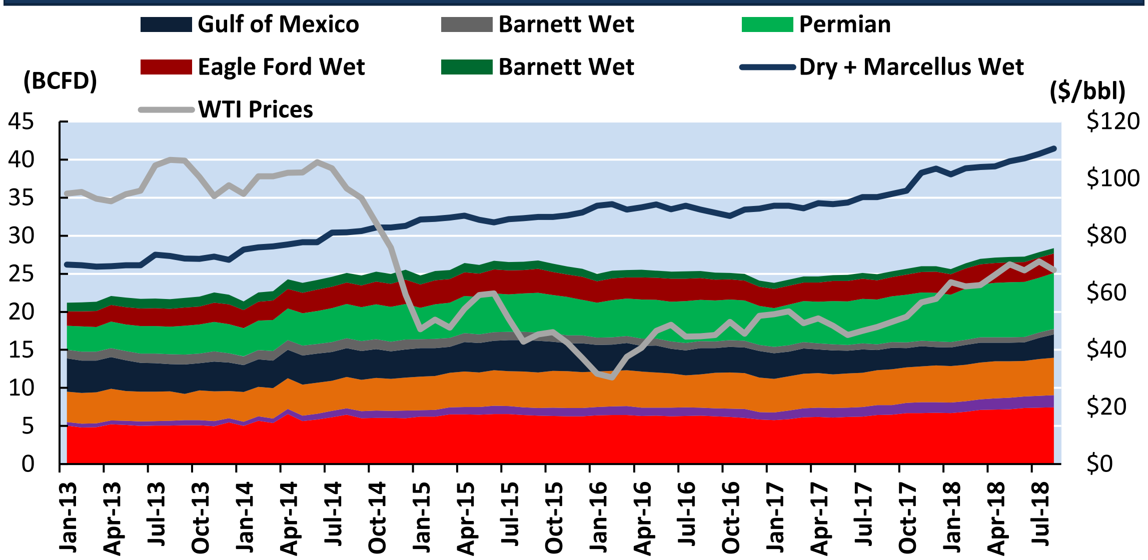
sending a market signal for slowed associated gas production and increased dry gas production, which could come from marginal producers with higher breakeven costs or vice versa.

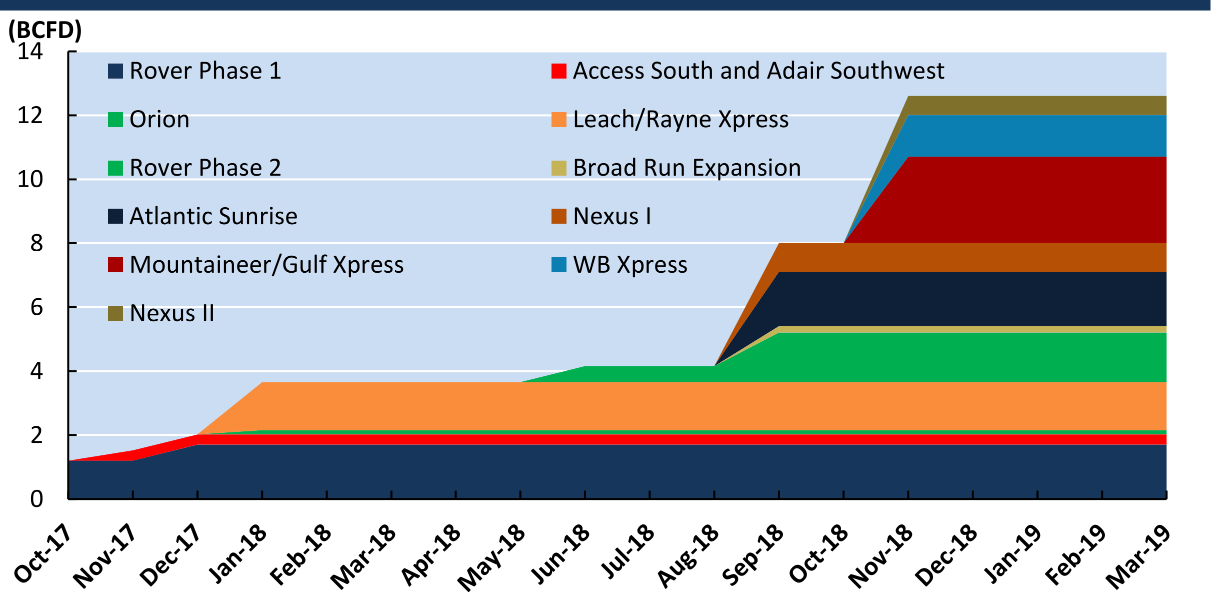
DRY PRODUCTION VS. ASSOCIATED PRODUCTION



Source: Pointlogic, EIA, EVA

Production is forecast to grow by 7.4 BCFD winter over winter. Northeast production is expected to grow by 3 BCFD from August 2018 to end of March 2019, contributing to the majority of the growth this winter. Rover Phase II, the greenfield portion of the Atlantic Sunrise, as well as Nexus mainline are expected to come online in September. WB Xpress, Mountaineer Xpress, and the rest of the Nexus project are expected to come into service in November, in time to enable production to ramp up to meet a portion of winter demand (see chart below).

NORTHEAST PIPELINE TAKEAWAY CAPACITY VS. PRODUCTION GROWTH

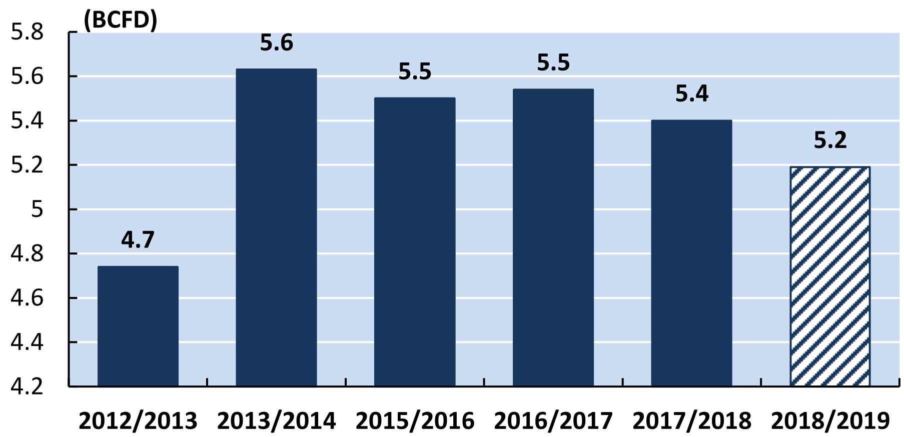


Source: EVA

Imports from Canada

Net imports from Canada are forecast to decline slightly this winter to 5.2 BCFD compared to last winter's 5.4 BCFD. By Q4, in addition to the Rover pipeline, Nexus will be online which is capable of exporting Northeast gas to East Canada through the Midwest.

NET IMPORTS FROM CANADA



Source: EVA

The increase of gas exports sourced from Rover and Nexus will be at the cost of exports sourced from the Joliet receipt points (see map below). 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. This year the dynamic will change as Vector's customers' primary receipt points will shift from the Joliet receipts to Rover and Nexus.

CANADA-U.S. PIPELINES

Source: EVA

Together, Nexus and Rover have 1.49 BCFD of firm delivery capacity on Vector, and the total receipts from Alliance, Northern Border and Guardian will drop by 0.9 BCFD.[5] As a result, Canadian imports through Alliance and Northern Border are forecast to decline due to the lack of re-exports demand. However, it would not be the full 0.9 BCFD. Some of the imports could find a home in the Midwest although the competition is fierce as Rockies, Midcon and the Northeast are already dampening basis in the region.

