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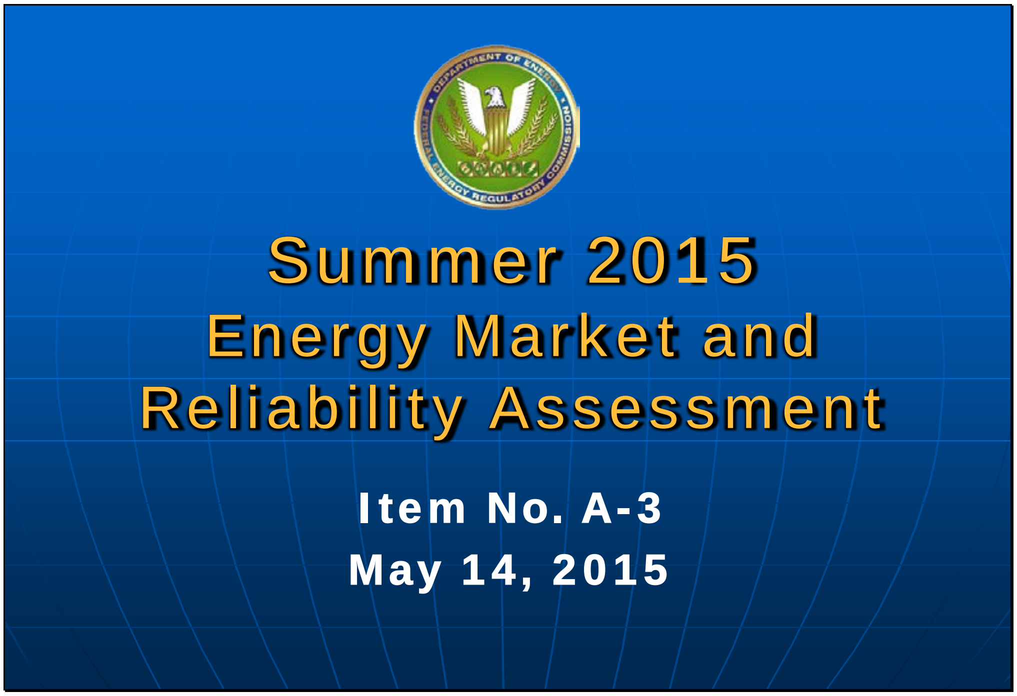

Good morning Mr. Chairman and Commissioners.

The Office of Electric Reliability and the Office of Enforcement are pleased to present the 2015 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.

Please note that some information in this presentation comes from NERC's 2015 Summer Reliability Assessment which will be considered for approval by the Board of Trustees this afternoon and still is subject to change.

Slide 2

Reliability and Market Outlook Highlights

- Plentiful fuel supplies with low natural gas prices and recovering coal stockpiles
- The economy has continued to recover and contributed to increased industrial demand, yet reserve margins remain adequate
- California drought will limit hydroelectric output

These bullets reflect the key takeaways from today’s presentation.

Market conditions going into the summer will reflect the continued low natural gas prices that have resulted from robust production, as well as the recovery of fuel stockpiles at coal-fired power plants.

Regional electric system reserve margins are adequate, despite modest growth in load, which is primarily attributable to increased industrial activity.

The historic drought in California and the West has entered its fourth year and is an area of particular concern. This may lead to elevated energy prices; however, both the NERC and the California ISO have concluded that the current situation is not a threat to reliability.

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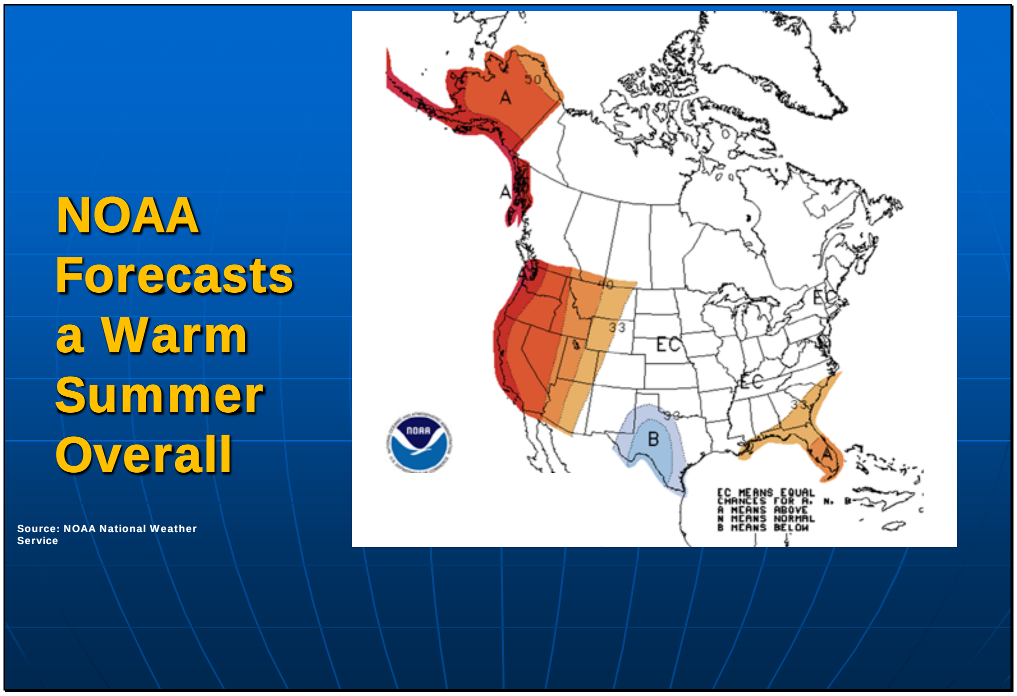

Weather conditions are among the most important, yet difficult to predict, factors affecting the energy markets. NOAA is forecasting potentially warmer than normal temperatures across the West and the Southeast, with the greatest likelihood along the West Coast. Below normal temperatures are forecasted for portions of Texas and eastern New Mexico.

