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Winter 2018-19 Energy Market Assessment

Item No.: AD06-3-000 | October 18, 2018

Introduction

- NOAA forecasts a warmer than average winter.
- Regional pipeline constraints in New York City, Boston, and Los Angeles increase the risk of price volatility.
- Winter reserve margins exceed the reference margins this winter for all assessment areas.
- Fuel security remains an area of focus given the increasing use of natural gas-fired generation capacity.

Good morning Mr. Chairman and Commissioners, the Office of Enforcement presents its 2018-2019 Winter Energy Market Assessment. The Winter Energy Market Assessment is staff's opportunity to look ahead to the coming winter and share its thoughts and expectations about market preparedness, including a high-level assessment of risks and challenges anticipated in the coming operating season.

Weather remains one of the largest determinants of market outcomes in the energy markets, and the National Oceanic and Atmospheric Administration (NOAA) forecasts a warmer than average winter. However, a warmer than average winter may still have prolonged periods of cold temperatures that can stress natural gas and electricity markets, as demonstrated by last winter's weather event known as the "Bomb Cyclone." Should similar cold weather materialize this winter, pipeline constraints on Algonquin Gas Transmission, Transcontinental Pipeline, and Tennessee Gas Pipeline could result in high gas prices at Transco Zone 6 near New York City, Algonquin Citygates in ISO New England Inc. (ISO-NE), and Transco Zone 5 South in PJM Interconnection LLC (PJM).

Some information in this presentation comes from a draft of the North American Electric Reliability Corporation's (NERC) 2018 Winter Reliability Assessment, which NERC will release at a later date and is still subject to change. According to NERC's draft assessment, winter reserve margins exceed the reference levels across all assessment areas, but the growing reliance on natural gas in the electricity sector has significant implications for fuel security and natural gas to oil switching by dual-fuel capable generation units. Oil-fired generation can play an important role in maintaining electric reliability when natural gas pipelines reach capacity and can only serve firm customers. For example, during the afternoon of January 2, 2018, oil-fired generation represented 33 percent of power generation in ISO-NE.

Recap of 2018 Winter Weather Events

The Eastern Interconnection experienced cold weather during the Bomb Cyclone from December 26 to January 8.

- ISO-NE, NYISO, PJM, and MISO experienced high but not record loads.
- Natural gas prices reached record levels.
- There was a notable increase in oil-fired generation.
- Generator outages contributed to tight electric supplies.
- Wholesale electricity prices were at high levels throughout this cold period.
- MISO South and SPP approached a short-term capacity shortage.

Last winter, electricity markets in the Eastern Interconnection experienced a period of extremely low temperatures, system stress, and high prices from December 26, 2017 to January 8, 2018, during the Bomb Cyclone.

The four most-affected RTOs – ISO-NE, New York ISO (NYISO), PJM, and Midcontinent ISO, Inc. (MISO) – experienced high peak loads, albeit short of record levels. For example, PJM realized a peak load of over 138,000 MW on January 5, compared to the record of just over 143,000 MW on February 20, 2015. Because of the persistence of the cold weather, load during off-peak hours averaged about 80 percent of peak load. This resulted in many intermediate and even peak load generating units operating at high utilization rates throughout this two-week period. As a result, forced outage rates increased toward the end of the cold wave.

Spot natural gas prices in NYISO increased sharply during the Bomb Cyclone, averaging \$52.33/MMBtu during the first week of January 2018 versus only \$4.82/MMBtu during the same period in 2017. A record high natural gas price for a single next-day transaction occurred on January 4, 2018 at Transco Zone 6-NY. The high price was \$175/MMBtu, while the volume weighted average price surged to a record \$141/MMBtu. Natural gas prices exceeded \$100/MMBtu at times at both Algonquin City Gate in New England ISO, and Transco Zone 5 South in PJM.

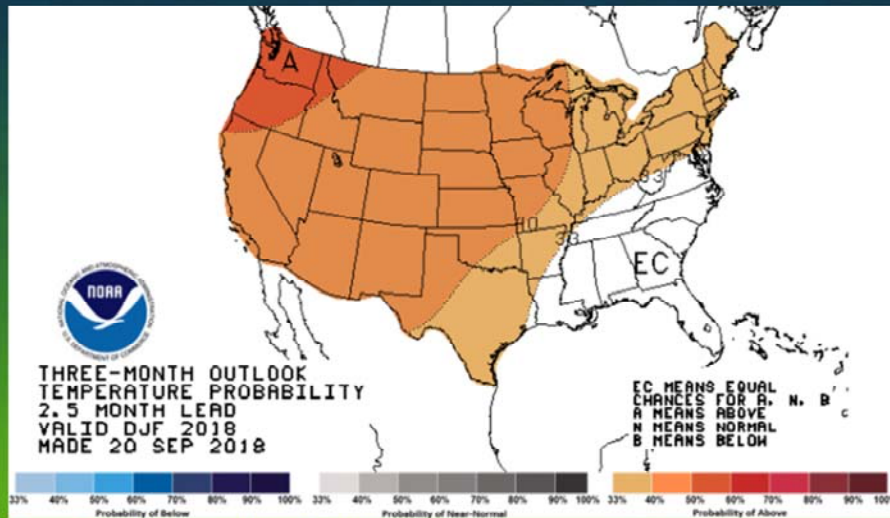
In the Mid-Atlantic and Northeast there was a notable increase in the dispatch of oil-fired generation between December 26, 2017 and January 8, 2018 due to fuel market conditions. The fuel shift from natural gas to oil was most pronounced in NYISO and ISO-NE, as natural gas availability for fuel generation became tighter because of constraints in the natural gas pipeline network.

