NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2015-16 Winter Reliability Assessment

December 2015

RELIABILITY | ACCOUNTABILITY




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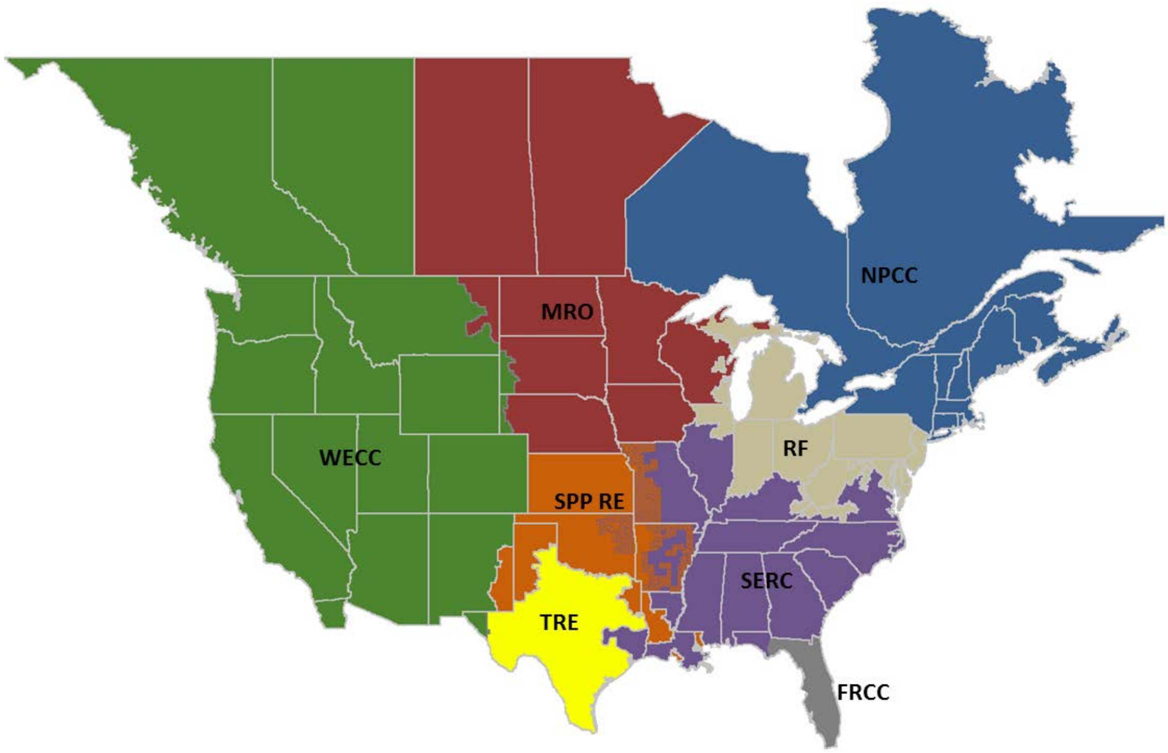
Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into several assessment areas within the eight Regional Entity (RE) boundaries, as shown in the map and corresponding table below.



The Regional boundaries in this map are approximate. The highlighted area between SPP and SERC denotes overlap as some load-serving entities participate in one Region while associated transmission owners/operators participate in another.

FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	Reliability First
SERC	SERC Reliability Corporation
SPP-RE	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Assessment Development

The *2015-16 Winter Reliability Assessment* (WRA) provides an independent assessment of the reliability of bulk electricity supply and demand in North America between December 2015 and February 2016. The assessment was developed with support from the Reliability Assessment Subcommittee[1] at the direction of the NERC Planning Committee (PC).

In September 2015, the eight NERC REs initially submitted data and information for each of their respective assessment areas to NERC and provided periodic updates throughout the development of the report. External data sources are appropriately cited. For this and other seasonal and long-term assessments, NERC uses an active peer review process to leverage a wide group of industry subject matter expertise to provide essential checks and balances for ensuring the accuracy and completeness of the data presented. Inquiries regarding the information, data, and analysis in this assessment may be directed to the NERC Reliability Assessment staff.

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[1] The RAS roster is included in Appendix I.

Executive Summary

The *2015-16 WRA* provides a high-level perspective on the adequacy of the necessary generation resources and transmission systems to meet projected winter peak demands. NERC independently identifies reliability issues of potential concern and regional challenges that may impact BPS reliability. The primary objectives of the report are to identify areas of concern regarding the reliability of the North American BPS, document preparations the industry is taking to address any risks, and to make recommendations as needed. The assessment process enables BPS users, owners, and operators to systematically document their operational preparations for the coming season and to exchange vital system reliability information. NERC evaluates both Region and assessment area resources and transmission adequacy to ensure BPS reliability is maintained for the upcoming season.

Overall, NERC finds that reserve margins for each assessment area are sufficiently met. NERC continues to observe resource mix changes and continued increases in gas-fired generation. This is a particular concern in the winter as extreme cold weather tends to affect electric and natural gas coordination.

NERC also finds that Regions and assessment areas have prepared well for the upcoming winter season. Lessons learned from the past two winter seasons have been implemented in planning and operating procedures at various entities.

As a result of developing NERC's *2015-16 Winter Reliability Assessment,* the following key findings were identified:

1. **Reserve Margins –** NERC-wide, sufficient generation and demand-side resources are in place to meet 2015-2016 winter peak demand.
2. **2015-16 Winter Preparedness –** Improving winter preparedness remains a high priority for the electric industry.
3. **Natural Gas and Electric Coordination in Northeast –** Reliability-focused programs help offset concerns and potential risks.
4. **PJM Capacity Performance –** Market incentives help bolster resource resilience and generator performance.
5. **Operational Risk Analysis –** Operational analysis identifies potential generation supply risks under scenario conditions.

NERC plans to continue conducting operational risk analysis for the 2015-16 winter. This analysis is used to determine the operational risks of a system based on past performance of resources used to serve peak winter loads. This analysis provides an in-depth understanding of the capability of a system in extreme demand conditions.

Key Findings

Key Finding 1: Reserve Margins Adequate for All Areas

NERC-wide, sufficient generation and demand-side resources are in place to meet 2015-2016 winter peak demand. All assessment areas are projected to have sufficient resources in place to meet normal peak winter demand. The planning reserve margins appear to be sufficient for normal operations as well as normal forced-out generation. Planning reserve margins for each area are shown below and explained in detail in the individual assessment area sections.

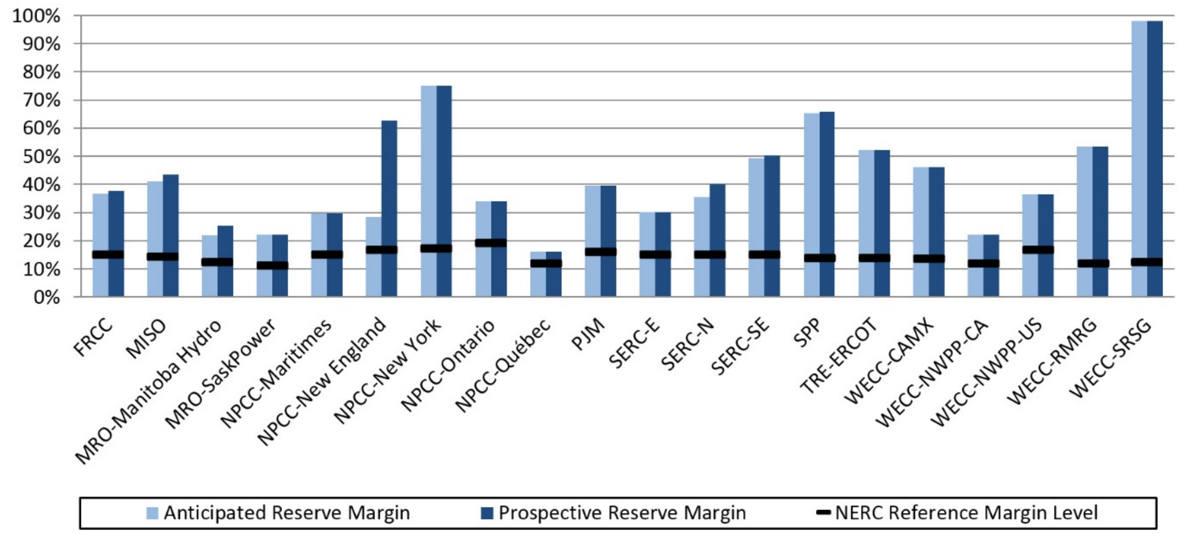
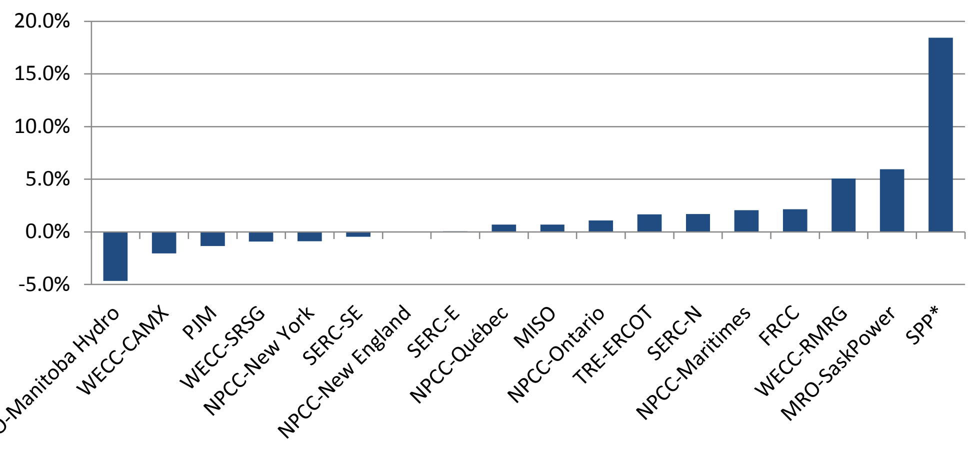


Figure 1: 2015–2016 winter reserve margins

A majority of all assessment areas experienced minor to no load growth across the projected winter peak when compared to NERC's 2014 *WRA*. This observed growth rate in total internal demand continues to trend downwards and is significantly augmented by the advancement of new energy efficiency programs, distributed energy resources, and behind-the-meter generation (BTMG) resources that are being incorporated into planners' load models and forecasts. NERC will continue to assess what challenges these increasingly installed system elements introduce to operations and planning.



*In 2015, SPP absorbed the majority of MRO-MAPP's footprint; this accounts for
The significant growth in this assessment area

Figure 2: Net change to total internal demand from 2014-15 *WRA Reference Case*

The addition of new demand response programs continues to help address potential resource adequacy concerns for areas during their winter peak. These programs vary greatly in their availability and load reduction capability, but often provide the flexibility needed during extreme conditions. New or updated demand response programs are reviewed in the regional section of this assessment. For assessment areas that are summer peaking and reporting more than adequate reserve margins for this winter season, there is minimal necessity for additional demand response programs to address resource adequacy. However, winter-peaking areas, like SaskPower and Québec, are incentivized to further add new demand response programs to mitigate any potential issues raised by a tightening reserve margin. Since the 2014 *WRA*, an additional 10.5 GW of capacity have been reported as available. Since the total capacity for all demand response programs has only increased by 2.6 GW, this winter will constitute a much greater percentage of available programs.

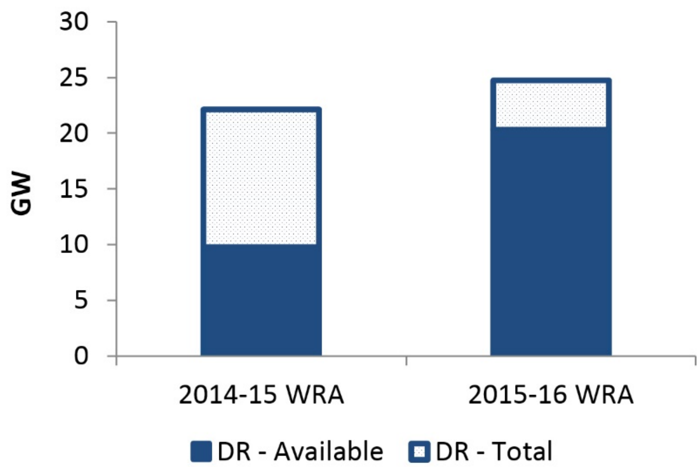


Figure 3: Total and available demand response compared with the 2014 *WRA*

Key Finding 2: 2015-16 Winter Preparedness Remains a Priority

Improving winter preparedness remains a high priority for the electric industry. North America, especially the north east portion of the continent, faced prolonged and adverse winter conditions in both 2014 and 2015. In particular, extreme cold conditions were experienced in January and February of 2015 and January of 2014. The January 2014 extreme winter event was characterized as the polar vortex. In general, temperatures and winter conditions were similar for both 2014 and 2015. The polar vortex of 2014 levied unprecedented stress on the grid and caused resource outages and tight operational challenges. In 2015, many US cities experienced lower than average temperatures and much higher than normal electricity demand.

The winter of 2015 posed similar challenges, but the system was prepared to address these conditions resulting from previous years' lessons learned and the implementation of recommendations. From a generation perspective, simultaneous forced outages for generators were less impactful in 2014/2015 than in 2013/2014.[2]

NERC has been extremely active in supporting winter preparedness activities, including annual webinars, event and root cause analysis, identification of comment themes and trends, recommendations for improvement, and the development of a reliability guideline. The following materials have been made available in support of maintaining vigilant winter preparedness programs:

- **2015 Winter Performance Update**[3]

[2] http://www.nerc.com/pa/rrm/ea/ColdWeatherTrainingMaterials/Winter_Review_2015.pdf
[3] http://www.nerc.com/pa/rrm/ea/ColdWeatherTrainingMaterials/Winter_Review_2015.pdf

- **Reliability Guideline** – Generating Unit Winter Weather Readiness[4]
- **Assessment of Previous Severe Winter Weather** – 1983–2011[5]
- **Cold Weather Training** – Extreme Weather Preparation Training[6]

Common issues found in cold weather events stem primarily from an inability to receive natural gas and freezing equipment. One of the common problems experienced by many generators involved in the severe cold weather events were units that tripped, suffered derates, or failed to start during the event due to weather-related causes, such as frozen sensing lines, frozen equipment, frozen water lines, frozen valves, blade icing, and low-temperature cutoff limits.

NERC continues to assess the increasing risk of the interdependency between electricity and natural gas, which is most visible during extreme winter conditions. Natural gas has become an increasingly popular fuel choice for electric generators and is expected to increase by up to 30 GW over the next ten years.[7] Concurrently, compressors used in the production and transportation of natural gas have come to rely increasingly on electricity for their power source rather than natural gas. Additionally, all compression stations require electricity to power the controls for the compressors.

One of the dominant contributing factors for generation capacity being lost and derated is inadequate gas supply during the cold winter season. Most generator owners purchase "nonfirm" capacity for pipeline transportation. As result, it is during those coldest and most critical times when natural gas customers are interrupted due to limited supply, typically due to the competing usage of natural gas for heating needs. Adding to the complexity, a number of natural-gas-generating units that attempted to switch fuels have a risk of being unable to do so, and units that do switch fuels often experience an operational derate. Therefore, during a severe cold weather event when generation is most needed, additional reductions in generator output due to fuel switching has the potential to exacerbate the deficiency in overall generation capacity.

NERC published two special assessments on the interdependency of natural gas and electric power. The Phase I report is a primer on the issues and challenges.[8] The Phase II report offers specific recommendations to the electric power industry from a bulk system planning and operational perspective.[9]

Regional Assessments

Some of NERC's assessment areas that experienced the abnormally cold temperatures have implemented various winter weather practices.

