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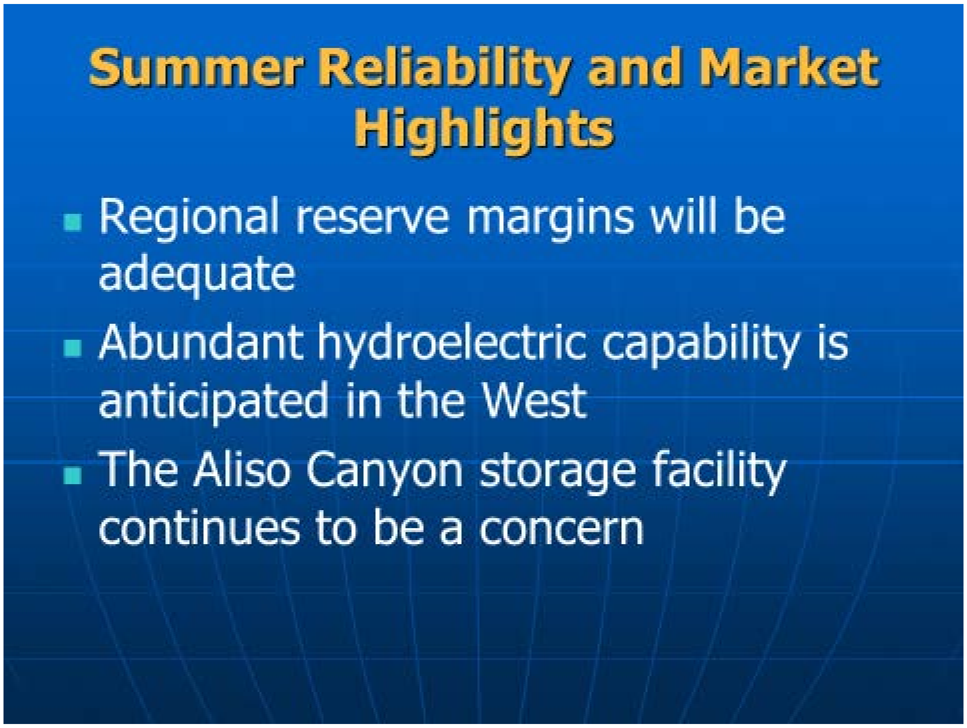


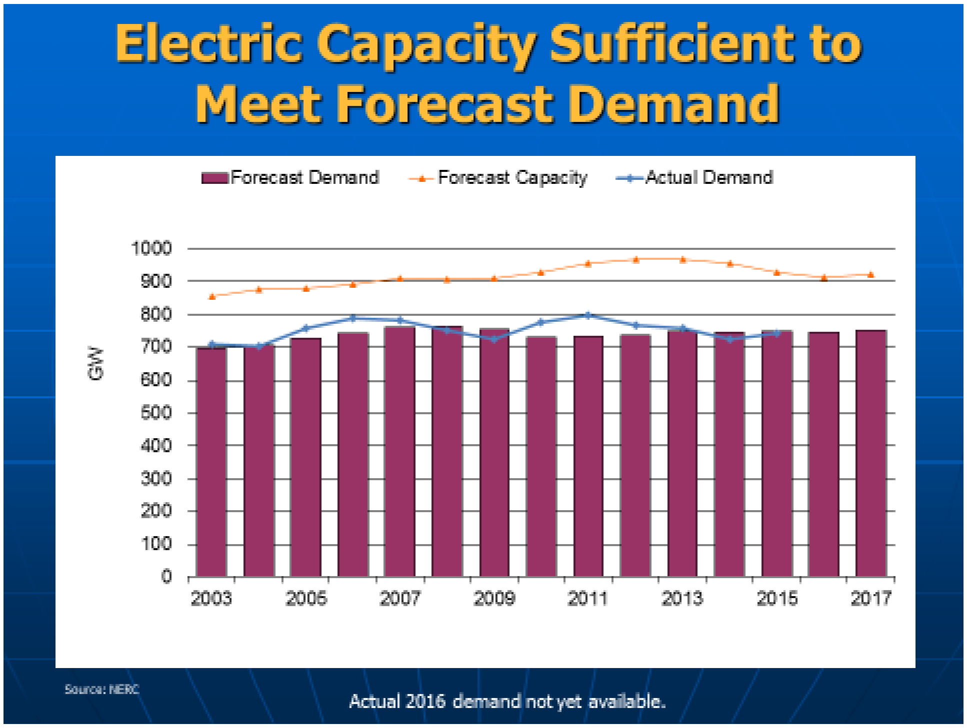
The Office of Electric Reliability and the Office of Enforcement are pleased to present the 2017 Summer Seasonal Assessment. This is staff's annual opportunity to share our summer outlook on the electricity and natural gas markets and reliability matters to better inform the Commission's understanding of current and future trends.

NERC anticipates that power resources will be able to meet the reference margin levels in most Assessment Areas this summer. The anticipated reserve margin in ISO-NE is projected to be at 14.88 percent, which is slightly below their Reference Margin Level of 15.1 percent.

Snowpack in the West, measured by snow water equivalents, reached levels well above average. The snow water equivalent in the West, particularly in California, had been tracking near the record-high levels that were set in 1982-1983. However, the statewide levels have started to shift downwards since February and are now at approximately 65 percent of the April 1st average. Given the abundance of accumulated snow water, high hydro generation is likely to continue into the early part of the summer, which could be leveraged to reduce natural gas constraints in Southern California.

FERC and other agencies continue to monitor the situation at the Aliso Canyon natural gas storage facility. This year marks the second summer that Aliso Canyon will be restricted. While the restrictions on Aliso Canyon did not pose any major issues during the 2016 summer, the limited availability of the Aliso Canyon natural gas storage facility in Southern California may pose a risk to gas and electric reliability this summer if hotter than normal weather conditions and unplanned gas pipeline outages materialize. This resource had been used to help maintain natural gas pipeline pressures, which are necessary for supporting gas-fired generation during swings in power plant demand. Currently, Aliso Canyon has less working gas than last summer because of withdrawals this past January, and current physical and regulatory limitations may affect the amount of stored gas that could be used this summer. Finally, the State of California has imposed new restrictions on all natural gas storage facilities, requiring facilities to inject and withdraw only through the well pipe, not through the casings, as has been done in the past. These limitations will reduce the rate at which injections and withdrawals can occur.