Generation outages also contributed to relatively tight electric supply conditions. The outage of the Pilgrim nuclear power station in Massachusetts, resulting from the loss of a transmission line, on January 4 and continuing through January 8 was particularly notable for ISO-NE.

Day-ahead and real-time locational marginal prices (LMP) rose sharply during the Bomb Cyclone. Throughout the cold wave, day-ahead prices at major hubs in the Northeast and Mid-Atlantic averaged over \$165/MWh, and real time prices averaged approximately \$190/MWh.

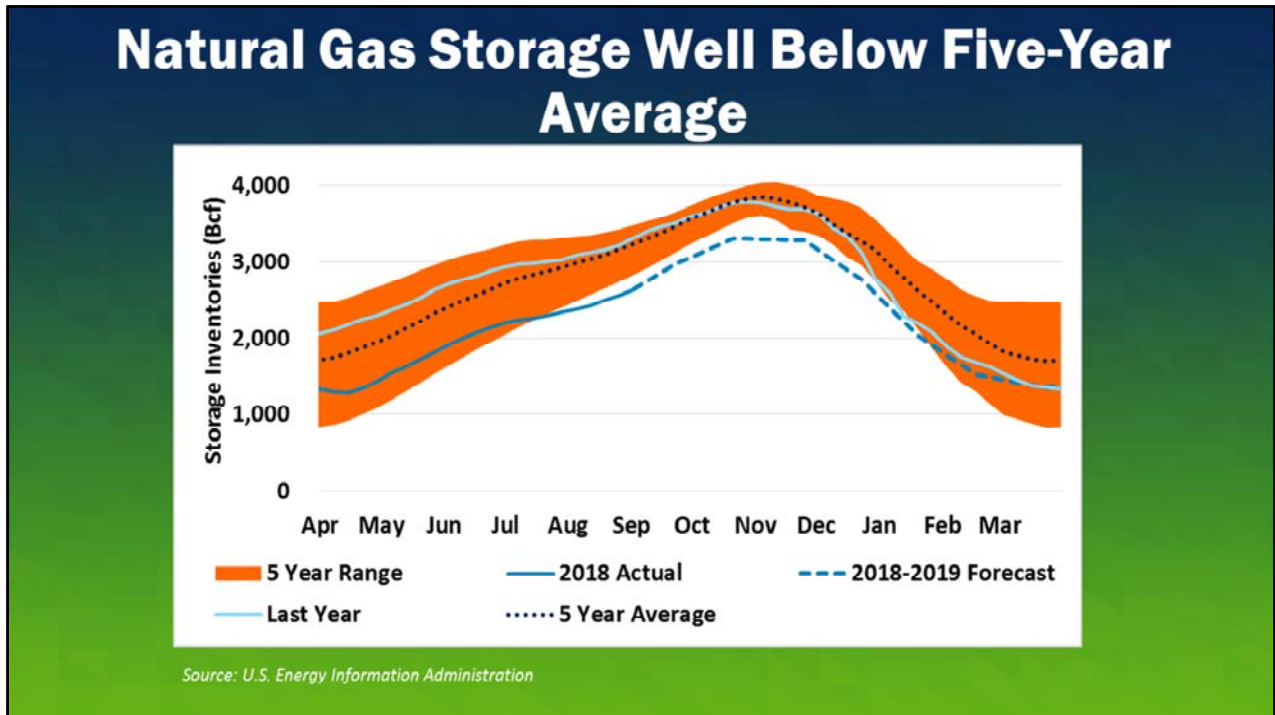
On January 17, 2018, regional operators in the Midwest and South Central U.S. issued public appeals for consumers to voluntarily reduce their electricity use due to abnormally cold temperatures and higher than forecast electricity demand. There were reports of multiple forced generation outages, voltage deviations and near-overloads during peak operations. FERC and NERC have initiated a joint inquiry to assess the event.

Forecasts Predict Warmer than Normal Winter



Source: National Oceanic and Atmospheric Administration

The current NOAA three-month outlook predicts a higher than average probability for warmer temperatures with higher precipitation than usual across much of the continental United States. NOAA also predicts an El Niño climate pattern this winter, which would result in warmer than average winter temperatures in the Northeast, Mid-West, and Western states, while Southeastern states would see temperatures on par with historical levels. El Niño weather patterns are expected to transport moisture from the Pacific, resulting in higher precipitation across the southern half of the country from California to Florida. A warmer than average winter would moderate fuel and electricity demand. However, as seen with last winter's bomb cyclone, prolonged cold weather events would increase short-term demand for natural gas and electricity.



Natural gas storage inventories began the 2018 injection season in April at 1,354 billion cubic feet (Bcf), which is on the low end of the 5-year range and has carried over to lower storage volumes for this winter. Storage inventories fell below the 5-year range in late July as a result of weather-related large storage withdrawals starting during the 2017-2018 winter and continuing throughout the spring and summer.