PJM

PJM set a new wintertime peak demand record of 143,086 MW in 2015 as compared to 142,863 MW in 2014 during the polar vortex event. PJM resource performance improved during the winter of 2014-2015 in relation to performance in the winter of 2013-2014. This is attributed to the steps PJM and generation owners initiated after the winter of 2013-2014 experience. These steps included, but are not limited to, prewinter operational testing for dual-fuel and infrequently run units, a winter preparation checklist program, better communication on fuel status, and increased coordination with natural gas pipelines. Generating units that participated in the prewinter operational testing observed a lower rate of forced outages compared to those that did not test in the 2014-2015

[4] http://www.nerc.com/pa/rrm/ea/ColdWeatherTrainingMaterials/Relibility_Guideline_Generating_Unit_Winter_Weather_Readiness.pdf
[5] http://www.nerc.com/pa/rrm/ea/February%202011%20Southwest%20Cold%20Weather%20Event/Final_Draft_Assessment_of_Previous_Severe_Winter_Weather_Report.pdf
[6] http://www.nerc.com/pa/rrm/ea/ColdWeatherTrainingMaterials/Cold%20Weather%20Training%20Presentation%2020131001.pptx
[7] 2014 Long-Term Reliability Assessment
[8] http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Gas_Electric_Interdependencies_Phase_I.pdf
[9] http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_PhaseII_FINAL.pdf

winter. The programs in place will be continued in the winter of 2015-2016. While the improvements were effective, PJM does not believe that these short-term measures are adequate to ensure long-term generation performance improvements on a sustained and dependable basis.

The capacity performance proposal was developed through an expedited stakeholder process last year. Capacity performance will enhance the incentives for capacity resources to be available when needed most, help reduce price spikes during system emergencies, and reduce the chance of expensive forced outages. More details on PJM's capacity performance implementation can be found under PJM's narrative section of this report.

SERC
The SERC Region experienced an all-time winter peak of 137,681 MW during the polar vortex event of 2014. Since then, the SERC Region has taken proactive cold weather winterization measures. Member entities have developed winter weather freeze plans to monitor generation facilities equipment. Winterization check lists have been established which provide operations personnel an opportunity to detect plant abnormalities which may impede plant operations. In addition, revisions to operational policies have been implemented to maintain additional reserves and situational awareness of fuel availability. All actions and their implementations are ensured by periodic meetings during cold weather conditions, specifically to coordinate activities and operational approaches between members and the first tier neighbors.

ERCOT
The ERCOT region experienced an all-time winter peak of 57,277 MW during the polar vortex event of 2014. The generators operators in TRE-ERCOT have made important strides over the last five years in improving the availability of units during extreme cold weather events. Subsequent to the cold weather event on February 2, 2011, that resulted in 8,000 MW of freezing-related unit outages and required the shedding of 4,000 MW of firm load, ERCOT and TRE made a concerted effort to improve communications on weatherization best practices and lessons learned by hosting workshops and building working relationships with generator operators for information sharing. ERCOT also significantly increased the scope of its annual weatherization spot check program, expanding the number of unit visits from 30 units for the winter of 2011-2012 to 76 units for the winter of 2014-2015 as well as including a sample of wind turbines prone to icing-related tripping. These spot checks are designed to help ensure that generator owners are compliant with their weatherization plans and their plants can operate to their design temperatures. As a consequence of these efforts, unit availability during the most extreme cold weather events has improved. For example, during the January 6, 2014 cold weather event, freezing-related outages reached only 3,541 MW, while for the cold weather event of January 8, 2015, freezing-related outages reached only 750 MW. Overall, ERCOT has implemented measures that maintain reliability in the event of extreme winter weather conditions.

MISO
The MISO area experienced an all-time winter peak of 109,336 MW during the polar vortex event of 2014. As the use of natural gas becomes more prevalent across the MISO footprint, MISO is coordinating with the natural gas pipeline industry and generator operators to ensure coordination of fuel delivery. Over the past two winters, this coordination has provided improved system intelligence that is integrated into real-time operations and decision making. MISO has implemented enhancements to assess the causes of winter and fuel-related generator outages. These types of outages can be widespread during periods of cold weather and are important to track for real-time and after-the-fact analysis. Additionally, MISO implemented several procedures to improve visibility into the natural gas pipeline system. This primarily includes increased communications with pipeline operators to increase situational awareness for MISO's operators as they manage the electric grid.

NPCC

Maritimes

As part of the winter planning process, dual-fueled units will have sufficient supplies of heavy fuel oil on-site to enable sustained operation in the event of natural gas supply interruptions.

Ontario

The IESO periodically meets with natural gas suppliers to coordinate maintenance outages as well as deliveries for the upcoming peak season. The current natural gas storage level in Ontario (at the Dawn Hub) is at the five-year average. IESO implemented a seasonal readiness program in 2014-15 that tests units that have been offline for a significant length of time to ensure their readiness for peak periods. For future improvements, the IESO continues to work on enhancing existing communication protocols with gas pipeline and distribution system operators to facilitate information sharing. There is currently a stakeholder engagement initiative[10] underway to seek input on proposed enhancements to the communication and coordination efforts.

NYISO

The NYISO Market Mitigation and Analysis Department performed on-site visits of several generating stations (sum 14,901 MW) to discuss past winter operations and preparations for winter 2015-16. Their visits focused on units with low capacity factors. A pre-visit questionnaire included assessments of natural gas availability during peak conditions, issues associated with burning or obtaining oil, emissions limitations, preventative maintenance plans, causes of failed starts, programs to improve performance, and programs in place to ensure switchyard reliability. They found that generators have increased generation testing, cold-weather preventative maintenance, fuel capabilities, and fuel switching capabilities to improve winter operations.

NYISO also sends out a cold weather survey. This survey is sent to all generating plants and assesses their primary and secondary fuel inventories.

Québec

Québec is a winter-peaking area. Québec's operations staff have a myriad of measures in place to address higher-than-expected peak winter demand. These vary from limitations on nonfirm transfers, the operation of hydro generating units at their near-maximum output (away from optimal efficiency, but still allowing for reserves), the use of import contracts with neighboring systems, and the use of interruptible load programs. Some programs are implemented after the previously mentioned measures are exhausted and if the system is still under stress conditions. These could vary from reduction of 30-minute reserve, reduction of stability reserve, voltage reduction, public appeals, and ultimately using cyclic load shedding to re-establish reserves. Most of the Québec area's hydro generators are located in the north of the province, where extremely cold ambient temperatures often occur during winter periods. Specific design requirements are implemented to ensure that extreme ambient temperatures do not affect operations. In case of any issues that might arise in real time, maintenance notices are issued to operators to handle such concerns.

Key Finding 3: Enhanced Coordination between Natural Gas and Electric Industries in the Northeast

Reliability-focused programs help offset concerns and potential risks. Natural gas is the predominant source of fuel for generating plants in New England. ISO New England (ISO-NE) continues to monitor the coordination between the natural gas and electric power sector during the winter periods and has determined that natural gas maintenance schedules should not decrease the availability of natural gas. However, ISO-NE expects approximately 4,200 MW of natural gas generation to be at risk because of the potential for single-fuel, gas-only power plants to be unavailable during extreme winter conditions. Historically, natural gas pipeline restrictions observed during the winter seasons have challenged reliability efforts, and ISO-NE has implemented many

[10] Gas-Electric Coordination Enhancements

provisions to address the constraints and maintain reliability. While the coordination of the electric power and natural gas sectors continues to mature in the area, many successful measures have been put in place, as follows, to mitigate risks and further improve this coordination.

- **2015/2016 Winter Reliability Program (WRP):** FERC approved the New England Power Pool proposal for the 2015/2016 WRP which entails the following components:
  - Incentives for generators to procure on-site fuel resources before the winter season begins
  - An incentive program for generations owners to contract for liquefied natural gas (LNG) for New England during the winter
  - A dual-fuel testing program to ensure that these generators can efficiently switch fuels
  - A dual-fuel commissioning program that will create incentives for developing more dual-fuel facilities in New England
  - Winter demand response program
- **Electric-Gas Operations Committee:** The Electric-Gas Operations Committee is a joint effort between ISO-NE and the Northeast Gas Association for regional electric power and natural gas coordination through enhanced communications, education, and situational awareness.
- **Outage Coordination:** Outage coordination takes into account the potential for natural-gas-fired generation to be at risk, recognizing that installed capacity may not equate to operable capacity. ISO-NE conducted training for generator operators to highlight the need for New England to maintain sufficient reserve margins during peak and shoulder operating periods. Because a large volume of maintenance occurs during the shoulder periods, ISO-NE may, at times, deny planned outages to maintain forecasted capacity margins. A natural-gas-fired generator may choose to schedule maintenance outages during extreme winter conditions and reduce its gas-at-risk capacity equal to its capability.
- **Gas Utilization Tool:** ISO-NE has developed a gas-utilization tool (GUT) that improves situational awareness and assists system operations in maintaining a wide-area view of the natural gas pipeline infrastructure that feeds the New England area. Five interstate pipelines supply natural gas to New England, each of which has its own unique characteristics. Each of the interstate pipelines is interconnected with at least one other pipeline at metered points in or around New England, which adds more flexibility to a constrained system but also more complexity.

  The key features of the GUT are visibility and awareness of the general conditions of the pipelines, accounting for pipeline use, and forecasting of pipeline availability. The pipeline capacity is posted on electronic bulletin boards (EBBs) along with planned service outages and notices, all of which is public information. Access to this information on the pipeline systems helps operators quickly assess the general conditions of the interconnected pipelines and understand the direction of gas flow throughout the area and its magnitude from outside New England through constrained areas and at scheduled delivery points. ISO-NE designed a dynamic pipeline one-line display that shows scheduled gas flow at key points on the system, which can help the operators determine gas availability on a certain pipeline.

  The most accurate assumption for the GUT calculation is the forecasted gas consumption from the pipelines by the generators ISO-NE schedules and dispatches. The schedule calculations are based on hourly commitment, megawatt (MW) dispatch, and the heat rate of each generator. Because most of the generators in New England are directly connected to the pipelines, information on most of their scheduled gas is publically available, which greatly facilitates the GUT evaluations. System operators can then better forecast the expected generation dispatch throughout the course of an operating day and the natural gas scheduled to meet that dispatch.

Knowing the amount of gas available to the area for consumption, the amount of gas firm customers are expected to use, and the amount of gas ISO-NE is counting on for power generation gives ISO-NE operators a better understanding of when and where problems may occur during the operating day and future operating days.

Key Finding 4: PJM Introduces Comprehensive Capacity Performance Program

Market incentives help bolster resource resilience and generator performance. PJM Interconnection implemented a capacity performance program that requires resources like generators or demand response to meet their commitments. The initiative is comprised of three parts: 1) performance requirements to perform in energy markets, 2) increased nonperformance penalties, and 3) creation of investment opportunities. As a pay-for-performance requirement, the resources may receive higher payments in return for their investment in modernizing equipment, framing up fuel supplies, or redesigning to fit dual-fuel use. The program provides clearly defined obligations for capacity resources and will enhance reliability at a reasonable cost. In addition, the generators that do not perform per requirements may have to pay more than they receive in capacity payments. This charge will be distributed amongst generators that exceed performance requirements. Because of the nature of the forward capacity market in PJM, the effect of capacity performance program will not be seen until the winter of 2016-2017.

Key Finding 5: NERC Continues to Analyze Operational Risk Analysis

The *2015 Summer Reliability Assessment* introduced a pilot analysis that focused on operational risks to the BPS. This analysis evaluated past performance of resources used to serve peak load to determine the operational sensitivities of any given system. NERC's seasonal assessments include reviews of the planning horizon and flexibility of an assessment area or Region through a deterministic planning reserve margin analysis. However, the seasonal assessment approach is limited as it only measures normal system conditions and does not take into account the operational issues that can occur on peak—mainly deviations in the demand forecast and random generator outages. Based on past performance and outages that occur throughout the winter, NERC can determine what average amount of capacity is out of service due to maintenance or forced outages for the entire season. This provides a much greater understanding of the capability of a given system, as well as measuring its resilience against severe BPS conditions.

This assessment's data request included both a normal demand[11] and extreme weather demand forecast[12] from all assessment areas. NERC averaged three years of event data provided by its Generator Availability Data System (GADS)[13] to determine the maintenance and forced outages for each of the areas for any given day during the winter season. This analysis evaluated two scenarios: normal and extreme weather loads, both compared to the maximum forced outages and averaged maintenance outages. The extreme weather scenario provided additional insight on low-probability conditions that could result in adverse system effects. While all system operators have operating procedures in place to mitigate adverse reliability impacts by means of demand response, voltage reduction, additional power purchases, and public appeals, firm load shedding may also be needed to maintain system stability during these severe conditions.

In summer-peaking assessment areas, such as those in SERC, winter loads do not typically pose a reliability challenge as these areas have abundant resources to manage a heavy load. This assessment will focus on winter-peaking areas in addition to other areas that have been affected by extreme winter loads.

[11] Load projections are based on a noncoincident 50/50 peak demand forecast, unless otherwise noted. Values represent the baseline values for each season, each with a range of possible outcomes based on probabilities around the baseline or midpoint. Projections are provided on an Assessment Area basis and are highly dependent on the data, methodologies, model structures, and other assumptions that often vary by Region, RC, Assessment Area, or BA.
[12] NERC requested a load projection based on the 90th percentile probability. In general, this means that the severe load forecast is expected to reach this higher level once in every 10 years.
[13] GADS

MISO – The anticipated forced and planned generator outages do not pose a concern for both normal and severe load conditions.

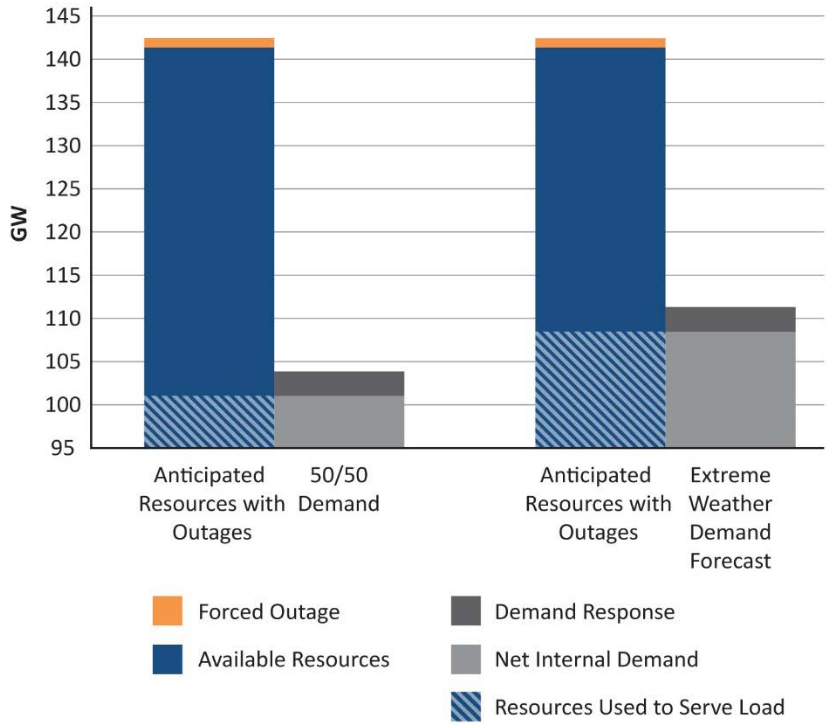


Figure 4: MISO operation risk

MRO-Manitoba Hydro – The anticipated forced and planned generator outages do not pose a concern for both normal and severe load conditions.

