

Slide 1 – 2019-2020 Winter Energy Market Assessment



2019–2020 Winter Energy Market Assessment
October 2019

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2019-2020 Winter Energy Market Assessment **October 2019**

Good morning Mr. Chairman and Commissioners, the Office of Enforcement and the Office of Energy Policy and Innovation present their 2019-2020 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.

Slide 2 - Highlights

Highlights

- NOAA forecasts a warmer than average winter.
- Natural gas storage levels are expected to be average going into winter.
- Natural gas futures prices are lower compared to last winter.
- A diverse set of generation resources will play a key role in maintaining electric reliability during the winter.
- Winter reserve margins exceed reference levels in all areas.



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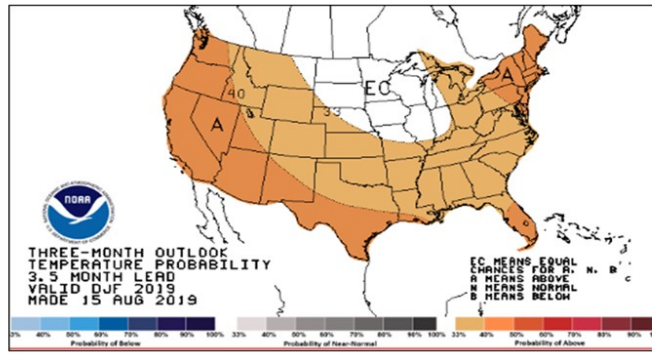
Weather remains one of the largest determinants of outcomes in the energy markets. As we will discuss on the next slide, the National Oceanic and Atmospheric Administration (NOAA) forecasts a high chance for a warmer than average winter.

Going into this winter, natural gas storage levels are close to the five-year average and natural gas futures prices are lower than last winter. Also, pipeline additions in the Permian and Marcellus Basins have bolstered the fuel supply chain, allowing additional natural gas supplies to reach markets. However, certain regions are more dependent on natural gas than others, and pipeline outages have the potential to increase both electric and natural gas price volatility. Coal and oil-fired generation continue to play an important role in maintaining electric reliability during the winter, especially in the Northeast, where winter demand for natural gas can exceed pipelines' capacity.

The North American Electric Reliability Corporation, or NERC, annually assesses the on-peak fuel mix and the availability of generators capable of serving peak winter loads. According to NERC's draft assessment, winter reserve margins are expected to exceed the reserve margin targets in all assessment areas. NERC will release its 2019 Winter Reliability Assessment at a later date and therefore this assessment is still subject to change.

Slide 3 – Forecasts Predict Warmer than Normal Winter

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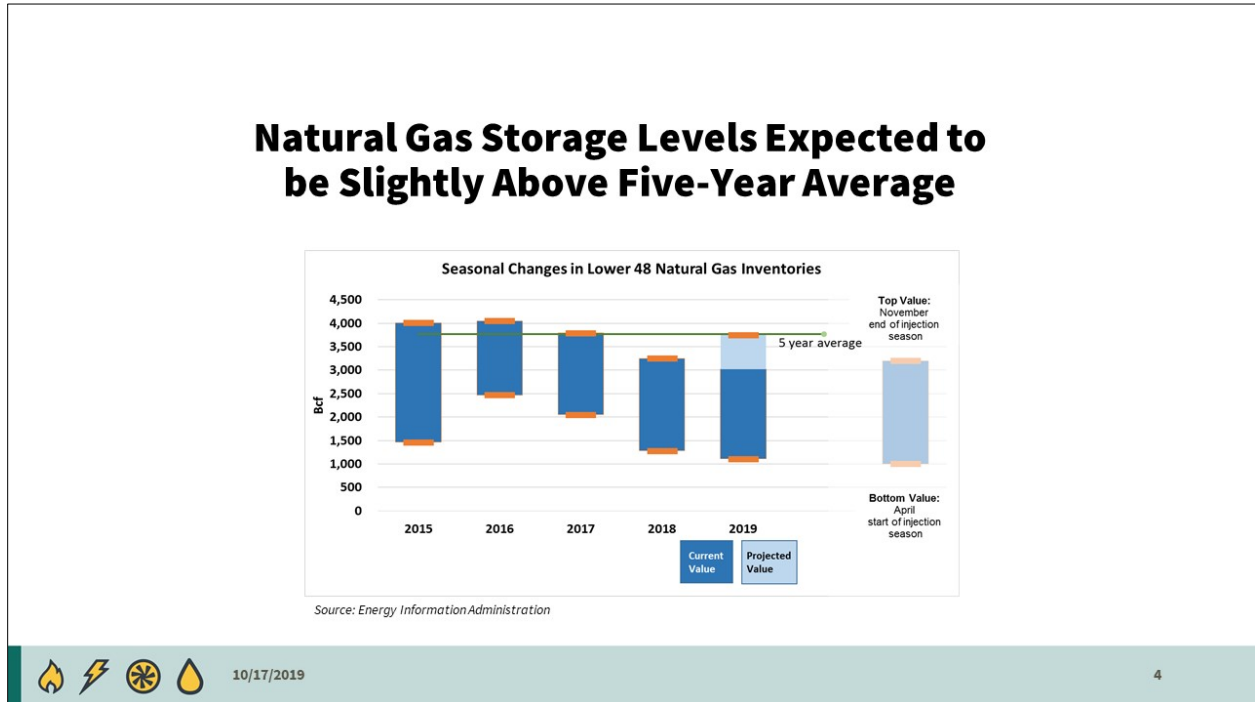
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As mentioned, the current NOAA three-month outlook for December 2019 through February 2020 predicts a higher than average probability for warmer temperatures across much of the continental United States. Warmer than average winter temperatures are expected in the Northeast, West, Texas, and Florida, with the Upper Midwest experiencing more normal conditions.

