

NATURAL GAS MARKET SUMMER OUTLOOK 2018

MAY 2018

Prepared for:



Prepared by:



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I. OVERVIEW

Summer 2018¹ began with a low March-end natural gas storage inventory level, 339 BCF lower than the five-year average. For the first three weeks of April, high demand caused by cold weather continued to pull natural gas out of the ground beyond the winter. Subsequent weather patterns through the second week of May, when this report was prepared, has alleviated this trend, with storage recovered to 75% of five-year average at this time of the year.

Given the low storage inventory, growth in production is required this summer to fill storage as well as to meet growing demand, both domestically and for exports. Dry natural gas production is expected to grow by 7.8 BCFD summer over summer, a record since 2005.

On the demand side, power burn and exports are the big growth sectors. Natural gas capacity added to the generation fleet since last summer coupled with low prices and low hydro will boost power burn by 2.7 BCFD summer over summer. Exports growth can be counted on as new LNG trains have been added and pipelines in Mexico are being completed (see summer fundamentals in the summary table below). Total natural gas demand including exports is expected to grow by 6.2 BCFD summer over summer.

Storage inventory is forecast to reach 3.5 TCF by October 2018. Injections will have to be almost 2 BCFD higher than last summer to get storage to this five-year minimum season-end level.

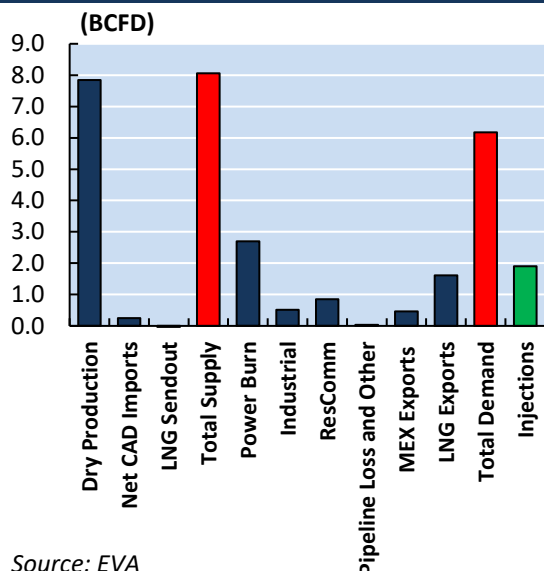
Summer 2018's cooling degree days (CDDs) are expected to total 1,256 according to National Weather Service, which is 6% lower than 10-year average and 5% lower than summer 2017. This cooler than normal forecast could offset some structural growth in natural gas demand, leading to more natural gas in the storage than the base case.

| SUMMER OUTLOOK FUNDAMENTALS SUMMARY TABLE | | | |
|---|--------------|--------------|----------------------------|
| BCFD | Summer 2018 | Summer 2017 | Summer-over-Summer Changes |
| Dry Production | 80.4 | 72.5 | 7.8 |
| Net Canadian Imports | 5.4 | 5.2 | 0.2 |
| LNG Imports Sendout | 0.2 | 0.2 | 0.0 |
| Total Supply | 86.0 | 77.9 | 8.1 |
| Power Burn | 30.0 | 27.3 | 2.7 |
| Industrial | 21.0 | 20.5 | 0.5 |
| Residential and Commercial | 11.5 | 10.7 | 0.9 |
| Pipeline Loss and Other | 5.0 | 5.0 | 0.0 |
| Mexico Exports | 4.7 | 4.2 | 0.5 |
| LNG Exports Feedgas Demand | 3.7 | 2.1 | 1.6 |
| Total Demand | 75.9 | 69.7 | 6.2 |
| Injections | 10.0 | 8.1 | 1.9 |
| CDDs | 1,256 | 1,328 | -72 |

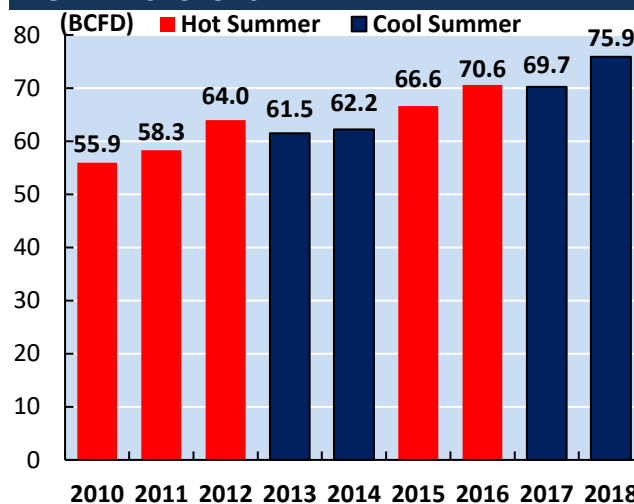
Source: EVA

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

2018 SUMMER-OVER-SUMMER CHANGES



TOTAL SUMMER NATURAL GAS DEMAND FOR ALL SECTORS

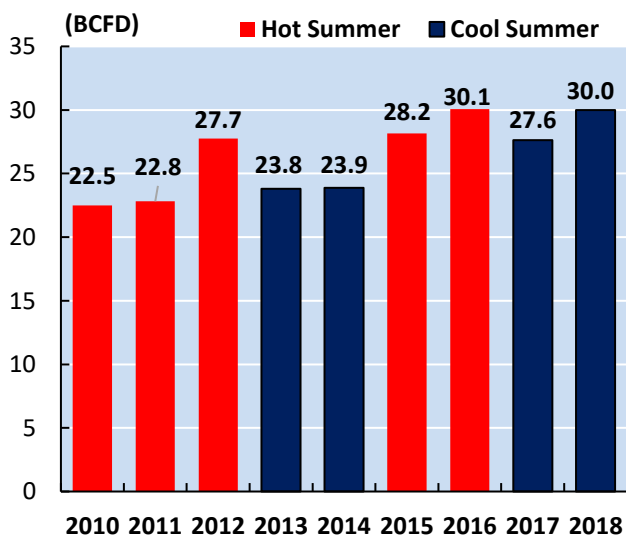


II. OUTLOOK FOR DEMAND

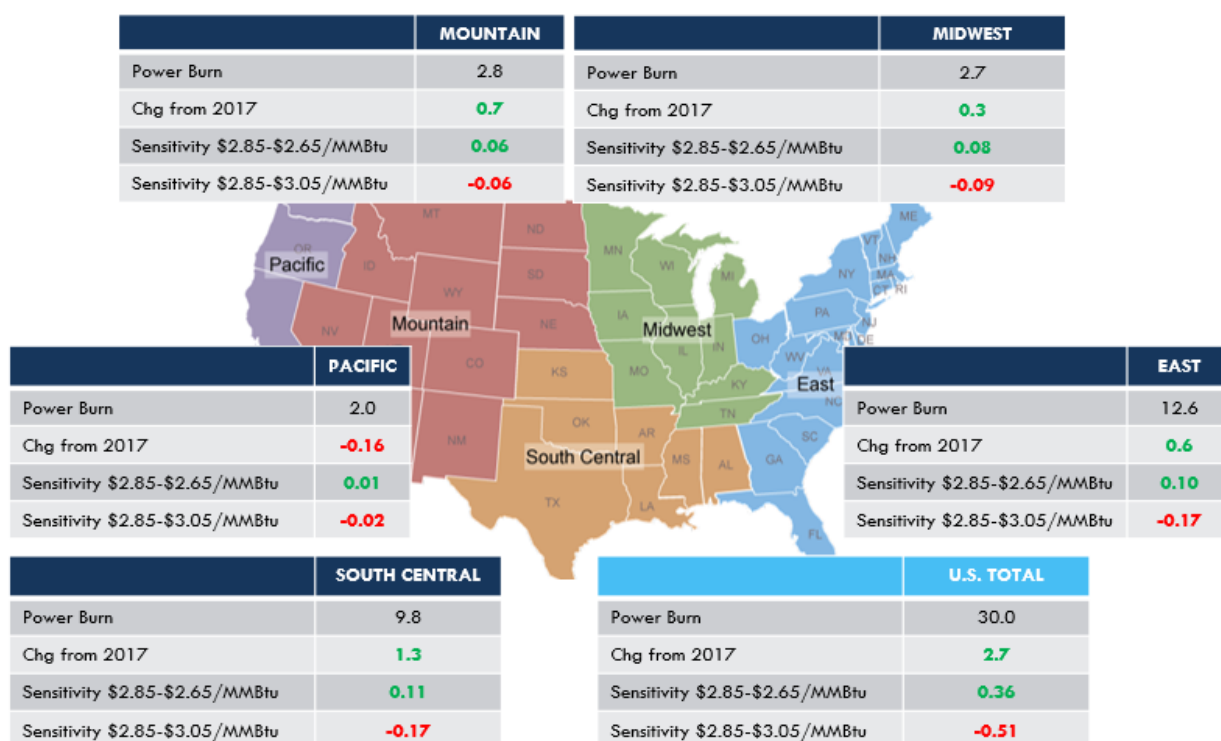
Power

Power demand for natural gas is forecast to grow by 2.7 BCFD, or almost 10%, summer-over-summer (see figure below and a regional breakdown in the map on the next page). The growth is not only driven by low natural gas prices but also by the massive natural gas capacity additions since last summer. Most of the summer-over-summer growth is expected in the South Central, East and Mountain regions while the Pacific region is expecting a slight decline as about 1 GW of gas capacity has retired in the region since last year.

SUMMER ELECTRIC GAS DEMAND

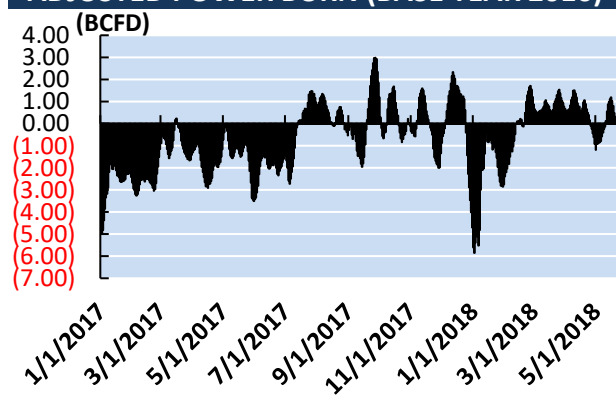


Power demand for natural gas usually acts as a balancing force in the gas market. When natural gas prices are high, power burn drops as generators switch to coal, thus reducing total demand and releasing the upward pressure on prices. This summer's natural gas prices are hovering around \$2.85/MMBtu in the futures market, which will continue to incentivize coal-to-gas switching. Energy Ventures Analysis's (EVA's) sensitivity analysis shows that if natural gas prices increase to \$3.05/MMBtu, power burn would drop by 0.51 BCFD. If prices fall to \$2.65/MMBtu, power burn would only rise by 0.36 BCFD, as most of the switching has already happened (see a regional breakdown of this summer's natural gas price sensitivity in the map on the next page).