SLIDE 3 Electric Capacity Sufficient to Meet Forecast Demand

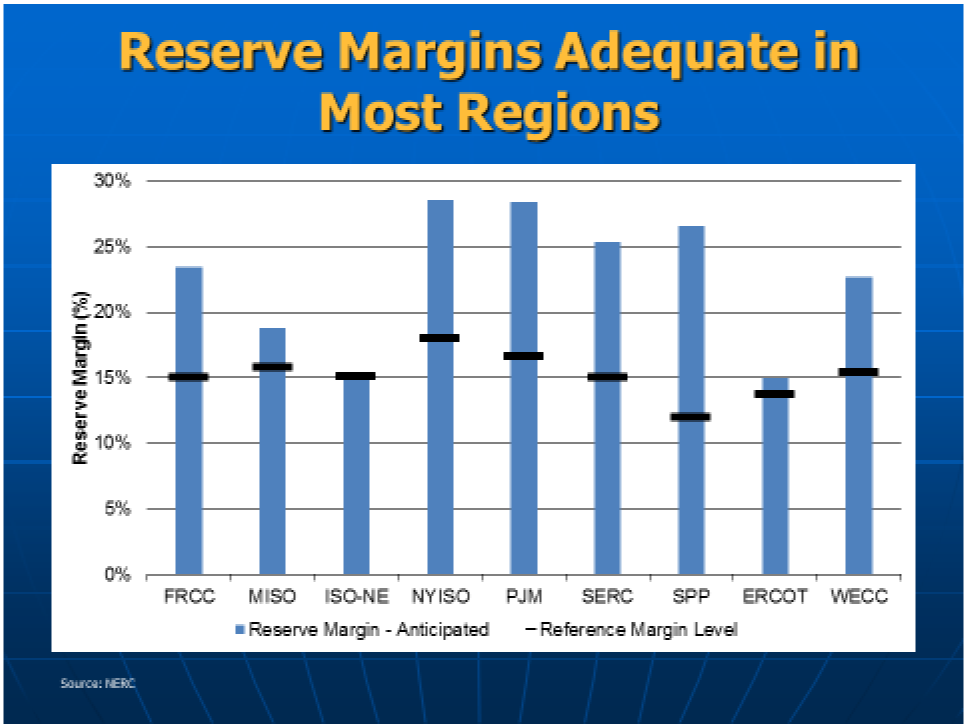


Data from NERC's Summer Assessment indicates that the total U.S. load forecast, when weather-adjusted, will be approximately 1.1 percent higher than it was last summer. Meanwhile, the total generating capacity in the U.S. has increased by approximately 1.0 percent since last summer and over 20 GW of new generating capacity is expected to be installed nationwide through the summer. A majority of the capacity additions will come from renewable resources such as wind and solar.

Approximately 10 GW of generating capacity has retired since May 2016, including approximately 4.0 GW of coal-fired capacity and 6.0 GW of natural gas-fired capacity. The 1,509 MW Moss Landing Power Plant in California, along with the 1,087 MW Willow Glen and 847 MW Michoud plants in Louisiana were the largest natural gas-fired facilities to retire over the past year. The 478 MW Fort Calhoun Nuclear Generating Station in Nebraska retired in October 2016.

Additionally, the Brayton Point coal- and oil-fired generators in ISO-NE were retired in May, representing a loss of approximately 1,500 MW of capacity.

SLIDE 4 Reserve Margins Adequate in Most Regions

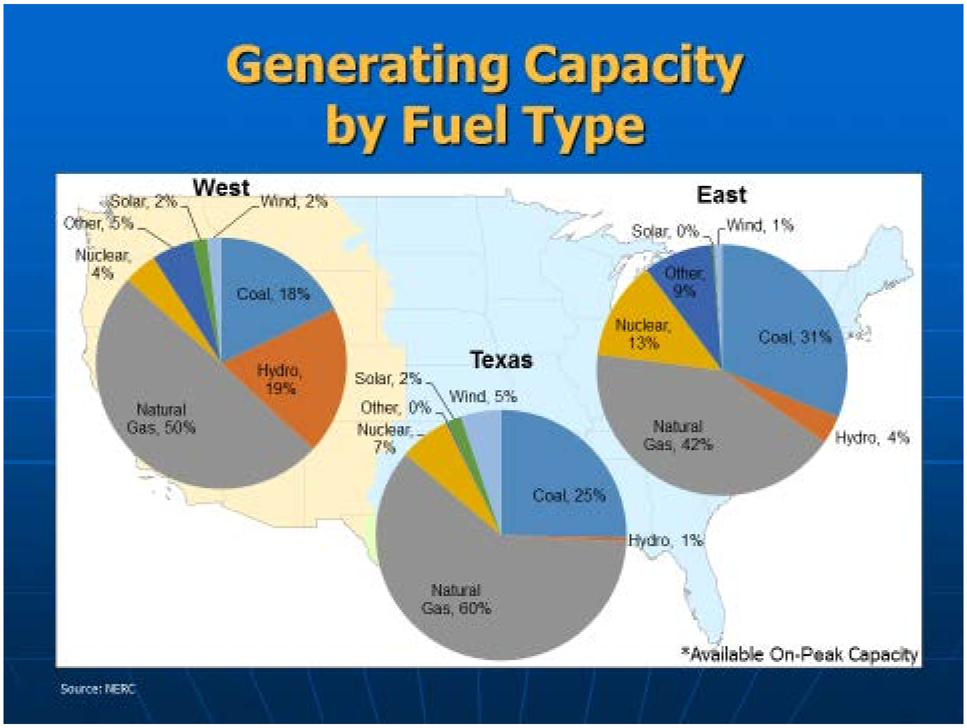


NERC's Summer Assessment data indicates that planning reserve margins for most assessment areas are anticipated to be adequate this summer. The columns shown on this chart display the anticipated reserve margins for various markets and regions, while the black bars indicate the Reference Margins.

The anticipated reserve margin in ERCOT continues to be tight when compared to the other regions, although ERCOT expects to have sufficient generating capacity to serve peak demand during this upcoming summer season. However, the Lower Rio Grande Valley, Laredo, and West Texas are a few areas in ERCOT that risk experiencing localized reliability issues due to strong load growth, transmission constraints, and limited generation resources.

If forecasted peak summer conditions in ISO-NE occur, tighter supply margins could develop as approximately 700 MW of new resources have been delayed and may not be placed into commission this season as expected. ISO-NE may be required to rely on additional imports from neighboring regions as well as implementing operating procedures to maintain reliability during possible periods of supply deficiencies.

SLIDE 5 Generating Capacity by Fuel Type



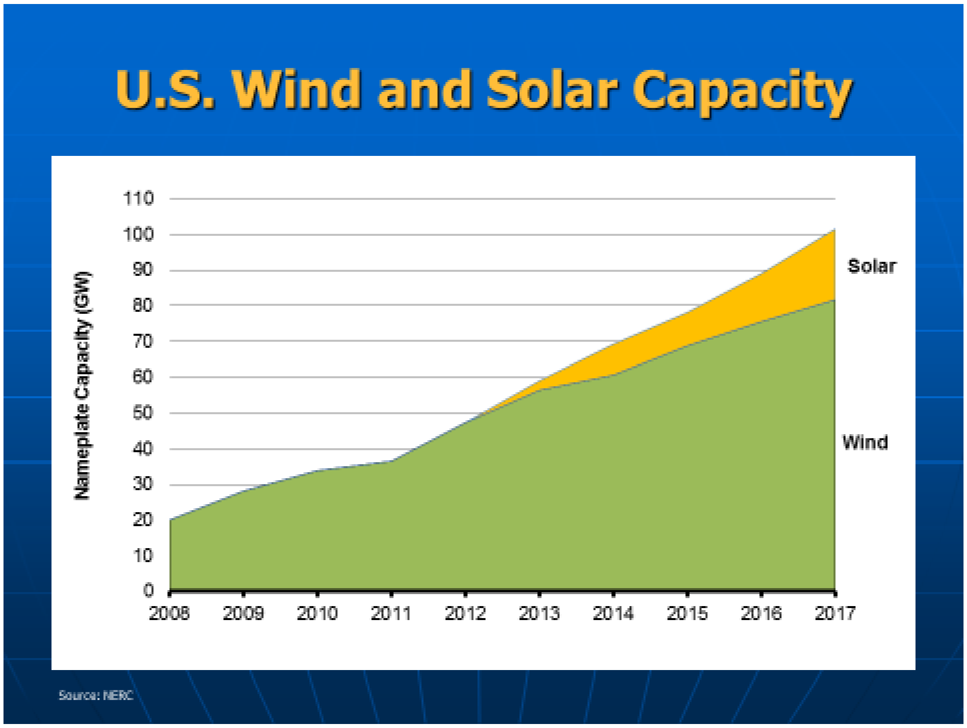
This graphic shows a breakdown of this summer's on-peak generating capacity by primary fuel type for power generation across the Western, Texas, and Eastern Interconnections.