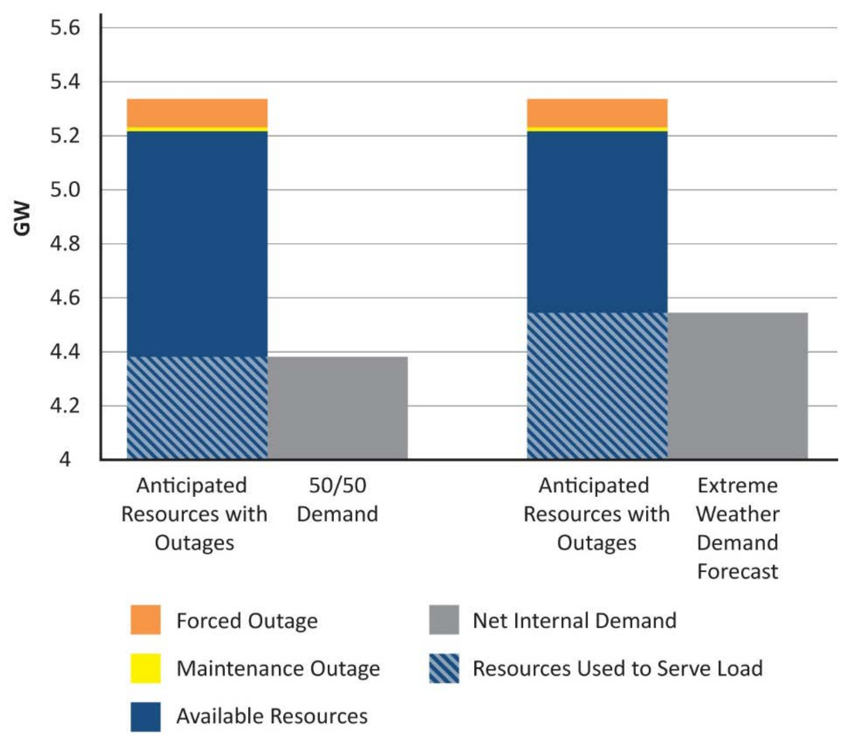


Figure 5: Manitoba Hydro operation risk

MRO-SaskPower – The anticipated forced and planned generator outages do not pose a concern for both normal and severe load conditions.

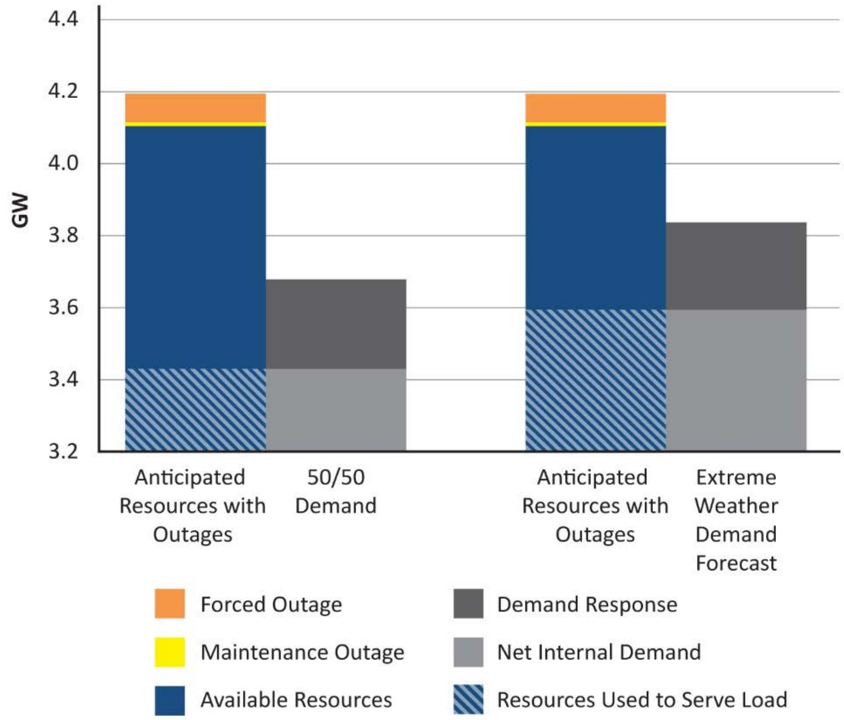


Figure 6: SaskPower operation risk

NPCC-Maritimes – The anticipated forced and planned generator outages do not pose a concern for both normal and severe load conditions.

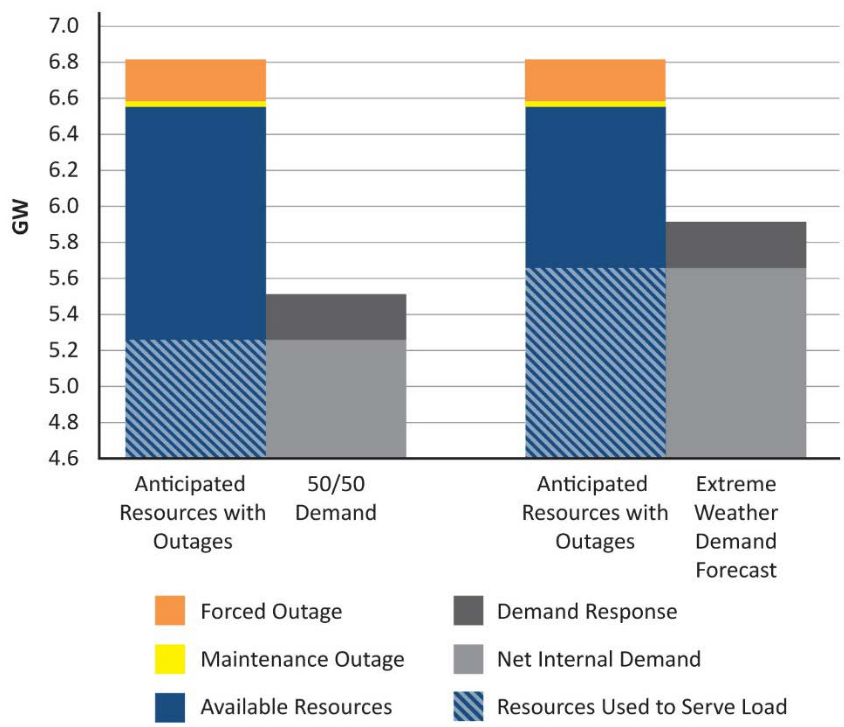


Figure 7: Maritimes operation risk

NPCC-New England – The anticipated forced and planned generator outages do not pose a concern for both normal and severe load conditions.

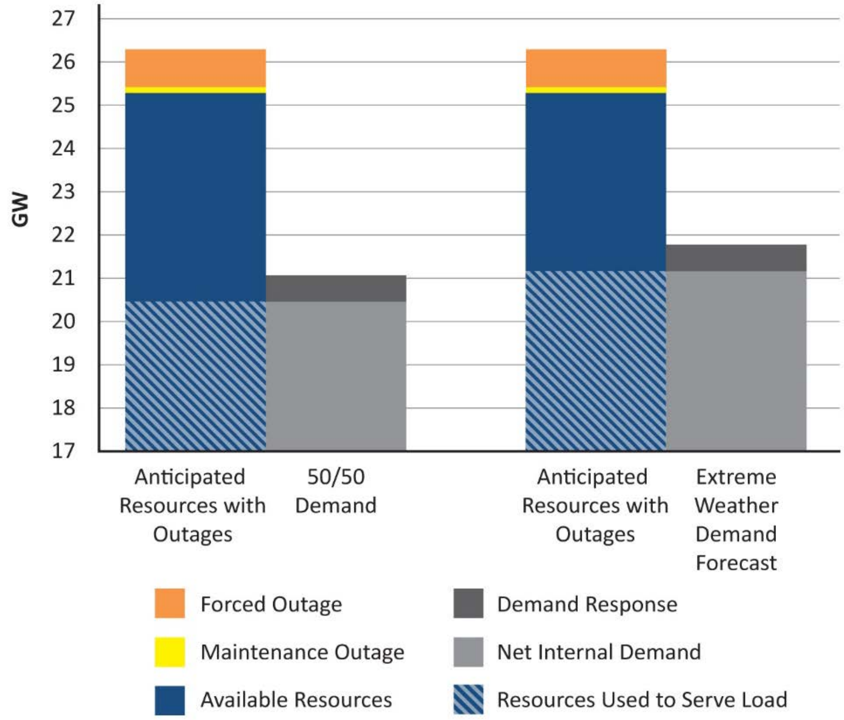


Figure 8: New England operation risk

NPCC-New York – The anticipated forced and planned generator outages do not pose a concern for both normal and severe load conditions.

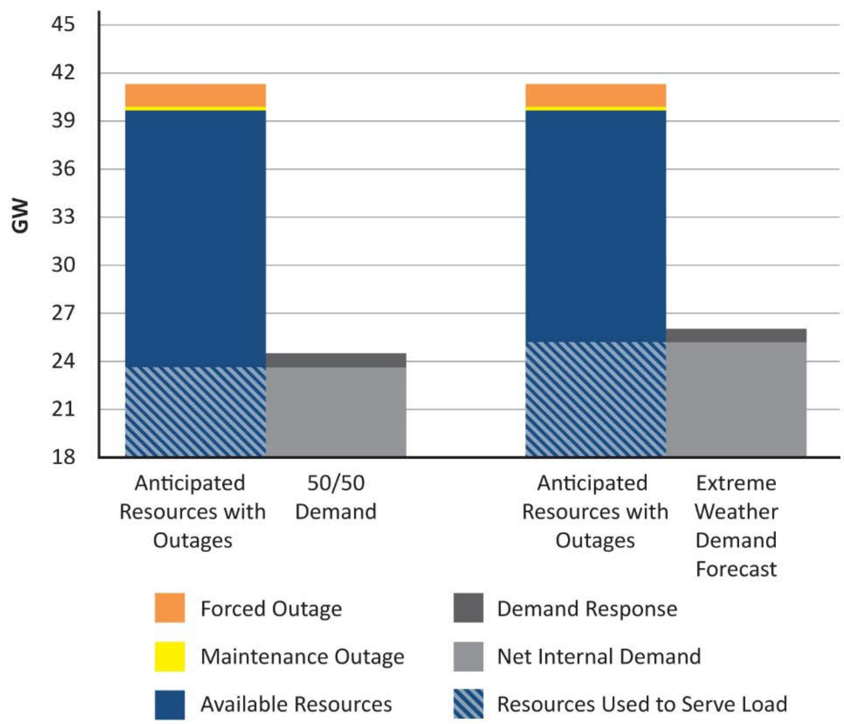


Figure 9: New York operation risk

NPCC-Québec – The anticipated forced and planned generator outages do not pose a concern for both normal and severe load conditions.

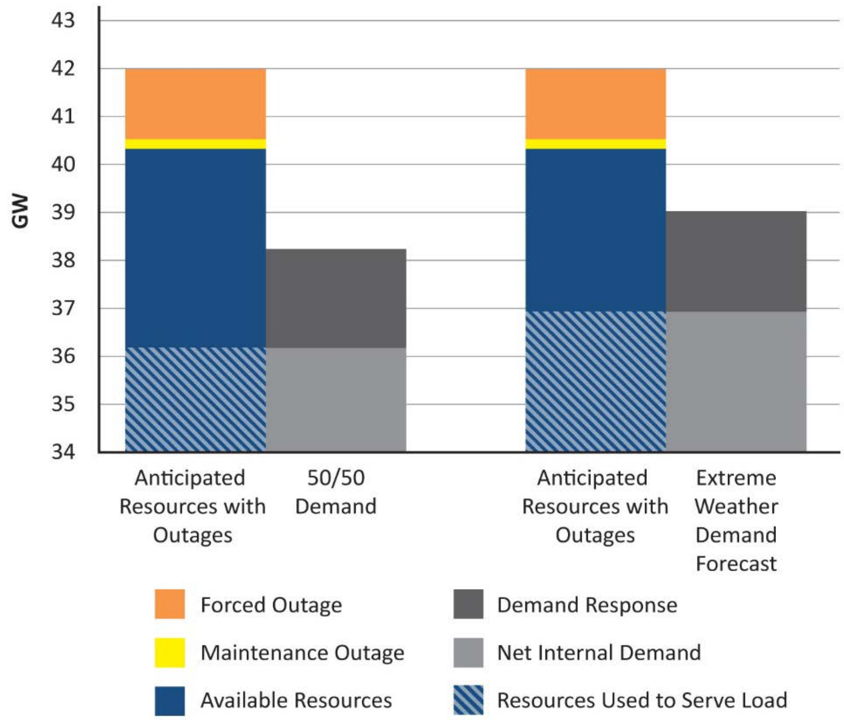


Figure 10: NPCC-Québec operation risk

WECC-NWPP-CA – The anticipated forced and planned generator outages do not pose a concern for both normal and severe load conditions.

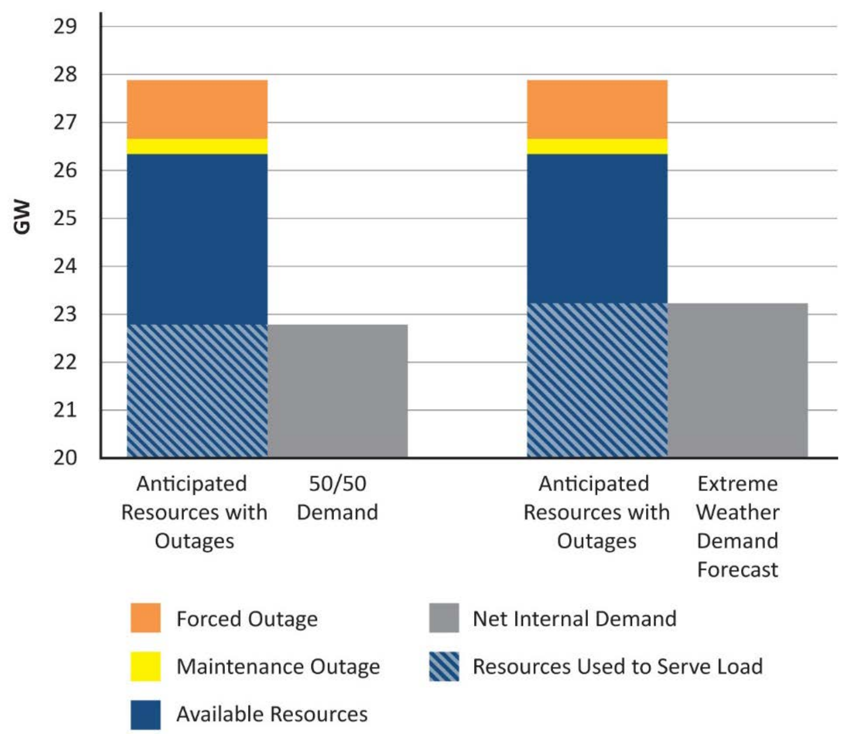


Figure 11: WECC-NWPP-CA operation risk

FRCC

Demand	Megawatts (MW)
Total Internal Demand	**45,600**
Total Demand Response – Available	2,976
Net Internal Demand	**42,624**
Projected Resource Categories	Megawatts (MW)
Existing Certain Capacity	57,041
Net Firm Capacity Transfers	1,242
Anticipated Resources	**58,284**
Existing-Other Capacity	402
Prospective Resources	**58,686**
Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**37%**
Prospective Reserve Margin	**38%**
NERC Reference Margin Level	**15.00%**

The Florida Reliability Coordinating Council's (FRCC) membership includes 23 members composed of investor-owned utilities (IOUs), cooperative systems, municipal utilities, power marketers, and independent power producers. FRCC is divided into 10 Balancing Authorities with 70 registered entities (both members and nonmembers) performing the functions identified in the NERC Reliability Functional Model and defined in the NERC Reliability Standards. The Region contains a population of over 16 million people and has a geographic coverage of about 50,000 square miles over Florida.

FRCC uses a 15 percent reserve margin as the NERC reference reserve margin criterion and, based on the expected load and generation capacity, the anticipated reserve margin is projected to be at 37 percent for the upcoming winter season.

The FRCC Region is forecasted to reach its 2015/16 winter noncoincident net internal demand of 42,624 MW in January. This projection for the 2015/16 winter is consistent with historical weather-normalized FRCC Region demand growth. The FRCC Region is projecting a decrease of 0.1 percent in the 2015/16 winter peak demand as compared to the previous year's projection for 2015/16.

The projected demand response capability is projected to remain consistent and will be approximately 6.5 percent of the upcoming winter total peak demand. The FRCC does not anticipate utilizing demand response with any significant frequency during the winter season to maintain reliability due to the projected 37 percent reserve margin. Demand response within the FRCC Region is treated as a load-modifier and not as a capacity resource. Demand response is primarily used to reduce the peak demand through cycling or complete shutdown of air conditioning, space heating, water heating, and pool pump equipment.

