NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2015 Long-Term Reliability Assessment

December 2015

RELIABILITY | ACCOUNTABILITY




3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Version 1.0 December 15, 2015
Version 1.1 January 14, 2016 (see Errata p. 98)

Current draft in bold

Table of Contents

Preface

The North American Electric Reliability Corporation (NERC) has prepared the following assessment in accordance with the Energy Policy Act of 2005, in which the United States Congress directed NERC to conduct periodic assessments of the reliability and adequacy of the bulk power system (BPS) in North America.[1] NERC operates under similar obligations in many Canadian provinces, as well as a portion of Baja California Norte, Mexico.

NERC is an international regulatory authority established to evaluate and improve the reliability of the BPS in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term (10-year) reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.[2]

Reliability Standards are the planning and operating rules that electric utilities follow to support and maintain a reliable electric system. These standards are developed by the industry using a balanced, open, fair, and inclusive process accredited by the American National Standards Institute (ANSI). While NERC does not have authority to set Reliability Standards for resource adequacy (e.g., Reserve Margin criteria) or to order the construction of resources or transmission, NERC can independently assess where reliability issues may arise and identify emerging risks. This information, along with NERC recommendations, is then made available to policy makers and federal, state, and provincial regulators to support decision making within the electric sector.

NERC prepares seasonal and long-term assessments to examine the current and future reliability, adequacy, and security of the North American BPS. For these assessments, the BPS is divided into 21 Assessment Areas,[3] both within and across the eight Regional Entity boundaries, as shown in the corresponding table and maps below.[4] The preparation of these assessments involves NERC's collection and consolidation of data from the Regional Entities. Reference case data includes projected on-peak demand and energy, Demand Response (DR), resource capacity, and transmission projects. Data and information from each NERC Region are also collected and used to identify notable trends, emerging issues, and potential concerns. This bottom-up approach captures virtually all electricity supplied in the United States, Canada, and the portion of Baja California Norte, Mexico. NERC's reliability assessments are developed to inform industry, policy makers, and regulators and to aid NERC in achieving its mission—to ensure the reliability of the North American BPS.

[1] H.R. 6 as approved by of the One Hundred Ninth Congress of the United States, the Energy Policy Act of 2005. The NERC Rules of Procedure, Section 800, further detail the objectives, scope, data and information requirements, and Reliability Assessment Process requiring annual seasonal and long-term reliability assessments.

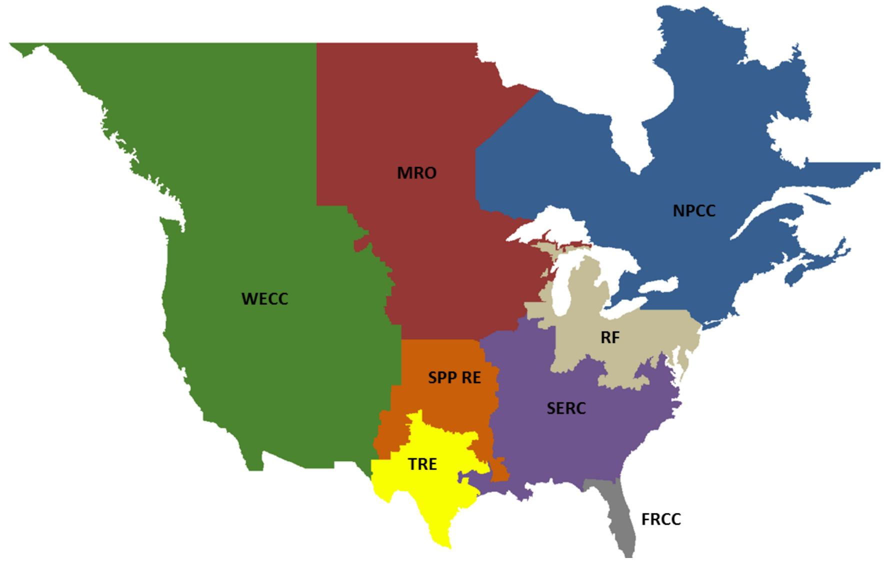
[2] As of June 18, 2007, FERC granted NERC the legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the BPS and made compliance with those standards mandatory and enforceable. Equivalent relationships have been sought and for the most part realized in Canada and Mexico. Prior to adoption of §215 in the United States, the provinces of Ontario (2002) and New Brunswick (2004) adopted all Reliability Standards that were approved by the NERC Board as mandatory and enforceable within their respective jurisdictions through market rules. Reliability legislation is in place or NERC has memoranda of understanding with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, Manitoba, Saskatchewan, British Columbia, and Alberta, and with the National Energy Board of Canada (NEB). NERC standards are mandatory and enforceable in Ontario and New Brunswick as a matter of provincial law. Manitoba has adopted legislation, and standards are mandatory there. In addition, NERC has been designated as the "electric reliability organization" under Alberta's Transportation Regulation, and certain Reliability Standards have been approved in that jurisdiction; others are pending. NERC standards are now mandatory in British Columbia and Nova Scotia. NERC and the Northeast Power Coordinating Council (NPCC) have been recognized as standards-setting bodies by the Régie de l'énergie of Québec, and Québec has the framework in place for Reliability Standards to become mandatory. NEB has made Reliability Standards mandatory for international power lines. In Mexico, the Comisión Federal de Electricidad (CFE) has signed WECC's reliability management system agreement, which only applies to Baja California Norte.

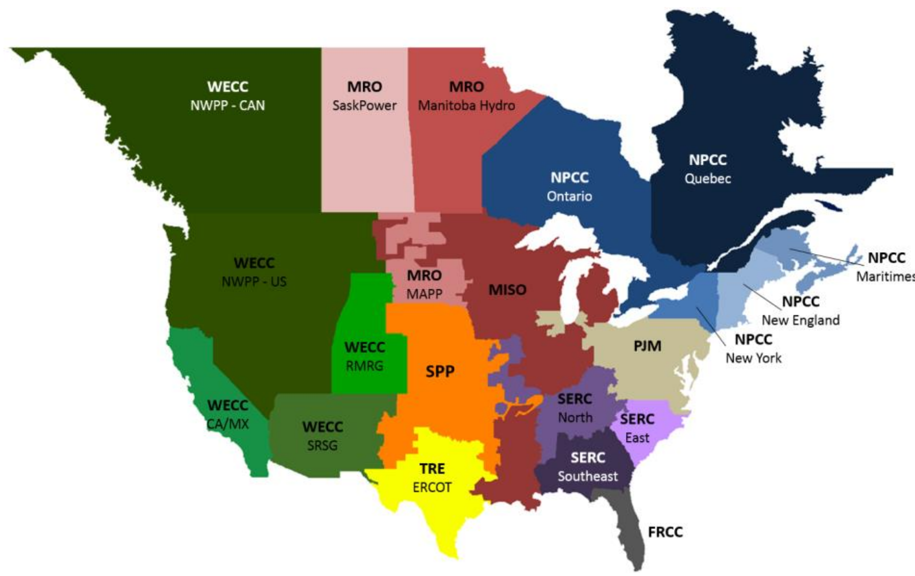
[3] The number of assessment areas has been increased from 20 to 21 since the release of the *2014LTRA*. WECC-NWPP was split into Canadian and U.S Assessment Areas.

[4] Maps created using Ventyx Velocity Suite.

NERC Regions and Assessment Areas

FRCC – Florida Reliability Coordinating Council	
	FRCC[5]
MRO – Midwest Reliability Organization	
	MISO[6]
	MRO-Manitoba Hydro
	MRO-MAPP
	MRO-SaskPower
NPCC – Northeast Power Coordinating Council	
	NPCC-Maritimes:
	NPCC-New England
	NPCC-New York
	NPCC-Ontario
	NPCC-Québec
RF – ReliabilityFirst	
	PJM[7]
SERC – SERC Reliability Corporation	
	SERC-East
	SERC-North
	SERC-Southeast
SPP RE – Southwest Power Pool Regional Entity	
	SPP
TRE – Texas Reliability Entity	
	TRE-ERCOT
WECC – Western Electricity Coordinating Council	
	WECC-CA/MX
	WECC-NWPP-US
	WECC-NWPP-CA
	WECC-RMRG
	WECC-SRSG





[5] FRCC Region and Assessment Area boundaries are the same.

[6] The MISO footprint is primarily located in the MRO Region, with smaller portions in the SERC and RF Regions. For NERC's assessments, the MRO Region oversees the collection of data and information from MISO.

[7] The PJM footprint is primarily located in the RF Region, with smaller portions in the SERC Region. For NERC's assessments, the RF Region oversees the collection of data and information from PJM.

Executive Summary

The 2015 Long-Term Reliability Assessment (*2015LTRA*) provides a wide-area perspective on generation, demand-side resources, and transmission system adequacy needed to maintain system reliability during the next decade. This assessment includes NERC's independent technical analysis to identify issues that may impact the reliability of the North American Bulk Power System (BPS) to allow industry, regulators, and policy makers to respond or otherwise develop plans to mitigate potential impacts caused by these issues. NERC collected projections from system planners and independently assessed this data. Four key findings are identified below.

Reserve Margins in all Assessment Areas appear sufficient but continue to trend downward.

Reserve Margins are trending downward in many Assessment Areas despite an ongoing decline in the growth rates of electricity demand. This decline in demand during the last decade can be primarily attributed to energy efficiency and Demand Response programs along with a general decline in large, end-use customer loads. Tighter margins in several Assessment Areas raise potential concerns as the entire system undergoes an unprecedented change in the resource mix at an accelerated pace. Despite the low load growth and declining Reserve Margins, none of the Assessment Areas' Reserve Margins fall below Reference Margin levels in the short-term horizon between 2016 and 2021.

A changing resource mix requires additional measures and approaches for assessing future reliability.

The North American electric power system is undergoing a significant transformation with ongoing retirements of fossil-fired and nuclear capacity as well as growth in natural gas, wind, and solar resources. This shift is caused by several drivers, such as existing and proposed federal, state, and provincial environmental regulations as well as low natural gas prices, in addition to the ongoing integration of both distributed and utility-scale renewable resources. The resource mix changes are directly impacting the behavior of the North American BPS. These developments will have important implications on system planning and operations, as well as how NERC and the industry assess reliability. In order to maintain an adequate level of reliability through this transition, generation resources need to provide sufficient voltage control, frequency support, and ramping capability as essential components to the reliable operations and planning of the BPS. It is necessary for policy makers to recognize the need for essential reliability services provided by the current and future mix of resources. Analyses of this transformation must be done to allow for effective planning and to provide System Operators the flexibility to modify real-time operations and future planning of the BPS.

Natural-gas-fired generation surpassed coal this year as the predominant fuel source for electric generation and is the leading fuel type for capacity additions. A growing reliance on natural gas continues to raise reliability concerns regarding the ability of both gas and electric infrastructures to maintain the BPS reliability, despite substantial progress made in addressing the interdependencies between these two industries. There is a need to enhance planning approaches to consider fuel deliverability, availability, and responses to pipeline contingencies that are unique to each area.

Operators and planners face uncertainty with increased levels of distributed energy resources and new technologies.

Distributed energy resources (DERs) are contributing to changing characteristics and control strategies in grid operations. DERs are not directly interconnected to the BPS, but to subtransmission and distribution systems generally located behind customer metering facilities. Visibility, controllability, and new forecasting methods of these resources are of paramount importance to plan and operate the BPS—particularly because the majority of DERs are intermittent in nature and outside the control of the System Operator. As more DERs are integrated, the supply of control to System Operators can decrease. However, distribution-centric operations can reliably support the BPS with adequate planning, operating and forecasting analyses, coordination, and policies that are oriented to reliably interface with the BPS. Coordinated and reliable integration of DERs into the BPS can also present opportunities to create a more robust and resilient system.

NERC continues its reliability assessment of the Clean Power Plan and other environmental rules.

In addition to the factors mentioned above, environmental regulations have contributed significantly to the change in resource mix and have been a large impetus behind the shift from coal and toward natural gas and renewables. NERC's long-term reliability assessments continue to track changes in the resource mix, reflecting the confluence of many environmental regulations and other various factors. The Clean Power Plan final rule was released by the EPA in August 2015, which mandates a 32% reduction in carbon emissions from 2005 levels by 2030. This rule will further accelerate the ongoing shift in the resource mix.

Each of these reliability issues, in conjunction with the ongoing reliability impacts of several other reliability issues such as reliability risks associated with early retirement of nuclear plants, energy storage, load forecasting uncertainties, and regional/interconnection-wide modeling must be strategically monitored and addressed in order to preserve BPS reliability. NERC's assessment provides the basis for understanding these risks and, more importantly, identifying how these interdependent trends and challenges require coordination between the electric industry, regulators, and policy makers.

Recommendations

1. **NERC should conduct more granular analysis in areas with significant resource mix changes and raise awareness of potential resource adequacy concerns**: NERC should continue to raise awareness of resource adequacy concerns with regular coordination with Regional Entities, involved Assessment Areas, and state regulators. One way to monitor and raise the awareness of adequacy concerns will be for NERC to conduct more granular analysis of the resource adequacy conditions in applicable Assessment Areas that are experiencing significant resource mix changes, including the potential retirement of conventional generation. Furthermore, NERC should closely monitor and evaluate the measures being taken by involved parties (e.g., market operators, state regulators, and utilities) to address any emerging resource adequacy challenges.

2. **NERC should advance new metrics and approaches for assessing reliability**: NERC should continue to develop new approaches and frameworks for assessing reliability in both the short (1-5 years) and long-term (5-10 years) time horizons. This includes the development and implementation of metrics to examine essential reliability services as an additional dimension to the traditional reserve margin analysis, especially applicable for Assessment Areas with projected high levels of variable resources. Additionally, energy adequacy metrics through probabilistic assessment should be advanced through the NERC Planning Committee. NERC should anticipate the need for increased information sharing and support for a wide variety of stakeholders.

3. **NERC, in collaboration with Planning and Operating Committees, should establish Reliability Guidelines to assess and consider fuel, generation operational characteristics, and other related risks:** A growing reliance on natural gas continues to raise reliability concerns, highlighting the interdependency between the electric and natural gas industries and concerns about being overly dependent on a single fuel source. To ensure reliable operation of the BPS, planning approaches must be enhanced and adapted to consider fuel deliverability, availability, and response to pipeline contingencies that are unique to each area. NERC should also closely monitor resource availability and operational impacts in areas with high concentrations of gas-fired generation (e.g., New England). In collaboration with Planning and Operating Committees, NERC should establish planning and operation Guidelines for both short- and long-term horizons to simulate and consider fuel, generation operational characteristics, and other related risks in reliability assessments.

4. **Policy makers should use NERC's analytic framework to ensure essential reliability services are maintained:** Federal, state, and local jurisdictional policy decisions have a direct influence on changes in the resource mix, and thus can affect the reliability of the BPS. An analytical basis for understanding potential reliability impacts must be used to understand potential reliability impacts from increasing integration of VERs. Consideration of the reliability implications extends beyond a reserve margin assessment, as it includes impacts on system configuration, composition, and the need for replenishment of essential reliability services. Policy makers, therefore, must recognize the need for essential reliability services provided by the current and future composition of resources and incorporate those needs through market mechanisms, interconnection requirements, and other initiatives as outlined in NERC's upcoming *Essential Reliability Services Task Force Framework* report.

5. **NERC should establish a task force focused on accommodating DER resources to further examine future reliability impacts:** NERC should leverage industry stakeholder expertise and create a task force to examine and proactively address potential BPS reliability impacts associated with the integration of large amounts of distributed resources, including variable energy resources connected to the distribution system. NERC in collaboration with Planning and Operating Committees, should consider establishing reliability guidelines which focus on reliability considerations when accommodating large amounts of distributed resources. The task force should also consider and evaluate the opportunities that may be provided by DERs that can enhance reliability and resiliency. Additionally, this initiative includes encouraging the IEEE 1547 stakeholder group to consider BPS reliability impacts due to high-levels of DERs.

6. **Policy makers should consider BPS reliability implications when integrating large amounts of DER:** For the reliable integration of large amounts of DER, policy makers should coordinate with electric industry to address potential reliability concerns. System upgrades will be needed to support the integration, which will require close coordination between Distribution Providers, System Operators, and state regulators. Phased approaches may be necessary as the system is currently not designed for distribution-centric operations. The ability to observe, control and dispatch DERs will be important considerations when planning and operating a reliable BPS with large amounts of DER—particularly because the majority of DERs are variable and outside the control of the System Operator. However, distribution-centric operations can reliably support the BPS with adequate planning, operating and forecasting analyses, coordination, and policies that are oriented to reliably interface with the BPS.

7. **NERC should continue to assess CPP impacts through a phased approach, as state and regional implementation plans are developed:** In its Phase I study, NERC recommended further consideration for the timing needed to implement the infrastructure changes requisite for compliance with the draft rule. Additionally, NERC recommended the inclusion of a Reliability Assurance Mechanism to ensure the maintenance of system reliability was prioritized. The final rule addressed both of these concerns. NERC will continue to examine the potential reliability impacts of the final rule's implementation. NERC plans to release a report in January 2016 that will underscore reliability issues that states should consider as they develop their state or regional plans. NERC will also release a scenario-based analysis close to the end of the first quarter of 2016.

Reliability Trends and Emerging Issues

This section provides an overview of each reliability issue as well as the potential impacts and corresponding importance of ERO-wide coordination in addressing them. Observations and recommendations are included for NERC, the industry, and policy makers.

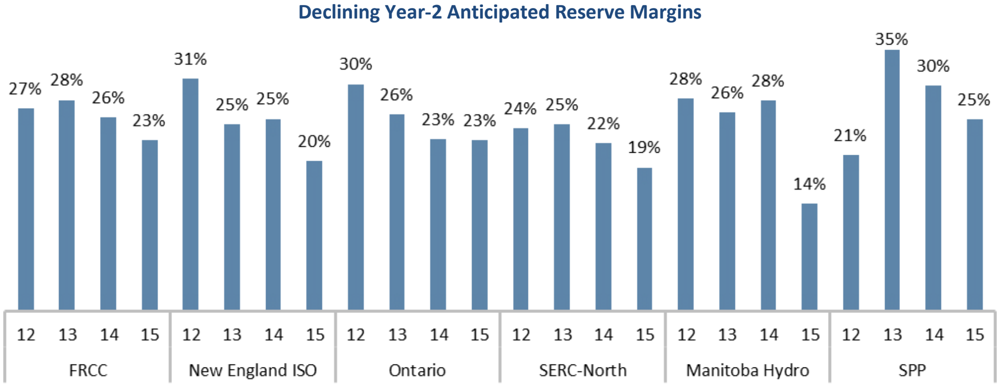
Reserve Margins in all Assessment Areas Appear Sufficient, but Continue to Trend Downward

All Assessments Areas appear to have sufficient plans for new generation and adequate resources through 2025. While many of the generation projects have not been "firmed" by contractual agreements that secure the capacity obligations, generation in project queues and earlier stages of development appear sufficient to support future reliability. Based on NERC's assessment, Anticipated Reserve Margins in several Assessment Areas fall below the Reference Margin Levels during the assessment period; however, these shortfalls occur later in the assessment period (2020 and beyond), and plans for generation are in place to secure the capacity at a later date.

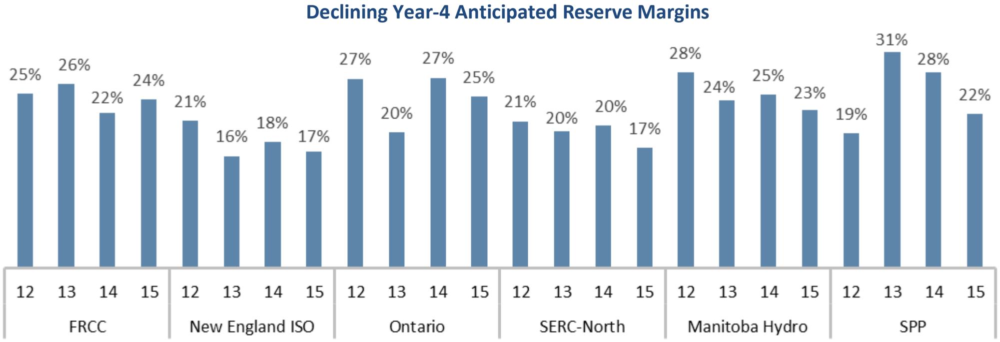
The Reference Margin Levels are established by individual Assessment Areas or state and provincial authorities. If no Reference Margin Level is provided, a 15% Reference Reserve Margin is applied by NERC. The following eight Assessment Areas' Anticipated Reserve Margins will fall below their respective Reference Margin Levels within the assessment period: MISO, MRO-MAPP, NPCC-New England, SERC-East, SERC-North, SPP, TRE-ERCOT, and WECC-NWPP-CA.

The ongoing decline in load growth rates is a contributing factor to fewer capacity additions. A trend throughout North America is an overall reduction of long-term planning reserves. Comparison of the second- and fourth-year Anticipated Reserve Margin projections using data from the *2012LTRA* through the *2015LTRA* shows a downward trend in some Assessment Areas, indicating tightening of Anticipated Reserve Margins over the past four years of projections. While reserves continue to remain above the target, tighter reserves compared to previous years are expected. For example, some Assessment Areas remain above the NERC Reference Margin Level, but the Anticipated Reserve Margins have reduced from 30% to 20% over the past four years. While in and of itself this does not signal a reliability issue, it does indicate that less resource flexibility may be available in the future.

Declining Year-2 Anticipated Reserve Margins

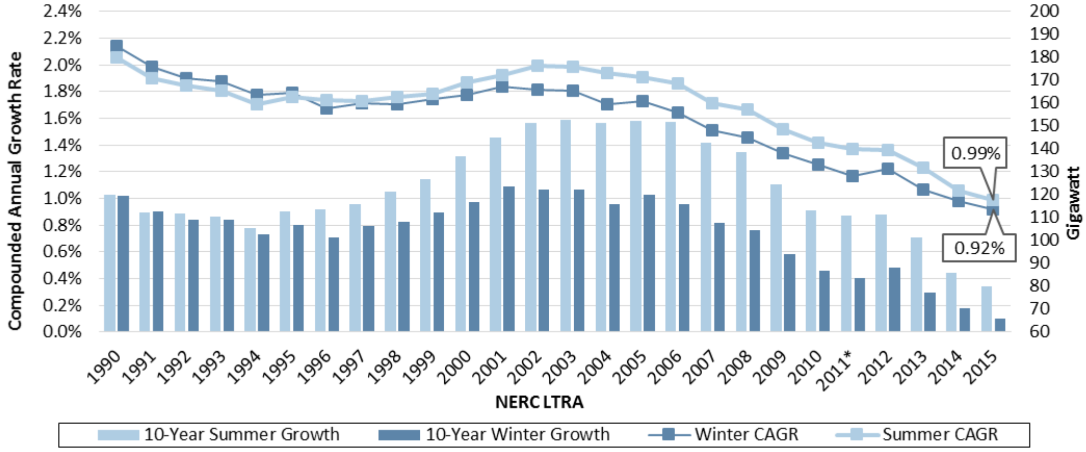


Declining Year-4 Anticipated Reserve Margins



NERC's 10-year forecast compounded annual growth rate (CAGR)[8] of peak summer and winter electricity demand has trended downward, dropping to the lowest rates on record. The *2015LTRA* reference case shows a CAGR of 0.99% and 0.92% for the summer and winter seasons, respectively. As energy efficiency and conservation programs increase, the declining demand growth rates are expected to continue. This is also true with continued growth in distributed photovoltaic solar and other behind-the-meter resources.

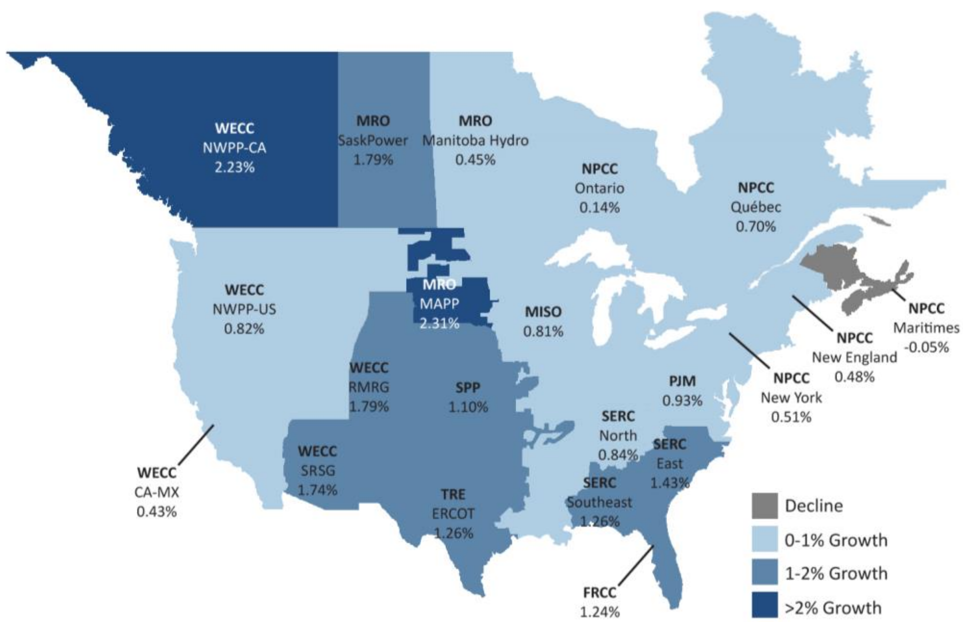
NERC-Wide Demand; 10-Year Growth Rates for Summer and Winter



*Prior to the *2011LTRA*, the initial year of the 10-year assessment period is the report year (e.g., the 10-year assessment period for the *1990LTRA* was 1990–1999). The *2011LTRA* and subsequent LTRAs examine the initial year of the assessment period as one year out (e.g., the 10-year assessment period for the *2011LTRA* is 2012–2023).

A reduced peak demand growth rate benefits reliability as the amount of additional capacity to maintain adequate Reserve Margins is reduced. Often, the timely construction of new resources to support an increasing peak demand is the greatest challenge to meeting reliability needs in the future. As less new capacity is needed, the industry can use more of its existing resources to meet future resource adequacy requirements.

10-Year Compounded Annual Growth Rates by Assessment Area



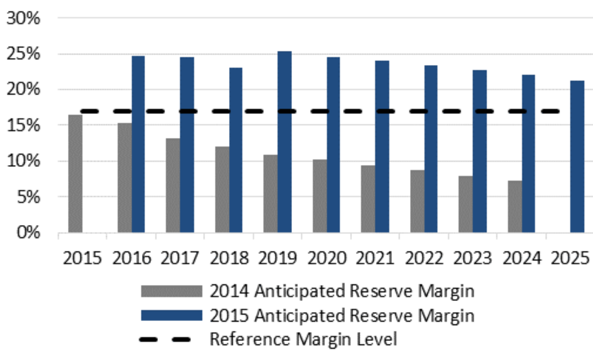
[8] Compounded annual growth rate (CAGR) provides the year-over-year growth rate over the duration of the assessment period. It is derived as follows: CAGR = (Year 10 TID / Year 1 TID)$^{(1/9)}$ – 1

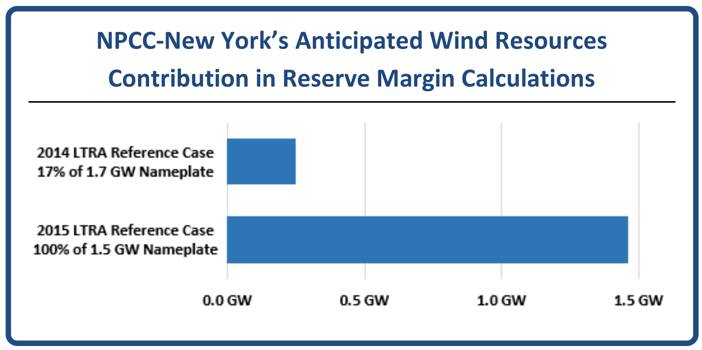
Despite the low load growth and declining Reserve Margins, none of the Assessment Areas' Reserve Margins fall below Reference Margin levels in the short-term horizon between 2016 and 2021. Four Assessment Areas (MISO, TRE-ERCOT, SERC-North, and WECC-NWPP-CA) with Anticipated Reserve Margins that drop below their Reference Margin Levels in the 5–10-year long-term outlook. Additionally, NERC re-examined the areas that projected shortfalls in the *2014LTRA* reference case (NPCC-New York, TRE-ERCOT, and MISO) by monitoring the net additions of on-peak availability of resources and changes to accounting methods and load modifiers. NERC will continue to monitor capacity and demand changes in these Assessment Areas.

NPCC-New York

The *2015LTRA* reference case shows that NPCC-New York has sufficient anticipated capacity to cover NERC's Reference Margin Levels through 2025. The major factors in NERC's Reserve Margin calculation modifications are the expected annual increase of energy efficiency programs (approximately 200 MW per annum) and a decrease in demand growth projections. In addition, NPCC-New York's economic incentives have led to distributed-generation-projected additions of customer-site solar photovoltaics (annual 80 MW), which will contribute to the increase in Reserve Margins. Additionally, seven mothballed units totaling 749 MW have returned to service along with an addition of 753 MW of Tier 1 resources. Existing nameplate wind capacity of 245 MW was not qualified to participate in New York's market and was not counted toward the total nameplate wind capacity of 1.5 GW from which 100 percent is counted toward the on-peak available resources.

NPCC-New York *2014LTRA* and *2015LTRA* Anticipated Reference Case Reserve Margins and Wind Capacity Contribution

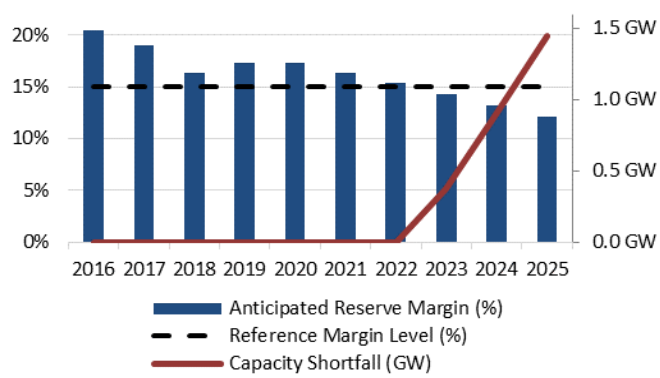




SERC-North

The SERC Region is comprised of several Assessment Areas: SERC-East, SERC-North, SERC-Southeast, and portions of the MISO and PJM Assessment Areas. SERC-North's Anticipated Reserve Margins will fall below NERC's Reference Margin Level of 15% by 2023 and continue to fall to 12%. SERC-North requires an additional 1.3 GW of on-peak resources to meet Reserve Margin requirements by 2025.

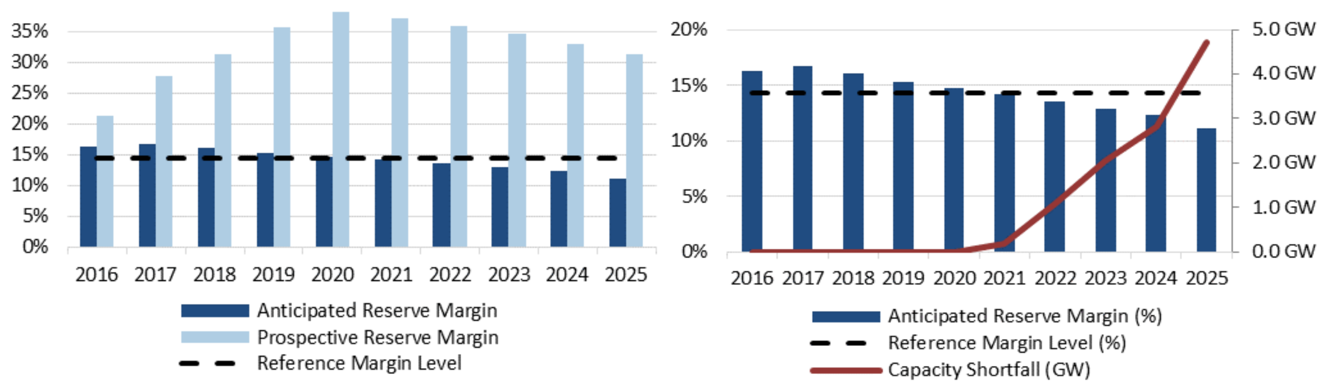
SERC-North Reserve Margins and Anticipated Reserve Margin Shortfall



MISO

Similar to the *2014LTRA* reference case, the *2015LTRA* reference case projects a shortfall in MISO's Anticipated Reserve Margins during the assessment period. MISO is projecting Anticipated Reserve Margins of 14.1% in 2021, which continues to trend downward to 11% by the end of 2025. MISO will require approximately 4.3 GW of additional resources by the end of the 10-year forecast in order to maintain their Reserve Margin of 14.3%. Additionally, MISO revised its Reference Margin Level from 14.8 to 14.3% since the release of the previous long-term reliability assessment report, and also reduced their load forecast. An addition of anticipated resources of 2.6 GW and a decrease in forecast total internal demand by 1 GW are the major contributing factors to the increase in resource availability when compared with the *2014LTRA* reference case.

MISO Reserve Margins and Anticipated Reserve Margin Shortfall



MISO has gathered data in 2014 and 2015 through the Organization of MISO States (OMS) Survey as part of their resource adequacy study. From these survey results, MISO projects the resources committed to serving load during the LTRA outlook. As a result, resources with low certainty are counted toward unconfirmed retirements, which affects the Prospective Reserve Margin calculations. Although MISO's Anticipated Reserves drop below their Reference Margin Level in 2021, there are a considerable amount of Tier 2 resources that could be advanced by 2021 to cover any resource adequacy concerns. NERC will continue to monitor capacity and demand changes in the MISO footprint for potential adverse impacts to reliability.

MISO OMS Generator Capacity Survey Highlights

The 2015 OMS survey results show a 1.7 GW surplus for 2016, primarily due to an increase in resources committed to serving MISO load and a decrease in load forecast. The 2014 OMS-MISO Survey had projected that the region faced a 2.3 GW shortfall starting in 2016.

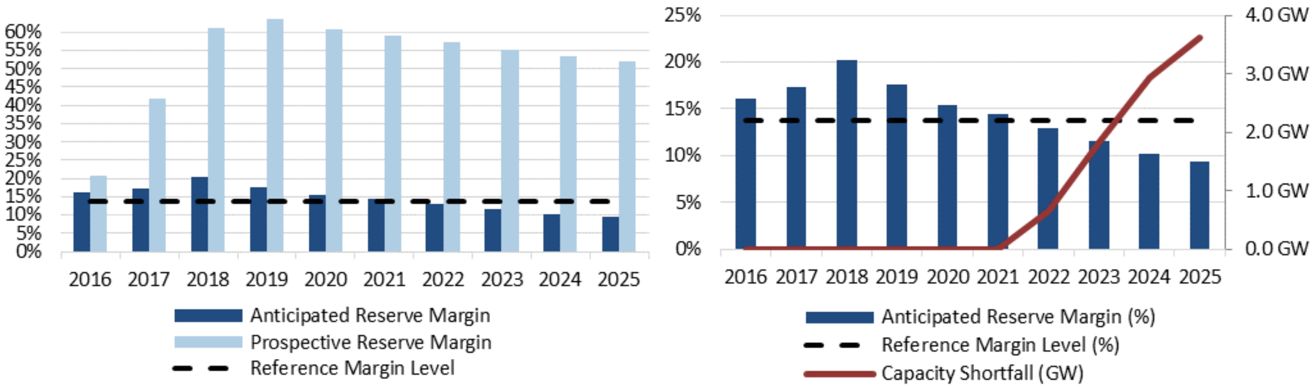
In addition, the survey indicates that part of the MISO region will fall below Reserve Margin requirements in 2016; however, these areas will be able to import needed capacity from neighboring zones to meet these requirements due to the benefits of membership in a regional transmission organization.

In MISO, load-serving entities, with appropriate oversight by state regulators, are responsible for ensuring resource adequacy.

TRE-ERCOT

The *2014LTRA* reference case identified TRE-ERCOT's Anticipated Reserve Margins falling below their Reference Margin Level of 13.75% in 2018, continuing this downward trend to 4.6% by 2024. The *2015LTRA* reference case shows an improvement in the Anticipated Reserve Margins as it remains above the Reference Margin Level through 2021 before declining to 9.7% by 2025.

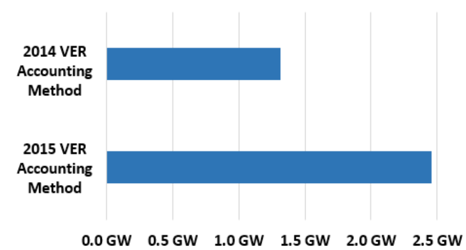
TRE-ERCOT Reserve Margins and Anticipated Reserve Margin Shortfall



TRE-ERCOT projects a deficit of approximately 3.3 GW by the end of the 10-year forecast in order to maintain the Reserve Margin of 13.75%. The capacity shortfall over the second half of the 10-year outlook is attributed to interconnection processes and the wholesale generation market, which typically sees project developers beginning to apply for permits and generation interconnection processes no more than four years before a new facility is expected to generate electricity.

One of the major contributors to the increase of Anticipated Reserve Margins in TRE-ERCOT is the addition of approximately 1.8 GW (2.3% of TRE-ERCOT's total available resources) of newly added Tier 1 natural gas and wind units. There is no change in load forecasts compared to the *2014LTRA* reference case.

ERCOT's Wind Resource Contribution Method Change when applied to the *2015LTRA* Wind Nameplate Capacity



Additionally, in October 2014, ERCOT updated their methods for calculating on-peak wind capacity contributions. Instead of using a probabilistic method for calculating a region-wide 8.7% of effective capacity contribution for their resources, ERCOT uses the highest 20 peak load hours from the past six years of historical performance data. This performance data projects different capacity values for summer and winter as well as coastal and non-coastal wind units. Based on the new projections, approximately 2.3 GW (17.5% of 13 GW of nameplate) is expected to be available. Under this new calculation method, an additional 1.2 GW of wind resources are accounted for in the anticipated resources.[9] If the 2014 wind contribution method is applied, ERCOT would fall below their Reference Margin Level in 2021 (as opposed to 2022), with the shortfall growing to 4.5 GW by 2025.

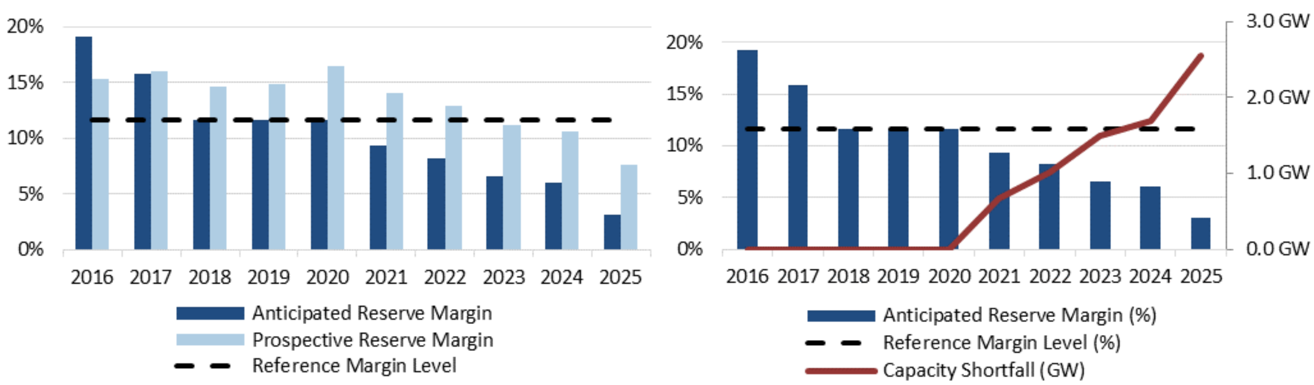
[9] Wind and solar profiles used in ERCOT planning studies.

WECC-NWPP-CA

The *2015LTRA* reference case examined the resource adequacy of WECC-NWPP's Canadian and American Assessment Area portions. WECC's Canadian portion of NWPP is a winter-peaking Assessment Area that projects an approximate 22% of total internal demand increase (from 23 GW to 29 GW) during the 10-year assessment period.

The Anticipated Reserve Margin in NWPP-CA falls below the Reference Margin Levels of 11.6% in 2021 to 9.3% and continues to trend downward to 3.1% by 2025. The significant anticipated demand growth in the area is a major contributor to the shortfall in Reserve Margins. No energy efficiency, Demand Response, behind-the-meter, or distributed generation were reported by WECC, which had less than 300 MW (approximately one percent of total available generation) of confirmed generation retirements during the assessment period. The Canadian portion of WECC-NWPP will require an additional 2.4 GW of on-peak available resources by 2025 to cover the capacity shortfall to maintain their Reference Margin Level. There are not sufficient Tier 2 resources to cover this capacity shortfall as their Prospective Reserve Margins also fall below the Reference Margin Level similar to the Anticipated Reserve Margins. However, a considerable amount of Tier 2 and Tier 3 resources could be advanced to cover any resource adequacy concerns.

WECC-NWPP-CA Reserve Margins and Anticipated Reserve Margin Shortfall



Reserve Margins in all Assessment Areas appear sufficient but continue to trend downward

Recommendations

NERC should conduct more granular analysis in areas with significant resource mix changes and raise awareness of potential resource adequacy concerns: NERC should continue to raise awareness of resource adequacy concerns with regular coordination with Regional Entities, involved Assessment Areas, and state regulators. One way to monitor and raise the awareness of adequacy concerns will be for NERC to conduct more granular analysis of the resource adequacy conditions in applicable Assessment Areas that are experiencing significant resource mix changes, including the potential retirement of conventional generation. Furthermore, NERC should closely monitor and evaluate the measures being taken by involved parties (e.g., market operators, state regulators, and utilities) to address any emerging resource adequacy challenges.

A Changing Resource Mix Requires Additional Measures and Approaches to Assess Future Reliability

The North American electric power system is undergoing a significant transformation with ongoing retirements of fossil-fired and nuclear capacity as well as growth in natural gas, wind, and solar resources. Additionally, the power system will further change as microgrids, smart networks, and other advancing technologies continue to be deployed. This shift is caused by several drivers, including existing and proposed federal, state, and provincial environmental regulations, as well as low natural gas prices and the ongoing integration of both distributed and utility-scale renewable resources.

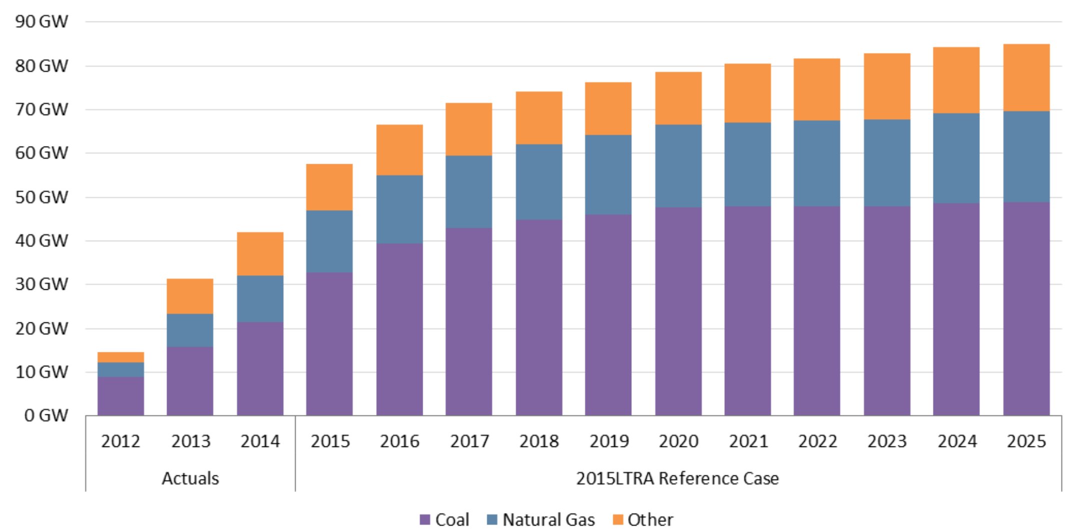
For successful integration of these new technologies and to support the changing resource mix, the BPS must remain reliable during and throughout this transition. Not all resources have the same characteristics and not all resources can be completely swapped and replaced. Therefore, key parameters that are critical to the reliable operation of the BPS must be monitored and sustained.

Resource mix changes directly impact the frequency response, voltage support, ramping capability, and behavior of the BPS. These developments will have important implications on system planning and operations, as well as how NERC and the industry assess reliability. In order to maintain an adequate level of reliability through this transition, generation resources need to provide sufficient frequency support, voltage control, and ramping capability, which are essential to the reliable operations and planning of the BPS.

To understand the changing dynamics of the system, current and future resource mix system behaviors and properties must be assessed. Analyses of the implications of this transformation are critical to enable effective planning and provide System Operators the flexibility to modify real-time operations. The transformed resource mix will have different characteristics and can be reliably integrated with planning, design, and coordination while System Operators monitor and recognize limitations in resource predictability, controllability, and responsiveness. New resources should have the capability to support voltage and frequency, and these capabilities should be present in the future resource mix. Monitoring and investigation of trends will highlight areas that could become reliability concerns if not addressed in a timely fashion. In addition, examination of forecasting methods and visibility and controllability of distributed energy resources is paramount for ensuring and maintaining reliability.