Citing the likely development of a moderate to strong El Niño pattern, forecasters are predicting a below average hurricane season for the Atlantic basin, with only three hurricanes forecasted. By comparison, seven hurricanes is considered normal for a season. Generally speaking, hurricanes do not have the same level of impact on the US energy markets as they did several years ago, due to the substantial shift in natural gas production from the Gulf of Mexico to onshore shale production.

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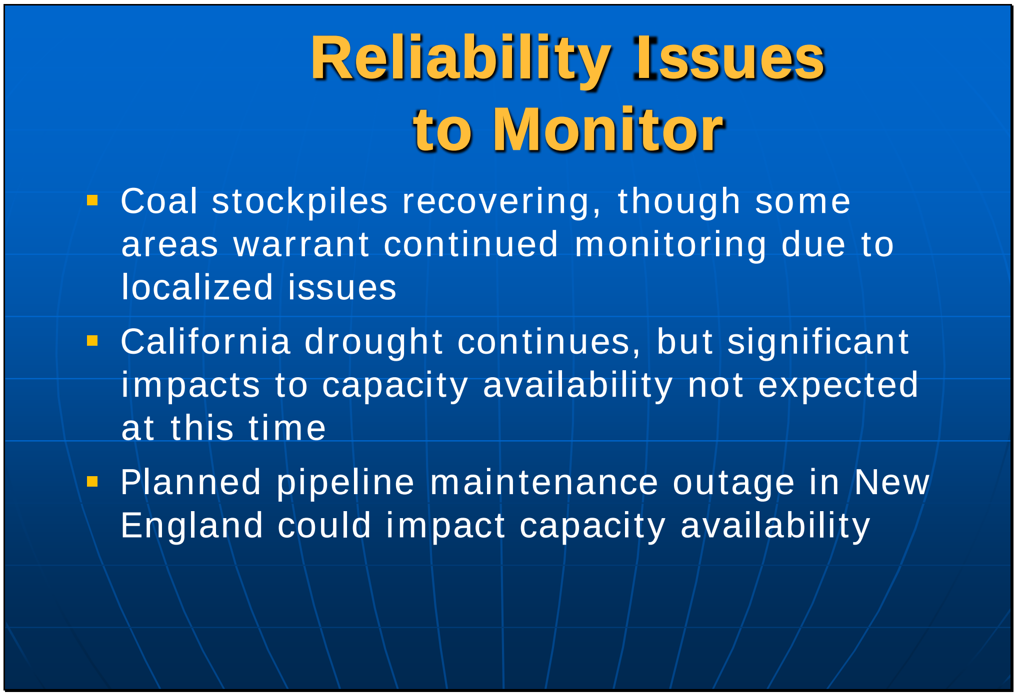

The Energy Information Administration reported that power plant coal stockpiles have been recovering since summer 2014; however, the forecasted stockpile levels are expected to remain modest throughout 2015. In some regions, localized issues have resulted in limited rebuilding of these stockpiles. If natural gas prices were to rise during the summer, increased coal-fired generator output may result in coal supply issues to reemerge in the Midwest.

The ongoing drought conditions in California and the West will limit the availability of hydroelectric generation over the summer. We will discuss the drought in greater detail later in this presentation.

In late August, ISO-NE may experience some impacts to the region's natural gas-fired generating fleet when Spectra Energy begins maintenance and expansion of the Algonquin pipeline.

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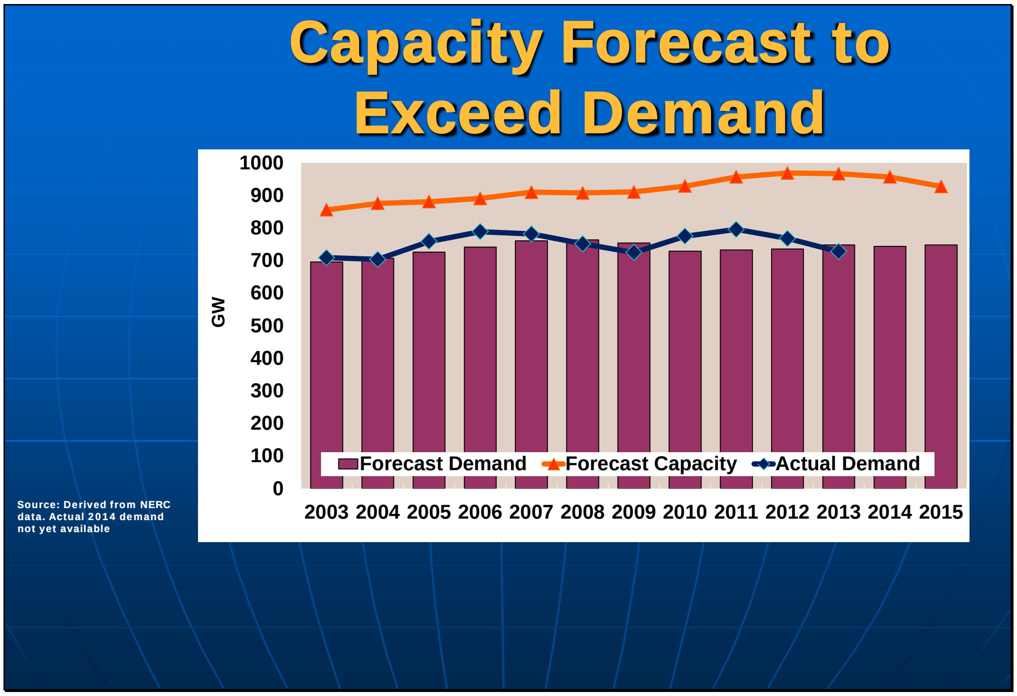

EIA has forecast a 2.9 percent increase in electric demand from 2014, reflecting an expected return to more typical conditions from last year's unusually mild weather. This compares to a weather adjusted increase of approximately 1 percent over last year's forecast. This growth is driven primarily by the commercial and industrial sectors, as opposed to the residential sector, which is a reversal from the past few years.

The historic correlation between economic growth and increased electrical demand has weakened in many markets. A recent report by the NYISO attributed this declining linkage to a combination of factors, including the expansion of energy efficiency programs and growing impact of behind-the-meter generation, which includes residential solar. If continued, this shift may further complicate the forecasting of energy demand, based on economic growth.