The FRCC Region is not expecting any issues that could lead to a large-scale impact to generator availability during the winter season. The FRCC Region has 413 MW of generation under firm contract, available to be imported into the Region from the SERC-SE assessment area throughout the winter season and another 829 MW of FRCC member-owned generation that is dynamically dispatched out of the SERC-SE assessment area. All firm on-peak capacity imports into the FRCC Region have firm transmission service agreements in place to ensure deliverability into the FRCC Region, with such capacity resources included in the calculation of the Region's anticipated reserve margin. The Operations Planning Working Group (OPWG), under the direction of the FRCC operations planning coordinator, holds weekly conference calls to coordinate outages and discuss any potential operational issues. Transmission Operators from the FRCC and SERC Regions participate in these calls.

The FRCC Region has not identified any specific large-scale projects needed to maintain or enhance reliability during the 2015/16 winter season. The FRCC operational seasonal study for the upcoming winter demonstrates that potential BES transmission constraints can be successfully mitigated to maintain reliability of the BES within the FRCC Region. The existing transmission projects in the FRCC Region are primarily related to expansion in order to serve localized load growth and generator integration and to maintain the reliability of the BES in the longer-term planning horizon. Therefore, no projects have been identified that would have an impact on reliability during the assessment period.

FRCC expects the BES to perform adequately over various system operating conditions with the ability to deliver the resources to meet the load requirements at the time of the winter peak demand. The FRCC performed a Winter Transmission Assessment and Operational Seasonal Study to assess the adequacy and robustness of the BES within the FRCC Region under expected 2015/16 winter peak load and under anticipated system conditions (taking into account generation and transmission planned maintenance activities). This regional assessment and operational study analyzed the performance of the transmission system under normal conditions, single-contingency events, and selected multiple-contingency events determined relevant by past studies. The results were coordinated and peer-reviewed by the FRCC's OPWG to ensure the BES performs adequately throughout the winter time frame. The study results demonstrated that potential thermal and voltage conditions exceeding the applicable screening criteria will be successfully mitigated under normal conditions, single-contingency events, and selected multiple-contingency events.

MISO

Demand	Megawatts (MW)
Total Internal Demand	**103,965**
Total Demand Response – Available	2,869
Net Internal Demand	**101,095**
Projected Resource Categories	Megawatts (MW)
Existing Certain Capacity	143,694
Net Firm Capacity Transfers	-1,128
Anticipated Resources	**142,566**
Existing-Other Capacity	2,474
Prospective Resources	**145,050**
Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**41%**
Prospective Reserve Margin	**43.5%**
NERC Reference Margin Level	**14.30%**

The Midcontinent Independent System Operator, Inc. (MISO) is a not-for-profit, member-based organization administering wholesale electricity markets that provide customers with valued service, reliable, cost-effective systems and operations, dependable and transparent prices, open access to markets, and planning for long-term efficiency. MISO manages energy, reliability, and operating reserves markets that consist of 36 local Balancing Authorities and 394 market participants, serving approximately 42 million customers. The MAPP portion of the MISO Reliability Coordination Area is reported separately in the MRO-MAPP section of this report. Although parts of the MISO fall in three NERC Regions, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

Footprint Changes: December 2013: Integration of the MISO South resulted in an expanded footprint.[14]

MISO forecasts a 41 percent anticipated reserve margin for 2015 winter peak, which is 26.7 percentage points higher than the reference margin level of 14.3 percent.

Load-serving entities submit monthly peak demand forecasts for two years and an additional eight years of summer and winter peak demand forecasts noncoincident to MISO's peak per Module E-1 of MISO's tariff.[15] Based on these forecasts, MISO anticipates a noncoincident peak demand of 108,526 MW for the upcoming winter season. MISO anticipates 4,561 MW diversity from MISO's Loss of Load Expectation (LOLE) analysis, which uses the 2005 and 2006 historic load shapes for the MISO North/Central and South regions respectively. This brings MISO's forecasted coincident total internal demand to peak at 103,965 MW during the 2015-2016 winter season.

In general, Arkansas, Mississippi, Louisiana, and Texas have higher than average growth rates when compared to the rest of the MISO area. A portion of the higher-than-average growth is due to the projected increase in LNG production for export.

Winter load forecast uncertainty (LFU)[16], a standard deviation statistical coefficient, applied to winter base 50/50 load forecast (coincident total internal demand) was used to calculate a 90/10 load level for each local resource zone. The system-wide 90/10 load for winter was calculated at 111,313 MW, which is 7,349 MW higher than the forecasted 50/50 total internal demand.

MISO currently separates demand response resources into two separate categories, direct control load management and interruptible load. Direct load control load management is the magnitude of customer service (usually residential) that can be interrupted at the time of peak by direct control of the applicable system operator. Direct control load management is typically used for peak shaving. Interruptible load is the magnitude of customer demand (usually industrial) that, in accordance with contractual arrangements, can be interrupted at the time of

[14] Includes Entergy Arkansas, Inc., Entergy Texas, Inc., Entergy Mississippi, Inc., Entergy Louisiana, LLC, Entergy Gulf States Louisiana, L.L.C., Entergy New Orleans, Inc., Cleco Power LLC, Lafayette Utilities System, Louisiana Energy & Power Authority, South Mississippi Electric Power Authority, and Louisiana Generating, LLC.

[15] Submittal of demand forecast is in accordance with Module E-1 Section 69 of the MISO Tariff. Section 3.2 of MISO's *Resource Adequacy Business Practice Manual and the Peak Forecasting Methodology Whitepaper* provide methods and assumptions for calculating MISO coincident peaks.

[16] Details on the LFU analysis can be found at the following hyperlink: *Loss of Load Expectation Study Report*.

peak by direct control of the system operator (remote tripping) or by action of the customer at the direct request of the system operator.

For this assessment, MISO uses the historic winter availability of demand side management resources. This amount is accounted to be fully available with a 12-hour notification. If some demand response resources don't perform, subsequent steps of the RTO-EOP-002 procedure would be implemented.

During times of peak conditions, or when MISO otherwise forecasts the potential for maximum generation conditions, MISO surveys local Balancing Authorities to obtain the amount of their demand response resources that would be available under a given notification time (2 hours for example). If MISO reaches the point of needing to call on these resources, MISO will deploy only the amount needed, and expect that all resources will perform. The use of these resources is part of the progression through our Capacity Emergency procedure.

MISO forecasts 3,428.5 MW of demand response programs to be available for this winter season. In addition, MISO expects 2,699 MW of BTMG to be available for this winter season, though it does not expect to rely on it due to high reserve margins.

For the 2015 winter, 2,225 MW of new nameplate capacity was integrated into the MISO system since the prior winter assessment. Of these additions, the contributions based on generation types are: 26 MW from petroleum, 669 MW from natural gas, and 1,530 MW from wind.

There is always the potential for frozen coal issues or fuel deliverability limitations to result from unusually cold weather. MISO studies several scenarios for the winter season, including a high forced outage rate scenario. Reserve margins are sustained well above the reference margin level in these scenarios, maintaining system reliability. This information is studied and included in the MISO Winter Resource Assessment report, with results presented at the Winter Readiness Workshop[17] held in October 2015.

MISO's wind resources receive a wind capacity credit based on the effective load carrying capability of wind generation. For the 2015-16 planning year, the average wind capacity credit is 14.7 percent. All other intermittent resources receive their unforced capacity rating based on historical performance.[18]

MISO anticipates net firm exports to be 1,128 MW for the 2015 winter. MISO assumes a forecast of 3,569 MW of capacity from outside of the MISO footprint to be designated firm for use during the 2015 winter and cannot be recalled by the source Transmission Provider. This capacity was designated to serve load within MISO through the Module E-1 process for the 2015 winter. MISO assumes a forecast of 3,525 MW of firm capacity exports to PJM based on the cleared results of their 2015 Capacity Market's base residual auction reliability pricing model. Additionally 78 MW are exported to SERC-N and 62 MW exported to SPP. There are also 1,032 MW of exports from capacity within MISO that are pseudo-tied to SPP.

For this assessment, MISO uses the registered amount of external support that is procured and cleared through the annual planning resource auction as firm imports. MISO collaborates with neighboring markets to determine firm export amounts. If a resource has cleared in another area's capacity market or is being studied for firm drive-out transmission service requests to participate in another areas capacity market, MISO assumes that resource to be a firm export as of the year the resource is planned to participate in that market. For this assessment, the amount of firm exports from MISO to PJM's market was used based on PJM's 2015 base auction results.

[17] MISO Winter Readiness Workshop – October 2015

[18] See the MISO BPM 011 – Resource Adequacy for more detail.

Each year MISO performs a seasonal assessment for both their summer and winter-peaking seasons. The results of the 2015 Winter Coordinated Seasonal Assessment for transmission were presented at the MISO 2015 Winter Readiness Workshop[19], planned for October 2015. The workshop presentation and winter assessment report will be available in November 2015. All seasonal assessment reports are publicly posted on the MISO website.

MISO's planning process evaluates all delayed projects to ensure reliability is maintained. Presently, there are no potential reliability impacts due to schedule delays of transmission identified. MISO is currently studying the effect of transmission lines or transformer outages in the assessment period. Results of the study are expected to be finalized and reported at the Winter Readiness Workshop.

During times of peak conditions, or when MISO otherwise forecasts the potential for maximum generation conditions, MISO surveys local Balancing Authorities to obtain the amount of their demand response resources that would be available under a given notification time (2 hours for example). If MISO reaches the point of needing to call on these resources, MISO will deploy only the amount needed and expect that all deployed resources will perform.

Similar to the previous winter assessment, instead of planning for the full availability of the non-air-conditioning programs that cleared in the planning resource auction, MISO uses the amount of load modifying resources availability reported through the MISO communications system (MCS) during the previous winter. The use of these resources is part of the progression through the RTO-EOP-002 procedure. If some demand response resources don't perform, subsequent steps of the RTO-EOP-002 procedure would be implemented to the extent necessary.

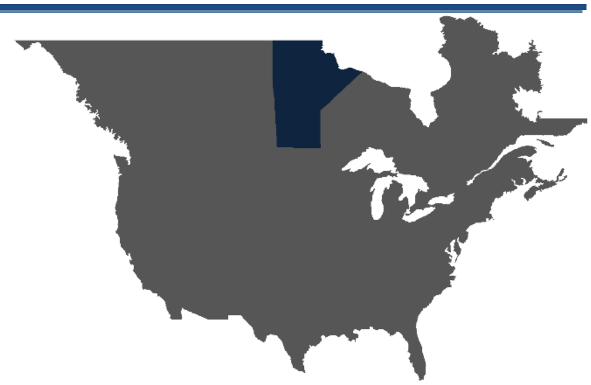
Polar vortex lessons learned actions have been implemented to increase system operator and generator operator situational awareness. These actions include holding a Winter Readiness Workshop every year, sending out a weatherization notification, making a gas pipeline notification website accessible, conducting emergency operating procedure workshops, enhancing electric-gas coordination efforts via the Electric and Natural Gas Coordination Task Force (ENGCTF), and incorporating CROW software cause code changes to provide more detailed reasons for outages.

Market participants (MP's) are responsible for submitting unit operational parameters and facility limitations per the *Energy and Operating Reserve Markets Business Practices Manual* (BPM-002). MISO depends on the MP's to update offer data, operational limits, etc. via the market portal or by contacting the regional generation dispatcher. Units with specific operating limitations can offer themselves as available maximum emergency (AME) and could be used during maximum generator emergencies.

[19] MISO Winter Readiness Workshop – October 2015

MRO-Manitoba Hydro

Demand	Megawatts (MW)
Total Internal Demand	**4,378**
Total Demand Response – Available	0
Net Internal Demand	**4,378**
Projected Resource Categories	Megawatts (MW)
Existing Certain Capacity	5,304
Net Firm Capacity Transfers	30
Anticipated Resources	**5,334**
Existing-Other Capacity	151
Prospective Resources	**5,485**
Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**22.00%**
Prospective Reserve Margin	**25.00%**
NERC Reference Margin Level	**12.00%**



Manitoba Hydro is a Provincial Crown Corporation providing electricity to 548,000 customers throughout Manitoba and natural gas service to 270,000 customers in various communities throughout southern Manitoba. The Province of Manitoba is 250,946 square miles. No change in the footprint area is expected during the assessment period. Manitoba Hydro is its own planning authority (PA) and Balancing Authority (BA). Manitoba Hydro is a coordinating member of the Midcontinent Independent System Operator (MISO). MISO is the reliability coordinator (RC) for Manitoba Hydro.

Manitoba Hydro is projecting the anticipated reserve margin to be above the reference margin level for the upcoming winter.

The winter demand peak forecast for 2015/16 is 4,378 MW, which is the maximum hourly load required to serve Manitoba Hydro's customers on the integrated system. There were no significant changes to the winter demand forecast since last winter. The decrease in the demand forecast from last winter includes an increase in indirect demand-side management efforts from the previous winter assessment and inclusion of Manitoba Hydro's curtailable load program in the calculation of total internal demand. The curtailable load program was previously captured under demand-side Management in the seasonal assessments; however, it no longer applies to this category under NERC's new definition of demand-side management.

There are no new capacity additions in the assessment area since the prior winter assessment.

There are no known concerns that could impact generation availability during the upcoming winter season. There are no changes to the methods in how expected on-peak capacity values are calculated for variable resources.

The expected on-peak capacity values for hydro are determined using testing and data processing procedures in accordance with the Standard MOD-025-2 FERC Order 796 issued March 20, 2014. The expected on-peak capacity that a unit can sustain is computed using the test results. These values are adjusted for ambient conditions and exclude capacity used for station service. Manitoba Hydro calculates these adjustments using only the peak load hours for each month. The adjustments are in compliance with MISO resource adequacy business practices and provide representative and stable capability values for hydro units.

For wind generation in the spring, fall, and summer months, Manitoba Hydro assumes a capacity value of 14.7 percent, based on the effective load carrying capability (ELCC) analysis in MISO's *Planning Year 2015-2016 Wind Capacity Credit* report[20]. For wind generation in the winter, Manitoba Hydro assumes a capacity value of zero percent.

Manitoba Hydro has 520 MW of on-peak capacity exports and 550 MW of on-peak capacity imports during the assessment period.

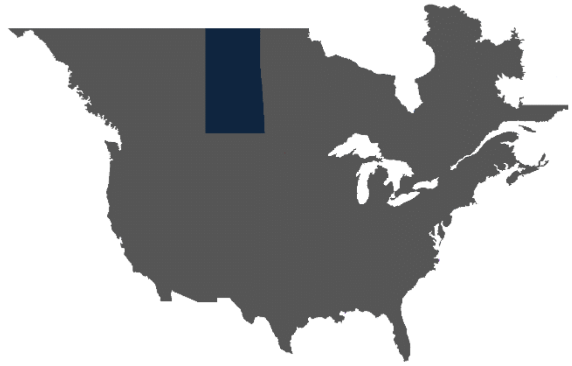
[20] MISO 2015-2016 Wind Capacity Credit Report

At a minimum annual basis, Manitoba Hydro performs an operational study to determine the necessary storage reserve requirements to meet demand under the lowest historic flow on record and a high load forecast. Given current storage and inflow conditions, drought is not a concern for the upcoming winter season. There have been no unique operational problems observed.

Manitoba Hydro is not aware of any significant issue in neighboring areas that could have a potential impact in Manitoba. Manitoba Hydro monitors the MISO resource adequacy situation and provides resource adequacy data to MISO as required. Manitoba Hydro does not depend on any supply from the adjacent Saskatchewan and Ontario regions for its long term resource adequacy requirements.

MRO-SaskPower

Demand	Megawatts (MW)
Total Internal Demand	**3,675**
Total Demand Response – Available	244
Net Internal Demand	**3,431**
Projected Resource Categories	Megawatts (MW)
Existing Certain Capacity	4,169
Net Firm Capacity Transfers	25
Anticipated Resources	**4,194**
Existing-Other Capacity	0
Prospective Resources	**4,194**
Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**22%**
Prospective Reserve Margin	**22%**
NERC Reference Margin Level	**11.00%**



Saskatchewan is a province of Canada and comprises a geographic area of 651,900 square kilometers with approximately 1.1 million people. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the planning coordinator and RC for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a Provincial Crown Corporation and under provincial legislation is responsible for the reliability oversight of the Saskatchewan bulk electric system and its interconnections.