Approximately 21 GW of mostly smaller coal-fired units were retired between 2012 and 2014, while an additional 27 GW are scheduled to retire by 2025.[10] NERC-wide, 11 GW of natural-gas-fired generation were retired between 2012 and 2014, and an additional 10 GW are scheduled to retire by 2025.[11] Renewable, petroleum, nuclear, and less-efficient units that have reached the end of their lifespans amount to 6 GW of planned retirements by the end of the assessment period.

Cumulative Actual and Forecast Confirmed Retirements between 2012 and 2025

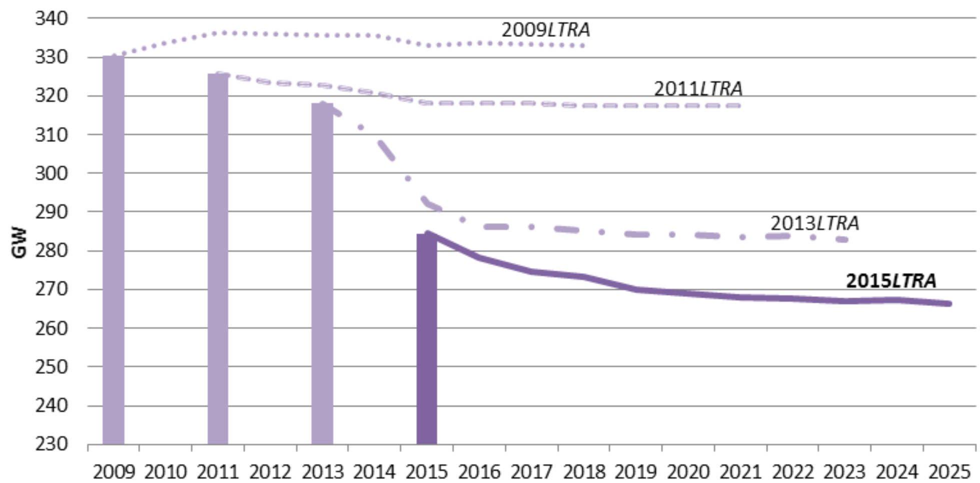


[10] Data for actual retirements (from 2012 to 2014) based on Ventyx Velocity Suite. Capacity is based on the net summer rating. Projected retirements (2015–2026) are based on the *2015LTRA* reference case.

[11] Ibid.

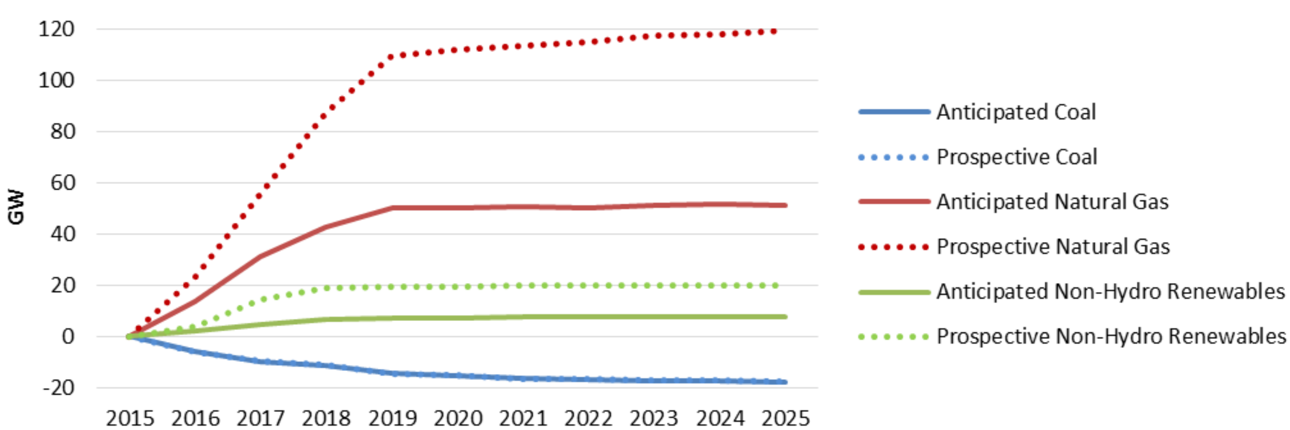
Coal capacity has continually decreased beyond reference case projections for all years since the *2009LTRA*, with 44 GW less coal generation available in 2015. In addition, the LTRA reference cases from 2011 through 2015 project coal-fired generation reductions in the 10-year projections. According to the *2015LTRA* reference case, coal capacity is projected to drop an additional 16 GW (including the addition of 470 MW of coal capacity during the assessment period), reducing coal contribution to 27% of the total available capacity by 2025.

NERC-Wide Coal-Fired Generation Outlook: 2009–2015 LTRA Reference Case Comparison



As coal contribution continues to decline, gas and renewable generation will continue to increase their roles in the future composition of the generation fleet. Anticipated gas capacity is projected to grow at an accelerated rate, adding an additional 10% (42 GW) of the total gas-fired anticipated generation capacity by 2019. Similarly, renewable generation is projected to provide a larger contribution in the total capacity, increasing from 33 GW in 2015 to 40 GW by the end of the assessment period. The prospective addition of renewable generation is almost twice the total anticipated renewable generation capacity additions by 2018. The additions of renewable energy will need to include the commensurate essential reliability services needed to ensure reliable operation of the BPS. This can be addressed through planning requirements and with interconnection agreements that require sufficient amounts of essential reliability services during and throughout the transformation of the resource mix.

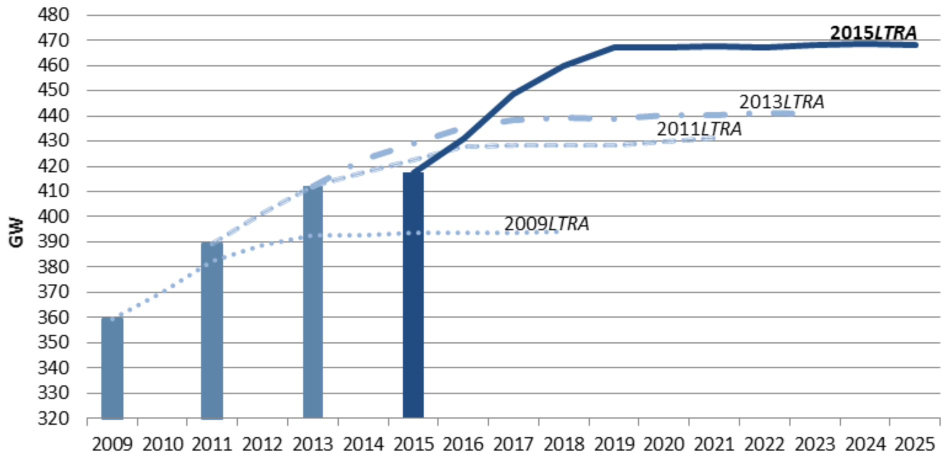
Cumulative Net Change in Anticipated and Prospective Capacity by Fuel Type for 2016–2025



Growing Reliance on Natural-Gas-Fired Generation Calls for Continued Enhancement to BPS Planning and Operations

With the shift toward more natural gas consumption in the power sector, the power industry will become increasingly vulnerable to risks from natural gas supply and transportation issues. Impacts due to extreme conditions should be integrated in planning scenarios to ensure the generating fleet is available to maintain BPS reliability.

NERC-Wide Gas-Fired Generation Outlook: 2009–2015 LTRA Reference Case Comparison



Nearly 49% of all Tier 1 nameplate capacity additions during the next decade are gas fired. By 2025, natural gas will contribute 43% of the anticipated on-peak resource mix, compared to 40% in 2015. A variety of drivers make natural-gas-fired capacity an attractive resource. Most impactful is the availability and price of natural gas, which is projected to remain low (relative to other fuels), with abundant supplies from shale formations throughout North America. Additionally, the emergence of more efficient natural-gas-combined-cycle generating technology requires lower engineering, procurement, and construction costs. The relative shorter build times for natural-gas-combined-cycle plants can help resource planners avoid procurement challenges that exist with other options. Another impetus behind this shift is the environmental advantage of lower carbon emissions when compared to coal-fired power plants without carbon capture and sequestration. Finally, natural-gas-fired units can provide System Operators with needed flexibility to address additional variability as VERs account for a larger portion of the resource mix in certain areas.

The electricity sector's growing reliance on natural gas has raised reliability concerns regarding the ability of both gas and electrical infrastructure to maintain BPS reliability. This is particularly of concern during extreme weather events, when there is high demand on both the natural gas and electric systems and the likelihood of natural gas deliverability interruptions is heightened. Vulnerability to these concerns varies by region and are particularly apparent in areas with a generation mix that is increasingly dominated by natural-gas-fired capacity with interruptible supply.

The *2014LTRA* provided an in-depth examination of the 2014 Polar Vortex event, with a scenario examining the specific Assessment Areas (SERC-E, PJM, MISO, and TRE-ERCOT) that experienced significant losses of generation during the event. Actual forced outage data were applied as derates to existing and projected (Tier 1) capacity projections using the *2014LTRA* reference case.[12] The scenario revealed that select areas with a high dependence on natural gas should take additional measures to ensure unit availability in order to maintain future system reliability during repeated extreme weather events.

With 97 GW of new natural-gas-fired generating units scheduled to come on-line by 2025, expansion of existing natural gas transportation infrastructure will be needed in some areas, while dual-fuel units will be necessary in others. Ultimately, the electricity sector's growing natural gas consumption has significantly increased the interdependency of the two systems and the inherent need for both sectors to coordinate efforts.

Natural-gas-fired generation requires high-volume, high-pressure fuel, which may exceed the capability of the existing pipeline infrastructure. As more gas-fired capacity is added, the system will be further strained as demand swings from generators could lead to pressure drops in pipelines that subsequently could jeopardize service to customers on the entire system.

---

12 *2014LTRA* Report – Appendix III

ISO-New England Gas and Electric Interdependency Analysis

ISO-New England's current generation mix is approximately 44% natural gas fired. Based on the projects in the interconnection queue, that percentage is likely to increase significantly in the future, further straining regional fuel supplies. Constraints on the regional natural gas delivery system as well as the cost and availability of imported liquefied natural gas (LNG) are among potential reliability issues in ISO-NE. The existing natural gas pipeline system in New England is being operated at maximum capacity more often, especially in winter. The priority for a pipeline's transmission capacity goes to customers who have signed long-term firm contracts. In New England these customers have been the local gas distribution companies (LDCs). Most natural gas plants have interruptible fuel arrangements that procure pipeline supply and transportation that has been released by these LDCs. As more homes and businesses convert to natural gas for heating, LDCs have had less capacity to release to the secondary market. This means that the increasing numbers of gas-fired generators are competing for limited amounts of fuel supply. Imported LNG can be used to meet spikes in regional gas demand, but it is significantly more expensive than natural gas. A study commissioned by the ISO highlights the problem; ICF International's 2014 gas study report projects regional shortfalls of natural gas supply during winter periods through 2020, even with the addition of 421 million cubic feet per day of new pipeline capacity.

The ISO is continuing to monitor its ability to maintain grid reliability during the coldest days of winter due to fuel availability. In winter 2014–2015, the ISO implemented for a second year a special reliability program to mitigate risks associated with the retirement of key non-gas generators, gas pipeline constraints, and difficulties in replenishing oil supplies. As part of the 2014–2015 winter program, oil-fired and dual-fuel generators and generators that can access LNG were paid to secure fuel inventory and test fuel-switching capability. They were compensated for any unused fuel inventory and were also subject to nonperformance charges. The 2014–2015 program included permanent improvements, such as the continued ability to test resources' fuel-switching ability and to compensate them for running the test. In addition, ISO-NE implemented a project that allowed generators to reflect fuel costs in their energy market offers as those costs change throughout the day. It also changed the timing of the day-ahead energy market to better align with natural gas trading deadlines. The ISO has initiated a stakeholder process to explore proposals to address reliability concerns for winter 2015–2016 and at least until 2018, when capacity market refinements to incentivize performance begin to take effect. Those refinements include Pay-for-Performance (PFP), which will strengthen availability incentives within the forward capacity market. Other efforts undertaken to shore up operations include the development of tools that help operations personnel more accurately predict the availability of natural gas supply for generators, improving unit commitment decisions; and increased communications with gas pipeline operators (assisted by FERC Order 787) to verify whether natural-gas-fired generators that are scheduled to run will be able to obtain fuel.

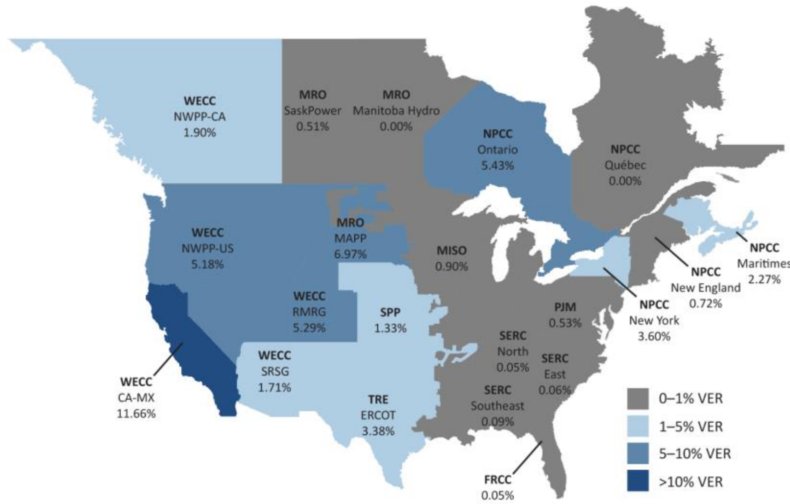
PFP, which will go into effect in June 2018, will create stronger financial incentives for generators to perform when called upon during periods of system stress: A resource that underperforms will effectively forfeit some or all capacity payments, and resources that perform in its place will get the payment instead. PFP will also create incentives to make investments to ensure performance, such as upgrading to dual-fuel capability, entering into firm gas supply contracts, and investing in new fast-responding assets. By creating incentives for generators to firm up their fuel supplies, PFP may indirectly provide incentives for the development of on-site oil or LNG fuel storage, or expanded gas pipeline infrastructure. However, PFP will not reach full effectiveness until the seven-year phase-in of the new performance rate is complete. Until that time, the region may be challenged to meet power demand at times when regional gas pipeline capacity is constrained. PFP may also hasten the retirement of inefficient resources with poor historical performance and the entrance of new, efficient, better-performing resources.

NERC's special assessment *Accommodating an Increased Dependence on Natural Gas for Electric Power*[13] provides detailed recommendations and enhancement opportunities for both BPS planning and operations.

[13] Accommodating an Increased Dependence on Natural Gas for Electric Power- Phase II.

Essential Reliability Services and the Increased Penetration of Variable Energy Resources

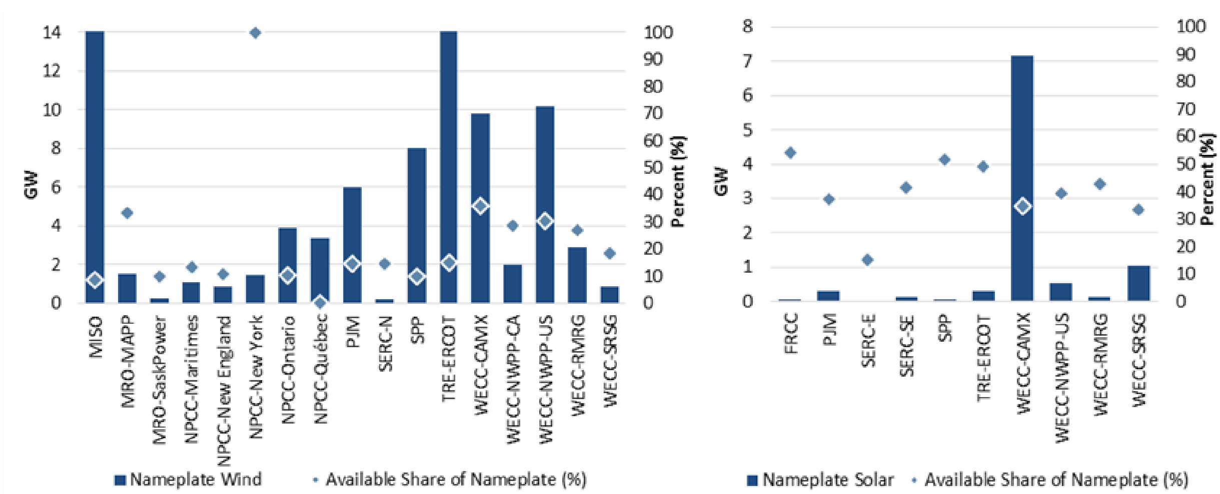
The changing resource mix and subsequent transmission expansions have transformed the planning and operation of the BPS. Retirements of coal-fired plants have increased growth in natural-gas-fired plants and variable energy resources. Increased demand-side management programs and distributed generation have also introduced new challenges. North America is experiencing significant growth in variable energy resources.



Existing VER On-Peak Penetration as Percentage of 2015 Total Generation Resources

The use of inconsistent methods to account for capacity contributions of VERs introduces complexities in accurate system reliability assessment and long-term transmission and resource planning development. Due to various methods for calculating the on-peak capacity contributions of VERs, as well as diverse availability of wind and solar resources at the time of peak demand, there are differences in each Assessment Area and the accounting approach for VER capacity in the calculation of their Anticipated Reserve Margins.

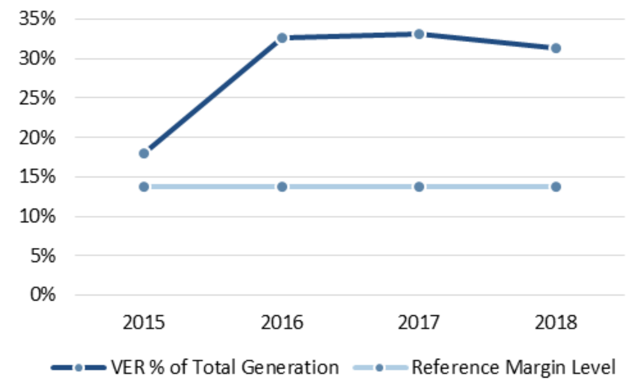
2015 Peak Season Contribution of Wind and Solar Anticipated Nameplate Capacity and Percentage Contributions[14]

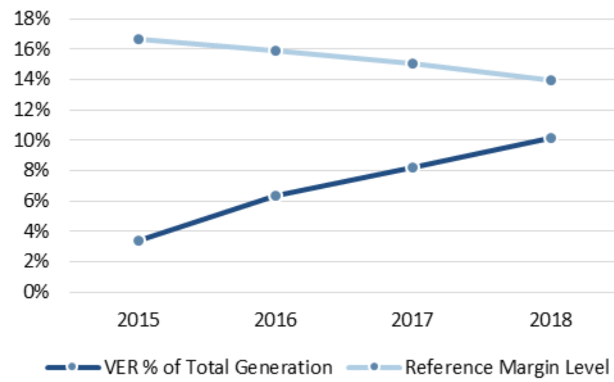


[14] NYISO calculates the Reference Reserve Margin value (17%) by a study conducted by the New York State Reliability Council (NYSRC) based on wind and solar at full Installed Capacity (ICAP) value modeled using an hourly supply shape for each wind and solar location.

The available capacity of a conventional generator can be approximated by multiplying that plant's installed capacity by its unforced outage rate. In addition to the capacity contribution levels of variable resources, demand and other resource availability on-peak demand also contributes to the total capacity availability of VERs. With the change in resource mix and greater energy production by wind and solar resources, assessing the availability of these resources at various hours of the day as well as throughout the seasons should be incorporated into probabilistic methods that calculate Reference Margin Levels. Some Assessment Areas, such as TRE-ERCOT and NPCC-New England, have projected greater VER on-peak contribution in the near-term horizon, with Reference Margin Levels unchanged or declining. The capacity value of renewable energy has a slightly diminishing return at progressively higher penetration, and the loss-of-load expectation/effective load carrying capability approach provides a rigorous methodology for accurate capacity valuation of renewable energy.[15]

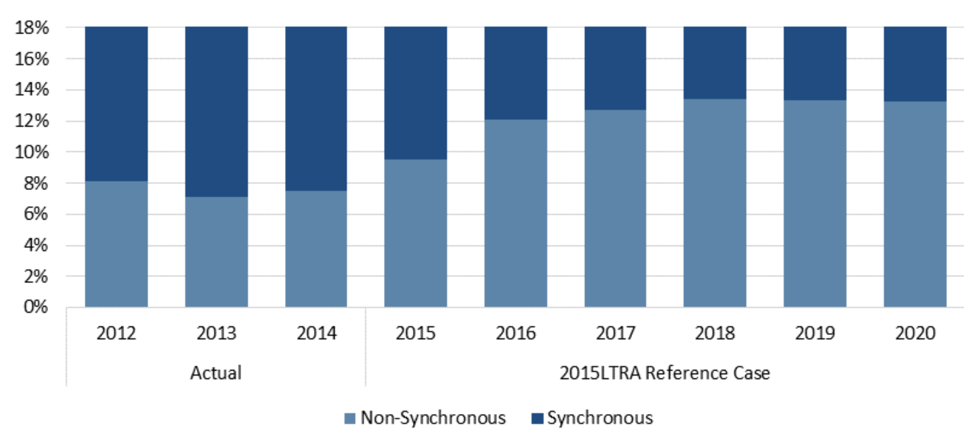
Short-Term Reference Margin Level vs. VER Nameplate Planned Resources as Percentage of Total Resources (TRE-ERCOT Left; NPCC-New England Right)





The classification of generating resources into synchronous and nonsynchronous by classifying the unit's prime mover[16] shows a growth in nonsynchronous nameplate capacity resources in the near term. The natural frequency response is not necessarily obtained from nonsynchronous generation where the electrical frequency and rotational speed are decoupled. The issues related to natural frequency response following an event will be more pronounced as the overall system inertia is reduced due to greater penetration of nonsynchronous generation into the BPS. The comparison of the past three years of total operating generation with the forecast installation of all future units demonstrates a growing percentage of nonsychronous generation. In order to maintain acceptable frequency response, minimum interconnection frequency response requirements and inertia on different system loading conditions should be evaluated and sustained. NERC-wide, the changes are not significant; however, in some Assessment Areas (e.g., ERCOT), the amount of nonsynchronous generation relative to synchronous generation is 18% in 2015 and increases to 32% by 2025.

Increasing Nameplate Capacity of Nonsynchronous Generation Compared to Synchronous Generation



[15] PJM Renewable Integration Study.

[16] All units analyzed in this assessment are reported with a single prime mover. A list of all prime movers are identified in the most recent EIA 860.

Assessment of areas with higher penetration of VERs shows that additional information and analysis is needed to formulate a comprehensive reliability assessment. For instance, ramping requirements can increase the amount of flexible capacity an areas must have to manage operational conditions like sunrise and sunset. Assessment Areas with a narrow longitude bands, such as WECC-CAMX, will undergo larger ramp rates in future years as more VERs are affected simultaneously. The effects of variable resources such as wind and solar will be more pronounced as they continue to comprise a greater portion of capacity within an area.

Essential Reliability Services Task Force

The Essential Reliability Services Task Force (ERSTF), created in 2014, has analyzed and assessed and continues to monitor current system behavior available today as well as the future services critical to the reliability of the system. New resources may have different operating characteristics but can be reliably integrated with proper planning, design, and coordination. Automatic voltage regulators and governors installed on conventional generation as well as power electronics controllers in VERs are critical components in providing frequency and voltage support. Future added generation must also have the capability to support voltage and frequency in the event of a disturbance and for day-to-day demand needs of the system. Therefore, interconnection agreements and other planning requirements need to be enhanced to ensure that sufficient amounts of essential reliability services and generation control and visibility are available. However, as part of this requirement, industry will need to understand how much is available and how much will be needed in the future to sustain reliability—a critical role for NERC to continue to address.

The task force report will be released at the end of 2015 and further discusses these concepts. The task force notes that as the resource mix continues to change, it is necessary for policy decisions to recognize the need for essential reliability services from the current and future mix of resources. A combination of measures and industry practices were developed to provide insight into trends and impacts of the changing resource mix.[17]

Summary of Measures and Industry Practice

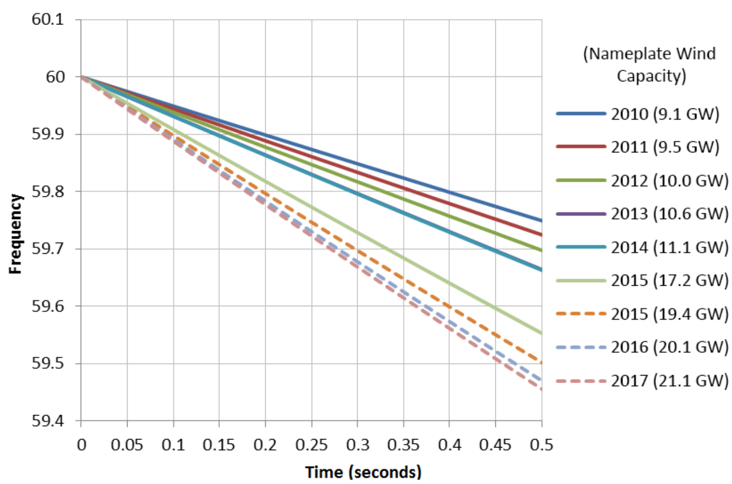
Measure	Brief Description	Balancing Area or Interconnection Level
Synchronous Inertial Response at Interconnection Level	Measure of Kinetic Energy. Historical and future (3 years out).	Interconnection
Initial Frequency Deviation Following Largest Contingency	At minimum Inertial Response, determine the frequency deviation within the first 0.5 seconds following the largest contingency.	Interconnection
Synchronous Inertial Response at Balancing Area Level	Measure of kinetic energy. Historical and future (3 years out).	Balancing Area
Frequency Response	Comprehensive set of frequency response measures at all relevant time frames as well as time-based measures capturing speed of frequency response and response withdrawal.	Interconnection
Real-Time Inertial Model	Industry Practice: Real-time model of inertia, including voltage stability limits and transmission overload criteria.	Balancing Area
Net Demand Ramping Variability	Measure of net demand ramping variability. Historical and future (3-years-out) view.	Balancing Area
Reactive Capability on the System	Measure: At critical load levels, measure static & dynamic reactive capability per total MW on the transmission system and track load power factor for distribution at low side of transmission buses.	Balancing Area
Voltage Performance of the System	Measure to track the number of voltage exceedances that were incurred in real-time operations.	No further Action
Overall System Reactive Performance	Industry Practice: Measure to determine reliability risk following event related to reactive capability and voltage performance. Evaluate adequate reactive margin and voltage performance (planning, seasonal, real-time horizons).	Balancing Area
System Strength	Industry Practice: Measure to determine reliability risk due to low system strength based on short circuit contribution. Calculate short circuit ratios to identify areas that may require monitoring/further study.	Planning Coordinator

[17] 2015 Essential Reliability Services Task Force Framework Report.

Frequency Support

Conventional generators' lack of sustainable frequency response, specifically in the Eastern Interconnection, in addition to substantial penetration of VERs on the BPS, can contribute to reductions in overall system frequency response.[18] The ERSTF recommended measures to track and project system inertia as well as frequency drop and response following events within each Balancing Area and Interconnection. Trends identified through various pilot assessments performed by the task force have identified future frequency response changes with the increase of variable resources. For instance, in the Texas Interconnection, the projections show a greater deviation from nominal frequency with the loss of a pre-defined generation at higher levels of installed VER capacity.

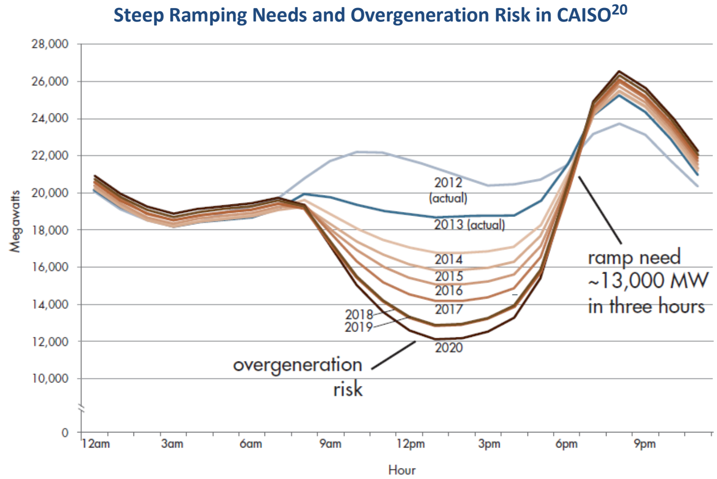
Texas System Frequency after 2750 MW Generation Trip



Net Demand Ramping Variability

Ramping is becoming a challenge for Balancing Areas experiencing significant penetrations of VERs, in addition to nondispatchable and other distributed resources. In particular, CAISO needs a resource mix that can react quickly to adjust electricity production to meet both variable demand and uncontrollable supply. To ensure supply and demand match at all times, controllable resources will need the flexibility to change output levels and operate as dictated by real-time grid conditions. The ISO is also facing risks in overgeneration (when there is more electricity supply than needed), as well as decreased frequency response.[19]

Steep Ramping Needs and Overgeneration Risk in CAISO[20]



Voltage Support

Maintaining adequate levels of system voltage is critical to BPS reliability and is achieved by resources' capability to absorb or produce reactive power. Voltage issues are local and require support from nearby generators or devices such as static or dynamic reactive resources. The task force analyzed three measures regarding voltage support and as a result determined that there is a need for enhanced planning studies in peak and shoulder seasons on a Balancing Area level.

[18] Frequency Response Initiative Report.

[19] What the duck curve tells us about managing a green grid – Fact Sheet.

[20] Ibid.

Probabilistic Approaches for Assessing Reliability

The North American generation mix is primarily comprised of conventional generation (hydroelectric, coal, petroleum, nuclear, and natural gas). With this generation mix, the use of a Reserve Margin continues to be an effective approach for assessing resource adequacy. Reserve Margins measure the amount of generation capacity available to meet expected demand during the planning horizon and have been a surrogate metric for examining and planning for resource adequacy and system reliability. Based on the premise of this metric, a system should be able to supply resources to meet the projected normal weather electricity demand (given an explicit amount of reserve capacity) with a high degree of certainty that the system can manage generator outages and modest deviations from the annual demand forecast. The Reference Margin Level includes a relative evaluation of the effects of unit size or performance, the size of the system, or the strength of its interconnections in each Assessment Area. In North America, given the static measure of generation reliability, Reference Margin Levels are reviewed and, if necessary, revised as significant system changes occur.

The one-event-in-ten-year (0.1 events per year) loss-of-load expectation is defined as the likelihood of disconnecting firm load due to a resource deficiency; on average, a generally accepted value is no more than 0.1 days per year. This commonly used industry reliability metric requires an electric system to be planned to maintain sufficient generation and Demand Response resources such that system peak load is likely to exceed available supply only once in a 10-year period. Industry and regulators across North America use or have adopted the one-event-in-ten-year industry reliability metric for ensuring and maintaining resource adequacy. Reliability outcomes depend on a host of complex and interdependent factors, such as the projected resource mix, generator availability, and weather uncertainty. Evaluating such factors, particularly with an increasing amount of variable generation, requires a probabilistic approach that statistically characterizes the uncertainty in load forecasts, generation dispatch, and import capability.

NERC conducts biannual probabilistic assessments to provide a common set of reliability indices and recommendations. Metrics used in the assessments include annual loss-of-load hours (LOLH), expected unserved energy (EUE), and expected unserved energy as a percentage of net energy for load (normalized EUE) for two common forecast years. Additionally, scenario analysis is performed to help identify sensitivities and extreme conditions.

In its *2014LTRA* report, NERC highlighted the need to leverage its periodic Probabilistic Assessment to evaluate the changing behavior of the BPS and to provide further insights on the resource adequacy concerns in certain areas that have tight Reserve Margins. Additional aspects for future probabilistic assessments can include shoulder season reliability indices, common mode of failure (e.g. natural gas supply interruptions), and operational forced outage rate metrics. The Probabilistic Assessment Improvement Task Force has developed an improvement plan report recommending enhancements to NERC's probabilistic assessment.[21]

Additional Considerations for Transmission Adequacy Assessments

Because of the downward trend in the Reserve Margins for several Assessment Areas, combined with ongoing changes to the characteristics of the system, resources planners should consider more comprehensive assessments of transfer capabilities with neighboring areas. These assessments should include future plans for resources and transmission, such as potential unit retirements and capacity additions, particularly for wind and solar. Integrating these plans into operations and planning models will yield more accurate and coordinated powerflow and dynamic studies. The results of these improved studies should also be shared between neighboring systems.

Future reliability assessments should include adequate collaboration between two or more Balancing Areas to support reliable BPS planning. Depending on the unique characteristics of each Balancing Area, transmission adequacy studies should include the following: (1) the use of powerflow models that contain a common economic generator dispatch that all parties accept; (2) the evaluation of non-BES elements that could potentially impact the BPS; and (3) the projection and evaluation of the potential system impacts from external contingencies on their systems. If contingencies are identified that would impact neighboring systems, the adequacy studies should be shared among all impacted parties.

[21] Probabilistic Assessment Improvement Plan – Summary and Recommendations Report.

A changing resource mix requires additional measures and approaches for assessing future reliability

Recommendations

NERC should advance new metrics and approaches for assessing reliability: NERC should continue to develop new approaches and frameworks for assessing reliability in both the short (1-5 years) and long-term (5-10 years) time horizons. This includes the development and implementation of metrics to examine essential reliability services as an additional dimension to the traditional reserve margin analysis, especially applicable for Assessment Areas with projected high levels of variable resources. Additionally, energy adequacy metrics through probabilistic assessment should be advanced through the NERC Planning Committee. NERC should anticipate the need for increased information sharing and support for a wide variety of stakeholders.

NERC, in collaboration with Planning and Operating Committees, should establish Reliability Guidelines to assess and consider fuel, generation operational characteristics, and other related risks: A growing reliance on natural gas continues to raise reliability concerns, highlighting the interdependency between the electric and natural gas industries and concerns about being overly dependent on a single fuel source. To ensure reliable operation of the BPS, planning approaches must be enhanced and adapted to consider fuel deliverability, availability, and response to pipeline contingencies that are unique to each area. NERC should also closely monitor resource availability and operational impacts in areas with high concentrations of gas-fired generation (e.g., New England). In collaboration with Planning and Operating Committees, NERC should establish planning and operation Guidelines for both short- and long-term horizons to simulate and consider fuel, generation operational characteristics, and other related risks in reliability assessments.

Policy makers should use NERC's analytic framework to ensure essential reliability services are maintained: Federal, state, and local jurisdictional policy decisions have a direct influence on changes in the resource mix, and thus can affect the reliability of the BPS. An analytical basis for understanding potential reliability impacts must be used to understand potential reliability impacts from increasing integration of VERs. Consideration of the reliability implications extends beyond a reserve margin assessment, as it includes impacts on system configuration, composition, and the need for replenishment of essential reliability services. Policy makers, therefore, must recognize the need for essential reliability services provided by the current and future composition of resources and incorporate those needs through market mechanisms, interconnection requirements, and other initiatives as outlined in NERC's upcoming *Essential Reliability Services Task Force Framework* report.

Operators and Planners Face Increased Levels of Distributed Energy Resources and New Technologies

The addition of DERs is contributing to a shifting paradigm in traditional grid operation. The Essential Reliability Services Task Force also recognized this transition underscores the need to further examine DER impacts on both the amount and quality of essential reliability services needed to maintain resource adequacy and operational reliability. Awareness and predictability of these resources is important in order to plan and operate the BPS, particularly because DERs are usually variable in nature and outside the control of the System Operators. With prudent planning, operating and engineering practices, and policy that is oriented to support reliability, DERs should be able to be reliably integrated into BPS operation.

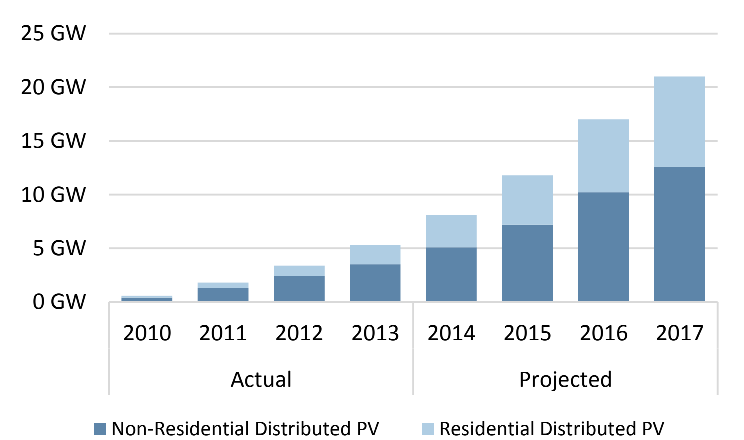
Existing interconnection requirements for DERs create reliability concerns related to disturbance tolerance. These concerns include the voltage and frequency ride-through capabilities of DERs. The *Summary and Recommendations of 12 Tasks* report developed by the Integration of Variable Generation Task Force examines current inconsistent requirements for BPS-connected and distribution-system-connected resources and outlines two requirements for these generating unit connections. The recommendations are:

- In the short term, NERC should consider initiating a task force to more closely examine and track DER impacts. This group would engage in current efforts to revise DER interconnection requirements and standards by providing information that supports BPS needs; supporting the efforts of IEEE with transmission reliability subject matter experts; raising industry, regulator, and policy maker awareness; and encouraging the consideration of the explicit voltage and frequency ride-through for DERs.
- In the longer term, NERC should establish a coordination mechanism with IEEE Standard 1547 and other regulator-approved interconnection requirements to ensure that BPS reliability needs are factored into revisions or new DER interconnection standards.

The rapidly changing characteristics on the distribution system introduce the potential for unintended impacts on the BPS. Specifically, widescale fluctuations in areas with concentrated amounts of DERs (e.g., a concentrated population of utility customers with solar PV units) could lead to BPS instability such as under-voltage or under-frequency tripping. This is a particular risk if BPS protection devices are calibrated to allow minimal tolerance for frequency deviations. Moreover, if BPS planners and operators are unaware of ongoing changes to the distribution network, wide-area frequency deviations could cause these protection devices to respond in unintended ways.

In terms of planning, most Assessment Areas are modeling DERs as load modifiers with the expectation that forecast peak load will consistently be served by resources on the distribution network (e.g., rooftop solar). The installation of distributed solar photovoltaics particularly in the residential sector has seen dramatic growth within the past years and is projected to grow at a rapid pace due to improvements in the economy and housing market and the decline in PV installation costs, as well as state and federal incentive programs.[22] Additionally, modifications to the amount of load and DER present on the system mask the characteristics of load and DERs in modeling efforts. Greater visibility of load characteristics and the effects of DERs on frequency response and system stability has been suggested by previous LTRAs.

Actual and Projected Cumulative Distributed PV Installed Capacity in U.S. Since 2010



[22] SEIA - Q2 2015 Solar Market Insight Fact Sheet.

While NERC has identified high levels of DERs as an emerging reliability issue, it also presents opportunities to create a more robust and resilient system. For example, widely dispersed resources on the distribution side could potentially address shortfalls in localized reactive power if System Operators have the appropriate visibility and control of these resources.[23] [24] The interplay between technologies such as Remedial Action Schemes (RASs) and phasor measurement units (PMUs) must also be further examined and understood. Additional data collection and analysis will facilitate a better understanding of DER characteristics, particularly in areas with high penetration. Collaborative efforts between NERC, state regulators, and the industry is prudent as DERs become increasingly located on the distribution system.

New Renewable Generation Technologies Present New Challenges

Certain entities in Europe—Germany in particular—operate systems with higher proportions of DERs compared to the North American BPS. With over 75 GW of distributed solar and wind (accounting for over half of the country's resources), Germany has taken a multifaceted approach of technical and regulatory enhancements to maintain reliability:

- The existence of a robust transmission system
- Flexible operation of coal and nuclear units
- Modifications to the market design to promote more expedient, effective, and transparent response to changing conditions.
- Improved system control software and day-ahead weather forecasting
- Improvements to local-level distribution systems:
  - Modified solar inverter equipment that converts DC to AC
  - Inverter setting adjustments of frequency tolerances to avoid a wide-scale automatic disconnection of solar resources due to frequency deviations.
- Bolstered transfer capabilities to systems in neighboring countries
- Revised interconnection standards for DERs

Understanding the Changing Nature of End-Use Loads

Conventional loads such as resistive heating and lighting are considered grid friendly[25] because of their electrical characteristics, particularly their response to grid disturbances such as faults. These loads exhibit a constant impedance consumption characteristic where reduction in voltage results in reduction of active and reactive power. In the event of a disturbance, overall power consumption by the loads will be proportionally reduced. Newer electronically coupled loads do not exhibit this constant impedance characteristic; rather, they tend to have controls that maintain constant power consumption regardless of system voltage or frequency. The make-up and characteristics of end-use load technology is continually and rapidly evolving, with continued penetration of electronically coupled loads such as electric vehicles, plug-in electric hybrids, higher efficiency single-phase air conditioners, compact fluorescent lighting, LED lighting, LCD and LED televisions, variable-frequency drives, and electronically commutated motors.

Dynamic load models, particularly composite load models,[26] are capable of capturing the dynamic response of various end-use loads, namely induction motor load, as required per TPL-001-4.[27] A phased adoption of these models enables organizations to capture load dynamics while gaining experience with the model in stability studies. The industry should continue monitoring modeling efforts and cohesively share necessary tools and educational materials for enhancement and development of these models.

NERC is also coordinating with the electric industry to understand the end-use load response needed for future reliability of the electric grid such that the BPS maintains stable equilibrium for major grid events. Preliminary studies have developed approaches for the "ideal" response of large power electronic (electronically coupled) loads such as electric vehicle chargers.

Interconnection and technology standards will be key for ensuring end-use load control is coordinated with the operation and performance of the BPS. The industry should be engaged in standards development processes to mitigate potential risks to long-term reliability.

[23] Potential Bulk System Reliability Impacts of Distributed Resources.

[24] How and Where Distributed Energy Resources Will Reduce the Need for Transmission.

[25] Grid-friendly load, in this instance, refers to load response that supports system stability and control through response to changes in voltage and frequency that proportionally affect real and reactive power consumption.

[26] In particular CMLD and CMPLDW models used in simulation programs.

[27] Standard TPL-001-4, Transmission System Planning Performance Requirements.

Operators and planners face uncertainty with increased levels of distributed energy resources and new technologies

Recommendations

NERC should establish a task force focused on accommodating DER resources to further examine future reliability impacts: NERC should leverage industry stakeholder expertise and create a task force to examine and proactively address potential BPS reliability impacts associated with the integration of large amounts of distributed resources, including variable energy resources connected to the distribution system. NERC in collaboration with Planning and Operating Committees, should consider establishing reliability guidelines which focus on reliability considerations when accommodating large amounts of distributed resources. The task force should also consider and evaluate the opportunities that may be provided by DERs that can enhance reliability and resiliency. Additionally, this initiative includes encouraging the IEEE 1547 stakeholder group to consider BPS reliability impacts due to high-levels of DERs.

Policy makers should consider BPS reliability implications when integrating large amounts of DER: For the reliable integration of large amounts of DER, policy makers should coordinate with electric industry to address potential reliability concerns. System upgrades will be needed to support the integration, which will require close coordination between Distribution Providers, System Operators, and state regulators. Phased approaches may be necessary as the system is currently not designed for distribution-centric operations. The ability to observe, control and dispatch DERs will be important considerations when planning and operating a reliable BPS with large amounts of DER—particularly because the majority of DERs are variable and outside the control of the System Operator. However, distribution-centric operations can reliably support the BPS with adequate planning, operating and forecasting analyses, coordination, and policies that are oriented to reliably interface with the BPS.

NERC Continues its Reliability Assessment of the Clean Power Plan and other Environmental Rules

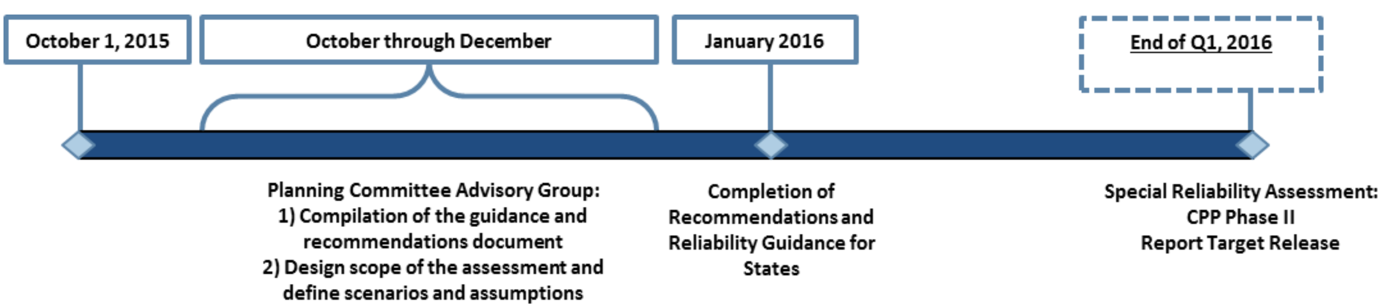
The EPA issued the final Clean Power Plan (CPP) on August 3, 2015, which aims to reduce CO_2 emissions levels by 32% by 2030, compared to 2005 levels. With an initial effective date of 2022, compliance with these regulations will effectively accelerate the shift in the generation mix away from coal and toward natural-gas-fired and renewable resources.

