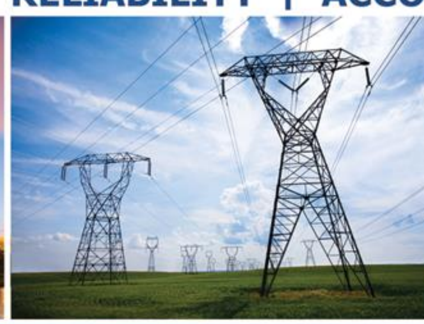
NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2013 Long-Term Reliability Assessment

December 2013

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) of North America.[1,2] NERC operates under similar obligations in many Canadian provinces, as well as a portion of Baja California Norte, Mexico.

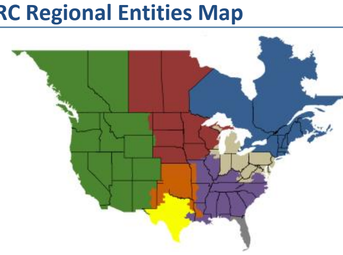
NERC is an international regulatory authority established to evaluate and improve the reliability of the BPS in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term (10-year) reliability; monitors the BPS through system awareness; and educates, trains, 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.[3]

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.

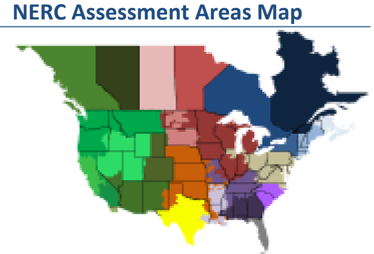
NERC Regional Entities

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

NERC Regional Entities Map



NERC Assessment Areas Map



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 26 assessment areas, both within and across the eight Regional Entity boundaries, as shown in the corresponding table and maps above.[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

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[1] H.R. 6 as approved by of the One Hundred Ninth Congress of the United States, the Energy Policy Act of 2005.

[2] 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.

[3] 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.

[4] Maps created using Ventyx Velocity Suite.

information from each NERC Region is 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.

Assessment Preparation and Design

The *2013 Long-Term Reliability Assessment* (*2013LTRA*) is published by NERC in accordance with Title 18, § 39.11[5] of the Code of Federal Regulations,[6] also referred to as Section 215 of the Federal Power Act, which instructs NERC to conduct periodic assessments of the BPS. Section 803 of NERC's Rules of Procedure[7] further describes NERC's obligation to develop annual long-term reports with a 10-year planning horizon.

This report provides an independent assessment of the 10-year[8] reliability outlook for the North American BPS[9] while identifying trends, emerging issues, and potential risks. Additional insight will be offered regarding resource adequacy, security, and operating reliability, as well as an overview of projected electricity demand growth for individual assessment areas.

NERC prepared the 2013 LTRA with support from the Reliability Assessment Subcommittee (RAS) under the direction of the NERC Planning Committee (PC). This report is based on data and information submitted by each of the eight Regional Entities, which are represented on the RAS. Initial data and information were submitted in June 2013, and periodic updates occurred throughout the development of the report. Any other data sources included by NERC staff are identified accordingly. Additional inquiries regarding the information, data, and analysis in this assessment may be directed to:

Table I: North American Electric Reliability Staff

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NERC uses a RAS peer review process to prepare both seasonal and long-term reliability assessments. This process allows NERC to leverage the knowledge and experience of subject matter experts who represent NERC Regions and the electricity industry at large. It also provides an essential balance that ensures the validity of data and information provided by the Regional Entities. Each assessment area's section is assigned to subcommittee members from other Regions to encourage a comprehensive review that is discussed and verified by the RAS in open meetings. The review process gives all RAS members the opportunity to verify that each Regional Entity produces quality assessments that are accurate and complete. The Planning Committee (PC) members reviewed this assessment and fully vet all findings and conclusions. Prior to release, NERC submits the assessment to the Board of Trustees (Board) for final review and approval.

[5] 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."

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

[7] NERC Rules of Procedure.

[8] The 10-year period observed in this assessment is from 2014 to 2023, with the 2014 summer as the initial season. Information and data for the 2013 summer and 2013–2014 winter seasons are provided in NERC's seasonal reliability assessments: NERC Seasonal Reliability Assessments.

[9] 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.

Table II: Assessment Structure

Section	Description
Long-Term Projections and Highlights	Includes data highlights identified from the *2013LTRA* reference case, including projections for Planning Reserve Margins, demand, Demand-Side resources, generation, and transmission.
Projected Demand, Resources, and Reserve Margins	Detailed tables including Total Internal Demand, Net Internal Demand, Anticipated, Prospective, and Adjusted-Potential Resources and Reserve Margins, and the NERC Reference Margin Level for each assessment area (years 2014, 2018, 2023).
Long-Term Reliability Challenges and Emerging Issues	Provides an assessment of emerging BPS reliability risks and NERC recommendations. Supports the development of scenarios—the analysis of which can indicate the sensitivity of the *2013LTRA* reference case to changes in prespecified conditions and provide insight into the risks to regional reliability. Emerging reliability issues are generally known or unknown risks NERC and its stakeholders have endorsed for assessment. Continued understanding of potential impacts to the BPS, the likelihood of those impacts, and regional implications are important characteristics to NERC's reliability assessment process.
Assessment Area Sections	Includes summary tables and corresponding text that provide a more comprehensive and granular reliability outlook for each assessment area.

Table III: Reliability Concepts

The concept of reliability is generally applied as the ability of the BPS to meet the electricity needs of end-use customers at all times. Reliability can be further understood by 'unbundling' the concept into three essential categories:	
Operating Reliability	For decades, NERC and the bulk power industry defined system security as the operating aspects that enable the BPS to withstand sudden, unexpected disturbances, such as short circuits or unanticipated loss of system elements due to natural causes. In today's world, the security focus of NERC and the industry has expanded to include withstanding disturbances caused by man-made physical or cyber attacks. The bulk power system must be planned, designed, built and operated in a manner that takes into account these modern threats, as well as more traditional risks to security.
Adequacy	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 account for scheduled and reasonably expected unscheduled outages of equipment, while maintaining a constant balance between supply and demand.
Fuel Security	Associated with both adequacy and operational reliability, access to reliable fuel supplies for generation must be maintained in the presence of ongoing changes to market structures, supply routes, and deliverability challenges.
These categories are interrelated and must all be considered to promote existing and future reliability. For example: the adequacy of a system can be threatened by fuel security challenges when there is an increased reliance on a single fuel source that may lack resilient deliverability channels. While the system may appear to have adequate resources, reliability can still be impacted if fuel security concerns are not identified and mitigated.	

Table IV: *2013LTRA* Reference Case Data Assumptions

Data Term	Assumptions
Peak demand (load) projections	Load projections are based on a noncoincident 50/50 peak demand forecast, unless otherwise noted. Values represent the baseline values for each season, each with a range of possible outcomes based on probabilities around the baseline or midpoint. Projections are provided on an assessment area basis and are highly dependent on the data, methodologies, model structures, and other assumptions that often vary by Region, Reliability Coordinator, assessment area, or Balancing Authority.[10]
Capacity	"Capacity" refers to the on-peak capacity available during the hour of peak demand for the peak season of each year. All generating and transmission equipment availability is based on historic performance, unless otherwise noted. For variable resources, capacity refers to the expected on-peak power contributions, unless otherwise denoted as

[10] Additional information on the methods and assumption used by each assessment area are available through the following link: NERC Reliability Assessments.

	"nameplate" capacity.
Demand-Side Management	All categories of DR will be available at the time of peak demand. Other Demand-Side Management programs, such as conservation, Energy Efficiency, and price-responsive DR, are incorporated into the Net Internal Demand projections.
Capacity Transactions	Firm or expected [firm] capacity transactions (transfers) between assessment areas are assumed to be available during the peak according to contractual arrangements.
General	The summer season represents June–September and the winter season represents December–February. Data updates are included until the entire assessment is submitted to the NERC Board of Trustees. Any subsequent revisions or corrections may not be included or otherwise represented in this assessment. Planned outages, additions, and upgrades of generation and transmission in the *2013LTRA* reference case will be completed as scheduled. Existing federal, state, and provincial laws and regulations in effect at the time of data and information collection are assumed throughout the 10-year period.

Table V: Demand Terms

Total Internal Demand	The sum of the metered (net) outputs of all generators within the system and the metered line flows into the system, less the metered line flows out of the system (forecast). Total Internal Demand includes adjustments conservation and Energy Efficiency programs, improvements in efficiency of electricity use, and all nondispatchable DR programs.
Net Internal Demand	Total Internal Demand less Dispatchable, Controllable Capacity Demand Response used to reduce peak load.

Table VI: Resource Terms

Anticipated Resources	Includes Existing-Certain, Future-Planned, Net Firm Capacity Transactions, and Supply-Side Demand Response.
Existing-Certain	This category includes generation resources available to operate and deliver power within or into the assessment area during the period of peak demand. Resources included in this category may be reported as a portion of the full capability of the resource, plant, or unit. This category includes, but is not limited to the following: (1) contracted (or firm) or other similar resource confirmed able to serve load during peak demand; (2) where organized markets exist, designated market resource that is eligible to bid into a market or has been designated as a firm network resource; (3) Network Resource, as that term is used for FERC pro forma or other regulatory-approved tariffs; (4) Energy-Only resources confirmed able to serve load during peak demand and will not be curtailed; (5) capacity resources that cannot be sold elsewhere; (6) other resources not included in the above categories that have been confirmed able to serve load and not to be curtailed during peak demand.
Future-Planned	This category includes generation resources anticipated to be available to operate and deliver power within or into the assessment area during the period of peak demand. This category includes, but is not limited to the following: (1) contracted (or firm) or other similar resource; (2) where organized markets exist, designated market resource that is eligible to bid into a market or has been designated as a firm network resource; (3) Network Resource, as that term is used for FERC pro forma or other regulatory approved tariffs; (4) Energy-Only resources confirmed able to serve load during the peak and not subject to curtailment; (5) where applicable, included in an integrated resource plan under a regulatory environment that mandates resource adequacy requirements and the obligation to serve.
Net Firm Capacity Transactions	Firm imports minus firm exports; a contract must be in place for the assessment period.
Supply-Side Demand Response	Includes all categories of DR treated as a resource.
Prospective Resources	Includes Anticipated Resources, plus Existing-Other, Future-Other, and Expected Capacity Transactions.
Existing-Other	This category includes generation resources that may be available to operate and deliver power within or into the assessment area during the period of peak demand but that may be curtailed or interrupted at any time for various reasons. This category includes, but is not limited to the following: (1) a resource with nonfirm or other similar transmission arrangements; (2) Energy-Only resources that have been confirmed able to serve load for any reason during the reporting period, but may be curtailed for any reason; (3) mothballed generation (that may be returned to service during peak demand); (4) generation resources constrained for other reasons.
Future-Other	This category includes all generation resources that do not qualify as Future-Planned or Conceptual Energy-Only resources. This category includes, but is not limited to the following: (1) a resource that may be curtailed or interrupted at any time for any reason; (2) Energy-Only resources that may be able to serve load during the peak.
Expected	Expected imports minus Expected exports; Expected transactions are nonfirm transactions with a reasonable

Transactions	expectation of being implemented.
Adjusted-Potential Resources	Includes Prospective Resources, plus Conceptual Resources after the application of a confidence factor by each assessment area.
Conceptual	This category includes future generation resources that do not meet the parameters defined for Future-Planned or Future-Other resources. Conceptual resources include those that have been identified or announced on a resource planning basis through one or more of the following: (1) corporate announcement; (2) in the early stages of an approval process; (3) included in a generator interconnection (or other) queue or study; (4) a "place-holder" generation for use in modeling.

Table VII: Reserve Margins

Anticipated Reserve Margin	$\frac{\text{(Anticipated Resources – Net Internal Demand)}}{\text{Net Internal Demand}}$
Prospective Reserve Margin	$\frac{\text{(Prospective Resources – Net Internal Demand)}}{\text{Net Internal Demand}}$
Adjusted-Potential Reserve Margin	$\frac{\text{(Adjusted-Potential Resources – Net Internal Demand)}}{\text{Net Internal Demand}}$

Table VIII: Reference Materials

Document	Description
Previous Long-Term Reliability Assessments	Electronic versions of the 1991 through current Long-Term Reliability Assessments
2013 Long-Term Reliability Assessment Request	The annual data and information request requiring response and completion by each Regional Entity
Electricity Supply and Demand (ES&D) Database	NERC collects, maintains, and annually publishes the ES&D, which includes data on the 10-year projections used to develop this report.
Assessment Area Part II Methods & Assumptions	The Methods and Assumptions document provides details on how the Regions conduct reliability assessments, develop associated criteria, and evaluate regional reliability.
Emerging Reliability Issues Survey	Summary data on the information collected as part of the 2013 Emerging Reliability Issues survey.
Probabilistic Assessments	A biennial report that supplements the Long-Term Reliability Assessment's deterministic reserve margin assessment with probabilistic indices for each assessment area.
Reliability Assessment Guidebook	The Guidebook is a reference for Regional Entities and registered entities to use to clarify current reliability assessment practices and objectives. The intent is to document practices and provide comprehensive reliability assessments.
Special Assessments	NERC performs special assessments based on findings in the long-term reliability assessments. NERC has written numerous special assessments that provide technical insight to emerging reliability challenges.
Reliability Assessment Subcommittee (RAS) Website	The RAS reviews, assesses, and reports on the overall reliability (adequacy and security) of bulk power systems, both existing and as planned. Those reviews and assessments verify that each assessment area conforms to its own planning criteria, guides, and the applicable NERC Reliability Standards.
Planning Committee (PC) Website	The PC supports the NERC reliability mission by executing the policies, directives, and assignments of the Board and by advising industry on matters related to BPS transmission planning and reliability and resource adequacy.

Executive Summary

In preparing this assessment, NERC evaluated key reliability indicators, including peak demand and energy forecasts, resource adequacy, transmission development, changes in overall system characteristics and operating behavior, and other external or regulatory issues that may impact the reliability of the BPS.

The electricity industry has prepared plans for the 2014–2023 assessment period in an effort to provide reliable electric service across North America. In some assessment areas, NERC has identified certain evolving issues that may potentially affect the reliability of the BPS. Over the next 10 years, the electric industry will face a number of significant emerging reliability issues, which are explained in detail throughout this report. These issues will change the industry, requiring better modeling and risk management and increasing the reliance on natural gas, renewable resources, and a more robust infrastructure. Each of these elements of change is critically interdependent, and industry action must be closely coordinated to ensure reliability.

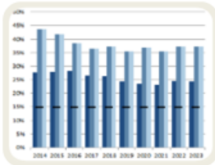
Impacts to long-term BPS reliability are categorized and assessed within three overarching risk areas:

1. **Resource and Transmission Adequacy**
   Resource and transmission adequacy risks can impact the projected ability of BPS infrastructure to serve customer demand during all hours over a specified horizon. Uncertainty in resource and transmission needs is driven by market and environmental regulations, customer demand, and impediments to constructing facilities within a needed time frame.
2. **Integration of New Technologies and Operations**
   The integration of new technologies can introduce potential future operational risks to the BPS. Resources or new technologies with unique operating characteristics require a level of enhanced understanding beyond traditional capacity and energy planning. Integrating these technologies without fully understanding their impacts can threaten real-time operations as well as the system's ability to withstand disturbances.
3. **Long-Term System Planning and Modeling**
   The approach and methods used for long-term planning and modeling, including potential inadequate assumptions, models, data, and methods, can lead to incorrect decision making and introduce risks to the BPS. Therefore, model and analysis inputs need to be accurate and enhanced to reflect a rapidly evolving range of future transmission and resource challenges.

The electric industry is becoming more complex due to political and societal drivers propelling new policies, such as a carbon-reduced resource portfolio. This assessment presents the contributing factors identified in the *2013LTRA* reference case and highlights potential reliability challenges and emerging issues. Each issue is ultimately related to the three overarching risk areas identified above.

Key Findings and Recommendations

The evolving operation of the BPS will require new operational tools and procedures that, in order to be implemented without adverse impacts to system reliability, will require careful consideration, preparation, and planning. Issues and challenges related to resource and transmission adequacy, integration of new technologies, and long-term system planning and modeling are highlighted in this assessment. While some of these challenges are more regional than others, their cumulative impacts can affect planning and operating fundamentals that can extend to the entire interconnection. Accordingly, NERC's stakeholder and subject matter expert committees evaluated six issues that NERC identified would be most impactful over the next 10 years and developed a comprehensive risk assessment. The six issues are summarized with corresponding recommendations below:



1. Resource Adequacy Assessments in TRE-ERCOT and MISO Fall Below Planning Reserve Margin Targets

TRE-ERCOT remains below the target throughout the 10-year period. MISO will fall below targets during the 2015 summer season. If resources do not come on-line, an increased likelihood of firm load shedding is possible.

Recommendation(s)

1-1 Heightened awareness required: NERC should increase its coordination with the Texas Reliability Entity (TRE), Electric Reliability Council of Texas (ERCOT), and state regulators and legislators to support active and planned measures to address the continuing challenges in meeting reserve margin targets. NERC should work with the relevant oversight entities to identify effective measures that would reverse the trend of declining reserve margins.

1-2 Initiate focused assessment: With respect to similar declining reserve margin trends within MISO, NERC should develop a more granular and near-term assessment of the resource adequacy conditions in the MISO assessment area. Furthermore, NERC should closely monitor and continuously evaluate the measures being taken in MISO to address the evolving resource adequacy challenges.

2. High Levels of Variable Generation May Present Operational and Planning Challenges

Reliably integrating high levels of variable resources (wind, solar, and some forms of hydro) into the North American BPS will require significant changes to traditional methods used for system planning and operation. Over 46 GW of wind and solar installed capacity is planned over the 10-year period.

Recommendation(s)

2-1 Expand NERC methodology for reliability assessment: NERC should develop a new approach and framework for the long-term assessment of essential reliability services to supplement existing resource adequacy assessments. The new approach may include the development of metrics for further evaluation in future long-term reliability assessments.

2-2 Develop primer on essential reliability services: NERC should develop a technical reference document on essential reliability services, which include frequency response, inertia, voltage stability, ramping capability, and other operational requirements needed to ensure BPS reliability. The primer can be used as a reference manual for regulators and policy makers and to inform, educate, and build awareness on the reliability ramifications of a changing resource mix.

2-3 Initiate focused assessment: Similar to its collaborative work with the California Independent System Operator, NERC should conduct a comprehensive assessment of essential reliability services for areas and systems approaching 20 or more percent variable resources over the next 10 years. Additionally, the focused assessments should identify the measures and initiatives needed to ensure the continued provision of these services.

2-4 Active engagement with IEEE: NERC strongly encourages industry to proactively address potential BPS reliability impacts associated with large amounts of aggregated distributed and variable energy resources (VERs). This initiative includes encouraging the IEEE 1547 stakeholder group to consider BPS reliability in its standards development process.

3. Fossil-Fired Retirements and Coordination of Outages for Environmental Control Retrofits Continue to Present Challenges

Capacity retirements are projected to surpass 85 GW by 2023. Since 2011, approximately 25 GW of fossil-fired generation have retired. Largely in response to the confluence of final and potential environmental regulations, low natural gas prices, and other economic factors, this trend is expected to continue through the 10-year period.

Recommendation(s)

3-1 Probabilistic insights needed: NERC should monitor retirements and emerging reliability issues—including local reliability effects—stemming from significant generator retirements. Additional insight on impacts from unit retirements will be provided in 2014 as a result of NERC's biennial probabilistic resource adequacy assessment.

3-2 Reliability signals must reflect system needs: Regional wholesale competitive market operators should ensure markets are functioning effectively and can support the development of new replacement capacity where needed. Reliability signals that are representative of BPS risks are essential for informing the market of a specific need (e.g., capacity, energy, and ancillary services).

3-3 Initiate focused assessment: In light of emerging and proposed environmental regulations, NERC should revisit its *2010 Special Reliability Assessment: Reliability Impacts of Climate Change Initiatives* report and reassess the emerging reliability impacts.

4. Continued Increases in Natural Gas-Fired Generation May Require Enhancements to Planning and Operations

Over 28 GW of gas-fired capacity are planned over the next 10 years (an additional 108 GW are considered Conceptual). The growing dependence on this resource is creating the need for additional planning and operational coordination to prevent or mitigate potential natural gas supply and transportation issues.

Recommendation(s)

4-1 Monitor high-risk regions: Through its reliability assessments, NERC should closely monitor resource availability and operational impacts in New England and other areas of North America that are quickly integrating large amounts of natural gas-fired generation.

4-2 Expand coordination with study groups: NERC should expand its coordination with regional and interregional study groups, as well as the natural gas industry, to further assess BPS reliability needs. Regional and interregional studies are focusing on the long-term needs of natural gas transportation for electric power. These efforts may provide better insight on the system planning and operating measures being taken to address an increasing dependency on natural gas.

4-3 Fulfill outstanding recommendations: NERC, the industry, and policy makers should continue addressing the recommendations included in the *2013 Special Reliability Assessment: Impacts of Increased Natural Gas for Electric Power*.

5. Increased Use of Demand-Side Management (DSM) Creates More Uncertainty for System Planners and Operators

Increases in DSM offset future capacity needs but also create additional uncertainty for system planners. These uncertainties include performance and availability, as well as long-term, sustained participation in Demand Response programs.

Recommendation(s)

5-1 Enhance performance analysis: NERC should leverage the Demand Response Availability Data System (DADS) data to identify availability and performance trends that may indicate future BPS risks. These findings should be reported in the annual *State of Reliability* report.

5-2 Evaluate the need for requirements or guidelines: NERC should determine whether requirements or guidelines are needed to support Demand Response planning and operations, specifically Demand Response that is relied on to meet bulk system reliability requirements. The Planning and Operating Committees should provide joint technical support to the Standards Committee on any reliability issues that should be considered during the development of NERC Reliability Standards.

6. Nuclear Generation Retirements and Long-Term Outages Reduce Flexibility and Present Potential Reliability Challenges

Since 2011, five plants totaling 4.2 GW have retired or announced decommission plans. NERC's concerns about the aging nuclear fleet have increased as several other plants are facing relicensing requirements in the near term and the potential for further retirements may exist.

Recommendation(s)

6-1 Prioritize through risk evaluation: NERC should consider developing a sensitivity study of the potential reliability impacts of accelerated nuclear plant retirements or shutdowns in the near future.

While these key findings are presented independently, they are cross-cutting, and interdependencies between many of the issues present unique challenges to the electricity industry. Growth in flexible resources such as Demand Response and quick-start natural gas-powered generators is an encouraging trend, as are transmission plans to integrate renewable resources distant from load centers. However, evolving risks, such as the increased dependency on natural gas, increasing amounts of variable generation, and the potential reduction of overall system inertia, must be considered in the development of future planning and operating strategies. These risks must be strategically monitored and mitigated in order to preserve the reliability of the BPS. NERC's annual long-term reliability assessment provides the basis for understanding these risks and, more importantly, how these interdependent challenges require ERO-wide coordination to be effectively addressed.

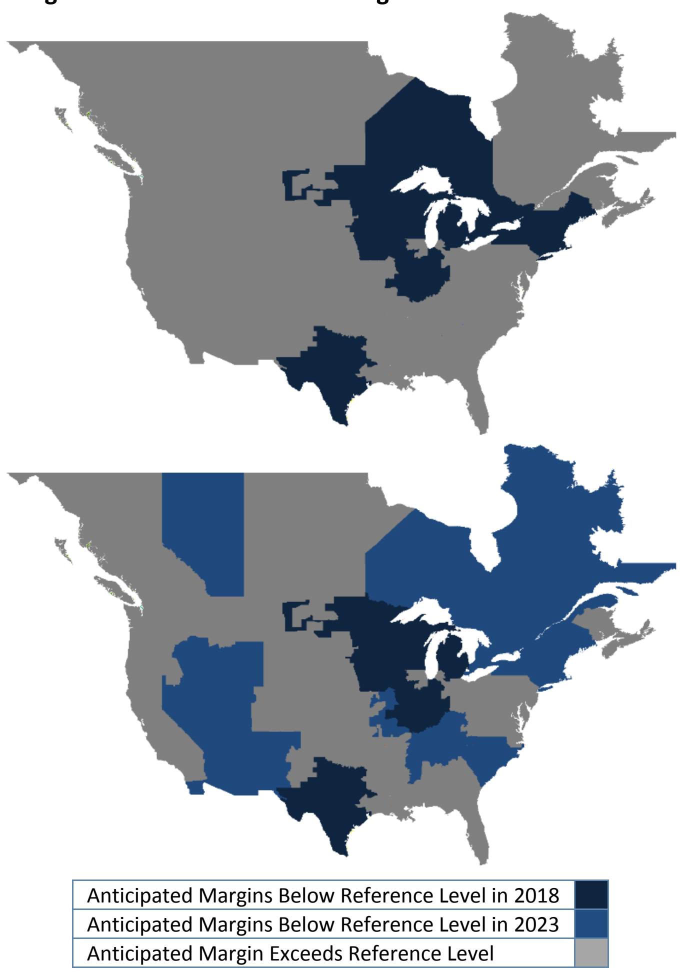
Long-Term Projections and Highlights

This section presents the key data findings of the *2013LTRA* reference case for projected demand (Total Internal Demand and Net Internal Demand), DR, generation, transmission projections, and Planning Reserve Margins (Anticipated, Prospective, and Adjusted-Potential). Projections are presented on an assessment area basis for the summer and winter seasons between 2014 and 2023.

Reserve Margins

Based on the *2013LTRA* reference case, the Anticipated Planning Reserve Margins for 13 of the 26 NERC assessment areas will remain above the NERC Reference Margin Levels throughout the 10-year period.[11] With the inclusion of less-certain resources, such as Conceptual capacity and nonfirm capacity transactions, the Adjusted-Potential Margin falls below the NERC Reference Margin Level for only three areas.

Figure 1: Anticipated Reserve Margins below the Reference Margin in 2018 and 2023



[11] The NERC Reference Margin Level for each assessment area is assigned according to the reserve requirement (or target), as established by the corresponding public utility commission, NERC Region, ISO/RTO, or provincial authority. Absent a provided reserve requirement, NERC assigns a 15-percent margin for predominately thermal systems and a 10-percent margin for predominately hydro systems.

Figure 2: 2018 Peak Planning Reserve Margins[12]

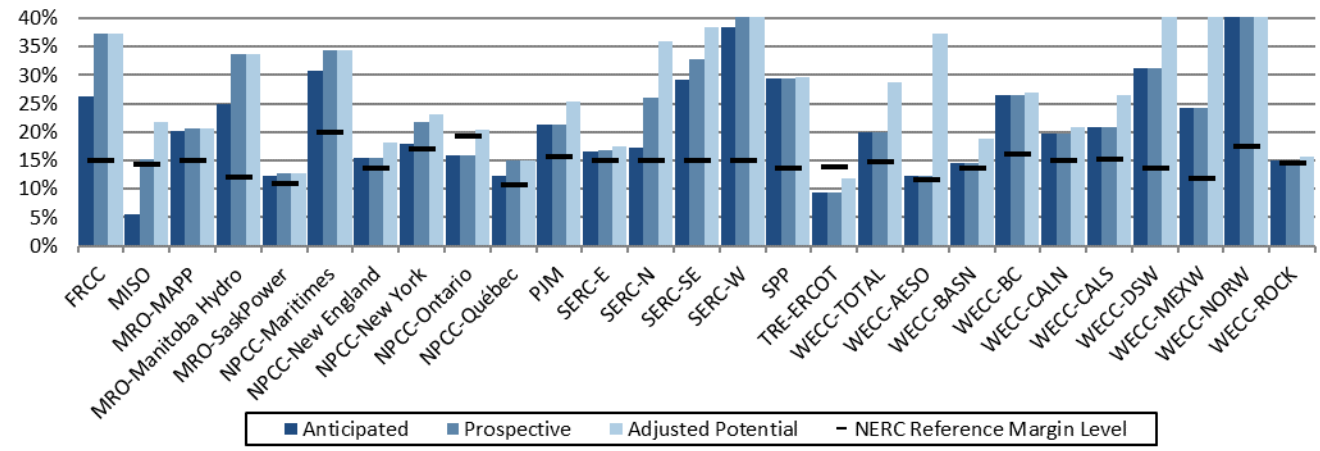
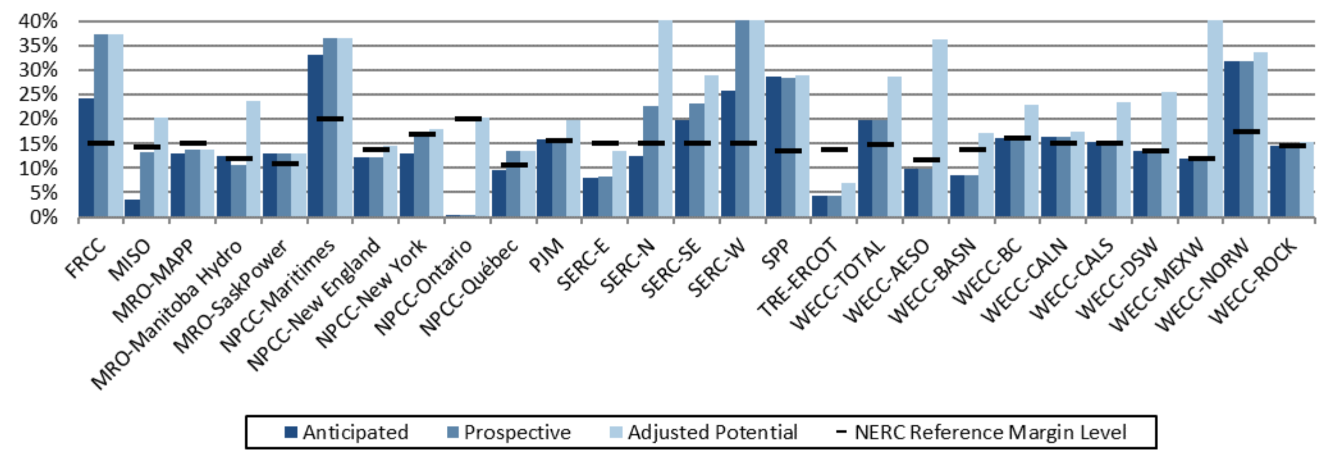


Figure 3: 2023 Peak Planning Reserve Margins[13]



When examining the latter half of the assessment period (2018–2023), it is important to understand NERC's Planning Reserve Margin assumptions, which are based on industry's long-term resource adequacy plans at the time the data and information was submitted to NERC. The assessment areas of most concern are ERCOT and MISO, as their Anticipated Margins fall below the NERC Reference Margin Level in the summer seasons of 2014 and 2015, respectively. These concerns are discussed in greater detail in the next section.

In the summer season of 2018, the NPCC-Ontario Anticipated Margin falls below the NERC Reference Margin Level. In addition to the shorter-term resource adequacy challenges in ERCOT and MISO, several other assessment areas fall below the NERC Reference Margin Level in the latter part of the assessment period (2019–2023) when plans for new resources are less certain.[14] An assessment area not meeting the reference margin projection does not necessarily signal an immediate reliability concern; however, that area may need to evaluate options throughout the next several years for constructing or obtaining more capacity or instituting demand reduction initiatives.

[12] Planning Reserve Margins over 40 percent are not shown. The 2018–2019 winter season is shown for winter-peaking assessment areas.

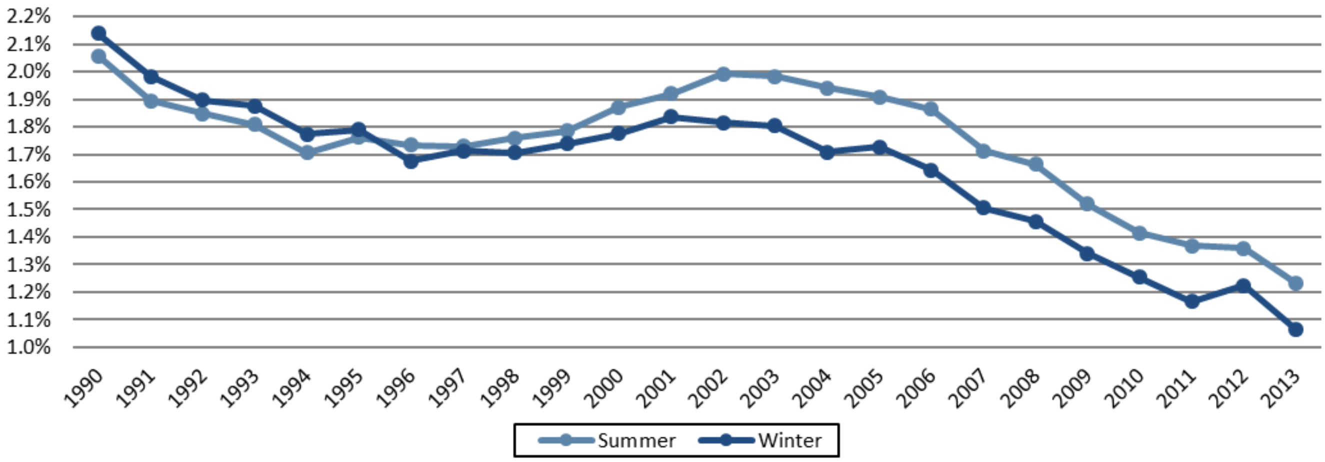
[13] Planning Reserve Margins over 40 percent are not shown. The 2023–2024 winter season is shown for winter-peaking assessment areas.

[14] Additional assessment areas below the NERC Reference Margin Level during the area's respective peak seasons include: MRO-MAPP, NPCC-New England, NPCC-New York, NPCC-Québec, SERC-E, SERC-N, WECC-AESO, WECC-BASN, WECC-DSW, WECC-MEXW.

Demand

The NERC-wide 10-year compound annual growth rate (CAGR) for on-peak summer demand is expected to fall for the 11th consecutive year to an all-time low of 1.23 percent from 2014 to 2023. Similarly, the winter demand growth rate has steadily declined since 2003.

Figure 4: NERC-Wide 10-Year Compound Annual Growth Rate

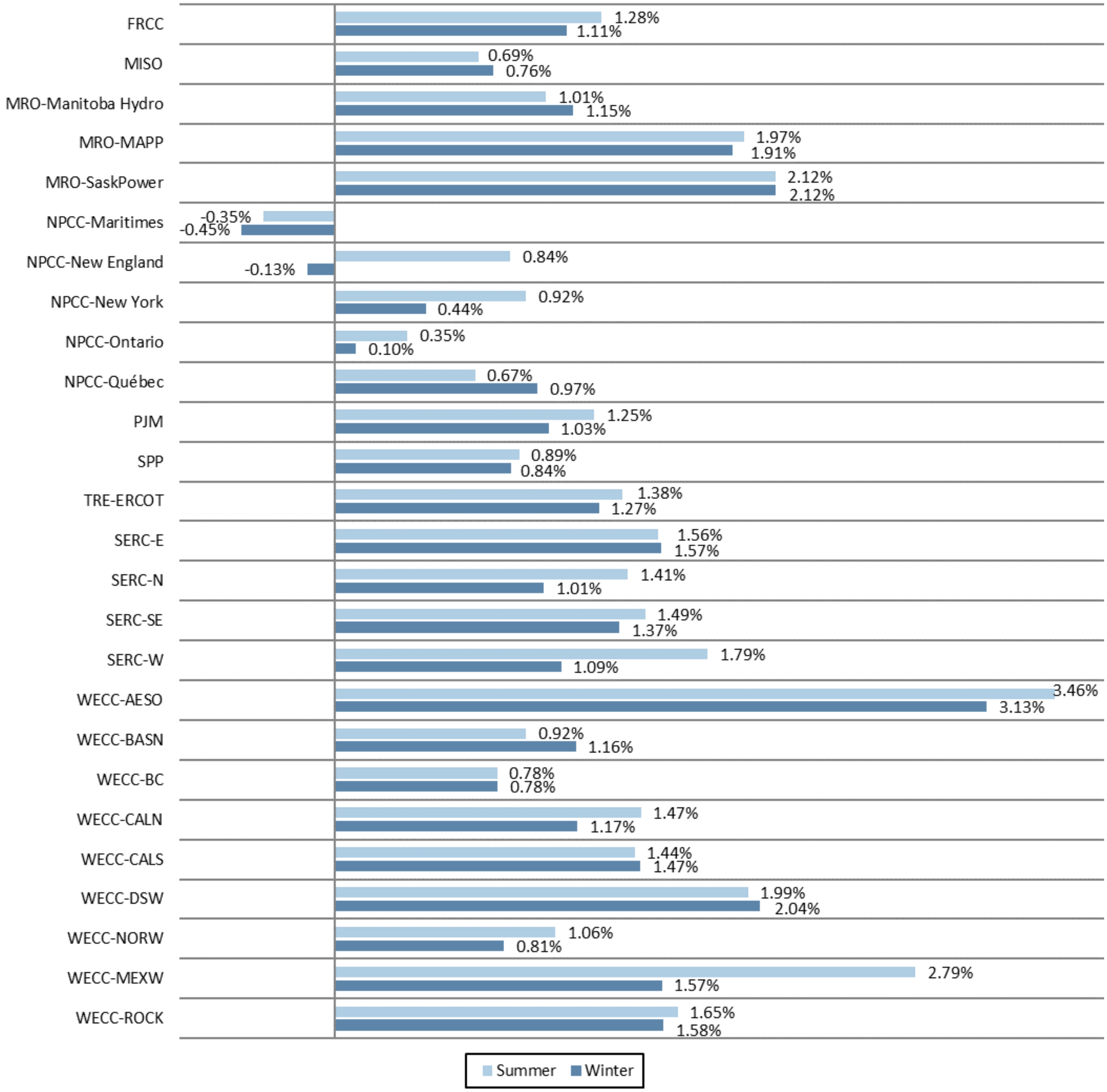


Summer projections for peak demand have been in decline for over a decade as a result of load forecasts that are impacted by a combination of slower economic growth, increased participation in Demand-Side Management (DSM) programs (including efficiency gains from new appliance standards), and additional reliance on behind-the-meter generation. These projections align with the U.S. Department of Energy's Energy Information Administration (EIA) data that indicates a continued decline in the growth rate of annual electricity usage (measured as energy). Energy usage has fallen each decade since the 1950s, from 9.8 percent (1949–1959) to only 0.7 percent per year (2002–2010).[15]

Although the NERC-wide demand growth rate continues to fall, the province of Alberta, Canada (WECC-AESO) is a clear exception. The area projects continued growth in both summer and winter electricity usage at rates of 3.46 percent and 3.13 percent, respectively. The ongoing, energy-intensive surface mining and extraction activities underway in Alberta's oil sands are the primary reason for load growth in the area. SPP has also experienced pockets of significant increases in demand caused by the recent and sudden growth of oil and natural gas drilling industries. ERCOT's load growth projections are substantially lower at only 1.38 percent, compared to 2.3 percent in the *2012LTRA* reference case. This reduction is the result of recent changes in the Moody's long-range economic forecast for ERCOT.

[15] EIA 2013 Annual Energy Outlook p. 71.

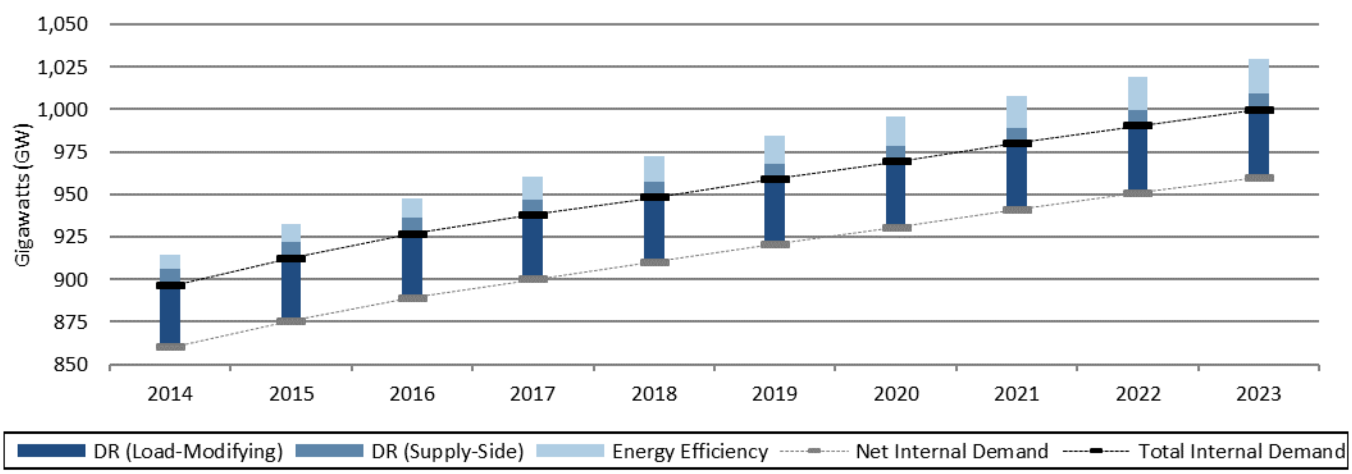
Figure 5: 10-Year Compound Annual Growth Rate (CAGR) by NERC Assessment Area



Demand-Side Management

According to the *2013LTRA* reference case, more DR during the peak will become available as industrial, commercial, and residential participation in these programs increases in most areas. DR programs (both load modifying and supply side) will increase by 3.3 GW during the next 10 years. Energy efficiency programs will also grow by 11.9 GW. During the 10-year period, total DSM growth will account for 14.8 percent of the NERC-wide, noncoincident Total Internal Demand growth.[16]

Figure 6: Available Demand Response during the Peak Season Compared to Noncoincident NERC-Wide Peak Demand[17]



On an assessment area basis, DR programs currently account for approximately 3.8 percent of Total Internal Demand on average. PJM has more established DR programs that account for over 8 percent of the assessment area's Total Internal Demand. In terms of growth, available DR programs remain steady in PJM, while TRE-ERCOT projects an increase of 646 MW during the next 10 years—an increase of almost 40 percent. The SERC-N Assessment Area also projects an increase of 1,261 MW by 2023, compared to 1,846 MW in 2014.

Generation

NERC assesses the availability of future generation based on two supply categories: Future-Planned and Conceptual. According to the *2013LTRA* reference case, a net of 23 GW of Future-Planned capacity will be added to the existing on-peak resource mix.

[16] This approach is used to more accurately reflect the amount of Demand Response available in each assessment area, since several Demand Response programs are only available during the area's peak season.

[17] NERC-wide, noncoincident demand is used to reflect the use of Demand Response programs during the peak season for each assessment area.

Figure 7: NERC-Wide Annual Planned Capacity Change (2014–2023)[18]

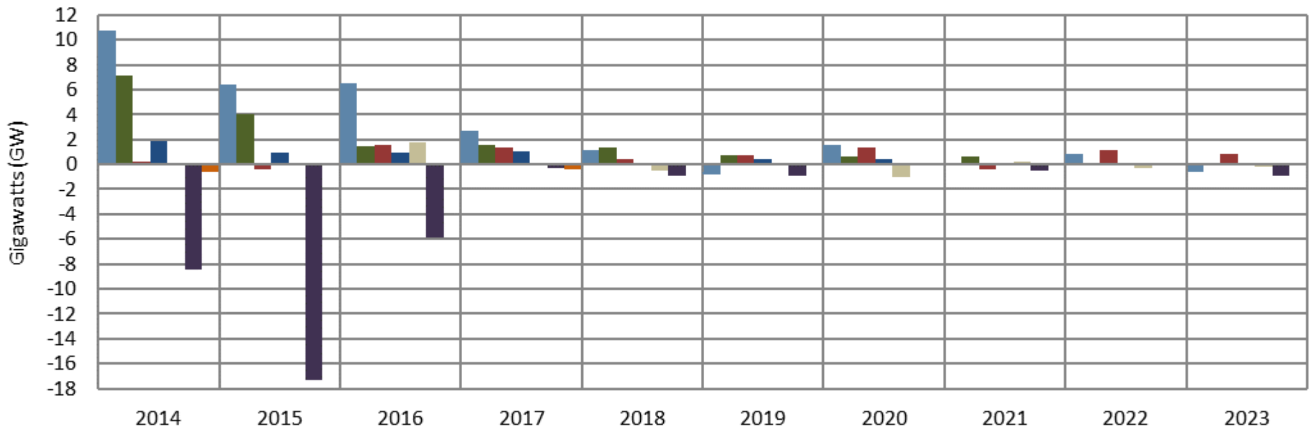


Figure 8: NERC-Wide Cumulative Planned Capacity Change (2014–2023)[19]

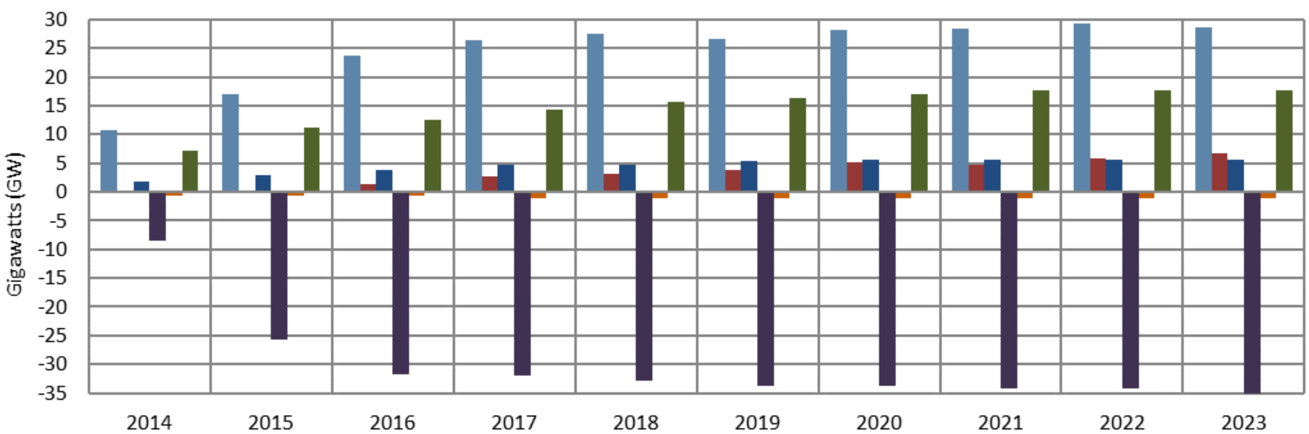


Table 1: NERC-Wide Cumulative Planned Capacity Change (2014–2023)

		Current		2023 Planned			2023 Planned & Conceptual		
		Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Coal		318,000	30.15%	282,890	26.25%	-35,110	250,534	19.18%	-67,465
Petroleum		48,871	4.63%	47,646	4.42%	-1,226	46,437	3.55%	-2,435
Gas		411,993	39.06%	440,613	40.88%	28,620	548,648	42.00%	136,655
Nuclear		115,215	10.92%	121,945	11.31%	6,730	131,150	10.04%	15,935
Hydro		117,731	11.16%	123,294	11.44%	5,563	130,209	9.97%	12,478
Pumped Storage		21,199	2.01%	22,064	2.05%	865	22,114	1.69%	915
Renewables (Non-Hydro)		21,723	2.06%	39,319	3.65%	17,596	177,254	13.57%	177,254
TOTAL		**1,054,731**	**100.0%**	**1,077,769**	**100.0%**	**23,038**	**1,483,600**	**100.0%**	**273,337**

COAL

The amount of coal-fired generation during peak is expected to decline substantially, as 39.4 GW of retirements and derates outpace 4.3 GW of new additions, resulting in a net reduction of 35.1 GW by 2023. Most unit retirements are planned between 2014 and 2016, when requirements of environmental regulations become effective. These projections

[18] The peak season is used for each assessment area. Annual capacity changes are impacted by new units, unit uprates, unit retirements, and unit derates.

[19] Ibid.

are substantially higher than the *2012LTRA* reference case, which projected a net reduction of 16.3 GW between 2014 and 2023. A large portion of retirements will occur in PJM, with 9.6 GW of announced coal retirements during the assessment period. NERC-wide coal-fired unit retirements totaled 3.5 GW in 2011 and 8.9 GW in 2012.[20] An additional 4.2 GW of coal-fired units were retired in the United States and Canada in 2013.[21]

Natural Gas

Continued lower natural gas prices in recent years creates further incentive for plant owners to convert existing units from coal or oil to gas. Retirement considerations for existing units are mostly affected by replacement costs, which are highly reliant on fuel costs. Therefore, the option of converting existing oil- and coal-fired units to natural gas becomes an attractive alternative as gas prices generally remain low.

Despite 15.2 GW of planned retirements of mostly older, less-efficient units, total gas-fired generation continues to grow, with a net increase of 28.6 GW by 2023. Several new units will become operational between 2014 and 2017, concurrent with the anticipated retirements of several coal-fired units. A majority of these new units will be built within WECC (10.6 GW), PJM (8.5 GW), FRCC (5.5 GW), and ERCOT (4.6 GW).

Petroleum

Approximately 1.2 GW of petroleum-fired generation will be taken out of service during the assessment period. In many cases, units with gas as the primary fuel type are able to switch to oil in response to gas supply shortages. NPCC-New England and NPCC-New York have a combined total of 12.6 GW of gas-fired capacity that uses oil as a secondary fuel source.

Nuclear

Electricity generation from nuclear power plants will increase by approximately 6.7 GW by 2023, primarily due to the planned addition of five units, totaling approximately 5.6 GW.[22] All additional units are planned within SERC. Unit uprates will also contribute to increased capacity from existing plants throughout NERC.

Since 2011, five units totaling over 4.2 GW have retired or announced plans to decommission reactors.[23] In NPCC-NYISO, the Indian Point plant units 2 and 3 remain in service as their license renewal requests remain under review by the Atomic Safety Licensing Board of the Nuclear Regulatory Commission. The *2013LTRA* reference case includes the retirement of the Vermont Yankee plant (620 MW) in NPCC-NYISO and the Oyster Creek plant (604 MW) in PJM in 2019. Despite these retirements, nuclear generation is still expected to account for 11.3 percent of on-peak capacity in 2023, up from its current contribution of 10.9 percent.

Renewables/Other

Generation from renewable energy (wind, solar, biomass, and geothermal), accounts for over 50 GW of nameplate capacity additions during the next 10 years (7.5 GW on-peak). These new resources are built in large part as a response to federal tax credits, state-level policies (Renewable Portfolio Standards), and federal requirements. The share of NERC-wide on-peak generation from renewable fuels (excluding hydropower) grows by 17.5 GW, from 2 percent to 3.7 percent during the next decade. In terms of on-peak contribution, electricity from solar power accounts for the largest increase, growing by 9.1 GW. In recent years, a majority of new solar resources has come online in the southwestern portion of WECC (WECC-DSW and

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[20] Actual U.S. coal-fired retirement data (2011 and 2012): EIA Today in Energy. Actual Canadian coal-fired retirement data (2011 and 2012): Ventyx Velocity Suite.

[21] Total retirements between January 1, 2013 and October 31, 2013. Data aggregated using Ventyx Velocity Suite. This data was not used in the *2013LTRA* reference case; planned retirements in Schedule 2 were used for 2013 and beyond.

[22] Includes the following planned units: Vogtle 3 & 4 (SERC-SE), Summer 2 &3 (SERC-E), and Watts Bar 2 (SERC-N).

[23] Includes both units that have retired and units that have announced plans to decommission: Crystal River 3 (FRCC), Gentilly 2 (NPCC-Québec), Kewaunee (MISO), Vermont Yankee (NPCC-New England), and San Onofre 2 & 3 (WECC-CALS). For additional information, see the respective assessment area sections.

WECC-CALS), and this trend is expected to continue. On-peak wind capacity will grow by 5.9 GW, while biomass and pumped storage increase by 1.5 GW and 1 GW, respectively. On-peak hydro power will increase by 5.5 GW during the assessment period, primarily due to uprates at existing facilities.

Transmission

Transmission additions during the 10-year period include plans for over 21,800 circuit miles. NERC continues to monitor the progress of transmission projects across North America. 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) and increasingly difficult in later years, plans should reflect realistic expectations in order to reliably support future system needs.

Table 2: Existing Transmission with Planned and Conceptual Additions[24]

	Existing	Current	2013–2018		2019–2023	
Assessment Area/ Interconnection	2012 Year-End	Under Construction	Planned	Conceptual	Planned	Conceptual
FRCC	12,037	119	309	48	77	0
MISO	43,325	18	1,948	52	1,043	16
MRO-Manitoba Hydro	7,487	0	0	236	0	1,098
MRO-MAPP	10,265	502	396	84	0	0
MRO-SaskPower	5,635	0	529	220	0	0
NPCC-Maritimes	5,103	0	42	50	0	240
NPCC-New England	8,643	255	270	278	7	0
NPCC-New York	10,981	0	0	0	0	0
NPCC-Ontario	17,931	93	0	0	0	240
NPCC-Québec	23,830	276	201	621	0	541
PJM	51,940	162	1,634	0	68	16
SERC-E	22,315	20	364	151	6	125
SERC-N	21,600	97	184	91	0	25
SERC-SE	27,672	41	560	57	118	0
SERC-W	14,295	98	178	81	15	95
SPP	33,743	507	1,228	157	315	60
TRE-ERCOT	30,047	2,564	3,346	1,088	84	528
WECC	129,398	686	7,137	3,548	1,805	2,818
EASTERN INTERCONNECTION	292,972	1,913	7,642	1,504	1,649	1,915
QUÉBEC INTERCONNECTION	23,830	276	201	621	0	541
TEXAS INTERCONNECTION	30,047	2,564	3,346	1,088	84	528
WESTERN INTERCONNECTION	129,398	686	7,137	3,548	1,805	2,818
TOTAL-NERC	**476,247**	**5,439**	**18,326**	**6,762**	**3,537**	**5,802**

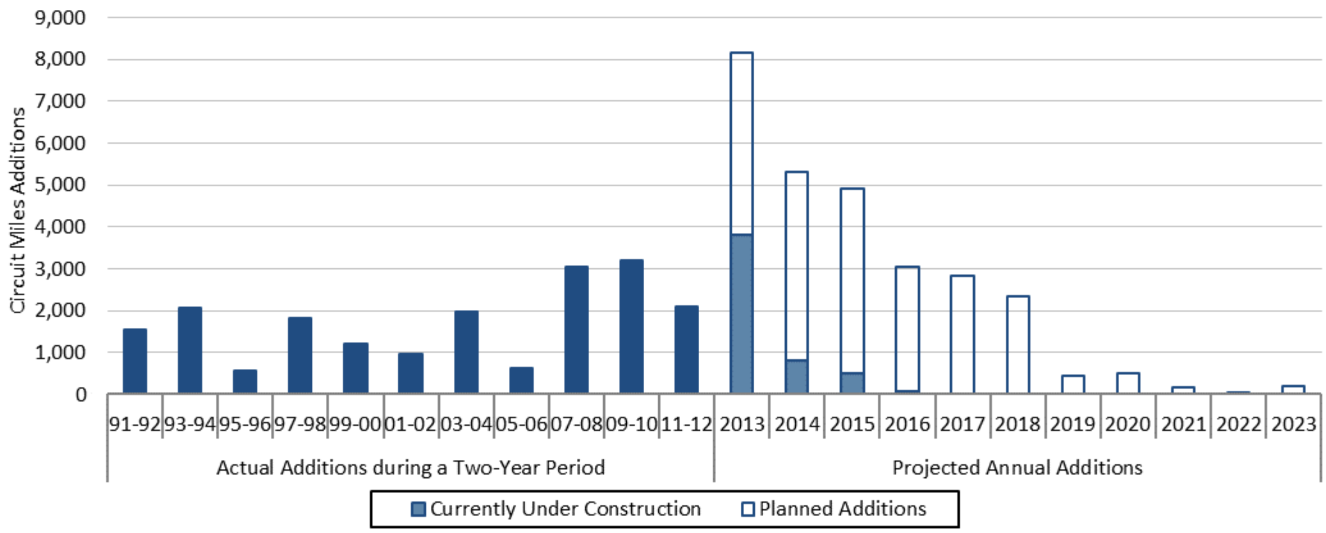
In the Western Interconnection, 15 new transmission line projects, each over 200 circuit miles in length, are planned to come into service by 2023 (an additional seven projects over 200 circuit miles are categorized as Conceptual). These larger projects are typical in the West, due to the geographically unique transmission system—especially as large amounts of widely dispersed renewable energy continue to be integrated. Conversely, in the Eastern Interconnection, only six Bulk Electric System (BES) transmission projects greater than 200 miles are planned. Longer transmission lines do not necessarily mean more capacity and enhanced reliability but may be necessary to meet Renewable Portfolio Standards (RPSs) in the future. Current plans do not show significant additions to west-to-east power transfer capability.

NERC-wide, the most notable transmission developments include plans in WECC for a 2,500-mile Canada/Pacific Northwest—Northern California Transmission Project (500 kV), with a split of ac and dc. In Texas, the CREZ transmission project is nearly complete with the addition of 1,600 circuit miles coming into service in 2014 to support ERCOT's wind integration efforts.

[24] In 2014, NERC will begin using inventory data collected in NERC's Transmission Availability Data System (TADS).

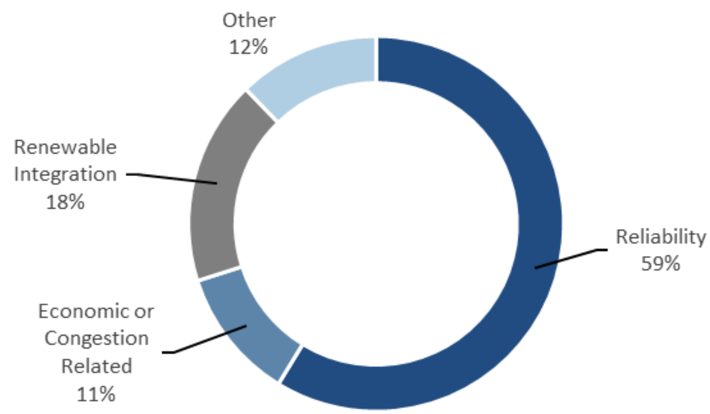
Since 1991, new transmission has been built at an average rate of approximately 1,730 circuit miles every two years. Currently, 3,800 circuit miles are classified as under construction and expected to be in-service before the end of 2013. An additional 800 and 500 circuit miles are under construction and expected to be in-service before 2014 and 2015, respectively. Transmission projects totaling approximately 21,800 circuit miles are categorized as planned with in-service dates before 2023.

Figure 9: Historical Actual Miles Added during each Two-Year Period and 10-Year Projections



According to industry, new transmission projects are being driven primarily to enhance reliability. Other reasons include congestion alleviation and integration of renewables.

