NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2014 Long-Term Reliability Assessment

November 2014

RELIABILITY | ACCOUNTABILITY




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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 20 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 a 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 reduced from 26 to 20 since the release of the 2013LTRA.

[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

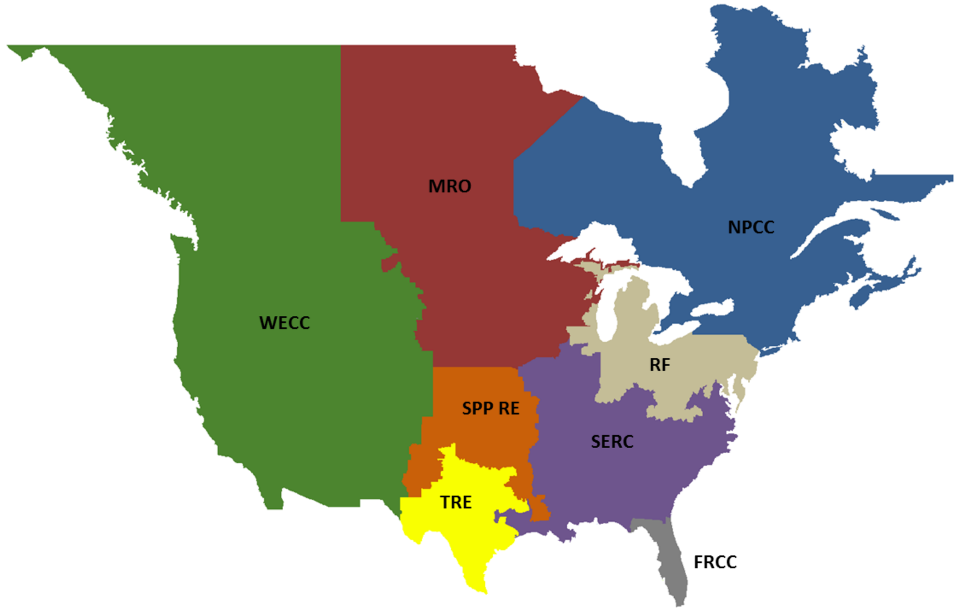
RF – ReliabilityFirst
- PJM[7]

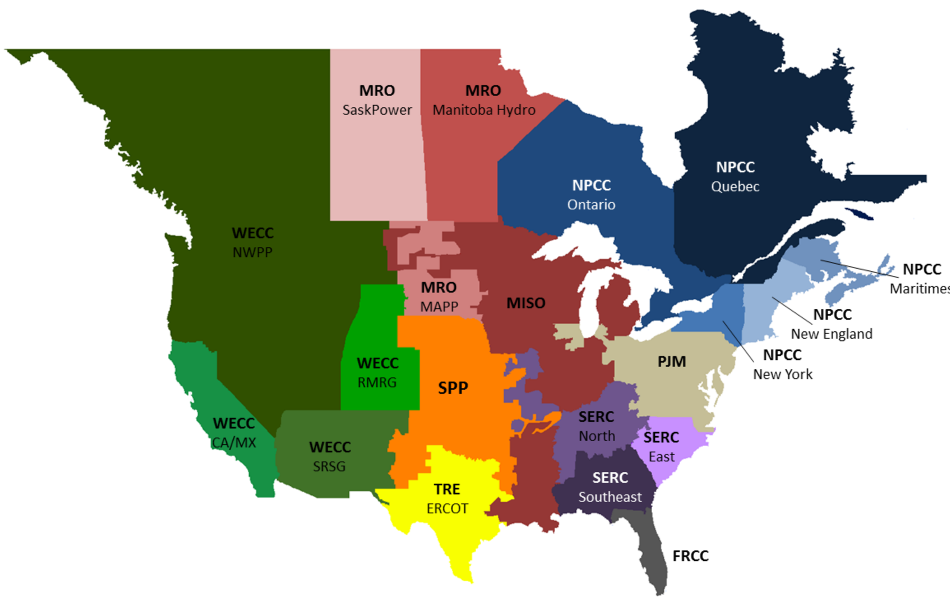
SERC – SERC Reliability Corporation
- SERC-East
- SERC-North
- SERC-Southeast

SPP RE – Southwest Power Pool Regional Entity
- SPP

TRE – Texas Reliability Entity
- TRE-ERCOT

WECC – Western Electricity Coordinating Council
- WECC-CA/MX
- WECC-NWPP
- 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.

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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 *2014 Long-Term Reliability Assessment*. However, extensive reproduction of tables and/or charts will require permission from NERC staff.

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Assessment Preparation and Design

The *2014 Long-Term Reliability Assessment* (2014LTRA) is based on resource adequacy[8] 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,[9] as well as Title 18, § 39.11[10] of the Code of Federal Regulations,[11] also referred to as Section 215 of the Federal Power Act, which instructs NERC to conduct periodic assessments of the North American BPS.[12]

This assessment is based on data and information collected by NERC from the Regions on an Assessment Area-basis as of September 2014. 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 endorsed by the PC. The NERC Board of Trustees also reviewed and approved this report.

The 2014LTRA reference case does not reflect impacts that may result from the D.C. Circuit Court's mandate to vacate FERC Order No. 745,[13] nor the impacts that may arise from the EPA's proposed Clean Power Plan (Clean Air Act–Section 111(d)), currently open for public comment through December 1, 2014. While NERC provides a summary of the EPA's proposed 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 (2015–2024).
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,[14] or Total Internal Demand, for the summer and winter of each year.[15]
Total Internal Demand projections are based on normal weather (50/50 distribution)[16] and is provided on a coincident basis for most Assessment Areas.[17]

[8] 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 refer to 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.

[9] NERC Rules of Procedure - Section 803.

[10] Section 39.11(b) of the U.S. 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."

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

[12] 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 percent of all electricity supply interruptions to end-use customers.

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

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

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

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

[17] 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.

Total Internal Demand includes considerations for reduction in electricity use due to projected impacts of energy efficiency and conservation programs.

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. Up to 50 percent of total 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.

Adjusted-Potential Resources: Includes all Prospective Resources, plus:

- Tier 3 capacity additions: includes additional resources that do not meet Tier 2 requirements. Up to 10 percent of total Tier 3 capacity is counted toward the Adjusted-Potential Resources category.

Reserve Margins

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

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

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

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

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 percent Reference Margin Level for predominately thermal systems and 10 percent 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:[18]

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)

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

Executive Summary

The *2014 Long-Term Reliability Assessment* (2014LTRA) is a report that provides a wide-area perspective on the adequacy of the generation, demand-side resources, and transmission systems necessary to meet system reliability needs over the next decade. This assessment includes NERC's independent identification of issues that may impact the reliability of the North American Bulk-Power System (BPS) to provide industry, regulators, and policy makers with adequate time to address or otherwise develop plans to mitigate potential reliability impacts caused by these issues. This assessment also documents current industry plans to maintain reliability during the next decade, advising regulators, policy makers, and the general public of existing and potential challenges, complexities, and interdependencies.

The electricity industry provided NERC with resource adequacy projections for the 2015–2024 assessment period. NERC independently assessed these projections and identified three key findings that will impact the long-term reliability of the North American BPS and materially change the way the system is planned and operated. These key findings are:

1. Reserve Margins in several Assessment Areas are trending downward, despite low load growth.
2. Environmental regulations create uncertainty and require assessment.
3. A changing resource mix requires new approaches for assessing reliability.

The on-peak resource mix has recently shifted to be predominately gas fired: now 40 percent, compared to 28 percent just five years ago.[19] This trend is expected to continue, as retiring coal, petroleum, nuclear, and other conventional generation is largely being replaced by gas-fired capacity and variable energy resources (VERs).[20] The fundamental transformation of the resource mix—largely driven by environmental regulations, legislation, state and provincial incentives for additional VERs, and impacts of fuel prices, particularly for natural gas—presents new challenges for the electricity industry.

System planners should ensure System Operators have the tools and resources needed to maintain reliability in the midst of this transformation. For example, typical planning approaches focus on ensuring capacity is procured and available to meet the hour of peak demand for each season, perceived as the highest stress on the system. However, stresses during shoulder periods or off-peak hours can introduce a different set of challenges, such as the management of overgeneration periods when generation exceeds demand; this is generally introduced by an excess of less-flexible resources. Additionally, gas generation and other flexible resources need further study to ensure availability to balance load during off-peak and shoulder periods.

These changes also provide opportunities to the industry as more responsive gas-fired generators can provide System Operators with needed flexibility to address additional VERs, such as wind and solar resources, on the system. Similarly, the application of energy storage and Demand-Side Management (DSM) technologies has the potential to offer approaches to meeting demand and balancing it with greater efficiency. New technologies (e.g., smart grid devices and applications, phasor measurement units (PMU), remedial action schemes, new forecasting capabilities, greater system awareness, etc.) can also advance the industry's ability to dynamically control grid facilities and improve coordination between System Operators, grid resources, and the consumer.

In preparing this assessment, NERC examined key reliability indicators of resource adequacy projections, including load forecasts, projected resources, and transmission enhancements. Based on these projections and input from the industry, NERC identified three key reliability findings that each include a subset of issues that will impact resource adequacy, transmission adequacy, or system operations during the next decade. These findings are cross-cutting and interdependent, as many of the issues present unique challenges to the electricity industry.

[19] NERC 2009 Long-Term Reliability Assessment.
[20] NERC IVGTF Reports.

Key Reliability Findings

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

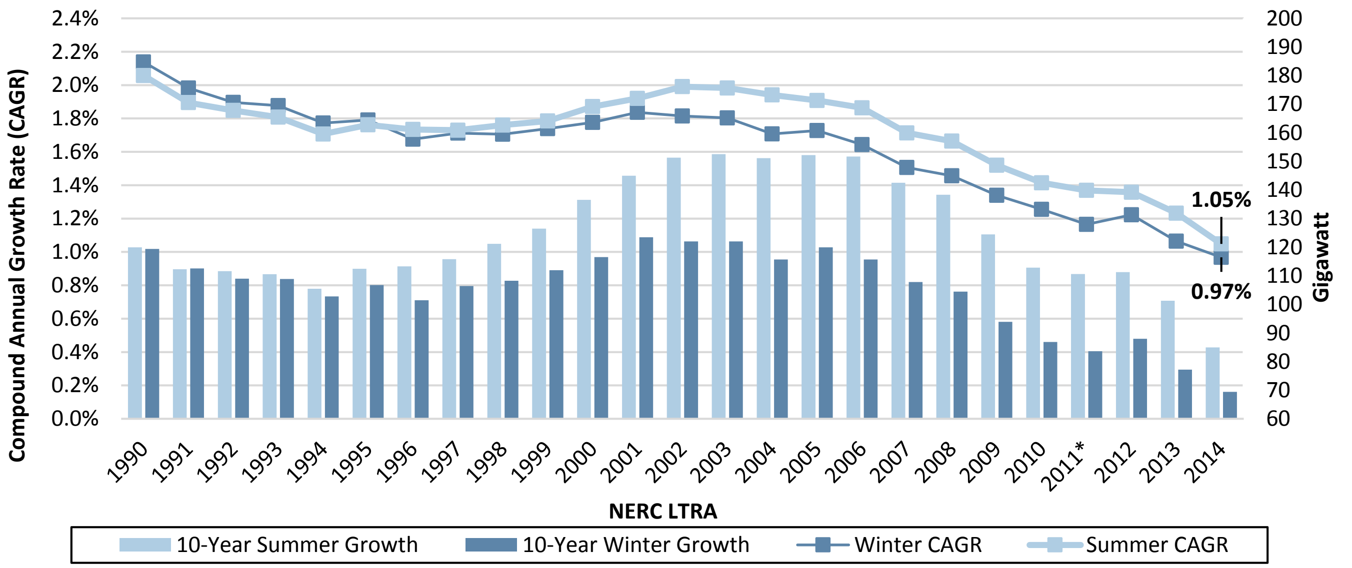
1. Reserve Margins in Several Assessment Areas Are Trending Downward, Despite Low Load Growth

Planning Reserve Margins are the primary metric used in this assessment to consistently examine future resource adequacy and raise industry awareness of potential resource adequacy concerns.[21]

Declining Demand Growth and Projected Capacity Additions

According to the 2014LTRA reference case, the NERC-wide annual demand growth rate is 1.05 percent for the summer and 0.97 percent for the winter, which are the lowest growth rates on record for both seasons.[22] With lower rates of demand growth, the contribution of Demand Response (DR) has also plateaued in recent years, with minimal additional program growth projected in the reference case.[23]

NERC-Wide Demand: 10-Year Growth Rates (Summer and Winter) at Lowest Levels on Record



*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 is 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).

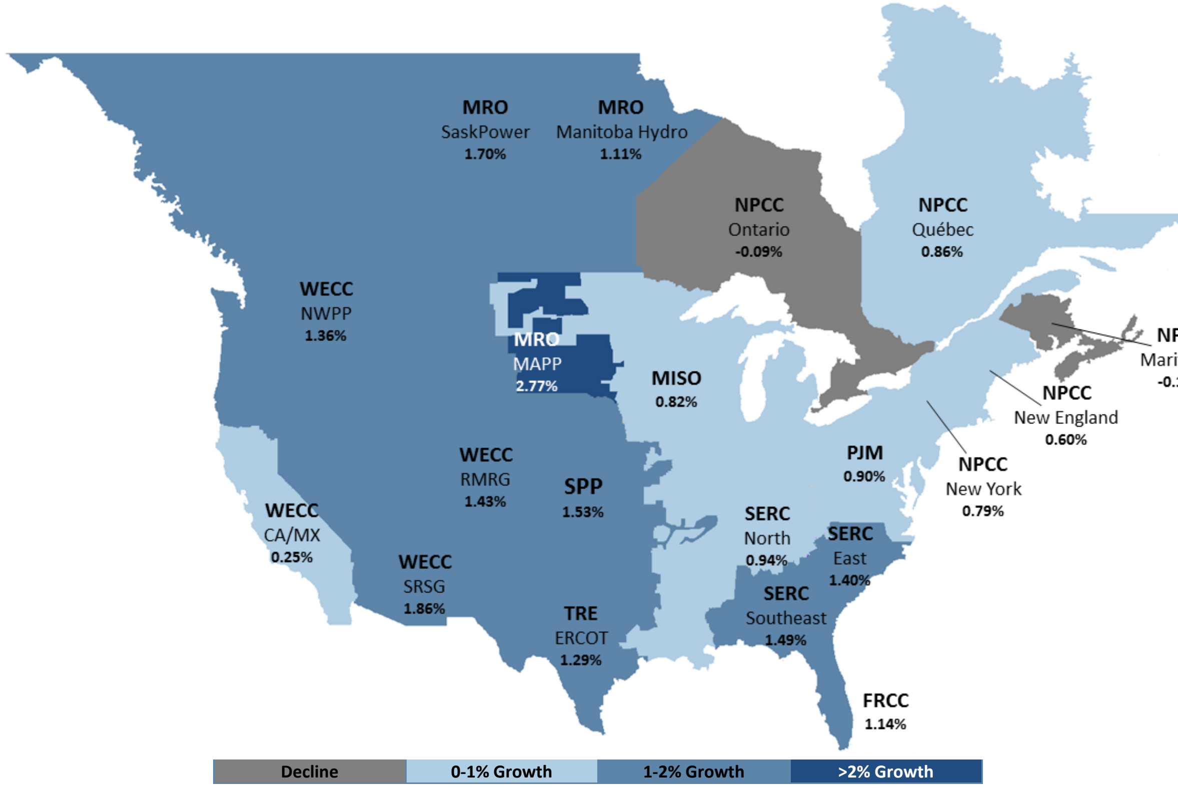
Most Assessment Areas attribute stagnant demand growth to the ongoing projected economic indicators (typically based on either employment levels or gross domestic product (GDP)) in the residential, commercial, and industrial sectors. Energy efficiency and conservation programs, as well as time-of-use rate programs in many areas continue to drive lower energy growth, and in some cases, the correlation between economic growth and load growth is no longer positive. Distributed generation (distributed energy resources) in NPCC-Ontario (-0.09 percent load growth) and WECC-CA/MX (0.25 percent load growth) has also reduced end-use or grid-supplied electricity demand. The following map includes peak season demand growth rates for each Assessment Area.

[21] Reserve Margin projections are presented in Appendix I.

[22] Compound 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 / Year 1)^(1 / 9) – 1.

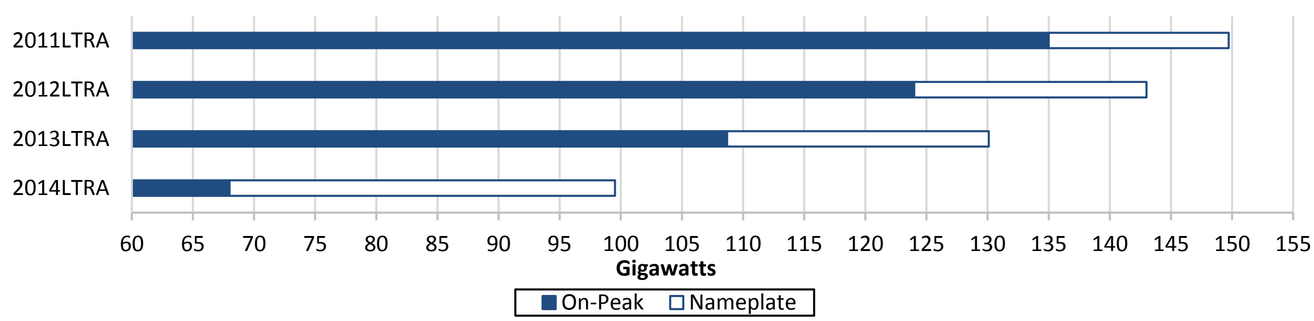
[23] When examining the peak season for each Assessment Area, NERC-wide Controllable and Dispatchable DR is projected to grow by 1.7 GW (increasing from 38.9 GW in 2015 to 40.6 GW in 2024).

10-Year Compound Annual Growth Rate (Peak Season) Below 2 Percent for Most Assessment Areas



Total capacity additions have paralleled the ongoing declines in load growth, with only 99.6 GW (66.9 GW on peak) of Tier 1 capacity additions projected during the next decade, compared to 150 GW projected in the 2011LTRA reference case. Additionally, 39 GW of capacity has retired since 2011, with another 44.6 GW[24] of retirements projected by 2024.

NERC-Wide 10-Year Projected Capacity Additions Declining Since 2011[25]

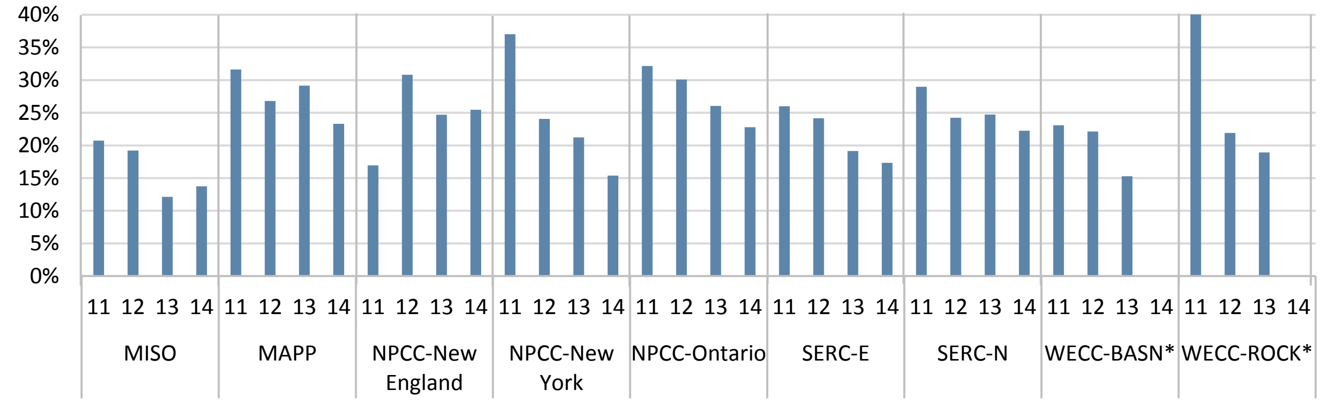


Considering the ongoing decline in load growth, fewer capacity additions are necessary to maintain adequate planning reserves. However, Anticipated Reserve Margins for several Assessment Areas have been showing declining trends, especially when examining short-term projections in the prior three LTRA reference cases.

[24] Includes 21.7 GW of coal, 15.8 GW of natural gas, 4.5 GW of nuclear, 2 GW of petroleum, and 0.5 GW of other capacity retirements (summer ratings).

[25] 2011, 2012, and 2013LTRA data includes Future-Planned capacity additions. The 2014LTRA data includes Tier 1 capacity additions.

Short-Term (Year 2 Forecast) Anticipated Reserve Margins Show Declining Trends for Some Assessment Areas



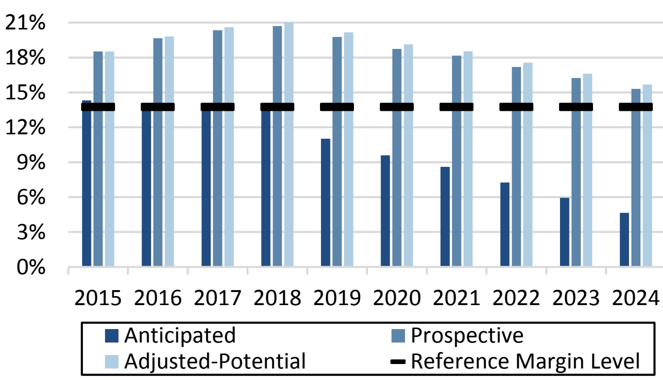
*Due to changes to the WECC subregional boundaries, resulting in four subregions instead of nine, the 2014 Anticipated Reserve Margins are not shown for WECC-BASN and WECC-ROCK for this comparison.

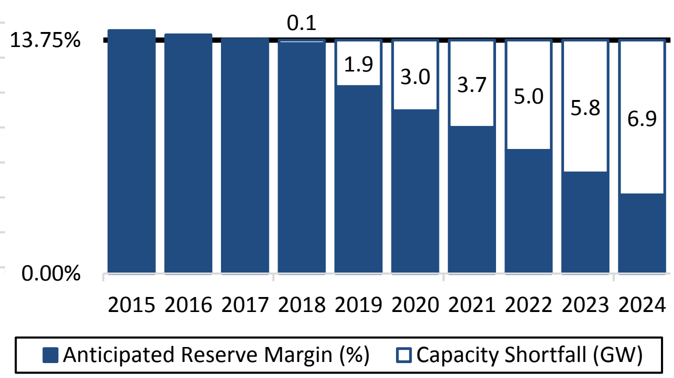
In recent long-term assessments, NERC highlighted resource adequacy concerns, particularly in ERCOT, NPCC-New York, and MISO, as projections continued to reflect declining Anticipated Reserve Margins that fell below each area's Reference Margin Level during the short term (1-5 years).

TRE-ERCOT: Recent Capacity Additions Elevate Planning Reserve Margins through 2018

Since ERCOT initially identified potential resource adequacy concerns in 2012, the RTO responded by incentivizing additional participation in Demand Response (DR) and energy efficiency programs. More recently, new gas-fired resources totaling 2,112 MW (summer rating) were added during the 2014 summer, which elevates ERCOT's Anticipated Reserve Margin to 14.3 percent in 2015. It will remain above the Reference Margin Level (13.75 percent) until summer 2018. Assuming the availability of less-certain Prospective Resources, including Tier 2 capacity additions, ERCOT will meet the Reference Margin Level for all years of the assessment period.

TRE-ERCOT Reserve Margins (Left) and Capacity Shortfall below the Reference Margin Level (Right)[26]





[26] 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 2014LTRA 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.

TRE-ERCOT Capacity Additions and Retirements

Capacity Additions	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Cumulative Tier 1 Additions	2,801	3,724	4,528	5,410	5,650	5,650	5,650	5,650	5,650	5,650
Cumulative Tier 2 Additions	4,369	14,027	21,360	25,814	25,814	25,814	25,814	25,814	25,814	25,814
Retirements	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Cumulative Retirements	-2,311	-2,430	-2,430	-2,430	-2,430	-3,270	-3,270	-3,270	-3,270	-3,270
Net Capacity Change	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Tier 1 Additions, Less Retirements	490	1,294	2,098	2,980	3,220	2,380	2,380	2,380	2,380	2,380
Tier 1 & Tier 2 Additions, Less Retirements	4,859	15,320	23,458	28,794	29,034	28,194	28,194	28,194	28,194	28,194

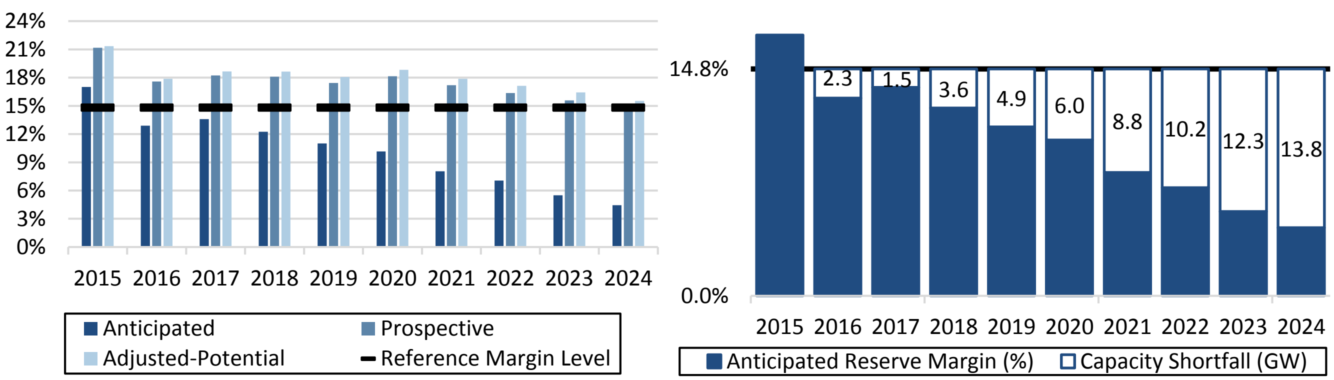
Additional Tier 1 capacity in TRE-ERCOT totals over 5.6 GW during the 10-year outlook, with an additional 25.8 GW of Tier 2 additions, while projected retirements total 2.3 GW (including unit suspensions and mothballs).

It is also important to note the impacts of recent modifications to ERCOT's load forecast method, which incorporates a neural network model to forecast daily energy. Additionally, ERCOT is now incorporating regional growth forecasts for each customer class (residential, commercial, and industrial) instead of observing only non-farm employment as the economic driver. These new assumptions result in a compound annual growth rate (CAGR) of 1.29 percent for the 10-year summer demand projections in the 2014LTRA reference case—substantially lower than the 2.35 and 1.38 percent CAGRs reflected in the 2012LTRA and 2013LTRA reference cases, respectively.

MISO: Generator Retirements, Transfer Limitations, and Resource Procurement Contribute to Deficit Margins in 2016

MISO's Anticipated Reserve Margin will drop below the Reference Margin Level (14.8 percent) in 2016, declining to 5.23 percent by 2024. The Reference Margin Level for MISO is based on a 14.8 percent requirement as determined by the 1-day-in-10-year Loss of Load Expectation (LOLE) (MISO criteria). Accordingly, in 2016, MISO projects it will operate at the reliability level of approximately 2-days-in-10-year LOLE, increasing the likelihood that resources will not be sufficient to serve peak demand. The number of expected days-per-year of an LOLE is projected to increase throughout the assessment period. Potential environmental regulations could further exacerbate resource adequacy concerns in the MISO footprint unless additional replacement capacity is built in a timely fashion.

MISO Reserve Margins (Left) and Capacity Shortfall below the Reference Margin Level (Right)



As MISO starts to operate at or near its Reference Margin Level, there is a higher likelihood that System Operators will call Emergency Operating Procedures more frequently to access Emergency-Only resources, load-modifying resources, and behind-the-meter generation (BTMG). The contributing factors driving the projected deficit include:

- Increased retirements and suspensions (temporary mothballing) due to Environmental Protection Agency (EPA) regulations and market forces and low natural gas prices
- Exclusion of low-certainty resources that were identified in the Resource Adequacy survey

- Exclusion of surplus of capacity in MISO South above the 1,000 MW transfer from the Planning Reserve Margin requirement (PRMR)[27]
- Increased exports to PJM and the removal of non-Firm imports[28]
- Inadequate Tier 1 capacity additions [29]

Considering the 8.6 GW of low-certainty resources captured in MISO's generator survey, the projected 10.8 GW of retirements far exceed Tier 1 capacity additions of 3.6 GW. Even when taking into account Tier 2 capacity additions, more resources will be needed to address the ongoing load growth of 0.82 percent annually.

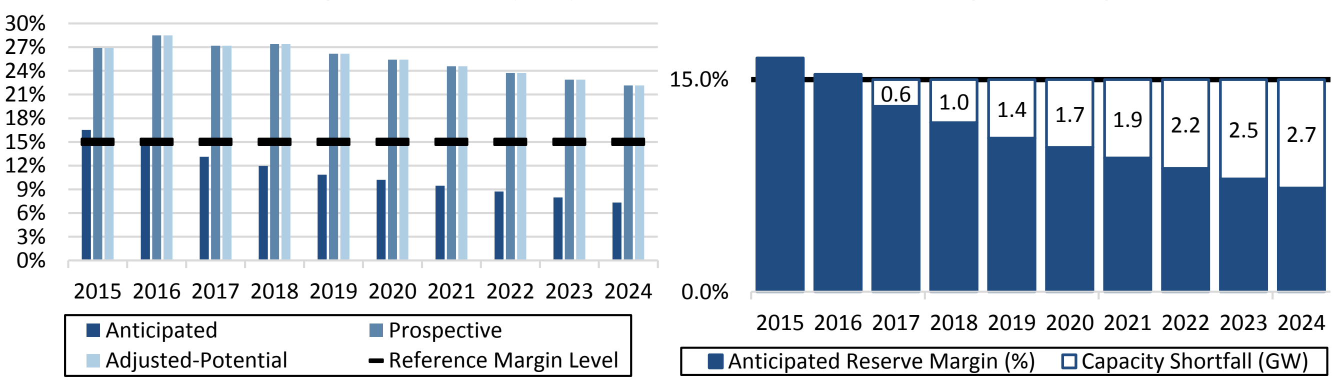
MISO Capacity Additions and Retirements

Capacity Additions	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Cumulative Tier 1 Additions	1,167	1,636	2,982	3,528	3,579	3,579	3,579	3,579	3,579	3,579
Cumulative Tier 2 Additions	626	642	642	642	642	642	642	642	642	642
Retirements	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Cumulative Retirements	-3,867	-4,824	-6,424	-6,424	-7,224	-7,524	-9,124	-9,424	-10,524	-10,824
Net Capacity Change	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Tier 1 Additions, Less Retirements	-2,699	-3,188	-3,442	-2,896	-3,645	-3,945	-5,545	-5,845	-6,945	-7,245
Tier 1 & Tier 2 Additions, Less Retirements	-2,073	-2,546	-2,800	-2,254	-3,003	-3,303	-4,903	-5,203	-6,303	-6,603

NPCC-New York: Capacity Retirements and Limited Tier 1 Capacity Additions Result in the Anticipated Reserve Margin Falling Below the Reference Margin Level in 2017

The New York Independent System Operator (NYISO) currently has an Installed Reserve Margin (IRM) requirement of 17 percent that extends from May 2014 to April 2015. However, because this requirement expires prior to the 2015 summer, a 15 percent Reference Margin Level is applied for all seasons and years of the assessment period. While the Anticipated Reserve Margin for NPCC-New York falls below the 15 percent Reference Margin Level in 2017, the Prospective Reserve Margin remains above for all seasons and years of the assessment period. NYISO reports inadequate capacity concerns in southeast New York beginning as soon as 2019.[30] Future transmission reliability issues were identified in four regions of the state with ongoing capacity retirements and continued demand growth.

NPCC-New York Reserve Margins (Left) and Capacity Shortfall below the Reference Margin Level (Right)



Projected Tier 1 capacity additions in New York, based on the NYISO planning criteria, include only one 19 MW biomass unit, expected to be in service by the 2016 summer. As demand continues to grow at an average rate of 0.79 percent each year,

[27] For this assessment, 1,000 MW of capacity is transferred from the MISO South to the MISO North/Central Region pending the outcome of regulatory issues currently under FERC review.

[28] Capacity sales (imports and exports) in MISO depend on decisions of the respective resource owners, assuming that the tariff requirements are met (including planning of necessary transmission of both the buying and selling areas). Regarding the removal of non-Firm imports, the MISO market monitor double-counted non-Firm imports in the 2013LTRA reference case. These imports are accounted for in the Reference Margin Level (PRMR).

[29] In the MISO footprint, 91 percent of the load is served by utilities with an obligation to serve customers reliably and at a reasonable cost. Resource planning and investment in resources are part of state and locally jurisdictional integrated resource plans that only become certain upon the receipt of a Certificate of Public Convenience and Necessity (CPCN).

[30] NYISO 2014 Reliability Needs Assessment.

planned retirements of natural gas, oil, and coal units during the initial years of the assessment period result in declining margins. The availability of Tier 2 capacity additions (3,688 MW) can help offset declining margins and alleviate resource adequacy concerns.

NPCC-New York Capacity Additions and Retirements

Capacity Additions	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Cumulative Tier 1 Additions	0	19	19	19	19	19	19	19	19	19
Cumulative Tier 2 Additions	88	2,002	2,653	3,682	3,688	3,688	3,688	3,688	3,688	3,688
Retirements	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Cumulative Retirements	-422	-422	-771	-771	-771	-771	-771	-771	-771	-771
Net Capacity Change	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Tier 1 Additions, Less Retirements	-422	-403	-752	-752	-752	-752	-752	-752	-752	-752
Tier 1 & Tier 2 Additions, Less Retirements	-334	1,599	1,901	2,930	2,936	2,936	2,936	2,936	2,936	2,936

Key Reliability Finding #1

Reserve Margins in Several Assessment Areas Trend Downward, Despite Low Load Growth

Observations

The near-term impacts of the Mercury and Air Toxics Standard (MATS), recently finalized by the EPA, are factored into this assessment. However, uncertainty remains for a large amount of existing conventional generation that may be vulnerable to retirement resulting from additional pending regulations—particularly EPA's recently proposed Clean Power Plan (section 111(d) of the Clean Air Act). These impacts are discussed in detail in Key Reliability Finding #2.

NERC does not have authority to set Reliability Standards for resource adequacy (e.g., reserve margin criteria) or order the construction of resources or transmission. However, NERC has the responsibility to independently assess where BPS reliability issues may arise and to identify emerging risks to resource adequacy.

Recommendations

Continued Heightened Awareness: NERC should continue to raise awareness of resource adequacy issues by coordinating regularly with involved parties (state regulators and public utility commissions), and support ongoing initiatives to effectively address declining reserve margins.

Further Assessment Using Probabilistic Analysis: NERC should leverage the *2014 Probabilistic Assessment* (based on 2014LTRA reference case data; scheduled for release in March 2015) to provide further insights on the resource adequacy concerns in MISO, ERCOT, and NPCC-New York. This probabilistic approach will examine resource adequacy from an energy perspective, offering a more in-depth understanding of the interplay between resource availability (with considerations for transmission constraints) and projected hourly demand. Additional information on these new approaches is provided in Key Reliability Finding #3.

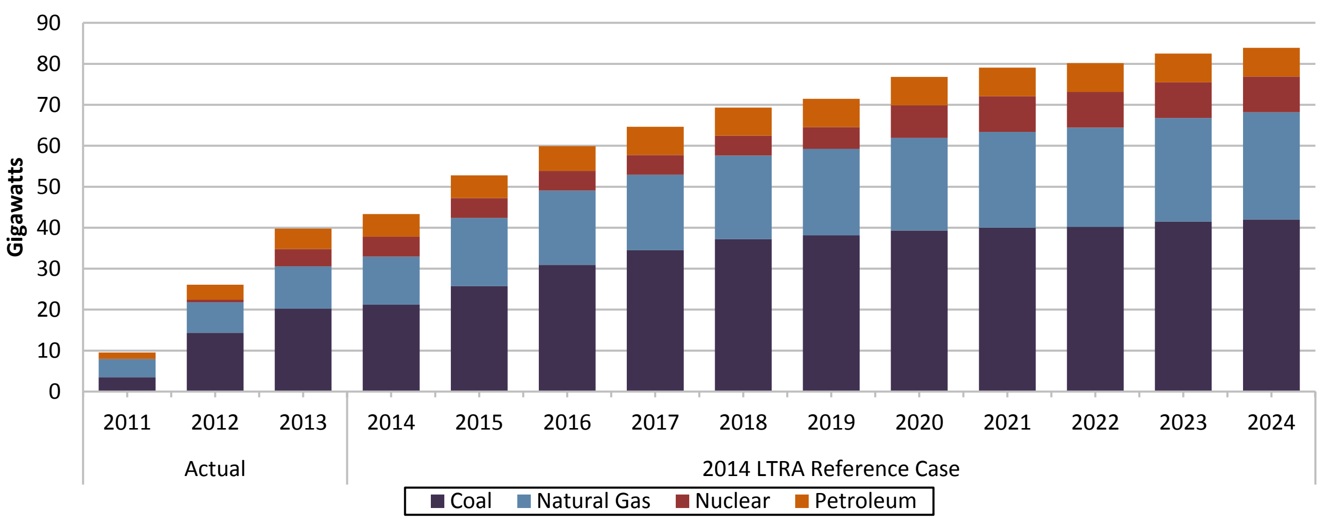
2. Environmental Regulations Create Uncertainty and Require Assessment

Environmental regulations at the state, provincial, and federal levels continue to be the primary drivers of ongoing retirements—primarily fossil-fired capacity. System planners are responding by aligning generation portfolios to comply with limits on cross-state air emissions, surface water regulation, and renewable portfolio standards. Accordingly, NERC continues to examine and report the corresponding resource adequacy implications and potential reliability concerns associated with these developments.

The accelerated retirement of fossil-fired generation is expected, due to increasing costs for compliance with environmental regulations. Coal-fired power plants are especially vulnerable to the impacts of declining revenues due to lower prices of natural gas (i.e., because natural gas often is the marginal fuel and thus sets prices in RTO/ISO markets, and natural gas influences wholesale electricity prices in non-RTO markets, the current trend of lower natural gas prices tends to reduce electricity prices and corresponding electricity payments received by all generators).[31] Concurrent increases in the operating costs of coal plants are often related to the required installation of environmental control technologies. Before these capital investments are made, plant owners must consider the future life of the unit(s), current and future fuel costs and revenues compared to other fuel types, and the impacts of additional environmental regulations. Accordingly, 20.2 GW of mostly smaller coal-fired units were retired between 2011 and 2013, while an additional 20.8 GW are projected to retire by 2024.[32]

NERC-wide, 10.3 GW of natural-gas-fired and 5 GW of petroleum-fired capacity—primarily less-efficient units that have reached the end of their lifespan—were retired between 2011 and 2013 and typically replaced with newer natural gas combined-cycle (NGCC) power plants.[33] Additionally, five nuclear units totaling 4.3 GW have retired since 2011, including four units in the US and one unit in Canada[34] despite the relatively lower fuel costs of nuclear compared to coal and natural gas, operations and maintenance costs.[35] The nuclear fleet in North America is projected to continue providing critical baseload capacity during the next decade, but operations and maintenance costs will continue to impact the economic viability of certain plants—particularly those that are smaller or older.

Cumulative Fossil-Fuel and Nuclear Retirements between 2011 and 2024 Total 83 GW



[31] EIA Annual Energy Outlook - Issues in Focus: Implications of accelerated power plant retirements.
[32] Data for actual retirements (from 2011 to 2013) based on EIA Electric Power Monthly – February 2014 and Ventyx Velocity Suite. Capacity is based on the net summer rating. Projected retirements (2014-2024) are based on the 2014LTRA Reference Case.
[33] IBID.
[34] IBID.
[35] NEI - Nuclear Energy in 2014: Status and Outlook.

According to the 2014LTRA reference case, an additional 44.2 GW of fossil-fired and nuclear capacity is projected to retire between 2014 and 2024.[36] These projections are based on the assumption that current environmental regulations will remain unchanged; it does not include potential impacts of EPA's recently proposed Clean Power Plan (section 111(d) of the Clean Air Act). An in-depth examination of the plan is provided in the next section, while the current status of existing environmental regulations is provided below.

Status of Existing Regulations

Mercury and Air Toxics Standards (MATS)

The EPA issued a rule in December 2011[37] to reduce emissions of toxic air pollutants from power plants. MATS was designed to reduce emissions from existing and planned coal- and oil-fired generators by requiring the installation of environmental controls. These controls typically involve the addition of dry sorbent injection systems and/or sulfur dioxide (SO_2) scrubbers. Other environmental controls (such as fabric filters) are also considered as technologies that remove or limit heavy metal particulate emissions. However, the final rule allows for upgrades to existing electrostatic precipitators, potentially negating the need for expensive retrofits.

The MATS rule in its current form includes important modifications, such as the ability to apply 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. Since the rule was implemented, over 107 applications have been submitted, and 98 have been granted.[38] In the coming years, affected generation owners will continue to comply either by closing plants or investing in environmental controls and technologies to ensure compliance with all regulations.

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

CSAPR was vacated in August 2012 by the U.S. Court of Appeals for the District of Columbia Circuit, at which point CAIR was reinstated. CAIR is designed as a cap-and-trade program aimed at reducing emissions of SO_2 and nitrogen oxides (NO_X) from fossil-fired units with capacities greater than 25 MW in 27 eastern states and the District of Columbia. The emissions caps went into effect in 2009 for NO_X and in 2010 for SO_2, and both caps are scheduled to be tightened in 2015.

The flue-gas desulfurization scrubbers or dry sorbent injection systems required to comply with MATS will ultimately result in SO_2 emissions falling to levels lower than the CAIR cap. Therefore, power plant emission controls that meet the SO_2 emission requirement of MATS will also fall in compliance with the cap established by CAIR.

In April 2014, the U.S. Supreme Court reversed the D.C. Circuit's judgment and remanded the case. In June 2014, the U.S. government filed a motion with the U.S. Court of Appeals for the D.C. Circuit to lift the stay of the CSAPR, which was accepted on October 23, 2014.[39]

Clean Water Act (CWA) – Section 316(b)

Cooling water intake operation and structures are regulated under Section 316(b) of the CWA.[40] The 316(b) rule is implemented by the state water permitting agencies through the National Pollution Discharge Elimination System (NPDES) permit program of the CWA. 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 CWA 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

[36] While the assessment period for the 2014LTRA is 2015-2024, projected retirements for 2014 are included in this analysis.

[37] MATS was challenged in the U.S. Court of Appeals for the District of Columbia Circuit in White Stallion Energy Center et al. v. U.S. EPA. The case was heard in December 2013, and a decision was made in April 2014 to uphold the rule.

[38] As of September 2014.

[39] CSAPR - Motion to Lift Stay

[40] 33 U.S.C. section 1326.

August 2014 in the Federal Register.[41] Section 316(b) and resulting impacts to existing and future resources will depend on how the rule is implemented in each state.