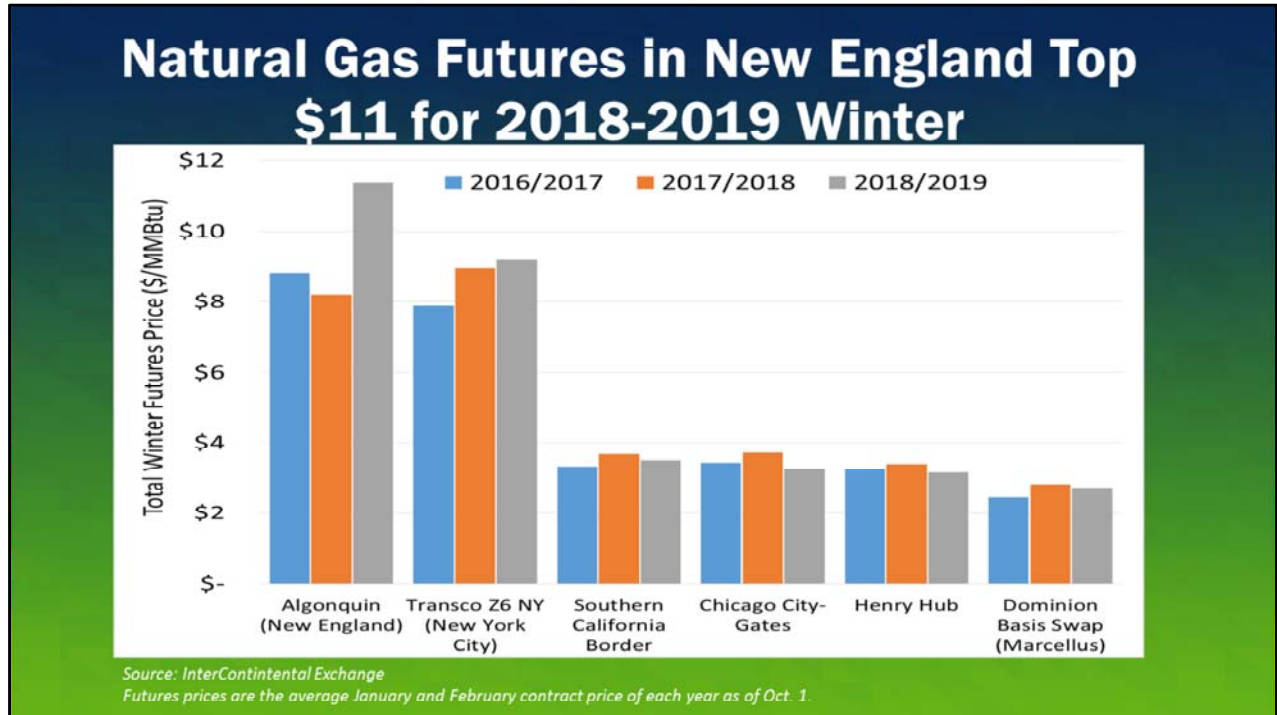
During the course of this year’s injection season, increased natural gas consumption offset gains in production throughout the country, keeping storage levels well below the 5-year average. Specifically, total U.S. natural gas consumption hit record highs for the summer season, averaging 71.9 billion cubic feet per day (Bcf/d). The main contributors to the increase in natural gas demand were electric power generation and LNG exports. Demand by generators averaged 30.7 Bcf/d between April and July 2018, a 12.9 percent increase from the same period the previous year. Likewise, LNG exports averaged 2.8 Bcf/d, a 62 percent increase from the same period the previous year. Meanwhile, U.S. marketed production set a new record, averaging 88 Bcf/d from April through July. Louisiana and Texas saw notable production growth, which increased by 2.4 Bcf/d and 1.73 Bcf/d, respectively, while Marcellus gas production increased by 3.3 Bcf/d in Ohio and Pennsylvania.

The Energy Information Administration (EIA) projects natural gas storage inventories to start the withdrawal season with 3,308 Bcf. This would be the lowest inventory level since 2005 and a 12.7 percent decrease from last year’s level.

Every region of the country currently has inventories below their 5-year averages. As of late September, the biggest deficits from the regional 5-year averages are in the South Central region, where inventories of 1,090 Bcf are 26 percent below average, the Midwest region, where inventories of 945 Bcf are 15.3 percent below average, and the East region, where inventories of 827 Bcf are 11.8 percent below average.

EIA forecasts that the storage deficit will decrease over the withdrawal season, with storage levels finally returning to levels within the 5-year range by the beginning of February. EIA predicts that storage levels will end the withdrawal season with 1,354 Bcf, only 347 Bcf below the 5-year average. These numbers imply that total withdrawals throughout the winter will reach 1,954 Bcf, which is below the average amount withdrawn over the past 5 years but greater than the 2015-2016 winter when only 1,451 Bcf was withdrawn. Deviations from the forecasted winter weather could have a large impact on withdrawals and the end-of-season storage levels. Continued high production levels should moderate price risk associated with lower than average storage inventory; however, should natural gas demand and LNG exports be higher than expected, this impact may be offset.