CPP implementation Timeline as Outlined by the EPA

Some of the important parameters of the final rule, which differed substantially from the draft rule, are:

- State plans are due in September 2016, with a possible extension of up to two years. The compliance averaging period begins in 2022 rather than 2020, and emissions reductions are phased in on a gradual glide path to 2030.
- Carbon emission reductions compared to 2005 levels were increased from 30 to 32%.
- The final rule establishes a Clean Energy Incentive Program (a voluntary matching fund program) that states can use to incentivize early investment in eligible renewable energy, as well as demand-side energy efficiency projects that are implemented in low-income communities.
- The final rule provides a reliability safety valve to address any reliability challenges that arise on a case-by-case basis.
- The final rule restructured the Best System of Emission Reduction (BSER), the method by which the EPA was able to evaluate potential CO_2 reductions. The best system of emission reduction comprises three building blocks, namely:
    1. Improving heat rate at affected existing coal-fired generation
    2. Increasing generation from lower-emitting existing natural gas combined-cycle units
    3. Increasing generation from new zero-emitting renewable energy capacity
- Nuclear generation is considered zero carbon emitting, which will allow nuclear units to remain more competitive with other generation types.

In its Phase I study,[28] NERC recommended further consideration for the timing needed to implement the infrastructure changes requisite for compliance with the draft rule. Additionally, NERC recommended the inclusion of a Reliability Assurance Mechanism to ensure the maintenance of system reliability was prioritized. The final rule addressed both of these concerns. NERC will continue to examine the potential reliability impacts of the final rule's implementation. NERC plans to release a guidance and recommendation document in January 2016 that will provide recommendations underscoring reliability issues that states should consider as they are developing their state or regional plans. NERC will also release a scenario-based analysis of the CPP close to the end of the first quarter of 2016.



[28] NERC Clean Power Plan - Phase I Study.

Status of Existing Regulations

Mercury and Air Toxics Standards (MATS)

The EPA issued a rule in December 2011 to reduce emissions of toxic air pollutants from power plants.[29] The MATS rule in its current form includes important modifications, such as the ability for a one-year extension (beyond the 2015 deadline) to alleviate potential impacts to system reliability and to allow Generator Owners to install needed compliance equipment. On June 29, 2015, the U.S. Supreme Court rejected the MATS rule, citing that the EPA did not evaluate costs associated with the rule. However, the EPA will most likely be granted permission by the lower court to amend the rule after adding an analysis of costs.

Cross-State Air Pollution Rule (CSAPR)/Clean Air Interstate Rule (CAIR)

On July 6, 2011, the EPA finalized the CSAPR.[30] The rule requires states to significantly reduce power plant emissions that contribute to ozone and/or fine particle pollution in other states. The timing of the CSAPR's implementation has been affected by a number of court actions. On December 30, 2011, CSAPR was stayed prior to implementation. On April 29, 2014, the U.S. Supreme Court issued an opinion reversing an August 21, 2012, D.C. Circuit decision that had vacated CSAPR. Following the remand to the D.C. Circuit Court, the EPA requested that the court lift the CSAPR stay and toll the CSAPR compliance deadlines by three years. On October 23, 2014, the D.C. Circuit granted the EPA's requests. CSAPR took effect starting January 1, 2015, for SO_2 and annual NO_x and May 1, 2015, for ozone season NO_x. Combined with other final state and EPA actions, the CSAPR will reduce power plant SO_2 emissions by 73 percent and NO_x emissions by 54% from 2005 levels.

Clean Water Act – Section 316(b)

Cooling water intake operation and structures are regulated under Section 316(b) of the Clean Water Act.[31] The 316(b) rule is implemented by the state water permitting agencies through the National Pollution Discharge Elimination System permit program of the Clean Water Act. The EPA provides state permitting agencies with regulatory guidance and standards to determine the best technology available to protect aquatic life from impingement (being trapped against the intake screen) and entrainment (passing through the screens and into the plant's cooling water system). Section 316(b) of the federal Clean Water Act requires that the location, design, construction, and capacity of cooling water intake structures for facilities reflect the best technology available for minimizing adverse environmental impact. The final rule was signed in May 2014 and released in August 2014 in the Federal Register.

Coal Combustion Residuals (CCR)

The EPA's regulation for the Disposal of Coal Combustion Residuals from electric utilities was signed on December 19, 2014, and it was published in the Federal Register on April 17, 2015.[32] The effective date of the rule was October 19, 2015. The final rule makes a number of changes from the proposal, including providing greater clarity on technical requirements in response to questions received during the comment period. The rule finalized national regulations to provide a comprehensive set of requirements for the safe disposal of CCR, commonly known as coal ash, from coal-fired power plants.

Canadian Provincial Regulations

Canadian regulations for CO_2 emissions continue to become more stringent, resulting in the imminent retirement of coal-fired units. Under Canadian law, both the federal government under Section 64 of the Canadian Environmental Protection Act of 1999, and provincial governments have jurisdiction over the regulation of greenhouse gas emissions. In April 2015, Ontario announced its intention to join the cap-and-trade system with other jurisdictions, including Québec and California; details of the system are still to be determined. In a report to the minister, in November 2015, the Alberta Climate Leadership Panel recommended that the Government of Alberta broaden and improve its existing carbon pricing regime, complement carbon pricing with additional policies to reduce the emissions intensity of electricity supply as well as oil and gas production, promote energy efficiency, and add value to resources through investments in technological innovation.[33]

---

[29] EPA - Mercury and Air Toxics Standards (MATS).

[30] EPA - Cross-State Air Pollution Rule (CSAPR).

[31] EPA - Cooling Water Intakes — Final 2014 Rule for Existing Electric Generating Plants and Factories.

[32] EPA - Disposal of Coal Combustion Residuals from Electric Utilities.

[33] Alberta Climate Leadership Panel's Report to Minister.

NERC continues its reliability assessment of the Clean Power Plan and other environmental rules

Recommendations

NERC should continue to assess CPP impacts through a phased approach, as state and regional implementation plans are developed: In its Phase I study, NERC recommended further consideration for the timing needed to implement the infrastructure changes requisite for compliance with the draft rule. Additionally, NERC recommended the inclusion of a Reliability Assurance Mechanism to ensure the maintenance of system reliability was prioritized. The final rule addressed both of these concerns. NERC will continue to examine the potential reliability impacts of the final rule's implementation. NERC plans to release a report in January 2016 that will underscore reliability issues that states should consider as they develop their state or regional plans. NERC will also release a scenario-based analysis close to the end of the first quarter of 2016.

Other Reliability Issues

In addition to the four reliability trends and emerging issues above, NERC continues to examine and assess the ongoing impacts of several other issues and will continue doing so if additional evaluation or special assessments are needed.

Reliability Risks Associated with Early Retirement of Nuclear Plants

Nuclear generation currently contributes approximately 9.5% of the total nameplate resources in North America. These units are critical in maintaining the reliability of the BPS and provide essential services such as frequency and voltage support. Since 2011, five nuclear reactors, representing approximately 4.3 GW in capacity, have retired. James A. Fitzpatrick nuclear unit (838 MW) in NPCC-New York and Pilgrim nuclear unit (680 MW) in NPCC-New England have also announced early retirement by early 2017 and June 2019, respectively, due to maintenance and operation costs of the plants.[34] [35] However, the Watts Bar 2 nuclear unit (1,270 MW) is scheduled to come online in late 2015, with two additional units totaling 2.2 GW expected by 2020. Vogtle units 3 and 4[36] are expected to be placed in service in 2019 and 2020, respectively, and construction of V.C. Summer nuclear units 2 and 3 is on schedule with expected completion years of 2019 and 2020.[37] With the integration of variable generation and greater power production from natural gas, the early retirement of existing nuclear plants will significantly challenge planners and operators in maintaining Reserve Margin levels, providing essential reliability services, addressing base-load generation needs, and lowering emissions to meet environmental regulations.

Energy Storage

At present, the United States has about 21 GW of grid storage. Over 95% of this is pumped storage hydro.[38] With the increased penetration of variable resources on the BPS, the need to compensate for that variability has resulted in an increased investment in storage development efforts. Energy storage technologies—such as pumped hydro, compressed air energy storage, various types of batteries, flywheels, electrochemical capacitors, etc.—provide for multiple applications: energy management, backup power, load leveling, frequency regulation, voltage support, and grid stabilization. Not every type of storage is suitable for every type of application, which motivates the industry to create a portfolio strategy for energy storage technology. NERC continues to evaluate the impacts of increased storage technologies on the BPS. The DOE is currently addressing challenges and barriers in areas such as validated reliability and safety, equitable regulatory environment, and industry acceptance.

Load Forecasting Uncertainties

Despite slower load growth projections, the electric industry continues to face several challenges in forecasting electricity demand. Specifically, conservation programs, smart grid technologies, and DERs have complicated load forecasting methods that were traditionally functions of weather conditions, economic cycles, and population growth.

In addition to other variables, there is sufficient empirical evidence to suggest that correlations between load growth and economic outlook—a critical input for most load forecasts—have diminished. As new variables are introduced to load forecasting models, further analysis will be necessary to gain a better understanding of the actual impacts and appropriately integrate them into short- and long-term load forecasting methods. New technologies, like advanced metering infrastructure, plug-in hybrid electric vehicles, and real-time pricing, may provide better-quality load data to utilities. However, in the near term (one to five years), these technologies may further contribute to the uncertainty due to changing residential customer behavior. Moreover, the benefits of these new technologies will not be realized until several years of baseline data has been collected and used to establish accurate residential profiles that can be relied on for future forecasting.

Potential Operational Risks Associated with Interaction of Special Protection Systems and Remedial Action Schemes

Special Protection Systems (SPSs) and Remedial Action Schemes (RASs) provide alternatives to the addition of new transmission facilities. System Operators need to be aware and informed of SPS and RAS devices in service, as well as the corresponding impacts associated with these devices.

---

[34] The Fitzpatrick and Pilgrim Nuclear Unit retirements were not accounted for in the Reserve Margin calculations in the *2015LTRA*.

[35] Entergy Nuclear Unit Retirement Announcements.

[36] Vogtle Units 3 & 4.

[37] V. C. Summer Units 2 & 3.

[38] DOE Global Energy Storage Database.

Regional/Interconnection-Wide Modeling

Examining interconnection-wide phenomena is necessary for industry to more effectively address frequency response, inertial response, small-signal stability, extreme contingency impacts, and geomagnetic disturbances. To support improved system performance and planning, validated models should accurately represent actual equipment performance in simulations. All devices and equipment attached to the electric grid must be modeled to accurately capture how that equipment performs under static and system disturbance conditions. Models provided for equipment must be open-source and shareable across the industry to support reliability.

System modeling issues have been identified in several significant system events during the past two decades (the latest being the Arizona–Southern California Outages).[39] Issues cover the full range of systems (i.e., transmission, generation, loads, and protection) and, more importantly, the interaction between all components. NERC has advanced the development of appropriate modeling standards, and the industry as a whole has begun addressing various pieces and parts of the modeling issues.

While the industry has made significant improvements in modeling practices, it continues to address issues and future system modeling needs, such as the following:

- Standardized component models to gain consistency in static and dynamic models used for power system studies.
- Consistency in model parameters to eliminate discrepancies between real-time contingency analysis and planning models.
- Benchmarking static and dynamic models to close the gap between study results with real-world behavior of the power system network.
- Modeling a larger array of system components to ensure greater accuracy in real-time and off-line studies.

Workforce Transformation

Projected retirements in the electricity industry during the next decade will require a well-trained industry workforce (primarily engineers). Workers entering the power industry will be tasked with understanding and implementing a variety of new technologies with smarter systems and devices as the BPS continues to rapidly evolve. The electric power industry is addressing this issue by creating partnerships between academia and the industry through internship and training programs.

Aging Infrastructure

Reliable operation of the electric system depends on an interconnected system of generation transmission and local distribution elements. The North American BPS was built over the course of a century; therefore, the age of the infrastructure varies widely. Maintaining the transmission system has many challenges, such as the unavailability of spare parts, the obsolescence of older equipment, and the potential inability to maintain system reliability due to outage scheduling restrictions, as well as reliably integrating new technologies. Investment in new transmission infrastructure and refurbishment of existing facilities in the United States by investor-owned utilities has increased substantially over the past 15 years but varies significantly across NERC Regions.[40] The implementation of any replacement strategy and in-depth training programs requires additional capital investment, engineering and design resources, and construction labor resources, all of which are in relatively short supply.

Coordinated Cyber or Physical Attacks on Electricity Infrastructure and GridEx Program

For decades, NERC and the bulk power industry defined system security as the operating aspects that enable the BPS to withstand sudden, unexpected disturbances, such as short circuits or unanticipated loss of system elements due to natural causes. In today's world, the security focus of NERC and the industry has expanded to include withstanding disturbances caused by man-made physical or cyber attacks. The bulk power system must be planned, designed, built and operated in a manner that takes into account these modern threats, as well as more traditional risks to security. Such an attack could damage or destroy key system components, significantly degrade system operating conditions, and, in extreme cases, result in prolonged outages to large parts of the system. From a BPS resilience and operations perspective, ensuring the grid has the ability to recover from a widespread, coordinated cyber attack is of critical importance.

On November 22, 2013, FERC approved Version 5 of the critical infrastructure protection cybersecurity standards (CIP Version 5), which represent significant progress in mitigating cyber risks to the bulk power system. The proposed Reliability Standards

[39] Arizona-Southern California Outages.

[40] EIA: Today in Energy - Electricity Transmission Investments Vary by Region.

are designed to mitigate the cybersecurity risks to bulk electric system facilities, systems, and equipment, which, if destroyed, degraded, or otherwise rendered unavailable as a result of a cybersecurity incident, would affect the reliable operation of the Bulk-Power System.[41] On May 7, 2015 NERC Board of Trustees adopted the proposed Reliability Standard CIP-014-2 which is to protect transmission stations and transmission substations, and their associated primary control centers, that, if rendered, inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or cascading within an interconnection.[42]

The GridEx program is a series of biennial exercises that evolved from work done by NERC with industry and government partners to study the risk of coordinated cyber and physical attacks on the grid in North America; this includes the 2010 High Impact Low Frequency report[43] and the 2012 Severe Impact Resilience report.[44] NERC staff and its Critical Infrastructure Protection Committee (CIPC) Grid Exercise Working Group designed the exercise scenario which was executed in November 2015. The Distributed Play portion of the exercise was continent-wide, with over 4,200 participants from 360 organizations in the U.S., Canada and Mexico, who responded to simulated cyber and physical attacks on the power system by assessing the rapidly-changing situation, mitigating the impact of the attacks, recovering, and restoring power. The Executive Tabletop session dealt with an even more disruptive scenario for electricity industry executives and senior government officials, who engaged in a robust discussion of the policy issues, decisions, and actions needed to respond to such a major grid disruption. Leaders identified security and reliability challenges and opportunities to improve prevention, response, and recovery strategies. Detailed reports on Distributed Play lessons learned and Executive Tabletop recommendations will be released to stakeholders in Q1 2016, and a public report will be posted on the GridEx program page.[45]

---

[41] CIP V5 Transition Program.

[42] Project 2014-04 Physical Security.

[43] 2010 High Impact Low Frequency report.

[44] 2012 Severe Impact Resilience report.

[45] GridEx Program page.

Assessment Area Reliability Issues

The North American BPS faces a changing market environment that features reduced or flattened demand projections, low natural gas prices, new environmental regulations, continued uncertainty about the future regulation of carbon emissions, and projected growth of VERs. The BPS is facing significant planning and operational challenges to avoid localized reliability problems and minimize impacts related to the accelerated change in resource mix. The intent of this section is to highlight the reliability trends and emerging issues identified by each Assessment Area.

FRCC

Continued Analysis to Evaluate Regional Resource Adequacy and Localized Fuel Availability in Extreme Events

FRCC's Resource Working Group has reviewed the results of both the 2014 NERC Probabilistic Assessment and 2014 FRCC Loss of Load Probability (LOLP) analysis and added more depth and detail to the resource adequacy analysis. The studies and analysis include LOLP analysis (with study parameters such as load forecasting uncertainties, maintenance schedule variations, and load modeling variations), transmission constraints, and analysis of growing dependency on DSM to maintain system reliability.[46] In addition, weather events in the Gulf of Mexico could potentially have an impact on the availability and transportation of natural gas. However, dual-fuel capability and the increase of onshore (outside of Florida) gas resources (with the use of fracking technologies) along with a third gas pipeline into central Florida would mitigate natural gas transportation and supply issues in extreme weather events, such as hurricanes. FRCC's Fuel Reliability Working Group (FRWG) provides oversight of the Regional Entity fuel reliability forum that studies the fuel availability and coordinates responses to fuel issues and emergencies.

MISO

Risks Associated with Policy and Decline in Reserve Margins in Future Years

Policy and changing generation trends continue to drive new potential risks to resource adequacy in MISO, requiring continued transparency and vigilance to ensure long-term needs. MISO projects that Reserve Margins will continue to tighten over the next five years, approaching the Reserve Margin requirement. Operating at the Reserve Margin creates a new operating reality for MISO members where the use of all resources available on the system and emergency operating procedures are more likely. This reality will lead to a projected dependency on the use of load-modifying resources such as behind-the-meter generation and Demand Response. Minnesota completed a renewable assessment study in the past year and demonstrated that high levels of wind and solar wouldn't impact reliability in Manitoba. The addition of wind and solar generation to supply 40% of Minnesota's annual electric retail sales can be reliably accommodated by the electric power system. Further analysis would be needed to ensure system reliability at 50% of Minnesota's annual electric retail sales from variable renewables.[47]

MRO-Manitoba Hydro

Extreme Weather Impacts on Resource Adequacy and Addition of VERs

Severe weather events such as tornados and ice storms can occur at any time. Their consequences are most severe at or near the system peak load. Loss of a major station or transmission corridor can impact the delivery of generation from northern hydro generation plants in Manitoba, which will impact resource adequacy. Manitoba Hydro is planning on adding a major new 500 kV HVdc transmission line in order to mitigate the loss of the Dorsey converter station and the loss of the Bipole I/II transmission corridor. This facility is planned to be in service by 2018. In addition, Manitoba Hydro is monitoring potential changes to renewable portfolio standards in neighboring areas, especially in Minnesota.

MRO-MAPP

Challenges to Increasing Nebraska Renewable Energy Exports

Reliability impacts of developing 5,000 to 10,000 megawatts of renewable generation capacity in Nebraska for export purposes can introduce challenges in Nebraska. These challenges include transmission constraints, limited and uncertain demand for renewable energy, and greater perceived risks compared to neighboring states.[48]

[46] FRCC 2014 Load & Resource Reliability Assessment Report.

[47] 2014 Minnesota Renewable Energy Integration and Transmission Study Report.

[48] Nebraska Renewable Energy Exports: Challenges and Opportunities (LB 1115 Study).

MRO-SaskPower

Impacts of Retirement of Thermal Generation and Addition of Variable Resources

The requirement to reduce emissions for thermal generating facilities will call for ongoing resource planning to ensure that retrofitting or the addition of new emission control equipment is done in a timely manner. Saskatchewan is working with both the provincial and federal governments on emission regulations and equivalency agreements. Saskatchewan will have an increase in wind integration in the near-term and long-term planning horizons. The inclusion of more intermittent resources may have operational impacts that need to be studied to determine the power system effects on both Saskatchewan and neighboring jurisdictions. Depending on the make-up of the future generation resources, intermittent resources may need to be curtailed, or other generation sources may be required before coming on-line to allow for the sudden changes in output.

NPCC-Maritimes

Increase in Renewable Resources and Load Growth in Localized Areas

Load growth in the southeastern corner of New Brunswick has outpaced the rest of that sub-area. Planners are monitoring transmission loads and voltages in the area to ensure reliability is not affected. Demand-side management programs aimed at reducing and shifting peak demands and any future potential imports to New Brunswick from Nova Scotia could reduce transmission loads in the southeastern New Brunswick area. Reserve Margin Reference levels are not affected by this issue.

The addition of renewable resources, particularly in Nova Scotia, is an emerging issue in the Maritimes Area within the assessment period. Nova Scotia’s Renewable Electricity Standard is seeking to displace significant amounts of fossil-fueled generation with renewable resources. Each year beginning with the calendar year 2015 and running until 2020, each load-serving entity must supply its customers with renewable electricity in an amount equal to or greater than 25% of the total amount of electricity supplied to its customers as measured at the customers’ meters for that year. In 2020, this target increases to 40%. Increasing amounts of renewable resources could affect BPS reliability if variable or low-mass slow-speed units are added without considering the reduction of frequency response after system contingencies or transmission enhancements to prevent voltage or overload problems. While in some cases the added generation may relieve congestion, the lack of adequate transmission facilities could delay or limit the development of new renewable resources. The variable output and intermittent nature of many renewable resources is a major consideration for generation dispatchers on a daily basis. The low inertia effects on system frequency response will be felt mostly during off-peak light-load periods when high-mass units have been displaced by low-mass new renewable resources. While frequency response is usually seen as an issue during recovery from system contingencies, individual generators could experience oscillations even with all facilities in service. The October 2017 addition of the Maritimes Link HVdc cable project between Nova Scotia and the Canadian Province of Newfoundland and Labrador should allow hydro capacity to offset conceptual low-mass variable resources in future renewable resource portfolios.

NPCC-New England

Increase in Distributed PV Resources and Natural Gas Availability in Extreme Cold Weather Conditions

Most of the New England PV resources are interconnected at the distribution level based on state-jurisdictional interconnection standards (IEEE 1547 standards). These standards were designed for relatively small penetrations of Distributed Generation (DG) and do not require PV resources to be able to ride through a fault on the transmission system. As a result, PV exhibits different electrical characteristics during system conditions typical of grid disturbances (e.g., low-voltage conditions during an unexpected outage of a large generator or transmission facility). A high-level screening conducted by ISO New England showed the potential loss of PV resources resulting from faults on the transmission system. The results show that areas with large amount of PV facilities are likely to trip off-line because of low voltage in the event of a fault on the 345 kV transmission system. This could result in thermal or stability problems and could cause the need for additional transmission upgrades. As PV resource penetrations grow, the severity of this potential problem will also grow. To understand the possible impact of large amounts of distributed resources, such as PV resources during grid disturbances, ISO New England is participating in an Electric Power Research Institute (EPRI) evaluation of this issue. ISO New England is working with the New England states, distribution utilities, and IEEE and other international experts to ensure that the future interconnection standards for PV (and other inverter-interfaced DG resources) better coordinate with broader system reliability requirements.[49] The ISO will participate in the revision of the IEEE standard with the aim of improving the coordination of distribution system needs and transmission system performance requirements.

ISO-New England’s current generation mix is approximately 44% natural gas fired. Based on the projects in the interconnection queue, that percentage is likely to increase significantly in the future, further straining regional fuel supplies.

[49] IEEE 1547 and interconnection requirements for low/high-voltage ride-through, low/high-frequency ride-through, ramp rates, and others.

Constraints on the regional natural gas delivery system as well as the cost and availability of imported liquefied natural gas (LNG) are among potential reliability issues in ISO-NE. The ISO is continuing to monitor its ability to maintain grid reliability during the coldest days of winter due to fuel availability. As part of the 2014–2015 winter program, oil-fired and dual-fuel generators and generators that can access LNG were paid to secure fuel inventory and test fuel-switching capability. They were compensated for any unused fuel inventory and were also subject to nonperformance charges. The 2014–2015 program included permanent improvements, such as the continued ability to test resources' fuel-switching ability and to compensate them for running the test. The ISO has initiated a stakeholder process to explore proposals to address reliability concerns for winter 2015–2016 and at least until 2018, when capacity market refinements to incentivize performance begin to take effect. Those refinements include Pay-for-Performance (PFP), which will strengthen availability incentives within the forward capacity market. Other efforts undertaken to shore up operations include the development of tools that help operations personnel more accurately predict the availability of natural gas supply for generators, improving unit commitment decisions; and increased communications with gas pipeline operators (assisted by FERC Order 787) to verify whether natural-gas-fired generators that are scheduled to run will be able to obtain fuel.

NPCC-New York

Generation Retirements and Fuel Availability

Though the winter 2014–2015 was not as severe as the winter 2013–2014, there were generator derates due to fuel and/or cold-weather-related issues. There were days where typically less-expensive gas was more expensive than oil, but the New York Balancing Area (NYBA) did not experience operational issues due to fuel availability during winter conditions. NYISO, in conjunction with its stakeholders, is exploring market rule changes to help ensure fuel availability during cold-weather conditions. Improvements will be considered in reporting seasonal fuel inventories and daily replenishment schedules. NYISO will work with New York State regulatory agencies to develop a formal process to identify reliability needs that would be mitigated by generator requests for certain waivers.

While NYISO concludes that long-term reliability needs have been satisfied in the draft 2014 Comprehensive Reliability Plan (CRP) report, the margin to maintain reliability narrows over the 10-year study period based upon projected load growth and the assumption that there are no additional resources added after 2017. Potential risk factors such as long-term generator unavailability or higher load levels in regions of upstate New York (including Rochester, Western and Central New York, and the Capital Region), could potentially lead to immediate and severe transmission security violations. The projected NYBA capacity margins are narrow in the later years of the study; therefore, a small decrease in their existing resource capacity or an increase in loads by 2024 would result in an LOLE violation in that year.

NPCC-Ontario

Aging Infrastructure and Challenges in Distributed Generation Growth

With the growth in distribution-connected variable generation capacity, demand forecasting has become increasingly more complex. Traditionally, demand was mainly a function of weather conditions, economic cycles, and population growth. The introduction of smart meters and higher on-peak electricity prices has resulted in a consumer price response previously not seen in Ontario. With multiple new factors influencing demand, determining the causality of demand changes has become increasingly nuanced.

Much of the current power system infrastructure, whether generation, transmission, or distribution equipment, is aging and needs to be refurbished, replaced, or upgraded to comply with new standards and meet demand. In particular, Ontario's nuclear fleet will require refurbishment in the next decade. In December 2013, a long-term energy plan (LTEP) was released by the government of Ontario that focused on building a clean, reliable, and cost-effective electricity system. The 2013 LTEP committed to annual reporting to update the public on changing supply-and-demand conditions and to track the progress to date.

NPCC-Quebec

Aging and Sustainability of Transmission Equipment

Equipment aging and sustainability have been standing issues at TransÉnergie for more than 15 years. However, during the years 2000–2010, it became evident that a global strategic investment policy was needed to tackle the issue. The strategy is based on the risk (sustainability) of losing equipment due to a major failure when the equipment is approaching the end of its life cycle. This risk assessment considers the probability of a major failure and its impact on the transmission system and on TransÉnergie as an asset owner. The strategy put forward in 2007 was presented to the Québec Energy Board and authorized by the Board with an accompanying annual budget.

Issues that could impact reliability in the context of aging equipment include significant investment cuts and personnel and equipment availability for maintenance outages, as well as new project construction and system availability during outages. At this time, there is no major concern regarding these issues that could have an impact on the BPS.

PJM

Extreme Cold Weather Natural Gas Supply/Transportation

Gas supply and transportation risks are captured in PJM resource planning studies to the extent they impact generator forced outage rates. All forced outages, whether outside management control or not, are included in the calculations used in planning studies. PJM is investigating gas supply and transportation risk considering the potential correlation with extreme cold weather (and high winter loads) and the potential for the loss of multiple units due to gas transportation disruptions.

SERC

RTO Integration Operational Management Challenges and Environmental Regulation Assessments

SERC member committees are continuing to assess the reliability impacts due to the expansion of PJM and MISO regional transmission organization (RTO) footprints within SERC. In addition to the RTO impacts, SERC is addressing assessment changes related to MATS retirements, Clean Power Plan, dispatch flow patterns, MOD-032 modeling changes, and the integration of renewables. As a result, the SERC Reliability Studies Steering Committee (SERC-RSSC) has created a task force to address these issues and to better address emerging uncertainties. SERC study groups continue to perform regional analysis and sensitivities to evaluate approaches for future assessment practices with the goal of identifying potential reliability concerns across a wide range of future conditions.

SPP

RTO Integration Operational Management Challenges

SPP, along with other joint parties in the Region and MISO, is currently managing reliability concerns from MISO's recent operational changes under the provisions of the Operations Reliability Coordination Agreement (ORCA). 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.

TRE-ERCOT

Localized Increase in Renewable Penetration

The Texas Panhandle region is currently experiencing significantly more interest from wind generation developers than what was initially planned for the area. The ERCOT Panhandle grid is remote from synchronous generators and requires long-distance power transfer to the load centers in the TRE-ERCOT Region. All wind generation projects in the Panhandle are expected to be equipped with advanced power electronic devices that will further weaken the system strength due to limited short circuit current contributions. Stability challenges and weak system strength are expected to be significant constraints for Panhandle export. The ERCOT Transmission Planning Department has been performing ongoing analysis to assess reliability when incorporating all wind generation in the Panhandle that will satisfy the requirements of ERCOT's Planning Guide.[50] The stability and system strength are evaluated to ensure reliable operations can be maintained through proper Panhandle export limits.

[50] Section 6.9, Addition of Proposed Generation Resources to the Planning Models.

WECC

Operational Challenges in California Associated with Increase in VERs

Load-serving entities historically experience two rapid increases in customer demand: early morning and late afternoon. These rapid changes were typically balanced by increased hydroelectric and thermal generation. However with greater generation contribution of intermittent resources, hydro and thermal units are required to follow larger daily demand fluctuations. The rate at which these decreases and increases occur, referred to as ramp rate, has the potential to exceed normally dispatched local area non-solar plant-ramping capability. Also of concern is the potential for localized overgeneration prior to the morning and late afternoon load ramps. Presently, concerns associated with these ramping issues are largely confined to California and, to some extent, reflect market issues that can be addressed through revised market mechanisms. Pertinent specific information relative to the California ramp-rate issue is available on the California ISO website.[51]

New Renewable Generation Technologies Present New Challenges

Wind and solar power generation are reliant on weather and no controllable elements. The viability and reliance on these resources are proven to be much harder than originally thought as some of the largest new solar projects are delivering less power than anticipated. The Ivanpah solar power project in the California desert is generating just 40% of the more than 1 million megawatt hours of electricity per year that it was anticipated to generate. The technology has proven more difficult to manage than conventional solar farms. The plant also needs much more steam to run than projected and more than four times as much natural gas to start the plant up in the morning as expected. In addition, weather predictions underestimated the amount of cloud cover the area has received.

51 Flexible Resource Capability Information - Fast Facts.

FRCC

Assessment Area Overview

The Florida Reliability Coordinating Council's (FRCC) membership includes 30 Regional Entity Division members and 23 Member Services Division 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.

Summary of Methods and Assumptions

Reference Margin Level
The Florida Public Service Commission's 15% Reserve Margin criteria for non-IOUs is applied as the Reference Margin Level.

Load Forecast Method
Noncoincident, based on individual LSE forecasts

Peak Season
Summer

Planning Considerations for Wind Resources
No wind capacity; no formalized method

Planning Considerations for Solar Resources
Small amount of solar capacity; based on historical average at peak

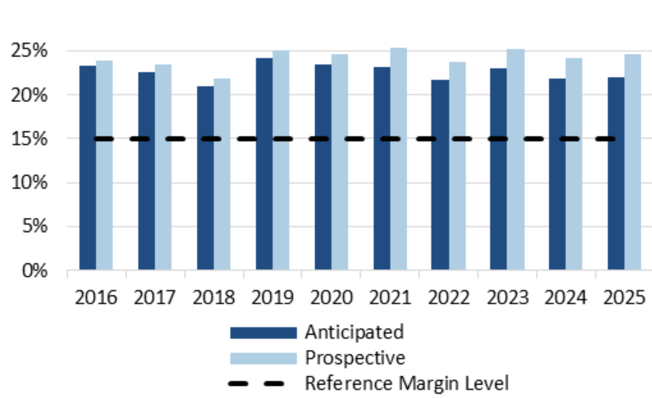
Footprint Changes
Region is the Assessment Area footprint; no recent changes

Assessment Area Footprint

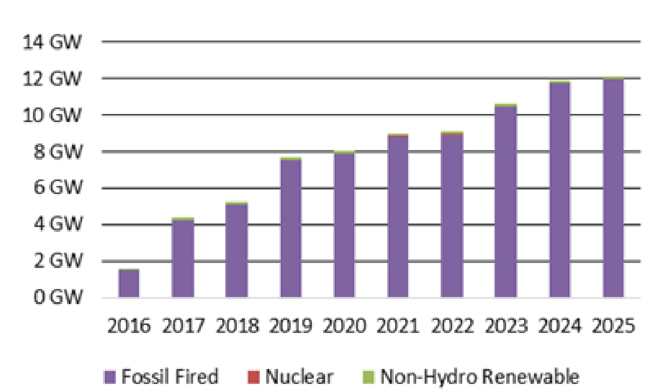
Peak Season Demand, Resources, and Reserve Margins[52]

Demand (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Internal Demand	47,304	48,097	48,784	49,498	50,133	50,756	51,378	52,074	52,837	52,837
Demand Response	3,140	3,182	3,211	3,273	3,342	3,377	3,412	3,413	3,449	3,449
Net Internal Demand	44,164	44,915	45,573	46,225	46,791	47,379	47,966	48,661	49,388	49,388
Resources (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	54,446	55,071	55,102	57,409	57,730	58,362	58,373	59,891	60,173	60,220
Prospective	54,683	55,470	55,517	57,833	58,276	59,367	59,378	60,896	61,310	61,511
Reserve Margins (%)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	23.28%	22.61%	20.91%	24.20%	23.38%	23.18%	21.70%	23.08%	21.84%	21.93%
Prospective	23.82%	23.50%	21.82%	25.11%	24.54%	25.30%	23.79%	25.14%	24.14%	24.55%
Reference Margin Level	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Excess/Shortfall (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	3,657	3,418	2,694	4,251	3,920	3,876	3,212	3,931	3,377	3,423
Prospective	3,894	3,817	3,108	4,674	4,466	4,881	4,217	4,936	4,514	4,715

Peak Season Reserve Margins



10-Year Peak Season Cumulative Generation Mix Change



[52] FRCC plans through 2024.

Planning Reserve Margins, Demand

Based on the expected load and generation capacity, all projected Reserve Margins are above the NERC Reference Margin Level of 15% for the FRCC Assessment Area with FRCC Reserve Margins remaining above 20% for all seasons during the assessment period. FRCC continues to project growth in peak load, but the projected growth is less than in the previous forecast. The Net Energy for Load (NEL) and summer and winter peak demands are forecast to be lower than in previous forecasts. The current average annual growth rate for NEL is 1.1% per year compared to 1.3% per year in the previous forecast. Firm summer peak demand is expected to grow by 1.5% per year compared to 1.7% peak demand growth rate in the previous forecast. For firm winter peak demand, the average growth rate is now expected to be 0.9% per year compared to 1.4% per year in the previous forecast. This is primarily due to more utilities capturing appliance efficiency in their load forecast models or using updated appliance efficiency assumptions.

Demand-Side Management

The FRCC Region is projecting some decrease in the growth rate of utility program Energy Efficiency (EE) which is expected due to two factors: (1) significant decreases in demand-side management (DSM) cost-effectiveness caused by lower fuel costs, etc., and (2) increased impacts from federal and state energy-efficiency codes and standards (e.g., 2005 National Energy Policy Act, 2007 Energy Independence and Security Act). The impacts from these EE codes and standards are lowering the potential for utility EE programs to lower demand and energy usage for those appliances and equipment addressed by the codes and standards. However, these codes and standards are resulting in significant reductions in demand and energy that are accounted for in load forecasts.

The Florida Public Service Commission (FPSC) evaluates and revises its DSM goals every five years. New DSM goals were set in 2014. Because of diminished cost-effectiveness of DSM programs, and the fact that EE codes and standards have lowered the potential for DSM programs, the FPSC set lower DSM goals for Florida utilities than had been set in 2009.

Demand Response from interruptible and load management programs within FRCC is treated as a load modifier and is projected to be relatively constant at approximately 6.6% of the summer and winter total peak demands for all years of the planning horizon. FRCC is not anticipating a significant increase of DR, and the percentage of DR to total peak demand is projected to stay relatively constant for all years of the planning horizon.

Generation

FRCC is projecting 10,584 MW (summer) and 11,385 MW (winter) of Tier 1 capacity to be added during the assessment period. The Tier 1 capacity will consist of mainly natural gas capacity with 114 MW of firm solar (PV) and 180 MW of biomass. There are also 562 MW of planned uprates to be added during the assessment period. The proposed generation additions are studied by the Interconnecting Transmission Owner, as well as by the FRCC Transmission Working Group (TWG) through the FRCC's Transmission Service and Generator Interconnection Service Request Assessment Area Deliverability Evaluation Process.

Entities within FRCC have capacity transfers with firm contracts available to be imported into the Assessment Area from SERC. There is approximately 840 MW of FRCC member-owned generation, which is dynamically dispatched out of the SERC Assessment Area. These imports from SERC have firm transmission service to ensure deliverability into the FRCC 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. In addition, the interface owners between the FRCC and SERC Assessment Areas meet quarterly to coordinate and perform joint studies to ensure the reliability and adequacy of the interface.

The FRCC Assessment Area is projecting 3,903 MW (summer) and 4,146 MW (winter) generation to be retired through the assessment period. These retirements will include approximately 2,200 MW of natural gas generation, almost 1000 MW of coal, and 700 MW of oil. FRCC is not anticipating any reliability impacts from these units being retired. These unit retirements are studied as part of the FRCC Long-Range Study process performed annually by the Transmission Working Group (TWG) and the Resource Working Group (RWG) to mitigate potential reliability impacts to the grid and the FRCC Reserve Margin criteria.

The FRCC is not anticipating any unavailability of larger generators during system peak. All known scheduled generation outages in the long-term horizon are incorporated into the annual FRCC Long Range Study process to mitigate any potential reliability impacts to the BES.

The FRCC Fuel Reliability Working Group (FRWG) has recently completed a natural gas pipeline study evaluating the loss of key compressor stations in the Assessment Area. The results indicate that the FRCC Assessment Area would not have a large-scale impact from extreme events. Some localized gas reduction could occur, but dual-fuel capability could be utilized if additional generation is required.

The FRCC Region has no wind capacity and currently has a small amount of solar capacity. The FRCC Planning Committee (PC) is in the early stages of developing a solar task force to determine the potential impacts to the BES as solar resource penetration increases. Only the historical firm capacity available at peak from variable resources (e.g., solar and hydro) has been included as firm generation so that any variability in unit output has been removed.

Transmission and System Enhancements

The FRCC Region has not identified any major projects that are needed to maintain or enhance reliability during the planning horizon. Planned projects are primarily related to expansion in order to serve forecast growing demand and maintain the reliability of the BPS in the longer-term planning horizon.

The FRCC Region is not anticipating any additional reliability impacts resulting from potential environmental regulations. In 2013, FRCC conducted a study identifying the impacts resulting from the retirement of two coal generating units (869 MW) starting April 2015 as an option to comply with MATS. These two units, combined with the recent retirement of an 825 MW unit at the same site, result in a total generation reduction from this site of 1,740 MW. The regional study determined that the proposed retirements of the two coal plants would have an adverse impact to the reliability of the BPS transmission system and have received an extension, which pushes the retirement date of these units to 2018. This extension allows sufficient time to construct two replacement natural-gas-fired combine-cycle units with a total summer capacity of 1,770 MW in order to maintain the reliability of the BPS within FRCC. However, FRCC will continue to monitor the progress of the Clean Power Plan to determine the potential impact to reliability once the details have been finalized.

MISO

Assessment Area Overview

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 MISO fall in three NERC Regions, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

Summary of Methods and Assumptions

Reference Margin Level
For planning year 2015–2016, MISO's System-Installed Generation Planning Reserve Margin requirement (PRMR) is 14.3%, which is applied as the Reference Margin Level for all 10 years.

Load Forecast Method
Coincident

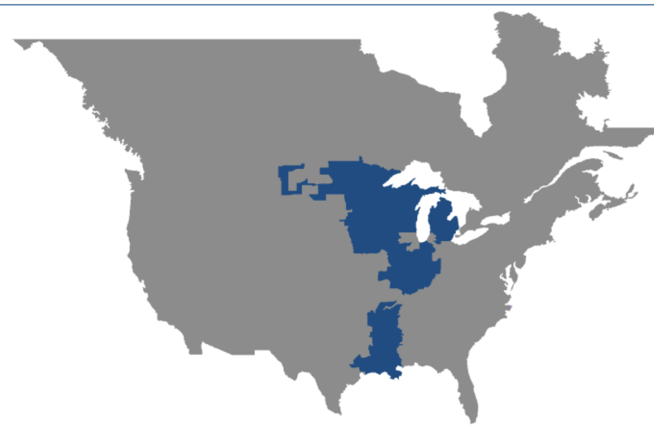
Peak Season
Summer

Planning Considerations for Wind Resources
Effective Load-Carrying Capability (ELCC); varies by wind node

Planning Considerations for Solar Resources
No utility-scale solar resources in MISO

Footprint Changes
December 2013: Integration of MISO South resulted in an expanded footprint.[53]

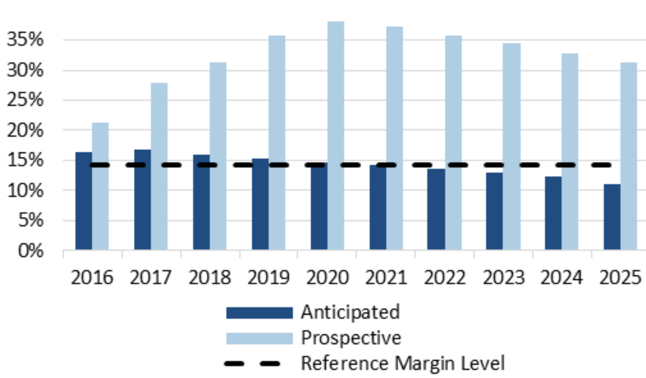
Assessment Area Footprint



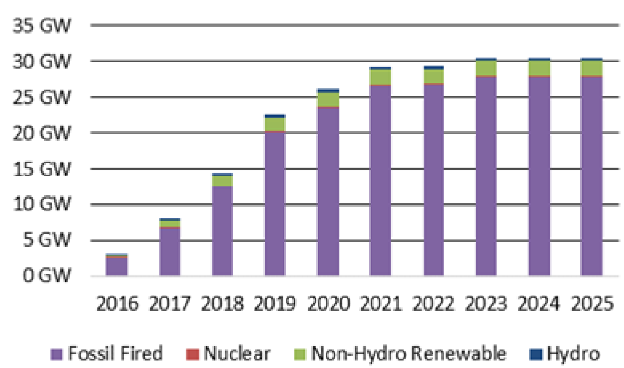
Peak Season Demand, Resources, and Reserve Margins

Demand (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Internal Demand	128,087	129,780	130,670	131,814	132,694	133,463	134,328	135,255	136,036	137,727
Demand Response	5,631	5,631	5,631	5,631	5,631	5,631	5,631	5,631	5,631	5,631
Net Internal Demand	122,457	124,150	125,039	126,183	127,063	127,832	128,697	129,624	130,405	132,096
Resources (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	142,389	144,960	145,083	145,422	145,732	145,956	146,138	146,338	146,538	146,738
Prospective	148,456	158,707	164,208	171,256	175,519	175,365	174,847	174,393	173,274	173,474
Reserve Margins (%)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	16.28%	16.76%	16.03%	15.25%	14.69%	14.18%	13.55%	12.89%	12.37%	11.08%
Prospective	21.23%	27.84%	31.33%	35.72%	38.14%	37.18%	35.86%	34.54%	32.87%	31.32%
Reference Margin Level	14.30%	14.30%	14.30%	14.30%	14.30%	14.30%	14.30%	14.30%	14.30%	14.30%
Excess/Shortfall (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	2,422	3,057	2,163	1,194	499	(156)	(963)	(1,822)	(2,515)	(4,248)
Prospective	8,489	16,804	21,288	27,029	30,286	29,253	27,746	26,233	24,222	22,489

Peak Season Reserve Margins



10-Year Peak Season Cumulative Generation Mix Change



[53] 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.

MISO projects a regional surplus for the summer of 2016, with a potential regional shortfall starting in 2021.

These results show significant improvements from the 2014 MISO LTRA results, which projected a shortfall against the reserve requirements of 2.3 GW in 2016.

- All zones within MISO are sufficient from a resource adequacy point of view in the near term when available capacity and transfer limitations are considered. Regional shortages in later years may be rectified by the utilities and as such do not cause immediate concern.
- The change in LTRA results was driven primarily by the combination of an increase in resources committed to serving MISO load and a decrease in load forecasts.
- The increase in committed resources reflects action taken by MISO load-serving entities and state regulators to address potential capacity shortfalls.
- MISO projects that each zone within the MISO footprint will have sufficient resources within their boundaries to meet their Local Clearing Requirements, or the amount of their local resource requirement, which must be contained within their boundaries.
- Several zones are short against their total zonal reserve requirement, when only resources within their boundaries or contracted to serve their load are considered. However, those zones have sufficient import capability, and MISO has sufficient surplus capacity in other zones to support this transfer. Surplus generating capacity for zonal transfers within MISO could become scarce in later years if no action is taken in the interim by MISO load-serving entities.

Policy and changing generation trends continue to drive new potential risks to resource adequacy, requiring continued transparency and vigilance to ensure long-term needs.

- MISO projects that Reserve Margins will continue to tighten over the next five years, approaching the Reserve Margin requirement.
- Operating at the Reserve Margin creates a new operating reality for MISO members where the use of all resources available on the system and emergency operating procedures are more likely. This reality will lead to a projected dependency in the use of load-modifying resources such as behind-the-meter generation and Demand Response.