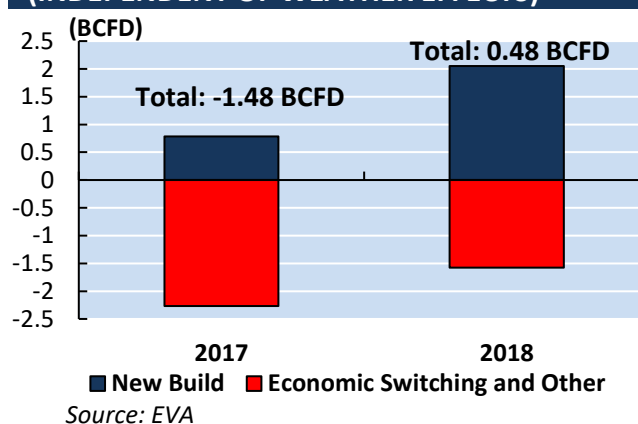
2016 was a record coal-gas switching year as prices averaged \$2.58/MMBtu in the summer, compared to 2017's \$2.98/MMBtu. 2016 summer power burn reached a record high of 30.1 BCFD. Holding 2016 as a base year and excluding the effect of weather, 2017 power burn declined 1.48 BCFD from 2016 mostly due to switching back to coal. Structural demand from new natural gas builds were not enough to offset the impact of high natural gas prices in 2017 (see the right chart below). In fact, utilization of natural gas plants dropped and heat rates increased (see appendix 11). 2018 is expected to see a recovery of coal-to-gas switching from 2017 due to lower expected natural gas prices, yet the switching level will still not be as high as the base year 2016. However, given that natural gas capacity has grown significantly this year, the structural demand from new natural gas builds is expected to offset the lower switching level than 2016, resulting a net gain of 0.48 BCFD in power burn excluding weather effects (see the right chart below).

U.S. ACTUAL POWER BURN MINUS WEATHER ADJUSTED POWER BURN (BASE YEAR 2016)



2

INCREMENTAL GAS BURN FROM 2016 BASE (INDEPENDENT OF WEATHER EFFECTS)



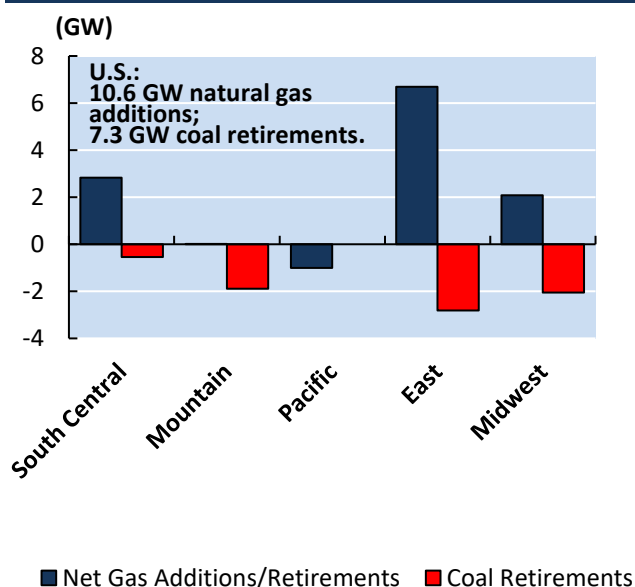
² This chart depicts the differentials between actual natural gas power burn and weather adjusted power burn. Positive differentials indicate more natural gas burn due to structural change or economic coal-to-gas switching compared to 2016, in other words, the differential is the power burn growth independent of the weather effects.

The structural change in the power sector is expected to be significant this year. Since last summer, the U.S. has added a net 10.6 GW of natural gas capacity (equivalent to about 2 BCFD of gas burn growth) and retired 7.3 GW of coal capacity (see chart below). Note that the East region added 6.7 GW of gas capacity but only retired 2.8 GW of coal capacity, indicating that gas-on-gas competition can be present in that region. EVA's model run shows that the average utilization of combined cycle gas turbines (CCGT) capacity in the East that is more than 30-years old fell from 20% in 2016 to 10% in 2018. Going forward, EVA tracks 21 GW of natural gas capacity net additions and 8.4 GW of coal retirements from May 2018 to Dec 2019.

Besides gas-on-gas competition, gas-renewable competition has become more evident. Since 2016, renewable generation from utility solar and wind has been growing by roughly 1 BCFD per year in gas-equivalent terms, putting pressure on natural gas generation growth, especially in the Pacific region. However, this year's hydro generation in the Pacific region is expected to be below normal, which will boost power burn by about 0.4 BCFD compared to the normal hydro case (see text box on the next page).

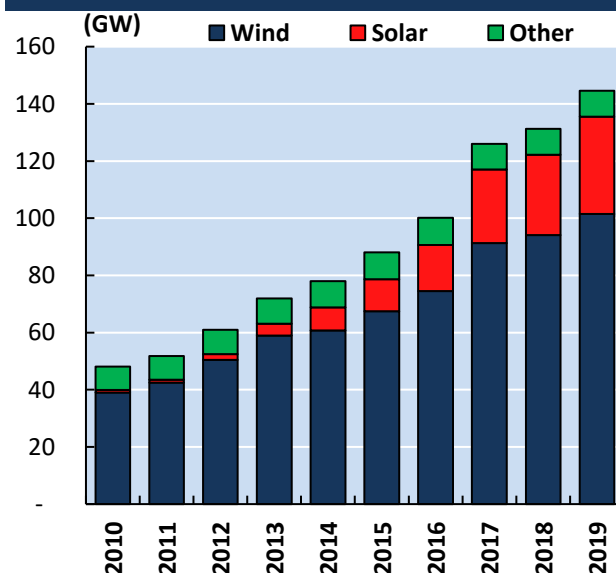
| YEARLY NET CAPACITY ADDITIONS AND RETIREMENTS (GW) | | | | | | | | | |
|--|---------|-------|-------------|-------------------|---------|--------|----------------|------|-------|
| | Coal | CCGT | Gas Turbine | Steam – Gas & Oil | Nuclear | Hydro | Peaker & Other | Wind | Solar |
| 2016 | (7.79) | 4.45 | 0.76 | 0.89 | 0.70 | 0.27 | 0.64 | 8.68 | 7.99 |
| 2017 | (8.86) | 7.71 | (1.09) | (5.75) | 0.00 | (0.12) | 0.31 | 6.26 | 4.59 |
| 2018 | (15.50) | 17.38 | 1.48 | (1.72) | (0.61) | 0.04 | 0.17 | 7.03 | 5.49 |
| 2019 | (4.77) | 4.99 | 0.82 | (0.56) | (1.48) | 0.03 | (0.01) | 7.56 | 6.50 |
| 2020 | (2.98) | 6.02 | 0.43 | (2.30) | 1.58 | 0.00 | (0.01) | 4.24 | 3.73 |

GENERATION CAPACITY SUMMER OVER SUMMER CHANGES



Source: EVA, Changes since Apr 2017

RENEWABLES CAPACITY



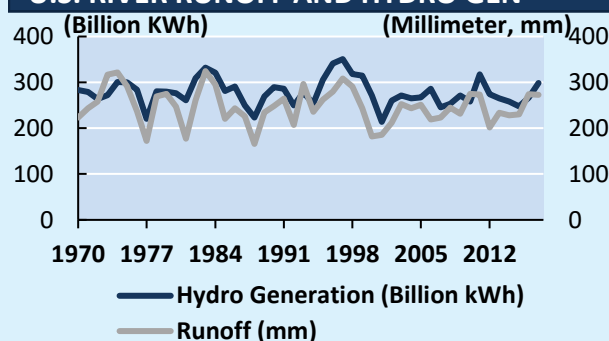
Source: EVA

*Other includes biomass, geothermal, municipal solid waste and landfill gas

Hydro Generation's Impact on Natural Gas Power Burn

Historically, hydro generation in the western U.S. has been highly correlated to river runoffs (see chart to the right). By transforming Natural Resources Conservation Service's (NRCS) streamflow forecast into a hydro generation utilization and running an integrated forecast with EVA's Aurora model, it was found that a relatively low hydro year in 2018 can boost summer natural gas power burn by 400 MMCFD compared to the normal hydro case. As the map below illustrates, the Southwest region could experience low streamflows thus low hydro generation compared to thirty-year normal, while the Pacific Northwest region could again enjoy a good hydro year like 2017. U.S. power burn could be boosted to 38.5 BCFD in July, which is 0.8 BCFD higher than the hydro normal base case (see table to below).

U.S. RIVER RUNOFF AND HYDRO GEN



Source: EVA, EIA, USGS

STREAMFLOW FORECAST APR 2018



Source: NRCS

Low Hydro Scenario Comparison

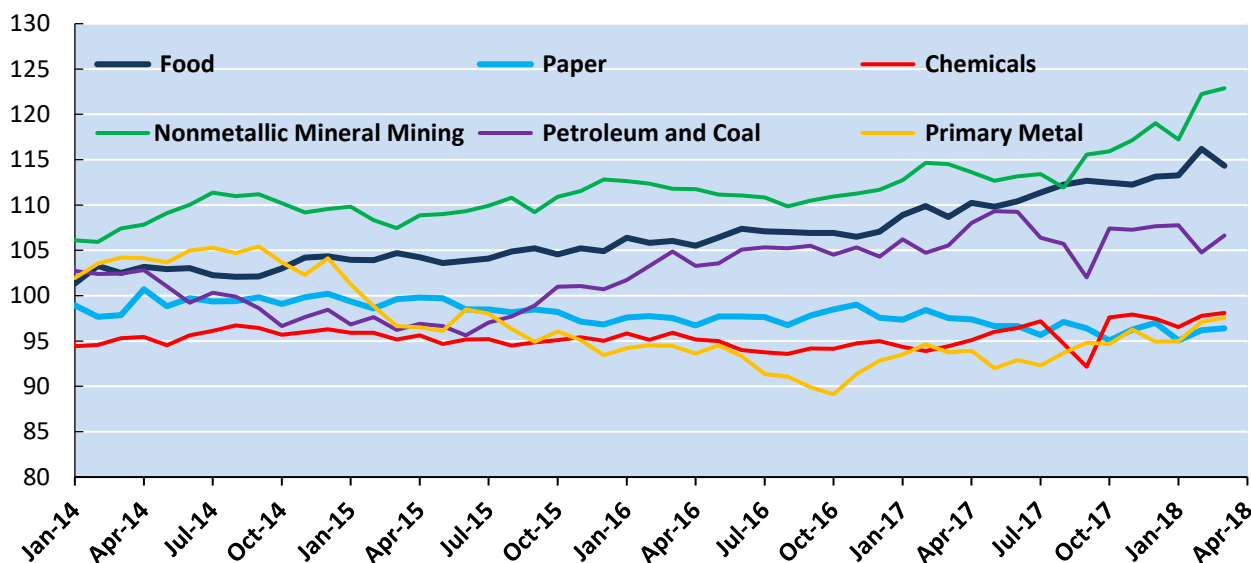
| BCFD | Low WECC Hydro | Base | Diff |
|--------|----------------|------|------|
| 18-Apr | 24.0 | 23.9 | 0.1 |
| 18-May | 26.2 | 25.3 | 0.9 |
| 18-Jun | 31.0 | 30.7 | 0.3 |
| 18-Jul | 38.5 | 37.7 | 0.9 |
| 18-Aug | 36.6 | 36.5 | 0.2 |
| 18-Sep | 29.1 | 29.0 | 0.2 |
| 18-Oct | 23.8 | 23.8 | 0.0 |
| Avg | 29.9 | 29.5 | 0.4 |