[5] Vector's customer meeting presentation

Exports sourced from Rover and Nexus are also not expected to grow to its full potential 1.49 BCFD as Northeast gas will face competition in East Canada. West Canadian natural gas can flow on TransCanada's mainline to Dawn. Gas on TransCanada's mainline can also get exported to Great Lakes and Viking at Emerson. These two routes have become more economical as TransCanada lowered its mainline rates and signed 1.4 BCFD of contracts which began last November. Given the low gas prices and continued production growth in West Canada, gas via these routes will continue to serve East Canada, squeezing the demand for Northeast gas.

On top of all of these, imports to the West are forecast to grow as NGTL's expansions[6] will enable more exports to the Pacific Northwest. This increase in imports will partially offset the gain in exports sourced from Rover and Nexus, resulting in a smaller change in net imports from Canada.

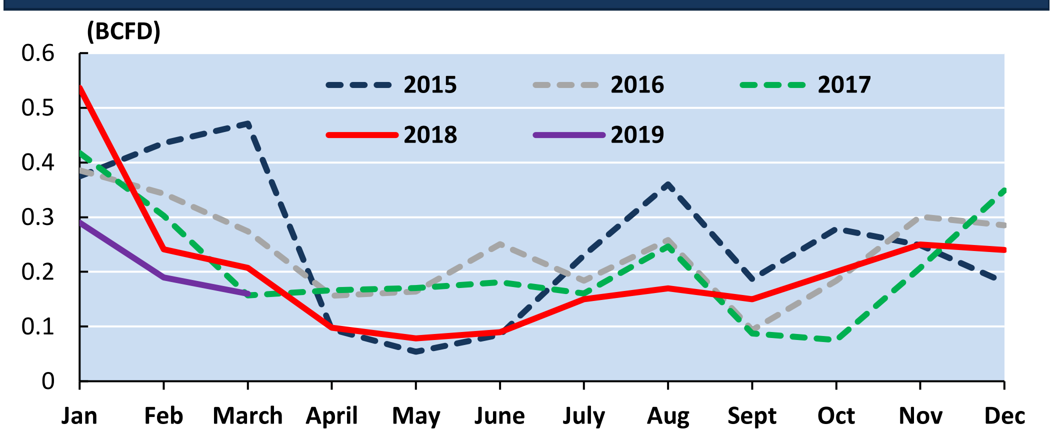
Another factor to watch is the winter weather. During the last winter (Dec 2017 to Feb 2018), imports into the Northeast grew by 0.32 BCFD year over year. Niagara, Iroquois, Portland, and Maritimes and Northeast pipelines (MNE) all came to the rescue as high demand in upper New York and New England lifted basis. If the weather pattern repeats itself, the same dynamic is expected to play out. On the contrary, the warm winter in 2012-2013 saw extremely low imports from Canada.

LNG Imports

LNG imports are forecast to decline by 0.2 BCFD due to the lack of imports at Cove Point and Elba Island as well as a return to normal weather in the New England market.

2018 LNG imports have averaged lower than the past three years' average except for the month of January. The cold spell in January brought in LNG cargoes not only to the Everett terminal in Massachusetts but also to the Elba Island terminal in Georgia and Cove Point in Maryland, although the cargoes imported into Cove Point could be related to its pre-commissioning activities before it was brought online as a bidirectional import-export terminal in April. By Q4 2018, Elba Island terminal will become bidirectional as well. It will be a rare event for these two bidirectional terminals to import LNG as it will take a very high regional demand for the two facilities to stop liquifying gas and start re-gasifying imported LNG. Therefore, total winter imports are forecast to be lower than last winter's imports barring extreme cold weather in the regional markets.

LNG IMPORTS



Source: DOE, EVA

Winter LNG imports are likely to be restricted to the Everett terminal. The Everett terminal provides gas to the Mystic Power Plant in ISO-NE, a 2 GW fossil power plant owned by Exelon Power, located in Charlestown,

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

Massachusetts.[7] The fate of the Mystic 8 and 9 units has major implications for future LNG imports through the terminal. In March 2018, Exelon announced its plans to retire the plant early in June 2022. In May, ISO-NE made a filing with FERC requesting a waiver of certain tariff provisions to allow it to retain Mystic units 8 and 9 for fuel security for the 2022-2024 planning years. However, the waiver was first rejected by FERC on procedural grounds. FERC subsequently ordered ISO-NE to (i) make a filing within 60 days providing for the filing of a short-term cost-of-service agreement to address demonstrated fuel security concerns and (ii) make a filing by July 1, 2019, proposing permanent tariff revisions that would improve its market design to better address regional fuel security concerns. FERC also extended the deadline by which Exelon must make a retirement decision for Mystic units 8 and 9 to January 4, 2019. On July 13, 2018, FERC issued an order accepting the cost-of-service agreement for filing, making findings on certain issues and establishing hearing procedures on an expedited schedule.[8] The outcome of these proceedings is speculative, but if Exelon decides to retire the power plant, the LNG imports facility at Everett will lose a major demand source thus making the continued operation of the facility less profitable. Given the pipeline constraints of the New England market, it's likely the power plants will be preserved, at least for the short term and that the terminal will continue to import LNG during the winter.

IV. STORAGE WITHDRAWAL

The balance of the injection season will bring 2018 October season-end inventory to 3.30 TCF, 14% or 553 BCF lower than the five-year average. It is noteworthy to keep in mind that the current five-year average is a bit inflated by the record October season-end inventory level of 4 TCF in 2016. Nevertheless, a 3.30 TCF winter-season start of storage inventory will be the lowest since 2005. With the supply and demand fundamentals explained in the previous chapters, storage inventory by 2019 March-end is forecast to be 1.43 TCF, 200 BCF lower than the five-year average.

STORAGE CAPACITY AND SEASON-ENDING STORAGE LEVELS

	2012	2013	2014	2015	2016	2017	2018 est.	2019 est.
Total Working Gas Capacity - Demonstrated Peak	4,103	4,265	4,333	4,336	4,363	4,317	4,351	4,354
Annual Capacity Additions	91	89	1	(7)	34	34	3	-
Total Working Gas Capacity Including New Capacity	4,194	4,354	4,334	4,329	4,397	4,351	4,354	4,354
End of Withdrawal Season from previous year	3,928	3,816	3,611	4,009	4,047	3,790	3,302	3,519
Percent of Capacity	94%	88%	83%	93%	92%	87%	76%	81%
End of Injection Season from previous year	2,472	1,687	824	1,461	2,468	2,051	1,354	1,429
Percent of Capacity	59%	39%	19%	34%	56%	47%	31%	33%

*Demonstrated maximum workding 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. For the purpose of comparing storage inventory levels across the years, end of injection season is loosely defined as the last week of October of the first week of November. End of withdrawal season is loosely defined as the last week of March or the first week of April.

