expected to reach 10.1 BCFD by 2021 driven by new trains coming online and growing global demand for cleaner fuel (see figure below). Exports to Mexico are expected to grow to 6.5 BCFD by 2021, facilitated by the development of pipelines and power plants in Mexico. Mexico's new president is actively reversing his predecessor's energy market liberalization by handing control back to CFE and PEMEX. Energy infrastructure investment and development in the long term could experience a setback, delaying natural gas import growth.

ANNUAL EXPORTS HISTORY AND FORECAST



Source: EVA

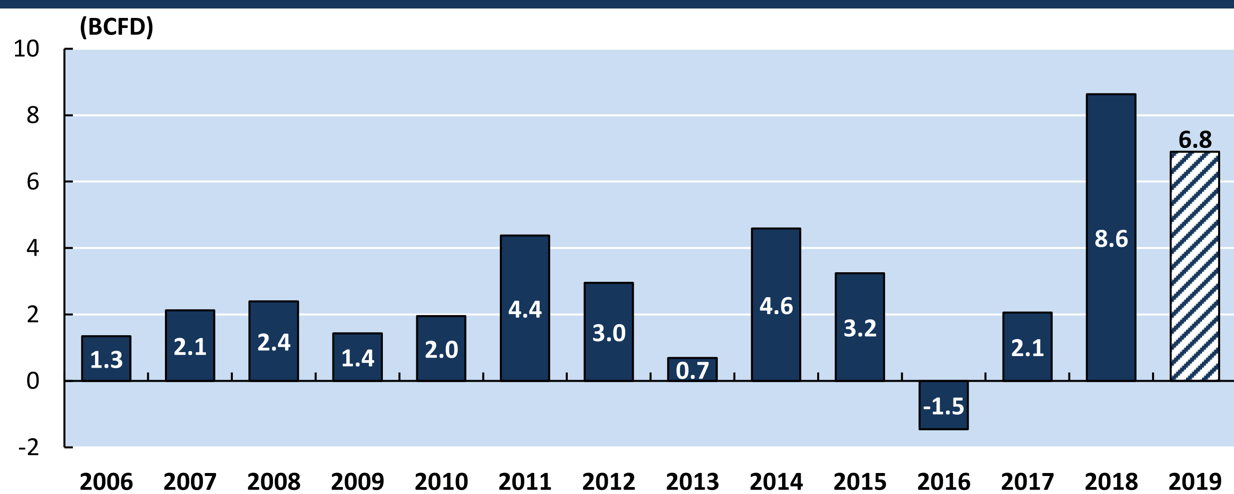
III. OUTLOOK FOR SUPPLY

Production

Production is expected to grow by 6.8 BCFD summer-over-summer. Growth this year will be more dispersed, featuring increases not only in the Northeast but also in Haynesville and Permian, among others.

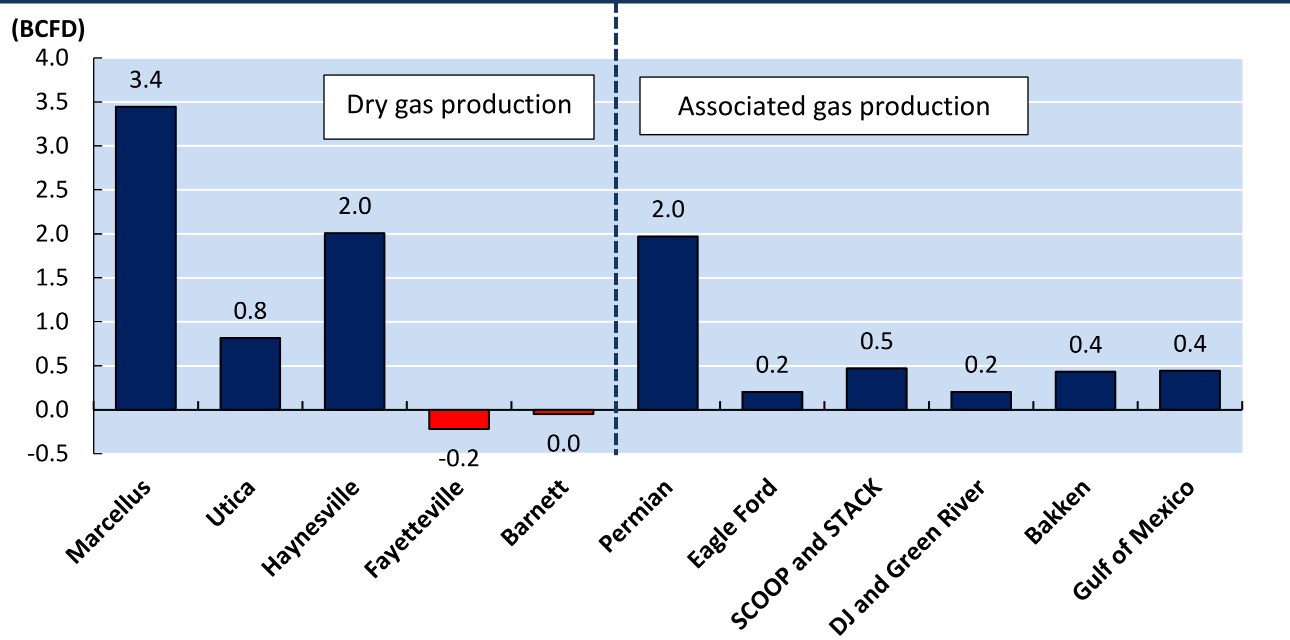
2018 was a record production growth year, doubling or tripling the growth from previous years. As of April 2019, dry gas production is 6 BCFD higher YoY, and associated gas production is 3.7 BCFD higher YoY (see figure below). Besides shale, Gulf of Mexico production also rebounded as a result of the start-up of eight major deepwater projects during 2018. These projects have offset the declines from existing wells and pushed Gulf of Mexico production higher by 0.4 BCFD YoY.