Meanwhile, the total generating capacity in the U.S. has decreased by about 3 percent, primarily because of increased coal generator retirements. This is a continuation of the trend that was seen last year. In contrast to coal, NERC forecasts an increase of approximately 3.5 GW in wind generation capacity over last year, or approximately 6 percent and brings the national wind total to approximately 65 GW. NERC is also projecting a net increase of approximately 2 GW of installed utility-scale solar capacity for this summer, though more solar generation is planned to come online this summer.

One notable transmission project is the rebuilding of the 500 kV Susquehanna-Roseland power line, which runs between Pennsylvania and New Jersey. It was placed into service on May 11th and is expected to lower congestion and increase market efficiency in this region of PJM.

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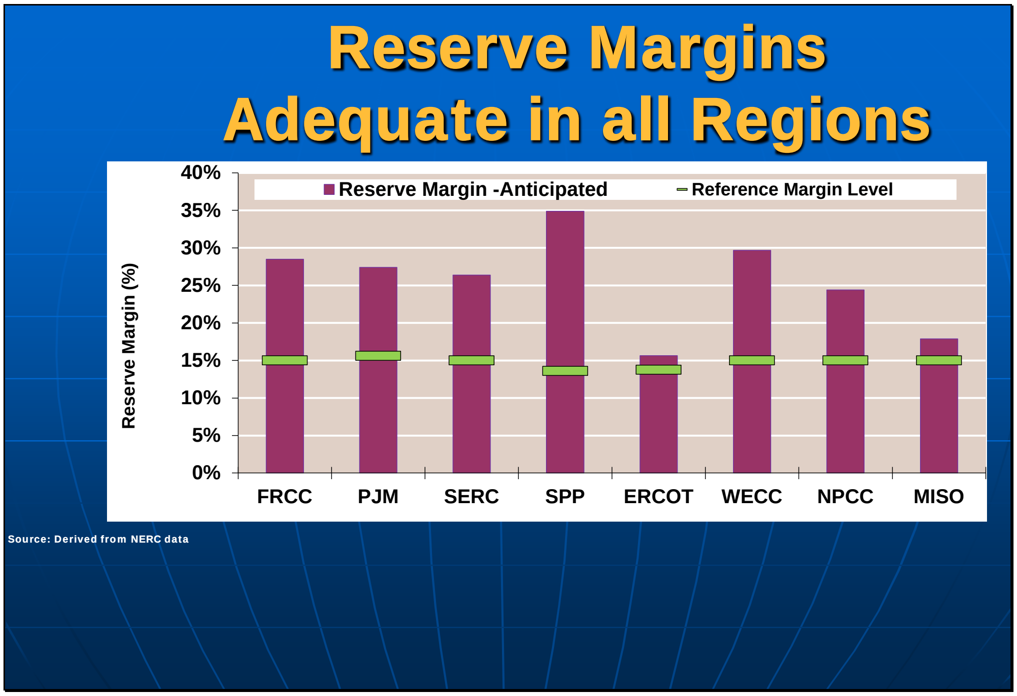

Data from NERC's Summer Assessment indicates that reserve margins will be adequate for all assessment areas this summer. This chart displays the reference reserve margin levels for various markets and regions, along with the anticipated reserve margins.

Resource adequacy is forecast to improve this summer in MISO, ERCOT and New York. In ERCOT, a new load forecasting methodology that has resulted in higher available wind capacity, coupled with new natural gas-fired capacity, have increased the reserve marginfrom 15 to 15.6 percent. In New York, margins have also improved because of repowered generation capacity and lower forecast demand.

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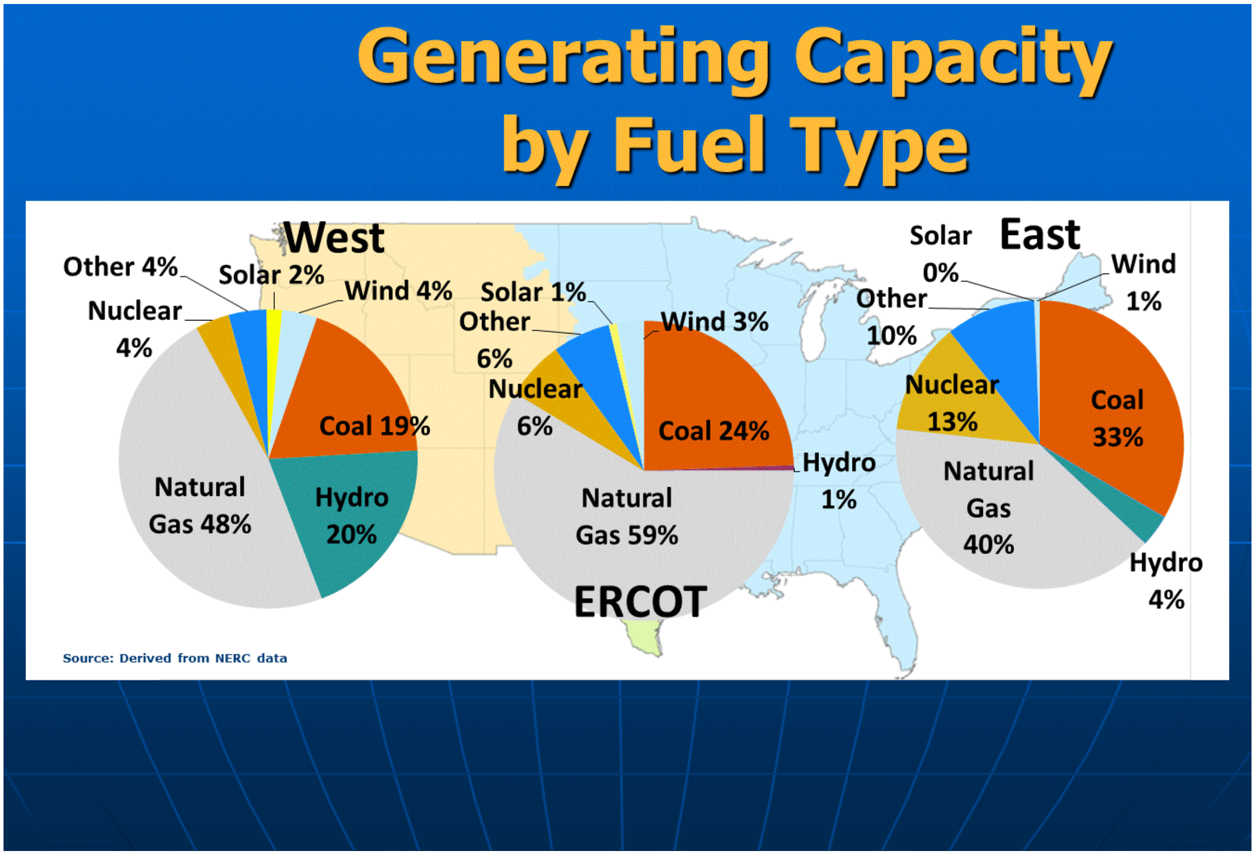