Saskatchewan experiences its peak demand in winter. The seasonal operating margins are expected to be adequate for the winter, and no significant seasonal constraints have been identified. Saskatchewan uses an 11 percent reference margin level, which has not changed since the prior winter assessment. An adequate anticipated reserve margin of 22 percent is projected for SaskPower during the 2015 winter assessment period.

SaskPower is not expecting significant changes in the demand forecast. Saskatchewan's total internal hourly interval demand is forecast to be 3,675 MW for the 2015 winter assessment period. Saskatchewan has already added 23 MW of wind generation and 209 MW of natural gas generation in 2015. There is also a new firm import of 25 MW from Manitoba on Saskatchewan's far north system. A total demand response of 244.4 MW is also expected to be available during the assessment period, which is 158.4 MW higher than the previous winter assessment period.

The 2015-16 winter season joint operating study with Manitoba Hydro, with input from North Dakota, determines the import and export capabilities with neighboring Balancing Authorities for the 2015-16 assessment period. This is an operating study that considers different operating scenarios and N-1 contingencies. This study identifies if there is a need for any seasonal transmission constraints and operating guides. As part of the study, applicable guidelines are issued to respective control rooms before the winter season begins.

NPCC-Maritimes

Demand	Megawatts (MW)
Total Internal Demand	**5,509**
Total Demand Response – Available	256
Net Internal Demand	**5,253**
Projected Resource Categories	Megawatts (MW)
Existing Certain Capacity	6,816
Net Firm Capacity Transfers	0
Anticipated Resources	**6,816**
Existing-Other Capacity	0
Prospective Resources	**6,816**
Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**30%**
Prospective Reserve Margin	**30%**
NERC Reference Margin Level	**15.00%**

The Maritimes assessment area is a winter-peaking NPCC subregion that contains two Balancing Authorities. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, Prince Edward Island, and the northern portion of Maine, which is radially connected to the New Brunswick power system. The area covers 58,000 square miles with a total population of 1.9 million people.

Maritimes has two Balancing Authorities, New Brunswick and Nova Scotia. The New Brunswick System Operator is the RC for the Maritimes Area which covers approximately 57,800 square miles.

This is a winter-peaking system and it is projected to have adequate surplus capacity margins above its operating reserve requirements for the 2015-16 winter assessment period. A 20 percent reserve criterion for planning purposes exceeds the NERC reserve margin of 15 percent.

No significant changes in the demand forecast are expected since the previous winter. Forecasted peak for the 2014-15 winter was 5,398 MW, and the peak for the 2015-16 winter is 5,509 MW, an increase of 111 MW. The only demand response considered in resource adequacy assessment for the Maritimes area is interruptible load, which comes from industrial customers under contract. Because of the variable of industrial load at any one time, and the small amount of MWs, these values do not carry much weight when a seasonal reliability assessment is being completed.

No generation retirements are scheduled during this winter assessment period. There has been a 191 MW increase in the total amount of wind generation scheduled to be on-line from various projects when compared to the scheduled amount of wind from the prior winter assessment period. Of the 191 MW, there is 177 MW already in service with the remaining 14 MW scheduled to be in service by the time the Maritimes is expecting their winter peak.

NPCC-New England

Demand	Megawatts (MW)
Total Internal Demand	**21,077**
Total Demand Response – Available	587
Net Internal Demand	**20,490**
Projected Resource Categories	Megawatts (MW)
Existing Certain Capacity	25,002
Net Firm Capacity Transfers	1,226
Anticipated Resources	**26,308**
Existing-Other Capacity	7,020
Prospective Resources	**33,328**
Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**28.4%**
Prospective Reserve Margin	**62.7%**
NERC Reference Margin Level	**16.7%**

ISO New England (ISO-NE) Inc. is a regional transmission organization (RTO) serving Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. It is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system and also administers the region's wholesale electricity markets and manages the comprehensive planning of the regional BPS. The New England regional electric power system serves approximately 14.5 million people over 68,000 square miles.

During the forecasted peak demand week of January 17, 2016, ISO-NE forecasts existing certain and net firm transfers of 26,228 MW, consisting of 25,002 MW of existing-certain generation and 1,226 MW of net firm imports, to meet the coincident net internal demand of 20,479 MW for the 2015-16 winter. The net internal demand takes into account 587 MW of demand response resources, which provides a total internal demand value of 21,077 MW. The ISO-NE prospective reserve margin of 62.7 percent and anticipated reserve margin of 28.4 percent are above the NERC reference margin level of 16.7 percent. The existing-certain generation value originates from the seasonal claimed capability (SCC) of 32,819 MW, then incorporates 7,817 MW of planned maintenance, natural-gas-fired generation that is at risk, and unplanned outages.

The amount of capacity for ISO-NE to meet the LOLE criterion of disconnecting firm load due to resource deficiencies on average no more than 1 in 10 days per year is purchased through the forward capacity market. This market has an annual auction three years in advance of the capacity year. After this primary auction and before the commencement year, annual reconfiguration auctions take place prior to the commencement year to readjust installed capacity purchases and ensure adequate capacity to meet system needs. The capacity needs can vary from year to year depending on system conditions. The anticipated reserve margin of 28.4 percent and prospective reserve margin of 62.7 percent include the SCC of generators and do not include the short-term capacity and energy purchases from neighboring systems that are anticipated to meet the system demand. If ISO-NE was to consider capacity supply obligations (CSO) procured through the annual energy markets, this would reflect an anticipated reserve margin of 14.9 percent and prospective reserve margin of 46.3 percent respectively.

The New England Capacity, Energy, Loads and Transmission (CELT[21]) report for 2015 provides reference (50/50) and extreme (90/10) internal demand forecast of 22,740 MW and 23,400 MW respectively. After accounting for 1,663 MW of passive demand resources, the total internal demand forecasts are 21,077 MW and 21,737 MW. The 2015-16 winter total internal demand forecast is approximately 9 MW (.04 percent) lower than the 2014-15 winter forecast of 21,086 MW and 521 MW (2.5 percent) more than the 2014-15 actual winter demand of 20,556 MW. The 2015-16 demand forecast has not changed significantly since last winter. If New England were to experience similar periods of low ambient temperatures, ISO-NE would expect the winter peak load to be higher than last year. Due to the effects of increased conservation and energy-efficiency measures fostered by the six New England states over the last several years has led to a significant decrease in its winter peak demand since the region's all-time record winter peak demand observed in January 2004 of 22,818 MW.

[21] CELT

During the 2015–16 winter period, a total of 587 MW of active demand resources are expected to be available on peak. These active demand resources consist of real-time demand response (RTDR) (413 MW) and real-time emergency generation (RTEG) (174 MW) which can be activated with the implementation of ISO-NE Operating Procedure No. 4 – Action During a Capacity Deficiency (OP 4). OP-4 Action 2 is implemented to dispatch RTDR and manage operating reserve requirements. Action 6, which is the dispatch of RTEG, may be implemented to maintain ten-minute reserve. Dispatchable RTDR and RTEG resources show significant variation in performance, depending on factors such as weather, day of week, time of dispatch, and planned or forced facility shutdowns. When called upon, these active demand resources are expected to meet their dispatch within thirty minutes.

New generation improvements since the previous winter assessment include one wind project with a nameplate totaling 34 MW, multiple small solar generators totaling 52 MW that became commercial prior to the 2015-16 winter assessment period, and an additional wood/wood refuse generator of 87 MW that moved from behind the meter during the summer capacity period. There are 80 MW of planned tier 1 nameplate capacity expected for the winter 2015-16 operating period. Significant reductions include the Vermont Yankee Nuclear generating facility, capable of providing 615 MW of capacity, which retired in December, 2014.

ISO-NE meets annually with their adjacent RCs to review applicable operating agreements and operating procedures. Transmission system changes that could have an impact on import and export capabilities are evaluated regularly and any adjustments to the established limits are shared with the adjacent RC for review in determining mutually reliable transfer limits. Efforts are coordinated for a simultaneous implementation for any required changes.

Since the 2014-15 winter assessment, New England has benefitted from transmission system improvements. With the completion of the Maine Power Reliability Project (MPRP), more than 450 miles of new or rebuilt 345 kV and 115 kV transmission lines have been placed into service. Five new substations also have been placed into service, and six major substation have been modified. In addition, six remedial action schemes and one automatic closing scheme have been retired. Improved load-serving and energy transfer capabilities have been observed across multiple interfaces within Maine as well as import/export capabilities with the Maritimes. The Interstate Reliability Project (IRP) is a portion of the New England East-West Solution that will further improve the New England transmission system. The 3271 line (a new 345 kV line in Connecticut from Card to Lake Road) went into service in the summer of 2015. In addition, the 341 line (Connecticut to Rhode Island) and 366 line (Rhode Island to Massachusetts) are 345 kV paths expected to go into service during the winter of 2015-16. These elements will help improve the Connecticut’s and Rhode Island’s import and export transfer capabilities, and New England East to West and West to East, and Rhode Island transfer capabilities. Upon completion of the IRP Project, the Lake Road Generating Station SPS (NPCC Type III) will be retired.

While natural gas continues to be the predominant fuel source in New England to produce electricity, ISO-NE continues to monitor factors affecting natural gas deliverability throughout the winter and summer reliability assessment periods. ISO-NE has reviewed natural gas pipeline maintenance schedules and has determined that they should have no adverse impacts to gas availability for the 2015-16 assessment period, however does anticipate the potential for various single-fuel, gas-only power plants to be temporarily unavailable during cold or extreme winter weather conditions or during force majeure conditions on the regional gas infrastructure. As such, New England forecasts that approximately 4,200 MW of natural-gas-fired capacity may be at risk for this winter period. To determine sufficient operable capacity margins, the ISO-NE’s long- and short-term outage coordination evaluates and accounts for gas-fired generation. ISO-NE would balance the mitigation of these scenarios with real-time supplemental commitment and the use of emergency procedures.

In measuring -at-risk gas-fired generation and improving situational awareness, ISO-NE has developed GUT that assists control room operators in the evaluation of current-day and next-day operating plans. The tool uses data gathered from EBBs provided by the gas pipelines serving New England. It also uses data from visualizations with estimated scheduled deliveries based on historical nominations for local distribution companies, commercial loads, and industrial loads. The results offer an estimation of the remaining natural gas pipeline capacity available for use by the New England power sector and forecast natural gas at risk.

The 2014-15 Winter Reliability Program proved to be a success and it is expected that the FERC approved 2015–16 Winter Reliability Program (ER15-2208-000 Winter Reliability Program – ISO New England) will continue to prepare ISO-NE to address several challenges that could have an impact on generation during the 2015–16 winter period. Similar to last year's program, the 2015–16 Winter Reliability Program and other supportive programs provide incentives that include the following components:

- A winter demand-response program
- A dual-fuel commissioning program that will compensate units for the some of the costs associated with dual-fuel commissioning to provide an incentive for creating more dual-fuel facilities in New England
- A dual-fuel testing program that compensate units for some of the costs associated with the fuel-swap testing to ensure a smooth fuel swap during the winter period
- An incentive program to store fuel oil onsite before the start of winter

During the 2015-16 winter period, ISO-NE plans to regularly participate in conference calls with Northeast RCs, share current and forecasted operating conditions, and continue to work with the regional natural gas industry to further improve the coordination and communication of planned and unplanned outages and convey real-time operating conditions that promote reliability of the bulk electric system. This is made possible through FERC Order 787.

ISO-NE has several procedures for dealing with loss of system capacity, including the following:

- Operating Procedure No. 4 – *Action during a Capacity Deficiency* (details use of demand response, emergency energy purchases, voltage reductions, reduction of system reserve requirements, requests for nonobligated capacity, and public appeals)
- Operating Procedure No. 7 – *Action in an Emergency* (covers shedding of firm system load)
- Operating Procedure No. 21 – *Energy Inventory Accounting and Action during an Energy Emergency* (details actions to be taken for forecast energy and fuel shortages)

NPCC-New York

Demand	Megawatts (MW)
Total Internal Demand	**24,515**
Total Demand Response – Available	885
Net Internal Demand	**23,630**
Projected Resource Categories	Megawatts (MW)
Existing Certain Capacity	41,312
Net Firm Capacity Transfers	338
Anticipated Resources	**41,725**
Existing-Other Capacity	0
Prospective Resources	**41,650**
Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**76%**
Prospective Reserve Margin	**76%**
NERC Reference Margin Level	**17.00%**

The New York Independent System Operator (NYISO) is the only BA within the state of New York (NYBA). The NYISO is a single-state ISO that was formed as the successor to the New York Power Pool, a consortium of the eight IOUs, in 1999. The NYISO manages the New York State transmission grid, encompassing approximately 11,000 miles of transmission lines over 47,000 square miles and serving the electric needs of 19.5 million New Yorkers. New York experienced its all-time peak load of 33,956 MW in the summer of 2013.

The New York control area (NYCA) is a summer-peaking region, so NYISO anticipates adequate resources will be available for the upcoming winter season. Reserve margins of approximately 77 percent are expected for the winter season before accounting for maintenance, derates, and unplanned outages. The reserve margin level for 2015-16 is 17 percent.

The New York State Reliability Council (NYSRC) has determined that an installed reserve margin (IRM) of 17 percent in excess of the NYCA coincident peak demand forecast is required to meet the Northeast Power Coordinating Council (NPCC) and NYSRC resource adequacy criterion for the capability year running from May 1, 2015, through April 30, 2016. The 2015-16 capability year IRM is unchanged from the IRM set for the prior capability year 2014-15.

Winter peak demand is relatively flat statewide. The baseline forecast of NYCA energy usage for 2015 is 160,121 GWh, which is 0.3 percent lower than the weather-normalized energy usage in 2014. Annual average energy growth is 0 percent in this year's forecast; last year it was 0.16 percent. The baseline forecast for the NYCA 2015 winter peak is 24,515 MW, which is 0.06 percent higher than the weather-normalized winter peak for 2014 and 0.54 percent lower than the actual 2014 winter peak of 24,648 MW. By contrast, the 2015 summer peak load forecast was 33,567 MW.

Since the winter 2014-15 season, there have been dual-fuel (gas and oil) nameplate additions of 555 MW. There are no additions planned during the upcoming winter season. A 75 MW coal unit is expected to be mothballed at the end of 2015.

A shunt reactor has been installed at the Coopers Corners 345 kV station for use in controlling high voltages during light load times, typically in light-load months. It is expected to be in service by the end of 2015.

A new tap station, Mainesburg, is expected to be in service in on the 345 kV Homer City-Watercure line between New York and PJM. The new station will change the NY-PJM interface definition by replacing the Homer City-Watercure (30) line with the Homer City-Mainesburg (47) and Mainesburg-Watercure (30) 345 kV lines.

A new national grid 345 to 115 kV tap station, Five Mile Road, is expected to be in service in the fourth quarter of 2015 on the 345 kV Homer City-Stolle Road line between New York and PJM. The new station will change the NY-PJM interface definition by replacing the Homer City-Stolle Road (37) line with the Homer City-Five Mile (37) line.

It is not unusual for the NYCA to experience extreme ambient temperatures during the winter season. Generators are prepared for such conditions and have adequate equipment installed to maintain normal operation during these times. For the past two winter seasons, there has been adequate capacity available to serve load and meet reserve requirements despite periods of record-setting low temperatures.

The NYISO Market Mitigation and Analysis Department performed on-site visits of several generating stations (sum 14,901 MW) to discuss past winter operations and preparations for winter 2015-16. Their visits focused on units with low capacity factors. A previsit questionnaire included assessments of natural gas availability during peak conditions, issues associated with burning or obtaining oil, emissions limitations, preventative maintenance plans, the causes of failed starts, programs to improve performance, and programs to insure switchyard reliability. They found that generators have increased generation testing, cold-weather preventative maintenance, fuel capabilities, and fuel-switching capabilities to improve winter operations.