DRY GAS PRODUCTION YOY GROWTH



Source: EIA, EVA

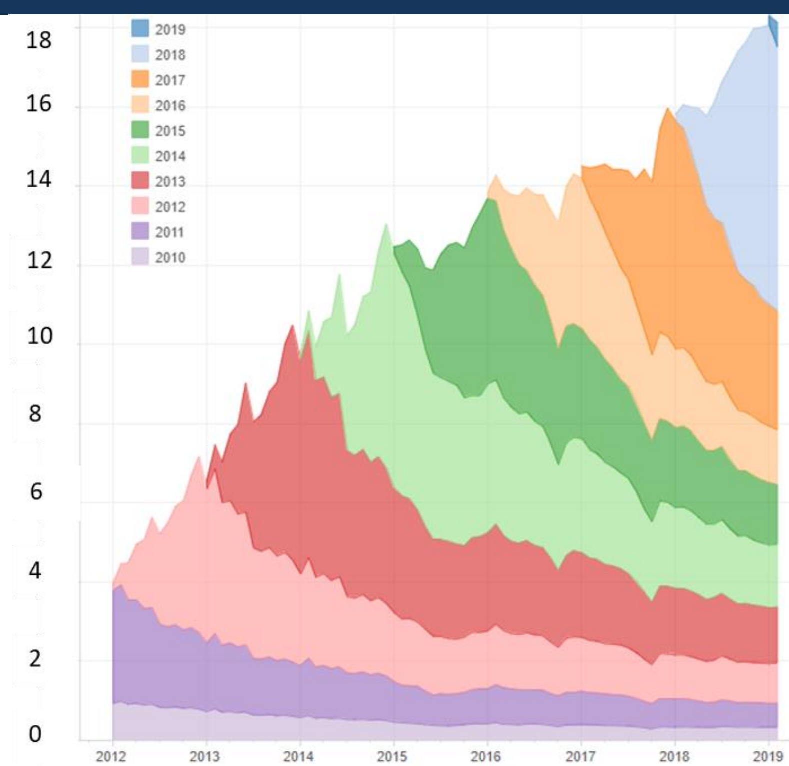
PRODUCTION YOY TRENDS BY PLAY - APRIL 2019 VS APRIL 2018



Source: PointLogic, EVA

The greater growth in 2018 has created a greater responsibility for producers in 2019 – countering the declines from the newly-added wells in 2018. Production from shale wells can decline by 30% to 70% during their first year of production depending on the location. The figure below shows that more wells were added in the Marcellus in 2018 which are poised to experience their first-year decline in 2019. With rigs at a similar level compared to last summer, production is unlikely to grow as fast because the newly drilled wells in 2019 will have to counter the declines from the wells that began production in 2018.

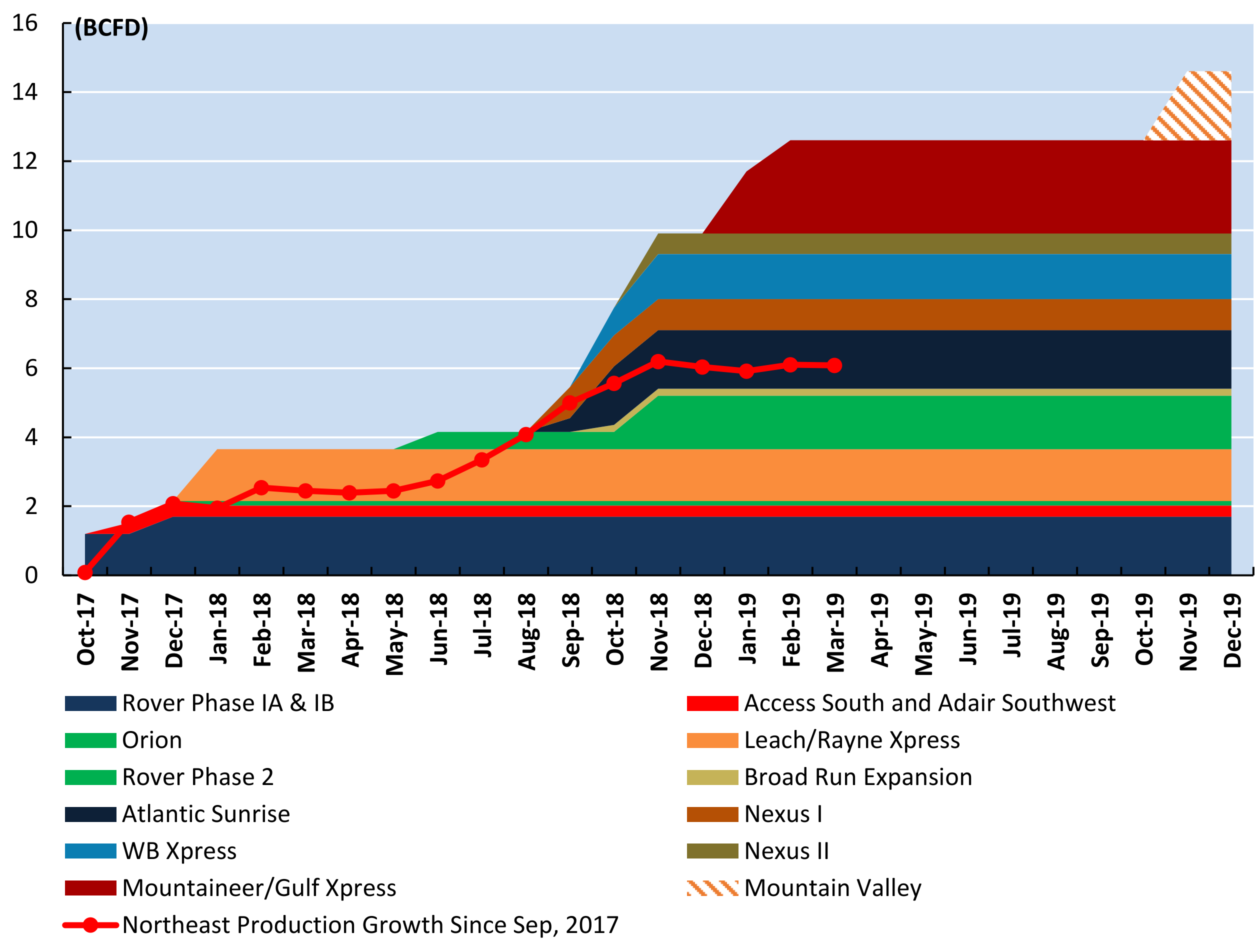
MARCELLUS DAILY GAS PRODUCTION BY YEAR OF FIRST FLOW (BCFD)