The Western Interconnection expects to add approximately 6 GW to the system: 3 GW of solar photovoltaic and 3 GW of wind capacity to the system.

In Texas, approximately 1 GW of renewable capacity is expected to be added to the region, with most of the capacity coming from wind installations.

Finally, the Eastern Interconnection expects to add approximately 13 GW of additional capacity: with 2 GW of natural gas-fired capacity, 6 GW of solar photovoltaic capacity, and 5 GW of wind capacity.

SLIDE 6 U.S. Wind and Solar Capacity



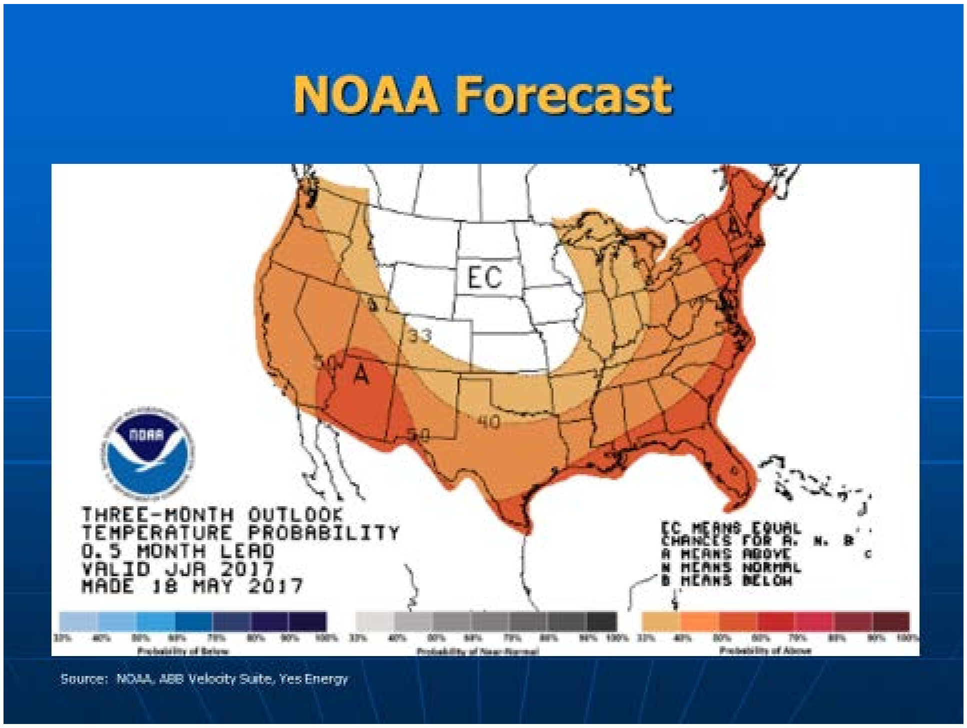
NERC anticipates that the total installed nameplate wind capacity this summer will be 82 GW, approximately 8 percent higher than in 2016. NERC also anticipates that about 6 GW of new utility-scale solar capacity will come on-line this summer.

The growing importance of renewable resources has continued in recent years, as both wind and solar capacity continue to expand. Grid operators are pursuing operational solutions to better integrate wind and solar resources as part of their operational and planning activities.

Notably, the Blue Cut Fire event in August 2016 illustrates why grid operators must work to integrate and minimize risks posed by new technologies such as increased penetration of solar units with inverters. As a result of the fire, multiple transmission line faults occurred across Southern California Edison's bulk electric system and resulted in a simultaneous disconnect of approximately 1,200 MW of inverter-connected generation. In response to the event, NERC, in collaboration with inverter equipment manufacturers and other interested parties, formed a group to investigate the event and to develop solutions to avoid similar future occurrences. This group concluded in a June 2017 NERC report that the loss of inverter power injection was primarily due to a perceived low-frequency condition and low-voltage blocking of the inverters. Through this effort, NERC also recommended long-term actions to allow the solar photovoltaic generation fleet to ride-through similar future events and in the near term will issue a NERC alert to raise awareness prior to the summer season to minimize the potential for abrupt disconnection of inverter-connected generation. These issues have also been the focus of recent Commission action on voltage requirements and frequency ride-through.

Staff will continue to monitor how the organized markets are managing the growing impacts of renewable generation this summer and how these challenges are being addressed.

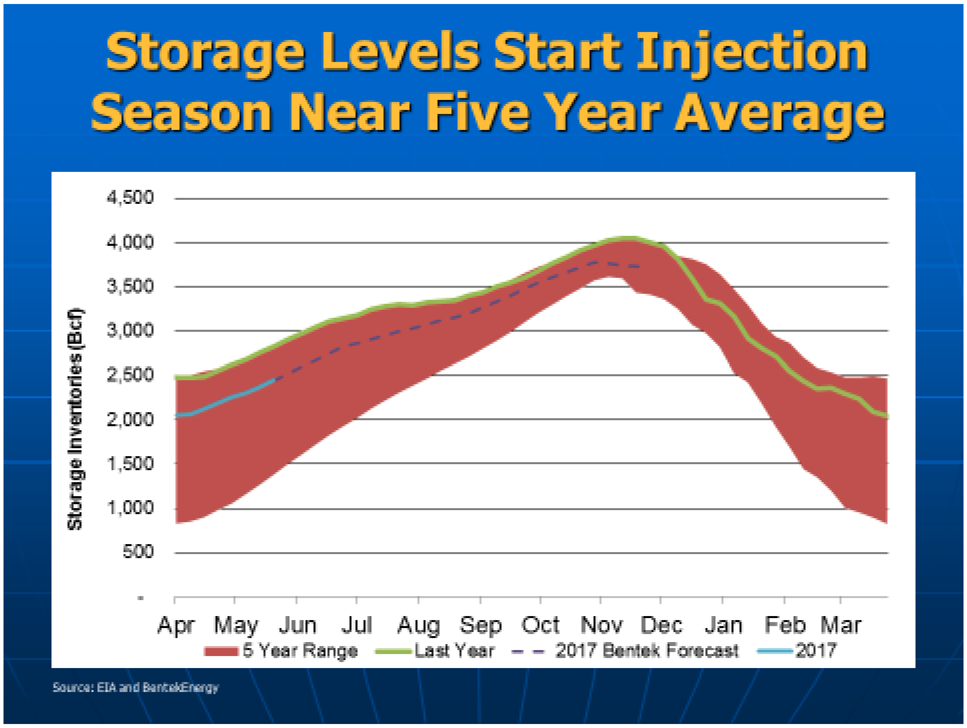
SLIDE 7 Temperature Forecast and Market Prices



The National Oceanic Atmospheric Administration (NOAA) forecasts above normal temperatures for most of the continental U.S. in June, July, and August. NOAA's forecast shows that nearly all regions are likely to see above normal temperatures, with the strongest possibility for above normal temperatures in the North Atlantic, Southeast, and Gulf of Mexico regions. Much of the Central, Great Lakes, and Western regions are also likely to see above normal temperatures. At this time, it is unclear whether the northern part of the Central region is likely to see normal, below average, or above average temperature levels.