Coal Combustion Residuals (CCRs)

The CCRs proposed EPA rule would regulate coal ash to address the disposal risks from waste generated by electric utilities and independent power producers. The EPA is considering two possible options for public comment regarding the management of coal ash. Under the first proposal, the EPA would list these residuals as special wastes subject to regulation under subtitle C of the Resource Conservation and Recovery Act (RCRA) when destined for disposal in landfills or surface impoundments. Under the second proposal, the EPA would regulate coal ash under subtitle D of RCRA, the section for nonhazardous wastes.[42]

Canadian Provincial Regulations

Canadian regulations for CO_2 emissions were finalized in September 2012, establishing regulations to reduce emissions by requiring stringent performance standards for new coal-fired electricity generation units and to coal-fired units that have reached the end of their economic life. Additional impacts are expected as the rule comes into effect in July 2015, and units commissioned prior to 1975 will have reached the end life after 50 years, or by 2019 (whichever comes first, depending on whether some units adopt carbon capture and sequestration technology). Other provincial regulations have been or continue to be developed with coordination between the provincial and federal governments.

Saskatchewan (MRO-SaskPower) is seeking greater flexibility to meet GHG regulations by working with the provincial and federal governments to develop an equivalency agreement. Development and finalization of federal regulations to limit CO_2 from natural-gas-based electricity generation could cause Saskatchewan to modify operational use of existing gas units in order to remain compliant. Pending federal natural gas rules for electricity generation will impact the timing and nature of capital projects and potential retirements, and of replacement/new energy decisions. These regulations are constantly monitored and are included in resource adequacy assessments. Saskatchewan plans to include sufficient time to perform retrofits or replacements to meet required regulations. Saskatchewan has not yet experienced any reliability issues related to GHG regulations and is expected to effectively mitigate any that arise.

Ontario (NPCC-Ontario) was the first Canadian province to phase out coal-fired capacity in 2014, while adding replacement capacity including nuclear, natural-gas, and variety of renewable resources. Similarly, MRO-Manitoba Hydro, which is predominately hydro, has one smaller coal unit remaining that will be impacted by the Manitoba Climate Change and Emissions Reduction Act and the Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations.[43] This unit is already regulated such that it can only be operated to provide for emergency operations.

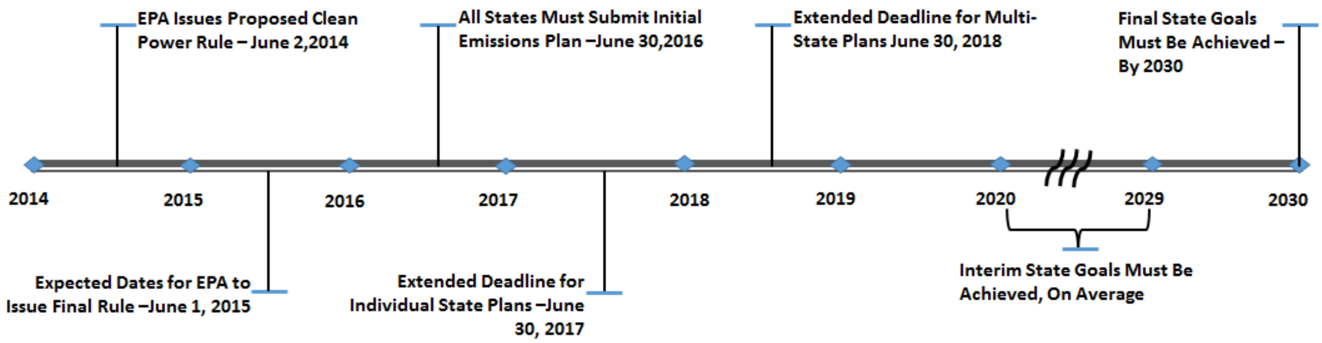
Overview of EPA's Proposed Clean Power Plan[44]

The EPA proposed draft rule released in June 2014 is aimed at reducing carbon dioxide emission from power plants to 30 percent below the 2005 levels by 2030.[45] According to the EPA analysis of the proposed plan, between 108 and 134 GW of fossil-fired and nuclear retirements would occur by 2020 (depending on the state of regional implementations of Options 1 or 2).[46] The proposed plan would apply to all fossil-fired generating units that meet four combined qualification criteria: (1)

[41] Federal Register Notice - August 15, 2014.
[42] EPA: Coal Combustion Residuals - Proposed Rule.
[43] Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations.
[44] Additional information and analysis of the proposed CPP was performed by Energy Ventures Analysis, Inc. (EVA) and provided to NERC in September 2014 for use in this assessment.
[45] EPA: Clean Power Plan Overview.
[46] Regional implementation of Option 2 assumes 108 GW of retirements (includes CC, Coal, CT, Nuclear, O/G, and IGCC) by 2020. State implementation of Option 1 assumes 134 GW of retirements (includes CC, Coal, CT, Nuclear, O/G, and IGCC) by 2020. For additional information, see Regulatory Impacts Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants (June 2014) and supporting IPM Model documentation and data.

units that commenced construction prior to January 8, 2014;[47] (2) units with design heat input of more than 250 MMBtu/hour, (3) units that supply over one-third of their potential output onto the power grid, and (4) units that supply more than 219,000 MWh/year on a three-year rolling average to the power grid.[48] Given these criteria, NERC estimates that nearly all U.S. fossil-fired power plants will be subject to the rule. The timeline of the proposed plan is provided below.

EPA Proposed Clean Power Plan Timeline



Within one year of finalizing the rule—expected in June 2015—state environmental agencies must submit implementation plans to the EPA for approval. Submitted state-specific plans, due in June 2016, must outline requirements and enforceable limitations for affected generating units to meet the rule's average CO_2 emission rate goal for each state within two compliance periods: (1) an initial 10-year average interim emission rate limit for the period 2020–2029, and (2) a final annual emission rate limit starting in 2030.

The EPA provides states with an option to convert CO_2 emission rate limitation into an annual mass-based limitation. It is likely that most states will elect to pursue this option due to the challenges state permitting agencies have in developing unit-specific emission rate limitations. The simpler mass-based CO_2 emission cap program also negates the need for state legislative action to authorize agencies to limit plant output and enact an enforceable program for compliance with average emission rates.

The EPA would have one year to review and approve implementation plans for each state in June 2017. Under this schedule, impacted generating units would have two and a half years to develop respective compliance strategies and potentially permit, finance, and build needed replacement capacity and transmission. In its current form, this implementation schedule would be a challenge for states to implement and for affected sources to comply with, especially given the expected legal challenges to both the EPA and state rules. In recognition of these challenges, the EPA would provide states with a one-year compliance extension to June 2017 if justification is provided and a two-year extension (June 2018) for states that elect to develop

EPA's Proposed Clean Power Plan: Options 1 & 2

The EPA is proposing a best system of emission reduction (BSER) goal approach, referred to as Option 1, and is taking comment on a second approach referred to as Option 2.

Option 1: involves higher deployment of emission reduction but allows a longer time frame to comply (2030).

Option 2: has a lower deployment of emission reductions over a shorter time frame (2025) by each state. The proposed guidelines would also allow states to collaborate and to demonstrate emission performance on a multi-state basis, in recognition that electricity is transmitted across state lines.

The BSER is not intended to impact resource planning and does not dictate retirements, additions, or operating practices for individual units. Instead, it would provide state emission rate limits that would shape the future resource mix through state and market processes in subsequent years as SIPs and multi-state plans are developed and implemented.

[47] All sources starting construction after January 8, 2014, would be subject to new source performance standards and exempt from the EPA Clean Power Plan requirements.
[48] Federal Register Proposed Rule - June 18, 2014.

multi-state (regional) programs (e.g., Regional Greenhouse Gas Initiative (RGGI)). While the EPA extensions apply to state plan submissions, the January 1, 2020, program start date for affected sources would not be extended. Therefore, the impacted fossil-fired units may be left with as little as six months to develop and implement compliance plans. Considering the number and variety of outcomes for each of the proposed rule scenarios, the industry should initiate planning immediately upon approval of the final rule.

Based on EPA analysis of historical data about emissions and the power sector, the proposed Clean Power Plan is to create a consistent national formula for reductions, reflecting their building block assumptions. The formula applies the four building blocks to each state's specific information, yielding a carbon intensity rate for each state.[49]

EPA's Proposed Clean Power Plan: Four Building Blocks

The EPA projects that by 2030, compliance with the objectives will reduce U.S. power industry CO_2 emissions to 30 percent below 2005 levels. The EPA developed state-specific CO_2 emission rates by applying the following four "best system of emission reduction" approaches and assumptions:

Make fossil fuel power plants more efficient by implementing a 6 percent (on average) unit heat rate improvement for all affected coal-fired units. The EPA suggests that some plants could further improve process efficiency by 4 percent through the adoption of best operational practices, and an additional 2 percent through capital upgrade investments.

Use low-emitting power sources more by re-dispatching existing NGCC units before the coal and older oil/gas steam units. EPA draft rate limitations include CO_2 reduction assumptions from the ongoing increases in the use of NGCC capacity (with up to a 70 percent capacity factor). This additional NGCC capacity (440 TWh/year) displaces coal (376 TWh/year) and oil/gas steam generation (64 TWh/year) by 2020, compared to 2012 levels.

Use more zero- and low-emitting power sources through building capacity by adding both non-hydro renewable generation and five planned nuclear units. EPA calculations assume qualifying non-hydro renewable generation can grow rapidly from 218 TWh/year in 2012 to 281 TWh/year by 2020, to reach 523 TWh/year by 2030.

Use electricity more efficiently by significantly expanding state-driven Energy Efficiency programs to improve annual electricity savings by up to 1.5 percent of retail sales per year. The calculation assumes the states and industry can rapidly expand Energy Efficiency programs to increase savings from 22 TWh/year in 2012, to 108 TWh/year in 2020, and to 380 TWh/year by 2029. Ultimately, EPA energy efficiency assumptions suggest that electric power savings will outpace electricity demand growth, resulting in declining electricity usage from 2020 through 2030.

Reliability Considerations for EPA's Proposed Clean Power Plan

To comply with the proposed Clean Power Plan, states are expected to select the mass-based limitation approach over the emission rate approach due to its greater flexibility and ease to enforce and implement. While the power industry has been successful in complying with prior mass-based emission cap and trade programs (e.g., Acid Rain program, Clean Air Interstate Rule, and RGGI) without creating major electric grid reliability problems, the proposed Clean Power Plan impacts a larger amount of capacity (over 700,000 MW) in a relatively short time frame, potentially posing greater grid reliability impacts compared to prior environmental compliance programs. Changes in generation resources, dispatch, and delivery require comprehensive local and regional reliability assessments. These assessments are needed to identify necessary transmission system enhancements to provide for reliable delivery, system stability, voltage support, and other system reliability needs. Accordingly, the following reliability challenges warrant further consideration by policy makers:

EPA Assumptions Require Accelerated Coal-Fired Reduction beyond the 2014LTRA Reference Case

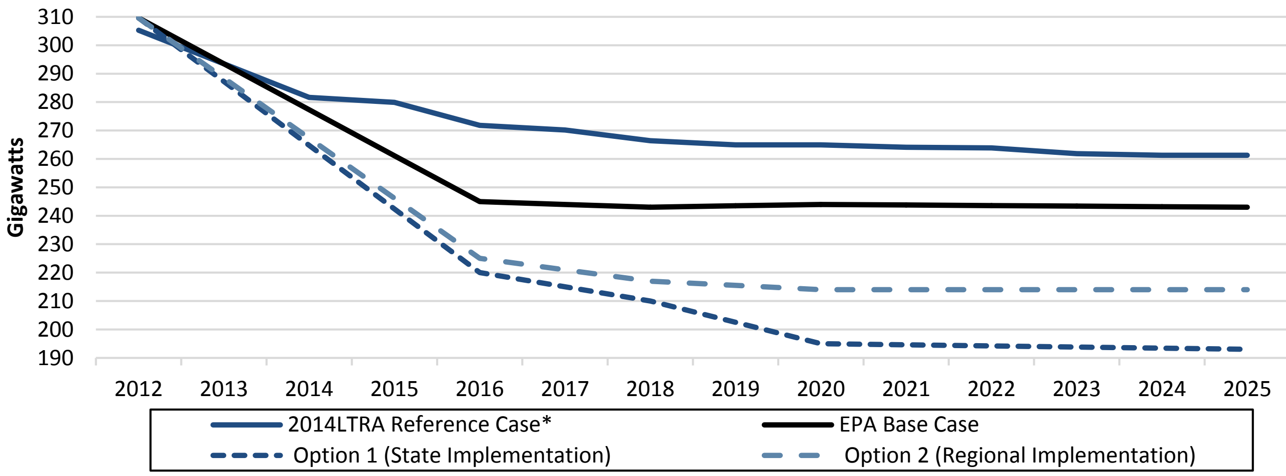
Although the Clean Power Plan may not become enforceable until 2020, its effect may overshadow and change large retrofit capital decisions needed to comply with earlier EPA regulations—primarily the Mercury and Air Toxics Standards (MATS). EPA's base case projections, with existing regulations, indicate that total coal-fired capacity will decline rapidly from approximately 310 GW in 2012 to just 245 GW by 2016 and 243 GW by 2025. The EPA's base case—including existing

[49] EPA Fact Sheet: Clean Power Plan - National Framework for States.

regulations, but excluding potential impacts of the proposed Clean Power Plan—assumes a significant reduction in coal-fired capacity by 2016: 27.2 GW beyond what is projected in the 2014LTRA reference case.

The EPA released a report titled *Regulatory Impacts Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants*. According to this analysis, the state implementation of Option 1 would result in the largest reduction in coal to 193 GW by 2025, while the regional implementation of Option 2 would result in the smallest reduction in coal to 214 GW by 2025.[50] These two options are shown in the table and chart below, along with the 2014LTRA reference case (total on-peak contribution for all coal-fired units in the United States).

Coal Projections: 2014LTRA Reference Case & EPA Clean Power Plan Assumptions



NERC 2014LTRA Reference Case - Total On-Peak Capacity (GW)	2016	2018	2020	2025*
Total Coal (Existing-Certain and Tier 1 Capacity Additions)	271.8	266.4	264.9	261.3
EPA Analysis of the Proposed Clean Power Plan - Total Coal Generating Capacity (GW)	**2016**	**2018**	**2020**	**2025**
Base Case	244.6	243.3	243.6	243.3
Option 1 (Regional Implementation)	217.5	207.8	198.0	197.2
Option 1 (State Implementation)	219.7	210.4	195.1	193.1
Option 2 (Regional Implementation)	225.0	217.3	214.3	214.3
Option 2 (State Implementation)	227.8	219.6	210.6	210.6
EPA Assumed Coal Reduction Beyond NERC 2014LTRA Reference Case (GW)	**2016**	**2018**	**2020**	**2025**
Base Case	27.2	23.1	21.3	18.0
Option 1 (Regional Implementation)	54.3	58.6	66.9	64.1
Option 1 (State Implementation)	52.1	56.0	69.8	68.2
Option 2 (Regional Implementation)	46.8	49.1	50.6	47.0
Option 2 (State Implementation)	44.0	46.8	54.3	50.7

*The 2014LTRA Reference Case includes data projections through 2024. 2024 projections were applied for 2025.

<u>Ongoing Coal Retirements Contribute to Increased Dependence on Natural Gas</u>

The EPA's proposed Clean Power Plan will accelerate the shift in the generation mix from coal to natural gas. The EPA projects that the natural gas market portion of total U.S. power generation will grow from 29 percent (energy) in 2013 to 33–34 percent between 2020 and 2030. A recent study conducted by Energy Ventures Analysis (EVA) indicates that natural gas generation will increase by an additional 400–450 TWh/year due to impacts of the proposed Clean Power Plan. This will result

[50] Regulatory Impacts Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants (June 2014) and supporting IPM Model documentation and data.

in an increase in the contribution of gas-fired generation in the energy market to a share of 35 percent in 2020, 39 percent in 2030, and 49 percent in 2040.[51]

With this 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 a suitable generating fleet is available to maintain BPS reliability. Adverse winter weather, such as the 2014 polar vortex, provided an example of the potential impacts to supply and transportation.[52] While several gas pipeline construction projects are underway to address deliverability issues in the Northeast, the shift toward additional natural gas consumption, as outlined in the proposed Clean Power Plan, would create additional pipeline needs. Sufficient lead times (more than three years) will be needed to plan and build new pipelines. This calls for a careful and deliberate review of the way in which natural gas is currently delivered and used by the electricity industry, so adjustments can be made to support enhanced reliability of both the gas and electric systems.

Increases in Variable Generation Are Creating Operational and Planning Challenges

The EPA Clean Power Program would provide states and developers additional incentives to rapidly expand their non-hydro renewable capacity to displace existing coal generation. The incremental increases in renewable generation would consist primarily of new wind and solar capacity.

To support such variable generating capacity increases, the power industry would need to invest heavily to expand transmission capacity to access more remote areas with high-quality wind resources. This further highlights the need for a resource mix with sufficient essential reliability services[53] that support integration and reliable operation. Given the natural wind variability in remote locations, these incremental wind project resources would have relatively low capacity factors that would require substantial new transmission.

Large penetration of VERs will also require maintaining a sufficient amount of reactive support, and ramping capability. More frequent ramping needed to provide this capability could increase cycling on conventional generation. This could contribute to increased maintenance hours and/or higher forced outage rates, potentially increasing the reserve requirements. Storage technologies can also support ramping needs and allow VERs to be more easily dispatched. While large-scale energy storage is not yet commercially viable,[54] the development of these technologies will enhance the industry's ability to balance load and resources as more VERs are added to the system.

Based on industry studies and prior NERC assessments,[55] as the penetration of variable generation increases, maintaining system voltage stability can become more challenging. Additional studies will be needed to further understand potential challenges that may indirectly result from the proposed Clean Power Plan. Additional information on the integration of VERs is included in the next section of this report.

Higher Retail Electricity Prices Could Cause a Sharp Increase in Distributed Energy Resources (DERs)

The EPA projects that retail electricity prices will increase by \$1/MWh to \$18/MWh under the Clean Power Plan[56] resulting from a combination of higher natural gas prices and the implementation of new carbon penalties on impacted fossil-fired

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[51] Energy Ventures Analysis: FuelCast – The Long-Term Outlook 2014, October 2014. Some information and analysis of the proposed CPP was performed by Energy Ventures Analysis, Inc. (EVA) and provided to NERC in September 2014 for use in this assessment.

[52] NERC Polar Vortex Review (September 2014).

[53] For additional information, see the NERC Essential Reliability Services Task Force.

[54] Pumped storage offers tremendous ramping capabilities to the BPS; however, increases in this technology are not likely, due to land restrictions, permitting limitations, and environmental opposition. Less than 1 GW of new pumped storage capacity is projected over the next 10 years.

[55] NERC-CAISO Joint Report: Maintaining Bulk Power System Reliability While Integrating Variable Energy Resources – CAISO Approach; other industry reports include those developed by the Integration of Variable Generation Task Force (IVGTF); Integrating Variable Renewable Energy in Electric Power Markets: Best Practices from International Experience (Appendix D).

[56] Regulatory Impacts Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants (June 2014) and supporting IPM Model documentation and data.

generators.[57] As retail power prices rise, some existing customers may resort to the installation of renewable DERs, when economically advantageous—especially in locations with prominent solar and wind resources. Depending on the price advantage, the market penetration of DERs could be substantial, creating potential reliability impacts for grid operators that don't have direct control of these resources. In some cases, resources without the direct control of the System Operator fall outside the jurisdiction of state utility regulators. A potential risk in additional DERs is the temporary displacement of utility-provided service, which could create additional planning challenges, considering utilities must act as a secondary supplier of electricity. This is particularly the case during periods when variable DERs are experiencing high levels of intermittency. This issue does not exist for utility-scale wind energy, which offers ride-through capabilities and other essential reliability services.

Generation variability over different periods (seconds, minutes, hours) and the uncertainty associated with forecasting errors are operational characteristics of wind and solar resources. Similarly, large onsets of non-dispatchable resources have been shown to create the potential for operational challenges in California (particularly for solar),[58] as well as Germany (particularly for wind). Additional information on DERs is included in the Other Reliability Issues section of this report.

EPA's Assumed Substantial Increases in Energy Efficiency Programs Exceed Recent Trends and Projections

The EPA assumes up to a 1.5 percent annual retail sales goal for its incremental growth in energy efficiency savings in its rate calculation for best practices by state that will be triggered by the carbon regulation. The EPA assumes that the states and industry would rapidly expand energy efficiency savings programs from 22 TWh/year in 2012, to 108 TWh/year in 2020, and reach 380 TWh/year by 2029. With such aggressive energy efficiency expansion, the EPA assumes that energy efficiency will grow faster than electricity demand, with total electricity demand shrinking beyond 2020. The implications of this assumption are complex. If the EPA-assumed energy efficiency growth rates cannot be attained, additional carbon reduction measures would be required, primarily through reduced fossil-fired generation in applicable states. More low-emitting and/or new generating capacity (not regulated under EPA Clean Power Plan) would need to be built. Construction of new replacement capacity would take time to plan, permit, finance, and build. If these needs are not identified at an early enough stage, either grid reliability or state CO_2 emission goals could be compromised.

NERC collects on-peak energy efficiency data with reductions that are already reflected in the load forecasts for each Assessment Area. Based on the EPA's projections for energy efficiency growth, a 1.5 percent annual increase is substantially above what has been examined in current and prior LTRA reference cases. Projected (on-peak) annual energy efficiency growth as a portion of Total Internal Demand since 2011 has ranged from only 0.12 to 0.15 percent, as shown in the table below.

2011-2014 LTRA Energy Efficiency Growth

LTRA	10-Year Growth of Energy Efficiency (%)	Portion of Total Internal Demand (%)		Annual Growth in Relation to Total Internal Demand (%)
		Year 1	Year 10	
2011	10.7	0.59	1.63	0.12
2012	12.2	0.72	1.88	0.13
2013	11.6	0.92	2.02	0.12
2014	13.4	0.87	2.25	0.15

[57] According to EIA's 2014 Annual Energy Outlook, closing coal plants will drive up natural gas prices by 150 percent over 2012 levels by 2040. This cost increase will cause electricity prices to jump 7 percent by 2025 and 22 percent by 2040. This is because natural gas prices are a key determinant of wholesale electricity prices, which in turn are a significant component of retail electricity prices. Accordingly, the cases with the highest delivered natural gas prices also show the highest retail electricity prices.

[58] NERC-CAISO Joint Report: Maintaining Bulk Power System Reliability While Integrating Variable Energy Resources – CAISO Approach; other industry reports include those developed by the Integration of Variable Generation Task Force (IVGTF); Integrating Variable Renewable Energy in Electric Power Markets: Best Practices from International Experience (Appendix D).

Transmission Considerations

The EPA assumes that adequate transmission capacity will be available to deliver any resources located in or transferred to a given area.[59] However, given the significant changes occurring in the resource mix, it is likely that additional new transmission, or enhancements to existing transmission, will be needed in some areas, particularly those with existing and planned resource additions that include higher penetration of renewable generation. Additionally, as replacement generation is constructed, new transmission will be needed to interconnect this capacity. The designing, engineering, and contracting requirements for these new lines, as well as siting, permitting, and various federal, state, provincial, and municipal approvals often require more than five years to complete. Thus, industry should consider the long lead times required for new transmission.

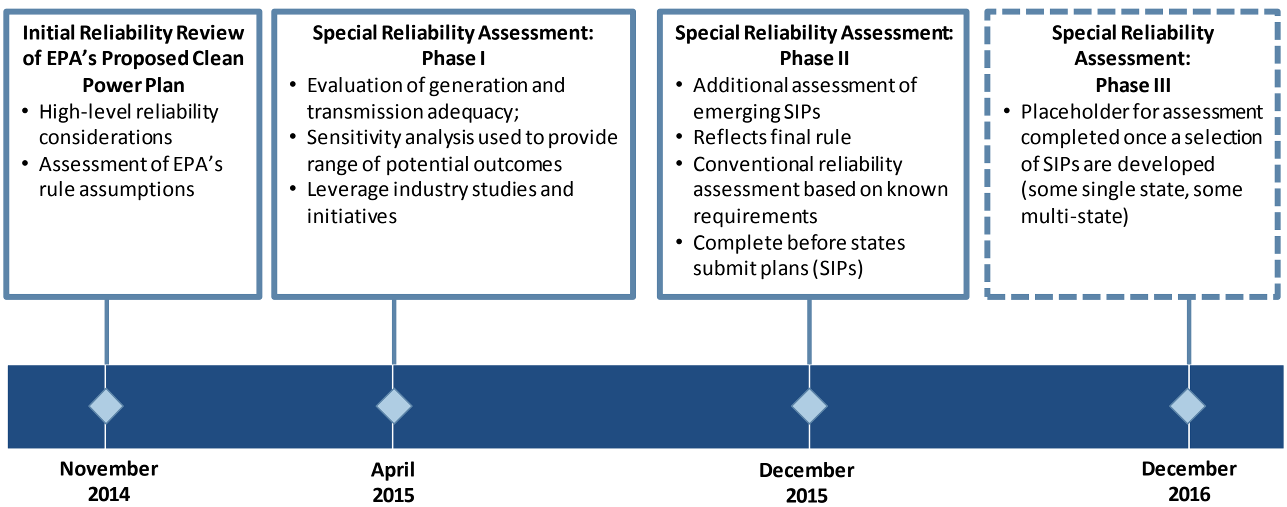
[59] Regulatory Impacts Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants (June 2014) and supporting IPM Model documentation and data.

Key Reliability Finding #2
Environmental Regulations Create Uncertainty and Require Assessment

Recommendations and Next Steps

NERC Board of Trustees Endorsed Assessment Plan: The NERC Board of Trustees endorsed a plan to review and assess the reliability impacts of the EPA proposal at its August 2014 Board meeting. This plan included a preliminary review of the assumptions and potential major reliability impacts resulting from the implementation of the EPA's notice of proposed rulemaking under Section 111(d). With the EPA scheduled to finalize its rule by June 2015, NERC will develop a reliability assessment that will focus on a more detailed analysis of the respective reliability impacts.

Phased Approach: An initial review of the EPA's proposed Clean Power Plan is included within this assessment. NERC will release an initial high-level reliability review based on the assumptions used in the proposed rule in November 2014. Subsequently, NERC will conduct a special reliability assessment to be released in phases. The first phase, expected to be released in April 2015, will be a detailed assessment to evaluate generation and transmission adequacy and leverage industry studies, prior to rule finalization. The second phase, with a target release date in December 2015, will incorporate the final rule prior to states submitting implementation plans to the EPA in June 2016. Additionally, a Phase III approach is tentatively planned for December 2016, which will examine finalized state implementation plans. A proposed timeline of these activities is provided below. Additionally, NERC will address reliability constraints identified and incorporated into transmission expansion plans for future long-term and seasonal assessments.

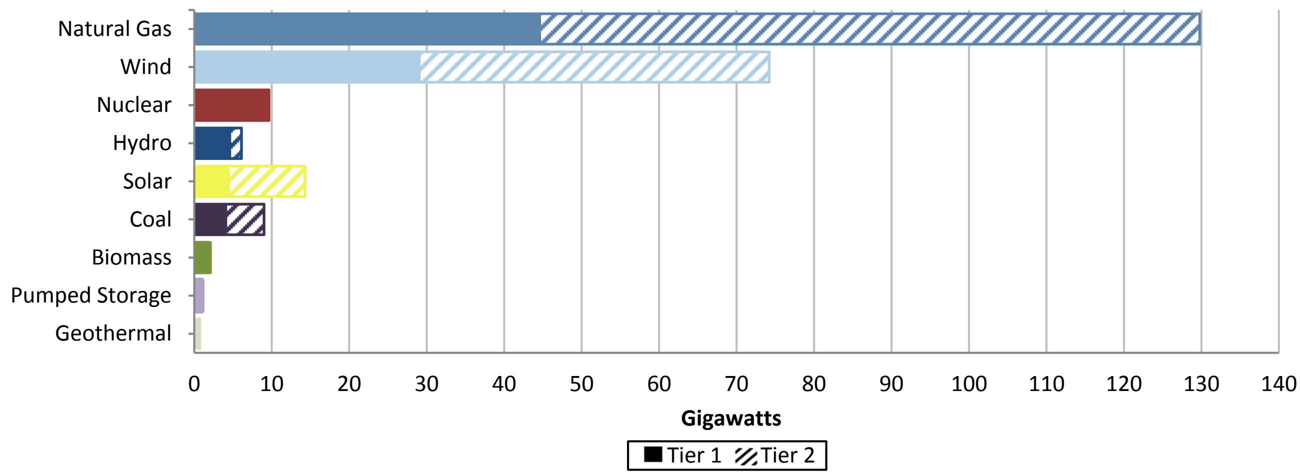


The NERC Steering Groups and Ongoing Stakeholder Involvement: Industry members should participate in steering groups to provide ongoing input on the EPA's proposed Clean Power Plan. NERC will also utilize its stakeholder process through the MRC and PC to solicit input and collaborate to identify and address potential reliability impacts due to the proposed rule.

3. A Changing Resource Mix Requires New Approaches for Assessing Reliability

North America's resource mix is undergoing a significant transformation at an accelerated pace with ongoing retirements of fossil-fired and nuclear capacity and growth in natural gas, wind, and solar resources. This shift is caused by several drivers, primarily existing and proposed federal, state, and provincial environmental regulations. Other drivers include lower natural gas prices due to abundant supply, along with policies incentivizing the movement from conventional energy resources toward ongoing integration of both distributed and utility-scale renewable resources. The convergence of these resource mix changes is directly impacting the behavior of the North American BPS. These developments will have important implications on industry planning and operations, as well as how NERC assesses reliability.

NERC-Wide Tier 1 and 2 Additions (2015–2024)[60]



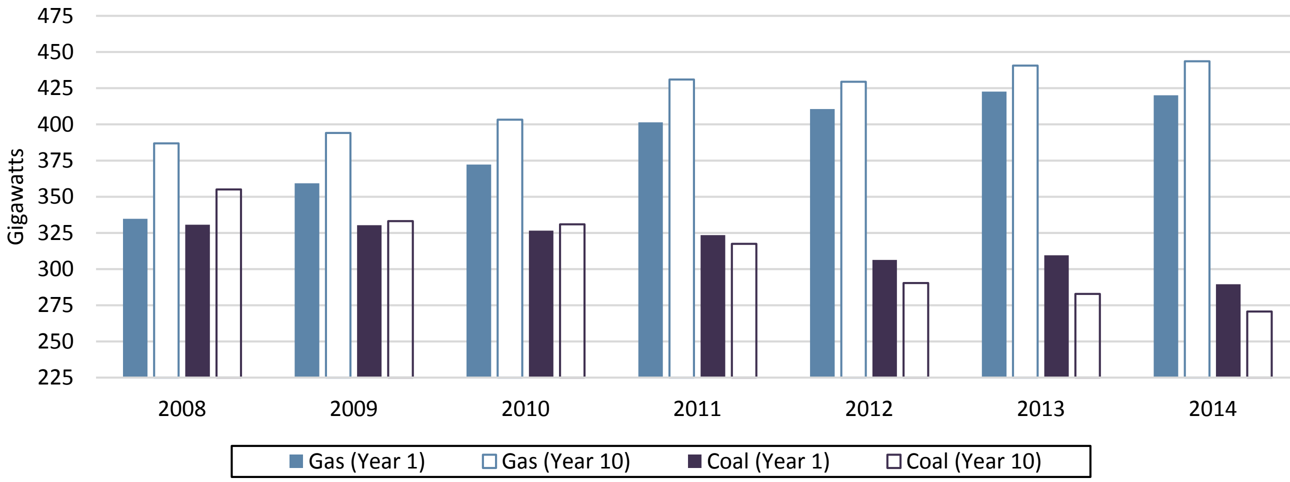
Increased Dependence on Natural Gas Due to Ongoing Decline in Coal-Fired Capacity

Natural-gas-fired capacity continues to be the replacement capacity of choice for resource planners as other fossil-fired units are retired. This trend is expected to continue with the addition of 44.6 GW of gas-fired capacity, accounting for nearly half of all Tier 1 nameplate capacity additions during the next decade. By 2024, natural gas will contribute 42 percent of the on-peak resource mix, compared to 40 percent in 2015.

A variety of drivers makes natural-gas-fired capacity an attractive resource. Most impactful is the price of natural gas, which is projected to remain low (relative to other fuels), with abundant supplies from shale formations throughout North America.[61] Additionally, the emergence of more efficient NGCC generating technology requires lower engineering, procurement, and construction costs. The shorter build times for NGCC plants can help resource planners avoid procurement challenges that exist with other options. Perhaps the most impactful benefit 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.

[60] Tier 1 includes capacity additions that are either under construction or have received approved planning requirements. Tier 2 includes capacity additions that have requested but not received approval for planning requirements.
[61] EIA Annual Energy Outlook 2014.

2008–2014 LTRA 10-Year Net Change Indicates Ongoing Declines in Coal and Growth in Gas



As planners rely more on natural gas for both baseload and on-peak capacity, it is important to also examine potential risks associated with increased dependence on a single fuel type. Currently, natural-gas-fired capacity accounts for large portions of both the total and on-peak generation mix in several Assessment Areas for both existing capacity and planned additions.

Assessment Areas with Natural-Gas-Fired Capacity Accounting for Over One-Third of Existing Nameplate Capacity

	Nameplate Capacity (GW)		On-Peak Capacity (GW)		10-Year Nameplate Capacity Additions (GW)		
Assessment Area	Gas-Fired	Portion of Total	Gas-Fired	Portion of Total	Tier 1	Tier 2	Tier 3
FRCC	40.2	64%	33.9	63%	10.1	0.0	0.0
MISO	69.0	39%	58.7	41%	2.8	0.0	10.0
NPCC-New England	18.6	54%	13.3	43%	1.1	3.3	0.0
NPCC-New York	21.0	55%	14.2	40%	0.0	3.5	0.0
PJM	80.0	43%	56.5	32%	10.0	47.5	0.0
SERC-SE	31.2	47%	28.4	46%	0.0	0.0	2.6
SPP	32.3	40%	30.2	47%	1.1	0.7	5.7
TRE-ERCOT	48.4	54%	45.2	63%	4.9	21.5	0.0
WECC-CA/MX	47.7	61%	43.9	70%	5.5	6.2	0.9
WECC-RMRG	7.2	36%	6.2	41%	1.2	0.0	0.0
WECC-SRSG	19.5	47%	16.3	50%	0.6	1.0	3.0

Higher Reliance on Natural Gas Further Exposes BPS to Impacts from Fuel Transportation Disruptions

The electricity sector's growing reliance on natural gas raises concerns regarding the electricity infrastructure's ability to maintain BPS reliability when facing constraints on the natural gas pipeline system. The extent of these concerns from Independent System Operators (ISOs), Regional Transmission Organizations (RTOs), electricity market participants, industrial consumers, national and regional regulatory bodies, and other government officials varies throughout North America; however, concerns are most acute in areas where power generators rely on non-Firm pipeline transportation as natural gas used for power generation continues to rapidly grow.

Natural gas supply and transportation infrastructure adequacy concerns, particularly in certain parts of North America, are causing NERC, industry, and policymakers to refocus attention on the interdependency between natural gas and electricity industries. System Operators and resource planners continue to make considerable progress to consider fuel supply and transportation adequacy as a formal part of reliability assessment.

Under average annual operating conditions, most pipelines have some level of capacity that is not used by Firm customers and is therefore available for non-Firm (interruptible) loads, including natural gas generators with non-Firm contracts. If the requirements for non-Firm deliveries are communicated to the pipeline within the nomination cycle timeline, the pipeline can use facilities to enable delivery of natural gas requested up to its allowed physical capabilities. This is the normal procedure for interruptible transportation service or capacity release from Firm shippers. In some power markets or areas where there is excess natural gas pipeline capacity available, these low-capacity-factor units can rely upon interruptible service with a reasonable degree of certainty that service will be available.

However, as growth in natural gas demand increases, pipeline transportation constraints will have a greater impact on natural-gas-fired generation, making units with non-Firm service vulnerable to more frequent interruption. If a generator served by interruptible service has no secondary fuel source, then that generating capacity could be unavailable during peak periods. While coordination efforts between the gas and electric industries continue to improve, the potential still exists for a mismatch between the availability of natural gas delivery and natural gas demand for electricity generation. This can be particularly challenging in areas where a significant amount of the capacity—or more importantly, reserve capacity—is susceptible to natural gas transportation interruptions, potentially resulting in more frequent generator outages.

What Does the 2014 Polar Vortex Tell Us about the Future?

As more generating capacity is natural gas fired, additional assessment of Firm pipeline transportation is needed to ensure sufficient gas is available during both normal operation and periods of high stress, as exemplified by the polar vortex event.[62]

Overdependence on a single fuel type increases the risk of common-mode disruptions as experienced during recent extreme weather events. Disruptions in natural gas transportation to power generators have prompted the gas and electric industries to further examine reliability implications associated with increasing natural-gas-fired generation.

As highlighted in this assessment, most new capacity additions are natural gas fired. Over the past two years, both industries have made significant progress to better link the operations of these vastly different industries.

The gas and electric industries operate under different regulatory structures and rules that affect how infrastructure is planned, built, maintained, and ultimately operated. As the dependence on natural-gas-fired generation increases in North America, the natural gas and electricity industries continue coordination efforts. The relationship between natural-gas-fired generation availability and low temperatures further challenges the industry's ability to manage extreme weather conditions, particularly when conditions affect a wide area and there is less support available from within an interconnection. These extreme weather events should serve as early indicators of more frequent impacts if natural gas supply and transportation is outstripped by the demand from new natural-gas-fired units continue to rely on interruptible gas.

2014 Polar Vortex
NERC Scenario: Considerations for Long-Term Planning

The 2014 polar vortex, impacting a majority of the midwestern and northeastern United States and southern Canada, tested the resilience of the North American BPS. This event served as an example of how extended periods of cold temperatures have direct impacts on fuel availability, especially for natural-gas-fired capacity. Higher-than-expected forced outages were observed during the polar vortex, particularly for natural-gas-fired generators, as well as higher-than-forecast peak demand. The following impacts were caused by fuel delivery challenges and extended periods of low temperatures:

Fuel Delivery

- Natural gas interruptions: supply injection, compressor outages, and one pipeline explosion
- Oil delivery problems
- Inability to procure gas
- Fuel oil gelling

Low Temperatures

- Low temperature limits for wind turbines
- Icing on hydro units
- Failed auxiliary equipment
- Stress of extended run times
- Frozen instrumentation (drum level sensors, control valves, and flow and pressure sensors

To examine the potential impacts of a similar event in the future, NERC ran scenarios on select Assessment Areas (SERC-E, PJM, MISO, and TRE-ERCOT) that experienced significant loss of generation during the 2014 polar vortex event. Actual forced outage data were applied as derates to existing and projected (Tier 1) capacity projections using the 2014LTRA reference case. Load was assumed to be consistent with the extreme loads that were observed.

Based on this NERC scenario, projected reserve margins combined with the projected increased dependence on natural gas will increase the adverse impacts to BPS reliability if similar extreme weather events occur in the future.

The complete scenario is included as Appendix III.

[62] For additional information, see NERC's Polar Vortex Review (September 2014).

Summer Considerations for Natural Gas

While gas-electric supply and transportation issues are especially important during the winter season, the summer season presents a separate set of potential reliability impacts that requires ongoing attention. Specifically, the electricity industry must be aware of pipeline maintenance schedules and promote ongoing coordination to ensure individual generators do not face supply shortages—principally those that can be resolved through coordination—during peak conditions.

Recent and Planned Industry Initiatives to Address Increasing Dependence on Natural Gas for Electric Power

The gas and electric industries have recently made substantial progress to enhance coordination and develop new strategies to address system reliability due to fuel supply and transportation concerns. These efforts helped to reduce the severity of impacts experienced during the 2014 polar vortex event. These developments are presented below for Assessment Areas with gas-fired capacity that accounts for over one-third of their existing generation mix.

FRCC

FRCC performs an annual review of natural gas infrastructure and maintains a Generating Capacity Shortage Plan that outlines communications, environmental, and political procedures in the event of a fuel shortage.

MISO

MISO developed procedures to facilitate communication between power plant operators and natural gas transportation service providers under which MISO is notified of all operational flow orders and other information to raise awareness of potential issues that may impact generation capacity.

The MISO Electric and Natural Gas Coordination Task Force (ENGCTF)[63] has also developed comprehensive examinations of three key gas-electric coordination challenges: (1) addressing gas-electric scheduling and market timeline misalignment, (2) capturing fuel risk in the resource adequacy construct, and (3) strengthening gas-electric communications. Recent ENGCTF developments include:

- Natural gas infrastructure displays in control rooms
- An online platform to consolidate natural gas pipeline operational flow orders and critical notices
- A database linking natural gas generators to their fuel supply sources, as well as to operational flow orders and critical notices
- A preliminary LOLE study, focusing on the concern of increased probability of load loss resulting from gas-fired generators' inability to access fuel during peak energy operating conditions

Additional topics are currently being explored by the ENGCTF:

- Polar vortex experiences (natural gas availability and enhanced RTO/pipeline communications)
- Potential competition between generator demand and upcoming gas storage injection
- Process and timeline considerations for natural gas infrastructure build-out

NPCC-New England

After the "cold-snap" of January 2004, ISO New England and the Northeast Gas Association (NGA) established the Electric-Gas Operations Committee (EGOC),[64] which meets quarterly to discuss issues common to both gas and electric sectors. ISO-NE also participates in the following activities: (1) coordinated studies with NYISO, PJM, Ontario, TVA, and MISO; (2) multi-regional static/transient hydraulic natural gas analyses; (3) NERC/NPCC natural gas assessments; and (4) the Eastern Interconnection Planning Collaborative (EIPC) Gas-Electric System Interface Study.[65] ISO-NE has also performed internal studies to evaluate regional pipeline capacity and local distribution company (LDC) operations, dual-fuel capability, environmental issues of generators, liquid fuel availability, and regional storage capability. Recent operational changes include: (1) moving forward the scheduled timelines of participant bid submittals; (2) processing and publishing the day-

[63] MISO Electric and Natural Gas Coordination Task Force.
[64] ISO-New England Electric/Gas Operations Committee.
[65] EIPC Gas-Electric Study.

ahead market results; (3) implementing a participant re-offer period; and (4) completing the resource adequacy assessment in order to provide startup notification to long-lead time resources that are needed to operate the next day to ensure system or sub-area reliability or transmission security.

NPCC-New York

NPCC-New York developed a cold weather procedure to monitor gas nominations, oil inventories, and expected oil replenishment schedules for all dual-fuel, gas-fired, and oil-fired generators prior to each cold day. NPCC-New York also conducts an annual survey each fall that requests information on gas transportation arrangements, oil inventory, and oil replenishment capability from the same generators and uses this fuel information to monitor a generator's capability to meet the day-ahead electricity schedules. NYISO is also working to increase awareness of the gas system in the control room in order to provide greater visibility into gas pipeline system conditions and generator fuel capability. This includes the ability to monitor the actual fuel capability of units. This will provide additional real-time information to help operations maintain electric system reliability—particularly during periods of the more restrictive hourly operational flow orders. Finally, NYISO is coordinating efforts with the interstate, intrastate, and LDC pipelines to incorporate gas pipeline outage scheduling with electric system outage scheduling.

PJM

PJM recently formed the Gas Electric Senior Task Force (GESTF)[66] to help identify and examine gas-electric issues and develop solutions. PJM continues to participate in both the EIPC Gas Electric System Interface study and the North American Energy Standards Board (NAESB) process to explore consensus development with the gas industry on market coordination issues. PJM also coordinates with other ISO/RTOs to improve and standardize communication practices with the gas pipelines. Increased coordination between gas pipelines and generator owners is a priority to ensure sufficient availability of resources, particularly during the 2014 polar vortex. PJM is addressing differences between the timing of generators' required natural gas purchase commitments and PJM's day-ahead energy market commitment.