Source: ShaleProfile

Northeast production has grown marginally since November 2018 (see figure below) partially due to the above-mentioned offset effect. Production will likely grow faster in the summer with more wells drilled as demand ramps up. In terms of takeaway capacity, plenty of pipeline capacity was brought online targeting LNG demand over the past year. However, several LNG trains were delayed into 2019, leaving spare takeaway capacity from the Northeast to the Southeast (e.g. Columbia Gulf pipeline added two expansions Rayne Xpress and Gulf Xpress). Even though Mountain Valley could be delayed into 2020, there is still some headroom in pipeline capacity (about 7 BCFD) for Northeast production to grow. The region is also adding processing capacity (i.e., Sherwood processing plant expansions) to facilitate this growth.

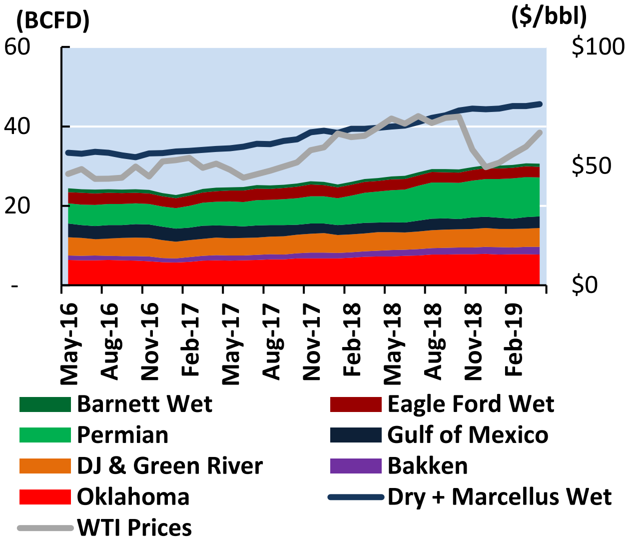
NORTHEAST PIPELINE TAKEAWAY CAPACITY



Source: EVA

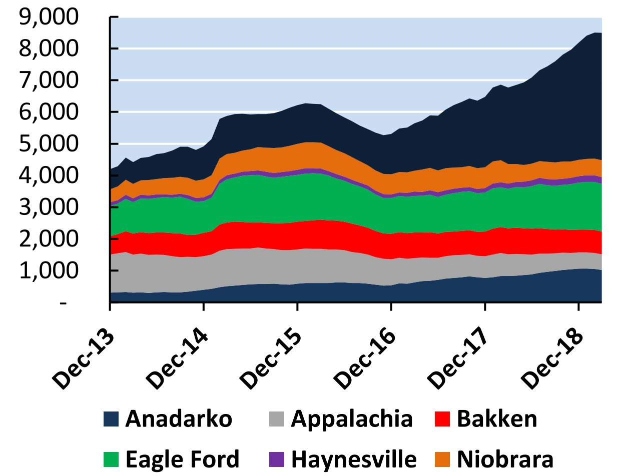
Associated gas production is likely to play a bigger role this summer, especially towards the end of the season. Oil prices dropped in late 2018, which slowed the quick pace of oil rig additions. However, associated production has not responded to the price drop (see stacked areas in the left figure next page). Typically, there is a lag in production's response to prices. Also, drilled but uncompleted wells (DUCs) have been accumulating, which could buffer any price volatilities. Oil prices have since recovered in light of OPEC's agreement to cut production and continued sanctions on Iran. As a result, the recent concerns over the potential for a pullback from associated gas production have largely dissipated.