The available generator capacity in WECC has increased by approximately 5 GW since last summer, with approximately 6 GW of additions and 1GW of retirements. These additions include over 2 GW of solar and approximately 1 GW of wind resources.

In ERCOT, approximately 2 GW of natural gas and 2 GW of wind capacity have entered commercial service since the last summer assessment. This includes the Panda Temple 2 natural gas combined cycle project and the Goldsmith peaker project with a combined summer capacity of approximately 1 GW.

Notably, in the Eastern Interconnection, the 615 MW Vermont Yankee Nuclear Power Plant retired in late December 2014. This brings the total to five nuclear power plants that have been decommissioned since 2012. While the loss of Vermont Yankee leaves New England even more dependent upon natural gas, 178 MW of new energy efficiency projects are expected to be in place this summer. Despite the loss of Vermont Yankee, the grid operator forecasts adequate resources to meet demand.

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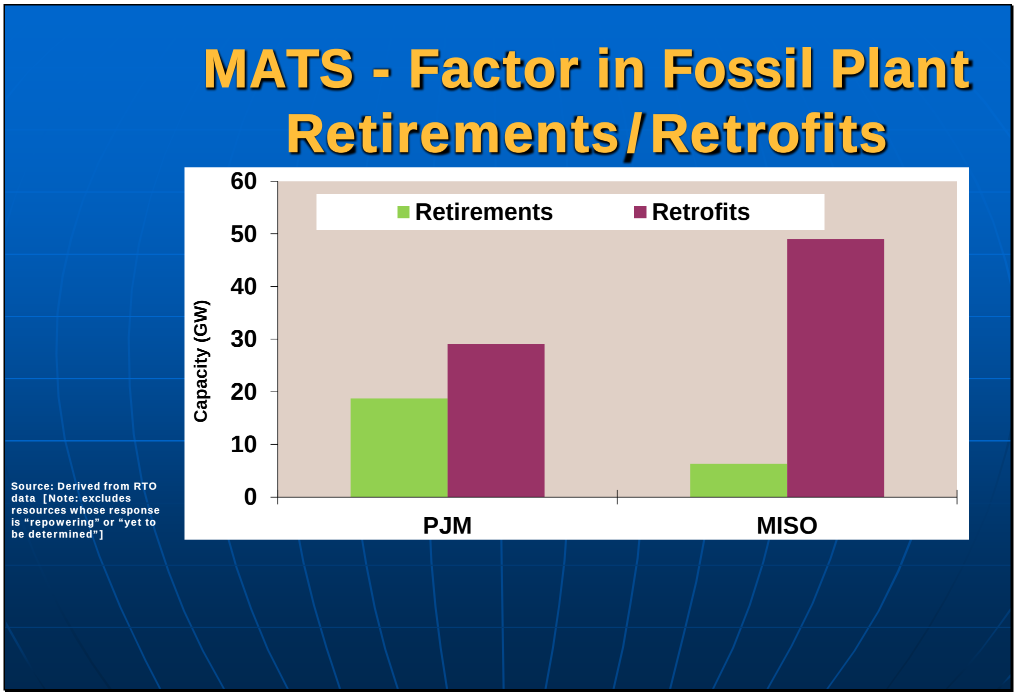

The Mercury and Air Toxics Standards (MATS) rules took effect in April and require advanced pollution controls on coal and oil-fired units larger than 25 MW. This has caused units in MISO and PJM to make capital-intensive pollution control retrofits to comply with the rule, as illustrated in this chart. While SPP has not published statistics that are similar to these regions, a recent Boston Pacific report, commissioned by the SPP Board of Directors, indicated that 1.1 GW of generation was expected to be retired as a result of EPA regulations.

Adding pollution controls increases the non-fuel operating and maintenance costs of coal plants, but provides added flexibility to burn lower-cost, higher sulfur coal. Many plants have elected to install pollution controls with comparatively lower capital costs and higher variable O&M costs. This can increase total plant operating costs by up to one-third, which is typically reflected in higher energy market offers or directly incorporated in the retail rates of vertically integrated utilities. In a low natural gas price and load growth environment, the MATS related costs were uneconomic for many older and less efficient coal plants and many of these units were retired. The closures have exceeded conventional generation replacements and may result in lower reserve margins and increased transmission congestion in the near-term, as well as a greater dependence upon natural gas for generation.