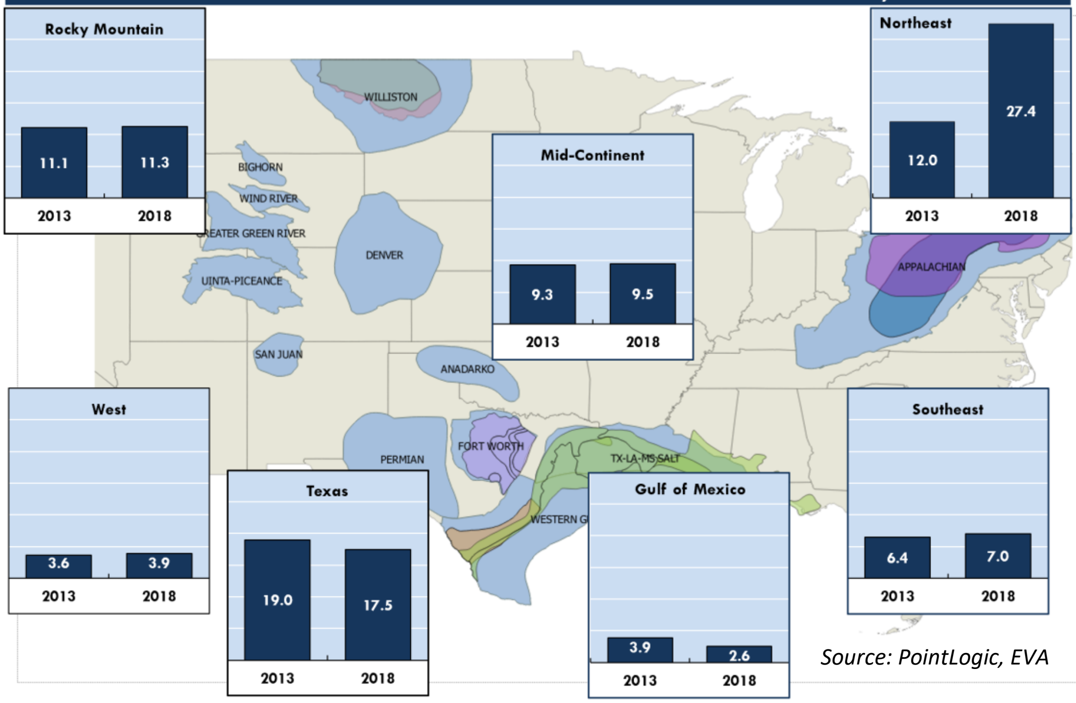
One of the reasons why storage can start low and end closer to five-year average is the high U.S. production levels currently being experienced. Over the past five years, production has grown by 14 BCFD or 21%, (see map

[7] Mystic 8 (0.7 GW) and 9 (0.7 GW) are 2-on-1 combined cycle gas turbines. Mystic 7 is a 0.6 GW unit that is fueled by either natural gas or oil, depending on market conditions. Mystic Jet is an 9 MW oil fueled peaking unit which is run during periods of high demand.

[8] Source: Exelon Second Quarter 2018 Results.

below). Almost all this growth happened in the Northeast. This growth, together with the buildout of the pipeline takeaway capacity, replaces part of the need for storage withdrawals in the winter.

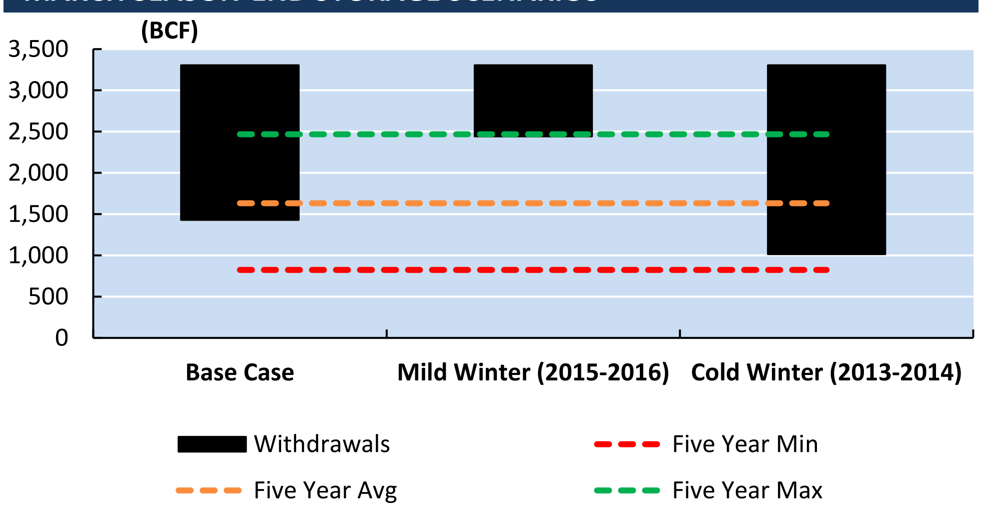
14 BCFD GROWTH IN U.S. GAS PRODUCTION FROM 2013 TO 2018 YTD, OR 21%



Source: PointLogic, EVA

One of the risk factors for the winter is the weather. Not only can weather swing ResComm demand by as much as 4 BCFD or about 10% of ResComm demand, but it can also create freeze-off events which could temporarily interrupt production (see the feature in the appendix). When assuming different weather scenarios for the winter, storage can deviate by almost 0.6 TCF (see figure below), ending close to five-year max and min.

MARCH SEASON-END STORAGE SCENARIOS



Source: EVA

Year Range	Total HDDs	Δ from Rolling 10y Avg		ResComm (BCFD)
		HDDs	Percent	
10 Year Avg	3,469	-	-	35.9
2015/2016	3,042	-416	-12%	31.9
2013/2014	3,865	407	12%	41.3
2017/2018	3,497	39	0.7%	37.8
2018/2019 Fcst	**3455**	**-14**	**-0.4%**	**36.9**

V. APPENDICES

1. The Impacts of Freeze-offs on Natural Gas Production

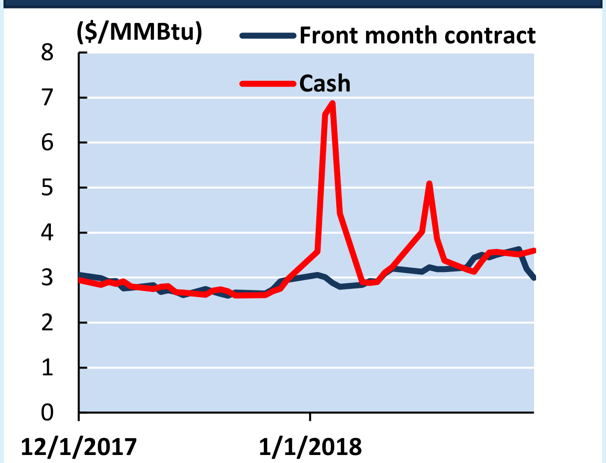
Freeze-offs can take away 5 BCFD of gas supply in a day, but impact is temporary

As total gas demand in the winter grows and the market depends more on production versus storage, freeze-off events can create short-term stress in the market as it could reduce supply by 5 BCFD in just one day.

The first few days of Jan 2018 saw extremely frigid weather in almost every producing region, taking off about 5 BCFD of supply from 30-day average for about a week. Although a similar event has happened in the Polar Vortex winter of 2013-2014, the demand level then was lower than today. Jan 2014's average demand was 104 BCFD versus 2018's 113 BCFD.