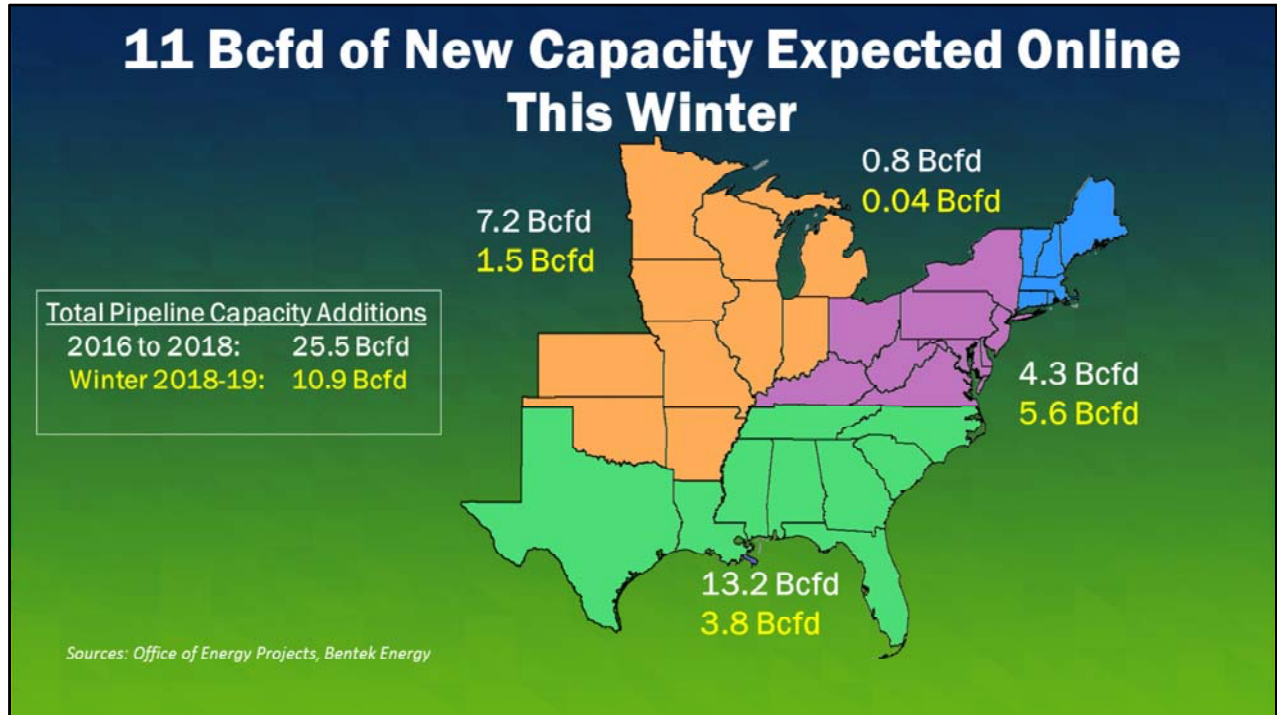
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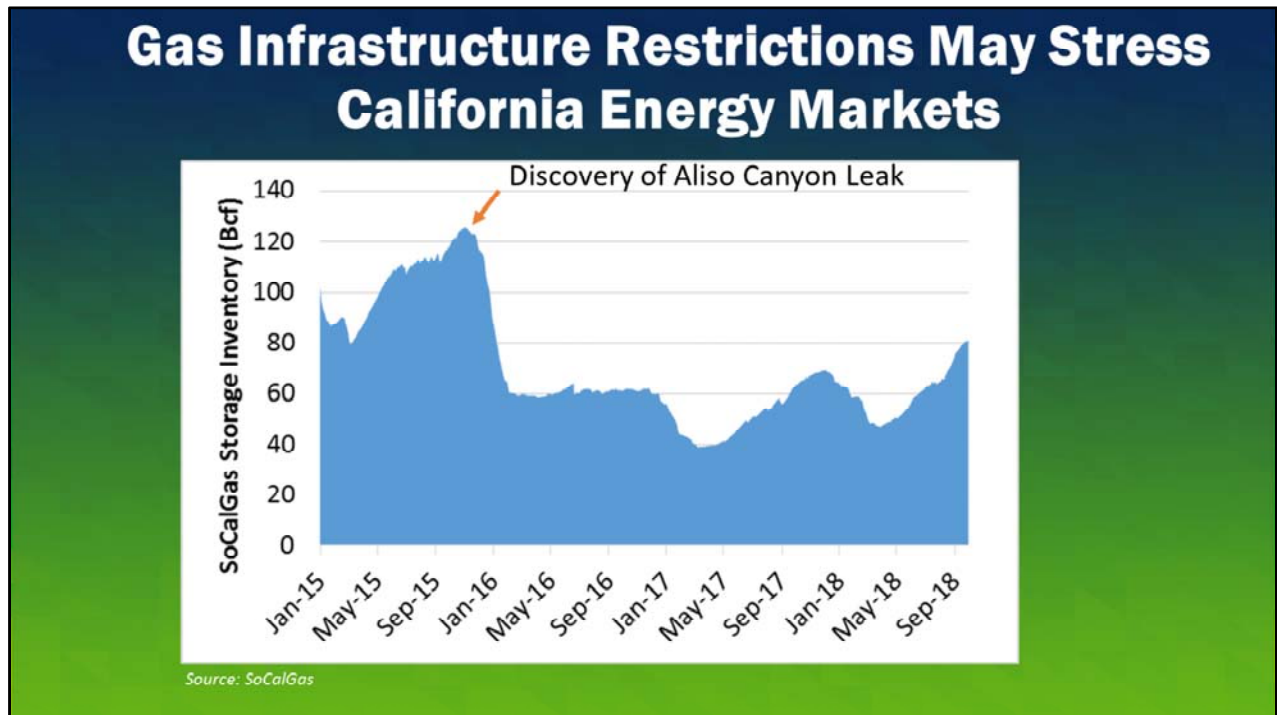
The graph above shows the total natural gas futures prices for the past and upcoming winters for regions across the U.S. The total price is calculated by adding the Nymex Henry Hub winter futures price to the winter basis futures prices at various U.S. trading hubs. As of October 1, 2018, the Henry Hub futures price, which measures the general cost of the natural gas commodity, was \$3.12/MMBtu, 24 cents below last winter's futures price measured on October 1, 2017. As a result, total prices across the U.S. (outside of New England and New York City) are lower than last year for the upcoming winter.