A warmer than average winter would moderate fuel and electricity demand. However, as seen in previous winters, acute cold weather events can occur during warmer than average seasons. These events increase the short-term demand for natural gas and electricity, which could create significant operational and market challenges.

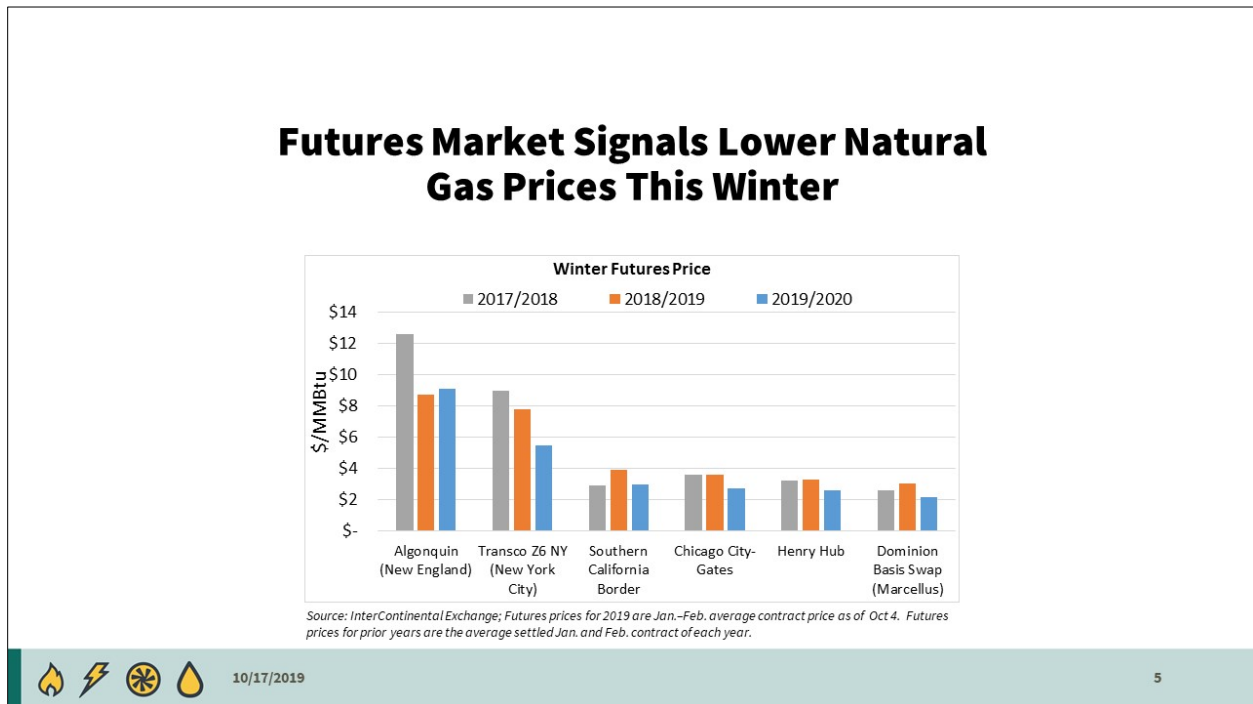
Slide 4 – Natural Gas Storage Levels Expected to be Slightly Above Five-Year Average



Natural gas storage inventories for the 2019 injection season, running from April 1 to October 31, began at 1.2 trillion cubic feet (Tcf), 30 percent lower than the prior five-year average. However, by November, inventories are expected to be slightly above the five-year average, reflecting robust storage injections throughout the season.

This year, natural gas storage levels have increased at the highest rate since 2015. As of September 6, natural gas inventories were at 3.0 Tcf, which is 15 percent higher than last year's levels at this time. According to an Energy Information Administration (EIA) forecast, the rate of natural gas injections into storage will be above the five-year average of 10.8 billion cubic feet per day (Bcfd) for the remainder of the injection season. This injection rate would result in natural gas inventories exceeding 3.7 Tcf by the end of October, a 16 percent increase over October 2018 levels and slightly above the five-year average. The EIA projects that the total withdrawals over the coming winter will be 2.1 Tcf, which is slightly more than last winter's total withdrawals of 2.0 Tcf.