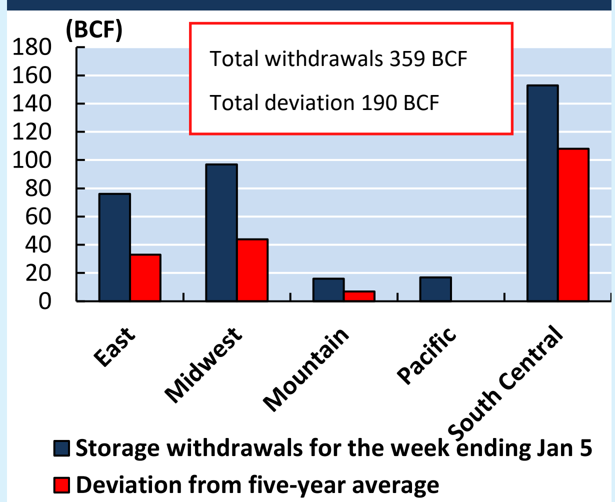
As a result of the lower production, on the storage week ended on Jan 5, 2018, storage withdrawals were a whopping 359 BCF, 190 BCF higher than the five-year average for the same week. This one week sent storage from 5.7% lower than the five-year average to 12.1% lower than the five-year average, creating short spikes in both the Henry Hub cash and front month prices.

HENRY HUB PRICES



Source: ICE, SNL

FREEZEOFFS' EFFECT ON STORAGE



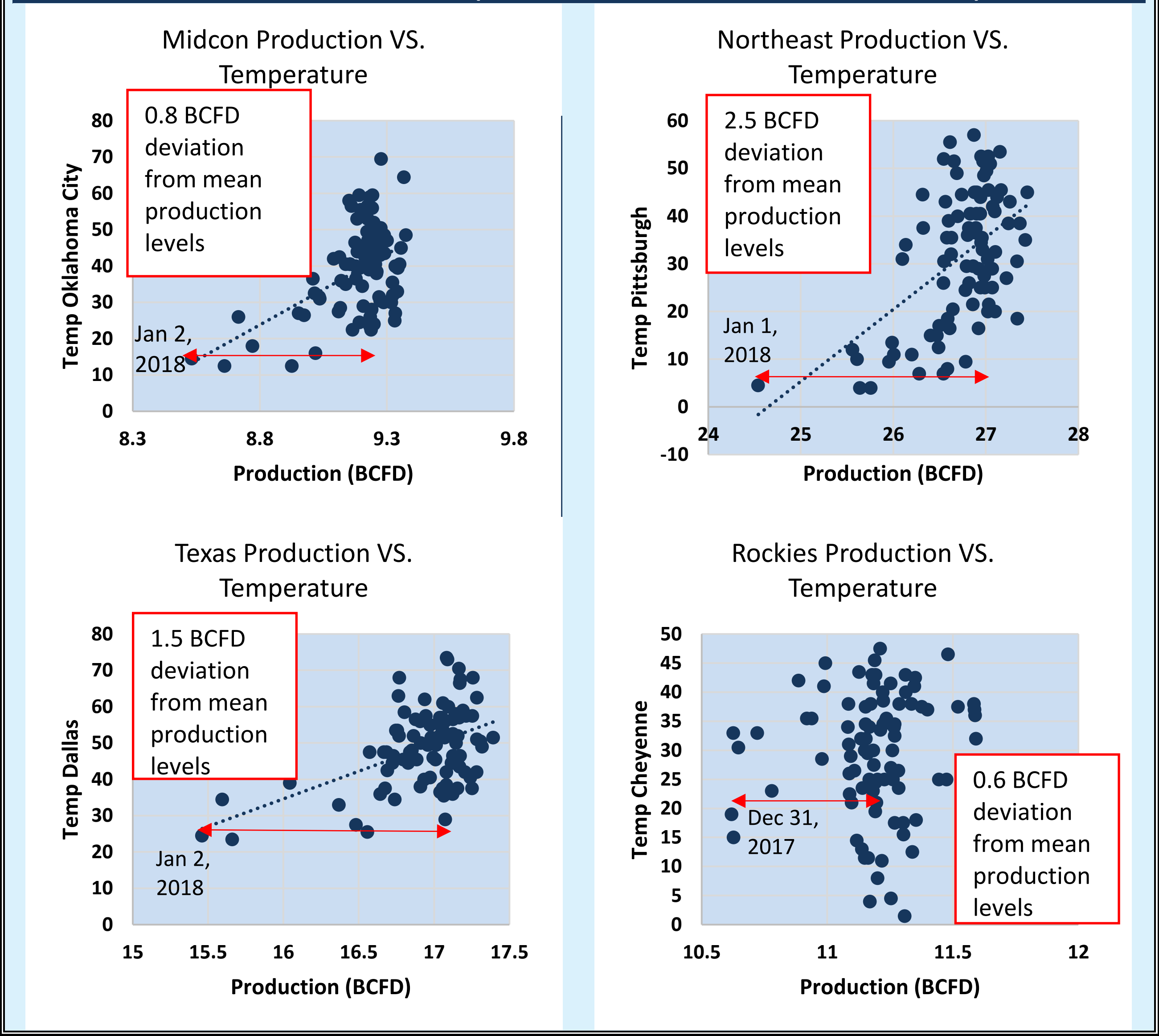
Source: EVA

Regionally, the biggest impact was seen in the Northeast this past winter, where production dropped by 2.5 BCFD from the 90-day mean (see figures on the next page). Texas also saw a significant drop in production, 1.5 BCFD from the mean. The regional declines in production have led to strong withdrawals in the Northeast as well as South Central regions. Although production was disrupted, and storage withdrawals were large, according to a study by RBN Energy, firm end-users were unaffected as storage and cooperative relationships among pipelines maintained supply and deliveries to the market. East Coast spot market customers who did not lock in firm pipeline access to low-cost supplies paid a price, but actual volumes traded at very high prices average at most 1-2% of the market, according to the study by RBN[9].

A repeat of historic cold weather events like Polar Vortex or Bomb Cyclone could prompt freeze-offs this winter, pulling gas out of storage and leading to short-lived price hikes, particularly if such events were to occur during the early winter given the level of working gas in storage inventory.

[9]Source: http://naturalgascouncil.org/weather-resilience-in-the-natural-gas-industry/

REGIONAL BREAKDOWN (Data Period: Dec 1, 2017 to Feb 28, 2018)



*Mean production levels refer to the average of daily production between Dec 1, 2017 and Feb 28, 2018, excluding the freeze-off week from Dec 31 to Jan 6.

2. LNG's Application in Marine Transportation

LNG's Application in Marine Transportation in the U.S.

The International Maritime Organization (IMO) mandates a global 0.50% sulfur cap on vessel emissions to be implemented on Jan 1, 2020. The marine industry is heading for a future that fleet owners will have to choose; low sulfur fuel oil (LSFO), LNG, methanol or installing scrubbers to continue usage of high sulfur fuel oil (HSFO) in order to comply with the emissions standards. In the U.S., a couple of companies opted to adopt LNG as the fuel for its vessels. TOTE, Crowley and Harvey Gulf are the early adopters in this field. Their experiences ranging from ordering ships to constructing bunkering facilities to building liquefaction facilities to comply with U.S. regulations and standards serve as examples for future development in utilizing LNG in marine transportation.

As the compliance deadline for 0.5% sulfur cap draws near, low sulfur fuel oil (LSFO) prices could rise given increasing demand and the lack of refining capability to produce LSFO as its current usage in the marine fuel mix is tiny. As of now, bunker fuel consumption is around 5 million barrel per day (mbpd), which accounts for 5% of the global liquids consumption. High Sulphur Fuel oil (HSFO) accounts for 65% while diesel (MGO) accounts for 25%. Some fleet owners have stated that they expect to pass on the high fuel prices of LSFO to its consumers. Another option is to continue to use HSFO by installing scrubbers. The scrubbers alternative could make sense for some as HSFO prices are likely to fall due to lack of demand. However, if the U.S. refiners decide to invest in upgrades and reduce sulfur at the point of fuel production, less HSFO will be available to the market.