Figure 10: Primary Drivers for New Transmission Projects



Projected Demand, Resources, and Reserve Margins

Summary Table A: Demand, Resources, and Reserve Margins by Interconnection: 2014 Summer

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			Ref.
Interconnection	Net Int.	Tot. Int.	Ant.	Pros.	Adj. Pot.	Ant.	Pros.	Adj. Pot.	Margin
EASTERN	584,960	614,953	755,936	774,296	778,765	29.23%	32.37%	33.13%	-
ERCOT	67,592	69,289	76,879	76,879	77,444	13.74%	13.74%	14.58%	13.75%
QUÉBEC	20,944	20,944	32,596	31,700	31,700	55.63%	51.35%	51.35%	12.00%
WESTERN	159,100	163,691	202,076	202,076	202,907	27.01%	27.01%	27.53%	14.70%

Summary Table B: Demand, Resources, and Reserve Margins by Interconnection: 2014–15 Winter

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			Ref.
Interconnection	Net Int.	Tot. Int.	Ant.	Pros.	Adj. Pot.	Ant.	Pros.	Adj. Pot.	Margin
EASTERN	563,138	577,860	842,925	860,663	865,332	49.68%	52.83%	53.66%	-
ERCOT	53,742	55,439	79,323	79,323	79,932	47.60%	47.60%	48.73%	13.75%
QUÉBEC	37,179	37,179	41,786	43,433	43,433	12.39%	16.82%	16.82%	10.30%
WESTERN	134,552	136,445	194,573	194,573	195,581	44.61%	44.61%	45.36%	14.50%

Summary Table C: Demand, Resources, and Reserve Margins by Interconnection: 2018 Summer

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			Ref.
Interconnection	Net Int.	Tot. Int.	Ant.	Pros.	Adj. Pot.	Ant.	Pros.	Adj. Pot.	Margin
EASTERN	616,617	647,984	743,310	767,995	792,053	21%	24.55%	28.45%	-
ERCOT	73,214	75,132	80,053	80,053	81,817	9.34%	9.34%	11.75%	13.75%
QUÉBEC	21,190	21,190	35,561	35,172	35,172	67.82%	65.99%	65.99%	12.00%
WESTERN	169,786	174,909	213,604	213,604	223,697	25.81%	25.81%	31.75%	14.70%

Summary Table D: Demand, Resources, and Reserve Margins by Interconnection: 2018–2019 Winter

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			Ref.
Interconnection	Net Int.	Tot. Int.	Ant.	Pros.	Adj. Pot.	Ant.	Pros.	Adj. Pot.	Margin
EASTERN	590,524	606,365	835,594	860,579	888,526	42%	45.73%	50.46%	-
ERCOT	57,640	59,558	81,438	81,438	83,181	41.29%	41.29%	44.31%	13.75%
QUÉBEC	38,950	38,950	43,697	45,344	45,344	12.19%	16.42%	16.42%	10.70%
WESTERN	143,336	145,328	202,477	202,477	211,642	41.26%	41.26%	47.65%	14.50%

Summary Table E: Demand, Resources, and Reserve Margins by Interconnection: 2023 Summer

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			Ref.
Interconnection	Net Int.	Tot. Int.	Ant.	Pros.	Adj. Pot.	Ant.	Pros.	Adj. Pot.	Margin
EASTERN	648,636	680,996	747,528	776,331	814,401	15%	19.69%	25.56%	-
ERCOT	76,070	78,413	79,441	79,441	81,375	4.43%	4.43%	6.97%	13.75%
QUÉBEC	22,246	22,246	36,103	35,714	35,714	62.29%	60.54%	60.54%	12.00%
WESTERN	183,165	188,500	215,167	215,167	230,103	17.47%	17.47%	25.63%	14.70%

Summary Table F: Demand, Resources, and Reserve Margins by Interconnection: 2023–2024 Winter

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			Ref.
Interconnection	Net Int.	Tot. Int.	Ant.	Pros.	Adj. Pot.	Ant.	Pros.	Adj. Pot.	Margin
EASTERN	617,844	635,092	842,691	871,920	913,309	36%	41.12%	47.82%	-
ERCOT	59,758	62,101	81,755	81,755	83,668	36.81%	36.81%	40.01%	13.75%
QUÉBEC	40,562	40,562	44,414	46,061	46,061	9.50%	13.56%	13.56%	10.70%
WESTERN	153,038	155,225	201,614	201,614	216,223	31.74%	31.74%	41.29%	14.50%

Summary Table G: Demand, Resources, and Reserve Margins by Assessment Area: 2014 Summer

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			Ref.
Assessment Area	Net Int.	Tot. Int.	Ant.	Pros.	Adj. Pot.	Ant.	Pros.	Adj. Pot.	Margin
FRCC	43,142	46,338	55,119	61,973	61,973	27.76%	43.65%	43.65%	14.99%
MISO	92,331	96,879	109,211	113,894	114,996	18.28%	23.35%	24.55%	14.20%
MRO-Manitoba Hydro	3,167	3,389	4,451	4,641	4,641	40.51%	46.52%	46.52%	12.00%
MRO-MAPP	5,161	5,249	6,658	6,658	6,658	29.01%	29.01%	29.01%	15.00%
MRO-SaskPower	3,118	3,204	3,679	3,679	3,679	17.99%	17.99%	17.99%	11.00%
NPCC-Maritimes	3,030	3,425	5,837	5,915	5,960	92.66%	95.23%	96.72%	20.00%
NPCC-New England	26,929	26,929	34,744	34,744	34,810	29.02%	29.02%	29.26%	13.85%
NPCC-New York	33,725	33,725	41,383	42,736	42,795	22.71%	26.72%	26.89%	17.00%
NPCC-Ontario	22,937	22,937	28,645	28,645	28,826	24.89%	24.89%	25.68%	18.60%
NPCC-Québec	20,944	20,944	32,596	31,700	31,700	55.63%	51.35%	51.35%	12.00%
PJM	144,497	158,717	189,088	189,088	190,797	30.86%	30.86%	32.04%	15.90%
SERC-E	41,789	43,786	50,857	50,909	50,910	21.70%	21.82%	21.83%	15.00%
SERC-N	41,009	42,855	51,980	53,386	53,971	26.75%	30.18%	31.61%	15.00%
SERC-SE	46,582	48,813	63,704	65,580	65,696	36.76%	40.78%	41.03%	14.99%
SERC-W	23,463	24,003	37,190	39,081	39,659	58.50%	66.56%	69.03%	14.99%
SPP	54,080	54,703	73,392	73,368	73,395	35.71%	35.67%	35.72%	13.60%
TRE-ERCOT	67,592	69,289	76,879	76,879	77,444	13.74%	13.74%	14.58%	13.75%
WECC-AESO	10,388	10,388	12,823	12,823	13,013	23.44%	23.44%	25.27%	12.25%
WECC-BASN	13,459	14,161	15,444	15,444	15,446	14.75%	14.75%	14.77%	13.72%
WECC-BC	8,353	8,353	9,894	9,894	9,901	18.45%	18.45%	18.53%	12.91%
WECC-CALN	25,708	26,476	31,407	31,407	31,479	22.17%	22.17%	22.45%	15.02%
WECC-CALS	33,706	35,748	39,850	39,850	39,932	18.23%	18.23%	18.47%	15.15%
WECC-DSW	27,638	28,222	38,154	38,154	38,540	38.05%	38.05%	39.44%	13.62%
WECC-MEXW	2,393	2,393	3,027	3,027	3,027	26.47%	26.47%	26.47%	11.93%
WECC-NORW	25,680	25,680	37,204	37,204	37,209	44.88%	44.88%	44.90%	17.48%
WECC-ROCK	11,775	12,270	14,272	14,272	14,359	21.21%	21.21%	21.94%	14.45%
NERC	**832,596**	**868,877**	**1,067,487**	**1,084,951**	**1,090,815**	**28.21%**	**30.31%**	**31.01%**	**15.00%**

Summary Table H: Demand, Resources, and Reserve Margins by Assessment Area: 2014–2015 Winter

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			Ref.
Assessment Area	Net Int.	Tot. Int.	Ant.	Pros.	Adj. Pot.	Ant.	Pros.	Adj. Pot.	Margin
FRCC	44,060	47,161	60,285	66,024	66,024	36.83%	49.85%	49.85%	14.99%
MISO	76,252	79,813	109,211	113,894	114,996	43.22%	49.36%	50.81%	14.20%
MRO-Manitoba Hydro	4,344	4,570	5,297	5,688	5,688	21.93%	30.92%	30.92%	12.00%
MRO-MAPP	5,500	5,500	7,381	7,381	7,381	34.20%	34.20%	34.20%	15.00%
MRO-SaskPower	3,481	3,567	4,136	4,136	4,136	18.81%	18.81%	18.81%	11.00%
NPCC-Maritimes	5,472	5,472	6,972	7,005	7,005	27.42%	28.02%	28.02%	20.00%
NPCC-New England	21,272	21,272	36,503	36,503	36,526	71.60%	71.60%	71.71%	13.90%
NPCC-New York	24,818	24,818	43,093	44,446	44,524	73.63%	79.09%	79.40%	17.00%
NPCC-Ontario	21,800	21,800	30,674	30,674	30,808	40.71%	40.71%	41.32%	18.70%
NPCC-Québec	37,179	37,179	41,786	43,433	43,433	12.39%	16.82%	16.82%	10.30%
PJM	134,742	134,742	191,384	191,384	192,670	42.04%	42.04%	42.99%	15.90%
SERC-E	40,819	42,331	53,217	53,269	53,269	30.37%	30.50%	30.50%	15.00%
SERC-N	39,896	41,623	54,057	55,824	56,696	35.50%	39.92%	42.11%	15.00%
SERC-SE	44,389	46,619	66,177	68,165	68,236	49.08%	53.56%	53.72%	14.99%
SERC-W	21,026	21,437	38,227	40,184	40,762	81.81%	91.12%	93.87%	14.99%
SPP	41,259	41,831	74,456	74,656	74,905	80.46%	80.95%	81.55%	15.00%
TRE-ERCOT	53,742	55,439	79,323	79,323	79,932	47.60%	47.60%	48.73%	13.75%
WECC-AESO	11,766	11,766	13,187	13,187	13,619	12.07%	12.07%	15.75%	11.64%
WECC-BASN	10,699	11,001	13,512	13,512	13,514	26.29%	26.29%	26.31%	13.74%
WECC-BC	11,368	11,368	13,238	13,238	13,247	16.45%	16.45%	16.53%	16.07%
WECC-CALN	18,181	18,455	25,921	25,921	25,994	42.58%	42.58%	42.98%	12.11%
WECC-CALS	22,637	23,327	32,818	32,818	32,861	44.97%	44.97%	45.16%	11.00%
WECC-DSW	17,589	17,931	36,683	36,683	36,973	108.56%	108.56%	110.21%	14.03%
WECC-MEXW	1,512	1,512	2,603	2,603	2,603	72.13%	72.13%	72.13%	10.72%
WECC-NORW	30,902	30,906	41,388	41,388	41,393	33.94%	33.94%	33.95%	19.17%
WECC-ROCK	9,899	10,180	15,223	15,223	15,376	53.78%	53.78%	55.33%	15.87%
NERC	**788,611**	**806,923**	**1,158,606**	**1,177,992**	**1,184,278**	**46.92%**	**49.38%**	**50.17%**	**15.00%**

Summary Table I: Demand, Resources, and Reserve Margins by Assessment Area: 2018 Summer

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			Ref.
Assessment Area	Net Int.	Tot. Int.	Ant.	Pros.	Adj. Pot.	Ant.	Pros.	Adj. Pot.	Margin
FRCC	45,457	48,881	57,437	62,382	62,382	26.36%	37.23%	37.23%	14.99%
MISO	95,076	99,624	100,342	109,492	115,659	5.54%	15.16%	21.65%	14.20%
MRO-Manitoba Hydro	3,203	3,425	4,801	4,792	4,792	49.88%	49.58%	49.58%	12.00%
MRO-MAPP	5,692	5,788	6,839	6,867	6,867	20.15%	20.64%	20.64%	15.00%
MRO-SaskPower	3,536	3,622	4,018	4,043	4,043	13.63%	14.34%	14.34%	11.00%
NPCC-Maritimes	3,042	3,435	5,912	6,143	6,188	94.37%	101.97%	103.45%	20.00%
NPCC-New England	28,213	28,213	32,548	32,548	33,305	15.36%	15.36%	18.05%	13.65%
NPCC-New York	35,103	35,103	41,383	42,736	43,207	17.89%	21.74%	23.09%	17.00%
NPCC-Ontario	22,610	22,610	26,227	26,227	27,197	16.00%	16.00%	20.29%	19.30%
NPCC-Québec	21,190	21,190	35,561	35,172	35,172	67.82%	65.99%	65.99%	12.00%
PJM	154,165	168,813	187,145	187,145	193,132	21.39%	21.39%	25.28%	15.60%
SERC-E	44,488	46,673	51,875	51,927	52,298	16.60%	16.72%	17.56%	15.00%
SERC-N	43,122	45,585	50,536	54,297	58,621	17.19%	25.91%	35.94%	15.00%
SERC-SE	49,569	51,841	63,991	65,867	68,568	29.09%	32.88%	38.33%	14.99%
SERC-W	26,336	26,895	36,442	39,749	41,869	38.37%	50.93%	58.98%	14.99%
SPP	57,004	57,475	73,816	73,782	73,925	29.49%	29.43%	29.68%	13.60%
TRE-ERCOT	73,214	75,132	80,053	80,053	81,817	9.34%	9.34%	11.75%	13.75%
WECC-AESO	12,615	12,615	16,113	16,113	19,575	27.73%	27.73%	55.17%	12.25%
WECC-BASN	13,514	14,570	15,464	15,464	16,067	14.43%	14.43%	18.89%	13.72%
WECC-BC	8,667	8,667	10,723	10,723	10,736	23.72%	23.72%	23.87%	12.91%
WECC-CALN	27,691	28,477	33,163	33,163	33,487	19.76%	19.76%	20.93%	15.02%
WECC-CALS	35,737	37,867	43,165	43,165	45,204	20.78%	20.78%	26.49%	15.15%
WECC-DSW	29,526	30,134	38,766	38,766	41,746	31.29%	31.29%	41.39%	13.62%
WECC-MEXW	2,672	2,672	3,321	3,321	3,888	24.27%	24.27%	45.51%	11.93%
WECC-NORW	26,752	26,752	38,392	38,392	38,407	43.51%	43.51%	43.57%	17.48%
WECC-ROCK	12,612	13,155	14,497	14,497	14,587	14.95%	14.95%	15.66%	14.45%
NERC	**880,806**	**919,214**	**1,072,529**	**1,096,824**	**1,132,739**	**21.77%**	**24.52%**	**28.60%**	**15.00%**

Summary Table J: Demand, Resources, and Reserve Margins by Assessment Area: 2018–2019 Winter

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			Ref.
Assessment Area	Net Int.	Tot. Int.	Ant.	Pros.	Adj. Pot.	Ant.	Pros.	Adj. Pot.	Margin
FRCC	46,105	49,377	61,673	66,721	66,721	33.77%	44.71%	44.71%	14.99%
MISO	78,651	82,212	100,342	109,492	115,659	27.58%	39.21%	47.05%	14.20%
MRO-Manitoba Hydro	4,433	4,659	5,535	5,926	5,926	24.85%	33.65%	33.65%	12.00%
MRO-MAPP	6,046	6,046	7,351	7,351	7,351	21.58%	21.58%	21.58%	15.00%
MRO-SaskPower	3,947	4,033	4,429	4,454	4,454	12.20%	12.84%	12.84%	11.00%
NPCC-Maritimes	5,393	5,393	7,056	7,242	7,242	30.84%	34.29%	34.29%	20.00%
NPCC-New England	21,295	21,295	35,554	35,554	36,192	66.96%	66.96%	69.95%	13.60%
NPCC-New York	25,219	25,219	43,093	44,446	45,010	70.87%	76.24%	78.48%	17.00%
NPCC-Ontario	21,376	21,376	27,918	27,918	28,997	30.61%	30.61%	35.66%	20.00%
NPCC-Québec	38,950	38,950	43,697	45,344	45,344	12.19%	16.42%	16.42%	10.70%
PJM	141,483	141,483	190,445	190,445	196,082	34.61%	34.61%	38.59%	15.60%
SERC-E	43,464	45,065	55,054	55,106	55,526	26.67%	26.79%	27.75%	15.00%
SERC-N	42,531	44,966	52,537	56,280	60,660	23.53%	32.33%	42.62%	15.00%
SERC-SE	46,737	49,011	65,206	67,194	69,983	39.52%	43.77%	49.74%	14.99%
SERC-W	22,055	22,478	37,588	40,964	43,108	70.43%	85.74%	95.46%	14.99%
SPP	43,615	44,187	74,935	75,210	75,544	71.81%	72.44%	73.21%	15.00%
TRE-ERCOT	57,640	59,558	81,438	81,438	83,181	41.29%	41.29%	44.31%	13.75%
WECC-AESO	14,035	14,035	15,755	15,755	19,273	12.25%	12.25%	37.32%	11.64%
WECC-BASN	11,260	11,565	13,709	13,709	14,420	21.75%	21.75%	28.07%	13.74%
WECC-BC	11,796	11,796	14,928	14,928	14,962	26.55%	26.55%	26.84%	16.07%
WECC-CALN	19,059	19,344	26,824	26,824	27,146	40.74%	40.74%	42.43%	12.11%
WECC-CALS	23,933	24,714	34,187	34,187	36,188	42.85%	42.85%	51.21%	11.00%
WECC-DSW	19,072	19,404	37,097	37,097	38,937	94.51%	94.51%	104.16%	14.03%
WECC-MEXW	1,610	1,610	2,443	2,443	3,010	51.71%	51.71%	86.95%	10.72%
WECC-NORW	31,922	31,926	42,628	42,628	42,646	33.54%	33.54%	33.59%	19.17%
WECC-ROCK	10,649	10,934	14,906	14,906	15,060	39.98%	39.98%	41.42%	15.87%
NERC	**830,450**	**850,201**	**1,163,207**	**1,189,838**	**1,228,692**	**40.07%**	**43.28%**	**47.95%**	**15.00%**

Summary Table K: Demand, Resources, and Reserve Margins by Assessment Area: 2023 Summer

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			Ref.
Assessment Area	Net Int.	Tot. Int.	Ant.	Pros.	Adj. Pot.	Ant.	Pros.	Adj. Pot.	Margin
FRCC	48,359	51,968	60,100	66,390	66,390	24.28%	37.29%	37.29%	14.99%
MISO	98,508	103,056	101,896	111,683	118,488	3.44%	13.37%	20.28%	14.20%
MRO-Manitoba Hydro	3,490	3,712	4,704	4,220	4,850	34.80%	20.92%	38.97%	12.00%
MRO-MAPP	6,148	6,254	6,946	6,989	6,989	12.98%	13.68%	13.68%	15.00%
MRO-SaskPower	3,783	3,869	4,290	4,290	4,290	13.40%	13.40%	13.40%	11.00%
NPCC-Maritimes	3,038	3,320	5,912	6,143	6,188	94.58%	102.18%	103.66%	20.00%
NPCC-New England	29,038	29,038	32,542	32,542	33,299	12.07%	12.07%	14.67%	13.65%
NPCC-New York	36,613	36,613	41,383	42,736	43,207	13.03%	16.72%	18.01%	17.00%
NPCC-Ontario	23,662	23,662	23,764	23,764	28,471	0.43%	0.43%	20.32%	20.00%
NPCC-Québec	22,246	22,246	36,103	35,714	35,714	62.29%	60.54%	60.54%	12.00%
PJM	162,791	177,439	188,722	188,722	194,916	15.93%	15.93%	19.73%	15.60%
SERC-E	48,027	50,311	51,890	51,942	54,514	8.04%	8.15%	13.51%	15.00%
SERC-N	45,496	48,603	51,177	55,869	63,749	12.49%	22.80%	40.12%	15.00%
SERC-SE	53,466	55,768	64,044	65,920	68,949	19.78%	23.29%	28.96%	14.99%
SERC-W	27,587	28,164	34,740	39,749	44,511	25.93%	44.09%	61.35%	14.99%
SPP	58,629	59,219	75,419	75,373	75,590	28.64%	28.56%	28.93%	13.60%
TRE-ERCOT	76,070	78,413	79,441	79,441	81,375	4.43%	4.43%	6.97%	13.75%
WECC-AESO	14,110	14,110	16,228	16,228	20,280	15.01%	15.01%	43.73%	12.25%
WECC-BASN	14,320	15,376	15,551	15,551	16,762	8.60%	8.60%	17.05%	13.72%
WECC-BC	8,958	8,958	11,053	11,053	11,658	23.38%	23.38%	30.14%	12.91%
WECC-CALN	29,414	30,194	34,216	34,216	34,540	16.32%	16.32%	17.43%	15.02%
WECC-CALS	38,282	40,664	44,178	44,178	47,285	15.40%	15.40%	23.52%	15.15%
WECC-DSW	33,100	33,686	37,600	37,600	41,535	13.60%	13.60%	25.48%	13.62%
WECC-MEXW	3,066	3,066	3,429	3,429	4,538	11.82%	11.82%	48.02%	11.93%
WECC-NORW	28,232	28,232	37,241	37,241	37,718	31.91%	31.91%	33.60%	17.48%
WECC-ROCK	13,683	14,214	15,671	15,671	15,788	14.53%	14.53%	15.39%	14.45%
NERC	**930,118**	**970,156**	**1,078,240**	**1,106,654**	**1,161,593**	**15.93%**	**18.98%**	**24.89%**	**15.00%**

Summary Table L: Demand, Resources, and Reserve Margins by Assessment Area: 2023–2024 Winter

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			Ref.
Assessment Area	Net Int.	Tot. Int.	Ant.	Pros.	Adj. Pot.	Ant.	Pros.	Adj. Pot.	Margin
FRCC	48,695	52,101	65,192	71,201	71,201	33.88%	46.22%	46.22%	14.99%
MISO	81,885	85,446	101,896	111,683	118,488	24.44%	36.39%	44.70%	14.20%
MRO-Manitoba Hydro	4,838	5,064	5,438	5,354	5,984	12.41%	10.66%	23.68%	12.00%
MRO-MAPP	6,521	6,521	7,346	7,346	7,346	12.66%	12.66%	12.66%	15.00%
MRO-SaskPower	4,221	4,307	4,774	4,774	4,774	13.09%	13.09%	13.09%	11.00%
NPCC-Maritimes	5,254	5,254	6,990	7,176	7,176	33.04%	36.58%	36.58%	20.00%
NPCC-New England	21,017	21,017	35,548	35,548	36,186	69.14%	69.14%	72.17%	13.60%
NPCC-New York	25,808	25,808	43,093	44,446	45,010	66.97%	72.22%	74.40%	17.00%
NPCC-Ontario	21,995	21,995	25,499	25,499	30,507	15.93%	15.93%	38.70%	20.00%
NPCC-Québec	40,562	40,562	44,414	46,061	46,061	9.50%	13.56%	13.56%	10.70%
PJM	147,730	147,730	190,445	190,445	196,289	28.91%	28.91%	32.87%	15.60%
SERC-E	47,055	48,704	54,403	54,455	57,285	15.62%	15.73%	21.74%	15.00%
SERC-N	42,161	45,543	53,544	58,246	66,385	27.00%	38.15%	57.46%	15.00%
SERC-SE	50,370	52,676	66,514	68,502	71,619	32.05%	36.00%	42.19%	14.99%
SERC-W	23,193	23,628	35,722	40,796	45,578	54.02%	75.90%	96.52%	14.99%
SPP	44,549	45,121	77,040	77,303	78,359	72.93%	73.52%	75.89%	15.00%
TRE-ERCOT	59,758	62,101	81,755	81,755	83,668	36.81%	36.81%	40.01%	13.75%
WECC-AESO	15,534	15,534	17,079	17,079	21,187	9.95%	9.95%	36.39%	11.64%
WECC-BASN	11,897	12,202	13,555	13,555	14,894	13.94%	13.94%	25.19%	13.74%
WECC-BC	12,192	12,192	14,166	14,166	14,985	16.19%	16.19%	22.91%	16.07%
WECC-CALN	20,216	20,484	27,043	27,043	27,365	33.77%	33.77%	35.36%	12.11%
WECC-CALS	25,568	26,600	34,532	34,532	37,600	35.06%	35.06%	47.06%	11.00%
WECC-DSW	21,179	21,511	36,818	36,818	39,706	73.84%	73.84%	87.48%	14.03%
WECC-MEXW	1,740	1,740	2,438	2,438	3,547	40.09%	40.09%	103.87%	10.72%
WECC-NORW	33,237	33,241	41,303	41,303	42,054	24.27%	24.27%	26.53%	19.17%
WECC-ROCK	11,475	11,721	14,680	14,680	14,885	27.93%	27.93%	29.71%	15.87%
NERC	**871,202**	**892,981**	**1,170,475**	**1,201,351**	**1,259,261**	**34.35%**	**37.90%**	**44.54%**	**15.00%**

Long-Term Reliability Challenges and Emerging Issues

Background

The electricity industry has prepared plans for the 2014–2023 assessment period in an effort to provide reliable electric service across North America. In some assessment areas, NERC has identified certain evolving issues that may potentially affect the reliability of the BPS. Over the next 10 years, the electric industry will face a number of significant emerging reliability issues, which are explained in detail throughout this report. These issues will change the industry, requiring better modeling and risk management and increasing the reliance on natural gas, renewable resources, and a more robust infrastructure. Each of these elements of change is critically interdependent, and industry action must be closely coordinated to ensure reliability.

Impacts to long-term BPS reliability are categorized and assessed within three overarching risk areas:

1. **Resource and Transmission Adequacy**
   Resource and transmission adequacy risks can impact the projected ability of BPS infrastructure to serve customer demand during all hours over a specified horizon. Uncertainty in resource and transmission needs is driven by market and environmental regulations, customer demand, and impediments to constructing facilities within a needed time frame.

2. **Integration of New Technologies and Operations**
   The integration of new technologies can introduce potential future operational risks to the BPS. Resources or new technologies with unique operating characteristics require a level of enhanced understanding beyond traditional capacity and energy planning. Integrating these technologies without fully understanding their impacts can threaten real-time operations as well as the system's ability to withstand disturbances.

3. **Long-Term System Planning and Modeling**
   The approach and methods used for long-term planning and modeling, including potential inadequate assumptions, models, data, and methods, can lead to incorrect decision making and introduce risks to the BPS. Therefore, model and analysis inputs need to be accurate and enhanced to reflect a rapidly evolving range of future transmission and resource challenges.

The electric industry is becoming more complex due to political and societal drivers propelling new policies, such as a carbon-reduced resource portfolio. This assessment presents the contributing factors identified in the *2013LTRA* reference case and highlights potential reliability challenges and emerging issues. Each issue is ultimately related to the three overarching risk areas identified above.

The Reliability Assessment Subcommittee (RAS) of the NERC Planning Committee (PC) provides input on reliability issues that are particularly important to the industry, including those that may not be apparent in the *2013LTRA* reference case. The intent is not to identify, evaluate, and address every issue that could potentially impact the future reliability of the BPS. Instead, NERC, with industry support, attempts to identify a limited set of issues that are of particular concern to reliability, with related impacts expected to develop or grow during the 10-year assessment period. Once all issues have been identified, NERC depends on input from industry to gauge the potential impacts each issue will have on resource and transmission adequacy, operations, and long-term planning and modeling.

For the development of this section of the *2013LTRA*, the NERC Reliability Assessment staff developed a survey that was distributed to members of the NERC PC, OC, MRC, and the RAS. Members of these committees include a wide range of electricity industry subject matter experts who offer both operational and planning perspectives. Accordingly, NERC's stakeholder and subject matter expert committees evaluated six issues that NERC identified would be most impactful over the next 10 years and developed a comprehensive risk assessment. Each issue is examined in more detail in this section.

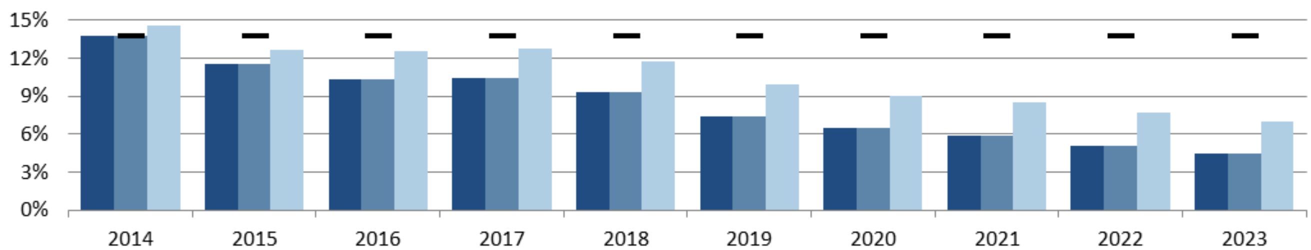
The evolving operation of the BPS will require new operational tools and procedures that, in order to be implemented without adverse impacts to system reliability, will require careful consideration, preparation, and planning. Issues and challenges related to resource and transmission adequacy, integration of new technologies, and long-term system planning and modeling are highlighted in this assessment. While some of these challenges are more regional than others, their cumulative impacts can affect planning and operating fundamentals that can extend to the entire interconnection.

Resource Adequacy Concerns in MISO and TRE-ERCOT

TRE-ERCOT Overview

Since 2011, NERC has highlighted resource adequacy challenges in ERCOT[25]. The Anticipated Reserve Margin drops slightly below the 13.75 percent NERC Reference Margin Level for ERCOT for the 2014 summer season and continues to decline during the next decade. This deficit exists despite a substantial reduction in ERCOT's projected CAGR of demand growth (1.38 percent, compared to 2.35 percent in the *2012LTRA* reference case.[26] The reduced demand projection results from the use of a lower long-range economic forecast. Higher load caused by sustained extreme weather conditions, multiple forced generator outages, or a combination of both, increase the likelihood of rotating outages. With reserves below target levels, these otherwise manageable operating conditions are magnified due to reduced operational flexibility.

Figure 11: TRE-ERCOT Planning Reserve Margins



TRE-ERCOT-Summer		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ANTICIPATED		13.74%	11.59%	10.34%	10.46%	9.34%	7.36%	6.44%	5.91%	5.11%	4.43%
PROSPECTIVE		13.74%	11.59%	10.34%	10.46%	9.34%	7.36%	6.44%	5.91%	5.11%	4.43%
ADJUSTED POTENTIAL		14.58%	12.71%	12.53%	12.71%	11.75%	9.98%	9.04%	8.49%	7.67%	6.97%
NERC REFERENCE	-	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**

ERCOT has responded via efforts to increase participation in DR and Energy Efficiency programs. Total DSM has grown to 2,215 MW for the 2014 summer peak, an increase of approximately 700 MW compared to last year's projections. Additionally, new resources have come online, including Sandy Creek, a 900-MW coal plant that became operational in the spring of 2013. Several new gas-fired units are also planned, including a 392-MW unit expected to come on-line before the end of 2013, and approximately 650 MW of capacity categorized as Conceptual with in-service dates in 2014. Capacity additions and the implementation of new DSM programs will help address reliability needs. As a result, the potential for emergency operating conditions, including the curtailment of firm load, will be substantially reduced. In addition, the Public Utility Commission of Texas (PUCT) is taking steps to provide economic incentives to address resource adequacy (as described in the TRE-ERCOT section of this assessment). NERC will continue to monitor these developments in future seasonal and long-term assessments.

MISO Overview

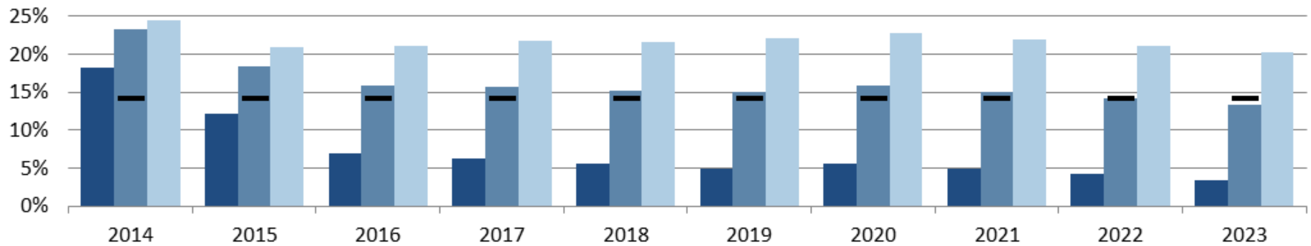
The Anticipated Reserve Margin for the Mid-Continent Independent System Operator (MISO) will fall to 12.13 percent during the 2015 summer season, which is below the NERC Reference Margin Level of 14.2 percent. This resource adequacy outlook could be further impacted by changing regulatory and economic drivers unique to MISO. Long-term Planning Reserve Margins have been higher in recent years, as observed in the 2010–2012 long-term assessments. The *2013LTRA* reference case Planning Reserve Margins have been reduced, partially due to the announced retirement of approximately

[25] ERCOT is the Independent System Operator for the ERCOT Interconnection and schedules power on an electric grid that connects 40,500 miles of transmission lines and more than 550 generation units. Texas Reliability Entity (TRE) is the Regional Entity responsible for assessing the reliability of the BPS within ERCOT.

[26] Comparison of the compound annual growth rate. For additional information, see the 2012 Long-Term Reliability Assessment.

11 GWs of Base Load coal units. MISO is working with the industry to conduct a Forward Resource Assessment[27] to capture critical risks in the planning horizon and depict a more comprehensive projection of long-term resource adequacy.

Figure 12: MISO Planning Reserve Margins



MISO-Summer		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ANTICIPATED		18.28%	12.13%	7.00%	6.29%	5.54%	4.86%	5.65%	4.90%	4.16%	3.44%
PROSPECTIVE		23.35%	18.44%	15.82%	15.65%	15.16%	15.08%	15.79%	14.98%	14.17%	13.37%
ADJUSTED POTENTIAL		24.55%	20.94%	21.12%	21.82%	21.65%	22.18%	22.85%	21.98%	21.13%	20.28%
NERC REFERENCE	-	**14.20%**	**14.20%**	**14.20%**	**14.20%**	**14.20%**	**14.20%**	**14.20%**	**14.20%**	**14.20%**	**14.20%**

This uncertainty heightens the potential for reserve requirement deficiencies. Avoiding these negative outcomes requires increased collaboration between MISO and its members, the Organization of MISO States (OMS), and other key players in the industry to fulfill reliability requirements and develop a system that enhances the economic benefits of a regional transmission system.

During the long-term assessment period, MISO will face significant uncertainties that will present new reliability challenges. These challenges will require increased collaboration, because resource adequacy plans will be dramatically impacted in response to existing and potential emission regulations. The impact of current and proposed regulations combined with concerns over reliable gas supply makes a 3-to-7-GW capacity shortfall possible as early as the 2015 summer.

The uncertainty increases with the potential for carbon emission limitations, which President Obama recently identified as a priority. While some details of this proposal are uncertain, it is evident that continued policies aimed at limiting carbon emissions will impact the coal generation fleet in MISO, increasing the potential for resource deficiencies and corresponding reliability impacts.

While these uncertainties raise regional concerns, MISO operating procedures note the following solutions to address potential shortages: calling on emergency generation resources, reducing load through the use of DR programs, and relying on operating reserves. As a last resort, operators would shed firm load on a pro-rata basis.

New challenges, however, require new approaches to fulfill reliability requirements. The MISO Forward Resource Assessment details ongoing initiatives to fulfill reliability, which include, but are not limited to, the following topics:

- Bridging the gap of limited visibility that exists between the annual Module E process and the Forward Resource Assessment.
- Increasing the visibility of future resource retrofits and retirements due to environment regulations and pursuing the development of processes to assure the most reliable coordination of retrofit outages.
- Enhancing the existing loss-of-load expectation (LOLE) study to incorporate fuel limitations in the development of planning requirements.
- Enhancing existing load forecasts by accurately predicting load forecast uncertainty (LFU), measuring economic and weather components of LFU, and including these enhancements in MISO's planning initiatives.

[27] 2013 MISO Forward Resource Assessment - Incorporating Risks (Presentation).

RECOMMENDATIONS

Recommendation(s)
1-1 Heightened awareness required: NERC should increase its coordination with the Texas Reliability Entity (TRE), Electric Reliability Council of Texas (ERCOT), and state regulators and legislators to support active and planned measures to address the continuing challenges in meeting reserve margin targets. NERC should work with the relevant oversight entities to identify effective measures that would reverse the trend of declining reserve margins. 1-2 Initiate focused assessment: With respect to similar declining reserve margin trends within MISO, NERC should develop a more granular and near-term assessment of the resource adequacy conditions in the MISO assessment area. Furthermore, NERC should closely monitor and continuously evaluate the measures being taken in MISO to address the evolving resource adequacy challenges.

Continued Integration of Variable Generation

Overview

Reliably integrating high levels of variable resources (wind, solar, and some forms of hydro) into the North American BPS will require significant changes to traditional methods used for system planning and operation. The amount of variable renewable generation is expected to grow considerably as policy and regulations on greenhouse gas emissions are being developed and implemented by federal authorities and individual states and provinces throughout North America. Power system planners must consider the impacts of variable generation in power system planning and design and develop the necessary practices and methods to maintain long-term BPS reliability. Operators will require new tools and practices, including potential enhancements to NERC Reliability Standards or guidelines to maintain BPS reliability.

During the past four years, the NERC Integration of Variable Generation Task Force (IVGTF) developed a number of recommendations that support the reliability considerations for accommodating large amounts of variable generation. These recommendations spurred significant action across the electric industry, including the identification of potential gaps and enhancements to NERC Reliability Standards. NERC IVGTF recommendations have provided industry with guidance on developing new operating procedures and planning considerations, including specifics on unique regional challenges, differing market structures, and regulatory policies.

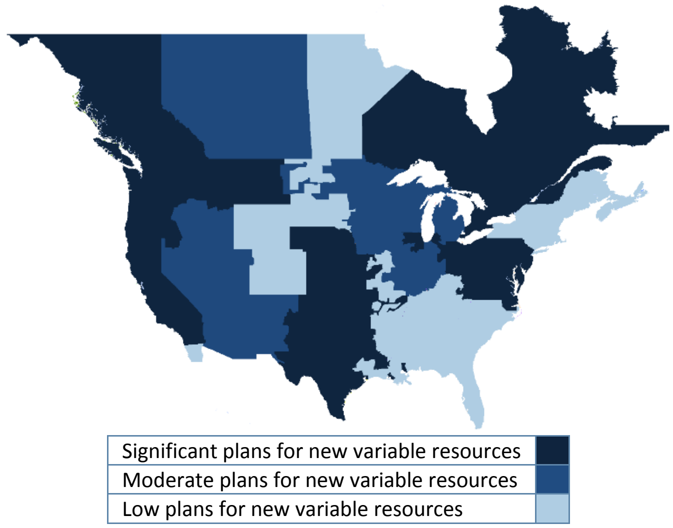
A recent NERC report focuses on the approach the California Independent System Operator (CAISO) is taking to address those recommendations and ensure reliability given the large penetration of VERs.[28] The solutions being implemented by CAISO build on existing IVGTF recommendations. In many ways, CAISO's ongoing efforts to effectively plan and operate a transformed electric grid with large penetration of variable resources can serve as a model for other areas to examine and build upon. Accordingly, the report also addresses challenges and enhancements needed in other areas in North America.

Accommodating higher levels of variable resources requires cooperation and coordination within each interconnection—especially between BPS and non-BPS entities. Frequency stability, frequency response, energy imbalance, and increased and dynamic transfers must be addressed at all levels. Specifically, increasing amounts of solar photovoltaic (PV) generation leads to decreased system inertia and frequency response capabilities that could potentially result in reliability impacts on the BPS.[29]

Regional differences will exist; however, this is largely an interconnection-wide issue. More than 28 continental states and the District of Columbia have RPSs,[30] and Canada has similar provincial policies. These policies mandate or encourage electricity producers to supply a certain minimum share of their electricity from designated renewable resources (wind, solar, biomass, geothermal, and some hydroelectric).[31] Additionally, greenhouse gas emission regulations (notably CO_2) and continually declining costs of renewable resources further incentivize renewable resource investment 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 renewable mandates need to be properly addressed.

[28] 2013 Special Reliability Assessment: Maintaining Bulk Power System Reliability While Integrating Variable Energy Resources – CAISO Approach.
[29] NERC IVGTF Reports.
[30] Also referred to as renewable electricity standards (RES).
[31] Database of State Incentives for Renewables & Efficiency.

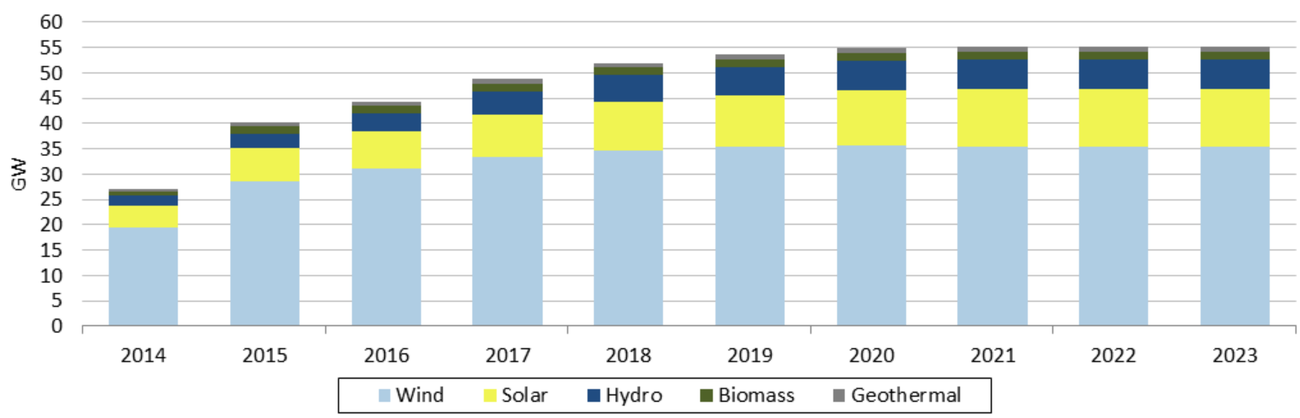
Assessment Area Impacts



Long-Term Trends

Nameplate renewable capacity (including wind, solar, hydro, biomass, and geothermal) will grow by approximately 55 GW by 2023. With over 35 GW of planned nameplate capacity, wind accounts for over half (64 percent) of these additions. A majority of the 11.5 GW of solar capacity additions will be in the southwestern portions of WECC, including WECC-DSW and WECC-CALS.

Figure 13: Net 10-Year Cumulative Nameplate Capacity Additions (2014–2023) [32]



The overall contribution from renewable resources during the peak is also expected to grow—from its current contribution of 21.7 GW to 39.3 GW of the on-peak resource mix in 2023. Although wind capacity leads renewables in terms of nameplate capacity additions, 7.2 GW of the additions are projected to be available for contribution to the on-peak resource mix. Alternatively, solar capacity will add 9.1 GW of projected capacity during the peak. Currently, renewable generation (geothermal, wind, solar, and biomass) provides about 2 percent of the on-peak resource mix and is expected to reach over 3.6 percent in 2023. If Conceptual renewable resources are built, the contribution could be as high as 12 percent by 2023.

A key goal for power system planners is not only to determine how much capacity there is on a system, but also to determine if that capacity can be reasonably expected to perform and operate on peak. In many areas, wind power output

[32] The peak season is used for each assessment area.

is inversely correlated with demand, with capacity output during times of peak demand generally amounting to a fraction of nameplate capacity. Significant on-peak wind capacity is projected in both the United States and Canada, totaling an increase of over 11.6 GW in WECC alone.

Currently, only MISO and ERCOT have a probabilistic basis for determining this factor. ERCOT is regularly reevaluating the Effective Load Carrying Capability (ELCC) for the area and making modifications as necessary. The most recent modification includes potentially calculating two values: one value for aggregated inland wind resources, and a separate value for those classified as coastal wind resources.[33] Coastal and off-shore wind patterns are generally more persistent and do not exhibit the same variability observed inland and near mountainous topology, where siting is more difficult for developers. NERC-wide, the on-peak capacity contributions from these wind plants in 2014 averages 17 percent of installed wind capacity.[34]

From an assessment area perspective, the CALS and DSW subregions in WECC are expecting the most future renewable on-peak capacity, with over 6.6 GW of new solar capacity. Approximately 11.1 GW of nameplate solar capacity are projected to come into service, primarily in WECC-CALS and WECC-DSW. Regional planners in these areas continue to assess the growing impacts of this variable resource into the generation mix.

Resource and Transmission Adequacy Impacts

The addition of significant amounts of variable generation to the BPS changes the way that transmission and resource planners develop their future systems to maintain reliability. Planners must consider the additional uncertainty in available peak capacity. Compared to today's power system, in scenarios of high variable generation penetration, a larger portion of the total supply resource portfolio will be comprised of energy-limited resources. This fact somewhat complicates—but does not fundamentally change—existing resource adequacy planning processes, which must remain driven by a reliability-based set of metrics.

As noted in other NERC assessments, the industry should develop consistent methods to determine on-peak wind capacity to ensure uniform measurement and resource adequacy assumptions.[35] As wind generation becomes a more significant contributor to an area's capacity mix, probabilistic planning techniques will be needed. Probabilistic planning techniques indicate that in most areas, wind's contribution to capacity is generally in the range of 5 to 10 percent of the wind energy nameplate capacity.[36]

Wind generation technology has evolved rapidly during the last decade; however, advances in physical equipment have outpaced industry's ability to develop accurate models to use in technical planning and operating studies. In some instances, the as-built equipment performance has differed significantly from the models provided during the system impact and preliminary operating studies.

Wind generation is often located substantial distances from the point of interconnection to the transmission system, which creates additional reliability implications. In many cases, the location of these variable resources only meets the minimum voltage support requirements.

Because of these technical and policy challenges, the operation of wind generators has at times been curtailed, especially during maintenance conditions on the transmission system. Without significant transmission expansion and improvements at the wind plants, these curtailments are expected to continue. In addition to customer interconnection studies of elective transmission upgrades that address marginal interconnections and transmission constraints above what currently is

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[33] ERCOT Loss-of-Load Study

[34] This percentage is based on a comparison between the 2014 on-peak wind projections to the nameplate projections for the peak season of each NERC assessment area.

[35] Currently, Regions and subregions (in particular, difference operating entities) use different methods to determine expected on-peak values of wind capacity. The IVGTF is addressing this issue in the following report *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning*.

[36] Capacity Value of Wind Power

required, the increasing amount of system operating complexity may necessitate other interconnection studies that include a wider range of system conditions.

Transmission planning processes to integrate large amounts of variable generation rely on a number of factors, including:

- Whether government renewable policies or mandates exist,
- The level of variable generation mandated and available in remote locations,
- The time horizon across which capital investments in variable generation are to be made, and
- The geographic footprint across which the investments occur.

In order to ensure reliability, transmission is needed to:

- Interconnect VERs planned in remote areas
- Accommodate the variable generation output with uniformity across a broad geographical region and resource portfolio
- Deliver ramping capability and ancillary services from inside and outside a Balancing Authority (BA) area to equalize supply and demand

Transmission system expansion is vital for unlocking the capacity available from variable generation, and it can be used as a tool to reduce overall variability across a broader area. Shared ramping capability and ancillary services between adjacent areas also provides additional reliability benefits, depending on how existing and planned interarea transmission assets are used. In regions with a competitive generation marketplace, regulatory targets such as RPSs heavily influence the location and timing of renewable generation investments and their development. Furthermore, government policy and any associated cost allocations (i.e., who pays for transmission, additional ancillary services, and ramping capability) will be key drivers for variable generation capacity expansion. Therefore, an iterative approach between transmission and generating resource planning is required to cost-effectively and reliably integrate all resources.

Operational Impacts

The expected significant increase in variable generation additions to the BPS will increase the amount of uncertainty that a system operator must factor into operating decisions. The system operator must have access to more accurate variable generation forecasting techniques and sufficient flexible resources to mitigate the added variability and uncertainty. Operating criteria, forecasting, commitment, scheduling, dispatch and balancing practices, procedures, and tools must be enhanced to assist operators in maintaining BPS reliability. Improved operating practices, procedures, and tools are critical for integrating variable generation into the power system, as well as improving its control performance and reliability characteristics. System resources supporting reliability, such as flexible generation and responsive load, are finite.

Compared to conventional generation, variable generation is less effective at providing the system sufficient inertia to arrest frequency decline. Similarly, variable generation may not create adequate governor response to stabilize system frequency following the loss of a large generator. Frequency excursions caused by overgeneration are possible during periods of high VER production and low system demand. If dispatchable resources are already operating at minimum load levels and regulation down capacity has been exhausted, higher-than-scheduled or higher-than-expected VER production levels can result in overgeneration and, ultimately, overfrequency conditions.

Distributed energy resources (DERs) in aggregate can have a significant impact on BPS operations and represent a potential reliability gap. Existing interconnection requirements for DERs do not specifically take into account potential effects on bulk system reliability. Of particular concern is the lack of disturbance tolerance, which entails voltage ride-through (VRT) and frequency ride-through (FRT) capability. Under high penetration scenarios, it is possible for a large amount of generation to trip on voltage or frequency due to a system disturbance, which could potentially affect bulk system stability. The need for high-frequency tolerance is also being discussed as part of a FERC stakeholder consultation on interconnection procedures for small generators.[37] Distribution-connected variable resources, like all other DERs, are required to comply with IEEE Standard 1547, which at present does not contain any VRT or FRT stipulations. Instead, IEEE Standard 1547 requires DERs to disconnect from the grid within a short period of time after voltage or frequency falls outside a certain range. With a significant amount of DERs online, the inability to remain interconnected, stable, and functional during and after a system disturbance presents a significant risk to the BPS.

Long-Term Planning and Modeling

The purpose of power system planning is to ensure that a reliable and robust power system is available to the power system operator within the planning horizon. To improve system reliability, the industry has already begun development of new planning methods and techniques that include the characteristics of variable generation assets. These tools need to be expedited to ensure the reliable operation of the BPS. New models need to take into account new technologies (e.g., storage), variable demand (e.g., DR), and incorporation of flexible resources. For example, storage technologies, if economical and properly planned and implemented, can provide the flexibility to accommodate large amounts of variable resources as an alternative to the construction of more conventional flexible generation resources or transmission.

At low variable generation penetration levels, traditional approaches toward sequential expansion of the transmission network and managing wind variability in Balancing Authorities may be satisfactory. However, at higher penetration levels, a regional and multiobjective perspective for transmission planning, including the identification of concentrated variable generation zones, may be needed.

System planning studies should continue to thoroughly examine voltage stability, frequency response, diminishing reactive power, and inertia impacts. Additional transmission will also be needed to interconnect VERs planned in remote regions, level the variable generation output across a broad geographical region and resource portfolio, and deliver ramping capability and ancillary services from inside and outside a Balancing Area to equalize supply and demand.

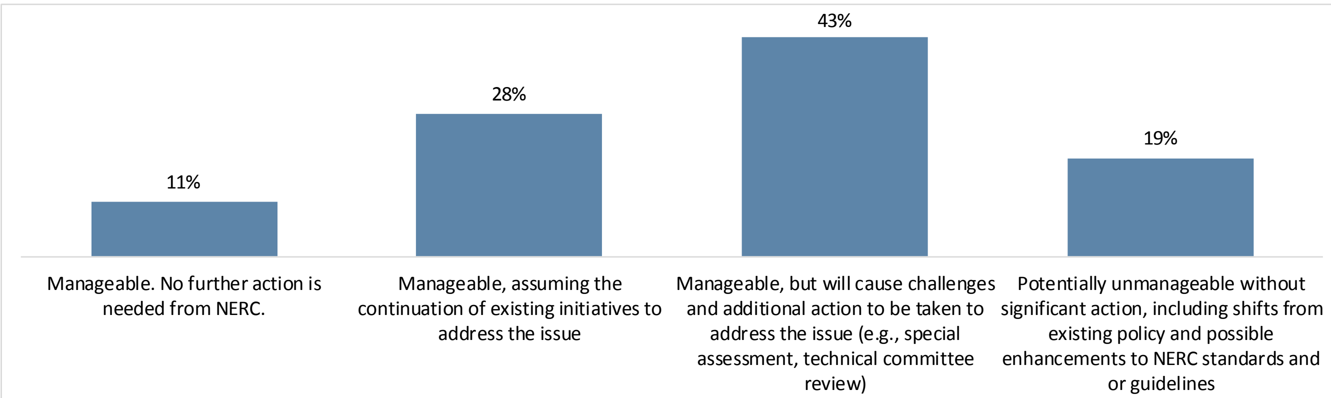
These capabilities also include having access to “standard models,” which are defined as nonproprietary and publicly available models for the simulation of steady-state (power flow), short-circuit (fault calculations), and dynamic (time-domain simulations) behavior of such variable generation. These models must be made readily available for use by power system planners.

[37] See FERC Docket No. RM13-2-000.

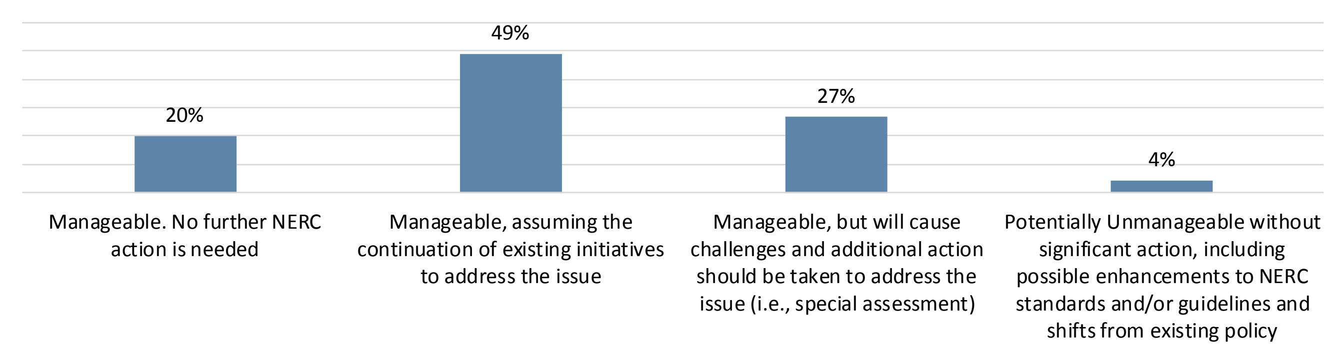
Industry Perspective

The following charts present a selection of responses to a survey developed by NERC staff that posed several questions to gauge the industry perspective on the impacts of the continued integration of variable generation.[38] Members of NERC's PC, OC, RAS, and MRC provided the following responses:

The likelihood that continued integration of variable generation will result in Planning Reserve Margins falling below the NERC Reference Margin Level (Target):

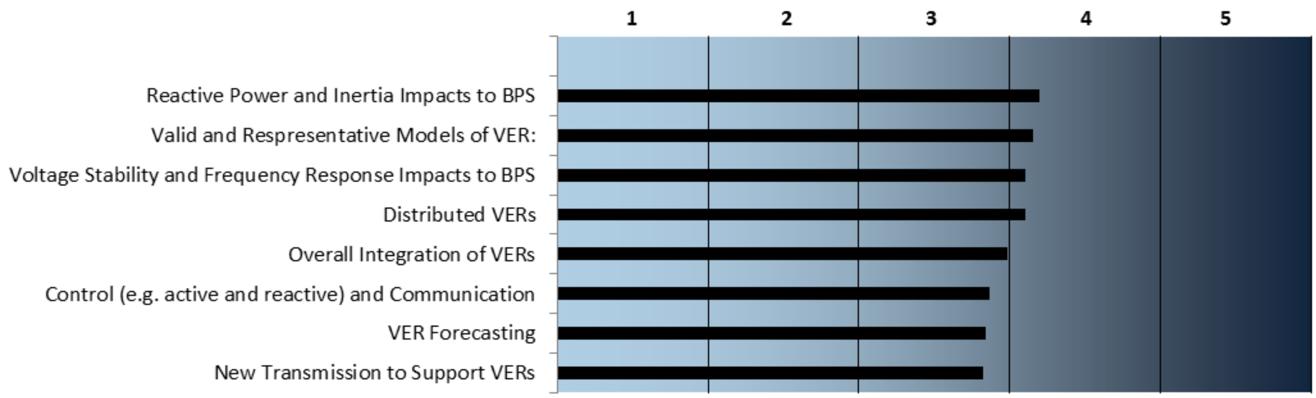


Addressing the reliability challenges associated with the integration of variable generation during the next 10 years will be:



[38] For additional information on the survey, please contact NERC staff (assessments@nerc.net).

Risk Profile



1-Manageable. No further action is needed from NERC
2-Manageable, assuming the continuation of existing initiatives to address the issue
3-Manageable, but will cause challenges and additional action to be taken to address the issue (e.g., special assessment, technical committee review)
4-Potentially unmanageable without significant action, including shifts from existing policy and possible enhancements to NERC standards and guidelines
5-Unmanageable under current trajectory; extreme risk; must be addressed immediately

Recommendations

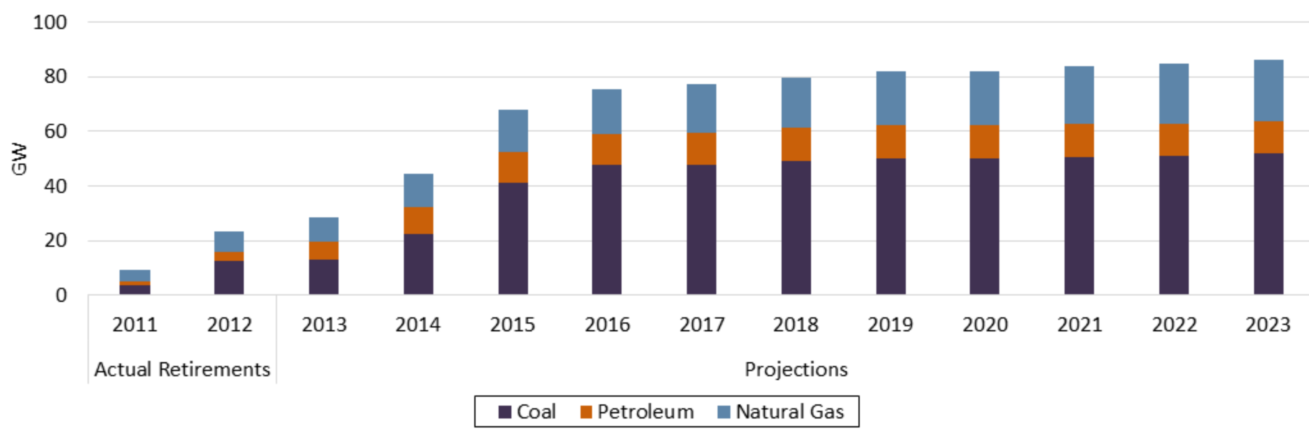
Recommendation(s)
2-1 Expand NERC methodology for reliability assessment: NERC should develop a new approach and framework for the long-term assessment of essential reliability services to supplement existing resource adequacy assessments. The new approach may include the development of metrics for further evaluation in future long-term reliability assessments.
2-2 Develop primer on essential reliability services: NERC should develop a technical reference document on essential reliability services, which include frequency response, inertia, voltage stability, ramping capability, and other operational requirements needed to ensure BPS reliability. The primer can be used as a reference manual for regulators and policy makers and to inform, educate, and build awareness on the reliability ramifications of a changing resource mix.
2-3 Initiate focused assessment: Similar to its collaborative work with the California Independent System Operator, NERC should conduct a comprehensive assessment of essential reliability services for areas and systems approaching 20 or more percent variable resources over the next 10 years. Additionally, the focused assessments should identify the measures and initiatives needed to ensure the continued provision of these services.
2-4 Active engagement with IEEE: NERC strongly encourages industry to proactively address potential BPS reliability impacts associated with large amounts of aggregated distributed and variable energy resources (VERs). This initiative includes encouraging the IEEE 1547 stakeholder group to consider BPS reliability in its standards development process.

Fossil-Fired Retirements and Coordination of Outages for Environmental Control Retrofits

Overview

NERC continues to assess the implications of environmental regulations in the United States as the industry continues to respond to various state, federal, and provincial requirements. Since the release of the report *Potential Impacts of Future Environmental Regulations*, included in the *2011LTRA*,[39] NERC has continued to monitor the reliability impacts of environmental regulations, such as resource adequacy implications and impacts to operations (e.g., deliverability, stability, localized issues, outage scheduling, operating procedures, and industry coordination). Since 2011, fossil-fired unit retirements, retrofits, and conversions have been largely attributed to the unique confluence of final and potential environmental regulations, as well as the continuation of low natural gas prices and other economic factors. According to the *2013LTRA* reference case, about 62.8 GW of fossil-fired generation (39.4 GW of coal, 8.3 GW of petroleum, and 15.2 GW of older natural gas) will be removed from the on-peak generation mix by 2023. A large portion of planned retirements will occur in PJM, with 13 GW of announced fossil-fired retirements during the assessment period (amounting to 6.9 percent of the existing PJM fleet).[40] Of the announced retirements, approximately 9.7 GW are coal, 2 GW are gas, and 1.3 GW are oil-fired generation.

Figure 14: Actual Retirements and Projected On-Peak Reduction of Coal, Petroleum, and Natural Gas Capacity (2011–2023) [41]



Between January 2011 and January 2012, 12.4 GW of coal-fired generation was taken out of service. During the same period, 3.6 GW of oil-fired generation and 7.4 GW of gas-fired generation was taken out of service. The retirement of significant amounts of fossil-fired generation each year has resulted in reduced Planning Reserve Margins in many areas. However, retirements during the next three to four years may bring to light important issues to system stability and the need for system enhancements which, if not addressed, could cause or exacerbate existing reliability concerns in some areas.

In the near-term, environmental control retrofits will be needed for industry to be able to comply with existing and proposed federal environmental regulations. Given the timelines for compliance (for example, MATS compliance by 2016), many of the affected units may need to take concurrent maintenance outages. The need to take multiple units out of

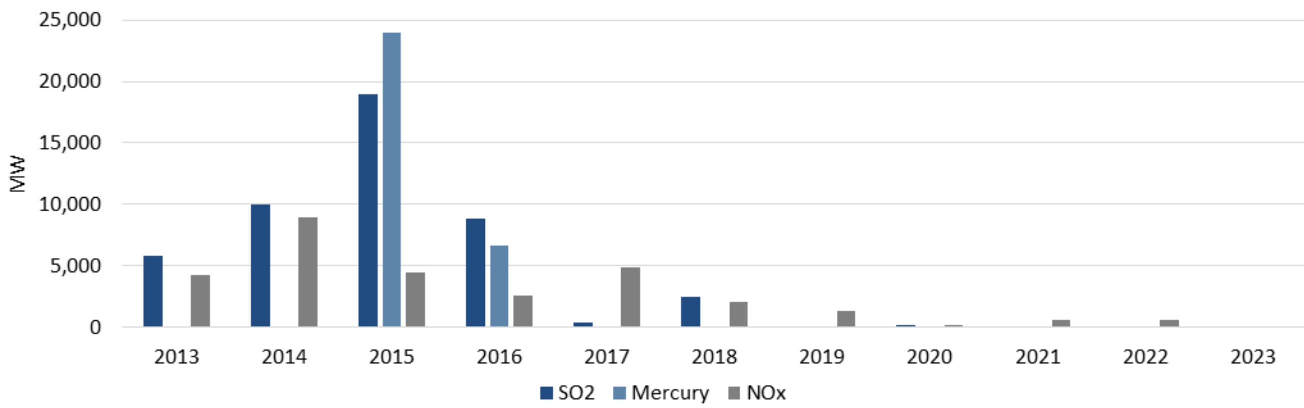
[39] Potential Impacts of Future Environmental Regulations Extracted from the 2011 Long-Term Reliability Assessment.

[40] PJM Generation Deactivation Summary Sheets.

[41] Actual U.S. coal-fired retirement data (2011 and 2012): EIA Today in Energy. Actual Canadian coal-fired retirement data (2011 and 2012): Ventyx Velocity Suite. Actual NERC-wide oil- and gas-fired retirement data (2011 and 2012): Ventyx Velocity Suite. Projections are aggregated by fuel type from the *2013LTRA* reference case. The reduction represents negative capacity changes due to unit derates and retirements.

service on extended scheduled outages can impact resource availability and reduce flexibility, particularly during shoulder months. Industry must focus on outage coordination to avoid resource adequacy concerns during maintenance periods. In the United States, industry has planned the following retrofits to be compliant with regulations that limit SO_X, CO_2, and NO_X emissions.

Figure 15: Planned Retrofits to Existing Units in the United States by Year[42,43]



Most retrofits are planned between 2013 and 2016 with a total of 43.5 GW for SO_2 controls, 30.6 GW for mercury controls, and 20.2 GW for NO_x controls.

As the long-term resource adequacy outlook experiences ongoing changes in response to new and proposed emission regulations, NERC continues to closely monitor reliability impacts in the United States and various Canadian provinces. The specific environmental regulations with their current statuses are provided below:

Regulation	Description and Status
Mercury and Air Toxics Standards (MATS)	On December 16, 2011, the EPA issued a rule to reduce emissions of toxic air pollutants from power plants. MATS will 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[44] or a scrubber on units to control emission levels. Generation owners will ultimately be charged with deciding between investing in the plant to ensure it complies with regulations, or closing it permanently.
Clean Air Act (Section 111)	The Clean Air Act impacts new and existing sources under Section 111 (a federal program for new sources and state programs for existing sources). Section 111 is being used by the EPA to issue standards, regulations, or guidelines as appropriate that address carbon pollution from new and existing power plants, including modifications of those plants. This section of the Act establishes a mechanism for controlling air pollution from stationary sources. Section 111(b) is the federal program to address new, modified, and reconstructed sources by establishing standards; Section 111(d) is a state-based program for existing sources. The EPA establishes guidelines, and the states subsequently design programs based on those guidelines to achieve the necessary reductions.
Cross-State Air Pollution Rule (CSAPR)	On August 21, 2012, the D.C. Circuit Court vacated the CSAPR,[45] which had originally required 23 states to reduce annual SO_2 and NO_X emissions. However, since CSAPR did not mandate physical requirements for electric generators, the rule had a smaller bearing on unit retirement decisions compared to other factors. The likely drivers behind retirement decisions will be the combination of other federal and state environmental rules, changing fuel

[42] Data provided by Energy Ventures Analysis, Inc.; Analysis performed by NERC staff.
[43] Planned retrofits for compliance with each regulation are examined separately. Capacity refers to the summer rating for each unit.
[44] EIA Today in Energy: Dry sorbent injection may serve as a key pollution control technology at power plants.
[45] The CSAPR was initially designed to replace EPA's 2005 Clean Air Interstate Rule (CAIR). A December 2008 court decision kept the requirements of CAIR in place temporarily but directed EPA to issue a new rule to implement Clean Air Act requirements concerning the transport of air pollution across state boundaries. This action responds to the court's concerns. For additional information see the EPA website EPA Interstate Air Pollution Transport.

	costs (i.e., lower natural gas prices), and other economic decisions. In October 2013, the Supreme Court upheld the EPA's ability to regulate greenhouse gas (GHG) emissions as a pollutant. With the decision reinforcing the EPA's regulatory authority under the Clean Air Act, additional requirements could be implemented in the coming years. The recently announced initiatives in the United States to reduce the carbon footprint in the electric sector include the tightening of appliance Energy Efficiency standards, continuing to support clean energy technologies, and reducing GHG emissions from both existing and future coal-fired plants by enforcing new regulations by the EPA as mandated under the Clean Air Act.
Clean Water Act (CWA) – Section 316(b)	Cooling water intake operation and structures are regulated under Section 316(b) of the CWA. 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 Best Technology Available (BTA) 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 (33 U.S.C. section 1326) 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. Final rules are expected in early 2014.[46]
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 for 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.[47]

Recently announced initiatives in the United States[48,49] to reduce the carbon footprint in the electric sector include the tightening of appliance Energy Efficiency standards, the continuation of support for clean energy technologies, and reduction of greenhouse gas (GHG) emissions from both existing and future coal-fired plants by enforcing new regulations by the EPA, as mandated under the Clean Air Act. Because of strict emission limits and a new technology-based solution that may be required (e.g., carbon capture and sequestration), the transition of coal to natural gas is expected to continue throughout and beyond the assessment period. Natural gas-fired generation is likely to replace a significant amount of less efficient coal- and oil-fired generation. However, natural gas emits significant amounts of GHGs and can only play a transitional role in the short to medium term until a long-term, low-carbon solution is in place. Potential solutions should include system reliability—planning and operational requirements, the availability and viability of integrating new technologies, and the timing requirements of both.