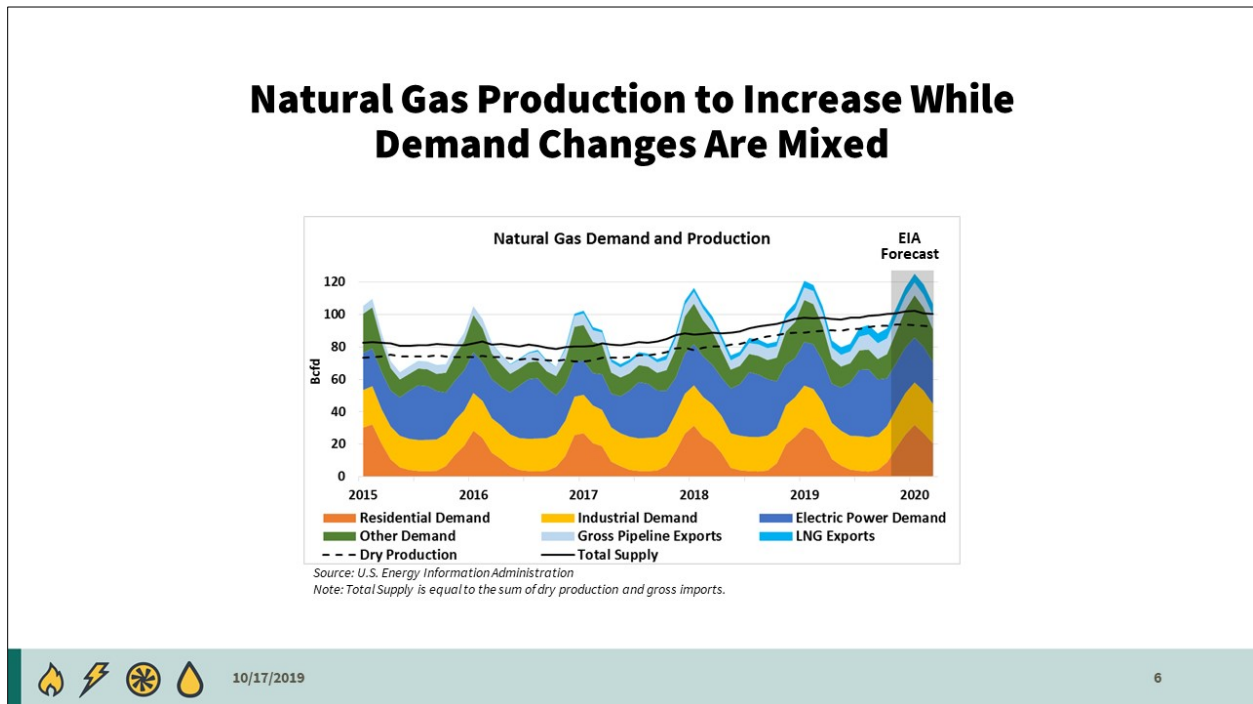
Slide 5 – Futures Market Signals Lower Natural Gas Prices This Winter



This graph shows the total natural gas futures prices for the past and upcoming winters for regions in the United States. Regional natural gas prices are calculated by adding the NYMEX Henry Hub winter futures price to the winter basis futures prices at major trading hubs in the United States. As of October 4, 2019, the NYMEX Henry Hub futures price, which measures the general cost of the natural gas commodity, was 73 cents below last winter’s average futures settlement price, with an average price of \$2.56/MMBtu for January and February 2020.

Basis futures prices, which approximate the cost to deliver natural gas to regional markets, were lower for the upcoming winter compared to last year’s futures settlement prices across all regions except New England. In Boston, basis futures prices averaged \$6.54/MMBtu, a \$1.16 rise from last winter. New York City experienced the largest declines from last winter. Basis futures prices in New York City averaged \$2.92/MMBtu, down \$1.56 from last year. Basis futures prices in the Southwest, Chicago, Southern California, and the Marcellus shale region all experienced moderate declines compared to last year.

Slide 6 – Natural Gas Production to Increase While Demand Changes Are Mixed

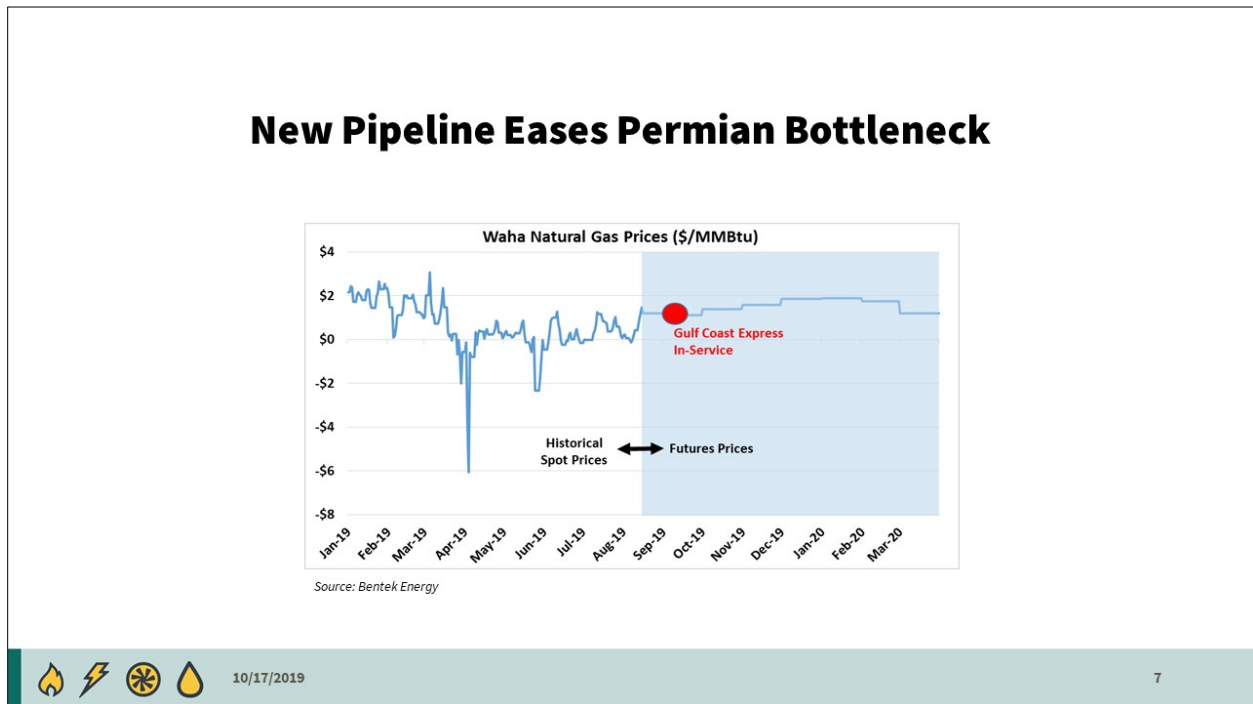


Dry natural gas production, or the process of producing consumer-grade natural gas, set new record highs in the first half of 2019, averaging 90 Bcf/d through June, a 12 percent increase from the 2018 level over the same period. The Marcellus Basin, located in Pennsylvania, West Virginia, Ohio, and New York, led all production regions with an average of 22 Bcf/d of production through June 2019. The Permian Basin, located in Texas and New Mexico, averaged 9 Bcf/d in 2019 through June, which represents a 38 percent increase year-over-year. The EIA Short Term Energy Outlook forecasts that production growth will continue through the winter, averaging 93 Bcf/d from November 2019 through March 2020.