DRY VS. ASSOCIATED PRODUCTION



Source: Pointlogic, EIA, EVA

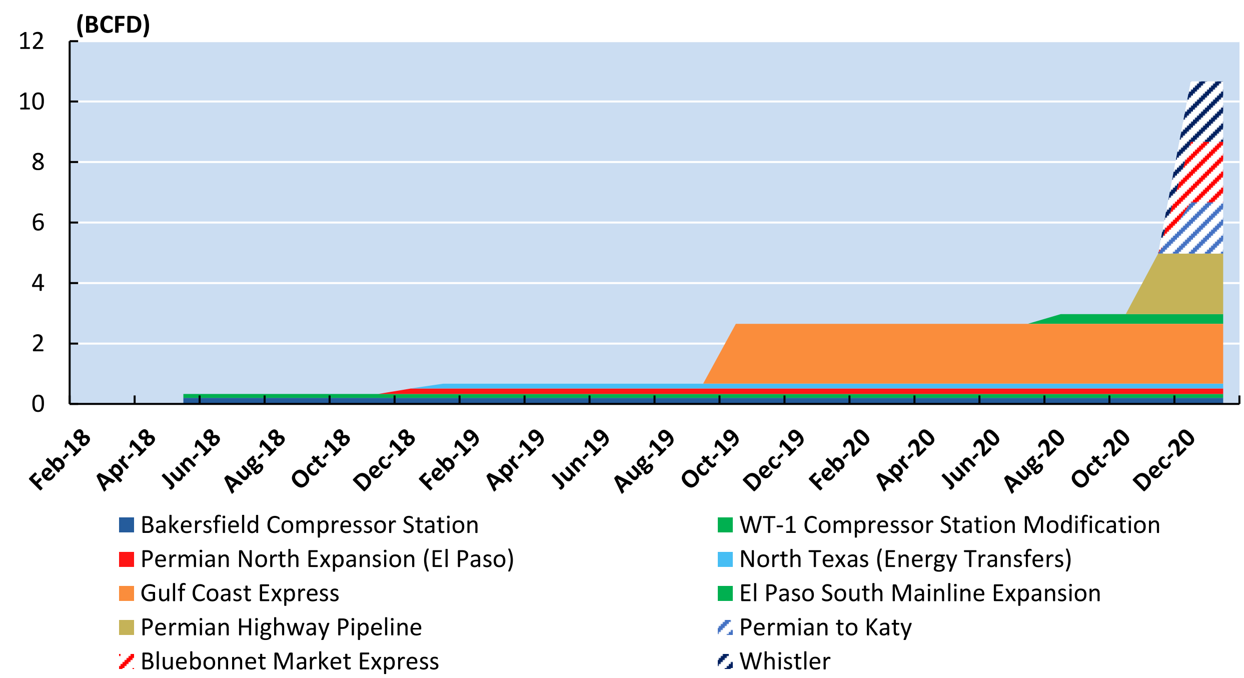
DRILLED BUT UNCOMPLETED WELLS



Source: EIA, EVA

In fact, Permian's first major greenfield gas takeaway pipeline, Gulf Coast Express (1.98 BCFD), is scheduled to come online in October. The long-awaited pipeline will most certainly fill quickly and boost production before the winter season. Permian's gas production grew 2 BCFD YoY to 9.7 BCFD as of April 2019 and is now 11% of total U.S. production. The high production and lack of takeaway capacity have led to negative pricing and gas flaring in the region. There are a couple of other Permian projects (about 10 BCFD of capacity) in the queue, however, only Kinder Morgan's Permian Highway has made its final investment decision so far. In the SCOOP&STACK, Cheniere's Midship pipeline could begin partial operation by October. The company said shippers (producers in the SCOOP&STACK) requested an early start for the pipeline. Cheniere has filed with FERC to potentially bring online roughly 1.1 BCFD of capacity in October. Production is likely to step higher in October barring project delays.

PERMIAN PIPELINE TAKEAWAY CAPACITY VS. PRODUCTION GROWTH

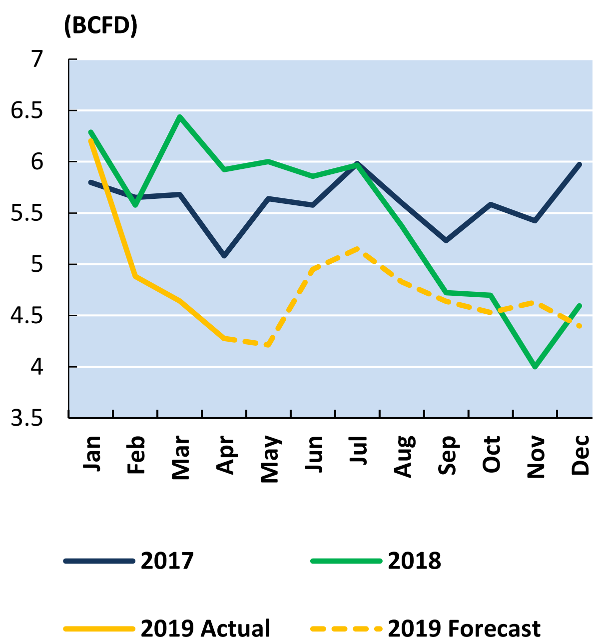


Source: EVA

Imports from Canada

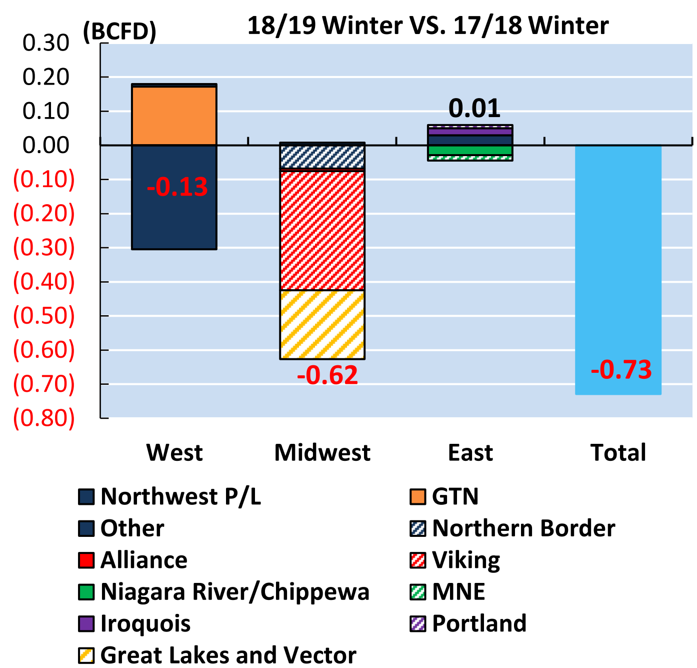
Net imports from Canada are forecast to drop 0.8 BCFD summer-over-summer. Since Rover Phase II and Nexus came online last fall, net imports from Canada started to decline (see figure below) as West Canadian gas lost market share to U.S. Northeast production. A closer look at peak winter flows shows that most of the winter-over-winter decrease happened in the Midwest corridor, where Great Lakes, Vector, Viking and Northern Border[4] saw the largest declines in net imports (see figure on the right below). Besides the competition with the Northeast, West Canadian gas also has to compete with associated production in Bakken. Bakken producers have reserved capacity on Northern Border which further crowds out Canadian supply. The trend of low net imports is forecast to continue into the summer given normal weather assumptions.