Warmer temperatures require increased power generation to meet increased demand for home and office cooling. In 2016, for example, the hottest average days correspond to above-average locational electricity prices. However, increased demand due to temperature is only one factor that could affect market prices this summer.

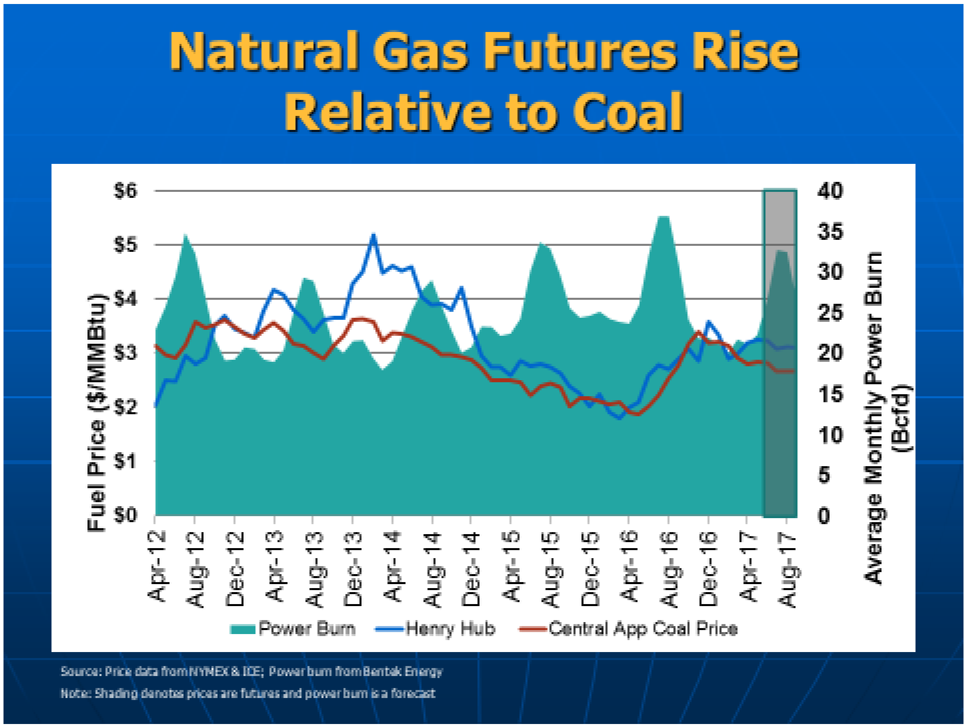
SLIDE 8 Natural Gas Storage and Production



Despite entering this past winter with record high storage levels of 4,047 Bcf, several factors increased the demand for storage withdrawals. A 3 percent year-over-year drop in natural gas production and relatively normal December temperatures created a tight natural gas market at the start of the 2016 – 2017 winter. Storage withdrawals totaled 1,998 Bcf during the most recent withdrawal season, 30 percent more than last year's withdrawal during the mild 2015 – 2016 winter. As a result, storage levels began the injection season this year at approximately 2,092 Bcf, or 401 Bcf below the levels at the start of last year's season. The 2016 – 2017 winter temperatures were overall significantly warmer than normal, as total heating degree days (HDDs) were 15 percent below the 30 year average. Specifically, February was 10 degrees Fahrenheit above the average monthly temperature over the past 30 years. During the week of February 24, 2017, the warm weather fostered the earliest net natural gas injection on record, posting a 7 Bcf net storage injection.

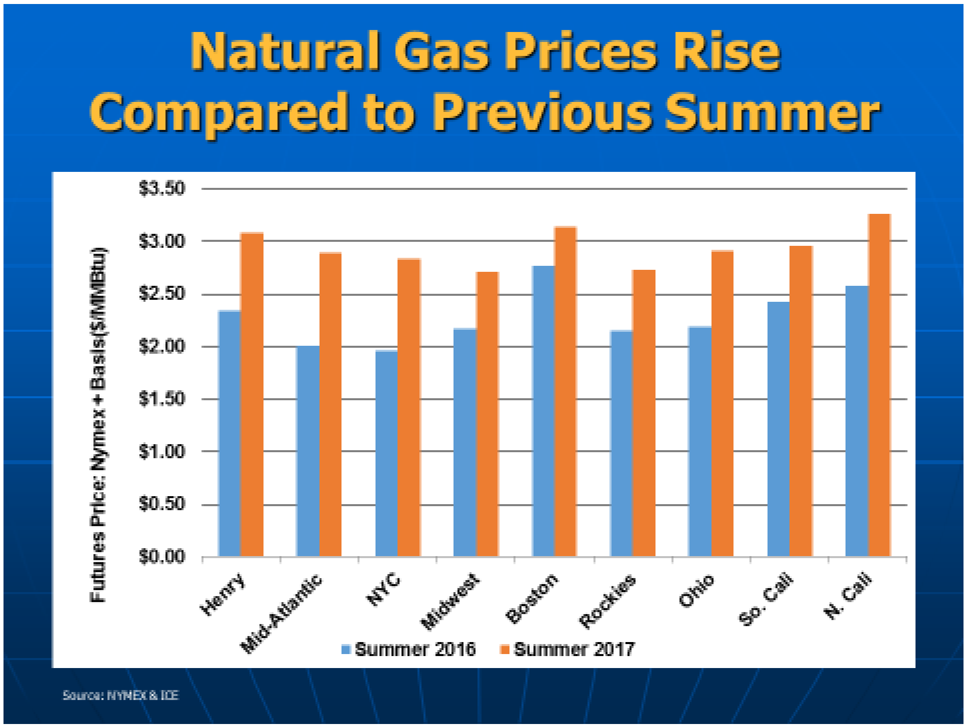
This summer's natural gas injections into storage will depend in part on countervailing forces in natural gas supply and demand fundamentals. Current natural gas futures show prices at the Henry Hub increasing this summer by $0.02/MMBtu to $3.09/MMBtu, indicating that market participants expect demand increases to more than offset increases in supply. A 125 percent year over year increase in the number of active oil and natural gas drilling rigs should strengthen natural gas supply during the 2017 injection season. However, much of the drilling activity is in oil-rich plays with associated gas production which exposes much of this future natural gas production to oil prices instead of natural gas prices. There are currently 907 active drilling rigs in the U.S., up 504 rigs or 125 percent from last year. Of these, 722 are targeting oil rich plays which may contain associated natural gas and 185 are targeting natural gas rich plays. However, temperatures, LNG exports, and exports to Mexico all increase competition for natural gas that may otherwise be injected into storage. Exports to Mexico have increased 306 percent from a 912 MMcfd average in 2010 to 3,707 MMcfd in 2016. Bentek Energy estimates storage volumes will end the 2017 injection season at 3,775 Bcf, 272 Bcf below last year's record level 4,047 Bcf, and closer to the five year average of 3,871 Bcf.