NPCC-Ontario

Demand	Megawatts (MW)
Total Internal Demand	**22,389**
Total Demand Response – Available	555
Net Internal Demand	**21834**
Projected Resource Categories	Megawatts (MW)
Existing Certain Capacity	29,197
Net Firm Capacity Transfers	-500
Anticipated Resources	**29,256**
Existing-Other Capacity	0
Prospective Resources	**29,256**
Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**34%**
Prospective Reserve Margin	**34%**
NERC Reference Margin Level	**19.0%**

Ontario's electrical power system is geographically one of the largest in North America, covering an area of 415,000 square miles and serving the power needs of more than 13 million people. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

For the winter peak demand, the reference reserve margin (RRM) is 19 percent. Both the anticipated and the prospective planning reserve margins are above the RRM for the Ontario system for the 2015-16 winter assessment period. There are no foreseen reliability concerns related to transmission constraints, environmental regulation, or generator availability.

The peak demand forecast for the 2015-16 winter is 22,389 MW, which is higher than the previous winter's actual peak demand of 21,814 MW. Last year, the peak demand was reduced due to the Industrial Conservation Initiative (ICI) program, which acts as a critical peak pricing program and reduced the winter peak demand by over 1,000 MW. This winter, the IESO does not expect the ICI to have a significant impact at the time of the winter peak.

The IESO's demand response programs are comprised of three separate programs: 1) dispatchable loads, 2) Peaksaver PLUS, and 3) capacity-based demand response (CBDR). Peaksaver PLUS is an air conditioning, electric hot water heater, and swimming pool pump cycling program that is not available during the winter period. However, both dispatchable loads and CBDR will be available for activation in the upcoming winter. The total installed winter capacity of these demand response programs is just under 1,200 MW (this excludes Peaksaver PLUS) with a reliable capacity of approximately 555 MW.

Since the last winter assessment, Ontario has added 666 MW of new installed wind capacity and 100 MW of new installed solar capacity connected to the BPS. In addition, 53 MW of distribution-connected wind and 457 MW of distribution-connected solar were also added within Ontario.

Planned new resources that are expected to be in service prior to the forecast winter peak include 635 MW of wind, 140 MW of solar, 298 MW of gas, and 40 MW of biomass capacity.

NPCC-Québec

Demand	Megawatts (MW)
Total Internal Demand	**38,252**
Total Demand Response – Available	1,899
Net Internal Demand	**36,353**
Projected Resource Categories	Megawatts (MW)
Existing Certain Capacity	40,844
Net Firm Capacity Transfers	26
Anticipated Resources	**41,117**
Existing-Other Capacity	0
Prospective Resources	**41,117**
Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**13.1%**
Prospective Reserve Margin	**13.1%**
NERC Reference Margin Level	**11.70%**

The Québec assessment area is located in the northeastern part of the NPCC Region. It covers 595,391 square miles and a population of 8 million people (Province of Québec). The area has ties with Ontario, New York, New England, and the Maritimes, consisting of either HVDC ties, radial generation, or radial load. Transmission voltages are 735, 315, 230, 161, 120 and 69 kV with a ± 450-kV HVDC multi-terminal line. Transmission line length totals 21,243 miles (34,187 km) as of December 31, 2014.

The Québec Area demand forecast for the 2015–2016 winter peak (38,252 MW) is 260 MW higher than the demand forecast presented in last year's winter assessment. This increase of 0.70 percent is comparable to the prior forecasted growth rates (average of 0.65 percent for the three prior years).

The reference reserve margin level (RML) is 11.7 percent and is drawn from the *2014 Québec Balancing Authority Area Comprehensive Review of Resource Adequacy*,[22] which was approved by NPCC's Reliability Coordinating Committee on December 2, 2014. This year, the reference reserve margin is slightly higher than the one provided in the prior Winter Assessment (10.8 percent). The anticipated reserve margin level of 13.1 percent is not expected to drop below the NERC reference margin level of 11.7 percent for the 2015–2016 winter operating period. For this winter assessment, reserve-margin-level evaluations were done for peak conditions only.

In the Québec area, demand response programs are specifically designed for peak-load reduction during winter operating periods. Demand response consists mostly of interruptible demand programs for large industrial customers and treated as supply-side resources totaling 1,649 MW for the 2015-2016 winter period. A voltage reduction program with an estimated impact of 250 MW is also implemented. This program allows the operator to strategically reduce voltage across designated portions of its distribution system, within regulatory guidelines, in order to reduce peak demand.

The energy efficiency and conservation program's impact is evaluated at 1,590 MW for the 2015-2016 Winter peak period and is included in the demand forecast (active and to-be-deployed programs). These programs have been in place for several years and the records show that customer response is very reliable. Demand forecasts take into account the load shaving resulting from the residential dual energy program, a rate option for residential customers equipped with a dual energy space heating system (electric/fuel oil). When the outside temperature falls below a given level (-12°C for Montréal), the space heating system automatically runs on the fuel oil and the electricity used during that period is billed at higher rates. The impact of this program on peak load demand is estimated to be approximately 600 MW over the period assessment.

A total of 508 MW of new installed capacity is planned for the 2015-2016 winter peak: 135 MW from hydro generation and 373 MW from wind resources (with a contribution at peak estimated at 112 MW). There are no significant resource retirements planned for this winter.

[22] 2014 Québec Balancing Authority Area Comprehensive Review of Resource Adequacy

The Québec Area presents a slightly positive net transfer during the 2015–2016 winter peak period with firm capacity sales totaling 974 MW and capacity purchases totaling 1,000 MW.

A major project presently underway is the construction of the Romaine River Hydro Complex. At the end of 2014, the first phase, La Romaine-2 (640 MW) generating station, was integrated at the Arnaud 735/315/161-kV substation with a 162-mile line operated at 315-kV. One 315/161-kV, 500-MVA transformer has been commissioned at Arnaud substation for this project. By the end of 2015, the first of two generators of the second phase, La-Romaine-1 (135 MW each), will be commissioned. This new hydro generating station will be integrated into La-Romaine-2 substation with a 16-mile line operated at 315 kV. The second generator is expected to be in service by summer 2016.

This project has required the construction of a new 735-kV switching station, named Aux Outardes, located between existing Micoua and Manicouagan substations. Two 735-kV lines have been redirected into the new station and one new 735-kV line (5 km or 3 miles) has been built between Aux Outardes and Micoua. This project was initially planned to be in service by the end of 2014 but was commissioned in the summer of 2015.

Most of the Québec area's hydro generators are located in the north of the province, where extremely cold ambient temperatures could be reached during winter periods. Specific design requirements are documented to ensure that extreme ambient temperature does not affect operations. In case of any issues that might arise in real time, maintenance notices are issued to operators to handle such concerns. The status of voltage regulators and power system stabilizers are also monitored in real-time. In case of their unavailability, transmission limits are reduced accordingly.

During the 2015–2016 winter operating period, no significant issues concerning neighboring areas that could impact operations in the Québec Area have been identified. During very cold weather periods, planned interchange schedules will be coordinated between NPCC subregions. In this context, NPCC conference calls will be held as necessary. There are no known potential issues that could substantially impact the assessment projections.

PJM

Demand	Megawatts (MW)
Total Internal Demand	**131,721**
Total Demand Response – Available	525
Net Internal Demand	**131,196**
Projected Resource Categories	Megawatts (MW)
Existing Certain Capacity	174,697
Net Firm Capacity Transfers	2,942
Anticipated Resources	**183,208**
Existing-Other Capacity	0
Prospective Resources	**183,208**
Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**40%**
Prospective Reserve Margin	**40%**
NERC Reference Margin Level	**16%**

PJM Interconnection is an RTO that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM companies serve 61 million people and cover 243,417 square miles. PJM is a Balancing Authority, planning coordinator, transmission planner, resource planner, interchange authority, transmission operator, transmission service provider, and reliability coordinator.

The anticipated reserve margin is above the reference margin level for the upcoming winter. Since PJM is summer peaking, meeting reserve margin requirements in the winter is typically not a concern. The PJM anticipated reserve margin is 40 percent with the PJM reserve requirement being 15.6 percent.

For the 2015 load forecast, PJM adopted an interim improvement to the peak demand forecast model as a transitional mechanism until more permanent changes can be implemented that are based on more extensive and rigorous analysis and review. The interim improvement includes a binary variable in the model specification for the years 2013 and 2014 to account for factors such as changing energy usage trends not being fully captured by the current model specification. This additional variable in the model results in a downward adjustment of approximately one percent for the PJM zonal forecasts this winter. The forecast of the East Kentucky Power Cooperative (EKPC) zone was recalculated to be consistent with load reported by other PJM members accounting for losses. This led to higher peak loads in EKPC for both summer and winter forecasts. The forecast of the Dominion Virginia Power zone has been adjusted to account for substantial ongoing growth in data center construction.

The extreme weather (90/10) weather forecast for PJM is 140,221 MW. PJM staff forecasts demand for the entire PJM area. Extreme weather is part of PJM's normal planning process and is considered consistent with the probability of its occurrence. Recent focus has been on the winter peak period of 2013-2014 and 2014-2015. New winter all-time peaks were experienced in early 2014 and then again in early 2015. Some investigation has been undertaken to determine if a winter reserve requirement is needed, but no changes have been made to our planning assumptions or methods due to extreme weather at this time.

In past years, no demand response was available in PJM outside the summer peak period from June 1 through the end of September. In recent years, PJM has added a demand response type that is available all year and for unlimited uses. 525 MW of demand response is now available during the winter peak period, which is an increase over last winter's amount of 43 MW.

PJM had a total net loss of 6,163 MW of installed capacity since last winter.

PJM expects to import 4,161 MW from external entities and to export 1,219 MW to external entities. Each import transaction is accepted with the agreement that the specific units in question are no longer available to any other party but PJM. Transfer capability is also a requirement of accepting an import. PJM Balancing Authority operators confirm each transaction before they actually go into effect.

There are no transmission constraints that impact system reliability. Normal operations include dispatching generators out of economic order to avoid transmission constraints. There are no project delays for any transmission facilities (lines or transformers) expected to impact reliability during the upcoming winter.

PJM performed its winter operations study for the upcoming winter period. No special operating procedures are necessary. Sensitivities were studied with a higher percentage of random generation outages.

Recent challenges were extensively investigated and reported on in the 2014 and 2015 winter post-seasonal assessment reports.[23] [24]

New Capacity performance initiative

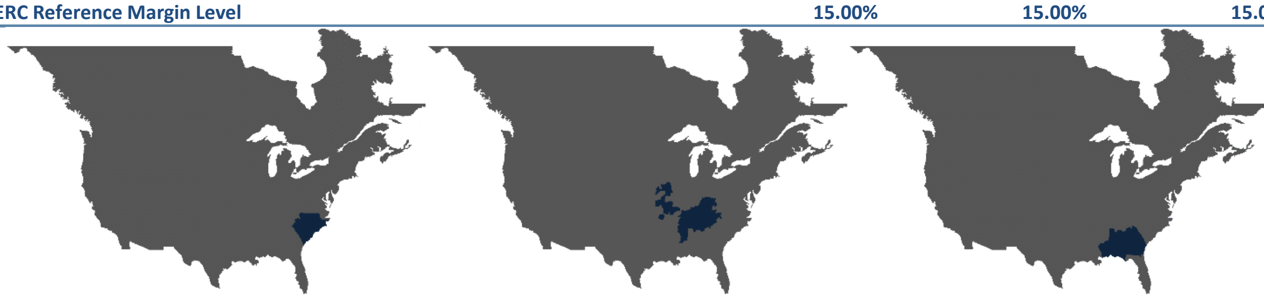
Capacity performance is a program that requires PJM generators to meet their commitments to deliver electricity whenever PJM determines they are needed to meet power system emergencies. As a "pay-for-performance" program, generators may receive higher capacity payments and are expected, in return, to invest in modernizing equipment, firming up fuel supplies and adapting to use different fuels. Natural gas plants will improve fuel security, placing them on a par with traditional resources having firmer fuel supplies. Generators that exceed performance commitments will be entitled to funds collected from generators that underperform. Generators assume virtually all financial risks if they do not meet their power supply obligations.[25]

PJM Generator Operational Requirements - Manual 14D Section 7.5 Cold Weather Generation Resource Preparation and the PJM Emergency Operations - Manual 13 provide the necessary Cold Weather preparation, testing, and Alerts/Warnings/Actions to ensure situational awareness for both system operations and generator owners. PJM Manuals contain details regarding cold weather preparation in Manual 14D - Generator Operational Requirements: Attachment N: Cold Weather Preparation Guideline and Checklist as well as a Winter Capability Testing Program (Manual 14D – Section 7.5.1 Generation Resource Operational Exercise).

[23] For 2014-2015 see: http://www.pjm.com/~/media/documents/reports/20150513-2015-winter-report.ashx
[24] For 2013-2014 see: http://www.pjm.com/~/media/documents/reports/20140509-analysis-of-operational-events-and-market-impacts-during-the-jan-2014-cold-weather-events.ashx and http://www.pjm.com/~/media/documents/reports/20140509-presentation-of-january-2014-cold-weather-events.ashx.
[25] For more info see: http://www.pjm.com/committees-and-groups/committees/elc.aspx.

SERC

	SERC-E	SERC-N	SERC-SE
Demand	Megawatts (MW)	Megawatts (MW)	Megawatts (MW)
Total Internal Demand	**41,922**	**40,989**	**43,973**
Total Demand Response – Available	803	1,470	2,107
Net Internal Demand	**41,119**	**39,519**	**41,866**
Projected Resource Categories	Megawatts (MW)	Megawatts (MW)	Megawatts (MW)
Existing Certain Capacity	53,165	53,594	65,170
Net Firm Capacity Transfers	307	-1,247	-2,787
Anticipated Resources	**53,472**	**53,558**	**62,526**
Existing-Other Capacity	42	1,834	345
Prospective Resources	**53,514**	**55,391**	**62,871**
Planning Reserve Margins	Percent (%)	Percent (%)	Percent (%)
Anticipated Reserve Margin	**30.04%**	**35.52%**	**49.35%**
Prospective Reserve Margin	**30.14%**	**40.16%**	**50.17%**
NERC Reference Margin Level	**15.00%**	**15.00%**	**15.00%**



SERC-E **SERC-N** **SERC-SE**

SERC is a summer-peaking assessment area that covers approximately 308,900 square miles and serves a population estimated at 39.4 million. SERC is divided into three assessment areas: SERC-E, SERC-N, and SERC-SE. The SERC Region includes 11 BAs: Alcoa Power Generating, Inc. – Yadkin Division (Yadkin), Associated Electric Cooperative, Inc. (AECI), Duke Energy Carolinas and Duke Energy Progress (Duke), Electric Energy, Inc. (EEI), LG&E and KU Services Company (as agent for Louisville Gas and Electric (LG&E) and Kentucky Utilities (KU)), PowerSouth Energy Cooperative (PowerSouth), South Carolina Electric & Gas Company (SCE&G), South Carolina Public Service Authority (Santee Cooper, SCPSA), Southern Company Services, Inc. (Southern), and Tennessee Valley Authority (TVA).

SERC has transitioned to RC area assessment boundaries due to how closely they align with the traditional subregional assessment boundaries: Tennessee Valley Authority for SERC-North, Southern Company for SERC-Southeast, and Virginia-Carolinas for SERC East.

The reserve margin for SERC's assessment area is anticipated to be above NERC's reference reserve margin of 15 percent during the upcoming winter season. The Region does not anticipate a significant change in the 2015/16 winter forecast from the previous winter. The Region anticipates a slight decline in demand for each of the assessment areas mostly due to minimal economic growth

Although the Region has a variety of energy efficiency and demand response programs, there is minimal direct impact on reserve margins during the winter assessment period. There have been no significant changes to the energy efficiency and demand response programs from the last winter. The 2015/16 controllable or dispatchable demand response is approximately 4,380 MW, which is only anticipated to be called upon during emergency situations in the event reserves drop below acceptable levels during extreme weather conditions.

There are several new units being commissioned during the winter season, totaling 2,174 MW. SERC's utilities do not anticipate fuel supply issues during the assessment period; however, if gas supplies were to become constrained, the combined effect throughout all assessment areas could impact generator availability. Open lines of communications, firm agreements with fuel providers, inventory management, and the use of dual-fueled units help to mitigate and minimize the possible risk of nondeliverability. Variable energy resources are taken into account for system peak demands, based on historical patterns.