While production continues to grow, the EIA forecasts U.S. demand will average 100 Bcf/d from November to March, a 1 percent increase from the previous winter. EIA forecasts domestic demand in January 2020 will average 112 Bcf/d. This is nearly 3 Bcf/d higher than the record for average monthly demand, which was observed in January 2019.

Electric power generation is a driver of the forecasted increase in domestic demand this winter, with an expected year-to-year increase of 6 percent to 27 Bcf/d, a projected all-time winter high. Industrial natural gas demand is also expected to increase, but only by 2 percent to 25 Bcf/d. However, residential natural gas demand, which is typically the biggest driver of peak winter demand, is expected to decrease 3 percent to 25 Bcf/d.

Slide 7 – New Pipeline Eases Permian Bottleneck

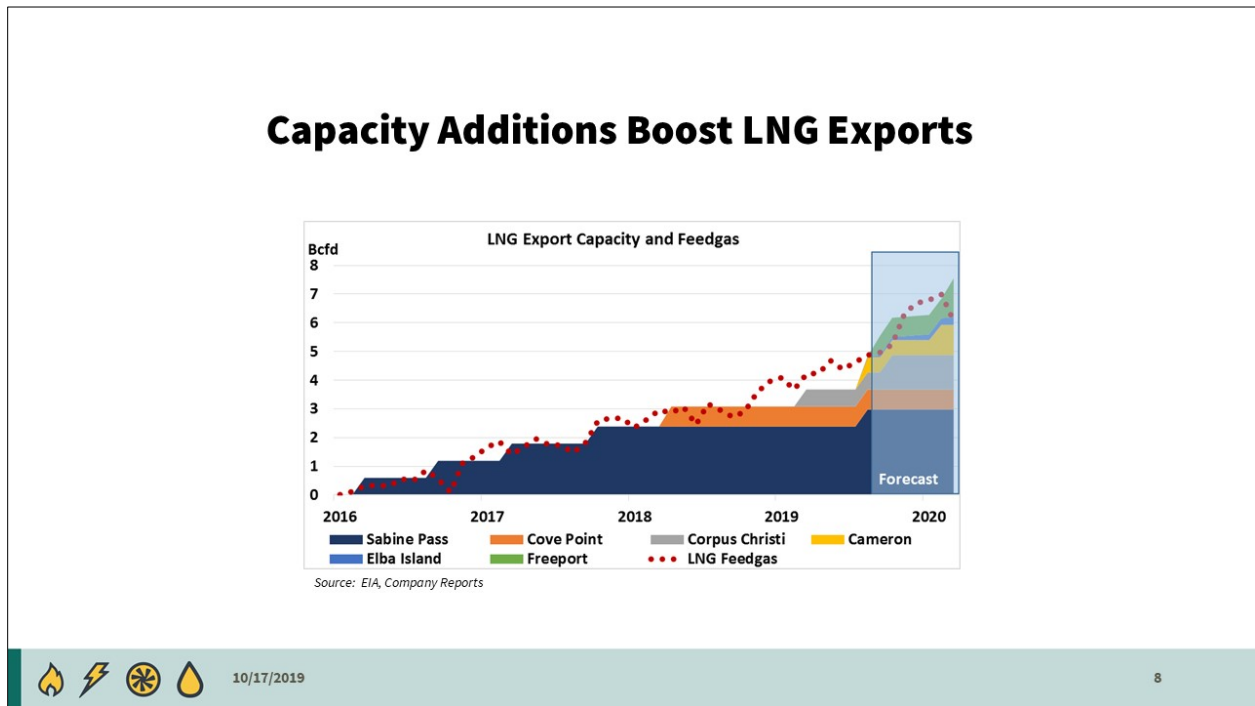


More than 12 Bcfd of new pipeline capacity, including 3.9 Bcfd of Commission-jurisdictional capacity, has been placed in-service across the U.S. since last winter. Some notable projects include Columbia Gas Transmission, LLC's 2.6 Bcfd Mountaineer Xpress and Kinder Morgan's 2.0 Bcfd Gulf Coast Express. Gulf Coast Express is a non-jurisdictional intrastate pipeline that transports Permian Basin natural gas from the Waha hub in west Texas to Agua Dulce in south Texas. Permian Basin natural gas production has exceeded local demand and saturated nearby markets. The regional oversupply caused 41 instances of negative prices at the Waha hub between March and August of this year. In August, spot natural gas prices at the Waha hub averaged just \$0.68/MMBtu.

Since Gulf Coast Express began commercial operation on September 25, spot natural gas prices have converged with other regional hubs. The project has eased binding local constraints, and placed upward pressure on pricing in nearby markets. This phenomenon is expected to continue through the winter and beyond. Basis futures at the Waha hub for January 2020 were priced at \$2.33/MMBtu on September 16.