SLIDE 9 Natural Gas Prices Expected to Rise Relative to Coal



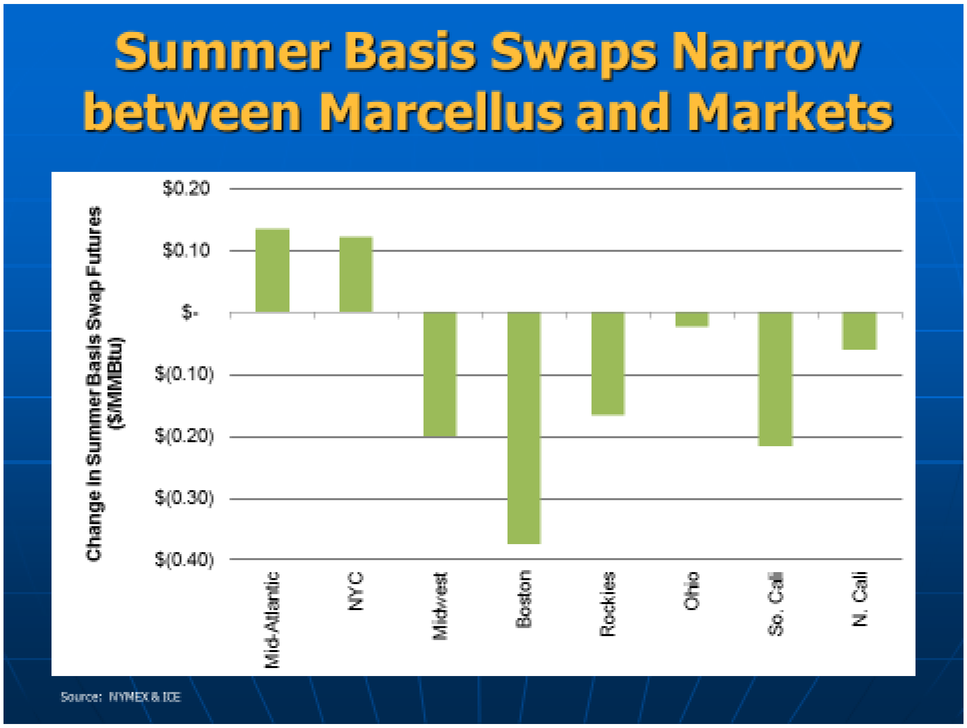
Electricity production from natural gas fired generation surpassed that of coal fired generation in 2016 for the first time ever on an annual basis, in part due to relatively low natural gas prices. However, both natural gas and coal prices have increased since bottoming out at a five-year low during 2016. As of May 2017, average monthly natural gas spot prices increased $1.44/MMBtu from the March 2016 five-year low of $1.81/MMBtu to $3.25/MMBtu. Although coal prices have increased from their May 2016 five-year low of $1.87/MMBtu, they have not increased to the same extent as natural gas prices. Since May 2016, coal prices have increased by $0.97/MMBtu to $2.84/MMBtu. The price premium for natural gas relative to coal persists in the current summer futures contracts for both commodities. The current $0.42/MMBtu natural gas price premium to coal is $0.32/MMBtu higher than the $0.10/MMBtu premium during 2016, and as of May 31st, 2017 this summer's futures contracts of natural gas were trading at a $0.43/MMBtu premium to coal.

SLIDE 10 Natural Gas Prices Rise Compared to Previous Summer



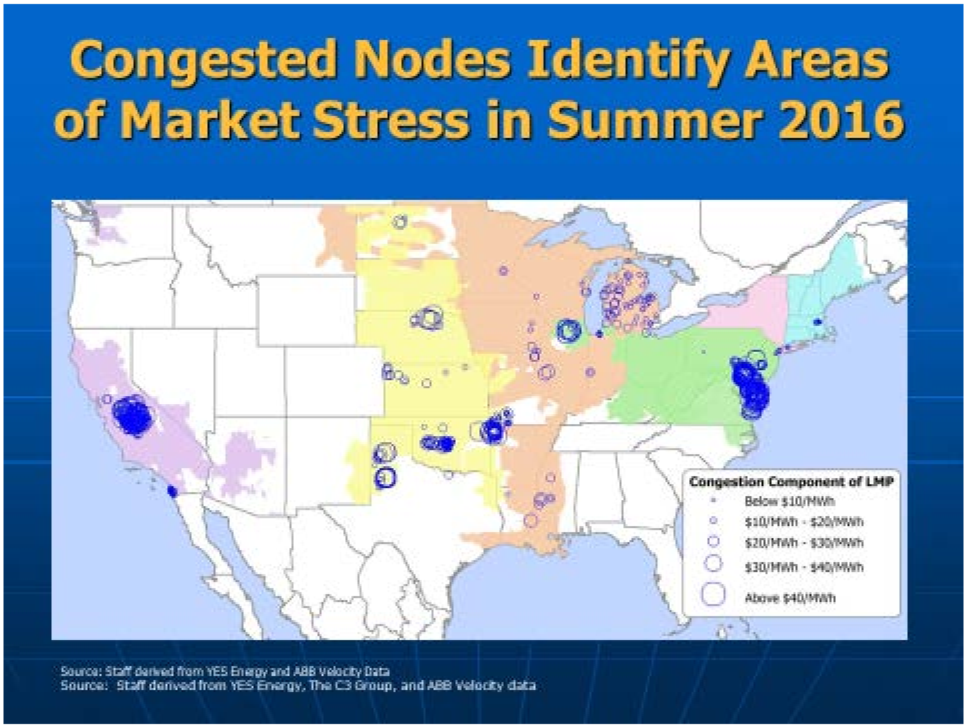
Lower storage inventories, a 1.7 percent year over year decrease in natural gas production rates, and a warmer than average forecasted summer have all contributed to increased gas futures prices in absolute terms across the country during summer 2017 relative to the previous summer. Summer over summer futures contract increases ranged from a $0.38/MMBtu increase at Boston to a $0.88/MMBtu increase in Mid-Atlantic prices. Although there has been a significant annual increase in futures prices, the price levels are still substantially below 2014 summer prices which exceeded $4.00/MMBtu at Henry Hub.

SLIDE 11 Summer Basis Swaps Narrow between Marcellus and Markets



The chart above shows the summer over summer change in the value of basis swap futures prices at major hubs. New York basis has increased from -$0.37/MMBtu in summer 2016 to -$0.25/MMBtu in summer 2017, a $0.12/MMBtu increase. Meanwhile, Boston basis has decreased $0.37/MMBtu, from $0.43/MMBtu in summer 2016 to $0.06/MMBtu in summer 2017. The changes relative to the previous summer reflect a narrowing of the basis between Marcellus and Utica supply hubs and market hubs such as Boston and Chicago, which are increasingly supplied by Marcellus and Utica natural gas. The narrowing basis is a price signal that the transportation costs between these points has decreased overall, which may reflect increased transportation capacity from production areas in the Marcellus/Utica and corresponding market destinations.