Due to a contract path limitation, MISO limited the transfer of capacity from the South region to the North/Central region to 1,000 MW. Any capacity in the south above its requirements and 1,000 MW was therefore excluded from the MISO-wide capacity reserves in these assessments, since this capacity was assumed unavailable for the North/Central region's capacity needs.

It should be noted that the transmission system can support flows above this 1,000 MW contract path and that these flows are allowed in the operational time frame. Flows between MISO North/Central and MISO South will be subject to the Operations Reliability Coordination Agreement (ORCA), where MISO will operationally limit flows to 3,000 MW. The ORCA is set to expire April 1, 2016.

This year marks the second iteration of the Organization of MISO States (OMS) MISO survey, which helps provide forward visibility into the resource adequacy position of the MISO Region. The survey also helped identify resources that had a low certainty of being available for each planning year.

The LTRA results represent a point-in-time forecast, and MISO expects these figures to change significantly as future capacity plans are solidified by load-serving entities and states. For example, there are enough resources in Tier 2 and 3 to mitigate any long-term resource shortfalls.

The annual MISO Transmission Expansion Plan (MTEP) proposes transmission projects to maintain a reliable electric grid and deliver the lowest-cost energy to customers in the MISO region. As part of MTEP14, MISO staff recommends $2.5 billion of new transmission expansion through 2023, as described in Appendix A of the MTEP report,[54] to the MISO Board of Directors for review, approval, and subsequent construction.

The 369 MTEP14 new Appendix A projects represent an incremental $2.5 billion in transmission infrastructure investment and fall into the following four categories:

[54] MISO - 2014 Transmission Expansion Plan.

- 50 Baseline Reliability Projects (BRP), totaling $269.5 million – BRPs are required to meet NERC's Reliability Standards.
- 6 Generator Interconnection Projects (GIP), totaling $38.8 million – GIPs are required to reliably connect new generation to the transmission grid.
- 312 other projects, totaling $1.5 billion – "Other" projects include a wide range of projects, such as those that support lower-voltage transmission systems or provide local economic benefit but do not meet the threshold to qualify as Market Efficiency Projects.
- 1 Transmission Delivery Service Project (TDSP), totaling $676 million – TDSPs are network upgrades driven by Transmission Service Requests (TSRs).

More detailed information on individual projects can be found on the MTEP webpage.[55]

MISO is actively involved in studying proposed environmental regulations to ensure that their impact on system reliability is captured. More information can be found on the MISO website.[56]

Compliance with the EPA's proposal puts up to an additional 14 GW of coal capacity in MISO's footprint at risk for retirement, beyond retirements due to the EPA's MATS rule.

[55] MISO – Transmission Expansion Planning.

[56] MISO - EPA Proposal to Reduce Carbon Dioxide Emissions.

MRO-Manitoba Hydro

Assessment Area Overview

Manitoba Hydro is a Provincial Crown Corporation that provides electricity to 556,000 customers throughout Manitoba and natural gas service to 272,000 customers in various communities throughout southern Manitoba. The Province of Manitoba is 250,946 square miles. Manitoba Hydro is winter peaking. No change in the footprint area is expected during the assessment period. Manitoba Hydro is its own Planning Coordinator and Balancing Authority. Manitoba Hydro is a coordinating member of MISO. MISO is the Reliability Coordinator for Manitoba Hydro.

Summary of Methods and Assumptions

Reference Margin Level
The capacity criterion, as determined by Manitoba Hydro, requires a minimum 12% Planning Reserve Margin, applied as the Reference Margin Level in this assessment.

Load Forecast Method
Coincident

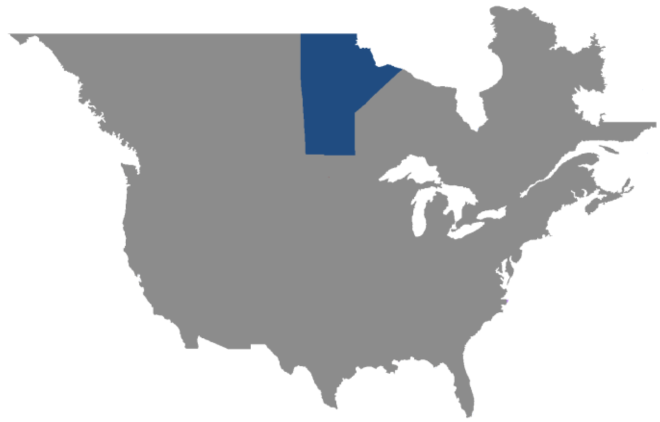
Peak Season
Winter

Planning Considerations for Wind Resources
Effective Load-Carrying Capability (ELCC) of 14.7% for the summer; wind is derated entirely for the winter season.

Planning Considerations for Solar Resources
No utility-scale solar resources

Footprint Changes
N/A

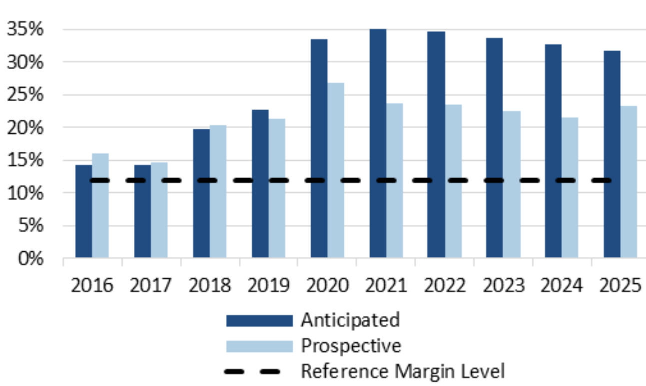
Assessment Area Footprint



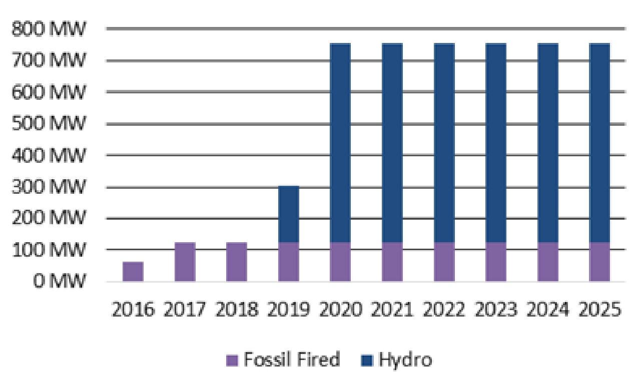
Peak Season Demand, Resources, and Reserve Margins

Demand (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Internal Demand	4,679	4,746	4,656	4,694	4,724	4,753	4,783	4,818	4,857	4,871
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	4,679	4,746	4,656	4,694	4,724	4,753	4,783	4,818	4,857	4,871
Resources (MW)	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Anticipated	5,343	5,420	5,582	5,762	6,312	6,420	6,445	6,445	6,445	6,420
Prospective	5,432	5,445	5,608	5,695	5,995	5,878	5,903	5,903	5,903	6,003
Reserve Margins (%)	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Anticipated	14.21%	14.20%	19.89%	22.75%	33.62%	35.09%	34.76%	33.78%	32.70%	31.81%
Prospective	16.09%	14.73%	20.43%	21.32%	26.90%	23.68%	23.42%	22.53%	21.53%	23.24%
Reference Margin Level	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%
Excess/Shortfall (MW)	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Anticipated	103	104	367	505	1,021	1,097	1,089	1,049	1,005	965
Prospective	192	130	393	437	704	555	546	507	463	547

Peak Season Reserve Margins



10-Year Peak Season Cumulative Generation Mix Change



Demand, Resources, and Reserve Margins

Manitoba Hydro is projecting Reserve Margins above the 12% Reference Margin Level during the assessment period.

Compared to the prior year's assessment, by 2024–25 the demand forecast is projected to be 5% higher, primarily attributable to an increase in the population forecast for Manitoba from Manitoba Hydro's economic outlook along with an expected demand increase in the pipeline sector.

Energy efficiency and conservation savings are forecast higher than prior years' assessments due to enhancements to existing programs and the addition of new programs based on opportunities identified in the market. These 15-year savings from the 2014 Power Smart Plan are approximately 2.3 times higher for demand savings and 2.6 times higher for energy savings.

There have been no capacity additions in Manitoba since the *2014LTRA*. The Keeyask Hydro Generating Station is now under construction and is considered a Tier 1 capacity addition. Manitoba Hydro anticipates that the first units of the 630 MW of net capacity addition from the Keeyask Hydro Generating Station will come into service in late 2019. The remaining six units are expected to come into service in 2020. Brandon Unit 5, Manitoba Hydro's sole remaining coal-fired generating unit, is assumed to remain available until December 31, 2019, at which time it is considered to be an unconfirmed retirement. This potential retirement of Brandon Unit 5's approximately 95 MW of capacity is not expected to have an impact on reliability as other resources are expected to come into service at that time.

Manitoba Hydro has up to 825 MW of firm and/or expected on-peak capacity exports in the winter, up to 550 MW of firm and/or expected on-peak capacity imports in the winter, and up to 1,425 MW of firm and/or expected on-peak capacity exports in the summer, and associated firm transmission reservations over the 10-year assessment period. Manitoba Hydro does not have any capacity imports during the summer and does not have any capacity transactions beyond the contract terms.

Manitoba does not have a legislated, renewable mandate such as an RPS, and no legislation is currently anticipated. The resource mix in Manitoba is already over 95% renewable under typical inflow conditions.

Long-Term Reliability Issues

No modifications have been made to planning assumptions in response to extreme weather events. Manitoba Hydro's energy planning assumptions already assume firm loads must be met under an extreme drought defined as the worst inflow conditions on a hydrologic record of over 100 years. The Planning Reserve Margin takes into consideration increased load due to extreme weather. Manitoba Hydro generators are designed for operation in a sub-arctic climate and operate in subzero Fahrenheit temperatures in winter on an almost daily basis.

Manitoba Hydro's system is predominately hydro, and the operating flexibility of the hydro resource is adequate to meet operating requirements during the shoulder (off-peak) periods.

The only remaining coal unit, Brandon Unit 5 (95 MW), is impacted by the 2008 Manitoba Climate Change and Emissions Reduction Act and the 2011 Canadian Federal Coal-Fired Electricity Regulations. This unit is regulated such that it can only be operated to support emergency operations. No adverse reliability impacts are expected as a result of these environmental regulations. At this time, no pending regulations are expected to impact existing gas and hydro generation in Manitoba.

Manitoba Hydro continues to monitor the adequacy of natural gas pipeline capacity/natural gas generator performance in the Midwest during extreme events. The Eastern Interconnection Planning Collaborative (EIPC) Gas-Electric System Interface Study suggests that in MISO, the gas infrastructure is adequate in 2018 and 2023 under the market conditions and resource mixes in nearly all scenarios and sensitivities tested. At this time, no short- or long-term impacts on resource adequacy in Manitoba are anticipated.

MRO-MAPP

Assessment Area Overview

The Mid-Continent Area Power Pool (MAPP) is an association of electric utilities and other electric industry participants operating in all or parts of Iowa, Minnesota, Montana, North Dakota, and South Dakota. Currently, the MAPP Planning Coordinator includes entities in two BAs and 13 LSEs. MAPP covers an area of approximately 200,000 square miles and serves a population of about 3.5 million. Ames Municipal Electric System (AMES) and Rochester Public Utilities (RPU) have withdrawn from the MAPP Planning Authority. The Integrated System (IS), Western Area Power Administration (WAPA) Upper Great Plains, Basin Electric, and Heartland Consumers Power District (Heartland) will be joining the SPP Planning Authority on October 1, 2015. The integration of these entities, primarily located in North and South Dakota, would add approximately 4,700 MW of load and 9,500 miles of transmission to SPP RTO.

Summary of Methods and Assumptions

Reference Margin Level
MAPP members use a range of Reserve Margin targets depending on each individual member's system. However, MAPP provides a 15% Reference Margin Level.

Load Forecast Method
Coincident; normal weather (50/50)

Peak Season
Summer; however, recent projections indicate higher Total Internal Demand during the winter seasons.

Planning Considerations for Wind Resources
Historical data

Planning Considerations for Solar Resources
No utility-scale solar resources

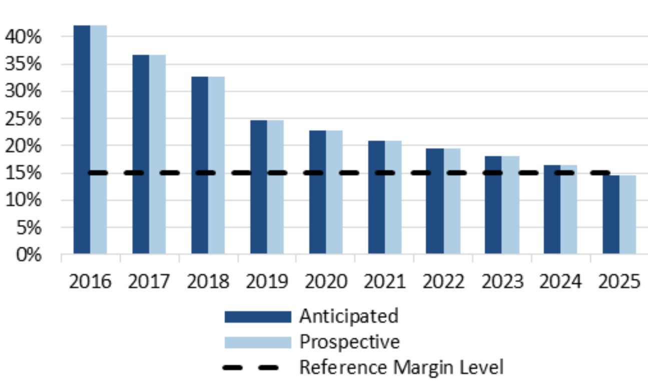
Footprint Changes
The Minnesota Municipal Utilities Association (MMUA) and Ames Municipal Utilities (AMES) are now reported in the MISO footprint.

Assessment Area Footprint

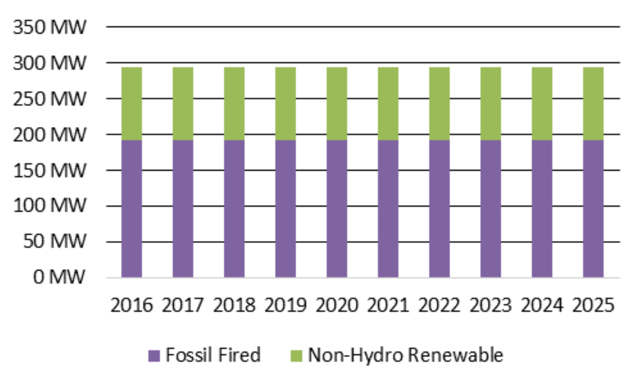
Peak Season Demand, Resources, and Reserve Margins

Demand (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Internal Demand	5,154	5,446	5,549	5,743	5,838	5,925	6,011	6,097	6,210	6,331
Demand Response	98	94	96	98	100	102	104	106	108	110
Net Internal Demand	5,056	5,352	5,453	5,645	5,738	5,823	5,907	5,991	6,102	6,220
Resources (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	7,188	7,318	7,240	7,040	7,040	7,040	7,060	7,080	7,100	7,120
Prospective	7,188	7,318	7,240	7,040	7,040	7,040	7,060	7,080	7,100	7,120
Reserve Margins (%)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	42.18%	36.74%	32.77%	24.71%	22.69%	20.90%	19.52%	18.17%	16.36%	14.46%
Prospective	42.18%	36.74%	32.77%	24.71%	22.69%	20.90%	19.52%	18.17%	16.36%	14.46%
Reference Margin Level	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Excess/Shortfall (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	1,374	1,164	969	548	441	343	267	190	83	(34)
Prospective	1,374	1,164	969	548	441	343	267	190	83	(34)

Peak Season Reserve Margins



10-Year Peak Season Cumulative Generation Mix Change



Demand, Resources, and Reserve Margins

MAPP is an association of electric utilities and other electric industry participants operating in all or parts of Iowa, Minnesota, Montana, North Dakota, and South Dakota. MAPP historically has experienced its annual peak demand in summer but recently began projecting higher total internal demand during the winter seasons. The Prospective and Adjusted Potential Planning Reserve Margins for MAPP fall below 15% during the 2023 summer season, reaching 14.5% that year. The Anticipated Reserve Margin for the MAPP area does not fall below the Reference Margin of 15% during the reporting time frame.

There have been some membership changes since the previous LTRA. Ames Municipal Electric System (AMES) and Rochester Public Utilities (RPU) have withdrawn from the MAPP Planning Authority. In addition, the Integrated System (IS), Western Area Power Administration (WAPA) Upper Great Plains, Basin Electric, and Heartland Consumers Power District (Heartland) will be joining the SPP Planning Authority on October 1, 2015. The integration of these entities, primarily located in North and South Dakota, would add approximately 4,700 MW of load and 9,500 miles of transmission to SPP. MAPP will dissolve Effective October 1, 2015.

Basin Electric has recently built six natural gas combustion turbine generators in the northwestern North Dakota area (total of 248 MW of accredited summer capacity) with about another 202 MW coming online in 2016. NorthWestern Energy has added 180 MW of wind since the previous LTRA with the addition of Oak Tree Wind and B&H Wind.

MAPP has 485 MW of firm imports and 1,145 MW of firm exports in summer 2015 and 700 MW of firm imports and 715 MW of firm exports in winter 2015–16. MAPP does not have any expected transfers to report. The duration of firm contracts varies with MAPP reporting 360 MW of firm imports and 750 MW of firm exports in summer 2025 and 666 MW of firm imports and 539 MW of firm exports in winter 2025–26.

Transmission Outlook and System Enhancements

MAPP has 10 miles of transmission line greater than 100 kV under construction and 201 miles of planned transmission line greater than 100 kV expected to be in service by 2017. The installation of a new 230/115 kV transformer at the Rapid City DC tie and construction of a new Rapid City DC tie to Rapid City 115 kV line is scheduled for completion in 2015. These system improvements will allow for the removal of the under-voltage load shedding at Rapid City, South Dakota. A parallel 230/115 kV transformer is scheduled to be installed at Oahe in 2015–16. At the same time, the Oahe 230 kV and 115 kV buses will be converted to double breaker/double bus configurations. Construction of an Ordway South substation and a second Ordway-Groton 115 kV line is scheduled for completion in 2017–18 to alleviate low-voltage concerns at Ordway. The majority of the planned transmission projects in MAPP are to the 345 kV system around Judson. These projects will support load growth in North Dakota.

Long-Term Reliability Issues

In the case of drought, MAPP could see lower expected generation from hydro units as well as base load coal units due to the availability of water for cooling. If there is extended heat, this would also lower the expected generation from the base load coal units due to rising lake temperatures that impact the output of the units.

MRO-SaskPower

Assessment Area Overview

Saskatchewan is a province of Canada and comprises a geographic area of 651,900 square kilometers (251,700 square miles) with approximately 1.1 million people. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the Planning Coordinator and Reliability Coordinator 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.

Summary of Methods and Assumptions

Reference Margin Level
Saskatchewan uses an Expected Unserved Energy (EUE) analysis to project its Planning Reserve Margins and as the criterion for adding new generation resources. This 11% margin is applied as the Reference Margin Level for this assessment.

Load Forecast Method
Coincident, 50/50 forecast

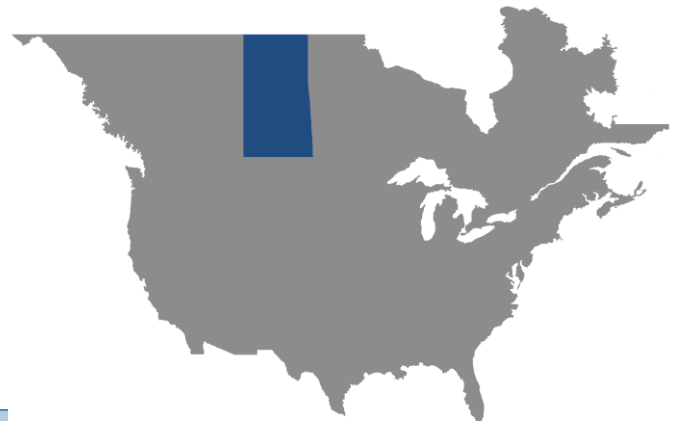
Peak Season
Winter

Planning Considerations for Wind Resources
10% of nameplate (summer); 20% of nameplate (winter)

Planning Considerations for Solar Resources
No utility-scale solar resources

Footprint Changes
N/A

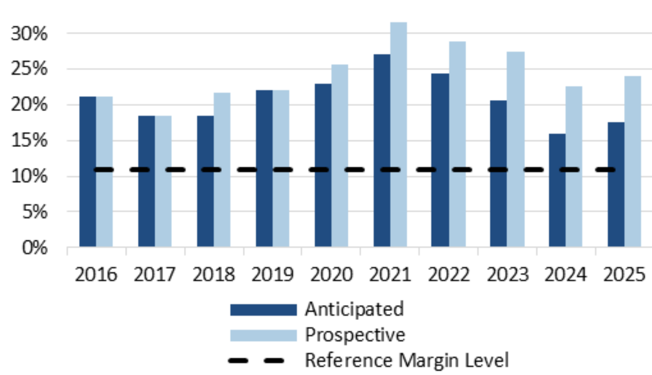
Assessment Area Footprint



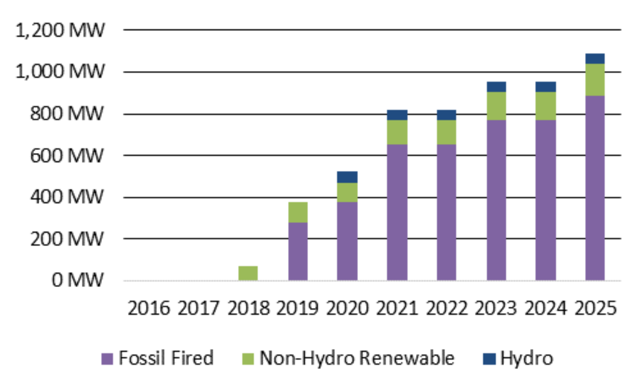
Peak Season Demand, Resources, and Reserve Margins

Demand (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Internal Demand	3,644	3,725	3,786	3,928	4,012	4,060	4,125	4,170	4,216	4,274
Demand Response	85	85	85	85	85	85	85	85	85	85
Net Internal Demand	3,559	3,640	3,701	3,843	3,927	3,975	4,040	4,085	4,131	4,189
Resources (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	4,309	4,309	4,381	4,687	4,831	5,053	5,026	4,927	4,788	4,923
Prospective	4,309	4,309	4,506	4,687	4,931	5,231	5,206	5,202	5,063	5,198
Reserve Margins (%)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	21.08%	18.39%	18.37%	21.95%	23.01%	27.12%	24.40%	20.60%	15.90%	17.51%
Prospective	21.08%	18.39%	21.74%	21.95%	25.56%	31.59%	28.85%	27.34%	22.55%	24.08%
Reference Margin Level	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%
Excess/Shortfall (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	359	269	273	421	472	641	541	392	202	273
Prospective	359	269	398	421	572	818	721	667	477	548

Peak Season Reserve Margins



10-Year Peak Season Cumulative Generation Mix Change



Demand, Resources, and Planning Reserve Margins

Saskatchewan plans to meet projected load requirements with Anticipated Resources throughout the assessment period. Saskatchewan's Anticipated Reserve Margin exceeds the 11% Reference Margin Level for the assessment period.

Saskatchewan experiences peak demand in the winter. Similar to last year, the average annual growth rate for Total Internal Demand is 1.8% during the assessment period. The growth is expected to be generally spread throughout the province. Saskatchewan is planning for an 8% average growth of energy efficiency and conservation programs, and Demand Response programs are projected to remain unchanged.

In Saskatchewan, projected unit retirements for the assessment period include 174 MW of natural gas facilities and 11 MW of wind facilities. Saskatchewan also plans to refurbish 278 MW of coal facilities, which will have a new nameplate capacity of 230 MW. For generation additions during the assessment period, a total capacity of 1,572 MW (nameplate) of resources is projected to come online. This total consists of 856 MW of gas, 630 MW (nameplate) of wind, 36 MW of biomass resources, and 50 MW of additional hydro resources.

For capacity transfers, Saskatchewan has a firm import contract for 25 MW until the spring of 2022. There are no anticipated firm exports for the assessment period. Saskatchewan expects to have an additional 125 MW of imports available for the winter of 2018–19 and 100 MW of imports from the summer of 2020 until the end of the assessment period.

Transmission Outlook and System Enhancements

Saskatchewan plans to invest in transmission infrastructure over the assessment period in order to maintain and enhance reliability. The related projects are dependent on load growth and include the construction of 716 km (445 miles) of new 138 kV and 230 kV transmission lines. In the near-term planning horizon, Saskatchewan also plans to add a Static Var System in the south-central region of the province to help with voltage control in the area.

Saskatchewan has several conceptual Remedial Action Schemes (RAS) planned to address potential generation deliverability concerns in the Near-Term Planning Horizon in the local area caused by N-2 outages. Once local area system reinforcements are installed to mitigate the N-2 contingency concerns, these protection systems may still remain installed to address more extreme operating scenarios.

Long-Term Reliability Issues

It is not expected that extreme weather events will impact long-term reliability in Saskatchewan; however, operation of the Saskatchewan system would be performed on a best-effort basis under extreme weather events. Demand would be offset by planning reserves and external markets. If necessary, operational measures include Demand Response, interruptible load contracts, public appeals, and rotating outages.

Typically, a significant amount of unit maintenance (partial and total unit outage) is planned for the shoulder periods in Saskatchewan. If short-term reliability issues are identified during a shoulder period, unit maintenance will be rescheduled.

Saskatchewan does not expect any long-term reliability impacts resulting from fuel supply or transportation constraints. Fuel disruptions are minimized as much as possible by system design practices, and Saskatchewan has a diverse energy mix of resources. Coal resources have firm contracts and are mine-to-mouth, and stockpiles are maintained at each facility in the event that mine operations are unable to meet the required demand of the generating facility. Natural gas resources have firm transportation contracts with large natural gas storage facilities located within the province backing those contracts up. Hydro facilities/reservoirs are fully controlled by Saskatchewan, and long-term hydrological conditions are monitored.

NPCC-Maritimes

Assessment Area Overview

The Maritimes Assessment Area is a winter-peaking NPCC subregion that contains two BAs. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, and 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.

Summary of Methods and Assumptions

Reference Margin Level
20%

Load Forecast Method
Coincident; 50/50 forecast

Peak Season
Winter

Planning Considerations for Wind Resources
Estimated capacity is derived from a combination of mandated capacity factors and reliability impacts.

Planning Considerations for Solar Resources
N/A

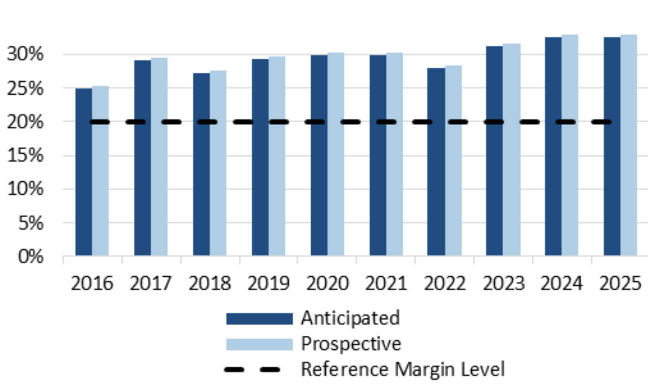
Footprint Changes
A conceptual tie line to the Canadian province of Newfoundland and Labrador could potentially impact the Maritimes footprint.

Assessment Area Footprint

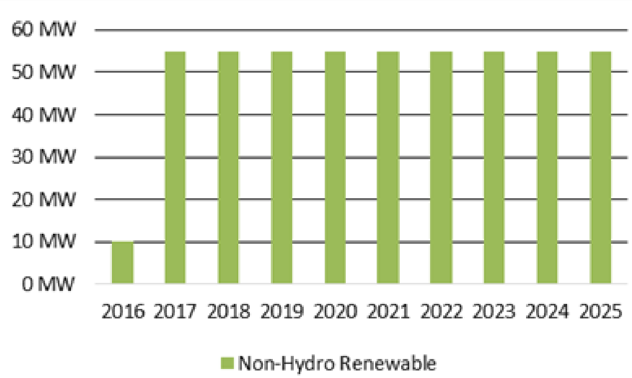
Peak Season Demand, Resources, and Reserve Margins

Demand (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Internal Demand	5,400	5,426	5,417	5,418	5,401	5,401	5,373	5,346	5,294	5,292
Demand Response	239	241	241	242	242	242	242	242	242	242
Net Internal Demand	5,162	5,185	5,176	5,176	5,159	5,159	5,131	5,105	5,052	5,051
Resources (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	6,453	6,698	6,584	6,698	6,698	6,698	6,571	6,698	6,698	6,698
Prospective	6,472	6,717	6,603	6,717	6,717	6,717	6,591	6,717	6,717	6,717
Reserve Margins (%)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	25.01%	29.18%	27.20%	29.41%	29.83%	29.83%	28.07%	31.21%	32.57%	32.60%
Prospective	25.39%	29.55%	27.58%	29.79%	30.21%	30.21%	28.45%	31.60%	32.96%	32.99%
Reference Margin Level	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Excess/Shortfall (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	259	476	373	487	507	507	414	572	635	637
Prospective	278	495	392	507	527	527	434	592	655	656

Peak Season Reserve Margins



10-Year Peak Season Cumulative Generation Mix Change



Demand, Resources, Reserve Margins, Transmission Outlook, and System Enhancements

The Maritimes Area is comprised of four sub-areas: New Brunswick (NB), Nova Scotia (NS), Prince Edward Island (PEI), and Northern Maine (NM).

During summer and winter peak load periods, the Existing Certain and Net Firm Transfers, Anticipated, Prospective, and Adjusted Potential Resources margins for the Maritimes Area do not fall below the target level at any time and exceed 86% and 26% during summer and winter periods, respectively, each year over this assessment's 10-year time frame. The Assessment Area does not anticipate any resource adequacy deficiencies during the assessment period.

The aggregated load growth rate for the combined sub-areas is practically unchanged for both the summer and winter seasonal peak load periods since last year's assessment. Overall, the Maritimes Area's 3,500 MW summer peak and 5,500 MW winter peak loads are both expected to decline slightly during the 10-year assessment period.

Current and projected energy efficiency effects are incorporated directly into the load forecast for each of the areas. Direct Control Load Management (DCLM) in New Brunswick (NB) is intended to shift load from peak periods into lower load periods, is embedded directly into the load forecast, and is included with energy efficiency. DCLM in NB is expected to rise from approximately 20 MW in 2015 to about 240 MW at the end of the assessment period. Interruptible load in 2015, projected at levels approximating 335 MW in the summer and 240 MW in the winter for the Maritimes Area, increases by about 10 MW for both seasons over the LTRA assessment period.

Additions of a total of 228 MW of wind generation capacity providing an expected 27 MW during the peak period and a 10 MW biomass plant, all in Nova Scotia (NS), are the new generation additions planned during the assessment period. Because of their small sizes, they will have virtually no impact on reliability. A 153 MW generator in NS is expected to be retired in October 2017. Its retirement depends on the planned construction of an undersea HVdc cable between NS and the Canadian Province of Newfoundland and Labrador as part of the Muskrat Falls hydroelectric generation development. NS plans to offset the retirement of the thermal unit with a 153 MW import of hydro capacity from Muskrat Falls.

During the winters of 2015–16 and 2016–17, the Maritimes will export 200 MW of capacity to a neighboring area. For a duration of one year, beginning in 2018 and ending in 2019, the Maritimes Area expects to export 114 MW of firm capacity to a neighboring area. In 2017, an expected import of 153 MW will be available from the Maritime Link project via Muskrat Falls hydro. This import will be timed simultaneously with the retirement of a similar amount of coal-fueled capacity in Nova Scotia. While the Maritimes Area includes 300 MW of tie benefits in its resource adequacy analyses, it is not dependent on these capacity transactions or emergency imports from neighboring areas to meet its Reserve Margin Reference targets. These tie benefits are not firm transactions and are not modeled in this LTRA analysis. Any such transactions are coordinated through the Northeast Power Coordinating Council (NPCC) working groups, which include members from all neighboring areas.

One major new transmission line addition in the Maritimes Area is planned for 2017. Development of the Muskrat Falls Generation Project in the Canadian province of Newfoundland and Labrador in 2017 will see the installation of an HVdc undersea cable link (Maritime Link) between that province and NS.

The construction periods for the planned projects mentioned above are all short and can be scheduled during times that will not significantly affect the reliability of the area. Capacity imports associated with the Maritime Link Project and the retirement of a comparable-sized unit will be timed to coincide so that the project will not have an impact on overall reliability.

The hydroelectric power supply system in the Maritimes Area with a capacity of approximately 1,330 MW is predominantly run of the river as opposed to storage based. Large quantities of energy cannot be held in reserve to stave off drought conditions. If such conditions occur, the hydro system would still be used to follow load in the area and respond to sudden short-term capacity requirements. Thermal units would be used to keep the small storage capability of the hydro systems usable only for load following and/or peak supply. The Maritimes area is not overly reliant on wind capacity to meet resource adequacy requirements. The lack of wind during peaks or very high wind speeds and/or icing conditions that would cause wind farms to suddenly shut down should not affect the dependability of supply to the area as ample spinning reserve is available to cover the loss of the largest base-loaded generator in the area. The latter situation is mitigated further by wide geographic dispersal of wind resources across the Assessment Area.

Renewable Portfolio Standards (RPSs) have led to the development of substantially more wind generation capacity than any other type of renewable generation. Reduced frequency response associated with wind generation may, with increasing levels of wind generation in the future, require displacement with conventional generation during light load periods. With the significant amount of large-scale wind energy currently being balanced on the NB system, the next phase of renewable energy development in NB will focus on smaller-scale projects with a particular emphasis on nonintermittent forms of generation, such as wood-based biomass. In NS, the Maritimes Link project will provide renewable hydro resources that may otherwise have been provided by intermittent resources and would have further reduced frequency response capability. For the purposes of LTRA assessments, NB, NS, and PEI capacity credits for wind resources are estimated based on probabilistic assessments. NM credits are based on capacity factors for separate summer and winter periods.

The Maritimes Assessment Area has a diversified mix of capacity resources fueled by oil, coal, hydro, nuclear, natural gas, wind (derated), dual-fuel oil/gas, tie benefits, and biomass with no one type feeding more than 26% of the total capacity in the area. There is not a high degree of reliance on any one type or source of fuel. The Maritimes Assessment Area does not anticipate fuel disruptions to pose significant challenges to resource adequacy in the area during the assessment period. This resource diversification also provides flexibility to respond to any future environmental issues such as potential restrictions to greenhouse gas emissions.

Load growth in the southeastern corner of the NB sub-area, though not specifically identified in the load projections, has outpaced the rest of that sub-area. Planners are monitoring transmission loads and voltages in the area to ensure reliability is not affected. No reinforcements have been planned at this time. Demand-side management programs aimed at reducing and shifting peak demands and any future potential imports to NB from NS could reduce transmission loads in the southeastern NB area. On the whole, the NB sub-area expects a slight decline in load during the LTRA 10-year assessment period. The impact on the resource adequacy loss-of-load expectancy (LOLE) value is captured by modeling a reduction in tie transfer capabilities between sub-areas. The 2013 Maritimes Area Comprehensive Review of Resource Adequacy for NPCC showed that after transfer levels are reduced from 300 MW to 150 MW, LOLE values do not exceed the NPCC target limit of 0.1 days per year of resource inadequacy. The LTRA Reserve Margin Reference levels will not be affected by this issue.

The addition of renewable resources particularly in NS is an emerging issue in the Maritimes area within the assessment period. Nova Scotia’s Renewable Electricity Standard (RES) is seeking to displace significant amounts of fossil-fueled generation with renewable resources. By 2015, 25% of the province’s electricity sales will be supplied by renewable energy sources, and by 2020, this number increases to 40%. Increasing amounts of renewable resources could affect BPS reliability if variable or low-mass slow-speed units are added without considering the reduction of frequency response after system contingencies or transmission enhancements to prevent voltage or overload problems. The process of completing system impact studies prior to interconnecting new generation should identify whether the emergence of any of these issues could limit operation of or the amount of new renewable generation added to the system on a case-by-case basis.

Because of the relative size of the Maritimes Assessment Area’s largest generating units compared to its aggregated load, the area carries substantial reserve capacity. Generators use a diverse mix of fuel types with the result that the Maritimes Assessment Area is not overly reliant on any particular fuel to meet its load. The area is strongly interconnected with neighboring areas via high-capacity transmission lines but is not dependent on these areas to supply area load. As a result, LOLE analysis suggests that even with reasonable foreseeable contingencies including load forecast uncertainty, extreme weather, fuel disruptions, and generator and transmission interruptions, the Maritimes Assessment Area load will be reliably supplied for the 10 years covered in this report.

NPCC-New England

Assessment Area Overview

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.

Summary of Methods and Assumptions

Reference Margin Level
The Installed Capacity Requirement (ICR) results in a Reference Margin Level of 15.9% in 2016, declining to 13.9% in 2018 and assumed to be 14.3 for the remainder of the period.

Load Forecast Method
Coincident; normal weather (50/50)

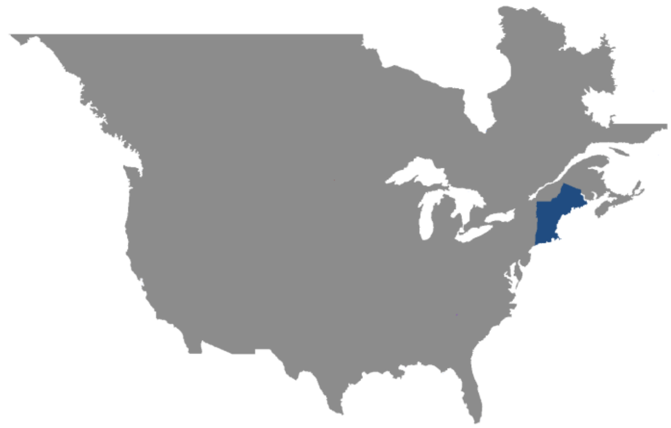
Peak Season
Summer

Planning Considerations for Wind Resources
5% of the total

Planning Considerations for Solar Resources
Seasonal claimed capability

Footprint Changes
N/A

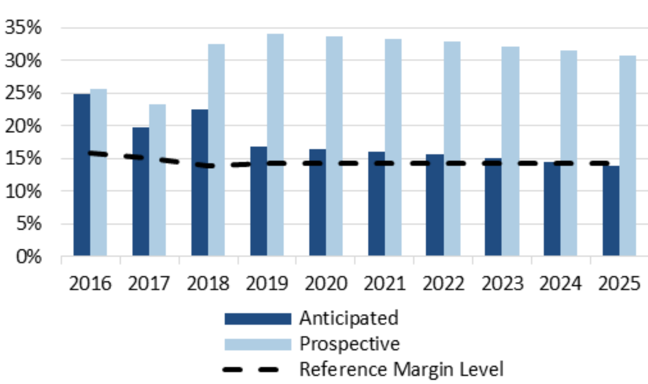
Assessment Area Footprint



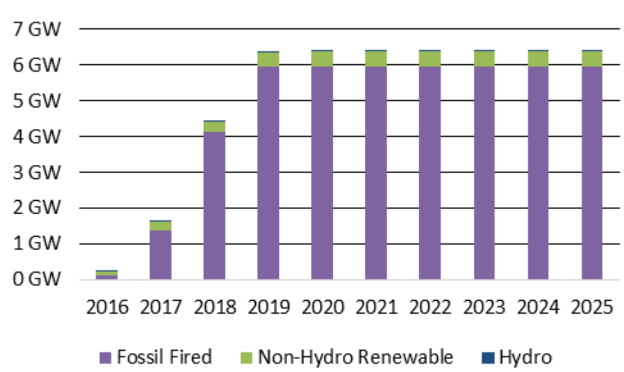
Peak Season Demand, Resources, and Reserve Margins

Demand (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Internal Demand	26,835	26,977	27,178	27,310	27,400	27,487	27,599	27,733	27,876	28,019
Demand Response	922	897	647	647	647	647	647	647	647	647
Net Internal Demand	25,913	26,080	26,531	26,663	26,753	26,840	26,952	27,086	27,229	27,372
Resources (MW)	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Anticipated	32,378	31,262	32,498	31,133	31,150	31,156	31,164	31,172	31,179	31,179
Prospective	32,571	32,170	35,184	35,743	35,790	35,797	35,805	35,812	35,820	35,820
Reserve Margins (%)	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Anticipated	24.95%	19.87%	22.49%	16.76%	16.44%	16.08%	15.63%	15.09%	14.51%	13.91%
Prospective	25.69%	23.35%	32.61%	34.06%	33.78%	33.37%	32.85%	32.22%	31.55%	30.86%
Reference Margin Level	15.91%	15.03%	13.94%	14.30%	14.30%	14.30%	14.30%	14.30%	14.30%	14.30%
Excess/Shortfall (MW)	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Anticipated	2,342	1,262	2,269	657	571	478	358	213	57	(107)
Prospective	2,535	2,170	4,954	5,267	5,212	5,119	4,999	4,853	4,697	4,534

Peak Season Reserve Margins



10-Year Peak Season Cumulative Generation Mix Change



Planning Reserve Margins

ISO-NE's Anticipated Reserve Margin will remain above its Reference Margin Levels throughout the study period except for the last year of this assessment. For 2025, New England will need an additional 107 MW of capacity resources to meet the 14.3% assumed Anticipated Reserve Margin for that year. Since ISO-NE has 4,600 MW of prospective capacity in its generator interconnection queue, and capacity needed to meet demand will be purchased through the Forward Capacity Market (FCM) three years in advance, the ISO will be able to secure enough capacity to meet reliability requirements through the assessment period.

Demand

The 2016 summer peak total internal demand (TID) of 26,835 MW takes into account 1,839 MW of energy efficiency as well as 237 MW of behind-the-meter photovoltaic resources. The demand forecast has decreased somewhat from the previous year's forecast, primarily due to ISO-NE's new forecast of behind-the-meter PV, which grows to 450 MW by 2024. This year's forecast of the 10-year summer TID compounded annual growth rate (CAGR) is 0.48%, as compared to the 2014 LTRA projection of 0.60%.

Demand-Side Management

Energy Efficiency and Conservation, which is secured by means of the FCM, includes installed measures (e.g., products, equipment, systems, services, practices, and strategies) on end-use customer facilities that result in additional and verifiable reductions in the total amount of electrical energy used during on-peak hours. For the years beyond the FCM commitment periods, ISO-NE uses an energy efficiency forecasting methodology that takes into account the potential impact of growing energy efficiency and conservation initiatives in the Region. Energy efficiency has generally been increasing and is projected to continue growing throughout the study period. The amount of EE is projected to increase to over 3,500 MW by 2024.

Active demand resources, which are also procured through the FCM, consist of Real-Time Demand Response (RTDR) and Real-Time Emergency Generation (RTEG), which can be activated with the implementation of ISO-NE Operating Procedure No. 4 – Action during a Capacity Deficiency (OP-4). Active demand resources are based on the Capacity Supply Obligations (CSOs) obtained through ISO-NE's FCM three years in advance. The CSOs decrease from 922 MW in 2016 to 647 MW in 2018. Since there are no further auction results, the ISO assumes that the CSOs will remain at the same level through the end of the reporting period.

The amount of Demand Response participating in ISO-NE's Forward Capacity Market has been decreasing since the start of FCM in 2010. Currently, the amount of dispatchable RTDR and RTEG demand resources is only about 2.4% of the summer TID. However, if in the future there is a substantial increase in the amount of these demand resources, there could be cause for concern. RTDR and RTEG can have significant variations in their availability and performance depending on several factors such as weather conditions, day of week, time of dispatch, and forced or planned facility or equipment shutdowns. While overall performance throughout the system has been high due to the large number and diversity of individual assets, ISO-NE has experienced relatively high variability of performance from one resource to another and from one dispatch zone to another.

Generation

A total of 104 MW (summer ratings) of new capacity consisting primarily of biomass and PV resources has been added in New England since the *2014LTRA*. Anticipated capacity additions include 85 MW of new wind capacity (393 MW nameplate) and approximately 1,800 MW of natural-gas-fired power plants. Prospective capacity in ISO-NE's generator interconnection queue consists of 3,642 MW of nameplate wind capacity (256 MW on peak), 4,277 MW of natural-gas-fired capacity, and 70 MW of biomass facilities. Brayton Point station, a 1,535 MW coal, oil, and natural-gas-fired power plant, has announced that it will retire by June 1, 2017. Despite these retirements, ISO-NE's Reserve Margin is not expected to fall below the 13.9% Reference Margin Level until 2025. Furthermore, there is an additional 4,600 MW of potential replacement capacity in the interconnection queue. [57]

The retirement of the Brayton Point station could result in additional demand for natural gas to fuel the generating resources to replace the energy lost from the Brayton Point station. ISO-NE does not expect adverse reliability impacts during the summer peak load period due to this plant retirement. However, the retirement of the oil- and coal-fired units in this plant

[57] On October 12, 2015, Entergy Nuclear Power Marketing announced their intention to retire the 680 MW Pilgrim nuclear unit by June 1, 2019. As required by its tariff, ISO New England will conduct a study to determine how the retirement will affect the overall reliability of the region's BPS. The results of this determination will be reflected in the *2016LTRA.*

could exacerbate the natural gas availability concerns during the winter months. ISO-NE has implemented various market rule changes to address these concerns.

PV resources constitute the largest segment of distributed generation resources throughout New England. The region has witnessed significant growth in the development of solar photovoltaic resources over the past few years, and continued growth of PV is anticipated. In order to determine what impacts future PV could have on the regional power grid, the ISO created a forecast of future PV. The total capability of all PV in New England, which is capacity rated at 40% of the nameplate, amounts to 494 MW in 2015 and is forecast to grow to 980 MW in 2024.

Regional PV installations are predominantly small (i.e., less than 5 MW) and state-jurisdictionally interconnected to the distribution system. States with policies more supportive of PV (e.g., Massachusetts, which had 73% of the total installed PV in New England as of the end of 2014) are experiencing the most growth of the resource. Existing amounts of PV have not caused noticeable effects on system operation, but as penetrations continue to grow and displace energy production from other resources, PV power production will introduce increased variability and uncertainty to the system, and eventually will have an impact on system operations (e.g., result in the need for increased reserve, regulation, and ramping).