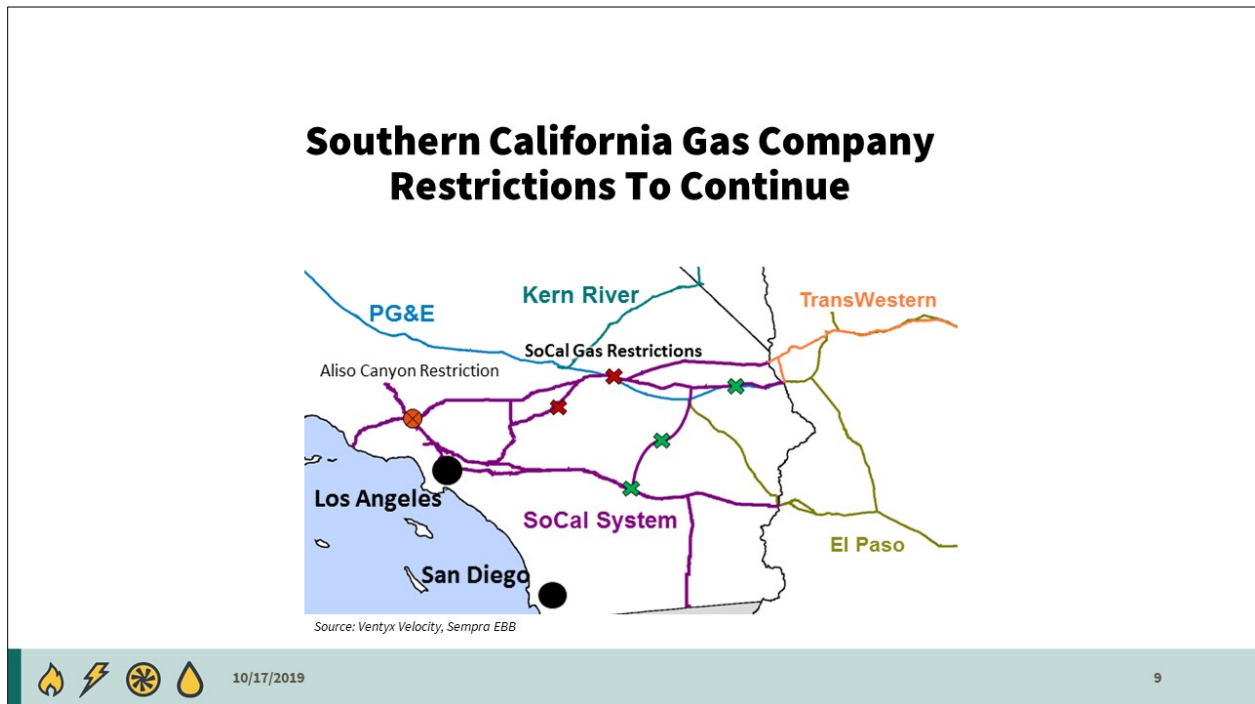
Looking forward, two additional natural gas pipeline projects are currently under construction to transport Permian Basin natural gas to the Southeast and Gulf Coast markets. Specifically, the 2.0 Bcfd Permian Highway Pipeline project is planned to be in-service in late 2020 and the 2.0 Bcfd Whistler Pipeline in 2021.

Slide 8 – Capacity Additions Boost LNG Exports



Since the beginning of 2019, the consumption of feedgas, which is natural gas used as a raw material for LNG liquefaction, has grown over 1.5 Bcfd—from 4.5 Bcfd to more than 6 Bcfd. From March to October 2019, more than 3 Bcfd of new LNG export capacity went in-service, representing the largest concentration of capacity additions in the short history of U.S. LNG exports. During that time, operations started on the first trains of LNG export plants at Corpus Christi and Freeport in Texas, Cameron in Louisiana, and Elba Island in Georgia. Additionally, a second LNG train at Corpus Christi and a fifth LNG train at Sabine Pass, in Louisiana, went in-service during that period. Increased demand for feedgas from all operational facilities should continue through this winter as utilization rates are expected to remain high. Second LNG trains at both Cameron and Freeport are expected to start operations during the winter months. Recent reports estimate that the in-service date for Freeport’s second train will be in January 2020, while the in-service date for Cameron’s second train will be in February 2020.

Slide 9 – Southern California Gas Company Restrictions to Continue



For the past several winters, service over the Southern California Gas Company's system has been limited due to outages and repairs on pipeline segments. Staff has observed increased prices and price volatility in both the regional natural gas and electric power markets during periods of high demand in winter and summer.