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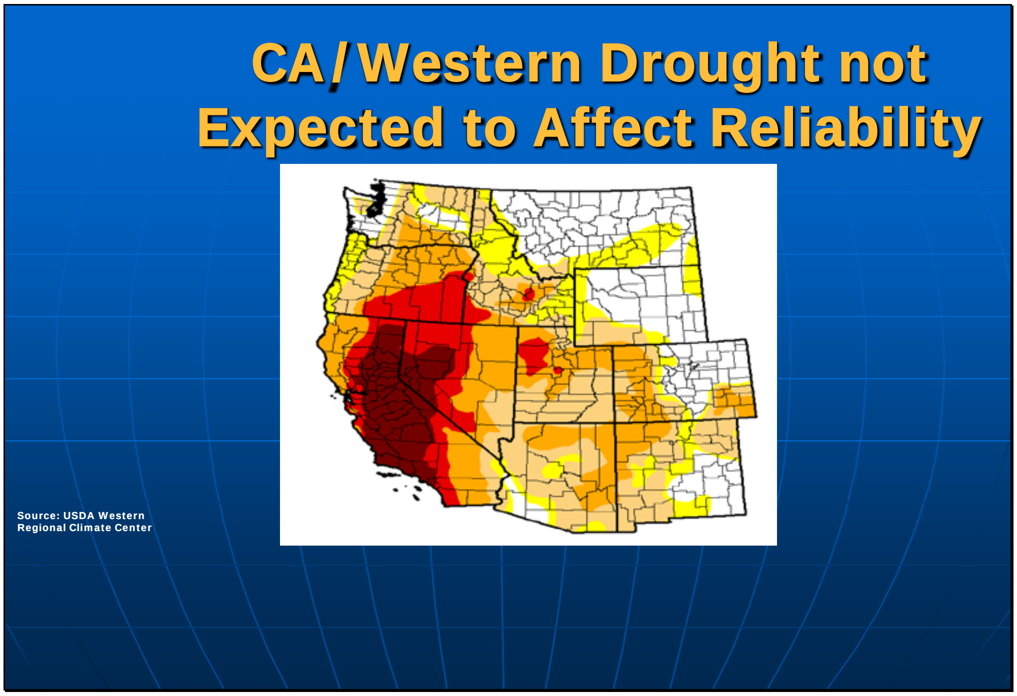

Below average precipitation and warmer than normal temperatures left the West with extremely low snowpack levels on April 1, the day at which snowpack traditionally peaks. California's snowpack fell to a record 5 percent of normal on April 1, reaching historical lows for the second year in a row. However, reservoir levels in the state rose over last year's levels because of early snow melt and rain.

CAISO expects that the reduced hydro generation will be offset by moderate load growth and 2.1 GW of new generation, of which 2 GW is solar. Solar generation now exceeds 6 GW at its peak output. Additionally, new transmission upgrades in the San Diego and Orange County areas will improve local resource adequacy. Staff will be monitoring the load area around Fresno, which is typically served by significant amounts of hydro generation. If the drought persists, power will need to be brought in from other areas and could potentially result in increased transmission congestion and elevated local power prices.

Snow pack was also below normal throughout the remainder of the West. For example, in Washington, precipitation was near normal, at 101 percent of typical, but warm temperatures kept snowpack from accumulating and was only 22 percent of normal on April 1.

Lastly, these conditions may create challenges during California’s fire season, as there may be a dramatically increased risk of wildfire activity, which has the potential to affect power grid operations. Lastly, these conditions may create challenges during California’s fire season, as there may be a dramatically increased risk of wildfire activity, which has the potential to affect power grid operations.

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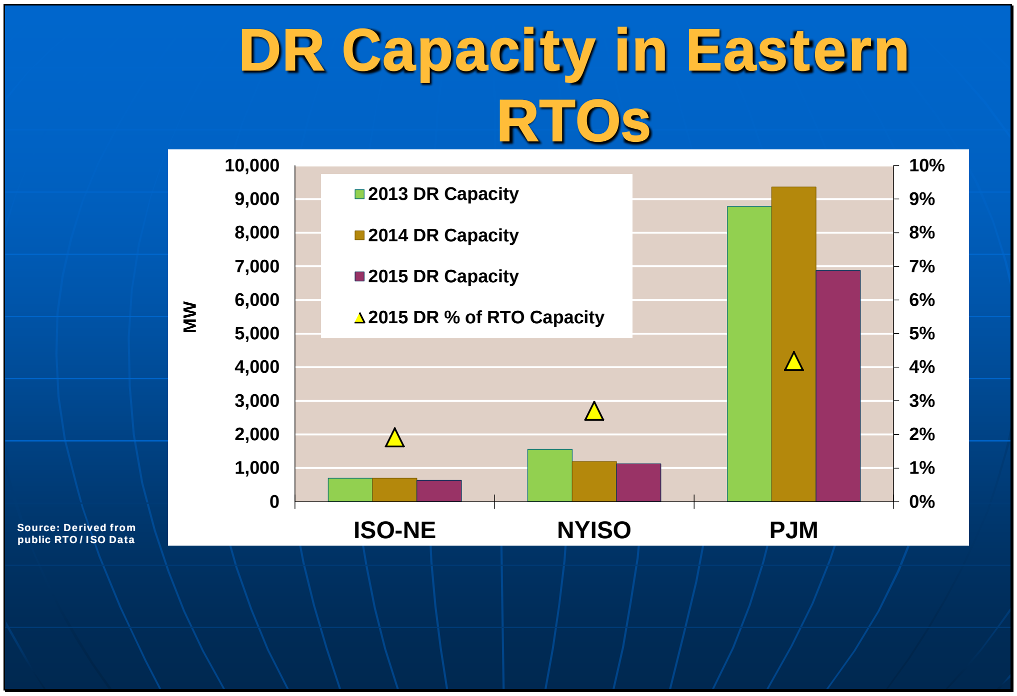

Demand response has traditionally been a summer resource to shave peaks on hot days or during other periods of stress. This chart shows participation in the capacity-based demand response (DR) programs in the three Northeastern RTOs. The colored bars indicate the actual amounts of enrolled demand response capacity, which have fallen in each of the regions from last year. This has occurred most notably in PJM, which has the largest of these programs, dropping by nearly 2,500 MW. Additionally, the current 6,900 MW of participation is less than half of the original 14,800 MW of DR that cleared in the forward capacity auction that was held in 2012, for the 2015/16 capability period. This reduction occurred when a substantial number of market participants traded away these positions in the RTO's capacity reconfiguration auctions and through other transactions.

In the NYISO and ISO-NE, the reductions were much more modest than in PJM, in terms of both megawatts and percentage of cleared capacity. In the case of New York, the amount of DR fell by 65 MW or 5 percent, and in New England it was 62 MW or 9 percent.

Last summer, there were no activations of the capacity based DR programs in these regions, primarily because of the mild weather and moderate system conditions.

However, if above normal temperatures occur this summer, we could expect to see demand response resources activated and dispatched in the real-time energy markets.