The ISO is participating in projects with various organizations to prepare for integrating significant amounts of PV into its system. These include a project to improve the state of the science of solar forecasting, which will assist the ISO in developing ways of incorporating the load-reducing effects of PV into improved load-forecasting processes required to support the efficient and reliable integration of increasing amounts of PV; an evaluation of the potential reliability impacts of large amounts of distributed generation, such as PV; and a project to ensure that the future interconnection standards for PV (and other inverter-interfaced DG resources) better coordinate with broader system reliability requirements.

In January 2014, ISO-NE began incorporating wind forecasting into its processes, scheduling, and dispatch services. In addition to the ISO's use of the wind forecast, the lead market participant of a wind resource can download the forecast of expected output for their individual unit(s), which can help them build a strategy for bidding in the day-ahead energy market. As part of the first phase of this wind forecasting project, the ISO has also created real-time displays that improve the control room operators' situational awareness and is now maintaining historical wind data for future use by the forecast service. With the wind forecast integration project complete, the ISO will be working toward implementing the full economic dispatch of wind resources in phase 2 of this project, which is scheduled for implementation in 2016.

Although currently there are only 92 MW of on-peak wind capacity in New England, and only 84 MW (on-peak capacity) of future planned wind additions during the study period, an additional 3,642 MW of nameplate wind capacity is proposed within the ISO's interconnection queue. ISO New England is conducting transmission system reliability assessments to identify the nature of system reinforcements necessary to integrate significant amounts of wind resources into the system. The Strategic Transmission Analysis examined the integration of 1,113 MW of wind resources in Maine and 547 MW in Vermont. Of these amounts, all but 85 MW in Maine could be accommodated without major new transmission investment. The studies showed conceptual (non-major) transmission improvements, including static and reactive dynamic support to provide voltage control and thyristor-controlled series compensators, which would allow for the reliable integration of these proposed wind resources.

Capacity Transfers

Firm summer capacity imports are based on FCM CSOs, which amount to 1,616 MW in 2016 and decrease to 1,479 MW in 2018. The imports that are assumed for 2019–2025 are those based on long-term firm contracts, totaling approximately 90 MW. However, it is expected that imports during those years will remain at the level of the CSOs, which have been at least 1,200 MW over the past five years. In addition to firm imports, external transactions can participate in the day-ahead and real-time energy markets. In past years, actual imports during peak periods have been significantly higher than the CSOs. During the assessment period, a firm capacity sale to New York (Long Island) of 100 MW is anticipated to be delivered via the Cross-Sound Cable.

ISO-NE meets annually with its adjacent RCs to review applicable operating agreements and procedures and routinely evaluates changes to the transmission system that could have an impact on import and export capabilities. ISO-NE also coordinates all its study assumptions regarding capacity transactions and interregional transmission transfer capability of its external ties with neighboring BAs through the NPCC meetings that relate to various resource adequacy/reliability studies that are conducted annually. Regarding the internal and external transmission interface limits, ISO-NE conducts annual studies to update, if necessary, transfer capability of all the relevant transmission internal and external interfaces and publishes the resulting assumptions in its annual regional transmission plan. These transmission transfer capability assumptions are shared with and used by NPCC in its studies. In addition, as part of its FCM qualification process, new import resources must provide detailed information to confirm that the generator has the ability to deliver the specified capacity to New England.

Transmission and System Enhancements

Several transmission projects that are important to the continuation of or enhancement to system or sub-area reliability are projected to come on-line during the assessment period. These projects are the result of progress made by the ISO and regional stakeholders in analyzing the transmission system in New England and developing and implementing solutions to address existing and projected transmission system needs. The major projects under development in New England include New England East–West Solution (NEEWS) and the greater Boston upgrades. NEEWS consists of a series of projects that will improve system reliability across southern New England, including helping to address concerns in Rhode Island that are exacerbated by upcoming resource retirements, and increasing total transfer capability across New England's east-to-west and west-to-east interfaces. Some of the system upgrades were placed in service in early 2015, with the rest scheduled to be completed by end of 2015. The greater Boston upgrades are critical to improving the ability to move power into the greater Boston area and also in moving power from northern New England to southern New England. This set of upgrades includes a Static synchronous compensator (STATCOM) in Maine that will also help to address concerns with the potential for system separation due to significant contingencies in southern New England. The greater Boston upgrades have been certified to be in service by June 2019.

Long-Term Reliability Issues

Environmental compliance obligations for generators due to existing and pending state, regional, and federal environmental requirements appear more likely to impose operational limits rather than a retirement risk on new and existing generators. The lower retirement risk is due in large part to exemptions offered under MATS for limited continued operation of certain (oil-fired) steam generators, recognizing the reliability value that low-capacity-factor fossil steam generators provide in maintaining system fuel diversity. Although approximately 6.3 GW of existing coal- or oil-fired capacity in the Region is subject to MATS, most affected generators in New England are already equipped with required air toxics control devices due to earlier compliance with state air toxics regulations in New England. In addition to MATS, 9.85 GW of generating capacity currently using once-through cooling will potentially be affected by the Clean Water Act 316(b) Cooling Water and may need to convert to closed-cycle cooling systems or retire. Other regulations that will likely affect existing and future fossil-generating capacity in New England include recent revisions to air quality standards limiting ambient concentrations of various air pollutants, as well as proposed federal carbon dioxide emission requirements beginning in 2020.

The continuing trend of retirement of non-natural gas capacity in New England is a cause for concern. Currently approximately 44% of the region's capacity is natural-gas-fired generation. Based on the projects in the interconnection queue, that percentage is likely to increase significantly in the future, further straining regional fuel supplies. Serious reliability issues have emerged because of constraints on the regional natural gas delivery system as well as the cost and availability of imported liquefied natural gas (LNG). The existing natural gas pipeline system in New England is being operated at maximum capacity more often, especially in winter. The priority for a pipeline's transmission capacity goes to customers who have signed long-term firm contracts, and in New England, these customers have been the local gas distribution companies. Most natural gas plants have interruptible fuel arrangements that procure pipeline supply and transportation that has been released by these LDCs. As more homes and businesses convert to natural gas for heating, LDCs have had less capacity to release to the secondary market. This means that the increasing numbers of gas-fired generators are competing for limited amounts of fuel supply. Imported LNG can be used to meet spikes in regional gas demand, but it is significantly more expensive than natural gas from the Marcellus shales.

Although Marcellus shale gas production holds the promise of plentiful and inexpensive natural gas supply for the foreseeable future, additional pipeline capacity to New England is required. Only eight of the 19 proposed pipeline-expansion projects across the Northeast would bring new or incremental pipeline capacity to New England. Although two pipeline expansion projects, Spectra Energy's Algonquin Incremental Market (AIM) project and Tennessee Gas Pipeline's Connecticut Expansion Project, are anticipated to be in service by winter 2016–17, these projects and their benefits will be more than offset by the retirement of Brayton Point Station. A study commissioned by the ISO highlights the problem; ICF International's 2014 gas study report projects regional shortfalls of natural gas supply during winter periods through 2020, even with the addition of 421 million cubic feet per day of new pipeline capacity.

The ISO is increasingly concerned about its ability to maintain power grid reliability during the coldest days of winter due to fuel unavailability. In winter 2014–15, the ISO implemented for the second year a special reliability program to mitigate risks associated with the retirement of key nongas generators, gas pipeline constraints, and generators' difficulties in replenishing oil supplies. As part of the 2014–15 winter program, oil-fired and dual-fuel generators, and generators that can access LNG were paid to secure fuel inventory and test fuel-switching capability; were compensated for any unused fuel inventory; and were also subject to nonperformance charges. The 2014–15 program also included permanent improvements such as the continued ability to test resources' fuel-switching ability and to compensate them for running the test. In addition, ISO-NE implemented a project that allowed generators to reflect fuel costs in their energy market offers as those costs change throughout the day, and changed the timing of the day-ahead energy market to better align with natural gas trading deadlines. The ISO has initiated a stakeholder process to explore proposals to address reliability concerns for winter 2015–16 and at least until 2018, when capacity market refinements to incentivize performance begin to take effect. Those refinements include Pay-for-Performance (PFP), which will strengthen availability incentives within the forward capacity market. Other efforts undertaken to shore up operations include the development of tools that help operations personnel more accurately predict the availability of natural gas supply for generators, improving unit commitment decisions; and increased communications with gas pipeline operators (assisted by FERC Order 787) to verify whether natural-gas-fired generators that are scheduled to run will be able to obtain fuel.

Pay-for-Performance, which will go into effect in June 2018, will create stronger financial incentives for generators to perform when called upon during periods of system stress: a resource that underperforms will effectively forfeit some or all capacity payments, and resources that perform in its place will get the payment instead. PFP will also create incentives to make investments to ensure performance, such as upgrading to dual-fuel capability, entering into firm gas-supply contracts, and investing in new fast-responding assets. By creating incentives for generators to firm up their fuel supply, PFP may indirectly provide incentives for the development of on-site oil or LNG fuel storage, or expanded gas pipeline infrastructure. However, PFP will not reach full effectiveness until the seven-year phase-in of the new performance rate is complete. Until that time, the region may be challenged to meet power demand at times when regional gas pipeline capacity is constrained. PFP may also hasten the retirement of inefficient resources with poor historical performance and the entrance of new, efficient, better-performing resources.

NPCC-New York

Assessment Area Overview

The New York Independent System Operator (NYISO) is the only BA within the state of New York (NYBA). 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. 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.

Summary of Methods and Assumptions

Reference Margin Level
The New York State Reliability Council (NYSRC) Installed Reserve Margin (IRM) of 17% extends through April 2016. New York's IRM is set annually, one year at a time, the NYISO will use the 2015 IRM of 17% throughout the assessment period.

Load Forecast Method
Coincident; normal weather (50/50)

Peak Season
Summer

Planning Considerations for Wind Resources
Modeled with a 100% Installed Capacity (ICAP) Value

Planning Considerations for Solar Resources
Modeled with a 48% capacity factor

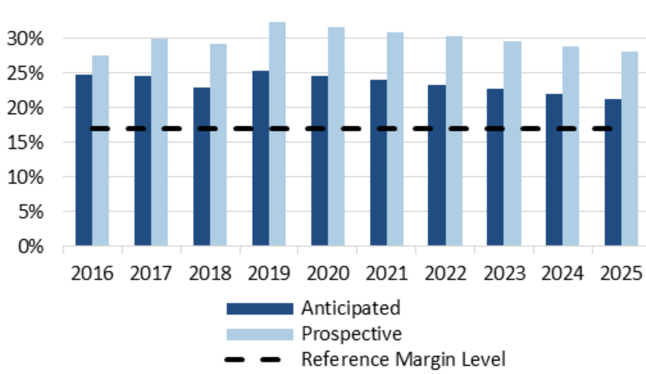
Footprint Changes
N/A

Assessment Area Footprint

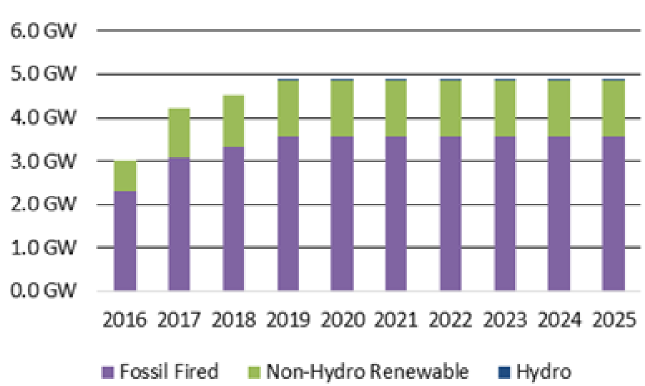
Peak Season Demand, Resources, and Reserve Margins[58]

Demand (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Internal Demand	33,636	33,779	33,882	34,119	34,309	34,469	34,639	34,823	35,010	35,219
Demand Response	1,124	1,124	1,124	1,124	1,124	1,124	1,124	1,124	1,124	1,124
Net Internal Demand	32,512	32,655	32,758	32,995	33,185	33,345	33,515	33,699	33,886	34,095
Resources (MW)	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Anticipated	40,546	40,669	40,293	41,347	41,347	41,347	41,347	41,347	41,347	41,347
Prospective	41,488	42,454	42,340	43,650	43,650	43,650	43,650	43,650	43,650	43,650
Reserve Margins (%)	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Anticipated	24.71%	24.54%	23.00%	25.31%	24.60%	24.00%	23.37%	22.70%	22.02%	21.27%
Prospective	27.61%	30.01%	29.25%	32.29%	31.54%	30.91%	30.24%	29.53%	28.82%	28.03%
Reference Margin Level	17.00%	17.00%	17.00%	17.00%	17.00%	17.00%	17.00%	17.00%	17.00%	17.00%
Excess/Shortfall (MW)	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Anticipated	2,508	2,463	1,967	2,743	2,521	2,334	2,135	1,920	1,701	1,456
Prospective	3,450	4,248	4,013	5,046	4,824	4,637	4,438	4,223	4,004	3,759

Peak Season Reserve Margins



10-Year Peak Season Cumulative Generation Mix Change



[58] Based on New York Installed Capacity (ICAP) values.

Planning Reserve Margins

For the LTRA Reference Margin, New York has agreed to using the current capability year 17% Installed Reserve Margin (IRM) value extended out for the entire 10-year window. New York has reported it that way in the past. The IRM value is determined and set each year by a study conducted by the New York State Reliability Council (NYSRC) and is based on wind and solar at full ICAP value modeled using an hourly supply shape for each wind and solar location. New York does not mix ICAP and UCAP in the IRM calculation. The data New York reported in the LTRA has wind and solar at full ICAP.

Demand

The energy forecast for the NYBA is lower than last year due to a change in the expected relationship of energy growth with the economy. Whereas economic growth (based on either employment or metro area GDP) continues to increase, the energy growth in most areas of the state is projected to be negative. Positive growth in summer and winter peak demand is expected. The decline in year-over-year energy usage is attributed to the continued impact of energy efficiency programs and additional incentives for customer-sited solar PV.

The average annual statewide energy growth is 0.00% for the period 2015 through 2025. In last year's forecast the annual average statewide energy growth was 0.16% for the period 2014 through 2024.

The average annual statewide summer peak demand growth is 0.48% for the period 2015 through 2025. In last year's forecast the annual average statewide energy growth was 0.83% for the period 2014 through 2024.

This difference between the energy growth and the summer peak demand growth from the 2014 forecast to the 2015 forecast indicates a continuation of the decoupling of the traditional relationship between growth patterns in annual energy consumption and summer peak demand.

Summer peak demand growth is expected to be slightly higher in the downstate region comprised of NYBA's Zones J and K (similar to New York City and Long Island), as compared to other areas of the state. This is expected to continue throughout the forecast horizon, but is not expected have any reliability impacts.

Demand-Side Management

Energy efficiency programs in the state are expected to continue to grow at the rate of about 200 MW (summer) per year, consistent with projections in prior years. In addition, NYISO expects summer peak reductions of about 80 MW per year due to customer-sited solar PV.

The Emergency Demand Response Program provides demand resources an opportunity to earn the greater of $500/MWh or the prevailing locational-based marginal price (LBMP) for energy consumption curtailments provided when the NYISO calls on the resource. Resources must be enrolled through Curtailment Service Providers (CSPs), which serve as the interface between NYISO and the resources, in order to participate in EDRP. There are no obligations for enrolled EDRP resources to curtail their load during an EDRP event.

Demand Response is considered in the NYISO planning processes including load forecast and resource adequacy analysis. Demand Response enrollments are currently trending at approximately at 3.5% of the NYISO system peak load. In addition, NYISO does not anticipate a significant increase in Demand Response enrollments in the near future. Given these factors, NYISO does not anticipate significant long-term reliability impacts from a modest increase in the Demand Response enrollments from the current enrollment levels.

Generation

Since the *2014LTRA*, seven previously mothballed units were returned to service, representing a total capability of 749 MW. Over the current *2015LTRA* assessment period, Tier 1 resources are expected to add 753 MW. These include the repowering of two former mothballed coal plants (360 MW) to run on natural gas; three units were rerated, adding 393 MW. Tier 2 resources, if they come on-line, are expected to add 2,550 MW.

Approximately 125 MWdc equivalent of customer-sited solar PV facilities were added in the NYBA from May 2014 to May 2015.

Two units (304 MW) are planned to retire/mothball in summer 2017.[59] When the NYISO receives a generator retirement/mothball notice, NYISO conducts an impact study to determine if a reliability need is created when the unit shuts down. If no reliability need is determined, then the unit may retire/mothball as planned. These units have completed the retired/mothball process and are now planned to retire/mothball in summer 2017.

No other large generators are expected to be unavailable over the assessment period.

The long-term forecast of annual energy and seasonal peak demands incorporates explicit adjustments for distributed energy resources, such as solar PV and distributed generation, along with energy efficiency. Based on approved funding levels, the expected on-peak impact of customer-sited solar PV is 799 MW by 2025. The expected impact of energy efficiency and other distributed energy resources is 1,939 MW by that year.

NYISO is currently conducting a Solar Integration Study with input of stakeholders and involved agencies to determine the impact of customer-sited solar PV on operational levels for regulation. It is also conducting a literature review, a solar forecasting evaluation, and a review of how solar PV is being accounted for by other ISOs/RTOs.

There have been no changes to the methods used to determine the on-peak capacity values for wind, solar, and hydro. Hourly unit output data for wind, run-of-river hydro, and solar units are collected for the summer peak hours (2:00 p.m. – 5:00 p.m. Eastern) from June 1 through August 31. The capacity on-peak for these resources is determined using an assumed capability for each resource class based on unit historic operating data and engineering judgment.

In addition, on-peak resources available from solar PV include a number of factors, such as inverter sizing and efficiency, the impact of cloud cover, other atmospheric conditions that attenuate solar irradiance, and the seasonal and diurnal variations in solar irradiance. These are compared to actual power production of solar PV systems to provide that the combined effect of all factors is consistent with current levels of technology.

Capacity Transfers

There are three classifications of capacity transfers. The first includes grandfathered contracts and external Capacity Resource Interconnection Service (CRIS) Rights. Grandfathered contracts predate the formation of NYISO and are honored at their capacity levels for their duration. External CRIS Rights authorize the owner to deliver capacity to New York from neighboring Balancing Authorities. These total 1,127 MW and cover the entire *2015LTRA* assessment period. The second class is Unforced Deliverability Rights (UDRs). These are rights to deliver capacity over controllable tie lines. The total UDR capability is 1,965 MW across the four controllable ties. The owners of the UDRs notify NYISO each year of the amount of capacity that will be delivered; UDR election levels are treated by NYISO as confidential information. Any transfer capability not utilized is available to provide emergency assistance in both our planning studies and operationally, if the need arises. The third classification is Import Rights. Once the annual Installed Reserve Margin (IRM) study is completed, an Import Rights study is conducted to determine the transfer capability available over and above the IRM requirement. For 2015, these total 580 MW and are available month to month on a first-come first-served basis in the capacity auctions.

Capacity transactions modeled in NYISO's assessments have met the capacity resource requirements as defined in NYISO's tariffs. Both NYISO and its respective neighboring Assessment Areas have agreed on the terms of the capacity transaction including, for example, (1) the MW value, (2) the duration, (3) the contract path, (4) the source of capacity, and (5) the capacity rating of the resource.

Transmission and System Enhancements

The Transmission Owner Transmission Solutions (TOTS) consists of three transmission projects in central New York, downstate New York, and New York City. TOTS is part of the Con Edison and the New York Power Authority (NYPA) filing in response to a November 2012 order from the New York Public Service Commission (PSC) that recognized significant reliability needs would occur if the Indian Point Energy Center (IPEC) was retired upon the expiration of IPEC's existing licenses or became unavailable for any reason. The three TOTS transmission projects are described in the following paragraphs.

The Ramapo-Rock Tavern project will establish a second 345 kV line from Con Edison's Ramapo 345 kV substation to Central Hudson Gas and Electric Corporation's (CHGE) Rock Tavern 345 kV substation. The project will increase the import capability

[59] On November 2, 2015, Entergy Nuclear Power Marketing announced their intention of retiring the 838 MW James A. Fitzpatrick nuclear unit at the end of the current fuel cycle, by June 2017. NYISO will be conducting an assessment to determine how this retirement will affect the overall reliability of the region's bulk power system. The results of this assessment will be reflected in the *2016LTRA*.

into Southeastern New York (SENY), including New York City, during normal and emergency conditions and will provide a partial solution for system reliability should the IPEC retire. The project will be located in Orange and Rockland Counties in New York along the right-of-way for the existing Con Edison 345 kV Feeder 77 (Ramapo to Rock Tavern) and using existing transmission towers. The transmission line terminals are located in NYISO Zone G. This project involves work that will be performed by Orange & Rockland Utilities (O&R) and CHGE; as such, Con Edison has and will continue to coordinate this effort with both O&R and CHGE.

The Staten Island Unbottling project will unbottle generation and transmission resources on Staten Island. It is a new resource and will be located in NYISO Zone J. The initial option for this project was to install a new 345 kV feeder and the forced cooling of four existing 345 kV feeders. The new option, a 1.5 mile feeder interconnecting the Goethals substation to the Linden substation, would mitigate a contingency within New York City by installing a new double leg feeder into new positions at the Goethals and Linden substations. Based on additional preliminary engineering and design work, Con Edison made certain changes to the project design. Instead of a new feeder installation, splitting an existing feeder between Goethals and Linden Cogen substations will provide a similar solution at a lower cost and with lower environmental impacts. The forced cooling of the existing four 345 kV feeders remains in the project scope and will increase transmission capacity between the Goethals, Gowanus, and Farragut substations. This project is located in Staten Island and Brooklyn, New York, and Union County (Linden), New Jersey.

The Marcy South Series Compensation project is a transmission improvement project that adds switchable series compensation to increase power transfer by reducing series impedance over the existing 345 kV Marcy South lines. Specifically, the project adds 40% compensation to the Marcy-Coopers Corners 345 kV line, 25% compensation to the Edic-Fraser 345 kV line, and 25% compensation to the Fraser-Coopers Corners 345 kV line through installation of series capacitors. The project also involves upgrades at Marcy and Fraser 345 kV substations. The project includes reconductoring of approximately 21.8 miles of the NYSEG-owned Fraser-Coopers Corners 345 kV line (FCC-33) with a higher thermal-rated conductor installed on existing wooden pole and steel tower structures. The project increases thermal transfer limits across the Total East Interface and the UPNY/SENY Interface.

The NYISO 2014 Reliability Needs Assessment identified thermal violations under N-1-1 post-contingency conditions (applying more stringent NPCC criteria) in the Rochester and Syracuse areas. The draft 2014 Comprehensive Reliability Plan states that these violations will be resolved with permanent solutions identified in the most recent Transmission Owner local transmission plans scheduled to be completed by summer 2017 in Rochester and the end of 2017 in the Syracuse area. In the interim, the local transmission owners will implement local operating procedures, if required, to prevent overloads, including the potential for limited load shedding in the Rochester and Syracuse areas.

Long-Term Reliability Issues

Recently agencies and generators have begun to examine or implement operational limits as an alternative means of achieving compliance with environmental regulations. Such limits may pose a risk to system reliability if generators exhaust their permitted emission limits and may not be in a position to operate for portions of the year when they are needed to maintain BPS reliability. The 2014 Reliability Needs Assessment (RNA) reviewed the impacts of federal and state environmental regulations on operation of the bulk power transmission facilities. The potential risks to system reliability posed by implementation of emission and operational limits to comply with pending environmental regulations are:

1. Phase I of CSAPR has begun replacing obligations under the Clean Air Interstate Rule (CAIR) for NOx and SO_2 emissions. Allocations under Phase I to NYBA generators are approximately equivalent with reported emissions for 2014. In 2016, it is expected that the operation of installed control equipment will be optimized to achieve compliance. CSAPR Phase II begins in 2017. In this phase, the SO_2 allocations are reduced, interstate trading limits are imposed, and NYS is seeking to have allowances directed to the State instead of the generators. The CSAPR Phase II Cap will be binding nationally, which will likely result in increased allowance prices. Nevertheless, under most conditions it appears that sufficient allowances should be available to the NYBA generation fleet.
2. Compliance with MATS began on April 16, 2015, for new and existing coal- and oil-fired units. Some dual-fuel units have chosen to limit oil use to avoid more challenging emission requirements. Depending on system conditions, such operational limits could pose a risk to system reliability, as they have the potential to reduce the effective aggregate dual-fuel capacity available to maintain the reliability of the New York Bulk Power Transmission Facilities (BPTF).
3. The draft EPA Clean Power Plan rules would require CO_2 emission reductions beginning in 2020. In comments on the proposal, the NYISO voiced concerns about the potential implications for electric system reliability and the lack

of recognition of the progress New York has already made in achieving significant reductions in CO_2 emissions. NYISO stated in its comments to the EPA, "As proposed, the Clean Power Plan presents potentially serious reliability implications for New York. A majority of the electric capacity within New York City is dual-fuel oil/gas steam-fired electric generating units. These units are critically important, both due to their location within the transmission-constrained New York City area and because they possess dual-fuel capability that provides a needed measure of protection against disruptions in the natural gas supply system." The comments questioned the EPA's assumption that the output from vital dual-fuel units could be reduced by over 99% while maintaining reliable electric service to New York City.

4. EPA is currently in the process of revising the National Ambient Air Quality Standard (NAAQS) for Ozone. Depending upon the ultimate level selected, the Ozone NAAQS will likely require further Nitrogen Oxides (NO_x) and Volatile Organic Compounds (VOC) emission reductions from NYCA generators. Such reduction requirements are not anticipated prior to 2022.

The NYBA is reliant on natural gas as the primary fuel for electric generation. Ongoing studies and efforts focus on:

1. improving communication and coordination between the sectors
2. addressing market structure enhancements, such as the closing time of the natural gas markets
3. providing for back-up fuel (primarily distillate oil) assurance to generation
4. addressing the electric system reliability impact of the sudden catastrophic loss of gas

NYISO, in conjunction with its stakeholders, is exploring market rule changes to help assure fuel availability during cold weather conditions. Improvements will be considered in reporting seasonal fuel inventories and daily replenishment schedules. NYISO will work with New York State regulatory agencies to develop a formal process to identify reliability needs that would be mitigated by generator requests for certain waivers. FERC has issued a NOPR to gather public comments to propose rule modifications in the gas market to provide better coordination between the electric and gas markets.

Generator retirements also pose the potential for an emerging reliability issue. While NYISO concludes that long-term reliability needs have been satisfied in the draft 2014 Comprehensive Reliability Plan (CRP) report, the margin to maintain reliability narrows over the 10-year study period based on projected load growth and the assumption that there are no additional resources added after 2017. Potential risk factors, such as long-term generator unavailability or higher load levels in regions of upstate New York (including Rochester, Western and Central New York, and the Capital Region), could potentially lead to immediate and severe transmission security violations. The projected NYBA capacity margins are narrow in the later years of the study; therefore, a small decrease in their existing resource capacity or an increase in loads by 2024 would result in an LOLE (loss-of-load event) violation in that year.

NPCC-Ontario

Assessment Area Overview

Ontario's electrical power system covers an area of 415,000 square miles and serves 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.

Summary of Methods and Assumptions

Reference Margin Level
The IESO-established Reserve Margin Requirement is applied as the Reference Margin Level.[60]

Load Forecast Method
Coincident; normal weather (50/50)

Peak Season
Summer

Planning Considerations for Wind Resources
Modeled, based on historic performance and historic weather data

Planning Considerations for Solar Resources
Modeled, based on historic weather data

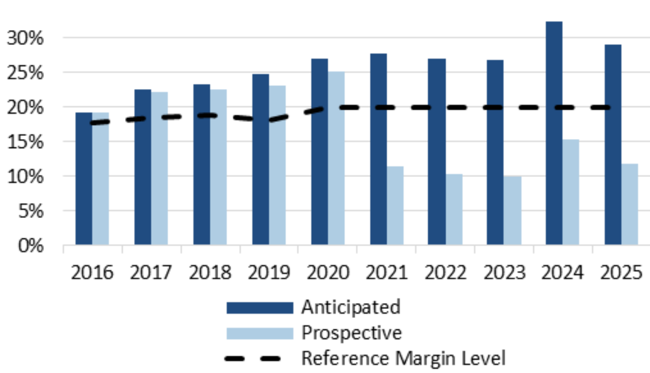
Footprint Changes
N/A

Assessment Area Footprint

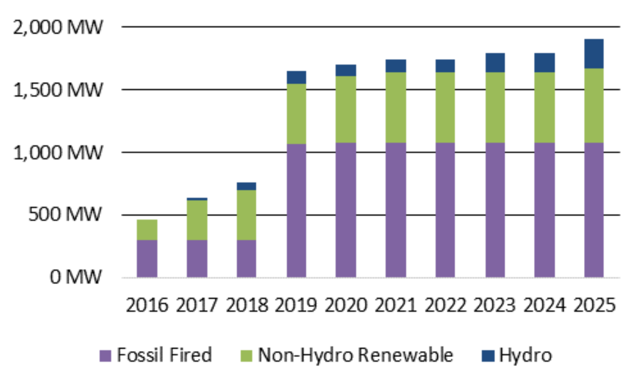
Peak Season Demand, Resources, and Reserve Margins

Demand (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Internal Demand	22,849	22,819	22,790	22,669	22,522	22,479	22,760	22,976	22,920	23,135
Demand Response	576	576	576	576	676	826	976	1,176	1,376	1,566
Net Internal Demand	22,273	22,243	22,214	22,093	21,846	21,653	21,784	21,801	21,544	21,569
Resources (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	26,548	27,274	27,406	27,545	27,748	27,659	27,659	27,653	28,531	27,827
Prospective	26,548	27,170	27,222	27,181	27,322	24,139	24,021	23,962	24,840	24,136
Reserve Margins (%)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	19.20%	22.61%	23.37%	24.68%	27.02%	27.74%	26.97%	26.84%	32.43%	29.01%
Prospective	19.20%	22.15%	22.55%	23.03%	25.07%	11.48%	10.27%	9.91%	15.30%	11.90%
Reference Margin Level	17.72%	18.40%	18.90%	18.02%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Excess/Shortfall (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	329	937	994	1,471	1,533	1,675	1,518	1,492	2,678	1,944
Prospective	329	834	810	1,107	1,107	(1,845)	(2,120)	(2,199)	(1,013)	(1,747)

Peak Season Reserve Margins



10-Year Peak Season Cumulative Generation Mix Change



[60] Ontario IESO, for its own assessments, treats Demand Response as a resource instead of as a load modifier. As a consequence, the Net Internal Demand, Planning Reserve Margins, and Target Reserve Margin numbers differ in IESO reports when compared to NERC reports. The Ontario reports would report lower Reserve Margins.

Demand, Resources, and Planning Reserve Margins

Ontario has invested heavily in electricity infrastructure over the past decade. Investments have enabled the phase-out of coal-fired generation in the province and have reduced the carbon intensity of Ontario's electricity supply mix. Growing net supply additions to manage the retirement of coal-fired generation and moderate demand resulted in substantial Reserve Margins in the recent past. With the recent phase-out of coal-fired generation in the province, Reserve Margins are reduced to levels that satisfy the reserve requirement.

Ontario is adequate for the entire duration of the assessment under the anticipated scenario. Under the prospective scenario, Ontario has enough confirmed planned resources (Tier 1) to meet its Reference Margin Levels for the first half of the assessment period and will rely on new resources (Tier 3) of up to 2,200 MW to meet the Reference Margin Level between 2022 and 2025. Ontario possesses a range of options to address these needs, including market-based mechanisms and capacity imports.

Over the 10-year period, Ontario expects increased demand for electricity, driven by modest economic expansion and population growth. However, these increases are being offset by three key factors:

1. The growth in embedded generation (behind-the-meter) capacity, which has a significant downward impact on grid-supplied electricity.
2. Conservation impacts that reduce the overall need for both end-use and grid-supplied electricity.
3. The increasing impact of price-sensitive demand through the implementation of time-of-use rates, as well as the Industrial Conservation Initiative.

Over the assessment period, the capacity of distribution-connected generation (DG) is expected to increase. As of December 31, 2014, more than 1,925 MW of variable generation was operating within distribution systems. Over the forecast period, about 1,900 MW of renewable capacity is projected to be added. Most of this embedded generation will be solar powered.

Overall growth in summer peak demand is modest due to the deployment of DG, especially the increased penetration of solar-powered DG. The summer peaks are also being influenced by efficiency changes to air conditioners. The winter peaks in Ontario occur after sunset so they are not significantly impacted by the mostly solar DG. However, the winter peak is seeing downward pressure from conservation savings due primarily to lighting efficiencies as end users move to compact fluorescent and LED technology.

There will be some variation in demand growth within Ontario. The greater Toronto area (GTA) has the largest share of the Ontario population and economy. The Essa zone, which lies just north of the GTA, will see positive growth resulting from ongoing expansion of the GTA. Primarily due to expected mining growth in the northern portions of the province, a rebound is expected during the later years of the forecast in the Northern Ontario zone.

The Demand Response programs during the summer are expected to increase from just over 500 MW at present to over 1,500 MW by the end of the forecast period. Ontario currently has three main Demand Response programs: Peaksaver PLUS® (primarily driven by air-conditioning load), dispatchable loads, and Capacity-Based Demand Response (CBDR), which is a new program for the previous Demand Response 3 (DR3) program participants. Future Demand Response may also participate in market-based mechanisms such as a Demand Response Auction. Participation in dispatchable load programs drops during the peak period as the loads take advantage of the Industrial Conservation Initiative.

Ontario is a strong proponent of conservation. The programs designed to achieve conservation targets are expected to deliver cumulative savings of 12.7 TWh over the forecast horizon. Those savings will be achieved through improved building codes, equipment standards, and incentive-based conservation programs. This includes time-of-use rates and the Industrial Conservation Initiative.

To meet the challenge of rapid deployment of renewables across the province and help capture the benefits of Ontario's investment in variable generation, the IESO implemented the Renewables Integration Initiative (RII) in 2013. RII has yielded results including the integration of the hourly centralized forecast into IESO scheduling tools, enhanced visibility of renewable output of distributed-connected variable generation facilities 5 MW or greater, and the dispatch of grid-connected variable generation. Frequency response, short-term inertial response, voltage ride-through capability, and voltage support are some of the performance requirements clearly identified during the connection process and validated through tests before the new grid-connected resources complete their facility registration with the IESO. Frequency response and voltage ride-through capability requirements also apply to distribution-connected resources larger than 10 MW.

In May 2015, the IESO signed a 500 MW seasonal firm capacity sharing agreement with Hydro Quebec. This agreement takes advantage of the provinces' complementary seasonal peaks to support reliability and will be in effect for 10 years, starting from December of 2015. The capacity will be shared, allowing Quebec to import up to 500 MW in winter months, and Ontario to import up to 500 MW in summer months. The energy associated with the capacity agreement will be scheduled through existing market mechanisms.

Transmission Outlook and System Enhancements

Transmission planning to address changes to the supply mix and ensure reliability throughout the province is ongoing. System enhancement projects that are underway include a new 230 kV double-circuit East-West Tie line, and the addition of a new 500-to-230 kV transformer station (TS), Clarington TS, in the eastern portion of the GTA. The in-service date for the new East-West Tie line has been revised from 2018 to 2020 due to slower than anticipated near-term load growth in northwestern Ontario. The Clarington transformer station is scheduled to be in service in the first half of 2018.

Planning studies are being finalized to manage the loading on the transmission lines between Trafalgar TS and Richview TS and the 500/230 kV transformers at Claireville TS and Trafalgar TS, which are forecast to be exceeded by 2020. Planning options have been assessed and are expected to include the installation of 500/230 kV autotransformers at the existing Milton Switching Station, with eight 230 kV circuit terminations and 12 km (7.5 miles) of new double-circuit line sections connecting the new Milton TS to Hurontario Switching Station.

Long-Term Reliability Issues

With the growth in the embedded variable generation capacity, demand forecasting has become increasingly more complex. Traditionally, demand was mainly a function of weather conditions, economic cycles, and population growth. With multiple new factors influencing demand, such as increased distribution-connected variable generation and increased consumer price-responsiveness, determining the causality of demand changes has become increasingly nuanced.

All coal units in Ontario have been phased out as of April 2014, in accordance with Ontario government policy. In the years following the coal phase-out, the province's next reliability challenge will be to carefully manage the renewal of its nuclear fleet. Nuclear units at Pickering Generating Station will not be refurbished, and current plans are to operate these units through approximately 2020. The other two nuclear plants in the province, Darlington and Bruce, are scheduled for refurbishment between 2016 and 2031. These changes may lead to a supply gap starting in 2021. Flexibility, cost, and environmental performance have been incorporated in Ontario's energy plan to ensure that commitment decisions are made in a timely manner. If additional resources are needed, market-based mechanisms such as the Demand Response Auction or the Capacity Auction are planned to facilitate procuring new resources. Other options include recontracting Non-Utility Generator (NUG) facilities as their contracts reach maturity, new gas-fired generation, imports, energy storage, and additional conservation above current targets.

High voltages are experienced in southern Ontario during light load periods and, with the planned shutdown of Pickering GS and the removal of its reactive absorption capability, the situation is expected to persist. Planning work for the new installation of new voltage control devices has been initiated.

NPCC-Québec

Assessment Area Overview

The Québec Assessment Area (Province of Québec) is a winter-peaking NPCC subregion that covers 595,391 square miles with a population of eight million. Québec is one of the four NERC Interconnections in North America, with ties to Ontario, New York, New England, and the Maritimes, consisting either of HVdc ties or radial generation or load to and from neighboring systems.

Summary of Methods and Assumptions

Reference Margin Level
Reference Margin Levels are drawn from the Québec Area 2014 Comprehensive Review of Resource Adequacy, which was approved by NPCC's Reliability Coordinating Committee in December 2014.

Load Forecast Method
Coincident; normal weather (50/50)

Peak Season
Winter

Planning Considerations for Wind Resources
On-peak contribution is approximately 30% of the total

Planning Considerations for Solar Resources
N/A

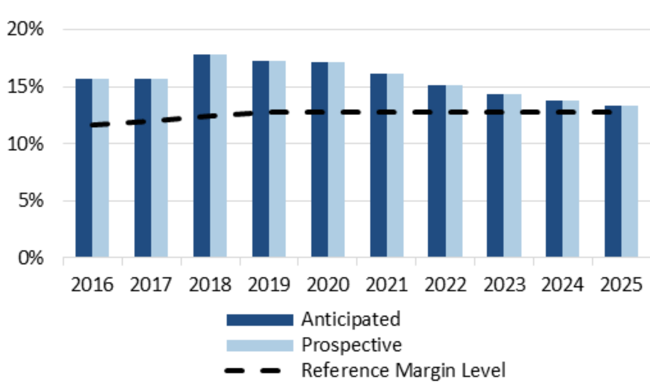
Footprint Changes
N/A

Assessment Area Footprint

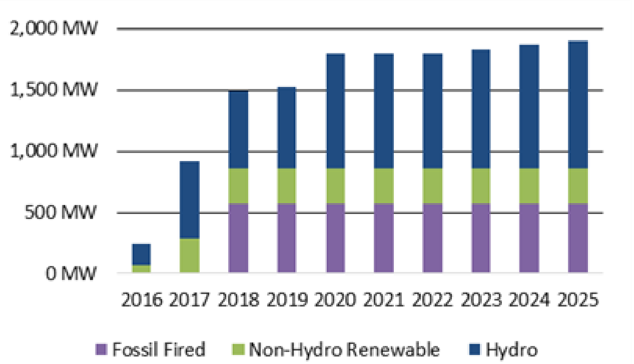
Peak Season Demand, Resources, and Reserve Margins

Demand (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Internal Demand	38,650	38,855	39,175	39,469	39,792	40,114	40,440	40,724	40,965	41,149
Demand Response	2,197	2,197	2,222	2,272	2,297	2,297	2,297	2,297	2,297	2,297
Net Internal Demand	36,453	36,658	36,953	37,197	37,495	37,817	38,143	38,427	38,668	38,852
Resources (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	42,179	42,421	43,544	43,624	43,905	43,905	43,905	43,940	43,975	44,010
Prospective	42,179	42,421	43,544	43,624	43,905	43,905	43,905	43,940	43,975	44,010
Reserve Margins (%)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	15.71%	15.72%	17.84%	17.28%	17.09%	16.10%	15.11%	14.35%	13.72%	13.28%
Prospective	15.71%	15.72%	17.84%	17.28%	17.09%	16.10%	15.11%	14.35%	13.72%	13.28%
Reference Margin Level	11.60%	12.00%	12.40%	12.80%	12.80%	12.80%	12.80%	12.80%	12.80%	12.80%
Excess/Shortfall (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	1,497	1,363	2,009	1,665	1,610	1,247	880	594	358	185
Prospective	1,497	1,363	2,009	1,665	1,610	1,247	880	594	358	185

Peak Season Reserve Margins



10-Year Peak Season Cumulative Generation Mix Change



Demand, Resources, and Planning Reserve Margins

The Anticipated Reserve Margin remains above the Reference Margin Level for all seasons and years during the assessment period.

The Québec Area demand forecast average annual growth is 0.7% during the 10-year period, a decrease since the *2014LTRA* report (0.9% average annual growth). This decrease in the demand forecast is mainly attributed to the industrial sector. Total Internal Demand is calculated for the Québec area as a single entity, and the area's peak demand forecast is coincident. Energy efficiency and conservation programs are integrated in the Assessment Area's demand forecasts and account for an average annual impact of 140 MW (at winter peak) over the 10-year period.

Demand Response (DR) programs in the Québec area specifically designed for peak-load reduction during winter operating periods are mainly interruptible load programs (for large industrial customers), totaling 1,747 MW for the 2016–17 winter period. The area is developing some interventions in DR (direct control load management and others) to its customers, which would provide 300 MW by 2021–22. The total on-peak DR for the 2025–26 winter period is projected to be 2,297 MW.

In 2014, the generating station La Romaine-2 was integrated for a total of 640 MW of new added hydro capacity. Work is underway on the La Romaine-1 (270 MW) and La Romaine-3 (395 MW) developments, which will be fully operational in 2016 and 2017, respectively. Some preparatory work has also begun on the La Romaine-4 (245 MW) development, which will be fully operational by the end of 2020. The retrofitting of some hydro units should also add 219 MW of capacity over the assessment period. For other renewable resources, about 480 MW of wind capacity and 60 MW of biomass have been added to the system since the beginning of 2014. Additionally, about 1,040 MW of wind capacity and 120 MW of biomass are expected to be in service by the end of 2017.

The Québec area will support firm capacity sales totaling 1,017 MW during the 2016–17 winter peak period, declining to 145 MW for the 2020–21 winter period. Also, a total of 1,800 MW of firm capacity purchases are planned for winter 2016–17, declining to 1,100 MW for the subsequent nine winter periods.

Transmission Outlook and System Enhancements

Romaine River Hydro Complex Integration

Construction of the first phase of transmission for the Romaine River Hydro Complex project is presently underway. Total capacity will be 1,550 MW. Romaine-2 (640 MW), which was commissioned in December 2014, is integrated on a 735 kV infrastructure initially operated at 315 kV to Arnaud 735/315/161 kV substation. One 315/161 kV, 500 MVA transformer has also been installed at this substation for the need of the project. The next generating station to be commissioned will be Romaine-1 (270 MW) at the end of 2015 and the beginning of 2016. Romaine-3 (395 MW) and Romaine-4 (245 MW) will be integrated between 2017 and 2020 at Montagnais 735/315 kV substation.

Main system upgrades for this project require construction of a new 735 kV switching station to be named Aux Outardes, which will be located between existing Micoua and Manicouagan Transformer substations. Two 735 kV lines will be redirected into the new station, and one new 735 kV line (5 km, or 3.1 miles) will be built between Aux Outardes and Micoua. This project was initially planned to be commissioned in 2014 and has been delayed to 2015.

Chamouchouane – Judith-Jasmin 735 kV Line

Planning studies have shown the need to reinforce the transmission system with a new 735 kV line in the near future in order to meet the Reliability Standards. The line will extend from the Chamouchouane substation on the eastern James Bay subsystem to a new substation (Judith Jasmin) in Montréal (about 400 km, or 250 miles). The new 735 kV substation is required to fulfill two objectives: providing a new source of electricity supply on the north shore of Montreal, and connecting the new 735 kV line from Chamouchouane to the Montreal metropolitan loop. This project will reduce transfers on other parallel lines on the Southern 735-kV Interface, thus optimizing operation flexibility and reducing losses.

Planning, permitting, and construction delays are such that the line is scheduled for the 2018–19 winter peak period. Public information meetings have begun on this project.

The Northern Pass Transmission Project

This project to increase transfer capability between Québec and New England is currently under study. It involves the construction of a ±320 kV dc transmission line about (75 km, or 47 miles) long from Des Cantons 735/230 kV substation to the Canada–U.S. border. This line will be extended into the United States to a substation built in Franklin, New Hampshire.

The project in Québec also includes the construction of an HVdc converter at Des Cantons and a 320 kV dc switchyard. The planned in-service date is now 2019.

The Champlain-Hudson Power Express Project

This project to increase transfer capability between Québec and New York by 1,000 MW is currently under study. The project involves construction of a ±320 kV dc underground transmission line about (50 km, or 31 miles) long from Hertel 735/315 kV substation just south of Montréal to the Canada–U.S. border. This line will be extended underground and underwater (Lake Champlain and Hudson River) to Astoria station in New York City. The project in Québec also includes the construction of one 1,000 MW converter at Hertel. The planned in-service date is 2018.