However, basis futures prices, which approximate the cost to deliver natural gas to regional markets this winter, have generally increased across the country. Basis futures prices in New York City and Boston averaged \$6.03/MMBtu and \$8.21/MMBtu, up \$0.47/MMBtu and \$3.40/MMBtu respectively from last year. This suggests a market expectation that both regions may face pipeline transportation constraints this winter. Basis futures price at Dominion South, a point representative of the Marcellus shale region also increased, rising from -\$0.57/MMBtu last year to -\$0.44/MMBtu this winter. The 13 cent rise in the Dominion South basis futures price is likely a result of recent increases in pipeline takeaway capacity out of the region leading to a reduction of the local natural gas production surplus. Chicago Citygates basis futures saw the largest year over year drop, falling from \$0.32/MMBtu in 2017 to \$0.10/MMBtu in 2018. Declining basis futures prices at the Chicago Citygates could be a result of an increased supply of natural gas to the region associated with the commencement of commercial operation of Rover pipeline. Finally, Southern California Border basis futures prices rose \$0.07/MMBtu from last year to \$0.35/MMBtu. The basis futures at the Southern California Citygates, a hub representative of the Los Angeles market area, averaged \$1.96/MMBtu, up \$1.45/MMBtu from last year, a result of expected regional pipeline congestion this winter.

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Numerous new large-scale pipeline projects have increased deliverability on the interstate natural gas pipeline system in recent years. Since 2016, industry has added nearly 25.5 Bcfd of new pipeline capacity in the Northeast, New England, the Midwest, and the Southeast. A large percentage of these projects provide outlets for growing supply from the Appalachian Basin. Nearly 11 Bcfd of pipeline capacity should be placed in service over the next several months. Some of the largest of these new pipelines and expansions target markets in the Northeast, Midwest, and Southeast. For example, the 1.5 Bcfd Nexus Gas Transmission pipeline, which is expected to begin commercial operation this month, links production fields in eastern Ohio to Michigan and Ontario, Canada. The 1.3 Bcfd Columbia Gas Transmission WB Xpress expansion carries natural gas from West Virginia to multiple interconnections in Virginia began commercial operation in recent weeks. These new pipeline capacity additions should, in general, lower prices as incremental supply from the Appalachian Basin is more broadly distributed to markets in the Northeast, Midwest, and Southeast. The New England region has seen the least pipeline development, and is expected to have only one project go in-service this winter: a 0.04 Bcfd expansion on Portland Natural Gas Transmission System.