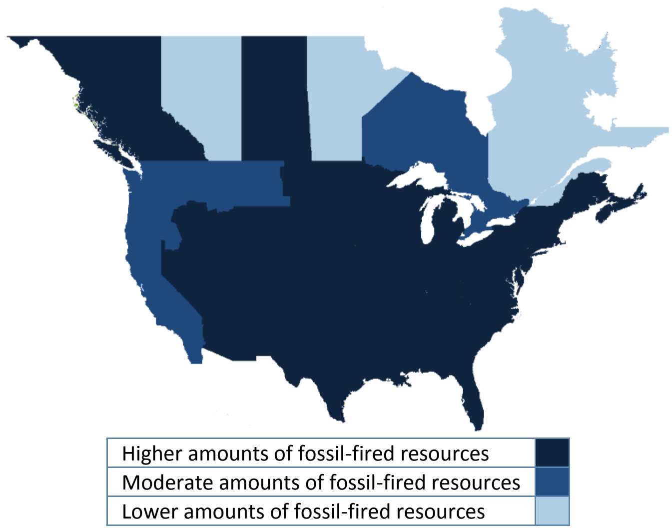
Resource adequacy challenges can often be remedied by sending clear and accurate price signals to incentivize new capacity. In some cases, a more immediate response to resource adequacy challenges may require regulatory action. However, reliability factors other than capacity and energy requirements can be more difficult to address; for example, the ability of the BPS to withstand disturbances and remain in compliance with NERC Reliability Standards. These and other less obvious reliability concerns are further exacerbated by the continued retirement of steam-driven generators (including nuclear), causing a decrease in total system inertia, voltage support, frequency control, and reactive power. Many of the resources that are replacing these retired units are variable in nature (e.g., wind, solar, and biomass) and do not have the same operating characteristics as traditional forms of generation.

As coal capacity is retired, the characteristics and system support provided by larger steam-driven turbines is reduced. When transmitting large amounts of power over vast geographic areas, it is vital to consider the reliability implications. 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 generation

[46] EPA Carbon Pollution Standards.
[47] Coal Combustion Residuals - Proposed Rule.
[48] Climate Change and President Obama's Action Plan.
[49] EPA Carbon Pollution Standards.

source. Photovoltaic solar generation offers no inertia and no frequency response; wind generation offers virtually none unless specifically designed to do so. As simple energy requirements are provided by these types of energy-only resources, the other necessary components of conventional generation resources must also be replaced.

ASSESSMENT AREA IMPACTS



RESOURCE AND TRANSMISSION ADEQUACY IMPACTS

Early retirement of multiple units in the short run can stress the BPS if plans are not in place to add resources. This can affect both short- and long-term planning strategies and reduce Planning Reserve Margins. With fewer resources, flexibility is reduced and the risk of a capacity shortage may increase, unless additional resources are available. Where Planning Reserve Margins fall below targets or requirements, resources in a specific area may be insufficient to meet future demands.

In order to maintain sufficient resources to meet peak demands, system planners continuously assess expected changes in generation and transmission assets (in this case, the retirement of a generating unit). For example, once a system planner is informed of an upcoming unit retirement, general studies must be conducted on the entire system to assess whether the retirement would cause a reliability issue. If issues are identified, mitigation plans must be developed. Potential solutions include replacing the unit with another form of capacity, confirming additional Demand-Side resources, or building new transmission or other equipment. Each of these options is associated with various implementation timelines. From a resource adequacy perspective, it is important to consider the typical time frame required for industry to plan and construct replacement capacity. Accordingly, policy makers should consider these challenges when developing environmental compliance timelines.

Unit retrofits will have alternative impacts on resource adequacy, potentially stressing the industry's ability to coordinate the necessary and possibly prolonged unit outages needed for the installation of environmental controls. Issues could emerge in load pocket areas (i.e., major metropolitan areas) due to the loss of critical bulk power resources. These vulnerabilities may persist in the shoulder months as well.

OPERATIONAL IMPACTS

Potential environmental regulations can substantially modify the overall fuel mix, ultimately changing the inherent operating characteristics of a given resource portfolio. For example, with less coal-fired capacity, more gas-fired generation may be needed to provide Base Load services. As a result, the interdependency of gas and electric supply, transport, and delivery must be further assessed to ensure reliability is not degraded.

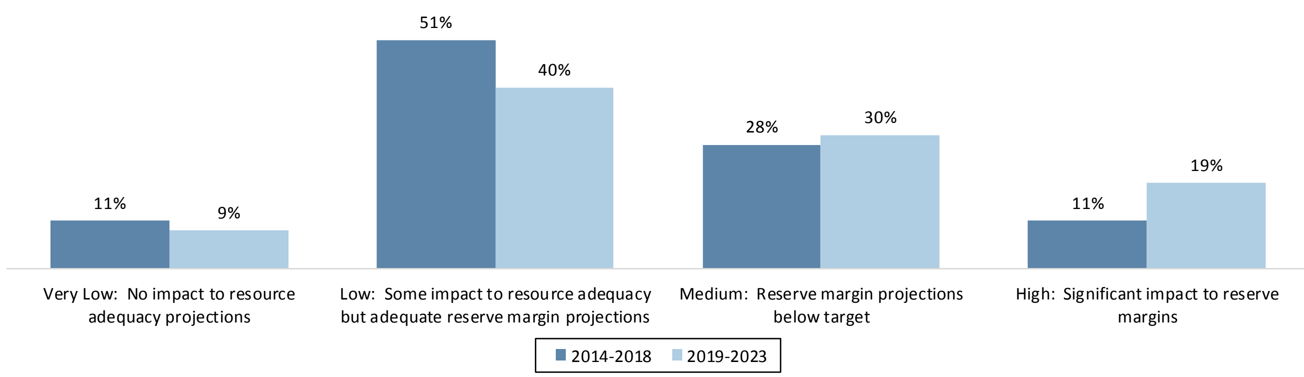
TRANSMISSION IMPACTS

New transmission may be needed to interconnect new generation as replacement generation is constructed. The transmission system may need to be enhanced to be able to support firm and reliable transmission service to support new generation. Enhancements and reconfiguration may create additional timing issues, because new transmission facilities take relatively longer to construct than generation. Second-tier effects include impacts to essential reliability services.

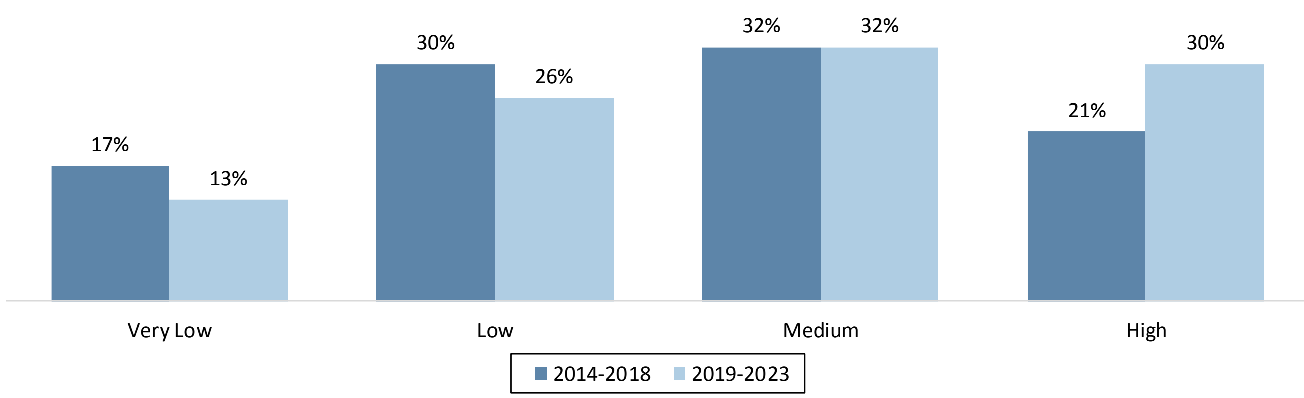
INDUSTRY PERSPECTIVE

The following charts present responses to a survey NERC developed that posed several questions to industry to gauge the perspective regarding the ongoing impacts of fossil-fired retirements and coordination of environmental control retrofits. Members of NERC's PC, OC, RAS and MRC provided the following responses:

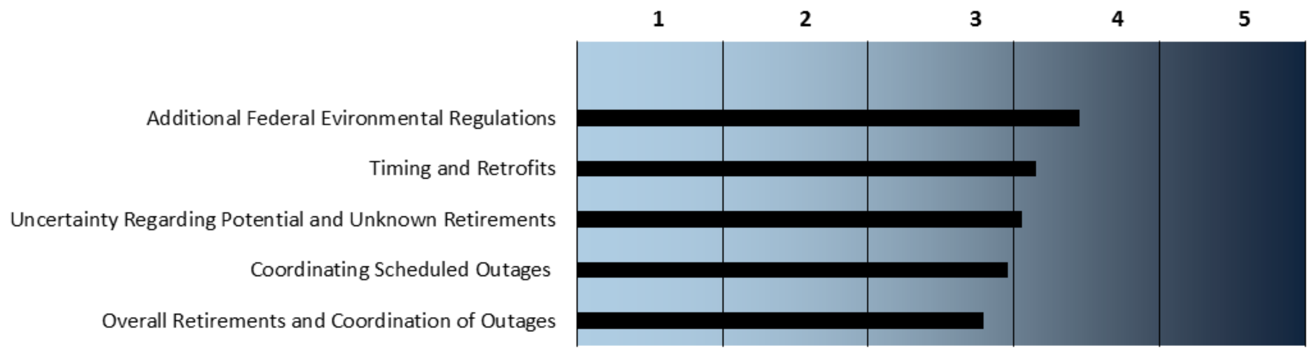
Resource adequacy impacts of retirements and environmental retrofits of fossil-fired units will be:



Likelihood that retirements and environmental retrofits of fossil-fired units will result in Planning Reserve Margins falling below the NERC Reference Margin Level (Target):



RISK PROFILE



1-Manageable. No further action is needed from NERC
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4-Potentially unmanageable without significant action, including shifts from existing policy and possible enhancements to NERC standards and guidelines
5-Unmanageable under current trajectory; extreme risk; must be addressed immediately

RECOMMENDATIONS

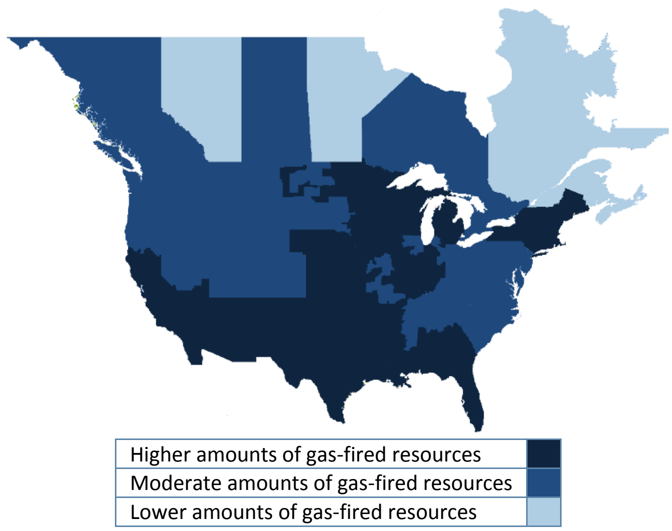
Recommendation(s)
3-1 Probabilistic insights needed: NERC should monitor retirements and emerging reliability issues—including local reliability effects—stemming from significant generator retirements. Additional insight on impacts from unit retirements will be provided in 2014 as a result of NERC's biennial probabilistic resource adequacy assessment.
3-2 Reliability signals must reflect system needs: Regional wholesale competitive market operators should ensure markets are functioning effectively and can support the development of new replacement capacity where needed. Reliability signals that are representative of BPS risks are essential for informing the market of a specific need (e.g., capacity, energy, and ancillary services).
3-3 Initiate focused assessment: In light of emerging and proposed environmental regulations, NERC should revisit its *2010 Special Reliability Assessment: Reliability Impacts of Climate Change Initiatives* report and reassess the emerging reliability impacts.

Increased Dependence on Natural Gas for Electric Power

Overview

Lower prices of natural gas (due to new conventional and unconventional supplies in North America) and climate change initiatives are projected to drive the transition from coal to gas generation. In North America, natural gas is the fastest-growing source of new capacity during the next 10 years. A growing dependence on gas-fired generation can increase BPS exposure to disruptions in fuel supply, transportation, and delivery. While extremely rare, disruptions in natural gas supply and transportation to power generators have prompted industry to seek an understanding of the reliability implications associated with increasing gas-fired generation.

Assessment Area Impacts

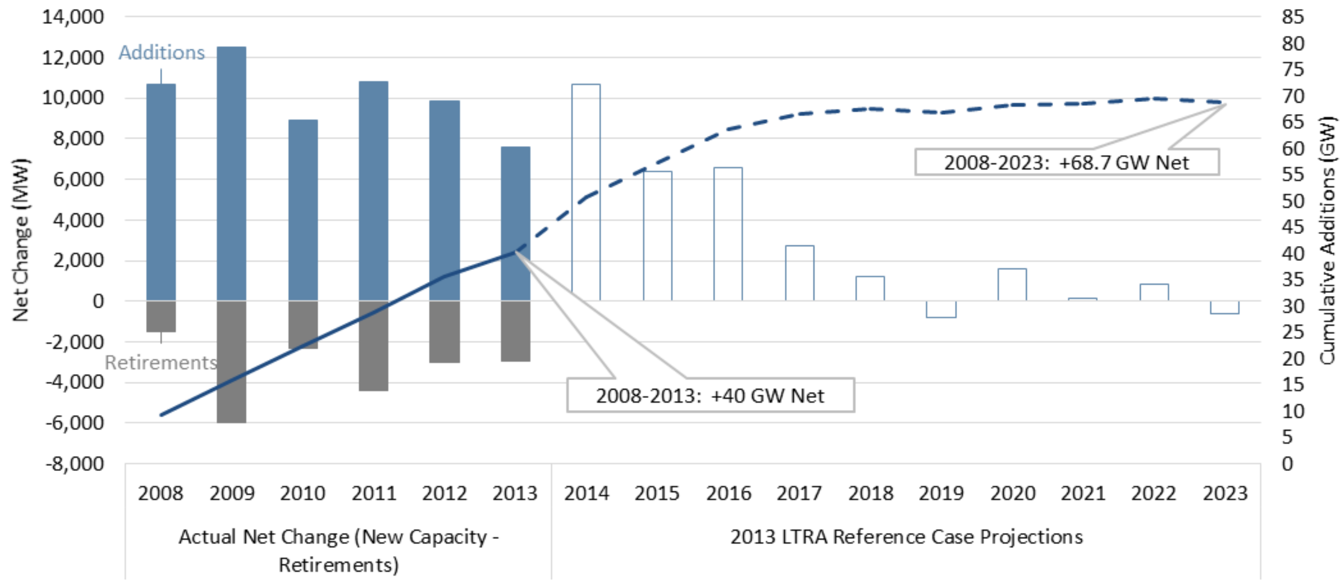


Long-Term Trends

Gas-fired generation has increased significantly since 2008, and according to the *2013LTRA* reference case, that trend is expected to continue. Currently, approximately 412 GW of gas-fired capacity provide over 39 percent of the on-peak resource mix. By 2023, this contribution is expected to grow to almost 41 percent, with the addition of 28.6 GW during the assessment period. From 2008 to 2013, over 20 GW of gas-fired capacity have retired, while 60.3 GW have been added during the same period. The inclusion of current projections amounts to a net increase of 68.7 GW between 2008 and 2023.[50]

[50] Actual additions and retirements: Ventyx Velocity Suite: cumulative aggregation of the summer rating for all gas-fired generator additions from January 1, 2008 to October 31, 2013. 2014–2022 projections: *2013LTRA* reference case: cumulative aggregation of all on-peak, gas-fired capacity additions categorized as either Future-Planned or Future-Other with an in-service date between 2014 and 2023.

Figure 16: Gas-Fired Capacity Change (2008–2023)[51]



Resource and Transmission Adequacy Impacts

Planning Reserve Margin projections include gas-fired capacity at its projected seasonal rating. While there are differences across the assessment areas, generally resource planning and adequacy assessments do not fully account for the risk of common-mode forced outages of gas-fired capacity that occur due to natural gas supply or transportation contingencies. Understating resource adequacy projections or overstating target reserve margins can lead to a decrease in operator flexibility during periods of system stress.

Operational Impacts

Increases in the amount of natural gas-fired generation on the system will require new operational approaches that enhance interaction and coordination with the natural gas industry. This includes information on daily fuel supply adequacy and contingencies on the gas pipeline or compressor stations. Electric system operators should be immediately notified of potential or impending fuel supply or transportation issues. The gas and electric industries have stated that sufficient coordination practices are underway at this time and that continued enhancements are planned for the future. Based on these practices, operational procedures should include formalized coordination with the gas supply and pipeline industry, as well as emergency procedures during extreme events.

Long-Term Planning and Modeling Impacts

As gas-fired generation replaces other retiring units, interconnecting these new resources will require new transmission. Additionally, the transmission system may need enhancements to support firm and reliable transmission service. Long lead times for additions and transmission enhancements create timing issues beyond those required for generation. Second-tier effects include impacts to essential reliability services.

The retirement of larger, strategically situated generating units will cause changes to the power flows and stability dynamics of the BPS. These changing characteristics will require enhancements to the interconnected transmission systems to provide reactive and voltage support, address thermal constraints, and provide for system stability. Based on information

[51] Actual additions and retirements: Ventyx Velocity Suite: cumulative aggregation of the summer rating for all gas-fired generator additions from January 1, 2008 to October 31, 2013. 2014–2023 Projections: *2013LTRA* reference case: cumulative aggregation of all on-peak, gas-fired capacity additions categorized as either Future-Planned or Future-Other with an in-service date between 2014 and 2023.

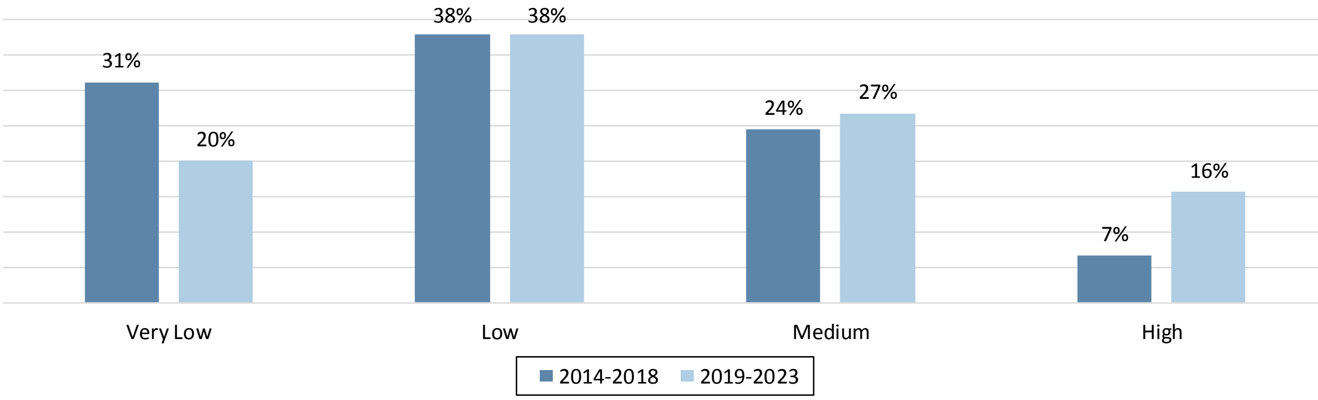
gathered from stakeholders and the Regional Entities, these issues may cause some reliability concerns unless the transmission system is reconfigured.

System planners should consider implementing the same probabilistic techniques currently applied to energy-limited resources for evaluating fuel supply risks associated with natural gas-fired generation. These new approaches, in combination with the institutionalized planning processes, can help pinpoint the BPS's risk exposure as well as support accurate price signals to meet specific reliability needs of individual systems.

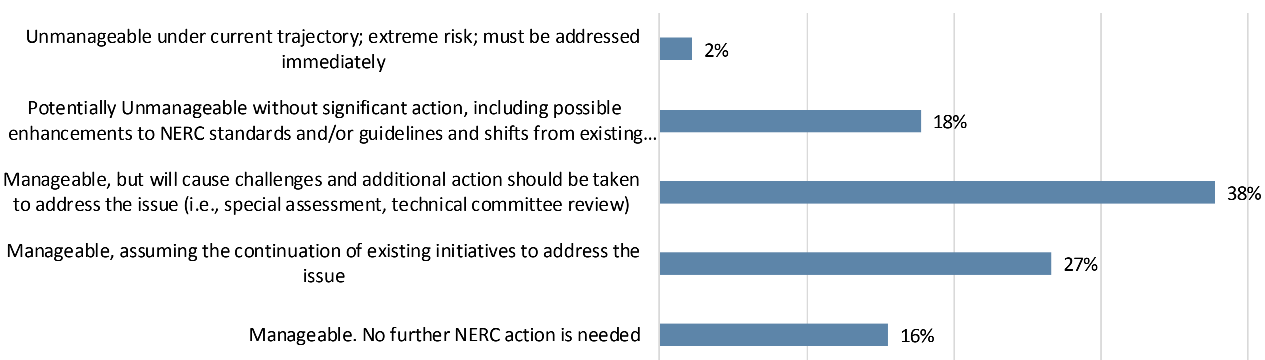
INDUSTRY PERSPECTIVES

The following charts present selected industry responses to a NERC survey on the ongoing impacts of increased dependence on natural gas for electric power.[52] Members of NERC's PC, OC, RAS and MRC provided the following responses:

Likelihood that increased dependence on natural gas for electric power will result in Planning Reserve Margins falling below the NERC Reference Margin Level (Target):

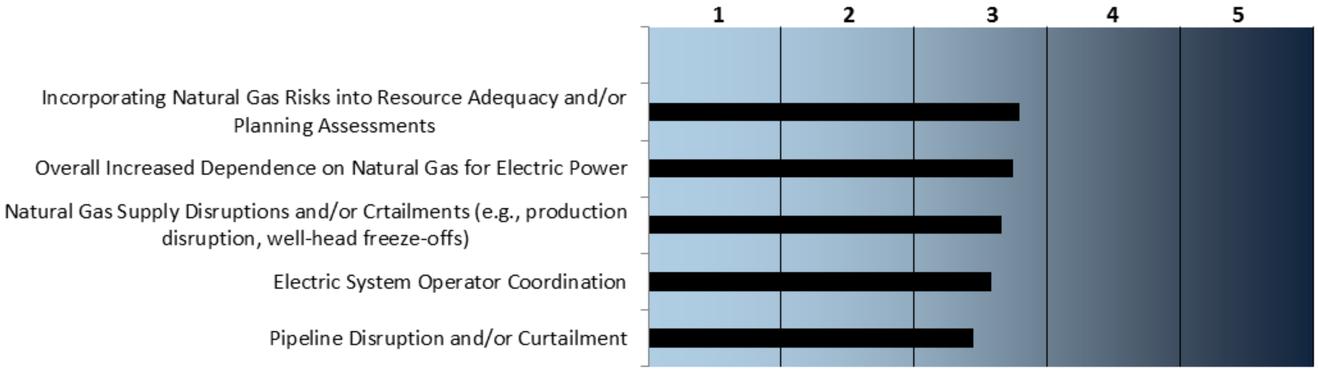


During the next 10 years, insufficient natural gas pipeline capacity leading to multiple generator outages will be:



[52] For additional information on the survey, please contact NERC staff (assessments@nerc.net).

Risk Profile



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4-Potentially unmanageable without significant action, including shifts from existing policy and possible enhancements to NERC standards and guidelines
5-Unmanageable under current trajectory; extreme risk; must be addressed immediately

Recommendations

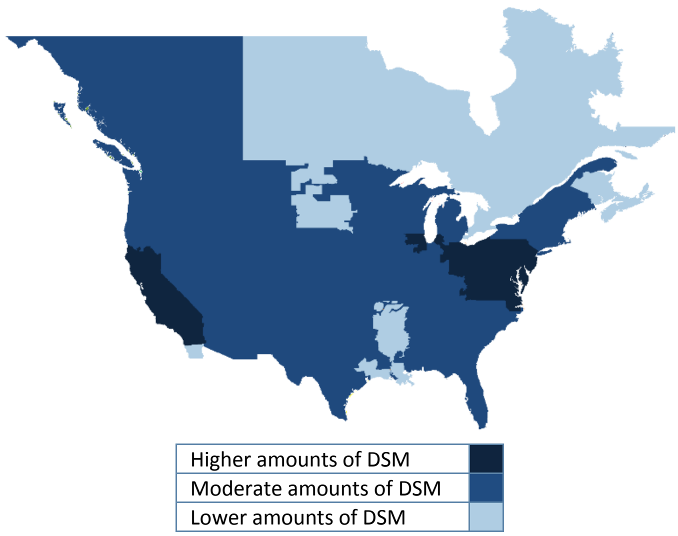
Recommendation(s)
4-1 <u>Monitor high-risk regions</u>: Through its reliability assessments, NERC should closely monitor resource availability and operational impacts in New England and other areas of North America that are quickly integrating large amounts of natural gas-fired generation.
4-2 <u>Expand coordination with study groups</u>: NERC should expand its coordination with regional and interregional study groups, as well as the natural gas industry, to further assess BPS reliability needs. Regional and interregional studies are focusing on the long-term needs of natural gas transportation for electric power. These efforts may provide better insight on the system planning and operating measures being taken to address an increasing dependency on natural gas.
4-3 <u>Fulfill outstanding recommendations</u>: NERC, the industry, and policy makers should continue addressing the recommendations included in the *2013 Special Reliability Assessment: Impacts of Increased Natural Gas for Electric Power*.

Increased Use of Demand-Side Management

Overview

Increases in DSM continue to help offset future resource needs but create additional uncertainty for system planners. These uncertainties include performance and availability, as well as long-term sustained participation in DR programs. Capacity from demand resources and Energy Efficiency used for planning and resource adequacy has increased significantly during the past five years and is expected to increase in the future. The initial scope of DR has expanded and evolved to provide additional benefits to operators, including added flexibility. However, these programs are not an unlimited resource; they may provide limited demand reductions during prespecified time periods. Unlike traditional generating resources with many decades of historic data for analysis, the long-term projections of DR have a shorter history and less certainty.

Assessment Area Impacts



Long-Term Trends

All assessment areas project at least some increase in DSM during the next 10 years. These programs will reduce peak demand, ultimately contributing either to the deferral of new generating capacity or improved flexibility in day-ahead or real-time operations. NERC-wide, DSM is projected to total almost 70 GW by 2023 (or about 6 percent of the NERC noncoincident peak demand), offsetting approximately six years of peak demand growth.

NERC has recently identified a number of resource and transmission projects that were cancelled or deferred as a result of increasing DSM. For example, last year, PJM's plans to construct the PATH and MAPP lines were deferred due to a combination of slowed economic growth in the impacted areas and the procurement of a significant amount of DR in the Forward Capacity Auction. Individual project deferments and cancellations do not create significant reliability issues. However, with long lead times to remedy a capacity shortfall, the viability and long-term sustainability of DSM must be closely monitored for performance. These observations can provide a basis for incorporating future risks into transmission and resource analyses.

Resource and Transmission Adequacy

DSM offers industry the ability to reduce future peak demand and potentially to defer the need for some future generation capacity. The amount of DSM used to meet resource adequacy requirements is increasing across North America, especially as resource and transmission planners are starting to depend on DR commitments in the long term to meet reserve and resource adequacy requirements (targets). Planners cannot sufficiently assess the viability of these resources because of the short-term commitments inherent to DR programs. As with many resource adequacy concerns, long lead times to build new infrastructure can impact the ability to maintain resource adequacy.

Operations

DR programs generally offer operators more flexibility. However, unresponsive demand can lead to real-time challenges. Nonperformance of DR during peak periods can contribute to a capacity shortage. Additionally, alternative transmission and generation resources may not be online, further complicating the issue if DR programs are planned as fixed reductions in load. DR provides services similar to generators (i.e., energy, capacity, ancillary services, and operating reserves). Overall, as DR becomes a larger part of the daily resource mix, it must contribute to reliability in the same manner as generation resources.

Long-Term Planning and Modeling

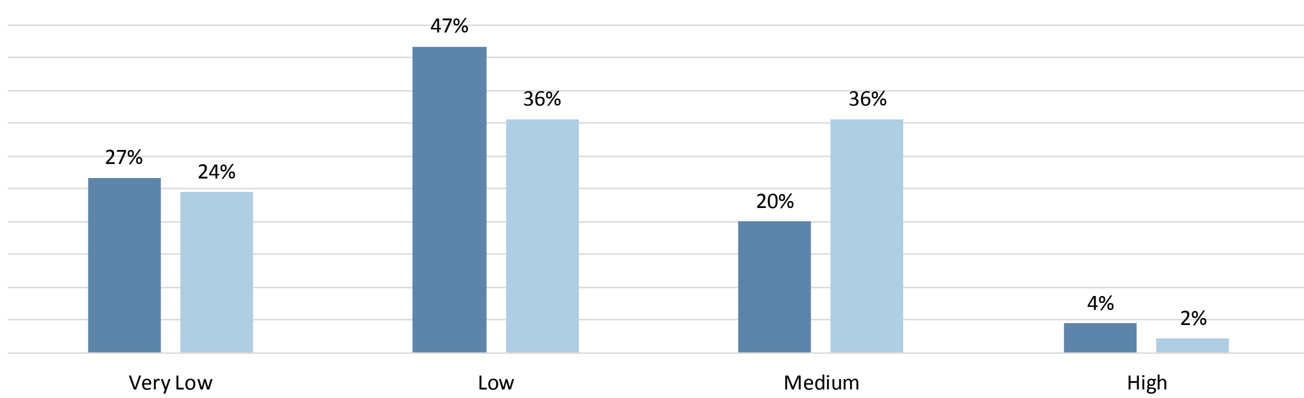
Long-term transmission planning relies on DSM to meet future demand. Therefore, uncertainties associated with DSM can affect long-term transmission planning, including capacity and other system requirements. Similar to traditional resources, the availability of DR resources should be included in long-term planning analyses.

Similar to the probabilistic planning techniques used to plan and accommodate generation that is energy-limited, probabilistic approaches should be used to evaluate the potential increased risk of nonresponsive DR. These studies, in combination with the institutionalized planning processes, can help in understanding the BPS's risk exposure as well as support accurate price signals to meet specific reliability needs of individual systems.

Industry Perspectives

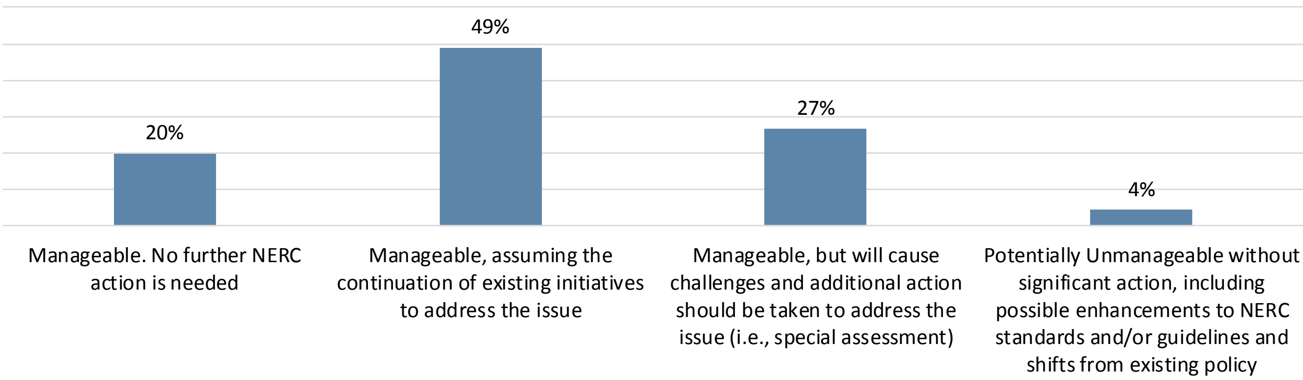
The following charts present selected industry responses to a NERC survey regarding the ongoing impacts of increased DR and the changing role of this resource.[53] Members of NERC's PC, OC, RAS, and MRC provided the following responses:

Likelihood that increased use and evolving role of Demand Response will result in Planning Reserve Margins falling below the NERC Reference Margin Level (Target):

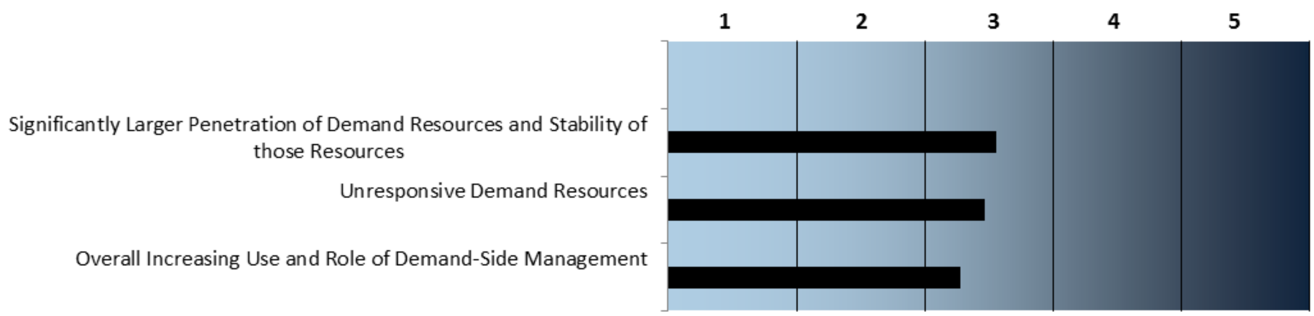


[53] For additional information on the survey, please contact NERC staff (assessments@nerc.net).

Addressing the reliability challenges associated with an increasing use and role of Demand-Side Management during the next 10 years:



RISK PROFILE



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4-Potentially unmanageable without significant action, including shifts from existing policy and possible enhancements to NERC standards and guidelines
5-Unmanageable under current trajectory; extreme risk; must be addressed immediately

RECOMMENDATIONS

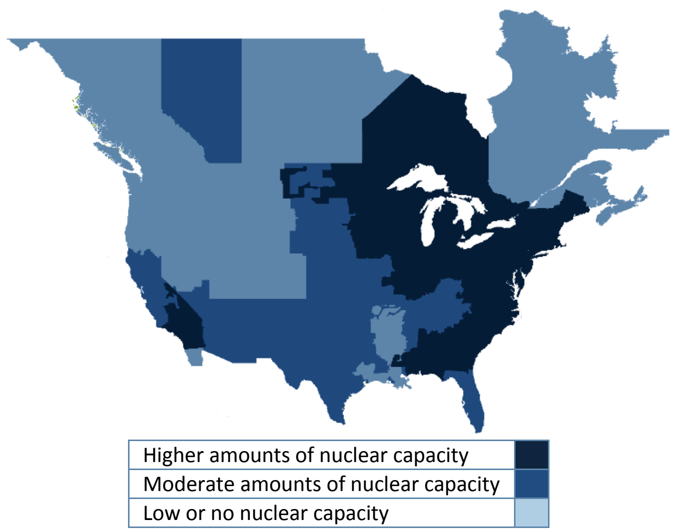
Recommendation(s)
5-1 <ins>Enhance performance analysis</ins>: NERC should leverage the Demand Response Availability Data System (DADS) data to identify availability and performance trends that may indicate future BPS risks. These findings should be reported in the annual *State of Reliability* report.
5-2 <ins>Evaluate the need for requirements or guidelines</ins>: NERC should determine whether requirements or guidelines are needed to support Demand Response planning and operations, specifically Demand Response that is relied on to meet bulk system reliability requirements. The Planning and Operating Committees should provide joint technical support to the Standards Committee on any reliability issues that should be considered during the development of NERC Reliability Standards.

Nuclear Generation Retirements and/or Long-Term Outages

Overview

Nuclear generation contributes approximately 11 percent to the on-peak resource mix in North America. More importantly, large steam turbines provide inertia and voltage support, both of which reinforce local system balancing efforts. Nuclear plants in the United States have an average capacity rating of 979 MW for the summer and 1,001 MW for the winter. These Base Load generators are critical reliability components that contribute to both the stability and integrity of the system. While this is generally a low-likelihood scenario, wide-scale nuclear generation retirements and long-term outages could have significant impacts on the BPS. It is important to examine these risks, especially considering the average age of the North American nuclear fleet and the long-term economic viability of continuing to operate these plants.

Assessment Area Impacts



Resource Adequacy Impacts

According to the EIA, the average commercial reactor fleet in the United States is 32 years old, which is approaching the typical life span of 40 years.[54] The continued operation of existing plants depends on the required refurbishments and upgrades at existing reactors. In the United States, the Nuclear Regulatory Commission (NRC) issued operating license renewals for 72 of the 100 reactors, and an additional 10 applications are currently under review. The Canadian Nuclear Safety Commission (CNSC) maintains similar regulatory oversight of four plants that house 19 operational reactors.

Although over 115 GW of nuclear capacity is currently operational in North America, five units have either retired or will be decommissioned between 2011 and 2013. The decision to retire many of these units is based on cost, as the operating expenses of required unit upgrades and maintenance have increased. As these units approach their intended their life spans, market conditions (due to renewable generation) drive uneconomic base light load dispatch at zero or negative marginal prices. These conditions make replacing these units with less-costly resources more economically viable. The number of unit retirements could increase beyond what is projected in the *2013LTRA* reference case as older units approach their intended lifespan. The age of a given unit is an important variable when considering the economic viability of investing additional capital to retrofit a unit, especially when replacement generation (e.g., natural gas, biomass, etc.) is often a more cost-effective option. Uprates of existing units are also at risk, due to low gas prices and required mitigation of reactive power reductions.

[54] EIA Frequently Asked Questions: How old are U.S. nuclear power plants and when was the last one built?

Since 2011, approximately 4,204 MW have either been retired or plans to decommission them have been announced. An additional 1,219 MW (summer rating) of planned retirements will occur before 2019, according to the *2013LTRA* reference case. Additionally, in the United States, existing operating licenses for seven units totaling 7,510 MW (summer rating) of capacity will expire before 2023.

U.S. Reactor Licenses Expiring during the Assessment Period

Reactor Name	NERC Assessment Area	Summer Rating (MW)	License Expires	Reactor Type
Davis-Besse	PJM	894	Apr-2017	Pressurized Water Reactor
Indian Point 2	NPCC-NYISO	1020	Sep-2013	Pressurized Water Reactor
Indian Point 3	NPCC-NYISO	1040	Dec-2015	Pressurized Water Reactor
La Salle 1	PJM	1137	Apr-2022	Boiling Water Reactor
La Salle 2	PJM	1140	Dec-2023	Boiling Water Reactor
Sequoyah 1	SERC-N	1152	Sep-2020	Pressurized Water Reactor
Sequoyah 2	SERC-N	1125.7	Sep-2021	Pressurized Water Reactor

In NPCC-NYISO, the Indian Points 2 & 3 are in service while the Atomic Safety Licensing Board of the Nuclear Regulatory Commission reviews the license renewal request for both units. It is important to note that despite the relicensing of the Vermont Yankee plant in March 2011, the plant is still expected to close in late 2014. The Indian Point Power Plant (two nuclear units) in NPCC-NYISO is speculated to retire by the end of 2015 (not included in the *2013LTRA* reference case). If the Indian Point Power Plant licenses were not renewed and the plant was retired by the end of 2015 or thereafter, it would result in immediate violations of resource adequacy criteria.

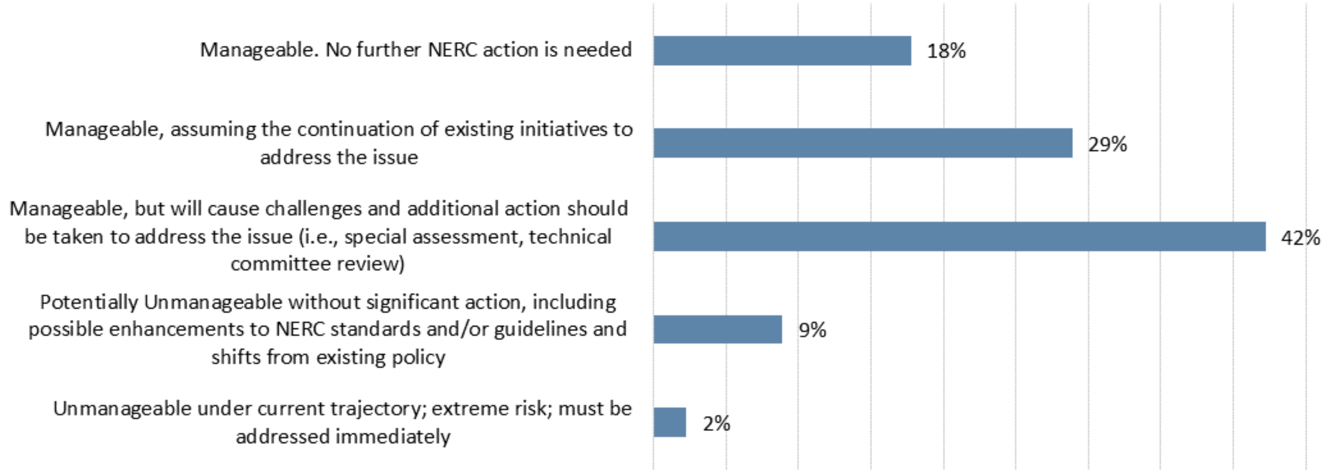
All 18 reactors in Ontario, including the Pickering B, Bruce B, and Darlington Nuclear Generating Stations, have existing licenses that will expire during the 10-year period. The Canadian Nuclear Safety Commission granted a five-year renewal of Ontario Power Generation's (OPG) operating license for the Pickering Nuclear Generating Station that will be valid until August 31, 2018. The license prohibits the operation of the Pickering B NGS beyond 210,000 effective full power hours. At a future public hearing, the Commission will consider OPG's request to remove this regulatory hold point. Units at Bruce and Darlington will undergo midlife refurbishments to extend their operating lives. The OPA is working with two nuclear operators to develop a coordinated plan for nuclear fleet renewal. Unit outages will be coordinated to minimize the number of nuclear units simultaneously on outage. The plan for nuclear renewal is complex as there are a number of aspects that need to be resolved: operational and technical coordination, regulatory and contractual terms, financing and revenue recovery, and risk allocation.

Industry Perspectives

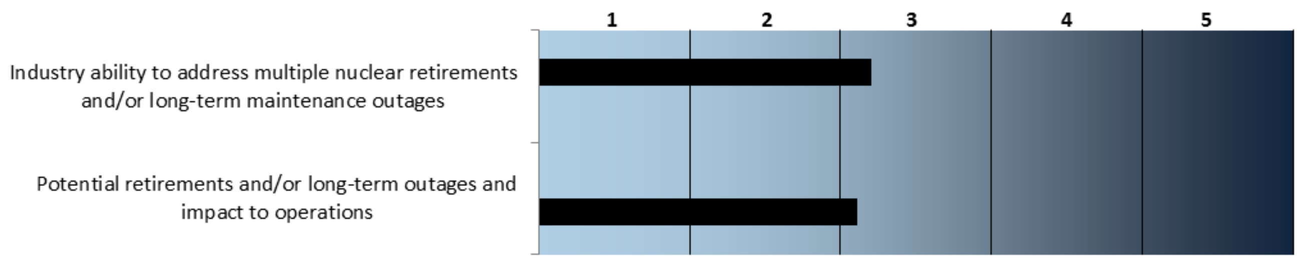
The following chart presents selected industry responses to a NERC survey on the potential impacts of substantial retirements or scheduled outages of nuclear reactors.[55] Members of NERC's PC, OC, RAS, and MRC provided the following responses:

[55] For additional information on the survey, please contact NERC staff (assessments@nerc.net).

Rate the ability of the industry to address the reliability challenges associated with the potential for nuclear retirements or long-term outages during the next 10 years:



RISK PROFILE



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RECOMMENDATIONS

Recommendation(s)
6-1 Prioritize through risk evaluation: NERC should consider developing a sensitivity study of the potential reliability impacts of accelerated nuclear plant retirements or shutdowns in the near future.

Other Challenges

NERC has also evaluated several other areas of potential concern. While the challenges noted below may not rise up to a level of significant concern, NERC will continue to monitor them and determine whether a more detailed evaluation and assessment are necessary.

Mid-Continent Independent System Operator (MISO) Reliability Plan

The creation of MISO's Southern Region is the result of (1) FERC's authorizing MISO as the Independent Coordinator of Transmission (ICT) for Entergy, and (2) regulatory approvals and new memberships by Entergy and other area Transmission Owners (TOs). This integration will add over 18,000 miles of transmission, approximately 40,000 MW of generation capacity, and approximately 40,000 MW of load into the MISO footprint. MISO's increased scale can drive access to more resources by consolidating Balancing Authorities and expanding options for generation commitment and dispatch from a more diverse set of fuel types.

In June 2013, the OC approved a revised MISO Reliability Plan. FERC approved it as well. A significant aspect of OC's approval was the review and consideration of an Operations Reliability Coordination Agreement (ORCA), which the various impacted parties negotiated and approved. MISO's integration of Entergy, the largest electric system joining MISO since its inception, requires a significant amount of joint analysis and study work. The ORCA provides a road map for continued studies and coordination of the expanded MISO Balancing BA footprint and the neighboring Balancing Authorities to ensure reliability. This consolidated MISO BA footprint stretches from the Gulf Coast through the Midwest to the U.S.–Canadian border. SERC also conducted an ERO certification of the new MISO BA operations in the latter half of 2013.

The ORCA helps vested parties understand and commit to specific operating practices—the agreement defines specific practices and principles to use during an Operations Transition Period (OTP) and a period after the OTP (Post-OTP). The agreement outlines vested parties' coordination of regional issues and long-term transmission planning. However, the physical connections between MISO North and South are currently limited, and the expected dispatch of MISO resources can create reliability challenges for the neighboring entities. While coordinated transmission planning will lead to solution sets that can alleviate these concerns, MISO is expected to need more resources from a resource adequacy perspective around the 2016 time frame. If real-time transmission constraints limit the south-to-north transfers, MISO may not be able to import power to meet demand—a particular concern during a summer peak with little weather and temperature diversity between the north and south borders of the United States.

Aging Workforce

The need for new infrastructure and technology innovations means a steady need for well-trained engineers and workers. The electric power industry is beginning to remedy the gap in qualified employees, which will be critical as the BPS continues to rapidly evolve. Workers entering the power industry will be tasked with understanding and implementing a variety of new technologies and smarter systems and devices. Across the industry, there is substantial interest in training and hiring workers to support these industry needs as well as transferring the expertise and knowledge of retiring workers.

Load Forecasting Uncertainty

The electric industry is currently facing several challenges in forecasting demand for electricity. The accuracy of demand forecasts has been decreasing since the beginning of the last recession, which officially began in late 2007 and ended in mid-2009. There is sufficient empirical evidence to suggest correlations such as the economic outlook, new technologies, and consumer awareness. With structural and cyclical effects of the recession continuing, demand forecasters are faced with the challenge of redefining methods to ensure accurate projections for both short- and long-term planning. As new variables are introduced to load forecasting models, further analysis will be necessary to gain a better understanding of their effects on short-run planning horizons and to ensure methods are consistent in long-term forecasting.

Many new technologies, like AMI, PHEVs, 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' worth of baseline data has been collected and used to establish accurate residential profiles that can be relied upon for future forecasting. Finally, any changes in climate or long-term weather forecasts may have residual effects on the load forecast and the distribution of potential outcomes.

Smart Grid

Governments, regulators, and industry organizations have proposed the smart grid to enhance consumer options, support climate change initiatives, and enhance the reliability of the North American BPS. The evolving smart grid integration will require significant changes in BPS planning, design, and operations. A NERC report[56] on smart grid integration identifies important reliability considerations from a BPS perspective and provides a preliminary assessment of successful smart grid integration. The report contains the following conclusions:

- Government initiatives and regulations promoting smart grid development and integration must consider BPS reliability.
- Smart grid integration requires development of new tools and analyses to support planning and operations.
- Smart grid technologies will change the character of the distribution system, and these changes must be incorporated into BPS planning and operations.
- Cybersecurity and control systems will require enhancements to ensure reliability.
- Research and development (R&D) has a vital role in successful integration of the smart grid.

Change in System Behavior and Composition of System Load

Representative risks to the BPS should be identified and reflected in long-term planning and system analysis. A large change in a given resource mix will also change system behavior, including 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.

Continued increases in energy-efficient products (including residential 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.

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

Despite higher expectations of planned transmission lines in the *2013LTRA* reference case, actually building new transmission is an ongoing challenge for the electricity industry. The issue is increasingly important as the resource mix in North America experiences an ongoing and rapid transformation. Transmission right-of-way issues required in the siting of new BPS lines that spans multiple states and provinces are highly visible and require increased coordination among multiple regulating agencies and authorities. A lack of coordination regarding cost allocation, coupled with public opposition due to land use and property valuation concerns, has often resulted in extended delays in transmission construction. In some cases, these delays require special operating procedures to maintain BPS reliability.

[56] Reliability Considerations from the Integration of Smart Grid.

Ongoing state and provincial policies will require continued integration of renewable resources, including wind and solar. These variable resources are most commonly built in remote areas where wind power densities and solar development are favorable. In many cases, the existing transmission network needs to be expanded to integrate these renewable resources and meet RPS mandates and other state-wide goals. Because many state and provincial renewable requirements must be fulfilled within the next five to 15 years, current siting and approval processes may create hurdles that could further impact operational measures and procedures. Access to less transmission than planned may cause additional stress on the system, particularly during periods of high demand, but also when other transmission is out of service for maintenance.

Stakeholders within the electric industry continually assess the ability of their internal transmission systems and interconnections with other systems to meet not only regional requirements but also to meet compliance with NERC Reliability Standards. Once a set of transmission alternatives has been identified, the project can take 10 or more years to complete, from project identification to final certification and energization. A majority of the time in this process is devoted to the siting, permitting, and land acquisition process, which has no definitive time frame and can vary greatly depending on the geographic location of proposed additions.

Based on the *2013LTRA* reference case, a significant amount of transmission is planned to come into service during the next 10 years. Of the more than 21,800 miles projected to come into service, approximately, 7,500 miles (34 percent) is primarily for integrating new renewable generation. However, there are ongoing hurdles that may prevent these plans from coming to fruition. Several of these long-distance transmission lines serve as the foundation of the electricity grid's renewable energy backbone and will be critical for the integration and accommodation of VERs. For example, in a major step forward for the first independent 500 kV transmission project in WECC, the Interior Department's Bureau of Land Management (BLM) issued a final environmental impact statement to the SunZia Southwest Transmission. SunZia consists of two 500 kV transmission lines running between central New Mexico and central Arizona (approximately 500 miles). The two SunZia lines will carry primarily renewable energy from new projects that will be built in those states to customers and markets across the southwestern United States, including California, by 2017.

Interconnection-wide studies in WECC identify opportunities to improve development and optimization of needed transmission infrastructure. During the next decade, WECC has the most transmission planned, and although transmission lines are inherently longer in the Western Interconnection, more west-to-east transmission will be needed to support the continued integration of VERs.

AGING INFRASTRUCTURE

Aging transmission system infrastructure has many challenges, such as the availability of spare parts, the obsolescence of older equipment, the ability to maintain equipment due to outage scheduling restrictions, and the ability to keep pace with technological advancements. Risk-based approaches for maintaining and replacing BPS facilities also incorporate resilience planning. This includes maintaining spare equipment and restoration teams trained for fast response. Larger scale "infrastructure revitalization" may be necessary in the future; however, with older generation retiring throughout the next decade, the average age of BPS generation facilities will be relatively young. 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.

REGION/INTERCONNECTION-WIDE MODELING

Examining interconnection-wide phenomena is becoming a necessary practice that enables the 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 interconnection to support its reliability. Such models cannot be considered proprietary.

System modeling issues have been identified in several significant system events during the past two decades (the latest being the Southwest Blackout). Issues cover the full gamut of the system (i.e., transmission, generation, loads, 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 continues to address various modeling issues, the most significant current risk is the lack of centralized coordination and oversight of the many efforts. Without a centralized entity overseeing all the individual efforts, the risk is duplicity in effort, lack of reaching industry consensus, and the use of invalid data input. Additionally, planning and operations models that use different representations (for instance, node-breaker models vs. bus-branch models) lead to inconstant understanding of contingencies and duplication of modeling efforts, both of which may lead to inaccurate prediction of power system behavior.

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

Special Protection Systems (SPS) and Remedial Action Schemes (RAS) provide alternatives to the addition of new transmission facilities. System operators need to be aware and informed of the SPS and RAS devices in service, as well as the corresponding impacts associated with these devices. The possible lack of modeling requirements and real-time analysis capabilities of an SPS/RAS reduces the planners' and operators' capability to evaluate the reliability impact that these tools bring into the system. These tools also had important implications during the Southwest outage in September 2011.[57] Accordingly, the objectives of this emerging issue are to: (1) evaluate historical and future trends in SPS application and deployment; (2) identify limitations of SPS deployment; (3) propose a framework for assessing SPS risks; and (4) propose modeling and assessment improvements.

Global Supply Chains and Fuel Reliability

Reliance on global supply chains for fuel and other products used to generate electricity must be managed with a common goal of reducing the risk of a prolonged disruption. The electric industry has a reputation for being risk averse; therefore, discrete or short disruptions in the supply chain are less likely to cause great issue—operational and strategic plans are often put in place to deal with a low-occurrence event. However, large and prolonged supply chain impacts could disrupt electricity production, which would therefore cause significant reliability concerns. The current constructs of global supply chains are of specific concern. Some examples include political uncertainty, instability of nation-states, and weak ties to North American foreign affairs. There are additional concerns regarding liquefied natural gas imports from the Middle East; however, the current supply of domestic natural gas has greatly reduced this risk.

Coordinated Cyber or Physical Attacks on Electricity Infrastructure

One of the principal types of High-Impact, Low-Frequency (HILF) events facing the BPS is a concerted, well-planned cyber, physical, or blended attack conducted by an active adversary against multiple points on the system. Such an attack, though as of yet never experienced in North America, could damage or destroy key system components, significantly degrade system operating conditions, and, in extreme cases, result in prolonged outages to large parts of the system. The rapid convergence of the electric power system's infrastructure with information and communications technologies, combined with a new awareness of the sophistication of adversary capabilities, requires a fresh understanding of the risk and subsequent well-coordinated steps needed to improve the protection, resilience, and response capabilities of the BPS. From a BPS resilience and operations perspective, ensuring the grid has the ability to recover from a widespread, coordinated cyber attack is of critical importance.

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[57] NERC Southwest Blackout Event Reports

FRCC

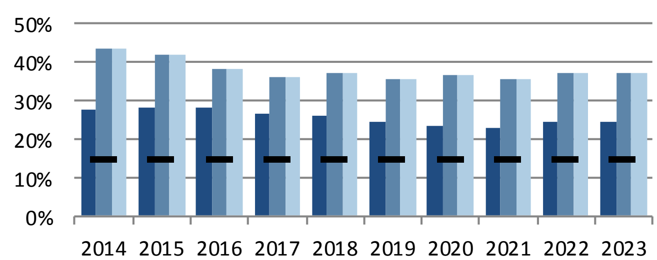
The Florida Reliability Coordinating Council's (FRCC) membership includes 30 Regional Entity Division and 24 Member Services Division members composed of investor-owned utilities (IOUs), cooperative systems, municipal utilities, power marketers, and independent power producers. FRCC is divided into 10 Balancing Authorities with 68 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 peninsular Florida.

Planning Reserve Margins

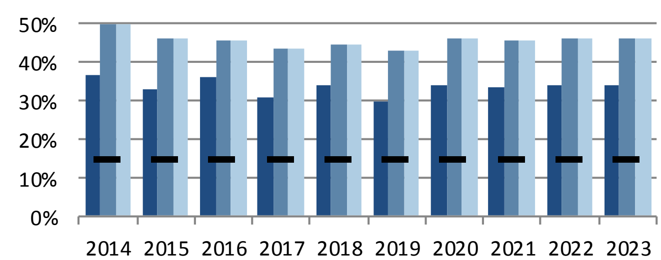
FRCC-Summer		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ANTICIPATED		27.76%	27.97%	28.30%	26.46%	26.36%	24.30%	23.50%	23.14%	24.62%	24.28%
PROSPECTIVE		43.65%	41.72%	38.32%	36.36%	37.23%	35.54%	36.87%	35.44%	37.29%	37.29%
ADJUSTED POTENTIAL		43.65%	41.72%	38.32%	36.36%	37.23%	35.54%	36.87%	35.44%	37.29%	37.29%
NERC REFERENCE	-	**14.99%**	**14.99%**	**14.99%**	**14.99%**	**14.99%**	**14.99%**	**14.99%**	**14.99%**	**14.99%**	**14.99%**

FRCC-Winter		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ANTICIPATED		36.83%	33.05%	36.14%	30.78%	33.77%	29.95%	34.01%	33.47%	33.88%	33.88%
PROSPECTIVE		49.85%	45.99%	45.77%	43.56%	44.71%	42.86%	46.38%	45.68%	46.22%	46.22%
ADJUSTED POTENTIAL		49.85%	45.99%	45.77%	43.56%	44.71%	42.86%	46.38%	45.68%	46.22%	46.22%
NERC REFERENCE	-	**14.99%**	**14.99%**	**14.99%**	**14.99%**	**14.99%**	**14.99%**	**14.99%**	**14.99%**	**14.99%**	**14.99%**

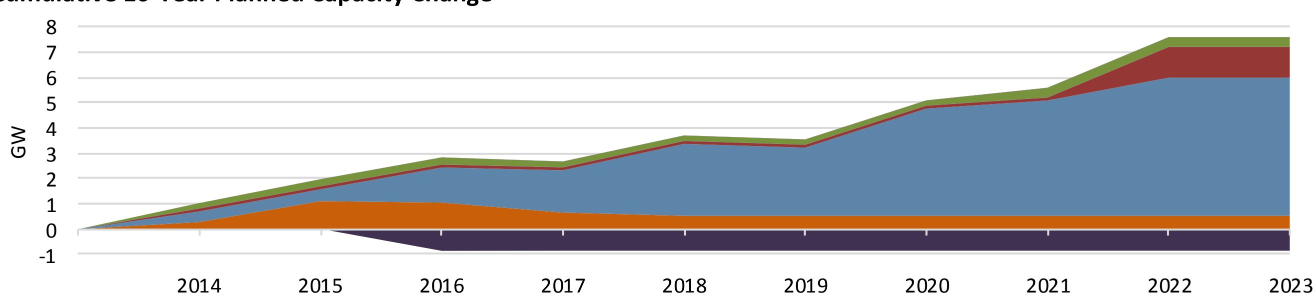
Summer



Winter



Cumulative 10-Year Planned Capacity Change



	2013 Existing		2023 Planned			2023 Planned & Conceptual		
FRCC	Capacity (MW)	Share (%)	Capacity (MW)	Share (%)	Change (MW)	Capacity (MW)	Share (%)	Change (MW)
Coal	8,434	16.2%	7,580	12.9%	-854	7,580	12.9%	-854
Petroleum	7,646	14.7%	8,173	13.9%	527	8,173	13.9%	527
Gas	32,054	61.6%	37,528	63.8%	5,474	37,528	63.8%	5,474
Nuclear	3,471	6.7%	4,691	8.0%	1,220	4,691	8.0%	1,220
Hydro	44	0.1%	44	0.1%	0	44	0.1%	0
Pumped Storage	0	0.0%	0	0.0%	0	0	0.0%	0
Geothermal	0	0.0%	0	0.0%	0	0	0.0%	0
Wind	0	0.0%	0	0.0%	0	0	0.0%	0
Biomass	383	0.7%	762	1.3%	379	762	1.3%	379
Solar	8	0.0%	16	0.0%	7	16	0.0%	7
TOTAL	**52,040**	**100.0%**	**58,793**	**100.0%**	**6,753**	**58,793**	**100.0%**	**6,753**

Demand, Resources, and Planning Reserve Margins

The Florida Public Service Commission requires a 15 percent reserve margin criteria for non-investor-owned utilities and a 20 percent reserve margin criteria for IOUs (applied as 15 percent for the NERC Reference Margin Level). Based on the expected load and generation capacity, the projected reserve margin is above 23 percent for all seasons during the assessment period.

Compared to the *2012LTRA* reference case, FRCC is projecting a small decrease in the peak demands for summer and winter. This is mainly attributed to lower-than-expected consumption and decreased economic activity in FRCC.

DR from interruptible and load management programs within FRCC is treated as a load modifier and is relatively constant at approximately 7 percent and 6.6 percent of the summer and winter total peak demands, respectively, for all years of the planning horizon.

FRCC recently conducted a study to identify the impact of the potential retirement of two coal-fired units (totaling over 900 MW) that a site would retire in order to achieve compliance with the EPA Mercury Air Toxics Standards (MATS) set to become effective in 2015. In addition, an 800-MW unit at the same site was announced to be retired due to a prolonged maintenance outage; however, this capacity was excluded from the reserve margin calculations in prior assessments. In large part due to equipment modernizations, several plants in FRCC are (or will be) undergoing capacity uprates (totaling 817 MW during the summer and 976 MW during the winter) in the near-term horizon. Short-term activation of offline capacity staged in Inactive Reserves[58] mitigated any potential impacts from the temporary removal of the generation. As a result, the Planning Reserve Margins will be maintained during all peak seasons.

To ensure that the inherent uncertainty associated with variability in the nonfirm output is minimized, only the contractual firm capacity from intermittent or energy-limited resources is included in the calculation of seasonal reserve margins. FRCC expects variable resources to grow by 2.88 percent by the end of the long-term planning horizon; no operational changes are needed to accommodate their integration.