Capacity transfers accounted for in the SERC assessment area are backed by firm generation and transmission contracts. These transfers are accounted for in the reserve margin calculations. SERC's near-term study group coordinates the development of cases to ensure there are sufficient transfer capabilities between the assessment areas and to assess potential impacts from capacity transfers. The challenges associated with this process are largely due to differences in how market and nonmarket organizations account for imports and exports.

The assessment areas within SERC do not anticipate any reliability concerns related to the use of demand response during the upcoming winter season. The most recent utilization of demand response was during the extreme cold weather in January 2014. During that extreme weather event, the utilization of demand response was performed successfully, therefore the SERC utilities are confident that these resources will be available and perform adequately if required for the upcoming season.

SERC utilities coordinate any planned work with their first-tier neighbors, as well as generator and transmission outages with potential interface impacts, on both a quarterly and weekly basis. Additionally, the methodologies for incremental transfer capability calculations includes the impact of identified constraints in neighboring systems. SERC utilities do not anticipate any significant issues for the upcoming winter due to extended transmission or generator outages, modifications to existing operational procedures, increased dependency on transfers, or identification of critical units for seasonal reliability. However, SERC member committees are continuing to assess the reliability impacts due to the expansion of the RTO footprint within SERC. In addition to the RTO impacts, SERC is addressing assessment changes related to Mercury and Air Toxic Standards retirements, the Clean Power Plan, dispatch flow patterns, MOD-032 modeling changes, and the integration of renewables. As a result, the SERC Reliability Studies Steering Committee has created a taskforce to address these issues and to better address emerging uncertainties. SERC study groups continue to perform regional analysis to evaluate approaches for future assessment practices with the goal of identifying potential reliability concerns across a wide-range of future conditions. Also, the Operations Reliability Coordination Agreement (ORCA) was recently extended, with newly defined parameters, until April 1, 2016, which will limit the amount of transfers between MISO-N and MISO-S in order to reduce reliability impacts on neighboring systems. SERC members continue to work towards identifying a long-term solution to ensure that the SERC Region beyond the ORCA is reliably operated.

SPP

Demand	Megawatts (MW)
Total Internal Demand	**41,766**
Total Demand Response – Available	766
Net Internal Demand	**41,000**
Projected Resource Categories	Megawatts (MW)
Existing Certain Capacity	67,566
Net Firm Capacity Transfers	-509
Anticipated Resources	**67,819**
Existing-Other Capacity	125
Prospective Resources	**67,944**
Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**65%**
Prospective Reserve Margin	**66%**
NERC Reference Margin Level	**13.60%**

Southwest Power Pool (SPP) is a NERC Region that covers 370,000 square miles and encompasses all or parts of Arkansas, Kansas, Louisiana, Mississippi, Missouri, New Mexico, Oklahoma, and Texas, serving approximately 6.2 million households. The footprint has 48,368 miles of transmission lines, 915 generating plants, and 6,408 transmission class substations. The SPP Winter Assessment is reported based on the planning coordinator footprint. Along with the SPP Regional Entity footprint, it also includes Nebraska Public Power District, Omaha Public Power District, and Lincoln Electric System, which are registered with the Midwest Reliability Organization (MRO) Region.

Beginning October 1, SPP will assume the planning coordinator functions for the integrated system (IS), which is comprised of the Western Area Power Administration – Upper Great Plains in Billings, Mont.; the Basin Electric Power Cooperative in Bismarck, N.D.; and the Heartland Consumers Power District in Madison, S.D., which are also registered with the Midwest Reliability Organization Regional Entity. The IS integration will expand the SPP assessment area to 84 members in Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas and Wyoming that serve more than 15 million customers along with adding more than 5,000 megawatts of peak demand and 9,500 miles of transmission infrastructure.

The SPP assessment area's reserve margin is above the anticipated target reserve margin of 13.6 percent for the upcoming winter season. The total internal demand for the 2015/2016 winter is roughly 5,500 MW higher than last year's winter forecast. The increase in the load is due mainly to the migration of the integrated system (IS), formally referred to as MAPP, into the SPP assessment area.

There are a variety of Energy Efficiency (EE) and demand response programs in the assessment area, but they are expected to have minimal impact during the winter season. The controllable, or dispatchable, demand response for the upcoming winter is approximately 765 MW. There are no anticipated reliability concerns due to use of the demand response programs.

The SPP assessment area integrated 2,173 MWs of nameplate capacity since the 2014 winter assessment and expects to integrate an additional 702 MW of nameplate capacity by the end of the winter time frame. The planning reserve margin in SPP is robust enough to handle short-term outages along with the operating reserves.

Capacity transactions included in the SPP winter assessment are backed by firm generation and transmission. These transfers are included in the assessment area's reserve margin calculation. The SPP assessment area coordinates with neighboring areas to ensure that adequate capacity transfer capabilities will be available.

The SPP assessment area does not anticipate any significant issues during the winter time frame due to extended transmission or generator outages, modifications to existing operational procedures, increased dependency on transfers, or identification of critical units for seasonal reliability. The SPP assessment area is historically capacity rich during the winter time frame. Because of this capacity, in combination with SPP's diverse generation fleet, SPP has not identified the need for an additional study assessing fuel unavailability impacts.

The SPP assessment area will notify members in the case of an extreme weather event so they can prepare personnel and facilities for expected extreme conditions. When extreme temperatures are forecasted and expected to persist for an extended period of time, the SPP assessment area will issue an extreme weather alert to members. SPP members monitor their fuel supplies and inventories and keep SPP updated about stations and units that are experiencing or projected to experience fuel limitations. Conference calls are scheduled to review the operating situations, as appropriate.

There are approximately 160 miles of 230 kV transmission in Texas and New Mexico expected to come in service over the 2015/2016 winter time frame.

ORCA has recently been extended to April 1, 2016 and has new operational limits that allow MISO to dispatch up to 3,000 MW between North and South. Similar to the previous ORCA, MISO must take initial relief obligations during congestion down to 2,000 MW of dispatch flow, at which time normal transmission limiting relief (TLR) is used. This revised ORCA procedure is coordinated between SPP, MISO, and the joint parties.

On March 1, 2015, SPP and MISO began using market-to-market mechanisms to more efficiently and economically control congestion on SPP and MISO flowgates in which both markets have a significant impact. During congestion on an SPP market-to-market flowgate, SPP will initiate the market-to-market process, and SPP and MISO will coordinate through an iterative process to identify and redispatch the most cost-effective generation between the two markets to relieve the congestion. SPP and MISO still rely on TLR to curtail the impact of transactions from entities other than SPP or MISO.

TRE-ERCOT

Demand	Megawatts (MW)
Total Internal Demand	**53,719**
Total Demand Response – Available	2,338
Net Internal Demand	**51,381**
Projected Resource Categories	Megawatts (MW)
Existing Certain Capacity	76,654
Net Firm Capacity Transfers	1,177
Anticipated Resources	**78,197**
Existing-Other Capacity	0
Prospective Resources	**78,197**
Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**52.19%**
Prospective Reserve Margin	**52.19%**
NERC Reference Margin Level	**13.75%**

The Electric Reliability Council of Texas (ERCOT) is the independent system operator for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. ERCOT is a summer-peaking area that covers approximately 200,000 square miles, connects 40,530 miles of transmission lines and 566 generation units, and serves 23 million customers. The Texas Reliability Entity (Texas RE) is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for the ERCOT area.

For the upcoming winter season, the anticipated reserve margin for the TRE-ERCOT area is forecasted at 52.2 percent, exceeding its reference margin of 13.75 percent by a wide margin. The 2015-2016 winter peak demand forecast of 53,719 MW is expected to occur in January 2016. This forecast is 1.7 percent above the 2014-2015 winter peak demand forecasted last year (52,837 MW). With 2,338 MW of demand response capacity expected, the TRE-ERCOT area's net internal demand for the winter season is forecasted at 51,381 MW.

Regarding generation resource additions, 1,112 MW of natural-gas-fired capacity (winter rating), 2,727 MW of wind (491 MW on-peak capacity), and 24 MW of utility-scale solar (1.4 MW on-peak capacity) entered commercial service since the last winter assessment. Planned wind resources for the upcoming winter season total 1,611 MW of installed capacity, which translates into an on-peak winter capacity contribution of 360 MW. About 23 percent of this capacity is located in the coastal area, comprising 11 counties that border the Gulf of Mexico. For this winter assessment, the winter capacity contribution percentages are 18 percent for noncoastal resources and 37 percent for coastal resources.

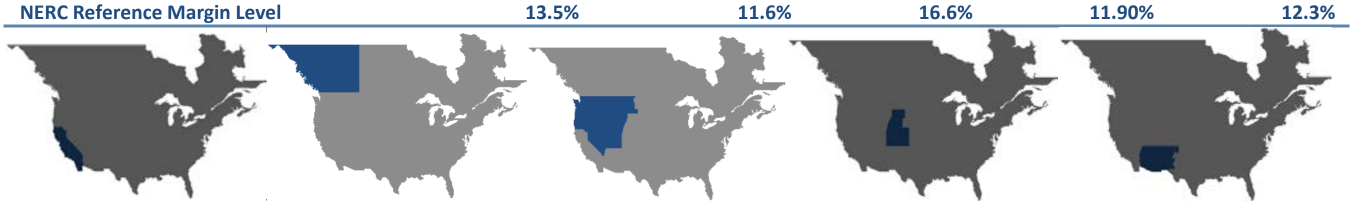
ERCOT continues to rely on a variety of demand response programs to support winter resource adequacy under emergency conditions. For the upcoming winter, ERCOT estimates that it will have 1,295 MW of load resources providing ancillary services that are contractually committed to ERCOT during winter peak hours. ERCOT also has emergency response service, a 10- and 30-minute demand response and distributed generation service, designed to be deployed in the late stages of a grid emergency prior to shedding firm load. ERCOT expects 1,043 MW of emergency response service to be available for the winter season. In aggregate, these demand response programs represent 4.4 percent of the TRE-ERCOT area's total internal demand forecast.

With respect to transmission system enhancements, there are multiple transmission upgrades scheduled to be completed in the West Texas area prior to this winter that are expected to reduce congestion and improve system reliability in the Permian Basin oil and natural gas exploration and production areas, where the transmission upgrades are still catching up with demand growth. Additionally, upgrades to support the Freeport Liquefied Natural Gas export facility in Brazoria County, which is under construction and expected to achieve commercial operation in 2018, are currently in progress and expected to be available by the winter season.

Although ERCOT does not expect significant issues with natural gas or water supply for the winter season based on projected conditions, natural gas curtailments continue to be a generation availability issue for certain gas-fired units in north Texas. ERCOT continues to improve generator preparedness for extreme weather conditions by conducting generator weatherization spot checks, hosting annual weatherization workshops to share and promote best practices, implementing new tools and procedures for weather-related risk assessment, and issuing a winter season fuel survey to gauge the readiness of units that have alternate fuel capability. As an example of new tools and procedures implemented in time for the upcoming winter season, ERCOT's wind generation forecasting tools have been updated to incorporate an extreme weather cut-out temperature for each wind resource as an additional forecast input. ERCOT has also analyzed performance information during extreme temperatures to identify wind resources that may be at risk of a shutdown during low temperatures.

WECC

	CAMX	NWPP-CA	NWPP-US	RMRG	SRSG
Demand	Megawatts (MW)	Megawatts (MW)	Megawatts (MW)	Megawatts (MW)	Megawatts (MW)
Total Internal Demand	**39,101**	**22,791**	**47,429**	**10,394**	**15,256**
Total Demand Response – Available	882	0	272	332	358
Net Internal Demand	**38,219**	**22,791**	**47,157**	**10,062**	**14,898**
Projected Resource Categories	Megawatts (MW)	Megawatts (MW)	Megawatts (MW)	Megawatts (MW)	Megawatts (MW)
Existing Certain Capacity	53,131	26,583	62,812	16,011	32,487
Net Firm Capacity Transfers	2,296	0	1,501	-575	-3,222
Anticipated Resources	**55,822**	**27,860**	**64,363**	**15,436**	**29,517**
Existing-Other Capacity	0	0	0	0	0
Prospective Resources	**55,822**	**27,860**	**64,363**	**15,436**	**29,517**
Planning Reserve Margins	Percent (%)	Percent (%)	Percent (%)	Percent (%)	Percent (%)
Anticipated Reserve Margin	**46.1%**	**22.2%**	**36.5%**	**53.4%**	**98.1%**
Prospective Reserve Margin	**46.1%**	**22.2%**	**36.5%**	**53.4%**	**98.1%**
NERC Reference Margin Level	**13.5%**	**11.6%**	**16.6%**	**11.90%**	**12.3%**



CAMX **NWPP-CA** **NWPP-US** **RMRG** **SRSG**

The Western Electricity Coordinating Council (WECC) is one of eight electric reliability councils in North America and is responsible for coordinating and promoting Bulk Electric System (BES) reliability in the Western Interconnection. WECC's 329 members, including 38 Balancing Authorities, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and approximately 82.2 million people, it is the largest and most diverse of the North American Electric Reliability Corporation (NERC) regional reliability organizations. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 Western states in between. For the Summer Assessment, the WECC assessment area is divided into five subregions; Rocky Mountain Reserve Group (RMRG), Southwest Reserve Sharing Group (SRSG), California/Mexico (CA/MX), and the Northwest Power Pool (NWPP), which is further divided into the NW-Canada and NW-US areas. These subregional divisions are used for this study as they are structured around reserve sharing groups that have similar annual demand patterns and operating practices.

Footprint Changes*: Silver State Energy Association, comprised of Southern Nevada Water Authority, City of Boulder City Nevada, Overton Power District No. 5, Lincoln County Power District No. 1 and The Colorado River Commission of Nevada, has moved from the NEVP Balancing Authority area to the WALC Balancing Authority area. This Balancing Authority footprint change has a nominal effect on either area as the summer peak demand is only about 200 MW.*

The existing and anticipated reserve margins for WECC, its five subregions, and all zones within the subregions, are expected to exceed their respective NERC reference reserve margins[26] for the upcoming winter season. The reference reserve margins are calculated using a building block methodology[27] created by WECC's Reliability Assessment Work Group. The elements of the building block margin calculation are consistent from year to year but the calculations can, and do, have slight annual variances by region and subregion. The reserve margins are adequate largely due to the construction of power plants to satisfy various state-mandated renewable resource acquisition policies, the fact the Western Interconnection is a summer peaking area, and resources have been built to cover the demand during the summer peak. The "extra" generation helps create the robust winter planning margins. It should be noted that abnormal weather conditions would result in different reserve margins and severe adverse weather conditions or unexpected equipment failure may result in localized power supply or delivery limitations.

[26] The NERC reference reserve margins referenced throughout the WECC assessment are planning reserve margins, and firm load would not be disrupted to maintain these margins. Rather, the margins are reference points that indicate areas that have lower reserves and tighter margins. The tighter margins are not forecasts of resource shortages. However, areas with tighter margins have a higher possibility, although not likelihood, of resource shortages associated with extreme events such as record-setting temperature deviations.

[27] Elements of the Building Block Target are detailed in NERC's Attachment II: Seasonal Assessment – Methods and Assumptions. http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Assessment%20Methods%20and%20Assumptions-Summer%202012_DRAFT.pdf

The Western Interconnection 2015-16 winter total coincident peak demand is forecast to be 134,007 MW and is projected to occur in December. The 2015-16 winter coincident peak demand forecast is 0.5 percent below last winter's forecast coincident peak demand of 134,693 MW, reflecting increases in energy efficiency and a continuation of slow, or negative, demand growth. Controllable and dispatchable demand response programs are mainly associated with the summer season and only account for about 1.4 percent of the total peak demand. All forecasted margin results assume demands associated with normal weather conditions.

Net nameplate additions to existing resources since last winter's assessment total 4,783 MW with under-construction resources expected to be on-line before the winter peak, totaling 3,335 MW. The existing and planned additions include 3,901 MW of solar facilities and 1,449 MW of wind-powered resources, with the addition of 321 MW of biomass and 376 MW of geothermal generation. Natural-gas-fired generation increased by 607 MW and hydro capacity increased by 1,863 MW. Nearly 398 MW of coal-fired generation were retired, as well as a small oil-fired unit of about 2 MW.