Methanol, made with natural gas, as an alternative fuel has been gaining traction with proponent claiming that only minor modifications are needed of the current bunkering infrastructure, and low costs to convert vessels to run on methanol. However, the environmental benefit of using methanol is not as appealing in a waterborne vessel. Also, the energy content is low per gallon of methanol requiring more frequent refueling or more tankage.

More recently, there have been discussions of "future-proof" solutions, such as hydrogen fuel cell powered or battery-powered vessels. These options though could have a market in the far future are currently cost-prohibitive. Also, IGF Code (The International Code of Safety for Ships using Gases or other Low-flashpoint Fuels) will need to be modified by the IMO in order to accommodate the new options.

LNG as a marine fuel has clear environmental benefits. It has no SOx emissions and no particulate matter emissions. NOx emissions and CO2 emissions can be reduced by 80% and 25% respectively compared to a diesel engine. However, the payback period of retrofitting could be long depending on the oil prices (5 years assuming a $7/MMBtu spread between diesel and LNG).

It is too early to pick winners as there is no clear trend in the U.S. as to which compliance option fleet owners prefer. However, LNG bunkering solutions are currently being demonstrated in the U.S. and experience with retrofitting is being accumulated in Europe. If gas prices stay competitive to the alternative fuels, demand for natural gas in the marine sector could demonstrate a steady growth post-2020. Assuming a conservative 5% of marine fuel market share for LNG, gas demand by 2030 could grow to 1.4 BCFD globally.

According to International Group of LNG Importers, the uptake of LNG as a fuel for ships is accelerating, with more than 220 ships in service and under construction worldwide at the end of 2017. In comparison, S&P Global Platts Analytics estimated that about 360 vessels had installed scrubbers as of early 2018.

U.S. Maritime LNG Adoption: Three Examples

TOTE Maritime operates two LNG powered container ships out of JAXPORT's Blount Island Marine Terminal in Florida. The company took delivery of North America's first LNG bunker barge, Clean Jacksonville, in August 2018. The vessel will enter service for TOTE Maritime Puerto Rico in the Port of Jacksonville, where it will be used to bunker two Marlin Class containerships, the Isla Bella and Perla Del Caribe, operating on LNG fuel between Jacksonville and San Juan, Puerto Rico. The long-term supplier of LNG to TOTE is JAX LNG,[10] a partnership between Pivotal LNG and NorthStar

[10] JAX LNG, LLC is a partnership of Pivotal LNG, a wholly owned subsidiary of Southern Company Gas, and NorthStar Midstream, LLC, a midstream transportation company backed by funds that are managed by Oaktree Capital Management, L.P. and Clean Marine Energy LLC. Through Pivotal LNG, JAX LNG has access to LNG supply from existing Southern Company Gas liquefaction plants in the southeast U.S.

Midstream. Through Pivotal LNG, JAX LNG has access to supply from existing Southern Company's gas liquefaction plants in the southeast U.S., including Elba Island. JAX LNG is also constructing a liquefaction and storage facility at Dames Point to serve TOTE's ships, with a capacity to produce 120,000 gallons of LNG per day, which is equivalent to 10 MMCFD of gas demand.

On a similar front, **Crowley** has signed an agreement with ExxonMobil and Eagle LNG Partners in June 2017 to collaborate on the development of LNG as a marine fuel. In this partnership, ExxonMobil provides technical support to help the parties carry out safe bunkering operations and sell LNG bunker fuel to vessel operators. Eagle LNG Partners supplies the LNG and designs, builds and operates small-scale LNG production and storage facilities as well as coordinates land-based LNG transportation. Crowley provides bunker logistics and ensures safe and reliable operations. The parties have an initial focus in Florida before considering expansions to other North American markets. Eagle LNG constructed and brought in service the Maxville LNG facility at JAXPORT's Talleyrand marine terminal. The grand opening was in July, although the plant has been in operation since early 2018. The plant has a 200,000-gallons per day of liquefaction capacity which is equivalent to 16.5 MMCFD. It currently loads LNG in ISO containers shipped to Puerto Rico for the pharmaceutical industry. In July 2018, Crowley also took delivery of one of the two LNG powered ships it ordered, El Coqui. These ships are combination container/roll-on, roll-off ships that are used in U.S.-to-Puerto Rico trade. Besides using LNG for its ships, Crowley has already exported LNG to Puerto Rico and has plans to expand the exports to Caribbean and Latin America countries. It also operates four LNG-ready petroleum product tankers. These tankers can be also be converted for propulsion by LNG.

Harvey Gulf International Marine, an operator of offshore supply vessels (OSVs) for deepwater operations in the Gulf of Mexico, has taken delivery of five of the six LNG-powered OSVs ordered over the past four years. The first three OSVs based out of Port Fourchon, Louisiana, have entered service with Shell to supply its deep-water operations in the Gulf of Mexico. The fourth is on a charter to an unnamed oil and gas company. Completing its supply chain, Harvey Gulf constructed and opened the first marine fueling terminal at its vessel facility in Port Fourchon in 2016. The facility has 270,000 gallons (22 MMCF) of LNG storage capacity from where it supplies LNG for bunkering via truck. The LNG is sourced from Pivotal LNG's Trussville, Alabama, plant, and Clean Energy's liquefaction facility in Willis, Texas. The company buys about 200,000 gallon/month of LNG (0.5 MMCFD). In August 2018, the facility also provided LNG bunkering trials to TOTE's Clean Jacksonville barge. In addition, the company recently formed a new marine transportation company (30% ownership), Qualify Liquefied Natural Gas Transport, LLC ("Q-LNG"). Q-LNG will own and operate assets providing marine transportation of LNG for deliveries to various ports in Florida and the Caribbean under a contract with Shell. Q-LNG has contracted for the construction of U.S.'s first offshore LNG Articulated Tug and Barge (ATB). The ATB will be constructed to meet the requirements of the International Gas Carrier (IGC) code and is designed to carry 4,000 cubic meters of LNG (85 MCF).