SERC

In SERC, many plants are covered by tolling agreements that include Firm pipeline transportation. The entity identified in the tolling agreement performs planning and operational procedures and coordination activities. Several entities individually perform these activities. Entities also coordinate activities surrounding facility startups and shutdowns, pipeline warnings, and pipeline outages or restrictions. Larger entities in SERC have a centralized unit commitment planning function that includes gas trading and power trading functions, as well as the generation dispatch function. Entities are also communicating with the pipeline operators to determine any potential issues in the development of contingency plans as required, including the acquisition of additional Firm transportation and storage capacity to meet projected demands.

SERC entities continue to work closely with FERC and NAESB from both a policy and business standards perspective on gas-electric coordination. Larger entities address gas supply and transportation issues during extreme weather events through conference calls. These calls are held to coordinate real-time contingency plans with key stakeholders including generator operators, transmission operators, and fuel providers. Firm natural gas pipeline agreements, Firm delivered fuel agreements, investments in gas storage, enabling agreements with multiple gas suppliers, and back-up fuel sources are all in place to ensure reliable fuel delivery in extreme weather events. Many entities within SERC use natural gas only for boiler startup, typically only a few times per year or for any forced outages that may occur.

SPP

In 2013, SPP formed the Gas Electric Coordination Task Force (GECTF)[67] to provide a greater operational awareness of the gas fuel supply. The GECTF recently created the Weather Operational Plan to improve communication between major gas suppliers and SPP grid operations (this plan was executed four times during the 2013–2014 winter season).

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[66] PJM Gas Electric Senior Task Force.

[67] SPP Gas Electric Coordination Task Force.

TRE-ERCOT

In ERCOT, the Black Start Working Group (BSWG)[68] coordinates efforts with the natural gas industry (the supply of gas to blackstart units in ERCOT is particularly important in the event of a total system restoration, which has been made evident after an examination of ERCOT's restoration system plans). The BSWG (including major gas pipeline operators and the electric transmission operators within ERCOT) is working to identify priority loads that need to be restored for gas facilities to continue to transport gas in the event of a total system restoration. Currently, the transmission operators are working to include these priority loads in their respective restoration plans. Initiatives continue with major pipelines to improve communications between the gas and electric industries and develop confidentiality agreements with involved entities. This will allow for the exchange of operational information to facilitate improved real-time decision making by informing parties of unit commitment and overall operations in times of stress on either system.

WECC

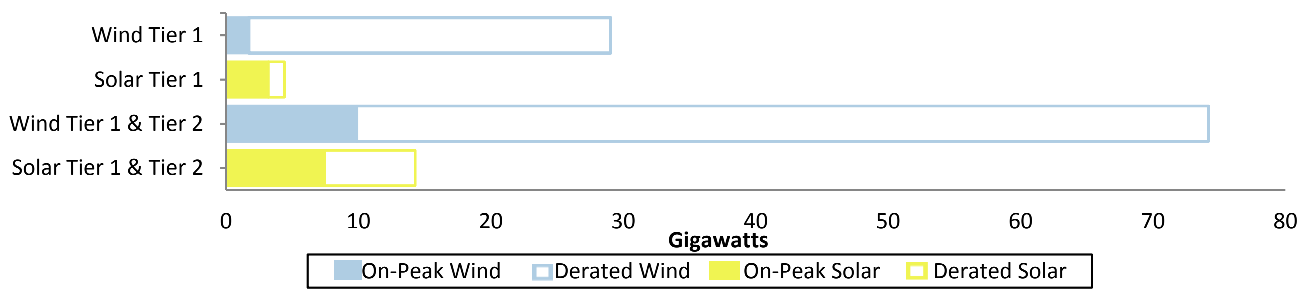
WECC subregions are involved in the FERC NOPR (RM14-2-000) process to better coordinate the scheduling of natural gas and electricity markets in light of increased reliance on natural gas for electric generation. During extreme weather events, daily calls occur between the generating resources and gas supply and transportation companies. These calls are done so that the generating units know the status of both gas supply and deliverability with the end goal of maintaining overall reliable operations of the BPS.

[68] ERCOT Black Start Working Group.

Ongoing Growth in Wind and Solar Resources Requires More System Flexibility

NERC-wide, 32 continental states and the District of Columbia have implemented renewable portfolio standards (RPSs),[69] with similar policies in several Canadian provinces. These policies mandate or otherwise establish goals for electricity producers to supply a specified portion of electricity from eligible renewable energy sources (typically wind, solar, biomass, geothermal, and some hydroelectric).[70] Additionally, greenhouse gas emission regulations (notably CO_2) and continually declining costs of renewable resources further incentivize construction of renewable resources throughout North America. The continued growth of renewable generation offers benefits such as newer generation resources, fuel diversification, and greenhouse gas reductions. However, to maintain BPS reliability, challenges presented by additional variable resources as a result of renewable energy policies need to be properly addressed.

NERC-Wide 10-Year Additions of Wind and Solar



Wind and solar will account for a large portion of Tier 1 nameplate capacity additions during the next decade, with 29 GW (1.7 GW on-peak) and 4.4 GW (3.2 GW on-peak), respectively. When examining Tier 1 and 2 capacity additions, up to 74.2 GW of wind additions and 14.3 GW of solar additions are projected by 2024. While VERs account for a growing portion of the total energy contribution, resource planners are relying on smaller amounts of wind and solar when examining resource availability during the hours of peak demand.

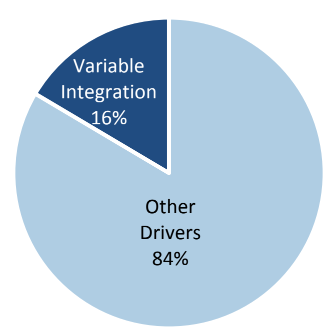
Nameplate additions of over 11 GW were projected in the 2013LTRA, primarily in the southeastern subregions of the WECC Interconnection. In the 2014LTRA reference case, 3.3 GW of Tier 1 and 8.5 GW of Tier 2 additions are planned by 2024.

High levels of wind and solar resources can create challenges for grid operators due to the inherent swings, or ramps, in power output. In certain Assessment Areas—particularly WECC-CA/MX and WECC-RMRG—the on-peak portion of VERs is projected to supply up to 9.7 and 6.7 percent of the 2015 Total Internal Demand. System planners in areas with higher concentrations of VERs must accommodate added variability by increasing the amount of available regulating reserves and carrying additional operating reserves. Because weather plays a key factor in determining wind and solar output, enhancing regional forecasting systems can provide more accurate generation projections. Other methods include curtailment and limitation procedures used when generation exceeds the

Transmission Considerations with Additional VERs

Reliably integrating the projected 30.8 GW of additional wind and solar resources will require additional transmission. VERs are often built in parts of North America that are distant from the point of interconnection to the transmission system. In many cases, the location of these variable resources only meets the minimum voltage support requirements. According to the 2014LTRA reference case, 16 percent of new transmission projects (under construction, planned, or conceptual) identify variable resource integration as a primary driver.

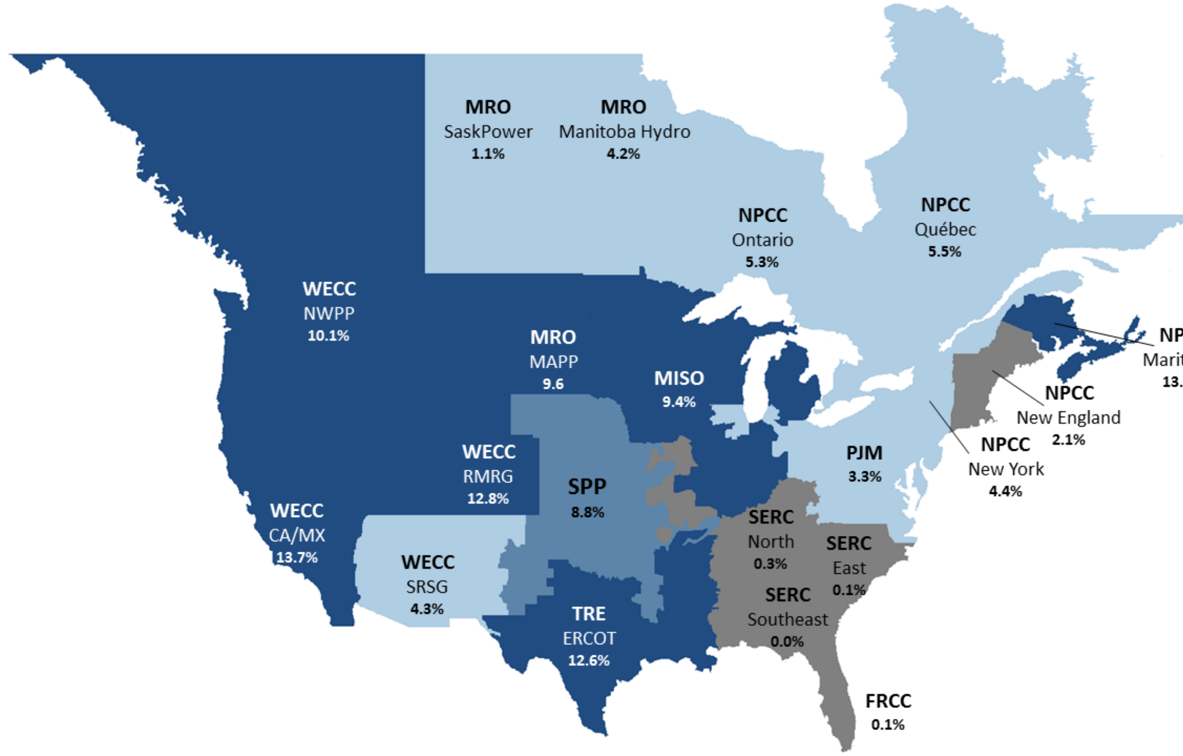
New Transmission Project Drivers



[69] Also referred to as renewable electricity standard or a renewable energy standard.
[70] Database of State Incentives for Renewables & Efficiency.

available regulating resources. In this respect, operating criteria, forecasting, commitment, scheduling, dispatch and balancing practices, procedures, and tools must be enhanced to assist operators in maintaining BPS reliability.

Several Assessment Areas with High Existing VER Penetration (Nameplate) as a Portion of the 2015 Generation Mix



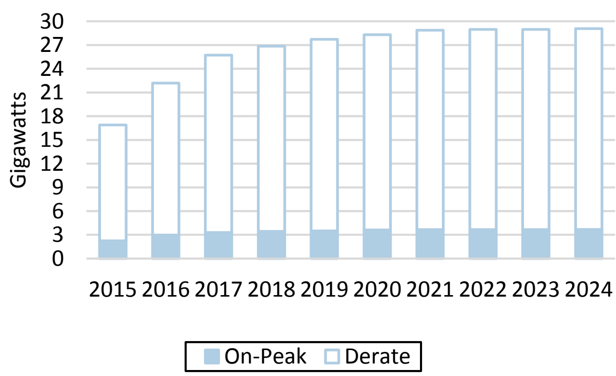
Assessment Area	Existing Nameplate (MW)	Existing On-Peak Contribution (MW)	Existing On-Peak Contribution (%)	Existing Nameplate (MW)	Existing On-Peak Contribution (MW)	Existing On-Peak Contribution (%)
FRCC	0	0	0.0%	56	7	0.0%
MISO	16,383	1,060	6.5%	0	0	0.0%
MRO-Manitoba Hydro	259	0	0.0%	0	0	0.0%
MRO-MAPP	1,114	260	23.6%	0	0	0.0%
MRO-SaskPower	198	40	19.8%	0	0	0.0%
NPCC-Maritimes	1,101	271	24.7%	0	0	0.0%
NPCC-New England	788	101	12.7%	0	99	0.0%
NPCC-New York	1,708	249	14.6%	212	11	5.2%
NPCC-Ontario	1,695	270	15.9%	32	0	0.0%
NPCC-Québec	2,400	0	0.0%	0	689	0.0%
PJM	5,824	908	15.7%	238	92	38.4%
SERC-E	0	0	0.0%	29	28	98.9%
SERC-N	179	28	15.3%	0	0	0.0%
SERC-SE	0	0	0.0%	4	4	100.0%
SPP	6986	242	3.5%	50	5	10.0%
TRE-ERCOT	11,093	996	8.7%	123	123	100.0%
WECC-CAMX	6,422	2,345	36.6%	4,297	1,565	36.4%
WECC-NWPP	11,167	3,258	29.1%	378	0	0.0%
WECC-RMRG	2,420	718	29.9%	127	54	42.8%
WECC-SRSG	789	155	19.3%	1,004	361	35.9%
NERC TOTAL	**70,540**	**10,901**	**15.5%**	**6,551**	**3,037**	**46.4%**

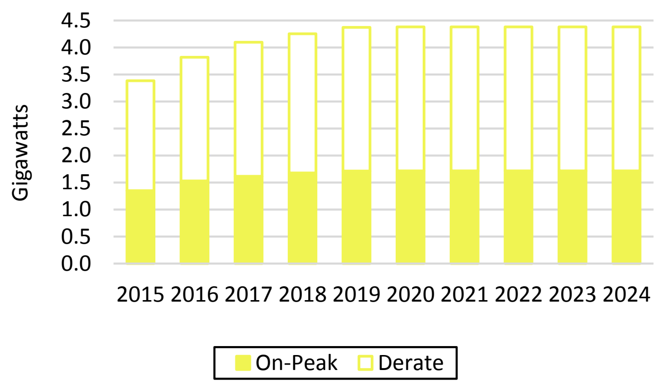
Planning Considerations for VERs in Long-Term Planning

Most Assessment Areas account for a small portion the total nameplate capacity of wind and solar resources when planning. MISO and ERCOT, for example, use a probabilistic basis for determining this factor. The Effective Load Carrying Capability (ELCC) establishes a percentage of total nameplate wind or solar capacity that is relied on for planning purposes. ERCOT currently employs an ELCC of 8.7 percent for all wind resources, meaning that 8.7 percent of the approximately 11 GW of wind is applied toward the Existing-Certain capacity category and included in the Anticipated Resources and Reserve Margin.

According to the 2014LTRA reference case, NERC-wide Tier 1 nameplate wind and solar additions amount to 29 GW and 4 GW, respectively, during the next decade. However, the on-peak contribution will increase by only 1.4 GW for wind and 0.4 GW for solar, based on current methods and assumptions values for planning variable capacity additions.

NERC-Wide 10-Year Wind (Left) and Solar (Right) Tier 1 Capacity Additions





Key Reliability Finding #3
A Changing Resource Mix Requires New Approaches for Assessing Reliability

Observations

Effects of environmental regulations, a less diverse resource mix, and an increase in VERs will result in greater dependence on natural gas for electric power generation in the future. With the demand for natural gas for power generation increasing, greater engagement among both sectors is needed to ensure sufficient resource allocation for reliable operation of the electric system.

Recommendations

Expanded Gas-Electric Planning and Coordination: Thorough harmonized efforts between electric and gas sectors are needed in order to meet future infrastructure needs to supply and transport fuel. System planners in certain areas (with high levels of natural-gas-fired resources) should examine system reliability needs to determine if more Firm fuel transportation or units with dual-fuel capability are needed. Additionally, fuel availability and deliverability should be specifically considered and integrated into resource adequacy and other planning assessments.

Operational Coordination Strategies between Gas and Electric Industries: System Operators should develop or enhance coordination strategies to address potential fuel interruptions, especially prior to anticipated extreme weather events. Generator owners should consider securing on-site secondary fuel in the event that non-Firm gas service is curtailed.

Variable Energy Resource Considerations: Because each system within the North American BPS is unique, detailed studies and investigations must be completed to understand how changes to the resource mix in certain areas, particularly those with a large onset of VERs, will impact their systems, particularly essential reliability services. The Essential Reliability Services Task Force (ERSTF) recently developed a concept paper that examines three building blocks that system planners should consider for maintaining reliability in the ongoing shift to systems with more variable resources:

- Balance of Load and Resources: The BPS should be planned and operated with the continued ability to raise and lower generation or load automatically or manually under normal and post-contingency conditions (i.e., ramping capabilities).
- Voltage Support: This is required to maintain system level voltages on the BPS within established limits, under pre- and post-contingency situations, thus preventing voltage collapse or system instability.
- Frequency Support: This is required to maintain stable frequency on the synchronized BPS by employing automatic response functions of a resource in response to deviations from normal operating frequency.

Essential Reliability Services: NERC urges the continued efforts of the ERSTF to develop additional metrics for measuring the reliability impacts of a resource mix that is increasingly dependent on variable resources.

The Need for Flexibility: Based on previous NERC assessments and analyses, as the level of VERs increases, more flexibility will be needed from the system. In the past decade, manufacturers have made significant advancements in control methods that can make VER power output more responsive to grid-level controls, including frequency response and down regulation. Industry should continue to examine how wind and solar plants can contribute to frequency response and work toward interconnection requirements that ensure System Operators will continue to maintain essential reliability services.

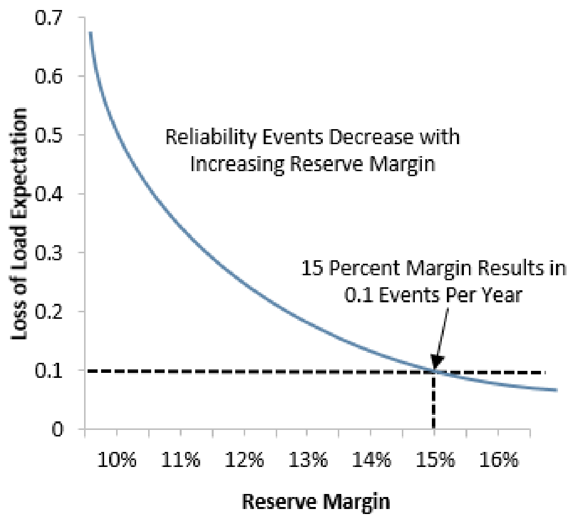
The Need for New Reliability Assessment Approaches: As part of its assessment of long-term reliability, NERC should consider using new approaches to evaluate the changing behavior of the BPS. These additional approaches should consider ERS, probabilistic, and transmission adequacy assessments—in conjunction with the existing Reserve Margin metric—to address and evaluate potential reliability issues in the future. Additional detail on these efforts can be found in the next section.

New 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 some 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 guideline does not evaluate 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.

Current Reserve Margin Method

The Reserve Margin and LOLE statistics are related. As shown the example below, as the reserve margin decreases, the likelihood of a supply deficit—or "reliability event"—increases.



The one-event-in-ten-year (0.1 events per year) LOLE is produced from this type of analysis. This industry guideline requires an electric system to maintain sufficient generation and Demand Response resources such that system peak load is likely to exceed available supply once in a ten-year period. Utilities, System Operators, and regulators across North America rely on variations of the one-event-in-ten-year guideline for ensuring and maintaining resource adequacy.

Although Reserve Margins offer insight into the relative ability of a system to serve load based on existing and planned resources, this metric does not fully capture important reliability attributes essential for ensuring BPS reliability. The Reference Margin Level assumes that various types of operating reserves are available (e.g., regulating reserves, spinning reserves, non-spinning reserves, and load-following reserves) to balance load and supply in real time and enable System Operators to quickly and reliably respond to a system contingency.[71] In contrast to an operating reserve requirement, which applies during real-time system operations (irrespective of load levels or generator availability), the Reserve Margin metric is developed to ensure that sufficient resources are available to address reliability challenges due to differences between: (1) short-term or medium-term peak load forecasts (reflecting normal weather) and typical generation outages; and (2) actual peak loads (which can exceed reflected weather-related discrepancies in load) and spikes in generation outages.

In addition, the Reserve Margin metric assumes that generator fuel availability is not correlated with load levels or weather. However, recent extreme weather events have caused an increased number of forced outages due to fuel unavailability, particularly natural gas. Assumptions of the Reserve Margin metric may be understating these risks. For VERs, a proxy for fuel availability is used to adjust installed or seasonally rated capacity values—with installed or nameplate capacity derated in Reserve Margin calculations. This approach fails to provide an evaluation of the reliability of VERs during off-peak hours or during extreme weather events.

[71] Defined as a sudden failure of an electrical facility, such as a transmission line, breaker, transformer, or generation unit.

Essential Reliability Services

In June 2014, NERC commissioned ERSTF to reconcile a collection of analytical approaches for understanding potential reliability impacts as a result of increasing variable resources and how these impacts can affect system configuration, composition, operation and the need for increased ERSs. The ERSTF identified three reliability attributes or building blocks to help define ERSs. These services represent the operating characteristics and reliability functions that are vital to ensuring BPS reliability. The ERS building blocks have three components: (1) load and resource balance, (2) voltage support, and (3) frequency support. In order to maintain reliability, the BPS must maintain sufficient levels of ERSs. While ERSs are technology neutral and must be provided regardless of the resource mix composition, gaps in ERSs can lead to adverse impacts on reliability. ERSs can be addressed with appropriate policies and standards.

While some VERs are capable of providing components of ERSs, the variability of these weather-dependent resources makes them difficult for System Operators to depend on. One of the reliability concerns presented by higher percentages of variable resources is the displacement of resources that have the ability to arrest and stabilize system frequency following a grid disturbance or the sudden loss of a large generator. Photovoltaic solar resources offer no inertia or frequency response. Wind resources can offer inertia and frequency response, depending on the design attributes of a given wind plant. However, by causing conventional generators to have their output dispatched down, wind and solar generation can increase generator headroom and, therefore, the amount of total frequency response being provided. Other potential approaches include the use of probabilistic methods to more accurately quantify the potential for challenges balancing resources with load.

Probabilistic Assessments

Reliability outcomes depend on a host of complex and interdependent factors, such as the projected resource mix, generator availability, and weather uncertainty. Evaluating these factors requires a probabilistic approach to provide a more robust understanding of resource adequacy. This requires statistically characterizing the following: (1) uncertainty in load forecasts; (2) output of the generation fleet; (3) inclusion of variable resources; (4) availability of imports; and a number of other factors that may impact the ability of a system's resources to contribute to reliability. Accordingly, NERC started conducting biannual probabilistic assessments to supplement the *Long-Term Reliability Assessment*.[72] These supplemental reports are released on even years, typically in March, to provide a common set of probabilistic reliability indices and recommendations. Probabilistic metrics used in the assessment include: (1) annual Loss-of Load Hours (LOLH), (2) Expected Unserved Energy (EUE), and (3) Expected Unserved Energy as a percentage of Net Energy for Load (normalized EUE) for two common forecast years (year 2 and year 5 of the LTRA assessment projections). Scenario analysis is also performed to help identify sensitivities and off-normal circumstances.

Additional Consideration for Transmission Adequacy

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 powerflow and dynamic studies. The results of these improved studies should also be shared between neighboring systems.

New approaches for assessing reliability should include adequate collaboration between two or more BAs to support reliable BPS planning. Depending on the unique characteristics of each BA, 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.

[72] The 2014 Probabilistic Assessment uses 2014LTRA reference case data. NERC's Probabilistic Assessments are released biannually (even years).

Other Reliability Issues

In addition to the three key findings above, NERC also continues to examine the ongoing impacts of several other issues. NERC will continue to monitor these issues to determine if additional evaluation or special assessments are needed.

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 traditional 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 upon for future forecasting.

Energy Efficiency and Conservation Programs

The recent growth of energy efficiency and conservation programs has had a substantial impact on the rate of load growth. Incorporating the impact of these programs into the load forecast requires special attention to consumer behavior, impacts of current and future economic conditions, and the overall effectiveness of a given program—all three of which are difficult to measure. The growth of energy efficiency programs depends on the behavioral response of participants (or consumers), which is impacted by a variety of circumstances, including the program’s structure and the overall economic conditions. Ultimately, overestimating the impacts of these programs could result in inaccurate load forecasts, potentially impacting reliability.

System Behavior Impacts Due to Changing System Resource Mix and Load Compositions

Resource Mix: This includes generation characteristics, frequency response, and inertia requirements. Robust and risk-oriented planning and modeling approaches will be needed to address transmission and operating reliability. Incorrect assumptions and methods can lead to incorrect decision making for system reinforcement, resources, transmission, flexibility, and operational needs.

Load Composition: Continued increases in energy-efficient products (including newer air conditioners, compact fluorescent and LED lighting, plasma, LCD and LED televisions, and other electronically coupled loads) are significantly changing the characteristics and behavior of system load, particularly during system disturbances. Preliminary studies indicate that such changes may exacerbate emerging problems, such as fault-induced delayed voltage recovery (FIDVR). An immediate gap is the inability of current load-modeling methods to predict system behavior with the integration of new electronically coupled loads. The changing nature of the load requires immediate improvements and additional sophistication in load modeling to properly analyze potential system performance issues.

High Levels of Distributed Energy Resources Create New Operational and Planning Challenges

Large amounts of DERs on the system could result in under-voltage or under-frequency tripping due to contingencies that could potentially impact BPS stability. Because frequency is a wide-area phenomena, resources set to allow minimal tolerance for frequency deviations (i.e., current solar PV units connected at the distribution level) can significantly impact BPS reliability, particularly when sharing identical trip points.

As an example, Germany has an installed capacity of over 10,000 MW of distributed PV and has recognized the need to integrate DERs into their network's dynamic support; they have proposed the following:

1. Prevent DERs from disconnecting from the system due to faults on the system;
2. Require DERs to support the network voltage during faults by providing reactive power into the system; and
3. Require DERs to consume the same or less reactive power after the fault clearance as prior to the fault.

Distributing generation resources throughout the power system can also have a beneficial effect if the generation has the ability to supply reactive power and is coordinated by the System Operator. Without this ability to control reactive power output, performance of the transmission and distribution system can be degraded. Given the growing penetration of distribution-connected variable generation, there is an increasing need to understand its characteristics and overall contribution to ERSs.

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. The lack of modeling requirements and real-time analysis capabilities of an SPS/RAS reduces the planners' and operators' capability to evaluate the reliability impact of installing these tools on the system. These tools also had important implications during the Southwest outage in September 2011.[73]

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[74]). 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 greater array of system components (to ensure greater accuracy in real-time and off-line studies).

Transmission Siting, Permitting, and Other Right-of-Way Issues

According to the 2014LTRA reference case, transmission additions during the 10-year period include 7,400 circuit miles of lines currently under construction, 20,622 circuit miles of planned lines, and 7,360 miles of conceptual lines. NERC continues

[73] NERC Southwest Blackout Event Reports.
[74] Arizona-Southern California Outages.

to monitor the progress of transmission projects across North America, and while transmission planning is dynamic (i.e., a planned project can later be deemed unnecessary due to reasons such as a reduction in load growth), resource planners should recognize the typical planning periods required to build transmission.

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 relies on an interconnected system of generation transmission and local distribution elements. The North American BPS was built over the course of a century and 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, the potential inability to maintain system reliability due to outage scheduling restrictions, as well as reliably integrating new technologies. Investment in new transmission infrastructure in the United States by investor-owned utilities has increased substantially over the past 15 years but varies significantly across NERC Regions.[75] 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. The electricity industry is committed to continual upgrade and maintenance of the electricity infrastructure.

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

Assessment Area Reliability Findings

FRCC

Localized Gas Supply Reduction in Extreme Events

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 on-shore gas resources (with the use of fracking technologies) would mitigate any natural gas transportation and supply issues in extreme weather events, such as hurricanes.

MISO

Risks Associated with Potential Generation Retirements and Addition of Natural Gas Resources

Studies have shown that with EPA MATS regulations, MISO could lose 23,000 MW of coal capacity and subsequently increase their natural gas generation within MISO's footprint. MISO has a number of available tools as an ISO/RTO to minimize the potential long-term reliability impacts of fuel supply and transportation constraints. If necessary, MISO may need to modify their tariff to minimize potential reliability impacts of growing demand and supply/transportation constraints of natural gas.

MRO-Manitoba Hydro

Increase in Variable Resource (Decrease in System Inertia) in Neighboring Systems

Manitoba Hydro is monitoring potential changes to renewable portfolio standards in neighboring areas, especially Minnesota. Renewable portfolio standards have the potential to cause a reduction in system inertia, which can impact the operation of Manitoba's HVdc converters or cause other potential reliability concerns, like activation of under-frequency load shedding relays for single contingencies. Southern Manitoba is quite sensitive to inertia changes due to the relatively large amount of HVdc converters connected and sensitive UFLS settings.

MRO-MAPP

High Load Growth Projections

MAPP's projection of 2.77 percent load growth is partially due to localized growth in northwestern North Dakota and in Rochester, Minnesota. The potential for minor instability issues is currently being studied; however, the MAPP Assessment Area does not foresee any reliability or resource adequacy issues during the assessment period.

MRO-SaskPower

Impacts of Retirement of Thermal Generation and Addition of Variable Resources

The requirement to reduce emissions for thermal generating facilities will require 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 to 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 with Retirement of Coal-Fired Generation

Parts of the Maritimes Area are seeking to displace significant amounts of fossil-fueled generation with renewable resources. Increasing amounts of renewable resources could affect BPS reliability if variable- or low-mass slow-speed units are added without considering (1) the impact of frequency response after system contingencies, or (2) the need for transmission enhancements to address and prevent the potential for voltage or overload problems.

NPCC-New England

Increase in PV Resources

In New England, there has been significant growth of DERs, especially PV resources that constitute the largest portion throughout the area. Therefore, ISO-NE's analysis of DERs focuses exclusively on the impact of projected PV. To help address the interrelated questions of exactly how much additional PV is expected in the ISO's 10-year planning horizon and what impact this future PV could have on the regional power grid, the ISO, in conjunction with stakeholders, endeavored to create a forecast of all future PV resources.

NPCC-New York

Environmental Regulations

State and federal regulatory initiatives cumulatively will require considerable investment by the owners of New York's existing thermal power plants, and as much as 33,200 MW in the existing fleet will have some level of exposure to the new regulations.

NPCC-Ontario

Aging Infrastructure

Asset renewal is a systematic approach for the continuous modernization of aging energy infrastructure. Much of the current power system infrastructure in generation, transmission, or distribution equipment is aging and needs to be refurbished, replaced, or upgraded to comply with new standards and meet demand. A long-term energy plan has been developed to coordinate the renewal of infrastructure to manage reliability, environmental, and cost impacts.

NPCC-Québec

Increase in Wind Generation

With the increasing amount of wind on the system, there is a potential for impacts on system management. Main topics under study include: (1) wind generation variability on system load and interconnection ramping, (2) frequency and voltage regulation, (3) increase of start-ups/shutdowns of hydroelectric units due to load following coupled with wind variability, (4) efficiency losses in generating units, and (5) reduction of low-load operation flexibility due to low inertia response of wind generation coupled with must-run hydroelectric generation.

PJM

Extreme Weather Natural Gas Supply/Transportation

PJM is investigating gas supply and transportation risk by considering the potential correlation with extreme weather (and high winter loads) and the potential for the loss of multiple units due to gas transportation disruptions. Gas supply and transportation risks are captured in PJM's 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 currently assumes all forced outage rates are random across all seasons and independent of each other.

SERC

RTO Integration Operational Management Challenges

Within this expanded MISO Balancing Area, market dispatches that result in power transfers between the midwest and south portions of the system can result in significant unscheduled power flows through neighboring systems (Tennessee Valley Authority (TVA), Associated Electric Cooperative, Inc. (AECI), Louisville Gas & Electric Company and Kentucky Utilities Company (LG&E/KU), Power South, Southwest Power Pool, Inc. (SPP), and Southern Company). To date, no long-term joint planning studies have been conducted to determine long-term transmission system impacts and any consequent reliability impacts. MISO and the neighboring systems have initiated discussions surrounding coordinated long-term planning studies. In addition, SERC regional study groups are assessing and refining SERC modeling and reliability assessments to better reflect the expanded MISO BA in regional long-term planning and operational planning assessments.

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). SPP and MISO have recently agreed to improvements to the method for accounting for the flow impacts of import and export transactions used in the congestion management process. Both parties are continuing to discuss additional improvements to ensure all sources of flows are properly accounted for within and between RTOs.

TRE-ERCOT

Weather-Related Resource Adequacy

Multi-year droughts in Texas continue to represent a reliability concern. Much of central Texas and the panhandle are currently under "exceptional" or "extreme" drought conditions. If drought conditions extend into 2015, there is the risk of multiple resources being taken off-line due to the lack of cooling water, with resource adequacy becoming an issue if operational restrictions extend over peak load periods.

WECC

Impacts of Retirement of Thermal Generation and Addition of Variable Resources and Natural Gas Units

In 2013, more than 4,700 MW of thermal generation (2,250 MW of nuclear, 909 MW of coal-fired, and 1,588 MW of gas-fired) was retired, and 9,500 MW was added (including 5,200 MW of variable resources such as wind and solar, and 3,162 MW of gas-fired). WECC is studying the impacts of potential planning and operational reliability impacts associated with the retirement of large thermal generating units alongside the impacts from higher levels of variable resources and natural gas supply and transportation conditions.

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 percent 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; no formalized method

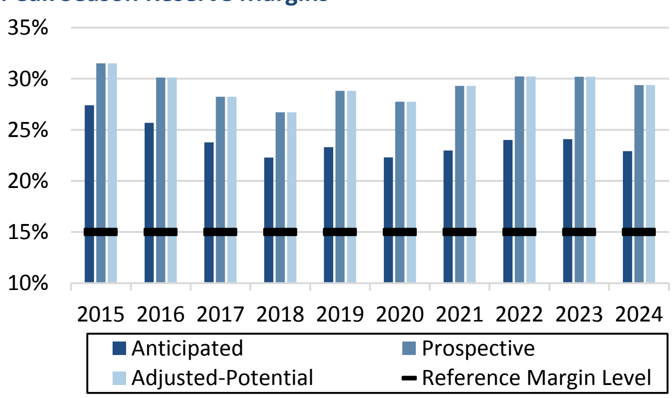
Footprint Changes
Region is the Assessment Area footprint; no recent changes

Assessment Area Footprint

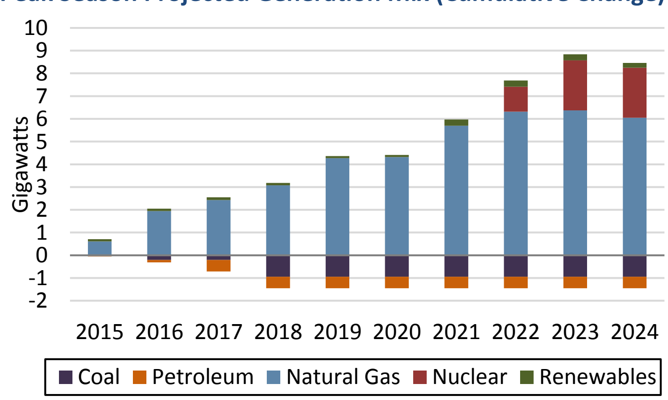
Peak Season Demand, Resources, and Reserve Margins[76]

Demand (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Internal Demand	46,719	47,615	48,501	49,147	49,852	50,554	51,263	52,049	52,981	52,981
Demand Response	3,140	3,173	3,242	3,288	3,373	3,427	3,461	3,491	3,523	3,523
Net Internal Demand	43,579	44,442	45,259	45,859	46,479	47,127	47,802	48,558	49,458	49,458
Resources (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	55,520	55,858	56,022	56,081	57,312	57,638	58,783	60,214	61,370	60,794
Prospective	57,311	57,827	58,036	58,110	59,874	60,202	61,806	63,237	64,393	63,988
Adjusted-Potential	57,311	57,827	58,036	58,110	59,874	60,202	61,806	63,237	64,393	63,988
Reserve Margins (%)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	27.40%	25.69%	23.78%	22.29%	23.31%	22.30%	22.97%	24.00%	24.09%	22.92%
Prospective	31.51%	30.12%	28.23%	26.71%	28.82%	27.74%	29.30%	30.23%	30.20%	29.38%
Adjusted-Potential	31.51%	30.12%	28.23%	26.71%	28.82%	27.74%	29.30%	30.23%	30.20%	29.38%
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)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	5,404	4,750	3,974	3,343	3,861	3,442	3,811	4,372	4,493	3,917
Prospective	7,195	6,718	5,988	5,372	6,423	6,006	6,833	7,395	7,516	7,111
Adjusted-Potential	7,195	6,718	5,988	5,372	6,423	6,006	6,833	7,395	7,516	7,111

Peak Season Reserve Margins



Peak Season Projected Generation Mix (Cumulative Change)



76 The FRCC plans through 2023.

Demand, Resources, and Planning Reserve Margins

Based on the expected load and generation capacity, all three the Anticipated, Prospective, or Adjusted-Potential Reserve Margins are above 22 percent for the FRCC Assessment Area for all seasons during the assessment period. Compared to the 2013LTRA, FRCC projects a small decrease in the 2015 summer net peak demand; it then returns to historical weather-normalized demand growth levels similar to last year's projections for the same time period. The winter net peak demands are projected to be approximately 3.9 percent lower compared to the 2013 projections for the same time period. This is attributed to revisions to the winter peak projections that remove the overestimation of the impact of past cold weather.

Demand Response (DR) 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 percent of the summer and winter total peak demands for all years of the planning horizon. In 2014, Florida is setting DSM goals for the years 2015–2024 in the Demand-Side Management goals docket with the Florida Public Service Commission, which is held every five years. New DSM goals for both DR and energy efficiency will be set in this docket; a decision is expected in the fourth quarter of 2014. A key reason for the proposed reduction is a significant decrease in the cost-effectiveness of DSM. Since the DSM goals were set in 2009, fuel price forecasts have dropped by approximately 50 percent, and projected environmental compliance costs, particularly for CO_2 emissions, have dropped. These changes result in a significant lowering of the projected DSM benefits from kWh reductions. These factors result in both fewer DSM options being cost-effective, and a lowering of incentive payments to DSM participants for other DSM options for them to remain cost-effective, which reduces the number of DSM participating customers. In addition, the projected impact of federal and state energy efficiency codes and standards has deferred a number of utility DSM programs that would have addressed the electrical equipment affected by these codes and standards, effectively reducing market potential for utility DSM programs. However, the projected impact of these codes and standards is accounted for in the utilities' load forecasts, thus reducing projected resource needs in an identical way as would occur if these impacts were delivered by utility DSM programs.

FRCC projects 12,613 MW (summer) and 13,608 MW (winter) of additional generation to come on-line 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 Regional Deliverability Evaluation Process. FRCC projects 3,391 MW (summer) and 3,619 MW (winter) generation to be retired through the assessment period. FRCC is not anticipating any reliability impacts resulting from these unit retirements. The unit retirements are being studied as part of the FRCC Long-Range Study process performed annually by the TWG and the Resource Working Group (RWG) to mitigate potential reliability impacts to the grid and the FRCC reserve margin criteria.

Entities within FRCC have generation under Firm contract available to be imported into the Assessment Area from SERC. In addition, approximately 840 MW of FRCC member-owned generation is dynamically dispatched out of the SERC Assessment Area. These purchases have Firm transmission service to ensure deliverability into the FRCC Assessment Area.

In 2013, FRCC conducted a study identifying the impacts of the retirement of two coal-generating units (915 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 of 1,740 MW from this site. The Assessment Area study determined that the proposed retirements of the two coal plants would have an impact on the BES transmission system; however, the plants have received an extension of the retirement date. The extension provides sufficient time to modify the plants, then construct transmission projects and the replacement of natural-gas-fired units to maintain the reliability of the BES within FRCC.

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 and the gas supply impacts resulting from an offshore hurricane. The results of these studies indicated that the FRCC Assessment Area would not have a large-scale impact from extreme events. Some localized gas reduction could occur; however, dual-fuel capability could be utilized if additional generation is required. Because of the expanded use of fracking technology, more gas is coming from on-shore sources rather than offshore sources, further reducing potential impacts from hurricanes in the Gulf of Mexico.

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 the 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 2014–2015, MISO's System-Installed Generation Planning Reserve Margin requirement (PRMR) is 14.8 percent, which is applied as the Reference Margin Level for all 10 years.

Load Forecast Method
Coincident

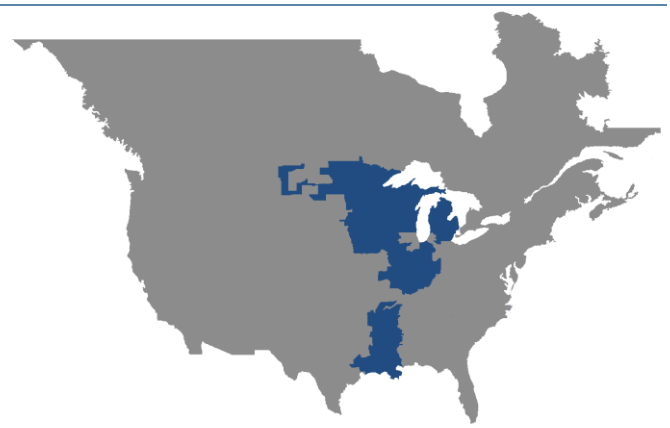
Peak Season
Summer

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 the MISO South resulted in an expanded footprint.[77]

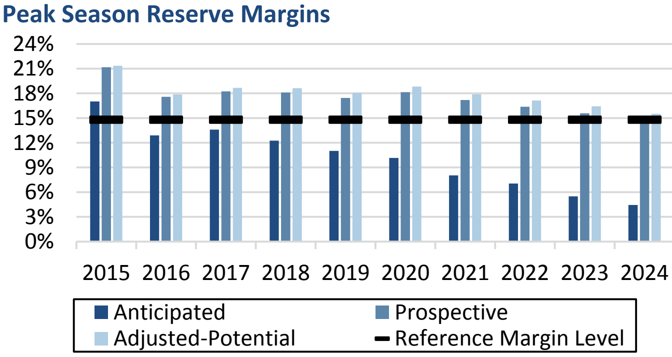
Assessment Area Footprint



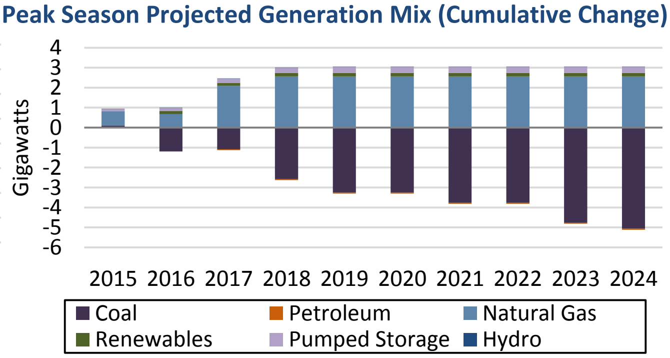
Peak Season Demand, Resources, and Reserve Margins

Demand (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Internal Demand	128,571	130,101	131,242	132,376	133,470	134,509	135,526	136,460	137,377	138,433
Demand Response	4,743	4,755	4,766	4,779	4,791	4,803	4,815	4,827	4,839	4,851
Net Internal Demand	123,828	125,345	126,475	127,598	128,679	129,707	130,711	131,633	132,538	133,582
Resources (MW)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Anticipated	144,893	141,510	143,669	143,225	142,852	142,889	141,221	140,921	139,821	139,521
Prospective	150,055	147,380	149,538	150,694	151,121	153,246	153,178	153,178	153,178	153,178
Adjusted-Potential	150,258	147,754	150,075	151,374	151,917	154,134	154,086	154,181	154,317	154,317
Reserve Margins (%)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Anticipated	17.01%	12.90%	13.59%	12.25%	11.01%	10.16%	8.04%	7.06%	5.50%	4.45%
Prospective	21.18%	17.58%	18.23%	18.10%	17.44%	18.15%	17.19%	16.37%	15.57%	14.67%
Adjusted-Potential	21.34%	17.88%	18.66%	18.63%	18.06%	18.83%	17.88%	17.13%	16.43%	15.52%
Reference Margin Level	14.80%	14.80%	14.80%	14.80%	14.80%	14.80%	14.80%	14.80%	14.80%	14.80%
Excess/Shortfall (MW)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Anticipated	2,739	(2,387)	(1,525)	(3,258)	(4,871)	(6,014)	(8,835)	(10,193)	(12,332)	(13,831)
Prospective	7,901	3,484	4,344	4,211	3,398	4,343	3,122	2,064	1,025	(174)
Adjusted-Potential	8,104	3,857	4,882	4,892	4,193	5,231	4,030	3,066	2,164	965

Peak Season Reserve Margins



Peak Season Projected Generation Mix (Cumulative Change)



[77] 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.