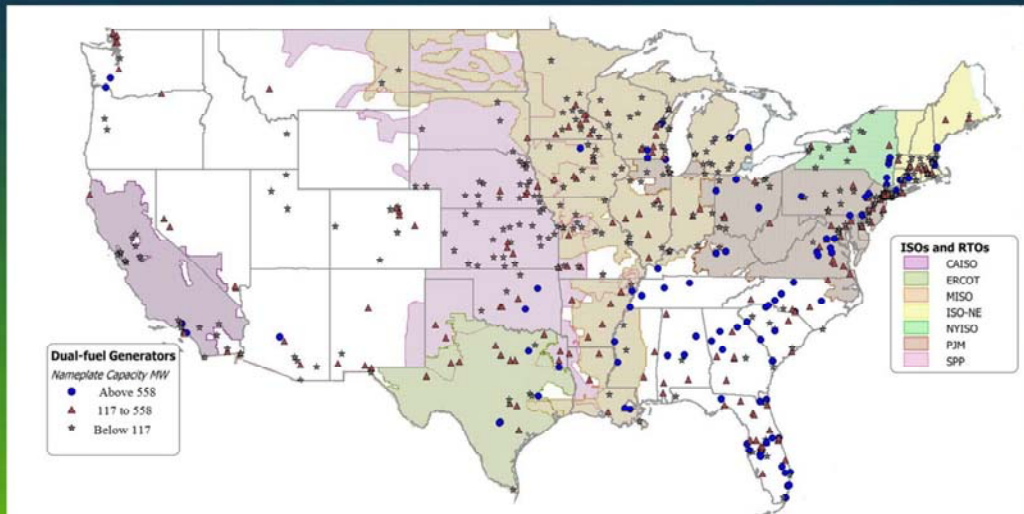


Intrastate and distribution level natural gas infrastructure outages in Southern California are likely to impact natural gas and electricity markets this winter. Ongoing restrictions on Southern California Gas Company's (SoCalGas) Aliso Canyon storage facility currently limit working gas capacity to 34 Bcf, down 60 percent from the 86 Bcf capacity prior to the 2015 leak. The California Public Utilities Commission (CPUC) has limited withdrawal from the storage facility by requiring that it only be used as a last resort to maintain natural gas reliability. In addition, ongoing pipeline maintenance has reduced system import capacity. Unplanned remediation work on SoCalGas's Line 4000 started on September 18, 2017, and a force majeure event related to a pipeline rupture on Line 235 began on October 1, 2017. Combined, these outages have reduced receipt point capacity in the Northern Zone of the SoCalGas system by approximately 1,070 million cubic feet per day (MMcfd). The completion date for the remediation work on the lines is currently unknown.

The restrictions to Lines 235 and 4000 have impacted both deliverability of natural gas supplies as well as regional natural gas prices, and will likely continue to affect both natural gas and electricity prices this winter when regional gas demand peaks. However, SoCalGas's natural gas storage inventories were 81 Bcf as of September 30, which is 17.6 Bcf or 28 percent greater than last year at that time. SoCalGas reported that the Aliso Canyon storage facility has reached the authorized maximum storage inventory of 34 Bcf.

The natural gas infrastructure limitations in southern California increase the risk to electric reliability in California, as much of the region is dependent on natural gas generation to meet electric peaking and ramping requirements. In the event of natural gas curtailments, CPUC rules require SoCalGas to first curtail up to 50 percent of the gas for electric generators. Curtailment of natural gas to electric generators does not necessarily imply that electric service would be curtailed because the California Independent System Operator (CAISO) has flexibility as to which generation it dispatches during the winter, since demand for electricity is lower in the winter than in the summer in California. However, CAISO and the Los Angeles Department of Water and Power (LADWP) require natural gas to maintain electric service. Last winter, a joint report released by the CPUC, California Energy Commission, CAISO, and LADWP estimated that the minimum amount of natural gas required to maintain electric service ranged between 38 and 293 MMcfd. The ongoing restrictions to natural gas pipelines and storage facilities increase the potential for natural gas curtailments this winter, but winter power system flexibility and cooperation between SoCalGas and CAISO should help maintain electric reliability.

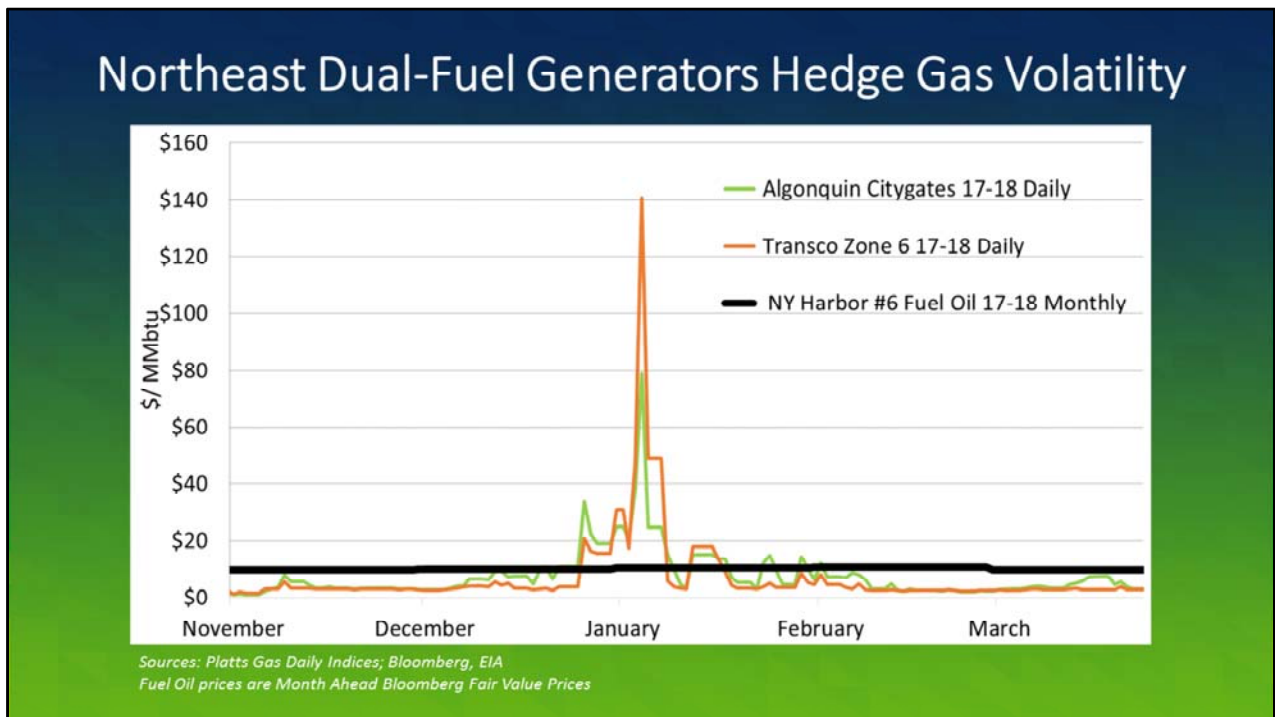
Most Gas-Oil Switching Occurs in the Eastern Interconnection



Sources: Derived from ABB Velocity Suite data.