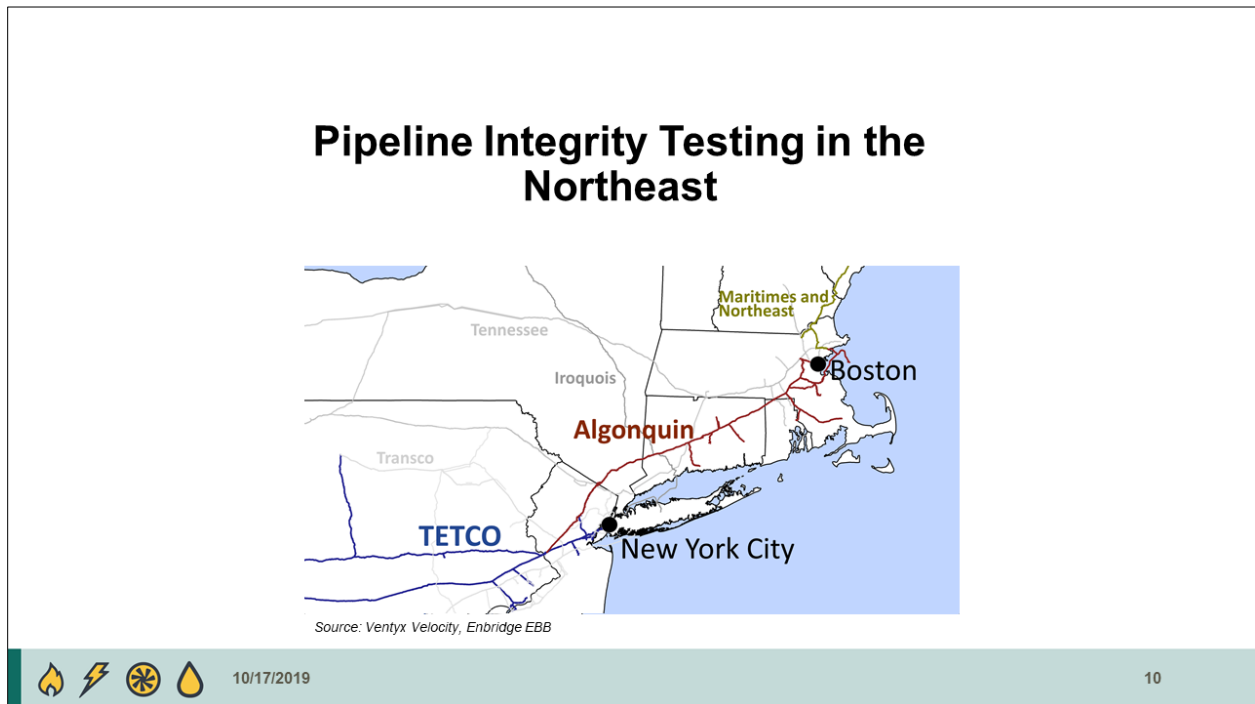
Southern California Gas Company continues to experience difficulty returning pipeline segments back to commercial operation due to their remote locations and permitting delays. For instance, 530 million cubic feet per day (MMcfd) of import capacity on Line 235-2 has been offline for the past two years. However, the repairs on Line 235-2 were recently completed on October 14, 2019, and 173 MMcfd of import capacity was returned while further inspections are conducted.

Southern California Gas Company's 540 MMcfd Line 4000 has also experienced outages. 270 MMcfd of Line 4000 capacity has been offline since last winter, and Southern California Gas Company has also said that it took the remaining 270 MMcfd on Line 4000 out of service starting September 19, 2019, with a preliminary return-to-service date of November 4, 2019. This additional outage will lengthen the time before the system's northern import path returns to full service. Thus, a total of 900 MMcfd of pipeline capacity in the company's system is currently unavailable, leaving 2.94 Bcfd of import capacity for the system.

Storage injections have slowed as a result of these outages, with the storage inventory 4 Bcf below last year's storage inventory at this time. The return of these pipeline

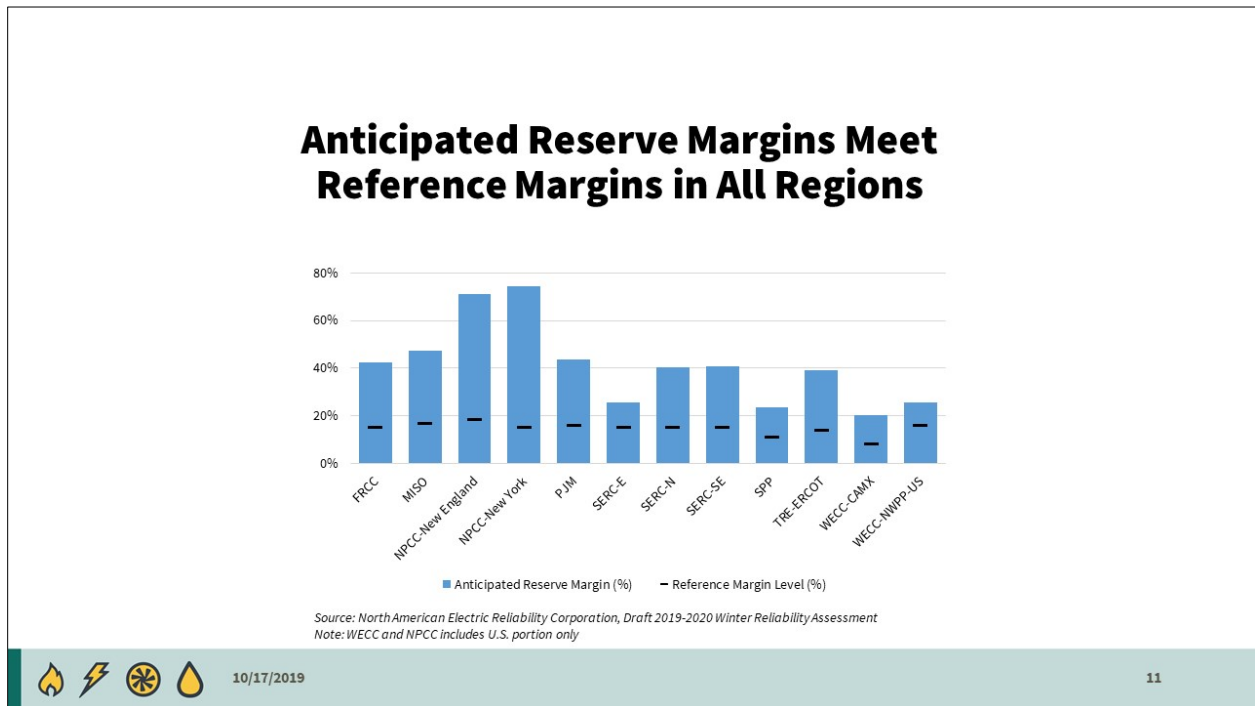
segments should better position the Southern California Gas Company system to deal with system stress and meet peak natural gas demand.