Demand, Resources, and Planning Reserve Margins

For planning year 2014–2015, MISO's System-Installed Generation Planning Reserve Margin requirement (PRMR) on a MISO coincident load basis is 14.8 percent, 0.6 percentage points higher than the 2013–2014 requirement. However, the PRMR for zone 8 (primarily covering the state of Arkansas) was set by the Local Clearing Requirement for zone 8, because the local 1-day-in-10 reliability criteria was higher than the system requirement. This resulted in a higher PRMR for zone 8. The major drivers of the change include: the MISO South integration, the adjustment to the amount of external support that can be used in time of need, and the ongoing improvement of MISO's load forecast uncertainty values. MISO performs out-year LOLE studies but only has a PRMR for the current planning year. For this assessment, the current planning year PRMR of 14.8 percent is used for the entire 10-year period.

MISO projects that the Anticipated Reserve Margin will drop below the 14.8 requirement in 2016 and stay below the Reference Margin Level for the remainder of the assessment period. The 14.8 requirement is determined by the 1-day-in-10-year LOLE criteria. Dropping below the Reference Margin Level (planning reserve margin requirement) means that the MISO system will have an increased chance of an LOLE; in 2016, MISO projects it will operate at the reliability level of approximately 2-days-in-10-year LOLE. As MISO starts to operate at or near the Reference Margin Level, there is a higher likelihood that System Operators will call Emergency Operating Procedures more frequently to access Emergency-Only resources, load-modifying resources, and BTMG. The contributing factors driving the projected deficit include:

- Increased retirements and suspensions (temporary mothballing) due to Environmental Protection Agency (EPA) regulations and market forces and low natural gas prices
- Exclusion of low-certainty resources that were identified in the Resource Adequacy survey
- Exclusion of surplus of capacity in MISO South above the 1,000 MW transfer from the Planning Reserve Margin requirement (PRMR)[78]
- Increased exports to PJM and the removal of non-Firm imports[79]
- Inadequate Tier 1 capacity additions [80]

MISO recently completed a Resource Adequacy survey in 2014 with assistance from load-serving entities (LSEs) and the Organization of MISO States (OMS). This survey provided additional visibility on the resource adequacy outlook to help address falling below the Reference Margin Level.[81] The survey also identified resources that had a low certainty of being available for each planning year. This assessment excludes these low-certainty resources from the Anticipated Resources and corresponding Reserve Margin.[82]

As a result of the risk associated with falling below the Reference Margin Level, MISO is conducting a study of the unused capacity that does not currently qualify as planning resources in MISO's planning resource auction.[83] The unused capacity comes from two places: (1) generators with generator-verification-tested capacity that is higher than the Total Interconnection Service; and (2) energy-only portions of generators. With the completion of this study, projects will be identified that would allow those resources to qualify as a planning resource, eligible for participation in the planning resource auction.

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[78] For this assessment, 1,000 MW of capacity is transferred from the MISO South to the MISO North/Central Region pending the outcome of regulatory issues currently under FERC review.

[79] Capacity sales (imports and exports) in MISO depend on decisions of the respective resource owners, assuming that the tariff requirements are met (including planning of necessary transmission of both the buying and selling areas). Regarding the removal of non-Firm imports, the MISO market monitor double-counted non-Firm imports in the 2013LTRA reference case. These imports are accounted for in the Reference Margin Level (PRMR).

[80] In the MISO footprint, 91 percent of the load is served by utilities with an obligation to serve customers reliably and at a reasonable cost. Resource planning and investment in resources are part of state and locally jurisdictional integrated resource plans that only become certain upon the receipt of a Certificate of Public Convenience and Necessity (CPCN).

[81] Synonymous with the MISO term, "Planning Reserve Margin Requirement."

[82] Low-certainty resources identified in the survey are included in the Prospective Resources and corresponding reserve margin.

[83] MISO Resource Adequacy.

The Prospective and Adjusted-Potential Reserve Margins remain above the 14.8 percent Reference Margin Level for the entire assessment period. Prospective Resources include low-certainty resources identified in the resource adequacy survey, Existing-Other capacity, and 50 percent of all Tier 2 capacity additions,[84] while the Adjusted-Potential resources includes 10 percent of additional Tier 3 capacity additions.[85] Although the Anticipated Reserve Margin is projected to fall below the Reference Margin Level in 2016, MISO fully expects that the Reference Margin Level shortfall will change significantly once LSEs and state commissions within the footprint solidify future capacity plans, as reflected in the Prospective and Adjusted-Potential Margins.

MISO forecasts the coincident Total Internal Demand to peak at 128,571 MW during the 2015 summer season. The major driver for the increased demand, compared to the 2013LTRA reference case, is the integration of the MISO South entities. MISO projects the summer coincident peak demand to grow at an average annual rate of 0.85 percent.

MISO projects between 4,743 MW and 4,851 MW of DR[86] to be available during the 10-year outlook. Additionally, 4,300 MW of BTMG is assumed to be available throughout the assessment period, included as Existing-Certain capacity. No growth in BTMG is projected at this time.

Firm imports into the MISO footprint amount to 3,157 MW. These imports are unable to be recalled by the source Transmission Service Provider (TSP) and were designated to serve load within MISO through the Module E process for summer 2014. The 3,157 MW of imports apply for the entire assessment period. MISO also assumes 2,044 MW of Firm exports to the PJM footprint for 2015, based on the cleared results of the PJM Base Residual Auction. Exports are projected to increase to 4,135 MW in 2016 and remain at that level for the remainder of the assessment period.

For this assessment, transfers between MISO South and MISO North/Central are limited to 1,000 MW, pending the resolution of the ongoing dispute regarding the MISO-SPP Joint Operating Agreement, which is currently under review at FERC. Any surplus capacity in MISO South beyond the 1,000 MW transfer and the MISO South PRMR is treated as Transmission-Limited Resources (TLR) for the purpose of this assessment. The amount of TLRs declines each year until reaching zero in the summer of 2021 due to a combination of load growth in MISO South, increasing capacity exports, and minimal capacity retirements.

Transmission Outlook and System Enhancements

The MISO Transmission Expansion Plan proposes transmission projects to maintain a reliable electric grid and deliver the lowest-cost energy to customers in the footprint. As part of the 2013 MISO Transmission Expansion Plan,[87] MISO staff recommends $1.48 billion of new transmission expansion expenses through 2023, as described in Appendix A, to the MISO Board of Directors for review, approval, and subsequent construction. The table below shows notable transmission projects approved as part of the 2013 MISO Transmission Expansion Plan:

- Petersburg – Francis Creek – Hanna Line 345 kV Line Rating Increase (Indianapolis Power and Light): May 2014
- Overton Transformer Replacement (Ameren Missouri): June 2014
- Straits Power Flow Control (American Transmission Company): July 2014
- Lafayette 230kV Substation Bus Modernization – Phase 1 (Duke Indiana): December 2014
- Stone Lake – Edgewater 161 kV (Xcel Energy): December 2014
- Pottawattamie County Substation and Po. County – Sub 701 161kV (MidAmerican Energy): December 2014
- Monroe County – Council Creek 161 kV (American Transmission Company): March 2015
- Lenawee 345/138 kV station (Michigan Electric Transmission Company): April 2015
- Turkey Hill – Cahokia and Cahokia Substation Upgrade (Ameren Illinois): June 2015
- Kokomo Highland Park to Tipton West 230 kV Line Rebuild (Duke Indiana): June 2015

[84] Resources currently under study in the MISO interconnection queue awaiting signed Interconnection Agreements.
[85] Resources that were identified in the Resource Adequacy survey but are not currently in the MISO interconnection queue.
[86] MISO's Demand Response Programs consist of Direct Control Load Management (DCLM) and Interruptible Load (IL).
[87] The MISO Transmission Expansion Plan for 2013.

- Bland 345/138 kV Substation (Ameren Missouri): December 2015
- Battle Creek – Island Road 138 kV Rebuild (Michigan Electric Transmission Company): December, 2015
- Five Points 230kV Substation Upgrade – Phase I (Duke Indiana): December 2015
- Marshall – Blackstone 138 kV Rebuild (Michigan Electric Transmission Company): December 2015
- Toll Road (ITC Transmission): December 2015
- Lafayette 230kV Substation Bus Modernization – Phase 2 (Duke Indiana): December 2016
- North Appleton – Morgan 345+138 kV, Holmes – 18th Road 138 kV (American Transmission Company): December 2016

Long-Term Reliability Issues

There continues to be significant risk associated with potential retirements during the assessment period. Previous studies have shown that considering all EPA regulations, MISO would potentially retire 23 GW of coal-fired capacity. Without final regulations, excluding MATS, final retirement decisions continue to be far below the 23 GW of potential retirements.

The early-2014 polar vortex brought extreme weather conditions to the MISO Region that introduced significant challenges to the reliable operation of the power grid. The effects were far reaching, spanning from the Canadian province of Manitoba to the Gulf Coast. MISO will perform a comprehensive review of this event and identify any lessons learned. Initial findings include the realized benefits of improved coordination with the gas pipeline operators, as well as the risk mitigation efforts achieved by proactive staff planning. The substantial variation in DSM availability between seasons was also noted, which MISO will study further with continued efforts targeted at improving the visibility and management of these resources.

To maximize preparedness for repeated extreme weather events, MISO will continue efforts to improve coordination between the electric and gas industries through the Electric-Natural Gas Coordination Task Force (ENGCTF).[88] Ongoing efforts include the continuation of field trials with the pipelines to identify improvement opportunities and establish best practices.

MISO has a number of available tools as an ISO/RTO to minimize the potential long-term reliability impacts of fuel supply and/or transportation constraints. Tools include modifying the MISO tariff. The extent that MISO will need to use these tools, (i.e., will need to modify market, planning, and operational constructs) is an ongoing conversation with our stakeholders. To address this question in the context of growing demand for natural gas, MISO's ENGCTF focused on the following objectives: (1) educate and build a common knowledge base between the gas and electric industries; (2) identify gas-electric coordination challenges and issues; (3) educate MISO entities on this issue; (4) develop potential solutions to these issues; and (5) thoroughly evaluate how all stakeholder groups could be impacted by these solutions. Before implementing any initiatives, MISO considers potential costs and benefits, as well as the reliable and efficient operation of the transmission system.

Specific initiatives from the ENGCTF include: (1) enhancing system awareness through control room improvements, such as the introduction of an overlay display for natural gas and transmission, an online platform for notices from all pipelines in the MISO footprint, and a database linking generators to their fuel sources; (2) improving cross-industry communications through MISO's six-month Coordination Field Trial with two major interstate pipeline companies, which has been extended through 2014; (3) scheduling monthly and as-needed conference calls between MISO Operation and Planning staff and natural gas pipeline operations staff; and (4) examining system impacts of interdependency.[89]

[88] MISO Electric and Natural Gas Coordination Task Force.

[89] For example, the 2014 Issue Summary Papers on the impacts of the polar vortex and the potential for competition between NG storage injection and power burn demand.

MRO-Manitoba Hydro

Assessment Area Overview

Manitoba Hydro is a Provincial Crown Corporation that provides electricity to 548,000 customers throughout Manitoba and natural gas service to 270,000 customers in various communities throughout southern Manitoba. The Province of Manitoba is 250,946 square miles. 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 and is a coordinating member of the Midcontinent Independent System Operator (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 percent Planning Reserve Margin, applied as the Reference Margin Level in this assessment.

Load Forecast Method
Coincident

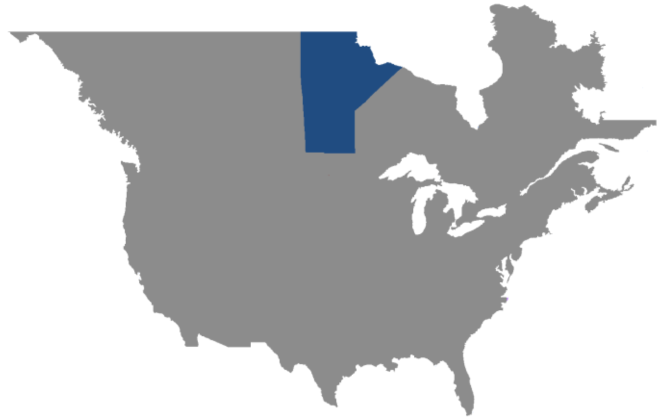
Peak Season
Winter

Planning Considerations for Wind Resources
Effective Load-Carrying Capability (ELCC) of 14.1 percent 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

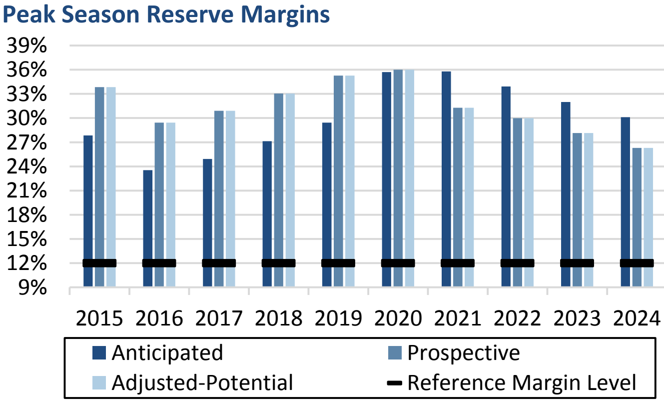
Assessment Area Footprint



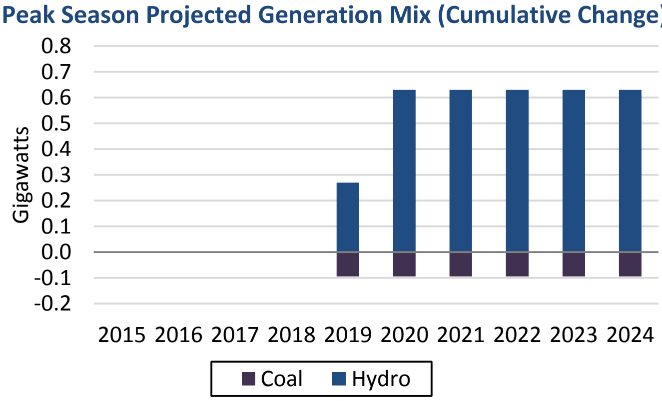
Peak Season Demand, Resources, and Reserve Margins

Demand (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Internal Demand	4,652	4,713	4,663	4,705	4,761	4,854	4,931	4,997	5,066	5,136
Demand Response	243	244	244	244	244	244	244	244	244	244
Net Internal Demand	4,409	4,469	4,419	4,461	4,517	4,610	4,687	4,753	4,822	4,892
Resources (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	5,637	5,521	5,521	5,671	5,847	6,257	6,365	6,365	6,365	6,365
Prospective	5,901	5,785	5,785	5,935	6,111	6,271	6,154	6,179	6,179	6,179
Adjusted-Potential	5,901	5,785	5,785	5,935	6,111	6,271	6,154	6,179	6,179	6,179
Reserve Margins (%)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	27.85%	23.54%	24.93%	27.14%	29.44%	35.71%	35.78%	33.91%	32.00%	30.11%
Prospective	33.83%	29.44%	30.90%	33.05%	35.28%	36.01%	31.28%	29.99%	28.13%	26.30%
Adjusted-Potential	33.83%	29.44%	30.90%	33.05%	35.28%	36.01%	31.28%	29.99%	28.13%	26.30%
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)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	699	516	572	675	788	1,093	1,115	1,041	964	886
Prospective	963	780	835	939	1,051	1,107	904	855	778	700
Adjusted-Potential	963	780	835	939	1,051	1,107	904	855	778	700

Peak Season Reserve Margins



Peak Season Projected Generation Mix (Cumulative Change)



Demand, Resources, and Reserve Margins

As a predominately hydro assessment area, Manitoba Hydro has both an energy criterion and a capacity criterion. Manitoba Hydro is projecting Anticipated, Prospective, and Adjusted-Potential Reserve Margins to remain above the Reference Margin Level for the entire period of the assessment.

At this time, Manitoba Hydro's long-term resource plans do not include operation of the sole coal generating unit in the Manitoba Hydro system (Unit 5, approximately 95 MW and located in Brandon, Manitoba) beyond 2019. Manitoba Hydro plans to mothball the unit in 2020 unless directed by the Province of Manitoba to retire the unit at that time. As new generating resources are expected to be in service in the 2019 time frame, discontinued operation of Brandon Unit 5 is not expected to have a reliability impact.

Manitoba Hydro also anticipates that the first units (270 MW) of the total 630 MW of net capacity addition from the Keeyask Hydroelectric Generating Station will begin coming into service in late 2019. This projected in-service date is several years ahead of projected needs within Manitoba and allows for flexibility, should there be regulatory or construction delays in the project.

Manitoba Hydro has recently updated its energy efficiency and conservation plan. The 2014 Power Smart Plan includes higher forecast energy and demand savings as compared with the 2013 Power Smart Plan. 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. The increased savings are the result of enhancements to existing programs and the addition of new programs based on opportunities identified in the market. Energy efficiency and conservation from the 2013 Power Smart Plan is used in this assessment, which is consistent with the values included in the current long-term resource plans.

All of Manitoba Hydro's dependable exports and imports are backed by contracts. Manitoba Hydro has up to 825 MW of Firm or Expected on-peak transfers (capacity exports) during the winter, up to 550 MW of Firm or Expected on-peak transfers (capacity imports) during the winter, and up to 1,425 MW of Firm or Expected on-peak exports in the summer, and associated Firm transmission reservations over the 2015–2024 assessment period. Manitoba Hydro does not have any capacity imports during the summer. These contractual agreements have Firm transmission reservations with staggered terms associated with them. Manitoba Hydro does not have any capacity transactions beyond the contract terms. Some Expected Transfers (Exports are contingent upon additional resources being built within the assessment time frame.

Long-Term Reliability Issues

Severe weather events can include tornados and ice storms, for example. These events can occur at any time, but the consequence is most severe at or near the system peak load in winter. Loss of a major station or corridor can impact delivery of generation from hydro generation located in the northern portion of the area, which will impact resource adequacy. Manitoba Hydro is planning on adding a major new 500 kV HVdc transmission line and new Riel switching station in order to mitigate the loss of the Dorsey converter station and the loss of the Bipole I/II transmission corridor. These facilities are planned to be in service by 2017 and are included in the reference case. Transmission siting and permitting issues have the potential to delay the in-service date, which will increase Manitoba Hydro's exposure to the loss of load risk.

Manitoba Hydro is not anticipating any reliability impacts from increased variable resources in Manitoba. However, Manitoba is monitoring potential changes to renewable portfolio standards in neighboring areas, especially Minnesota. Renewable portfolio standards, resulting in additional VERs, have the potential to cause a reduction in system inertia, which can impact the operation of Manitoba's HVdc converters or cause other potential reliability concerns, including activation of under-frequency load shed relays for single contingencies. Southern Manitoba is quite sensitive to inertia changes due to the relatively large amount of HVdc converters connected and sensitive UFLS settings. 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 percent renewable under typical inflow conditions.

Manitoba Hydro is not planning to increase or decrease Demand Response programs and does not foresee any reliability impacts associated with the Demand Response loads. There are not significant levels of distributed and BTMG in Manitoba, and this is not expected to change over the next 10 years. Therefore, no reliability impacts are expected from distributed and BTMG.

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 Manitoba Climate Change and Emissions Reduction Act and the Canadian Federal Coal-Fired Electricity Regulations. This unit is regulated such that it can only be operated to provide for emergency operations. At this time, no pending regulations are expected to impact existing gas and hydro generation in Manitoba.

The Manitoba Hydro system is predominately hydro and is designed and operated to serve all Firm load requirements under the worst inflow conditions on record coincident with high winter load conditions. Manitoba Hydro also accounts for the possibility of a drought in its operations planning processes. The largest gas generators in Manitoba, the Brandon Unit 6 and 7 combustion turbines (119 MW and 118 MW, respectively), are dual fueled natural gas fired with diesel backup.

The adequacy of natural gas pipeline capacity and natural gas generator performance in the Midwest during extreme events, and the resulting impact on Manitoba, is being monitored. 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. The MAPP covers an area of approximately 200,000 square miles and serves a population of about 3.5 million. MAPP typically experiences its annual peak demand in summer, but recently started projecting peak internal demand during the winter seasons. For this long-term outlook, MAPP is considered a summer-peaking area. However, depending on the load forecasts, MAPP may shift to a winter-peaking area in future long-term assessments. There have not been any changes to the MAPP Assessment Area footprint in the last two years, and no changes are expected in the future.

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 percent 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

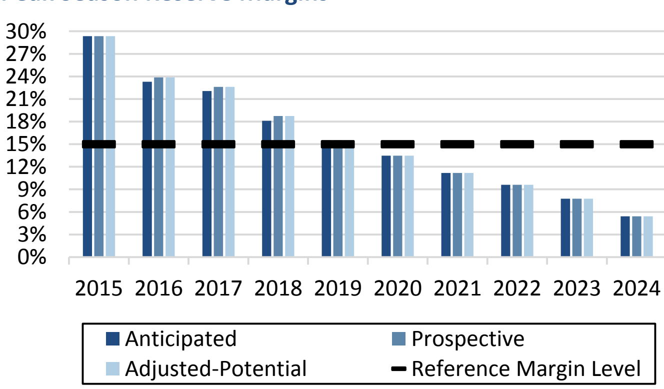
Footprint Changes
The Minnesota Municipal Utilities Association (MMUA) and Ames Municipal Utilities (AMES) are now reported in the MISO footprint.

Assessment Area Footprint

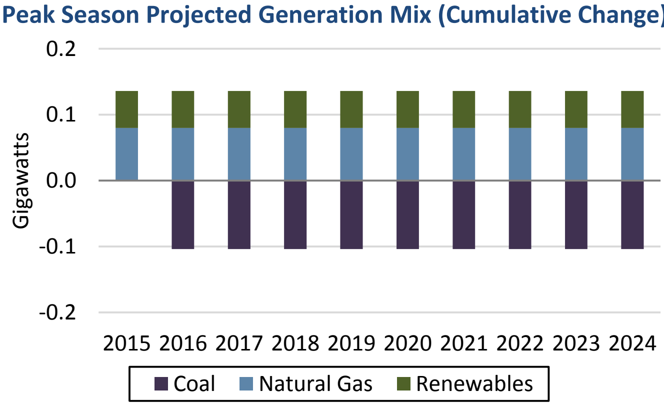
Peak Season Demand, Resources, and Reserve Margins

Demand (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Internal Demand	5,028	5,374	5,500	5,690	5,810	5,927	6,038	6,145	6,257	6,427
Demand Response	96	98	94	96	98	100	102	104	106	108
Net Internal Demand	4,932	5,276	5,406	5,594	5,712	5,827	5,936	6,041	6,150	6,319
Resources (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	6,379	6,505	6,598	6,607	6,599	6,612	6,599	6,621	6,628	6,661
Prospective	6,379	6,535	6,628	6,642	6,599	6,612	6,599	6,621	6,628	6,661
Adjusted-Potential	6,379	6,535	6,628	6,642	6,599	6,612	6,599	6,621	6,628	6,661
Reserve Margins (%)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	29.35%	23.30%	22.05%	18.11%	15.52%	13.48%	11.17%	9.60%	7.76%	5.41%
Prospective	29.35%	23.86%	22.61%	18.74%	15.52%	13.48%	11.17%	9.60%	7.76%	5.41%
Adjusted-Potential	29.35%	23.86%	22.61%	18.74%	15.52%	13.48%	11.17%	9.60%	7.76%	5.41%
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)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	708	438	381	174	30	(89)	(227)	(326)	(445)	(606)
Prospective	708	468	411	209	30	(89)	(227)	(326)	(445)	(606)
Adjusted-Potential	708	468	411	209	30	(89)	(227)	(326)	(445)	(606)

Peak Season Reserve Margins



Peak Season Projected Generation Mix (Cumulative Change)



Demand, Resources, and Reserve Margins

The Anticipated, Prospective, and Adjusted-Potential Reserve Margins for MAPP are below the Reference Margin Level of 15 percent beginning in 2020 and remain below it through 2024. MAPP has traditionally always met its target reserve margin through the mid-term planning horizon, and beyond that time frame, Firm contracts or capacity additions may be currently unknown. The long-term resource adequacy outlook for MAPP will be updated with load projections and the execution of long-term contracts, and new capacity additions are planned.

High forecast load growth in Rochester and Minnesota, as well as the ongoing growth of oil and gas development in the Bakken Formation in western North Dakota and eastern Montana, has contributed to a Total Internal Demand annual growth rate of nearly 3 percent. With Minnesota Municipal Utilities Association (MMUA) and Ames Municipal Utilities (AMES) now submitting data through MISO, MAPP demand growth is expected to be lower in the near term, compared to what was forecast in the 2013LTRA.

Since the 2013LTRA, the Rochester Public Utilities' (RPU) Silver Lake Plant (85.2 MW) was decommissioned, while 226 MW of capacity was added, of which 146 MW were wind resources. MAPP is projecting 349 MW of imports and 1,289 MW of exports, retaining the status of a net exporting Assessment Area with a net export of 940 MW. For these transfers, Firm contracts exist for both the capacity and the transmission service. MAPP forecasts meet the various reserve margin targets without needing to include energy-only, uncertain, or transmission-limited resources.

Transmission Outlook and System Enhancements

Several transmission projects are projected to be completed during the assessment period, all of which are intended to increase the reliability of the MAPP transmission system. RPU is a joint owner of the Hampton – North Rochester – LaCrosse portion of the CAPX2020 project; this portion is expected to be in service by 2016. Although it has experienced some delays, Minnkota Power Cooperative's Center – Grand Forks line was scheduled to be completed by July 2014, which will improve reliability with additional wind resources coming online.

Long-Term Reliability Issues

The integration of variable resources presents new challenges in the Assessment Area, changing the nature of how the BPS is operated. There is expected high load growth in the northwestern North Dakota area and greater load growth projected in Rochester, Minnesota. There is some minor instability that is currently being studied, and the MAPP assessment area does not foresee any reliability or capacity issues becoming problematic during the long-term assessment period.

MRO-SaskPower

Assessment Area Overview

Saskatchewan is a province of Canada and comprises a geographic area of 651,900 square kilometers with approximately 1.1 million people. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the Planning Coordinator and 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 percent margin is applied as the Reference Margin Level for this assessment.

Load Forecast Method
Coincident, 50/50 forecast

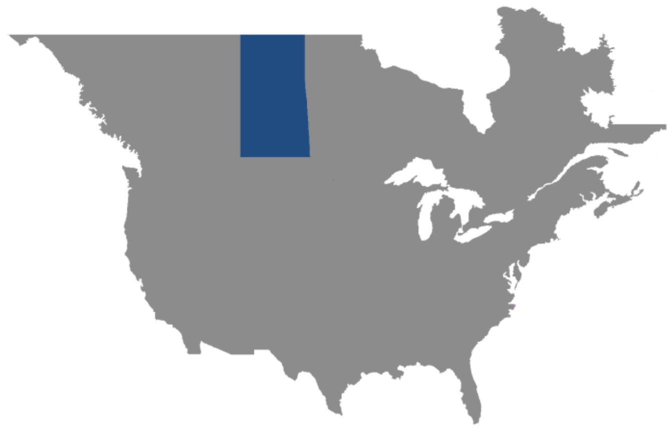
Peak Season
Winter

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

Planning Considerations for Solar Resources
No utility-scale solar resources

Footprint Changes
N/A

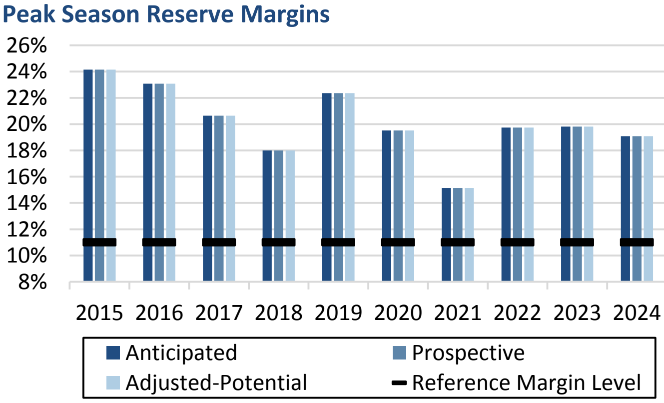
Assessment Area Footprint



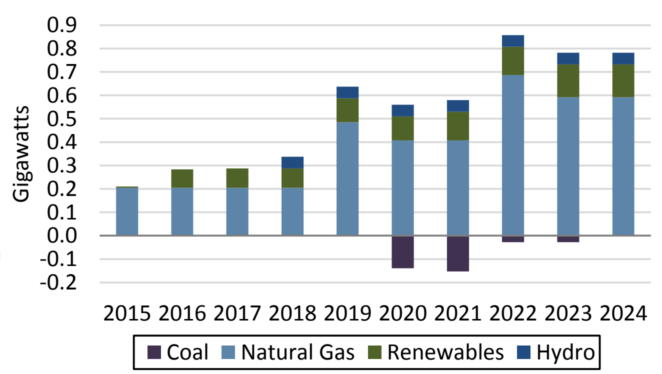
Peak Season Demand, Resources, and Reserve Margins

Demand (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Internal Demand	3,557	3,647	3,722	3,846	3,957	3,984	4,029	4,077	4,116	4,141
Demand Response	86	86	86	86	86	86	86	86	86	86
Net Internal Demand	3,471	3,561	3,636	3,760	3,871	3,898	3,943	3,991	4,030	4,055
Resources (MW)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Anticipated	4,309	4,383	4,387	4,437	4,737	4,659	4,540	4,779	4,829	4,829
Prospective	4,309	4,383	4,387	4,437	4,737	4,659	4,540	4,779	4,829	4,829
Adjusted-Potential	4,309	4,383	4,387	4,437	4,737	4,659	4,540	4,779	4,829	4,829
Reserve Margins (%)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Anticipated	24.15%	23.08%	20.65%	18.00%	22.36%	19.52%	15.14%	19.74%	19.82%	19.08%
Prospective	24.15%	23.08%	20.65%	18.00%	22.36%	19.52%	15.14%	19.74%	19.82%	19.08%
Adjusted-Potential	24.15%	23.08%	20.65%	18.00%	22.36%	19.52%	15.14%	19.74%	19.82%	19.08%
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)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Anticipated	457	430	351	263	440	332	163	349	355	328
Prospective	457	430	351	263	440	332	163	349	355	328
Adjusted-Potential	457	430	351	263	440	332	163	349	355	328

Peak Season Reserve Margins



Peak Season Projected Generation Mix (Cumulative Change)



Demand, Resources, and Reserve Margins

Saskatchewan plans to meet projected load with Anticipated Resources throughout the assessment period. Based on the deterministic calculation made within this assessment, Saskatchewan's Anticipated Reserve Margin ranges between 13 and 24 percent, remaining above the Reference Margin Level of 11 percent throughout the assessment period.

Saskatchewan does not anticipate any challenges that would lead to significant detractions of its Planning Reserve Margin projections. Greenhouse gas regulations are expected to become an issue as specific federal and provincial regulations are introduced and clarified. The consequence of such regulations is expected to have a low impact on reliability, because it is expected that sufficient lead time will be given to allow for appropriate mitigation.

The forecast growth rate for Total Internal Demand is 1.7 percent during the winter seasons of the assessment period. Since last year's assessment, the forecast growth in internal demand has decreased slightly, primarily due to reduced economic growth forecast.

An upswing in the economy could lead to an increase in electricity usage and cause a spike to the overall demand. Saskatchewan has plans in place to meet resource reliability requirements, should a sudden economic change cause a need for new capacity. Load growth in Saskatchewan is primarily due to economic growth in the industrial sector and in general is spread throughout the province.

It is expected that 170 MW of DSM will be available during the first year of the assessment and 253 MW of DSM will be available during year 10 of the assessment period. Projected annual growth in energy efficiency and conservation declines throughout the assessment period, ranging from 12 percent per year in year 1 to 6 percent growth in year 10. The primary driver for DSM programs in Saskatchewan is the economic incentive or the difference in cost between providing the DSM program and the cost of serving the load. Increases in DSM will come from growth of existing and new programs. DSM savings are counted as a load modifier and are netted from the load forecast. Saskatchewan considers DR to be a capacity resource used for peak shaving and has energy-limited contracts in place with a number of customers to provide this service. Saskatchewan will continue to initiate new economically viable DSM programs and will monitor and expand (if required) the DR programs.

The primary sources of fuel in Saskatchewan are coal, hydro, and natural gas. Throughout the assessment period, a total capacity of 1,631 MW (nameplate) of Future-Planned resources are projected to come on-line. This total consists of 250 MW of refurbished coal, 765 MW of gas, 530 MW (nameplate) of wind, 36 MW of biomass resources, and 50 MW of additional hydro resources. Projected unit retirements during the long-term planning horizon include a 79 MW natural gas facility, two 139 MW coal facilities, an 11 MW wind facility, and a 95 MW natural gas facility. Saskatchewan manages unit retirements and negative impacts to capacity within its resource planning process and allows adequate time for new supply resources to be put in service to meet the reliability requirements during the assessment period.

Saskatchewan plans for 10 percent of wind nameplate capacity to be available to meet summer peak demand and 20 percent of wind nameplate capacity to be available to meet winter peak demand. The wind available to meet peak requirements is based on the historical actual wind generation over a four-hour period during the peak for each day for the entire year. Historical data was used for each wind installation from the time it was first in service. On-peak expected values for hydro assume nameplate net generation less expected seasonal derates due to water conditions. Saskatchewan plans for 100 percent of biomass nameplate capacity to be available to meet demand, based on a base-load contract.

Saskatchewan has not identified any impacts on operational procedures due to integrating variable resources over the assessment period. Saskatchewan performs reviews of operational procedures when planning to integrate variable resources. The addition of VERs in the future may require System Operators to be able to curtail these resources, or to have additional fast-ramping capacity available from other resources to follow the intermittency of the variable resource.

Saskatchewan does not rely on capacity transactions for reliability assessments unless there is a Firm contract for both the supply source and transmission. Saskatchewan anticipates having a Firm import contract for 25 MW from winter 2015 to spring 2022. There are no Firm exports planned for the assessment period. Saskatchewan does not rely on emergency imports to meet its demand.

Transmission Outlook and System Enhancements

The following are the top transmission projects that relate to the maintenance of or enhancement to reliability during the near-term planning horizon of the assessment period for Saskatchewan:

- Approximately 300 km of 138 kV transmission line in the northern region of Saskatchewan.
- Approximately 110 km of 230 kV transmission line in the east-central region of Saskatchewan.
- Approximately 225 km of 230 kV transmission, 225 km of 138 kV transmission, and salvage of 135 km of 138 kV line in the southwest region of Saskatchewan.
- Approximately 100 km of 230 kV transmission line in the southeast region of Saskatchewan.
- Seven new 230-138 kV auto-transformers in the southeast region of Saskatchewan.

These projects are heavily dependent on load growth. Delays are assessed when indicated, and interim measures (if required) are implemented to ensure system reliability is not impacted

For the assessment period, Saskpower has been identified that the local Swift Current area (southwest region of Saskatchewan) is reactive power-limited in the long term. To address this, a static var system (SVS) is planned in the near-term planning horizon.

One under-voltage load shedding (UVLS) scheme is planned in the near-term planning horizon, in the Tantallon area in the southeastern region of the province. This scheme will be installed to mitigate potential low voltages under certain generation dispatch scenarios caused by local N-1 outages (until planned transmission reinforcements into Tantallon are in place) and a few local N-2 outages in the southeastern region of the province. The planned UVLS scheme targets less than 100 MVA of load to be shed in stages. A new 230 kV transmission line is proposed in the near-term planning horizon that will reinforce the Tantallon-area voltage. The UVLS scheme will then be used to mitigate potential low voltages for N-1-1 and N-2 outages under certain generation dispatch scenarios.

The following conceptual Special Protection Systems (SPS) in Saskatchewan 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:

- Estevan Area (southeastern region): This protection system is planned to be temporary until projected industrial load growth in the region materializes.
- Nipawin Area (east-central region): This protection system is planned to be permanent for the assessment period.
- Melfort Area (east-central region): This protection system is planned to be temporary until a planned 110 km, 230 kV transmission line is in service in the region.

Long-Term Reliability Issues

Resource adequacy and operational concerns can apply for various reasons, including extreme weather events, hydro conditions, standards, Demand Response programs, variable generation, and other unit conditions.

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.

Saskatchewan hydro resource planning is based on median flow conditions utilizing historical data. Most of Saskatchewan's hydro facilities have some form of storage and are capable of achieving near-full-load output for some period of time under most operating conditions.

Demand Response (DR) programs are contracted on an as-needed basis. If additional DR programs are required, Saskatchewan will actively solicit additional DR customers.

One of the largest factors for operational concerns is the addition of variable resources, such as wind and solar. Saskatchewan performs wind integration studies and is in the process of developing a 10-year wind power strategy. The amount of load that is offset by DERs or BTMG is reflected in the load forecast used for reliability assessments. It is not anticipated that Saskatchewan will encounter any long-term reliability impacts due to DERs or BTMG.

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

Canadian federal regulations for CO_2 emissions have been finalized and lay out the requirements and timelines for existing coal-fired generation for the reduction of GHG. These regulations could impact the direction taken on carbon capture and storage technology and new natural gas generation. These impacts will have a cascading effect on many other significant areas, including current and projected contracts for future supply of coal and natural gas. Provincial regulations are currently being developed, and an equivalency agreement between the provincial and federal governments may be created to allow greater flexibility to meet GHG regulations. Saskatchewan is working with the provincial government in developing the equivalency agreement.

Development and finalization of federal regulations to limit CO_2 from natural-gas-based electricity generation could cause Saskatchewan to modify operational use of existing gas units in order to remain compliant. Pending federal natural gas rules for electricity generation will impact the timing and nature of capital projects, potential retirements, or new energy decisions. These regulations are constantly monitored and are included in resource adequacy assessments. Saskatchewan plans to include sufficient time to perform retrofits or replacement to meet required regulations. Saskatchewan has not yet experienced any reliability issues related to GHG regulations and is expected to effectively mitigate any future issues related to them.

The requirement to reduce NOx, SO_2, and CO_2 emissions for both coal and natural gas facilities will require ongoing resource planning to ensure that retrofitting or the addition of new emission control equipment is done in a timely manner. The parasitic load for emission equipment is substantial. It must be included in determining net outputs from generation facilities and is dependent on the intensity limits for emission reductions. Saskatchewan is working with both the provincial and federal governments on emission regulations and equivalency agreements.

Saskatchewan will have approximately 8.5 percent (capacity) of wind integration by 2017 and is looking at adding more in the long term. The addition of VERs may have operational impacts that need to be studied to determine the power system effects to both Saskatchewan and neighboring jurisdictions. Depending on the makeup of the future generation resources, variable resources may need to be curtailed, or other generation sources may need to come on-line to allow for the sudden changes in output.

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 percent

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

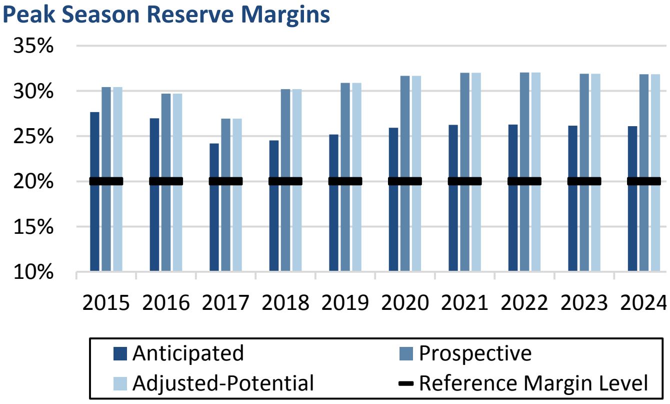
Footprint Changes
A conceptual tie line to the Canadian province of Newfoundland and Labrador could potentially impact the Maritimes footprint.

Assessment Area Footprint

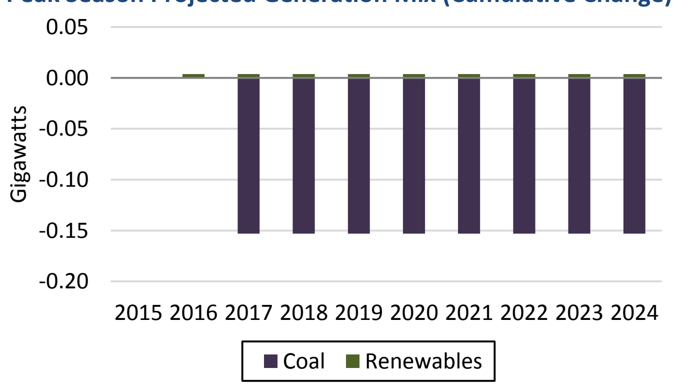
Peak Season Demand, Resources, and Reserve Margins

Demand (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Internal Demand	5,477	5,513	5,508	5,493	5,466	5,434	5,421	5,420	5,425	5,427
Demand Response	247	252	252	252	251	251	251	251	251	251
Net Internal Demand	5,230	5,261	5,256	5,241	5,214	5,183	5,170	5,169	5,174	5,176
Resources (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	6,676	6,680	6,527	6,527	6,527	6,527	6,527	6,527	6,527	6,527
Prospective	6,820	6,824	6,671	6,824	6,824	6,824	6,824	6,824	6,824	6,824
Adjusted-Potential	6,820	6,824	6,671	6,824	6,824	6,824	6,824	6,824	6,824	6,824
Reserve Margins (%)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	27.66%	26.97%	24.19%	24.53%	25.18%	25.93%	26.25%	26.28%	26.16%	26.11%
Prospective	30.42%	29.71%	26.93%	30.20%	30.88%	31.67%	32.00%	32.03%	31.90%	31.85%
Adjusted-Potential	30.42%	29.71%	26.93%	30.20%	30.88%	31.67%	32.00%	32.03%	31.90%	31.85%
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)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	401	366	220	238	270	308	323	325	319	316
Prospective	545	511	364	535	567	605	620	622	616	613
Adjusted-Potential	545	511	364	535	567	605	620	622	616	613

Peak Season Reserve Margins



Peak Season Projected Generation Mix (Cumulative Change)



Demand, Resources, and Reserve Margins

The Reference Margin Level for the Maritimes Area is 20 percent and has not changed since the 2013LTRA. During summer and winter peak load periods, the Anticipated, Prospective, and Adjusted Potential Reserve Margins remain above the Reference Margin Level during the assessment period.

Compared to the 2013LTRA, the aggregated load growth rate for the combined sub-areas is practically unchanged for both the summer and winter seasonal peak load periods. 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 effects of energy efficiency 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 peak load into lower load periods and this program is directly embedded in the load forecast (reported as energy efficiency).[90] DCLM in NB is expected to rise from approximately 20 MW in 2015 to about 240 MW by the end of the assessment period. The amount of Interruptible Load in 2015 will be approximately 335 MW during the summer and 240 MW during the winter, increasing by about 10 MW/year over the assessment period.