Source: EVA

Industrial demand

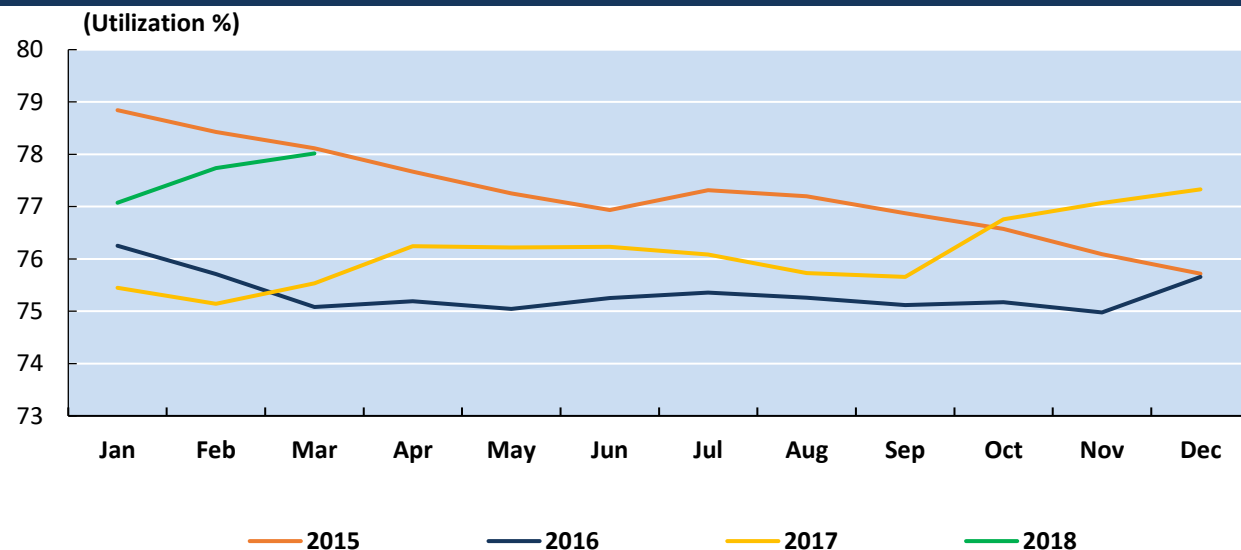
Industrial demand has been quite robust this year. Healthier activity in the energy intensive industries provided solid base demand and new facilities are expected to lead to additional growth this summer. The industrial sectors' performance, as measured by the U.S. Federal Reserve's production indices as well as industrial capacity utilization, has partially recovered from the lows of 2016 and 2017. Among the six energy intensive industries shown in the chart below, production indices of nonmetallic mineral mining, food, as well as chemicals are trending much higher than the same time period last year. Capacity utilization for the industrial sector as a whole is much higher than 2016 and 2017 levels, trending towards 2015's level (see charts on the next page).

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



Source: U.S. Federal Reserve

INDUSTRIAL CAPACITY UTILIZATION

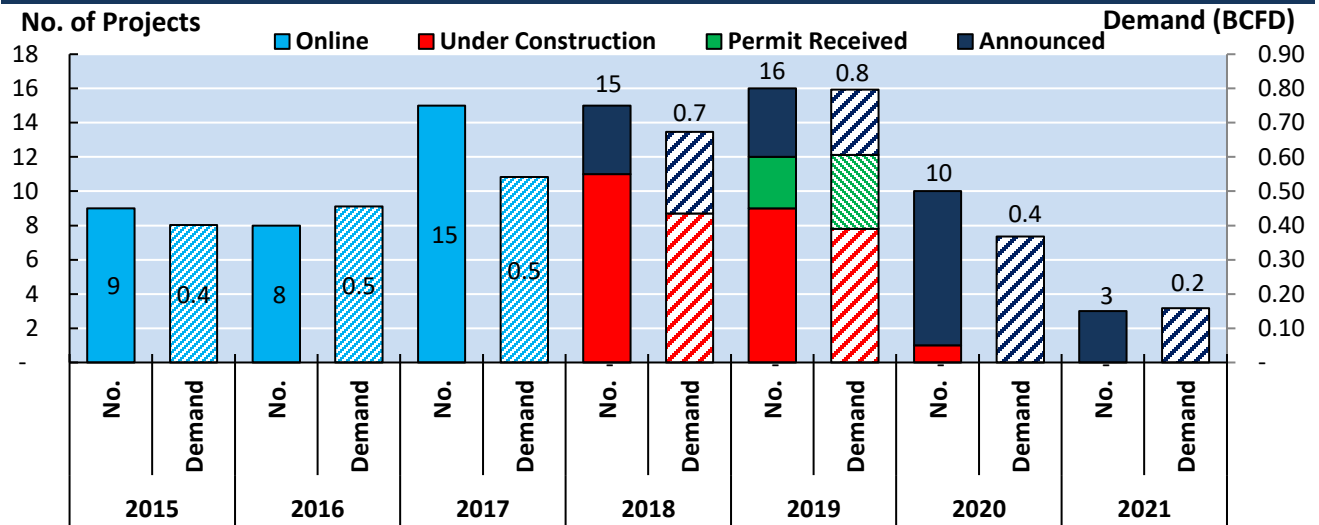


Source: U.S. Federal Reserve

In addition, new projects are coming online this year to boost demand. Noticeably, Yara and BASF started up an ammonia plant in Freeport on April 11, 2018. The plant has a capacity of 750,000 mt/year (60-70 MMCFD of gas demand when running at full capacity). The Natgasoline methanol plant, owned jointly by OCI and G2X Energy, could start up in May 2018. The project has a 1.75 million mt/year capacity which is equivalent to 163 MMCFD of demand when running at capacity.

Besides fertilizer and methanol plants, new ethylene, propylene, and polyethylene facilities could also boost gas demand this summer. In total, industrial demand is expected to be 0.5 BCFD higher, or 2.4% higher summer over summer (see charts on the next page).

INDUSTRIAL PROJECTS AND NATURAL GAS DEMAND



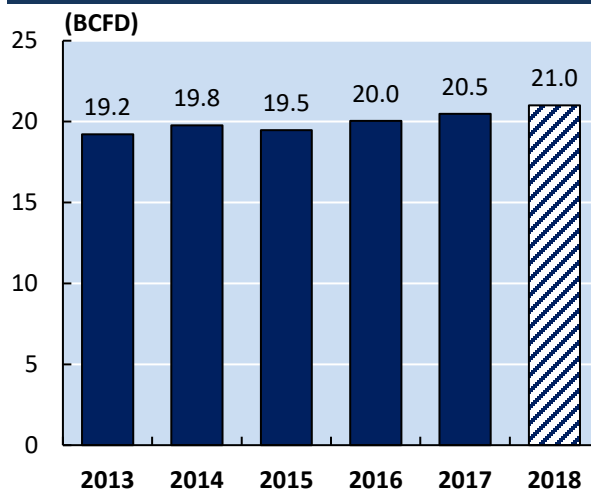
Source: EVA

32 projects (2015-2017), total natural gas demand: 1.4 BCFD

44 projects (2018-2021), total natural gas demand: 2 BCFD

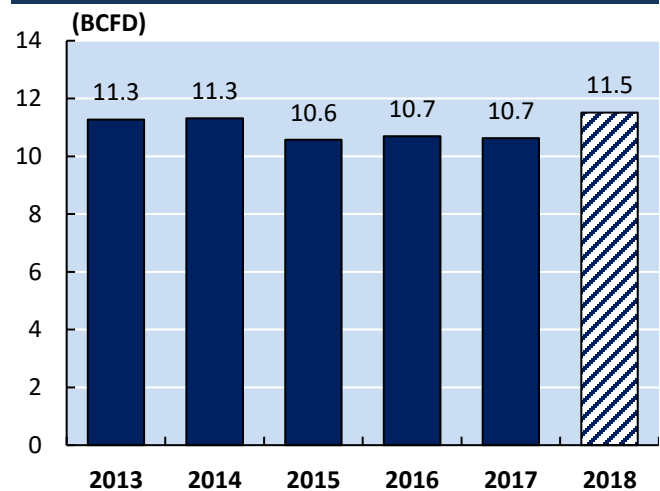
Summer Natural Gas Demand

INDUSTRIAL



Source: EVA

RESIDENTIAL AND COMMERCIAL



Source: EVA

Residential and Commercial

The growth in the Residential and Commercial (ResComm) sectors this summer is mostly caused by the high demand in April due to the lingering cold that carried over from this past winter. Heating degree days (HDDs) in April were 86 degree days higher than 30-year normal. Other than the growth driven by weather, ResComm demand is not expected to grow structurally.

Exports

U.S. will again be a net exporter of natural gas this summer, with LNG exports growing by 1.6 BCFD to reach 3.7 BCFD and exports to Mexico growing by 0.5 BCFD to reach 4.7 BCFD. While LNG exports levels will be mainly influenced by seasonal LNG demand shapes, Mexico exports will mainly be decided by the readiness of Mexico's domestic pipelines.