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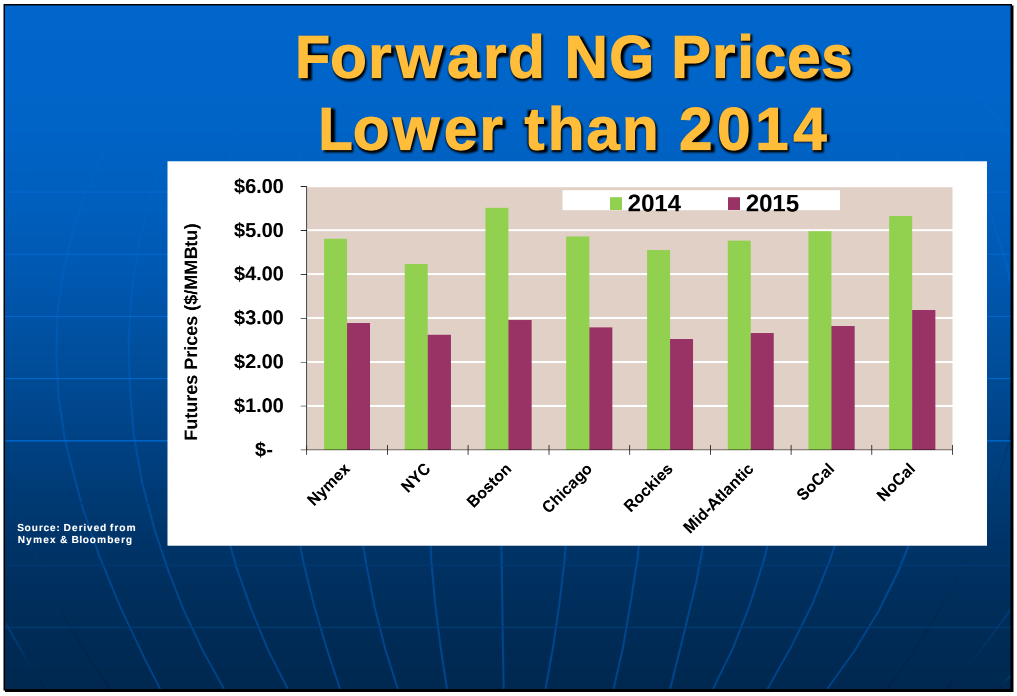

Forward prices are not a predictor of actual prices, but reflect the cost of hedging market risk and can help us understand market dynamics.

Going into the summer, the average Nymex futures price for June through August is $2.89/MMBtu, which is 40 percent lower than in 2014. This is consistent across the country, with the Boston area's Algonquin Citygate showing the largest differential, at 46 percent below last year, and averaging $2.96/MMBtu for the summer. This can be attributed to a 5.7 percent year-on-year increase in natural gas production and storage inventories that are 71 percent higher than in 2014, or 4 percent below the 5-year average.

The injection season began on April 3 with 1.5 Tcf of natural gas in storage, 79 percent above last year. Since then, weekly injections have averaged 65 Bcf, versus 47 Bcf last year. If injections continue at this rate, inventories could set a new record by the end of the injection season on October 31.

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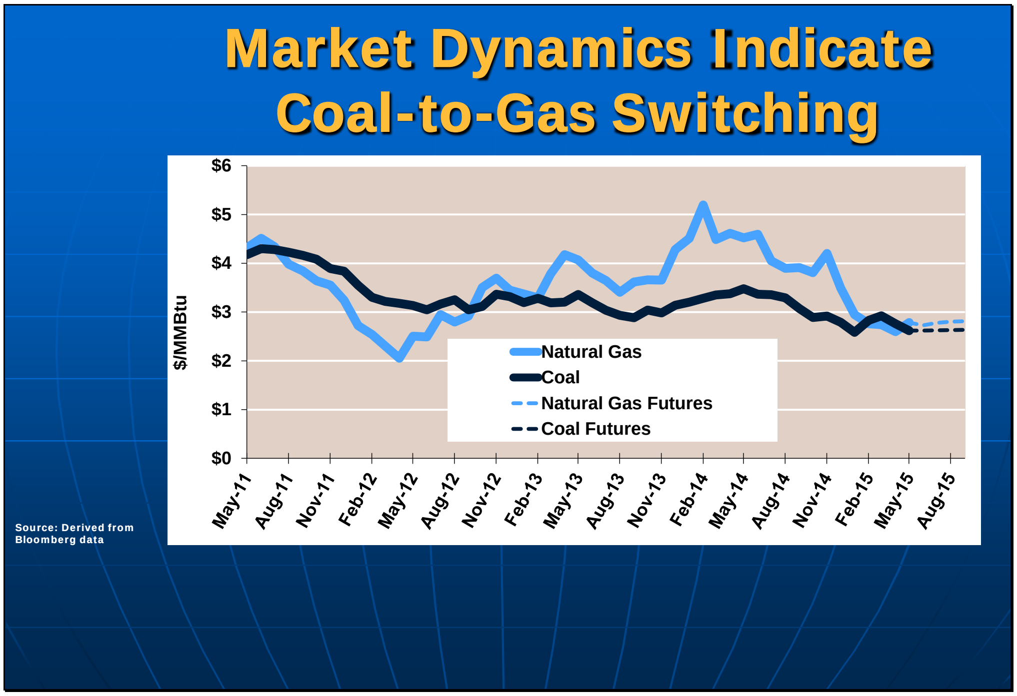

With summer futures prices below $3.00/MMBtu in most regions, natural gas is expected to be competitive with coal on a $/MMBtu basis, when adjusted for the relative efficiency of natural gas versus coal-fired electric generation units. The only region where summer futures are above $3.00/MMBtu is Northern California; however, since the region has no coal-fired plants, it will not experience any coal-to-gas switching.

Any further downward price pressure would give natural gas an even greater advantage in the supply stack and is comparable to 2012, when the Henry Hub price dropped to the lowest level in over ten years, averaging $2.65/MMBtu. According to industry estimates, this resulted in 5.1 Bcfd coal-to-gas fuel switching. Estimates for this summer indicate that a $2.50/MMBtu natural gas price could result in 4-5 Bcfd of incremental natural gas demand from power generators.