Planned capacity additions include 231 MW (28 MW during the peak) of wind capacity, along with a 10 MW biomass plant, both in Nova Scotia (NS). These additions will have virtually no reliability impacts, due to their smaller size. A 153 MW generator in NS is expected to be retired in October 2017. This 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 hydro-electric generation development. NS plans to offset the retirement of the thermal unit with a 153 MW import of hydro capacity from Muskrat Falls.

Currently there are no Firm capacity contracts between the Maritimes Area and neighboring areas. 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 Reference Margin Level. Any such transactions are coordinated through NPCC working groups, which include members from all neighboring areas.

Transmission Outlook and System Enhancements

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

The Eel River, NB HVdc interconnection with the Canadian Province of Québec will be refurbished during 2014. This interface provides import and export capability up to 350 MW with the Province of Québec and contributes to frequency response in the Maritimes Area. An additional 230 kV breaker installation will allow the separation of supplies to two 230/138 kV transformers in the substation at Eel River.

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.

Long-Term Reliability Issues

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 or peak supply. The Maritimes Area is not overly reliant on wind capacity to meet resource adequacy requirements. Neither (1) the lack of wind during peaks, (2) very high wind speeds, nor (3) icing conditions that

[90] DCLM for the Maritimes area is in the early stages of development. Future effects are included in Energy Efficiency until they can be clearly identified and itemized in forecasts.

would cause wind farms to suddenly shut down should affect the dependability of supply to the area, as ample spinning reserve is available to cover the loss of the largest baseload generator in the area. The latter situation is mitigated further by wide geographic dispersal of wind resources across the area.

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 non-variable forms of generation, such as wood-based biomass. In NS, the Maritimes Link project will displace several conceptual wind farm installations with renewable hydro resources and should help mitigate potential and related frequency response issues.

The Maritimes 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 percent of the total capacity in the area. There is not a high degree of reliance upon any one type or source of fuel. Resource planners in the Maritimes Area do not anticipate that fuel disruptions will pose significant challenges to resource adequacy during the assessment period. This resource diversification also provides flexibility to respond to any future environmental issues, such as potential restrictions to GHG 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. DSM 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 assessment period. The impact on the resource adequacy LOLE value is captured by modeling a reduction in tie transfer capabilities between sub-areas. The *NPCC - 2013 Maritimes Area Comprehensive Review of Resource Adequacy*[91] showed that after transfer levels were 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 Reference Margin 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-fired generation with renewable resources. By 2015, 25 percent of the province's electricity sales (energy) will be supplied by renewable energy sources, and by 2020 this number increases to 40 percent. 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 the operation of or amount of new renewable generation added to the system on a case-by-case basis.

Because of the relative size of the largest generating unit in the Maritimes Area 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 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 Area load will be reliably supplied for the 10 years covered in this report.

[91] NPCC - 2013 Maritimes Area Comprehensive Review of Resource Adequacy.

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 15.7 percent in 2015, declining to 14.3 percent in 2017 and remaining at that level for the duration of the period.

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

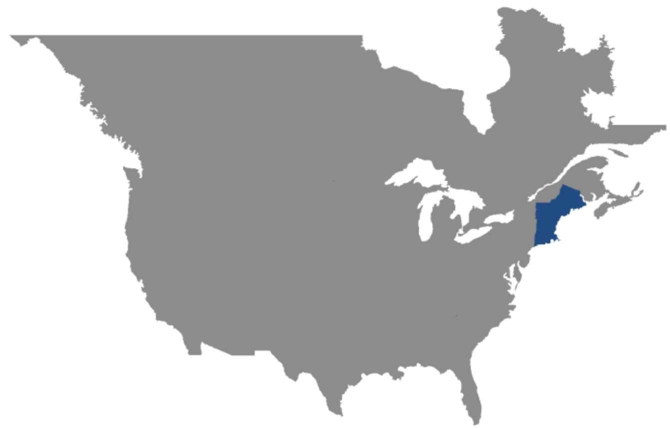
Peak Season
Summer

Planning Considerations for Wind Resources
5 percent of the total

Planning Considerations for Solar Resources
Seasonal claimed capability

Footprint Changes
N/A

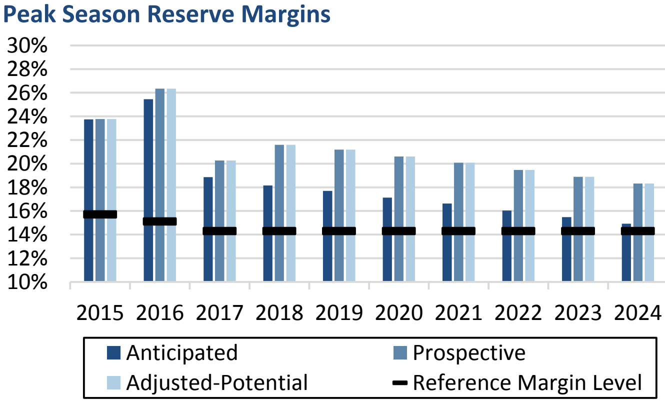
Assessment Area Footprint



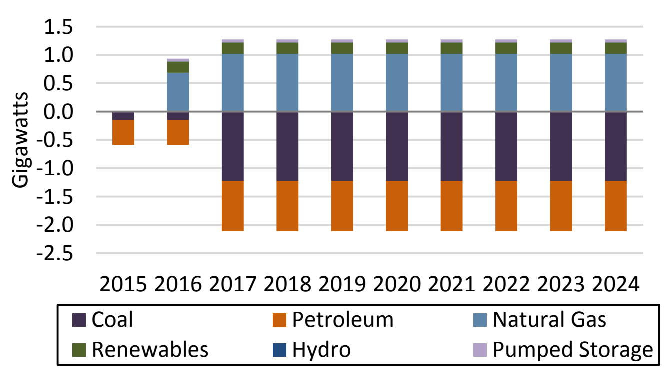
Peak Season Demand, Resources, and Reserve Margins

Demand (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Internal Demand	26,930	27,291	27,521	27,677	27,782	27,911	28,028	28,167	28,298	28,430
Demand Response	1,167	944	994	994	994	994	994	994	994	994
Net Internal Demand	25,763	26,347	26,527	26,683	26,788	26,917	27,034	27,173	27,304	27,436
Resources (MW)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Anticipated	31,880	33,052	31,529	31,529	31,529	31,529	31,529	31,529	31,529	31,529
Prospective	31,887	33,286	31,904	32,446	32,463	32,463	32,463	32,463	32,463	32,463
Adjusted-Potential	31,887	33,286	31,904	32,446	32,463	32,463	32,463	32,463	32,463	32,463
Reserve Margins (%)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Anticipated	23.75%	25.45%	18.85%	18.16%	17.70%	17.13%	16.63%	16.03%	15.47%	14.92%
Prospective	23.77%	26.34%	20.27%	21.60%	21.18%	20.60%	20.08%	19.47%	18.89%	18.32%
Adjusted-Potential	23.77%	26.34%	20.27%	21.60%	21.18%	20.60%	20.08%	19.47%	18.89%	18.32%
Reference Margin Level	15.70%	15.10%	14.30%	14.30%	14.30%	14.30%	14.30%	14.30%	14.30%	14.30%
Excess/Shortfall (MW)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Anticipated	2,073	2,727	1,208	1,030	910	762	629	470	320	169
Prospective	2,080	2,961	1,583	1,947	1,844	1,697	1,563	1,404	1,254	1,103
Adjusted-Potential	2,080	2,961	1,583	1,947	1,844	1,697	1,563	1,404	1,254	1,103

Peak Season Reserve Margins



Peak Season Projected Generation Mix (Cumulative Change)



Demand, Resources, and Planning Reserve Margins

New England's (ISO-NE) Reference Margin Level is based on the capacity needed to meet the NPCC one-day-in-10-years LOLE resource planning reliability criterion. The amount of capacity needed—referred to as the Installed Capacity Requirement (ICR)—varies from year to year depending on expected system conditions. The ICR, which is calculated three years in advance for each Forward Capacity Market (FCM) auction, results in a Reference Margin Level of 15.7 percent in 2015, 15.1 percent in 2016, and 14.3 percent in 2017. In this assessment, the last calculated Reference Margin Level (14.3 percent) is applied for the remaining years.

ISO-NE's Anticipated Reserve Margin during the annual peak reflects the Seasonal Claimed Capability of all ISO-NE generators, as well as demand resources and imports that have Capacity Supply Obligations (CSOs) as a result of the FCM auctions. In the 2015 summer, ISO-NE's Anticipated Resources amount to 31,880 MW, which results in an Anticipated Reserve Margin of 23.8 percent of the Net Internal Demand of 25,763 MW. The Anticipated Reserve Margin remains above the 14.3 percent Reference Margin Level through the entire assessment period.

The 2015 summer peak Total Internal Demand, which takes into account 1,685 MW of passive demand resources, or energy efficiency, is 26,930 MW. There has been no substantial change in the forecast since last year.

DSM in the ISO-NE BPS includes both active and passive demand resources. Active demand resources consist of real-time DR and real-time emergency generation, 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 CSOs obtained through ISO-NE's FCM three years in advance. The CSOs decrease slightly from 1,167 MW in 2015 to 944 MW in 2016 and then increase to 994 MW in 2017. Since there are no further auction results, the CSOs are assumed to remain at the same level through the end of the reporting period.

Passive demand resources (i.e., energy efficiency and conservation) include 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. Passive DR is also secured by means of the FCM. However, ISO-NE has developed an energy efficiency forecasting method that takes into account the potential impact of growing energy efficiency and conservation initiatives in the region to project the amount of energy efficiency beyond the years when the FCM CSOs have already been procured. Energy efficiency has generally been increasing and is projected to continue growing throughout the study period. The amount of energy efficiency in 2015 is 1,685 MW and is projected to increase to nearly 3,500 MW by 2024.

Active demand resources are treated like generating resources in ISO New England and are dispatched by ISO operators when they are needed to meet load and operating reserve requirements. A number of retirements are expected to take place in the region within the next three years. Salem Harbor Units 3 and 4, which are coal- and oil-fired units with a combined capacity of 587 MW, were scheduled to retire by June 1, 2014. Salem Harbor Units 1 and 2, which were coal-fired units with a total capacity of 158 MW, were previously retired in December 2011. As a result of these retirements, upgrades to five transmission lines in the North Shore area (northwest of Boston) were identified as being needed to address immediate reliability concerns. Those transmission upgrades have been placed in service. The capacity lost with the retirement of Salem Harbor is expected to be replaced by the new Footprint Power 674 MW generating plant, which is to be located at the Salem Harbor site.

In August 2013, the Vermont Yankee nuclear plant (619 MW) announced that it would be shutting down by the end of 2014. Later in 2013, ISO-NE was notified that an additional 1,877 MW planned to retire on June 1, 2017. This total consisted of five coal- and oil-fired resources representing 1,535 MW from the Brayton Point Station and three oil-fired resources representing 342 MW from Norwalk Harbor Station.

Even with these retirements, the reserve margin is not expected to fall below the 14.3 percent Reference Margin Level during the assessment period. However, since new environmental requirements may result in the retirement of additional resources, the ISO is working with stakeholders to identify issues and find the means of meeting future capacity needs.

Approximately 6,900 MW of proposed generation is in the ISO Generator Interconnection Queue. Market incentives are under development to increase resource development where and when needed.

By design, the level of the ICR specified for New England could necessitate the use of specific OP-4 actions because the ICR calculation includes capacity and accounts for the load relief these actions provide. Operable capacity study results show that the need for load and capacity relief by OP-4 actions will be approximately 2,600 MW during extremely hot and humid summer peak load conditions. This amount is likely achievable through OP-4 actions by depleting operating reserves, scheduling emergency transactions with neighboring systems, operating real-time emergency generators, and implementing five percent voltage reductions.

Preserving the reliable operation of the system will become increasingly challenging with potential retirements and the need for operating flexibility, particularly in light of the reliance on natural gas resources. These factors are expected to increase the need for reliable resources, especially those able to provide operating reserves and ramping capabilities. To begin addressing this need, the ISO has procured additional 10-minute reserves and replacement operating reserves.

These challenges will be addressed over the long term through the Strategic Planning Initiative.[92] As part of this initiative, the ISO has been actively collaborating with stakeholders on comprehensive near- and long-term rule changes across the region's suite of energy, reserve, and capacity markets. Proposed enhancements to the FCM include modification of the zonal structure used in the capacity market, flexibility in Energy Market offers, and a "pay-for-performance" mechanism in the FCM that will create stronger financial incentives for capacity suppliers to perform when called on during periods of system stress.

New England has witnessed significant growth in the development of solar photovoltaic (PV) resources over the past few years, and continued growth of PV is expected. Solar PV resources installed in New England are predominantly BTMG, not visible to ISO Operations in real time. An estimated one-third of these projects are registered in ISO's energy market as Settlement-Only Resources. ISO-NE is not directly involved in the interconnection of most of these resources and has therefore not traditionally been aware of when and where they are installed. ISO-NE recently formed a stakeholder working group to increase its understanding of development trends of PV and other DERs, and to develop a forecast of PV over the next 10 years. At the end of 2013, 500 MWac of PV was installed in New England, and projections indicate that over 1,800 MWac will be added by 2023.

In January 2014, ISO-NE began incorporating wind forecasting into its processes, scheduling, and dispatch services. With wind forecast integration complete, the ISO will be working toward the full economic dispatch of wind resources in phase 2 of this project. The ISO will continue to analyze wind integration issues and work with stakeholders to address the issues challenging the wind interconnection process and the performance of the system with wind resources in locally constrained areas. New England is applying advanced technologies, including FACTS and HVdc, phasor measurement units (PMUs), and smart meters, which may be used to provide the regulation and reserve services required to reliably integrate variable renewable resources. Currently there is only 101 MW of on-peak wind capacity in New England, and only 185 MW (on-peak capacity) of future planned wind additions during the study period.

Given the embedded nature of most PV development in New England—projects are interconnected to the distribution system and can neither be directly observed nor dispatched by the regional System Operator—the influence of increased amounts of PV 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). As such, new forecasting techniques eventually will be required to account for PV generation appropriately. To prepare for this, ISO-NE is actively tracking the growth of PV in the region, monitoring its impact on operational load forecasting performance, and researching forecasting options that may serve as short- and/or long-term solutions.

[92] ISO-NE Strategic Planning Initiative Key Project.

Firm summer capacity imports are based on FCM CSOs, which amount to 1,642 MW in 2015 and decrease to 1,267 MW in 2017. Firm transactions beyond 2017 are held constant at the value in 2017. Only Firm imports are reported in this assessment. However, in addition to capacity imports that have CSOs, external transactions can participate in the day-ahead and real-time energy markets. In past years, actual imports during the peak have been significantly higher than the CSOs. For example, in 2013 the imports to New England from New York, New Brunswick, and Quebec at the time of the peak demand totaled 3,172 MW, or 1,969 MW more than the CSO of 1,203 MW. During the assessment period, there is a Firm capacity sale to New York (Long Island) of 100 MW that is expected to be delivered via the Cross-Sound Cable.

In the case of inadequate 10-minute operating reserves, ISO-NE can implement an OP-4 action to arrange for the purchase of up to 1,000 MW of available emergency capacity and energy, or energy only (if capacity backing is not available), from market participants or neighboring control areas. ISO-NE coordinates with other Assessment Areas to evaluate changes to the transmission system that would have an impact on import and export capabilities, and to determine a safe and reliable transfer limit if changes are needed. For long-term studies, ISO-NE confirms imports and exports through NPCC working group studies.

Transmission Outlook and System Enhancements

Several future transmission projects coming on-line during the assessment period are important to the continuation of, or enhancement to, system or sub-area reliability. The major projects under development in New England include the Maine Power Reliability Program (MPRP) and the New England East–West Solution (NEEWS). The new paths that are part of MPRP (many components of which are under construction) will provide the basic infrastructure necessary to increase the ability to move power from New Hampshire into Maine and improve the ability of Maine's transmission system to move power into the local load pockets as necessary. NEEWS consists of a series of projects that will improve system reliability in areas including Springfield, Massachusetts, and Rhode Island, and increase total transfer capability across the New England east-to-west and west-to-east interfaces.

New smart grid technologies such as FACTS are being used in New England to improve the electric power system's performance and operating flexibility. In addition, several investor-owned and municipal utilities in New England are conducting smart grid pilot programs or projects ranging from smart meter deployments to full-scale direct load control and distribution automation projects. ISO-NE anticipates that these projects may lead to more significant smart grid assets becoming available for potential utilization during the assessment period.

Long-Term Reliability Issues

If New England experiences extreme summer weather that results in 90/10 peak demands or greater, ISO-NE still should have enough operable capacity available to reliably manage the BPS. However, if supply-side outages diminish New England's operable capacity to serve these 90/10 peak demands, ISO-NE will be able to invoke OP-4 to meet the demand and maintain the operating reserve requirement.

RPSs mandate that by 2023, energy efficiency and renewable resources such as wind and solar must supply approximately one-third of the projected electric energy in New England. Possible solutions for meeting the regional RPSs include developing the renewable resources already in the ISO generator interconnection queue; importing renewable resources from adjacent balancing authority areas; building new renewable resources in New England not yet in the queue; and using BTMG projects and eligible renewable fuels, such as biomass, at existing generators.

Concerns exist over the resultant impacts from compliance with state RPSs and the potential build-out of these new renewable resources. Because of concerns over the increasing amounts of wind capacity, ISO-NE completed a major wind integration study that identified the detailed operational issues of integrating large amounts of wind resources into the New England power grid. The New England Wind Integration Study (NEWIS) found that the large-scale integration of wind resources is feasible, but resource planners will need to continue addressing a number of issues, including the development of an accurate means of forecasting wind generation outputs. As a result of that recommendation, ISO-NE implemented a centralized wind power forecasting service. The addition of variable energy resources, particularly wind and solar, will likely grow with time, hence increasing the need for flexible resources to provide operating reserves as well as other ancillary services, such as regulation and ramping.

Since ISO-NE's Demand Response resources are treated as capacity and are procured three years in advance in its Forward Capacity Auctions, approximately 1,000 MW of active DR are expected to be available. As previously noted, active DR can be triggered by ISO-NE in real time under OP-4 to help mitigate a capacity deficiency by reducing the peak demand. Over the past three years, the actual performance of these resources during summer peak period OP-4 events has ranged from 95 to 100 percent, and winter response rates have ranged from 75 to 100 percent.

PV resources (and to a lesser extent other types of DG resources) are rapidly developing in New England and predominantly are not directly observable or controllable by ISO-NE. Because of the differences between the state-jurisdictional interconnection standards that apply to most PV resources and the FERC-jurisdictional standards that apply to larger conventional generators, PV exhibits different electrical characteristics during system conditions typical of grid disturbances. ISO-NE is working with the New England states, distribution utilities, IEEE, and various international experts to ensure that the future interconnection standards for PV (and other inverter-interfaced DG resources) better coordinate with broader system reliability requirements.

Environmental compliance obligations for generators due to existing and pending state, regional, and federal environmental requirements are likely to impose operational limits on new and existing generators but pose only a limited retirement risk and lower reliability impacts compared to earlier assessments. The lowered retirement risk is due in large part to the flexibility that the EPA has provided in its cooling water rule and MATS, recognizing the reliability value that low-capacity-factor fossil steam generators provide in maintaining system fuel diversity.

Up to 12.1 GW of generating capacity in New England that currently utilizes once-through cooling, including a subset of units with larger withdrawal capacities, may potentially need to convert closed-cycle cooling systems.

Approximately 7.9 GW of existing coal- or oil-fired capacity in New England is subject to MATS. Most affected generators in New England are equipped with required air toxics control devices due to earlier compliance with state air toxics regulations in New England. No retirements have been announced or are expected in New England due to MATS. However, a one-year compliance extension request has been sought by a generator for less than 100 MW of affected coal-fired capacity. Recent revisions to air quality standards limit ambient concentrations of ozone, and its precursors (fine particulate matter and sulfur dioxide) are expected to require additional emissions reductions from fossil-fired generators.

New England faces a number of concerns for ensuring the reliability of the fuel supply, particularly the supply of natural gas and oil. Operating experience has exposed some vulnerabilities associated with the strategic risks of resource performance and flexibility and the increased reliance on natural-gas-fired capacity. During severe winter weather, such as that experienced in winter 2013–2014, System Operators faced challenges due to the combination of high winter loads resulting from cold weather, and limited natural gas and oil used to fuel generating units. In such situations, gas pipelines are often operating at their maximum levels to supply local distribution companies (LDCs) that supply retail natural gas customers. Although oil-fired generators could compensate for the reduced availability of gas-fired generation, they may be limited by inadequate oil inventory at the beginning of winter, and securing midwinter replenishment of oil can be difficult due to challenges with oil transportation and availability.

ISO-NE had implemented a winter reliability program in 2013–2014 and will initiate a modified program for the winter of 2014–2015, along with scheduled market improvements. The major components of the planned winter reliability program include annual audits of dual-fuel resources; additional compensation to offset testing costs associated with restoring or commissioning dual-fuel capability; additional winter period Demand Response; and additional compensation for unused oil inventory at the end of the winter period.

Recent and planned improvements to the regional and interregional natural gas infrastructure provide initial steps for expanding the access to natural gas supply sources to meet New England's increasing demand for natural gas for power generation. More expansion is required, however. Although natural gas production volumes in the northeast region are forecast to rise, New England cannot access the full benefit of production because of existing pipeline capacity constraints. The natural gas pipelines serving the region are at or near capacity, but they will not expand until customers commit to Firm service. A study performed by ICF International found that if one assumes the same weather conditions as winter 2013–2014, winter peak-day gas supplies will be barely adequate or slightly in deficit through 2020. Outages of capacity that is not fueled by natural gas, such as a disruption to a nuclear unit, or unforeseen outages of natural gas infrastructure, would result in a serious gas supply deficit.

An emerging reliability issue currently being addressed by ISO-NE is the significant growth of DG resources in New England. Because PV resources constitute the largest segment of DG resources throughout New England, the ISO's analysis of DG focuses exclusively on the impact of additional distributed PV. To help address the interrelated questions of exactly how much additional PV is projected in the ISO's 10-year planning horizon and what impact this future PV could have on the regional power grid, the ISO, in conjunction with stakeholders, endeavored to create a forecast of all future PV resources. In September 2013, the ISO established the Distributed Generation Forecast Working Group (DGFWG) to assist its development of a DG forecast and provide a forum to discuss DG integration issues.

Due to the complexities associated with creating a PV forecast, the ISO began with an interim PV forecast that was limited to PV that results from state policies. The PV estimates are based on state-by-state policy initiatives, with discounts to account for the uncertainty of existing and future policies. The ISO is working with the DGFWG to find ways to improve on the forecast in future years.

Results of the forecast will inform various ISO system planning functions. For example, the ISO intends to use data from the DG forecast in transmission studies, new generator interconnection studies, and economic studies. The ISO will work with stakeholders to explore how the DG forecast may potentially be used in these planning analyses and other market-related assessments. These may include such tasks as the development of the ICR.

The growth in DG presents some challenges for grid operators and planners. Challenges for the ISO include: (1) a limited amount of data concerning DG resources, including their size, location, and operational characteristics; (2) a current inability to observe and control DG resources in real time; (3) a need to better understand the impacts of growing DG on system operations, including ramping, reserve, and regulation requirements; and (4) potential reliability impacts to the regional power system posed by future amounts of DG resulting from existing state interconnection standards.

Ongoing work between ISO-NE and the DGFWG will help position New England to best integrate rapidly growing DG resources in a way that maintains reliability and allows the states to realize the public policy benefits they have identified as the basis for their DG programs.

NPCC-New York

Assessment Area Overview

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

Summary of Methods and Assumptions

Reference Margin Level
The New York State Reliability Council (NYSRC) Installed Reserve Margin (IRM) of 17 percent extends through April 2015. Because this margin will be reassigned in 2015, NYISO will use the default Reference Margin Level of 15 percent.

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

Peak Season
Summer

Planning Considerations for Wind Resources
Modeled with a 17 percent capacity factor

Planning Considerations for Solar Resources
Modeled with a 65 percent capacity factor

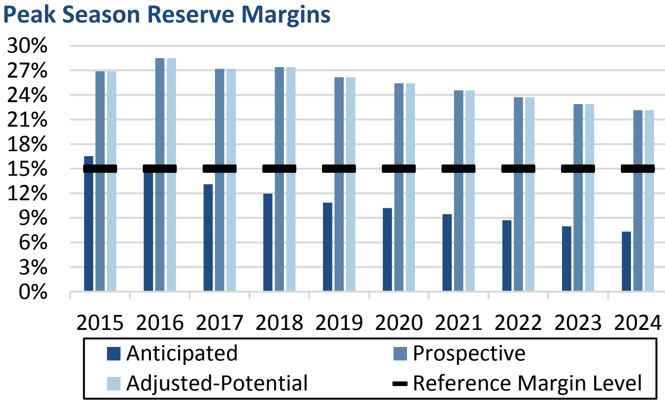
Footprint Changes
N/A

Assessment Area Footprint

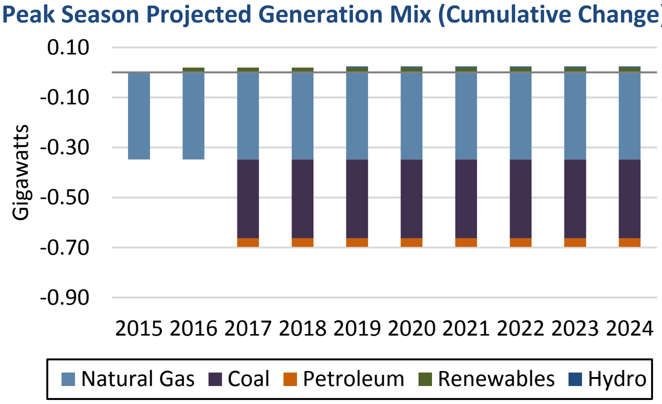
Peak Season Demand, Resources, and Reserve Margins

Demand (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Internal Demand	34,066	34,412	34,766	35,111	35,454	35,656	35,890	36,127	36,369	36,580
Demand Response	1,189	1,189	1,189	1,189	1,189	1,189	1,189	1,189	1,189	1,189
Net Internal Demand	32,877	33,223	33,577	33,922	34,265	34,467	34,701	34,938	35,180	35,391
Resources (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	38,311	38,330	37,980	37,980	37,985	37,985	37,985	37,985	37,985	37,985
Prospective	41,715	42,691	42,702	43,217	43,228	43,228	43,228	43,228	43,228	43,228
Adjusted-Potential	41,715	42,691	42,702	43,217	43,228	43,228	43,228	43,228	43,228	43,228
Reserve Margins (%)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	16.53%	15.37%	13.11%	11.96%	10.86%	10.21%	9.46%	8.72%	7.97%	7.33%
Prospective	26.88%	28.50%	27.18%	27.40%	26.16%	25.42%	24.57%	23.73%	22.88%	22.14%
Adjusted-Potential	26.88%	28.50%	27.18%	27.40%	26.16%	25.42%	24.57%	23.73%	22.88%	22.14%
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)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	502	123	(633)	(1,030)	(1,420)	(1,652)	(1,921)	(2,194)	(2,472)	(2,715)
Prospective	3,907	4,485	4,088	4,207	3,823	3,591	3,322	3,049	2,771	2,528
Adjusted-Potential	3,907	4,485	4,088	4,207	3,823	3,591	3,322	3,049	2,771	2,528

Peak Season Reserve Margins



Peak Season Projected Generation Mix (Cumulative Change)



Demand, Resources, and Planning Reserve Margins

The current Installed Reserve Margin (IRM) requirement for the NYBA that covers the period from May 2014 to April 2015 (2014 Capability Year) is 17 percent. The New York State Reliability Council (NYSRC) sets this requirement annually based upon an annual study conducted by its Installed Capacity Subcommittee (ICS). Because the IRM will be reassigned after April 2015, a 15 percent Reference Margin Level has been used for this long-term assessment. While the Anticipated Reserve Margin falls below the 15 percent Reference Margin Level in 2017, the Prospective Reserve Margin remains above for all seasons and years of the assessment period.

The energy forecast for the downstate area is lower than that of 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) is expected to increase, some of the zones in the downstate area are projected to have negative energy growth, but continue to expect positive summer and winter peak demand growth. This decline in year-over-year energy usage is attributed to the continued impact of energy efficiency programs and is reflective of a recent history of negative energy usage on a weather-adjusted basis.

FERC approved changes to the ICAP/SCR program (Docket No. ER14-39) that became effective on March 15, 2014. These changes went through an extensive discussion and review process through the NYISO committees prior to filing a tariff change with FERC. The process to determine the ICAP value of SCR resources was modified as a result of these changes.

New York State has recently announced new initiatives in DER, BTMG, and customer-sited solar photo-voltaic power. The impact of solar PV has been incorporated in this year's energy efficiency projections. It is still too early to determine the impact of DER on energy and summer peak, as the new policy has not yet been translated into specific targets or goals.

NYBA's existing generation, Special Case Resources (SCR), and net imports total 41,307 MW for 2015. There are 4,579 MW of proposed generation included in the 2014 Load and Capacity Data Report. Of this total, 3,461 MW are fossil fuel projects, 1,044 MW are wind turbine projects, and 22 MW are non-wind renewable energy projects. Additionally, based on publicly available information, 806 MW of summer capacity may be retired or mothballed by 2017.

Capacity transactions modeled in NYBA reliability studies are part of the NYBA's resource mix to meet LOLE criteria. These transactions would be expected to perform on peak or any other time as needed to meet the demand. Capacity transactions modeled in NYBA's assessments have met the requirements as defined in the NYBA's tariffs. Both the NYBA and the respective neighboring assessment areas have agreed upon the terms of the capacity transaction. The NYBA does not rely on emergency imports to meet the assessment area's Reference Margin Level. However, transfer capability is reserved on the ties with neighboring areas in NYBA's planning studies to allow for emergency imports as one potential emergency operating procedure step in the event of a system emergency.

Transmission Outlook and System Enhancements

The Transmission Owner Transmission Solutions (TOTS) consist 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 the significant reliability needs that would occur if the Indian Point Energy Center (IPEC) were retired upon the expiration of IPEC's existing licenses.

Long-Term Reliability Issues

The 2012 RNA identified new environmental regulatory programs. These state and federal regulatory initiatives cumulatively will require considerable investment by the owners of New York's existing thermal power plants in order to comply. The NYBA has determined that as much as 33,200 MW in the existing fleet will have some level of exposure to the new regulations.

Since the publication of the RNA, the U.S. Supreme Court has consented to hear an appeal of the Cross State Air Pollution Rule (CSAPR). In July 2011, the EPA replaced the Clean Air Transport Rule (CATR) proposal with the finalized CSAPR. The rule requires significant additional reductions of SO_2 and NO_x emissions beyond those previously identified. The CSAPR establishes a new allowance system for units larger than 25 MW of nameplate capacity. Affected generators will need one allowance for each ton emitted in a year. In New York, CSAPR will affect 154 units that represent 25,900 MW of capacity. The EPA has estimated New York's annual allowance costs for 2012 at $65 million. There are multiple scenarios that show that New York's generation fleet can operate in compliance with the program in the first phase. Compliance actions for the second phase may include emission control retrofits, fuel switching, and new clean, efficient generation. If the EPA appeal is successful, it may be reasonable to expect delays in the implementation of the rule until 2016, which would place it on a schedule that is nearly concurrent with MATS.

The EPA finalized a regulation in February 2012 to establish emission rate standards for MATS that will limit emissions through the use of Maximum Achievable Control Technology (MACT) for hazardous air pollutants (HAP) from coal- and oil-fueled steam generators with a nameplate capacity greater than 25 MW. The majority of the New York coal fleet has installed emission control equipment that may place compliance within reach. The heavy oil-fired units will need to either make significant investments in emission control technology or switch to (or maintain) a cleaner mix of fuels in order to comply with the proposed standards. Given the current outlook for the continued attractiveness of natural gas compared to heavy oil, it is anticipated that compliance will be achieved by dual-fuel units through the use of natural gas to maintain fuel ratios such that the effective capacity factor on oil is less than 8. Compliance requirements begin in March 2015.

The EPA has proposed a Section 316(b) rule providing standards for the design and operation of power plant cooling systems. This rule will be implemented by the New York State Department of Environmental Conservation (NYSDEC), which has finalized a policy for the implementation of this rule is known as Best Available Technology (BAT) for plant cooling water intake structures. This policy is activated upon renewal of a plant's water withdrawal and discharge permit. Based upon a review of current information available from NYSDEC, NYISO has estimated that between 4,400 and 7,300 MW of capacity could be required to retrofit closed-cycle cooling systems.

The class of steam electric units constructed between 1963 and 1977 is subject to continuing emission reductions required by the Clean Air Act. In New York, 16 units with 8,400 MW of capacity are affected. The owners of these units have submitted their plans for Best Available Retrofit Technology (BART) and have received modified Title V air permits incorporating the final plans. The oil-fired units are proposing alternatives that include maintaining the status quo, lower sulfur fuels, and low NO_x combustion systems. Two smaller coal plant owners have chosen to retire small boilers. The new permit limitations became effective January 1, 2014. No additional capacity losses are anticipated as a direct result of the implementation of BART.

The NYSDEC has promulgated revised regulations for the control of NO_x emissions from fossil-fueled electric generating units. These regulations are known as NO_x RACT (Reasonably Available Control Technology) for oxides of nitrogen. In New York, 254 units with 27,800 MW of capacity are affected. Emission reductions required by these revised regulations must be in place by July 2014.

The Regional Greenhouse Gas Initiative (RGGI) established a cap over CO_2 emissions from most fossil-fueled power plants with more than 25 MW in 2009. In 2012, the RGGI states undertook a program review, which concluded in February 2013. The program review called for reducing the cap by 45,000,000 to 91,000,000 tons for 2014 and then applying annual reductions of 2.5 percent until 2020. A key provision to keeping the allowance and electricity markets functioning is the Cost Containment Reserve (CCR). If demand exceeds supply at predetermined trigger prices, an additional 10,000,000 in allowances would be added to the market.

The EPA has released a revised rule for final comments that is designed to limit CO_2 emissions from new fossil-fueled steam generators and combined-cycle units. The rules are generally less stringent than the NYSDEC's Part 251 that is applicable in NY. This EPA rule does not apply to simple-cycle turbines that limit their sales to the grid to less than one-third of their potential output.

NPCC-Ontario

Assessment Area Overview

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

Summary of Methods and Assumptions

Reference Margin Level
The IESO-established Reserve Margin Requirement is applied as the Reference Margin Level.[93]

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; 30 percent for summer

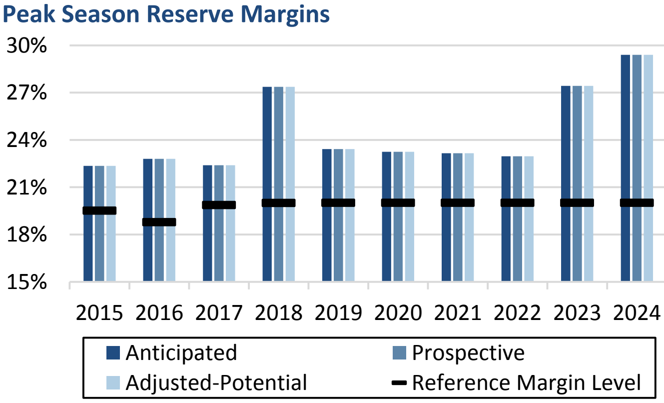
Footprint Changes
N/A

Assessment Area Footprint

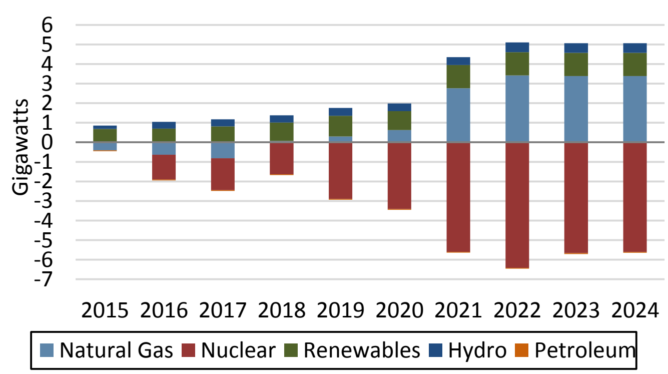
Peak Season Demand, Resources, and Reserve Margins

Demand (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Internal Demand	22,726	22,535	22,344	22,301	22,272	22,170	22,479	22,609	22,616	22,541
Demand Response	567	621	695	695	695	795	945	1,095	1,295	1,495
Net Internal Demand	22,158	21,914	21,649	21,606	21,576	21,375	21,534	21,514	21,321	21,046
Resources (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	27,112	26,910	26,497	27,519	26,630	26,345	26,520	26,455	27,169	27,232
Prospective	27,112	26,910	26,497	27,519	26,630	26,345	26,520	26,455	27,169	27,232
Adjusted-Potential	27,112	26,910	26,497	27,519	26,630	26,345	26,520	26,455	27,169	27,232
Reserve Margins (%)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	22.36%	22.80%	22.39%	27.36%	23.42%	23.25%	23.16%	22.96%	27.43%	29.39%
Prospective	22.36%	22.80%	22.39%	27.36%	23.42%	23.25%	23.16%	22.96%	27.43%	29.39%
Adjusted-Potential	22.36%	22.80%	22.39%	27.36%	23.42%	23.25%	23.16%	22.96%	27.43%	29.39%
Reference Margin Level	19.50%	18.78%	19.86%	19.99%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Excess/Shortfall (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	633	880	549	1,593	738	695	680	638	1,583	1,977
Prospective	633	880	549	1,593	738	695	680	638	1,583	1,977
Adjusted-Potential	633	880	549	1,593	738	695	680	638	1,583	1,977

Peak Season Reserve Margins



Peak Season Projected Generation Mix (Cumulative Change)



93 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 the 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. Ontario's electricity demand growth has been low to moderate during this period. Growing net supply additions and moderate demand have resulted in substantial capacity margins. Capacity margins have been reduced to more normal levels with the recent phase-out of coal-fired generation in the province. Ontario's evolving supply mix features increasing and significant penetrations of renewable sources.

The Reference Margin Levels for the first four years of the assessment period vary between 18.78 and 20 percent through 2020, then remain at 20 percent through 2024. This variance is necessary to reflect the changes in outages, demand forecast, and available resources. However, the Reference Margin Levels published in this report have been modified to reflect NERC's reserve margin calculation. Previously, Demand Response (DR) was treated as a resource, but now it must be accounted for in the margin calculation as a load modifier for all Assessment Areas. This approach results in a higher percent for both the Reference Margin Level and the projected Reserve Margins.

Between 2020 and 2024, Ontario will rely on new planned resources of up to 3,640 MW, as per Ontario's Long-Term Energy Plan (LTEP), to meet the Reference Margin Level. Ontario possesses a range of options to address these needs, including market-based mechanisms. Additional planning activities to meet future resource adequacy needs are currently underway.

This year's forecast of Net Energy for Load (NEL) has an average annual growth rate of -0.4 percent during the 10-year period, similar to the 2013LTRA forecast of -0.2 percent average growth for 2013–2023. Although there is increased demand for electricity driven by modest economic expansion and population growth, these increases are being more than offset by three key factors:

1. The growth in embedded generation and BTMG capacity, which has a significant downward impact on grid-supplied electricity, which is the demand value being considered (rather than total consumption).
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.

In general, distributed (embedded) generation (DG) is having the largest impact on grid-supplied energy demand. Summer peaks are particularly affected by the increased penetration of solar-powered DG. The summer peaks are also being influenced by efficiency changes to air conditioners.

The winter peaks are not significantly impacted by DG, because in Ontario, most is comprised of solar facilities, and the peak occurs after sunset, when solar DG is no longer generating power. 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.

While overall demand is expected to decline, there will be some variation 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 associated with vast untapped natural resources in the northern portions of the province, a rebound is expected during the later years of the forecast. The Net Internal Demand forecast in the 2014LTRA reference case is reduced by the amount of DR programs, previously counted as resources in Ontario. For its own provincial assessments, DR programs will continue to be treated as resources.

Over the course of the forecast, the DR program impacts during the summer are expected to increase from just over 500 MW, at present, to less than 1,500 MW by the end of the forecast period. Starting in 2020, the increased DR is expected to show significant growth. In the IESO, DR is comprised of three programs: Demand Response 3 (DR3), Peaksaver PLUS® (primarily driven by air-conditioning load), and dispatchable loads. Participation in dispatchable load programs drops during the peak period.

Conservation is expected to yield incremental peak savings of more than 3,000 MW by 2024. The Ontario government's Long-Term Energy Plan (LTEP) established a provincial conservation and demand management target of 30 TWh/year of cumulative savings by 2032. The reference year for the savings is 2005, with projected milestones of 11 TWh/year by 2015 and 21 TWh/year by the end of 2024. Those savings will be achieved through improved building codes, equipment standards, and conservation programs.

LTEP 2013 has also set a goal to use DR to be able to meet 10 percent of net peak demand by 2025, equivalent to approximately 2,400 MW under forecast condition. This includes all DR programs, such as Time-of-Use rates, Industrial Conservation Initiative, market dispatchable load, DR3, and Peaksaver PLUS®. The responsibility for existing and newly introduced DR initiatives has been transferred from the Ontario Power Authority (OPA) to the IESO.

In June 2014, the IESO implemented a redesigned framework for activation of the DR3 program through integration into the electricity market. DR3 is a contractual peak load reduction program that encourages businesses to reduce their electricity use during periods of peak demand. The redesigned framework will model DR3 as aggregated resources within IESO market and system tools. In place of activations that are based on a combination of supply cushion and price-based triggers, DR3 resources are activated when they represent a competitively priced energy resource in the pre-dispatch time frame (i.e., activated on a price trigger only).

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.

Supply options for maintaining resource adequacy over this time period are being considered. These options include conservation, re-contracting Non-Utility Generator (NUG) facilities as their contracts reach maturity, new gas-fired generation, and conversion of some or all of the Lambton and Nanticoke coal-fired units to natural gas, imports, and energy storage. About 1,400 MW of NUG contracts have the opportunity to be renegotiated as the contracts are expiring within the next decade. The OPA is in the process of renegotiating the NUG contracts.

Over the assessment period, the capacity of embedded generation, such as DERs and BTMG, is expected to increase significantly. The Feed-in Tariff (FIT) and microFIT programs drive this growth with renewable generation. Over the forecast period, about 2,500 MW of wind and solar DG is projected to be added—most of which is solar. By 2024 there will be over 4,000 MW of DG in Ontario.

In 2014, the IESO issued a request for proposals to procure up to 35 MW of energy storage to explore how new technologies can provide additional flexibility to carry out grid operations. The IESO storage procurement process supports the LTEP, which calls for 50 MW of energy storage in Ontario. Subsequent to the IESO's procurement process, the OPA will issue a request for proposals for the remaining 15 MW. These procurements are structured to maximize learning about energy storage services and how they can best serve Ontario's needs. Contracts were planned to be executed during the summer of 2014 and become operational sometime in 2017.

About 14 percent of the installed wind capacity is assumed to be available at the time of summer peak, and 33 percent is assumed to be available at the time of winter peak. Ontario's solar capacity value is forecast to be 30 percent of installed capacity for the summer peak and 4 percent for the winter peak. The assumed capacity contribution for hydroelectric is 71 percent for the summer peak and 76 percent for the winter peak.

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 has adapted power system planning and operations, as well as the IESO-administered markets to accommodate the influx of renewables. The IESO implemented the Renewables Integration Initiative (RII) in 2013 to effectively integrate up to 10,700 MW of renewable generation by 2021. RII has already yielded results, including the integration of the hourly centralized forecast into IESO scheduling tools, and enhanced visibility of renewable output of distributed-connected variable generation facilities 5 MW or greater. This was accomplished by providing System Operators with greater levels of awareness of system conditions. Improved variable generation forecasting and greater visibility is expected to bring measurable benefits to the maintenance of system reliability and market efficiency. The dispatch of grid-connected renewable resources provides increased flexibility from available variable generation resources and will allow IESO to operate the system reliably by providing the needed tools to manage issues such as ramp needs and surplus baseload generation (SBG) situations.