WECC continues to track and study the impacts on reliability, as well as other issues, associated with the retirement of large thermal generating units in response to higher air emission and water quality standards. Associated with the retirement of large coal generating units is the increased demand on natural gas supply and transportation as natural gas becomes the primary fuel for new thermal generation. WECC is participating with the natural gas industry to study potential impacts to reliability as the Western Interconnection becomes more reliant on natural-gas-fired generation.

The CA/MX subregion is expected to have adequate reserves for the upcoming winter season, but this area could experience localized operational issues due to reduced hydro generation associated with the ongoing drought condition. The California Independent System Operator (CAISO) does not anticipate this situation due to the abundance of nonhydro generation and the availability of transfer capability, but expects those issues, should they arise, to be addressed through operating procedures with little or no interruption of service to customers. WECC scenario studies, assuming 100 percent reductions in California hydroelectric generation, support CAISO's conclusions regarding overall regional adequacy. For example, a WECC 100 percent hydro reduction case produced a 39.9 percent anticipated reserve margin for the entire California/Mexico subregion compared to the base case figure of 46.1 percent. This margin is well above the WECC planning reserve target of 13.5 percent and should have minimal impacts on system reliability. The WECC modeling was associated with overall interconnection conditions and did not investigate potential impacts to localized internal California load areas.

The BPS is expected to be adequate to handle normal intra-area transfers. This adequacy expectation applies despite the continued 1,100 MW derate of the Pacific DC Intertie.

WECC staff does not perform special operating studies concerning extreme weather or drought conditions for the seasonal assessments. However, these studies are performed by the individual load-serving entities and Balancing Authorities within the Western Interconnection, and none of these entities have reported any issues related to extreme weather.

The Western Interconnection is a summer peaking region and it is anticipated that available resources will be adequate to supply all demand, under normal temperature and weather conditions, during the upcoming winter season. Recent industry focus on winter weatherization processes are expected to reduce potential generator unavailability during extreme cold spells. However, as has been seen in prior years, localized gas supply issues could occur due to short-term load forecasting errors or unexpected gas-supply interruptions.

Appendix I: Reliability Assessment Subcommittee Roster

Reliability Assessment Subcommittee Roster

Name	Organization
Layne Brown (Chairman)	Western Electricity Coordinating Council
Mohammed Ahmed	AEP
Alan C Wahlstrom	Southwest Power Pool, Inc.
Barbara A Doland	SERC Reliability Corporation
Brad Woods	Texas Reliability Entity, Inc.
Chris Haley	Southwest Power Pool, Inc.
Hubert C Young	South Carolina Electric & Gas Co.
James Leigh-Kendall	Sacramento Municipal Utility District
Jin Chen	SERC Reliability Corporation
John G Mosier	Northeast Power Coordinating Council
John Reinhart	MISO
K. R Chakravarthi	Southern Company Services, Inc.
Lewis De La Rosa	Texas Reliability Entity, Inc.
Mark J. Kuras	PJM Interconnection, L.L.C.
Matt Hart	Southern Company
Michael Courchesne	ISO New England, Inc.
Peter Warnken	ERCOT
Peter Wong	ISO New England, Inc.
Philip A Fedora	Northeast Power Coordinating Council
Richard Becker	Florida Reliability Coordinating Council
Ryan Westphal (Vice-Chair)	MISO
Salva R. Andiappan	Midwest Reliability Organization
Srinivas Kappagantula	PJM Interconnection, L.L.C.
Tim Fryfogle	ReliabilityFirst
Travis Tate	SERC Reliability Corporation
William B Kunkel	Midwest Reliability Organization

Appendix II: Seasonal Reliability Concepts

Seasonal Reliability Concepts

Demand	Definition
Total Internal Demand	The sum of the metered (net) outputs of all generators within the system and the metered line flows into the system, less the metered line flows out of the system (forecast). Total internal demand includes adjustments for the indirect Demand-side management programs such as Conservation programs, improvements in efficiency of electricity use, and all nondispatchable demand response programs.
Demand Response – Available	The amount of controllable and dispatchable demand-side management (DSM) programs expected to be available during peak demand. DSM is defined as all activities or programs undertaken by a load-serving entity or its customers to influence the amount or timing of electricity they use. For NERC assessments, the following four demand response programs are included: direct control load management (DCLM), interruptible load (IR), critical peak pricing with load control, and load as a capacity resource (LCR).
Net Internal Demand	Total internal demand, less demand response – available (direct control load management (DCLM), interruptible load (IR), critical peak pricing with load control, and load as a capacity resource (LCR).
Demand Response	**Definition**
Direct Control Load Management (DCLM)	Demand-side management that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises. DCLM, as defined here, does not include interruptible demand. Note: This type of control usually reduces the demand of residential or small commercial customers. [Source: NERC demand response availability data systems definitions]. "Program Total" represents total enrolled in this program. "Available" represents the estimated amount of customer demand that will be interruptible at the time of peak hour demand by direct control of a system operator by interrupting power supply to individual appliances or equipment on customer premises.
Interruptible Load (IR)	A program where the electrical consumption is subject to curtailment or interruption under tariffs or contracts that provide a rate discount or bill credit for agreeing to reduce load during system contingencies. In some instances, the Demand reduction may be affected by action of the system operator, called “remote tripping,” after notice to the customer in accordance with contractual provisions. [Source: NERC demand response availability data systems Definitions]. "Available" represents the estimated magnitude of customer demand that will be interruptible at the time of peak hour demand by direct control of a system operator by interrupting power supply to individual appliances or equipment on customer premises. "Program Total" represents the total amount of customer demand categorized as interruptible load (IL).
Critical Peak Pricing (CPP) with Load Control	Price structure designed to encourage reduced consumption during periods of high wholesale market prices or system contingencies by imposing a prespecified high rate or price for a limited number of days or hours. Critical peak pricing with direct load control combines direct load control with a prespecified high price for use during designated critical peak periods triggered by system contingencies or high wholesale market prices. [Source: NERC demand response availability data systems definitions] "Program Total" represents the total amount of customer demand enrolled in critical peak pricing programs. "Available" represents the magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted at the time of peak hour demand by direct control of the System Operator or by action of the customer by responding to high prices of energy triggered by system contingencies or high wholesale market prices.
Load as a Capacity Resource (LCR)	Customers that commit to making prespecified load reductions when system contingencies arise. [Source: NERC demand response availability data systems definitions] "Program Total" represents total amount of customer demand enrolled in LCR programs. "Available" represents the magnitude of customer demand that, in accordance with contractual arrangements, is committed to prespecified load reductions when called upon when system contingencies arise.
Projected Resource Categories	**Definition**
On-Peak Capacity	Includes existing-certain and planned-tier 1 capacity projected to be operable and available to deliver power during peak demand.
Net Firm Transfers	Total firm imports into the assessment area, minus firm exports out of the assessment area. All transfers are based on the existence of firm contracts.
Anticipated Resources	On-peak capacity, plus net firm transfers
Existing-Other	Existing or planned generation resources that may be operable and available to deliver power during the peak demand, but may be curtailed or interrupted for various reasons.
Prospective Resources	Anticipated resource, plus existing-other resources.
Planning Reserve Margins	**Definition**
Anticipated Reserve Margin	Anticipated resources, minus net internal demand, divided by net internal demand
Prospective Reserve Margin	Prospective resources, minus net internal demand, divided by net internal demand
NERC Reference Margin Level	The NERC reference margin Levels identified throughout the assessment are planning reserve margins and firm load would not be disrupted to maintain these margins. Rather, the margins are reference points that indicate areas that have lower reserves and tighter margins. The tighter margins are not forecasts of resource shortages. However, areas with tighter margins have a higher possibility, although not likelihood, of resource shortages associated with extreme events such as record-setting temperature deviations. Each Region/subregion may have their own specific margin level (or method) based on load, generation, and transmission characteristics as well as regulatory requirements. If provided in the data submittals, the assessment area’s target reserve margin level is adopted as the NERC reference margin level. If not, NERC assigned 15 percent and 10 percent for predominately thermal and hydro systems, respectively.

Appendix III: Data for Pilot Assessment of NERC Regions and Assessment Areas

FRCC

	Anticipated Resources with Outages	Normal Demand Forecast	Anticipated Resources with Outages	Severe Demand Forecast
Anticipated	58,284		58,284	
Forced Outage	2,540		2,540	
Maintenance Outage	763		763	
Available Resources	54,980		54,980	
Net Internal Demand		42,624		45,369
Demand Response		2,976		2,976
Capacity Deficit[28]		-		-

MISO

	Anticipated Resources with Outages	Normal Demand Forecast	Anticipated Resources with Outages	Severe Demand Forecast
Anticipated	142,566		142,566	
Forced Outage	1,236		1,236	
Maintenance Outage	64		64	
Available Resources	141,266		141,266	
Net Internal Demand		101,095		108,444
Demand Response		2,869		2,869
Capacity Deficit		-		-

MRO-Manitoba Hydro

	Anticipated Resources with Outages	Normal Demand Forecast	Anticipated Resources with Outages	Severe Demand Forecast
Anticipated	5,334		5,334	
Forced Outage	103		103	
Maintenance Outage	14		14	
Available Resources	5,216		5,216	
Net Internal Demand		4,378		4,541
Demand Response		-		-
Capacity Deficit		-		-

MRO-SaskPower

	Anticipated Resources with Outages	Normal Demand Forecast	Anticipated Resources with Outages	Severe Demand Forecast
Anticipated	4,194		4,194	
Forced Outage	81		81	
Maintenance Outage	11		11	
Available Resources	4,101		4,101	
Net Internal Demand		3,431		3,592
Demand Response		244		244
Capacity Deficit		-		-

[28] Operationally, capacity deficits would be mitigated by Demand Response, additional power purchases, voltage reduction, and public conservation appeals prior to resorting to firm load shedding.

NPCC-Maritimes

	Anticipated Resources with Outages	Normal Demand Forecast	Anticipated Resources with Outages	Severe Demand Forecast
Anticipated	6,816		6,816	
Forced Outage	233		233	
Maintenance Outage	33		33	
Available Resources	6,551		6,551	
Net Internal Demand		5,253		5,657
Demand Response		256		256
Capacity Deficit		-		-

NPCC-New England

	Anticipated Resources with Outages	Normal Demand Forecast	Anticipated Resources with Outages	Severe Demand Forecast
Anticipated	26,308		26,308	
Forced Outage	900		900	
Maintenance Outage	127		127	
Available Resources	25,281		25,281	
Net Internal Demand		20,490		21,150
Demand Response		587		587
Capacity Deficit		-		-

NPCC-New York

	Anticipated Resources with Outages	Normal Demand Forecast	Anticipated Resources with Outages	Severe Demand Forecast
Anticipated	41,351		41,351	
Forced Outage	1,411		1,411	
Maintenance Outage	199		199	
Available Resources	39,740		39,740	
Net Internal Demand		23,630		25,212
Demand Response		885		885
Capacity Deficit		-		-

NPCC-Ontario

	Anticipated Resources with Outages	Normal Demand Forecast	Anticipated Resources with Outages	Severe Demand Forecast
Anticipated	29,256		29,256	
Forced Outage	999		999	
Maintenance Outage	141		141	
Available Resources	28,117		28,117	
Net Internal Demand		21,834		22,626
Demand Response		555		555
Capacity Deficit		-		-

NPCC-Quebec

	Anticipated Resources with Outages	Normal Demand Forecast	Anticipated Resources with Outages	Severe Demand Forecast
Anticipated	41,976		41,976	
Forced Outage	1,433		1,433	
Maintenance Outage	202		202	
Available Resources	40,341		40,341	
Net Internal Demand		36,171		36,931
Demand Response		2,081		2,081
Capacity Deficit		-		-

PJM

	Anticipated Resources with Outages	Normal Demand Forecast	Anticipated Resources with Outages	Severe Demand Forecast
Anticipated	183,208		183,208	
Forced Outage	2,391		2,391	
Maintenance Outage	329		329	
Available Resources	180,488		180,488	
Net Internal Demand		131,196		139,696
Demand Response		525		525
Capacity Deficit		-		-

SERC-E

	Anticipated Resources with Outages	Normal Demand Forecast	Anticipated Resources with Outages	Severe Demand Forecast
Anticipated	53,472		53,472	
Forced Outage	3,704		3,704	
Maintenance Outage	777		777	
Available Resources	48,991		48,991	
Net Internal Demand		41,119		43,568
Demand Response		803		803
Capacity Deficit		-		-

SERC-N

	Anticipated Resources with Outages	Normal Demand Forecast	Anticipated Resources with Outages	Severe Demand Forecast
Anticipated	53,558		53,558	
Forced Outage	3,710		3,710	
Maintenance Outage	779		779	
Available Resources	49,069		49,069	
Net Internal Demand		39,519		46,983
Demand Response		1,470		1,470
Capacity Deficit		-		-

SERC-SE

	Anticipated Resources with Outages	Normal Demand Forecast	Anticipated Resources with Outages	Severe Demand Forecast
Anticipated	62,526		62,526	
Forced Outage	4,331		4,331	
Maintenance Outage	909		909	
Available Resources	57,286		57,286	
Net Internal Demand		41,866		44,766
Demand Response		2,107		2,107
Capacity Deficit		-		-

SPP

	Anticipated Resources with Outages	Normal Demand Forecast	Anticipated Resources with Outages	Severe Demand Forecast
Anticipated	67,819		67,819	
Forced Outage	2,966		2,966	
Maintenance Outage	564		564	
Available Resources	64,289		64,289	
Net Internal Demand		41,000		43,088
Demand Response		766		766
Capacity Deficit		-		-

ERCOT

	Anticipated Resources with Outages	Normal Demand Forecast	Anticipated Resources with Outages	Severe Demand Forecast
Anticipated	78,199		78,199	
Forced Outage	4,323		4,323	
Maintenance Outage	831		831	
Available Resources	73,045		73,045	
Net Internal Demand		51,381		57,848
Demand Response		2,338		2,338
Capacity Deficit		-		-

WECC-CA/MX

	Anticipated Resources with Outages	Normal Demand Forecast	Anticipated Resources with Outages	Severe Demand Forecast
Anticipated	55,822		55,822	
Forced Outage	2,456		2,456	
Maintenance Outage	627		627	
Available Resources	52,739		52,739	
Net Internal Demand		38,219		38,378
Demand Response		882		882
Capacity Deficit		-		-

WECC-NWPP-CA

	Anticipated Resources with Outages	Normal Demand Forecast	Anticipated Resources with Outages	Severe Demand Forecast
Anticipated	27,861		27,861	
Forced Outage	1,226		1,226	
Maintenance Outage	313		313	
Available Resources	26,322		26,322	
Net Internal Demand		22,791		23,225
Demand Response		-		-
Capacity Deficit		-		-

WECC-NWPP-US

	Anticipated Resources with Outages	Normal Demand Forecast	Anticipated Resources with Outages	Severe Demand Forecast
Anticipated	64,363		64,363	
Forced Outage	2,832		2,832	
Maintenance Outage	723		723	
Available Resources	60,808		60,808	
Net Internal Demand		47,157		49,196
Demand Response		272		272
Capacity Deficit		-		-

WECC-RMRG

	Anticipated Resources with Outages	Normal Demand Forecast	Anticipated Resources with Outages	Severe Demand Forecast
Anticipated	15,436		15,436	
Forced Outage	679		679	
Maintenance Outage	174		174	
Available Resources	14,584		14,584	
Net Internal Demand		10,062		10,191
Demand Response		332		332
Capacity Deficit		-		-

WECC-SRSG

	Anticipated Resources with Outages	Normal Demand Forecast	Anticipated Resources with Outages	Severe Demand Forecast
Anticipated	29,518		29,518	
Forced Outage	1,299		1,299	
Maintenance Outage	332		332	
Available Resources	27,887		27,887	
Net Internal Demand		14,898		15,253
Demand Response		358		358
Capacity Deficit		-		-