NET IMPORTS FROM CANADA



Source: EVA

NET IMPORT CHANGES BY PIPELINE



Source: EIA, EVA, Winter refers to Dec, Jan and Feb
Note: Data labels are net volumes for the region

CANADA-U.S. PIPELINES

Source: EVA

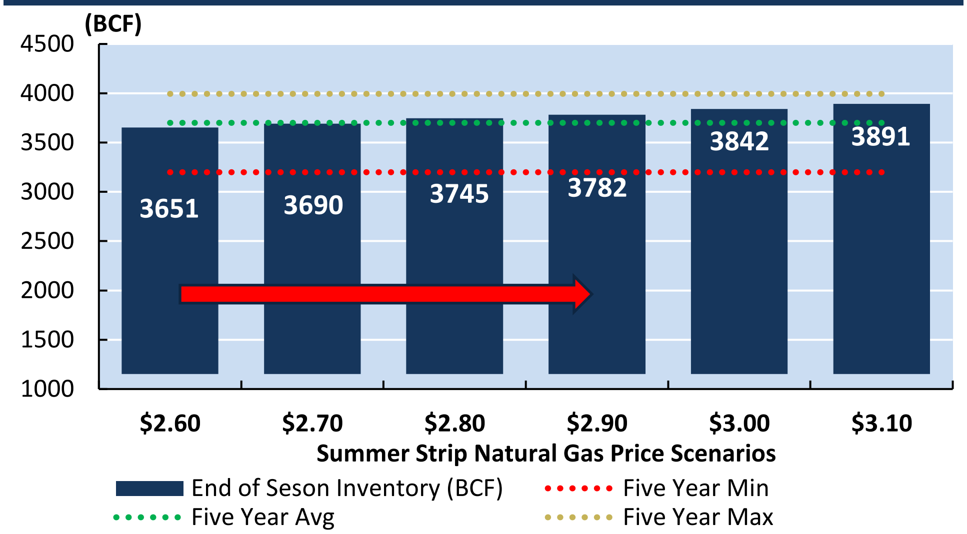
[4] Traditionally, the Vector pipeline receives gas from Alliance, Northern Border and Guardian at Joliet and sends the gas to Dawn in East Canada. Part of this gas was imported to the U.S. via Alliance and Northern Border from West Canada, mixed with Bakken supply, and then re-exported to East Canada through the Midwest. The dynamic has changed this past winter as Vector's customers' primary receipt points has shifted from the Joliet receipts to Rover and Nexus.

IV. STORAGE INJECTION

With the supply and demand fundamentals explained above, end-of-October storage inventories are forecast to be 3,745 BCF. Despite some uncertainties, storage is most likely to fall between the 3,651 BCF and 3,782 BCF levels as illustrated below. These scenarios were developed based on power burn sensitivities to price changes under normal weather conditions. In other words, all fundamentals were kept the same and power burn was allowed to fluctuate given varying Henry Hub summer strip prices.

The forecast storage inventory level, 3,745 BCF, is near the five-year average level and about 87.8% of demonstrated available capacity (see table below). The NYMEX curve for Henry Hub is currently hovering around $2.65/MMBtu, which will incentivize high power burn, providing price support.

OCTOBER SEASON-END STORAGE SCENARIOS



Source: EVA

Source: EVA

Demand for LNG feedgas has created a new challenge for the U.S. gas storage, particularly in the South Central region. Despite that LNG tanks onsite could provide some buffer to balance demand and supply, storage flexibility in the South Central region is essential to absorb supply surplus or respond to acute demand spike (see feature on the next page).

STORAGE CAPACITY AND SEASON-ENDING STORAGE LEVELS

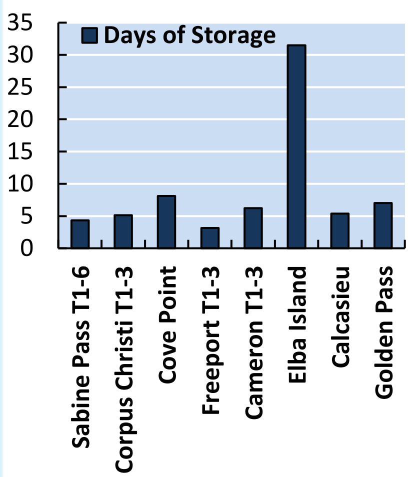
	2012	2013	2014	2015	2016	2017	2018	2019 est
Working Gas Capacity - Demonstrated Peak* (a)	4,103	4,265	4,333	4,336	4,363	4,317	4,263	4,263
Annual Capacity Additions (b)	91	89	1	(7)	34	34	(13)	-
(a)+(b)	4,194	4,354	4,334	4,329	4,397	4,351	4,250	4,263
End of Injection Season Inventory Level	3,928	3,816	3,611	4,009	4,047	3,790	3,247	3,745
Percent of Capacity	94	88	83	93	92	87	76	88

**Demonstrated maximum working gas volume, or demonstrated peak, is the sum of the highest storage inventory levels of working gas observed in each distinct storage reservoir over the previous five-year period as reported by the operator on the Form EIA-191, Monthly Underground Gas Storage Report. The timing of the peaks for different facilities need not coincide. Inactive fields were removed from aggregate statistics.*

LNG Export Terminals' Impact on Regional Storage and Prices

U.S. LNG terminals on average have six days of storage[5] on site as shown in the table below. While it is true that terminals are designed to have full-containment storage tanks on-site to store LNG before being loaded onto LNG ships, this on-site storage certainly has its limits as seen in the table below.