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. To capture the effects of all DG on the performance of the grid, including those smaller than 10 MW, the IESO periodically conducts system studies. If needed, mitigating measures such as grid-connected SVCs will be developed and requested to be implemented.

Capacity transfers are not considered in this assessment, as Ontario does not have any Firm contracts with other areas. Emergency imports are not considered in this assessment. However, for use during daily operation, operating agreements between IESO and neighboring jurisdictions in NPCC, RF, and MRO include contractual provisions for emergency imports into IESO. IESO also participates in a shared activation of reserve groups, including IESO, ISO-NE, Maritimes, NYISO, and PJM.

Transmission Outlook and System Enhancements

Northwestern Ontario is connected to the rest of the province by the double-circuit, 230 kV East–West Tie. The primary source of generation within the northwest is hydroelectric. In addition, strong local load growth is forecast, as mentioned above. Additional capacity is required to maintain reliable supply to this area under the wide range of possible system and water conditions. The expansion of the East–West Tie with the addition of a new double-circuit 230 kV transmission line is expected to be in service by 2018 and will provide reliable and cost-effective long-term supply to the northwest.

Long-Term Reliability Issues

The renewable resources target for wind, solar, and biomass is 10,700 MW by 2021, which is accommodated through transmission expansion and maximized use of the existing system. Ontario will add a few hundred MW of hydroelectric capacity to reach a target of 9,300 MW by 2025. A substantial amount of renewable generation is embedded and included in the demand forecast. This level of variable generation will be incorporated into the system through the development of new facilities and significant investments to upgrade existing facilities in Ontario. The operational and adequacy concerns of integrating of new variable generation are addressed through RII and the connection requirements imposed by the IESO on grid-connected resources, and on resources larger than 10 MW connecting to the distribution system.

A reduction of SBG events is expected after the nuclear refurbishment programs begin. The vast majority of SBG is currently managed through normal market mechanisms, including export scheduling and nuclear maneuvering. The IESO's variable generation dispatch tools have provided additional flexibility to alleviate most SBG events.

In light of environmental and other concerns, coal-fired generation has been replaced in Ontario by sources that emit less carbon. In the years ahead, natural gas-fired generation will play an important role in Ontario's supply mix balance, providing the flexibility to cushion the electricity system when demand and intermittent resources rise or fall.

Almost all of Ontario's oil and natural gas comes from outside the province. In addition to the use of these fuels for electricity generation, Ontario relies on oil and natural gas to support basic needs such as heat and transportation. In particular, reliance on natural-gas-fired generation will grow as this form of generation represents an essential element in the sustainability of a responsive and flexible electricity system. Supply to Ontario's gas fleet is supported by significant Firm supply and transportation contracts. The IESO is an active participant in the Eastern Interconnection Planning Collaborative effort in the ongoing development of the Gas-Electric System Interface Study,[94] which evaluates the capability of natural gas systems to satisfy the future needs of the electric system across most of the Eastern Interconnection.

With the growth in conservation savings and DG, demand forecasting has become more complex. Smart meters and higher on-peak electricity prices has introduced consumer price response previously not seen in Ontario. Traditionally, demand was a function of weather conditions, economic cycles, and population growth. With multiple factors influencing demand, determining the causality of demand changes has become increasingly nuanced and requires greater data and analysis.

[94] EIPC: Gas-Electric System Interface Study.

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 2013 Interim Review of Resource Adequacy, which was approved by NPCC's Reliability Coordinating Committee in December 2013.

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

Peak Season
Winter

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

Planning Considerations for Solar Resources
N/A

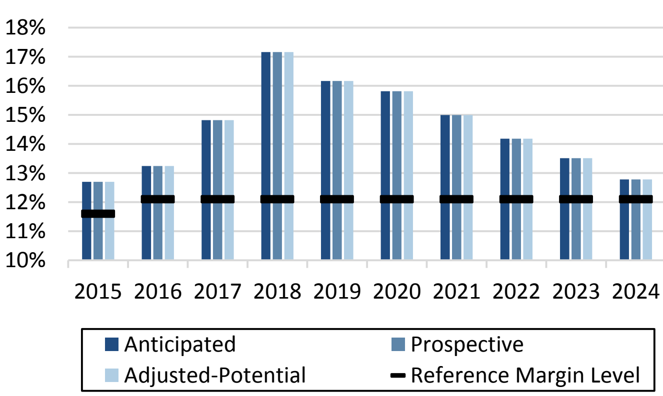
Footprint Changes
N/A

Assessment Area Footprint

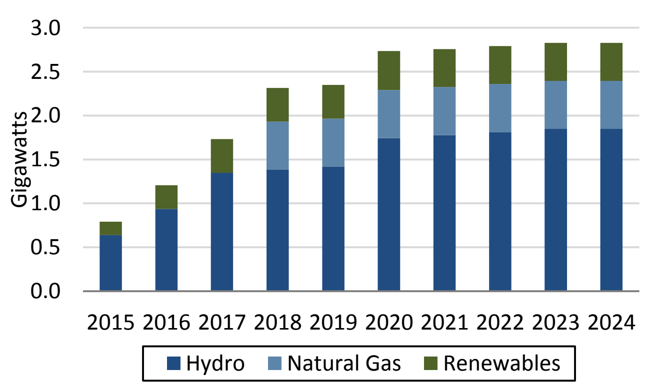
Peak Season Demand, Resources, and Reserve Margins

Demand (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Internal Demand	38,316	38,612	38,847	39,168	39,567	40,218	40,558	40,862	41,120	41,373
Demand Response	1,708	1,852	1,902	1,952	2,002	2,202	2,252	2,252	2,252	2,252
Net Internal Demand	36,608	36,760	36,945	37,216	37,565	38,016	38,306	38,610	38,868	39,121
Resources (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	41,257	41,628	42,421	43,602	43,637	44,028	44,051	44,086	44,121	44,121
Prospective	41,257	41,628	42,421	43,602	43,637	44,028	44,051	44,086	44,121	44,121
Adjusted-Potential	41,257	41,628	42,421	43,602	43,637	44,028	44,051	44,086	44,121	44,121
Reserve Margins (%)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	12.70%	13.24%	14.82%	17.16%	16.16%	15.81%	15.00%	14.18%	13.51%	12.78%
Prospective	12.70%	13.24%	14.82%	17.16%	16.16%	15.81%	15.00%	14.18%	13.51%	12.78%
Adjusted-Potential	12.70%	13.24%	14.82%	17.16%	16.16%	15.81%	15.00%	14.18%	13.51%	12.78%
Reference Margin Level	11.60%	12.10%	12.10%	12.10%	12.10%	12.10%	12.10%	12.10%	12.10%	12.10%
Excess/Shortfall (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	476	384	968	1,845	1,489	1,374	1,071	765	511	226
Prospective	476	384	968	1,845	1,489	1,374	1,071	765	511	226
Adjusted-Potential	476	384	968	1,845	1,489	1,374	1,071	765	511	226

Peak Season Reserve Margins



Peak Season Projected Generation Mix (Cumulative Change)



Demand, Resources, and Planning Reserve Margins

The Reference Margin Levels are drawn from the Québec Area 2013 Interim Review of Resource Adequacy[95] and vary between 10 and 12 percent. The Anticipated Reserve Margin varies between 12.8 and 17.2 percent, remaining above the Reference Margin Level for all seasons and years during the assessment period.

The Québec Area demand forecast has increased compared to the 2013LTRA report, mainly due to industrial sector growth. The demand forecast average annual growth is 0.9 percent during the 10-year period, similar to the 1.0 percent forecast in the 2013LTRA.

Energy efficiency and conservation programs are integrated in the demand forecasts and account for 1,550 MW for the 2015–2016 winter peak. These programs are implemented throughout the year by Hydro-Québec Distribution (HQD) and by the provincial government, through its Ministry of Natural Resources. Energy efficiency will continue to grow during the entire assessment period.

Demand forecasts also take into account the load shaving that results from the residential dual-energy space-heating program. The impact of this program on peak load demand is estimated to be around 650 MW during the assessment period

Demand Response (DR) programs in the Québec Area are specifically designed for peak load reduction during winter operating periods and are mostly interruptible demand programs (for large industrial customers), totaling 1,458 MW for the 2015–2016 winter period. DR is usually used in situations when load is expected to reach high levels, or when resources are not expected to be sufficient to meet load during peak periods. DR remains relatively stable during the assessment period, with a maximum of 2,252 MW reached during 2021–2022 winter season.

The Québec Area is currently developing new DR programs, including Direct Control Load Management (DCLM), which could provide an additional 300 MW of DR by 2021–2022. Total on-peak DSM (including energy efficiency and conservation programs) for the 2024–2025 winter period is projected to be approximately 5,250 MW.

A total of 1,560 MW of new hydro generation is expected to be in service by 2021. Additional updates to existing hydro generation will add an additional 400 MW of capacity during the assessment period. With regard to other renewable resources (biomass and wind), a total of 1,900 MW is expected to be in service by 2021. At this time, all projects are expected to be on time and there are no cancellations or deferments.

Biomass and wind resources are owned by Independent Power Producers (IPPs). These IPPs have signed contractual agreements with Hydro-Québec. Therefore, for biomass resources, maximum capacity and expected on-peak capacity are equal to contractual capacity, representing almost 100 percent of nameplate capacity. For wind resources, capacity contribution at peak is estimated at 30 percent of contractual capacity, representing 970 MW and 1,220 MW, respectively, for the 2015–2016 and 2024–2025 winter periods. Maximum wind capacity is set equal to contractual capacity, which generally equals nameplate capacity. For summer peak period calculations, the expected on-peak wind capacity is set to zero as wind resources are derated by 100 percent. BTMG is negligible and is embedded in the load forecast.

Expected transfer (capacity) purchases are planned by Hydro-Québec Distribution as needed to meet the Québec internal demand. These purchases are set at 1,100 MW throughout the assessment period and may be supplied by resources located in Québec or in neighboring markets. In this regard, Hydro-Québec Distribution has designated the Massena–Châteauguay (1,000 MW) and Dennison–Langlois (100 MW) interconnections' transfer capacity to meet its resource requirements during winter peak periods. These purchases are not backed by Firm long-term contracts. However, on a yearly basis, Hydro-Québec Distribution proceeds with short-term capacity purchases of Unforced Capacity (UCAP) as needed in order to meet its capacity requirements for the upcoming winter. The Québec Area does not rely on any emergency capacity imports to meet its Reference Margin Level. The Québec Area will support Firm capacity sales totaling 974 MW to New England and Ontario

[95] Québec Area 2013 Interim Review of Resource Adequacy, approved by NPCC's Reliability Coordinating Committee on December 3, 2013.

(Cornwall) during the 2015–2016 winter peak period. This capacity is backed by Firm contracts for both generation and transmission and declines to 145 MW in 2020.

Transmission Outlook and System Enhancements

TransÉnergie's system consists of an extensive 735 kV network underlain with 315 kV, 230 kV, 120 kV, and 69 kV subsystems totaling 20,886 line miles (33,613 km). The system uses telecommunications and advanced protection and control applications to ensure its reliability and improve its performance. This will continue into the future. The system is planned according to NPCC and NERC Planning Standards, but with additional criteria that (1) consider system topology and substation characteristics particular to TransÉnergie's system (complementary contingencies) and (2) address voltage sensitivity to load variation and interconnection ramping.

Romaine River Hydro Complex Integration

Construction of the first phase of transmission for the Romaine River Hydro Complex project is presently underway. The total capacity will be 1,550 MW. The generating stations will be integrated on a 735 kV infrastructure initially operated at 315 kV. Romaine-2 (640 MW) and Romaine-1 (270 MW) will be integrated between 2014 and 2016 at Arnaud 735/315/161 kV substation. One 315/161 kV, 500 MVA transformer is required at Arnaud for this project. Romaine-3 (395 MW) and Romaine-4 (245 MW) will be integrated between 2017 and 2020 at Montagnais 735/315 kV substation.

The main system upgrades for this project require construction in 2014 of a new 735 kV switching station to be named Aux Outardes. It will be located between the existing Micoua and Manicouagan transformer substations. Two 735 kV lines will be redirected into the new station, and one new 3 mile (5 km) 735 kV line will be built between Aux Outardes and Micoua.

Bout-de-l'Île 735 kV Section

In 2013, TransÉnergie added a new 735 kV section at Bout-de-l'Île substation located at the east end of Montréal Island. The Boucherville – Duvernay line (Line 7009) has been looped into this substation, and the first of two ±300 MVar Static Var Compensators (SVC) has been added to the 735 kV section.

The second SVC will be added in 2014, as well as two 735/315 kV 1,650-MVA transformers banks. This new 735 kV source will allow redistribution of load around the Greater Montréal area and will accommodate load growth in the eastern part of Montréal. This project will enable future major modifications to the Montréal area regional sub-system. Many of the present 120 kV distribution substations will be rebuilt into 315 kV substations, and the Montréal regional network will be converted to 315 kV.

Chamouchouane – Montréal 735 kV Line

Planning studies have shown the need to reinforce the transmission system with a new 735 kV line in the near future. The line will extend from the Chamouchouane substation on the eastern James Bay subsystem to a substation in Montréal (255 miles (410 km)). It will reduce transfers on other parallel lines on the 735 kV Southern Interface, thus optimizing operation flexibility and reducing losses.

Planning, permitting, and construction delays are such that the line is scheduled with an on-line date of 2018–2019 winter peak period. Public information meetings have begun on this project. The final line route has not completely been determined yet, and authorization processes are ongoing.

The Northern Pass Transmission Project

This project to increase transfer capability between Québec and New England by 1,200 MW is currently under study. It involves construction of a ±300 kV dc transmission line about 75 km (47 miles) long from Des Cantons 735/230 kV substation to the Canada–United States border. This line will be extended into the United States to a substation to be built in Franklin, New Hampshire.

The project in Québec also includes the construction of two 600 MW converters at Des Cantons and a 300 kV dc switchyard. The planned in-service date has been re-evaluated to winter 2018–2019.

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.[96] The project involves the construction of a ±320 kV dc underground transmission line about 50 km (31 miles) long from the Hertel 735/315 kV substation just south of Montréal to the Canada–United States 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 fall 2017.

Other regional substation and line projects are in the planning or 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 2014 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

Given the importance of hydroelectric resources within the Québec Area, an energy criterion has been developed to assess energy reliability. The criterion states that sufficient resources should be available to go through sequences of two or four consecutive years of low water inflows totaling 64 TWh and 98 TWh, respectively, with a 2 percent probability of occurrence. These assessments are presented three times a year to the Régie de l'énergie du Québec (Québec Energy Board). Normal hydro conditions are projected during the assessment period, and reservoir levels are expected to be sufficient to meet both peak demands and daily energy demand.

However, 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 on the system, there is a potential for impacts on system management. Accordingly, the following issues are currently 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.

[96] Federal Register Notice – October 1, 2014.

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 cover 243,417 square miles. PJM is a Balancing Authority, Planning Coordinator, Transmission Planner, Resource Planner, Interchange Authority, Transmission Operator, Transmission Service Provider, and Reliability Coordinator.

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
On-peak contribution of 13 percent of installed capacity

Planning Considerations for Solar Resources
38 percent of nameplate capacity

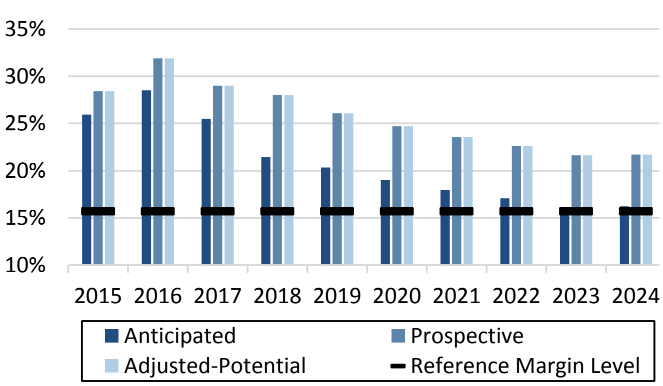
Footprint Changes
The East Kentucky Power Cooperative (EKPC), which integrated into the PJM RTO on June 1, 2013, is now part of PJM's load and generation data.

Assessment Area Footprint

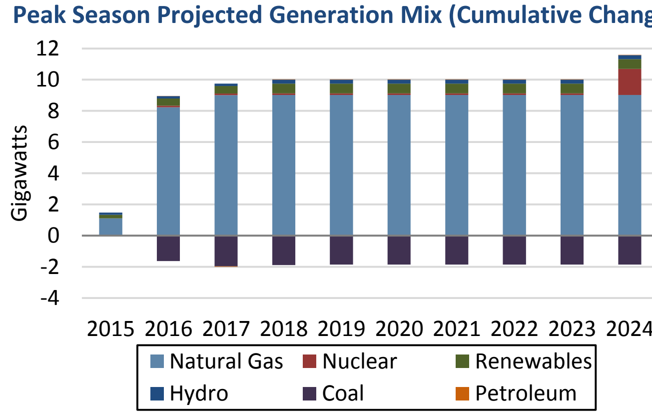
Peak Season Demand, Resources, and Reserve Margins

Demand (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Internal Demand	160,259	162,470	164,195	165,479	166,900	168,593	170,027	171,217	172,542	173,729
Demand Response	14,812	12,402	12,402	12,402	12,402	12,402	12,402	12,402	12,402	12,402
Net Internal Demand	145,447	150,068	151,793	153,077	154,498	156,191	157,625	158,815	160,140	161,327
Resources (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	183,163	192,850	190,497	185,904	185,928	185,928	185,928	185,928	185,928	187,498
Prospective	186,787	197,909	195,818	195,962	194,767	194,768	194,768	194,768	194,768	196,338
Adjusted-Potential	186,787	197,909	195,818	195,962	194,767	194,768	194,768	194,768	194,768	196,338
Reserve Margins (%)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	25.93%	28.51%	25.50%	21.44%	20.34%	19.04%	17.96%	17.07%	16.10%	16.22%
Prospective	28.42%	31.88%	29.00%	28.02%	26.06%	24.70%	23.56%	22.64%	21.62%	21.70%
Adjusted-Potential	28.42%	31.88%	29.00%	28.02%	26.06%	24.70%	23.56%	22.64%	21.62%	21.70%
Reference Margin Level	15.70%	15.70%	15.70%	15.70%	15.70%	15.70%	15.70%	15.70%	15.70%	15.70%
Excess/Shortfall (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	14,880	19,221	14,873	8,793	7,173	5,215	3,555	2,179	646	842
Prospective	18,504	24,280	20,193	18,852	16,013	14,055	12,395	11,019	9,486	9,682
Adjusted-Potential	18,504	24,280	20,193	18,852	16,013	14,055	12,395	11,019	9,486	9,682

Peak Season Reserve Margins



Peak Season Projected Generation Mix (Cumulative Change)



Demand, Resources, and Planning Reserve Margins

The PJM RTO Reserve Requirement as calculated by PJM is 15.7 percent for the 2015–2016 planning period, which runs from June 1, 2015, through May 31, 2016. The PJM RTO Reserve Requirement is 0.5 percentage points lower this year compared to the 2014–2015 value due to the retirement of coal units with high forced outage rates. The 15.7 percent PJM RTO Reserve Requirement (applied as the Reference Margin Level) is applicable for the entire assessment period. PJM RTO will have an adequate Anticipated Reserve Margin though the entire assessment period. The Prospective and Adjusted-Potential Reserve Margins are also above the Reference Margin Level for the entire assessment period.

Use of more granular historical economic data and the addition of another year of load experience to the load forecasting model resulted in generally lower (approximately 0.5 percent) peak and energy forecasts this year compared to the forecast done last year. Annualized 10-year growth rates for individual zones range from 0.4 percent (Rockland Electric) to 1.8 percent (Dominion Virginia Power).

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. PJM has created three different DR products to address the issue of availability: Limited DR (10 days for 6 hours per day during the summer peak period), Extended Summer DR (unlimited days during the summer peak period for 10 hours per day) and Annual DR (unlimited days for 10 hours per day any time of the year). These programs require necessary amounts of annual capacity to fulfill the PJM reliability requirements.

The PJM reported transactions are the aggregate of generator-specific transactions. These transactions include the Firm reservation rights for the generation and Firm transmission rights to transfer the power across the PJM border. Long-term Firm capacity transfer contacts exist, but they are not accepted into PJM installed capacity until the PJM Reliability Planning Model (RPM) three-year planning window. The impact of transactions is minimal in PJM since they only amount to about two percent of the forecast peak load. PJM previously forecast transactions using the Firm capacity contracts but has recently decided to only show capacity transactions through a three-year planning window to coordinate with neighboring entities.

Energy efficiency programs included in the 2015–2017 load forecast are approved for use in the RPM and total 685 MW for the 2015 summer. This value increases to 918 MW in 2016 and remains constant through the end of the assessment period.

Transmission Outlook and System Enhancements

Northeast New Jersey Transmission Enhancement

PJM 2013 RTEP process results have validated the need for a solution to identified short circuit duty violations at the Essex, Kearney, and New Jersey Transit Meadowlands (NJT Meadows) 230 kV substations. Notably, 2013 short circuit analyses revealed that the two 345 kV tie lines connecting PSE&G's Hudson substation to ConEd's Farragut substation contribute to short circuit duties at Hudson, Kearney, and Essex. As a result, the Hudson/Farragut HVdc alternative was originally recommended in large part for its ability to block this fault current pass-through to the northern New Jersey PSE&G system. However, circuit breaker short circuit over duties were not the only NERC criteria violations identified. Generator deliverability tests identified thermal violations on lines in northern New Jersey that have required reconsideration of PJM's initial HVDC solution proposal and the subsequent development of a more comprehensive solution.

In collaboration with PSE&G planning staff, PJM evaluated two northern New Jersey double-circuit upgrade solutions: one at 230 kV and one at 345 kV. Additionally, the double-circuit 345 kV solution also solves the identified thermal criteria violations in northern New Jersey.

In parallel with the analytical work performed to compare the double-circuit 345 kV and HVDC alternatives, PJM also retained an independent engineering consultant to review each project, validate cost estimates, and assess the project constructability. From that perspective, the consultant's findings did not identify any "fatal flaws" that would prevent either project from being implemented. Based on the performance of each of the alternatives, the cost of each, and the findings of the independent consultant regarding constructability, PJM recommended the double-circuit 345 kV alternative to address the short circuit and thermal problems in northern New Jersey. The PJM Board approved the recommendation in December 2013.[97]

Need for Byron – Wayne Confirmed

PJM reviewed—as it does every year—transmission plans developed in earlier years. By doing so, PJM can determine whether, as a result of changing assumptions, previously approved transmission upgrades are still required. And, if so, PJM can determine whether they are still required in the year originally identified, as with the Byron – Wayne 345 kV transmission line (Grand Prairie Gateway). As part of its 2012 RTEP process, PJM conducted its annual simultaneous feasibility analysis to assess the transmission system's ability to accommodate all transmission rights for the next 10-year period. PJM's 2012 transmission rights analysis identified 16 thermal constraints in ComEd and nine PJM-MISO market-to-market constraints. RTEP analysis in 2013 also identified a number of thermal constraints similar to those identified in 2012, confirming the need for the Byron – Wayne 345 kV in 2017.

Artificial Island Order 1000 Proposal Window

PJM sought proposals from April 29, 2013, through June 28, 2013, to improve operational performance on Bulk Electric System (BES) facilities in the southern New Jersey Artificial Island area, the site of PSE&G's Salem 1 and 2 and Hope Creek 1 nuclear generating plants. Under certain system conditions, this area's complexity has presented PJM and PSE&G System Operators with limited solutions, potentially forcing them in some circumstances to remove an Artificial Island unit from service in order to stay within operating limitations to maintain reliability. PJM specified that RTEP proposals improve limited stability margins, minimum Artificial Island MVar output requirements, and previously identified high-voltage reliability issues.

Seven different sponsors submitted 26 separate proposals. Proposals reflected a diverse range of technologies at both 500 kV and 230 kV—new transformation, substations and associated equipment, additional circuit breakers, system reconfiguration, dynamic reactive devices, dynamic series compensation and DC technology—spanning a range of project risk exposure levels and lead-time requirements. In parallel with analytical evaluation, PJM enlisted engineering consultants in 2013 to evaluate project proposal constructability in terms of physical characteristics, feasibility, cost, design commonalities, and other challenges associated with line and river crossings. Additionally, the consultants examined the ability to expand or reconfigure existing substations and determine required transmission and generation outages.

Market Efficiency Order 1000 Proposal Window

During this window, PJM sought proposals to identify transmission projects to relieve internal PJM transmission congestion. The scope of the request encompassed the top 25 congestion events observed in 2013 Market Efficiency Analysis for study years 2017, 2020, and 2023 and for which no reliability-based RTEP upgrades have been already identified. Proposed enhancements must provide a benefit/cost ratio of at least 1.25 and must not introduce any reliability criteria violations. Six different sponsors submitted 17 separate proposals during the window to meet the stated requirements. Analysis identified three proposals for further evaluation. All three addressed, either in whole or part, congestion on the Hunterstown 230/115 kV transformer. PJM expects to make a recommendation to the Board in 2014 that comprises adding a second Hunterstown 230/115 kV transformer and reconductoring the existing Hunterstown–Oxford 115 kV line.

AEP/Dominion Transmission Rebuilds

PJM's RTEP includes 500 kV transmission line rebuild projects over the next eight years by AEP and Dominion as shown below. The towers of all six lines, built in the 1960s, are nearing the end of their useful lives and will soon require rebuild. Now the Cloverdale – Lexington and Lexington – Dooms 500 kV line rebuilds have been identified to solve PJM baseline reliability criteria violations.

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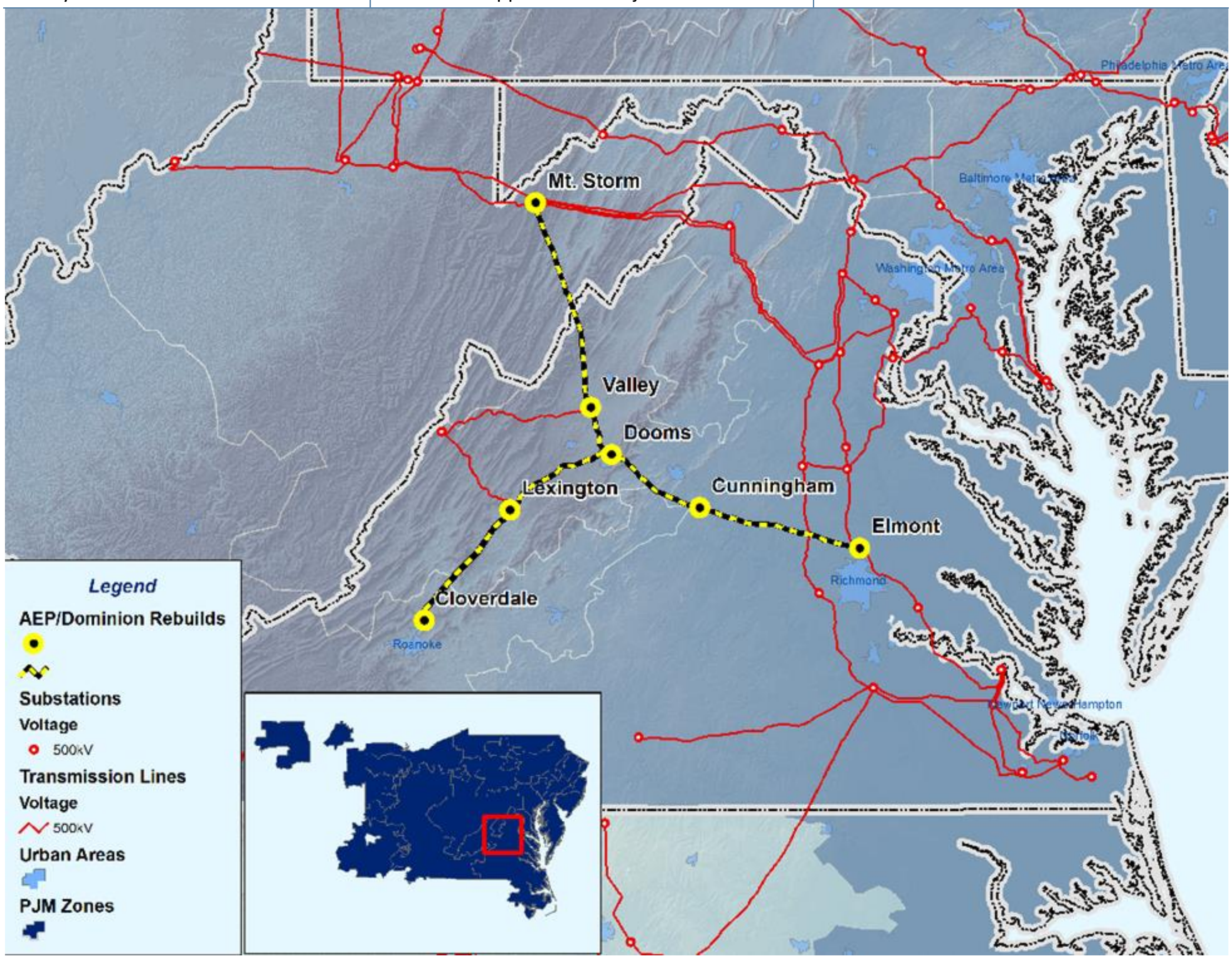
[97] 2013 Regional Transmission Expansion Plan Report (see page 7).

AEP/Dominion Line Rebuilds

Line Rebuild	Driver	In-Service Month, Year
Cloverdale – Lexington 500 kV	NERC Category C3 “N-1-1” Criteria	December 2016
Lexington – Dooms 500 kV	Dominion Reliability Criteria Violation	June 2016
Dooms – Cunningham 500 kV	Dominion Supplemental Project	December 2018
Cunningham – Elmont 500 kV	Dominion Supplemental Project	May 2018
Mt. Storm – Valley 500 kV	Dominion Supplemental Project	June 2021
Valley – Dooms 500 kV	Dominion Supplemental Project	December 2021



Cloverdale – Lexington 500 kV Line

RTEP analysis conducted in 2013 identified reliability criteria violations under PJM light-load criteria tests on the AEP portion of the Cloverdale – Lexington 500 kV line. In October 2013, the Board approved PJM’s upgrade recommendation to rebuild the AEP portion of the Cloverdale – Lexington 500 kV line, including replacement of 11 tower structures. This follows December 2011 PJM Board approval to reconductor the Dominion portion of the Cloverdale – Lexington 500 kV circuit to solve NERC criteria Category C violations. Jointly owned by Dominion and AEP, coordinated plans are underway to rebuild and/or reconductor their respective portions of the 44 mile line in order to increase the operational limit of that line to meet PJM’s minimum summer emergency requirement of 3,992 MVA.

Dooms – Lexington 500 kV Line

PJM 2012 RTEP analysis identified a Dominion reliability criteria violation in 2016 in which the Dooms – Lexington line would be overloaded for several N-1-1 contingencies. In May 2012, the PJM Board approved the recommended solution to reconductor the line, increasing its rating from 2,913 MVA to 4,340 MVA. The project is expected to be completed by December 2016.

State RPS laws require entities that serve load to do so using various eligible renewable resources including wind, solar, and other technologies. States in the PJM footprint have a variety of RPS definitions and targets. Overall, approximately 38 GW of renewable energy would be required from renewable resources to meet aggregate RPS targets by 2028 in states in which PJM operates. And, while NERC Reliability Standard violations remain PJM's principal basis under the RTEP Protocol for justifying transmission expansion, construction of major transmission infrastructure will likely be necessary to support the achievement of RPS public policy goals.

Wind- and solar-powered facilities—now an expanding percentage of interconnection requests—constitute a growing driver of regional transmission expansion. The emergence of state RPS standards has prompted PJM to further examine the impacts of extensive penetration of wind resources, which could have implications on reliability and market efficiency. During 2013, both internal scenario studies and interregional studies examined the penetration of renewable-powered generation to meet state RPS targets. Those studies confirm that significant build-out of transmission will be needed for PJM to deliver the aggregate wind generation required to meet states' RPS goals.

BTMG is not counted as PJM capacity and has no effect on the PJM Reserve Margin. During a hot-weather event in September 2013,[98] PJM called on some BTMG to operate to alleviate specific transmission-related operating concerns. PJM will establish and document an approach for representing known BTMG in PJM's energy management systems and the related operating criteria for dispatchers. Working with the states and the Transmission Owners, PJM will better incorporate BTMG into emergency operations.

Long-Term Reliability Issues

Light-load system conditions, as low as 30 percent of summer peak for some transmission owners, present system dispatchers with operational performance issues. Generation dispatch under such conditions differs markedly from that under peak-load conditions, particularly for units powered by renewable sources such as wind. PJM has begun to experience thermal overloads and high-voltage events driven by low demand dispatch patterns and the capacitive effects of lightly loaded transmission lines. From a 15-year planning perspective, these light-load concerns gave rise to the approval of new reliability criteria analysis procedures in 2010, first implemented and benchmarked in 2011, for both baseline analysis and queued interconnection request studies. Light-load reliability analysis ensures that the system transmission is capable of delivering generating capacity under such conditions.

As part of its 2013 cycle of RTEP studies, PJM identified six light-load criteria violations, five of which represented normal and N-1 thermal overloads. The most significant of these is a project to rebuild the AEP portion of the Cloverdale – Lexington 500 kV line in Virginia that will require $40 million, expected by June 2015. The remaining four thermal criteria violations will require 138 kV upgrades in AEP and ComEd; they are much lower in scope and estimated cost and are expected by June of 2017. The sixth criteria violation, voltage in nature, requires an upgrade to the 765 kV Cloverdale substation, also in Virginia, and construction of a new 500 kV bus with an estimated project cost of $85 million projected to be in service by the end of 2016.

PJM planning staff has initiated efforts with operations staff and individual TOs to examine real-time high-voltage events across the RTO. Based on additive power flow studies completed in 2013, PJM collaborated with TOs to develop solutions approved by the PJM Board that ultimately included shunt reactors, SVCs, reactor breakers, and modifications to, and

[98] PJM Report: Technical Analysis of Operational Events and Market Impacts.

optimization of existing facilities, generator voltage schedule adjustments, transformer tap settings, and switched shunt capacitor settings.

Planning study results that were reviewed with TOs to determine optimal reactor sizes and locations across PJM to maximize their effectiveness at mitigating high voltages were subsequently confirmed by additional power flow analysis. In-service dates for these projects begin in June 2015.

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 percent 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

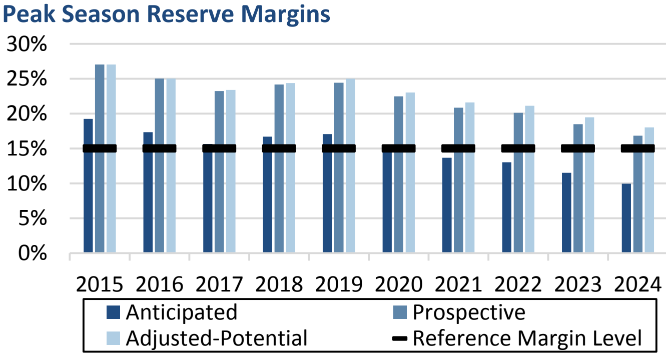
Footprint Changes
East Kentucky Power Cooperative (EKPC) joined PJM on June 1, 2013, and is no longer reported in SERC's Assessment Area. Additionally, entities within the SERC-W Assessment Area joined MISO in December 2013.

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

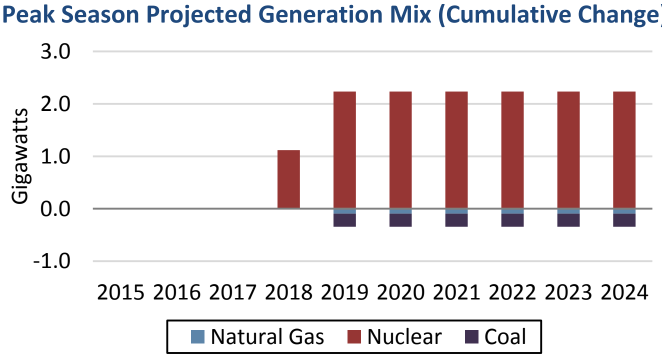
SERC-East: Peak Season Demand, Resources, and Reserve Margins

Demand (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Internal Demand	44,086	44,768	45,398	45,992	46,669	47,289	47,928	48,579	49,251	49,943
Demand Response	1,757	1,819	1,869	1,913	1,934	1,952	1,970	1,986	2,003	2,006
Net Internal Demand	42,329	42,949	43,529	44,079	44,735	45,337	45,958	46,593	47,248	47,937
Resources (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	50,475	50,396	50,339	51,440	52,363	52,226	52,243	52,666	52,682	52,702
Prospective	53,773	53,694	53,637	54,738	55,661	55,524	55,541	55,964	55,980	56,000
Adjusted-Potential	53,773	53,694	53,712	54,826	55,918	55,781	55,882	56,429	56,445	56,577
Reserve Margins (%)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	19.24%	17.34%	15.64%	16.70%	17.05%	15.19%	13.68%	13.03%	11.50%	9.94%
Prospective	27.04%	25.02%	23.22%	24.18%	24.42%	22.47%	20.85%	20.11%	18.48%	16.82%
Adjusted-Potential	27.04%	25.02%	23.39%	24.38%	25.00%	23.04%	21.59%	21.11%	19.47%	18.02%
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)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	1,796	1,004	280	749	918	88	(609)	(916)	(1,653)	(2,426)
Prospective	5,095	4,303	3,579	4,047	4,216	3,387	2,689	2,382	1,645	873
Adjusted-Potential	5,095	4,303	3,654	4,135	4,472	3,643	3,030	2,847	2,110	1,450

Peak Season Reserve Margins



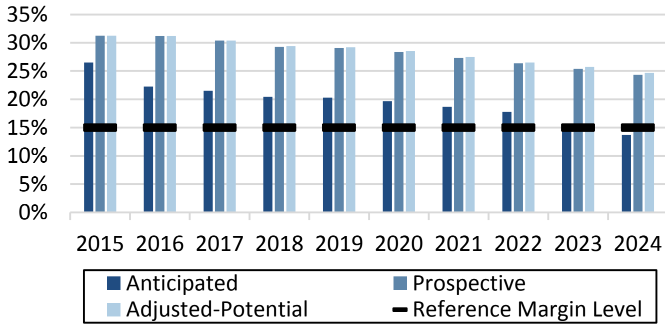
Peak Season Projected Generation Mix (Cumulative Change)



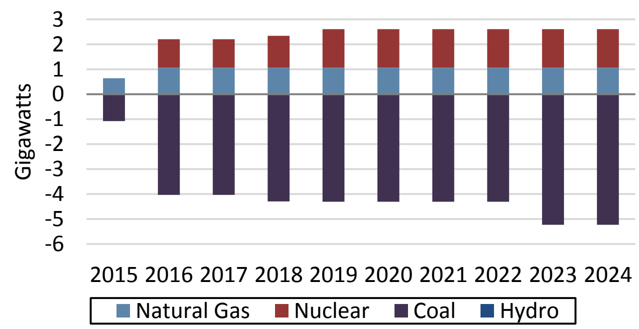
SERC-North: Peak Season Demand, Resources, and Reserve Margins

Demand (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Internal Demand	42,100	42,571	42,917	43,298	43,677	44,018	44,470	44,908	45,359	45,797
Demand Response	2,117	2,224	2,314	2,437	2,555	2,670	2,786	2,908	3,022	3,105
Net Internal Demand	39,983	40,347	40,603	40,861	41,122	41,348	41,684	42,000	42,337	42,692
Resources (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	50,585	49,326	49,342	49,212	49,471	49,471	49,471	49,471	48,547	48,547
Prospective	52,478	52,926	52,942	52,812	53,071	53,071	53,071	53,071	53,078	53,078
Adjusted-Potential	52,478	52,926	52,942	52,878	53,137	53,137	53,137	53,137	53,222	53,222
Reserve Margins (%)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	26.52%	22.25%	21.52%	20.44%	20.30%	19.65%	18.68%	17.79%	14.67%	13.71%
Prospective	31.25%	31.18%	30.39%	29.25%	29.06%	28.35%	27.32%	26.36%	25.37%	24.33%
Adjusted-Potential	31.25%	31.18%	30.39%	29.41%	29.22%	28.51%	27.48%	26.52%	25.71%	24.67%
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)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	4,604	2,927	2,648	2,222	2,181	1,921	1,534	1,171	(141)	(549)
Prospective	6,498	6,527	6,249	5,822	5,781	5,521	5,135	4,771	4,391	3,983
Adjusted-Potential	6,498	6,527	6,249	5,888	5,847	5,587	5,200	4,837	4,534	4,126

Peak Season Reserve Margins



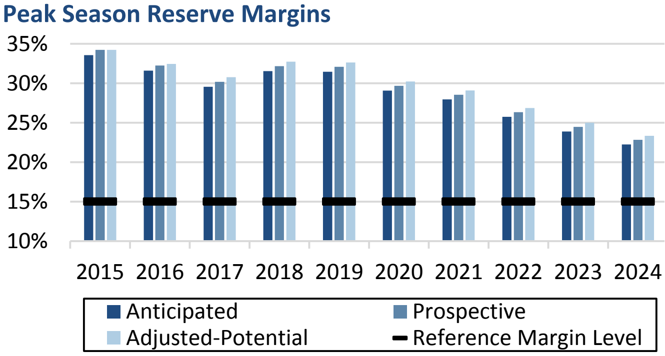
Peak Season Projected Resource Mix (Cumulative Change)



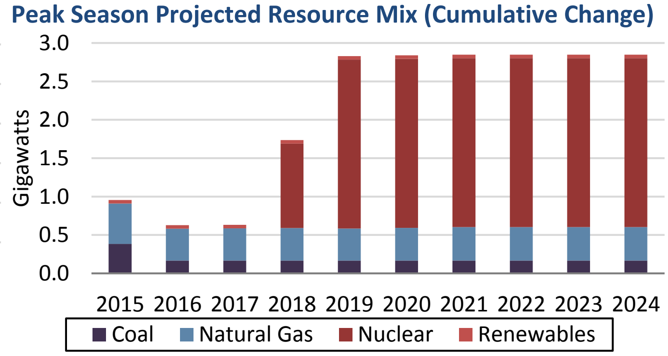
SERC-Southeast: Peak Season Demand, Resources, and Reserve Margins

Demand (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Internal Demand	47,116	48,137	48,931	49,427	50,124	51,135	51,563	52,292	53,046	53,844
Demand Response	2,166	2,190	2,213	2,206	2,215	2,224	2,229	2,233	2,251	2,252
Net Internal Demand	44,950	45,947	46,718	47,221	47,909	48,911	49,334	50,059	50,795	51,592
Resources (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	60,035	60,461	60,522	62,109	62,978	63,124	63,120	62,943	62,927	63,068
Prospective	60,331	60,757	60,818	62,405	63,274	63,420	63,416	63,239	63,223	63,364
Adjusted-Potential	60,333	60,852	61,084	62,671	63,540	63,686	63,682	63,505	63,489	63,630
Reserve Margins (%)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	33.56%	31.59%	29.55%	31.53%	31.45%	29.06%	27.94%	25.74%	23.88%	22.24%
Prospective	34.22%	32.23%	30.18%	32.15%	32.07%	29.66%	28.54%	26.33%	24.47%	22.82%
Adjusted-Potential	34.22%	32.44%	30.75%	32.72%	32.63%	30.21%	29.08%	26.86%	24.99%	23.33%
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)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	8,343	7,622	6,796	7,805	7,883	6,877	6,386	5,375	4,512	3,737
Prospective	8,639	7,917	7,092	8,101	8,179	7,173	6,681	5,671	4,808	4,033
Adjusted-Potential	8,641	8,013	7,358	8,367	8,445	7,439	6,947	5,937	5,074	4,299

Peak Season Reserve Margins



Peak Season Projected Resource Mix (Cumulative Change)



Demand, Resources, and Planning Reserve Margins

The Prospective Reserve Margins for all three SERC Assessment Areas remain above the Reference Margin Level of 15 percent throughout the assessment period. The Anticipated Reserve Margin for the SERC-E and SERC-N subregions falls below the Reference Margin Level in 2021 and 2023, respectively. The SERC demand forecast is expected to be lower than previous forecasts due to a number of factors, including lower economic growth.