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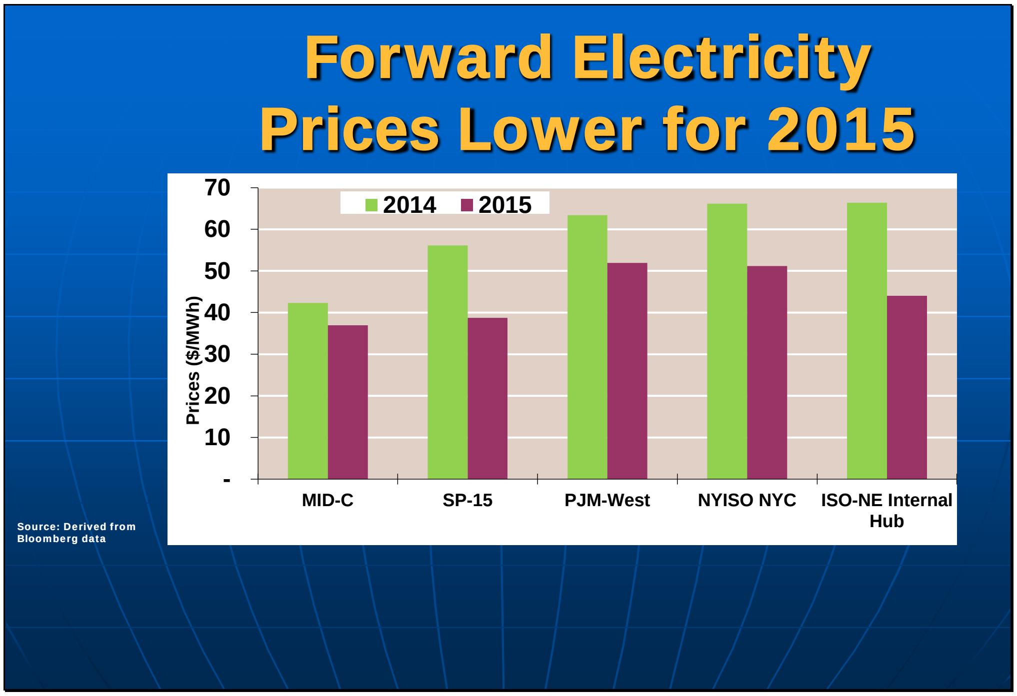

Similar to natural gas, forward peak power prices are down by an average of 24 percent from this time last year. By region, this ranges from down 34 percent at the ISO-NE internal hub to down 13 percent at the Mid-Columbia hub, reflective worsening drought conditions in the Pacific Northwest. These price changes are further driven by regional differences in generating resources, fuel input costs, and other market fundamentals.

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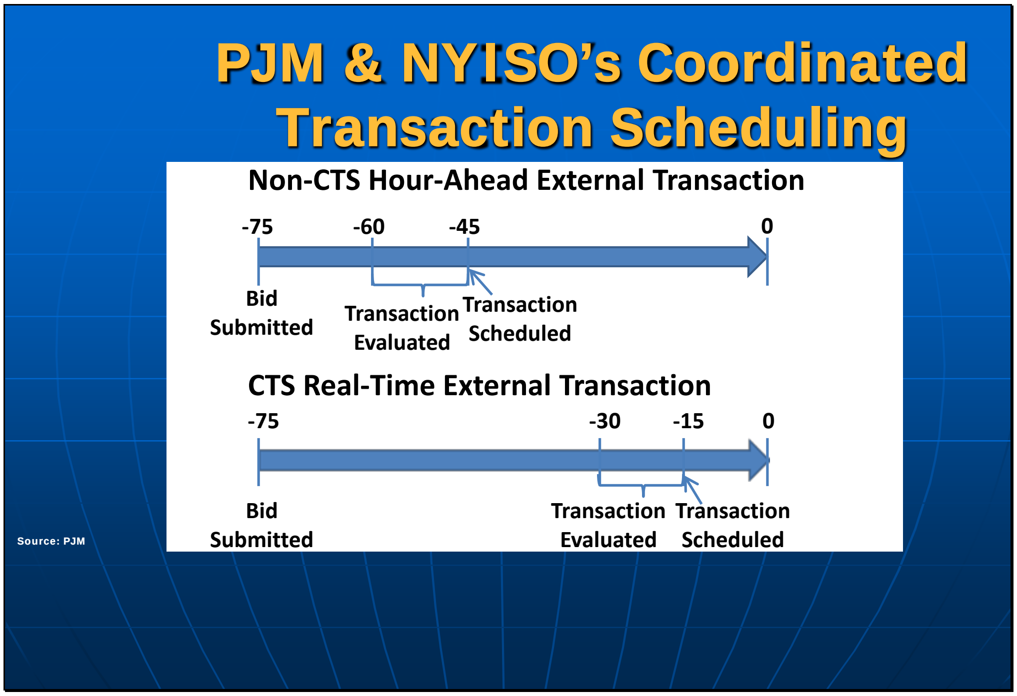

In November, PJM and NYISO implemented Coordinated Transaction Scheduling, which provides market participants with the option to submit intra-hour bids between the two regions. These 15-minute transactions are an additional way trade power between these RTOs and represent approximately 5 percent of the total flows between the two regions. They are based on forward-looking prices, as determined by PJM and the NYISO's dispatch and real-time commitment tools. CTS transactions are intended to improve the overall efficiency of electricity sales between the regions by allowing market participants to access the least-cost source of power, thus helping to lower the combined energy production costs of both RTOs.

This graphic depicts the timelines of the typical hour-ahead, or non-CTS, transaction as well as the new CTS transaction. The major difference between the two is that the CTS transaction is finalized 15 minutes before the actual flow of power, which increases the likelihood that a transaction will be economically efficient, or flowing from a region with lower prices to one with higher prices. Additionally, CTS integrates both the bid evaluation and checkout processes, which reduces the potential for a transaction to be scheduled, but subsequently cancelled.