Through 2015, 1,340 MW of generation are available under firm contract to be imported from SERC-SE into FRCC. Approximately 840 MW more of FRCC member-owned generation is dynamically dispatched out of southern SERC-SE. These purchases have firm transmission service to ensure deliverability into FRCC. While FRCC does not rely on external resources for emergency imports and reserve sharing, there are emergency power contracts in place between SERC members and FRCC entities.

FRCC has 143 MW of generation under firm contract to be exported only during the summer season into the SERC-SE assessment area through 2020. These sales have firm transmission service to ensure deliverability.

Transmission and System Enhancements

FRCC recently conducted a study to identify the potential impact of multiple generation retirements. The study identified the need to develop remedial actions depending on system conditions in the near-term until permanent solutions are further investigated and implemented. FRCC has plans for 41 new BES transmission projects (399 miles), 13 BES rebuild projects (102 miles), and 19 BES reconductor projects (138 miles). These projects are primarily related to expansion needed to serve forecasted growing demand in certain local areas and maintain the long-term reliability of the BES.

During this assessment period, there are no foreseen project delays that would keep planned transmission facilities with an impact on long-term reliability from meeting the in-service date. Temporary service outages required for construction will be performed during off-peak seasonal conditions and studied in the operations horizon. No significant substation equipment (i.e., static var compensators (SVCs), flexible alternating-current transmission systems (FACTS) controllers, high-voltage direct current (HVdc), etc.) additions are expected through 2023.

[58] Classified by NERC as Inoperable Resources.

There is no change to the approximately 1,020 MW of under-voltage load shedding (UVLS) programs within FRCC; most are designed to respond to localized low-voltage conditions potentially caused by multiple contingency events. FRCC does not plan to install any additional Special Protection Systems (SPSs) during the study horizon. However, ongoing generation retirement studies may identify the need for additional SPSs until permanent transmission and generation projects are constructed.

Entities in FRCC continue to evaluate new technologies, such as FACTS devices and high-temperature conductors, to address specific transmission conditions or issues. Presently, there are several transmission lines constructed with high-temperature conductors within the FRCC Region. However, at this time there are no FACTS devices installed within the Region. FRCC TOs are considering enhancements to existing transmission planning tools (e.g., enhancements to existing software, new software, etc.) to address the expected planning needs of the future.

Long-Term Reliability Issues

The FRCC Region recently conducted a study identifying the impacts of the retirement of two generators (915 MW) starting in April 2015 to comply with the EPA's MATS. These two units, combined with the recent retirement of an 825 MW unit at the same site, total 1,740 MW. The regional study determined that the required retirements do have an impact on the BES transmission system and demonstrated the need to extend the retirement date of these units, to allow sufficient time to construct transmission projects in order to maintain the reliability of the BES within the FRCC Region.

The Florida Electric Power Coordinating Group's (FCG) Environmental Committee was actively involved in petitioning for judicial review of EPA's final Cross-State Air Pollution Rule (CSAPR), which was to take effect on January 1, 2012. On August 21, 2012, the court vacated the rule. The EPA appealed the court's ruling to the U.S. Supreme Court, but the court has not yet decided whether to hear the case. It is unknown what regulatory program may be developed to replace CSAPR, but, for the near term, CSAPR's predecessor (the Clean Air Interstate Rule (CAIR)) will continue to be implemented. The EPA's MATS became effective on April 16, 2012, and require compliance within three years, with the possibility of a one- or two-year extension under specific circumstances.

In 2010, the EPA issued national emission standards for hazardous air pollutants (NESHAP) for existing compression ignition reciprocating internal combustion engines (RICE) (i.e., diesel generators), which must comply with the rule beginning May 3, 2013. The RICE NESHAP imposes stringent emission limits and other requirements on nonemergency RICE. As amended in January 2013, it also imposes hourly limits on the operation of emergency RICE in nonemergency situations, including for emergency DR, local system reliability, peak shaving (not allowed at all after May 3, 2014), and other nonemergency operation. The full impact that CSAPR and its replacement rule, MATS, and the RICE NESHAP will have on the long-range reliability of the BES in the FRCC Region is still unknown.

MISO

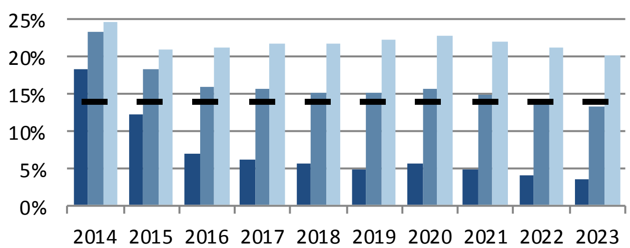
The Midcontinent Independent System Operator, Inc. (MISO) is a not-for-profit, member-based organization administering wholesale electricity markets that provide customers with valued service, reliable and cost-effective systems and operations, dependable and transparent prices, open access to markets, and planning for long-term efficiency. MISO manages energy and operating reserves markets, which consists of 12 BAs, including the MISO BA (reliability), 28 local BAs, and 362 market participants, who serve approximately 48 million people. This section assesses the reliability of this market area—consisting of seven Local Resource Zones (LRZs)—during the next 10 years. MISO developed LRZs to reflect the need for an adequate amount of Planning Resources located in the right physical locations within MISO to reliably meet demand and loss-of-load expectation (LOLE) requirements.

Planning Reserve Margins

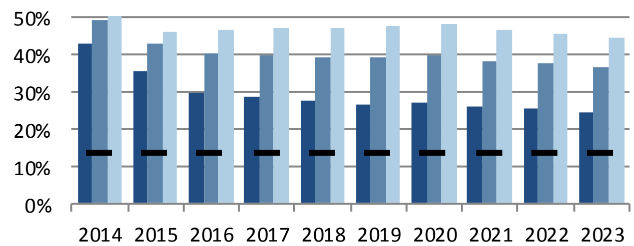
MRO-MISO-Summer	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ANTICIPATED	18.28%	12.13%	7.00%	6.29%	5.54%	4.86%	5.65%	4.90%	4.16%	3.44%
PROSPECTIVE	23.35%	18.44%	15.82%	15.65%	15.16%	15.08%	15.79%	14.98%	14.17%	13.37%
ADJUSTED POTENTIAL	24.55%	20.94%	21.12%	21.82%	21.65%	22.18%	22.85%	21.98%	21.13%	20.28%
NERC REFERENCE -	**14.20%**	**14.20%**	**14.20%**	**14.20%**	**14.20%**	**14.20%**	**14.20%**	**14.20%**	**14.20%**	**14.20%**

MRO-MISO-Winter	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ANTICIPATED	43.22%	35.35%	29.59%	28.55%	27.58%	26.70%	27.39%	26.34%	25.41%	24.44%
PROSPECTIVE	49.36%	42.97%	40.27%	39.87%	39.21%	39.05%	39.63%	38.48%	37.46%	36.39%
ADJUSTED POTENTIAL	50.81%	45.98%	46.70%	47.33%	47.05%	47.63%	48.13%	46.92%	45.83%	44.70%
NERC REFERENCE -	**14.20%**	**14.20%**	**14.20%**	**14.20%**	**14.20%**	**14.20%**	**14.20%**	**14.20%**	**14.20%**	**14.20%**

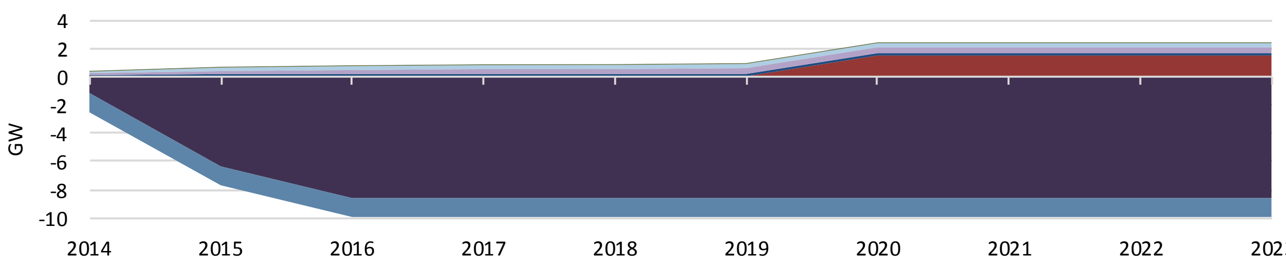
Summer



Winter



Cumulative 10-Year Planned Capacity Change



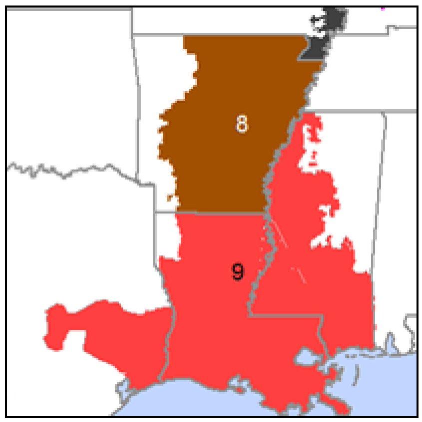
MISO		2013 Existing Capacity (MW)	2013 Existing Share (%)	2023 Planned Capacity (MW)	2023 Planned Share (%)	2023 Planned Change (MW)	2023 Planned & Conceptual Capacity (MW)	2023 Planned & Conceptual Share (%)	2023 Planned & Conceptual Change (MW)
Coal		59,771	56.3%	51,156	51.9%	-8,615	51,156	48.8%	-8,615
Petroleum		2,401	2.3%	2,401	2.4%	0	2,401	2.3%	0
Gas		31,798	30.0%	30,451	30.9%	-1,346	35,687	34.1%	3,890
Nuclear		7,455	7.0%	9,007	9.1%	1,552	9,007	8.6%	1,552
Hydro		725	0.7%	891	0.9%	166	895	0.9%	170
Pumped Storage		2,308	2.2%	2,723	2.8%	415	2,723	2.6%	415
Geothermal		0	0.0%	0	0.0%	0	0	0.0%	0
Wind		1,122	1.1%	1,423	1.4%	301	2,311	2.2%	1,189
Biomass		509	0.5%	557	0.6%	48	557	0.5%	48
Solar		0	0.0%	0	0.0%	0	0	0.0%	0
TOTAL		**106,087**	**100.0%**	**98,608**	**100.0%**	**-7,480**	**104,736**	**100.0%**	**-1,352**

Demand, Resources, and Planning Reserve Margins

MISO Boundary Change

MISO is expanding its reliability and market areas into the South, with six Entergy operating companies, Cleco, and South Mississippi Electric Power Association (SME) working toward full integration into MISO's market operations by December 2013. Two additional Local Resource Zones (LRZs) will come out of this expansion. LRZ #8 consists of Entergy Arkansas and Arkansas Electric Cooperative Corporation (AECC), and LRZ #9 consists of all other integrating entities. MISO plans on assuming reporting responsibilities for the southern MISO Region in next year's (i.e., 2014) assessments. However, in this year's assessments, the SERC-W Assessment Area is reporting for the majority of LRZs #8 and #9, with a portion of LRZ #9, Louisiana, being reported by the SPP Assessment Area (Cleco, Lafayette Utilities System, and Louisiana Energy and Power Authority).

Addition of MISO Southern Region LRZs (Right)



The MISO Reference Margin Level[59] is 14.2 percent and remains constant throughout the 10-year assessment period.[60] Through the MISO stakeholder process, it was determined that a one-day-in-10-year LOLE is an acceptable risk level for planning. Approximately 54.0 percent of this reserve level is for managing system outages, while the remaining 44.0 percent is utilized for managing LFU and OMC events. If MISO Midwest's system had enough planning resources to meet its 14.2 percent requirement (i.e., one-day-in-10-years LOLE), MISO would initiate an EEA Level 2b event to access LMRs or rely on non-Planning Resources,[61] such as nonfirm imports or energy-only resources, nearly 100 percent of the daily peak hours during the summer season, and would accept the annual risk of a 7.8 percent chance of shedding firm load on peak. The waterfall chart below breaks the 14.2 requirement into its operating components and illustrates how the Planning Reserve Margin (NERC Reference Margin Level) manages risk.

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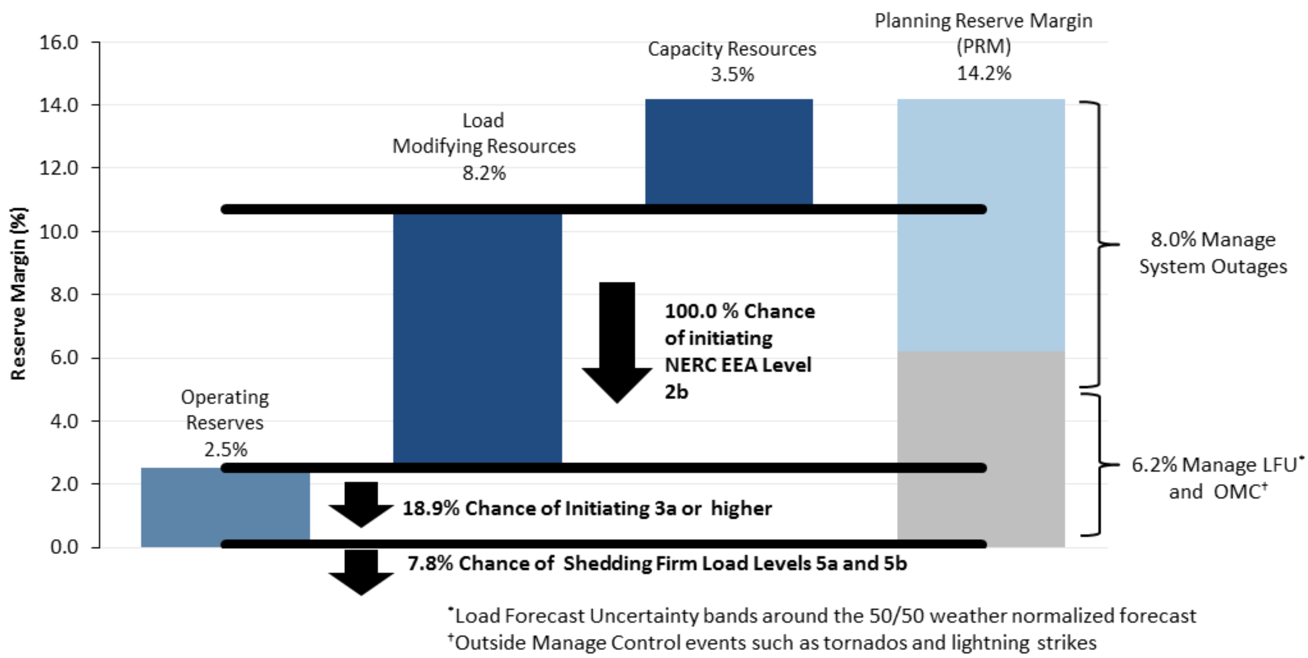
[59] Planning Reserve Margin (PMR) is the reserve margin target level (in percent form) that represents the reserve percentage the MISO system must hold above its applicable demand to meet a reliability criterion of one-day-in-10-years LOLE (2013 LOLE Study Report). MISO conducts an LOLE study to determine the next planning year's PMR on an annual basis. MISO's Planning Reserve Margin is on an installed capacity basis for planning year 2013–2014, which runs from June 1, 2013 through May 31, 2014.

[60] The purpose of the Planning Reserve Margin is to have enough installed capacity on the system to manage uncertainties such as differences in the load forecast versus actual load (e.g., LFU, system outages, and Outside Management Control (OMC) events (tornados, lightning strikes, etc.)). MISO allows Load-Serving Entities (LSEs) to register DSM programs, such as Direct Control Load Management (DCLM), interruptible load programs, and behind-the-meter generation, to meet MISO's Planning Reserve Margin. MISO refers to these DSM programs and behind-the-meter generation resources as Load-Modifying Resources (LMRs), which are only accessible to MISO during a NERC Energy Emergency Alert (EEA) Level 2b per MISO's Emergency Operating Procedures. For more information, see MISO's Emergency Operating Procedures.

[61] Per Module E of MISO's Tariff, a Capacity Resource meets all qualifications to be eligible to meet an LSE's Planning Reserve Margin requirement.

MISO Midwest Region Planning Reserve Margin by Operating Components and Percent Chance of NERC Energy Emergency Alert Events[62]



Based on MISO's current awareness of projected retirements and the resource plans of its membership, Planning Reserve Margins will erode over the course of the next couple of years and will not meet the 14.2 percent requirement. The impacts of environmental regulations and economic factors contribute to a potential shortfall of 6,750 MW, or a 7.0 percent Anticipated Reserve Margin (7.2 percentage points below the Reference Margin Level) by summer 2016. Accordingly, Existing-Certain resources are projected to be reduced by 10,382 MW due to retirement and suspended operation.

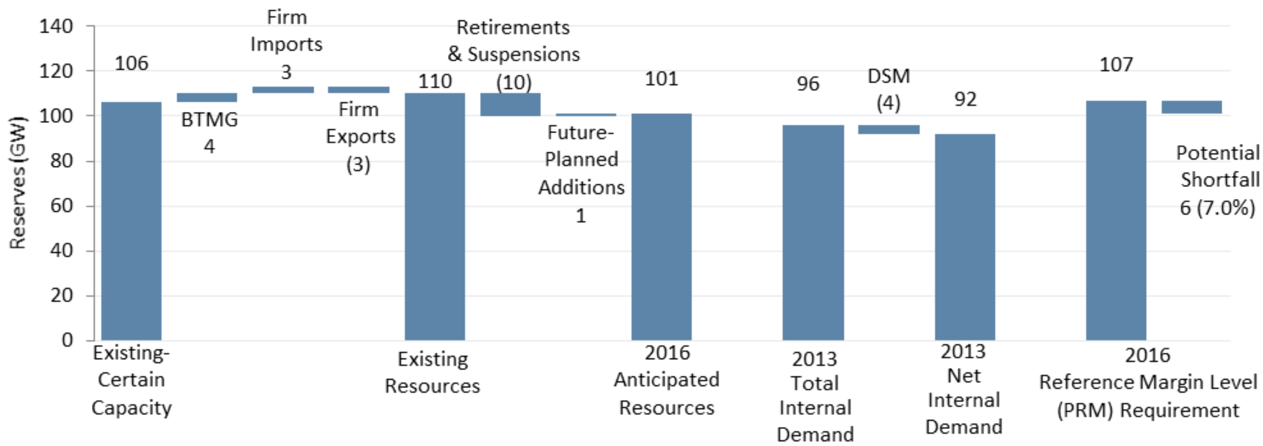
MISO Anticipated Reserve Margins by Year with Calculation Components[63]

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
NERC Ref. Margin Level (%)	14.20%	14.20%	14.20%	14.20%	14.20%	14.20%	14.20%	14.20%	14.20%	14.20%
Net Internal Demand (MW)	92,331	93,017	93,703	94,390	95,076	95,763	96,449	97,136	97,822	98,508
Requirement (MW)	105,442	106,225	107,009	107,793	108,577	109,361	110,145	110,929	111,713	112,497
Anticipated Resources (MW)	109,211	104,298	100,260	100,329	100,342	100,414	101,896	101,896	101,896	101,896
Reserve Margin (MW)	16,880	11,281	6,556	5,939	5,266	4,651	5,447	4,760	4,074	3,387
Reserve Margin (%)	18.30%	12.10%	7.00%	6.30%	5.50%	4.90%	5.60%	4.90%	4.20%	3.40%

The next waterfall chart breaks down the incremental changes in capacity from 2013 Existing-Certain Capacity Resources to 2016 Anticipated Capacity Resources. The graphic also breaks down 2013 Total Internal Demand to 2013 Net Internal Demand (net 4 GW of DSM). Finally, the graphic shows the 2016 requirement (92 GW grown annually at 0.8 percent and multiplied by 1.142 percent) and the potential shortfall in GW (2016 Anticipated Resources minus 2016 Planning Reserve Margin Requirement).

[62] Modeled as if system resources only equaled requirement.
[63] As of September 9, 2013.

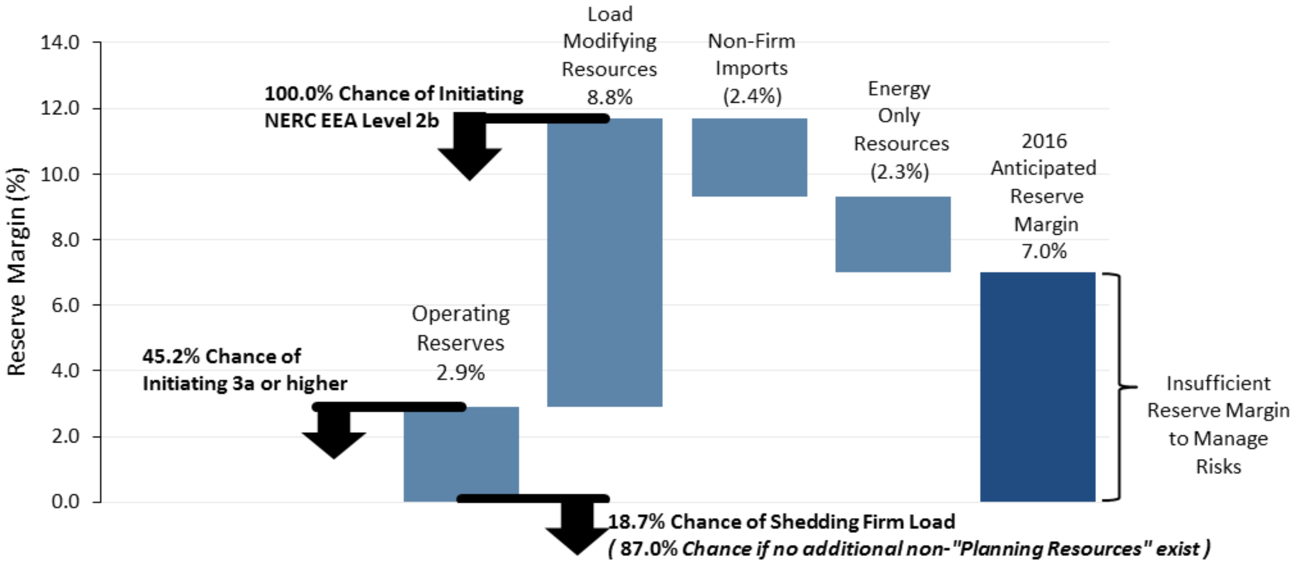
MISO Midwest Region Anticipated Reserves Shortfall[64]



At a 7.0 percent Anticipated Reserve Margin in 2016, MISO does not have enough Planning Resources to effectively manage risk associated with load uncertainty and system outages and has an 87.0 percent chance of shedding firm load on 2016 peak. However, this assumes MISO would not be able to benefit from its diversity with neighboring systems through nonfirm capacity imports or any of its energy-only resources on peak (non-Planning Resources). Historically, neighboring systems have provided MISO with an additional 4,500 MW of nonfirm external support on peak; however, given future external capacity uncertainty, MISO derates the 4,500 MW by 50.0 percent to 2,250 MW of nonfirm imports. Also, MISO has 2,124 MW of Existing-Other Energy-Only resources in its generation fleet, which may be available to serve MISO load on peak. MISO would need to rely on the majority of its non-Planning Resources and LMRs on peak to mitigate the high risk of shedding firm load. The waterfall chart below breaks the 7.0 percent Anticipated Reserve Margin into its operating components and illustrates how real-time operations would have to manage increasing risk.

[64] Based on 0.8% Load Growth and 14.2% PRM; as of September 9, 2013.

MISO Midwest Region 2016 Anticipated Reserve Margin Percent Chance of Utilizing Non-Planning Resources and Initiating NERC Energy Emergency Alert Events[65]



POTENTIAL MITIGATION OF ERODING RESERVES AND ADDITIONAL UNCERTAINTIES

MISO and Organization of MISO States (OMS) are conducting a joint survey of LSEs to bridge the gap of limited visibility that exists between the annual Module E Tariff process and Forward Resource Assessment. MISO needs more granular data with respect to DSM growth and resource procurement to conduct Forward Resource Assessment and more accurately predict reserve margins in later years. MISO will not disseminate individual LSE data but will use the data for MISO system-level assessments and to support individual state jurisdictional Integrated Resource Planning requirements, where applicable.[66]

The potential exists to mitigate some—or all of—the projected 2016 shortfall by assessing key components of the projected Anticipated Reserve Margin including, but not limited to, the potential for more Future-Planned additions, the potential for growth in DSM, the additional support anticipated from the MISO Southern Region, the potential for transmission upgrades to mitigate current generation deliverability constraints, and the potential for transmission upgrades to convert current energy-only resources to network resources.

Per NERC's definition that a Future-Planned Capacity addition be a designated Network Resource expected to be in service in a related out year and, where applicable, included in a state Integrated Resource Plan, MISO only counts those Generator Interconnection Queue projects being studied for Network Resource Interconnection Service (NRIS) with signed Generator Interconnection Agreements that are actively participating in MISO's post-queue process. Therefore, MISO's Future-Planned Capacity additions equal 1,267 MW of the total 2016 Anticipated Capacity Resources. MISO also considers an additional 1,737 MW of other queue study statuses that require significant financial obligations to be expected by 2016, which increases the 2016 Anticipated Reserve Margin by 1.9 percentage points to an 8.9 percent MISO Expected Reserve Margin, or a potential shortfall of 5,103 MW.

Per individual state mandates, MISO's current 2013 noncontrollable DR totaling 1,489 MW may grow to 1,561 MW by 2016, an increase of 72 MW. MISO's current 2013 Energy Efficiency programs totaling 208 MW may grow to 1,294 MW by 2016, an increase of 1,086 MW. Assuming that none of this growth is embedded in MISO's 10-year Total Internal Demand

[65] As of August 9, 2013.
[66] Joint MISO-OMS Long-Term Resource Adequacy Survey Presentation.

forecasts and that the incremental DSM registers as an LMR per Module E of MISO's Tariff, this incremental growth increases the 2016 Anticipated Reserve Margin by 1.4 percentage points.

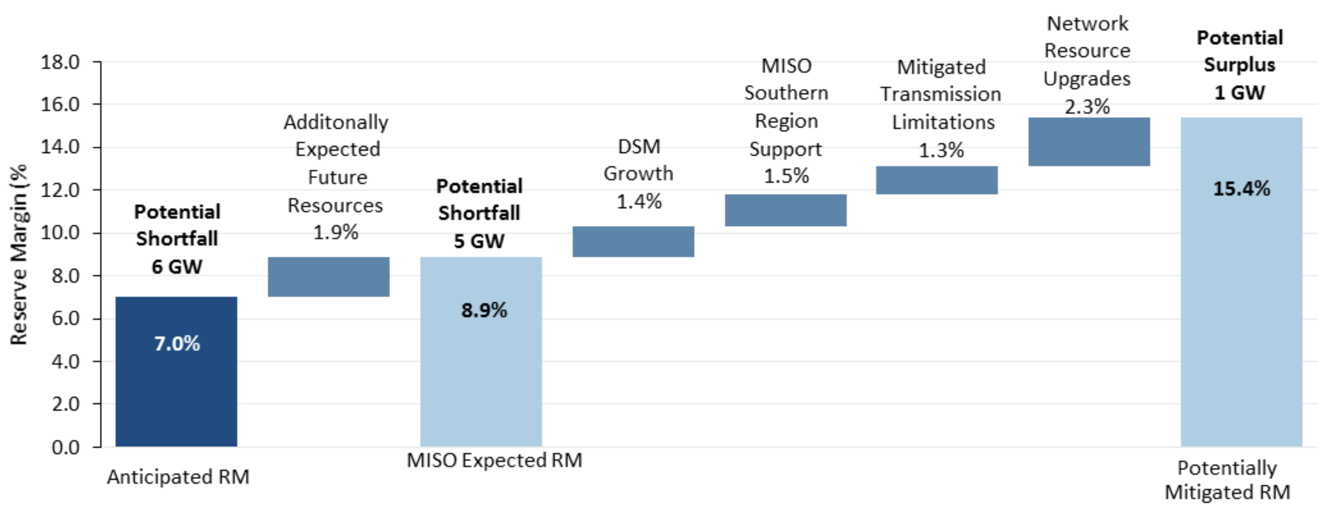
The *MISO 2013 Summer Coordinated Seasonal Transmission Assessment* analyzed a high South–North transfer from MISO Southern Region into MISO Midwest Region LRZs #4 and #6 (i.e., Illinois and Indiana). The analysis indicates an interregional transfer capability of at least 1,400 MW.[67] The assumption of an additional 1,400 MW from the Southern Region into the Midwest Region increases the 2016 Anticipated Reserve Margin by 1.5 percentage points.

MISO's generation fleet contains 1,471 MW of Existing-Other transmission-limited resources based on generation deliverability test results. Transmission limitations of 1,236 MW in aggregate are generator units limited by 10 MW or more. Assuming the applicable network upgrades are done by 2016 to mitigate these 1,236 MW of transmission limitations, the 2016 Anticipated Reserve Margin increases by 1.3 percentage points.

MISO's generation fleet contains 2,124 MW of Existing-Other energy-only resources with no firm point-to-point transmission. Assuming the applicable network upgrades are done by 2016 to convert these energy-only resources to network resources, the 2016 Anticipated Reserve Margin increases by 2.3 percentage points.

The waterfall chart below presents the potential measures that could completely mitigate the projected shortfall in 2016. It should be noted that uncertainty factors for each potential measure are unknown at this time. MISO expects to gain further certainty through the joint MISO/OMS survey and the Forward Resource Assessment.

MISO Midwest Region 2016 Anticipated Resource Shortfall Potential Mitigation Measures[68]



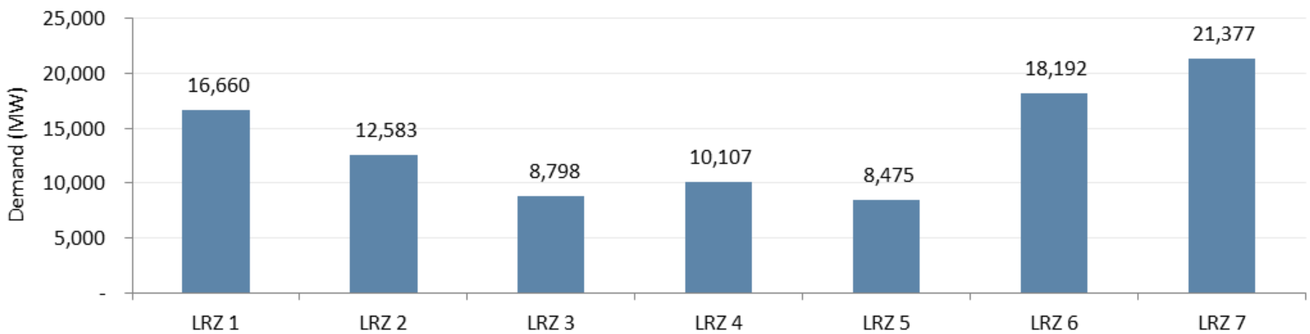
Future sensitivities regarding uncertainty in load forecasts and the impact of potential fuel supply limitations on resource adequacy are discussed in the Long-Term Reliability Issues section of this report. Further enhancements to current LOLE models are being studied to better project risks associated with lack of fuel for power generation and monthly variations in load forecasts, which would influence more accurate portrayal of future reserve margins. These studies are ongoing and expected to be revised for the next long-term assessment.

Per Module E of MISO's tariff, LSEs submit an annual peak demand forecast coincident to MISO's time of peak for use in MISO's annual Planning Resource Auction. Section 3.2 of MISO's *Resource Adequacy Business Practice Manual*[69] and the

[67] MISO 2013 Summer Coordinated Seasonal Transmission Assessment section 8.12.
[68] As of August 9, 2013.
[69] BPM 011- Resource Adequacy.

Peak Forecasting Methodology white paper[70] provide assumptions and methodologies for calculating MISO coincident peaks. Starting November 1 and concluding March 1 annually, MISO undergoes a review of all forecasts. The summation of all 2013 MISO peak demand forecasts (i.e., Total Internal Demand) totals 96,192 MW.[71] The bar chart below shows MISO's Total Internal Demand by LRZ and the table shows MISO's demand outlook.

MISO Midwest Region 2013 Total Internal Demand (Coincident) Peak Forecast by LRZ[72]



Per Module E of MISO's tariff, LSEs also submit monthly peak demand forecasts for two years and an additional eight years' worth of seasonal peak demand forecasts noncoincident to MISO's peak. MISO uses these forecasts to calculate growth rates for each of the seven LRZs. Based on these forecasts, MISO anticipates a system-wide growth rate of approximately 0.72 percent, causing Total Internal Demands of 96,879 MW and 103,056 MW in 2014 and 2023, respectively. From an LRZ perspective, the highest load growths occur in LRZ #1 and LRZ #3 at 0.94 percent and 1.21 percent, respectively, and the lowest load growths occur in LRZ #5 and LRZ #7 at 0.41 percent and 0.48 percent, respectively.

MISO LRZ Annual Percentage Growth Rates during the Assessment Period

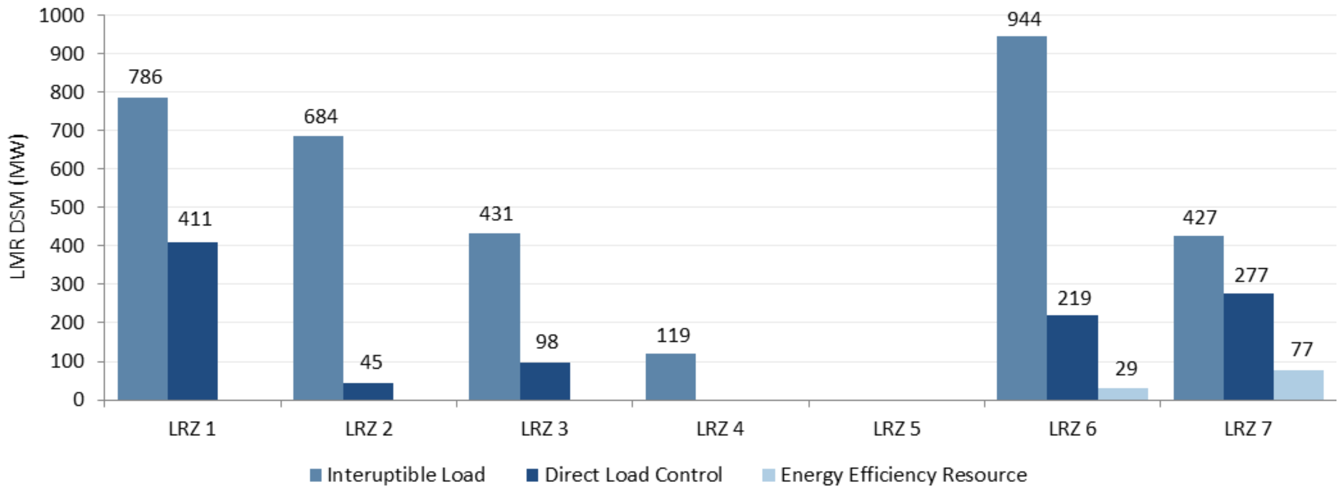
LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7
0.94%	0.75%	1.21%	0.69%	0.41%	0.67%	0.48%

In the Long-Term Reliability Issues section, MISO evaluates load forecast sensitivity impacts on the reserve margins. The sensitivities include LFU, weather, and economic variability. For more information on load forecast assumptions and methodology, see the Demand section of MISO's Methodology and Assumptions document.

Interruptible load, DCLM, and Energy Efficiency resources are eligible to participate in the Planning Resource Auction as registered LMRs.[73] Per MISO's Emergency Operating Procedures, LMR DSM is an emergency resource callable by MISO only during a Maximum Generation Emergency Event Level 2b. As MISO's visibility of future expansion of LMR DSM is low, MISO assumes that the 4,548 MW that cleared in the 2013 Planning Resource Auction will be available throughout the assessment period. The bar chart below shows each zone's portion of MISO's LMR DSM.

[70] Peak Forecasting Methodology Review Whitepaper.
[71] 2013 MISO Coincident Load Forecasts; Slide 5 (PRMR Obligation divided by 1.062)
[72] As of April 15, 2013.
[73] See section 4.3 of the Resource Adequacy Business Practice Manual

MISO Midwest Region Load-Modifying Resource (LMR) DSM by LRZ[74]

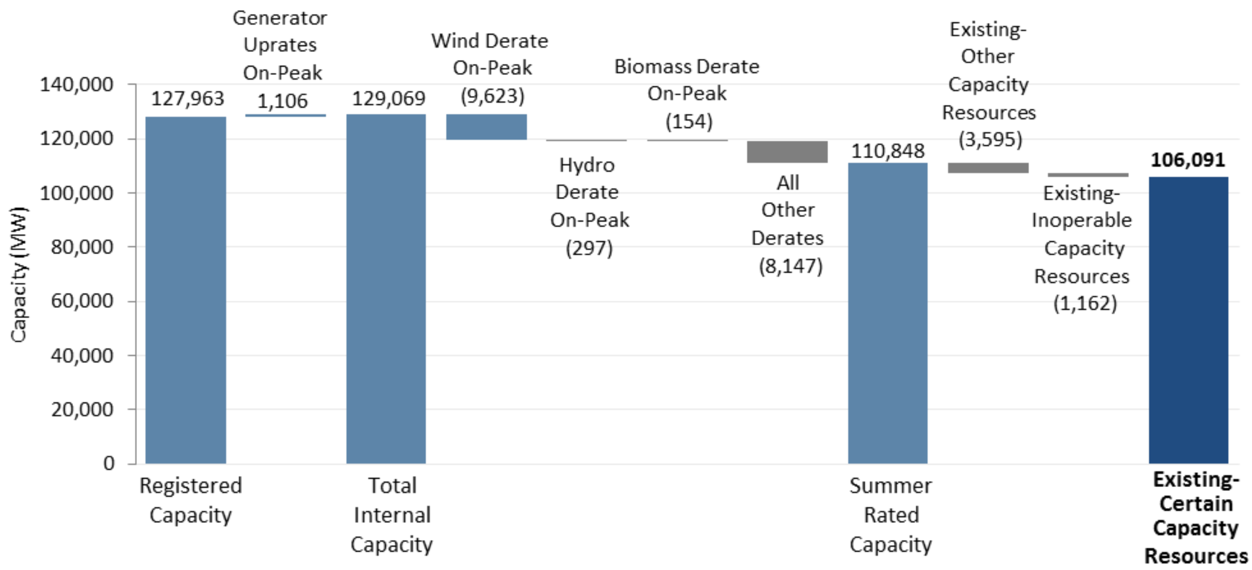


As of 2013, Energy Efficiency resources are eligible to participate in the MISO Market as Planning Resources. Energy efficiency resources are installed measures on retail customer facilities that achieve a permanent reduction in electric energy usage while maintaining a comparable quality of service. The Energy Efficiency resource must achieve a permanent, continuous reduction in electric energy consumption (during the defined Energy Efficiency performance hours) that is not reflected in the peak load forecast used for the Planning Resource Auction for the planning year.[75]

MISO's current registered capacity (nameplate) is 127,963 MW; however, when accounting for summer on-peak generator performance, transmission limitations, and energy-only capacity, MISO only relies on 106,091 MW toward its Planning Reserve Margin requirement to meet a LOLE of one day in 10 years. The graphic below illustrates the incremental MW changes from registered capacity to Existing-Certain Capacity Resources.

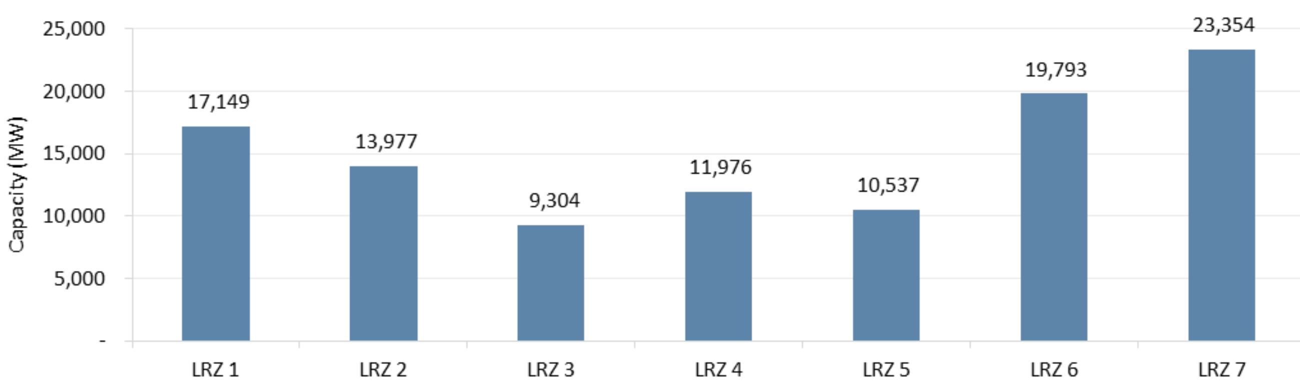
MISO Midwest Region Incremental MW Breakdown from Registered Capacity to Existing Capacity Resources[76]

[74] As of April 15, 2013.
[75] For more information regarding Energy Efficiency resources please see Section 4.3.4 of MISO's Resource Adequacy Business Practice Manual.
[76] As of August 9, 2013.



MISO determines the total summer rated capacity of its existing generation fleet (referred to as Existing-Certain Capacity Resources) that is eligible to participate in the annual Planning Resource Auction. Section 4.2 of MISO's *Resource Adequacy Business Practice Manual* contains these eligibility requirements, which in summary state that generation must be fully deliverable to load within MISO. Furthermore, deliverability is tested by MISO, and the results may be found on MISO's public website in a Generation Deliverability Workbook.[77] In total, MISO has 106,091 MW of Existing-Certain Capacity Resources. The bar chart below shows each zone's portion of that total.

MISO Midwest Region Existing-Certain Capacity Resources by LRZ[78]



In addition to Existing-Certain Capacity Resources, 3,595 MW of Existing-Other Capacity Resources (summer-rated capacity) exist in MISO, including 1,471 MW of transmission-limited Capacity Resources and 2,124 MW of energy-only Capacity Resources. Also, 1,162 MW of MISO's capacity resources are currently in suspended operations—identified as Existing-Inoperable Capacity Resources. In the projections of expected capacity found in the Forward Resource Assessment, MISO does not account for Existing-Other or Existing-Inoperable Capacity Resources as these resources do not qualify as Planning Resources in MISO's capacity auction and do not have high certainty of returning to service in the future. For more

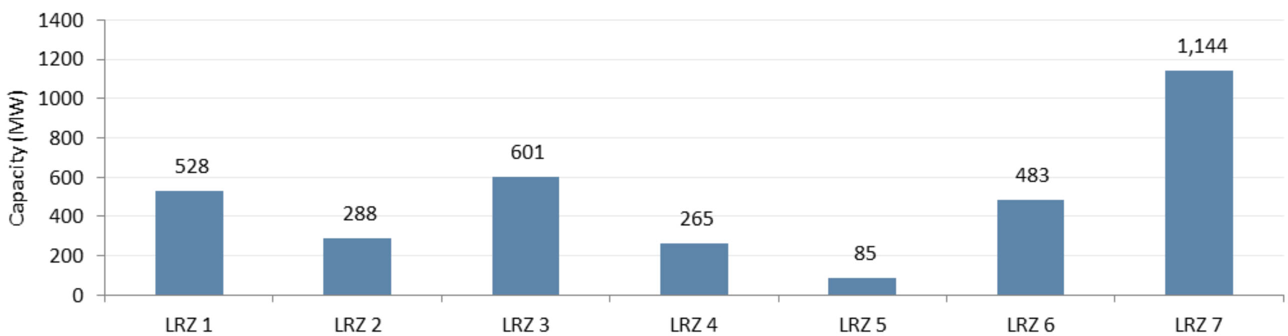
[77] Generation Deliverability Workbook
[78] As of August 9, 2013.

information on the basis of these supply category determinations, refer to the Generation section of MISO's Methodology and Assumptions document.

Based on the effective load-carrying capability of wind generation, MISO's Existing Capacity wind resources receive a wind capacity credit. The average wind capacity credit for MISO is 13.3 percent.[79] Per section 4.2.2 of MISO's *Resource Adequacy Business Practice Manual*, all other variable generation resources receive unforced capacity ratings based on historical summer performance.

Behind-the-meter generation is eligible to participate in the Planning Resource Auction as a registered LMR.[80] LMR behind-the-meter generation is an emergency resource callable by MISO only during a Maximum Generation Emergency Event Step 2b, per MISO's Emergency Operating Procedures. Since MISO's visibility of future expansion or reduction of behind-the-meter generation is low, MISO assumes the 3,394 MW that cleared in the 2013 Planning Resource Auction will be available throughout the assessment period, along with 152 MW of DR resources. The bar chart below shows each zone's portion of MISO behind-the-meter generation.

MISO Midwest Region Load Modifying Resources (LMR) Behind-the-Meter Generation (BTMG) by LRZ[81]



Largely due to new EPA rules, MISO anticipates the potential retirement and suspended operation of its older Base Load generation fleet. During the last two years, approximately 1 GW of summer-rated capacity has been retired, and MISO is projecting that 10,383 MW of Existing-Certain Capacity Resources will be retired or suspended by 2016.

On a quarterly basis, MISO sends an EPA survey to its asset owners to gauge the retrofit and retirement decisions of the coal generation fleet due to environmental regulations and other economic factors. Asset owners also must submit a completed Attachment Y[82] to MISO at least six months prior to retiring or suspending operations of a resource. To ensure no transmission issues result from the resource being decommissioned and to comply with section 6.2 of MISO's *Transmission Planning Business Practice Manual*,[83] MISO will conduct a detailed System Support Resource (SSR) study. If transmission constraints are identified, the generation resource must operate per the tariff and Business Practices Manual (BPM) until said constraints are mitigated. If an asset owner wants MISO to perform a nonbinding study of reliability impacts due to the potential retirement or suspension of a resource, that asset owner may submit an Attachment Y2. The following waterfall chart breaks up the 10.3 GW of Existing-Certain Capacity Resource retirement and suspension by 2016 according to data source, whether it is the EPA survey, Attachment Y, or Attachment Y2.

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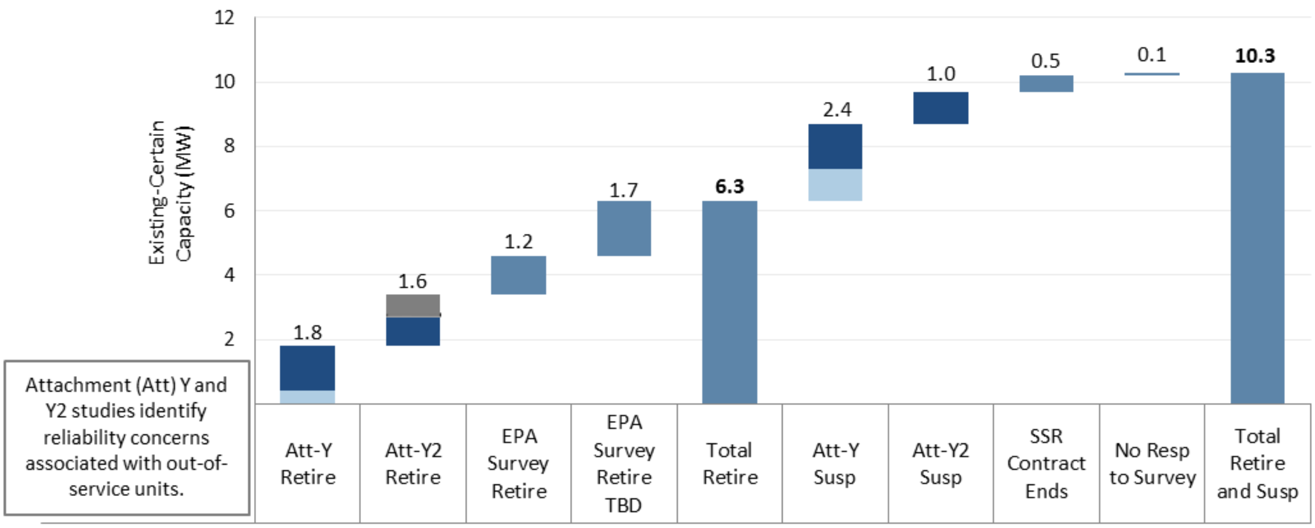
[79] 2013 Wind Capacity Report
[80] see section 4.3.2 of the Resource Adequacy Business Practice Manual
[81] As of April 15, 2013.
[82] Attachment Y of MISO's Tariff.
[83] BPM 020 Section 6.2.

The majority of the 6.3 GW of potential Existing-Certain Capacity Resource retirements are from coal-fired units (1 GW of gas-fired units). Of the Attachment Y, Attachment Y2, and SSR contracts, 1.3 GW of potential Existing-Certain Capacity Resource suspensions are from gas-fired units, while the remaining 2.7 GW are from coal-fired units.

Midwest Region 2016 Potential Retirements and Suspensions of Existing-Certain Capacity Resources by Data Source[84]



	Att-Y Retire	Att-Y2 Retire	EPA Survey Retire	EPA Survey Retire TBD	Total Retire	Att-Y Susp	Att-Y2 Susp	SSR Contract Ends	No Resp to Survey	Total Retire and Susp
Reliability Concerns	0	0.6	0	0	0	0	0	0	0	0
No Concerns	0	0.1	0	0	0	0	0	0	0	0
Under Study	1.4	0.9	0	0	0	1.4	1	0	0	0
Approved	0.4	0	0	0	0	1	0	0	0	0

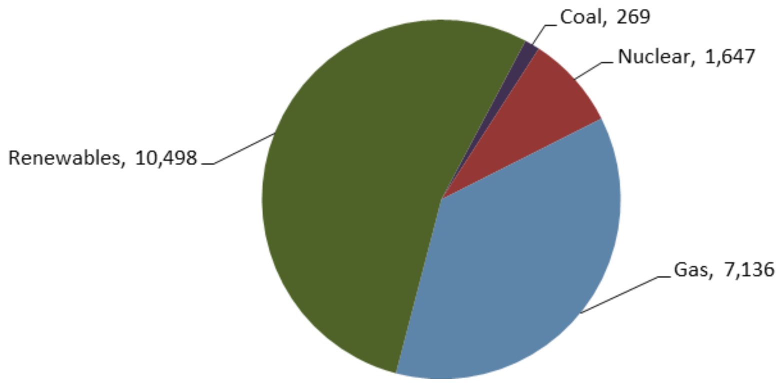
To date, MISO knows of approximately 1.2 GW of the Total Retirements that have been granted a one-year extension to operate through April 2016. Through the EPA survey, MISO is working toward increasing its visibility on extension requests past the compliance deadline of April 2015.

The Generator Interconnection Queue (GIQ) database posted on MISO's public website lets generation customers and TOs check the status of projects at any time.[85] MISO conducts a thorough assessment of the GIQ to forecast future resource additions and MW uprates to existing facilities during the 10-year planning horizon.

As of July 1, 2013, the GIQ contained 1,297 projects, although only 101 of these projects (totaling 19,550 MW of max output) were identified by MISO as actively awaiting approval or construction to come into service within the assessment period.[86] Of the 19,550 MW Active Queue, 674 MW are uprates to existing facilities (170 MW coal, 420 MW hydro, and 84 MW nuclear). Over half of the Active Queue maximum output comes from wind projects in the queue totaling 9,857 MW. The following chart breaks out the 19,550 MW by fuel type.

[84] As of August 9, 2013.
[85] Generator Interconnection Queue.
[86] For more information on the assessment of the GIQ refer to the Generation section of MISO's Methods and Assumptions document.

MISO Midwest Region "Active Queue" Max Output, MW by Fuel Type[87]



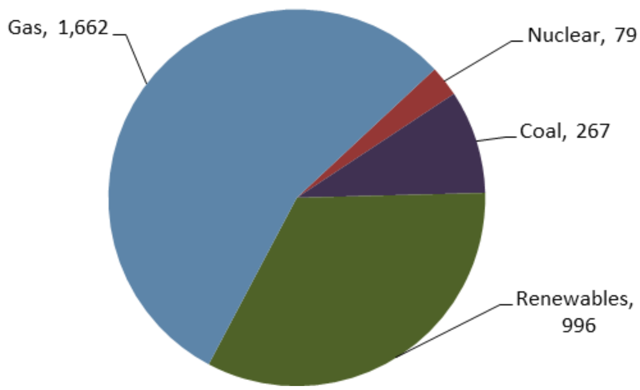
Upon evaluation of the Active Queue projects, 6,906 MW of Future Capacity Resources, including all the uprates to existing facilities (674 MW), are expected to be in service within the assessment period. Of the remaining 12,644 MW of Conceptual Resources, it is anticipated that only 10.0 percent (totaling 1,264 MW) will come in service within the assessment period.

MISO applies a Wind Capacity Credit averaging 13.3 percent to all wind projects and applies fuel-type average derates to all other queue projects. Based on these derates, on-peak Future Capacity Resources projections for 2023 amount to 3,906 MW (on-peak Conceptual Resources amount to an additional 613 MW).

In order for a Future Capacity Resource to be a Future-Planned Capacity Resource, which is included in Anticipated Capacity Resources, the queue project must be studied for Network Resource Interconnection Service, have a signed Interconnection Agreement, and be actively participating in MISO's post-queue process. By 2016, 1,267 MW of Future-Planned Capacity Resources are expected to be in service, and 2,903 MW are expected to be in service by 2023.

The following graphic presents MISO's 3,004 MW of capacity additions by 2016, including 1,737 MW of other projects scheduled for 2016 that are in the queue and currently without signed Interconnection Agreements.

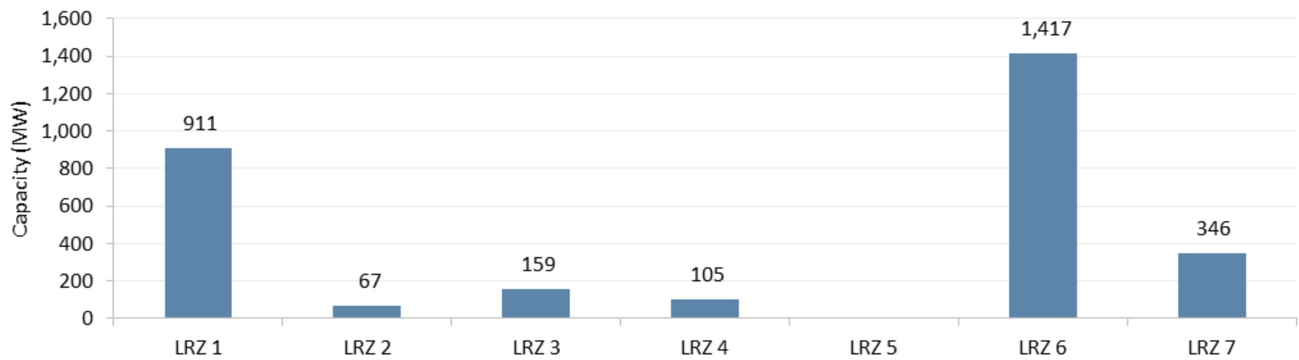
MISO Midwest Region 2016 Expected Capacity Additions On-Peak, MW by Fuel Type[88]



[87] As of July 1, 2013.
[88] As of July 1, 2013.

The following bar chart graphic breaks out MISO's expected 2016 capacity additions (3,004 MW) by LRZ.

MISO Midwest Region 2016 Expected Capacity Additions by LRZ[89]

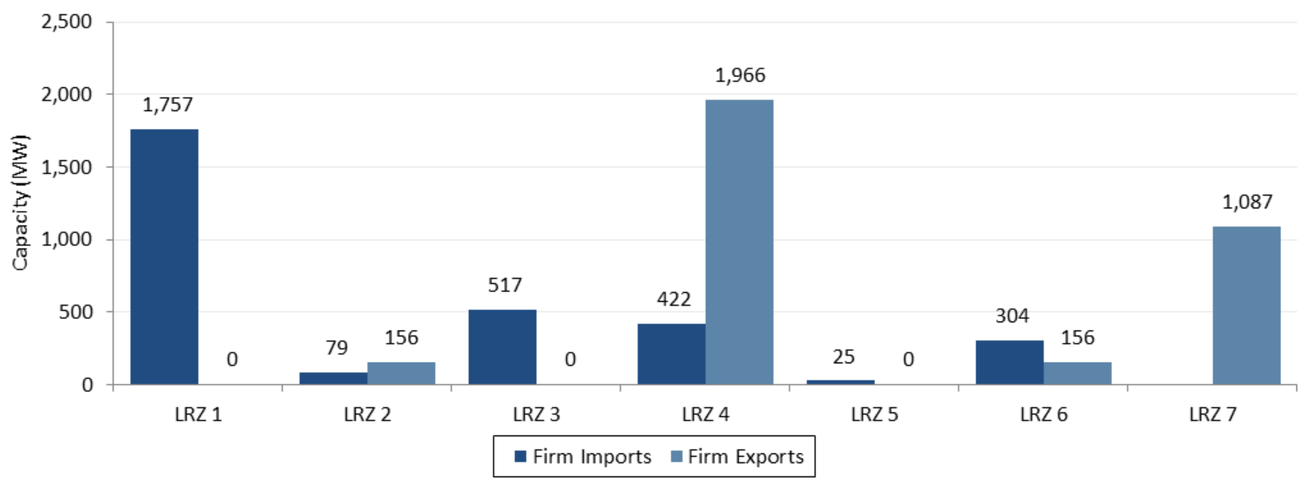


Capacity Transactions

Imports – As stated in section 4.2.4 of the *Resource Adequacy Business Practice Manual*, external resources are eligible to participate in the Planning Resource Auction as registered Capacity Resources. As the Region's visibility of future expansion or reduction of firm imports is low, MISO assumes the 3,103 MW that cleared in the 2013 Planning Resource Auction will be available throughout the assessment period.

Exports – Based on information received from PJM, MISO projects 3,365 MW of firm exports into PJM by 2016.[90] The chart below shows net firm capacity transactions by LRZ.

MISO Midwest Region 2016 Expected Capacity Transactions by LRZ[91]



Changes in MISO's 2016 Reserve Margin Forecasts from Prior NERC LTRA Reports

In 2011, MISO conducted an independent analysis of the impact of four proposed EPA regulations the Region's resource adequacy. In October 2011, the EPA Impact Analysis white paper was published, and the results were summarized in the

[89] As of July 1, 2013.

[90] Of the 3,365 MW of projected firm exports, 2,278 MW have Transmission Service Requests (TSR), 867 MW have one firm path confirmed, and 220 are actively being studied in MISO and PJM.

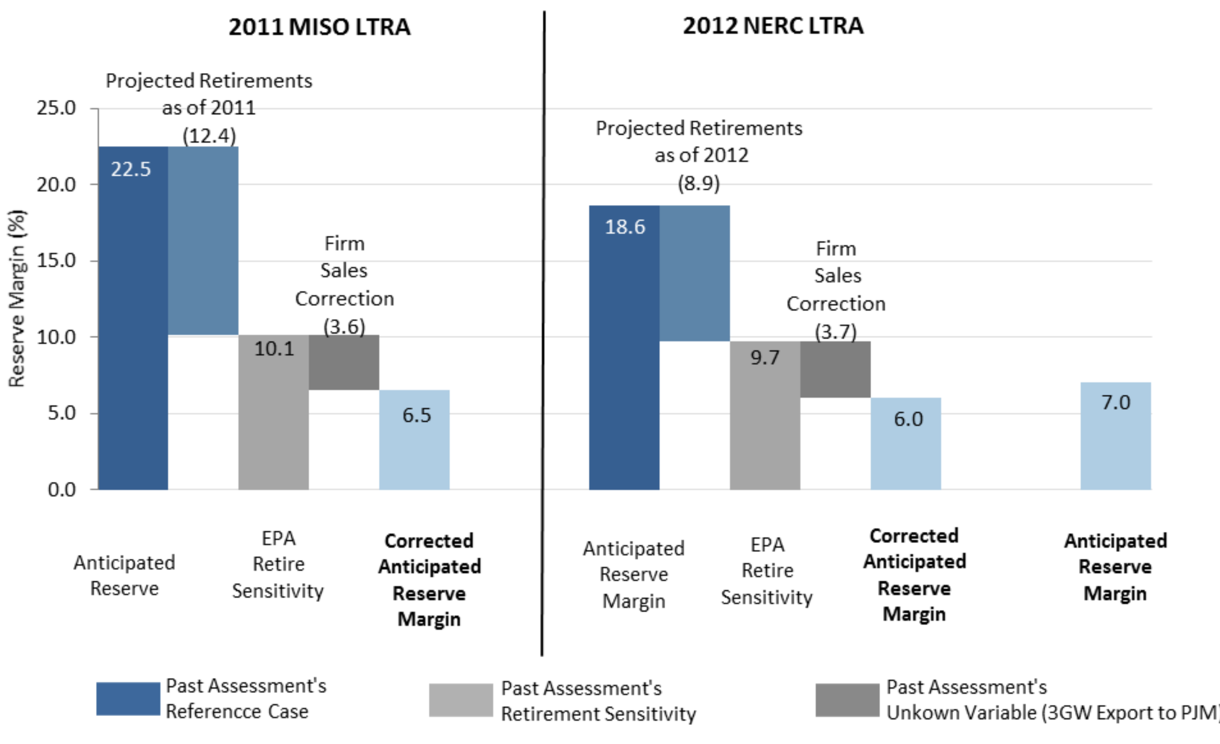
[91] As of April 15, 2013.

MISO Transmission Expansion Plan 2011 Report (MTEP). The study indicated that 12.6 GW of coal generation within MISO's footprint could potentially be retired as a direct result of the EPA regulations.

As the EPA regulations had not yet been finalized in 2011, the 12.6 GW of retirements were assessed in the MISO *2011LTRA* as a future sensitivity rather than as part of the *2013LTRA* reference case. The *2011LTRA* reference case without EPA retirements indicated a 2016 reserve margin of 22.5 percent. The *2011LTRA* reference case with EPA retirements indicated a 2016 reserve margin of 10.1 percent, or a 3,750 MW shortfall, based on a 14.2 percent Planning Reserve Margin requirement. In the 2011 assessment, MISO did not have information regarding firm sales out of MISO into PJM. Assuming 3,365 MW of sales from MISO into PJM (reported in 2011 for planning year 2016 and currently being reported), the 2016 reserve margin with EPA retirements would have been 6.5 percent, or a 7,115 MW shortfall based on a 14.2 percent Planning Reserve Margin requirement.

Again, in the NERC *2012LTRA* reference case, MISO did not report EPA-related retirements. However, the potential shortfall in 2016 was identified as a sensitivity in the MISO Standing and Emerging Issues section of the *2012LTRA*, in which MISO projected a 9.7 percent Anticipated Reserve Margin, or a 4,103 MW shortfall based on a 14.2 percent Planning Reserve Margin requirement. Keeping consistent with current forecasted firm sales into PJM for planning year 2016, the 2016 reserve margin would have been 6.0 percent, or a 7,468 MW shortfall based on a 14.2 percent Planning Reserve Margin requirement. The following chart illustrates the evolution of the 2016 Anticipated Reserve Margin from 2011 to the current projection in which EPA retirements have been moved from the sensitivity analysis to the reference case.