SLIDE 12 Congested Nodes from Summer 2016



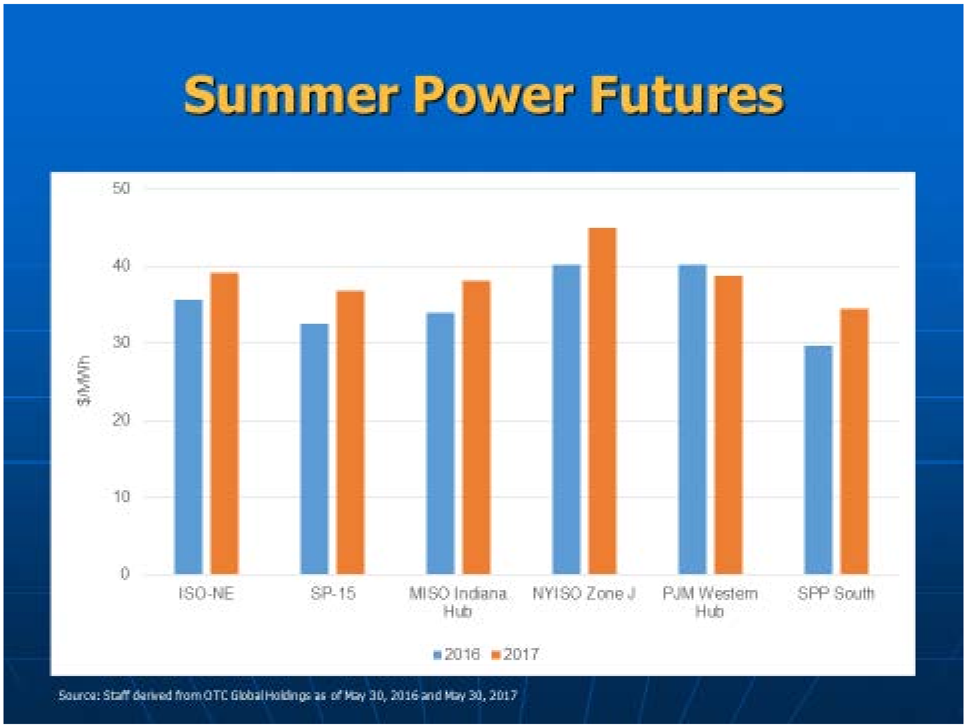
The map above identifies nodes that had elevated congestion prices last summer and did not have elevated prices the rest of the year. The larger "bubbles" correspond with highest prices.

During the summer, grid congestion can be a significant issue, as system operators focus on moving power from areas of greater supply to those of greater demand. These situations can occur for a number of reasons, such as extreme weather; transmission or generator outages; seasonal load changes for cooling and other needs; grid maintenance; and other factors.

Staff analyzed 2016 prices to identify nodes, or specific grid locations, which experienced higher congestion pricing during summer 2016 than during the other three seasons of the year. To identify specific locations of interest, staff analyzed nodal price extremes and volatility, relative to the broader RTO/ISO market. These high congestion prices indicate where it is relatively more difficult to deliver power or where additional generation is particularly valuable for relieving congestion. Last summer, this occurred in various locations including Maryland and Northern Illinois in PJM, Central and Southern California in CAISO, and near the seams between RTOs. Staff will continue to analyze congestion in RTO/ISO markets during the summer months of 2017.

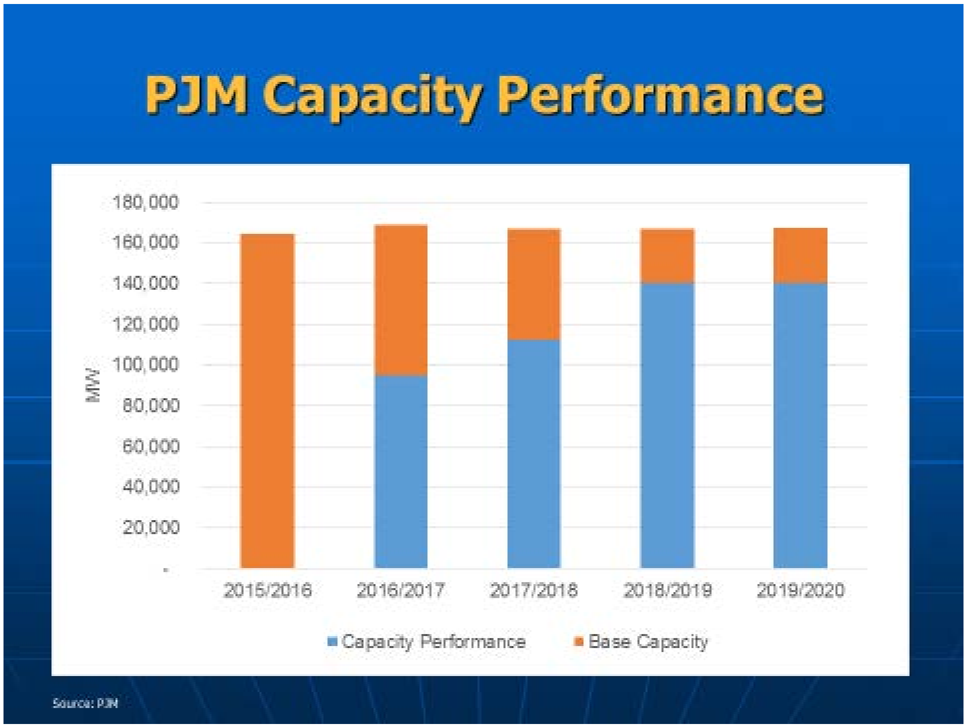
Since last summer, more than $5 billion of transmission upgrades entered operation in the six RTO/ISO markets. These infrastructure investments may help relieve grid congestion and could reduce some of the high price volatility in summer 2017.

SLIDE 13 Summer Power Futures



As depicted in the figure above, average monthly on-peak futures prices since 2016 have risen 15 percent at SPP South, 11 percent at MISO Indiana Hub, 11 percent at SP-15 in California, 9 percent at ISO-NE internal hub, and 11 percent in NYISO Zone J. Futures prices at PJM's Western hub have decreased 3 percent.