Wind Generation Integration Projects

Different calls for tenders for wind generation have been issued in the past years. About 3,950 MW (including wind generation already in service) is forecast to be on-line by the end of 2017. A number of wind transmission projects with voltages ranging from 120 kV to 315 kV are either under construction or in planning stages to complete the integration of wind generation resulting from the past calls for tenders. These projects are distributed in many areas of the Province of Québec, but most are near the shores of the Gaspésie Peninsula, along the Gulf of St. Lawrence down to the New Brunswick border.

Upcoming Regional Projects

Other regional substation and/or line projects are in the planning/permitting stages. There are about a dozen regional transmission projects in the Montréal and Québec City areas and another dozen in other areas with in-service dates from 2015 to 2020, consisting mostly of 315/25 kV and 230/25 kV distribution substations to replace 120 kV and 69 kV infrastructures.

Long-Term Reliability Issues

While technical developments in recent years have contributed to creating a more reliable system, sustainable system reliability may be challenged by several issues. For example, wind generation integration has not significantly impacted day-to-day operation of the system, and the actual level of wind generation does not require particular operating procedures. However, with the increasing amount of wind in the system, the foreseeable impact on system management may show up, and the following are under study:

- Wind generation variability on system load and interconnection ramping
- Frequency and voltage regulation
- Increase of start-ups/shutdowns of hydroelectric units due to load following coupled with wind variability
- Efficiency losses in generating units and/or reduction of low-load operation flexibility due to the low inertia response of wind generation coupled with must-run hydroelectric generation

In addition to these issues, there are occasions during recent summers when several 735 kV lines in the southern part of the system became heavily loaded due to the hot temperatures in southern Québec. Although this is a new issue for the Québec area, it is expected to occur again with increased air-conditioning loads and growing exports to other summer-peaking systems. More recently, studies have been performed and thermal limits have been optimized with other mitigating measures to address the potential for future line overloads following a contingency during periods of hot temperatures.

PJM

Assessment Area Overview

PJM Interconnection is a regional transmission organization (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 covers 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.

Summary of Methods and Assumptions

Reference Margin Level
The PJM RTO Reserve Requirement is applied as the Reference Margin Level for this assessment.

Load Forecast Method
Coincident; normal weather (50/50)

Peak Season
Summer

Planning Considerations for Wind Resources
Initially 13% of nameplate replaced with historic information tracked over the peak period

Planning Considerations for Solar Resources
Initially 38% of nameplate replaced with historic information tracked over the peak period

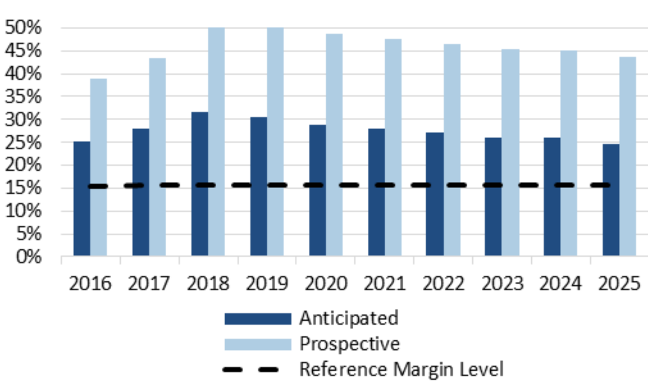
Footprint Changes
The East Kentucky Power Cooperative (EKPC), which integrated into the PJM RTO on June 1, 2013, is now part of PJM's load and generation data.

Assessment Area Footprint

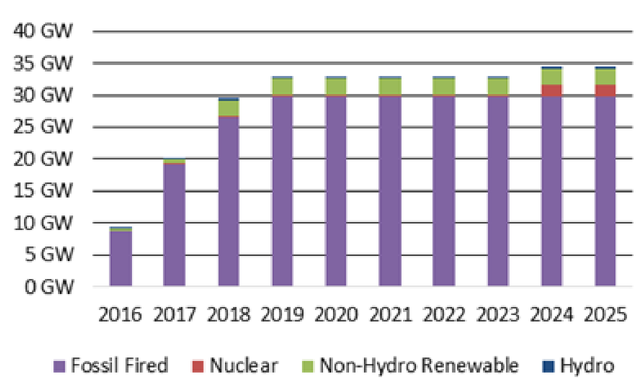
Peak Season Demand, Resources, and Reserve Margins

Demand (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Internal Demand	157,912	159,808	161,128	162,618	164,443	165,764	166,902	168,399	169,706	171,580
Demand Response	7,896	7,990	8,056	8,131	8,222	8,288	8,345	8,420	8,485	8,579
Net Internal Demand	150,016	151,818	153,072	154,487	156,221	157,476	158,557	159,979	161,221	163,001
Resources (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	187,811	194,181	201,330	201,538	201,420	201,420	201,420	201,420	202,990	202,990
Prospective	208,288	217,664	230,700	232,608	232,490	232,490	232,490	232,490	234,060	234,060
Reserve Margins (%)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	25.19%	27.90%	31.53%	30.46%	28.93%	27.91%	27.03%	25.90%	25.91%	24.53%
Prospective	38.84%	43.37%	50.71%	50.57%	48.82%	47.64%	46.63%	45.33%	45.18%	43.59%
Reference Margin Level	15.50%	15.70%	15.70%	15.70%	15.70%	15.70%	15.70%	15.70%	15.70%	15.70%
Excess/Shortfall (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	14,542	18,528	24,226	22,797	20,673	19,221	17,970	16,324	16,458	14,398
Prospective	35,019	42,011	53,596	53,867	51,743	50,291	49,040	47,394	47,528	45,468

Peak Season Reserve Margins



10-Year Peak Season Cumulative Generation Mix Change



PJM meets its Reference Margin Level using Anticipated Resources for the entire assessment period. The PJM Reserve Requirement is 15.6% in 2015, 15.5% in 2016, and 15.7% for the rest of the assessment period. Winter season Reserve Margins remain above the Reserve Margin requirement through the entire assessment period.

All load models were estimated with historical data from January 1998 through August 2014. There are 13 weather-variable rotations for each year. A scenario is created for the date in question plus one each for the six prior days and the six succeeding days. The models were simulated with weather data from years 1973 through 2013, generating 533 scenarios. The economic forecast used was Moody's Analytics' October 2014 release.

During 2014, amid growing evidence that the PJM load forecast model was persistently overforecasting, PJM investigated a more fundamental change to the load forecast model to account for missing factors that could be influencing recent electricity usage patterns. PJM acquired historical and forecast appliance saturation data as well as residential and commercial end-use data as drawn from the U.S. Energy Information Administration. From this data, PJM derived three additional variables for its energy (GWh) model:

1. A cooling equipment trend
2. A heating equipment trend
3. A trend for miscellaneous uses

Benchmarking tests demonstrated that this refined energy model provided a better estimate of the slowdown in energy usage in recent years and produced forecasts that tend to start lower than the current model, ultimately growing at a slightly faster rate. PJM reviewed the model and benchmark results with the PJM Load Analysis Subcommittee and PJM Planning Committee and has elected to publish the results of the new model as an alternative energy forecast. Going forward, PJM will attempt to extend the new model specification in order to apply it to peak load megawatt forecast.

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 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 fully captured by the current model specification. This additional variable in the model results in a downward adjustment for the majority of PJM zonal forecasts. The forecast of the EKPC zone used historic load values that were recalculated to be consistent with load on that transmission system. This led to higher peak loads 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, which adds 150–730 MW to the summer peak beginning in 2016.

Energy efficiency impacts have increased from approximately 900 MW to 1,200 MW. Assumptions for EE are based on PJM Reliability Pricing Model (RPM) auction results.

In 2014, PJM began to investigate potential changes in its planning assumptions to address concerns that the recent expected demand resource levels may be too high. The concern has arisen because providers have bought out a significant portion of their RPM auction's demand resource positions or replaced it with other capacity resources prior to the start of the delivery year. The impact has been that PJM has assumed the availability of more demand resources in its planning studies than actually is committed to PJM at the time the delivery year arrives. Planning assumption changes recognize such factors: existing uncleared generation and the average percentage of PJM demand resource net replacement (e.g., capacity) that has occurred in recent RPM auctions. The new method uses an average of the percent amount of DR that committed in the three most recent historical years. For the RTO, that number is pretty consistent at 5% of the unrestricted load each year, so it is assumed that ratio will be about the same in summer 2015 and in the future.

Another source of some uncertainty regarding future demand resource availability arises out of a recent federal appellate decision in Electric Power Supply Associations vs. FERC, 753 F.3d 216 (D.C. Circuit 2014), coupled with the pending Complaint of FirstEnergy Service Company at Docket EL14-55-00. These cases call into question demand resource eligibility to participate in any wholesale electricity market, including RPM auctions. Recently, demand resources totaling between 11,000 and 15,000 MW have cleared PJM auctions. The loss of these megawatts could have serious implications for PJM reliability. Given this uncertainty, PJM will need to adjust its planning procedures going forward to include scenarios in which all or a significant portion of cleared demand resources in future years is no longer committed to PJM.

PJM has filed tariff changes with FERC that will require more robust reporting of the DR operational capability in real time for Curtailment Service Providers. PJM does not have reliability concerns with DR expansion, but the additional operational information will help avoid the dispatch of DR that may not be necessary to meet the need of the emergency conditions.

Tier 1 resources increase rapidly in 2019 to over 21,590 MW then level off in subsequent years before jumping again with the addition of a new nuclear unit in 2024. It is anticipated that approximately 35% of capacity will be moved from the prospective (Tier 2) category to the planned category (Tier 1) in the coming years. Almost all the significant development is natural gas powered. Minor amounts of biomass and landfill gas development are also augmented by new wind and solar resources.

PJM requested that all impacted Generator Owners provide the most accurate information regarding unit retirements, environmental retrofits, unit derates, and potential regulatory issues related to the environmental regulations. Combined with the publically announced unit retirements and the deactivation analysis results, PJM is utilizing this information to address short-term impacts and long-term projections through 2018. PJM is communicating with interconnected Transmission Owners as required to address local reliability issues and is also communicating with neighboring Reliability Coordinators to compare reliability analyses and coordinate outages. The majority of retirements are coal powered, but some natural gas retirements are included. The loss of resources, no matter what the fuel, is the real concern.

The same imports and exports as the 2016–17 planning period are expected for the remaining years of the assessment. Each import transaction is accepted with the agreement that the specific units in question are no longer available to any other party but PJM. PJM treats exports in the same manner and does not consider units to be exported as PJM capacity. Transfer capability across PJM's border is also a requirement of accepting an import or export. PJM Balancing Authority operators confirm each transaction before they actually go into effect.

PJM's transmission expansion recommendation to the PJM Board in December 2014 encompassed a set of 22 projects to address 56 flowgate violations. They included several line reconductor projects, replacement of existing transformers with larger transformers, upgrades to terminal equipment on existing facilities, and circuit breaker replacements. All 22 recommended projects were upgrades to existing facilities.

PJM's transmission expansion recommendation to the PJM Board in February 2015 encompassed a set of 33 upgrades to address 132 flowgate violations. The recommendations included Greenfield solutions, reactor installations, capacitor installations, relay upgrades, line rebuilds, and new transformers.

Consistent with established practice, PJM's 15-year planning horizon encompassed both reliability and market efficiency analysis. PJM's planning horizon exceeds the scope of that specified by NERC and permits PJM to identify potential reliability criteria violations that may require larger-scale, longer-lead-time solutions. Results are reviewed to identify violations that occur across multiple deliverability areas or multiple violations clustered in a specific area. Long-term reliability analyses included the following test procedures for model year 2022: Generator Deliverability and Common Mode Outage Analysis, Load Deliverability Thermal and Voltage Analysis, and Specific Load Deliverability. These results were then extrapolated out through 2029 based on distribution factor calculations and applying incremental load increases based on PJM's 2014 Load Forecast Report. None of the identified reliability criteria violations suggested the need for a long-lead-time, larger-scope transmission solution. PJM communicated to stakeholders that while it intended to open a long-term RTEP proposal window, PJM did not believe that a transmission solution at this point was needed to resolve these specific violations. Rather, the major focus of the window would be to seek technical solution alternatives to relieve market efficiency congestion identified in related 2014 RTEP analyses.

PJM continually reviews its entire system for reactive concerns and initiates enhancements if necessary. Along with several dynamic reactive control devices, there are plans to install over 5,000 MVar of static capacitors.

No new SPSs are planned. Several existing SPSs will be removed from service over the assessment period.

Extreme weather is part of the PJM normal planning process. Extreme weather is considered in line with the probability of its occurrence. Recent focus has been on the winter peak period of 2013–14 and 2014–15. 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 at this time no changes have been made to PJM's planning assumptions or methods due to extreme weather.

PJM developed an analysis of coal generation at risk of retiring based on an assessment of required environmental retrofit costs versus the cost of constructing a new natural-gas-fired turbine. This at-risk generation analysis concluded that there is no overall resource adequacy concern for the PJM footprint; however, there may be localized reliability concerns that will need to be addressed either with replacement generation capacity or transmission upgrades if the impacted units are retired or need lengthy environmental retrofit outages. PJM continues to coordinate closely with PJM Generator Owners, PJM

Transmission Owners, and neighboring systems through the PJM Committee structure and consistent with the PJM Tariff and manuals. In order to maintain system reliability, PJM will designate units as reliability-must-run if their retirement date is targeted to be in advance of required system reinforcements.

At this point PJM has added the environmental retrofit outages to the extent provided by the Generator Owners to projections for maintenance outages from 2015 to 2018, and they are continuing to assess the impact to off-peak reliability. PJM will continue to coordinate closely to analyze the impact of retiring generation, planned outage to perform retrofits, normal generation, and transmission maintenance outages as well as transmission outages required to perform planning upgrades resulting from retiring generation. Generator Owners have indicated that while at this time there appears to be sufficient time to complete environmental retrofits, if there are delays in scheduling retrofit outages due to system constraint issues or capital budget limitations, there may be significant challenges in completing the retrofit outages in the required time to comply with environmental regulations.

Gas supply and transportation risks are captured in PJM resource planning studies to the extent they impact generator-forced outage rates. All forced outages, whether outside management control or not, are included in the calculations used in planning studies. PJM is investigating gas supply and transportation risk, considering the potential correlation with extreme cold weather (and high winter loads) and the potential for the loss of multiple units due to gas transportation disruptions.

SERC

Assessment Area Overview

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).

Summary of Methods and Assumptions

Reference Margin Level
Entities within the SERC footprint adhere to state-set targets that vary throughout the footprint. For this assessment, NERC applies a 15% Reference Margin Level for all SERC subregions.

Load Forecast Method
Noncoincident; normal weather (50/50)

Peak Season
Summer

Planning Considerations for Wind Resources
As reported by individual Generator Owners

Planning Considerations for Solar Resources
As reported by individual Generator Owners

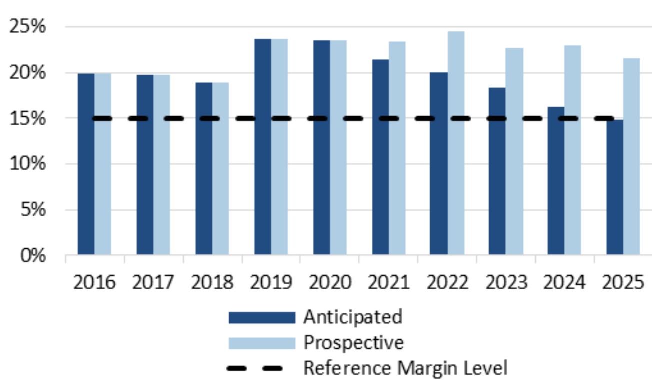
Footprint Changes
East Kentucky Power Cooperative (EKPC) joined PJM on June 1, 2013, and is no longer reported in SERC's Assessment Area. Additionally, entities within the SERC-W Assessment Area joined MISO in December 2013.

Assessment Area Footprints (SERC-E, SERC-N, SERC-SE)

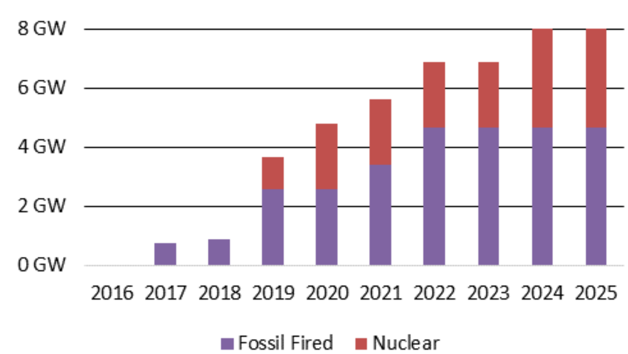
SERC-East: Peak Season Demand, Resources, and Reserve Margins

Demand (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Internal Demand	43,370	44,006	44,553	45,191	45,831	46,503	47,176	47,868	48,576	49,279
Demand Response	978	984	991	994	996	999	1,002	1,005	1,008	1,011
Net Internal Demand	42,392	43,022	43,562	44,197	44,835	45,504	46,174	46,863	47,568	48,268
Resources (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	50,821	51,494	51,789	54,645	55,378	55,284	55,408	55,425	55,293	55,436
Prospective	50,831	51,504	51,799	54,655	55,388	56,137	57,507	57,524	58,509	58,652
Reserve Margins (%)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	19.88%	19.69%	18.89%	23.64%	23.51%	21.49%	20.00%	18.27%	16.24%	14.85%
Prospective	19.91%	19.72%	18.91%	23.66%	23.54%	23.37%	24.54%	22.75%	23.00%	21.51%
Reference Margin Level	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Excess/Shortfall (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	2,070	2,019	1,693	3,818	3,818	2,954	2,308	1,532	590	(72)
Prospective	2,080	2,029	1,703	3,828	3,828	3,807	4,407	3,631	3,806	3,144

Peak Season Reserve Margins



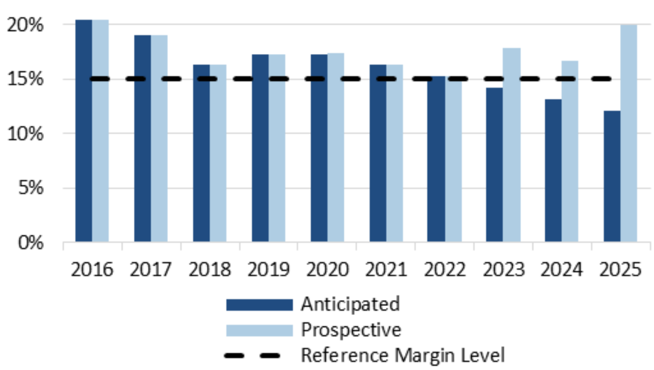
10-Year Peak Season Cumulative Generation Mix Change



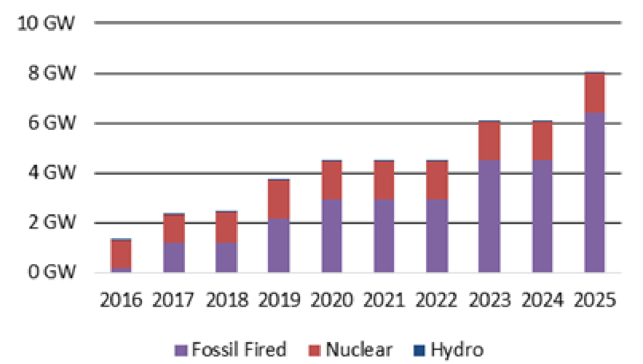
SERC-North: Peak Season Demand, Resources, and Reserve Margins

Demand (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Internal Demand	42,688	43,226	43,617	43,746	44,036	44,394	44,792	45,201	45,604	46,029
Demand Response	1,606	1,620	1,635	1,643	1,643	1,643	1,650	1,655	1,647	1,649
Net Internal Demand	41,082	41,606	41,982	42,103	42,393	42,751	43,142	43,546	43,957	44,380
Resources (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	49,491	49,518	48,835	49,387	49,746	49,746	49,746	49,746	49,746	49,746
Prospective	49,492	49,519	48,836	49,388	49,747	49,747	49,747	51,307	51,307	53,239
Reserve Margins (%)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	20.47%	19.02%	16.32%	17.30%	17.34%	16.36%	15.31%	14.24%	13.17%	12.09%
Prospective	20.47%	19.02%	16.33%	17.30%	17.35%	16.37%	15.31%	17.82%	16.72%	19.96%
Reference Margin Level	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Excess/Shortfall (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	2,247	1,671	556	969	994	582	133	(332)	(805)	(1,291)
Prospective	2,248	1,673	557	970	996	584	134	1,230	757	2,202

Peak Season Reserve Margins



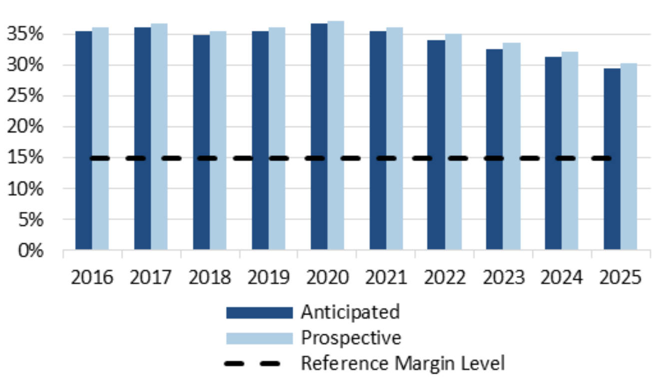
Peak Season Projected Resource Mix (Cumulative Change)



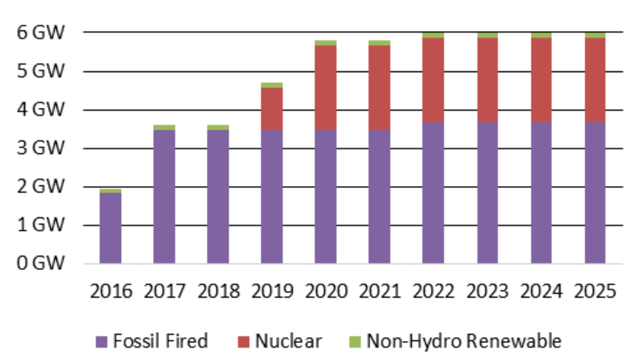
SERC-Southeast: Peak Season Demand, Resources, and Reserve Margins

Demand (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Internal Demand	47,173	48,198	48,689	49,221	49,768	50,283	50,849	51,421	52,114	52,808
Demand Response	2,230	2,255	2,268	2,279	2,290	2,294	2,298	2,301	2,306	2,306
Net Internal Demand	44,943	45,943	46,421	46,942	47,478	47,989	48,551	49,120	49,808	50,502
Resources (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	60,831	62,496	62,541	63,620	64,881	65,018	65,094	65,077	65,371	65,337
Prospective	61,120	62,785	62,830	63,909	65,170	65,307	65,577	65,560	65,854	65,820
Reserve Margins (%)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	35.35%	36.03%	34.73%	35.53%	36.66%	35.49%	34.07%	32.49%	31.25%	29.38%
Prospective	35.99%	36.66%	35.35%	36.14%	37.26%	36.09%	35.07%	33.47%	32.22%	30.33%
Reference Margin Level	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Excess/Shortfall (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	9,147	9,661	9,157	9,637	10,281	9,831	9,261	8,589	8,092	7,260
Prospective	9,436	9,950	9,445	9,926	10,570	10,120	9,744	9,072	8,575	7,743

Peak Season Reserve Margins



Peak Season Projected Resource Mix (Cumulative Change)



SERC has no regional Reserve Margin requirement and is assigned the NERC Reference Margin Level of 15% for the Assessment Areas. The Region's prospective outlook remains above the 15% reference margin; however, SERC's Anticipated Reserve Margin dips slightly below the 15% Reference Margin in 2025. This shortfall can be met by future capacity resources (Tier 3 reported resources). SERC anticipates no problems meeting the NERC Reference Margin through the year 2025.

Demand-Side Management

There were no significant energy efficiency or conservation program (EECP) impacts for the SERC Assessment Area for 2015. All projected EECPs have been incorporated into the forecast and are reflected in the Reserve Margin projections. Due to no significant increase or decrease in Demand Response for the Assessment Area, no significant long-term reliability impacts related to Demand Response were identified for the *2015LTRA* assessment period.

Generation

SERC entities continue to plan the transmission system to address the transmission reliability needs to interconnect, deliver, and retire identified generating units.

A large portion of future SERC-E resource projects are in the early planning stages and are reported as Tier 3 resources in this assessment. Since there is sufficient time to finalize these plans and construct these resources before the 2022–25 time frame, SERC-E is expecting that in future assessments, SERC-E will meet or exceed the NERC Reference Margin as plans for these new projects will be more completely developed and reported as Tier 1 or Tier 2 capacity, at the appropriate time.

Entities within the SERC Assessment Area perform a variety of generation scenarios in their long-term planning processes. These scenarios include evaluating the impacts of the expected changing resource mix, including integration of variable resources, additional natural gas capacity, etc. The transmission system is being expanded to account for the change in system dispatch so that potential operational issues don't occur or can be mitigated real time.

Capacity Transfers

The SERC Long-Term Study Group coordinates the development of quarterly planning cases for near-term and long-term reliability assessments. Transactions are included in these planning studies, which are developed for the respective time periods. The coordinated development of these cases ensures consistent treatment among Assessment Areas. SERC entities coordinate with their first-tier neighbors to ensure sufficient transmission interface capability and to assess whether potential impacts to capacity transfers exist due to any neighbors' planned system modifications.

Firm import and export reservations are managed via the OASIS (Open Access Same-time Information System) and are sold on a yearly, monthly, and daily basis with appropriate lead time required for each. The SERC Assessment Areas report no capacity imports from outside SERC Assessment Areas and average 3,200 MW of exports for the entire assessment period.

Transmission Additions

Several transmission projects are taking place in the SERC footprint to address the changing resource mix, provide voltage support for reactive limited areas, and to enhance overall reliability. Areas of SERC-E have identified contingency loading conditions that could exceed facility ratings depending on system loading and local area generation dispatch. Transmission facility upgrades have been planned to eliminate or greatly reduce the need to reconfigure the transmission system or redispatch system generation to address these potential high-contingency loadings. Also within SERC-E, a new ~32 mile 230 kV transmission line is planned to reinforce transmission service in the Myrtle Beach, SC area following retirement of local generating facilities. SERC-N has indicated that the retirement of generating units in northwest Alabama have caused the need for multiple new transmission facilities to address a number of voltage and thermal issues. The addition of a new Static VAR compensator (SVC) will also increase dynamic reactive reserves.

Long-Term Reliability Issues

SERC entities are evolving their long-term modeling practices to better assess uncertainties associated with increased renewables penetrations, environmental rules, and the expansion of the regional transmission organization. A significant uncertainty in the planning horizon is the proposed Clean Power Plan (CPP) and its potential impact on resource availability in 2020. Because other new environmental rules related to water and ash must be implemented as early as 2018, plant availability and power flow impacts may arise even before the proposed CPP is implemented. Additionally, SERC is in the process of evaluating regional impacts of the CPP with plans to proceed with required transmission projects identified by current and future studies of each plant impacted by the regulation deadline. Mitigation action plans are being developed based on the results of resource adequacy studies of generation resources that indicate potential system risks. To address uncertainties associated with the expansion of the RTO into the SERC footprint, 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 the MISO subregions in order to limit reliability impacts on neighboring systems. SERC members continue to work toward identifying a long-term solution to ensure that the SERC Region beyond the ORCA is reliably operated.

SPP

Assessment Area Overview

Southwest Power Pool (SPP) is a NERC Regional Entity 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 SPP Long-Term Assessment is reported based on the Planning Coordinator footprint. Along with the SPP RE footprint, it also includes Nebraska Public Power District, Omaha Public Power District, and Lincoln Electric System, which are registered with the Midwest Reliability Organization Regional Entity. The SPP Assessment Area footprint has 48,368 miles of transmission lines, 915 generating plants, and 6,408 transmission-class substations.

Summary of Methods and Assumptions

Reference Margin Level
SPP established target of 13.6%

Load Forecast Method
Coincident; normal weather (50/50)

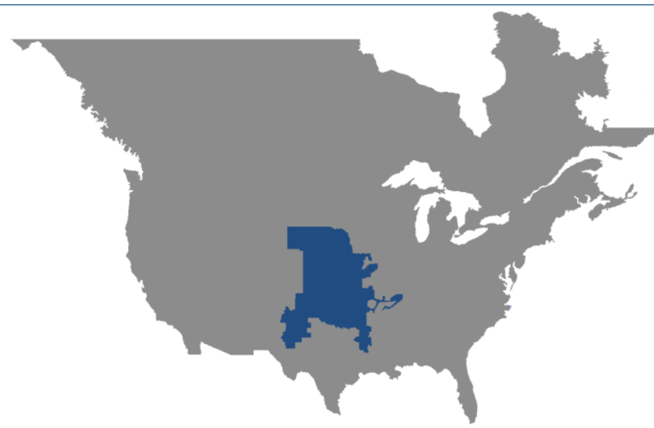
Peak Season
Summer

Planning Considerations for Wind Resources
On-peak contribution of 3% of nameplate capacity

Planning Considerations for Solar Resources
On-peak contribution of 10% of nameplate capacity

Footprint Changes
Western Area Power Administration (WAPA) Upper Great Plains, Basin Electric, and Heartland Consumers Power District (Heartland) are expected to join the SPP Assessment Area and be fully integrated into SPP on October 1, 2015. The integration of these entities, primarily located in North and South Dakota, will add approximately 5,000 MW of load and 9,500 miles of transmission to the SPP RTO footprint.

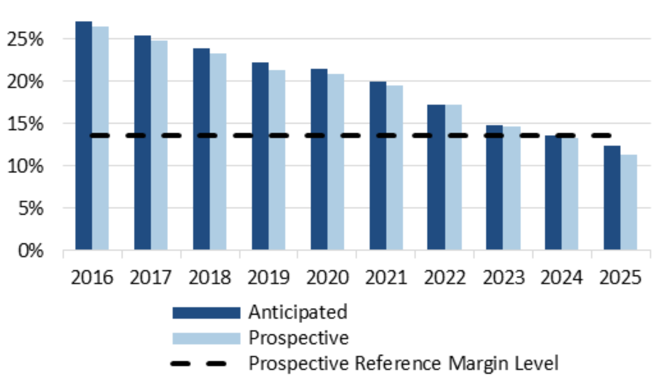
Assessment Area Footprint



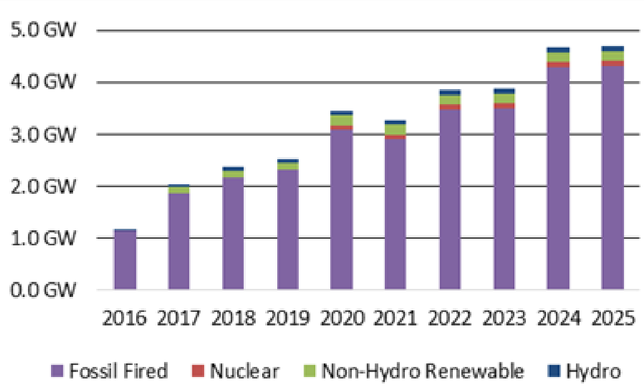
Peak Season Demand, Resources, and Reserve Margins

Demand (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Internal Demand	48,547	49,527	50,074	50,540	50,850	51,312	51,987	52,507	53,044	53,584
Demand Response	687	819	913	910	989	1,057	1,101	1,144	1,187	1,203
Net Internal Demand	47,860	48,708	49,160	49,630	49,862	50,256	50,886	51,363	51,857	52,382
Resources (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	60,829	61,070	60,941	60,649	60,540	60,276	59,661	58,950	58,874	58,817
Prospective	60,534	60,774	60,646	60,247	60,248	60,009	59,643	58,846	58,733	58,281
Reserve Margins (%)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	27.10%	25.38%	23.96%	22.20%	21.42%	19.94%	17.24%	14.77%	13.53%	12.29%
Prospective	26.48%	24.77%	23.36%	21.39%	20.83%	19.41%	17.21%	14.57%	13.26%	11.26%
Reference Margin Level	13.60%	13.60%	13.60%	13.60%	13.60%	13.60%	13.60%	13.60%	13.60%	13.60%
Excess/Shortfall (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	6,461	5,738	5,095	4,269	3,897	3,186	1,854	601	(35)	(689)
Prospective	6,165	5,442	4,800	3,867	3,605	2,918	1,837	497	(176)	(1,225)

Peak Season Reserve Margins



10-Year Peak Season Cumulative Generation Mix Change



The SPP Assessment Area is forecast to meet the 13.6% target Reserve Margin through the year 2024, but to fall below the target Reserve Margin in 2025 at 12.49%. SPP expects to meet this shortfall with future planned generation.

The SPP Assessment Area forecasts the noncoincident summer peak growth at an average annual rate of 1%.

The SPP Assessment Area's energy efficiency and conservation programs are incorporated into the reporting entities' demand forecasts. There are no known impacts to the SPP Assessment Area's long-term reliability related to the forecast increase in energy efficiency and Demand Response across the Assessment Area.

The SPP Assessment Area studies different scenarios in short-term and long-term planning to address the impacts of renewable portfolio standards, the integration of variable resources, and the changes in the resource mix. A 2016 wind integration study will be performed to analyze the reliability impacts of the system as new resources become available. The studies performed will be strictly reliability based and not an economic-based solution, and the study scenario will consider low load with high wind injection.

The SPP Assessment Area expects to retire approximately 3,000 MW of confirmed generation by 2025 with another 1,600 MW of unconfirmed generation that could potentially be retired. The generation being retired is a mixture of coal and natural gas units. These retirements do not reflect the impacts of the Clean Power Plan.

Since the previous long-term reliability assessment, the SPP Assessment Area has not changed how on-peak capacity values for wind, solar, and hydro are calculated. The expected on-peak capacity values for variable generation are determined by guidelines established in SPP Criteria section 12.1.5.3(g).[61]

The Tap Hitchland – Finney 345 kV and NewSub – Walkemeyer – North Liberal 115 kV project taps the Hitchland to Finney 345 kV line and adds a new substation with a 345/115 kV transformer. A new one-mile NewSub to Walkemeyer 115 kV line will be added, along with a Walkemeyer to North Liberal 21-mile 115 kV line. The in-service date for this project is June of 2019, and it will address the overload and area low-voltage outages in southwest Kansas. The 138 kV line from Broken Bow to Lone Oak is being rebuilt, upgrading the 16 miles of line from Broken Bow to Lone Oak to an updated rating of 286 MVA. This project has an in-service date of 2023 and addresses the overloads of 138 kV lines created by the outage of a 345 kV line.

The High-Priority Incremental Load Study showed that the SPP Assessment Area is experiencing an increase in oil and gas drilling, causing substantial load growth in northern Oklahoma, southwestern Kansas, Texas, and New Mexico. This localized growth has created the need for new transmission projects and generation in specific areas. SPP is working with members to make sure that reliability needs are being addressed. SPP staff provides a quarterly report to the Markets and Operations Policy Committee addressing any changes that may affect an issued Notice to Construct.

SPP's Integrated Transmission Plan for the period of 2015–25 was approved on April 28, 2015, by the SPP Board of Directors.

The SPP Assessment Area's Strategic Planning Committee (SPC) directed SPP staff to proceed with a Clean Power Plan assessment to identify impacts on existing and planned resources, identify at-risk generation, and evaluate resource-planning measures to ensure compliance with carbon emission goals in SPP's Region. The SPC instructed staff to analyze regional compliance first, followed by a state-by-state compliance assessment. The regional compliance analysis has been completed, but staff is currently working on the state-by-state analysis.

Compliance with 111(d) as it is currently perceived puts approximately 13,000–14,000 MW of generation at risk above and beyond the current retirements at risk for retirement.

The Operations Reliability Coordination Agreement (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.

[61] http://www.spp.org/section.asp?group=2766&pageID=27

TRE-ERCOT

Assessment Area Overview

The Electric Reliability Council of Texas (ERCOT) is the Independent System Operator (ISO) for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. ERCOT is a summer-peaking Region 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 RE functions described in the Energy Policy Act of 2005 for the ERCOT Region.

Summary of Methods and Assumptions

Reference Margin Level
ERCOT-established Reference Margin of 13.75%

Load Forecast Method
Coincident; normal weather (50/50)

Peak Season
Summer

Planning Considerations for Wind Resources
Effective Load-Carrying Capability (ELCC) of 8.7%

Planning Considerations for Solar Resources
ERCOT incorporates 100% capacity contribution

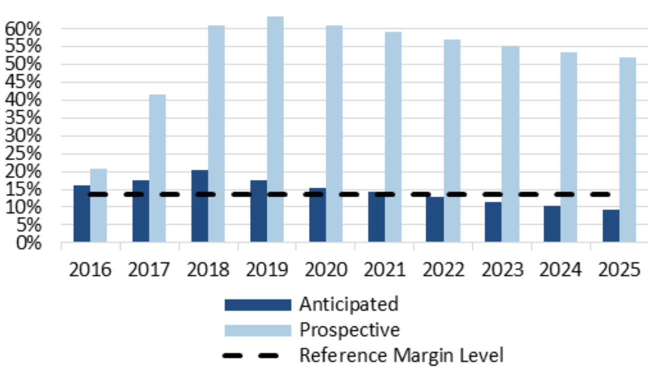
Footprint Changes
N/A

Assessment Area Footprint

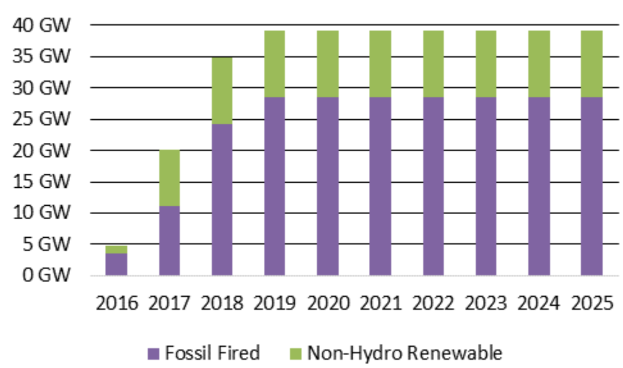
Peak Season Demand, Resources, and Reserve Margins[62]

Demand (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Internal Demand	70,014	70,871	71,806	72,859	73,784	74,710	75,631	76,550	77,471	78,384
Demand Response	2,357	2,357	2,357	2,357	2,357	2,357	2,357	2,357	2,357	2,357
Net Internal Demand	67,657	68,514	69,449	70,502	71,427	72,353	73,274	74,193	75,114	76,027
Resources (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	78,533	80,425	83,525	82,925	82,475	82,775	82,775	82,775	82,775	83,175
Prospective	81,689	97,095	111,793	115,295	114,845	115,145	115,145	115,145	115,145	115,545
Reserve Margins (%)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	16.07%	17.39%	20.27%	17.62%	15.47%	14.40%	12.97%	11.57%	10.20%	9.40%
Prospective	20.74%	41.71%	60.97%	63.53%	60.79%	59.14%	57.14%	55.20%	53.29%	51.98%
Reference Margin Level	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%
Excess/Shortfall (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	1,573	2,491	4,527	2,729	1,227	473	(574)	(1,620)	(2,667)	(3,306)
Prospective	4,729	19,160	32,794	35,099	33,596	32,843	31,795	30,750	29,702	29,064

Peak Season Reserve Margins



Projected Peak Season Generation Mix (Cumulative Charge)



[62] The Frontera power plant (three natural-gas-fired units totaling 524 MW) is assumed to be available to serve peak load for all years in the *2015LTRA* Reference Case. However, the plant's owner recently announced plans to begin exporting 170 MW of capacity to Mexico as soon as 2015 and the entire 524 MW in 2016 with the completion of certain transmission projects. ERCOT and the Frontera Facility's owners have agreed on the reliability safeguards for ensuring the plant will be available if needed in an emergency and have filed those conditions with the U.S. Department of Energy as part of the plant's export authorization.

The Anticipated Reserve Margin is expected to remain above the Reference Margin Level (13.75%) until 2023. The TRE-ERCOT Region would need 830 MW (or two% of Planned Tier 2 capacity) by the summer of 2023 to maintain the Reference Margin Level. Decreasing Reserve Margin predictions for the TRE-ERCOT Region are largely driven by ERCOT's interconnection process and the largely deregulated wholesale generation market. Project developers typically submit interconnection requests no more than three to four years before the facility is expected to enter commercial operations. As a result, the TRE-ERCOT Region will always show declining Reserve Margins in resource adequacy assessments beyond roughly three years out, with market solutions anticipated to address any potential capacity shortfalls due to continued robust load growth expectations.

The ERCOT peak demand forecast (Total Internal Demand) for summer 2016 is 70,014 MW and is expected to grow at an average annual rate of 1.3% for the assessment period. The 2016 peak demand forecast is 1.4% higher than the forecast for 2015 and is identical to the previous load forecast that was included in the 2014 LTRA. The forecast shows stronger load growth in ERCOT's South and Far West weather zones, due primarily to oil and gas production. Both of these areas are expected to grow twice as fast on a percentage basis as compared to the overall TRE-ERCOT Region growth rate.

New installed capacity by generation type since the 2014 LTRA includes the following: natural gas – 733 MW, wind – 1,936 MW (232 MW summer on-peak contribution), and utility-scale solar – 68 MW. The largest single-capacity addition is the 717 MW Panda Temple 2 gas-fired combined-cycle facility that entered commercial service in May 2015. New Planned Tier 1 capacity since last year's LTRA is dominated by gas-fired combined-cycle projects, representing 69% of the 4,500 MW of new Planned Tier 1 gas-fired capacity planned to be added through 2018. There is also 3,992 MW of new Planned Tier 1 wind nameplate capacity (with a summer on-peak contribution of 480 MW) to be added by 2017, along with 565 MW of new utility-scale solar capacity (summer on-peak contribution of 424 MW).

With respect to ERCOT's method for calculating on-peak wind capacity, the ERCOT Board of Directors approved a new methodology in October 2014 that uses historical operational data at the time of seasonal peak load hours in place of the modeled Effective Load Carrying Capability (ELCC) approach to derive expected on-peak capacity contribution values for wind resources. The new methodology includes calculation of summer and winter season capacity contribution percentages, as well as percentages for coastal and noncoastal resources, reflecting the significantly different diurnal wind patterns for these regions. For the summer season, the capacity contribution percentages are 12% for noncoastal resources and 56% for coastal resources. For the winter season, the capacity contribution percentages are 18% for noncoastal and 37% for coastal. These values are based on average historical output during seasonal peak load hours over the last six years for noncoastal resources and five years for coastal resources, and will be recalculated after each season with new seasonal historical data. In contrast, only a single annual percentage value for all of ERCOT was calculated using the ELCC approach: 8.7%. The impact of the new methodology is to increase anticipated 2016 summer peak wind capacity by 1,479 MW (1,526 MW to 3,005 MW).

ERCOT continues to rely on a variety of Demand Response programs administered by both ERCOT and several Transmission and Distribution Service Providers (TDSPs) to support resource adequacy under emergency conditions. For summer 2016, ERCOT estimates that it will have about 1,251 MW of Load Resources (LRs) providing ancillary services that are contractually committed to ERCOT during summer peak hours. ERCOT also has Emergency Response Service (ERS), 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 898 MW of ERS to be available for the 2016 summer season based on actual procurement results for summer 2015. Finally, this assessment accounts for individual TDSP contractual programs with loads that can respond to instructions to reduce total energy usage. These programs are expected to attract approximately 208 MW of additional Demand Response capacity and are subject to concurrent deployment with existing ERCOT Demand Response programs, pursuant to agreements between ERCOT and the TDSPs. In aggregate, these Demand Response programs represent 3.4% of the ERCOT Region's Total Internal Demand forecast.

Regarding potential reliability risks during the assessment period, a potential reliability impact could result from multiple coal units retiring during the 2018–20 time frame, primarily as a result of the Environmental Protection Agency's Regional Haze Program. While no official retirement announcements have been made by owners of coal units in the TRE-ERCOT Region, unit owners may opt to retire their coal units in lieu of installing the necessary control equipment. If that happens, there could be periods of reduced system-wide resource adequacy and localized transmission reliability issues due to the loss of generation resources in and around major urban centers. Market solutions are expected to address any loss of coal unit capacity.

Other reliability risks that ERCOT closely monitors include multiyear droughts and fuel supply disruptions. Although the current multiyear drought in Texas has effectively ended, future severe drought events continue to be a concern. To address the risk of generator derates and outages due to inadequate water levels, ERCOT monitors storage levels at Texas reservoirs and has developed a drought risk prediction tool for identifying generators at risk of reaching critical water supply levels. The tool identifies such at-risk generation resources based on generation resource-specific information, current reservoir storage, and historic water withdrawals. When a generator is identified as at-risk, ERCOT coordinates with the resource owner on understanding operational impacts and potential mitigation strategies. As an example of long-term water supply planning to address future drought conditions, the Lower Colorado River Authority announced the Lane City Reservoir Project that would help with downstream water demands near the Texas Gulf Coast and relieve some of the upstream impacts of water demands in the central Texas region. Ground-breaking of the reservoir project occurred in December 2014 and is expected to be completed in 2018.

ERCOT does not anticipate any widespread issues impacting generator availability due to fuel supply constraints for the remainder of the decade. Texas has a robust and extensive natural gas pipeline infrastructure that helps mitigate gas supply problems that might affect other markets in the United States. Nevertheless, ERCOT expects some gas-fired generator outages and derates to occur in north Texas as a result of severe winter weather events, and now coordinates with natural gas pipeline companies to receive advance notice of planned gas curtailments. Longer term, the expected increased use of natural gas nationally due to the EPA's Clean Power Plan and other environmental regulations could lead to increased market dislocations such those as seen in the winter of 2013–14, as well as overall increasing prices and price volatility due to the higher gas demand. Depending on the magnitude of these issues, there could be implications for maintaining reliable natural gas supply in the TRE-ERCOT Region.