Evolution of 2016 Anticipated Reserve Margin (from 2011 to Present)[92]



[92] Current as of August 9, 2013

Transmission and System Enhancements

MISO's MTEP12[93] recommends 242 new transmission expansion projects through 2022 for inclusion in its Appendix A and eventual construction. This is part of a continuing effort to ensure a reliable and efficient electric grid that keeps pace with energy and policy demands. The projects fall into the following four categories: (1) 31 Baseline Reliability Projects (BRPs) (i.e., projects required to meet NERC Reliability Standards); (2) 23 Generator Interconnection Projects (GIPs) (i.e., projects required to reliably connect new generation to the transmission grid); (3) 1 Market Efficiency Project (MEP) (i.e., a project to reduce market congestion, as required by Attachment FF of the Tariff); (4) 187 Other projects (i.e., wide range of projects, including those that support lower-voltage transmission systems or provide local economic benefit, but do not meet the threshold to qualify as MEPs).

The following is a breakdown of MISO's near-term transmission projects grouped by LRZ.

LRZ #1

- Couderay–Osprey 161-kV line (Xcel Energy) – The project has an in-service date of December 2014.
- During summer peak conditions, river conditions can be such that there is low or no hydro generation along the Flambeau River. These conditions, in addition to load growth in the area, result in low voltages on the transmission system for Category B outages.

LRZ #2

- Green Bay–Morgan 345-kV line; Holmes–Escanaba 138-kV line (ATC) – The project has an in-service target of January 2017.
- A major loss-of-load event in northeastern Wisconsin and northwestern Michigan in May 2011 drew attention to shifting supply-and-demand patterns and emerging reliability needs in the area. Multiple Category B and C contingencies led to overloads and voltage instability on the five-year horizon and drove a package of projects through an out-of-cycle study that terminated in August 2012. Those projects include:
    - A new 345-kV Green Bay substation between North Appleton and Kewaunee,
    - 40 miles of new 345 kV,
    - 60 miles of new 138 kV, and
    - Approximately 150 Mvar of new 138-kV reactive supply.

LRZ #3

- Salix–Kellogg 161-kV line (MidAmerican Energy Co.) – The anticipated in-service date is June 2015.
- For a common tower, Category C5, outage of the Raun–Sioux City 345-kV and the Raun–Morningside 161-kV lines will overload the Raun–Interchange 161-kV line. Adding a new line from the Salix substation to the Kellogg substation, both 161 kV, will mitigate the overload.

LRZ #4

- Ameren Illinois is replacing more than 80 miles of its older 138-kV lines that were built with copper conductors. These lines have integrity issues and were originally constructed in the 1940s. The new lines will have modern ACSS conductors.

LRZ #6

- Upgrades needed to accommodate the PJM Auction Revenue Rights (ARR) request.
- Replace existing Burr Oak Substation Transformer (NIPSCO) with a 556 MVA 345/138-kV transformer. The anticipated in-service date is March 2013.

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[93] https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MTEP12.aspx.

- This project is identified in PJM's ARR Queue as V3-052 and is a Market Participant-sponsored project.
- Add an additional 345-kV breaker at Burr Oak Substation (NIPSCO) – The anticipated in-service date is March 2013.
- The addition of one 345-kV breaker at Burr Oak Substation will alter the existing 345-kV bus configuration to a ring bus configuration. A ring bus configuration will increase the thermal rating of the Burr Oak – R.M. Schafer 345-kV line.
- This project is identified in PJM's ARR queue as V3-052 and is a Market Participant-sponsored project.

LRZ #7

- Tippy static var compensator (SVC) (METC) – The project has an expected in-service date of June 1, 2015.
- The planned maintenance plus forced contingency for the loss of two sections of 345-kV lines in Michigan may potentially result in low-voltage issues in the northern Michigan area. Installation of one 216-Mvar SVC at Tippy will help provide fast-acting reactive power and continuously regulate system voltage.

These projects are anticipated to come into service during the 10-year study period to enable reliable and efficient transmission service for the MISO Region. While the majority of projects are expected to be completed on schedule, some projects will have delays in the construction schedules. MISO has not identified any potential reliability impacts due to schedule delays of transmission.

Renewable energy resources whose capabilities are limited by fuel-dependent forecasts create challenges for grid operators who dispatch generation to balance the moment-to-moment electricity demand as efficiently and reliably as possible. Given the current and projected increase in wind generation in the footprint, MISO began working with stakeholders in January of 2010 to design and implement a market mechanism to take advantage of advances in wind technology that make the concept of nondispatchability less applicable. The introduction of DIRs will allow such resources to fully participate in the energy markets and result in more economic and reliable grid operations.

Through the use of industry-leading, wide-area visualization tools, system operators gain a clearer look at system conditions. One of these tools, Synchrophasors, provides more precise grid measurements by using data collected from phasor measurement units (PMUs). PMU measurements are taken at very high speeds (typically 30 observations per second, as compared to once every four seconds using current technology). Each measurement is time-stamped to synchronize data from widely dispersed locations in the power system network. This provides a more comprehensive view of the entire interconnection. Synchrophasors can give better indications of grid stress, allowing operators to be more proactive when corrective actions are necessary.

Long-Term Reliability Issues

FOSSIL-FIRED RETIREMENTS

From MISO's vantage point, the long-term resource adequacy picture changes dramatically as the landscape changes in response to new and proposed emission regulations. This assessment on the potential impact of current and proposed air regulations shows the potential for a 3-to-7-GW capacity shortfall as early as planning years 2015 and 2016.

The uncertainty increases with the potential for carbon emission limitations. While the specifics of any carbon proposal are unclear, it is clear that any carbon emission limitations will negatively impact MISO's coal generation fleet and further increase the resource deficiency.

These uncertainties raise regional concerns. For example, in times of shortage, MISO's operating procedures allow for a number of solutions including calling on emergency generation resources, DR, and operating reserves. As a last resort, MISO would need to use firm load shed on a pro-rata basis. Based on the potential 5 GW shortfall in 2016 or an 8.5 percent

Anticipated Reserve Margin, the chance of shedding firm load is 50 percent. For more information on the calculation of percent chance based on the forecasted reserve margin, please see A.1.a.ii of MISO's *2013 Summer Resource Assessment*.[94]

MISO is currently reaching out to regulators and MISO members through the Forward Resource Assessment initiative to increase visibility on future resource plans. The 8.5 percent reserve margin is based on limited visibility on final retirement decisions (aside from the EPA Survey), future resource procurement (aside from what is being tested for interconnection service in MISO's GIQ), and projected growth in DR and distributed generation. MISO will continue to address these issues and come to collaborative solutions to mitigate the potential impact on resource adequacy.

Coordination of Outages for Compliance with Environmental Regulations

As part of the efforts to manage the influx of outage requests associated with recent environmental regulations, MISO has been conducting a maintenance limit analysis to determine acceptable daily outage levels that can be allowed while still maintaining resource adequacy. Proposed methods and next steps may be found in the *Maintenance Limit Analysis* one-pager.[95] To keep track of the progress of this initiative, follow the Supply Adequacy Working Group (SAWG) and Loss-of-Load Expectation Working Group (LOLEWG) meeting. Times and dates, dial-in information, and meeting materials are posted on MISO's public website.

Increased Dependence on Natural Gas for Electric Power

MISO formed the Electric and Natural Gas Coordination Task Force (ENGCTF) as part of their efforts to better understand system impacts of a changing resource mix to potentially more reliance on natural gas generation due to recent environmental regulations and economic factors. The ENGCTF meets on a monthly basis and is comprised of members from both the natural gas and electric power industries. MISO also conducted two gas analysis studies (Phase I[96] and Phase II[97]) that were published in 2012 and indicated that gas storage, future pipeline capacity, timing of infrastructure build-outs, and insufficient capacity are areas of concern.[98]

The Phase I and II studies looked at historical natural gas flow patterns; however, changing natural gas flow patterns and the expansion of MISO's territory call for a new look at the adequacy of natural gas pipeline infrastructure within the MISO footprint. Phase III analysis is ongoing.[99] An update on the Phase III Study was presented at the July 2013 SAWG, LOLEWG, and ENGCTF joint meeting.[100]

On April 11, 2013, the ENGCTF motioned that MISO perform a LOLE Fuel Availability Study to ascertain the threat to LOLE due to a changing resource mix. MISO is pursuing this study based on the concern with fuel availability impacts on Planning Reserve Margins as the fuel mix changes and MISO's reserve margin gets closer than ever before to the reserve requirement or potentially is deficient due to future generation requirements. At the same time, MISO would like to incorporate fuel limitations into its Planning Reserve Margin to allow its members the flexibility of developing solutions to meet the resource adequacy criteria. An update on this study was presented at the July 2013 SAWG, LOLEWG, and ENGCTF joint meeting.[101]

Increased Uncertainty in Load Forecasting

In order to have a robust load futures development for the planning horizon, MISO examines the variability in load growth (economy), deviations from normal weather, and estimated diversity when addressing uncertainty in load forecasts.

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[94] Appendix A.1 Risk Assessment; Probabilistic Results
[95] Maintenance Limit Analysis
[96] Phase I Study
[97] Phase II Study
[98] Gas-Electric Infrastructure Analyses I, II
[99] Phase III
[100] Phase III Update
[101] Fuel Availability LOLE Study Details

Historically, MISO's practice for determining LFU was to apply the NERC bandwidth approach to historical data. This approach examines the historical variability of annual peak demands through the use of a statistical methodology.[102] MISO has enhanced this methodology in order to calculate uncertainty beyond year one using a combination of the NERC bandwidth methodology and a MISO-developed methodology—called MISO Blended Approach.[103] MISO uses this approach to account for future year uncertainty in load forecast while reducing volatility in out-year forecasts due to outlying historical events like the recession of 2007–2008. The following line chart illustrates the three different approaches to calculate out year LFU.

LFU Blended Approach by LRZ

Planning Year	MISO Midwest	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7
2014	3.8%	2.9%	4.5%	3.0%	4.7%	4.4%	3.5%	5.3%
2015	4.5%	3.6%	4.6%	3.1%	4.7%	5.5%	3.9%	6.0%
2016	4.5%	3.6%	4.7%	3.1%	4.7%	5.7%	4.0%	6.1%
2017	4.6%	3.7%	4.8%	3.2%	4.8%	5.8%	4.1%	6.2%
2018	4.8%	3.8%	5.0%	3.3%	4.8%	6.1%	4.2%	6.4%
2019	5.1%	4.0%	5.3%	3.5%	4.9%	6.5%	4.5%	6.8%
2020	5.5%	4.3%	5.7%	3.8%	4.9%	7.0%	4.9%	7.4%
2021	5.7%	4.5%	5.9%	3.9%	5.1%	7.3%	5.0%	7.6%
2022	5.9%	4.6%	6.1%	4.0%	5.3%	7.6%	5.2%	7.9%
2023	6.2%	4.8%	6.3%	4.2%	5.5%	8.0%	5.5%	8.3%

For this assessment, it is assumed that the first year's LFU, 3.8 percent for the MISO Midwest Region, is due to weather variability and is assumed to be constant throughout the entire assessment period. The difference between the first year's LFU to the other years' is due to economic uncertainty, which increases each year of the assessment period. The following table shows each year's difference from the first year by LRZ.

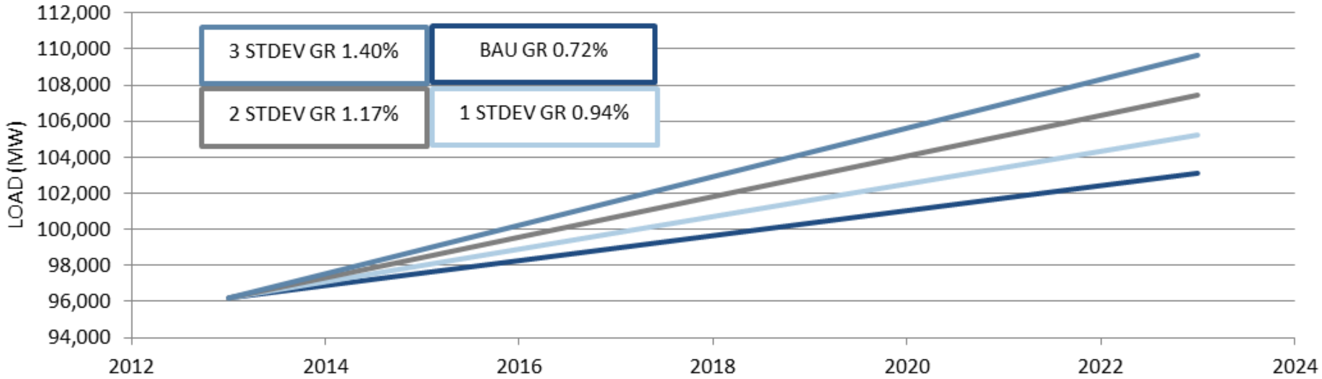
MISO Annual Differences by LFU Compared to 2014

Planning Year	MISO Midwest	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7
2014	-	-	-	-	-	-	-	-
2015	0.70%	0.70%	0.10%	0.10%	0.00%	1.10%	0.40%	0.70%
2016	0.70%	0.70%	0.20%	0.10%	0.00%	1.30%	0.50%	0.80%
2017	0.80%	0.80%	0.30%	0.20%	0.10%	1.40%	0.60%	0.90%
2018	1.00%	0.90%	0.50%	0.30%	0.10%	1.70%	0.70%	1.10%
2019	1.30%	1.10%	0.80%	0.50%	0.20%	2.10%	1.00%	1.50%
2020	1.70%	1.40%	1.20%	0.80%	0.20%	2.60%	1.40%	2.10%
2021	1.90%	1.60%	1.40%	0.90%	0.40%	2.90%	1.50%	2.30%
2022	2.10%	1.70%	1.60%	1.00%	0.60%	3.20%	1.70%	2.60%

Using the 10th year Business as Usual 50/50 weather normalize coincident load projections (103,056 MW for MISO Midwest) and the 10th year economic portion of LFU (2.4 percent for MISO Midwest), three varying load growth scenarios in addition to the Business as Usual are calculated. The economic portion of LFU is the sigma applied to the 10th year Business as Usual coincident peak.

[102] MISO NERC bandwidth methodology presentation
[103] LFU Blended Approach Discussion; results on slide 15

MISO Load Growth Scenarios, MW

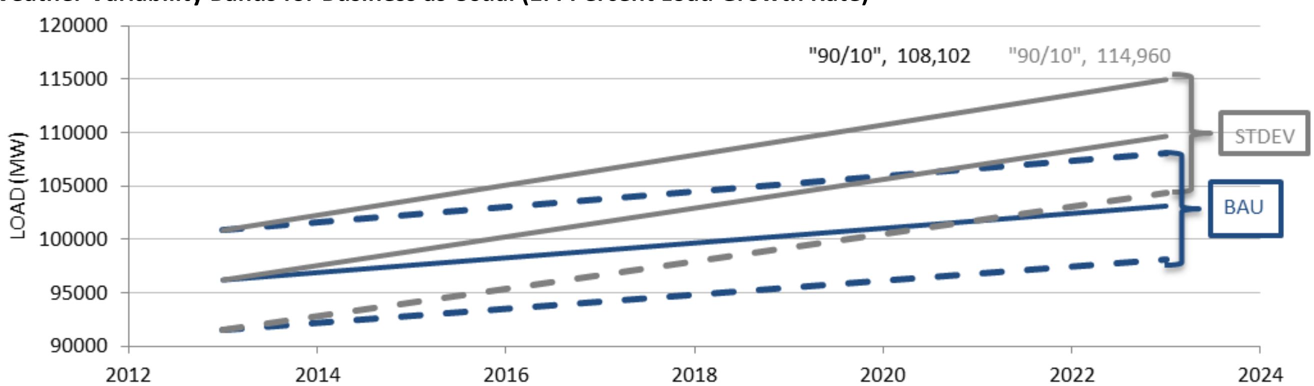


Anticipated Reserve Margins with Calculation Components (1.4 Percent Load Growth Rate)

	2014	2015	2016	2017	2018	2019	2020	2021	2022
NERC Reference Margin Level, %	14.20%	14.20%	14.20%	14.20%	14.20%	14.20%	14.20%	14.20%	14.20%
Net Internal Demand, MW	92,331	94,444	95,336	96,276	97,478	99,001	100,846	102,153	103,540
Requirement, MW	105,442	107,855	108,874	109,947	111,320	113,059	115,166	116,659	118,243
Anticipated Capacity Resources, MW	109,211	104,298	100,260	100,329	100,342	100,414	101,896	101,896	101,896
Reserve Margin MW	16,880	9,854	4,924	4,053	2,864	1,413	1,050	-257	-1,644
Reserve Margin %	18.30%	10.40%	5.20%	4.20%	2.90%	1.40%	1.00%	-0.30%	-1.60%

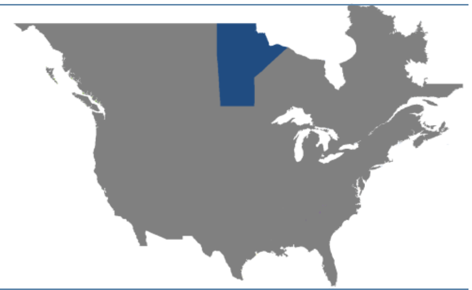
The weather variability is applied to the four different 50/50 load growth scenarios based on the first year's LFU (i.e., 3.8 percent).

Weather Variability Bands for Business as Usual (1.4 Percent Load Growth Rate)



MRO-Manitoba Hydro

Manitoba Hydro is a Provincial Crown Corporation providing electricity to 542,000 customers throughout Manitoba and natural gas service to 267,000 customers in various communities throughout southern Manitoba. The province of Manitoba is 250,946 square miles. Manitoba Hydro also has formal electricity export sale agreements with more than 35 electric utilities and marketers in the midwestern United States, Ontario, and Saskatchewan. Manitoba Hydro is its own Planning Authority and BA. Manitoba Hydro is a coordinating member of the MISO. MISO is the Reliability Coordinator (RC) for Manitoba Hydro.

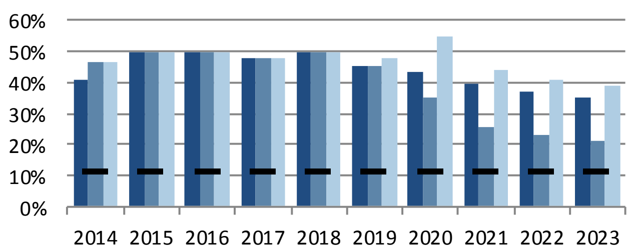


Planning Reserve Margins

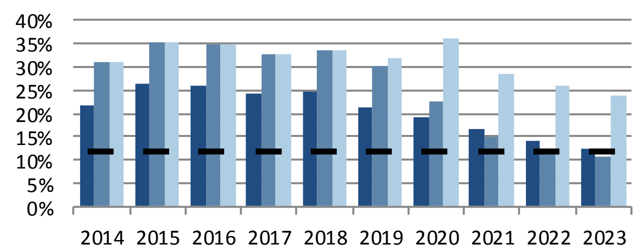
MRO-Manitoba Hydro-Summer	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ANTICIPATED	40.51%	49.71%	49.72%	47.74%	49.88%	45.49%	43.33%	39.80%	36.88%	34.80%
PROSPECTIVE	46.52%	49.42%	49.42%	47.45%	49.58%	45.20%	35.42%	25.40%	22.79%	20.92%
ADJUSTED POTENTIAL	46.52%	49.42%	49.42%	47.45%	49.58%	47.98%	54.62%	44.12%	41.12%	38.97%
NERC REFERENCE -	**12.00%**	**12.00%**	**12.00%**	**12.00%**	**12.00%**	**12.00%**	**12.00%**	**12.00%**	**12.00%**	**12.00%**

MRO-Manitoba Hydro-Winter	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ANTICIPATED	21.93%	26.27%	25.87%	24.11%	24.85%	21.29%	19.36%	16.64%	14.28%	12.41%
PROSPECTIVE	30.92%	35.18%	34.75%	32.86%	33.65%	30.00%	22.44%	14.83%	12.50%	10.66%
ADJUSTED POTENTIAL	30.92%	35.18%	34.75%	32.86%	33.65%	32.01%	36.27%	28.34%	25.74%	23.68%
NERC REFERENCE -	**12.00%**	**12.00%**	**12.00%**	**12.00%**	**12.00%**	**12.00%**	**12.00%**	**12.00%**	**12.00%**	**12.00%**

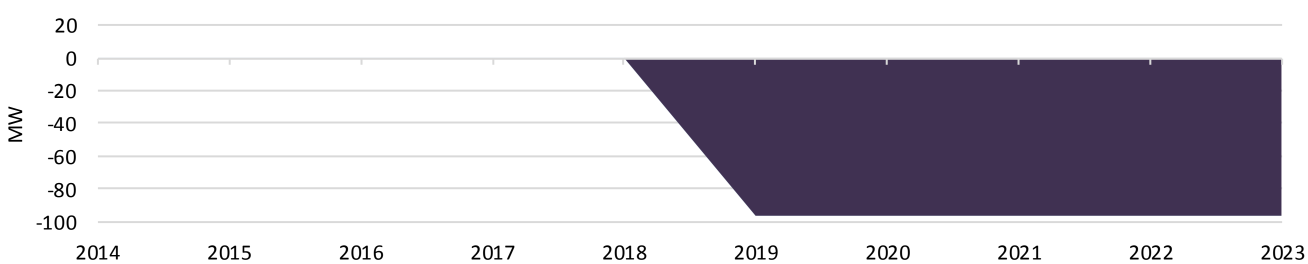
Summer



Winter



Cumulative 10-Year Planned Capacity Change



Manitoba Hydro	2013 Existing Capacity (MW)	Share (%)	2023 Planned Capacity (MW)	Share (%)	Change (MW)	2023 Planned & Conceptual Capacity (MW)	Share (%)	Change (MW)
Coal	97	1.8%	0	0.0%	-97	0	0.0%	-97
Petroleum	0	0.0%	0	0.0%	0	0	0.0%	0
Gas	242	4.4%	242	4.5%	0	242	4.0%	0
Nuclear	0	0.0%	0	0.0%	0	0	0.0%	0
Hydro	5,172	93.9%	5,172	95.5%	0	5,802	96.0%	630
Pumped Storage	0	0.0%	0	0.0%	0	0	0.0%	0
Geothermal	0	0.0%	0	0.0%	0	0	0.0%	0
Wind	0	0.0%	0	0.0%	0	0	0.0%	0
Biomass	0	0.0%	0	0.0%	0	0	0.0%	0
Solar	0	0.0%	0	0.0%	0	0	0.0%	0
TOTAL	**5,510**	**100.0%**	**5,413**	**100.0%**	**-97**	**6,043**	**100.0%**	**533**

Demand, Resources, and Planning Reserve Margins

As a predominately hydro system, the Manitoba Hydro Assessment Area has both an energy criterion and a capacity criterion. The capacity criterion requires a minimum 12 percent Planning Reserve Margin.

Manitoba Hydro is projecting adequate Planning Reserve Margins throughout the 10-year period. Assessment projections show ample resources during the next five years due to the addition of the Wuskwatim Generating Station in 2012. Potential issues that could result in differences from the long-term assessment projection are sustained higher than expected load growth and delays in the licensing and construction of new resources that may be required after 2020.

According to the normal-weather forecast, demand is projected to grow at a rate of 1.15 percent per year through 2023. The demand forecast is down approximately 3.0 percent in each year compared to the *2012LTRA* reference case. The change is mainly attributed to a correction of the calculation of distribution losses for the peak.

The Energy Efficiency and conservation growth pattern for DSM is expected to be minimal. Current DR implementations are limited to interruptible customer load and are not expected to grow during the assessment period.

DR programs are load-modifying and are used to provide operational flexibility for the system operator under emergency conditions. These DR programs are all interruptible customer load for which the industrial customers receive reduced electricity rates in exchange for these services. The interruptible customer load may only be used to reduce peak demand if contingency reserve obligations are in jeopardy of not being met.

DR programs used for Ancillary Services (Nonspinning Reserves) in place at Manitoba Hydro is the Curtailable Customer Load Option R. Option R consists of an agreement between Manitoba Hydro and a large industrial customer to carry 50 MW of Nonspinning Reserves in the form of a curtailable customer load.

Manitoba Hydro's fleet of primarily hydro generation units continues to perform well from an availability perspective, and there are no notable issues expected during the next decade that would lead to large-scale impacts.

At this time, it is anticipated that Manitoba Hydro's sole coal generating unit (approximately 95 MW and located in Brandon, Manitoba) will be retired in 2019, when replacement resources are expected to be completed. However, Manitoba Hydro is investigating the possibility of keeping this unit available until 2029. Units taken out of service for planned maintenance during the summer and winter peaks during the assessment period range between 13 MW and 91 MW.

Wind generation in Manitoba Hydro is fully derated for December, January, and February, the three months during which the annual peak load will occur given the winter-peaking load. The zero value is used as the winter peak load is expected to occur at temperatures below negative 30°C, when wind generation is expected to shut down due to low-temperature operating restrictions. For spring, fall, and summer months, Manitoba Hydro assumed a capacity value of 13.3 percent, based on the Effective Load Carrying Capability (ELCC) analysis.[104] To date, the integration of wind generation in Manitoba has not significantly impacted operational procedures. As no additional wind generation is anticipated for at least five years, additional operations impacts are not expected in that time period.

For reservoir and variable hydro generation (also referred to as run-of-river hydro) expected on-peak values are determined using the testing guideline and data processing procedures in accordance with the Midwest Reliability Organization (MRO) Generator Testing Guidelines approved on March 29, 2007.[105]

[104] See MISO's *Planning Year 2013–2014 Wind Capacity Credit* report.
[105] MRO Generator Testing Guidelines

All of Manitoba Hydro's dependable exports and imports are backed by contracts. Manitoba Hydro has up to 600 MW of firm on-peak capacity exports and 500 MW of firm on-peak capacity imports during the winter, 1,100 MW of on-peak capacity exports in the summer, and associated firm transmission reservations during the 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 exports transactions are contingent upon additional resources being built within the assessment time frame.

Transmission and System Enhancements

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 or loss of the Bipole I or II transmission corridor. These facilities are planned to be in-service by 2017 and are included in the *2013LTRA* reference case.

The following new transmission projects and line refurbishments are expected during the 10-year time frame.

New Transmission Projects

A new 500/230-kV Riel Station with a scheduled in-service date of 2014 consists of establishing a new station, which will include:

- Installing a 1,200-MVA 230-kV/500-kV transformer bank,
- Sectionalizing the existing Dorsey–Forbes 500-kV line, and
- Sectionalizing two existing 230-kV lines (i.e., Ridgeway–St. Vital lines R32V and R33V).

A New Bipole III transmission line with a scheduled in-service date of 2017 will run from Keewatinoow Station in the North to Riel Station near Winnipeg. The Bipole III project includes:

- A ±500-kV HVdc transmission line, about 833 miles long, from Keewatinoow Converter Station to Riel Converter Station;
- A 2,000-MW converter station at Keewatinoow;
- Five 230-kV ac transmission lines each approximately 19 miles in length to connect the Keewatinoow Converter Station to the northern collector system; and
- A 2,000-MW converter station at Riel, including four 250-Mvar synchronous compensators.

Transmission Line Refurbishments

Winnipeg Area Transmission Refurbishments consist of upgrading an estimated 113 miles of 230-kV transmission lines to carry higher loads with various scheduled in-service dates within this assessment period.

The Rockwood 230/115-kV Station consists of the development of a new 230/115-kV Rockwood East Station supplied from sectionalized Ashern to Rosser 230-kV transmission line A3R. A 285-MVA, 230/115-kV transformer and associated structural and electrical apparatus will be needed to connect this new station to the existing 115-kV system. The scheduled in-service date for this project is 2015.

Improvements to the Winnipeg to Brandon transmission system include the addition of a fourth 54-Mvar, 115-kV capacitor bank at Brandon Generating Station and the construction of a new Dorsey–Portage South 230-kV transmission line that runs 44 miles. The scheduled in-service date for all facilities is 2015.

The Stafford Station Rebuild project is required in order to provide additional load-serving transformer capacity to the core Winnipeg area load and to facilitate the replacement of aging equipment at the existing Scotland Station. In addition, the 138-kV transmission systems between Pointe Du Bois, Slave Falls, and Stafford will be converted to 115 kV so that the former Winnipeg Hydro transmission can be integrated into the Manitoba Hydro 115-kV system. The scheduled in-service date for this project is estimated to be 2014.

The Pointe du Bois transmission line replacement consists of four transmission lines on two parallel sets of steel towers covering a distance of 77 miles and operating at 66 kV. The scheduled in-service date for this project is 2015. The lines were first installed in 1910 and need to be replaced. The current plan is to remove the existing Pointe to Rover 66-kV lines and replace them with a new 115-kV line that will run from Pointe du Bois to Whiteshell Station. Several other system modifications are required to accommodate this, including the advance construction of a new 115-kV switchyard at Pointe du Bois.

A fourth transformer addition is required at Cornwallis Station in order to meet the provincial Greenhouse Gas (GCG) reduction target that the government passed as legislation to restrict operation of coal-fired generation in Manitoba. The new legislation (assented on June 12, 2008) specified a coal phase-out requirement, meaning that after December 31, 2009, Brandon Unit 5 (the only coal-fired generation in Manitoba Hydro) cannot be used to generate power except under emergency or drought conditions. This provision has not changed since 2008. Without support of coal-fired generation, a shortage of firm transformation has been identified in the Brandon area. There are plans to extend Cornwallis Station to accommodate a fourth 230/115-kV transformer and a new 230-kV breaker. Upgrades and rerouting of transmission lines BE3 (Brandon to Victoria), CB3 (Cornwallis to Brandon), MR11 (Raven Lake to Brandon Victoria), and CB4 (Cornwallis to Brandon) are also planned. Installation of the fourth transformer and associated transmission line upgrades are estimated to be in-service by June 30, 2013.

A 21.1-mile, 230-kV transmission line from La Verendrye to St. Vital will be added. This project will form a 230-kV ring around the city of Winnipeg, which will greatly increase reliability. The scheduled in-service date for this project is estimated to be 2015. A 77.7-mile, 230-kV transmission line from St. Vital to Letellier will be added. This line is required to address load growth issues and low voltage concerns in the southern central area of Manitoba and has a scheduled in-service year of 2016.

The new 695-MW Keeyask Generating Station will require new outlet transmission facilities to connect the generating station to the Manitoba Hydro grid. A new Keeyask Switching Station will be established to terminate seven new 138-kV lines, including four unit lines (approximately 1.9 miles each) to receive the power from Keeyask Generating Station and three 138-kV transmission lines (approximately 24 miles each) to deliver the power to Manitoba Hydro’s existing Radisson Converter Station. The scheduled in-service date for all facilities is 2019.

Improvements to the 115-kV Southwest Winnipeg Transmission System consist of improvement and reconfiguration of the Southwest Winnipeg 115-kV transmission system required to enhance reliability. This project deals with a requirement for additional 115-kV transmission capacity into the southwestern Winnipeg. Potential overload scenarios exist due to future load growth. The project is divided into four stages:

1. The first stage consists of rebuilding approximately 12.4 miles of 115-kV line YH33 (now YS33) from La Verendrye to Harrow station as well as upgrading of undersized line terminations at La Verendrye and Harrow.
2. The second stage involves rebuilding approximately nine miles of 115-kV line VS27 from St. Vital to Harrow and using and upgrading the former HS5 to complete the 115-kV line VS27 from St. Vital to Scotland. Stage two also involves the creation of a new 115-kV line YS33 from La Verendrye to Scotland using the existing 115-kV line YH33 and rebuilding the former VS27 right-of-way to complete the Harrow to Scotland portion of this new line. The upgrade of undersized terminations at St. Vital will also be completed.
3. The third stage consists of opening 115-kV line YV5, creating a La Verendrye to Wilkes radial line, and terminating the former 115-kV line YV5 into Fort Garry Mohawk station, which will create the new St. Vital to Fort Garry Mohawk line.
4. The fourth stage includes the reconductoring of three miles of line VH1. The proposed alternative has been deemed to be superior based on technical and economic analysis of all alternatives considered. The various stages of the project are expected to be completed between 2013 and 2021.

The construction of a new 500-kV ac transmission tie line from Dorsey to the U.S. border is planned for 2020. There are two options being studied in detail: Dorsey–Fargo–Minneapolis and Dorsey–Iron Range–Duluth.

The project to establish a 230/66-kV Neepawa station and tap the existing 230-kV line Dorsey–Cornwallis D54C was originally planned for an in-service date of 2011. Due to budget constraints this project's in-service date was deferred to 2015. The deferral of the Neepawa 230/66-kV station and the proposed new oil and gas pipeline load increases the risk of under-voltage conditions for various single contingency outage conditions. Operating guides will be put in place as required to mitigate the under-voltage conditions. Planned voltage support equipment includes:

- Riel 230-kV three 73.4 Mvar capacitors (May 2014)
- Keewatinoow and Riel – 2,000-MW converters at each station (October 2017)
- Riel synchronous condensers (four 250 Mvar) (October 2017)
- Dorsey 150 Mvar line reactor – new (September 2019)
- Dorsey capacitor bank 51, second stage 73.4 Mvar tertiary caps (May 2019)
- Riel second 230/500-kV transformer bank with two 73.4 Mvar tertiary caps (May 2019)

A new SPS is in service at Raven Lake Station on 115-kV line MR11. When North to South transfers are high during summer and off-peak loads coincident with maximum generation, there is a potential to thermally overload this line (> 115 percent) for the loss of 230-kV line C28R. Over-current tripping of line MR11 has been initiated and no other thermal or voltages issues exist. This will be a permanent solution.

Manitoba Hydro has already deployed FACTS devices in the form of SVCs and Statcom at several stations to improve system reliability. A number of PMUs have also been deployed at various points on Manitoba Hydro's system and a data analysis tool is being used to extract information from the collected data to improve system simulation models and fine-tune control systems. Future plans include the use of PMU data for real-time visualization and decision support tools for system operators. Near-term plans to increase reliability through the use of technology include dynamic security assessment, dynamic equipment ratings, advanced equipment monitoring, and fault current mitigation.

Long-Term Reliability Issues

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

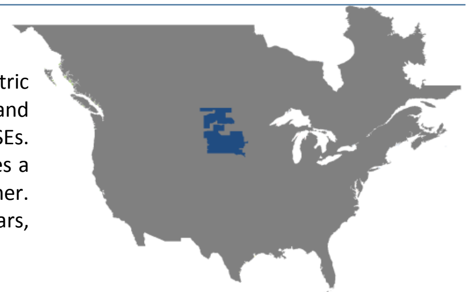
There are no resource adequacy concerns related to DR programs in Manitoba Hydro. No significant increases in DR are expected as current actual DR curtailments only use approximately 20 percent of available DR curtailments. The most significant operational concern for scenarios of unresponsive or unavailable DR is the need to carry contingency reserves elsewhere. In addition, when interruptible customer load is unavailable, system operators will have to rely on emergency energy purchases prior to shedding firm load under severe system contingencies.

The Brandon coal unit is impacted by the Manitoba Climate Change and Emissions Reduction Act and the Canadian federal Coal-Fired Electricity Regulations, and these have been considered in developing the plan to close this unit in 2019. As legislation evolves, Manitoba Hydro is investigating the possibility of keeping this unit available until 2029. At this time, there are no pending regulations that are expected to impact existing hydro generation in Manitoba.

Extreme weather events that may impact critical infrastructure and aging infrastructure have been identified as two emerging 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 access to northern hydro generation, which will impact resource adequacy.

Generation and transmission assets are aging. Many assets were put in service in the 1960s and 1970s during periods of high load growth. There is the potential for increased forced outages if additional investment is not made to replace this infrastructure. Should such additional infrastructure investments not be made, there may be some small incremental risk of loss-of-load events. The *2013LTRA* reference case was not adjusted to consider aging infrastructure. Capital constraints have the potential to defer investments in infrastructure replacement, which may elevate the risk.

MRO-MAPP



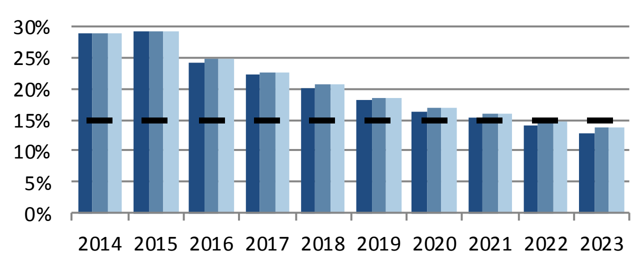
The Mid-Continent Area Power Pool (MAPP) is an association of electric utilities and other electric industry participants operating in all or parts of Iowa, Minnesota, Montana, North Dakota, and South Dakota. Currently, the MAPP Planning Authority includes entities in two BAs and 13 LSEs. The MAPP Planning Authority 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. 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.

Planning Reserve Margins

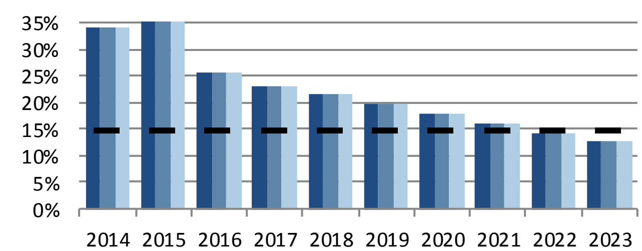
MRO-MAPP-Summer		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ANTICIPATED		29.01%	29.15%	24.36%	22.20%	20.15%	18.10%	16.29%	15.49%	14.22%	12.98%
PROSPECTIVE		29.01%	29.15%	24.76%	22.64%	20.64%	18.64%	16.87%	16.11%	14.88%	13.68%
ADJUSTED POTENTIAL		29.01%	29.15%	24.76%	22.64%	20.64%	18.64%	16.87%	16.11%	14.88%	13.68%
NERC REFERENCE	-	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**

MRO-MAPP-Winter		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ANTICIPATED		34.20%	36.08%	25.76%	23.18%	21.58%	19.62%	17.86%	16.09%	14.40%	12.66%
PROSPECTIVE		34.20%	36.08%	25.76%	23.18%	21.58%	19.62%	17.86%	16.09%	14.40%	12.66%
ADJUSTED POTENTIAL		34.20%	36.08%	25.76%	23.18%	21.58%	19.62%	17.86%	16.09%	14.40%	12.66%
NERC REFERENCE	-	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**

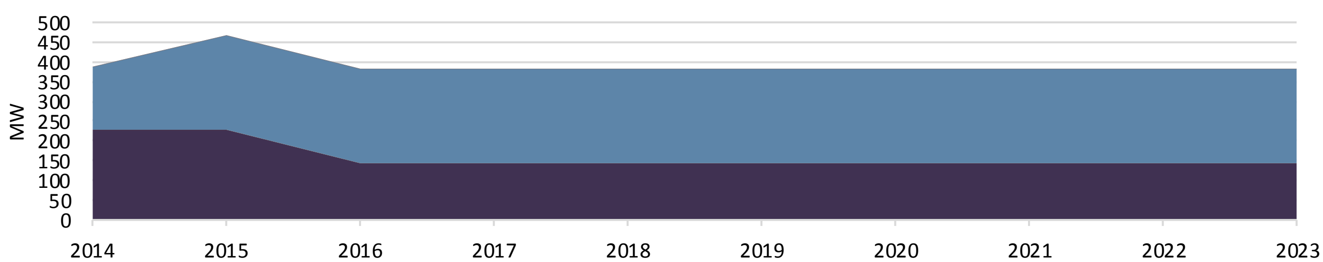
Summer



Winter



Cumulative 10-Year Planned Capacity Change



		2013 Existing		2023 Planned			2023 Planned & Conceptual		
MRO-MAPP		Capacity (MW)	Share (%)	Capacity (MW)	Share (%)	Change (MW)	Capacity (MW)	Share (%)	Change (MW)
Coal		3,205	44.1%	3,347	43.7%	142	3,347	43.7%	142
Petroleum		564	7.8%	564	7.4%	0	564	7.4%	0
Gas		1,059	14.6%	1,299	17.0%	240	1,299	17.0%	240
Nuclear		60	0.8%	60	0.8%	0	60	0.8%	0
Hydro		2,135	29.4%	2,135	27.9%	0	2,135	27.9%	0
Pumped Storage		0	0.0%	0	0.0%	0	0	0.0%	0
Geothermal		0	0.0%	0	0.0%	0	0	0.0%	0
Wind		247	3.4%	247	3.2%	0	247	3.2%	0
Biomass		3	0.0%	3	0.0%	0	3	0.0%	0
Solar		0	0.0%	0	0.0%	0	0	0.0%	0
TOTAL		**7,273**	**100.0%**	**7,656**	**100.0%**	**382**	**7,656**	**100.0%**	**382**

Demand, Resources, and Planning Reserve Margins

All Planning Reserve Margins exceed the target reference margins (NERC Reference Margin Level) of 15 percent through 2021. The Anticipated Reserve Margin falls below 15 percent in 2022 and reaches 12.7 percent in 2023. Falling short of the target reserve margin in the final two years is not a new trend in MAPP. MAPP has traditionally met its target reserve margin through the mid-term planning horizon, but beyond that time frame, firm contracts or new peaking capacity units may not yet be known. MAPP will have a more accurate picture of 2020–2023 in the next few years as load projections become more accurate, long-term contracts are executed, and new generation resources are planned.[106]

In the *2012LTRA* reference case, MAPP forecasted 10-year annual growth rates of 2.0 percent for Total Internal Demand and 2.2 percent for Net Energy for Load. In the *2013LTRA*, the forecasted 10-year annual growth rate for Total Internal Demand decreased slightly to 1.9 percent over the assessment period, while the forecasted 10-year annual growth rate for Net Energy for Load decreased to 2.0 percent.

Most of the MAPP utilities report annual demand growth near the composite MAPP annual growth demand. One localized area of greater load growth is Rochester Public Utilities, which serves the greater Rochester, Minnesota area and has a forecasted 10-year annual growth rate of 6.5 percent for Total Internal Demand. This growth rate is primarily due to the development of downtown Rochester and the expansion of the Mayo Clinic. Another area of strong load growth is attributed to the increasing development in the oil and gas production in the Bakken Formation in western North Dakota and eastern Montana. Western Area Power Administration (WAPA) and Basin Electric Power Cooperative (BEPC) performed studies of the northwestern North Dakota region to evaluate the impact of the load growth in this area. Transmission and system enhancements are noted in the sections below as a result of these studies.

The growth pattern for DR is a flat 1.0 percent throughout the assessment period, with the amount of available DR increasing from 102 MW in 2014 to 122 MW in 2023. The growth pattern for Energy Efficiency and conservation increases 300 percent throughout the assessment period from 18.9 MW in 2014 to 56.6 MW in 2023.

A wide variety of programs, including direct load control (such as electric appliance cycling) and interruptible load, may be used to reduce peak demand during the assessment period. Minnkota's DR—which accounts for a majority of DR in the MAPP Assessment Area–is treated as load modifying.

There are 382 MW of Future-Planned and Conceptual resources projected to come on-line throughout the assessment time frame, with 85.2 MW of projected retirements. Rochester Public Utilities plans to retire Silver Lake units 1–4 in 2016, accounting for all 85.2 MW of retirements. The retirement of these units is not expected to have a significant impact on reliability during the assessment period. Regarding existing capacity resources, 250 MW of wind generation is expected on peak, with a nameplate rating of 1,100 MW. There are 2,135 MW of hydro and 3 MW of biomass Existing-Certain capacity resources in MAPP.

MAPP is traditionally a net capacity exporting area and is projecting total firm imports of 398 MW and firm exports of 1,458 MW. For both imports and exports, firm contracts exist for both the generation and the transmission service.[107]

Transmission and System Enhancements

MAPP has 502 miles of greater than 100-kV transmission lines under construction. Additionally, there are 396 miles of planned projects and 84 miles of conceptual projects greater than 100-kV expected to be in service within five years. These

[106] MAPP has not received any notice from neighboring areas about issues that could impact operations during the assessment period. MAPP is part of the MISO RC footprint and operating issues are coordinated through the RC.

[107] Firm contracts are at least one year in length, and some extend out 10 years or more. Capacity transactions projected beyond the length of firm contracts may be based on extensions of those contracts. Transmission providers within MAPP handle Liquidated Damage Contracts (LDC) according to their tariff policies. Most MAPP LSEs are within nonretail access jurisdictions and therefore liquidated damages products are not typically used. MAPP is forecasted to meet the various reserve margin targets without needing to include Energy-only, uncertain, or transmission-limited resources.

projects are anticipated to come into service during the 2013–2017 time frame to enable reliable and efficient transmission service for the MAPP Region. Significant 345-kV projects include Center–Prairie, Antelope Valley Station–Neset, and Brookings County–Hampton. Basin Electric is monitoring voltage stability performance in its Bakken Area studies, which could identify any static reactive limits in the area. One of the transmission projects was identified to have permitting delays but this delay is not expected to impact reliability.

In December 2012, a temporary UVLS scheme was installed at the Williston 57-kV bus due to unforecasted load growth in that area attributed to the increasing development in the oil and gas production in the Bakken Formation. The UVLS prevents low post-contingent voltages in the local area for the loss of certain transmission facilities. Approximately 70 MW of peak load can be tripped by the UVLS in three stages. In April 2014, a parallel 230/115-kV transformer is scheduled to be energized at Williston, at which time the temporary UVLS will be removed. Additional transmission projects are being reviewed and planned to address the needs of the unforecast demands of the Bakken Formation (e.g., the Antelope Valley Station–Neset 345-kV line noted above).

MAPP and its members continue to research new technologies and tools (e.g., smart grids or FACTS) to improve BPS reliability. There is no timeline on deploying new technologies or smart grid programs during the assessment period.

Long-Term Reliability Issues

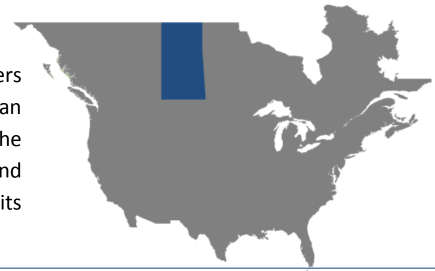
Several states in MAPP have a renewable energy mandate or goal, creating the expectation that the primary source of new renewable energy will come from intermittent resources, including wind. The integration of intermittent resources presents new challenges in the Region. As the amount of wind resources increases, their contribution to resource adequacy will also increase. This may introduce additional uncertainty in maintaining system reliability. New wind resources will have an impact on the transmission system and may increase the potential for congestion on the system. Intermittent resources also have an impact on the operation of the system generation fleet as resources that will need to be considered in meeting the potential ramp and minimum generation issues that could occur.

Currently, wind development is focused around meeting the existing state renewable energy mandates. However, if additional regulations (e.g., clean energy standards, carbon reduction) are pushed forward, more resources may be required. Additionally, economic factors such as higher gas prices or lower construction costs may increase the amount of intermittent resources found on the system.

MAPP has not conducted any assessment area-wide studies around environmental or regulatory restrictions that could impact reliability, including from minimum demand or over-generation situations.

Another emerging issue that impacts MAPP, as well as other Regions, is the complex process building transmission projects. Transmission projects that do not get built or are delayed may impact reliability through congestion on the existing BES. This could impact the amount of transmission loading relief (TLR) used. Currently, this issue is not impacting resource adequacy as reported through the LTRA. Siting and permitting issues could be barriers to transmission in-service dates, which may constrain the existing BES and affect real-time operations.

MRO-SaskPower

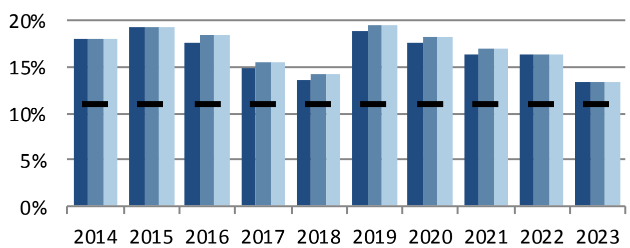


Saskatchewan is a province of Canada and comprises a geographic area of 651,900 square kilometers and approximately one million people. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the Planning Authority and RC for Saskatchewan and is the principal supplier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

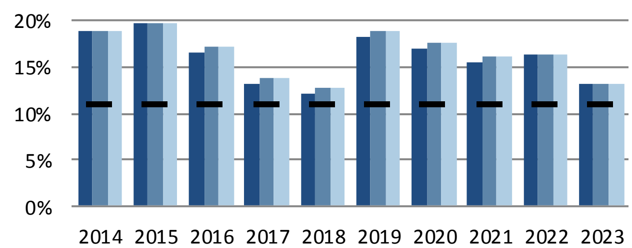
Planning Reserve Margins

MRO-SaskPower-Summer		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ANTICIPATED		17.99%	19.30%	17.64%	14.80%	13.63%	18.89%	17.61%	16.37%	16.35%	13.40%
PROSPECTIVE		17.99%	19.30%	18.39%	15.52%	14.34%	19.59%	18.30%	17.04%	16.35%	13.40%
ADJUSTED POTENTIAL		17.99%	19.30%	18.39%	15.52%	14.34%	19.59%	18.30%	17.04%	16.35%	13.40%
NERC REFERENCE	-	**11.00%**	**11.00%**	**11.00%**	**11.00%**	**11.00%**	**11.00%**	**11.00%**	**11.00%**	**11.00%**	**11.00%**
MRO-SaskPower-Winter		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ANTICIPATED		18.81%	19.73%	16.50%	13.21%	12.20%	18.28%	17.02%	15.59%	16.45%	13.09%
PROSPECTIVE		18.81%	19.73%	17.17%	13.85%	12.84%	18.91%	17.64%	16.20%	16.45%	13.09%
ADJUSTED POTENTIAL		18.81%	19.73%	17.17%	13.85%	12.84%	18.91%	17.64%	16.20%	16.45%	13.09%
NERC REFERENCE	-	**11.00%**	**11.00%**	**11.00%**	**11.00%**	**11.00%**	**11.00%**	**11.00%**	**11.00%**	**11.00%**	**11.00%**

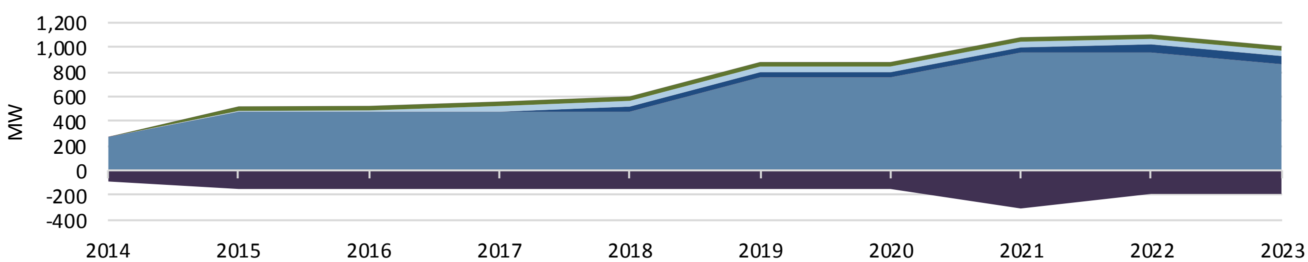
Summer



Winter



Cumulative 10-Year Planned Capacity Change



	2013 Existing		2023 Planned			2023 Planned & Conceptual		
MRO-SaskPower	Capacity (MW)	Share (%)	Capacity (MW)	Share (%)	Change (MW)	Capacity (MW)	Share (%)	Change (MW)
Coal	1,683	42.6%	1,491	31.2%	-192	1,491	31.2%	-192
Petroleum	0	0.0%	0	0.0%	0	0	0.0%	0
Gas	1,361	34.4%	2,226	46.6%	865	2,226	46.6%	865
Nuclear	0	0.0%	0	0.0%	0	0	0.0%	0
Hydro	860	21.8%	927	19.4%	67	927	19.4%	67
Pumped Storage	0	0.0%	0	0.0%	0	0	0.0%	0
Geothermal	0	0.0%	0	0.0%	0	0	0.0%	0
Wind	40	1.0%	83	1.7%	44	83	1.7%	44
Biomass	10	0.3%	46	1.0%	36	46	1.0%	36
Solar	0	0.0%	0	0.0%	0	0	0.0%	0
TOTAL	**3,954**	**100.0%**	**4,774**	**100.0%**	**820**	**4,774**	**100.0%**	**820**

Demand, Resources, and Planning Reserve Margins

For the purpose of this assessment, Saskatchewan's Reference Margin Level is 11 percent throughout the assessment period. Saskatchewan uses an Expected Unserved Energy (EUE) analysis to project its Planning Reserve Margins and as the criterion for adding new generation resources. Saskatchewan also uses a most likely load forecast (50/50).

Saskatchewan has planned for adequate resources to meet anticipated load throughout the assessment period. Based on the deterministic calculation made within this assessment, Saskatchewan's Anticipated Reserve Margin ranges from 12.20 to 19.73 percent for the winter season and does not fall below the Reference Margin Level.

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

The forecasted compound annual growth rates (CAGR) for Total Internal Demand is 2.12 percent for the winter during the assessment period (2014–2023). Saskatchewan has modified its load forecasting methodology and has begun using a 50/50 load forecast for the purposes of the MRO and NERC assessments. The change to the 50/50 load forecast methodology has caused a corresponding decrease in the expected peak demand.

Saskatchewan does not anticipate any significant economic or weather-related forecast changes. An upswing in the economy could lead to an increase in electricity usage and cause a spike to the overall demand. Saskatchewan has plans 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 that is spread evenly throughout the province.

It is expected that 86 MW of Contractually Interruptible (Curtailable) DR and 66 MW of Energy Efficiency will be available during the 2014–2015 winter. DR will remain constant but Energy Efficiency will increase to 149 MW by the 2023–2024 winter. The primary driver for DSM programs in Saskatchewan is the economic incentive or the difference in cost between providing the DSM programs and the cost of serving the load. Increases in DSM will come from growth of existing and new programs. Energy efficiency and conservation savings are counted as load-modifying 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 1,720 MW (nameplate) of Future-Planned resources is projected to come on-line. This total consists of 348 MW of refurbished coal, 1,039 MW of gas, 230 MW (nameplate) of wind, 36 MW of biomass resources, and 67 MW of additional hydro resources.

Saskatchewan relies on conventional, pulverized coal plants to supply a significant portion of the energy demand. Canadian federal GHG regulations (released in September 2012) stipulate that coal units must either meet a CO_2 emission intensity factor equivalent to an efficient natural gas facility (420 Mg/MWh) or be shut down based on the age of the unit. An equivalency agreement is currently being discussed at the provincial level to further define how coal facilities may be allowed to operate during the assessment period. Once this agreement is determined, there will be more certainty as to how Saskatchewan's coal-fired units will be affected. Approximately 278 net MW of Saskatchewan's coal fleet must meet federal regulations in the assessment period.

In addition to the 62-MW coal facility that was retired in 2013, new unit retirements throughout the assessment period include a 61-MW coal facility in 2015 and a 79-MW gas-fired facility in 2023. Saskatchewan is also developing plans to convert existing pulverized coal units into Integrated Carbon Capture and Storage (ICCS) facilities that would result in an incremental decrease in net capacity of approximately 15 percent. 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.[108] On-peak expected values for hydro assume nameplate net generation minus 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.

Due to integrating variable resources, operational procedures for the assessment period have not been impacted. The addition of future variable resources will require the ability to curtail the resource or have additional fast ramping capacity available 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 anticipated firm exports for the assessment period. Saskatchewan does not rely on emergency imports to meet its demand.

Transmission and System Enhancements

The following are the top transmission projects that relate to the maintenance or enhancement to reliability over the assessment period for Saskatchewan. These projects are heavily dependent on load growth. Project scopes have been defined, funds have been secured, and engineering and construction resources are currently being allocated. Delays are assessed when indicated and interim measures (if required) are implemented to ensure system reliability is not impacted. No long-term transmission constraints have been identified within Saskatchewan for the assessment period.

At this time there are no planned interconnection-related projects. Materialization of such projects would occur as a result of study work performed for transmission service requests and approval of requests would only be granted once required facilities are in service.

At this time there are no confirmed delays for targeted in-service dates for planned projects and there are no major concerns with temporary service outages for any existing line or transformer facilities. For planned and emergency outages, further detailed study work is performed and temporary operating guides are issued as required.

- Approximately 300 km of 138-kV line in the Island Falls to Key Lake area (northern Saskatchewan) by mid-2015
- Approximately 110 km of 230-kV line in the Saskatoon-Wolverine area (central Saskatchewan) by mid-2014
- Approximately 225 km of 230-kV line, 225 km of 138-kV, and salvage of 135 km of 138-kV line in the Moose Jaw-Swift Current area (central Saskatchewan) by late 2016
- Approximately 100 km of 230-kV line in the Kennedy-Tantallon area (eastern Saskatchewan) by late 2016. This project also includes two new 300-MVA 230/138-kV auto-transformers in the Tantallon area by late 2013.
- Two new 300-MVA 230/138-kV auto-transformers in the Fleet Street area (southeast Saskatchewan) by late 2013.
- Two new 350-MVA 230/138-kV auto-transformers in the Boundary Dam area (southeast Saskatchewan) by late 2013 and 2014 (phased approach)
- To support local area voltage control, a 100-Mvar static var system (SVS) is planned for the Swift Current area (southwestern Saskatchewan) in mid-2014

One UVLS scheme is currently under construction in Saskatchewan in the Tantallon (eastern) area of the province with a projected in-service date of mid-2014. This scheme will be installed to mitigate potential low voltages under certain generation dispatch scenarios caused by N-1 outages (until planned transmission reinforcements in 2016 are in place) and a

[108] The wind available to meet peak requirements is based on the historic, 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.

few N-2 outages. These outages are in the southeastern portion of the province. The planned UVLS scheme targets approximately 70 MVA of load to be shed. This equates to approximately two percent of the projected total Saskatchewan 2013 winter peak load. This UVLS scheme does not influence this reliability assessment as it is being implemented to mitigate potential local area post-contingency voltage concerns. A new 230-kV transmission line is planned into the Tantallon area, which will reinforce the area's voltage. This line has a projected in-service date of mid-2016. 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.

For the assessment period, the following conceptual SPSs in Saskatchewan address potential generation deliverability concerns in the local area caused by N-2 outages of 230-kV double circuits. 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:

- Boundary Dam area (southeastern) - Planned in-service date of 2015
  - This protection system is planned to be temporary until 2016 when planned generation unit retirements and projected industrial load growth in the southeastern portion of the province materialize.
- E.B. Campbell area (eastern) - Planned in-service date of 2015
  - This protection system is planned to be permanent for the assessment period.
- Beatty area (central) - Planned in-service date of 2015
  - This protection system is planned to be temporary until 2016 when the Beatty–Wolverine 230-kV line is planned to be in-service.

Saskatchewan evaluates new technologies as they become available, and uses them if economic. Saskatchewan does not have any significant smart grid programs that affect the BES. Current efforts are primarily focused on the distribution system.

Long-Term Reliability Issues

Reliability issues in Saskatchewan with the highest level of priority include the addition of intermittent resources and the inclusion of emission regulations for both GHGs and criteria air contaminants.

Resource adequacy and operational concerns can apply for various reasons, including hydro conditions, standards, DR programs, variable generation, and other unit conditions. Saskatchewan's hydro planning is based on median flow conditions using 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. Currently there are no RPSs for the assessment area. Saskatchewan is planning the system based on a portfolio of supply options and will ensure that there is sufficient time to meet any RPS that could be initiated in the future. DR programs are contracted on an as-needed basis. If additional DR programs are required, Saskatchewan will initiate further customer uptake. One of the largest factors for operational concerns is the addition of more intermittent or 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.

Saskatchewan will have approximately 8.5 percent of wind integration in 2016 and is looking at adding more in the 2020 to 2025 time frame. 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 neighbouring jurisdictions. Depending on the makeup of the future power system, intermittent resources may need to be curtailed or other generation sources may be required on-line to allow for the sudden changes in output.

Finalized federal regulations for CO_2 emissions lay out the requirements and timelines for existing coal-fired generation for the reduction of GHGs. These regulations could impact direction taken on ICCS 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 to develop 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 timing and nature of capital projects, potential retirements, and the replacement and creation of new energy decisions. These regulations are constantly monitored and included in any decision making processes related to system reliability. Saskatchewan includes these factors in all reliability analyses and includes sufficient time to perform retrofits or replacements to meet the required regulations. Saskatchewan has not yet experienced any reliability issues related to GHG regulations and is expected to effectively mitigate any future reliability issues related to GHG.

Emission regulations will begin to affect Saskatchewan as early as 2015 for NO_x and SO_2 and as early as 2019 for CO_2. The requirement to reduce emissions for both coal and natural gas facilities will require proper 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 and dependent on the intensity limits for emission reductions; it must be included in determining net outputs from generation facilities. Saskatchewan is working with both the provincial and federal governments on emission regulations and equivalency agreements.

NPCC-Maritimes

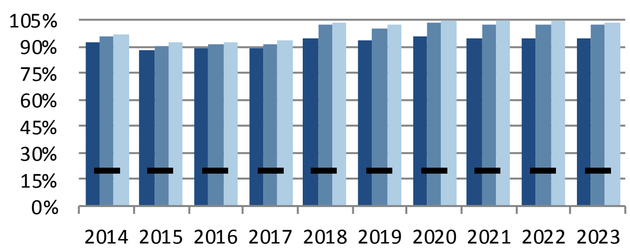
The Maritimes Assessment Area is a winter-peaking subregion of the Northeast Power Coordinating Council (NPCC) Region that contains two BAs. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, and Prince Edward Island, and the northern portion of Maine, which is radially connected to the New Brunswick power system. The area covers 58,000 square miles with a total population of 1.9 million people. The footprint has not changed during the last two years and is not expected to change during the 10-year assessment period unless a conceptual tie line to the Canadian province of Newfoundland and Labrador is constructed.