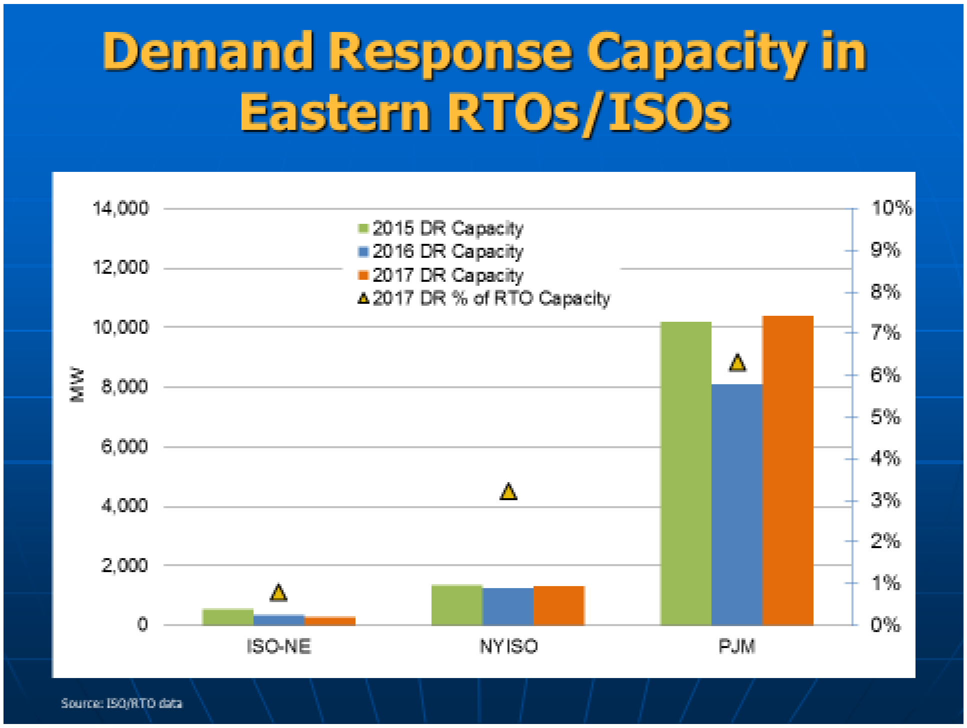
SLIDE 14 Capacity Performance



June 1, 2017 marks the start of PJM's second year transitioning toward the full implementation of its Capacity Performance program. These rules set performance requirements on capacity resources during system emergencies and impose substantial penalties for non-performance. Additionally, generators that exceed performance commitments during these events are entitled to funds collected from generators that underperform and fail to meet their power supply obligations.

The stronger incentives were needed to encourage investment for better generation performance. The RTO noted that the rapid and significant shift from coal to natural gas-fired generation has driven electricity prices sharply lower and inhibited needed investments in plant upgrades and modernization, highlighting the importance of these reliability standards.

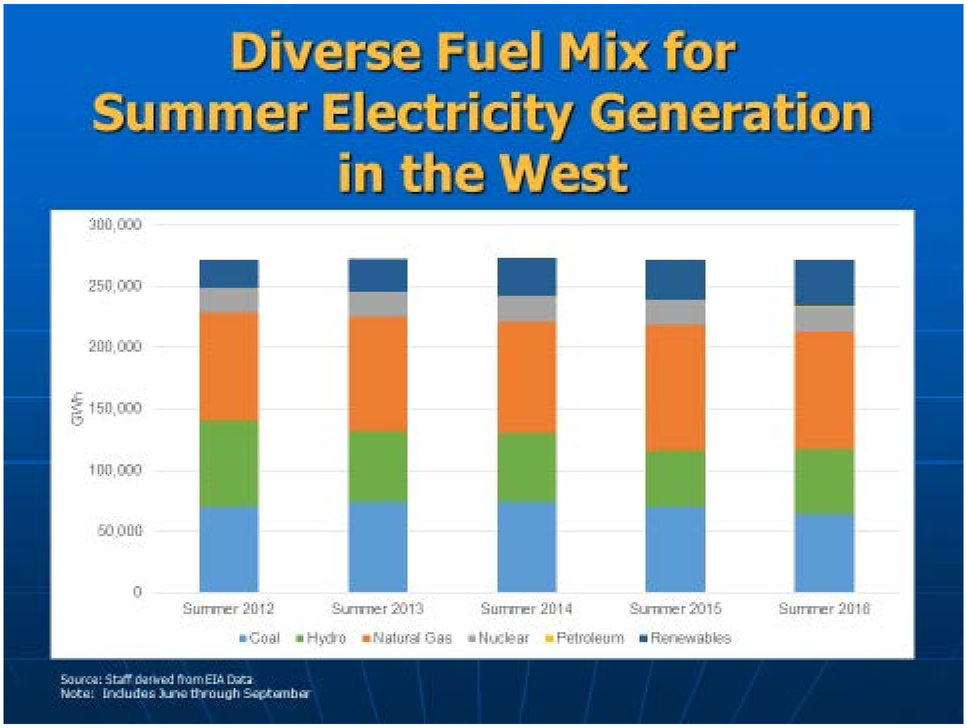
SLIDE 15 Demand Response



Demand response is an important resource that is used to maintain reliability during periods of market stress, such as peak summer days or during system emergencies. As shown in this chart, the amount of cleared demand response capacity in the three northeast RTOs has shifted since last summer. This has been most notable in PJM, where demand response has increased by 2,256 MW, or 28 percent from last year, and now represents 6.3 percent of the RTO's total capacity. In comparison, the amounts of demand response in NYISO and ISO-NE are much lower than in PJM, in terms of both absolute megawatts and percentage of capacity. This gap is continuing to expand as the rates of participation in NYISO and ISO-NE have continued to decline for 2017. This chart reflects the amount of demand response that cleared and received a capacity supply obligation in 2015 through 2017. FERC staff's annual Assessment of Demand Response and Advanced Metering issued in December 2016 reflected a notably higher number of 2,696 MW of demand response in ISO-NE — a higher number that includes energy efficiency and all enrolled demand response.

It is also important to note that, this summer, demand response providers in PJM will be subject to the Capacity Performance obligations mentioned on Slide 14 and that similar rules will be enacted in ISO-NE next year. Lastly, there were no activations of these emergency resources last summer in PJM and ISO-NE. However, the NYISO relied upon demand response statewide on August 12th, when the system operator projected reserve shortages due to high demand. NYISO also activated a voluntary New York City program on four other days to address local system reliability problems at the request of its Transmission Owners.

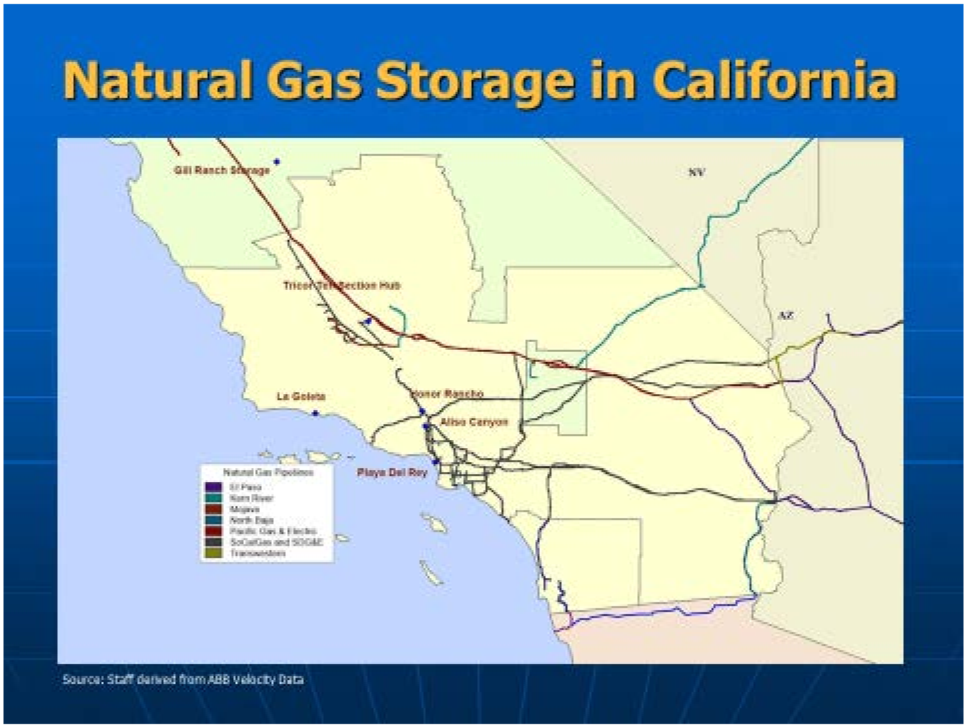
SLIDE 16 Diverse Fuel Mix for Summer Electricity Generation in the West