Regarding transmission planning, the recently updated ERCOT future transmission projects list includes the additions or upgrades of 4,289 miles of 138 kV and 345 kV transmission circuits, 19,904 MVA of 345/138 kV autotransformer capacity, and 4,330 MVar of reactive capability projects that are planned in the TRE-ERCOT Region between 2015 and 2024.

A new Houston Import Project (130-mile 345 kV double-circuit line from Limestone to Gibbons Creek to Zenith) is planned to be in service before the summer peak of 2018. The Houston area is one of the two largest demand centers in the ERCOT System and the fourth largest city in the United States. The Houston area demand is met by generation located within the area and by importing power via high-voltage lines from the rest of the ERCOT System. This new line will support anticipated long-term load growth in the Houston region. Power imports into the Houston area are expected to be constrained until the new import line is constructed.

In the Lower Rio Grande Valley (LRGV), a new 345 kV import line and an upgrade of the two existing 345 kV import lines are part of a project to increase the overall import capability into the area by 2016. The new 163 mile, 345 kV line from the Lobo station, near Laredo, to the North Edinburgh station is expected to be completed by 2016. This new line will provide a third 345 kV import circuit into the LRGV from outside of the area. In July 2014, the owners of the Frontera generation plant, a 524 MW natural gas facility located on the west side of the LRGV, announced that they were planning to switch part of the facility (170 MW) out of the ERCOT market in 2015, and the entire facility would no longer be available to ERCOT in 2016. ERCOT evaluated the impact of the absence of the Frontera generation plant on the LRGV system and concluded that the two planned 345 kV projects will largely relieve the reliability issues in 2016, but additional system improvements will be required after 2016.

A new Cross Valley 345 kV, 106 mile line from the North Edinburg station, located on the west side of the LRGV, to the Loma Alta station, located on the east side of the LRGV, is expected to be in service before the summer peak of 2016. This new line will support load growth in the cities, including Brownsville, along the eastern side of the LRGV. Part of the LRGV import project includes the installation of a new composite core conductor on each of the existing 345 kV import lines into the area.

ERCOT performed a special West Texas Sensitivity Study in 2013 to evaluate the transmission system needs due to this oil- and gas-related load growth. Sixty-three projects were identified in the study and many have been implemented. It should be noted that these are in addition to projects previously planned or under construction. These transmission projects will serve existing customers and help meet the future load growth in the area due to oil production expansion in the Permian Basin. ERCOT is conducting a similar analysis in 2015 because the development has been increasing at a rate faster than the normal transmission planning study cycle.

WECC

Assessment Area Overview

The Western Electricity Coordinating Council (WECC) is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members, which include 38 BAs, 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 geographically the largest and most diverse of the NERC Regional Entities.

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. The WECC Assessment Area is divided into five subregions:[63] 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.[64] These subregional divisions are used for this study as they are structured around Reserve Sharing groups that have similar annual demand patterns and similar operating practices.

Summary of Methods and Assumptions

Reference Margin Level
Determined by WECC's building block method for each subregion

Load Forecast Method
Coincident (Western Interconnection); normal weather (50/50)

Peak Season
Summer: CA/MX; RMRG; SRSG
Winter: NWPP

Planning Considerations for Wind Resources
Modeling, primarily based on historic data

Planning Considerations for Solar Resources
Modeling, primarily based on historic data

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 BA area to the WALC BA area. This BA footprint change has a nominal effect on either area as the summer peak demand is only about 200 MW.

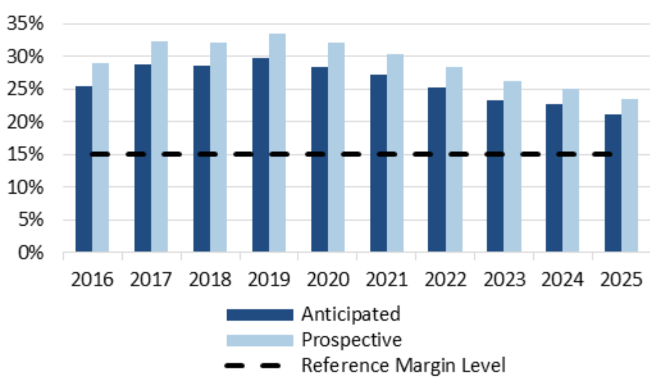
Assessment Area Footprints (CA/MX, NWPP-US NWPP-CA, RMRG, SRSG)

WECC-CA/MX: Peak Season Demand, Resources, and Reserve Margins

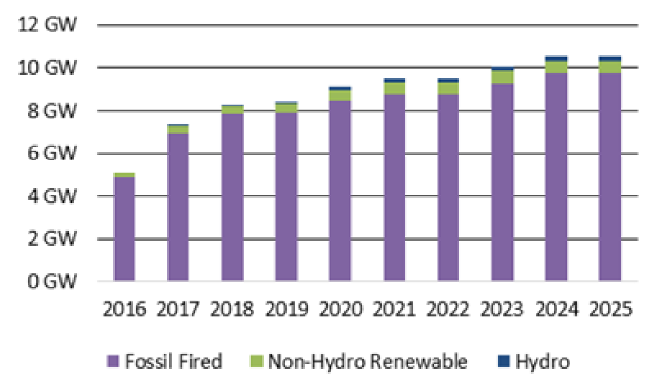
Demand (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Internal Demand	54,621	54,895	55,154	55,435	55,749	56,035	56,321	56,511	56,679	56,774
Demand Response	1,952	1,976	2,012	2,062	2,112	2,162	2,212	2,262	2,312	2,362
Net Internal Demand	52,669	52,919	53,142	53,373	53,637	53,873	54,109	54,249	54,367	54,412
Resources (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	66,044	68,119	68,301	69,234	68,864	68,597	67,820	66,849	66,710	65,959
Prospective	67,898	70,061	70,243	71,248	70,912	70,294	69,517	68,546	67,963	67,212
Reserve Margins (%)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	25.39%	28.72%	28.53%	29.72%	28.39%	27.33%	25.34%	23.23%	22.70%	21.22%
Prospective	28.91%	32.39%	32.18%	33.49%	32.21%	30.48%	28.48%	26.35%	25.01%	23.52%
Reference Margin Level	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Excess/Shortfall (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	5,475	7,262	7,188	7,855	7,181	6,643	5,595	4,463	4,188	3,385
Prospective	7,328	9,204	9,130	9,869	9,229	8,340	7,292	6,159	5,441	4,638

[63] The terms "subregion" and "Assessment Area" are used interchangeably in this assessment.
[64] Northwest Power Pool, Rocky Mountain Reserve Group, Southwest Reserve Sharing Group.

Peak Season Reserve Margins



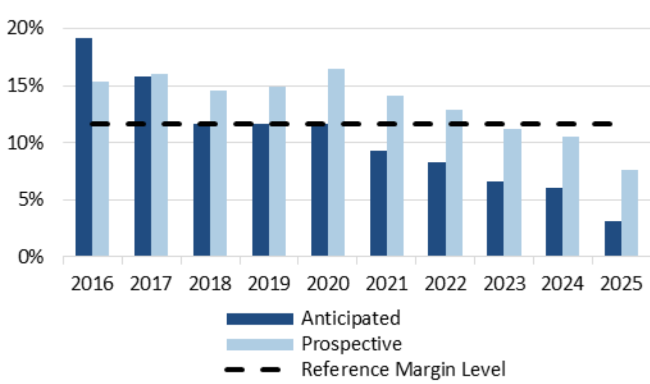
10-Year Peak Season Cumulative Generation Mix Change



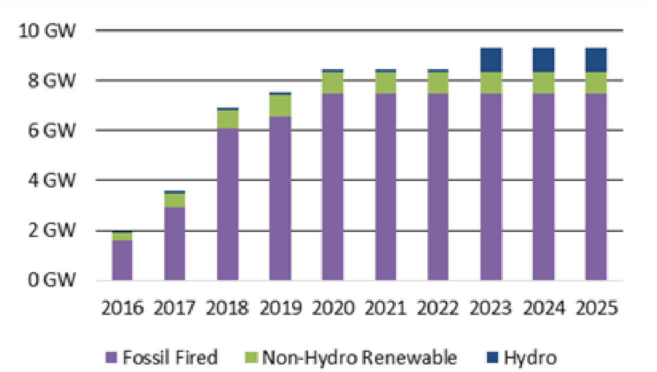
WECC-NWPP-CA: Peak Season Demand, Resources and Reserve Margins

Demand (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Internal Demand	23,777	24,568	25,374	26,263	26,830	27,326	27,733	28,147	28,569	28,996
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	23,777	24,568	25,374	26,263	26,830	27,326	27,733	28,147	28,569	28,996
Resources (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	28,336	28,455	28,335	29,315	29,943	29,877	30,016	30,007	30,294	29,896
Prospective	27,416	28,492	29,081	30,161	31,239	31,173	31,312	31,304	31,591	31,192
Reserve Margins (%)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	19.17%	15.82%	11.67%	11.62%	11.60%	9.34%	8.23%	6.61%	6.04%	3.10%
Prospective	15.30%	15.97%	14.61%	14.84%	16.43%	14.08%	12.91%	11.22%	10.58%	7.57%
Reference Margin Level	11.60%	11.60%	11.60%	11.60%	11.60%	11.60%	11.60%	11.60%	11.60%	11.60%
Excess/Shortfall (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	1,801	1,037	17	5	0	(619)	(934)	(1,405)	(1,589)	(2,463)
Prospective	880	1,074	764	851	1,297	677	362	(108)	(292)	(1,167)

Peak Season Reserve Margins



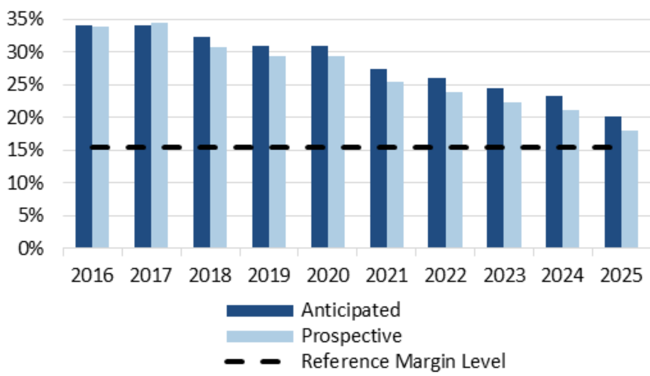
10-Year Peak Season Cumulative Generation Mix Change



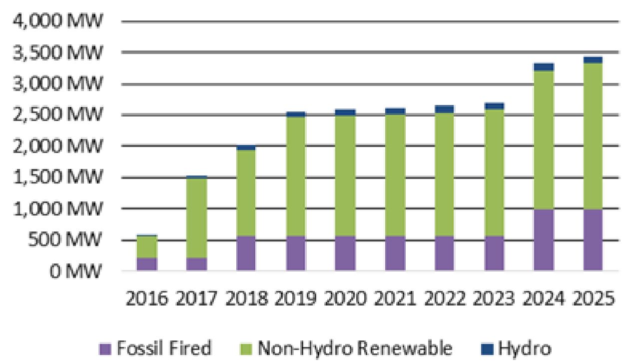
WECC-NWPP-US: Peak Season Demand, Resources and Reserve Margins

Demand (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Internal Demand	50,001	50,417	50,941	51,387	51,803	52,172	52,579	52,956	53,367	53,796
Demand Response	1,285	1,294	1,292	1,289	1,286	1,283	1,285	1,293	1,290	1,287
Net Internal Demand	48,716	49,123	49,649	50,098	50,517	50,889	51,294	51,663	52,077	52,509
Resources (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	65,322	65,928	65,680	65,651	66,174	64,814	64,701	64,311	64,211	63,103
Prospective	65,201	66,043	64,965	64,820	65,342	63,811	63,586	63,196	63,095	61,988
Reserve Margins (%)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	34.09%	34.21%	32.29%	31.04%	30.99%	27.36%	26.14%	24.48%	23.30%	20.18%
Prospective	33.84%	34.44%	30.85%	29.39%	29.35%	25.39%	23.96%	22.32%	21.16%	18.05%
Reference Margin Level	15.40%	15.40%	15.40%	15.40%	15.40%	15.40%	15.40%	15.40%	15.40%	15.40%
Excess/Shortfall (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	9,104	9,240	8,385	7,838	7,877	6,088	5,508	4,692	4,114	2,508
Prospective	8,983	9,355	7,670	7,007	7,046	5,085	4,392	3,577	2,999	1,392

Peak Season Reserve Margins



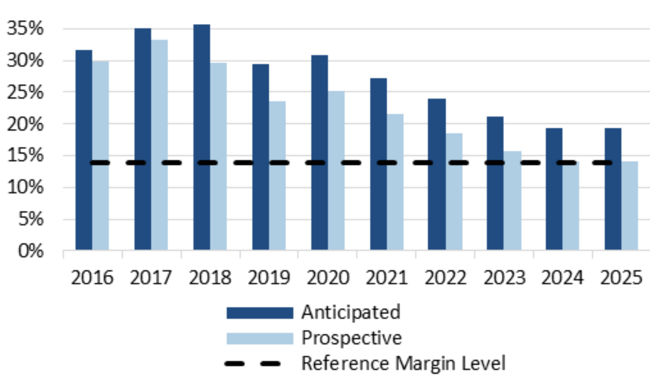
10-Year Peak Season Cumulative Generation Mix Change



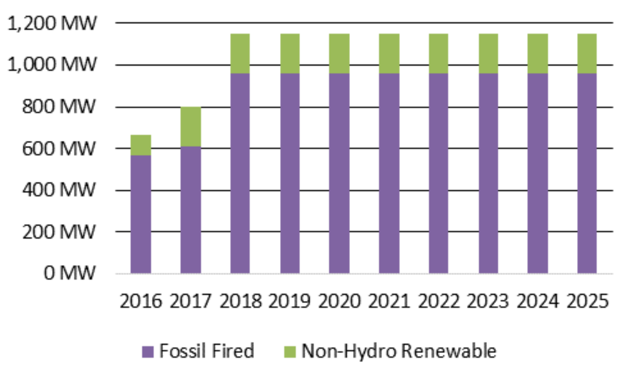
WECC-RMRG: Peak Season Demand, Resources, and Reserve Margins

Demand (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Internal Demand	12,613	12,738	12,994	13,253	13,424	13,706	14,000	14,329	14,532	14,800
Demand Response	558	567	577	586	594	577	586	593	600	606
Net Internal Demand	12,055	12,171	12,417	12,667	12,830	13,129	13,414	13,736	13,932	14,194
Resources (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	15,876	16,435	16,838	16,407	16,800	16,710	16,643	16,652	16,639	16,938
Prospective	15,664	16,223	16,090	15,659	16,052	15,962	15,895	15,904	15,891	16,190
Reserve Margins (%)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	31.70%	35.04%	35.61%	29.52%	30.94%	27.27%	24.07%	21.23%	19.43%	19.33%
Prospective	29.94%	33.29%	29.58%	23.62%	25.11%	21.58%	18.50%	15.78%	14.06%	14.06%
Reference Margin Level	13.90%	13.90%	13.90%	13.90%	13.90%	13.90%	13.90%	13.90%	13.90%	13.90%
Excess/Shortfall (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	2,145	2,572	2,695	1,979	2,187	1,756	1,364	1,006	771	771
Prospective	1,933	2,360	1,947	1,231	1,439	1,008	616	258	23	23

Peak Season Reserve Margins



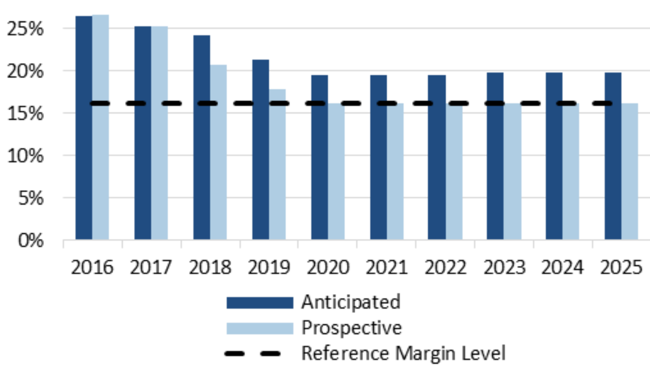
10-Year Peak Season Cumulative Generation Mix Change



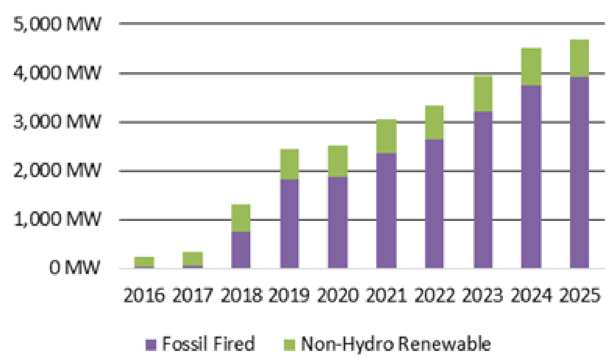
WECC-SRSG: Peak Season Demand, Resources, and Reserve Margins

Demand (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Internal Demand	23,773	23,932	24,407	24,894	25,444	25,902	26,120	26,595	27,149	27,764
Demand Response	476	446	380	380	386	386	386	386	386	387
Net Internal Demand	23,297	23,486	24,027	24,514	25,058	25,516	25,734	26,209	26,763	27,377
Resources (MW)	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Anticipated	29,466	29,434	29,828	29,758	29,960	30,494	30,743	31,382	32,062	32,788
Prospective	29,506	29,429	28,986	28,900	29,102	29,636	29,884	30,442	31,072	31,798
Reserve Margins (%)	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Anticipated	26.48%	25.33%	24.14%	21.39%	19.56%	19.51%	19.46%	19.74%	19.80%	19.77%
Prospective	26.65%	25.31%	20.64%	17.89%	16.14%	16.15%	16.13%	16.15%	16.10%	16.15%
Reference Margin Level	16.10%	16.10%	16.10%	16.10%	16.10%	16.10%	16.10%	16.10%	16.10%	16.10%
Excess/Shortfall (MW)	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Anticipated	2,418	2,167	1,933	1,297	868	870	866	953	990	1,004
Prospective	2,458	2,162	1,091	439	9	12	7	14	0	14

Peak Season Reserve Margins



10-Year Peak Season Cumulative Generation Mix Change



Planning Reserve Margins

As depicted in the tables at the beginning of this section, the Planning Reserve Margins for most of the WECC subregions remain above the NERC Reference Margin Level[65] throughout the assessment period. Beginning in 2021, the Northwest-CA subregion's Anticipated Reserve Margin drops below its Reference Margin, and by 2023 the Prospective Reserve Margin also drops below the Reference Margin. However, the reported Reserve Margins were calculated using hydro availability expected under adverse hydro conditions. When the Reserve Margins are calculated using expected hydro conditions, which is appropriate for this subregion due to the abundance of hydro storage, the NWPP-CA subregion is expected to have resources in excess of the Reference Margin Level throughout the assessment period. It should be noted that abnormal weather conditions in any subregion would result in Reserve Margins different from those reported in this assessment. In addition, severe adverse weather conditions or unexpected equipment failure may result in localized power supply or delivery limitations.

Throughout the 10-year assessment period, the NERC Reference Margins for the subregions range between 11 and 17%. The NERC Reference Margin Levels have not changed significantly compared to those reported in last year's assessment. WECC does not have an interconnection-wide formal Planning Reserve Margin standard. Instead, the NERC Reference Margin Levels for WECC and its subregions are calculated using a building block methodology[66] created by WECC's Reliability Assessment Work Group (RAWG) for its annual Power Supply Assessment (PSA).[67] 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.

By the summer of 2025, the difference between WECC's Prospective Resources (210,947 MW) and WECC's Net Internal Demand (166,621 MW) is anticipated to be 44,326 MW (26.6% margin). As the potential resources in excess of Net Internal Demand significantly exceed target margins, it is reasonable to assume that only a portion of the reported resource additions will ultimately enter commercial service within the planning horizon.

Similar to WECC's PSA, resources that are energy-only or energy-limited (e.g., the portion of wind resources that is not projected to provide generation at the time of peak) are not counted toward meeting resource adequacy in this assessment.

Demand

Actual Total Internal Demand for the summer, the peak season for the entire WECC Region, decreased by 2.3% from 150,926 MW in 2013 to 147,466 MW in 2014, due to generally mild temperatures and increased distributed solar generation. The Total Internal Demand for the summer season is projected to increase by 1.1% per year for the 2016–25 time period, which is essentially unchanged from the 1.0% projected last year for the 2015–24 period. The annual energy load is projected to increase by 1.2% per year for the 2016–25 time period, which is unchanged from the 1.2% projected last year for the 2015–24 period.

Demand-Side Management

The WECC Total Internal Demand forecast includes summer Demand Response that varies from 4,220 MW in 2016 to 4,593 MW in 2025. The direct control demand-side management capability is located mostly in the California/Mexico subregion, totaling 1,952 MW in 2016 and increasing to 2,362 MW in 2025. Demand-side management programs in other subregions are also increasing. The most prevalent Demand Response programs in WECC involve air-conditioner cycling as well as interruptible load programs that focus on the demand of large water pumping operations and large industrial operations (e.g., mining). Currently, the most significant Demand Response development activity within WECC is taking place in California. CAISO is actively engaged with stakeholders in developing viable wholesale Demand Response products with direct market participation capability. Also of note is CAISO's Demand Response product implementation that facilitates the participation of existing retail demand programs in the CAISO market. Further information regarding these initiatives is available on CAISO's website.[68]

---

[65] The NERC Reference Margin Level and all Reserve Margins are for planning purposes. 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.

[66] Elements of the Building Block Target are detailed in the NERC: Long-Term Assessment – Methods and Assumptions report.

[67] WECC's Power Supply Assessments.

[68] California ISO Demand Response Initiatives.

Overall Demand Response program growth has been rather static and is not expected to increase dramatically during the 10-year planning horizon. The various demand-side management programs within WECC are treated as load modifiers that reduce Total Internal Demand when calculating planning margins. In some situations, these programs may be activated by load-serving entities (LSE) during high-power cost periods but in general are only activated during periods in which local power supply issues arise. Generally, Demand Response programs in WECC have limitations, such as having a limited number of times they can be activated.[69]

Generation

All of the Balancing Authorities within the Western Interconnection provided the generation data for this assessment, and WECC staff—under the direction of the WECC RAWG—processed the data. The reported generation additions generally reflect partial extractions from generation queues.

The Existing-Certain and Anticipated resources projected for the 2016 summer peak period total 198,503 MW and reflect the monthly shaping of variable generation and the seasonal ratings of conventional resources. The Expected Capacity modeling for wind and solar resources are based on curves created using at least five years of actual hourly generation data. Hydro generation is dispatched economically, limited by expected annual energy generated during an adverse hydro year. Biomass and geothermal capabilities are based on nominal plant ratings.

A few utilities attributed coal-fired plant retirements and fuel conversions to existing air emissions regulations. Based on news media accounts and information related to western coal-fired plant environmental regulation cost exposure, it is expected that future LTRA information will report additional retirements and fuel conversions as more plant owners establish their preferred approaches for addressing emission regulations. California regulations essentially specify that existing long-term contracts with coal-fired plants will be allowed to run to expiration but these contracts will not be renewed.[70] This regulation may result in the sale, retirement, or repowering of some power plants during the assessment period. Due to the somewhat fluid situation in California regarding retirements associated with once-through cooling (OTC) regulations, potential associated capacity reductions have not necessarily been reported for this year's LTRA for all affected plants. Current information regarding the California OTC is available on the California Energy Commission's website.[71] It is expected that any future capacity reductions will be offset by new plants that may or may not be reflected in the current generation queue data.

Greater wind generation has resulted in an increased fluctuation in instantaneous generation and a need for increased operating reserves to compensate for the wind-induced fluctuations. Improved wind forecasting procedures and reduced scheduling intervals have only partially addressed the wind variability issue. Increased wind generation has also exacerbated high-generation issues in the Bonneville Power Administration (BPA) area during light load and high hydroelectric generation conditions. BPA provides current information regarding the issue on its website.[72]

Distributed energy resources, including rooftop solar and behind-the-meter generation, currently represent a very small portion of both the existing and planned resources, but are expected to increase in future years. As the load served by these resources is not included in the actual or forecast peak demands and energy loads, these resources are excluded from the resource adequacy calculation.

Capacity Transfers

WECC does not rely on imports from outside the Region when calculating peak demand reliability margins. The Region also does not model exports to areas outside of WECC. However, imports and exports may be scheduled across three back-to-back dc ties with SPP and five back-to-back dc ties with MRO.

---

[69] NERC's assessment process assumes that Demand Response may be shared among load serving entities, Balancing Authorities, and subregions. However, demand-side management sharing is not a contractual arrangement. Consequently, Reserve Margins may be overstated as they do not reflect Demand Response that could potentially be unavailable to respond to external energy emergencies. Energy efficiency and conservation programs vary by location and are generally offered by the LSEs. The reduction to demand associated with these programs is reflected in the load forecasts supplied by the Balancing Authorities.

[70] CEC Emission Performance Standards.

[71] CEC Once-Through Cooling, and February 2015 Status.

[72] BPA Oversupply Management Protocol.

Inter-subregional transfers are derived from resource allocation computer simulations that incorporate transmission constraints among various path-constrained zones within WECC.[73] The WECC resource allocation model places conservative transmission limits on paths between 19 load groupings (zones) when calculating the transfers between these areas. These load zones were developed for WECC's PSA studies. The aggregation of PSA load zones into WECC subregions may obscure differences in adequacy or deliverability between zones within the subregion.

The resource data for the individual subregions includes transfers between subregions that either are plant-contingent transfers or reflect projected transfers with a high probability of occurrence. Plant-contingent transfers represent both joint plant ownership and plant-specific transfers from one subregion to another. Projected transfers reflect the potential use of seasonal demand diversity between the winter-peaking Northwest and the summer-peaking Southwest, as well as other economy and short-term purchases that may occur between subregions.

While these transactions may not be contracted, they reflect a reasonable modeling expectation given the history and extensive activity of the western markets, as well as the otherwise underused transmission from the Northwest to the other subregions.

Transmission and System Enhancements

WECC is spread over a wide geographic area with significant distances between generation and load centers. In addition, the northern portion of the Assessment Area is winter peaking, while the southern portion is summer peaking. Consequently, entities within the Western Interconnection may seasonally exchange significant amounts of surplus electric energy. These conditions result in periodic full utilization of numerous transmission lines, which does not adversely impact reliability. Due to the inter-subregional transmission constraints, reliability in the Western Interconnection is best examined at a subregional level.

Several entities have proposed major transmission projects to connect renewable resources on the eastern side of WECC to load centers on the Pacific Coast—California in particular. These projects, however, are often subject to significant development delays due to permitting issues, etc. In light of past experience regarding the veracity of long estimates, WECC essentially only focuses on projects under construction or nearly under construction. WECC provides transmission facility additions information as requested by NERC but does not vet projects beyond the information provided for WECC's published 10-Year Planning Map and 10-year power flow base case.

The WECC Transmission Project Information Portal[74] provides a single location where interested parties can find basic information about major transmission projects in the Western Interconnection. As WECC does not vet the new projects or identify minimum transmission addition needs, reported additions may not closely reflect transmission additions that could occur during the assessment period. A delay of these projects may impact the timing and location of resource additions but should not adversely impact system reliability.

WECC's Transmission Expansion Planning Policy Committee's (TEPPC) Regional Planning Coordination Group analyzed the development status of the major reported transmission projects and identified 22 projects with a high probability of being in service by 2024. Information regarding the projects is available in the group's report, *2024 Common Case Transmission Assumptions (CCTA)*.[75]

To help monitor the impact of new generation resources on the transmission systems, individual entities within the Western Interconnection have established generator interconnection requirements that include power flow and stability studies to identify adverse impacts from proposed projects. In addition, WECC has established a review procedure that is applied to larger transmission projects that may impact the interconnected system. The details of this review procedure are located in WECC's Project Coordination and Path Rating Processes.[76] These processes identify potential deliverability issues that may result in actions such as the implementation of system protection schemes designed to enhance deliverability and to mitigate possible adverse power system conditions.

[73] WECC reports feasible transfers, not contracted transfers. This is done to eliminate double counting of resources. This treatment is different from the other NERC Assessment Areas.

[74] WECC Transmission Project Information Portal

[75] 2024 Common Case Transmission Assumptions (CCTA).

[76] WECC's Project Coordination, Path Rating and Progress Report Processes.

The power transfer capabilities of most major subregion transmission interconnections within WECC are limited by system stability constraints rather than by thermal limitations. These stability constraints are sensitive to system conditions and may often be increased significantly at nominal cost by applying Special Protection Systems (SPSs) or Remedial Action Schemes (RASs). In addition, transmission operators may install SPSs or RASs to address localized transmission overloads related to single- and multiple-contingency transmission outages. The future use of such relatively inexpensive schemes in lieu of costly transmission facility additions—and whether they will be permanent or temporary additions—will depend on as-yet-undetermined system conditions.

LSEs within WECC are rapidly expanding the use of smart meters and the associated interface equipment. The impacts of such facilities relative to power system reliability have not yet been quantified. Area entities are also taking steps to install and interface with equipment that may morph into full-fledged smart grid installations. The pace and extent of such changes is presently unknown. CAISO's website presents its smart grid initiatives, which are typical of activities within the Assessment Area.[77]

Long-Term Reliability Issues

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 more stringent 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 working with the natural gas industry to study potential impacts to reliability as the Western Interconnection becomes more reliant on natural-gas-fired generation.

LSEs historically experience two rapid increases in customer demand: in the early morning and late afternoon. These rapid changes were typically balanced by increased hydroelectric and thermal generation. However with greater generation contribution of intermittent resources, hydro and thermal units are required to follow larger daily demand fluctuations. The rate at which these decreases and increases occur, referred to as ramp rate, has the potential to exceed normally dispatched local area nonsolar plant ramping capability. Also of concern is the potential for localized overgeneration prior to the morning and late afternoon load ramps. Presently, concerns associated with these ramping issues are largely confined to California and, to some extent, reflect market issues that can be addressed through revised market mechanisms. Pertinent specific information relative to the California ramp rate issue is available on the California ISO website.[78]

A joint NERC/CAISO report[79] presents some potential operational impacts from higher levels of variable resources (e.g., ancillary services for ramp rates). While WECC studies to date have not identified significant issues relative to inertia and frequency response, at some as-yet-unidentified penetration level, inertia and frequency response may become an issue. WECC continues to work with entities within the Interconnection to identify and study reliability concerns associated with the increasing levels of variable generation, including behind-the-meter rooftop solar facilities.

[77] CAISO Smart Grid Roadmap.

[78] Flexible Resource Capability Information – Fast Facts.

[79] Joint NERC/CAISO Maintaining Bulk Power System Reliability While Integrating Variable Energy Resources report.

Appendix I: 2015LTRA Reference Case Data Summary

Summer 2016: Projected Demand, Resources, & Planning Reserve Margins

Assessment Area / Interconnection	Demand (MW) Total Internal	Demand (MW) Net Internal	Resources (MW) Anticipated	Resources (MW) Prospective	Reserve Margins (%) Anticipated	Reserve Margins (%) Prospective	Reference Margin Level
FRCC	47,304	44,164	54,446	54,683	23.28%	23.82%	15.00%
MISO	128,087	122,457	142,779	148,846	16.60%	21.55%	14.30%
MRO-Manitoba Hydro	3,388	3,388	4,259	4,351	25.70%	28.42%	12.00%
MRO-MAPP	5,154	5,056	7,061	7,061	39.67%	39.67%	15.00%
MRO-SaskPower	3,286	3,201	3,887	3,887	21.41%	21.41%	11.00%
NPCC-Maritimes	3,351	3,029	5,849	5,869	93.10%	93.75%	20.00%
NPCC-New England	26,835	25,913	32,378	32,571	24.95%	25.69%	15.91%
NPCC-New York	33,636	32,512	40,546	41,488	24.71%	27.61%	15.00%
NPCC-Ontario	22,849	22,273	26,548	26,548	19.20%	19.20%	17.72%
NPCC-Québec	20,833	20,833	31,844	31,844	52.85%	52.85%	11.60%
PJM	157,912	150,016	186,737	207,214	24.48%	38.13%	15.50%
SERC-E	43,370	42,392	50,821	50,831	19.88%	19.91%	15.00%
SERC-N	42,688	41,082	48,039	50,359	16.93%	22.58%	15.00%
SERC-SE	47,173	44,943	58,044	58,354	29.15%	29.84%	15.00%
SPP	48,547	47,860	61,024	60,729	27.51%	26.89%	13.60%
TRE-ERCOT	70,014	67,657	78,948	82,197	16.69%	21.49%	13.75%
WECC-CAMX	54,621	52,669	67,054	68,907	27.31%	30.83%	15.00%
WECC-NWPP-CA	19,770	19,770	30,510	29,264	54.32%	48.02%	10.90%
WECC-NWPP-US	50,001	48,716	66,351	66,230	36.20%	35.95%	15.40%
WECC-RMRG	12,613	12,055	16,232	16,020	34.65%	32.89%	13.90%
WECC-SRSG	23,773	23,297	33,068	33,108	41.94%	42.11%	16.10%
Eastern Interconnection	613,581	588,286	722,420	752,792	22.80%	27.96%	-
Québec Interconnection	20,833	20,833	31,844	31,844	52.85%	52.85%	11.60%
ERCOT Interconnection	70,014	67,657	78,948	82,197	16.69%	21.49%	13.75%
Western Interconnection	160,778	156,507	213,215	213,530	36.23%	36.43%	-
TOTAL-NERC	**865,206**	**833,283**	**1,046,427**	**1,080,363**	**25.58%**	**29.65%**	**-**

Winter 2016-2017: Projected Demand, Resources, & Planning Reserve Margins

Assessment Area / Interconnection	Demand (MW) Total Internal	Demand (MW) Net Internal	Resources (MW) Anticipated	Resources (MW) Prospective	Reserve Margins (%) Anticipated	Reserve Margins (%) Prospective	Reference Margin Level
FRCC	46,019	43,015	59,141	59,594	37.49%	38.54%	15.00%
MISO	105,407	100,880	143,847	149,914	42.59%	48.61%	14.30%
MRO-Manitoba Hydro	4,679	4,679	5,343	5,432	14.21%	16.09%	12.00%
MRO-MAPP	5,732	5,347	7,990	7,990	49.45%	49.45%	15.00%
MRO-SaskPower	3,644	3,559	4,309	4,309	21.08%	21.08%	11.00%
NPCC-Maritimes	5,400	5,162	6,453	6,472	25.01%	25.39%	20.00%
NPCC-New England	21,268	20,361	34,207	34,411	68.00%	69.01%	15.91%
NPCC-New York	24,524	23,639	41,743	42,702	76.58%	80.64%	15.00%
NPCC-Ontario	21,961	21,248	28,365	28,365	33.50%	33.50%	18.40%
NPCC-Québec	38,650	36,453	42,179	42,179	15.71%	15.71%	11.60%
PJM	133,442	132,917	186,995	207,472	40.69%	56.09%	15.50%
SERC-E	42,455	41,652	53,759	53,759	29.07%	29.07%	15.00%
SERC-N	41,366	39,896	51,374	53,776	28.77%	34.79%	15.00%
SERC-SE	44,659	42,552	57,019	57,381	34.00%	34.85%	15.00%
SPP	35,420	35,044	60,167	60,343	71.69%	72.19%	13.60%
TRE-ERCOT	54,579	51,935	81,200	90,877	56.35%	74.98%	13.75%
WECC-CAMX	39,121	38,213	57,730	59,578	51.07%	55.91%	13.50%
WECC-NWPP-CA	23,777	23,777	30,533	29,613	28.41%	24.54%	11.60%
WECC-NWPP-US	47,887	47,607	65,311	65,395	37.19%	37.37%	16.60%
WECC-RMRG	10,495	10,162	16,017	15,805	57.62%	55.53%	11.90%
WECC-SRSG	15,388	15,017	32,456	32,498	116.13%	116.41%	12.30%
Eastern Interconnection	535,976	519,949	740,713	771,921	42.46%	48.46%	-
Québec Interconnection	38,650	36,453	42,179	42,179	15.71%	15.71%	11.60%
ERCOT Interconnection	54,579	51,935	81,200	90,877	56.35%	74.98%	13.75%
Western Interconnection	136,668	134,776	202,046	202,889	49.91%	50.54%	-
TOTAL-NERC	**765,873**	**743,114**	**1,066,138**	**1,107,866**	**43.47%**	**49.08%**	**-**

Summer 2020: Projected Demand, Resources, & Planning Reserve Margins

Assessment Area / Interconnection	Demand (MW) Total Internal	Demand (MW) Net Internal	Resources (MW) Anticipated	Resources (MW) Prospective	Reserve Margins (%) Anticipated	Reserve Margins (%) Prospective	Reference Margin Level
FRCC	50,133	46,791	57,730	58,276	23.38%	24.54%	15.00%
MISO	132,694	127,063	145,918	179,105	14.84%	40.96%	14.30%
MRO-Manitoba Hydro	3,430	3,430	5,035	4,721	46.78%	37.64%	12.00%
MRO-MAPP	5,838	5,738	7,113	7,113	23.96%	23.96%	15.00%
MRO-SaskPower	3,618	3,533	4,267	4,367	20.75%	23.58%	11.00%
NPCC-Maritimes	3,408	3,087	5,904	5,924	91.28%	91.92%	20.00%
NPCC-New England	27,400	26,753	31,150	35,790	16.44%	33.78%	14.30%

NPCC-New York	34,309	33,185	41,347	43,650	24.60%	31.54%	15.00%
NPCC-Ontario	22,522	21,846	27,748	27,322	27.02%	25.07%	20.00%
NPCC-Québec	21,298	21,298	33,348	33,348	56.58%	56.58%	12.80%
PJM	164,443	156,221	195,122	226,192	24.90%	44.79%	15.70%
SERC-E	45,831	44,835	52,816	52,826	17.80%	17.82%	15.00%
SERC-N	44,036	42,393	46,942	49,262	10.73%	16.20%	15.00%
SERC-SE	49,768	47,478	61,399	61,709	29.32%	29.97%	15.00%
SPP	50,850	49,862	60,349	60,057	21.03%	20.45%	13.60%
TRE-ERCOT	73,784	71,427	83,320	117,830	16.65%	64.97%	13.75%
WECC-CAMX	55,749	53,637	70,248	72,296	30.97%	34.79%	15.00%
WECC-NWPP-CA	22,602	22,602	31,078	32,377	37.50%	43.25%	10.90%
WECC-NWPP-US	51,803	50,517	66,986	66,155	32.60%	30.96%	15.40%
WECC-RMRG	13,424	12,830	17,156	16,408	33.72%	27.89%	13.90%
WECC-SRSG	25,444	25,058	33,412	32,554	33.34%	29.92%	16.10%
Eastern Interconnection	638,280	612,213	742,839	816,314	21.34%	33.34%	-
Québec Interconnection	21,298	21,298	33,348	33,348	56.58%	56.58%	12.80%
ERCOT Interconnection	73,784	71,427	83,320	117,830	16.65%	64.97%	13.75%
Western Interconnection	169,022	164,644	218,880	219,790	32.94%	33.49%	-
TOTAL-NERC	**902,384**	**869,582**	**1,078,388**	**1,187,283**	**24.01%**	**36.53%**	**-**

Winter 2020-2021: Projected Demand, Resources, & Planning Reserve Margins

	Demand (MW)		Resources (MW)		Reserve Margins (%)		Reference Margin
Assessment Area / Interconnection	Total Internal	Net Internal	Anticipated	Prospective	Anticipated	Prospective	Level
FRCC	47,794	44,640	62,207	62,807	39.35%	40.70%	15.00%
MISO	109,587	105,060	146,983	180,171	39.90%	71.49%	14.30%
MRO-Manitoba Hydro	4,724	4,724	6,312	5,995	33.62%	26.90%	12.00%
MRO-MAPP	6,478	6,073	7,959	7,959	31.07%	31.07%	15.00%
MRO-SaskPower	4,012	3,927	4,831	4,931	23.01%	25.56%	11.00%
NPCC-Maritimes	5,401	5,159	6,698	6,717	29.83%	30.21%	20.00%
NPCC-New England	20,951	20,304	33,441	38,554	64.70%	89.89%	15.91%
NPCC-New York	24,757	23,872	42,544	44,987	78.22%	88.45%	15.00%
NPCC-Ontario	21,242	20,529	30,490	26,982	48.52%	31.43%	18.40%
NPCC-Québec	39,792	37,495	43,905	43,905	17.09%	17.09%	11.60%
PJM	138,018	136,586	195,084	226,153	42.83%	65.58%	15.50%
SERC-E	44,650	43,847	55,726	55,726	27.09%	27.09%	15.00%
SERC-N	42,385	40,915	50,357	52,759	23.08%	28.95%	15.00%
SERC-SE	46,627	44,520	57,758	58,120	29.74%	30.55%	15.00%
SPP	38,861	38,498	62,622	62,631	62.66%	62.69%	13.60%
TRE-ERCOT	57,962	55,318	85,450	120,473	54.47%	117.78%	13.75%
WECC-CAMX	39,754	38,685	57,732	59,780	49.24%	54.53%	13.50%
WECC-NWPP-CA	26,830	26,830	32,813	34,109	22.30%	27.13%	11.60%
WECC-NWPP-US	49,234	48,952	63,104	62,243	28.91%	27.15%	16.60%
WECC-RMRG	11,161	10,826	16,539	15,791	52.77%	45.86%	11.90%
WECC-SRSG	16,622	16,296	32,069	31,221	96.79%	91.59%	12.30%
Eastern Interconnection	555,487	538,653	763,011	834,492	41.65%	54.92%	-
Québec Interconnection	39,792	37,495	43,905	43,905	17.09%	17.09%	11.60%
ERCOT Interconnection	57,962	55,318	85,450	120,473	54.47%	117.78%	13.75%
Western Interconnection	143,601	141,589	202,256	203,144	42.85%	43.47%	-
TOTAL-NERC	**796,842**	**773,055**	**1,094,623**	**1,202,013**	**41.60%**	**55.49%**	**-**

Summer 2025: Projected Demand, Resources, & Planning Reserve Margins

	Demand (MW)		Resources (MW)		Reserve Margins (%)		Reference Margin
Assessment Area / Interconnection	Total Internal	Net Internal	Anticipated	Prospective	Anticipated	Prospective	Level
FRCC	52,837	49,388	60,220	61,511	21.93%	24.55%	15.00%
MISO	137,727	132,096	146,924	177,060	11.23%	34.04%	14.30%
MRO-Manitoba Hydro	3,494	3,494	6,073	5,659	73.80%	61.97%	12.00%
MRO-MAPP	6,331	6,220	7,192	7,192	15.61%	15.61%	15.00%
MRO-SaskPower	3,855	3,770	4,260	4,519	13.01%	19.88%	11.00%
NPCC-Maritimes	3,335	3,014	5,904	5,924	95.89%	96.54%	20.00%
NPCC-New England	28,019	27,372	31,179	35,820	13.91%	30.86%	14.30%
NPCC-New York	35,219	34,095	41,347	43,650	21.27%	28.03%	15.00%
NPCC-Ontario	23,135	21,569	27,827	24,136	29.01%	11.90%	20.00%
NPCC-Québec	22,013	22,013	33,693	33,693	53.06%	53.06%	12.80%
PJM	171,580	163,001	196,692	227,762	20.67%	39.73%	15.70%
SERC-E	49,279	48,268	52,874	52,884	9.54%	9.56%	15.00%
SERC-N	46,029	44,380	46,942	49,262	5.77%	11.00%	15.00%
SERC-SE	52,808	50,502	61,855	62,165	22.48%	23.09%	15.00%
SPP	53,584	52,382	58,860	58,323	12.37%	11.34%	13.60%
TRE-ERCOT	78,384	76,027	83,565	118,075	9.91%	55.31%	13.75%
WECC-CAMX	56,774	54,412	71,943	73,196	32.22%	34.52%	15.00%
WECC-NWPP-CA	24,525	24,525	30,992	32,292	26.37%	31.67%	10.90%
WECC-NWPP-US	53,796	52,509	62,115	61,000	18.29%	16.17%	15.40%
WECC-RMRG	14,800	14,194	17,344	16,596	22.19%	16.92%	13.90%

WECC-SRSG	27,764	27,377	33,391	32,401	21.97%	18.35%	16.10%
Eastern Interconnection	667,231	639,551	748,148	815,868	16.98%	27.57%	-
Québec Interconnection	22,013	22,013	33,693	33,693	53.06%	53.06%	12.80%
ERCOT Interconnection	78,384	76,027	83,565	118,075	9.91%	55.31%	13.75%
Western Interconnection	177,659	173,017	215,786	215,485	24.72%	24.55%	-
TOTAL-NERC	**945,287**	**910,607**	**1,081,193**	**1,183,121**	**18.73%**	**29.93%**	**-**