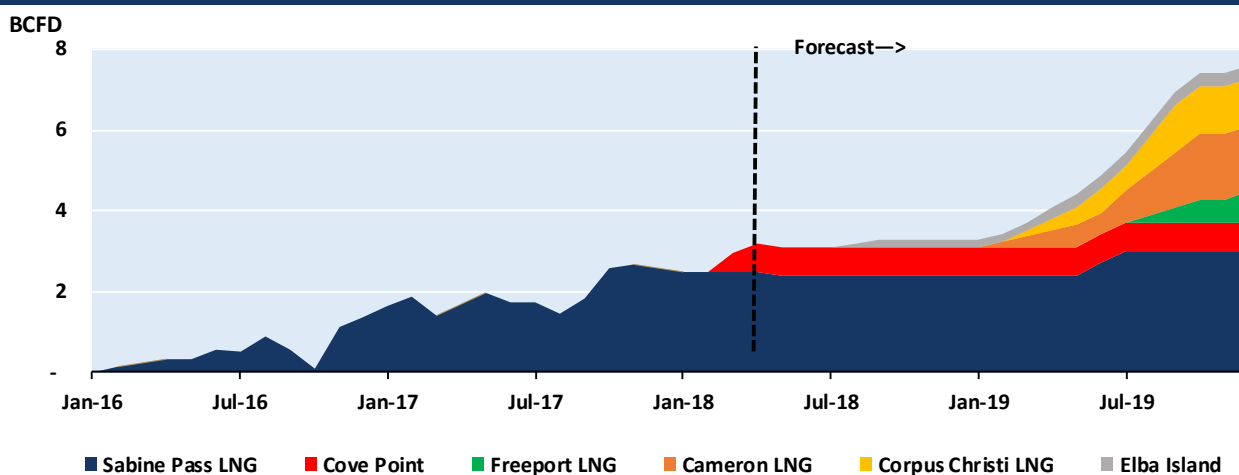
This summer's LNG exports growth is mostly driven by the addition of Sabine Pass Train 4 as well as Cove Point. Existing capacity is split between Cheniere's 2.8 BCFD Sabine Pass train 1-4 on the Gulf Coast and Dominion's 0.75 BCFD Cove Point project in Maryland.

The four trains at Sabine Pass continue to operate at high capacity utilizations, however, April's flow to Sabine has averaged 2.9 BCFD (including feedgas used at the facility) which is 0.3 BCFD lower than the peak flows seen at the facility this past winter, indicating that a seasonal trend could be emerging.

Cove Point exported its first cargo in March 2018. It has long-term contracts with GAIL India and a joint venture involving Japan's Sumitomo and Tokyo Gas, indicating cargoes this summer might head to Asia. However, GAIL proposed swaps to sell their U.S. cargoes free-on-board and take a delivery of equal amount of cargoes in India which may not be shipped from the U.S.. These swaps could add some uncertainties on the destination of U.S. cargoes.

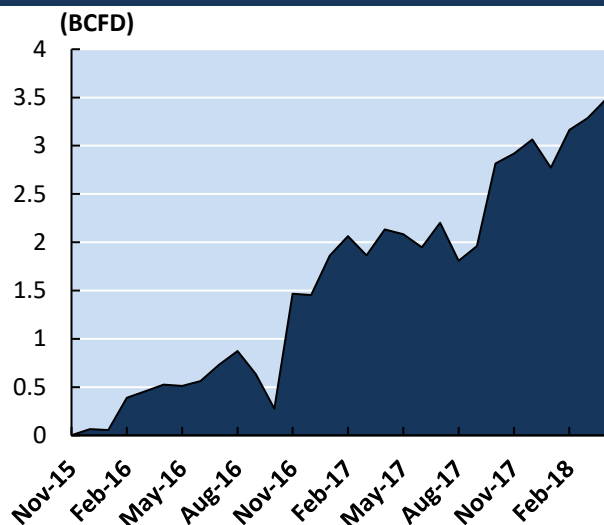
Of the projects that are still under construction, a few have experienced unexpected delays (see chart on the next page). Elba Island could be the only facility that will go into service by the third quarter of 2018. It will become the second East Coast LNG export plant. The project includes ten movable modular liquefaction system (MMLS) units with a total liquefaction capacity of 2.5 Mtpa of LNG (0.35 BCFD). The first MMLS unit could come online mid-2018, with remaining units to start operations sequentially.

U.S. LNG EXPORTS BY PROJECT: 2016-2019



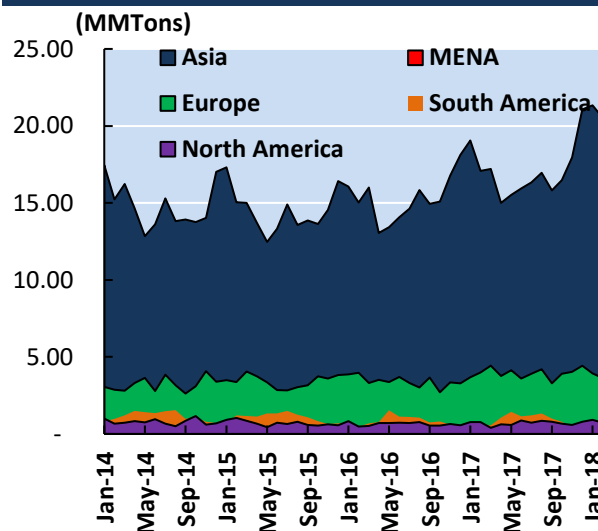
U.S. LNG exports have not shown a seasonal shape as the ramp-up was mostly driven by new trains coming into service (see chart on the next page). However, going forward, a seasonal shape could emerge for exports at terminals. Historically, global LNG imports exhibit a winter peak and a smaller summer peak (see chart on the next page). The gap between peak to trough is about 8 BCFD. The seasonal shape is mainly driven by demand in Asia and Europe. South America imports are mainly in the summer (their winter).

U.S. LNG EXPORTS



Source: EVA

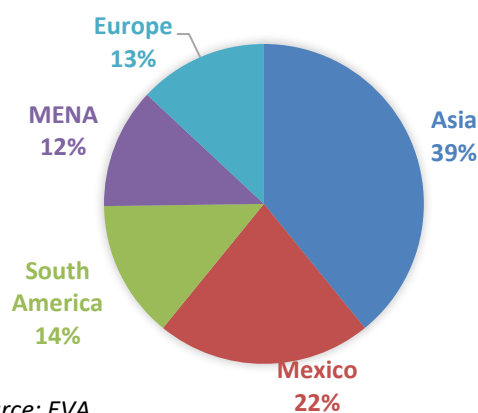
GLOBAL LNG IMPORTS SEASONALITY



Source: EVA

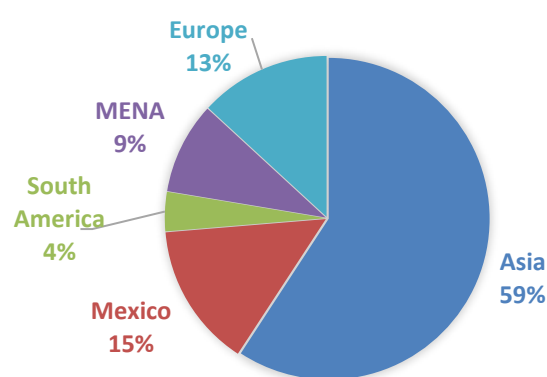
Last summer, South America and Mexico took a large share of total exports by destination. While in winter 2017-2018, most cargoes went to Asia which could be a result of Korea Gas Corporation's (KOGAS) contract with Sabine Pass Train 3 coming into effect (see charts below).

SABINE PASS CARGOES BY REGION (SUMMER 2017)



Source: EVA

SABINE PASS CARGOES BY REGION (WINTER 2017-2018)

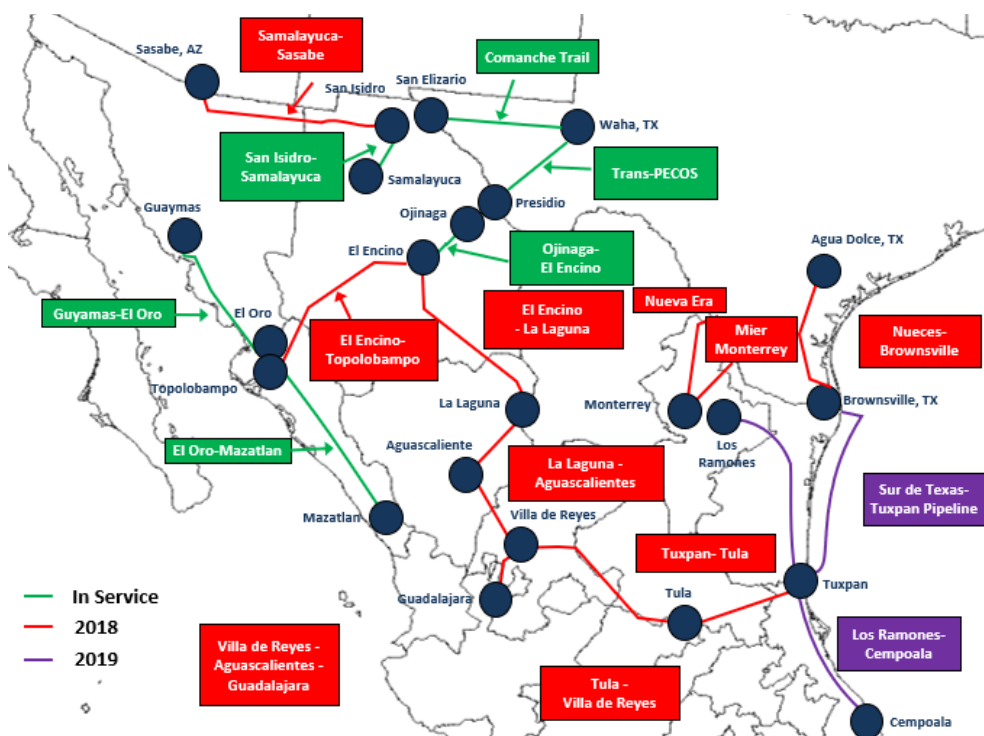


Source: EVA

Contracts with U.S. terminals that are operating this summer are mainly with Asian players as well as Shell and Gas Natural Fenosa. Last summer, Cheniere's marketing company also sold spot cargoes themselves. Given the shape in global LNG seasonal demand, it's likely that buyers that have contracts at the terminals will allocate more of their contracted volumes to the winter and take fewer cargoes in the summer. Furthermore, there is certainly less demand for spot cargoes globally in the summer season. Therefore, this summer Sabine Pass would likely be running less hard than they did this past winter.