Planning Reserve Margins

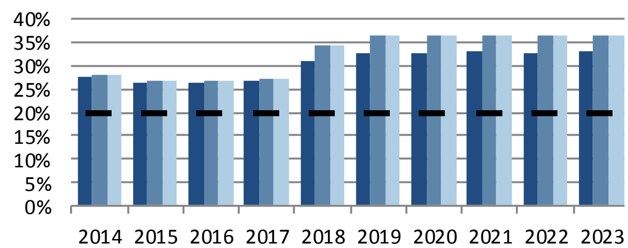
NPCC-Maritimes-Summer		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ANTICIPATED		92.7%	88.0%	88.9%	89.1%	94.4%	93.2%	95.8%	95.0%	95.2%	94.6%
PROSPECTIVE		95.2%	90.6%	91.4%	91.6%	102.0%	100.7%	103.4%	102.7%	102.8%	102.2%
ADJUSTED POTENTIAL		96.7%	92.1%	92.9%	93.1%	103.4%	102.2%	104.9%	104.1%	104.3%	103.7%
NERC REFERENCE	-	**20.00%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**

NPCC-Maritimes-Winter		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ANTICIPATED		27.4%	26.3%	26.3%	26.8%	30.8%	32.8%	32.8%	32.9%	32.8%	33.0%
PROSPECTIVE		28.0%	26.9%	26.9%	27.4%	34.3%	36.4%	36.4%	36.5%	36.3%	36.6%
ADJUSTED POTENTIAL		28.0%	26.9%	26.9%	27.4%	34.3%	36.4%	36.4%	36.5%	36.3%	36.6%
NERC REFERENCE	-	**20.00%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**

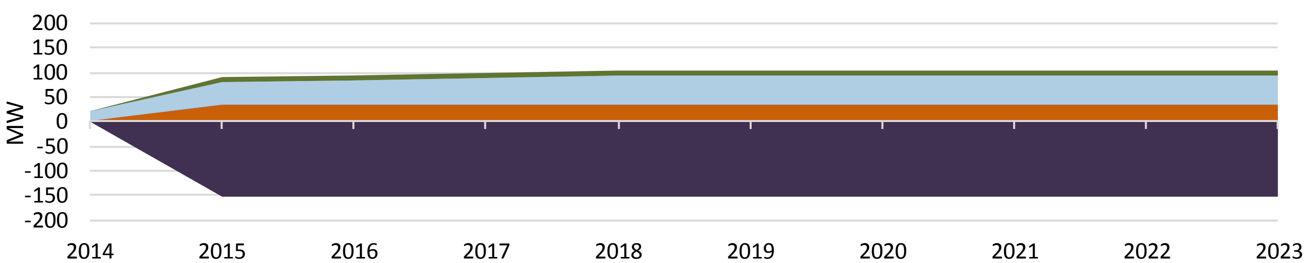
Summer



Winter



Cumulative 10-Year Planned Capacity Change



NPCC-Maritimes		2013 Existing Capacity (MW)	2013 Existing Share (%)	2023 Planned Capacity (MW)	2023 Planned Share (%)	2023 Planned Change (MW)	2023 Planned & Conceptual Capacity (MW)	2023 Planned & Conceptual Share (%)	2023 Planned & Conceptual Change (MW)
Coal		1,709	25.1%	1,556	23.0%	-153	1,556	23.0%	-153
Petroleum		1,857	27.3%	1,892	28.0%	35	1,892	28.0%	35
Gas		848	12.5%	848	12.6%	0	848	12.6%	0
Nuclear		660	9.7%	660	9.8%	0	660	9.8%	0
Hydro		1,333	19.6%	1,333	19.7%	0	1,333	19.7%	0
Pumped Storage		0	0.0%	0	0.0%	0	0	0.0%	0
Geothermal		0	0.0%	0	0.0%	0	0	0.0%	0
Wind		252	3.7%	311	4.6%	59	311	4.6%	59
Biomass		141	2.1%	151	2.2%	10	151	2.2%	10
Solar		0	0.0%	0	0.0%	0	0	0.0%	0
TOTAL		**6,800**	**100.0%**	**6,752**	**100.0%**	**-49**	**6,752**	**100.0%**	**-49**

Planning Reserve Margins

During summer and winter peak load periods, all Planning Reserve Margins for the Maritimes Area do not fall below the Reference Margin Level at any time, and they exceed 26 percent during the assessment time frame.

With fiscal restraint, challenging economic conditions, and anticipated gain and loss-of-loads, the aggregated growth rate for the combined subareas increases slightly and then turns marginally negative for both the summer and winter seasonal peak load periods over the 10-year assessment period. This indicates that any aggregated growth will be effectively offset by the sum of any DSM projections or load losses included in the subarea forecasts.

Though not specifically identified in the load projections, the load growth in the southeastern corner of New Brunswick has outpaced the rest of that subarea. Planning studies to propose transmission solutions that will reliably supply load in the southeastern area, which includes the Prince Edward Island and Nova Scotia Interconnections, are ongoing. Nova Scotia is expected to experience modest load reductions. The declines in these two subareas more than offset the modest growth forecast for the much smaller Prince Edward Island area, where an increase in electric heating is driving an average annual increase of 1.7 percent for the assessment period, and the northern Maine region, where a practically flat annual growth rate of 0.5 percent was projected for all assessment years.

Current and projected Energy Efficiency effects are incorporated directly into the load forecast for each of the areas. DR is specifically identified. Winter DR is projected at levels approximating 250 MW until 2019; after 2019, it drops to about 185 MW. DR in the Maritimes Area is uniformly load-modifying and is not used for peak shaving. It is used to reduce demand during emergencies and is not backed by capacity reserves.

Jurisdictions within the Maritimes Area have established Energy Efficiency corporations or government agencies whose mandates are to provide sustainable Energy Efficiency and conservation solutions to customers. Policy drivers include maintaining affordable electricity prices for customers and lessening the impact of energy use on the environment.

Additionally, a pilot program called PowerShift Atlantic is developing the capability to use load control for Ancillary Services. Launched in 2010 as part of the Clean Energy Fund, PowerShift Atlantic is a collaborative research project led in partnership by New Brunswick Power, Saint John Energy, Maritime Electric, Nova Scotia Power, New Brunswick Power – System Operator, the University of New Brunswick, Natural Resources Canada, the government of New Brunswick, and the government of Prince Edward Island. This four-year innovative program will run until 2014, piloting technology that shifts energy supply to specific appliances in homes and commercial buildings in order to optimize wind generation with minimal or no disruption to participating electric utility customers.

There is one planned retirement over the assessment period, located in Nova Scotia. A 153-MW generator is expected to be retired in January 2018 and is tied to the conceptual construction of an undersea HVdc cable between Nova Scotia and the Canadian Province of Newfoundland and Labrador as part of the Muskrat Falls hydroelectric generation development. Unit retirements in Nova Scotia are reviewed and re-evaluated based on system requirements and regulatory compliance. The 33-MW Burnside 4 generator in Nova Scotia unit is out of service and is expected to be back in service in 2015. Because of its small size, it does not have a significant effect on resource adequacy measures.

In an effort to retain large industrial customers that own renewable energy sources in New Brunswick and promote renewable energy, New Brunswick Power, the government-owned utility in New Brunswick, purchases surplus renewable energy from them. The energy produced never enters the New Brunswick system and is netted out against the customers' load. Current load forecasts assume no further uptake of this program. The impact of this program on resource adequacy is minimal since the major sources are already included in area capacity totals. There are no other significant increases in distributed generation identified in the Maritimes Area except in Nova Scotia. Existing distributed resources are netted against load and not counted as capacity. In Nova Scotia, increased amounts of renewable generation will be connected to the distribution system through the Community Feed-in-Tariff as outlined in the province's Renewable Electricity Plan in April 2010. Further study will be required to fully understand the cost and technical implications related to possible transmission upgrades and new operational demands on existing infrastructure. Nova Scotia Power has commissioned a renewables integration study with General Electric. The results of the study will be available this year and should provide insight into the resource adequacy and operational issues related to increased renewables.

The PowerShift Atlantic pilot project (described in the DSM section of this report) is an example of a potential "nontraditional" Demand-Side resource that could be developed in the Maritimes Area. The program attempts to balance variable wind generation against loads that contain some degree of energy storage, such as water heaters to make more effective use of wind resources. Any impact on resource adequacy would be positive since it allows wind to be dispatched with less variability.

With the exception of minimal summer derates in northern Maine, biomass facilities in the Maritimes are not derated during peak load periods. Hydro facilities contain enough storage at the sites to allow them to be dispatched at their full ratings during peak load periods. Currently in New Brunswick, Prince Edward Island, and Northern Maine, wind generators are accredited with on-peak capacity based on their observed or expected seasonally adjusted capacity factors. In Nova Scotia, the firm capacity of wind projects is assumed to be 20 percent of the installed capacity if the project has the necessary transmission capacity available. The Maritimes Area is reviewing and assessing previously used methods for attributing on-peak wind capacity. To this end, for probabilistic resource adequacy analysis at the NPCC regional level, the Maritimes Area supplies an hourly wind profile rather than a derated capacity value during peak load periods.

Plans are underway for the individual jurisdictions within the Maritimes Area to coordinate the sharing of wind data and possibly wind forecasting information and services. With the integration of more variable resources, it may become necessary to curtail these generation levels at light load periods to ensure adequate levels of Spinning Reserves and inertia for frequency control. The grid codes in the area require the ability to curtail to be designed into the control systems for large-scale variable resources and to be available for system operators to dispatch accordingly.

The Maritimes Area is not dependent on capacity transactions with neighboring areas to meet its Reserve Margin Reference targets. Beginning in 2018 and continuing well beyond the assessment period, the Maritimes Area has included 153 MW of firm imports from the Newfoundland utility, Nalcor, but this is completely offset by the corresponding retirement of a coal-fired generator in Nova Scotia with no significant impacts on resource adequacy.

Transmission and System Enhancements

During the review period, one major new transmission line addition is categorized as Conceptual. In 2018, development of the Muskrat Falls hydroelectric project would see the installation of an HVdc undersea cable link (Maritime Link) between Newfoundland and Labrador and Nova Scotia.

In recent years, the load growth in southeastern New Brunswick has exceeded growth in other areas of the province. This has resulted in increased reliance on the Dedicated Path Logic (DPL) SPS as well as the eastern UVLS schemes for loss of 345-kV lines feeding the Southeast. Planning studies are ongoing to propose transmission solutions that will reliably supply load in the southeastern area, which includes the Prince Edward Islands and Nova Scotia Interconnections.

In 2014, a 345-kV breaker installation will complete a ring bus at the tap point to which the 467-MW Belledune plant in New Brunswick is connected, increasing the reliability supply from the second-largest generator in the Maritimes Area. Additionally, the Eel River 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 Quebec and contributes to frequency response in the Maritimes Area. An additional 240-kV breaker will be installed to allow the separation of supplies to two 240/138-kV transformers in the substation at Eel River.

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

Regarding system enhancements, a new 75-Mvar reactor will be installed during 2014 at the Belledune Terminal and will provide additional voltage control in the area during times of light load. UVLS is used throughout the Maritimes Area to maintain adequate voltages during contingencies to major transmission facilities. In particular, this is the case in southeastern New Brunswick where, driven by a lack of generating facilities, UVLS and SPS facilities are critical to maintain voltages during loss of major transmission facilities feeding that sector. In that region, up to 475 MW (as estimated at peak load) can be interrupted using UVLS. This is not expected to change during the assessment period; however, studies are underway to identify specific enhancements that may increase transfer capabilities and reliability and reduce exposure to events that may trigger UVLS operation.

There are currently no specific plans to install more SPS schemes in the Maritimes Area, but this does not rule out the possibility during the assessment period. SPS schemes are considered when it is in the best interests of the customer to provide an efficient and reliable electric system. The ongoing studies to enhance the capabilities of the southeastern transmission supply lines will assess the use of such technology. Current SPS schemes are expected to remain in service for the assessment period.

As previously mentioned in this report, while still in pilot study mode, PowerShift Atlantic seeks to take control of loads with some inherent energy storage capability (such as water heaters), dispatching their reduction as variable wind resources drop in output and reintroducing them when the wind generation picks back up. This levels the output from these variable resources and frees up traditional resources from this balancing duty, allowing them to be used to supply the remaining loads.

The main utility in New Brunswick (New Brunswick Power) is investing heavily in smart grid technology, which includes capabilities to control loads in its jurisdiction. To the extent that this leads to a reduction in peak loads, it will enhance reliability.

Long-Term Reliability Issues

With a capacity of approximately 1,330 MW, the hydroelectric power supply system in the Maritimes Area is predominantly run-of-the-river (as opposed to storage-based) and is not able to be held in reserve to stave off drought conditions. If such conditions were to exist in the Maritimes Area, operation of the system would be relatively unchanged. 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 for load following and peak supply.

RPSs have led to the development of substantially more wind generation capacity than any other renewable generation type. Reduced frequency response is associated with wind generation and, with increasing levels in the future, may require displacement with conventional generation during light load periods.

Because of the relative size of the area’s largest generating units compared to its aggregated load, the area carries substantial reserve capacity. For this reason, a lack of response from some of the loads expected to be shed during an interruption request will not significantly affect resource adequacy. For the same reason, and because the area peaks in winter as opposed to neighboring jurisdictions that peak in summer, long-term outages to individual units do not cause undue stress from a technical perspective. It is expected that any capacity or energy shortfalls due to long-term unit outages could be offset by purchases from New England during their off-peak season, or from Québec.

There are no significant increases in distributed generation identified in the Maritimes Area except in Nova Scotia, where increased amounts of renewable generation will be connected to the distribution system through the Community Feed-in-Tariff outlined in the province’s Renewable Electricity Plan in April 2010. Further study will be required to fully understand the cost and technical implications related to possible transmission upgrades and new operational demands on existing infrastructure.

The government has acknowledged the need to develop less intermittent sources of renewable energy in the New Brunswick subarea. With the significant amount of large-scale wind energy currently being balanced on New Brunswick's system, the next phase of renewable energy development will focus on smaller scale projects, with a particular emphasis on nonintermittent forms of generation, such as wood-based biomass. Wind energy will continue to be integrated in the New Brunswick balancing area, but in measured and manageable stages. In Nova Scotia, approximately 216 MW of wind generation, including distributed resources, is planned for installation during the assessment period. Additional RPS energy is expected to be sourced from the Conceptual tie Maritime Link HVdc connection to the Muskrat Falls hydroelectric power project in the Canadian province of Newfoundland and Labrador. The Maritimes Area examines cases where a complete absence of wind in the area occurs due to weather conditions and has concluded that the area is not overly reliant on wind generation to meet its 20 percent reserve criterion, the level at which the area meets the NPCC resource adequacy reliability criterion.

To reduce emissions associated with energy production, governments in the Maritimes Area introduced RPSs that led to a large-scale development of wind energy resources. Current emissions limits in the Maritimes Area are specified as annual system volumes rather than generator-specific volumes, providing flexibility in the operation of the fleet. Future regulations limiting GHG emissions are expected and could limit the future utilization of fossil-fuelled generation. System Operators in the Maritimes Area are tracking such developing standards and conducting analyses regarding their impact on future resource adequacy.

Currently, the increasing load in southeastern New Brunswick and additional renewable resources throughout the area are being examined in the Maritimes Area as two emerging reliability issues. Load growth in the southeastern area of New Brunswick has been more rapid than in other areas in the province. Voltages and thermal loading on lines are approaching unacceptable levels during 345-kV contingencies for various operating scenarios. This issue may require transmission reinforcements four to eight years from now. With recent reductions in load forecasts, emphasis on peak load reduction in DSM programs, and a potential conceptual tie to Newfoundland that may provide a new source in the area, New Brunswick Power is studying transmission enhancements and SPS solutions to the overload and undervoltage issues that currently do not include 345-kV line construction within the assessment period.

If enhancements are not made and load continues to grow, this issue could affect system reliability by threatening voltage instability and potentially overloading circuits for 345-kV outages feeding that area. Though the load growth and potential voltage issues are localized to southeastern New Brunswick, the circuit overloads occur on parallel 138-kV circuits leading from sources in southwestern New Brunswick to the high load areas in the Southeast. The localized low voltages and overloads of parallel circuits during contingencies would be moderate and unlikely to create reliability problems in neighboring Regions.

Generation levels are unaffected and with lower expected loads, the issue is purely transmission-related—predominately affecting transfer capabilities from New Brunswick to Prince Edward Island and Nova Scotia. The impact on the resource adequacy LOLE value is captured by modeling a reduction in tie transfer capabilities between subareas. The *2012 NPCC Interim Review of Resource Adequacy*[109] showed that after transfer levels were reduced from 300 MW to 150 MW, LOLE values did not exceed the NPCC target limit of one day in 10 years of resource inadequacy. The Reference Margins will not be affected by this issue.

In southeastern New Brunswick, interconnection of any new resources would likely help mitigate this emerging issue. New Transmission circuits (if required) would be feasible, since New Brunswick Power has already secured right-of-way corridors for the circuits needed to address the issue.

[109] NPCC 2012 Maritimes Area Interim Review of Resource Adequacy.

The issue is most problematic for 345-kV contingencies when New Brunswick loads are at near peak levels during particularly high southern or northern New Brunswick generation dispatches with high exports to Prince Edward Island and/or Nova Scotia.

Nova Scotia's Renewable Electricity Standard (RES) would displace significant amounts of fossil-fuelled generation with renewable resources. By 2015, 25 percent of the province's electricity sales will be supplied by renewable energy sources. This increases to 40 percent by 2020.

The addition of renewable resources—particularly in Nova Scotia—is an emerging concern in the Maritimes area. Nova Scotia has commissioned a renewables integration study with General Electric. The results of the study will be available by the end of 2013 and will provide insight into the resource adequacy and operational issues related to increased renewables. The impacts on LTRA Reserve Margin Reference levels are positive as the addition of new resources actually enhances resource adequacy (provided that existing traditional resources are not prematurely retired as a result of the new capacity).

Increasing the amount of renewable resources could affect system 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. Completing system impact studies prior to interconnecting new generation should identify whether the emergence of any of these issues could limit operation of—or the amount of—new renewable generation added to the system on a case-by-case basis.

Many of the sites chosen for new renewable generation facilities are located near the energy sources or existing transmission infrastructure. There is potential for such additions across the entire Maritimes area. While the added generation may relieve congestion in some cases, the lack of adequate transmission facilities could delay or limit the development of new renewable resources. The variable output and intermittent nature of many renewable resources is a major daily consideration for generation dispatchers. The low inertia effects on system frequency response will be felt mostly during off-peak, light load periods when high-mass units have been displaced by low-mass new renewable resources.

Several new resources being considered have short installation timelines, which makes long-term capacity projections used in the *2013LTRA* reference case less reliable as projects come and go in response to changing government incentive policies.

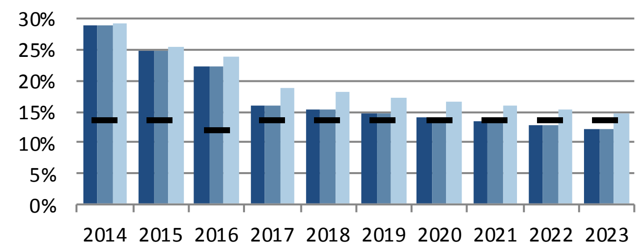
NPCC-New England

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. New England is a summer-peaking electric system.

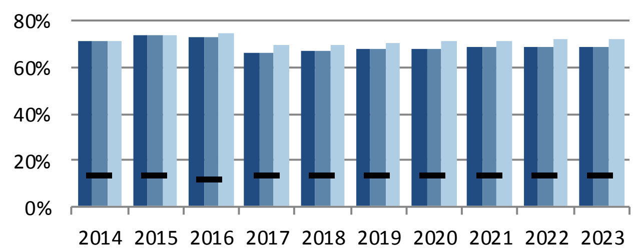
Planning Reserve Margins

NPCC-New England-Summer		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ANTICIPATED		29.02%	24.70%	22.39%	16.12%	15.36%	14.64%	14.02%	13.30%	12.69%	12.07%
PROSPECTIVE		29.02%	24.70%	22.39%	16.12%	15.36%	14.64%	14.02%	13.30%	12.69%	12.07%
ADJUSTED POTENTIAL		29.26%	25.35%	24.01%	18.81%	18.05%	17.31%	16.67%	15.94%	15.31%	14.67%
NERC REFERENCE	-	**13.85%**	**13.69%**	**12.33%**	**13.65%**	**13.65%**	**13.65%**	**13.65%**	**13.65%**	**13.65%**	**13.65%**
NPCC-New England-Winter		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ANTICIPATED		71.60%	73.46%	72.67%	66.34%	66.96%	67.56%	68.05%	68.45%	68.79%	69.14%
PROSPECTIVE		71.60%	73.46%	72.67%	66.34%	66.96%	67.56%	68.05%	68.45%	68.79%	69.14%
ADJUSTED POTENTIAL		71.71%	74.12%	74.54%	69.33%	69.95%	70.57%	71.06%	71.47%	71.82%	72.17%
NERC REFERENCE	-	**13.90%**	**13.70%**	**12.30%**	**13.60%**	**13.60%**	**13.60%**	**13.60%**	**13.60%**	**13.60%**	**13.60%**

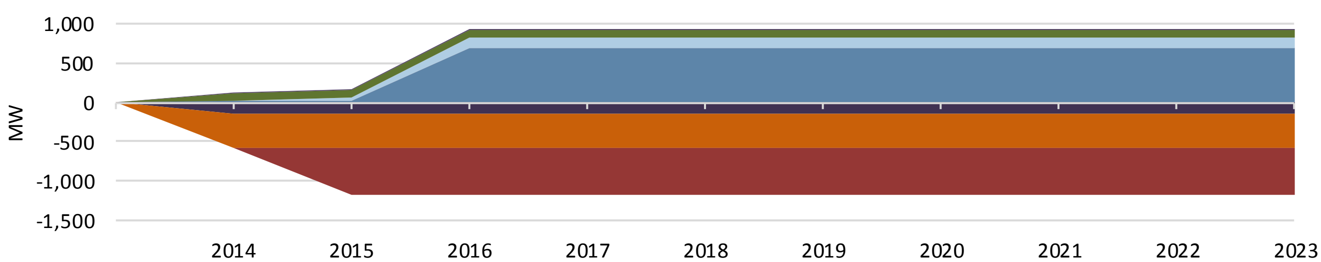
Summer



Winter



Cumulative 10-Year Planned Capacity Change



		2013 Existing		2023 Planned			2023 Planned & Conceptual		
NPCC-New England		Capacity (MW)	Share (%)	Capacity (MW)	Share (%)	Change (MW)	Capacity (MW)	Share (%)	Change (MW)
Coal		2,289	7.2%	2,142	6.8%	-147	2,142	6.1%	-147
Petroleum		7,083	22.3%	6,646	21.1%	-437	6,660	18.9%	-423
Gas		13,598	42.8%	14,290	45.4%	692	16,512	46.8%	2,914
Nuclear		4,624	14.6%	4,024	12.8%	-600	4,024	11.4%	-600
Hydro		1,374	4.3%	1,374	4.4%	0	1,392	3.9%	19
Pumped Storage		1,720	5.4%	1,720	5.5%	0	1,770	5.0%	50
Geothermal		0	0.0%	0	0.0%	0	0	0.0%	0
Wind		97	0.3%	232	0.7%	135	1,636	4.6%	1,539
Biomass		932	2.9%	1,029	3.3%	96	1,098	3.1%	166
Solar		32	0.1%	45	0.1%	13	51	0.1%	19
TOTAL		**31,749**	**100.0%**	**31,501**	**100.0%**	**-249**	**35,285**	**100.0%**	**3,536**

Planning Reserve Margins

New England's (ISO-NE) Reference Margin Level (target reserve margin) is based on the capacity needed to meet the NPCC one day in 10 years loss-of-load expectation (LOLE) resource planning reliability criterion. The amount of capacity needed, referred to as the Installed Capacity Requirement (ICR), can and does vary from year to year, depending on expected system conditions. The ICR, which is calculated three years in advance for each Forward Capacity Auction, results in Reference Margin Level of 13.85 percent in 2014, 13.69 percent in 2015, 12.33 percent in 2016, and 13.65 percent in 2017.[110] In this assessment, the last calculated Reference Margin Level (13.65 percent) is applied for the remaining years.

In the 2014 summer, ISO-NE's Anticipated Resources will amount to 34,744 MW, which will result in an Anticipated Reserve Margin of 29.0 percent of the reference demand forecast of 26,929 MW.[111] The Anticipated Reserve Margin falls just below the assumed Reference Margin Level of 13.65 percent beginning in 2021, decreasing to 12.07 percent by 2023.

This Anticipated Reserve Margin during the annual peak reflects the Seasonal Claimed Capability[112] (which could be higher than the Capacity Supply Obligation (CSO))[113] of all ISO-NE generators as well as demand resources and imports that have CSOs as a result of ISO-NE's Forward Capacity Market (FCM) auctions.

The primary reason for the Anticipated Reserve Margin falling below the Reference Margin Level is that ISO-NE does not extend the import CSOs that are in place in 2016 through the remainder of the assessment period. The imports that are assumed for 2017 through 2023 are those based on long-term firm contracts, which are approximately 1,500 MW lower than the CSOs in 2016. In reality, that steep reduction in capacity will not occur because ISO-NE will procure the capacity needed to meet the Installed Capacity Requirement with its FCM. If the 2016 import amount was carried through the remainder of the assessment period, the Anticipated Reserve Margin would be nearly 20 percent in 2023. If the Anticipated Reserve Margin falls below the level required to meet the regional reliability standards due to retirements associated with environmental regulations, ISO-NE will purchase the needed capacity through its FCM.

As there has not been any change in the New England footprint or any significant changes in the economic outlook or the long-term weather outlook, the 2013 demand forecast has not changed significantly from the 2012 demand forecast. There are no particular areas where load growth is significantly above or below the regional aggregate New England load growth.

The 2014 summer peak demand forecast is 28,290 MW, and the Total Internal Demand, which takes into account 1,361 MW of passive demand resources (Energy Efficiency),[114] is 26,929 MW. This year's forecast of the 10-year summer Total Internal Demand compound annual growth rate (CAGR) is 0.84 percent, which is slightly higher than the *2012LTRA* reference case projection of 0.79 percent. Changes in the economic forecast led to this decrease.

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).[115] Some assets in the real-time DR programs are under direct load control by the load response providers (LRP). The LRP implements direct load control of these assets upon dispatch instructions from ISO-NE—for example, interruption of central air conditioning systems in residential and commercial facilities. 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

[110] The ICR values for 2017–2018 are proposed and will be filed with FERC by November 2013.
[111] Without a reduction of 1,361 MW to account for passive demand resources, the demand would be 28,290 MW.
[112] Seasonal Claimed Capability is the audited capacity rating of the resource. The audits are conducted every season.
[113] Capacity Supply Obligation is the amount of installed capacity obligation a resource has assumed for a Capacity Commitment Period extending from June 1 of a particular year to May 31 of the following year.
[114] Energy Efficiency is treated as Demand Response in ISO-NE and receives a capacity payment.
[115] OP-4 is used by ISO-NE operators when resources are insufficient to meet the anticipated load plus Operating Reserve Requirement.

verifiable reductions[116] in the total amount of electrical energy used during on-peak hours. Active demand resources are based on the CSOs obtained through ISO-NE's FCM three years in advance. The CSOs decrease slightly from 1,694 MW in 2014 to 1,621 WM in 2015 and then drop to 1,044 MW in 2016. Since there are no further auction results, the CSOs are assumed to remain at the same level through the end of the reporting period.

Energy efficiency is also secured by means of FCM CSOs. However, ISO-NE has developed an Energy Efficiency forecasting methodology 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, but at a continually decreasing growth rate. The amount of Energy Efficiency in 2014 is 1,361 MW, increasing by 13 percent to 1,535 MW in 2015, and then decreasing slightly to 1,520 MW in 2016. The amount of Energy Efficiency is projected to be about 2,800 MW by 2023.

Both passive and active demand resources are treated as capacity in New England's FCM. As previously noted, the active demand resources can be triggered by ISO-NE in real time under OP-4 to help mitigate an actual or anticipated capacity deficiency by reducing the peak demand. For example, on July 22, the 2011 peak demand day, a total of 642 MW of active demand resources were activated and 644 MW responded, corresponding to a response rate of 100.3 percent. On another OP-4 occurrence on the morning of December 19, 2011, active demand resources reduced the load by 380 MW, which was 75.4 percent of the 504 MW activated. The reason for the lower response on that winter day was that the event occurred early in the morning when the loads were low and fewer demand resources were available to respond.

A significant number of active demand resources are serving as capacity in the FCM. Most of these resources are not dispatched in the ISO's energy-market clearing process; rather, they are activated when the ISO faces a capacity deficiency during the operating day. ISO-NE is proposing market rule changes that allow DR to set market-clearing prices that better reflect the costs of activating these resources in the day-ahead and real-time energy markets.

In response to Order 745: Demand Response Compensation in Organized Wholesale Energy Markets, ISO-NE proposed two sets of market rule changes associated with the full integration of price-responsive demand into the energy markets.[117] These market rule changes will require all real-time DR programs to participate as capacity resources, with the associated requirement to participate in the energy market starting on June 1, 2017.

ISO-NE is analyzing changing environmental compliance requirements that could impact generator availability due to economic impairment of generators complying with air, water, and GHG restrictions. Both the Salem Harbor and Vermont Yankee retirements were included in the Planning Reserve Margin calculations, and the reserve margin does fall below the 13.6 percent Reference Reserve Margin in 2021. ISO-NE has adequate capacity up to three years in advance with its Forward Capacity Auctions and Annual Reconfiguration Auctions.

Salem Harbor Units 3 and 4, which are coal- and oil-fired units with a combined capacity of 587 MW, are scheduled to retire by June 1, 2014. As the Salem Harbor plant is located in the Boston subarea, ISO-NE performed a reliability review to determine the impact of the retirement of the full plant. ISO-NE found that under certain second contingency scenarios with a 345-kV line-out as the initial outage, thermal overloads could exist in the local area. To address these thermal overloads, ISO-NE and the affected TOs developed plans to perform 115-kV transmission line reconductoring projects on portions of five lines prior to the plant retirement. In addition, the Vermont Yankee Nuclear Power Plant, with a capacity of 600 MW, recently announced that it will be shutting down by the end of 2014.

[116] New passive demand resources must submit a Measurement and Verification (M&V) Plan, which must be approved by ISO-NE. The project sponsor is required to submit an annual certification that the project continues to comply with their ISO-approved M&V Plan. ISO-NE has the authority to initiate an audit of any demand resource, including Energy Efficiency resources (see Market Rule 1).

[117] ISO-NE Price Responsive Demand.

ISO-NE continues to integrate new resources, including variable resources, into the network. All new resources are studied in detail by ISO-NE Operations Engineering prior to commercial operation. These are all integrated through the use of operating guides, interface limits, and the Energy Management System (EMS).

The ISO has made progress implementing the recommendations from the *New England Wind Integration Study* (NEWIS),[118] which analyzed various planning, operating, and market aspects of wind integration for up to a 12-GW addition of wind resources to the system. The recommendations developed from NEWIS led ISO-NE to implement a centralized wind power forecast, which is currently under development. To facilitate system operation with potentially large amounts of wind power, ISO-NE Operating Procedure No. 14 Appendix F – Wind Plant Operators Guide (OP-14F)[119] was implemented in September 2011. OP-14F is chiefly concerned with requirements for Real-time and static-type data that will facilitate accurate wind power forecasting over the intra-day, day-ahead, and week-ahead timescales, as well as data for use in situational awareness functions for ISO system operators.

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 97 MW of on-peak wind capacity in New England, and only 135 MW (on-peak capacity) of Future-Planned wind additions during the study period.

Photovoltaic (PV) resources are rapidly developing in New England and predominantly are situated relatively close to load centers. Most of the PV resources, however, are not directly observable or controllable by the ISO and may respond differently to grid disturbances than larger, conventional generators. New ISO initiatives are addressing these highly complex issues with stakeholders.[120]

Firm summer capacity imports are based on FCM CSOs, which amount to 1,851 MW in 2014 and decrease to 1,607 MW in 2016. In addition to capacity imports that have CSOs, external transactions can participate in the Day-Ahead and Real-time Energy Markets. In 2012, the imports to New England from New York, New Brunswick, and Quebec at the time of the peak demand totaled 2,251 MW or 1,475 MW more than the CSO of 776 MW. At the time of the 2011 peak, the amount of actual imports was 2,001 MW, which was 765 MW more than the CSO. As the Forward Capacity Auction imports are based on one-year contracts, beginning in 2017 the imports will reflect only known, long-term Installed Capacity (ICAP) contracts totaling approximately 100 MW. If the imports beyond the 2016 summer do not clear in future FCM commitment periods, the lost capacity will be replaced by other supply or Demand-Side resources. For the 2014 summer, there is a firm capacity sale to New York (Long Island) of 100 MW anticipated to be delivered via the Cross-Sound Cable (CSC). This firm capacity sale holds constant through the assessment period.

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[118] New England Wind Energy Study (NEWIS).

[119] ISO New England Operating Procedure No. 14.

[120] Solar photovoltaic (PV) resources being installed in New England are "behind-the-meter," meaning that they are not visible to ISO operations in real time. However, a portion of these projects are registered in ISO's energy market. As of the end of 2012, ISO estimated that approximately two-thirds of the installed behind-the-meter PV capacity in the Region (approximately 250 MW, dc nameplate) is not registered in ISO's energy market. ISO-NE has small amounts (less than 5 MW total) of nontraditional resources (e.g., battery storage, flywheels, electric thermal storage, and aggregated load control) that provide regulation service through a pilot program. After the pilot program concludes, these resource types will remain eligible to provide regulation service. There is no current expectation that these resources will participate in the energy and capacity markets in the future. However, technologies with multi-hour storage capability may become economically viable participants in the energy market depending on fuel prices, penetration of renewable resources, and localized transmission congestion.

Transmission and System Enhancements

There are several transmission projects projected to come on-line during the assessment period that are important to the continuation of, or enhancement to, system or subarea reliability. These projects are the result of progress made by the ISO and regional stakeholders in analyzing the transmission system in New England and developing and implementing back-stop solutions to address existing and projected transmission system needs. The major projects under development in New England include the Maine Power Reliability Program (MPRP), the New England East–West Solution (NEEWS), and the Long-Term Lower Southeast Massachusetts (SEMA) project. 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. The Long-Term Lower SEMA project addresses reliability concerns in the lower southeastern Massachusetts area, which includes Cape Cod.

At this time, there are no plans to install more UVLS schemes in New England. Currently, northern New England has the potential to use approximately 600 MW of load shedding as part of UVLS. However, it is important to recognize that a significant portion of this load shedding is normally not armed and is only armed under severe loading conditions with a transmission line or autotransformer already out of service. Presently, two significant projects could completely eliminate the need for the UVLS or significantly reduce the likelihood of depending on such schemes: the Vermont Southern Loop Project (completed in late 2010) and the MPRP (scheduled to be completed in 2015).

There are no SPSs that are proposed to be installed in lieu of proposed regulated transmission facilities to address system reliability needs. However, two new, temporary SPSs are to be installed in Maine as part of the MPRP. The first SPS is needed to ensure reliable system operation due to configuration changes at South Gorham while the MPRP is under construction. The second SPS is needed to ensure reliable system operation due to configuration changes in the Rumford area while the MPRP is under construction. Once construction of the necessary portions of the MPRP is complete (anticipated in 2015), these two temporary SPSs will be removed. It should also be noted that several existing SPSs will be removed from service after the MPRP project is completed.

New smart grid technologies are being used in New England to improve the electric power system's performance and operating flexibility. Smart grid technologies, such as FACTS, are used to facilitate the integration of variable resources in the power system. Because much of the potential for wind development is remote from load centers, additional transmission development may be pursued. Some of these transmission improvements may use HVdc technology, which is cost-effective over long distances. Both HVdc and FACTS are regularly considered as part of transmission planning studies when their application economically meets system or generator interconnection needs.

On July 1, 2010, ISO-NE received a U.S. Department of Energy (DOE) Smart Grid Investment Grant Award and subsequently began a three-year Synchrophasor Installation and Data Utilization (SIDU) project. The goal of the project is to provide ISO-NE and associated TOs with a significantly expanded base of PMUs, Phasor Data Concentrators, and greatly enhanced phasor data analytical tools. The SIDU project supplements the five existing PMUs in the Region with at least 30 new PMUs at various substations around New England. The project is focused on the deployment of Synchrophasor technology as a foundation for the next generation of power grid situational awareness and serves as the smart grid technology platform upon which advanced analysis and visualization tools can be deployed. It is hoped that the SIDU project will yield efficiencies in the way the grid is operated and will improve reliability, serving as a backbone for regional smart grid efforts.

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

The New England area is not currently experiencing a drought. However, in the event that the Region was to experience an extended drought, some traditional hydroelectric stations could be temporarily capacity- or energy-constrained. Due to the relatively small contribution to overall capacity from hydroelectric facilities (1,374 MW or 4.3 percent), any potential reduction in hydroelectric energy production due to regional drought conditions could be readily supplemented by increased levels of other types of generation.

New England has witnessed significant growth in the development of solar PV resources over the past few years, and continued growth of PV is anticipated. Regional PV installations are small (i.e., less than 10 MW) and interconnected to the distribution system. States with policies more supportive of PV (e.g., Massachusetts) are experiencing the most growth of the resource. While existing amounts of PV have yet to have a significant impact on system operations, the ISO is working on several initiatives aimed at facilitating the reliable and efficient integration of significant amounts of PV in the Region.

RPSs mandate that Energy Efficiency and renewable resources must supply 31.8 percent of the Region's projected electric energy by 2022,[121] and 20.2 percent of RPSs and policies addressing renewable supply goals.

Possible solutions for meeting or exceeding the Region's RPSs include (1) developing the renewable resources in the ISO generator interconnection queue; (2) importing renewable resources from adjacent Control Areas; (3) building new renewable resources in New England not yet in the queue; (4) using new behind-the-meter projects; and (5) using eligible renewable fuels, such as biomass, in existing generators. Achievements in Energy Efficiency in the Region that exceed the levels in the Energy Efficiency forecast could reduce the amount of new renewable resources required to meet state RPSs.

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 the Region 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 Wind Power Forecast Integration Project (WPFIP) is being implemented in two phases.[122] The addition of VERs, particularly wind, will likely grow with time, increasing the need for flexible resources to provide operating reserves as well as other ancillary services, such as regulation and ramping.

Distributed energy resources must be integrated into the local electric company's distribution systems and therefore must comply with the interconnection standards applicable to such systems. Although distributed generation has not traditionally been a major concern for BPS operation, the amount of distributed generation, particularly PV, has been increasing rapidly.

ISO-NE has been informed of two impending retirements: Salem Harbor Units 3 and 4 will cease operations in June 2014, and Vermont Yankee is scheduled to close by the end of 2014. Preserving the reliable operation of the system will become

[121] This percentage includes an 11.6 percent reduction in the Region's projected electric energy consumption in 2022 that resulted from passive demand resources and the forecasted energy-efficiency savings, as reported in the *2013–2022 Forecast Report of Capacity, Energy, Loads, and Transmission* (2012 CELT Report).

[122] Phase 1 of the WPFIP, scheduled to be completed in the second half of 2014, focuses on setting up the communications and database systems to enable the delivery of wind power forecasting-related data from wind plants through ISO-NE to the wind power forecaster service and vice-versa, as well as incorporating the forecasts into the day-ahead unit commitment and periodic unit commitment refinement processes. Phase 2 of the WPFIP will integrate wind power into the real-time dispatch process, which means that wind plants will submit economic offers and be able to set price at their local bus, and transmission congestion will be managed in a transparent and automated process (versus the typically manual process that is currently used for real-time self-schedule resources). Phase 2 will also include closer coupling with the short-term outage scheduling process, and will include publishing of the aggregate week-ahead wind power forecast in order for market participants to be able to incorporate this information into their decision-making processes and market strategies.

increasingly challenging with other potential retirements and the need for operating flexibility, particularly in light of the reliance on natural gas resources. As a result of these factors, the need for reliable resources, especially those able to provide operating reserves and ramping capabilities, is expected to increase. To begin addressing this need, the ISO procured additional operating reserves. To compensate for the observed nonperformance of generators relied on for contingency response, the ISO increased the total 10-minute operating reserve requirement by 25 percent. Consequently, the total 10-minute operating reserve previously equivalent to the largest single contingency is now 125 percent of this contingency.

Existing and pending state, regional, and federal environmental requirements will require the addition of pollution control devices to many generators, reducing water use and wastewater discharges, and in some cases, limiting operations and increasing retirements. The ISO initiated a study to better quantify the implications of the likely retirement of several generating units and their potential replacements. Most of the at-risk capacity would face compliance or retirement decisions starting late in this decade and extending into the early part of the next decade.

Pending EPA restrictions may require existing fossil fuel and nuclear capacity to mitigate the adverse impacts of cooling water use, with compliance due between 2014 and 2021 for some generators. Modification of cooling water use may be necessary for up to 12.1 GW of generating capacity, with a subset of 5.6 GW (those with larger withdrawal capacities) potentially needing to convert from once-through to closed-cycle cooling systems.[123]

The EPA's proposed revisions to the Effluent Limitation Guidelines (ELG) would require many thermal generating stations to reduce or remove certain contaminants from their wastewater discharges beginning in 2017. However, based on EPA's proposed approach to the ELG revisions, ISO anticipates limited impact on existing fossil and nuclear stations in the Region.

Approximately 7.9 GW of existing coal- or oil-fired capacity in the Region is subject to EPA's final MATS, which require compliance by early 2015. However, much of this capacity is already retrofitted with the controls needed to comply with state air toxics regulations and less than 1 GW of affected capacity is expected to retire due to MATS.[124] Recent revisions to air quality standards that limit ambient concentrations of ozone and its precursors, fine particulate matter, and sulfur dioxide will require additional reductions from larger fossil fuel-fired generators while technology-based performance standards affect other generators.[125] At this time there are no planned outages for generator environmental retrofits that would impact reliability. Any retrofits required under MATS are expected to be completed (or have already been completed) during traditional outage periods. At this time, ISO-NE does not anticipate an impact on reliability during shoulder months due to environmental regulations being implemented.

The procedures currently in place to maintain system reliability include reliability agreements and out-of-merit unit commitments. However, ISO-NE is studying longer-term solutions to the problem, such as appropriate enhancements to wholesale market design and system planning procedures. Losing a significant quantity of coal, oil, and nuclear capacity could further increase the Region's dependence on natural gas-fired resources. If all of the Region's older oil units were to seek retirement, new capacity would be required to satisfy the Installed Capacity Requirement.

As part of the Strategic Planning Initiative, the ISO is collecting and analyzing data to identify the units expected to face significant capital investments in the longer term because of environmental compliance deadlines. In addition, a Strategic

[123] EPA, Cooling Water Intake Structures § 316(b), Notice of Proposed Rulemaking, 76 FR 22174 (April 20, 2011). Applies to existing and new cooling water intake structures (CWIS) at power plants and manufacturers.

[124]EPA, *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units*, Final Rule 77 FR 9304 (February 16, 2012). EPA developed standards under Section 112(d) to reduce hazardous air pollutant (HAP) emissions from this source category. MATS was proposed on May 3, 2011 (76 FR 24976), and included proposed amendments to the criteria pollutant new source performance standards (NSPS) for utilities.

[125] EPA, National Ambient Air Quality Standards for Ozone, Final Rule, 73 FR 16436 (March 27, 2008), National Ambient Air Quality Standards for Particulate Matter, Final Rule, 78 FR 3086 (January 15, 2013), National Ambient Air Quality Standards for Sulfur Dioxide, Final Rule, 75 FR 35520 (June 22, 2010).

Transmission Analysis was used to evaluate how the retirement of at-risk units would affect reliability and to locate the most favorable locations for replacing the retired units. As part of this analysis, ISO-NE is also developing a conceptual system build-out, which would be necessary for combinations of unit retirements, repowering, and integrating remote wind generators.

During the past few years, ISO-NE grid operators experienced numerous events during stressed system conditions when the performance and flexibility of power plants and demand resources were insufficient to correct these situations in a timely manner. This led to a growing concern that as the power system continues to evolve, the mix of supply resources may be unable to operate when and as needed to maintain the grid's present level of reliability.

These concerns arise from several different challenges ISO-NE is facing: (1) the increasing reliance on natural gas as a fuel source for power plants and the potential for reduced operational performance during stressed system conditions; (2) the large number of aging, economically challenged oil- and coal-fired generators that provide fuel diversity to the resource mix; and (3) the greater future needs for flexible supply resources to balance variable renewable resources that have operating characteristics markedly different from those of traditional generating resources. These three challenges are discussed below in order of urgency.

MITIGATING THE RISKS OF NEW ENGLAND'S DEPENDENCE ON NATURAL GAS

Approximately 12,000 of the 14,000 MW of generating capacity built in New England during the past 15 years is natural gas combined-cycle units, and gas continues to be the fuel of choice for new power plant construction. The Region's growing dependence on natural gas and its related issues have been a consistent concern during winter when the priority for natural gas supplies goes to heating New England's homes and businesses. But as the use of natural gas has increased, this dependence has become a major challenge for managing the electric grid throughout the year. As older coal- and oil-fired plants retire and new gas-fired plants are built to replace them, it is likely the Region will come to rely even more on this fuel. In addition, gas-fired plants can provide much of the flexibility needed to balance variable wind power resources; therefore, it is expected that gas-fired resources will be needed on-line as wind resources are built and interconnected.

The lack of dependable fuel arrangements by generators,[126] limited on-site fuel storage or alternate fuel arrangements, and increasing constraints on the pipeline system have hindered the performance of New England's natural gas generators, creating potentially serious, immediate risks to grid reliability. The Region's growing dependence on natural gas for power generation is a rapidly escalating strategic risk.

If contingencies occur during situations when the weather is cold and gas-supply margins are tight, the electric system is vulnerable. When other resources suddenly become unavailable, the ISO's system operators face significant challenges identifying additional resources to cover the load and the operating reserve requirement. A large, single-source contingency on the power system at times such as this could put the Region immediately into a reserve shortage and cause the activation of multiple steps of procedures to manage capacity deficiencies (i.e., OP 4) or more serious actions, including load shedding.

AGING GENERATOR FLEET

By 2020, nearly 8,300 MW of ISO-NE's generation is expected to be more than 40 years old. Representing more than 25 percent of total generating capacity, a significant portion of New England's generator fleet faces retirement.

The rising costs associated with oil and coal and the declining costs of natural gas have made it difficult for older oil and coal power plants to compete against newer, more efficient natural gas generators. For example, the Region's oil-fired generators represent more than 20 percent of existing capacity but provided less than 1 percent of the Region's electricity

[126] Most natural gas-fired generators do not make forward gas procurement arrangements, and rely on the procurement of "spot" gas if called upon to run. The gas-supply market is largely illiquid during evening and weekend hours.

needs in 2011 and 2012—most of it during periods of peak demand. By operating so infrequently, these units cannot recover costs for capital investments that would help them become more efficient. In addition, strict environmental regulations requiring extensive investment may force a number of these power plants to retire in the coming years.

If the assumed at-risk generators retire, over 6,000 MW of resources would need to be retained, repowered, or replaced to satisfy ISO-NE's Installed Capacity Requirement. As generators retire, they will likely be replaced by natural gas-fired generation, amplifying the Region's dependence on natural gas.

Many of the at-risk units are located at critical locations on the transmission grid. If they retire without repowering, transmission security challenges could be created on both the local and regional scale. Many of the Region's older oil- and coal-fired generators were built at or near major electricity demand centers, such as the Boston area, to best meet peak consumer demand. The replacement of a large number of these resources could alter the makeup of the grid and create transmission reliability and security issues, depending on where the new resources are located.

Transmission development expected between 2013 and 2020 will significantly expand and fortify the Region's energy trading hub (the Hub)[127] and the connections to it from other areas of the grid. The addition of new capacity electrically located at or deliverable to the Hub would allow the Region to serve most of its load reliably. The southeastern Massachusetts and Connecticut load zones, however, may need some resources to provide local capacity or transmission reinforcements to address reliability concerns. If the retired units are not replaced, the direct result would be a decrease in seasonal reserve margins during the assessment period.

Integrating Variable Resources While Maintaining Reliability

Region-wide RPSs and other environmental targets call for 30 percent of New England's projected total electric energy needs in 2020 to be met by renewable resources and Energy Efficiency. Currently, approximately 40 percent of the proposed projects in the ISO's generator Interconnection Queue are wind-powered.

During the past several years, a number of wind generation projects have interconnected to the northern portions of the New England transmission system. This is an area remote from New England's larger load centers, with a transmission system sufficient to serve the relatively small amounts of area load but not designed for integrating large amounts of resources. Project developers have proposed additional wind projects to interconnect in these areas as well; however, the operation of wind resources in these areas is challenging for reasons presented below.

While new wind resources are being added to the system, substantial increases are not expected for several years. During the assessment period, only 232 MW of on-peak wind capacity is expected to be in service. With respect to all types of variable resources, only a total of 751 MW[128] (on peak) of such resources are currently in service, and only 147 MW of Future-Planned wind and PV projects are expected to be added during the assessment period.

Contemporary wind generators are a relatively new and evolving technology that to date has not typically self-provided significant voltage or stability support to the system.

Wind generation technology has evolved rapidly during the last few years. The advances in physical equipment have outpaced industry's ability to develop accurate models for use in technical planning and operating studies. In some instances the as-built equipment performance differed significantly from the models provided during the system impact studies and preliminary operating studies.

[127] The New England Trading Hub is a central trading location in the energy market where no significant energy congestion is expected. Approximately 32 electrical buses/nodes in West-Central Massachusetts make up the Hub.

[128] ISO-NE generators that are classified as variable include wood (236 MW), refuse (243 MW), hydro (121 MW), wind (97 MW), solar (32 MW), and landfill gas (22 MW) units.

Wind generators are often located many miles from their point of interconnection to the transmission system. Many are connected to electrically weak parts of the New England power system, most often with the bare minimum of voltage support required.

Wind generators often interconnect on the basis of what is minimally required pursuant to meeting the respective interconnection standard and lack elective transmission enhancements. Resources compete for transmission access in the energy market based on offer price. The fact that wind resources rarely bid into the Day-Ahead Energy Market contributes to their risk of curtailment.

Wind generation is subject to regional and local transmission constraints. Most recent wind curtailments have been due to local constraints.

Power system operating conditions are often much different from those studied during the interconnection process. The narrow scope of conditions examined in the interconnection study construct pursuant to Order 2003 and FERC interconnection requirements for wind pursuant to Order 661, along with wind generators only being minimally upgraded to meet the respective interconnection standard, result in sensitivity to operating conditions and a greater risk of curtailment for these resources. This situation significantly complicates system operations.

Because of the confluence of these technical and policy challenges, the operation of wind generators has at times been curtailed, especially during maintenance conditions on the transmission system. These curtailments are expected to continue in the absence of improvements at the wind plants and significant transmission expansion.

In addition to customer interconnection studies of elective transmission upgrades that address marginal interconnections and transmission constraints above what currently is required, other interconnection studies may be needed to consider a wider range of system conditions due to the increasing amount of system operating complexity.

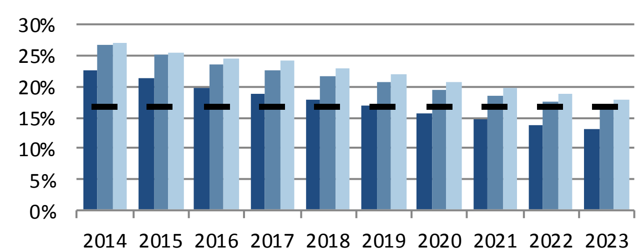
NPCC-New York

The New York Independent System Operator (NYISO) is the only BA within New York state.(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 experiences its peak load in the summer period with the all-time peak load of 33,956 MW in the summer of 2013.

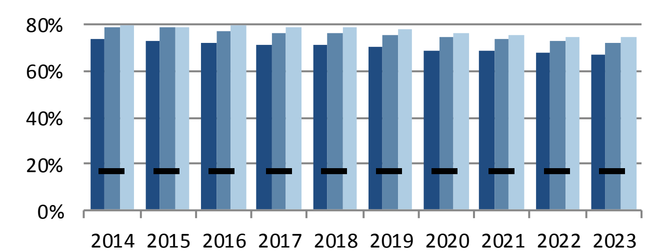
Planning Reserve Margins

NPCC-New York-Summer		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ANTICIPATED		22.71%	21.22%	19.75%	18.85%	17.89%	16.85%	15.77%	14.73%	13.83%	13.03%
PROSPECTIVE		26.72%	25.18%	23.67%	22.74%	21.74%	20.67%	19.56%	18.49%	17.55%	16.72%
ADJUSTED POTENTIAL		26.89%	25.40%	24.45%	24.09%	23.09%	22.00%	20.88%	19.79%	18.85%	18.01%
NERC REFERENCE	-	**17.00%**	**17.00%**	**17.00%**	**17.00%**	**17.00%**	**17.00%**	**17.00%**	**17.00%**	**17.00%**	**17.00%**
NPCC-New York-Winter		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ANTICIPATED		73.63%	73.02%	71.72%	71.36%	70.87%	70.53%	69.11%	68.42%	67.51%	66.97%
PROSPECTIVE		79.09%	78.45%	77.11%	76.74%	76.24%	75.88%	74.42%	73.70%	72.77%	72.22%
ADJUSTED POTENTIAL		79.40%	78.94%	79.36%	78.98%	78.48%	78.12%	76.63%	75.91%	74.96%	74.40%
NERC REFERENCE	-	**17.00%**	**17.00%**	**17.00%**	**17.00%**	**17.00%**	**17.00%**	**17.00%**	**17.00%**	**17.00%**	**17.00%**

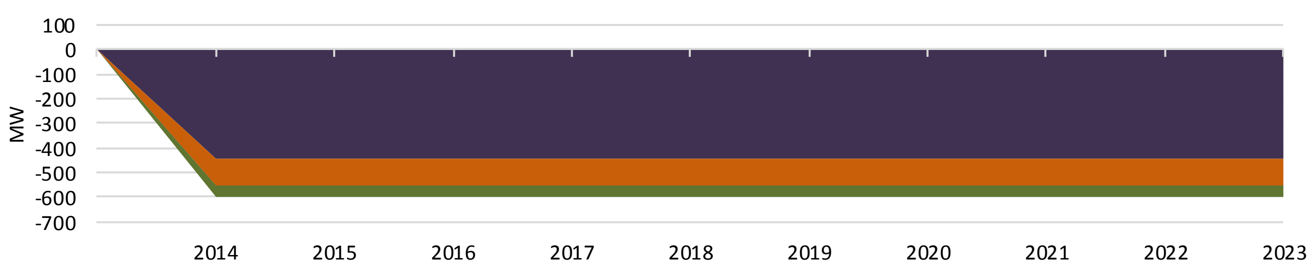
Summer



Winter



Cumulative 10-Year Planned Capacity Change



		2013 Existing		2023 Planned			2023 Planned & Conceptual		
NPCC-New York		Capacity (MW)	Share (%)	Capacity (MW)	Share (%)	Change (MW)	Capacity (MW)	Share (%)	Change (MW)
Coal		1,992	5.6%	1,548	4.5%	-445	1,548	4.2%	-445
Petroleum		8,948	25.3%	8,839	25.5%	-109	8,839	23.8%	-109
Gas		13,143	37.2%	13,143	37.9%	0	15,340	41.4%	2,198
Nuclear		5,411	15.3%	5,411	15.6%	0	5,411	14.6%	0
Hydro		3,826	10.8%	3,826	11.0%	0	3,826	10.3%	0
Pumped Storage		1,407	4.0%	1,407	4.1%	0	1,407	3.8%	0
Geothermal		0	0.0%	0	0.0%	0	0	0.0%	0
Wind		137	0.4%	137	0.4%	0	276	0.7%	139
Biomass		449	1.3%	402	1.2%	-46	425	1.1%	-24
Solar		0	0.0%	0	0.0%	0	0	0.0%	0
TOTAL		**35,311**	**100.0%**	**34,711**	**100.0%**	**-600**	**37,069**	**100.0%**	**1,759**

Demand, Resources, and Planning Reserve Margins

The current Installed Reserve Margin (IRM) requirement that covers the period from May 2013 to April 2014 (2013 Capability Year) is 17.0 percent. For this assessment, the IRM is applied as the Reference Margin Level for the entire 10-year period. This requirement is set by the New York State Reliability Council (NYSRC) based upon an annual study conducted by its Installed Capacity Subcommittee (ICS). This is an increase of 1.0 percent compared to the *2012LTRA* reference case. The principal drivers for the increased IRM are a change in Special Case Resource (SCR) modeling, an updated LFU model, and an updated external area model.

There have been no footprint changes since the *2012LTRA*. The economic outlook was updated in January 2013 with projections resulting in lower annual energy growth compared to a year earlier—0.47 percent per year in 2013 versus 0.59 percent per year in 2012. The long-term weather outlook has not changed compared to the *2012LTRA*.

Due to the higher levels of consumer spending and economic growth associated with the Nassau and Suffolk counties, energy growth is projected to be higher in Long Island than the state as a whole. There has been a gradual increase in the share of annual energy use during summer months—from 27.5 percent in 2000 to 28.6 percent in 2012. This is attributed to an increase in air conditioning usage.

The peak demand forecast shows a higher annual average rate of growth in the *2013LTRA* reference case compared to the *2012LTRA* reference case—0.96 percent in 2013 versus 0.85 percent in 2012. This is related to a gradual decline in the state-wide annual load factor that has been observed during the past eight years (a decrease in load factor occurs when the ratio of average annual energy to peak demand decreases from one year to the next). This indicates that summer peak demand is growing faster than annual energy supply.

DR is reported under Load as a Capacity Resource and treated on the supply-side in the calculation of Planning Reserve Margins. Voluntary DR is also reported as a resource. DR resources are modeled conservatively in planning studies to account for the possibility of the resources being unavailable or nonresponsive.

The New York Public Service Commission has authorized budgets for the state's investor-owned utilities (IOUs) and the New York State Energy Research and Development Agency through 2015. In addition, the state's two power authorities, Long Island Power Authority and the New York Power Authority, each have authorized spending through at least 2015 and have long-term plans for additional spending beyond 2015.

The Indian Point Power Plant (2 nuclear units) is speculated to retire by the end of 2015. If the Indian Point Power Plant licenses were not renewed and the plant was retired by the end of 2015 or thereafter, it would result in immediate violations of resource adequacy criteria. As reliance on natural gas as the primary fuel for electric generation increases, disruptions of natural gas supplies will have a greater impact on generator availability.

During the 10-year period, there is only one scheduled retirement amounting to 97 MW in June 2015. There are an additional 402 MW of proposed retirements, but no retirement dates are known. Two of those units (309 MW) submitted notices of intent to mothball or retire. As a result of the generator outage process described in the next paragraph, those units are currently operating under a Reliability Support Services agreement as their retirements would result in a reliability need.[129]

The NYBA neither plans for nor relies on behind-the-meter generation for reliability purposes, except for those resources that opt to participate in one of the NYBA's DR programs.

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There are only two nontraditional resources in the NYBA's markets: a 20 MW flywheel and an 8 MW storage battery, as listed in the *2013 Load and Capacity Data Report* (Gold Book).[130] There is no reliability impact from these resources expected during the assessment period.

As variable resources, such as wind, have been added to the resource mix, procedures have been modified and updated. For example, the NYBA implemented a centralized wind forecasting program to provide NYBA operations with a better estimate of the amount of energy produced by wind resources over various time frames.

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.

Unforced Capacity Deliverability Rights (UDRs) are rights associated with new incremental controllable transmission projects that provide a transmission interface to a NYBA locality where a minimum amount of installed capacity must be maintained. Three such projects are currently in-service with a total transmission capability of 1,290 MW. A fourth project, the Hudson Transmission Project (HTP), with a 660 MW transmission capability went into service May 2013. Capacity transactions associated with UDRs are considered confidential market data. Only net capacity import totals can be publicly disclosed in order to maintain market confidentiality.

External capacity (ICAP) purchases and sales are administered by NYISO. An annual study is performed to determine the maximum level of capacity imports from neighboring BAs allowed without violating the LOLE criteria. For the Capability Year 2013–2014, the amount is 2,480 MW. Except for grandfathered contracts, these import rights are allocated on a first-come, first-served basis with a monthly obligation. While capacity purchases are not required to have accompanying firm transmission, adequate external transmission rights must be available to assure delivery to the NYBA border when scheduled. All external ICAP suppliers must also meet the eligibility requirements as specified in the Installed Capacity Manual.[131]

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 the Region's neighbors in planning studies to allow for emergency imports as one potential emergency operating procedure step in the event of a system emergency.

Capacity transactions modeled in NYBA's assessments have met the requirements as defined in NYBA's tariffs. Both NYBA and the respective neighboring assessment areas agreed upon the terms of the capacity transaction, including, for example, a) the megawatt value, b) the duration (minimum of one year), c) the contract path, d) the source of capacity, d) the capacity rating of the resource. Transfer capability is reserved on the ties with the Region's neighbors in planning studies to allow for emergency imports as one potential emergency operating procedure step in the event of a system emergency.

Transmission and System Enhancements

The HTP is a new market-based tie line between PJM and NYISO from PSE&G's Bergen 230-kV substation to Con Edison's W.49th Street 345-kV station. The project consists of a back-to-back HVdc converter in New Jersey with a submarine 345-kV ac cable from the converter station to New York City. The project is capable of transferring 660 MW, but has firm capacity withdrawal rights from PJM of 320 MW. The project went into service May 2013. Additional local TO plans include transmission and subtransmission system reinforcements throughout the state.

The NYISO 2012 CRP identified solutions to thermal overloads identified in the RNA. The reliability needs identified in the Rochester and Syracuse areas will be resolved by 2017 with permanent solutions identified in the most recent TO Local Transmission Plans. These permanent solutions include a new RG&E 345/115-kV substation and reconductoring of a National Grid 115-kV line. In the interim, mitigating measures, including local operating procedures, will be called on—if

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[130] 2013 Load and Capacity Data - "Gold Book".
[131] NYISO Installed Capacity Manual (April 2013).

required—to prevent overloads. The reliability need identified for Ramapo 345/138-kV transformers was mitigated by the installation of new independent protective relay in 2013.

Historically, the most congested transmission paths in New York are Central East, Leeds–Pleasant Valley, and Dunwoodie–Shore Road. The constraints on Central East and Leeds–Pleasant Valley are driven by demands in the lower Hudson Valley resulting in high transfers of power from Upstate New York to New York City. The Dunwoodie–Shore Rd. constraint is driven by Long Island demand. These constraints could be mitigated through additional transmission, generation, or demand reduction.

There are no project delays or temporary service outages for any transmission facilities that will impact long-term reliability of BPTFs during the assessment period. However, if the Indian Point Power Plant licenses are not renewed and the plant was to retire by the end of 2015 or thereafter, it would result in immediate violations of transmission security criteria.

As part of the DOE Smart Grid Investment Grant, 938 Mvar of smart grid-enabled capacitor banks will be installed at various subtransmission voltage levels and 39 PMUs will be installed at bulk power stations throughout New York by June 2013.

NYBA BPS security is maintained by limiting power transfers according to the determined transfer limits, including voltage-constrained transfer limits. Therefore, UVLS schemes are not expected to be needed.

There are no current plans to install additional SPSs in NYBA. The Athens generation rejection SPS is currently used to mitigate curtailment of Athens generation in securing the UPNY–SENY interface. This SPS is expected to be removed if a permanent solution, such as the addition of bulk power transmission facilities, was installed.

The deployment of a NYBA-wide, open, flexible, interoperable, secure, and expandable Phasor Measurement Network (PMN) system will work in concert with the existing control and monitoring systems. The PMN system will operate using standard information models and communication protocols and will be the integral part of the interconnection-wide North American Synchrophasor Initiative Network (NASPInet). The PMN system will enhance NYISO's ability to detect system vulnerabilities and disturbances in real time and potentially mitigate their impact.

Integration of new reactive power sources through the installation of additional shunt capacitors will enhance the control and coordination of the voltage profile on the New York power grid, resulting in improvements to the efficiency and reliability of the state's grid. These switched or controllable capacitor banks will provide for additional reactive power resources, which will be available to the BPS during system conditions in which they are most needed.

Three operational system tools are in the process of acceptance, testing, or deployment. Real-time Dynamics Monitoring System (RTDMS), a situational awareness application from Electric Power Group (EPG), was tested in 2012 and is currently in site acceptance testing. An enhanced State Estimator application was tested in 2012 and deployed in the first quarter of 2013. A voltage stability monitoring application was deployed to production in June 2013.