Winter 2025-2026: Projected Demand, Resources, & Planning Reserve Margins

	Demand (MW)		Resources (MW)		Reserve Margins (%)		Reference Margin
Assessment Area / Interconnection	Total Internal	Net Internal	Anticipated	Prospective	Anticipated	Prospective	Level
FRCC	49,555	46,301	64,855	66,287	40.07%	43.17%	15.00%
MISO	113,151	108,624	147,989	178,126	36.24%	63.98%	14.30%
MRO-Manitoba Hydro	4,871	4,871	6,420	6,003	31.81%	23.24%	12.00%
MRO-MAPP	7,008	6,578	8,018	8,018	21.89%	21.89%	15.00%
MRO-SaskPower	4,274	4,189	4,923	5,198	17.51%	24.08%	11.00%
NPCC-Maritimes	5,292	5,051	6,698	6,717	32.60%	32.99%	20.00%
NPCC-New England	20,789	20,142	33,441	38,554	66.03%	91.41%	15.91%
NPCC-New York	25,020	24,135	42,544	44,987	76.27%	86.40%	15.00%
NPCC-Ontario	21,623	20,110	31,514	27,827	56.71%	38.38%	18.40%
NPCC-Québec	41,149	38,852	44,010	44,010	13.28%	13.28%	11.60%
PJM	143,610	142,178	196,654	227,723	38.32%	60.17%	15.50%
SERC-E	47,764	46,961	55,535	55,535	18.26%	18.26%	15.00%
SERC-N	44,322	42,852	50,253	52,655	17.27%	22.88%	15.00%
SERC-SE	49,450	47,343	63,740	64,102	34.64%	35.40%	15.00%
SPP	40,957	40,604	66,769	66,333	64.44%	63.37%	13.60%
TRE-ERCOT	62,152	59,508	85,450	120,473	43.59%	102.45%	13.75%
WECC-CAMX	40,482	39,163	59,107	60,360	50.93%	54.13%	13.50%
WECC-NWPP-CA	28,996	28,996	32,442	33,738	11.88%	16.35%	11.60%
WECC-NWPP-US	50,902	50,620	59,726	58,575	17.99%	15.71%	16.60%
WECC-RMRG	12,194	11,883	16,394	15,646	37.96%	31.67%	11.90%
WECC-SRSG	17,897	17,570	32,085	31,157	82.61%	77.33%	12.30%
Eastern Interconnection	577,687	559,939	779,352	848,066	39.19%	51.46%	-
Québec Interconnection	41,149	38,852	44,010	44,010	13.28%	13.28%	11.60%
ERCOT Interconnection	62,152	59,508	85,450	120,473	43.59%	102.45%	13.75%
Western Interconnection	150,471	148,232	199,754	199,476	34.76%	34.57%	-
TOTAL-NERC	**831,459**	**806,531**	**1,108,566**	**1,212,025**	**37.45%**	**50.28%**	**-**

Summer - Projected Total Internal Demand

Assessment Area / Interconnection	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	10-Year CAGR
FRCC	47,304	48,097	48,784	49,498	50,133	50,756	51,378	52,074	52,837	52,837	1.24%
MISO	128,087	129,780	130,670	131,814	132,694	133,463	134,328	135,255	136,036	137,727	0.81%
MRO-Manitoba Hydro	3,388	3,443	3,355	3,390	3,430	3,467	3,491	3,519	3,549	3,494	0.34%
MRO-MAPP	5,154	5,446	5,549	5,743	5,838	5,925	6,011	6,097	6,210	6,331	2.31%
MRO-SaskPower	3,286	3,360	3,415	3,543	3,618	3,662	3,720	3,761	3,802	3,855	1.79%
NPCC-Maritimes	3,351	3,399	3,418	3,414	3,408	3,399	3,385	3,373	3,343	3,335	-0.05%
NPCC-New England	26,835	26,977	27,178	27,310	27,400	27,487	27,599	27,733	27,876	28,019	0.48%
NPCC-New York	33,636	33,779	33,882	34,119	34,309	34,469	34,639	34,823	35,010	35,219	0.51%
NPCC-Ontario	22,849	22,819	22,790	22,669	22,522	22,479	22,760	22,976	22,920	23,135	0.14%
NPCC-Québec	20,833	20,954	21,042	21,171	21,298	21,411	21,556	21,724	21,886	22,013	0.61%
PJM	157,912	159,808	161,128	162,618	164,443	165,764	166,902	168,399	169,706	171,580	0.93%
SERC-E	43,370	44,006	44,553	45,191	45,831	46,503	47,176	47,868	48,576	49,279	1.43%
SERC-N	42,688	43,226	43,617	43,746	44,036	44,394	44,792	45,201	45,604	46,029	0.84%
SERC-SE	47,173	48,198	48,689	49,221	49,768	50,283	50,849	51,421	52,114	52,808	1.26%
SPP	48,547	49,527	50,074	50,540	50,850	51,312	51,987	52,507	53,044	53,584	1.10%
TRE-ERCOT	70,014	70,871	71,806	72,859	73,784	74,710	75,631	76,550	77,471	78,384	1.26%
WECC-CAMX	54,621	54,895	55,154	55,435	55,749	56,035	56,321	56,511	56,679	56,774	0.43%
WECC-NWPP-CA	19,770	20,591	21,309	22,096	22,602	23,050	23,412	23,780	24,143	24,525	2.42%
WECC-NWPP-US	50,001	50,417	50,941	51,387	51,803	52,172	52,579	52,956	53,367	53,796	0.82%
WECC-RMRG	12,613	12,738	12,994	13,253	13,424	13,706	14,000	14,329	14,532	14,800	1.79%
WECC-SRSG	23,773	23,932	24,407	24,894	25,444	25,902	26,120	26,595	27,149	27,764	1.74%
Eastern Interconnection	613,581	621,865	627,101	632,816	638,280	643,362	649,017	655,007	660,626	667,231	0.94%
Québec Interconnection	20,833	20,954	21,042	21,171	21,298	21,411	21,556	21,724	21,886	22,013	0.61%
ERCOT Interconnection	70,014	70,871	71,806	72,859	73,784	74,710	75,631	76,550	77,471	78,384	1.26%
Western Interconnection	160,778	162,573	164,805	167,065	169,022	170,865	172,432	174,171	175,870	177,659	1.12%
TOTAL-NERC	**865,206**	**876,264**	**884,755**	**893,910**	**902,384**	**910,349**	**918,637**	**927,453**	**935,853**	**945,287**	**0.99%**

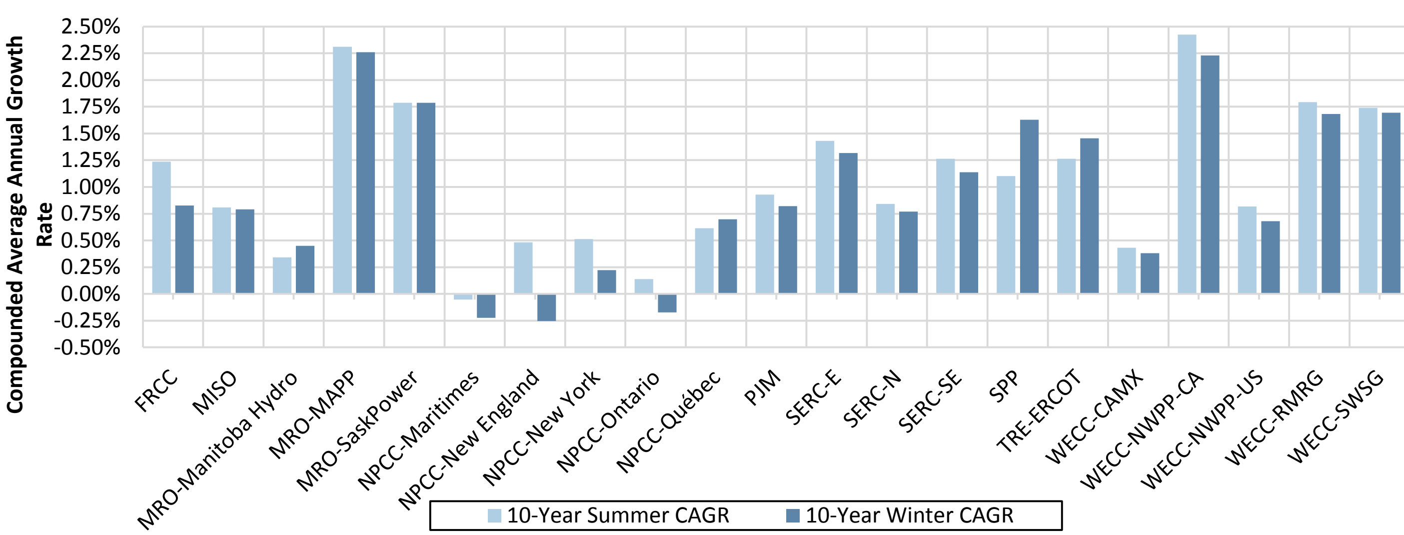
Winter - Projected Total Internal Demand

Assessment Area / Interconnection	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	10-Year CAGR
FRCC	46,019	46,412	46,912	47,381	47,794	48,199	48,614	49,089	49,555	49,555	0.83%
MISO	105,407	105,910	108,135	109,007	109,587	110,305	111,042	111,942	112,618	113,151	0.79%
MRO-Manitoba Hydro	4,679	4,746	4,656	4,694	4,724	4,753	4,783	4,818	4,857	4,871	0.45%

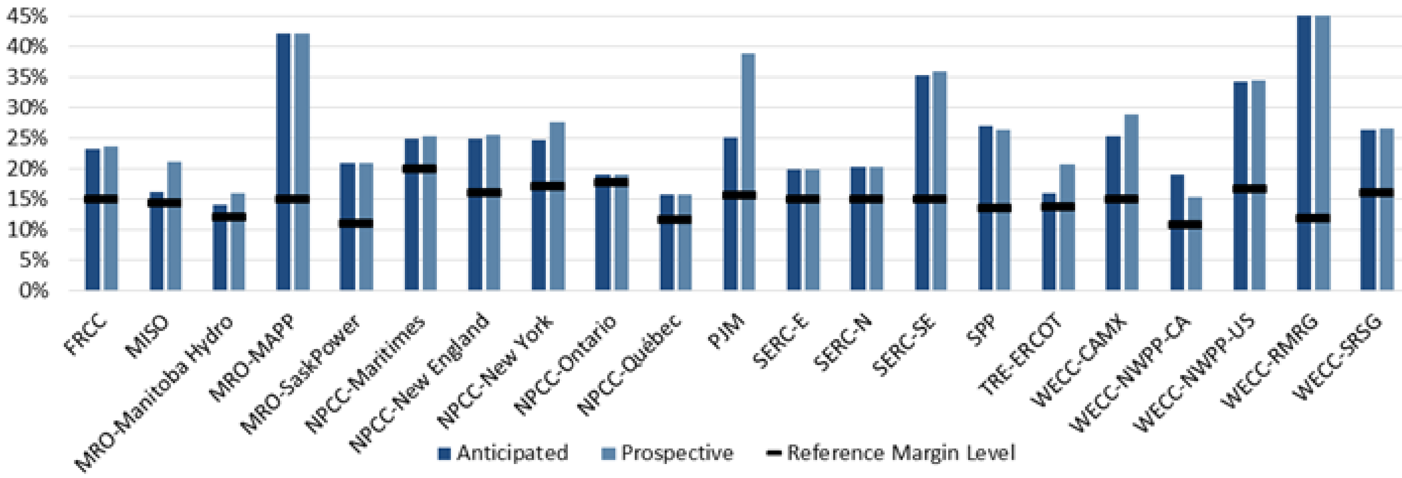
MRO-MAPP	5,732	6,048	6,180	6,375	6,478	6,582	6,685	6,811	6,911	7,008	2.26%
MRO-SaskPower	3,644	3,725	3,786	3,928	4,012	4,060	4,125	4,170	4,216	4,274	1.79%
NPCC-Maritimes	5,400	5,426	5,417	5,418	5,401	5,401	5,373	5,346	5,294	5,292	-0.22%
NPCC-New England	21,268	21,273	21,109	21,028	20,951	20,890	20,847	20,821	20,805	20,789	-0.25%
NPCC-New York	24,524	24,488	24,463	24,603	24,757	24,796	24,843	24,895	24,951	25,020	0.22%
NPCC-Ontario	21,961	21,542	21,423	21,307	21,242	21,090	21,251	21,381	21,552	21,623	-0.17%
NPCC-Québec	38,650	38,855	39,175	39,469	39,792	40,114	40,440	40,724	40,965	41,149	0.70%
PJM	133,442	134,770	135,813	136,788	138,018	139,319	140,479	141,516	142,561	143,610	0.82%
SERC-E	42,455	43,083	43,558	44,007	44,650	45,214	45,858	46,484	46,981	47,764	1.32%
SERC-N	41,366	41,710	41,826	42,015	42,385	42,831	43,206	43,497	43,898	44,322	0.77%
SERC-SE	44,659	45,101	45,636	46,119	46,627	47,111	47,646	48,213	48,800	49,450	1.14%
SPP	35,420	38,155	38,257	38,392	38,861	39,207	39,748	40,093	40,541	40,957	1.63%
TRE-ERCOT	54,579	55,441	56,281	57,116	57,962	58,804	59,643	60,480	61,321	62,152	1.45%
WECC-CAMX	39,121	39,178	39,344	39,525	39,754	39,983	40,183	40,314	40,402	40,482	0.38%
WECC-NWPP-CA	23,777	24,568	25,374	26,263	26,830	27,326	27,733	28,147	28,569	28,996	2.23%
WECC-NWPP-US	47,887	48,420	48,758	49,070	49,234	49,572	50,019	50,293	50,607	50,902	0.68%
WECC-RMRG	10,495	10,683	10,753	10,952	11,161	11,323	11,577	11,804	12,048	12,194	1.68%
WECC-SRSG	15,388	15,716	16,074	16,375	16,622	16,674	17,019	17,568	17,970	17,897	1.69%
Eastern Interconnection	535,976	542,388	547,171	551,062	555,487	559,757	564,499	569,075	573,540	577,687	0.84%
Québec Interconnection	38,650	38,855	39,175	39,469	39,792	40,114	40,440	40,724	40,965	41,149	0.70%
ERCOT Interconnection	54,579	55,441	56,281	57,116	57,962	58,804	59,643	60,480	61,321	62,152	1.45%
Western Interconnection	136,668	138,565	140,303	142,185	143,601	144,878	146,531	148,126	149,596	150,471	1.07%
TOTAL-NERC	**765,873**	**775,249**	**782,929**	**789,832**	**796,842**	**803,554**	**811,112**	**818,405**	**825,422**	**831,459**	**0.92%**

Load Factor

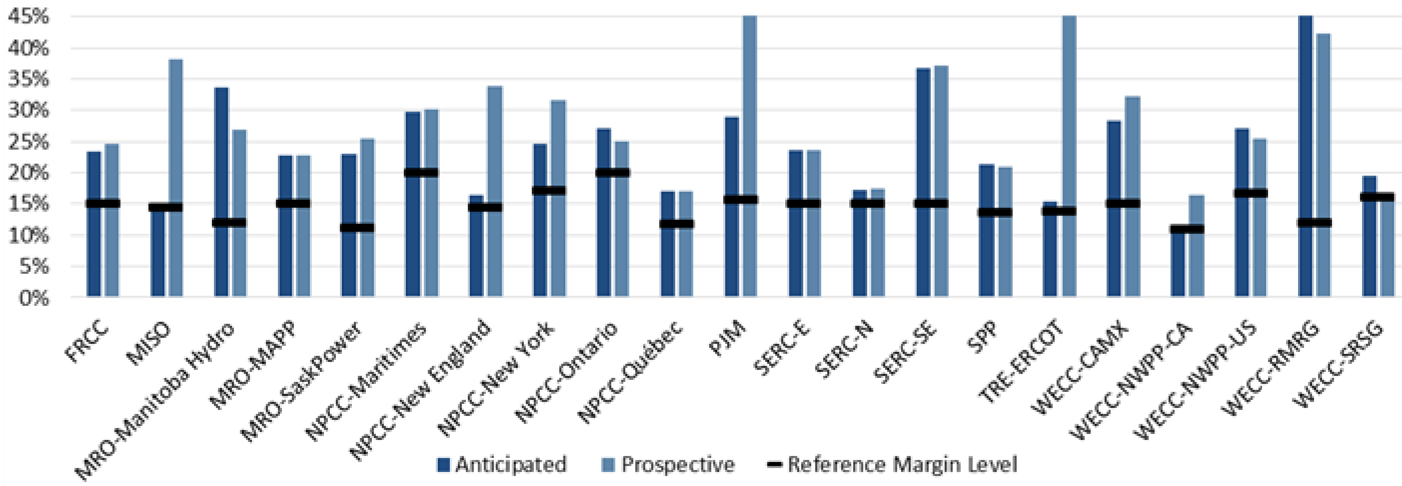
Assessment Area / Interconnection	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
FRCC	56.28%	55.97%	55.83%	55.70%	55.65%	55.38%	55.23%	54.97%	54.84%	54.84%
MISO	63.86%	63.70%	64.06%	64.04%	63.95%	64.07%	64.06%	64.08%	63.91%	63.77%
MRO-Manitoba Hydro	86.74%	86.58%	89.33%	89.05%	88.43%	88.12%	88.18%	88.23%	88.30%	90.02%
MRO-MAPP	78.24%	65.03%	66.19%	66.57%	67.11%	67.32%	67.49%	67.64%	67.76%	67.51%
MRO-SaskPower	84.38%	84.11%	84.58%	85.15%	85.09%	84.89%	85.04%	84.97%	85.13%	85.10%
NPCC-Maritimes	92.58%	92.39%	92.80%	93.34%	93.66%	93.99%	94.50%	95.08%	96.05%	96.35%
NPCC-New England	59.38%	59.71%	59.90%	60.16%	60.49%	60.83%	61.15%	61.44%	61.70%	61.97%
NPCC-New York	54.29%	53.73%	53.33%	53.13%	53.10%	52.74%	52.51%	52.29%	52.17%	51.88%
NPCC-Ontario	69.82%	68.52%	67.23%	67.15%	67.49%	67.41%	66.47%	66.62%	67.21%	67.07%
NPCC-Québec	101.92%	101.76%	101.89%	102.05%	102.46%	102.17%	102.19%	102.14%	102.46%	101.97%
PJM	59.89%	59.79%	59.93%	59.84%	59.89%	59.83%	60.02%	60.03%	60.23%	59.91%
SERC-E	58.78%	58.57%	58.52%	58.39%	58.33%	58.14%	58.01%	57.88%	57.71%	57.52%
SERC-N	58.77%	58.47%	58.47%	58.59%	58.61%	58.45%	58.36%	58.31%	58.36%	58.23%
SERC-SE	59.41%	59.09%	59.06%	59.06%	59.07%	59.07%	59.08%	59.15%	59.14%	59.08%
SPP	57.24%	57.27%	57.29%	57.64%	57.94%	58.00%	58.44%	58.65%	58.67%	57.53%
TRE-ERCOT	56.97%	57.33%	57.60%	57.77%	58.02%	58.27%	58.51%	58.75%	58.98%	59.20%
WECC-CAMX	57.68%	57.45%	57.31%	57.26%	57.24%	57.26%	57.30%	57.41%	57.45%	57.56%
WECC-NWPP-CA	87.53%	63.92%	62.86%	61.67%	61.27%	60.95%	60.92%	60.85%	60.80%	60.65%
WECC-NWPP-US	69.10%	69.16%	69.25%	69.22%	69.31%	69.25%	69.25%	69.31%	69.48%	69.38%
WECC-RMRG	60.01%	60.18%	59.84%	59.38%	59.60%	59.54%	59.15%	58.88%	59.06%	59.12%
WECC-SRSG	54.61%	55.00%	54.88%	54.74%	54.42%	54.24%	54.61%	54.41%	54.07%	53.57%



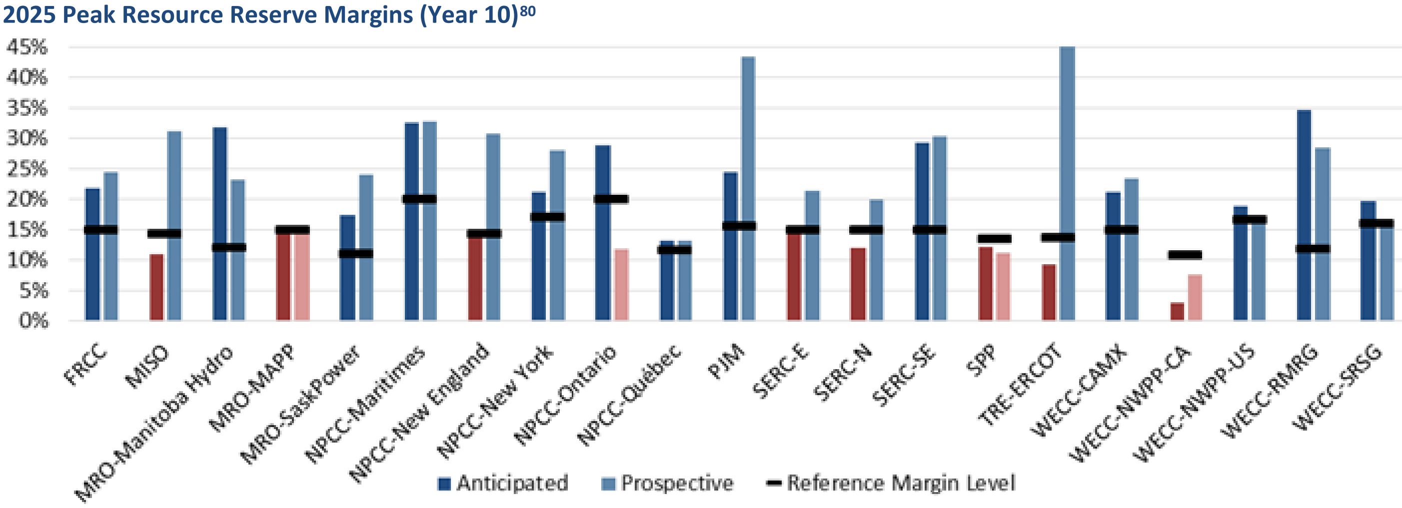
2016 Peak Resource Reserve Margins (Year 1)



2020 Peak Resource Reserve Margins (Year 5)



2025 Peak Resource Reserve Margins (Year 10)[80]



[80] NERC's Perspective Reserve Margin includes unconfirmed retirements, which include unit retirements without a formalized announced plan or without an approved deactivation request. Due to this Reserve Margin accounting method, some areas have lower prospective than anticipated Reserve Margins.

Appendix II: Reliability Assessment Glossary

Term	Definition
Ancillary Services	Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Service Provider's transmission system in accordance with good utility practice (Source: NERC Glossary of Terms)
Anticipated Resources	Includes Existing-Certain Capacity, Net Firm Transfers (Imports – Exports), and Tier 1 Capacity Additions.
Anticipated Reserve Margin	Anticipated Resources minus Net Internal Demand, divided by Net Internal Demand, shown as a percentile.
Assessment Area	Based on existing ISO/RTO footprints; otherwise, based on individual Planning Coordinator or group of Planning Coordinators. NERC collects data for seasonal and long-term assessments based on these footprints that align with how the system is planned and operated.
Balancing Authority	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time. (Source: NERC Glossary of Terms)
Bulk Electric System	See NERC Glossary of Terms
Bulk-Power System	(A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy. (Source: NERC Glossary of Terms)
Capacity Transfers (Transactions)	There are three types of capacity transfers (transactions): Firm: "Firm" transfers that require the execution of a contract that is in effect during the projected peak. The net of all Firm transfers (imports minus exports) are applied towards Anticipated Resources. Modeled: transfers that are applicable for Assessment Areas that model potential feasible transfers (imports/exports). While these transfers do not have Firm contracts, modeling of the existing transmission, including transfer capability, has been executed to verify these transfers can occur during the peak season. The net of all Modeled transfers (imports minus exports) are applied towards Anticipated Resources. Expected: transfers without the execution of a Firm contract, but with a high expectation that a Firm contract will be executed in the future and will be in effect during the projected peak. The net of all Modeled transfers (imports minus exports) are applied towards Prospective Resources.
Conservation (Energy Conservation)	A reduction in energy consumption that corresponds with a reduction in service demand. Service demand can include buildings-sector end uses such as lighting, refrigeration, and heating; industrial processes; or vehicle transportation. Unlike energy efficiency, which is typically a technological measure, conservation is better associated with behavior. Examples of conservation include adjusting the thermostat to reduce the output of a heating unit, using occupancy sensors that turn off lights or appliances, and car-pooling. (Source: DOE-EIA)
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 pre-specified high rate or price for a limited number of days or hours. Critical Peak Pricing (CPP) with Direct Load Control combines Direct Load Control with a pre-specified high price for use during designated critical peak periods triggered by system contingencies or high wholesale market prices. Subset of Controllable and Dispatchable Demand Response.
	Dispatchable and Controllable Demand-Side Management that combines direct remote control with a pre-specified high price for use during designated critical peak periods, triggered by system contingencies or high wholesale market prices.
Curtailment	A reduction in the scheduled capacity or energy delivery of an Interchange Transaction. (Source: NERC Glossary of Terms)
Demand	1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer.
Demand Response	Changes in electric use by Demand-Side resources from normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices, or when required to maintain system reliability. Demand Response can be counted in resource adequacy studies either as a load-modifier, or as a resource. Controllable and Dispatchable Demand Response requires the System Operator to have physical command of the resources (Controllable) or be able to activate it based on instruction from a control center. Controllable and Dispatchable Demand Response includes four categories: Critical Peak Pricing (CPP) with Load Control; Direct Control Load Management (DCLM); Load as a Capacity Resource (LCR); and Interruptible Load (IL).
Demand-Side Management	All activities or programs undertaken by any applicable entity to achieve a reduction in Demand. (Source: NERC Glossary of Terms)
Derate	The amount of capacity that is expected to be unavailable during the seasonal peak.

Designated Network Resource	Any designated generating resource owned, purchased or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a Commission-approved reserve sharing program.
Distributed Energy Resources (DERs)	Distributed energy resources (DERs) are smaller power sources that can be aggregated to provide power necessary to meet regular demand. As the electricity grid continues to modernize, DERs such as storage and advanced renewable technologies can help facilitate the transition to a smarter grid. (Source: EPRI)
Distributed Generation	See *Distributed Energy Resources*
Energy Efficiency	Refers to programs that are aimed at reducing the energy used by specific end-use devices and systems, typically without affecting the services provided. These programs reduce overall electricity consumption (reported in megawatt-hours), often without explicit consideration for the timing of program-induced savings. Such savings are generally achieved by substituting technologically more advanced equipment to produce the same level of end-use services (e.g. lighting, heating, motor drive) with less electricity. Examples include high-efficiency appliances, efficient lighting programs, high-efficiency heating, ventilating and air conditioning (HVAC) systems or control modifications, efficient building design, advanced electric motor drives, and heat recovery systems. Results in permanent changes to electricity use by replacement of end-use devices with more efficient end-use devices or more effective operation of existing devices. Generally, it results in reduced consumption across all hours rather than event-driven targeted load reductions. (Source: DOE-EIA)
Estimated Diversity	The electric utility system's load is made up of many individual loads that make demands on the system, with peaks occurring at different times throughout the day. The individual loads within the customer classes follow similar usage patterns, but these classes of service place different demands upon the facilities and the system grid. The service requirements of one electrical system can differ from another by time-of-day usage, facility usage, and/or demands placed upon the system grid.
Existing-Certain Capacity	Included in this category are existing generator units (expressed in MW), or portions of existing generator units, that are physically located within the Assessment Area that meet at least one of the following requirements when examining the projected peak for the summer and winter of each year: (1) unit must have a Firm capability (defined as the commitment of generation service to a customer under a contractual agreement to which the parties to the service anticipate no planned interruption (applies to generation and transmission), a Power Purchase Agreement (PPA), and Firm transmission; (2) unit must be classified as a Designated Network Resource; (3) where energy-only markets exist, unit must be a designated market resource eligible to bid into the market.
Disturbance	An unplanned event that produces an abnormal system condition; any perturbation to the electric system, or the unexpected change in ACE that is caused by the sudden failure of generation or interruption of load. (Source: NERC Glossary of Terms)
Existing-Other Capacity	Included in this category are existing generator units, or portions of existing generator units, that are physically located within the Assessment Area that do not qualify as Existing-Certain when examining the projected peak for the summer and winter of each year. Accordingly, these are the units, or portions of units, may not be available to serve peak demand for each season/year.
Energy-Only	Generating resources that are designated as energy-only resources or have elected to be classified as energy-only resources and may include generating capacity that can be delivered within the area but may be recallable to another area. Designated energy –only resources do not have capacity rights.
Firm (Transmission Service)	The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption. (Source: NERC Glossary of Terms)
Forced Outage	The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons. Also, the condition in which the equipment is unavailable due to unanticipated failure. (Source: NERC Glossary of Terms)
Frequency Regulation	The ability of a Balancing Authority to help the Interconnection maintain Scheduled Frequency. This assistance can include both turbine governor response and Automatic Generation Control. (NERC Glossary of Terms)
Frequency Response	Equipment: The ability of a system or elements of the system to react or respond to a change in system frequency. System: The sum of the change in demand, plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 Hertz (MW/0.1 Hz). (Source: NERC Glossary of Terms)
Expected (Provisional) Capacity Transfers	Future transfers that do not currently have a Firm contract, but there is a reasonable expectation that a Firm contract will be signed. These transfers are included in the Prospective Resources.
Generator Operator	The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services. (NERC Glossary of Terms)
Generator Owner	Entity that owns and maintains generating units. (NERC Glossary of Terms)
Independent Power Producer	Any entity that owns or operates an electricity generating facility that is not included in an electric utility’s rate base. This term includes, but is not limited to, cogenerators and small power producers and all other nonutility electricity producers, such as exempt wholesale generators, who sell electricity. (NERC Glossary of Terms)
Interconnection	When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Québec. (NERC Glossary of Terms)
Interruptible Load or	Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment. (NERC Glossary of Terms)

Interruptible Demand	
Load	An end-use device or customer that receives power from the electric system. (NERC Glossary of Terms)
Load-Serving Entity	Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers. (NERC Glossary of Terms)
Net Energy for Load (NEL)	The amount of energy required by the reported utility or group of utilities' retail customers in the system's service area plus the amount of energy supplied to full and partial requirements utilities (wholesale requirements customers) plus the amount of energy losses incurred in the transmission and distribution. (Source: FERC-714)
	Net Balancing Authority Area generation, plus energy received from other Balancing Authority Areas, less energy delivered to Balancing Authority Areas through interchange. It includes Balancing Authority Area losses but excludes energy required for storage at energy storage facilities. (NERC Glossary of Terms)
Net Internal Demand	Total Internal Demand reduced by dispatchable and controllable Demand Response. (NERC Glossary of Terms)
Non-Firm Transmission Service	Transmission service that is reserved on an as-available basis and is subject to curtailment or interruption. (NERC Glossary of Terms)
Non-spinning Reserves	The portion of Operating Reserve consisting of (1) generating reserve not connected to the system but capable of serving demand within a specified time; or (2) interruptible load that can be removed from the system in a specified time.(NERC Glossary of Terms)
Off-Peak	Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of lower electrical demand. (NERC Glossary of Terms)
On-Peak	Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of higher electrical demand. (NERC Glossary of Terms)
Open Access Same Time Information Service	An electronic posting system that the Transmission Service Provider maintains for transmission access data and that allows all transmission customers to view the data simultaneously. (NERC Glossary of Terms)
Open Access Transmission Tariff	Electronic transmission tariff accepted by the U.S. Federal Energy Regulatory Commission requiring the Transmission Service Provider to furnish to all shippers with non-discriminating service comparable to that provided by Transmission Owners to themselves. (NERC Glossary of Terms)
Operating Reserves	The capability above Firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve.
Planning Coordinator (Planning Authority)	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems. (NERC Glossary of Terms)
Planning Reserve Margins	Anticipated Reserve Margin: Anticipated Resources, less Net Internal Demand, divided by Net Internal Demand. Prospective Reserve Margin: Prospective Resources, less Net Internal Demand, divided by Net Internal Demand. Adjusted-Potential Reserve Margin: Adjusted-Potential Resources, less Net Internal Demand, divided by Net Internal Demand.
Peak Demand	The highest hourly integrated Net Energy For Load (or highest instantaneous demand) within a Balancing Authority Area occurring within a given period (e.g., day, month, season, or year). (NERC Glossary of Terms)
Power Purchase Agreement	Guarantees a market for power produced by an independent power producer and the price at which it is sold to a purchaser. Such an agreement imposes legal obligations on both the parties to perform previously accepted tasks in a predetermined manner.
Prospective Capacity Resources	Anticipated Resources plus Existing-Other capacity plus Tier 2 Capacity plus net Expected transfers.
Prospective Capacity Reserve Margin	Prospective Capacity Resources minus Net Internal Demand shown divided by Net Internal Demand, shown as a percentile.
Ramp Rate (Ramp)	Schedule: the rate, expressed in megawatts per minute, at which the interchange schedule is attained during the ramp period. Generator: the rate, expressed in megawatts per minute, that a generator changes its output. (NERC Glossary of Terms)
Rating	The operational limits of a transmission system element under a set of specified conditions. (NERC Glossary of Terms)
Reactive Power	The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (Kvar) or megavars (MVar). (NERC Glossary of Terms)
Real Power	The portion of electricity that supplies energy to the load. (NERC Glossary of Terms)
Reference Margin Level	This metric is typically based on the load, generation, and transmission characteristics for each Assessment Area. In some cases, it is a requirement implemented by the respective state(s), provincial authority, ISO/RTO, or other regulatory body. If such a requirement exists, the respective Assessment Area generally adopts this requirement as the Reference Margin Level. In some cases, the Reference Margin Level may fluctuate for each season of the assessment period. If a Reference Margin Level is not provided by an Assessment Area, NERC applies a 15% Reference Margin Level for predominately thermal systems and 10% for predominately hydro systems.
Reliability Coordinator	The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the

	calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision. (NERC Glossary of Terms)
Renewable Energy (Renewables	Energy derived from resources that are regenerative or for all practical purposes cannot be depleted. Types of renewable energy resources include moving water (hydro, tidal and wave power), thermal gradients in ocean water, biomass, geothermal energy, solar energy, and wind energy. Municipal solid waste (MSW) is also considered to be a renewable energy resource. (Source: DOE-EIA)
Reserve Sharing Group	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of Disturbance Control Performance, the Areas become a Reserve Sharing Group. (Source: NERC Glossary of Terms)
Stand-by Load under Contract	Demand which is normally served by behind-the-meter generation, which has a contract to provide power if the generator becomes unavailable.
Spinning Reserves	Unloaded generation that is synchronized and ready to serve additional demand.(NERC Glossary of Terms)
Time-of-Use (TOU)	Rate and/or price structures with different unit prices for use during different blocks of time. Time-Sensitive Pricing (Non-dispatchable Demand Response) — Retail rates and/or price structures designed to reflect time-varying differences in wholesale electricity costs, and thus provide consumers with an incentive to modify consumption behavior during high-cost or peak periods.
Total Internal Demand	Projected 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. The demands for station service or auxiliary needs (such as fan motors, pump motors, and other equipment essential to the operation of the generating units) are not included. Total Internal Demand should be reduced by indirect Demand-Side Management programs such as conservation programs, improvements in efficiency of electric energy use, Stand-by Load under Contract, all non-dispatchable Demand Response programs (such as Time-of-Use, Critical Peak Pricing, Real Time Pricing and System Peak Response Transmission Tariffs). Adjustments for controllable Demand Response should not be included in this value.
	The demand of a metered system, which includes the Firm demand, plus any Controllable and Dispatchable DSM load and the load due to the energy losses incurred within the boundary of the metered system. (Source: NERC Glossary of Terms)
Transmission-Limited Resources	The amount of transmission-limited generation resources that have deliverability limitations to serve load within the Region. If capacity is limited by both studied transmission limitations and generator derates, the generator derates takes precedence.
Uncertainty	The magnitude and timing of variable generation output is less predictable than for conventional generation.
Variable Energy Resources	Resources with output that are highly variable subject to weather fluctuations such as wind speed and cloud cover.
Variability	The output of variable generation changes according to the availability of the primary fuel (wind, sunlight and moving water) resulting in fluctuations in the plant output on all time scales.

Appendix III: Assessment Preparation, Design, and Data Concepts

The North American Electric Reliability Corporation

Atlanta
3353 Peachtree Road NE, Suite 600 – North Tower
Atlanta, GA 30326
404-446-2560

Washington, D.C.
1325 G Street NW, Suite 600
Washington, DC 20005
202-400-3000

Assessment Data Questions

Please direct all data inquiries to NERC staff (assessments@nerc.net). References to the data and/or findings of the assessment are welcome with appropriate attribution of the source to the NERC *2015 Long-Term Reliability Assessment*. However, extensive reproduction of tables and/or charts will require permission from NERC staff.

NERC Reliability Assessment Staff

Name	Position
Mark G. Lauby	Senior Vice President and Chief Reliability Officer
John N. Moura	Director, Reliability Assessment and System Analysis
Thomas H. Coleman	Director, Reliability Assessment
Ganesh Velummylum	Senior Manager, System Analysis
David A. Calderon	Engineer, Reliability Assessment
Elliott J. Nethercutt	Senior Technical Advisor, Reliability Assessment
Amir Najafzadeh	Engineer, System Analysis
Noha Abdel-Karim	Senior Engineer, Reliability Assessment
Pooja Shah	Senior Engineer, Reliability Assessment
Ryan Quint	Senior Engineer, System Analysis
Michelle Marx	Executive Administrative Assistant, Reliability Assessment and System Analysis

NERC Reliability Assessment Subcommittee Roster

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

Assessment Preparation and Design

The *2015 Long-Term Reliability Assessment* (*2015LTRA*) is based on resource adequacy[81] information collected from the eight Regional Entities (Regions) that is used to independently assess the long-term reliability of the North American BPS while identifying trends, emerging issues, and potential risks. The LTRA is developed annually by NERC in accordance with the ERO's Rules of Procedure,[82] as well as Title 18, § 39.11[83] of the Code of Federal Regulations,[84] also referred to as Section 215 of the Federal Power Act, which instructs NERC to conduct periodic assessments of the North American BPS.[85]

This assessment is based on data and information collected by NERC from the Regions on an Assessment Area basis as of September 2015. The Reliability Assessment Subcommittee (RAS), at the direction of the Planning Committee (PC), supports the LTRA development. Specifically, NERC and the RAS perform a thorough peer review that leverages the knowledge and experience of industry subject matter experts while providing a balance to ensure the validity of data and information provided by the Regions. Each Assessment Area section is peer reviewed by members from other Regions to achieve a comprehensive review that is verified by the RAS in open meetings. The review process ensures the accuracy and completeness of the data and information provided by each Region. This assessment has been reviewed and accepted by the PC. The NERC Board of Trustees also reviewed and approved this report.

The *2015LTRA* reference case does not reflect impacts that may result from the D.C. Circuit Court's mandate to vacate FERC Order No. 745,[86] nor the impacts that may arise from the EPA's Clean Power Plan (Clean Air Act–Section 111(d)). While NERC provides a summary of the EPA's Clean Power Plan, quantitative impacts from these developments will be considered for inclusion in future NERC assessments.

Data Concepts and Assumptions Guide

The table below explains data concepts and important assumptions used throughout this assessment.

Data Concepts and Assumptions Guide

General Assumptions
The Reserve Margin calculation is an important industry planning metric used to examine future resource adequacy. This deterministic approach examines the forecast peak demand (load) and projected availability of resources to serve the forecast peak demand for the summer and winter of the 10-year outlook (2015–24).
All data in this assessment are based on existing federal, state, and provincial laws and regulations.
Demand Assumptions
Electricity demand projections, or load forecasts, are provided by each Assessment Area.
Load forecasts include peak hourly load,[87] or Total Internal Demand, for the summer and winter of each year.[88]
Total Internal Demand projections are based on normal weather (50/50 distribution)[89] and are provided on a coincident basis for most Assessment Areas.[90]
Total Internal Demand includes considerations for reduction in electricity use due to projected impacts of energy efficiency and conservation programs.

[81] Adequacy means having sufficient resources to provide customers with a continuous supply of electricity at the proper voltage and frequency, virtually all of the time. Resources are a combination of electricity-generating and transmission facilities that produce and deliver electricity, and Demand Response programs that reduce customer demand for electricity. Adequacy requires System Operators and planners to account for scheduled and reasonably expected unscheduled outages of equipment while maintaining a constant balance between supply and demand.

[82] NERC Rules of Procedure - Section 803.

[83] Section 39.11(b) of FERC's regulations provide: "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

[84] Title 18, § 39.11 of the Code of Federal Regulations.

[85] BPS reliability, as defined in the How NERC Defines BPS Reliability section of this report, does not include the reliability of the lower-voltage distribution systems, which systems use to account for 80% of all electricity supply interruptions to end-use customers.

[86] United States Court of Appeals for the District of Columbia Circuit - No.11-1486.

[87] Glossary of Terms Used in NERC Reliability Standards.

[88] The summer season represents June–September and the winter season represents December–February.

[89] Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.

[90] Coincident: The sum of two or more peak loads that occur in the same hour. Noncoincident: The sum of two or more peak loads on individual systems that do not occur in the same time interval. Meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC and FRCC calculate Total Internal Demand on a noncoincidental basis.

Net Internal Demand, used in all Reserve Margin calculations, is equal to Total Internal Demand, reduced by the amount of Controllable and Dispatchable Demand Response projected to be available during the peak hour.

Resource Assumptions

NERC collects projections for the amount of existing and planned capacity, and net capacity transfers (between Assessment Areas) that will be available during the forecast hour of peak demand for the summer and winter seasons of each year. Resource planning methods vary throughout the North American BPS. NERC uses the following categories to provide a consistent approach for collecting and presenting resource adequacy:

Anticipated Resources

- Existing-Certain generating capacity: includes operable capacity expected to be available to serve load during the peak hour with Firm transmission.
- Tier 1 capacity additions: includes capacity that is either under construction or has received approved planning requirements.
- Firm Capacity Transfers (Imports minus Exports): transfers with Firm contracts.

Prospective Resources: Includes all Anticipated Resources, plus:

- Existing-Other capacity: includes operable capacity that could be available to serve load during the peak hour, but lacks Firm transmission and could be unavailable for a number of reasons.
- Tier 2 capacity additions: includes capacity that has been requested, but not received approval for planning requirements. Tier 2 capacity is counted toward the Prospective Resources category.
- Expected (non-Firm) Capacity Transfers (Imports minus Exports): transfers without Firm contracts, but a high probability of future implementation.

Reserve Margins

Reserve Margins: the primary metric used to measure resource adequacy, defined as the difference in resources (Anticipated, or Prospective) and Net Internal Demand, divided by Net Internal Demand, shown as a percentile.

$$\textbf{Anticipated Reserve Margin} = \frac{(\text{Anticipated Resources} - \text{Net Internal Demand})}{\text{Net Internal Demand}}$$

$$\textbf{Prospective Reserve Margin} = \frac{(\text{Prospective Resources} - \text{Net Internal Demand})}{\text{Net Internal Demand}}$$

Reference Margin Level: the assumptions of this metric vary by Assessment Area. Generally, the Reference Margin Level is typically based on load, generation, and transmission characteristics for each Assessment Area and, in some cases, the Reference Margin Level is a requirement implemented by the respective state(s), provincial authorities, ISO/RTO, or other regulatory bodies. If such a requirement exists, the respective Assessment Area generally adopts this requirement as the Reference Margin Level. In some cases, the Reference Margin Level will fluctuate over the duration of the assessment period, or may be different for the summer and winter seasons. If one is not provided by a given Assessment Area, NERC applies a 15% Reference Margin Level for predominately thermal systems and 10% for predominately hydro systems.

Fuel Types

NERC collects and presents data on the generation mix based on the general fuel type identified for each unit. The fuel type is based on the prime movers and primary fuel type codes identified in the Form EIA-860 and provided below:[91]

Coal: Anthracite (ANT), Bituminous (BIT), Lignite (LIG), Subbituminous (SUB), Waste/Other (WC), Refined (RC)

Petroleum: Distillate Fuel Oil (DFO), Jet Fuel (JF), Kerosene (KER), Petroleum Coke (PC), Residual Fuel Oil (RFO), Waste/Other Oil (WO)

Natural Gas: Blast Furnace (BFG), Natural (NG), Other (OG), Propane (PG), Synthesis from Petroleum Coke Gas (SGP), Coal-Derived Synthesis Gas (SGC)

Biomass: Agricultural By-Products (AB) Municipal Solid Waste (MSW) Other Biomass Solids (OBS), Wood/Wood Waste Solids (WDS), Other Biomass Liquids (OBL), Sludge Waste (SLW), Black Liquor (BLQ), Wood Waste Liquids (WDL), Landfill Gas (LFG), Other Biomass Gas (OBG)

Renewables: Solar (SUN), Wind (WND), Geothermal (GEO), Hydroelectric (fuel type: WAT; primary mover: HY)

Pumped Storage: Pumped Storage (fuel type: WAT; primary mover: PS)

Nuclear: Nuclear (NUC)

[91] Additional information on fuel codes and prime movers are available in the Form EIA-860.

January 14, 2016

Page 14: Footnote 14: NYISO calculates the Reference Reserve Margin value (17%) by a study conducted by the New York State Reliability Council (NYSRC) based on wind and solar at full Installed Capacity (ICAP) value modeled using an hourly supply shape for each wind and solar location.

Footnote was added to detail the wind resources accounting method in calculating Reference Reserve Margin levels.

Page 16: Footnote 17: 2015 Essential Reliability Services Task Force Framework Report

Hyperlink reference to the *2015 Essential Reliability Services Task Force Framework* Report was added.