Gas-oil switching refers to the ability of a dual-fuel generator to change between natural gas and oil as its generating fuel. This capability is important for winter preparedness, especially in the Northeast and California where natural gas supply can become constrained in the winter. Dual-fuel units not only allow for oil to be used as a secondary fuel, but also allow for the storage of oil on-site, providing some mitigation with regard to fuel deliverability issues. The map shows the concentration of units with gas-oil fuel switching capability, as reported to EIA. Most of the dual fuel capability is located in the Eastern Interconnection. NYISO has the largest proportion of natural gas capacity that is capable of gas-oil switching.

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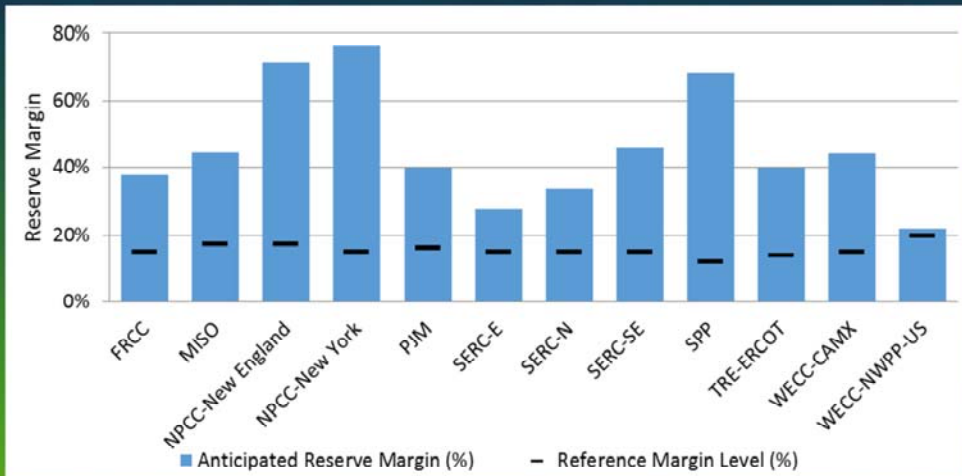


Many gas-oil switching generators in the Northeast commonly operate on natural gas and switch to fuel oil when there are natural gas constraints and/or prevailing market prices require it. Typically, the monthly futures price of non-firm natural gas, even at constrained locations, is considerably cheaper than fuel oil futures, often by three or four times. Given the price disparity, most gas-oil switching capable plants would prefer to generate electricity using natural gas. However, firm natural gas transportation and supply contracts can be difficult and expensive to procure in the winter. There are gas-oil switching capable generators that hedge against gas supply and price risks by relying on interruptible natural gas transportation and keeping a storable fuel, often fuel oil, on-site during periods of expected constrained natural gas supply.

As previously noted, most gas-oil switching generation is located in the Northeast region where daily gas prices at the Transco Z6 non-New York and Algonquin Citygates hubs are volatile during the winter months. These two locations experienced several price spikes during the 2017-2018 winter, with Transco Z6 non-New York prices reaching a peak of \$140.85/MMBtu on January 5th. Last winter, the daily gas price at Transco Z6 and Algonquin Citygates exceeded the monthly fuel oil price for 18 and 29 days respectively. There is no guarantee that the daily price of gas will exceed the price of a contracted fuel oil supply at any point this winter, but during severe weather events an alternative fuel supply increases economic options for meeting fuel demand.

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Anticipated Reserve Margins Meet Reference Margins in All Regions

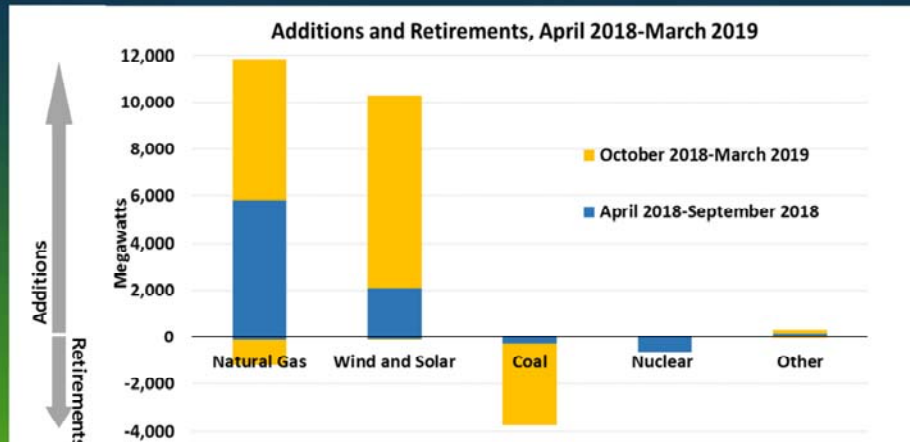


Source: North American Electric Reliability Corporation, Draft 2018-2019 Winter Reliability Assessment

Note: WECC and NPCC includes U.S. portion only

In its preliminary 2018-2019 Winter Reliability Assessment, NERC estimates that reserve margins for all assessment areas will meet reference margins this winter, a finding similar to last year's 2017-2018 Winter Assessment. The columns on the chart display the anticipated reserve margins for the regions comprising the U.S., while the black bars indicate the reference margins identified by the RTO or reliability region. Although all regions are expected to maintain healthy reserve margins through the winter, reserve margins are not always guarantors of reliable operations during the winter. Staff notes that fuel availability, particularly natural gas and fuel oil, and transmission systems can affect electric reliability, and must be regularly and comprehensively monitored.