The growth of exports to Mexico is currently hindered by the pipeline delays in Mexico. The average delay time for the announced pipelines is more than a year. The pipelines shown in the figure on the next page are slated to come online this summer; however, delays could slow down growth in pipeline exports.

| Summer Additions | Pipeline |
|----------------------------------|----------|
| Tarahumara expansion (0.2 BCFD) | |
| El Encino – La Laguna (1.5 BCFD) | |
| El Encino-Topolobampo (0.7 BCFD) | |
| Nueva Era (0.5 BCFD) | |



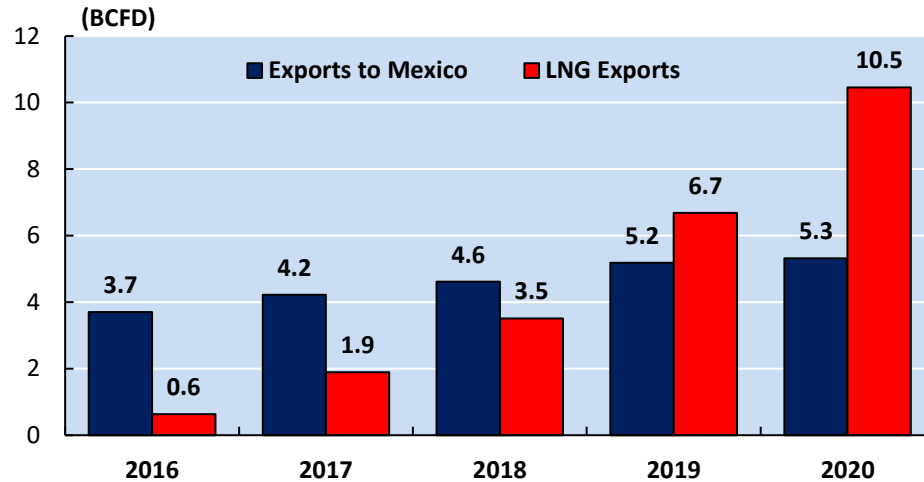
Source: EVA

If Mexico rushes to complete their long-delayed domestic pipelines, exports could grow more than the current forecast. Although if Mexico imports more pipeline natural gas from the U.S., it will reduce their LNG demand, 56% of which was supplied by the U.S. last summer.

In the longer term, LNG exports are expected to reach 10.5 BCFD by 2020 driven by new trains coming online (see table and chart below). Exports to Mexico is expected to grow to 5.3 BCFD by 2020 facilitated by the developments of pipelines and power plants in Mexico.

| U.S. LNG TRAINS | | | |
|-----------------------|------------|-----------------|-----------------|
| Train | Start Date | Capacity (Mtpa) | Capacity (BCFD) |
| Sabine Pass LNG T1 | 16-May | 4.5 | 0.7 |
| Sabine Pass LNG T2 | 16-Sep | 4.5 | 0.7 |
| Sabine Pass LNG T3 | 17-Apr | 4.5 | 0.7 |
| Sabine Pass LNG T4 | 17-Oct | 4.5 | 0.7 |
| Sabine Pass LNG T5 | 19-Aug | 4.5 | 0.7 |
| Cove Point T1 | 18-Mar | 5.3 | 0.8 |
| Elba Island T1-6 | 18-Oct | 1.5 | 0.2 |
| Elba Island T7-10 | 19-Jun | 1.0 | 0.1 |
| Freeport LNG T1 | 19-Sep | 4.4 | 0.6 |
| Freeport LNG T2 | 20-Jan | 4.4 | 0.6 |
| Freeport LNG T3 | 20-May | 4.4 | 0.6 |
| Cameron LNG T1 | 19-Feb | 4.0 | 0.6 |
| Cameron LNG T2 | 19-Jul | 4.0 | 0.6 |
| Cameron LNG T3 | 19-Sep | 4.0 | 0.6 |
| Corpus Christi LNG T1 | 19-Mar | 4.5 | 0.7 |
| Corpus Christi LNG T2 | 19-Aug | 4.5 | 0.7 |

ANNUAL EXPORTS HISTORY AND FORECAST



Source: EVA

III. OUTLOOK FOR SUPPLY

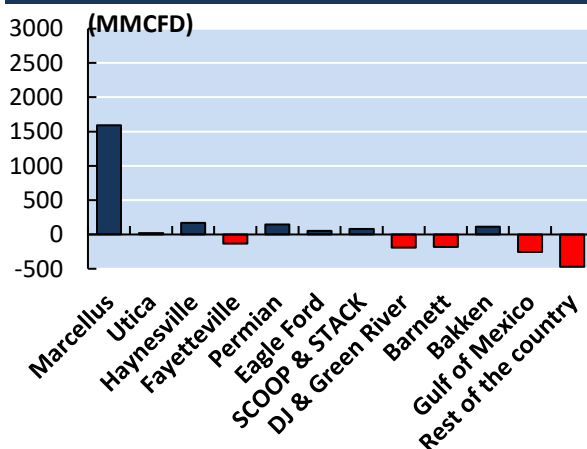
Production

Production is expected to grow by 7.8 BCFD summer over summer. This growth is well supported by incremental production from the Northeast, and also by growing or stabilized production from the rest of the country.

When last summer started in Apr 2017, production from the Northeast was counted on to carry the burden of growth as quite a few basins/shales were still declining due to the rig reductions since the collapse of the oil prices (see chart on the left below).

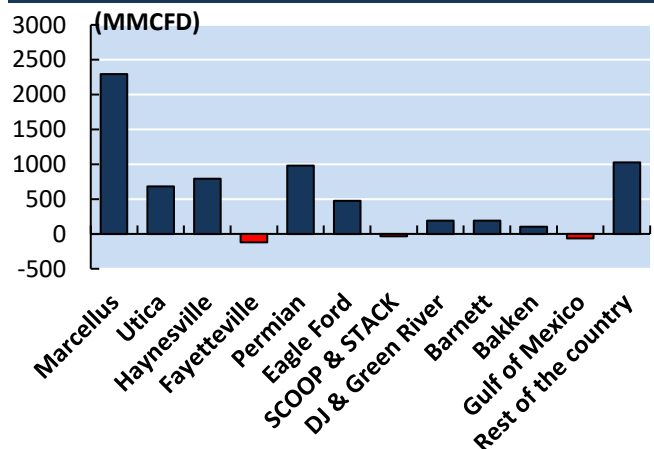
As of April 2018, production from the declining basins have stabilized and thanks to high oil prices, the Permian basin's growth has been strong (see chart on the right below). Together with high Dominion South prices as well as new pipeline expansions (see chart on the next page), production is expected to grow by 7.8 BCFD summer over summer. The stabilized production from previously declining basins will provide a "trampoline effect" for total production when adding the surge of Northeast production, instead of that production fighting the sliding sand dunes of other production that was experienced last summer.

SIX MONTH GROWTH FROM OCT 2016 TO APR 2017

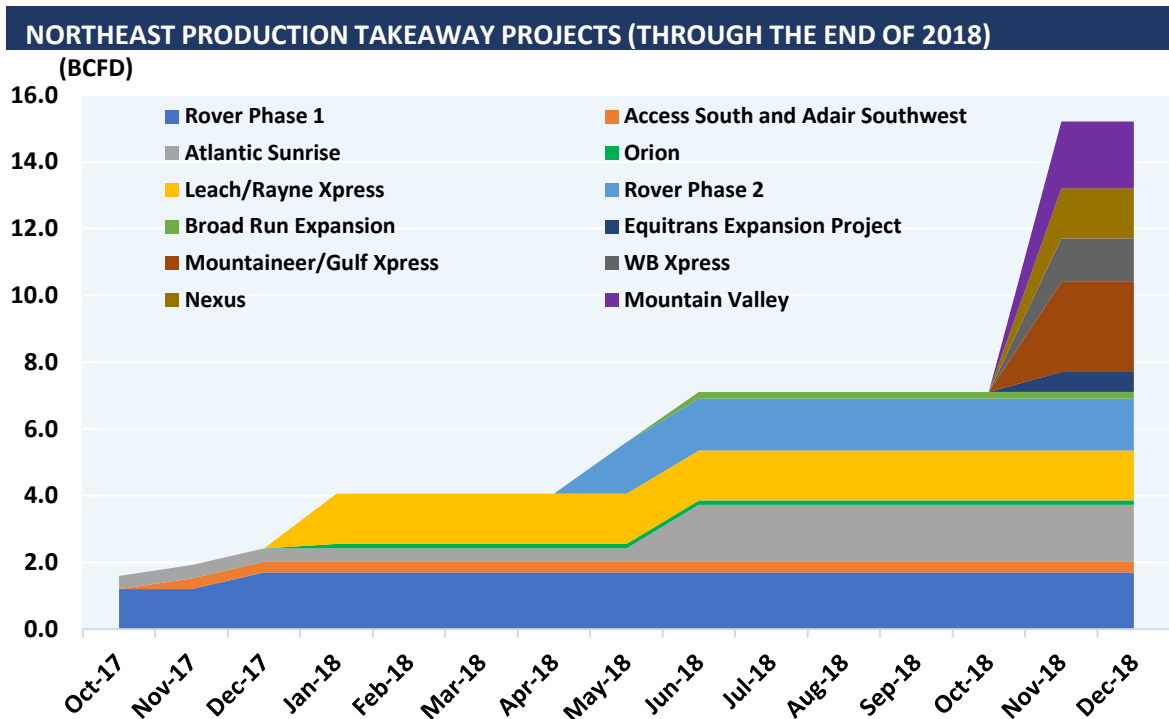


Source: EVA

SIX MONTH GROWTH FROM OCT 2017 TO APR 2018



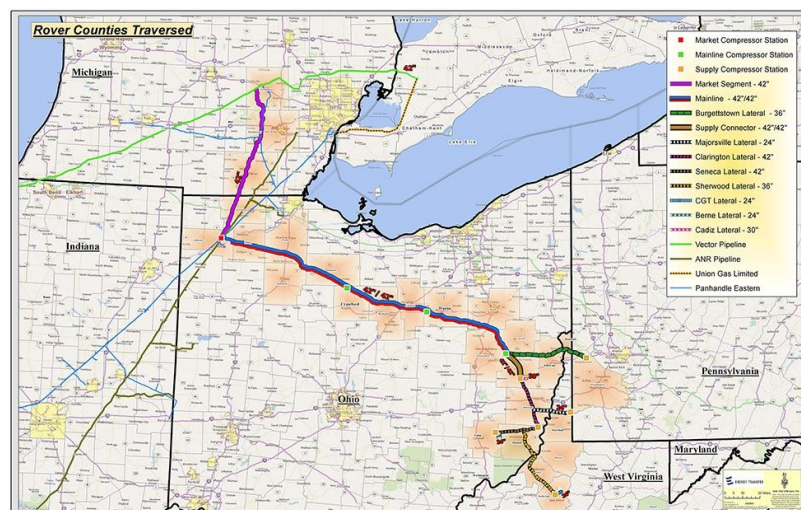
Source: EVA



Imports from Canada

Imports from Canada is forecast to slightly grow this summer compared to last summer thanks to TransCanada's NGTL expansion projects³ and the low-cost production in West Canada. These new takeaway projects from West Canada could result in more exports to the Pacific region of the U.S. However, risks exist to the growth of net imports as Rover has sought approval from FERC to bring online the market segment of the pipeline, which could send natural gas to Dawn via the Vector pipeline (see map below). This natural gas from the Northeast could displace flows from Alliance to Vector, which is mostly West Canadian gas. Exports from the Midwest to East Canada will likely offset gains of imports from West Canada to the Pacific region.