Slide 10 – Pipeline Integrity Testing in the Northeast



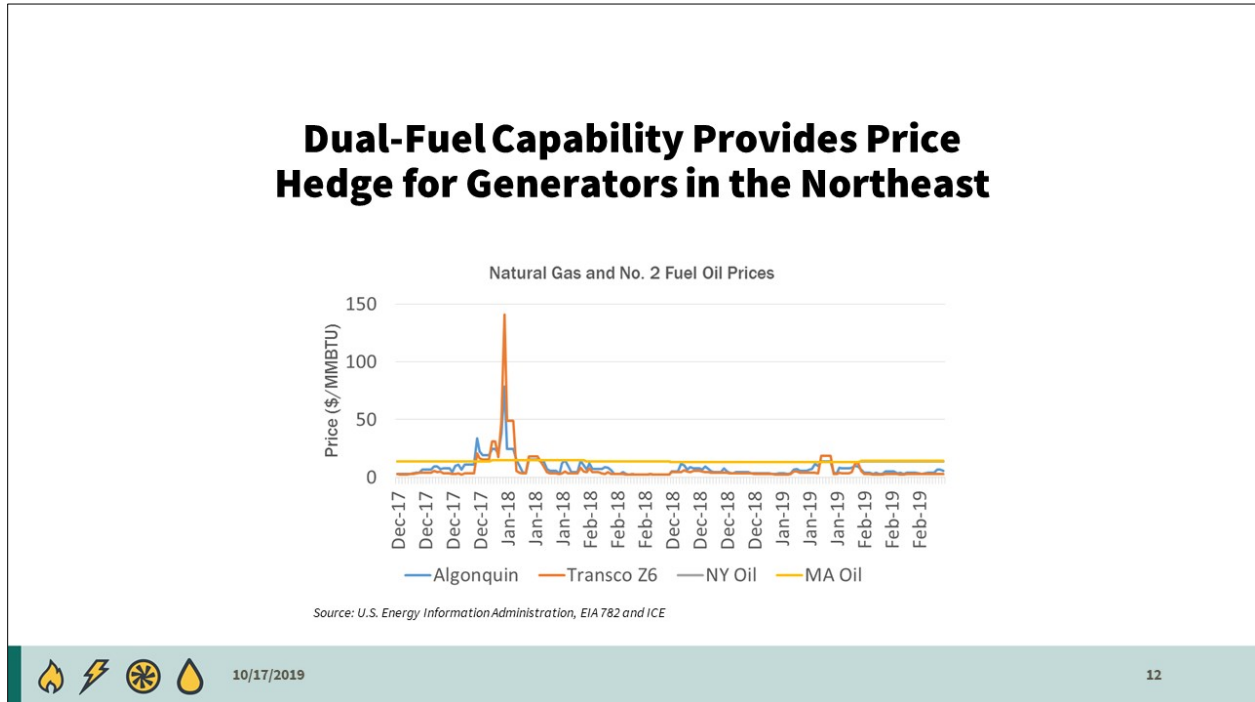
Algonquin Gas Transmission and Texas Eastern Transmission have announced capacity reductions to accommodate pipeline safety and integrity testing. The restrictions vary by both location and magnitude; however, the publicly available schedules posted by the companies suggest most restrictions should end by December. Staff will continue to monitor the timelines and any potential impacts on natural gas and electric markets.

Slide 11 - Anticipated Reserve Margins Meet Reference Margins in All Regions



In its preliminary 2019-2020 Winter Reliability Assessment, NERC estimates that reserve margins for all assessment areas will exceed their reference margin targets this winter. 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, can affect electric operations and must be monitored.

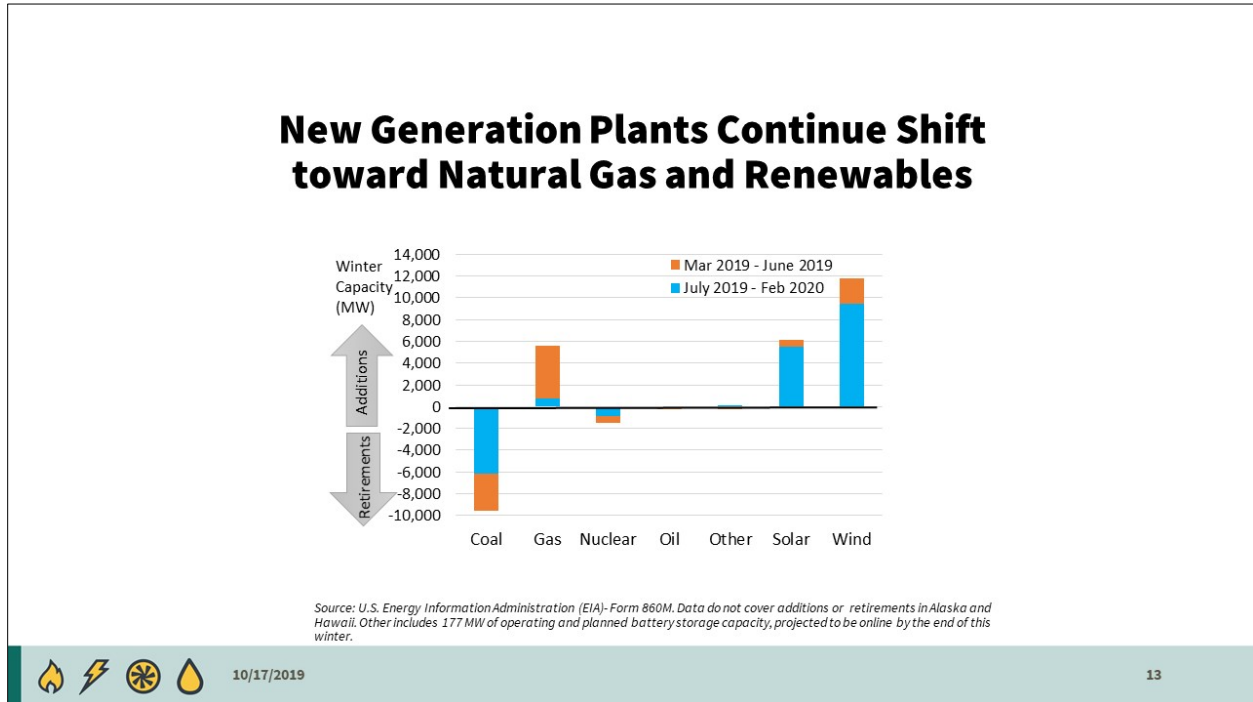
Slide 12 – Dual-fuel Capability Provides Price Hedge for Generators in the Northeast