LNG STORAGE TANKS



Source: EVA

	Capacity MMTPA	Capacity BCFD	Storage Capacity BCF	Days of Storage
Sabine T1-6	27.0	3.9	17.0	4
Corpus T1-3	13.5	2.0	10.1	5
Cove Point	12.3	1.8	14.6	8
Freeport T1-3	15.0	2.2	6.9	3
Cameron T1-3	15.0	2.2	13.6	6
Elba Island	2.5	0.4	11.5	32
Calcasieu	10.8	1.6	8.5	5
Golden Pass	16.0	2.3	16.4	7

Assuming normal operations, LNG terminals also keep storage relatively full in order to load the ships quickly when they arrive. Therefore, the buffer these storage tanks can provide can be fewer than the average of six days' onsite storage capacity.

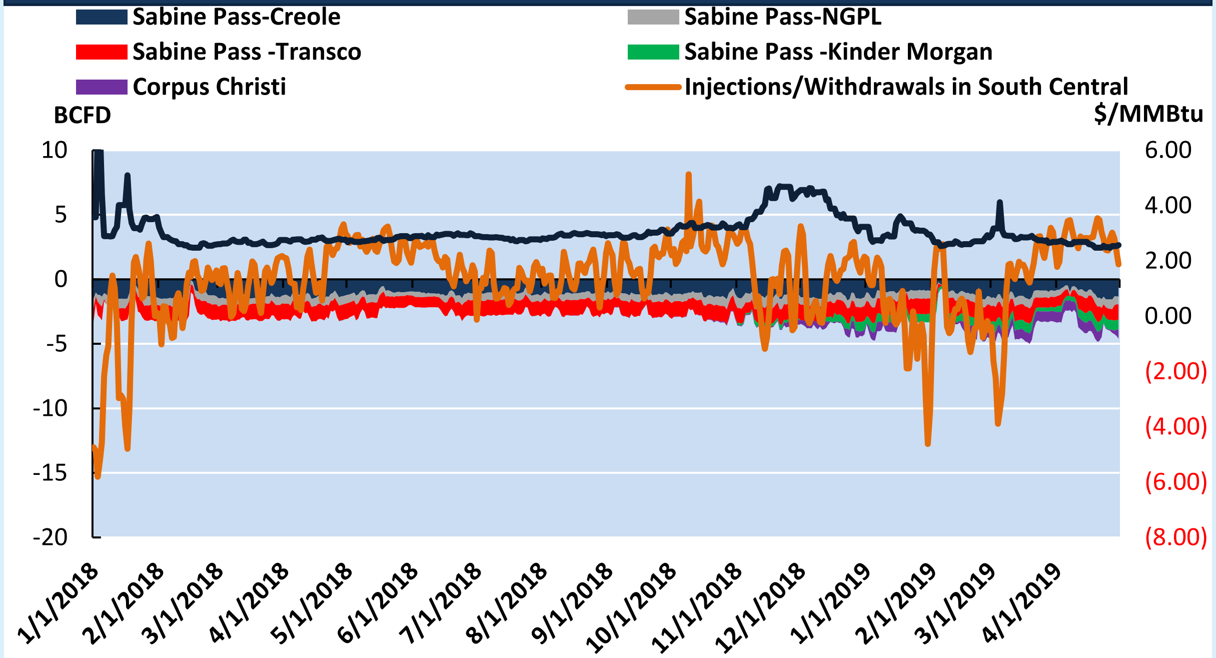
When flows to LNG terminals are disrupted for a sustained period, which could be a result of pipeline maintenance, LNG train maintenance, weather events, or low demand, storage facilities in the South Central region have responded by withdrawing less or injecting more gas to buffer low LNG flows (see figure next page).

When isolating the days during which LNG feedgas flow fluctuates by more than 0.5 BCFD, LNG changes and storage activity changes demonstrate a positive correlation that is more than 50%, meaning when there is a big drop in LNG demand, South Central frequently sees more injections.

Visually, the figure below shows how in Feb 2019, when heavy fog stopped LNG ships from taking deliveries, LNG flows dropped by 2.5 BCFD in the Gulf region over just a few days. South Central storage facilities in turn saw big injections which softened the Henry Hub cash prices. A similar event occurred in April. Low flows due to maintenance at Sabine Pass led to high injections and low Henry Hub prices.

[5] Calculated as total storage capacity divided by daily liquefaction capacity. The average excludes Elba as it appears to be an outlier in terms of storage capacity.

LNG FEEDGAS VS. SOUTH CENTRAL STORAGE ACTIVITIES

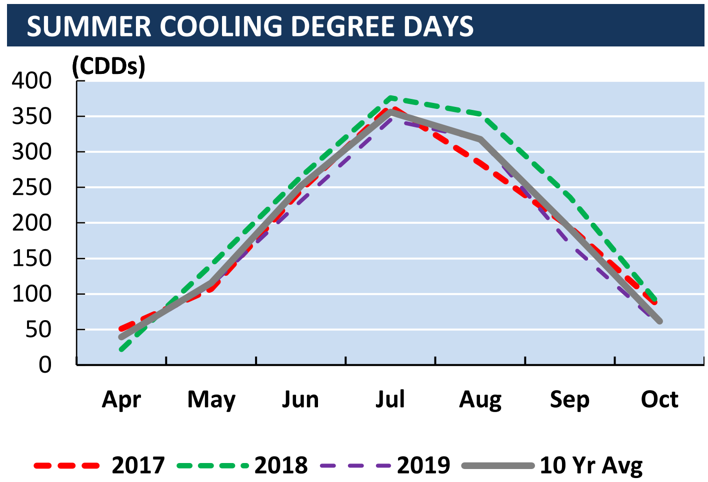


Source: Pointlogic, EVA

In conclusion, South Central storage facilities play an essential role in buffering volatilities created by LNG operations on top of on-site LNG storage tanks. Salt facilities that are connected to the major LNG delivery pipelines (e.g. Transco, NGPL, Kinder Morgan LA, TGPL) have demonstrated their flexibility and value in the era of growing LNG exports.