ROVER'S MARKET SEGMENT TO SEND GAS TO DAWN VIA VECTOR

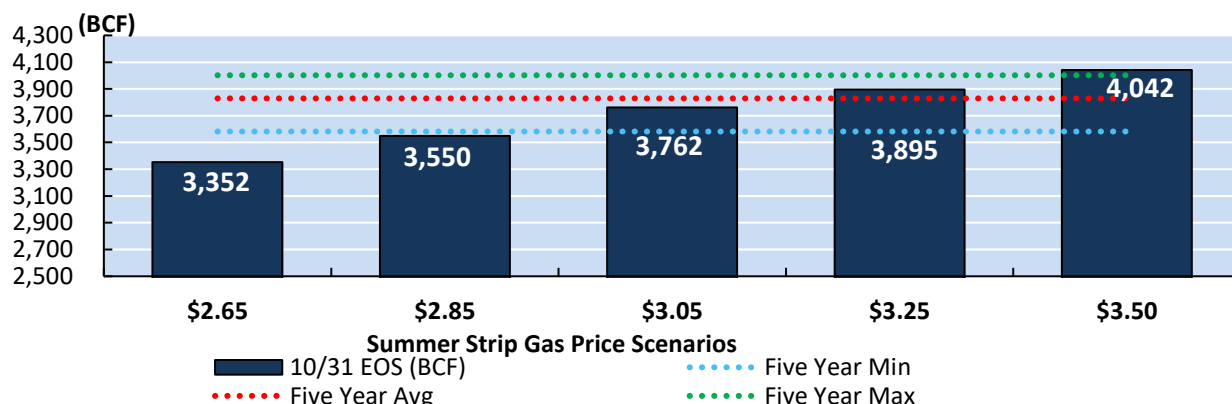


³ TransCanada brought online the Northwest Mainline Loop-Boundary Lake pipeline and the Sundre Crossover project in April.

IV. STORAGE INJECTION

With the supply and demand fundamentals explained above, storage inventory by October-end is forecast to be 3,507 BCF. Despite uncertainties, storage is most likely to fall between the 3,352 BCF and 3,550 BCF scenarios as illustrated below. These scenarios were developed based on the demand and supply sensitivities to price changes under normal weather assumptions.

SEASON-END STORAGE SCENARIOS



Source: EVA

The forecast storage inventory level, 3,507 BCF, is around the five-year minimum level and about 81% of demonstrated available capacity. Even with the low inventory expectations, there has yet to be any fear for shortage of natural gas. As illustrated in the Northeast pipeline projects chart, this winter will see more than 8 BCFD of pipeline capacity coming online, enabling production takeaways to the demand regions.

| STORAGE CAPACITY AND SEASON-ENDING STORAGE LEVELS | | | | | | | |
|---|--------|--------|--------|--------|--------|--------|-----------|
| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 est. |
| Total Working Gas Capacity - Demonstrated Peak* | 4103.0 | 4265.0 | 4333.0 | 4336.0 | 4363.0 | 4317.0 | 4351.0 |
| Annual Capacity Additions | 91.0 | 89.0 | 1.0 | - 7.0 | 34.0 | 34.0 | - |
| Total Working Gas Capacity Including New Capacity | 4194.0 | 4354.0 | 4334.0 | 4329.0 | 4397.0 | 4351.0 | 4351.1 |
| End of Injection Inventory Level | 3928.0 | 3816.0 | 3611.0 | 4009.0 | 4047.0 | 3790.0 | 3507.0 |
| Percent of Capacity | 93.7 | 87.6 | 83.3 | 92.6 | 92.0 | 87.1 | 80.6 |

*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.

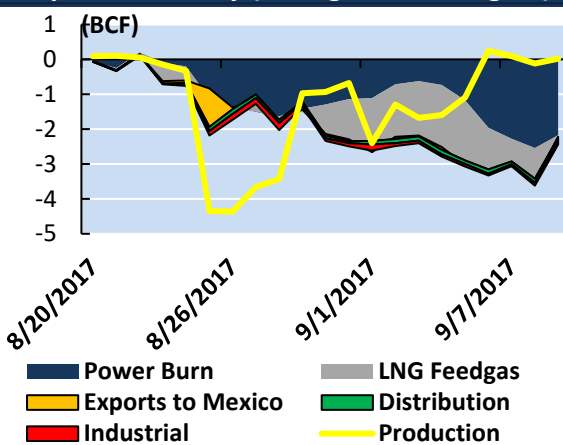
V. APPENDICES

1. The Impacts of Hurricanes on Supply and Demand of Natural Gas

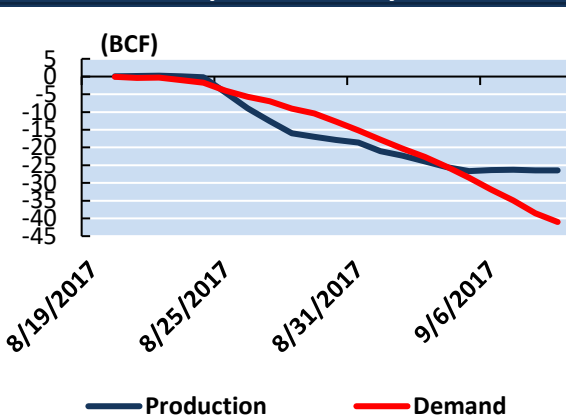
Summer 2018 is forecast to have a higher probability of major hurricanes making U.S. landfall, 63% probability for the entire U.S. coastline versus a 10-year average of 52%. Last year's data from Harvey and Irma is a reminder that the net effect of Hurricanes on the gas market largely depends on where they land. Harvey landed on the Gulf Coast which seriously affected both production and demand of natural gas. Irma landed in Florida which had minimal impacts on natural gas production but seriously destroyed demand. Also, the impact to production could be drastic but short-lived, versus the impact to demand could be relatively long-lasting.

Even before Harvey landed, producers had shut down platforms in preparation for the hurricane landing (see chart below). Interestingly, not only off-shore production was affected, production in Eagle Ford was also impacted due to both upstream and midstream disruptions. However, production returned to pre-Harvey levels less than two weeks after the hurricane made landfall in Texas. The effect on natural gas demand was less immediate. All sectors of demand were affected. Power burn was cut as power services in Texas were cut due to the hurricane and the cool weather lowered power and ResComm demand. Industrial demand dropped as facilities were forced to shut down. LNG feedgas demand did not see an immediate impact, but as LNG storage got full and ships couldn't get access to the port, feedgas volume dropped significantly. Cumulatively, Harvey destroyed slightly more demand than production (see chart below).

Impact of Harvey (Changes from Aug 19)

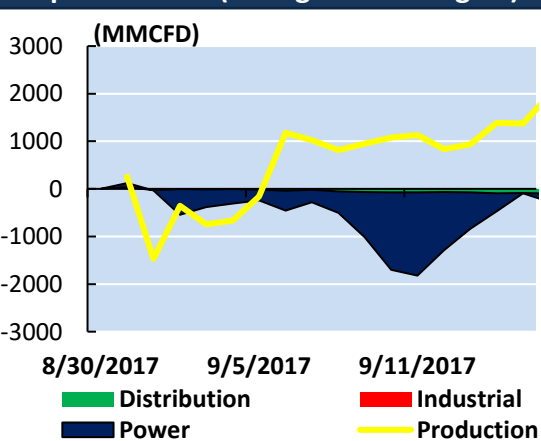


Cumulative Impact of Harvey



In contrast, as Irma landed in Florida, production was hardly affected but the impact on demand was quite significant. On the demand side, power was taken out as Irma traveled up in Florida causing power outages (see chart below). Therefore, the impact of Irma ended up being mostly demand-destruction. However, demand was able to recover within a week, therefore the cumulative effect was not as significant as Harvey.

Impact of Irma (Changes from Aug 30)



Probability of Major Hurricanes Making U.S. Landfall 2018

| | 2018 (%) | Avg for Last Century (%) |
|--|----------|--------------------------|
| Entire U.S. Coastline | 63 | 52 |
| East Coast including Florida Peninsula | 39 | 31 |
| Gulf Coast from Florida Panhandle westward | 38 | 30 |
| Caribbean | 52 | 42 |

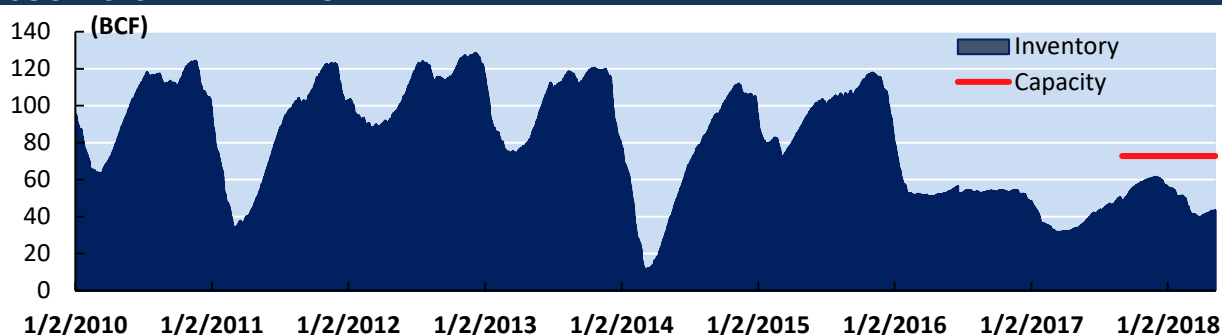
Source: Colorado State University
Numbers represent probabilities

2. Aliso Canyon and SoCalGas System – Status Update and Summer Assessment

SoCalGas's Aliso Canyon storage facility was permitted to resume injections in July 2017, but the inventory is capped at 24.6 BCF as specified by the California Public Utility Commission (CPUC). Withdrawals are still limited by the CPUC to conditions needed to preserve reliability. This past winter the facility was utilized for five days during a cold spell in February and one day in March. These peak day withdrawals have generated concerns about whether withdrawal protocol's requirements were met. SoCalGas has since filed analysis to show why withdrawals from Aliso Canyon was necessary during those peak demand days.

The injection season has started and SoCalGas plans to inject to Aliso Canyon's allowed capacity by the end of June (see SoCal inventory levels in the chart below). SoCalGas also provided scenarios to argue that the CPUC should allow the facility to inject to 30 BCF.

SOCAL SYSTEM INVENTORY



Source: SoCalGas

The overall SoCal gas system this summer is handicapped by continued pipeline outages that may grow over the summer period. SoCalGas presented two pipeline capacity cases in its March 30, 2018, assessment. The best-case scenario assumes 2,905 MMCFD pipeline supply and the worst-case scenario assumes 2,475 MMCFD of pipeline supply. SoCalGas discounts this pipeline capacity by 15%, to 2,478 MMCFD and 2,113 MMCFD, respectively, based on the historic underutilization of pipeline capacity.