DR, as well as energy efficiency and conservation programs, are projected to grow through 2020, after which some of these programs will plateau.

The SERC Assessment Area expects a number of changes to generation capabilities during the assessment period, including additions of the following: (1) Lee Steam Combined-Cycle power station, (2) V.C. Summers, (3) Watts Bar, and (4) Vogtle Nuclear Stations. Planned retirements in SERC's subregions are not expected to have any adverse impact on reliability; however, SERC entities continue to plan their system to address reliability needs to interconnect, deliver, and retire generating units.

There is a very limited amount of BTMG, DG, and variable energy resources (VERs) in SERC. The small existing amount of BTMG currently contracted (mostly solar) is incorporated into the load forecast. The impacts from this generation have been incorporated into the long-term plan as a reduction in the forecast demand, and it is expected that these types of resources will further reduce peak demand through impacts to the daily load shape. Due to the relative capacity and the operational nature of DG and VERs, expected on-peak capacity values in SERC are predictable and consistent.

All capacity transfers that are counted as capacity are backed by specific generation designations or transmission service reservations. SERC entities coordinate with their first-tier neighbors to ensure sufficient transmission interface capability, and to assess if potential impacts to capacity transfers exist due to any neighbors' planned system modifications.

Specific areas within the SERC Assessment Area are known to have large penetrations of induction motor loads, which are one of the main drivers behind Fault-Induced Delayed Voltage Recovery (FIDVR). SERC entities perform annual studies to decrease potential FIDVR exposure by ensuring sufficient dynamic reactive sources are available in the potential exposure area. With current load forecast, SERC entities do not anticipate that any FIDVR-affected areas will impact system reliability during the long-term assessment period.

Transmission Outlook and System Enhancements

Several transmission projects are in progress to improve reliability within the SERC Assessment Area. To name a few, Southeast Voltage Project involves building a new 115 kV line from Bonifay to Chipley substations, and Gulf Coast Loop Project involves building a new 115 kV line from Southport to Bayou George substation to Gaskin Switching station. In addition, to enhance current carrying capability across the VACAR-Southern interface, a 230 kV circuit will be built between Purrysburg and McIntosh substations.

During the assessment period, Southern Company Inc. is planning to add two 100 MVar SVCs, and TVA is adding a [-150/+300 MVar] SVC with an additional 250 MVar of caps controlled by this SVC to enhance voltage profile. Southern Company is developing and deploying smart grid technologies, including installing smart meters and an integrated distribution management system. These systems should provide better monitoring and enable quicker restoration in the event of storms or other damage. Southern also has several PMUs or the equivalent installed on the system and will add many more in the future. Several other SERC entities are deploying PMU, smart grid, and system awareness technology during the coming years. Duke Energy is working to integrate PMU information into the energy management systems. TVA is continuing with a program to install PMUs and GIC detectors across the Tennessee Valley.

Long-Term Reliability Issues

Shoulder (off-peak) periods, with lower network loading, reduced hydro generation, and significant resource maintenance outages, introduce a variety of challenges. During certain shoulder months and winter midday low-load periods, when solar output is negatively correlated with load, operational concerns arise during these minimal load conditions. SERC entities are currently studying the impacts of significant levels of potential solar penetration.

Retirements of generation in the SERC Assessment Area, some of which are caused by environmental regulations, are mitigated by gas-fired resources, purchase power agreements, and diversification of generation mix. SERC entities are optimistic that they can complete all necessary retrofits and improvements without sacrificing system reliability.

Entergy, with its six utility operating companies, and South Mississippi Electric Power Association, which previously reported data and information primarily in the SERC-W Assessment Area, integrated into MISO in December 2013. This shift added approximately 15,500 miles of transmission, 50,000 MW of generation capacity, and 35,000 MW of peak load to the MISO footprint. MISO now coordinates all RTO activities in the newly combined area, consisting of all or parts of 15 states.

Within this expanded MISO Balancing Area, the contract path capacity is limited to 1000 MW between the original MISO Central/North system and the new MISO South system. MISO market dispatches that result in power transfers between the MISO Central/North and MISO South portions of its system can result in significant unscheduled power flows through neighboring systems Tennessee Valley Authority (TVA), Associated Electric Cooperative, Inc. (AECI), Louisville Gas & Electric Company and Kentucky Utilities Company (LG&E/KU), Power South, Southwest Power Pool, Inc. (SPP), and Southern Company. These neighboring systems have raised concerns regarding these power flows, especially if the market dispatches exceed the 2,000 MW transfer limit from MISO South to MISO Central/North. At this time, no long-term joint planning studies have been conducted to determine long-term transmission system impacts. MISO and the neighboring systems have begun to establish long-term arrangements for both reliable operations and coordinated planning. In addition, SERC regional studies groups are assessing and refining SERC modeling and reliability assessments to better reflect the expanded MISO BA in regional long-term planning and operational planning assessments.

Prior to MISO starting merged market operations in December 2013, MISO and the neighboring systems developed an Operations Reliability Coordination Agreement (ORCA) to address reliability concerns during an initial operating transition period. The ORCA is set to expire in April 2015. MISO and their neighboring systems continue to explore other reliability processes to mitigate any adverse impacts on system reliability in the operational time frame.

Another potential emerging issue is that very long HVDC lines are being considered by independent transmission developers in economic projects such as shipping wind to the southeast. The capacity of a single line is typically greater than the largest single-contingency-generation loss in a system. The capacity of two poles will probably be larger than that of the largest multi-unit generating plant. On very long lines, the risk of losing both poles may be appreciable, and that risk plus the high power level could impact reliability. An emerging issue may be the ability of present study criteria to adequately model the impact of these lines on a system.

Also, due to the current tax subsidies in North Carolina, a large number of solar qualifying facilities have been requested in the transmission queue. These projects create uncertainty in planning for various reasons, including the uncertainty of the projects actually coming to fruition (i.e., the companies being able to rely on the capacity and/or generation from these facilities) and the intermittent nature of solar.

SPP

Assessment Area Overview

Southwest Power Pool (SPP) is a NERC Regional Entity (RE) 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 Winter 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 percent

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

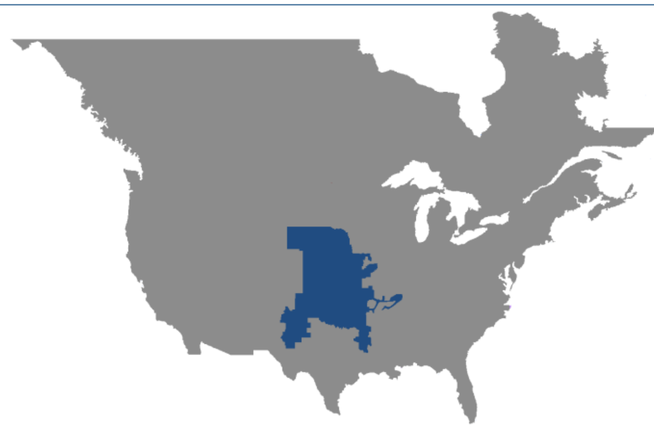
Peak Season
Summer

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

Planning Considerations for Solar Resources
On-peak contribution of 10 percent 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.

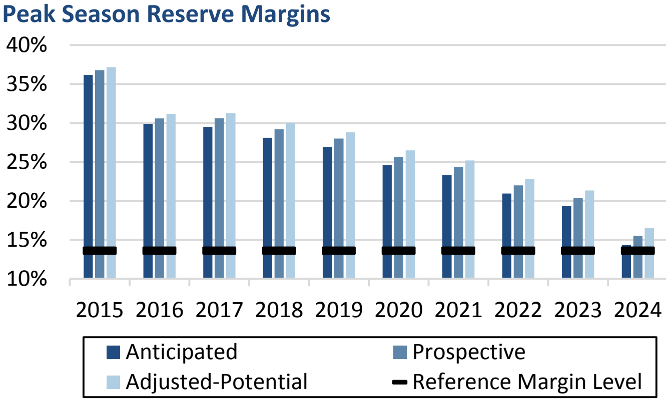
Assessment Area Footprint



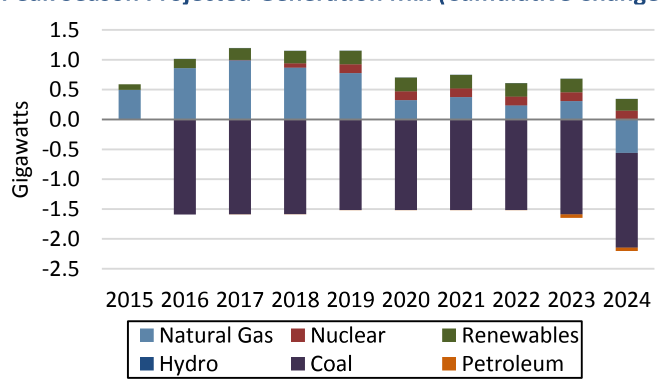
Peak Season Demand, Resources, and Reserve Margins

Demand (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Internal Demand	49,710	50,993	51,700	52,267	52,849	53,454	53,999	54,817	55,438	56,991
Demand Response	1,284	1,306	1,316	1,323	1,326	1,327	1,326	1,326	1,326	1,327
Net Internal Demand	48,426	49,687	50,384	50,944	51,523	52,128	52,673	53,491	54,112	55,663
Resources (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	65,942	64,539	65,247	65,258	65,394	64,945	64,949	64,693	64,579	63,634
Prospective	66,241	64,888	65,804	65,815	65,951	65,502	65,507	65,250	65,136	64,299
Adjusted-Potential	66,426	65,174	66,133	66,230	66,366	65,929	65,938	65,706	65,648	64,877
Reserve Margins (%)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	36.17%	29.89%	29.50%	28.10%	26.92%	24.59%	23.31%	20.94%	19.34%	14.32%
Prospective	36.79%	30.59%	30.60%	29.19%	28.00%	25.66%	24.37%	21.98%	20.37%	15.51%
Adjusted-Potential	37.17%	31.17%	31.26%	30.01%	28.81%	26.48%	25.18%	22.83%	21.32%	16.55%
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)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	10,930	8,094	8,011	7,386	6,864	5,728	5,113	3,927	3,108	400
Prospective	11,228	8,443	8,568	7,943	7,421	6,285	5,670	4,484	3,665	1,066
Adjusted-Potential	11,414	8,729	8,897	8,358	7,836	6,712	6,101	4,940	4,177	1,644

Peak Season Reserve Margins



Peak Season Projected Generation Mix (Cumulative Change)



Demand, Resources, and Planning Reserve Margins

Based on the 2014LTRA reference case, the Reserve Margins for the SPP Assessment Area will remain above the Reference Margin Level of 13.6 percent for all seasons and years of the assessment period.

The SPP Assessment Area is showing approximately an 8 percent decrease in Total Internal Demand compared with the 2013LTRA. This decrease is primarily due to several SPP members moving to the MISO footprint. Other drivers include a mild 2013 summer and higher projected impacts from both energy efficiency and DR programs. Several SPP members have also reported load forecasts with decreased annual growth percentages, impacted by changing economic conditions during the past several years. The SPP Assessment Area continues to forecast modest average annual growth of approximately 3.5 percent in energy efficiency and DR programs through 2024. DR programs in the SPP Assessment Area are voluntary and are primarily targeted for summer peak load reduction.

The High-Priority Incremental Load Study indicated 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 its stakeholders to ensure that reliability needs are being addressed.

Approximately 3,150 MW of nameplate capacity are expected to be retired during the assessment period (with the inclusion of retirements in 2014). With approximately 7,500 MW of new nameplate capacity projected to come into service during the assessment period, there are no operational or planning concerns at this time.

The expected on-peak capacity values for variable generation are determined by historical performance guidelines.[99] The net capability for wind is determined on a monthly basis using an eight-step process for establishing net capability. Wind facilities that have been in commercial operation for three years or less must include the most recently available engineering data. If MW values are not available, estimates may be used based on wind data that is correlated with reference towers outside a 50-mile radius of the facility's location. Such estimates must be approved by the SPP RTO Generation Working Group (GWG).

The net capability for solar resources is determined on a monthly basis using the same eight-step process as that of wind resources. Solar data that is correlated beyond 200 miles of the reference measuring device must also receive SPP GWG approval.[100]

The SPP GWG's proposed revisions to section 12.1.5.3.g of SPP Criteria (SPP Criteria), the Accreditation for Renewable Resource (Wind and Solar), were passed by the SPP Board of Directors at the July Meeting. The GWG's intention was to ensure the accreditation process meets the SPP Assessment Area's needs while not being overly cumbersome to the resource owners. The SPP GWG performed an analysis using operations data from the SPP footprint and sample data from 17 wind resources (varying wind turbine type, geographical location, and age of the facility). The GWG then applied this data to the existing SPP Criteria, proposed criteria language, and compared the results to a more rigorous ELCC study. The proposed language will now include the 3 percent top load hours, which will occur 60 percent of the time. It allows SPP members to apply more stringent criteria if desired by their area.

The GWG made these changes after extensive discussions and researching the operations data. The new proposed SPP Criteria covers accreditation for both wind and solar renewable resources, has a less-stringent confidence interval, and has been benchmarked against solar operational data for the resources and detailed ELCC studies.

The SPP Assessment Area continually evaluates operational procedures to determine if efficiency and reliability improvements can be made. Because of the level of wind resources in the footprint, SPP has included some variable resources

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[99] Section 12.

[100] Facilities that have been in commercial operation for four years or more must include a minimum of four years or up to 10 years of the most recent commercial operation data available, whichever is greater. Metered hourly net power output (MWh) data may be used. After three years of commercial operations, if the Load-Serving Member does not perform or provide the net capability calculations to SPP, then the net capability for the resource will be 0 MW. Net capability calculations are to be updated at least once every three years.

into its automatic, security-constrained dispatch calculations. This allows the SPP Assessment Area to better manage local congestion issues for which wind is the primary impacting resource. SPP is now able to better manage system reliability by using quicker and more effective control actions. New wind installations are required to be dispatchable.

SPP Assessment Area members, along with some members of the SERC Region, jointly participate in a Reserve Sharing Group (RSG). Members of the RSG receive contingency reserve assistance from each other and do not require support from generation resources outside the RSG. The SPP Operating Reliability Working Group sets the Minimum Daily Contingency Reserve Requirement for the RSG.

Long-Term Reliability Issues

Drought and flooding conditions are the most impactful weather events within the SPP Assessment Area. Current drought conditions in the western portion of the SPP Assessment Area are projected to continue into the assessment period. Most of the SPP Assessment Area's heavily water-dependent resources are located in the eastern half of the footprint, which has also experienced drought conditions in the past. SPP planning staff is studying the potential impacts of drought conditions in the SPP Assessment Area. The 2015 Integrated Transmission Planning (ITP) 10-year study includes a future scenario with a decreased baseload capacity in which units susceptible to drought conditions are derated or retired.

SPP's Operational Planning group performs biannual system planning studies to capture the potential reliability impacts of retirements and retrofits of generation. Any identified reliability concerns are passed to the SPP RTO long-term planning group. This study process consists of the creation of weekly snapshots through the next four years that consider load forecasts and known transmission and generation outages. Local issues are reported to the impacted SPP Transmission Operators. Since the SPP Assessment Area has sufficient capacity, the impacts of long-term maintenance outages are expected to be more economic in nature. Current studies indicate there will be adequate time to perform generator retrofits necessary to comply with current known environmental regulations. These currently planned retrofits are expected to impact generation supply economics more than the ability to reliably serve load. SPP continues to monitor and evaluate the impacts of generator retirements resulting from environmental regulations in its planning studies. SPP's 2015 ITP 10-year study included assumptions about generator retirements that were expected at the time the models were built for that study. After the ITP 10-year study began, the EPA issued its proposed Clean Power Plan on June 2, 2014. SPP is concerned about the reliability implications of additional generator retirements that could result from new regulations included in that proposed rule. Any additional retirements resulting from these new regulations have not yet been included in SPP's planning processes and will need to be thoroughly studied to ensure that any resulting reliability impacts are properly addressed.

SPP, along with other joint parties in the Region and MISO, are currently managing reliability concerns from MISO's recent operational changes under the provisions of the Operations Reliability Coordination Agreement (ORCA). Under Phase 1 of the ORCA, unless otherwise agreed to by the joint parties, MISO transfers between MISO Central/North and MISO South are limited. The joint parties and MISO continue to work to develop, test, and implement subsequent phases of the ORCA that would allow this reliability limit to potentially increase under certain conditions.

SPP will not impede reliability by limiting the exchange of energy between MISO Central/North and MISO South except as required for SPP to maintain its own reliable operations, even if it requires MISO to exceed their current 1,000 MW path. While SPP and MISO are currently in litigation over the terms and conditions of the compensation due to SPP when MISO may exceed its 1,000 MW path, the two assessment areas continue to work together to ensure reliable operation.

SPP and MISO have also recently agreed to improvements to the method for accounting for the flow impacts of import and export transactions used in the congestion management process. SPP and MISO continue to discuss additional improvements to ensure all sources of flows are properly accounted for within the Region. SPP is currently working with MISO to implement a market-to-market congestion management process that will serve to enhance reliability by more efficiently responding to congestion that occurs on flowgates impacted by both RTOs. It is expected that the market-to-market process will be in place by March 1, 2015.

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 percent

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

Peak Season
Summer

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

Planning Considerations for Solar Resources
ERCOT incorporates 100 percent capacity contribution

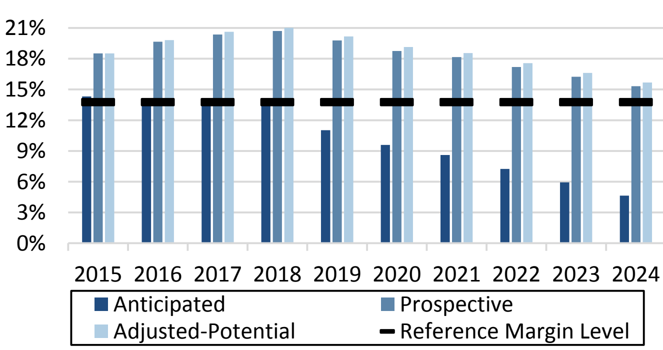
Footprint Changes
N/A

Assessment Area Footprint

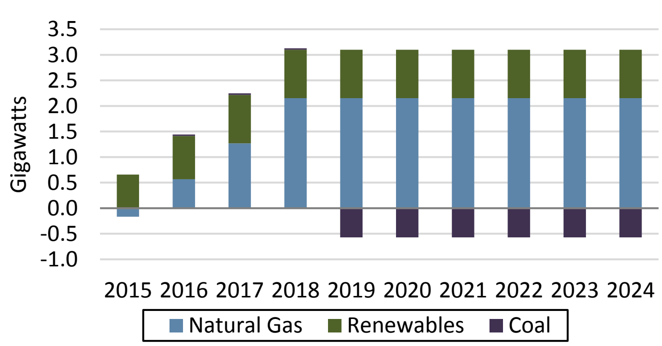
Peak Season Demand, Resources, and Reserve Margins[101]

Demand (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Internal Demand	69,057	70,014	70,871	71,806	72,859	73,784	74,710	75,631	76,550	77,471
Demand Response	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917
Net Internal Demand	67,140	68,097	68,954	69,889	70,942	71,867	72,793	73,714	74,634	75,554
Resources (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	76,751	77,673	78,478	79,360	78,760	78,760	79,060	79,060	79,060	79,060
Prospective	79,574	81,486	82,991	84,361	84,972	85,343	86,014	86,384	86,755	87,126
Adjusted-Potential	79,574	81,588	83,172	84,580	85,251	85,621	86,292	86,663	87,033	87,404
Reserve Margins (%)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	14.31%	14.06%	13.81%	13.55%	11.02%	9.59%	8.61%	7.25%	5.93%	4.64%
Prospective	18.52%	19.66%	20.36%	20.71%	19.78%	18.75%	18.16%	17.19%	16.24%	15.32%
Adjusted-Potential	18.52%	19.81%	20.62%	21.02%	20.17%	19.14%	18.54%	17.57%	16.61%	15.68%
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)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	379	212	43	(139)	(1,937)	(2,989)	(3,742)	(4,790)	(5,836)	(6,882)
Prospective	3,203	4,025	4,556	4,863	4,275	3,594	3,212	2,534	1,859	1,183
Adjusted-Potential	3,203	4,127	4,737	5,081	4,554	3,873	3,490	2,813	2,138	1,462

Peak Season Reserve Margins



Projected Peak Season Generation Mix (Cumulative Charge)



[101] 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 2014LTRA 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.

Demand, Resources, and Planning Reserve Margins

New gas-fired resources totaling 2,112 MW (summer rating) being added during the summer of 2014 help elevate the Anticipated Reserve Margin to 14.3 percent in 2015. The Anticipated Reserve Margin is expected to remain above the Reference Margin Level of 13.75 percent until 2018, while the Prospective Reserve Margin remains above the Reference Margin Level for the entire assessment period. The expected addition of the Panda Temple II combined-cycle plant (717 MW summer rating) in August 2015 and the FGE Texas 1 combined-cycle plant (703 MW summer rating) in July 2016 largely offset forecast load growth through 2017. After 2017, there is insufficient Anticipated resources to keep pace with load growth.

The generation market in ERCOT is unregulated, with generators making resource decisions based on market dynamics as well as administratively applied scarcity pricing mechanisms intended to incentivize the provision of adequate operating reserves. In an environment of continuing economic and load growth, tight reserve margins are expected beyond three to four years in the future, given the lead time for proposed resources to proceed through ERCOT's interconnection request process and meet ERCOT's requirements for inclusion in resource adequacy assessments. If there is a risk of insufficient capacity to meet resource adequacy requirements in the short-term future, the Public Utility Commission of Texas (PUCT), with input from ERCOT and market participants, would be expected to investigate and implement measures to address potential capacity shortages.

As a temporary measure to address system reliability problems stemming from generators that are planned to be taken out of service by their owners, ERCOT can enter into Reliability Must-Run (RMR) contracts with those generators or others that would otherwise not operate.

The ERCOT peak demand forecast (Total Internal Demand) for summer 2015 is 69,057 MW and is expected to occur in early August. The 2015 peak demand forecast is 1.4 percent higher than the forecast for 2014, driven in part by the continued expansion of oil and gas production in the Permian Basin and Eagle Ford Shale areas, but is 3.4 percent lower than the 2015 forecast reported in the 2013LTRA. This decrease is due to major changes to ERCOT's load forecast method that better capture the relationship between economic indicators and electric demand, as well as the impacts of energy efficiency and other efforts by industrial and commercial sector customers to reduce electricity usage during periods of high demand.

With respect to the TRE-ERCOT Region's reliance on DSM programs, significant growth has recently occurred for ERCOT's Emergency Response Service (ERS). This program, which includes 10- and 30-minute Demand Response resources as well as distributed generation service, is designed to be deployed in the late stages of a grid emergency, prior to shedding involuntary Firm load. Procurement of ERS summer peak time period procurement grew from 422 MW in 2013 to 626 MW in 2014, nearly a 50 percent increase. The ERS program remains capped at $50 million per year, in accordance with an existing rule implemented by the PUCT. This spending cap is expected to cause the growth rate to flatten during the next few years. Load Resource capacity providing ancillary services is also expected to increase due to new rules enabling Controllable Load Resources to bid into the real-time market for the provision of non-spinning reserves. ERCOT also accounts for the peak load impacts of Demand Response programs managed by several Transmission Service Providers (TSPs). These TSPs have individual contractual programs with loads that can respond to instructions to reduce total energy usage. These programs are expected to remain flat for the foreseeable future at approximately 240 MW.

A significant amount of generating capacity has been added since 2013, and more is expected in 2014 and 2015. These additions have entered commercial operations and are listed below:

- Sandy Creek 1 (coal-fired, 970 MW)
- WA Parish addition (gas-fired, 74 MW)
- Acacia Solar (solar PV, 10 MW)
- OCI Alamo 1 (solar PV, 39 MW)
- Blue Summit Wind 5 and 6 (135 MW)
- Los Vientos Wind I and II (402 MW)

ERCOT forecasts 2,801 MW of new summer-rated capacity to be available for the 2015 summer peak load. Out of this total, 2,144 MW are gas-fired, 489 MW are wind, and 168 MW are solar PV facilities.

Natural-gas-fired additions in 2014 include: two new combined-cycle gas-fired power plants (Panda Sherman and Panda Temple 1) with a combined summer capacity rating of 1,437 MW; the 510 MW Ferguson combined-cycle plant, which replaced the original 354 MW unit (retired in September 2013); a 165 MW (summer rating) expansion of the Deer Park Energy Center; and two small plant upgrade projects for a total of 32 MW. New renewable resources available for the 2015 summer peak load include three solar PV plants: White Camp Solar 1 (100 MW nameplate), Pecos Barilla Solar (30 MW nameplate), OCI Alamo 4 (38 MW nameplate), and 30 wind plants for a total of 5,625 MW nameplate capacity. The wind plant sizes range from 68 to 600 MW.

Regarding units planned for retirement or suspended operations, NRG recently announced that its five S.R. Bertron gas-fired units (combined summer rating of 727 MW) will not return from mothball status for summer operation. Additionally, the J.T. Deely coal plant (840 MW) is expected to enter indefinite mothball status at the end of 2018.

The TRE-ERCOT Region is a separate interconnection with only asynchronous ties to SPP and Mexico's Comisión Federal de Electricidad (CFE). As such, ERCOT does not share reserves with other Regions. There are two asynchronous ties between ERCOT and SPP with a total of 820 MW of transfer capability, and four asynchronous ties between ERCOT and Mexico with a total of 436 MW of transfer capability (once the Sharyland Utilities expansion project (150 MW) was expected to be completed in 2014). For the assessment period, ERCOT assumes that all of the generating capacity of the Tenaska Kiamichi Generating Station (1,246 MW summer rating and 1,330 MW winter rating) located in Pittsburgh County, Oklahoma, is dedicated to the ERCOT market. Also included in the assessment is 463 MW of import capability determined by analyzing historical flows across the dc ties during peak hours.

Transmission Outlook and System Enhancements

With respect to transmission planning, the recently updated ERCOT future transmission projects list includes the addition or upgrade of 1,602 miles of 138 kV and 345 kV transmission circuits, 7,472 MVA of 345/138 kV autotransformer capacity, and 5,538 MVar of reactive capability projects that are planned in ERCOT between 2014 and 2023. Sixty-four projects were identified as being necessary to meet the system needs in West Texas through 2017. A new Houston Import Project consisting of a 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. Other significant projects include a new 345 kV import line and an upgrade of the two existing 345 kV import lines to support load growth in the Lower Rio Grande Valley (LRGV), a new Cross Valley 345 kV, 106-mile line to support load growth in Brownsville and other cities along the eastern side of the LRGV, and multiple transmission upgrades in the Odessa North area (west Texas). ERCOT has received requests to study two projects that would add asynchronous tie capacity between ERCOT and the Eastern Interconnection. The Southern Cross project would connect on the eastern portion of the ERCOT system and add up to 3,000 MW of tie capacity by 2016. The Tres Amigas project would add 1,500 MW of tie capacity in the Texas Panhandle by 2017. These new lines will provide access to several Regions adjacent to ERCOT. The additional dc tie capacity is being proposed for commercial purposes.

Long-Term Reliability Issues

New and proposed federal environmental regulations continue to be a concern from a long-term resource adequacy perspective. ERCOT is monitoring the impacts of multiple proposed federal environmental regulations, including CSAPR and MATS. The U.S. Supreme Court affirmed the U.S. Environmental Protection Agency's authority to promulgate the CSAPR on April 29, 2014. ERCOT is analyzing the implications of the Supreme Court's decision and will work closely with TRE-ERCOT Region generators to assess the impact of CSAPR implementation on resource adequacy and grid reliability once updated proposed regulations are issued. For MATS, survey data collected from ERCOT's solid fuel generators in mid-2013 indicated that while unit retirements are not an immediate concern, a number of generators that are not currently in compliance with the standard, representing about 32 percent of all the capacity covered by the survey, did not have their compliance strategies finalized. As with CSAPR, ERCOT will continue to closely monitor MATS compliance efforts and assess the risk for unit retirements. Other proposed regulations being monitored by ERCOT include the Cooling Water Intake Structures Rule (under Section 316(b) of the Clean Water Act), the Coal Ash Disposal Rule (under the Resource Conservation and Recovery Act (RCRA)), the Steam Electric Effluent Limitation Guidelines, and CO_2 emission regulations from existing plants. All of these proposed regulations are not expected to have a material impact on reliability for the next two to three years if enacted. However, their combined impact on coal plant economic viability further out in the assessment period may become an issue if significant retired coal plant capacity is the resulting outcome.

From an operational perspective, the combination of a large seasonal variance in system load and the high penetration of wind generation has increased challenges for voltage support and frequency control, particularly during large ramp events. Nevertheless, ERCOT has been successfully operating the system with high wind penetration over the past few years. To address these new challenges, ERCOT has proposed the phased implementation of a redesigned ancillary services framework consisting of new and revised unbundled ancillary services products intended to take advantage of evolving system needs and capabilities of existing resources, as well as emerging technologies such as battery storage. New ancillary services products include Synchronous Inertial Response Service, Fast Frequency Response Service, and Primary Frequency Response Service. To implement the ancillary services framework, a Future Ancillary Services Team (FAST) has been established to facilitate stakeholder input and address substantive implementation issues prior to ERCOT's development of proposed market protocol revisions later in 2014.[102]

Finally, multi-year droughts in Texas continue to represent a reliability concern. Much of central Texas and the panhandle are currently under "exceptional" or "extreme" drought conditions, although reservoir levels are not expected to drop below power plant physical input limits during the remainder of 2014. If drought conditions extend into 2015, there is the risk of multiple resources being taken off-line due to the lack of cooling water. If operational restrictions extend over peak load periods, resource adequacy then becomes an issue. Depending on the location of the drought, local area transmission congestion can result and must be relieved. If an extended drought occurs, additional transmission may need to be added to support an affected area. The entire system would be impacted by additional pressure placed on other resources. The specific location with the outage may have congestion problems to overcome in addition to voltage support issues.

[102] Concept Paper: Future Ancillary Services in ERCOT.

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 million people, it is geographically the largest and most diverse of the NERC Regions. WECC's service territory includes the Canadian provinces of Alberta and British Columbia, the northern portion of Baja California in Mexico, and all or portions of the 14 western states between. The WECC Assessment Area is divided into four subregions:[103] Northwest Power Pool (NWPP), Rocky Mountain Reserve Group (RMRG), Southwest Reserve Sharing Group (SRSG), and California/Mexico (CA/MX). These subregional divisions are structured around Reserve Sharing groups that have similar annual demand patterns as well as 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)

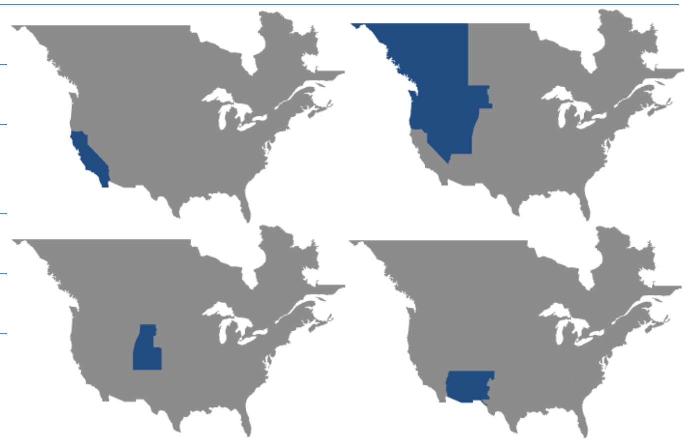
Peak Season
Summer: CA/MX; RMRG; SRSG
Winter: NWPP

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

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

Footprint Changes
In early 2014, the Nevada Power and Sierra Pacific BAs were consolidated into one BA (Nevada Power) and incorporated into the NWPP subregion, and the old Nevada Power BA was removed from the SRSG subregion.

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

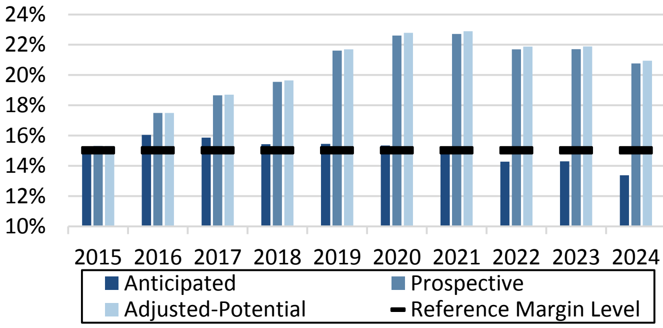


[103] Northwest Power Pool, Rocky Mountain Reserve Group, Southwest Reserve Sharing Group.

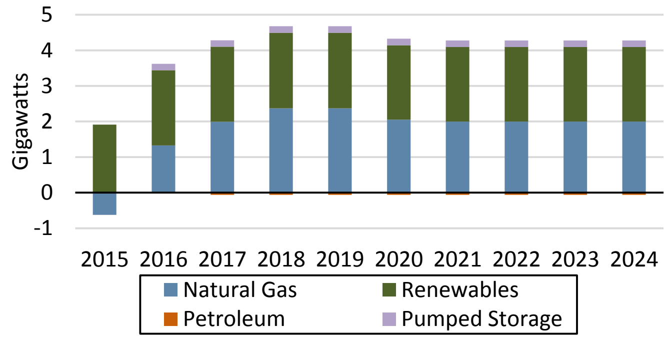
WECC-CA/MX: Peak Season Demand, Resources, and Reserve Margins

Demand (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Internal Demand	57,606	56,767	57,004	57,245	57,580	58,003	58,257	58,542	58,742	58,930
Demand Response	1,996	2,019	2,055	2,081	2,132	2,184	2,236	2,287	2,339	2,389
Net Internal Demand	55,610	54,748	54,949	55,164	55,448	55,819	56,021	56,255	56,403	56,541
Resources (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	64,102	63,531	63,670	63,675	64,014	64,383	64,576	64,289	64,470	64,106
Prospective	64,126	64,327	65,205	65,951	67,431	68,441	68,744	68,462	68,646	68,285
Adjusted-Potential	64,126	64,327	65,225	65,998	67,478	68,541	68,847	68,565	68,748	68,387
Reserve Margins (%)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	15.27%	16.04%	15.87%	15.43%	15.45%	15.34%	15.27%	14.28%	14.30%	13.38%
Prospective	15.31%	17.50%	18.66%	19.55%	21.61%	22.61%	22.71%	21.70%	21.71%	20.77%
Adjusted-Potential	15.31%	17.50%	18.70%	19.64%	21.70%	22.79%	22.89%	21.88%	21.89%	20.95%
Reference Margin Level	15.02%	15.02%	15.02%	15.02%	15.02%	15.02%	15.02%	15.02%	15.02%	15.02%
Excess/Shortfall (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	139	559	467	226	238	180	141	(415)	(405)	(927)
Prospective	164	1,356	2,003	2,501	3,655	4,238	4,309	3,758	3,771	3,251
Adjusted-Potential	164	1,356	2,022	2,549	3,702	4,338	4,412	3,860	3,874	3,354

Peak Season Reserve Margins



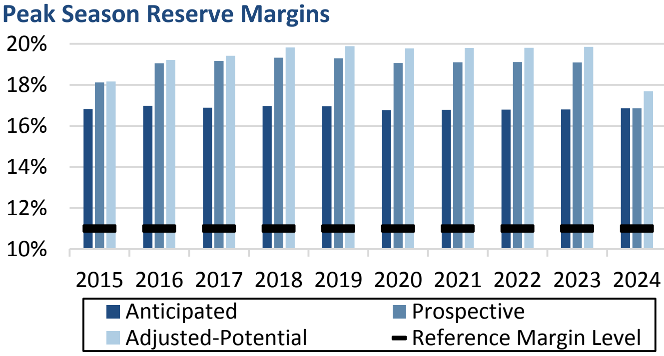
Peak Season Projected Generation Mix (Cumulative Change)



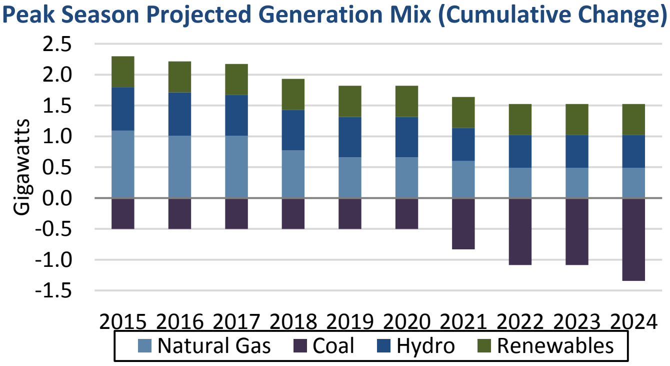
WECC-NWPP: Peak Season Demand, Resources and Reserve Margins

Demand (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Internal Demand	70,778	71,786	73,217	74,430	75,490	76,482	77,422	78,320	79,189	79,912
Demand Response	325	325	325	325	325	325	325	325	325	325
Net Internal Demand	70,453	71,461	72,892	74,105	75,165	76,157	77,097	77,995	78,864	79,587
Resources (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	82,304	83,592	85,197	86,683	87,910	88,927	90,037	91,090	92,109	93,002
Prospective	83,217	85,075	86,863	88,422	89,660	90,677	91,819	92,898	93,918	93,002
Adjusted-Potential	83,246	85,191	87,045	88,789	90,106	91,215	92,357	93,437	94,519	93,661
Reserve Margins (%)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	16.82%	16.98%	16.88%	16.97%	16.96%	16.77%	16.78%	16.79%	16.79%	16.86%
Prospective	18.12%	19.05%	19.17%	19.32%	19.28%	19.07%	19.09%	19.11%	19.09%	16.86%
Adjusted-Potential	18.16%	19.21%	19.42%	19.81%	19.88%	19.77%	19.79%	19.80%	19.85%	17.68%
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)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	4,101	4,270	4,287	4,426	4,478	4,393	4,460	4,516	4,570	4,660
Prospective	5,014	5,753	5,953	6,166	6,227	6,143	6,241	6,324	6,379	4,660
Adjusted-Potential	5,043	5,870	6,135	6,532	6,673	6,681	6,780	6,863	6,980	5,319

Peak Season Reserve Margins



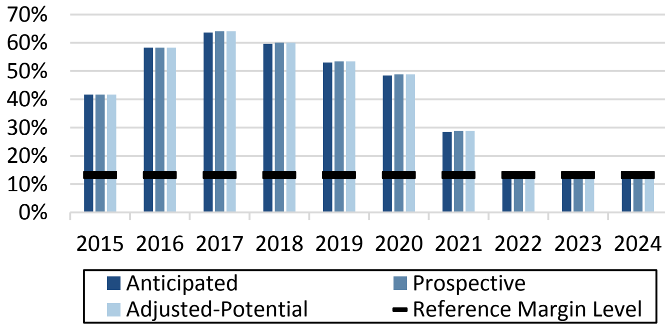
Peak Season Projected Generation Mix (Cumulative Change)



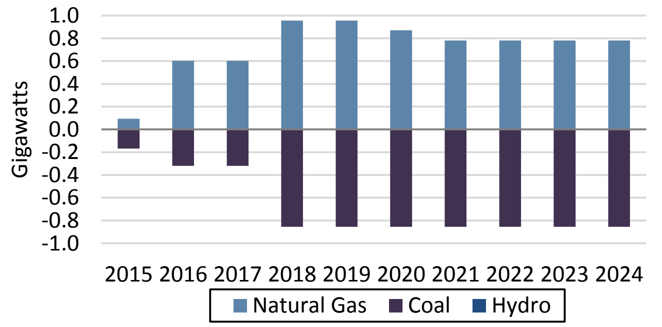
WECC-RMRG: Peak Season Demand, Resources, and Reserve Margins

Demand (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Internal Demand	9,899	10,100	10,239	10,410	10,558	10,709	10,843	10,901	11,046	11,249
Demand Response	557	567	576	586	592	602	611	620	627	633
Net Internal Demand	9,342	9,533	9,663	9,824	9,966	10,107	10,232	10,281	10,419	10,616
Resources (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	15,106	15,088	15,814	15,681	15,249	15,002	13,139	11,647	11,820	12,028
Prospective	15,106	15,089	15,856	15,723	15,292	15,045	13,182	11,690	11,863	12,070
Adjusted-Potential	15,106	15,089	15,856	15,723	15,292	15,045	13,185	11,693	11,866	12,073
Reserve Margins (%)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	41.71%	58.27%	63.65%	59.62%	53.01%	48.43%	28.41%	13.29%	13.45%	13.30%
Prospective	41.71%	58.28%	64.09%	60.05%	53.44%	48.86%	28.83%	13.71%	13.86%	13.70%
Adjusted-Potential	41.71%	58.28%	64.09%	60.05%	53.44%	48.86%	28.86%	13.73%	13.88%	13.73%
Reference Margin Level	13.20%	13.20%	13.20%	13.20%	13.20%	13.20%	13.20%	13.20%	13.20%	13.20%
Excess/Shortfall (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	4,531	4,297	4,875	4,560	3,968	3,561	1,556	9	26	10
Prospective	4,531	4,297	4,918	4,603	4,010	3,604	1,599	52	68	53
Adjusted-Potential	4,531	4,297	4,918	4,603	4,010	3,604	1,602	55	71	56

Peak Season Reserve Margins



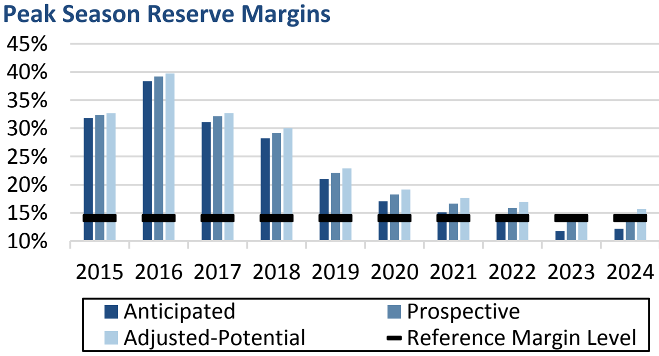
Peak Season Projected Generation Mix (Cumulative Change)



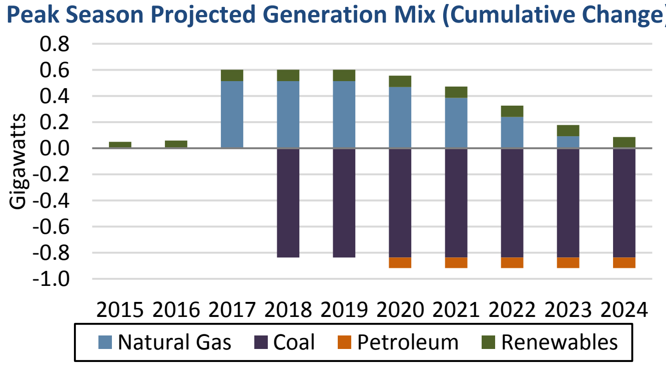
WECC-SRSG: Peak Season Demand, Resources, and Reserve Margins

Demand (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Internal Demand	22,635	22,760	23,282	23,762	24,335	24,707	25,113	25,694	26,193	26,709
Demand Response	418	421	430	372	377	382	382	382	382	383
Net Internal Demand	22,217	22,339	22,852	23,390	23,958	24,325	24,731	25,312	25,811	26,326
Resources (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	29,289	30,904	29,958	29,992	28,991	28,469	28,459	28,895	28,843	29,536
Prospective	29,413	31,092	30,190	30,223	29,258	28,771	28,846	29,317	29,300	30,066
Adjusted-Potential	29,473	31,208	30,320	30,405	29,443	28,979	29,098	29,598	29,609	30,448
Reserve Margins (%)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	31.83%	38.35%	31.10%	28.22%	21.01%	17.03%	15.08%	14.16%	11.75%	12.19%
Prospective	32.39%	39.19%	32.11%	29.21%	22.12%	18.27%	16.64%	15.82%	13.51%	14.21%
Adjusted-Potential	32.66%	39.71%	32.68%	29.99%	22.89%	19.13%	17.66%	16.93%	14.72%	15.66%
Reference Margin Level	14.06%	14.06%	14.06%	14.06%	14.06%	14.06%	14.06%	14.06%	14.06%	14.06%
Excess/Shortfall (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	3,949	5,425	3,893	3,313	1,665	724	252	24	(597)	(492)
Prospective	4,072	5,613	4,125	3,544	1,932	1,025	638	446	(141)	38
Adjusted-Potential	4,133	5,729	4,255	3,726	2,116	1,234	890	727	169	420

Peak Season Reserve Margins



Peak Season Projected Generation Mix (Cumulative Change)



Demand, Resources, and Planning Reserve Margins

Throughout the 10-year assessment period, the Reference Margin Levels range between 11 and 15 percent for the four subregions. The Reference Margin Levels[104] for each subregion are calculated using a building block method[105] created by WECC's Reliability Assessment Work Group (RAWG),[106] formerly Loads and Resources Subcommittee, for its annual Power Supply Assessment (PSA).[107] The elements of the building block margin calculation are consistent from year to year, but the calculations may have slight annual variances by region and subregion.