V. APPENDICES

1. Weather



Source: NOAA, EVA

Summer CDDs (April to October)

Year Range	Total CDDs	Δ from Rolling 10y Avg	
		CDDs	Percent
10 Year Avg	1,334	-	-
2015	1373	60	5%
2016	1,503	169	13%
2017	1,328	-6	0%
2018	1,477	143	11%
2019	1,272	-88	-6%

2. Estimated Probability of One or More Landfalling Category 3-4-5 Hurricanes for 2019

PROBABILITY OF MAJOR HURRICANE MAKING U.S. LANDFALL 2019		
	Probability Forecast (%)	**Average for the Last Century (%)**
Entire U.S. Coastline	48	52
Gulf Coast	28	30
Florida plus East Coast	28	31
Caribbean	39	42

Source: Colorado State University, April 2019

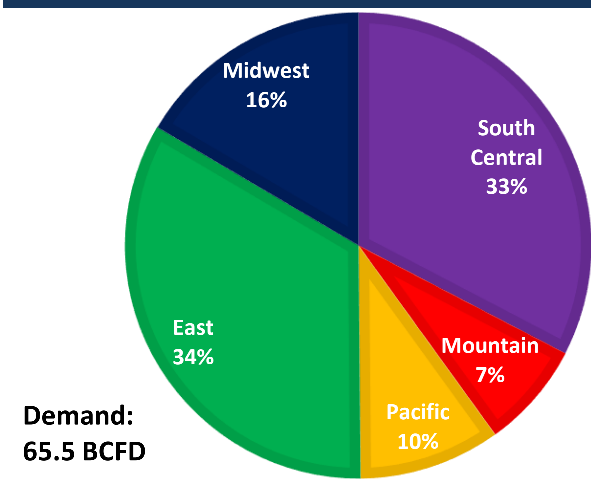
3. *Summer Imports and Exports of Natural Gas*

U.S. IMPORTS AND EXPORTS								
Summer 2018								
Canada			**Mexico**			**LNG**		
Imports	Exports	Net	Imports	Exports	Net	Imports	Exports	Net
7.35	(1.94)	5.41	0.01	(4.69)	(4.68)	0.14	(3.26)	(3.12)
Summer 2019								
Canada			**Mexico**			**LNG**		
Imports	Exports	Net	Imports	Exports	Net	Imports	Exports	Net
7.01	(2.29)	4.72	0.00	(5.49)	(5.49)	0.11	(5.93)	6.04