New Plants and Retirements Continue Shift Toward Natural Gas and Renewables



Note: Based on net winter capacity. Planned is all changes with effective dates October 2018-March 2019; excludes AK and HI.
 Source: U.S Energy Information Administration, Form No. 860M, June 2018

The largest share of planned capacity additions this winter are powered by natural gas, solar, and wind, according to EIA. PJM will see the most total capacity added this winter; these additions are predominantly natural gas-fired capacity. CAISO will add the most renewable capacity.

Expected retirements this winter include coal and natural gas-fired capacity, with most occurring in PJM. This follows retirement trends in recent years.

In recent years, nuclear power plant retirements have occurred in CAISO, ISO-NE, PJM, MISO, and SPP. For example, Oyster Creek nuclear power plant in New Jersey ceased operations in September 2018. In addition, the Pilgrim nuclear power plant in Massachusetts will operate through the 2018-2019 winter before closing at the end of May 2019.

Natural Gas Has a High Share of Capacity in RTO and Non-RTO Regions



Source: Resource to BAA mappings are as reported by EIA in Form 860M, June 2018.

Note: Percentages based on net winter capacity; excludes AK, HI, and resources that do not report a BAA. Includes resources with status of operating and standby.

An assessment of each region's preparation for the winter season should take into account capacity mix and fuel source. Nuclear and coal power plant retirements combined with natural gas power plant additions are resulting in an increasing reliance on natural gas-fired generation. This growing dependence is reflected in the relatively high percentage of natural gas-fired capacity in nearly all RTOs. Bilateral markets exhibit a similar pattern, with natural gas-fired capacity having the largest generation market share, except in the Northwest.

The widespread dependence on natural gas-fired generation is resulting in some regions taking actions to ensure that there are adequate fuel supplies during extreme or extended cold weather when power generation and direct heating compete with other uses for available natural gas. Both ISO-NE and PJM have amended their capacity constructs to reward resources performing at high levels, and penalize resources who fail to perform under emergency and other high stress conditions. Also, each of the RTOs have instituted formal gas-electric coordination programs with pipelines serving natural gas power plants. This has included RTOs hiring personnel experienced in natural gas operations. RTOs are now better informed on pipeline operations, including the effects of non-firm natural gas deliveries during times of system stress. The enhanced coordination provides RTO dispatchers and plant operators with advance information on the likelihood of pipeline Operational Flow Orders (OFOs) and subsequent availability of natural gas fuel supplies. Updates to natural gas pipeline conditions are provided by pipelines to the RTOs, but the updates are dependent on how promptly information can be collected. In contrast to gas markets located within RTO footprints, much of the natural gas deliveries in the Southeast and Florida are under firm natural gas pipeline capacity contracts. When cold weather or other conditions stress these markets, there is greater assurance of natural gas fuel deliveries to generators with firm natural gas pipeline capacity contracts than generators served under non-firm or interruptible contracts.

ISO-NE's Capacity Market Was Modified in Response to Fuel Delivery Issues

- Dependence on natural gas for power generation continues to increase.
- Pipeline capacity is limited and frequently operates at maximum capacity during cold weather.
- New England has limited natural gas storage capacity.
- Price responsive demand is fully integrated into the daily energy market.
- Pay-for-performance capacity market incentives take effect, replacing the Winter Reliability Program.

As staff has indicated in prior Winter Assessments, New England continues to be an area of notable attention for the winter months. The region has continued to become increasingly dependent on natural gas for both home heating and power generation, yet pipeline capacity into the region is constrained and frequently operates at or near its operationally available capacity during periods of extreme or extended cold weather. Further compounding these circumstances is a very limited amount of underground natural gas storage capability.

Two major market rule changes were implemented on June 1, 2018, which have implications for ISO-NE's potential response to challenging winter conditions. The first is the full integration of price-responsive demand into the daily energy market. With these rules, New England became the first U.S. grid operator to fully integrate demand response resources into its daily energy and reserve economic dispatch process on a level comparable to generation resources. ISO-NE estimates that 408 MW of demand response resources will be available to offer to sell demand reductions in the energy market. Because demand response resources will be able to participate in the real-time energy markets, they will no longer be considered an emergency resource only to be dispatched in shortage conditions.

The second is the introduction of the Pay-For-Performance capacity market incentives. These rules established protocols to reward resources that over-perform during shortage conditions on the regional power system by requiring underperforming resources to pay the over-performers. The incentives were added to the Forward Capacity Market after ISO-NE observed a weak linkage between capacity payments and actual performance by resources during times of system stress.

Finally, this is the first winter that ISO-NE will operate without its Winter Reliability Program, since its start in 2013-2014. This market feature had multiple components, but the most significant were rules that

incentivized oil-fired generators to fill their fuel storage tanks at the beginning of the winter season. These resources were compensated under differing mechanisms in varying years, but in the most recent years they received payments for unused fuel at the end of the season.