CTS transactions have been economic in the vast majority of instances, averaging 83 percent of the time since their inception in November. By comparison, non-CTS trades were only economic 56 percent of the time in 2014. Staff will be monitoring the volumes and pricing trends of the CTS transactions over the course of this summer.

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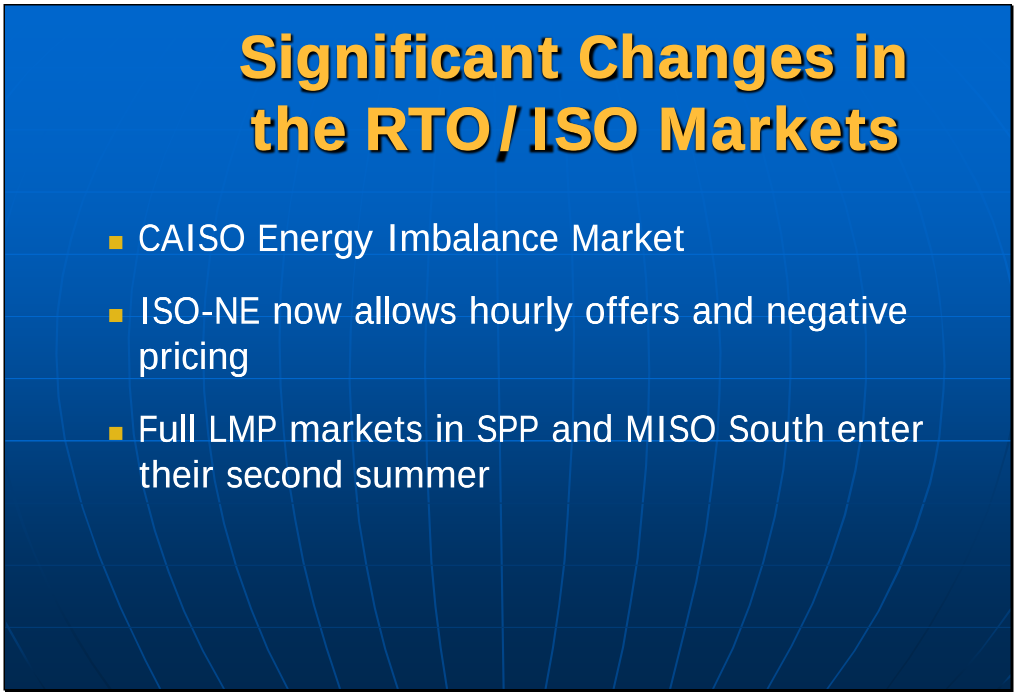

Significant changes have recently been made in both the structure and operation of the wholesale power markets.

The California ISO Energy Imbalance Market started in November and will be entering its first summer. The EIM enables entities with balancing authority areas outside of the CAISO to voluntarily take part in the imbalance energy portion of the CAISO real-time market, alongside participants from within the CAISO balancing area. This market provides services to five western states served by PacifiCorp.

This will be the first summer where ISO-NE makes use of hourly offers in its market. Hourly offers were initiated in December and allow resource owners to submit up to 24 separate hourly offers for the following day, and to allow participants to update their offers during the operating day. Previously, resources were limited to a single offer for all hours of the following day, and were only provided with a single opportunity to revise the offer before the operating day. Additionally, resources could not alter their offers during the operating day. The ISO has also enabled resources to submit negative offers as low as -$150 per MW/hour. This is intended to improve price signals to resource owners to reduce output or shut down when consumer demand is low and there is a risk of excess generation. This should help to enhance reliability and efficiency during periods of system-wide stress.

The operation of MISO South, as part of the greater MISO footprint, will enter its second summer this year. Similarly, SPP has completed its first full-year of operating a full nodal market in March.

Staff will be monitoring these developments and market performance to assess any implications that may arise under this summer's peak load conditions.

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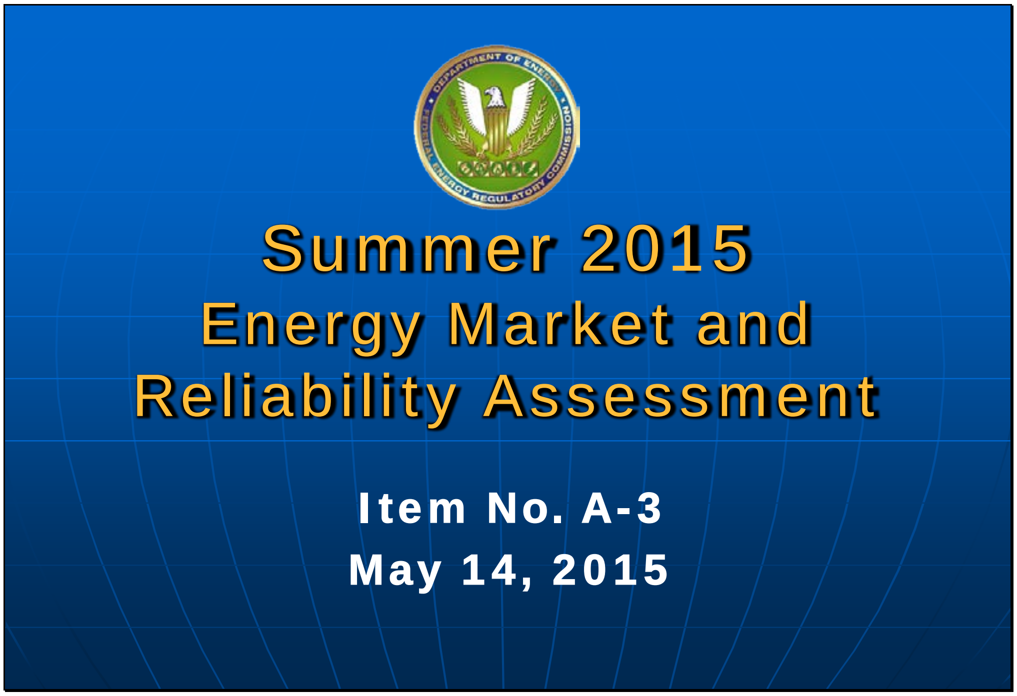

This concludes staff's assessment. A copy of this presentation will be posted on the Commission's website. Thank you.