Together with the available capacity from storage, SoCalGas's analysis result in a supported demand of 3,400 MMCFD in the best-case scenario and 3,271 MMCFD in the worst-case scenario. Both cases require the use of natural gas from storage but do not use gas from Aliso Canyon. If Aliso Canyon is used, the maximum supported demand increases.⁴

Looking at the distributions of natural gas demand over the past three summers (see table below), demand above 3.2 BCFD occurred for an average of 10 days.

| Distribution of Natural Gas Demand Last Three Summers | | | | |
|---|---------|-------|-------|------|
| No. of Days | 2.6-2.8 | 2.8-3 | 3-3.2 | 3.2+ |
| Summer 2015 | 23 | 18 | 11 | 14 |
| Summer 2016 | 26 | 14 | 6 | 6 |
| Summer 2017 | 16 | 9 | 5 | 10 |
| Average | 22 | 14 | 7 | 10 |

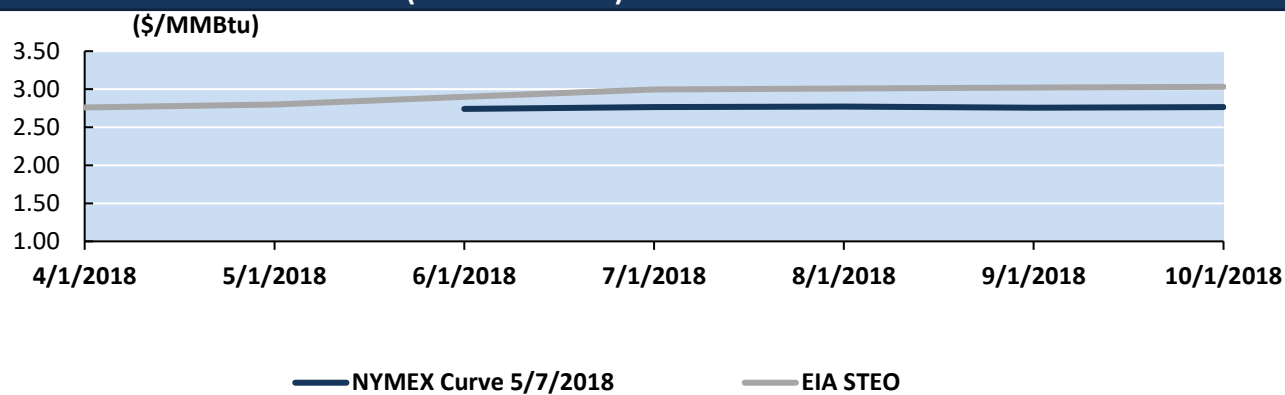
Source: CPUC

To ensure system reliability, CAISO and LADWP are expected to use a combination of operational flow orders, weather notices, curtailment watches, customer advisories, demand response, restricted maintenance, and Flex Alert days to manage demand on high-demand days this summer.

⁴ Source: Aliso Canyon Risk Assessment Technical Report, May 7, 2018

3. EIA's Short-Term Forecast Versus NYMEX

SUMMER HENRY HUB PRICES (EIA VS. NYMEX)

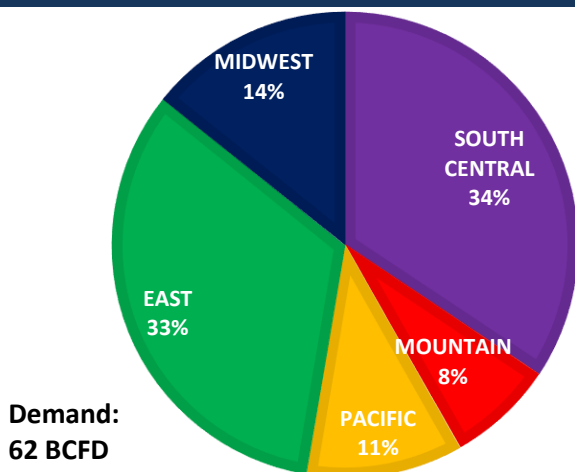
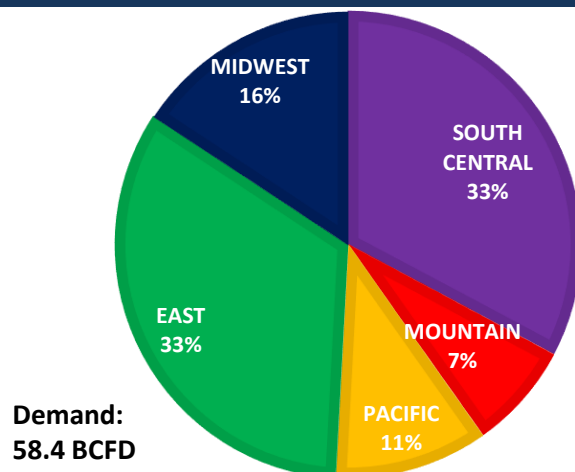
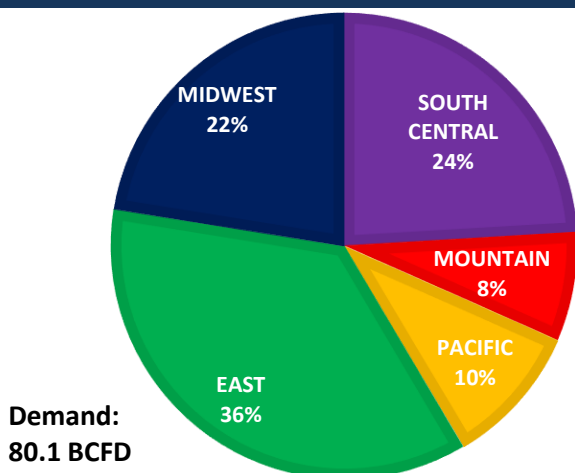
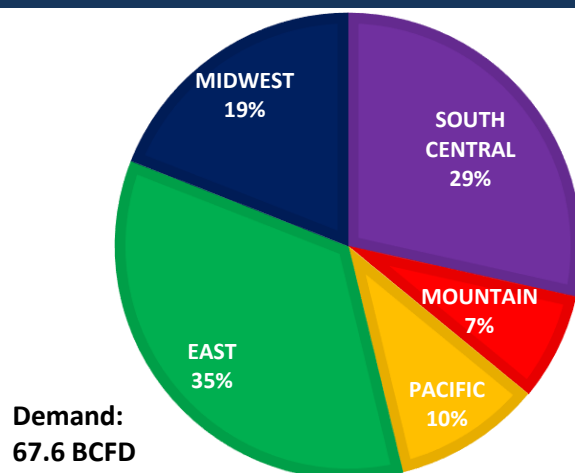


Source: EIA, ICE

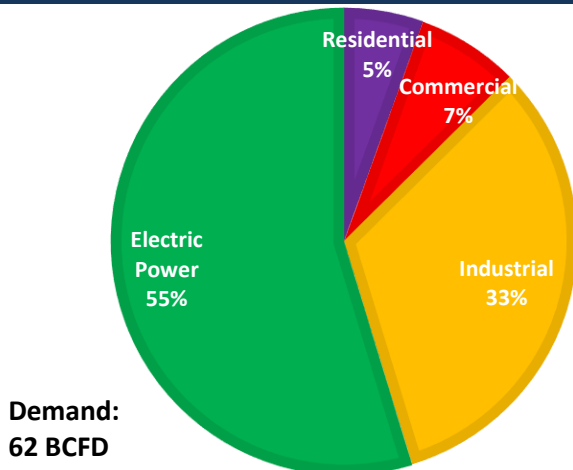
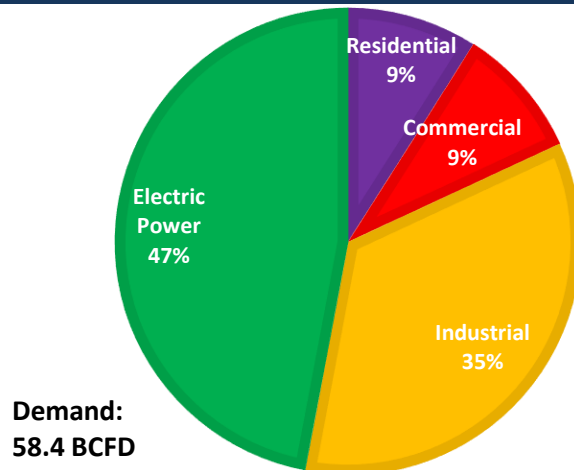
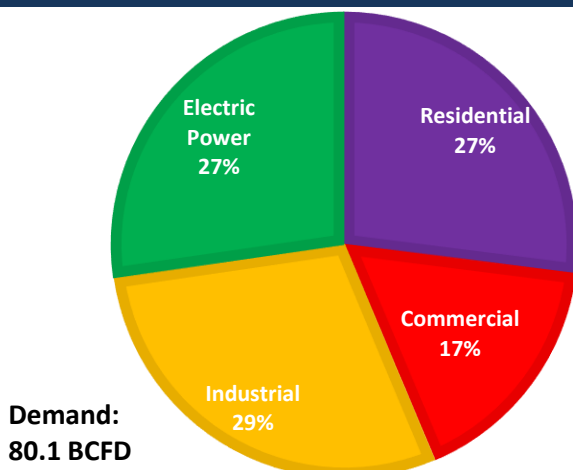
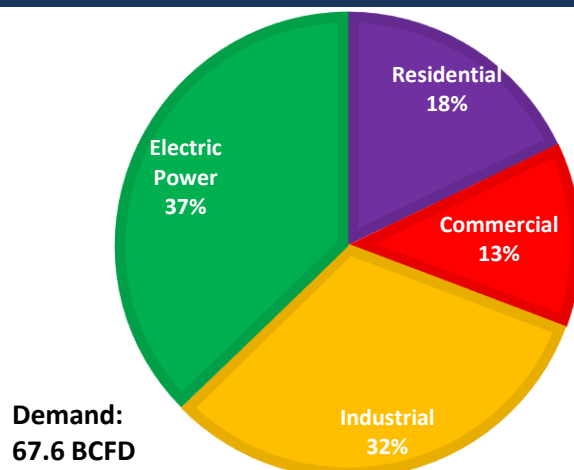
4. Summer Imports and Exports of Natural Gas

| Summer 2017 | | | | | | | | |
|-------------|---------|------|---------|---------|--------|---------|---------|--------|
| Canada | | | Mexico | | | LNG | | |
| Imports | Exports | Net | Imports | Exports | Net | Imports | Exports | Net |
| 7.45 | (2.22) | 5.23 | 0.00 | (4.24) | (4.24) | 0.19 | (2.10) | (1.91) |
| Summer 2018 | | | | | | | | |
| Canada | | | Mexico | | | LNG | | |
| Imports | Exports | Net | Imports | Exports | Net | Imports | Exports | Net |
| 7.61 | (2.21) | 5.40 | 0.00 | (4.70) | (4.70) | 0.20 | (3.70) | 3.90 |