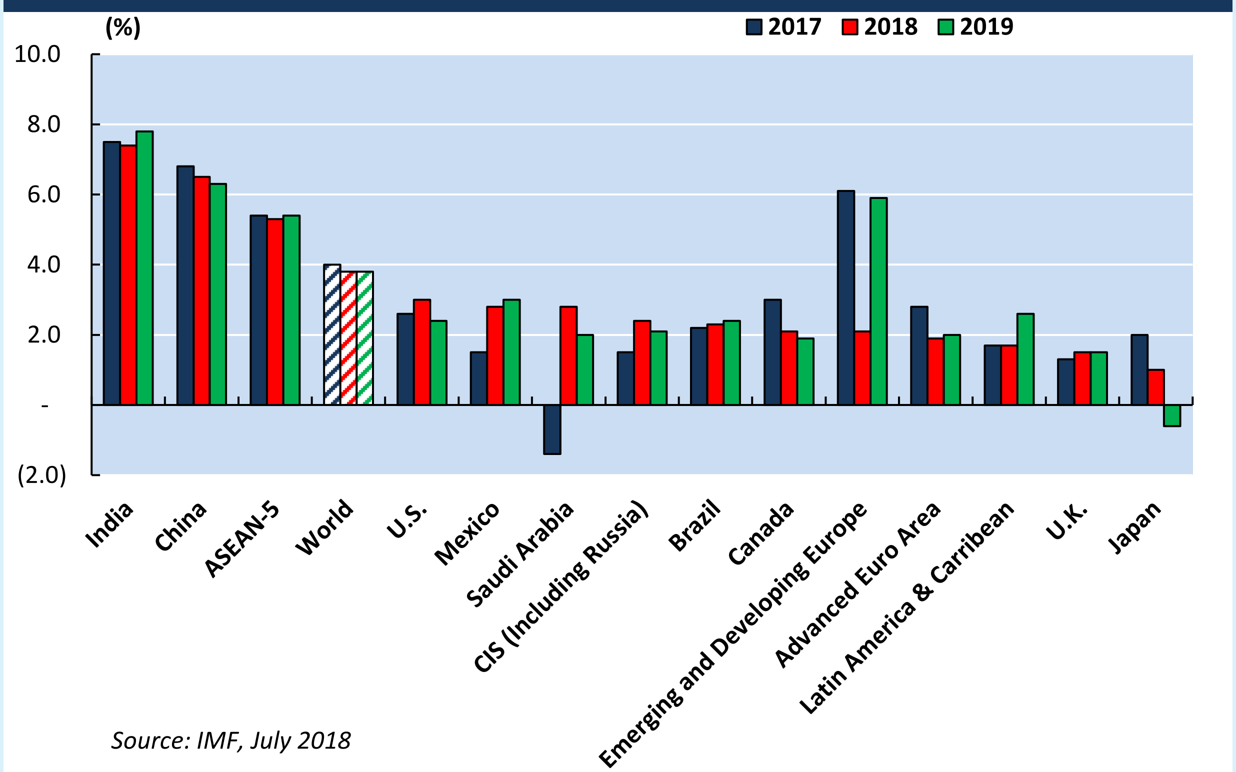
3. Global Macroeconomic Growth Outlook

The U.S. natural gas market has historically been defined as consisting of the contiguous "Lower 48" (L-48) states, with some consideration of the pipeline interconnections between the L-48, Canada, and that of Mexico. The L-48 market definition has been shaped by the growth of the pipeline system connecting the different regions of the U.S. The surge in pipeline investments into and across Mexico have laid the infrastructure for the consideration of a larger North American natural gas market, as discussed in previous outlooks. The rapid growth in U.S. LNG exports is now raising a few new factors that must be considered when assessing L-48 natural gas markets, such as the economic growth of LNG importing and exporting countries and seasonal weather patterns globally. In addition, an awareness of global macroeconomic growth trends also aides in understanding potential fluctuations in U.S. exports and imports that would, in turn, affect U.S. industrial output and, hence, natural gas demand. This appendix discusses the global macro-economic growth picture and is mainly based on the International Monetary Fund's (IMF) *World Economic Outlook Update* (WEO), which was released during July.

Leading into the fall and winter, the IMF's WEO forecasts that Q4 global growth at 3.8 percent over Q4 2017, this is 0.2 percentage points lower than the Q4 growth in 2017 over Q4 2016 (see figure below). 2018 annual world GDP growth is forecast to be 3.9%. 2019 annual rate is forecast to be the same 3.9% although regional growths will vary. As illustrated in the figure below, India and China which import a large share of U.S. LNG, are expected to experience the highest macroeconomic growth rates. The remainder of the world's economies are expected to grow at much lower rates. The one exception involves the "emerging and developing" European countries that are expected to recover in 2019 from a low growth in 2018.

The current macroeconomic expansion is becoming less even, and risks to the outlook are mounting. This phenomenon is recently showing up more among the emerging and developing economies, which are being affected by trade tensions, higher U.S. bond yields, higher oil prices, and local currency pressures. Also, there have been downward revisions in growth for Europe, the U.K., and Japan due to negative events. While U.S. and advanced economies continue to exhibit strong short-term growth, their continued growth is potentially vulnerable to "triggers" such as trade disruptions and conflicts, as well as higher inflation.

WORLD GDP Q4 OVER Q4 GROWTH RATE



Source: IMF, July 2018

4. EIA's Short-Term Forecast Versus NYMEX

HENRY HUB PRICES			
	Q4 2018	Q1 2019	2019
EIA Forecast	3.14	3.23	3.12
NYMEX Futures (As of Sep 10)	2.84	2.93	2.71

5. LNG Facilities

U.S. LNG TRAINS			
Train	Start Date*	Capacity (MMtpa)	Capacity (MMCFD)
Sabine Pass LNG T1	Feb-2016	4.5	658
Sabine Pass LNG T2	Jul-2016	4.5	658
Sabine Pass LNG T3	Jan-2017	4.5	658
Sabine Pass LNG T4	Aug-2017	4.5	658
Sabine Pass LNG T5	Dec-2018	4.5	658
Cove Point T1	Apr-2018	5.3	768
Elba Island T1-6	Jan-2019	1.5	219
Elba Island T7-10	Jun-2019	1.0	146
Freeport LNG T1	Sep-2019	4.4	644
Freeport LNG T2	Jan-2020	4.4	644
Freeport LNG T3	May-2020	4.4	644
Cameron LNG T1	May-2019	5.0	729
Cameron LNG T2	Jul-2019	5.0	729
Cameron LNG T3	Sep-2019	5.0	729
Corpus Christi LNG T1	Dec-2018	4.5	658
Corpus Christi LNG T2	Oct-2019	4.5	658

**Note: for trains that are currently operating, start dates indicate when the train saw significant feedgas flow. For trains that are not in service yet, start dates are an estimation of commercial start dates. Feedgas flows could be seen before the commercial start date. Corpus Christi T3 made a final investment decision (FID) however the official commercial start date is not available yet.*
MMtpa is million metric tons per year.

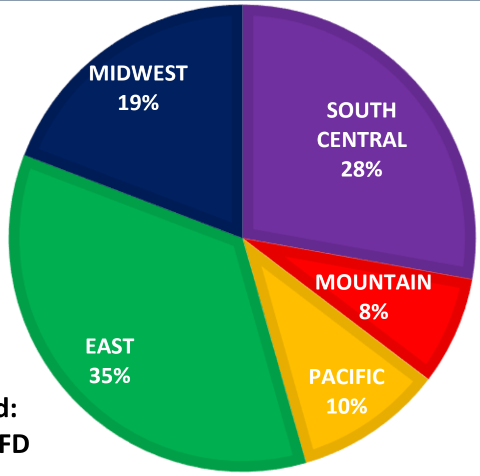
6. Winter Imports and Exports of Natural Gas

WINTER 2017/2018								
Canada			Mexico			LNG		
Imports	Exports	Net	Imports	Exports	Net	Imports	Exports	Net
8.5	3.1	5.4	0.01	4.40	4.39	0.45	3.01	2.56

WINTER 2018/2019								
Canada			Mexico			LNG		
Imports	Exports	Net	Imports	Exports	Net	Imports	Exports	Net
8.6	3.4	5.2	0.01	5.15	5.14	0.23	4.74	4.51

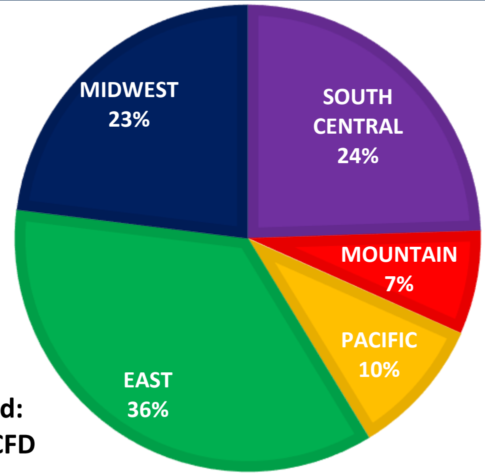
7. *Total 2017 Primary Natural Gas Demand by EIA Natural Gas Region and Time of Year (Excluding Exports)*