By the summer of 2024, the difference between WECC's Prospective Resources (198,259 MW) and WECC's Net Internal Demand (169,314 MW) is calculated as 28,945 MW (17.1 percent margin). As the expected resources exceed the Reference Margin Levels, it is reasonable to assume that only a portion of the reported resource additions will ultimately enter commercial service within the planning horizon.

As depicted in the graphic at the beginning of this section, the reserve margins for the WECC subregions remain above the Reference Margin Levels through 2021. Beginning in 2022, individual subregions do drop below their Reference Margin Levels, but the potential resource additions that have been reported exceed these possible shortages.

In the resource adequacy process, each BA is responsible for complying with the resource adequacy requirements of the state or provincial areas in which they operate. Some BAs perform resource adequacy studies as part of their integrated resource plans, which usually provide a 20-year outlook. Other BAs perform resource adequacy studies that focus on the very short term (i.e., one to two years), but most projections provide at least a 10-year outlook. WECC's PSA uses a study period of 10 years and the same subregional reserve target margins throughout the entire period.

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. Also, resources such as DERs or BTMG that are not monitored by the BA's energy management systems are excluded from the resource adequacy calculation.

Total Internal Demand for the summer, the peak season for the entire WECC Region, increased by 1.1 percent from 2012 to 2013, mostly due to warmer than normal temperatures in 2013. The Total Internal Demand for the summer seasons during the next 10 years is projected to increase by 1.0 percent per year, which is a decrease from the 1.7 percent projected in the 2013LTRA (2014–2023). The annual energy load is projected to increase by 1.2 percent per year for the 2015–2024 time frame, which is also a decrease from the 1.5 percent projected in the 2013LTRA.

The WECC Total Internal Demand forecast includes summer Demand Response that varies from 3,878 MW in 2015 to 4,226 MW in 2024. The direct control DSM capability is located mostly in the California/Mexico subregion, totaling 1,996 MW in 2015 and 2,389 MW in 2024. DSM 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; the California ISO (CAISO) is actively engaged with stakeholders in developing viable wholesale Demand Response products with direct market participation capability. Also of note is CAISO's

[104] 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.

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

[106] All of the BAs 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 extractions from generation queues.

[107] WECC's Power Supply Assessments.

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.[108]

Overall Demand Response program growth has been rather static and is not expected to increase dramatically during the 10-year planning horizon. The various DSM 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 (LSEs) 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.[109]

Distributed energy resources, including rooftop solar and BTMG, currently represent a very small portion of both the existing and planned resources. As the load served by BTMG is not included in the actual or forecast peak demands and energy loads, these resources are excluded from the resource adequacy calculation.

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, though not be renewed.[110]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 potentially affected plants. Current information regarding the California OTC is available on the California Energy Commission's website.[111] It is expected that any future capacity reductions will be offset by new plants that may or may not be reflected in the current conceptual resources data.

The Anticipated Resources projected for the 2015 summer peak period total 188,221 MW and reflect the monthly shaping of variable generation and the seasonal ratings of conventional resources. The expected on-peak capacity modeling for wind resources is based on curves created using at least five years of actual hourly wind generation data. The data is averaged into six four-hour blocks for each day of each week of the year. Solar resource energy curves were created using up to five years of actual hourly solar generation data. The data is averaged into three block curves for each day of the week of the year. 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. The individual BAs report 37,410 MW as the total gross future capacity projected to be in service by the end of this assessment period.

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 are methods that 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 is working on long-term solutions to this issue and provides current information on its website.[112] Increased wind penetration is expected to worsen the operating reserve situation. Solar generation may also

[108] California ISO Demand Response Initiatives.

[109] NERC's assessment process assumes that Demand Response may be shared among LSEs, BAs, 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 load serving entities. The reduction to demand associated with these programs is reflected in the load forecasts supplied by the balancing authorities.

[110] CEC Emission Performance Standards.

[111] CEC Once-Through Cooling.

[112] BPA Wind Activities.

reach a level sufficient to add to the operational issues relative to short-term (sub-hourly) load following. A joint NERC/California ISO report addresses this potential operational issue.[113]

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 may be scheduled across three back-to-back dc ties with SPP and five back-to-back dc ties with Assessment Areas in MRO.

Inter-subregional transfers are derived from resource allocation computer simulations that incorporate transmission constraints among various path-constrained zones within WECC.[114] 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 NWPP and the summer-peaking SRSG, 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.[115] When examining all Adjusted-Potential Resources, all subregions maintain adequate reserves (above respective targets) throughout the assessment period.

Transmission Outlook 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 of the assessment area 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.

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 any adverse impact 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.[116] 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.

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 (SPS) or Remedial Action Schemes

[113] Maintaining Bulk Power System Reliability While Integrating Variable Energy Resources – CAISO Approach.

[114] 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.

[115] Modeled Transfers: applicable for Assessment Areas that model potential feasible transfers (imports/exports) to eliminate potential double counting of capacity. Because of delivery options, the Assessment area does not attempt to align the purchase and sale of contracts. Instead, the assessment area, using conservative transfer limits on associated transfer paths, models feasible transfers between areas. Although these transfers are not contracts, Firm transmission capacity is held by the importing or exporting entities, and modeling of the existing transmission, including transfer capability, has been executed to verify these transfers can occur during the peak season.

[116] WECC's Project Coordination and Path Rating Process.

(RAS). 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 Western Interconnection.[117]

Long-Term Reliability Issues

In 2013 more than 4,700 MW of thermal generation was retired, including 2,250 MW of nuclear generation, 909 MW of coal-fired generation, and 1,588 MW of natural-gas-fired generation. However, those retirements were replaced by more than 9,500 MW of generation additions, including 1,206 MW of wind generation, 3,162 MW of natural-gas-fired generation, and 3,990 MW of solar generation. WECC continues to track and study the impacts on reliability, as well as other issues, associated with the retirement of large thermal generating units in response to higher air emission and water quality standards. Associated with the retirement of large coal generating units is the increased demand on natural gas supply and transportation as natural gas becomes the primary fuel for new thermal generation. WECC is working with the natural gas industry to study potential impacts to reliability as the Western Interconnection becomes more reliant on natural-gas-fired generation.

The joint NERC/CAISO study addresses some potential operational impacts from higher levels of variable resources (e.g., ancillary services for ramp rates). WECC studies to date have not identified significant issues relative to inertia and frequency response, but at some as-yet-unidentified penetration level, inertia and frequency response may become an issue. WECC continues to work with entities within the Western Interconnection to identify and study reliability concerns associated with the increasing levels of variable and BTMG resources.

[117] CAISO Smart Grid Roadmap.

Appendix I: 2014LTRA Reference Case Data Summary

Demand, Resources, and Reserve Margins by Assessment Area: 2015 Summer

Assessment Area / Interconnection	Demand (MW) Total Internal	Demand (MW) Net Internal	Resources (MW) Anticipated	Resources (MW) Prospective	Resources (MW) Adjusted-Potential	Reserve Margins (%) Anticipated	Reserve Margins (%) Prospective	Reserve Margins (%) Adjusted-Potential	Reference Margin Level
FRCC	46,719	43,579	55,520	57,311	57,311	27.40%	31.51%	31.51%	15.00%
MISO	128,571	123,828	144,893	150,055	150,258	17.01%	21.18%	21.34%	14.80%
MRO-Manitoba Hydro	3,434	3,193	4,552	4,815	4,815	42.57%	50.79%	50.79%	12.00%
MRO-MAPP	5,028	4,932	6,379	6,379	6,379	29.35%	29.35%	29.35%	15.00%
MRO-SaskPower	3,208	3,122	3,750	3,750	3,750	20.12%	20.12%	20.12%	11.00%
NPCC-Maritimes	3,420	3,087	5,808	5,952	5,952	88.17%	92.84%	92.84%	20.00%
NPCC-New England	26,930	25,763	31,880	31,887	31,887	23.75%	23.77%	23.77%	15.70%
NPCC-New York	34,066	32,877	38,311	41,715	41,715	16.53%	26.88%	26.88%	15.00%
NPCC-Ontario	22,726	22,158	27,112	27,112	27,112	22.36%	22.36%	22.36%	19.50%
NPCC-Québec	21,436	21,436	31,517	30,621	30,621	47.03%	42.85%	42.85%	15.00%
PJM	160,259	145,447	183,163	186,787	186,787	25.93%	28.42%	28.42%	15.70%
SERC-E	44,086	42,329	50,475	53,773	53,773	19.24%	27.04%	27.04%	15.00%
SERC-N	42,100	39,983	50,585	52,478	52,478	26.52%	31.25%	31.25%	15.00%
SERC-SE	47,116	44,950	60,035	60,331	60,333	33.56%	34.22%	34.22%	15.00%
SPP	49,710	48,426	65,942	66,241	66,426	36.17%	36.79%	37.17%	13.60%
TRE-ERCOT	69,057	67,140	76,751	79,574	79,574	14.31%	18.52%	18.52%	13.75%
WECC-CAMX	57,606	55,610	64,102	64,126	64,126	15.27%	15.31%	15.31%	15.02%
WECC-NWPP	66,283	65,467	79,724	80,084	80,113	21.78%	22.33%	22.37%	15.50%
WECC-RMRG	9,899	9,342	15,106	15,106	15,106	61.70%	61.71%	61.71%	13.20%
WECC-SWSG	22,635	22,217	29,289	29,413	29,473	31.83%	32.39%	32.66%	14.06%
Eastern Interconnection	617,372	583,673	728,404	748,586	748,977	24.80%	28.25%	28.32%	-
Québec Interconnection	21,436	21,436	31,517	30,621	30,621	47.03%	42.85%	42.85%	15.00%
ERCOT Interconnection	69,057	67,140	76,751	79,574	79,574	14.31%	18.52%	18.52%	13.75%
Western Interconnection	156,423	152,636	188,221	188,730	188,819	23.31%	23.65%	23.71%	-
TOTAL-NERC	**864,288**	**824,885**	**1,024,892**	**1,047,511**	**1,047,991**	**24.25%**	**26.99%**	**27.05%**	**-**

Demand, Resources, and Reserve Margins by Assessment Area: 2015 Winter

Assessment Area / Interconnection	Demand (MW) Total Internal	Demand (MW) Net Internal	Resources (MW) Anticipated	Resources (MW) Prospective	Resources (MW) Adjusted-Potential	Reserve Margins (%) Anticipated	Reserve Margins (%) Prospective	Reserve Margins (%) Adjusted-Potential	Reference Margin Level
FRCC	45,668	42,668	58,546	60,670	60,670	37.21%	42.19%	42.19%	15.00%
MISO	104,414	99,671	139,972	145,134	145,337	40.43%	45.61%	45.82%	14.80%
MRO-Manitoba Hydro	4,652	4,409	5,637	5,901	5,901	27.85%	33.83%	33.83%	12.00%
MRO-MAPP	5,457	5,071	7,163	7,193	7,193	41.26%	41.85%	41.85%	15.00%
MRO-SaskPower	3,557	3,471	4,309	4,309	4,309	24.15%	24.15%	24.15%	11.00%
NPCC-Maritimes	5,477	5,230	6,676	6,820	6,820	27.66%	30.42%	30.42%	20.00%
NPCC-New England	22,755	19,963	34,624	34,993	34,993	73.44%	75.29%	75.29%	15.70%
NPCC-New York	24,795	23,952	39,584	44,026	44,026	65.26%	83.81%	83.81%	15.00%
NPCC-Ontario	21,901	21,172	29,420	29,420	29,420	38.95%	38.95%	38.95%	19.50%
NPCC-Québec	38,316	36,608	41,257	41,257	41,257	12.70%	12.70%	12.70%	11.60%
PJM	135,526	135,526	183,163	188,772	188,772	35.15%	39.29%	39.29%	15.70%
SERC-E	42,466	41,449	55,111	56,676	56,676	32.96%	36.74%	36.74%	15.00%
SERC-N	40,288	38,312	55,418	57,392	57,392	44.65%	49.80%	49.80%	15.00%
SERC-SE	44,692	44,634	60,637	60,982	60,984	35.85%	36.63%	36.63%	15.00%
SPP	36,702	35,642	65,224	65,631	65,817	83.00%	84.14%	84.66%	13.60%
TRE-ERCOT	53,719	52,057	78,277	82,765	82,767	50.37%	58.99%	58.99%	13.75%
WECC-CAMX	40,189	39,203	51,919	52,772	52,772	32.44%	34.61%	34.61%	11.00%
WECC-NWPP	70,778	70,453	82,304	83,217	83,246	16.82%	18.12%	18.16%	16.75%
WECC-RMRG	10,061	9,717	13,995	13,995	13,995	44.03%	44.03%	44.03%	14.98%
WECC-SWSG	15,650	15,314	30,572	30,735	30,848	99.63%	100.70%	101.44%	14.99%
Eastern Interconnection	538,350	521,171	745,485	767,920	768,312	43.04%	47.35%	47.42%	-
Québec Interconnection	38,316	36,608	41,257	41,257	41,257	12.70%	12.70%	12.70%	11.60%
ERCOT Interconnection	53,719	52,057	78,277	82,765	82,767	50.37%	58.99%	58.99%	13.75%
Western Interconnection	136,678	134,687	178,790	180,720	180,861	32.74%	34.18%	34.28%	-
TOTAL-NERC	**767,063**	**744,522**	**1,043,808**	**1,072,662**	**1,073,197**	**40.20%**	**44.07%**	**44.15%**	**-**

Demand, Resources, and Reserve Margins by Assessment Area: 2019 Summer

Assessment Area / Interconnection	Demand (MW)		Resources (MW)			Reserve Margins			Reference Margin Level
	Total Internal	Net Internal	Anticipated	Prospective	Adjusted-Potential	Anticipated	Prospective	Adjusted-Potential	
FRCC	49,852	46,479	57,312	59,874	59,874	23.31%	28.82%	28.82%	15.00%
MISO	133,470	128,679	142,852	151,121	151,917	11.01%	17.44%	18.06%	14.80%
MRO-Manitoba Hydro	3,482	3,238	4,549	4,786	4,786	40.47%	47.80%	47.80%	12.00%
MRO-MAPP	5,810	5,712	6,599	6,599	6,599	15.52%	15.52%	15.52%	15.00%
MRO-SaskPower	3,569	3,483	4,330	4,330	4,330	24.33%	24.33%	24.33%	11.00%
NPCC-Maritimes	3,455	3,114	5,659	5,956	5,956	81.73%	91.27%	91.27%	20.00%
NPCC-New England	27,782	26,788	31,529	32,463	32,463	17.70%	21.18%	21.18%	14.30%
NPCC-New York	35,454	34,265	37,985	43,228	43,228	10.86%	26.16%	26.16%	15.00%
NPCC-Ontario	22,272	21,576	26,630	26,630	26,630	23.42%	23.42%	23.42%	20.00%
NPCC-Québec	21,471	21,471	33,311	32,415	32,415	55.15%	50.97%	50.97%	15.00%
PJM	166,900	154,498	185,928	194,767	194,767	20.34%	26.06%	26.06%	15.70%
SERC-E	46,669	44,735	52,363	55,661	55,918	17.05%	24.42%	25.00%	15.00%
SERC-N	43,677	41,122	49,471	53,071	53,137	20.30%	29.06%	29.22%	15.00%
SERC-SE	50,124	47,909	62,978	63,274	63,540	31.45%	32.07%	32.63%	15.00%
SPP	52,849	51,523	65,394	65,951	66,366	26.92%	28.00%	28.81%	13.60%
TRE-ERCOT	72,859	70,942	78,760	84,972	85,251	11.02%	19.78%	20.17%	13.75%
WECC-CAMX	57,580	55,448	64,014	67,431	67,478	15.45%	21.61%	21.70%	15.02%
WECC-NWPP	71,799	70,973	82,492	84,361	84,774	16.23%	18.86%	19.45%	15.50%
WECC-RMRG	10,558	9,966	15,249	15,292	15,292	53.01%	53.44%	53.44%	13.20%
WECC-SWSG	24,335	23,958	28,991	29,258	29,443	21.01%	22.12%	22.89%	14.06%
Eastern Interconnection	645,365	613,122	733,577	767,711	769,510	19.65%	25.21%	25.51%	-
Québec Interconnection	21,471	21,471	33,311	32,415	32,415	55.15%	50.97%	50.97%	15.00%
ERCOT Interconnection	72,859	70,942	78,760	84,972	85,251	11.02%	19.78%	20.17%	13.75%
Western Interconnection	164,272	160,345	190,746	196,342	196,988	18.96%	22.45%	22.85%	
TOTAL-NERC	**903,967**	**865,880**	**1,036,394**	**1,081,441**	**1,084,163**	**19.69%**	**24.90%**	**25.21%**	**-**

Demand, Resources, and Reserve Margins by Assessment Area: 2019 Winter

Assessment Area / Interconnection	Demand (MW)		Resources (MW)			Reserve Margins			Reference Margin Level
	Total Internal	Net Internal	Anticipated	Prospective	Adjusted-Potential	Anticipated	Prospective	Adjusted-Potential	
FRCC	48,241	45,051	61,517	64,244	64,244	36.55%	42.60%	42.60%	15.00%
MISO	110,457	105,667	139,590	147,859	148,655	32.10%	39.93%	40.68%	14.80%
MRO-Manitoba Hydro	4,761	4,517	5,847	6,111	6,111	29.44%	35.28%	35.28%	12.00%
MRO-MAPP	6,311	5,911	7,079	7,079	7,079	19.76%	19.76%	19.76%	15.00%
MRO-SaskPower	3,957	3,871	4,737	4,737	4,737	22.36%	22.36%	22.36%	11.00%
NPCC-Maritimes	5,466	5,214	6,527	6,824	6,824	25.18%	30.88%	30.88%	20.00%
NPCC-New England	21,062	20,084	34,015	34,948	34,948	69.36%	74.01%	74.01%	14.30%
NPCC-New York	25,104	24,261	39,280	44,688	44,688	61.91%	84.20%	84.20%	15.00%
NPCC-Ontario	21,578	20,722	28,392	28,392	28,392	37.01%	37.01%	37.01%	20.00%
NPCC-Québec	39,567	37,565	43,637	43,637	43,637	16.16%	16.16%	16.16%	12.10%
PJM	139,975	139,975	185,928	194,768	194,768	32.83%	39.14%	39.14%	15.70%
SERC-E	44,186	43,102	56,881	58,446	58,716	31.97%	35.60%	36.22%	15.00%
SERC-N	41,955	39,428	53,054	56,844	56,911	34.56%	44.17%	44.34%	15.00%
SERC-SE	46,997	46,934	63,867	64,212	64,492	36.08%	36.81%	37.41%	15.00%
SPP	39,546	38,493	64,484	65,171	65,586	67.52%	69.30%	70.38%	13.60%
TRE-ERCOT	56,281	54,619	79,527	85,777	86,055	45.61%	57.05%	57.56%	13.75%
WECC-CAMX	40,636	39,520	49,913	53,177	53,216	26.30%	34.56%	34.66%	11.00%
WECC-NWPP	75,490	75,165	87,910	89,660	90,106	16.96%	19.28%	19.88%	16.75%
WECC-RMRG	10,584	10,241	13,265	13,306	13,306	29.53%	29.93%	29.93%	14.98%
WECC-SWSG	16,852	16,506	27,398	27,679	27,862	65.99%	67.69%	68.80%	14.99%
Eastern Interconnection	559,596	543,230	751,198	784,321	786,148	38.28%	44.38%	44.72%	-
Québec Interconnection	39,567	37,565	43,637	43,637	43,637	16.16%	16.16%	16.16%	12.10%
ERCOT Interconnection	56,281	54,619	79,527	85,777	86,055	45.61%	57.05%	57.56%	13.75%
Western Interconnection	143,562	141,432	178,486	183,822	184,490	26.20%	29.97%	30.44%	-
TOTAL-NERC	**799,005**	**776,845**	**1,052,848**	**1,097,557**	**1,100,331**	**35.53%**	**41.28%**	**41.64%**	**-**

Demand, Resources, and Reserve Margins by Assessment Area: 2024 Summer

Assessment Area / Interconnection	Demand (MW)		Resources (MW)			Reserve Margins			Reference Margin Level
	Total Internal	Net Internal	Anticipated	Prospective	Adjusted-Potential	Anticipated	Prospective	Adjusted-Potential	
FRCC	52,981	49,458	60,794	63,988	63,988	22.92%	29.38%	29.38%	15.00%
MISO	138,433	133,582	139,521	153,178	154,317	4.45%	14.67%	15.52%	14.80%
MRO-Manitoba Hydro	3,753	3,509	5,242	5,029	5,029	49.38%	43.32%	43.32%	12.00%
MRO-MAPP	6,427	6,319	6,661	6,661	6,661	5.41%	5.41%	5.41%	15.00%
MRO-SaskPower	3,735	3,649	4,349	4,349	4,349	19.21%	19.21%	19.21%	11.00%
NPCC-Maritimes	3,421	3,080	5,659	5,956	5,956	83.75%	93.39%	93.39%	20.00%
NPCC-New England	28,430	27,436	31,529	32,463	32,463	14.92%	18.32%	18.32%	14.30%
NPCC-New York	36,580	35,391	37,985	43,228	43,228	7.33%	22.14%	22.14%	15.00%
NPCC-Ontario	22,541	21,046	27,232	27,232	27,232	29.39%	29.39%	29.39%	20.00%
NPCC-Québec	22,557	22,557	33,770	32,874	32,874	49.71%	45.74%	45.74%	15.00%
PJM	173,729	161,327	187,498	196,338	196,338	16.22%	21.70%	21.70%	15.70%
SERC-E	49,943	47,937	52,702	56,000	56,577	9.94%	16.82%	18.02%	15.00%
SERC-N	45,797	42,692	48,547	53,078	53,222	13.71%	24.33%	24.67%	15.00%
SERC-SE	53,844	51,592	63,068	63,364	63,630	22.24%	22.82%	23.33%	15.00%
SPP	56,991	55,663	63,634	64,299	64,877	14.32%	15.51%	16.55%	13.60%
TRE-ERCOT	77,471	75,554	79,060	87,126	87,404	4.64%	15.32%	15.68%	13.75%
WECC-CAMX	58,930	56,541	64,106	68,285	68,387	13.38%	20.77%	20.95%	15.02%
WECC-NWPP	76,652	75,831	85,828	87,838	88,513	13.18%	15.83%	16.73%	15.50%
WECC-RMRG	11,249	10,616	12,028	12,070	12,073	13.30%	13.70%	13.73%	13.20%
WECC-SWSG	26,709	26,326	29,536	30,066	30,448	12.19%	14.21%	15.66%	14.06%
Eastern Interconnection	676,604	642,680	734,419	775,163	777,866	14.27%	20.61%	21.03%	-
Québec Interconnection	22,557	22,557	33,770	32,874	32,874	49.71%	45.74%	45.74%	15.00%
ERCOT Interconnection	77,471	75,554	79,060	87,126	87,404	4.64%	15.32%	15.68%	13.75%
Western Interconnection	173,540	169,314	191,497	198,259	199,422	13.10%	17.10%	17.78%	
TOTAL-NERC	**950,171**	**910,105**	**1,038,746**	**1,093,421**	**1,097,566**	**14.13%**	**20.14%**	**20.60%**	**-**

Demand, Resources, and Reserve Margins by Assessment Area: 2024 Winter

Assessment Area / Interconnection	Demand (MW)		Resources (MW)			Reserve Margins			Reference Margin Level
	Total Internal	Net Internal	Anticipated	Prospective	Adjusted-Potential	Anticipated	Prospective	Adjusted-Potential	
FRCC	50,584	47,295	65,420	68,866	68,866	38.32%	45.61%	45.61%	15.00%
MISO	115,031	110,180	136,310	149,967	151,106	23.72%	36.11%	37.14%	14.80%
MRO-Manitoba Hydro	5,136	4,892	6,365	6,179	6,179	30.11%	26.30%	26.30%	12.00%
MRO-MAPP	7,009	6,584	7,106	7,106	7,106	7.94%	7.94%	7.94%	15.00%
MRO-SaskPower	4,141	4,055	4,829	4,829	4,829	19.08%	19.08%	19.08%	11.00%
NPCC-Maritimes	5,427	5,176	6,527	6,824	6,824	26.11%	31.85%	31.85%	20.00%
NPCC-New England	20,790	19,812	34,015	34,015	34,015	71.69%	71.69%	71.69%	14.30%
NPCC-New York	25,537	24,694	39,280	42,566	42,566	59.07%	72.37%	72.37%	15.00%
NPCC-Ontario	21,628	19,972	29,208	29,208	29,208	46.25%	46.25%	46.25%	20.00%
NPCC-Québec	41,373	39,121	44,121	44,121	44,121	12.78%	12.78%	12.78%	12.10%
PJM	144,913	144,913	187,498	193,012	193,012	29.39%	33.19%	33.19%	15.70%
SERC-E	47,557	46,451	56,827	58,392	58,993	22.34%	25.71%	27.00%	15.00%
SERC-N	44,263	41,021	53,102	57,851	58,006	29.45%	41.03%	41.41%	15.00%
SERC-SE	50,399	50,331	66,238	66,583	66,863	31.61%	32.29%	32.85%	15.00%
SPP	42,064	41,011	62,956	63,146	63,724	53.51%	53.97%	55.38%	13.60%
TRE-ERCOT	60,480	58,818	79,827	83,013	83,292	35.72%	41.14%	41.61%	13.75%
WECC-CAMX	41,564	40,198	51,820	51,820	51,914	28.91%	28.91%	29.15%	11.00%
WECC-NWPP	79,912	79,587	93,002	93,002	93,661	16.86%	16.86%	17.68%	16.75%
WECC-RMRG	11,251	10,905	14,800	14,800	14,803	35.72%	35.72%	35.74%	14.98%
WECC-SWSG	18,439	18,090	28,329	28,329	28,697	56.60%	56.60%	58.63%	14.99%
Eastern Interconnection	584,478	566,387	755,681	788,543	791,296	33.42%	39.22%	39.71%	-
Québec Interconnection	41,373	39,121	44,121	44,121	44,121	12.78%	12.78%	12.78%	12.10%
ERCOT Interconnection	60,480	58,818	79,827	83,013	83,292	35.72%	41.14%	41.61%	13.75%
Western Interconnection	151,166	148,780	187,950	187,950	189,074	26.33%	26.33%	27.08%	-
TOTAL-NERC	**837,497**	**813,105**	**1,067,580**	**1,103,628**	**1,107,783**	**31.30%**	**35.73%**	**36.24%**	**-**

Projected Total Internal Demand by Assessment Area and Interconnection: 2015–2024 Summer

Assessment Area / Interconnection	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	10-Year CAGR
FRCC	46,719	47,615	48,501	49,147	49,852	50,554	51,263	52,049	52,981	52,981	1.41%
MISO	128,571	130,101	131,242	132,376	133,470	134,509	135,526	136,460	137,377	138,433	0.82%
MRO-Manitoba Hydro	3,434	3,483	3,424	3,446	3,482	3,555	3,610	3,655	3,703	3,753	0.99%
MRO-MAPP	5,028	5,374	5,500	5,690	5,810	5,927	6,038	6,145	6,257	6,427	2.77%
MRO-SaskPower	3,208	3,289	3,357	3,469	3,569	3,593	3,634	3,677	3,712	3,735	1.70%
NPCC-Maritimes	3,420	3,529	3,497	3,481	3,455	3,444	3,425	3,421	3,418	3,421	0.00%
NPCC-New England	26,930	27,291	27,521	27,677	27,782	27,911	28,028	28,167	28,298	28,430	0.60%
NPCC-New York	34,066	34,412	34,766	35,111	35,454	35,656	35,890	36,127	36,369	36,580	0.79%
NPCC-Ontario	22,726	22,535	22,344	22,301	22,272	22,170	22,479	22,609	22,616	22,541	-0.09%
NPCC-Québec	21,436	21,196	21,320	21,335	21,471	21,673	22,110	22,274	22,421	22,557	0.57%
PJM	160,259	162,470	164,195	165,479	166,900	168,593	170,027	171,217	172,542	173,729	0.90%
SERC-E	44,086	44,768	45,398	45,992	46,669	47,289	47,928	48,579	49,251	49,943	1.40%
SERC-N	42,100	42,571	42,917	43,298	43,677	44,018	44,470	44,908	45,359	45,797	0.94%
SERC-SE	47,116	48,137	48,931	49,427	50,124	51,135	51,563	52,292	53,046	53,844	1.49%
SPP	49,710	50,993	51,700	52,267	52,849	53,454	53,999	54,817	55,438	56,991	1.53%
TRE-ERCOT	69,057	70,014	70,871	71,806	72,859	73,784	74,710	75,631	76,550	77,471	1.29%
WECC-CAMX	57,606	56,767	57,004	57,245	57,580	58,003	58,257	58,542	58,742	58,930	0.25%
WECC-NWPP	66,283	67,733	69,233	70,674	71,799	72,745	73,586	74,390	75,364	76,652	1.63%
WECC-RMRG	9,899	10,100	10,239	10,410	10,558	10,709	10,843	10,901	11,046	11,249	1.43%
WECC-SWSG	22,635	22,760	23,282	23,762	24,335	24,707	25,113	25,694	26,193	26,709	1.86%
Eastern Interconnection	617,372	626,567	633,293	639,161	645,365	651,809	657,879	664,123	670,366	676,604	1.02%
Québec Interconnection	21,436	21,196	21,320	21,335	21,471	21,673	22,110	22,274	22,421	22,557	0.57%
ERCOT Interconnection	69,057	70,014	70,871	71,806	72,859	73,784	74,710	75,631	76,550	77,471	1.29%
Western Interconnection	156,423	157,360	159,758	162,092	164,272	166,165	167,798	169,527	171,345	173,540	1.16%
TOTAL-NERC	**864,288**	**875,137**	**885,242**	**894,393**	**903,967**	**913,430**	**922,497**	**931,555**	**940,682**	**950,171**	**1.06%**

Projected Total Internal Demand by Assessment Area and Interconnection: 2015–2024 Winter

Assessment Area / Interconnection	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	10-Year CAGR
FRCC	45,668	46,415	47,165	47,692	48,241	48,769	49,323	49,934	50,584	50,584	1.14%
MISO	104,414	107,352	108,414	109,506	110,457	111,360	112,219	113,053	113,797	115,031	1.08%
MRO-Manitoba Hydro	4,652	4,713	4,663	4,705	4,761	4,854	4,931	4,997	5,066	5,136	1.11%
MRO-MAPP	5,457	5,818	5,949	6,176	6,311	6,440	6,572	6,702	6,832	7,009	2.82%
MRO-SaskPower	3,557	3,647	3,722	3,846	3,957	3,984	4,029	4,077	4,116	4,141	1.70%
NPCC-Maritimes	5,477	5,513	5,508	5,493	5,466	5,434	5,421	5,420	5,425	5,427	-0.10%
NPCC-New England	22,755	21,274	21,238	21,153	21,062	20,986	20,918	20,865	20,822	20,790	-1.00%
NPCC-New York	24,795	24,856	24,906	24,966	25,104	25,177	25,252	25,334	25,427	25,537	0.33%
NPCC-Ontario	21,901	21,901	21,529	21,592	21,578	21,535	21,646	21,541	21,508	21,628	-0.14%
NPCC-Québec	38,316	38,612	38,847	39,168	39,567	40,218	40,558	40,862	41,120	41,373	0.86%
PJM	135,526	137,308	138,314	139,213	139,975	141,369	142,489	143,481	144,359	144,913	0.75%
SERC-E	42,466	42,560	42,907	43,476	44,186	44,858	45,603	46,300	46,847	47,557	1.27%
SERC-N	40,288	41,022	41,348	41,639	41,955	42,419	42,902	43,322	43,642	44,263	1.05%
SERC-SE	44,692	45,292	45,946	46,332	46,997	47,635	48,300	48,996	49,679	50,399	1.34%
SPP	36,702	38,123	38,549	39,181	39,546	40,062	40,664	41,141	41,639	42,064	1.53%
TRE-ERCOT	53,719	53,719	54,579	55,441	56,281	57,116	57,962	58,804	59,643	60,480	1.33%
WECC-CAMX	40,189	40,227	40,292	40,432	40,636	40,946	41,209	41,424	41,515	41,564	0.37%
WECC-NWPP	70,778	71,786	73,217	74,430	75,490	76,482	77,422	78,320	79,189	79,912	1.36%
WECC-RMRG	10,061	10,205	10,355	10,466	10,584	10,724	10,863	10,994	11,121	11,251	1.25%
WECC-SWSG	15,650	15,862	16,138	16,443	16,852	17,190	17,492	17,814	18,156	18,439	1.84%
Eastern Interconnection	538,350	545,794	550,157	554,970	559,596	564,883	570,270	575,163	579,742	584,478	0.92%
Québec Interconnection	38,316	38,612	38,847	39,168	39,567	40,218	40,558	40,862	41,120	41,373	0.86%
ERCOT Interconnection	53,719	53,719	54,579	55,441	56,281	57,116	57,962	58,804	59,643	60,480	1.33%
Western Interconnection	136,678	138,080	140,002	141,771	143,562	145,341	146,986	148,551	149,981	151,166	1.13%
TOTAL-NERC	**767,063**	**776,205**	**783,586**	**791,350**	**799,005**	**807,558**	**815,776**	**823,381**	**830,486**	**837,497**	**0.98%**

Projected Transmission Additions by Assessment Area and Interconnection: 2014–2024

Assessment Area/ Interconnection	Under Construction	10-Year Planned	10-Year Conceptual
FRCC	67	513	20
MISO	1,489	4,525	0
MRO-Manitoba Hydro	1,908	301	0
MRO-MAPP	379	201	102
MRO-SaskPower	0	663	220
NPCC-Maritimes	0	201	50
NPCC-New England	234	164	261
NPCC-New York	0	1,217	343
NPCC-Ontario	0	0	240
NPCC-Québec	266	689	199
PJM	740	1,694	584
SERC-E	421	139	0
SERC-N	45	202	190
SERC-SE	175	434	12
SPP	1,171	2,006	176
TRE-ERCOT	85	682	426
WECC-CAMX	288	652	1,307
WECC-NWPP	12	4,652	1,343
WECC-RMRG	2	562	1,169
WECC-SRSG	172	1,125	719
EASTERN INTERCONNECTION	6,629	12,260	2,198
QUÉBEC INTERCONNECTION	266	689	199
TEXAS INTERCONNECTION	85	682	426
WESTERN INTERCONNECTION	475	6,992	4,538
TOTAL-NERC	**7,454**	**20,622**	**7,360**

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 Interruptible Demand	Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment. (NERC Glossary of Terms)
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 50 percent of 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 percent Reference Margin Level for predominately thermal systems and 10 percent 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: 2014 Polar Vortex Scenario Analysis

Overview

The 2014 polar vortex involved extended periods of extreme cold weather from January 6–8, 2014, in several parts of North America, presenting challenges for System Operators in both the Eastern and Texas Interconnections. During the event, the BPS was stressed with high periods of demand, establishing new records for several areas. Concurrently, an increased number of units experienced forced outages amounting to over 10,000 MW, resulting in the use of emergency operating procedures and calling DR programs in several areas. Despite these extreme conditions, the BPS remained stable and generally performed reliably throughout the duration of the event, primarily because of preparation efforts prior to the cold snap. Specifically, generator owners took preemptive steps to prepare equipment for the freezing temperatures. These steps included: cancelling scheduled generator outages, installing additional insulation, and testing dual-fuel capabilities. Similarly, System Operators coordinated with neighboring areas to ensure resource availability and share other pertinent information.

Subsequent to a thorough review of the event, NERC released the *Polar Vortex Review* report in September 2014, based on data and information provided from the NERC Generator Availability Data System (GADS), as well as supplemental support from the impacted Assessment Areas. According to these data, it was concluded that forced outages during the event were primarily caused by the following:

1. Inoperable equipment in extreme low temperatures,
2. Unavailability of fuel at generating units (due to supply or transportation or a combination of both), and
3. Challenges for some dual-fuel capable units in switching from a primary to a secondary fuel.

Colder temperatures contributed to higher electricity demand while also increasing the demand for natural gas used for residential heating in some parts of North America. These conditions stressed the ability of pipeline operators and suppliers to deliver natural gas to the power sector, which resulted in a significant amount of gas-fired generation being unavailable due to gas curtailments. This was particularly relevant considering that gas-fired units accounted for approximately 40 percent of the generation mix during the 2014 polar vortex. Accordingly, natural-gas-fired units were also the most impacted compared to other generators, representing over 55 percent of all forced outages during the event.

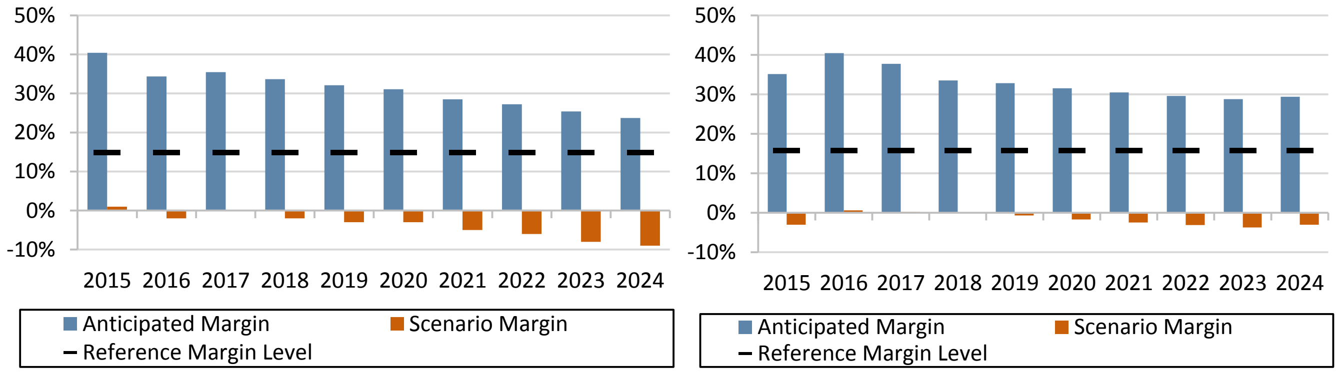
Scenario Assumptions and Results

In addition to the *Polar Vortex Review*, NERC staff also conducted scenarios for MISO, PJM, SERC-E, and TRE-ERCOT. Each of these Assessment Areas experienced high forced outage rates during the event. NERC's scenario assumptions involved applying these actual forced outage rates as derates to existing and projected (Tier 1) capacity data from the 2014LTRA reference case. Similarly, projected load was assumed to be consistent with the extreme loads during the event.

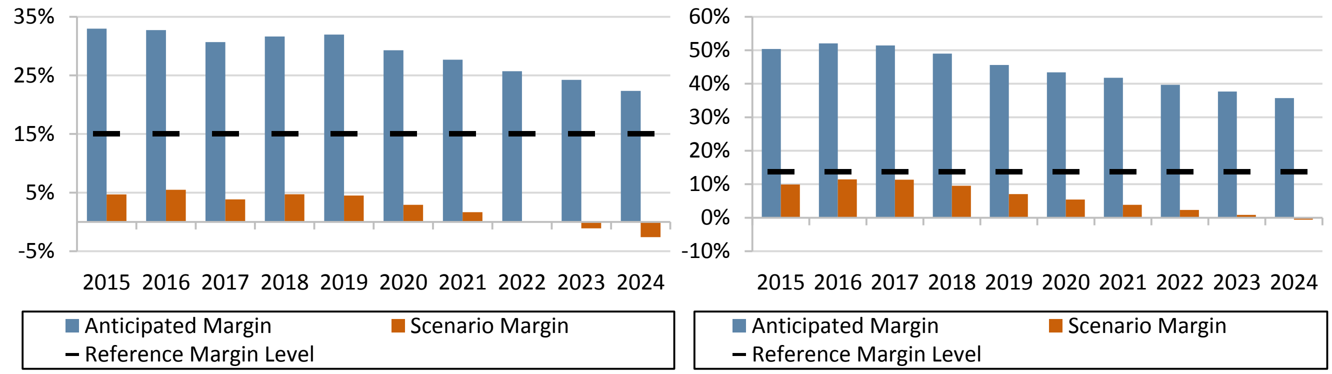
Fuel Derates and Net Internal Demand Assumptions (Based on Actual Forced Outages and Demand)

	Applied Derate							
Assessment Area	Coal	Petroleum	Natural Gas	Nuclear	Wind	Solar	Other Generation	Assumed Net Internal Demand
MISO	15%	10%	30%	0%	100%	100%	0%	110%
PJM	30%	10%	20%	20%	100%	100%	0%	105%
SERC-E	0%	0%	0%	0%	100%	100%	0%	118%
TRE-ERCOT	15%	0%	25%	0%	100%	100%	0%	110%

MISO (Right) and PJM (Left)



SERC-E (Right) and TRE-ERCOT (Left)



Scenario Observations

This analysis demonstrates that a repeated extreme weather event with conditions similar to those observed during the 2014 polar vortex would result in inadequate Anticipated Resources, based on the 2014LTRA reference case. This highlights the need for system planners to more strongly consider generator performance during extreme weather events, particularly for natural-gas-fired units.

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