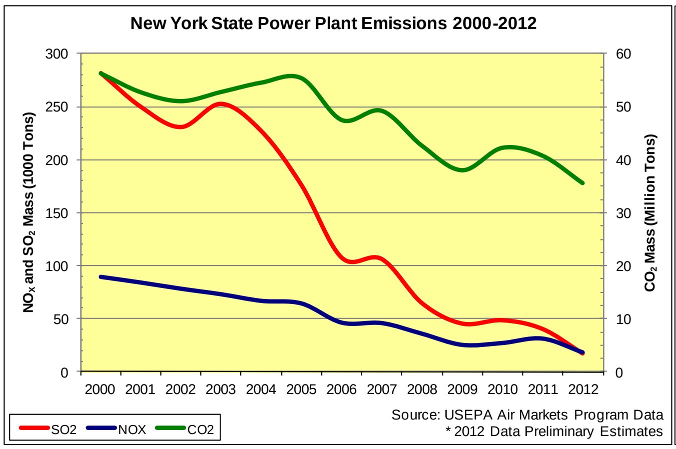
Long-Term Reliability Issues

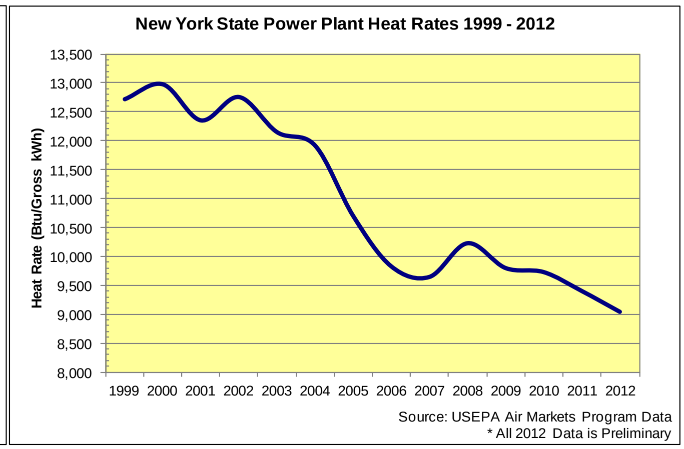
NYBA has a significant amount of hydro resources. Many of these resources are located on rivers throughout the state. The output of these run-of-river resources is subject to water levels, which may vary greatly on a month-to-month basis based on weather conditions (e.g., snowfall amounts, temperature, rainfall amounts, etc.) For reliability purposes, these units are modeled with a 45-percent derate factor. This derate factor represents a severe scenario case for drought or low water level.

RPS resources are incorporated into NYBA's planning studies as information becomes available and these resources meet criteria to be in-service. As the amount of variable resources, such as wind, has been added to the resource mix, procedures have been modified and updated. For example, the NYBA has implemented a centralized wind forecasting program to better estimate the amount of energy to be produced by wind resources over various time frames.

Retirement of additional generating units beyond those already contemplated for either economic or environmental factors could adversely affect the reliability of NYBA's BPS. NYISO recognizes that numerous risk factors can contribute to reliability concerns with the need to take swift actions to maintain reliability, which may need to be preceded by putting sufficient replacement resources into operation depending on the units in question.

Historically, this Region has actively participated in the development of the environmental policies and regulations that govern the permitting, construction, and operation of power generation and transmission facilities. Currently, New York's standards for permitting new generating facilities are among the most stringent in the nation. The combination of tighter environmental standards coupled with competitive markets administered by NYISO since 1999 has resulted in the retirement of older plants equaling approximately 5,000 MW of capacity and the addition of over 10,000 MW of new efficient generating capacity. In turn, these changes have led to marked reduction of power plant emissions and a significant improvement in the efficiency of the generation fleet. The following charts show the change in New York power plant emissions of SO_2, NO_x and CO_2 between 2000 and 2013(left), and the change in New York power plant heat rates between 1999 and 2012.





Notwithstanding the progress toward achieving New York's clean energy and environmental goals, various environmental initiatives that will affect the operation of the existing fleet are in place or pending. Environmental initiatives that may affect generation resources may be driven by either or both the state or federal programs. Since the previous LTRA, the EPA has promulgated several regulations that will affect the majority of NYBA's thermal fleet of generators. Similarly, New York State Department of Environmental Conservation (NYSDEC) has undertaken the development of several regulations that will apply to most of the thermal fleet in New York.

The purpose of the development of this analysis is to gain insight into the population of resources that are likely to be faced with major capital investment decisions in order to achieve compliance with several evolving environmental program initiatives. The premise of this analysis is that the risk of unplanned retirements is related to two factors: first, the capital investment decisions resource owners need to make in order to achieve compliance with the new regulatory program requirements, and secondly the recent change in the relative attractiveness of gas vs. coal has challenged the viability of some former Base Load units. The goal of this scenario analysis is to identify when and where these risks occur on the New York Power System.

Five environmental initiatives are sufficiently broad in application and have requirements that may require retrofitting environmental control technologies. Therefore, generator owners will likely need to address the retirement vs. retrofit question. These environmental initiatives are: (1) NYSDEC's Reasonably Available Control Technology for Oxides of Nitrogen (NOx RACT), (2) Best Available Retrofit Technology (BART), (3) Best Technology Available (BTA), (4) U.S. EPA's Mercury and Air Toxics Standards (MATS), and (5) Clean Air Interstate Rule (CAIR).

Reasonably Available Control Technology (NOx RACT)

The NYSDEC finalized new regulations for the control of emissions of nitrogen oxides (NOx) from fossil fueled power plants (Part 227-2).[132] The regulations establish presumptive emission limits for each type of fossil fueled generator and each fuel used as an electric generator in New York that has a capacity greater than 25 MW. Compliance options include averaging emissions with lower emitting units, fuel switching, or installing emission reduction equipment (e.g., low NOx burners or combustors), selective catalytic reduction units, or retirement. Generators have filed permit applications and RACT analyses with NYSDEC. As required, Title V permits have been amended. Compliance with approved plans is required by July 1, 2014. Publically available compliance plans have been reviewed. Several generators requested that their submittals be considered Competitive Business Information; however, NYSDEC denied these requests. The resolution of this issue may extend beyond 2023.

Reviewing the plans that are public, it is seen that approximately 28,000 MW of capacity is subject to this rule, of which approximately 4,000 MW of generating capacity are involved in emission reduction projects. Several of these projects are underway, and the remaining projects should be accomplished prior to the July 2014 compliance date.

System averaging plans, known as emission bubbles, have been used as compliance methods for a number of generation portfolios under common ownerships. These systems have some units that are capable of achieving emission rates lower than presumptive limits prescribed by the NOx RACT rule, while other generating units were unable to achieve the prescribed limits. The rules provided for a system average that is based on heat input and the application of the relevant emission rate. The revised NOx RACT standard, which will take effect in 2014, lowers the prescribed emission rate for boilers. When this reduction takes effect, the ability to average emission rates across the owner's portfolio will be significantly reduced. This will result in further limitations on the duration of operation of high-emitting generators that are typically only called for on days with high electric demand.

A review of historical emission patterns suggests that some portfolios will need to either undertake emission control technology retrofits or limit the number of hours per day that the higher emitting machines are available. This review also determined that there are approximately 1,000 MW of high emitting resources in Zone J.

Current and New Presumptive NOx RACT Emission Limits (NOx/mmBTU)

	Current Limits				New Presumptive Limits			
Fuel Type	Tangential	Wall	Cyclone	Stokers	Tangential	Wall	Cyclone	Fluidized Bed
Gas Only	20.0%	20.0%	n/a	n/a	8.0%	8.0%	n/a	n/a
Gas/Oil	25.0%	25.0%	43.0%	n/a	15.0%	15.0%	20.0%	n/a
Coal Wet Bottom	100.0%	100.0%	60.0%	n/a	12.0%	12.0%	20.0%	n/a
Coal Dry Bottom	42.0%	45.0%	n/a	30.0%	12.0%	12.0%	n/a	8.0%

Best Available Retrofit Technology (BART)

NYSDEC recently promulgated a new regulation: Part 249, Requirements for the Applicability, Analysis, and Installation of BART Controls.[133] The regulation applies to fossil-fueled electric generating units with approximately 8,200 MW of capacity that were built between August 7, 1962, and August 7, 1977. The state must comply with provisions of the federal Clean Air Act that are designed to improve visibility in national parks. Affected generation plant owners have prepared analyses to determine the impact of each affected unit's emissions on visibility in national parks. NYSDEC and the EPA determined that emission reductions must be made at the affected units. These new emission limitations are now included in amended Title V permits. The compliance deadline is January 1, 2014.

[132] Subpart 227-2 Reasonably Available Control Technology (RACT) For Major Facilities of Oxides Of Nitrogen (NOx).
[133] Part 249: Best Available Retrofit Technology (BART).

Emission controls of sulfur dioxide (SO_2), NOx, and particulate matter are necessary. Compliance plans were filed with NYSDEC in October 2011. Several units have been chosen to retire, representing a capacity loss of approximately 300 MW. To achieve the required emission reductions, several plants will use cleaner fuels while others will undertake retrofit projects.

Best Technology Available (BTA)

NYSDEC finalized its policy document "Best Technology Available (BTA) for Cooling Water Intake Structures."[134] The proposed policy applies to plants with design intake capacity greater than 20 million gallons per day and prescribes reductions in fish mortality. It also establishes performance goals for new and existing cooling water intake structures. The performance goals call for the use of wet, closed-cycle cooling systems at existing generating facilities. The policy does provide some limited relief for plants with historical capacity factors less than 15 percent.

The policy will be applied at the time that the State Pollution Discharge Elimination System Permit is renewed—theoretically in five years. The application of this policy is one of the main issues being decided on in the Indian Point relicensing process. Generators with approximately 18,000 MW of capacity are subject to this policy and may be required to retrofit 4,000–7,000 MW of generating capacity. If cooling tower retrofits are required, compliance deadlines will be project specific.

The EPA announced the MATS in December 2011, replacing the Maximum Achievable Control Technology (MACT) rule. The MATS establish limits for HAPs for acidic gases, hydrogen chloride (HCl), hydrogen fluoride (HF), mercury (Hg), and particulate matter. Alternative limits were also established. These limits will apply to coal- and oil-fired generators. The compliance date is March 2015. If necessary, NYSDEC may provide an additional year to comply. If retrofitting of emissions control technology is required or the reliability improvement project will take an additional year, reliability-critical units may qualify for another year to achieve compliance.

In New York, 11,331 MW of capacity will be affected by this regulation. The EPA established a subcategory for limited-use, oil-fired generators. This means that units maintaining a capacity factor on oil that is less than eight percent will be more lightly regulated. No oil-fired EGUs have exceeded the eight-percent capacity factor threshold since 2009. While they remain subject to MATS, it is not expected that significant emission control retrofit projects will be required at these units.

Emission records were reviewed to determine the best level of emission reductions that is proven to be sustainable. These emission levels were then compared to those necessary to comply with MATS for coal-fired units. The review showed that most of the coal-fired units in New York are already or nearly capable of complying with MATS. In addition, NYSDEC has promulgated Part 246: Mercury Reduction Program for Coal-Fired Electric Utility Steam Generating Units, which establishes currently in-effect emission limitations in New York for the reduction of mercury emissions. Phase II of this regulation will require additional reductions from coal-fired boilers in 2015. The Phase II emission limitations are more stringent than the EPA MATS limits. The owner of one reliability-critical unit (Cayuga 2) notified the NYISO that it will need the fifth year in order to install the emissions control technology necessary for compliance with MATS.

Cross State Air Pollution Rule (CSAPR)

CSAPR is the EPA's revision of the Clean Air Interstate Rule (CAIR), which was vacated by the U.S. Supreme Court. In doing so, the Court ordered that the Clean Air Interstate Rule (CAIR) remain in effect until replacement rule is implemented. CAIR has a significant reduction in allowable emissions scheduled for 2015. The CAIR emission allowance system currently is over-supplied. In its current form, the rule will have only a limited impact on the reduction of emissions and it not a major consideration in the retirement versus retrofit decision. While it may be reasonable to assume that a national program will eventually be in effect for limiting emissions of SO_2 and NOx via a cap and trade program, the timing remains uncertain.

[134] CP-#52 / Best Technology Available (BTA) for Cooling Water Intake Structures.

In December 2011, the EPA finalized the CSAPR, which is designed to reduce emissions of SO_2, annual NOx, and Ozone season NOx from fossil-fueled power plants in 28 central and eastern states. The regulation is implemented through the use of emission allowances and limited trading programs. The regulation establishes emission budgets for each affected state. The emission budget is divided on a pro-rata basis determined by historic heat input for existing facilities. There are set-asides to provide allowances for new fossil generators. The use of emission allowances is expected to increase offering prices for generation from affected facilities. The final rule was vacated by the U.S. District Court. But for the action of the courts, the rule would currently be in effect with another reduction in the SO_2 cap scheduled for 2014.

National Emission Standards for Hazardous Air Pollutants (NESHAP) and New Source Performance Standards (NSPS) for Reciprocating Internal Combustion Engines (RICE)

In January 2013, the EPA promulgated these rules concurrently. The new rules will apply to central-station, engine-driven generators and engine-driven generators at major and area sources of HAPs. The rules establish emission limits for engines based on fuel, ignition, and size. The rules allow owners who do not make the upgrades to the emission control systems needed for the machines to meet the new emission limits to continue to participate in the NYISO's Special Case Resource (SCR) and Emergency DR programs by limiting the hours of operation. Emergency generators can continue to participate in these programs by undertaking commitments to limit operations to either 50 hours or 15 hours depending on which compliance route they choose.

NYISO is conducting a poll of SCR providers to quantify the potential reduction in capacity resulting from owners' decisions to not upgrade emission control systems but rather to limit their participation in NYISO's SCR and Emergency DR programs.

NYISO conducted the analysis described above to identify generating units that are subject to the key environmental initiatives. The analysis also estimated the amounts of capacity that would be potential candidates for retrofits and thus require recapitalization. These units could become unplanned retirements. The analysis was then extended to identify the amount of capacity subject to multiple environmental requirements. The bi-annual Reliability Needs Assessment includes scenario evaluations and comparisons of the zones at risk with the amount of capacity that could be considered at risk for unplanned retirement due to the need to add capital for retrofitting environmental control technology.

Environmental Initiatives Summary

Regulation	Status	Compliance Deadline	Est. Capacity Affected	Potential Retrofits
NOx RACT	In effect	4182100.0%	27,700 MW (242 units)	5,700 MW (20 units)
BART	In effect	4164000.0%	8,500 MW (18 unit)	1,500 MW (4 units)
MATS	In effect	Mach 2015	10,000 MW (25 units)	200 MW (1 unit)
BTA	In effect	Upon Permit Renewal	16,500 MW (35 units)	4,400 – 7,300 MW
CSAPR	Implementation stayed (rule in litigation)	January 2012 & January 2014	26,000 MW (155 units)	2,000 MW (9 units)
RGGI	In effect	In effect	26,000 MW (157 units)	N/A

The 2012 CRP determined that under the conditions studied and with the market-based solutions submitted and the responsible TO-updated local transmission plans, the proposed system upgrades and local transmission solutions will maintain the reliability of the New York BPS. The projects included in the regulated backstop or alternative regulated solutions, if they need to be triggered or are otherwise put into service, may further improve system reliability. Market-based projects may also further improve system reliability.

NPCC-Ontario

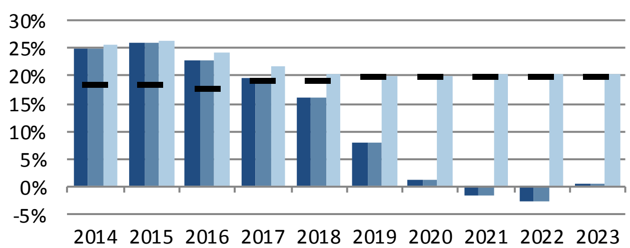
Ontario's electrical power system is, geographically, one of the largest in North America covering an area of 415,000 square miles and serving the power needs of more than 13.5 million people. Ontario is interconnected electrically with Quebec, Manitoba, Minnesota, Michigan, and New York. No footprint changes occurred during the past two years and no changes are anticipated.

Planning Reserve Margins

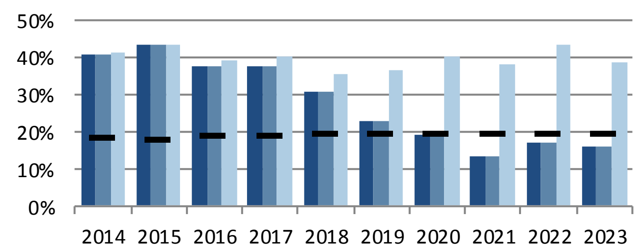
NPCC-Ontario-Summer		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ANTICIPATED		24.89%	26.05%	22.86%	19.53%	16.00%	7.93%	1.28%	-1.60%	-2.54%	0.43%
PROSPECTIVE		24.89%	26.05%	22.86%	19.53%	16.00%	7.93%	1.28%	-1.60%	-2.54%	0.43%
ADJUSTED POTENTIAL		25.68%	26.22%	24.18%	21.84%	20.29%	20.08%	20.14%	20.21%	20.27%	20.32%
NERC REFERENCE	-	**18.60%**	**18.70%**	**18.00%**	**19.10%**	**19.30%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**

NPCC-Ontario-Winter		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ANTICIPATED		40.71%	43.35%	37.74%	37.80%	30.61%	22.77%	19.16%	13.63%	17.38%	15.93%
PROSPECTIVE		40.71%	43.35%	37.74%	37.80%	30.61%	22.77%	19.16%	13.63%	17.38%	15.93%
ADJUSTED POTENTIAL		41.32%	43.62%	39.26%	40.54%	35.66%	36.68%	40.14%	38.22%	43.43%	38.70%
NERC REFERENCE	-	**18.70%**	**18.00%**	**19.10%**	**19.30%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**

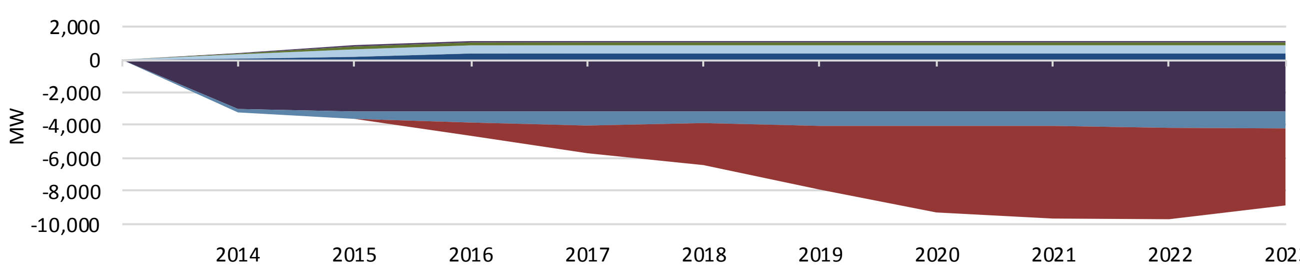
Summer



Winter



Cumulative 10-Year Planned Capacity Change



NPCC-Ontario		2013 Existing Capacity (MW)	2013 Existing Share (%)	2023 Planned Capacity (MW)	2023 Planned Share (%)	2023 Planned Change (MW)	2023 Planned & Conceptual Capacity (MW)	2023 Planned & Conceptual Share (%)	2023 Planned & Conceptual Change (MW)
Coal		3,166	10.2%	0	0.0%	-3,166	0	0.0%	-3,166
Petroleum		2,145	6.9%	2,145	9.2%	0	2,145	7.7%	0
Gas		6,753	21.8%	5,720	24.7%	-1,033	10,006	35.9%	3,253
Nuclear		12,844	41.5%	8,139	35.1%	-4,705	8,139	29.2%	-4,705
Hydro		5,662	18.3%	6,046	26.1%	384	6,046	21.7%	384
Pumped Storage		89	0.3%	89	0.4%	0	89	0.3%	0
Geothermal		0	0.0%	0	0.0%	0	0	0.0%	0
Wind		197	0.6%	693	3.0%	495	957	3.4%	759
Biomass		106	0.3%	282	1.2%	176	282	1.0%	176
Solar		0	0.0%	84	0.4%	84	240	0.9%	240
TOTAL		**30,963**	**100.0%**	**23,197**	**100.0%**	**-7,766**	**27,904**	**100.0%**	**-3,059**

Demand, Resources, and Planning Reserve Margins

The Reference Margin Levels (target reserve margins) for the first five years of the assessment period vary from 18.6 percent in 2014 to 19.3 percent in 2018.[135] Ontario Power Authority's (OPA's) Reference Margin Level (target reserve margin) of 20 percent is applied from 2019 to 2023, which has not changed from the *2012LTRA* reference case. The OPA target reserve margin, like the IESO's, is also based on meeting NPCC LOLE criteria. The OPA calculations include additional allowance for project uncertainty.

Anticipated Reserve Margins are projected to fall below the target reserve margin in 2018. Some of the Bruce and Darlington nuclear units will be out of service for refurbishment during this time frame. Various options described below are under consideration to ensure that future resources are available to maintain adequacy.[136]

This forecast for Net Energy for Load has an average annual growth rate of -0.2 percent during the 10-year period, similar to last year's forecast of -0.3 percent average growth for 2012–2022. This is the product of modest economic expansion, conservation impacts, and growing embedded generation capacity. Due to a number of factors, the growth rate for overall consumption is lower than the peak growth rates. Conservation is initially aimed at reducing peaks, but as those peak reduction opportunities are realized, conservation and embedded generation will start to impact nonpeak hours, affecting overall energy demand.

Since the underlying drivers are very similar to last year, the projected growth rates remain similar as well. Canada is expected to post modest growth during the assessment period, though Ontario will lag in the near-term. The oil-producing regions in Canada will see stronger growth than Ontario's manufacturing- and export-based economy. In fact, Canada's oil wealth puts upward pressure on the dollar, which is more detrimental to central Canada.

Throughout the forecast, Ontario's economy will continue to undergo structural changes. By the fifth year of the assessment period, projections indicate the economy will see a continued transition from energy-intense industrial processes to a larger service sector and specialized or high-value added manufacturing. This will lead to a less energy-intense economy. However, the very end of the forecast will see the rise in mineral extraction as Ontario begins exploiting its vast but untapped mineral resources in the far North.

The forecasting methodology has not changed since last year's forecast. The models have been updated and re-estimated to incorporate the latest information regarding the relationship between electricity demand and the economy, demographics, and weather.

Within Ontario there will be some localized variation in demand. The Golden Horseshoe, which encapsulates the Greater Toronto area and the Niagara peninsula, has the largest share of Ontario's population and economy. This area will maintain its dominant position in the province. The northern areas of the province will see a rebound later in the forecast at the location of the aforementioned mineral resources. The northwestern area, in particular, will see a rebound as its load drops due to lower demand from the pulp and paper sector. Mining will help boost demand in the northern areas of the province.

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[135] The Reference Margin Level requirements are calculated annually for the next five years and published on the Independent Electricity System Operator (IESO). The IESO determines the required reserve levels based on probabilistic methods deemed by NPCC to be acceptable for meeting regional LOLE criteria.

[136] The IESO and the OPA recognize the potential for certain adverse conditions (e.g., extended forced outages, drought conditions, and particular fuel interruptions) to result in higher-than-expected resource unavailability and have established planning reserves sufficient to address many of these conditions. To the extent resource procurement exceeds the planning reserve requirements, resource adequacy can be maintained for higher than normal contingencies. However, there are always conditions that can exceed those planning assumptions. In such extreme situations, IESO's operations would rely on interconnection support and available control actions to maintain system reliability. Through retention and further development of a diverse resource mix, the potential consequence of these events is reduced.

IESO treats demand measures as a resource and conservation as a decrement to demand. Conservation is projected to increase throughout the assessment period, whereas demand measures will increase through 2015, remaining constant thereafter.

Over the course of the forecast, effective Demand Measures Capacity[137] is expected to be just over 500 MW, rising to just under 600 MW at the end of the forecast. The effective capacity of these programs has been significantly reduced compared to last year. The Global Adjustment Allocation (GAA) has led to a significant reduction in the offers of dispatchable loads during peak periods. The GAA allows customers with peak demands of greater than 5 MW to reduce their share of the Global Adjustment costs by reducing demand during the five highest peak demand days. As a result, this has led to a reduction of roughly 400 MW in the offers of dispatchable loads during peak conditions. The GAA has acted to reduce peak demands by over 900 MW, a greater reduction in the peak than the reduction in demand measures resources. The conservation projections are consistent with those included in the *2012LTRA* reference case. Conservation is expected to yield incremental peak savings of more than 3,000 MW by 2023.

Two coal units at Lambton will be shut down in October 2013 and four units at Nanticoke are expected to be shut down by the end of 2013. As coal inventories are depleted, the Nanticoke units will be removed from service by the facility owner. By 2014, all coal units in Ontario will be phased out in accordance with 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.

Units at the Pickering B, Bruce B, and Darlington Nuclear Generating Stations will be reaching their end of service lives during the 10-year period. The Canadian Nuclear Safety Commission granted a five-year renewal of Ontario Power Generation's operating license for the Pickering Nuclear Generating Station, valid until August 31, 2018. The license prohibits the operation of the Pickering B NGS beyond 210,000 effective full power hours. The Commission will consider OPG's request to remove this regulatory hold point at a future public hearing.

Units at Bruce and Darlington will undergo mid-life refurbishment to extend their operating lives. The OPA is working with two nuclear operators to develop a coordinated plan for nuclear fleet renewal. Unit outages will be coordinated to minimize the number of nuclear units simultaneously on outage. The plan for nuclear renewal is complex as there are a number of aspects related to operational and technical coordination, regulatory and contractual terms, financing and revenue recovery, and risk allocation that need to be resolved.

Supply options for maintaining resource adequacy over this time period are being considered. These options include conservation, recontracting Non-Utility Generator (NUG) facilities, new gas-fired generation, conversion of some or all of the Lambton and Nanticoke coal-fired units to natural gas, imports, and energy storage. There are about 1,500 MW of NUG contracts with the opportunity to be renegotiated as the contracts are expiring now and within the next decade. Currently, the structure of the contracts consists of fixed-price payments that limit the effective operation of resources and efficient participation within the electricity market. The OPA is in the process of assessing the opportunities and merits of renegotiating the NUG contracts, and the procurement process for some NUGs has already begun.

A 280-MW, gas-fired generating station under construction in Mississauga was cancelled in the fall of 2011. The power plant has been relocated to the Lambton Generating Station site and is expected to be in-service by third quarter of 2017. In 2010, a 900-MW, gas-fired generating station intended to be constructed in Oakville was cancelled. Work is underway to relocate the generating station to the existing gas- or oil-fired Lennox generating station site in the Napanee by fourth quarter of 2018. The new station will include two gas turbine units and one steam turbine unit. They will be connected to two 500-kV buses at Lennox Substation. No other major generation or transmission projects have been cancelled or significantly deferred that affect reliability.

[137] Considered in this assessment as Load as a Capacity Resource, a category of Demand Response.

During the assessment period, the amount of renewables' penetration is expected to increase significantly through the Feed-in Tariff (FIT) and microFIT programs, some of which will be behind-the-meter generation. Much of this generation could be variable in nature, which adds more volatility as on-grid demand is impacted by underlying demand and variable generation within the distribution system. The majority of distribution-connected generation is expected to be solar, with lesser amounts of wind.

While a vast number of storage technologies are available for development, five are particularly promising and are being developed by companies within Ontario. These include batteries, pumped hydro, compressed air energy storage (CAES), flywheels, and hydrogen storage. While most of these technologies are only recently seeing major development for grid applications, some technologies have a long history in the province such as hydroelectric pumped storage at the Sir Adam Beck Pump Generating Station in Niagara Falls.

While all these technologies offer energy storage, each provides its own specific utility to the grid. Short-term storage systems, which can supply power for less than two minutes, are generally used for frequency regulation and to maintain grid power quality. Technologies such as batteries and larger flywheels can supply limited energy storage suitable for providing frequency regulation and ramping capability and can help improve system reliability. More sustained energy supply can be provided from technologies such as pumped hydro, CAES, hydrogen, and some battery technologies that are capable of lasting more than one hour. These solutions, among others, can be used to increase grid capacity, offering firm output. If installed in the right location, energy storage can also defer transmission and distribution system upgrades.

As renewables make up an increasingly large portion of the supply, energy storage systems can address some of the problems caused by the intermittent nature of some renewable energy sources such as wind and solar

Through a Request for Proposals issued last year, IESO sought to procure up to 10 MW of regulation from alternative sources such as dispatchable loads, aggregated DR, and storage technologies, including batteries and flywheels. To allow IESO to acquire experience with a range of technologies, the request for proposal (RFP) sought proposals from multiple vendors, each providing a small quantity of regulation.

IESO has entered contracts with the three successful proponents. This procurement process is part of IESO's efforts to broaden access to Ontario's electricity markets. These resources have significantly different operating characteristics than conventional units, allowing them to contribute to Ontario's energy needs in different ways and complement the performance of existing generators.

As the supply mix quickly evolves, IESO is adapting the manner in which the electricity grid is operated while preparing for a continuing increase in variable renewable generation. By 2018, an estimated 10,700 MW of wind and solar generation is expected to be in-service, with substantial amounts by 2014.

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. Monthly Wind Capacity Contribution (WCC) values are used to forecast the contribution from wind generators. WCC values (percent of installed capacity) are determined by picking the lower value between the actual historic median wind generator contribution and the simulated 10-year wind historic median contribution at the top five contiguous demand hours of the day for each winter and summer season, or shoulder-period month. The process of picking the lower value between actual historic wind data and the simulated 10-year historic wind data will continue until 10 years of actual wind data is accumulated, at which point the simulated wind data will be phased out of the WCC calculation. WCC values are updated annually.

Ontario's solar capacity value is forecast to be 30 to 34 percent of installed capacity for the summer peak and 0 to 4 percent contribution for the winter peak. The difference is due to the fact that the summer peak occurs in the afternoon whereas the winter peak occurs after sunset in the evening. The projected solar output is observed for the top demand hours during the summer and winter months.

On average, the assumed capacity contribution for biomass generation is about 95 percent of installed capacity.[138] The assumed capacity contribution for hydroelectric is 72 percent for the summer and 76 percent for the winter.

A formal review of Ontario's Long-Term Energy Plan (LTEP) is currently underway which will include province-wide consultations on a variety of topics including the province's mix of energy sources such as wind, solar and nuclear, and conservation. The updated LTEP will be released in the fall.

IESO is working with OPA and industry stakeholders to develop and implement the necessary changes to accommodate increased renewable generation. As Ontario's renewable energy landscape changes and evolves so must the operation of the grid. Specifically with the influx of wind generation facilities connected to the Ontario electricity transmission system, a new set of operational and reliability considerations have emerged. An IESO stakeholder initiative, Renewables Integration Initiative (RII), is nearing completion by addressing three major issues facing wind and solar generation. The RII addresses the following issues:

- Forecast: the implementation of a centralized forecasting service for wind and solar generation;
- Visibility: access to Real-time information on embedded renewable generation; and
- Dispatch: the dispatch of directly connected wind and solar generation.

RII has already yielded results, including the integration of the hourly centralized forecast into IESO scheduling tools and enhanced visibility of renewable output within the IESO control room, which will provide greater levels of awareness of system conditions.

The dispatch of grid-connected renewable resources, which started the second week of September, 2013 will provide increased flexibility from available variable generation resources and will allow IESO to operate the system more efficiently.

No firm imports into Ontario or firm exports to other Regions or emergency generation are considered in this long-term assessment. However, for use during daily operation, operating agreements between IESO and neighboring jurisdictions in NPCC, RFC, and MRO include contractual provisions for emergency imports directly by IESO. IESO also participates in a shared activation of reserve group, which includes IESO, ISO-NE, the Maritimes, NYISO, and PJM.

Transmission and System Enhancements

A new 176-km (110 mile), 500-kV double-circuit line from the Bruce Power nuclear complex to Milton Switching Station was officially declared in-service in June 2012. This new line was built to accommodate the output of all eight generating units at the Bruce complex, approximately 500 MW of existing wind generating capacity, and 1,200 MW of new renewable generating capacity that is forecasted for development within the area. With all eight Bruce nuclear generating units and new renewables, the combined generation in the Bruce area can reach 8,000 MW.

Northwestern Ontario is connected to the rest of the province by the double-circuit, 230-kV East–West Tie. The northwest region has significant amounts of hydroelectric generation as well as other resources such as coal, gas, and biomass. As part of the coal shutdown, Thunder Bay Generating Station (totaling 300 MW of capacity) will cease coal-fired operation by 2014. In addition, strong local load growth is forecast as a result of an active mining sector in the Region. Additional supply is required to maintain supply security in this area under the wide range of possible system and water conditions. The reinforcement of the East–West Tie with the addition of a new 230-kV transmission link will provide reliable, cost-effective, and long-term supply to the Northwest. The line is anticipated to be in-service in 2018. Additional options are being developed to address interim needs and any supply requirements that may exceed the capabilities of the new transmission.

[138] The hydroelectric generation output forecast is based on historical values of median hydroelectric production and contribution to operating reserves during weekday peak demand hours. Routine maintenance and actual forced outages of the generating units are implicitly accounted for in the historical data.

The Lambton to Longwood transmission upgrade consists of replacing approximately 70 km of existing double-circuit transmission line between Lambton Transmission station (near Sarnia, Ontario) and Longwood Transmission station (near London, Ontario) with a higher ampacity conductor. This project will increase the transfer capability from southwestern Ontario toward London. The purpose of this project is to incorporate additional renewable resources and increase deliverability of system capacity located west of London. It is anticipated that the project will be completed by 2014. Two new 500-kV switching stations planned to be in-service by the end of 2014, Evergreen and Ashfield, are being built to accommodate 384 MW and 270 MW of wind generation respectively.

The transmission projects that are under various stages of construction and other planned projects will address the transmission constraints identified. The TOs in Ontario, together with the OPA, proactively plan the transmission network in order to ensure timely system adjustments, upgrades, and expansions. Delays to the in-service dates of bulk transmission projects caused by delays in obtaining required approvals or delays in construction may result in increased congestion or usage of SPSs in the interim.

System reinforcements are also being considered in a number of regional areas (e.g., Kitchener–Waterloo–Cambridge–Guelph, York region, and Ottawa) throughout the province in order to maintain a reliable, local supply of electricity. The OPA's regional planning approach develops options for each need, in a coordinated manner, guided by principles that maintain a long-term view that anticipates uncertainties and maintains flexibility. Conservation, supply, and transmission plans are coordinated to deliver the solutions that are required for each locale. This approach also addresses interim needs when projects are delayed.

To enable the connection of additional renewable generation in the Bruce area, a static var compensator (SVC) rated at 350 MVA and connecting to the 500-kV voltage level at the Milton station was planned to be in-service by 2015. However, the project is delayed pending a stakeholder consultation on the issue.

Ontario will monitor the progress of the continued operation of nuclear units at Pickering Nuclear Generating Station. Pickering Nuclear Generating Station units connect directly to the 230-kV system at Cherrywood Transformer Station, east of the greater Toronto area. The retirement of Pickering NGS would require an additional 230-kV supply source for the Pickering and Oshawa areas. This will be provided by a new Clarington 500/230-kV transformer station with a 2017 in-service date. Clarington Transformer Station will also improve load restoration capabilities to loads east of Cherrywood following certain contingencies.

As demand increases in the western part of the greater Toronto area, the loads on the 500/230-kV transformers at Claireville Transformer Station and Trafalgar Transformer Station are forecast to exceed capacity near the end of this decade. An additional 500 to 230-kV supply source—involving the installation of 500/230-kV transformers at the 500-kV Milton Switching Station by 2018—would be required to relieve the loading on these existing transformers.

There are no wide-area UVLS programs in Ontario, and there are no plans to install any such UVLS schemes in future. The majority of the SPSs that are in use within Ontario are intended to address the effects of contingencies under outage conditions and are not intended to avoid or delay the construction of bulk transmission facilities. The principal exception is the North–East load and generation rejection SPS that mitigates the effects of contingencies involving the single-circuit, 500-kV line that services the North-East area. This SPS is designed to achieve a post-contingency match between the load and available generation in the area to minimize load loss and prevent possible separation and islanding of a portion of the North–East system.

The existing Bruce SPS has been enhanced to accommodate the two new 500-kV circuits between the Bruce complex and Milton Switching Station and to address other contingency conditions not previously covered by the SPS. The intent of the expanded coverage is to limit the extent of restrictions imposed on the output from the Bruce units during transmission element outage conditions while also assisting with the repreparation of the system following a permanent fault when subsequent contingency conditions may become more critical. This SPS will be a permanent feature to deal with planned outages and is not intended for normal operations or to avoid or delay the construction of bulk transmission facilities. The enhanced system was approved by NPCC and placed into service in 2012. The current Bruce SPS hardware is approaching its end-of-life. A replacement is being developed and is scheduled to become fully operational in 2015.

To coincide with the completion of the new Bruce–Milton 500-kV line, a 350-Mvar SVC was installed at Nanticoke Switching Station, connected to the 500-kV bus, and another 350-Mvar SVC was installed at Detweiler Transformer Station, connected to the 230-kV bus. These SVCs were required to provide dynamic reactive support following a critical double-circuit contingency involving the 500-kV lines between the Bruce complex and Milton Switching Station.

IESO has advanced the development of an on-line limit derivation tool to maximize transmission capability in the operating time frame. Currently, this tool is used in operational planning to calculate a limited set of operating security limits in southern, northeast, and east Ontario. The use of the tool is being extended to other parts of the province with an aim to use this tool for the entire province by mid-2014. The limits calculated by the tool are used to plan and schedule equipment outages and to re-prepare the power system following forced outages that impact Interconnection Reliability Operating Limits (IROLs).

Long-Term Reliability Issues

As described in Generation section, hydroelectric generation capacity contributions are based on median historic values of hydroelectric production plus operating reserves that have been observed during weekday peak demand hours. Hydroelectric production is monitored on a monthly basis and due allowance is made for the median historical values when drought conditions are expected in the midterm forecasts. However, it is expected that the production would bounce back to median levels for the longer time frame.

The renewable resources target for wind, solar, and bioenergy is 10,700 MW by 2018, 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 9,000 MW by 2018. A substantial amount of renewable generation is embedded and included in the demand forecast. This will be achieved through the development of new facilities and significant investments to upgrade Ontario's existing facilities. As described in the Generation section, the operational and adequacy concerns of integration of new variable generation are addressed through RII.

IESO includes a quantity of demand measures termed the “Reliably Available Capacity” in its reliability analyses. This does not represent the total registered capacity of DR programs. For market-based programs, IESO uses historical information to ascertain the amount of DR capacity that is typically bid into the market at the time of the weekly peak demand. For programs that have contracts, IESO uses both historical information and contract information in order to determine the quantity of Reliably Available Capacity. As mentioned in the DSM section, the quantity of reliable capacity was significantly reduced after the introduction of the GAA.

IESO’s initial studies indicated that there is no threat to system reliability based on the projected distribution connected generation. The majority of the generation is solar, small scale, and geographically diverse. These factors combine to mitigate much of the variability in the generation output.

As a result of the increase in the level of penetration of variable generation combined with the return of two units at Bruce Nuclear Generating Station, potential surplus energy is expected to continue well into the decade. Potential surplus energy conditions, referred to as surplus Base Load generation, are expected to be significantly reduced when the nuclear refurbishment programs begin. A vast majority of surplus Base Load generation is being managed via IESO tools and processes, such as nuclear maneuvering and managing inter-tie trades. In September 2013, IESO gained another tool to help manage surplus Base Load generation as wind became a dispatchable resource and helps maintain market efficiency.

The Ontario government has implemented GHG emissions targets for coal-powered generation between 2013 and 2014, ensuring that annual emissions are two-thirds lower than 2003 levels. Moving forward, Ontario’s low carbon portfolio mix has the potential for producing surplus energy. As described earlier, potential surplus energy conditions are expected to significantly diminish when nuclear refurbishment programs begin. A low carbon portfolio will also increase operability complexities. Increases in wind resources in the system increases the ramping requirements during periods when demand picks up and wind output drops off. Traditionally, coal-fired generation contributed to ramping flexibility, but that capability will be reduced with the coal phase-out. In the years ahead, gas-fired generation will play an important role in Ontario's balance supply mix, providing the flexibility to cushion the electricity system when demand and intermittent resources rise or fall.

With the growth in conservation savings and embedded generation capacity, demand forecasting has become increasingly more complex. Additionally, the introduction of 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.

Technological change is always challenging to capture in long-term forecasts. IESO is evaluating two pilot project storage technologies. The success of these programs could provide further growth in storage capacity within Ontario. To date, the time-shifting impacts have not been factored into the demand forecast but, if widespread, could impact the hourly demand profile. Other unforeseen technological changes may also present forecasting challenges.

Asset renewal is a systematic approach for continuous modernization of aging energy infrastructure. Much of the current power system infrastructure, be it 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 plan is required to coordinate the renewal of infrastructure to manage reliability, environmental, and cost impacts.

Within the next 10 years, nuclear units at the Bruce, Darlington, and Pickering facilities reach the end of their service lives and will be taken out of service for refurbishment or retirement. Elsewhere, some transmission and distribution components are over 80 years old and require upgrading. Although owners have programs in place for asset renewal, the overall scope of the problem is what presents the challenge. Moreover, challenges can be expected in the coordination between parties and the competition for resources from other major nonelectrical infrastructure developments.

NPCC-Québec

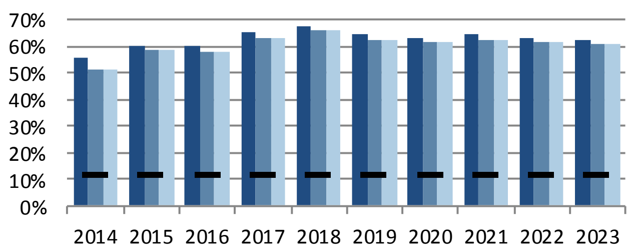
The Québec Assessment Area (Québec Area) is a NERC subregion in the northeastern part of the NPCC Region, covering 643,803 square miles with a population of eight million (province of Québec). The Area is winter peaking and one of the four NERC Interconnections in North America with ties to Ontario, New York, New England, and the Maritimes, consisting either of HVdc ties or radial generation or load to and from neighboring systems.

Planning Reserve Margins

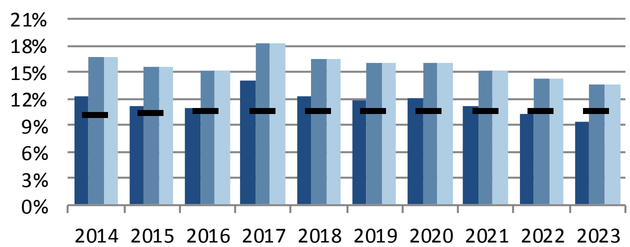
NPCC-Québec-Summer		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ANTICIPATED		55.63%	60.20%	59.81%	64.97%	67.82%	64.28%	63.44%	64.41%	63.41%	62.29%
PROSPECTIVE		51.35%	58.33%	57.95%	63.12%	65.99%	62.48%	61.66%	62.64%	61.65%	60.54%
ADJUSTED POTENTIAL		51.35%	58.33%	57.95%	63.12%	65.99%	62.48%	61.66%	62.64%	61.65%	60.54%
NERC REFERENCE	-	**12.00%**	**12.00%**	**12.00%**	**12.00%**	**12.00%**	**12.00%**	**12.00%**	**12.00%**	**12.00%**	**12.00%**

NPCC-Québec-Winter		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ANTICIPATED		12.39%	11.17%	10.90%	13.96%	12.19%	11.76%	11.97%	11.10%	10.24%	9.50%
PROSPECTIVE		15.35%	14.11%	13.80%	16.84%	15.01%	14.56%	14.74%	13.85%	12.97%	12.21%
ADJUSTED POTENTIAL		15.35%	14.11%	13.80%	16.84%	15.01%	14.56%	14.74%	13.85%	12.97%	12.21%
NERC REFERENCE	-	**10.30%**	**10.50%**	**10.70%**	**10.70%**	**10.70%**	**10.70%**	**10.70%**	**10.70%**	**10.70%**	**10.70%**

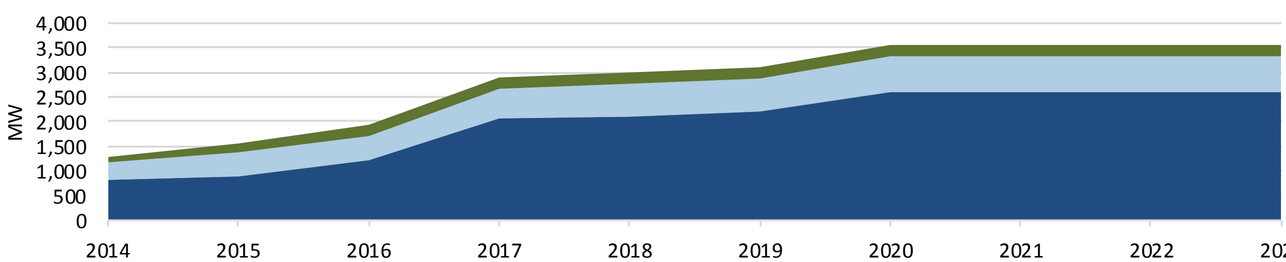
Summer



Winter



Cumulative 10-Year Planned Capacity Change



		2013 Existing		2023 Planned			2023 Planned & Conceptual		
NPCC-Québec		Capacity (MW)	Share (%)	Capacity (MW)	Share (%)	Change (MW)	Capacity (MW)	Share (%)	Change (MW)
Coal		0	0.0%	0	0.0%	0	0	0.0%	0
Petroleum		436	1.1%	436	1.0%	0	436	1.0%	0
Gas		0	0.0%	0	0.0%	0	0	0.0%	0
Nuclear		0	0.0%	0	0.0%	0	0	0.0%	0
Hydro		38,276	97.0%	40,877	95.0%	2,601	40,877	95.0%	2,601
Pumped Storage		0	0.0%	0	0.0%	0	0	0.0%	0
Geothermal		0	0.0%	0	0.0%	0	0	0.0%	0
Wind		483	1.2%	1,213	2.8%	730	1,213	2.8%	730
Biomass		254	0.6%	483	1.1%	229	483	1.1%	229
Solar		0	0.0%	0	0.0%	0	0	0.0%	0
TOTAL		**39,449**	**100.0%**	**43,009**	**100.0%**	**3,561**	**43,009**	**100.0%**	**3,561**

Demand, Resources, and Planning Reserve Margins

The Reference Reserve Margin Levels are drawn from the Québec Area's 2012 Interim Review of Resource Adequacy, which was approved by NPCC's Reliability Coordinating Committee on November 27, 2012. These levels vary between 10 and 11 percent during the four-year planning assessment.

The Québec Area demand forecast has decreased compared to the *2012LTRA* reference case, reaching -1,000 MW for the 2015–2016 winter peak period. This decline in the demand forecast is mainly attributed to lower than expected load from the industrial sector.

Energy efficiency and conservation programs and energy saving trends are accounted for directly in the assessment area's demand forecasts and count for 2,150 MW toward the 2014–2015 winter peak demand. Energy efficiency and conservation programs are implemented throughout the year by Hydro-Québec Distribution and by the provincial government through its Ministry of Natural Resources. Energy efficiency will continue to grow throughout the assessment period.

DR programs in the Québec Area—specifically designed for peak load reduction during winter operating periods—are interruptible demand programs (for large industrial customers), totaling 1,439 MW for the 2014–2015 winter period. DR is usually used in situations in which load is expected to reach high levels or when resources are not expected to be sufficient to meet load at peak periods. DR is considered as a resource and is relatively stable during the assessment period, with a maximum reached for the 2014–2015 winter peak period then settling down to 1,300 MW starting at the 2019–2020 winter period. The total on-peak DR and Energy Efficiency and conservation for the 2023–2024 winter period is projected to be approximately 4,900 MW.

There are no significant unit retirements planned during the assessment period. A few small hydroelectric projects, totaling 80 MW, have been cancelled by the provincial government. TransCanada Energy's 547 MW natural gas combined-cycle power plant in Bécancour is mothballed. Each summer, Hydro-Québec Distribution must decide whether to mothball the Bécancour power plant for an additional year or restart it for the coming year. Although this plant is expected to be mothballed until December 2020, it could be restarted sooner if needed. For that reason, it accounts for the total Existing-Other resources. On the other hand, hydro generator uprates will be adding close to 500 MW of capacity during the assessment period. Behind-the-meter generation is negligible and is accounted for in the load forecast.[139]

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 840 MW and 1,210 MW respectively for the 2014–2015 and 2023–2024 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.

Wind generation integration has not significantly impacted day-to-day operation of the system, and the actual level of wind generation does not require particular operating procedures. However, with the increasing amount of wind in the system, the foreseeable impact on system management may show up.

Currently, the studies are underway, examining the following issues (1) wind generation variability on system load and interconnection ramping; (2) frequency and voltage regulation problems; (3) increase of start-ups and shutdowns of hydroelectric units due to load following coupled with wind variability; (4) expected efficiency losses in generating units;

[139] When calculating on-peak capacity values for hydro resources, maximum capacity is set equal to the power that each plant can generate at its maximum rating during two full hours, while expected on-peak capacity is set equal to maximum capacity minus scheduled maintenance outages and restrictions.

and (5) reduction of low load operation flexibility due to low inertia response of wind generation coupled with must-run hydro generation.

Expected capacity purchases are planned as needed for the Québec internal demand by Hydro-Québec Distribution. 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 (UCAP) in order to meet its capacity requirements, if needed. The Québec Area does not rely on any emergency capacity imports to meet its Reserve Margin Reference Level. The Québec Area will support firm capacity sales totaling 626 MW to New England and Ontario (Cornwall) during the 2014–2015 winter peak period, backed by firm contracts for both generation and transmission, declining to 145 MW in 2020.

Transmission and System Enhancements

ROMAINE RIVER HYDRO COMPLEX INTEGRATION

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

For 2014, main system upgrades for this project will require construction of a new 735-kV switching station to be named "Aux Outardes" and located between existing Micoua and Manicouagan Transformer Stations. Two 735-kV lines will be redirected into the new station and one new 735-kV line (5 km or 3 miles) will be built between Aux Outardes and Micoua.

BOUT-DE-L'ÎLE 735-KV SECTION

Hydro-Québec TransÉnergie (TransÉnergie) is adding a new 735-kV section at Bout-de-l'Île substation (located at east end of Montréal Island). This was originally a 315/120-kV station. The Boucherville – Duvernay line (line 7009), which passes by Bout-de-l'Île, will be looped into the new station. A new -300/+300-Mvar SVC will be integrated into the 735-kV section in 2013.

The project also includes the addition of two 735/315-kV 1,650-MVA transformers in 2014. This new 735-kV source will allow redistribution of load around the Greater Montréal area and absorb load growth in eastern Montréal. This project will enable future major modifications to the Montréal area regional subsystem. Many of the present 120-kV distribution stations will be rebuilt into 315-kV stations and the Montréal regional network will be converted to 315-kV. The addition of a second -300/+300-Mvar SVC at Bout-de-l'Île in 2014 is also projected.

CHAMOUCHOUANE–MONTRÉAL 735-KV LINE

Planning studies have shown the need to consolidate the transmission system with a new 735-kV line in the near future. Generation additions (such as the Romaine Complex and wind generation) and new transmission services are the reason the new line is warranted. The line will extend from the Chamouchouane substation on the eastern James Bay subsystem to the Duvernay substation just north of Montréal (about 400 km or 250 miles).

Planning, permitting, and construction delays are such that the line is scheduled for the 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 new line will also reduce transfers on other parallel lines on the Southern Interface, thus optimizing operation flexibility and reducing losses.

OTHER 735-KV PROJECTS

Additionally, a 735-kV series compensation upgrade at Bergeronnes switching station is scheduled for 2014.

THE NORTHERN PASS TRANSMISSION PROJECT

This project will increase interconnection transfer capability between Québec and New England by 1,200 MW and is now being studied. The project involves construction of a ±300-kV dc transmission line about 75 km (46 miles) long from Des Cantons 735/230-kV substation to the Canada–United States border. This line will extend to a substation 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. Permitting for this project is presently ongoing. The initial planned in-service date (fall 2015) has been re-evaluated to 2017–2018.

THE CHAMPLAIN-HUDSON POWER EXPRESS PROJECT

This project will increase interconnection transfer capability between Québec and New York by 1,000 MW and is now under study. The project involves construction of ±320-kV dc underground transmission line about 50 km (31 miles) long from the Hertel 735/315-kV substation just south of Montréal to 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 two 550-MW converters at Hertel and a 320-kV dc switchyard. Permitting for this project is presently ongoing. The planned in-service date is fall 2017.

WIND GENERATION INTEGRATION PROJECTS

Hydro-Québec Distribution has issued different calls for tenders for wind generation in past years. A total of approximately 3,350 MW (including wind generation already in-service) is forecasted to be on-line in 2015. A number of wind transmission projects with voltages ranging from 120-kV to 315-kV are either under construction or in planning stages to integrate this wind generation. These wind generation projects are distributed in many areas of Québec, but most are near the shores of the Gaspésie Peninsula, along the Gulf of St. Lawrence down to the New Brunswick border.

OTHER 735-KV CONCEPTUAL PROJECTS

The subregion is planning a new 735/315-kV transformer station near the existing Lebel 315/120-kV station in the Abitibi region of the system. This will consolidate the Abitibi subsystem, which presently has a 120-kV infrastructure with a 315-kV feed at Lebel and Figuery substations. A new 142-km (88-mile), 735-kV line is projected from Abitibi 735-kV station on the western James Bay system to feed this new station. Two 735/315-kV, 1650-MVA transformers and four 315-kV line feeders will complete the station. The projected in-service date is fall 2018, but this may vary depending on the projected industrial loads in the area.

UPCOMING REGIONAL PROJECTS

There are a number of regional projects now underway. The three important projects scheduled for fall 2014 are:

- Charlesbourg 315/25-kV substation and 315-kV transmission (Québec City)
- Lefrançois 315/25-kV substation and 315-kV transmission (Québec City)
- St-Césaire–Bedford 230-kV, double-circuit line (Eastern Townships to upgrade feed to Highgate)

Other regional substation and line projects are now in the planning and 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 2013 to 2018, consisting mostly of replacing the 120-kV and 69-kV infrastructure with 315/25-kV and 230/25-kV satellite (distribution) substations. Other regional upgrade projects (i.e., in the Abitibi and Manicouagan subsystems) will also be commissioned in the upcoming years.

Planning studies leading to system enhancement projects, such as those mentioned above, ensure that there will be no long-term transmission constraints in the assessment area. Generation on the system is integrated on a 100 percent firm basis.

SYSTEM ENHANCEMENTS

In the Québec Interconnection, load shedding caused by an under voltage is initiated by a specific remote UVLS named TDST. A maximum of 1,500 MW is targeted by TDST. It has been designed to operate following contingencies involving the loss of two or more 735-kV lines. Contingencies range from the loss of two parallel 735-kV lines to the loss of a 735-kV line with series compensation bypass on parallel lines. These contingencies do not require more than 1,500 MW of load shedding, although TDST operates on a pre-defined pool of 2,500 MW located in the Montréal Area. The last NPCC Comprehensive Review Assessment of the Québec transmission system for the year 2017—conducted by TransÉnergie (approved by NPCC June 2013)—shows that TDST is adequate to preserve system stability after the contingencies for which it is designed.

No additional load is expected to be assigned to UVLS during the next 10 years.

There are no plans to install SPSs or Remedial Action Schemes in lieu of planned bulk power transmission facilities in the Québec Area.

Hydro-Québec intends to deploy a number of new technologies, systems, and tools (including smart grid incentives) to improve future BPS reliability. Government policies and targets for renewable energy integration, Energy Efficiency, electric or rechargeable hybrid vehicles, and GHG emission reductions are among the major drivers for the development of smart grid programs.

TransÉnergie's system consists of an extensive 735-kV network with 315-kV, 230-kV, 120-kV, and 69-kV underlying subsystems totaling 33,639 km (i.e., 20,902 line miles). 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 includes additional criteria that consider system topology and substation characteristics particular to TransÉnergie's system (complementary contingencies) and address voltage sensitivity to load variation and interconnection ramping. SPSs to ensure reliability (for extreme events) are presently in use and will continue to be used. These include Remote Generation Rejection and Load Shedding (RPTC SPS), Undervoltage Remote Load Shedding (TDST SPS), and Under Frequency Load Shedding.

Other technologies such as synchronous condensers, SVCs, 735-kV series compensation, multi-band power system stabilizers (MBPSSs), HVdc systems, and a variable frequency transformer (VFT) are in use. Such systems are planned for future system upgrades or for generation integration as needed.

In order to upgrade transfer capability and improve system reliability, another project is aimed at regulation systems and SPS improvement. This includes installation of MBPSSs in a great number of generating stations, new regulation circuits for the dynamic shunt compensation equipment, new relaying for SPSs, new control strategies for HVdc converters, development of severity indices for angular and voltage stability, etc. The project also includes the potential introduction of a type of global regulation for dynamic shunt equipment (as opposed to regulation based on local parameters) employing measurement units, a data concentrator, control units, all linked by synchronized digital communications.

For more than two decades now, TransÉnergie has been operating an angular displacement measuring system to accurately monitor and register system frequency and angular displacement between major generating stations and load centers. This is used for online reporting and provides priceless data for all system events involving frequency variations and angular displacements. The system also measures voltage and current distortion and is quite valuable for monitoring harmonic content during solar magnetic disturbances (SMDs).

No smart grid programs have been fully implemented at Hydro-Québec during the past year. In 2013, the IMAGINE project, which involves automated maintenance and enhanced processing of monitoring data, is still ongoing. This project, which focuses first and foremost on power transformers, will enable TransÉnergie to optimize target maintenance efforts to prevent equipment failures and improve system reliability. The IMAGINE program is carried out with Hydro-Québec Research Institute (IREQ), Hydro-Québec's research center, with the help of industrial partners.

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 two 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.

Also, as a member of the Western Climate Initiative, the Province of Québec implemented a cap-and-trade system in 2012, with compliance beginning January 1, 2013. Given the significant proportion of renewable generation in the Québec Area, this new regulation will not impact reliability in the Québec Area.

However, there are several important issues that may impact system reliability during the assessment period. While there is no doubt that during recent years technical developments have contributed to creating a more reliable system, sustainable system reliability may be challenged by several issues. The two issues described and analyzed below are considered as standing reliability issues.

WIND PLANT INTEGRATION TO GRID

As a separate NERC Interconnection, the Québec Area is responsible for its own frequency regulation. System inertia is quite low compared to the Eastern Interconnection, for example. Large post-contingency frequency excursions—up to ±1.5 Hz—can occur after normal contingencies, and operating limits related to post-contingency frequency behavior are required.

Through 2015, Hydro-Québec will have integrated around 3,350 MW of nameplate wind capacity. This kind of large-scale wind capacity integration on the system has triggered a need for frequency support by wind plants as it displaces conventional hydro generation that inherently provides inertia. In order to maintain present system performance, TransÉnergie (the Transmission Planner) has requested from manufacturers an inertia emulation function that would cover lack of inertia and spinning reserve from modern variable speed wind turbine generators. In 2012, the first wind plants able to provide this function were commissioned. TransÉnergie is now beginning to observe and assess the performance of the inertia emulation function for real system events. Further studies are needed to implement fine-tuning of the feature. Inertia emulation is required for Hydro-Québec’s wind generation resulting from the second and third calls for tenders, totaling 2,295 MW of capacity.

EQUIPMENT AGING AND SUSTAINABILITY

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

Significant investment cuts, personnel and equipment availability for maintenance outages as well as new projects, and system availability for outages are all issues that could impact reliability in the context of equipment aging.

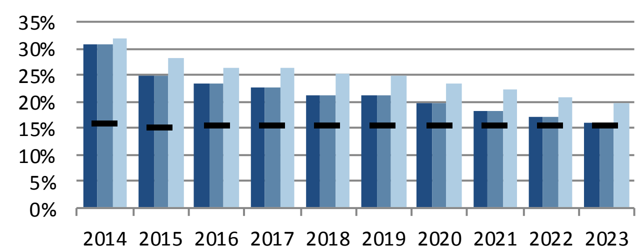
PJM

PJM Interconnection is an RTO that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. Acting as a neutral, independent party, PJM operates a competitive wholesale electricity market and manages the high-voltage electricity grid to ensure reliability of an area that spans 214,000 square miles and serves more than 60 million people. PJM's long-term regional planning process provides a broad, interstate perspective that identifies the most effective and cost-efficient improvements to the grid to ensure reliability and economic benefits on a system-wide basis. PJM is the Planning Coordinator, RC, and BA for the entire PJM Region.

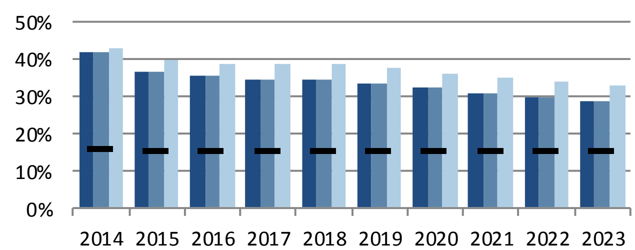
Planning Reserve Margins

PJM-Summer		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ANTICIPATED		30.86%	24.93%	23.40%	22.67%	21.39%	21.07%	19.66%	18.30%	17.11%	15.93%
PROSPECTIVE		30.86%	24.93%	23.40%	22.67%	21.39%	21.07%	19.66%	18.30%	17.11%	15.93%
ADJUSTED POTENTIAL		32.04%	28.08%	26.43%	26.52%	25.28%	25.05%	23.58%	22.18%	20.96%	19.73%
NERC REFERENCE	-	**15.90%**	**15.30%**	**15.60%**	**15.60%**	**15.60%**	**15.60%**	**15.60%**	**15.60%**	**15.60%**	**15.60%**
PJM-Winter		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ANTICIPATED		42.04%	36.60%	35.54%	34.49%	34.61%	33.68%	32.16%	30.94%	29.89%	28.91%
PROSPECTIVE		42.04%	36.60%	35.54%	34.49%	34.61%	33.68%	32.16%	30.94%	29.89%	28.91%
ADJUSTED POTENTIAL		42.99%	39.98%	38.58%	38.51%	38.59%	37.78%	36.22%	34.96%	33.88%	32.87%
NERC REFERENCE	-	**15.90%**	**15.30%**	**15.60%**	**15.60%**	**15.60%**	**15.60%**	**15.60%**	**15.60%**	**15.60%**	**15.60%**

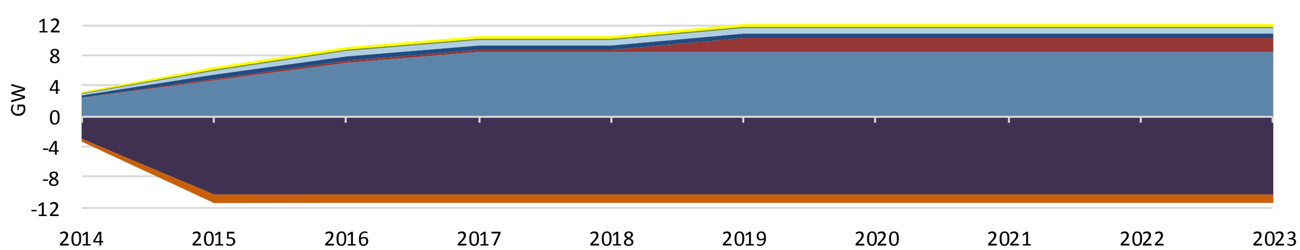
Summer



Winter



Cumulative 10-Year Planned Capacity Change



		2013 Existing		2023 Planned			2023 Planned & Conceptual		
PJM		Capacity (MW)	Share (%)	Capacity (MW)	Share (%)	Change (MW)	Capacity (MW)	Share (%)	Change (MW)
Coal		76,540	41.3%	66,264	35.6%	-10,276	68,168	30.0%	-8,372
Petroleum		12,208	6.6%	11,104	6.0%	-1,104	11,106	4.9%	-1,102
Gas		52,783	28.5%	61,274	33.0%	8,491	97,676	42.9%	44,893
Nuclear		33,771	18.2%	35,616	19.2%	1,845	36,389	16.0%	2,618
Hydro		2,683	1.4%	3,265	1.8%	582	3,367	1.5%	684
Pumped Storage		5,145	2.8%	5,145	2.8%	0	5,145	2.3%	0
Geothermal		0	0.0%	0	0.0%	0	0	0.0%	0
Wind		872	0.5%	1,578	0.8%	706	3,607	1.6%	2,736
Biomass		1,107	0.6%	1,292	0.7%	186	1,528	0.7%	421
Solar		55	0.0%	407	0.2%	352	512	0.2%	456
TOTAL		**185,164**	**100.0%**	**185,944**	**100.0%**	**781**	**227,499**	**100.0%**	**42,335**

BOUNDARY CHANGE

This year's report includes the load and generation of Duke Energy Ohio/Kentucky (DEOK), which was integrated into the PJM regional transmission organization (RTO) on January 1, 2012, and the generation and load of East Kentucky Power Cooperative (EKPC), which was integrated into PJM on June 1, 2013.