As shown in the figure above, the mix of generation in the West comes from a diverse set of resource types during the summer months. As mentioned earlier on Slide 2, the snow water equivalent in the West has been high this year, providing relatively high hydro generation in the spring and early summer. The combination of strong hydroelectric generation, coupled with high spring renewable output, led to warnings from CAISO that up to 8,000 MW of renewable generation could be curtailed to maintain reliability during the spring. Over the course of the summer, hydro generation typically drops by June, and is replaced with natural gas-fired generation and, to a lesser extent, coal-fired generation. However, because of this year's abundant Northwest and California snowpack levels, it is possible that high hydro generation could extend until July, if temperatures remain moderate in the early summer.

The Energy Imbalance Market, or EIM, helps to manage energy imbalances and integrate diverse resource types across a wide geographic area. In this regard, the EIM has provided an outlet for CAISO to sell renewable energy that it cannot use on its own system. For instance, in recent months, CAISO has sold into the EIM during the middle of the day when solar output peaks, often at negative prices. During summer months, this pattern may change as CAISO uses more of its renewable generation to meet its own summer load.

SLIDE 17 Natural Gas Storage in California



The summer season is when electric generation demand for natural gas typically peaks. Although overall natural gas demand is lower in the summer, generator demand for natural gas requires natural gas pipeline operators to balance their pressures as generator demand surges and subsides to serve load and balance rapid daily ramps and intra-hour fluctuations, which result from unexpected swings in renewable generation and load, unexpected generator and transmission outages, and other factors. California state regulators continue to review whether Aliso Canyon should resume operations, and if so, at what levels. Consequently, Aliso Canyon is not expected to be available this summer except in cases of emergency. Further, Aliso Canyon has 14.77 Bcf of working gas this summer, slightly less working gas than last summer. This reduction may affect whether the state would use the remaining inventory to aid electric generation, if necessary this summer, since it may need it to support winter demand.

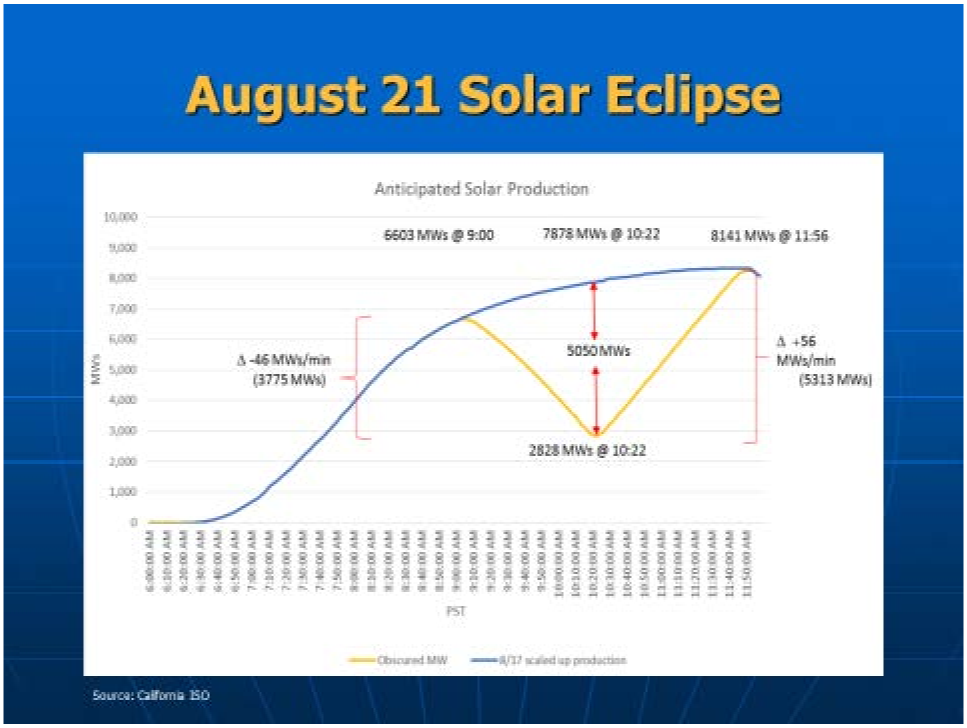
As mentioned earlier, California state regulators have required natural gas storage fields to limit their injections and withdrawals to the pipes, and not use the casings. This will further reduce the rate at which gas companies can inject and withdraw, reducing their ability to quickly inject gas from storage into their systems to support pressure.

However, the construction of additional electric transmission into Southern California will help ease the stress on natural gas-fired generation in the region and the associated natural gas systems. SoCal Edison has completed construction of the 173 mile Tehachapi Renewable Transmission Project, which will bring non-local generation into Southern California.

Finally, other measures implemented to address the loss of Aliso Canyon will remain in place, including CAISO's ability to implement a natural gas constraint and the ability of the natural gas pipelines to require that shippers balance their supplies. Staff also expects that the Los Angeles Department of

Water and Power will continue to have dual fuel capability at most of its LA Basin gas units, which allow these units to continue generating in the event of natural gas curtailments.

SLIDE 18 Anticipated Effects on CAISO of the August 21 Solar Eclipse



On August 21st of this year, the California ISO will be observing the effects of the first solar eclipse to occur since the region added significant amounts of combined utility scale and rooftop solar capacity. This is anticipated to affect system operations, as up to 5,000 MW of output from these resources declines over an 80 minute period, then subsequently returns back to normal. This drop is equal to more than 10 percent of a typical summer day's peak load and could result in rapid ramping conditions and other challenges. In addition to California, NERC has identified a similar concern for utility operations in North Carolina because of the significant installed solar capacity in the state.

A similar event occurred in Germany two years ago, causing operators to rely upon neighboring areas to provide capacity and reserves. In anticipation of this event, both NERC and the CAISO have undertaken studies to examine the potential effects and develop mitigating actions to address them. Staff will be monitoring the anticipated market and reliability effects of the eclipse. These include ramping and balancing concerns on the bulk power system, procuring additional non-photovoltaic generation during the period of obscuration, potential negative and positive price movements, reserve pricing conditions and a likelihood that there will be greater than normal transactions within the EIM.