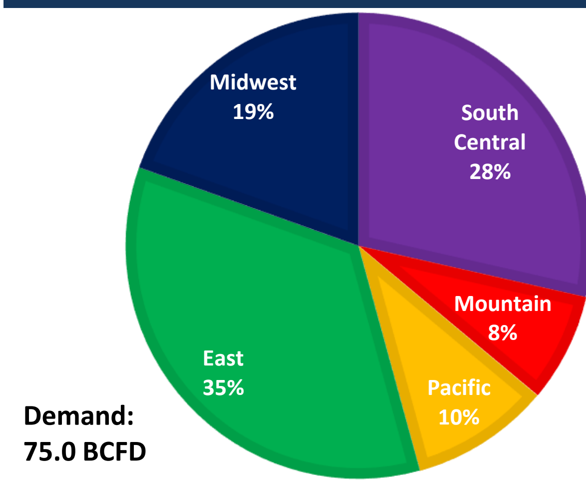
Source: EIA, EVA

4. *Domestic Primary Natural Gas Demand[6] by EIA Natural Gas Region*

SUMMER 2018



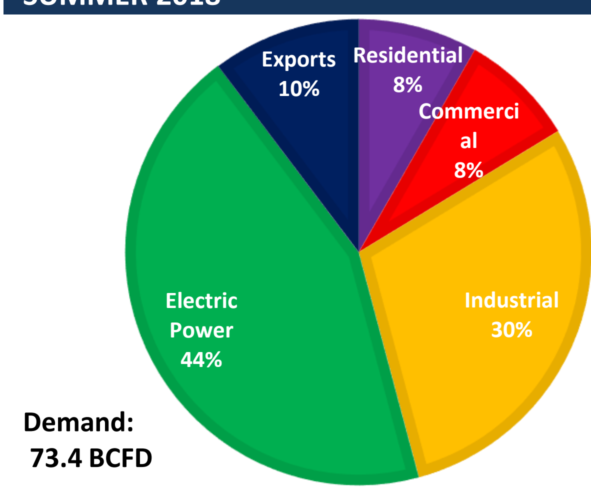
TOTAL YEAR



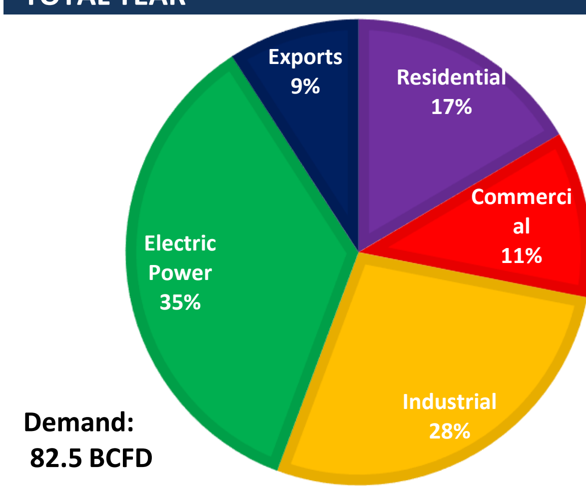
Source: EIA, EVA

5. *Total Primary Natural Gas Demand by Sector*

SUMMER 2018



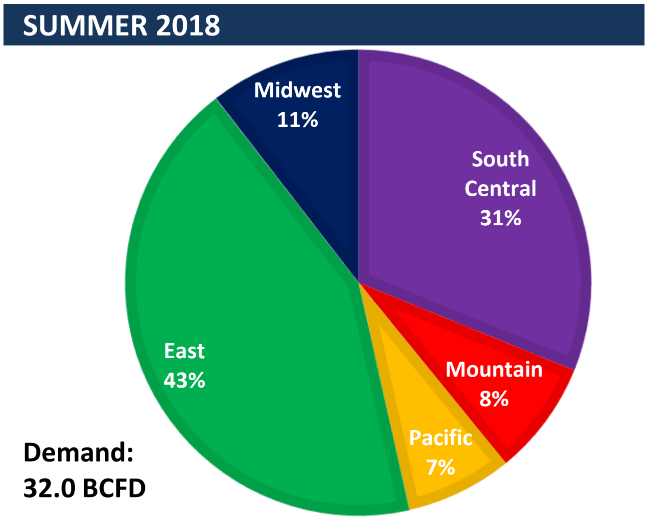
TOTAL YEAR

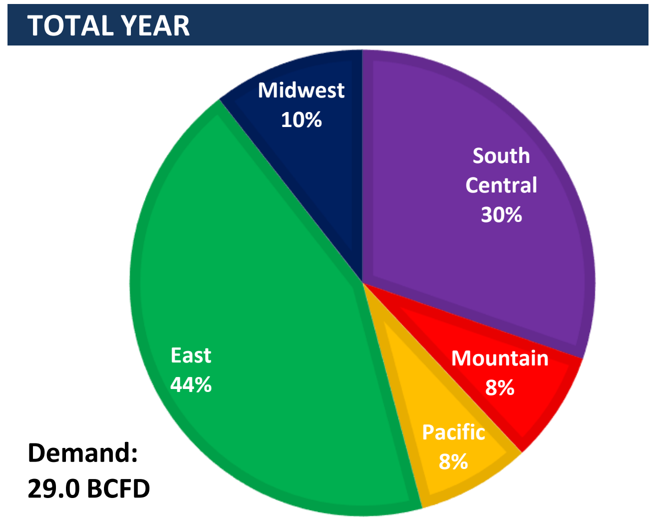


[6] Domestic Primary Demand includes power burn, industrial and residential and commercial demand.

Source: EIA, EVA

6. Power Natural Gas Demand by Natural Gas Region





Source: EIA, EVA

7. GDP Index

	2017	2018	2019	2020	2021	2022	2023	2024
Advanced Economies	2.40	2.20	1.80	1.70	1.70	1.60	1.60	1.60
Emerging and Developing	4.80	4.50	4.40	4.80	4.90	4.80	4.90	4.90
World	3.80	3.60	3.30	3.60	3.60	3.60	3.60	3.70
U.S.	2.20	2.90	2.30	1.90	1.80	1.60	1.60	1.60

Source: IMF

8. U.S. Lower 48 Gas Consumption (Summer Season April to October, BCFD)

	ResComm	Industrial	Electric	Other	Vehicles	Total
2013	11.3	19.2	23.8	5.6	0.1	60.0
2014	11.3	19.8	23.9	5.4	0.1	60.4
2015	10.6	19.5	28.2	5.5	0.1	63.8
2016	10.7	20.0	30.1	5.5	0.1	66.4
2017	10.6	20.5	27.6	5.6	0.1	64.4
2018	11.9	21.6	32.1	6.1	0.1	71.7
2019	11.0	22.1	31.3	6.1	0.1	70.8

Source: EIA, EVA

9. Performance Characteristics of Natural Gas Combined Cycle Units by Region

ANNUAL

Census Region	Capacity Factor								
	2010	2011	2012	2013	2014	2015	2016	2017	2018
New England	53%	58%	55%	45%	43%	49%	48%	46%	43%
Middle Atlantic	46%	51%	58%	54%	56%	61%	60%	56%	56%
East North Central	23%	31%	48%	34%	35%	54%	59%	51%	57%
West North Central	18%	15%	26%	21%	17%	26%	32%	27%	37%
South Atlantic w/o Florida	43%	52%	61%	58%	56%	66%	67%	68%	66%
South Atlantic	53%	58%	62%	59%	57%	64%	64%	62%	63%
East South Central	45%	49%	60%	49%	52%	64%	68%	61%	62%
West South Central w/o ERCOT	36%	38%	47%	37%	39%	49%	49%	46%	53%
West South Central	41%	43%	49%	44%	45%	54%	51%	45%	50%
Mountain	41%	35%	40%	43%	40%	44%	44%	39%	44%
Pacific Contiguous w/o CA	51%	26%	33%	51%	47%	56%	49%	46%	49%
California	54%	40%	57%	55%	54%	53%	43%	39%	40%
Total U.S.	44%	45%	53%	48%	48%	56%	55%	50%	53%

Source: EIA and EVA

SUMMER (APR-OCT)

Census Region	Capacity Factor								
	2010	2011	2012	2013	2014	2015	2016	2017	2018
New England	60%	65%	63%	55%	52%	58%	57%	52%	48%
Middle Atlantic	52%	56%	65%	58%	61%	66%	67%	61%	62%
East North Central	27%	31%	52%	36%	36%	53%	60%	53%	59%
West North Central	23%	19%	33%	22%	19%	30%	38%	31%	44%
South Atlantic w/o Florida	61%	65%	68%	64%	64%	70%	70%	69%	70%
South Atlantic	61%	65%	68%	64%	64%	70%	70%	69%	70%
East South Central	50%	54%	66%	49%	56%	67%	74%	66%	69%
West South Central w/o ERCOT	49%	51%	58%	50%	51%	59%	57%	53%	59%
West South Central	49%	51%	58%	50%	51%	59%	57%	53%	59%
Mountain	47%	41%	48%	51%	49%	53%	53%	47%	52%
Pacific Contiguous w/o CA	52%	34%	52%	55%	55%	61%	48%	43%	45%
California	52%	39%	60%	57%	58%	60%	47%	42%	43%
Total U.S.	68%	66%	80%	72%	73%	82%	81%	75%	79%