TOTAL YEAR



Demand:
67.7 BCFD

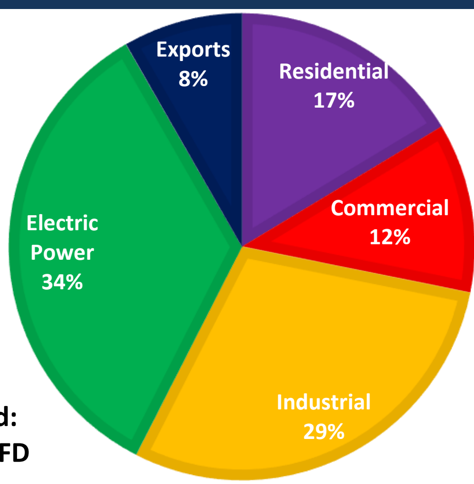
WINTER 2017/2018



Demand:
86.0 BCFD

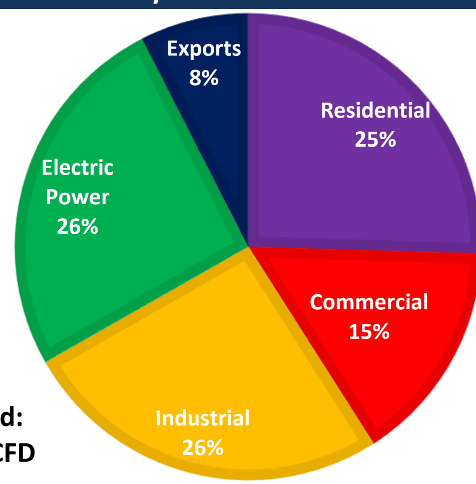
8. *Total 2017 Natural Gas Demand by Sector and Time of Year (Including Exports)*

TOTAL YEAR



Demand:
73.7 BCFD

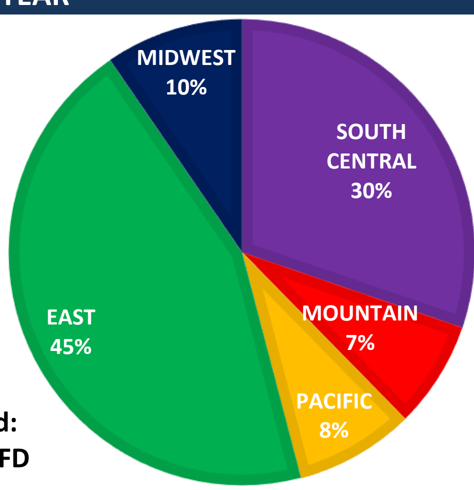
TOTAL WINTER 17/18



Demand:
93.3 BCFD

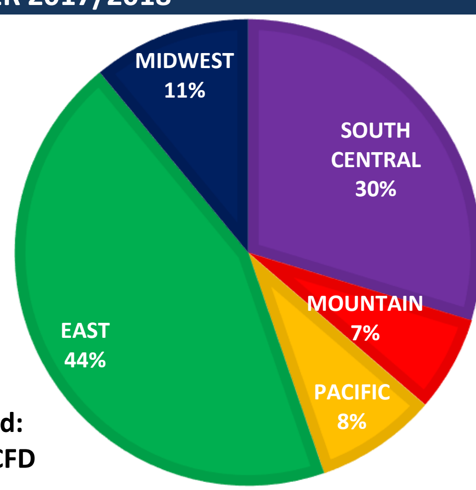
9. *2017 Power Natural Gas Demand by Natural Gas Region and Time of Year*

TOTAL YEAR



Demand:
25.2 BCFD

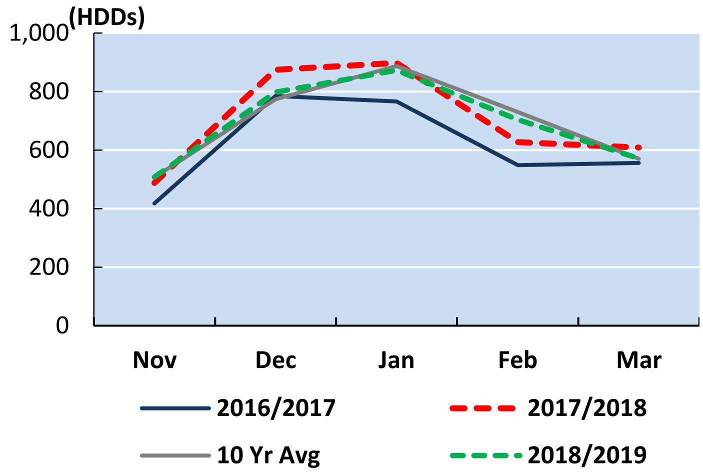
WINTER 2017/2018



Demand:
24.1 BCFD

10. Weather

WINTER HEATING DEGREE DAYS



Source: NOAA, EVA

11. U.S. Macro Indicators

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%	1.48%
Industrial Production Growth	2.05%	3.56%	1.20%	-0.20%	1.27%	3.06%

Source: Moody's

IPD: Implicit Price Deflator

12. U.S. Lower 48 Gas Consumption (Winter Season Nov-Mar, BCFD)

Winter	ResComm	Industrial	Electric	Other	Exports to Mexico	LNG Feedgas	Total Demand
2012/2013	35.9	21.3	19.7	5.9	1.7	0.0	84.5
2013/2014	41.3	22.7	20.1	6.0	1.7	0.0	91.8
2014/2015	39.5	22.4	21.8	6.0	2.2	0.0	91.9
2015/2016	31.9	22.1	24.3	5.9	3.2	0.1	87.5
2016/2017	33.7	22.9	21.2	5.8	4.0	1.7	89.3
2017/2018	37.8	24.1	24.1	5.9	4.4	3.0	99.4
2018/2019 est.	36.9	24.5	24.8	6.6	5.2	4.7	102.7

Source: EIA, EVA

13.Natural Gas Supply (Winter Season Nov-Mar, BCFD)

SUPPLY BY SECTOR (BCFD)

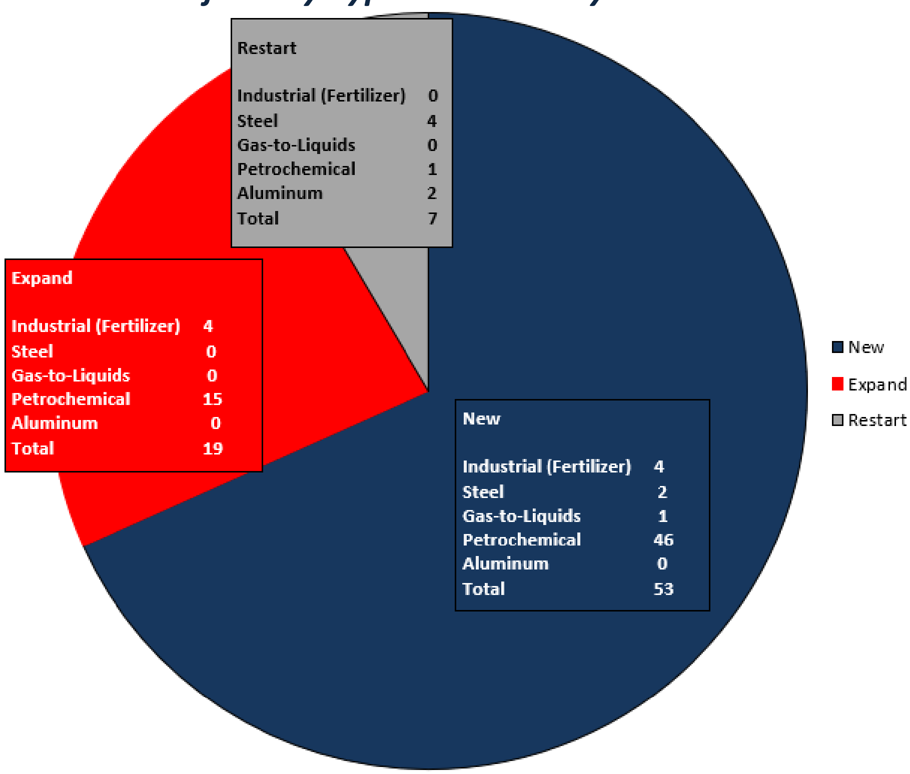
Winter	Production	LNG Imports	Net Imports from Canada	Storage Withdrawals	Total Supply
2012/2013	64.8	0.4	4.7	15.0	85.0
2013/2014	66.8	0.1	5.7	20.2	92.8
2014/2015	72.6	0.3	5.6	14.5	93.1
2015/2016	73.2	0.3	5.5	9.8	88.8
2016/2017	70.5	0.3	5.5	12.9	89.2
2017/2018	77.4	0.5	5.4	16.0	99.2
2018/2019 est.	84.9	0.2	5.2	12.4	102.7