In PJM, NYISO, and ISO New England, dual-fuel generators play an important role in moderating electricity prices during the winter by offering optionality to plant operators and dispatchers when the system is facing natural gas pipeline constraints. Typically, dual-fuel generators run on natural gas except when high heating demand creates natural gas scarcity, or when they are required to consume fuel oil to maintain electric reliability in anticipation of a sudden loss of natural gas supply.

Fuel oil can be price-competitive during periods when natural gas prices spike. For instance, in New England, there were 19 days during the 2017-2018 winter when the next-day natural gas price, adjusted for heat content, exceeded the price for No. 2 fuel oil. Milder weather during the 2018-2019 winter created only four days where the next-day natural gas price exceeded oil prices in New England.

Slide 13 –New Generation Plants Continue Shift toward Natural Gas and Renewables



The past three years have seen significant additions of natural gas-fired and renewable generation across RTO/ISO and non-RTO/ISO regions, offsetting retirements of coal capacity and nuclear capacity. This chart shows actual and planned capacity additions and retirements in the 48 contiguous states from March 2019 to February 2020, as reported to the EIA.

More than 3.4 GW of coal capacity retired from March 2019 to June 2019, and another 6.2 GW of coal capacity is expected to retire between July 2019 and February 2020. Approximately 680 MW of nuclear capacity retired from March 2019 to June 2019, and an additional 829 MW of nuclear capacity has announced plans to retire between July 2019 and February 2020.

From the end of last winter through the upcoming winter, 5.6 GW of natural gas capacity has been or will be added across the United States. The installed capacity of renewable resources continues to increase, including significant additions of wind in MISO and SPP and of solar photovoltaic in CAISO. In both cases, this follows capacity addition trends from the past three years.

Power Markets Meet Winter Weather with Market Enhancements

- Generator outages have jeopardized organized markets' ability to maintain sufficient reserves in some areas during winter weather.
- MISO is working to expand demand response availability and reduce generator outages.
- PJM and ISO New England's performance requirements for capacity resources are in full implementation.
- ISO New England continues to develop incentives for fuel assurance.



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In recent winter seasons, generator outages during extreme cold weather have led to emergency events and stressed system conditions. Events like the 2014 Polar Vortex have highlighted the need to ensure resource availability to meet winter peak demand. Instances of generator outages and fuel unavailability became issues that led to new market and regulatory solutions, some of which continue to be developed. A brief summary of the winter reliability initiatives in MISO, PJM, and ISO New England follows.

In MISO, a cold weather event in January 2018 caused emergency conditions in MISO South and disruption in neighboring regions. FERC and NERC staff published a joint report on the event in July 2019. The loss of generators due to the cold weather itself was the major cause of the event. The report recommends—through market rules, Reliability Standards, and outreach—improvements in the winterization of generators and in the assessments of the capabilities of generators, transmission lines, and gas pipelines during cold weather. MISO and SPP have revised their coordination protocol to better manage such events. MISO's Resource Availability and Need (RAN) initiative changed existing rules—some effective for the 2019-20 capacity auction and some for the 2020-21 auction—requiring testing of demand response resources, making demand response more available in non-summer months, and improving the timing of generator outages.

PJM and ISO New England have implemented performance requirements designed to incentivize capacity resources to perform during critical load periods throughout the year. Specifically, in 2014, the Commission approved ISO New England's Pay-for-

Performance capacity market redesign which ties capacity payments to resource performance during stressed system conditions. Similarly, in 2015, the Commission approved PJM's Capacity Performance Program, which imposes penalties and bonuses during capacity critical periods.

In addition, ISO New England has been working actively with its stakeholders to develop market-based fuel security enhancements. In an order issued in July of 2018, the Commission directed ISO New England to develop short-term and long-term market-based mechanisms to ensure regional fuel security. In response, ISO New England proposed an interim solution for the 2023-2024 and 2024-2025 winter seasons in the form of the Inventoried Energy Program, providing a compensation mechanism for generators beginning in the Capacity Commitment Period starting June 2023. That proposal became effective May 28, 2019. ISO New England is still working to develop long-term market-based mechanisms, which are expected to be filed in April 2020.

Slide 15 – 2019-2020 Winter Energy Market Assessment

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This concludes staff's prepared comments. A copy of this presentation will be posted on the Commission's website. The online version of this report contains additional information on pipeline additions, pipeline restrictions in Southern California and the Northeast, dual-fuel capability in the Northeast, and winter reliability initiatives. We are available to answer any questions you may have.