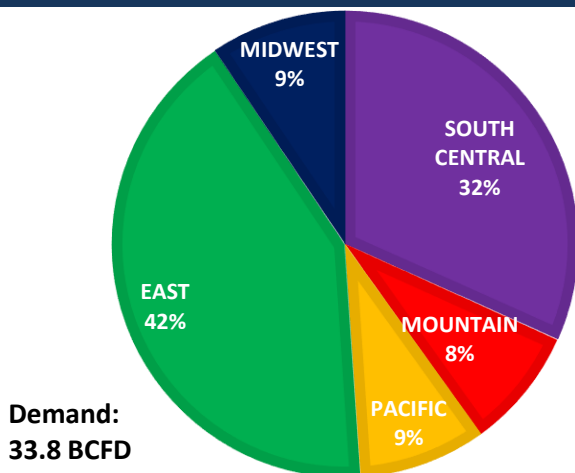
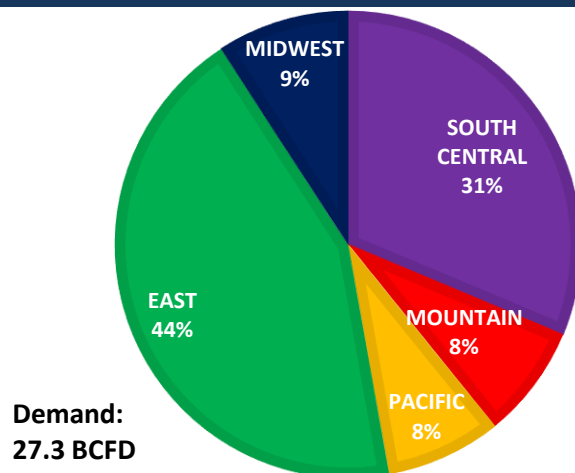
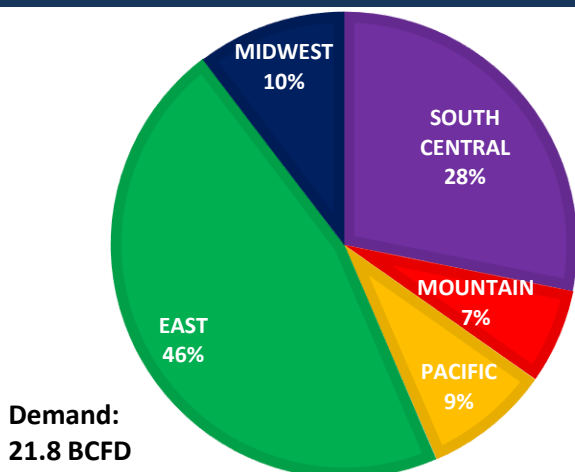
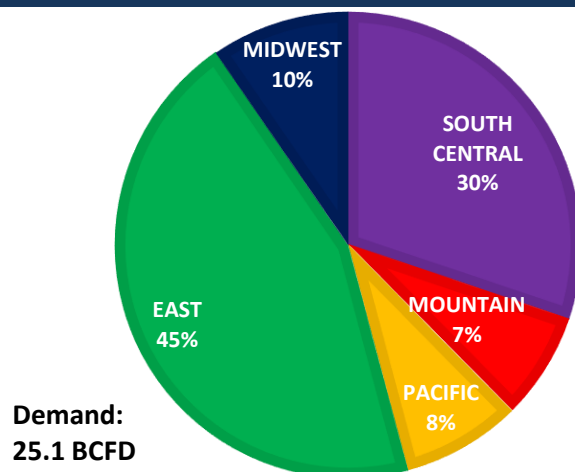
5. Total 2017 Primary Natural Gas Demand by EIA Natural Gas Region and Time of Year

PEAK SUMMER**TOTAL SUMMER****CALENDAR WINTER****TOTAL YEAR**

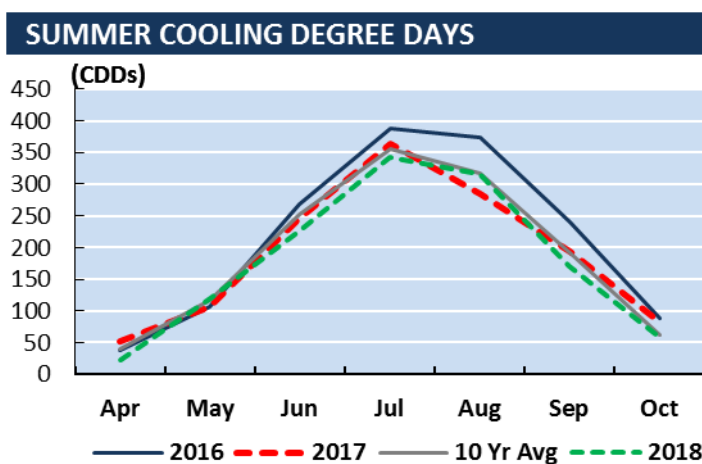
6. Total 2017 Primary Natural Gas Demand by Sector and Time of Year

PEAK SUMMER**TOTAL SUMMER****CALENDAR WINTER****TOTAL YEAR**

7. 2017 Power Natural Gas Demand by Natural Gas Region and Time of Year

PEAK SUMMER**TOTAL SUMMER****CALENDAR WINTER****TOTAL YEAR**

8. 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 | 1,373 | 60 | 5% |
| 2016 | 1,503 | 169 | 13% |
| 2017 | 1,328 | -6 | 0% |
| 2018 Fcst | 1,256 | -78 | -6% |

9. GDP Index

| MACRO HISTORY AND FORECAST | | | | | | |
|------------------------------|-------|-------|-------|--------|-------|-------|
| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
| Inflation (GDP-IPD) | 1.62% | 1.59% | 0.81% | 1.45% | 1.99% | 2.40% |
| Real GDP Growth | 1.68% | 2.57% | 2.86% | 1.49% | 2.25% | 3.08% |
| Household Growth | 0.89% | 0.60% | 1.00% | 1.57% | 1.44% | 1.38% |
| Industrial Production Growth | 2.05% | 3.56% | 1.20% | -0.20% | 1.27% | 1.27% |

Source: Moody's

Note: Base year is 2005

10. 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 | 10.7 | 20.5 | 27.3 | 4.8 | 0.1 | 63.4 |
| 2018 | 11.5 | 21.0 | 30.0 | 4.9 | 0.1 | 67.5 |

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

| Census Region | Capacity Factor | | | | | | | | | |
|------------------------------|-----------------|------|------|------|------|------|------|------|------|------|
| | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
| New England | 47% | 47% | 53% | 58% | 55% | 45% | 43% | 49% | 48% | 44% |
| Middle Atlantic | 34% | 43% | 46% | 51% | 58% | 54% | 56% | 61% | 60% | 50% |
| East North Central | 15% | 17% | 23% | 31% | 48% | 34% | 35% | 54% | 59% | 51% |
| West North Central | 20% | 13% | 18% | 15% | 26% | 21% | 17% | 26% | 32% | 24% |
| South Atlantic w/o Florida | 22% | 34% | 43% | 52% | 61% | 58% | 56% | 66% | 67% | 67% |
| South Atlantic | 41% | 45% | 53% | 58% | 62% | 59% | 57% | 64% | 64% | 62% |
| East South Central | 27% | 37% | 45% | 49% | 60% | 49% | 52% | 64% | 68% | 58% |
| West South Central w/o ERCOT | 38% | 41% | 36% | 38% | 47% | 37% | 39% | 49% | 49% | 43% |
| ERCOT | 48% | 46% | 43% | 46% | 51% | 49% | 49% | 57% | 52% | 44% |
| West South Central | 44% | 44% | 41% | 43% | 49% | 44% | 45% | 54% | 51% | 44% |
| Mountain | 47% | 46% | 41% | 35% | 40% | 43% | 40% | 44% | 44% | 39% |
| Pacific Contiguous w/o CA | 54% | 56% | 51% | 26% | 33% | 51% | 47% | 56% | 49% | 40% |
| California | 62% | 53% | 54% | 40% | 57% | 55% | 54% | 53% | 43% | 39% |
| Total U.S. | 40% | 42% | 44% | 45% | 53% | 48% | 48% | 56% | 55% | 49% |

Source: EIA and EVA

| Census Region | Heat Rate (BTU/kWh) | | | | | | | | | |
|------------------------------|---------------------|-------|-------|-------|-------|-------|-------|-------|-------|-------|
| | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
| New England | 7,500 | 7,493 | 7,522 | 7,470 | 7,492 | 7,531 | 7,548 | 7,592 | 7,533 | 8,048 |
| Middle Atlantic | 8,204 | 7,970 | 7,764 | 7,746 | 7,431 | 7,423 | 7,453 | 7,650 | 7,519 | 7,821 |
| East North Central | 9,400 | 9,096 | 8,718 | 8,275 | 7,437 | 7,561 | 7,517 | 7,838 | 7,690 | 7,699 |
| West North Central | 7,739 | 7,892 | 7,795 | 7,819 | 7,433 | 7,584 | 7,621 | 7,391 | 7,437 | 8,683 |
| South Atlantic w/o Florida | 7,709 | 7,482 | 7,486 | 7,433 | 7,311 | 7,215 | 7,270 | 7,279 | 7,236 | 7,249 |
| South Atlantic | 7,549 | 7,533 | 7,489 | 7,416 | 7,313 | 7,274 | 7,299 | 7,287 | 7,270 | 7,308 |
| East South Central | 7,643 | 7,437 | 7,409 | 7,375 | 7,296 | 7,327 | 7,345 | 7,306 | 7,238 | 7,404 |
| West South Central w/o ERCOT | 8,292 | 8,106 | 7,885 | 7,957 | 7,302 | 7,419 | 7,362 | 7,517 | 7,479 | 7,534 |
| ERCOT | 8,459 | 8,304 | 8,364 | 8,320 | 7,324 | 7,294 | 7,333 | 8,012 | 7,872 | 8,116 |
| West South Central | 8,404 | 8,234 | 8,197 | 8,195 | 7,316 | 7,336 | 7,343 | 7,839 | 7,726 | 7,902 |
| Mountain | 7,528 | 7,600 | 7,596 | 7,706 | 7,492 | 7,495 | 7,534 | 7,543 | 7,533 | 7,621 |
| Pacific Contiguous w/o CA | 7,484 | 7,445 | 7,550 | 7,781 | 7,182 | 7,282 | 7,305 | 7,427 | 7,538 | 8,233 |
| California | 7,458 | 7,490 | 7,441 | 7,595 | 7,308 | 7,276 | 7,346 | 7,518 | 7,486 | 7,569 |
| Total U.S. | 7,880 | 7,800 | 7,734 | 7,730 | 7,359 | 7,362 | 7,383 | 7,555 | 7,485 | 7,641 |

Source: EIA and EVA