Source: EIA, EVA

PRODUCTION BREAKDOWN (BCFD)

	CBM	Conventional /Tight	Offshore	Shale	Others	Total
2012/2013	3.9	28.5	4.4	28.0	0.1	64.8
2013/2014	3.5	27.9	3.7	31.6	0.1	66.8
2014/2015	3.2	27.9	3.6	37.7	0.1	72.6
2015/2016	3.0	26.3	3.6	40.3	0.1	73.2
2016/2017	2.7	23.7	3.4	40.6	0.2	70.5
2017/2018	2.6	24.5	2.5	47.6	0.2	77.4
2018/2019 est.	2.5	24.4	2.3	55.5	0.2	84.9

14.Industrial Projects by Type and Industry



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

ANNUAL CAPACITY FACTOR

	Capacity Factor								
Census Region	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018***
New England	53%	58%	55%	45%	43%	49%	48%	44%	38%
Middle Atlantic	46%	51%	58%	54%	56%	61%	60%	50%	53%
East North Central	23%	31%	48%	34%	35%	54%	59%	51%	56%
West North Central	18%	15%	26%	21%	17%	26%	32%	24%	37%
South Atlantic w/o Florida	43%	52%	61%	58%	56%	66%	67%	67%	65%
South Atlantic	53%	58%	62%	59%	57%	64%	64%	62%	61%
East South Central	45%	49%	60%	49%	52%	64%	68%	58%	61%
West South Central w/o ERCOT	36%	38%	47%	37%	39%	49%	49%	43%	53%
West South Central	41%	43%	49%	44%	45%	54%	51%	44%	48%
Mountain	41%	35%	40%	43%	40%	44%	44%	39%	36%
Pacific Contiguous w/o CA	51%	26%	33%	51%	47%	56%	49%	40%	32%
California	54%	40%	57%	55%	54%	53%	43%	39%	31%
Total U.S.	44%	45%	53%	48%	48%	56%	55%	49%	50%

*2018's estimates are based on data from Jan to June

WINTER (NOV-MAR) CAPACITY FACTOR

	Capacity Factor							
Census Region	**2010-11**	**2011-12**	**2012-13**	**2013-14**	**2014-15**	**2015-16**	**2016-17**	**2017-18**
New England	51%	53%	39%	32%	37%	40%	40%	40%
Middle Atlantic	46%	54%	51%	52%	57%	56%	51%	51%
East North Central	28%	47%	35%	35%	51%	63%	52%	59%
West North Central	12%	14%	20%	16%	20%	28%	19%	31%
South Atlantic w/o Florida	50%	58%	57%	51%	57%	62%	56%	59%
South Atlantic	50%	58%	57%	51%	57%	62%	56%	59%
East South Central	43%	57%	53%	47%	62%	65%	55%	61%
West South Central w/o ERCOT	32%	41%	37%	41%	48%	48%	37%	42%
West South Central	32%	41%	37%	41%	48%	48%	37%	42%
Mountain	30%	33%	31%	34%	32%	40%	29%	33%
Pacific Contiguous w/o CA	41%	54%	51%	57%	45%	48%	38%	39%
California	44%	55%	54%	56%	47%	45%	37%	38%
Total U.S.	39%	49%	45%	45%	49%	52%	44%	48%

Source: EIA and EVA

ANNUAL HEAT RATE

	Heat Rate (Btu/kWh)								
Census Region	2010	2011	2012	2013	2014	2015	2016	2017	2018*
New England	7,522	7,470	7,492	7,531	7,548	7,592	7,533	8,048	7,779
Middle Atlantic	7,764	7,746	7,431	7,423	7,453	7,650	7,519	7,821	7,576
East North Central	8,718	8,275	7,437	7,561	7,517	7,838	7,690	7,699	7,683
West North Central	7,795	7,819	7,433	7,584	7,621	7,391	7,437	8,683	7,495
South Atlantic w/o Florida	7,486	7,433	7,311	7,215	7,270	7,279	7,236	7,249	7,210
South Atlantic	7,489	7,416	7,313	7,274	7,299	7,287	7,270	7,308	7,266
East South Central	7,409	7,375	7,296	7,327	7,345	7,306	7,238	7,404	7,212
West South Central w/o ERCOT	7,885	7,957	7,302	7,419	7,362	7,517	7,479	7,534	7,566
West South Central	8,197	8,195	7,316	7,336	7,343	7,839	7,726	7,902	7,846
Mountain	7,596	7,706	7,492	7,495	7,534	7,543	7,533	7,621	7,688
Pacific Contiguous w/o CA	7,550	7,781	7,182	7,282	7,305	7,427	7,538	8,233	7,796
California	7,441	7,595	7,308	7,276	7,346	7,518	7,486	7,569	7,600
Total U.S.	7,734	7,730	7,359	7,362	7,383	7,555	7,485	7,641	7,540

WINTER (NOV-MAR)

	Heat Rate (Btu/kWh)							
Census Region	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18
New England	7,460	7,435	7,489	7,643	7,509	7,516	7,808	7,896
Middle Atlantic	7,731	7,483	7,438	7,499	7,589	7,662	7,554	7,661
East North Central	8,463	7,520	7,520	7,591	7,847	7,718	7,482	7,678
West North Central	7,848	7,513	7,429	7,687	7,425	7,348	8,496	8,143
South Atlantic w/o Florida	7,378	7,304	7,252	7,306	7,250	7,271	7,276	7,281
South Atlantic	7,378	7,304	7,252	7,306	7,250	7,271	7,276	7,281
East South Central	7,328	7,286	7,266	7,365	7,261	7,243	7,307	7,280
West South Central w/o ERCOT	8,414	7,603	7,268	7,385	7,625	7,864	7,477	7,993
West South Central	8,414	7,603	7,268	7,385	7,625	7,864	7,477	7,993
Mountain	7,713	7,506	7,518	7,462	7,585	7,521	7,589	7,728
Pacific Contiguous w/o CA	7,536	7,313	7,250	7,273	7,440	7,520	7,516	7,620
California	7,507	7,338	7,261	7,271	7,458	7,537	7,410	7,494
Total U.S.	7,721	7,419	7,322	7,381	7,477	7,535	7,449	7,596

Source: EIA and EVA