Demand, Resources, and Planning Reserve Margins

The PJM RTO Reserve Requirement is 15.9 percent for the 2014–2015 planning period, which runs from June 1, 2014, through May 31, 2015. The PJM RTO Reserve Requirement is 15.3 percent for the 2015–2016 planning period, which runs from June 1, 2015, through May 31, 2016. The PJM RTO Reserve Requirement is 15.6 percent for the 2016–2017 planning period through the end of the LTRA assessment period. For more information, see the 2012 PJM Reserve Requirement Study.[140] The PJM RTO will have an adequate Anticipated Reserve Margin and the Adjusted-Potential Resources Reserve Margin is above the PJM Reserve Requirement though the entire assessment period.

With the exception of the addition of EKPC demand on June 1, 2013, the demand forecast for the rest of PJM has remained at a historically typical rate of 1.3 percent. DEOK was integrated into the PJM RTO on January 1, 2012, and added approximately 5,400 MW to the PJM forecast at the time. The load of EKPC added approximately 1,910 MW of load to the PJM RTO forecast.[141]

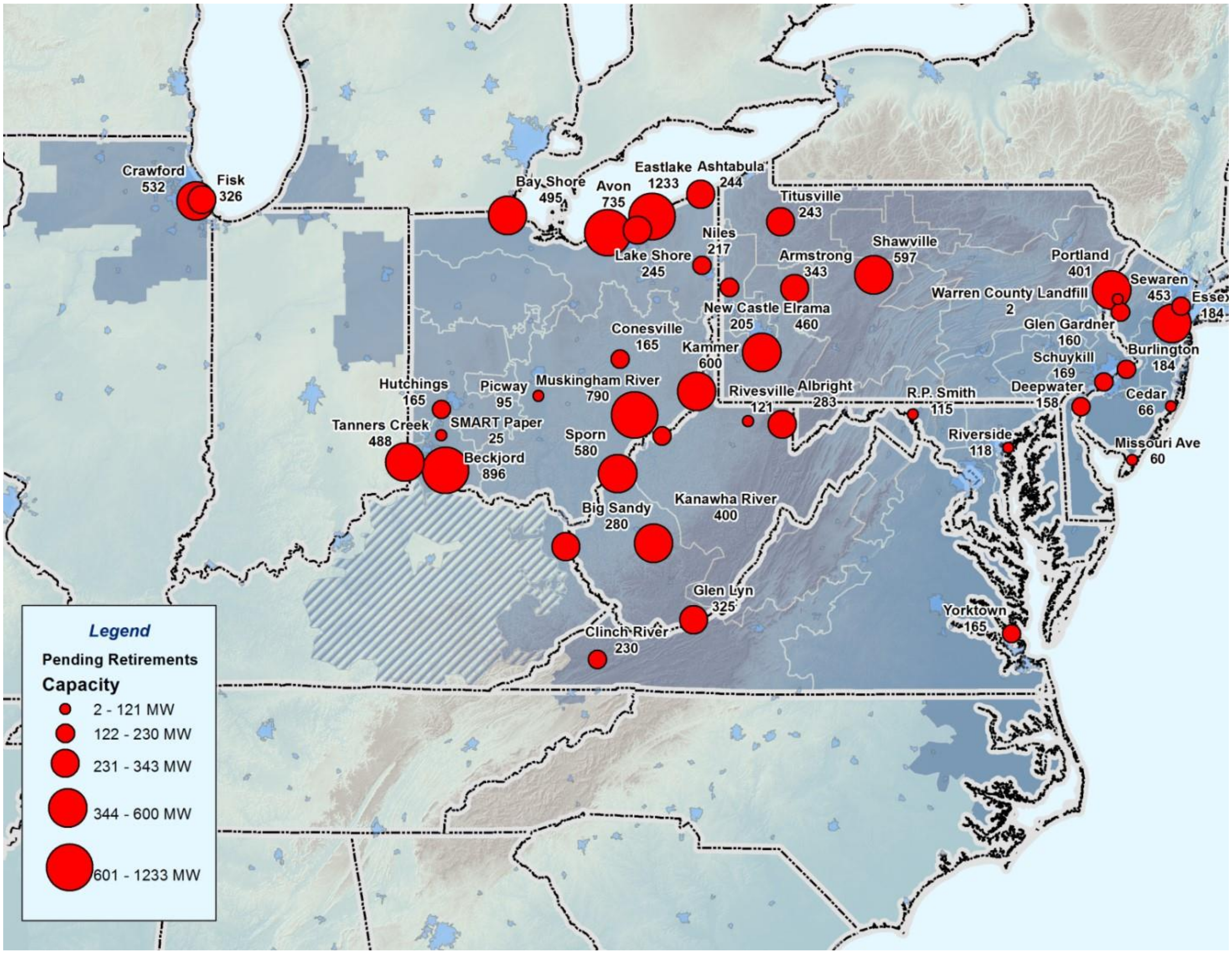
The total amount of Energy Efficiency for the PJM Area that is expected to be available on peak for summer 2014 is 924 MW. This value decreases to 891 MW in 2015 and remains constant through the end of the assessment period. Demand-Side resources available during the 2014 summer peak period are forecasted to total 11,250 MW and remain relatively constant through the entire assessment period. DSM used for reserves is limited by the RFC criteria to 25 percent of the PJM Operating Reserve requirement. This type of DSM is typically fully subscribed and can range up to approximately 2,500 MW during a peak summer day.

PJM has announced plans for over 13,000 MW (6.9 percent of the PJM Existing-Certain fleet) of generator retirements during the assessment period.[142] Of the announced retirements, approximately 9,700 MW is coal, 2,000 MW is gas, and 1,300 MW is oil-fired generation. From a Regional Transmission Expansion Plan (RTEP) perspective, generation deactivations coupled with steady load growth and sluggish generation additions can lead to the emergence of reliability criteria violations in many areas of PJM. Each generation deactivation is reviewed and any required transmission upgrades to address the transmission network reliability needs as result of the generation deactivation are included in the RTEP.

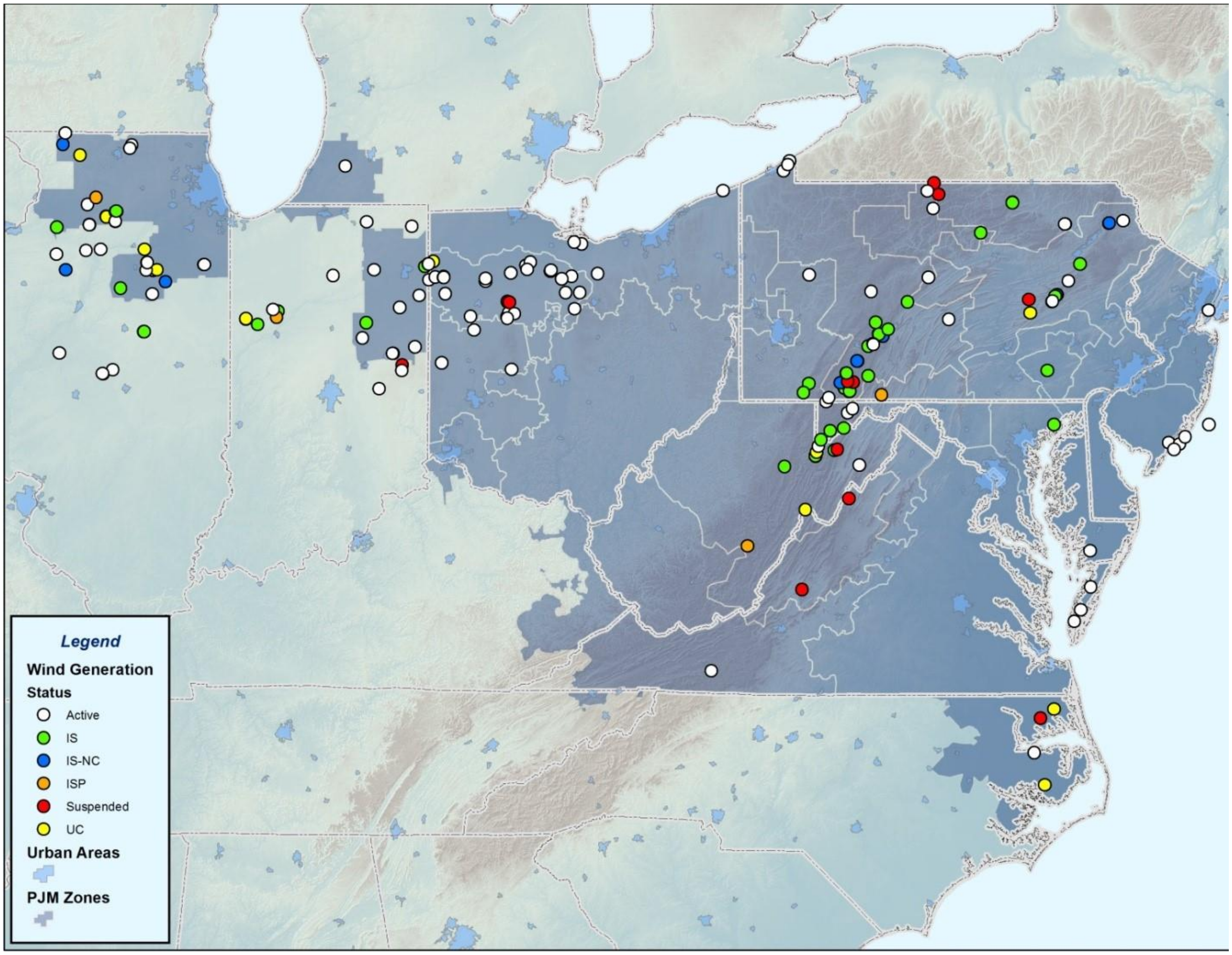
[140] PJM Reserve Requirement Study

[141] There is no change in economic outlook or weather assumptions for this year's assessment.

[142] Generator Deactivation Summary Sheets.



In the PJM RTEP analysis, generator uprates are considered exactly the same as adding a new generator. There are over 100 generator uprates in the PJM Interconnection Queue ranging from 200 MW to less than 1 MW. No significant generation is planned to be out-of-service during the peak periods. Behind-the-meter-generation is not counted as PJM capacity and has no effect on the PJM reserve margin.



Capacity transactions amount to a net import of 4,255 MW in 2014 and then increasing to 4,340 MW in 2015. In 2016, and for the remainder of the assessment period, the net import is expected to be 3,022 MW. This import is composed of specific transactions for each generator. These transactions include the firm reservation rights for the generation and firm transmission rights to transfer the power across the PJM border. All import and export contracts that are counted toward the PJM Reserve Margin are firm for both capacity and transmission service. PJM has no reliance on outside assistance for emergency imports. Capacity Benefit Margin is reserved on transmission across the PJM border but there is no reservation of capacity with our neighbors. The original transaction agreements include the firm reservation rights for the generation and firm transmission rights to transfer the power across the PJM border.

Transmission and System Enhancements

Susquehanna to Roseland

The Susquehanna–Roseland 500-kV line (Susquehanna–Lackawanna–Hopatcong–Roseland) had a required in-service date of June 1, 2012. Regulatory process delays pushed the expected in-service to June 1, 2015. In February 2010, the Pennsylvania Public Utility Commission approved the line, and the New Jersey Board of Public Utilities approved it in April 2010. The line received final approval from the National Park Service (NPS) when they issued a Record of Decision on October 2, 2012, affirming the route chosen by PPL and PSE&G; the NPS issued a Special Use (Construction) Permit on

December 12, 2012. PJM will continue to operate to double circuit tower line limits in real-time operation until the new line is placed in-service.

Mid-Atlantic Power Pathway (MAPP)

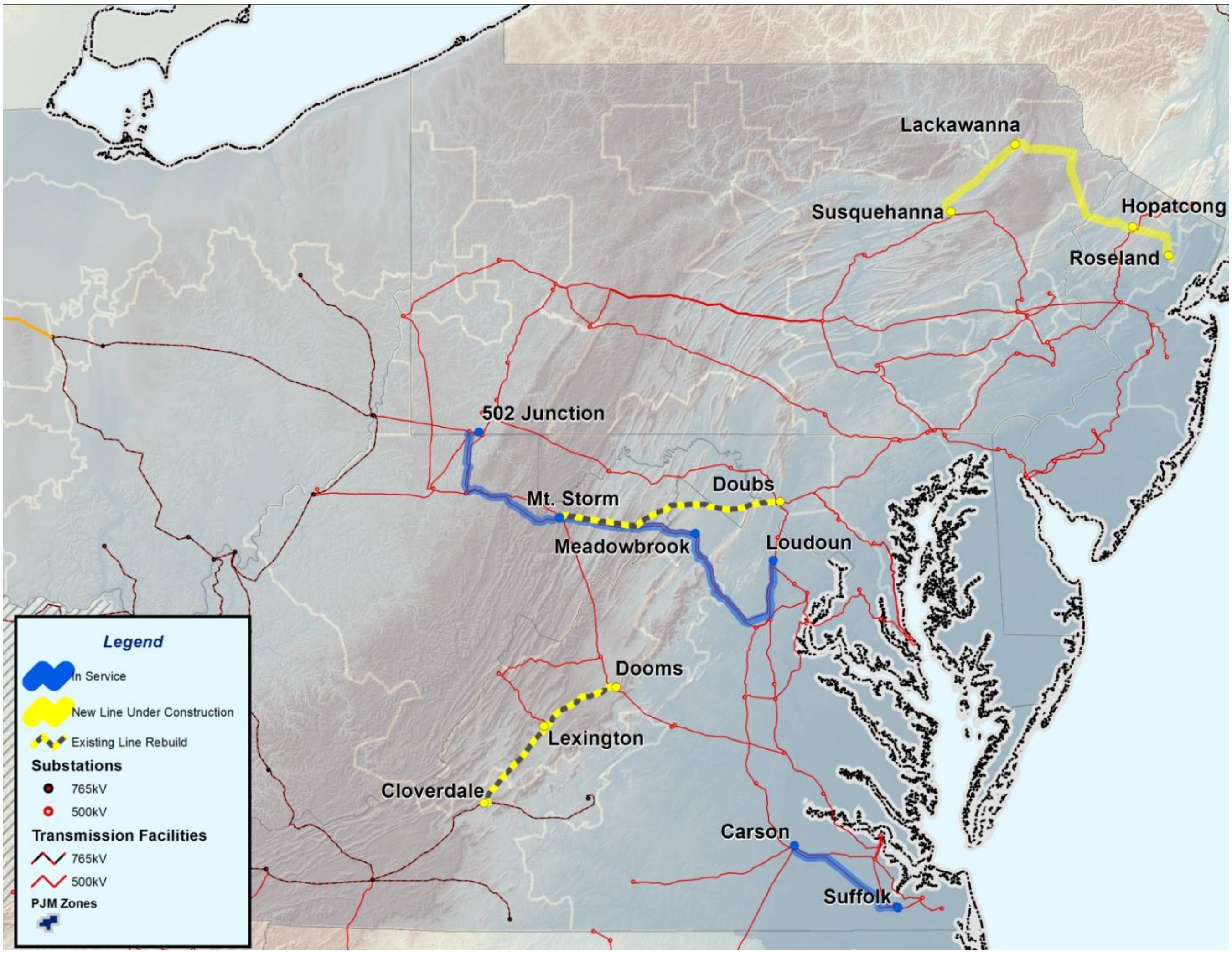
PJM's 2011 RTEP analysis, which included various generation sensitivities, indicated that the need for the MAPP 500-kV line (Possum Point–Burches Hill–Chalk Point–Calvert Cliffs–Vienna–Indian River) had moved several years into the future, beyond 2015. In 2011, the PJM Board decided to hold the project in abeyance with a 2019–2021 in-service date. On August 24, 2012, the Board formally removed the MAPP project from the PJM RTEP.

Potomac–Appalachian Transmission Highline (PATH)

PJM's 2011 RTEP analysis also indicated that the need for the PATH 765-kV line (Amos–Welton Springs–Kemptown) had moved out several years, beyond 2015. Based on these analyses, the PJM Board decided to hold the project in abeyance and requested that the TO suspend development activities. On August 24, 2012, the Board formally removed the PATH project from the PJM RTEP.

Mount Storm–Doubs

The 2011 RTEP analysis identified a required in-service date of June 2020 for the Mount Storm–Doubs line rebuild. However, recognizing the urgency of upgrading these aging facilities, Dominion indicated its intention to complete the reconductoring project by June 1, 2015. To that end, the capacity of the rebuilt line–with a rating 65 percent higher than the original—was reflected in PJM's 2017 power flow case modeling.



The Hudson Transmission Partners (HTP) Project

The HTP project—a back-to-back HVdc interconnection between PJM and New York City (New York Zone J)—went into service in May 2013. While the interconnection facility is rated at 660 MW, only 320 MW are designated for firm transmission service, with the remaining 340 MW designated for non-firm transmission service. Currently, only a small portion of the firm transmission rights (13 MW) are available because the required network transmission upgrades needed to make the full 320 MW deliverable in the PJM system will not be in-service until June 1, 2014. The remaining capability will be available for non-firm service.

Current plans include over 9,000 Mvar of reactive reinforcements that will be installed on the PJM system during the next five years. The reactive reinforcements include both static (capacitor and reactor) as well as dynamic (SVC) installations.

Planned SVCs

- 138th Street 138-kV Dayton 75 Mvar (December 31, 2013)
- Meadowbrook 500-kV FirstEnergy (AP) 600 Mvar (June 1, 2014)
- Mt. Storm 500-kV Dominion 250 Mvar (June 1, 2014)
- Hunterstown 500-kV FirstEnergy (ME) 500 Mvar (June 1, 2014)
- Altoona 230-kV FirstEnergy (ME) 250 Mvar (June 1, 2014)
- Loudon 500-kV Dominion 450 Mvar (June 1, 2014)

- New Castle 138-kV FirstEnergy (ATSI) 150 Mvar (June 1, 2015)
- Prospect Heights (Red) 138-kV ComEd 300 Mvar (June 1, 2015)
- Prospect Heights (Blue) 138-kV ComEd 300 Mvar (June 1, 2015)
- Crawford (Green) 138-kV ComEd 300 Mvar (June 1, 2016)
- Crawford (Yellow) 138-kV ComEd 300 Mvar (June 1, 2016)
- Landstown 230-kV Dominion 500 Mvar (June 1, 2016)

PLANNED FAST-SWITCHING CAPACITORS

- Mansfield 345-kV FirstEnergy (PN) 100 Mvar (June 1, 2014)
- Pleasant View 500-kV Dominion 150 Mvar (June 1, 2014)
- Jack's Mountain 500-kV FirstEnergy (PN) 100 Mvar (June 1, 2017)
- Jack's Mountain 500-kV FirstEnergy (PN) 500 Mvar (June 1, 2017)

PLANNED SERIES COMPENSATIONS

- 0.5 percent reactor in the Red Bank–Oakley 138-kV line Duke
- 3.8 ohm 138-kV reactor in Red Bank–Ashland 138-kV line Duke

PLANNED VARIABLE REACTORS

- Cedar Creek 230-kV Dayton 100 Mvar
- New Castle 138-kV Dayton 100 Mvar
- Churchland 230-kV Dominion 100 Mvar
- Shawboro 230-kV Dominion 100 Mvar

UVLS is utilized at two 138-kV buses in PJM. The relays trip approximately 25 MW of load and work in conjunction with other non-BES UVLS installations. The relays are installed to prevent voltage collapse or instability for one possible Type C (loss of two 345-kV lines) contingency and three Type D (two loss of right-of-way and one loss of substation - two voltage levels) contingencies.

Two new SPSs are planned. The first SPS is a load drop scheme that was installed on June 1, 2013 in Delmarva due to low voltage after a double contingency, voltage drop, and nonconvergence problems. The SPS will be retired when the Wye Mills–Church 138-kV line is installed on June 1, 2015. The second SPS is to sectionalize the Stanton 230-kV bus in PPL for several double-contingency losses. This SPS will go into service on November 1, 2014, and will be retired when line upgrades are completed on November 30, 2019.

Long-Term Reliability Issues

PJM has very little hydro generation and reservoir levels are adequate. PJM expects no problems with warm cooling water. Significant development of wind, solar and biomass has already occurred in PJM. Much of this development is in response to existing RPSs. The challenges of integration this variable generation will grow as more and more generation of this type is added. Demand side resources are not of a significant enough size to be of great concern for unresponsiveness. Penalties exist to make unresponsiveness financially unattractive. Distributed energy resources has been increasing in PJM especially solar installations which are mostly connected to lower voltage lines. No special operating procedures required. PJM has developed a Wind Power Forecast tool and visualization to assist operations.

PJM developed an analysis of coal generation at risk of retiring based on an assessment of required environmental retrofit costs vs. the cost of constructing a new natural gas-fired turbine. This at risk generation analysis concluded that there is no overall resource adequacy concern for the PJM footprint, however there may be localized reliability concerns that will need to be addressed either with replacement generation capacity or transmission upgrades if the impacted units are retired or need lengthy environmental retrofit outages. PJM continues to coordinate closely with PJM Generation Owners, PJM TOs and neighboring systems through the PJM Committee structure and consistent with the PJM Tariff and manuals. In order to maintain system reliability, PJM will designate units as "Reliability Must Run" if their retirement date is targeted to be in advance of required system reinforcements.

PJM requested that all impacted generation owners provide the most accurate information regarding unit retirements, environmental retrofits, unit derates and potential regulatory issues related to the environmental regulations. Combined with the publically announced unit retirements and the deactivation analysis results, PJM is utilizing this information to address short term impacts and long term projections through 2018. PJM is communicating with interconnected TOs as required to address local reliability issues, and also communicating with MISO to compare reliability analyses and coordinate outages.

At this point PJM has added the environmental retrofit outages, to the extent provided by the generation owners, to projections for maintenance outages from 2012–2018, and we are continuing to assess the impact to off-peak reliability. PJM will continue to coordinate closely to analyze the impact of retiring generation, planned outage to perform retrofits, normal generation and transmission maintenance outages as well as transmission outages required to perform planning upgrades to resulting from retiring generation.

Generation owners have indicated that while at this time there appears to be sufficient time to complete environmental retrofits, if there are delays in scheduling retrofit outages due to system constraint issues or capital budget limitations, then there may be significant challenges in completing the retrofit outages in the required time to comply with environmental regulations.

SERC-E

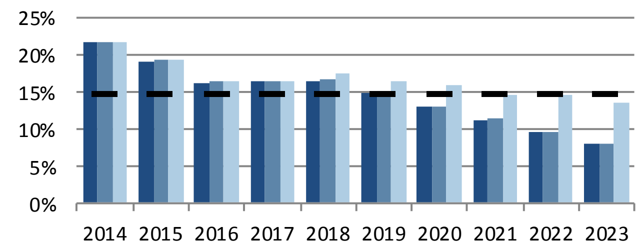
SERC-E is an assessment area covering portions of North and South Carolina, excluding SERC entities that are in PJM. The five BAs in this area are Alcoa Power Generating, Inc. – Yadkin Division (Yadkin), Duke Energy Carolinas and Duke Energy Progress (Duke), South Carolina Electric & Gas Company (SCE&G), and South Carolina Public Service Authority (SCPSA). The SERC-E Assessment Area serves about 4.4 million customers over approximately 32,000 square miles. There have been no changes to the footprint during the past two years, other than the merger of Duke Energy and Progress Energy.

Planning Reserve Margins

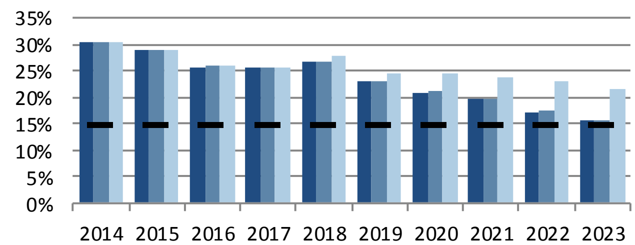
SERC-E-Summer		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ANTICIPATED		21.70%	19.15%	16.28%	16.44%	16.60%	15.00%	12.97%	11.29%	9.60%	8.04%
PROSPECTIVE		21.82%	19.28%	16.40%	16.56%	16.72%	15.12%	13.09%	11.40%	9.71%	8.15%
ADJUSTED POTENTIAL		21.83%	19.28%	16.40%	16.56%	17.56%	16.35%	16.01%	14.76%	14.68%	13.51%
NERC REFERENCE	-	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**

SERC-E-Winter		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ANTICIPATED		30.37%	28.84%	25.83%	25.65%	26.67%	22.97%	21.02%	19.80%	17.33%	15.62%
PROSPECTIVE		30.50%	28.97%	25.96%	25.77%	26.79%	23.08%	21.14%	19.92%	17.45%	15.73%
ADJUSTED POTENTIAL		30.50%	28.97%	25.96%	25.77%	27.75%	24.51%	24.49%	23.72%	23.06%	21.74%
NERC REFERENCE	-	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**

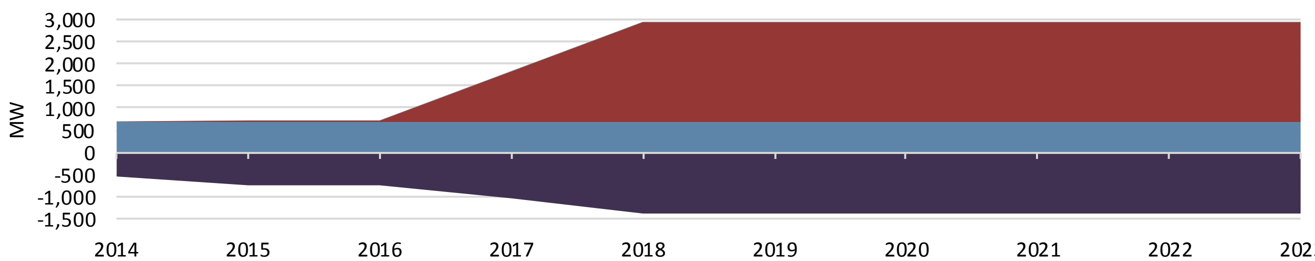
Summer



Winter



Cumulative 10-Year Planned Capacity Change



SERC-E	2013 Existing Capacity (MW)	2013 Existing Share (%)	2023 Planned Capacity (MW)	2023 Planned Share (%)	2023 Planned Change (MW)	2023 Planned & Conceptual Capacity (MW)	2023 Planned & Conceptual Share (%)	2023 Planned & Conceptual Change (MW)
Coal	17,257	33.9%	15,864	30.3%	-1,393	15,864	28.8%	-1,393
Petroleum	1,865	3.7%	1,865	3.6%	0	1,865	3.4%	0
Gas	13,941	27.4%	14,623	27.9%	682	16,752	30.5%	2,811
Nuclear	11,564	22.7%	13,831	26.4%	2,267	14,273	25.9%	2,709
Hydro	3,079	6.1%	3,079	5.9%	0	3,079	5.6%	0
Pumped Storage	3,044	6.0%	3,044	5.8%	0	3,044	5.5%	0
Geothermal	0	0.0%	0	0.0%	0	0	0.0%	0
Wind	0	0.0%	0	0.0%	0	0	0.0%	0
Biomass	97	0.2%	97	0.2%	0	98	0.2%	2
Solar	28	0.1%	28	0.1%	0	28	0.1%	0
TOTAL	**50,874**	**100.0%**	**52,430**	**100.0%**	**1,556**	**55,003**	**100.0%**	**4,129**

Demand, Resources, and Planning Reserve Margins

Generation resources are planned to ensure that Planning Reserve Margins are met. Resource plans are reviewed and revised by entities in the assessment area to achieve individual entity Planning Reserve Margins. Results show that entities are planning for reserves in the range of 14 to 20 percent for the 2014–2023 reporting period. There have been no changes made to the Reference Margin Levels since the release of the 2012 long-term assessment.

Entities in SERC-E anticipate a slightly decreasing trend in demand growth compared to last year's forecast. Differences are accounted for through lower load projections and a shift in load-serving responsibilities among entities in the area. This is due to contractual agreements scheduled between 2013 and 2019 and a lower level of energy sales due to the sluggish economy and increased conservation.

A variety of Energy Efficiency and DR programs are offered to customers in SERC-E. Some of the current Energy Efficiency, DR, and DSM programs include: interruptible capacity, load control curtailing programs, residential air conditioning direct loads, energy products loan programs, standby generator controls, residential time-of-use, interruptible and related rate structures, Power Manager Power Share conservation programs, residential Energy Star rates, Good Cents new home program, commercial Good Cents program, thermal storage cooling program, H_20 Advantage water heater program, general service and industrial time-of-use, hourly pricing for incremental load interruptible, product additions to lighting programs, new residential construction programs to address new building codes, and standards. The commitment to these programs is part of a long-term balanced strategy to meet future energy needs.[143] Entities in North Carolina include renewables in their portfolios to meet the state's Renewable Energy and Efficiency Portfolio Standard (REPS) requirement.[144] Energy Efficiency and DR programs are considered part of utility resource planning and are used as load modifiers during periods of peak demand.

The SERC-E entities have reported that some generating unit retirements will impact available capacity during the next 10 years. Some of the retirements are directly related to compliance with the EPA's new MATS. In order to minimize this impact and respond to projected growing demand, SERC-E utilities are adding new, more efficient generating units while retrofitting older units. This will result in a more efficient, environmentally friendly generating fleet, with an increased amount of nuclear and renewable capacity.

There are a small number of generator uprates during the assessment period, with no addition of nontraditional resources. SERC methods of data collection do not identify specific uprates or derates throughout the year. Rather, entities reporting to SERC make changes to unit generation continually throughout the year. These entities also use behind-the-meter generation for load modification.

Variable generation is limited within the assessment area. However, these renewable resources are assessed for reliable and economic availability, based on regulatory requirements and the utility's plan for long-term resource flexibility. The utilities will continue to evaluate these resources within their Integrated Resource Planning (IRP) process. Due to the small amount of variable resources, no changes to entity planning or operational procedures are needed.

SERC-E imports and exports have been accounted for in the reserve margin calculations, with average annual firm imports and exports of 972 MW and 1,555 MW, respectively. Most of the contracts are for a 10-year period for the winter- and summer-peaking seasons and are both internal and external to the reporting area and to the Region. All purchases are backed by firm contracts for both generation and transmission and are not considered partial path reservations. Very few imports and exports are associated with Liquidated Damages Contracts (LDCs), in which the contracts are considered 100

[143] Load response will be measured by trending Real-time load data from telemetry and statistical models that identify the difference between actual and projected consumption, absent a curtailment event.

[144] North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (REPS).

percent "make-whole." Firm transmission reservations vary in length from two to eight years, with most qualifying for roll-over rights.

The SERC-E entities do not rely on resources outside the assessment area for emergency imports, reserve sharing, or outside assistance or external resources in order to meet reserve margins during the assessment period. Most SERC-E entities participate in Reserve Sharing Agreements (RSAs) with other VACAR utilities. The members of the VACAR RSA hold 1.5 times the largest single contingency (1,135 MW) in the VACAR RSA area to meet Operating Reserve Margin targets for responding to loss of generation.

To ensure the availability of Expected imports during peak demand, neighboring entities discuss each member's daily load forecasts and expected system conditions. Coordination with neighboring assessment areas is done through standard operating procedures.

Transmission and System Enhancements

The SERC-E entities do not anticipate any long-term transmission constraints or that any current transmission project in-service dates will be at risk for the assessment period. Construction efforts are focused on facility completion ahead of the seasonal peaks. The companies monitor construction project status and continually review and confirm completion dates. Transmission projects that receive the highest priority are those which address a potential System Operating Limit or Interconnection Reliability Operating Limit. Close coordination between construction management and operations planning ensures schedule and completion requirements are understood.

To maintain and enhance reliability, Duke Energy Progress is implementing a transmission project in response to NERC's recommendation entitled "Consideration of Actual Field Conditions in Determination of Facility Ratings."[145] Duke is using Light Detection and Ranging (LiDAR) technology to analyze actual field conditions, and the project is scheduled for completion by the end of 2014.[146] The LiDAR technology has been proven accurate and dependable.

The SERC-E utilities have plans to modernize the bulk communication infrastructure, deploy PMUs to be used for events analysis, and employ strategies such as smart grid Distribution System Demand Response (DSDR) to enhance overall system reliability.

Long-Term Reliability Issues

The SERC-E utilities report that resource adequacy and operational concerns are primarily associated with fuel interruptions and water availability during droughts, even though hydro capacity is a small portion of total generating resources. To address these concerns, water levels are carefully managed. Capacity can be added and hydro reserve margins increased. These precautions are in place for future droughts, extended outages, or unavailable DR.

The SERC-E entities have incorporated the impact of current and pending environmental regulations during the upcoming peak seasons into their reliability plans. The EPA MATS regulation is forcing the potential retirement of some generating units, and studies are underway to plan for the short-term and long-term replacement of needed capacity. Since many factors influence reliability plans, no specific impact regarding a given environmental regulation can be identified at this time.

[145] NERC Recommendation to Industry: Consideration of Actual Field Conditions in Determination of Facility Ratings.

[146] The NERC recommendation to Transmission Owners and Operators, Generator Owners and Operators, Reliability Coordinators, Transmission Planner, and Planning Authorities should review the current Facility Ratings Methodology for their solely and jointly owned transmission lines to verify that the methodology used to determine facility ratings is based on actual field conditions.

SERC-N

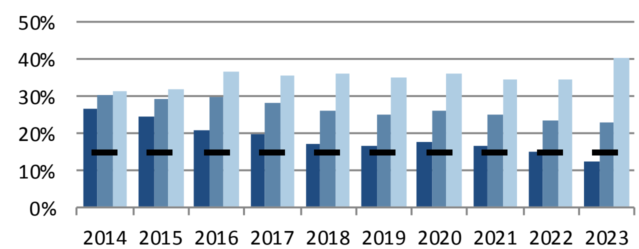
SERC-N is an assessment area covering most of Tennessee, Kentucky, northern Alabama, northeastern Mississippi, and small portions of Georgia, Iowa, Missouri, North Carolina, Oklahoma, and Virginia; this excludes the SERC entities that are in PJM. There are five BAs in SERC-N: Associated Electric Cooperative, Inc. (AECI), Constellation Energy Control and Dispatch, LLC (CECD), Electric Energy, Inc. (EEI), LG&E and KU Services Company (as agent for Louisville Gas and Electric Company and Kentucky Utilities Company, LG&E/KU), and the Tennessee Valley Authority (TVA). East Kentucky Power Cooperative (EKPC), which was previously reported in SERC-N, joined PJM on June 1, 2013, and will no longer be reported in the SERC-N Assessment Area.

Planning Reserve Margins

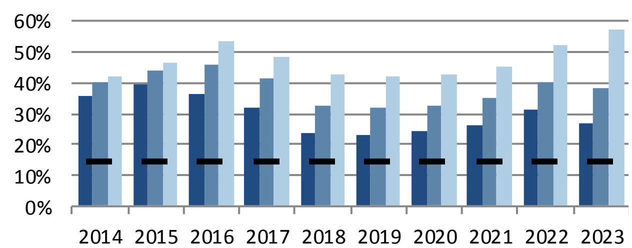
SERC-N-Summer		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ANTICIPATED		26.75%	24.73%	20.92%	19.64%	17.19%	16.45%	17.83%	16.60%	15.29%	12.49%
PROSPECTIVE		30.18%	29.18%	29.84%	28.46%	25.91%	25.07%	26.34%	25.02%	23.62%	22.80%
ADJUSTED POTENTIAL		31.61%	31.65%	36.82%	35.36%	35.94%	34.98%	36.13%	34.71%	34.49%	40.12%
NERC REFERENCE	-	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**

SERC-N-Winter		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ANTICIPATED		35.50%	39.78%	36.46%	32.14%	23.53%	23.18%	24.34%	26.42%	31.12%	27.00%
PROSPECTIVE		39.92%	44.24%	46.01%	41.39%	32.33%	31.84%	32.88%	35.11%	40.12%	38.15%
ADJUSTED POTENTIAL		42.11%	46.44%	53.28%	48.43%	42.62%	41.97%	42.87%	45.27%	52.25%	57.46%
NERC REFERENCE	-	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**

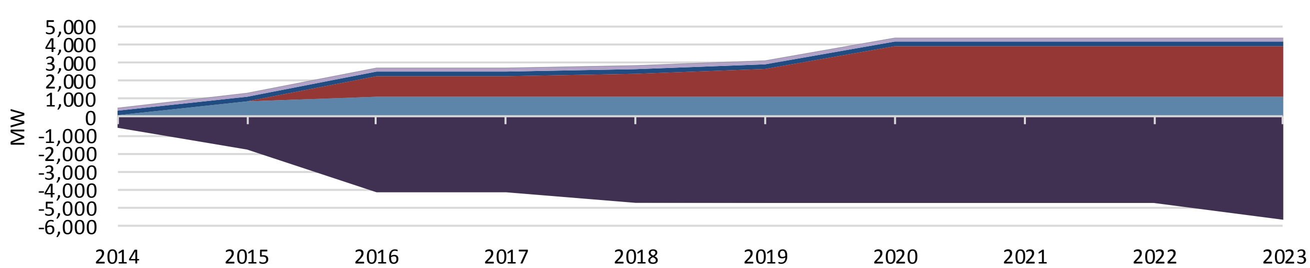
Summer



Winter



Cumulative 10-Year Planned Capacity Change



	2013 Existing		2023 Planned			2023 Planned & Conceptual		
SERC-N	Capacity (MW)	Share (%)	Capacity (MW)	Share (%)	Change (MW)	Capacity (MW)	Share (%)	Change (MW)
Coal	24,317	45.7%	18,627	35.9%	-5,690	18,627	33.3%	-5,690
Petroleum	51	0.1%	51	0.1%	0	51	0.1%	0
Gas	16,498	31.0%	17,627	34.0%	1,129	20,377	36.4%	3,879
Nuclear	6,687	12.6%	9,487	18.3%	2,800	10,747	19.2%	4,060
Hydro	4,081	7.7%	4,339	8.4%	258	4,339	7.8%	258
Pumped Storage	1,414	2.7%	1,616	3.1%	202	1,616	2.9%	202
Geothermal	0	0.0%	0	0.0%	0	0	0.0%	0
Wind	154	0.3%	154	0.3%	0	154	0.3%	0
Biomass	0	0.0%	0	0.0%	0	0	0.0%	0
Solar	0	0.0%	0	0.0%	0	0	0.0%	0
TOTAL	**53,202**	**100.0%**	**51,901**	**100.0%**	**-1,301**	**55,911**	**100.0%**	**2,709**

BOUNDARY CHANGE

Entergy, CLECO, Lafayette Utilities System, Louisiana Energy and Power Authority, Louisiana Generating LLC, South Mississippi Electric Power Association, Constellation Energy Control and Dispatch, City of Rushton, City of Osceola, Union Power Partners, Plum Point Energy Associates, City of West Memphis, City of Benton, City of Conway, and City of North Little Rock will be integrated into the MISO BA Area and the MISO Market on December 19, 2013. This transition into the MISO BA Area and MISO Market has the potential to result in significant flow changes, compared to what has historically been observed and managed on neighboring transmission systems. TVA, AECI, LG&E/KU, Southern Company, Power South, and SPP signed a temporary coordination agreement with MISO called the Operations Reliability Coordination Agreement to mitigate reliability impacts from these operational changes and initiate development of a long-term seams agreement that would alleviate reliability impacts in the long-term. MISO and the impacted entities are implementing the processes outlined in the agreement in preparation for the integration on December 19.

Demand, Resources, and Planning Reserve Margins

Generation resources are planned to ensure that Planning Reserve Margins are met. Resource plans are reviewed and revised as needed to achieve these Planning Reserve Margins. Reporting results show that entities are planning for reserves in the range of 14.5 to 29 percent during the 2014–2023 reporting period.

While system-wide projections of both energy sales and demand continue to indicate lower growth rates, planning analyses show Energy Efficiency to be a cost-effective option as a part of the long-term supply plan. Adjustments to projected impacts are made on a semi-annual basis to incorporate ongoing program performance results. At present, the focus on successful commercial and industrial efforts coupled with short-term budget constraints have produced conservative projections of energy savings with respect to estimated potential. However, the overall impact is slightly greater than the previous iteration due to a shift in focus on Energy Efficiency over DR efforts.

The SERC-N entities reported the anticipated retirement of some generating units (1,672 MW) within the next 10 years, which will impact available capacity. Some unit retirements are directly related to compliance with the EPA's MATS. In order to minimize this impact and respond to projected growing demand, SERC-N utilities are adding new, more efficient generating units (3,000 MW) during the next 10 years, retrofitting older units, and increasing purchased capacity.

All unit outage impacts have been considered in capacity and generation planning for the long-term assessment period, with no impacts to overall system reliability. As-needed purchases from the short-term markets will also ensure system reliability.

Firm capacity transactions are about 7.0 percent of the total firm peak capacity for summer 2013, assuming capacity transactions are the same as capacity transfers in the summer assessment. The majority of the firm capacity transfers are under contract for the peak season, with less than 0.4 percent of the peak firm capacity expected to be acquired under short-term contract or from the spot market. During the assessment period, firm capacity transactions average about 8.0 percent of the total firm peak capacity.

Transmission and System Enhancements

TVA has identified the C33–Marshall 161-kV line as a constraint for transfers from Ameren to TVA and from Big Rivers Electric Corporation (BREC) to Southern Illinois Power Cooperative (SIPC). This line will no longer be a constraint after its planned upgrade in summer 2014. There are no other long-term transmission constraints identified in the assessment area.

There are several planned transmission projects in the SERC-N assessment area that will increase transfer capability and, thereby, increase the reliability of the system. AECI is constructing a new West New Madrid 500/345-kV substation. This station is located on the New Madrid–Dell 500-kV transmission line, approximately a quarter mile from New Madrid.

TVA finished a facility study to interconnect two generators with 106 MW summer and 122 MW winter capabilities. Additionally, TVA identified a need for various upgrades at the interconnection substation and transmission lines of four generators with 122 MW capacity. The planned completion date for both projects is June 2015 and June 2014.

TVA plans to retire a number of fossil fuel generating units and is conducting studies to evaluate the use of SVCs and FACTS controllers and the conversion of generators to synchronous condensers to make up for the retired capacity. TVA is also evaluating HVdc wind import interconnections from the West.

The majority of utilities in SERC-N reported that there are no existing system conditions that require UVLS protection devices, which protect the system during wide-area, under voltage events. The few existing UVLS schemes cover approximately 380 MW, and the events that would cause these schemes to operate have a low probability of occurrence.

Utilities in SERC-N continue to evaluate and install new technologies that can be used to improve BES reliability. TVA continues to install PMUs across the Tennessee Valley and assess various smart grid technologies. TVA continues to install Geomagnetically Induced Current (GIC) detectors across the Tennessee Valley as part of the EPRI Sunburst program and work with the Smart Wire Group on a pilot project to install Discrete Series Reactors on transmission lines. TVA is also working with ORNL, SPX Transformer, and the University of Tennessee at Knoxville to develop a magnetic flow controller.

The SERC-N utilities continue to assess the costs and benefits of various smart grid technologies and implement those which are economically justifiable and appropriate for each system. Current projects include the:

- Development and instrumentation of a CIP and smart grid lab;
- Evaluation and integration of low-cost wireless sensors for substations;
- Design, evaluation, and integration of field data for asset management support;
- Evaluation of the Doble ARMS product for asset management support;
- Development of a Telecommunications Infrastructure Management and Monitoring Architecture;
- Use of software to improve reactive reserves management for grid operations; and,
- Development of a transformer management system using sensor data.

Long-Term Reliability Issues

The EPA MATS regulation will force the retirement of some generating units. The SERC-N entities are conducting studies to assess the short-term and long-term impact on transmission from the loss of this capacity. Based on the study results, some changes in seasonal outages and maintenance management may be necessary to maintain BES reliability. Utilities in SERC-N continue to prepare for compliance with MATS and other pending regulatory requirements by adapting current operating practices while maintaining reliability.

Utilities in SERC-N have identified three emerging issues that could potentially impact reliability during the assessment period. Utilities need to control or idle coal units as a consequence of their age, EPA regulations, or economics. Significant work is required to ensure transmission outage coordination, construction, and acquisition of replacement capacity. Unexpected consequences might result from new EPA regulations, supply mandates, or technology-related events that could limit the use of alternate fuels for generation, such as coal, natural gas, or nuclear. New planning standards may increase the complexity of planning and implementation processes. TVA and other SERC-N utilities are conducting probability studies to minimize the effect such issues could have on BES reliability.

The SERC-N Region continues to anticipate Planning Reserve Margins above minimum requirements. The Region is actively assessing and implementing smart grid technologies. The most notable emerging issue is control or idling of coal generation, which will require significant effort to coordinate transmission work with generation schedules.

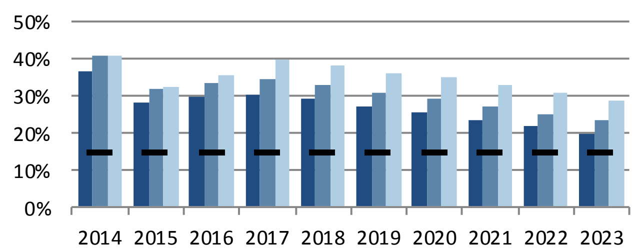
SERC-SE

SERC-SE is a summer-peaking Area covering all or portions of four southeastern states (Alabama, Georgia, Mississippi, and Florida). The four BAs in this assessment area are: PowerSouth Energy Cooperative (PowerSouth), South Mississippi Electric Power Association (SMEPA), Southeastern Power Administration (SEPA), and Southern Company Services, Inc. (Southern). SERC-SE serves about 14.2 million customers over approximately 120,000 square miles. There have been no changes to the footprint during the past two years.

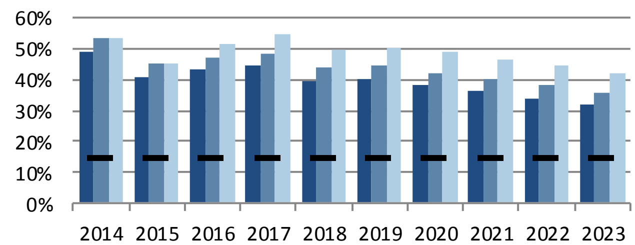
Planning Reserve Margins

SERC-SE-Summer		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ANTICIPATED		36.76%	28.01%	29.73%	30.48%	29.09%	27.08%	25.47%	23.57%	21.67%	19.78%
PROSPECTIVE		40.78%	31.96%	33.61%	34.30%	32.88%	30.81%	29.14%	27.19%	25.24%	23.29%
ADJUSTED POTENTIAL		41.03%	32.20%	35.78%	39.80%	38.33%	36.19%	35.08%	33.04%	30.99%	28.96%
NERC REFERENCE	-	**14.99%**	**14.99%**	**14.99%**	**14.99%**	**14.99%**	**14.99%**	**14.99%**	**14.99%**	**14.99%**	**14.99%**
SERC-SE-Winter		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ANTICIPATED		49.08%	40.76%	43.07%	44.29%	39.52%	40.19%	38.16%	36.11%	34.07%	32.05%
PROSPECTIVE		53.56%	45.18%	47.42%	48.61%	43.77%	44.38%	42.29%	40.18%	38.07%	36.00%
ADJUSTED POTENTIAL		53.72%	45.34%	51.41%	54.66%	49.74%	50.26%	48.76%	46.56%	44.36%	42.19%
NERC REFERENCE	-	**14.99%**	**14.99%**	**14.99%**	**14.99%**	**14.99%**	**14.99%**	**14.99%**	**14.99%**	**14.99%**	**14.99%**

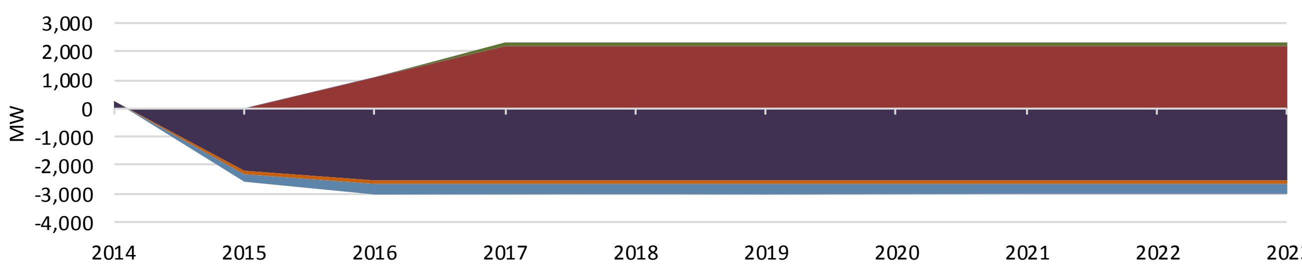
Summer



Winter



Cumulative 10-Year Planned Capacity Change



SERC-SE		2013 Existing Capacity (MW)	2013 Existing Share (%)	2023 Planned Capacity (MW)	2023 Planned Share (%)	2023 Planned Change (MW)	2023 Planned & Conceptual Capacity (MW)	2023 Planned & Conceptual Share (%)	2023 Planned & Conceptual Change (MW)
Coal		24,620	38.1%	22,074	34.5%	-2,546	22,074	33.0%	-2,546
Petroleum		1,017	1.6%	893	1.4%	-124	893	1.3%	-124
Gas		28,091	43.5%	27,737	43.4%	-354	30,650	45.8%	2,559
Nuclear		5,818	9.0%	8,018	12.5%	2,200	8,018	12.0%	2,200
Hydro		3,353	5.2%	3,353	5.2%	0	3,353	5.0%	0
Pumped Storage		1,632	2.5%	1,632	2.6%	0	1,632	2.4%	0
Geothermal		0	0.0%	0	0.0%	0	0	0.0%	0
Wind		0	0.0%	0	0.0%	0	0	0.0%	0
Biomass		67	0.1%	194	0.3%	127	248	0.4%	181
Solar		4	0.0%	4	0.0%	0	20	0.0%	16
TOTAL		**64,602**	**100.0%**	**63,905**	**100.0%**	**-697**	**66,888**	**100.0%**	**2,286**

Demand, Resources, and Planning Reserve Margins

Planning Reserve Margins are anticipated to be adequate due to a slightly decreasing demand forecast related to the economy. The demand and energy forecasts were developed using low short-term growth scenarios. SERC-SE's load growth has not yet returned to its prerecession level. As a result, the Energy Efficiency and DR levels are expected to be slightly lower than previously stated. There have been no further updates to SERC-SE's DSM programs since last year's assessment.

Energy efficiency and conservation is reflected in the load forecast using historical data. The majority of utilities in SERC-SE consider DSM a load-modifying component. Southern considers nondispatchable (passive) DSM as a load-modifying component and dispatchable (active) DR as a capacity resource. Since the *2012LTRA*, PowerSouth enhanced and expanded their H_2O plus program to reduce demand during peak periods. In July 2012, PowerSouth also added a new Energy Efficiency program that provides rebates to consumers who purchase high-efficiency heating, cooling, and lighting devices. PowerSouth is also developing a consumer financing program for residential Energy Efficiency improvements.

Few utilities in SERC-SE have limited variable resources that are evaluated by analyzing historical or projected output profiles, and no changes have been made to how these values are calculated. About 200 MW of nameplate wind capacity were added in SERC-SE. Considering the small size of this capacity relative to the whole, no operational procedure changes are needed.

The SERC-SE utilities report firm imports and exports. These transactions are considered in the SERC-SE reserve margin calculation. The majority of the contracts are multi-year firm agreements, typically lasting five or more years. All imports and exports are backed by firm contracts for both generation and transmission. Reporting entities maintain emergency reserve sharing agreements with organizations such as the SPP Reserve Sharing Group and other entities in the area (~250 MW). Other contract agreements with neighboring utilities provide capacity for outages of specific generation. The entities did not report their total emergency MW from these imports but that information is available if needed. Overall, entities are not dependent on outside imports or transfers to meet load.

Transmission and System Enhancements

PowerSouth has installed a new 115-kV capacitor bank at the Gulf Shores substation. Meanwhile, Southern is planning to install two SVCs during the long-term planning horizon. Since the *2012LTRA*, Southern fully deployed smart meters throughout its territory. These smart meters provide accurate Real-time data, which enhances demand management and helps isolate grid problems for faster restoration.

Long-Term Reliability Issues

The uncertainty of generating resource availability in 2015 and beyond due to the recent implementation of EPA MATS and other pending environmental rules presents significant reliability concern. Southern, as a Planning Authority, is working with LSEs and Generator Operators to assess resource availability and potential unit retirements. Potential additional transmission enhancements have been identified and will be reassessed during the spring planning cycle for possible inclusion in 2014 expansion plans. These assessments may also lead to requests associated with MATS implementation requirements for operating units beyond 2015, as needed to maintain reliability.

A related reliability concern involves the extensive generation and transmission construction work that must be completed prior to the implementation of MATS in 2015. The RC and Transmission Operators are working with impacted entities to coordinate construction and outage schedules to maintain reliable operations.

Because the EPA has not yet established a time frame for the implementation of pending compliance requirements, the future impact upon grid reliability is uncertain. Utilities in SERC-SE will continue to monitor environmental compliance developments and evaluate their options, including resource replacements and the installation of controls on existing generation.

SERC-W

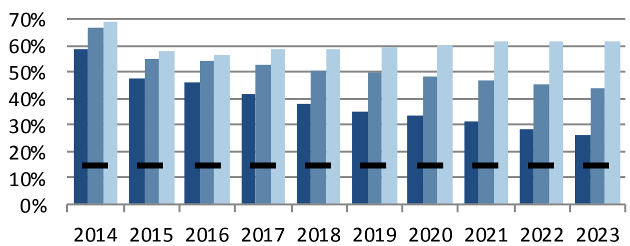
SERC-W is an assessment area covering portions of four southeastern states (Arkansas, Louisiana, Mississippi, and Texas) and including the SPP RC entities registered in SERC. The eleven registered BAs serve about 5.3 million people across approximately 91,000 square miles.

Planning Reserve Margins

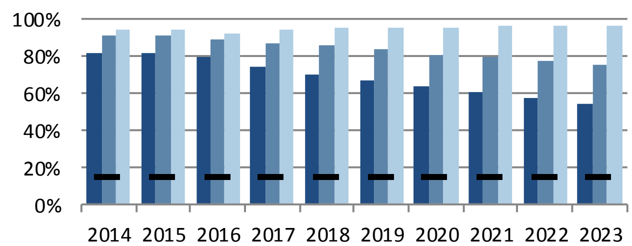
SERC-W-Summer		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ANTICIPATED		58.50%	47.96%	46.50%	41.79%	38.37%	35.34%	33.88%	31.09%	28.54%	25.93%
PROSPECTIVE		66.56%	55.35%	54.09%	52.42%	50.93%	49.46%	48.08%	46.72%	45.36%	44.09%
ADJUSTED POTENTIAL		69.03%	57.62%	56.60%	58.49%	58.98%	59.11%	59.97%	61.43%	61.28%	61.35%
NERC REFERENCE	-	**14.99%**	**14.99%**	**14.99%**	**14.99%**	**14.99%**	**14.99%**	**14.99%**	**14.99%**	**14.99%**	**14.99%**

SERC-W-Winter		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ANTICIPATED		81.8%	82.1%	79.9%	74.0%	70.4%	66.5%	63.8%	60.3%	57.3%	54.0%
PROSPECTIVE		91.1%	91.3%	89.3%	87.0%	85.7%	83.8%	81.1%	79.3%	77.6%	75.9%
ADJUSTED POTENTIAL		93.9%	94.0%	92.3%	94.3%	95.5%	95.5%	95.4%	97.0%	96.6%	96.5%
NERC REFERENCE	-	**14.99%**	**14.99%**	**14.99%**	**14.99%**	**14.99%**	**14.99%**	**14.99%**	**14.99%**	**14.99%**	**14.99%**

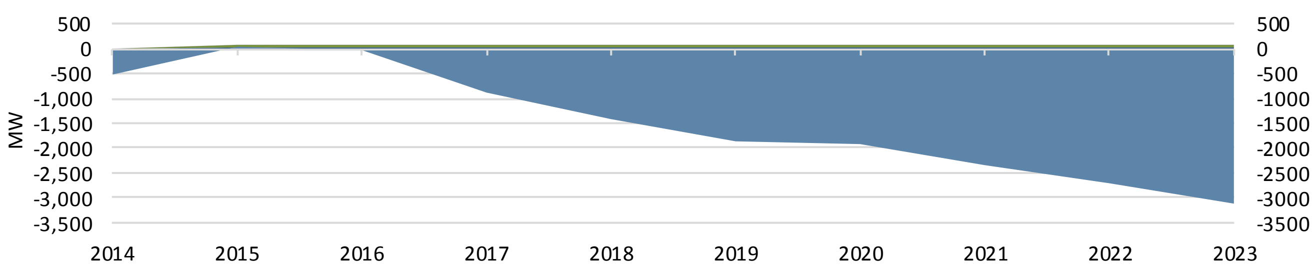
Summer



Winter



Cumulative 10-Year Planned Capacity Change



SERC-W		2013 Existing Capacity (MW)	2013 Existing Share (%)	2023 Planned Capacity (MW)	2023 Planned Share (%)	2023 Planned Change (MW)	2023 Planned & Conceptual Capacity (MW)	2023 Planned & Conceptual Share (%)	2023 Planned & Conceptual Change (MW)
Coal		6,290	16.1%	6,290	17.5%	0	6,290	15.4%	0
Petroleum		259	0.7%	254	0.7%	-5	254	0.6%	-5
Gas		26,820	68.6%	23,704	65.8%	-3,116	27,330	66.9%	510
Nuclear		5,392	13.8%	5,392	15.0%	0	5,517	13.5%	125
Hydro		311	0.8%	338	0.9%	27	607	1.5%	296
Pumped Storage		0	0.0%	0	0.0%	0	0	0.0%	0
Geothermal		0	0.0%	0	0.0%	0	0	0.0%	0
Wind		0	0.0%	0	0.0%	0	23	0.1%	23
Biomass		0	0.0%	50	0.1%	50	860	2.1%	860
Solar		0	0.0%	0	0.0%	0	0	0.0%	0
TOTAL		**39,073**	**100.0%**	**36,029**	**100.0%**	**-3,044**	**40,881**	**100.0%**	**1,809**

BOUNDARY CHANGES

Significant footprint changes will be completed by December 2013. In 2014, Entergy will be reported by MISO, and it is anticipated that several of the remaining entities in SERC-W will also join MISO. The SPP RC is working with Entergy and MISO for the transition to the MISO RC footprint and for the eventual transition into the MISO BA Area and the MISO Market. The transition to the MISO RC footprint began in June 2013, and the transition of these entities to the MISO BA and the MISO Market is expected to occur in December 2013. This transition is expected to result in significant changes in flows, as compared to what has historically been observed and managed using existing congestion management processes. SPP and MISO are evaluating ways to mitigate reliability concerns from these operational changes by improving how flows are accounted for and by reviewing congestion management techniques for potential enhancements. These coordination activities are expected to ensure the continued reliable operation of the interconnected transmission system.

Demand, Resources, and Planning Reserve Margins

While load growth remains high in a few areas of SERC-W, the overall demand forecast for the Region is down due to the economy. The exception is found in certain residential and commercial load pockets—such as Louisiana and New Orleans—where load growth is occurring due to specific industrial and commercial projects. Load growth remains high in the western portion of Entergy (Texas service area) where residential and commercial load growth is spurred by strong economic growth. Specific industrial and commercial expansion projects are also driving load growth in the Entergy Gulf States (Louisiana and New Orleans service areas).

Some utilities in SERC-W have just started implementing Energy Efficiency and conservation programs and may or may not include Energy Efficiency impacts in the load forecast, as would those entities with regulator-approved programs in place and operating. The load forecast also reflects Energy Efficiency and conservation created by evolving efficiency codes and standards. The load forecast incorporates Energy Efficiency by making an adjustment to the sales forecast prior to the development of the final forecast. , At the SERC-W utilities that use it, DR consists primarily of commercial and industrial load on interruptible rates. DR is considered a LMR that differentiates between total and firm load requirements. Long-term annual growth in DR is expected to be around 0.8 percent, in line with industrial customer demand growth. Utility-administered Energy Efficiency programs are expected to continue at current levels.

Some of the generating units in SERC-W may be deactivated during the next 10 years, based on factors such as current operating role, unit age and condition, historical and projected investment, and projected cost. Deactivation assumptions, used in the planning process, are not actual decisions regarding the future investment in resources. Unit-specific portfolio decisions (e.g., sustainability investments, environmental compliance investments, or unit retirements and betterments) are based on economic and technical evaluations that consider such factors as projected forward costs, anticipated operating roles, and the cost of supply alternatives. As a result of these dynamic factors, future decisions may differ from current planning assumptions as greater certainty is gained regarding legislative, regulatory, or economic requirements. The alternatives available to address these needs include: (1) future investments in units to keep them operational beyond assumed deactivation dates; (2) incremental long-term resource additions, such as self-supply alternatives, acquisitions, or Power Purchase Agreement (PPAs) (including contract extensions); (3) limited-term power purchase agreements; and (4) Demand-Side initiatives.

Peak imports and exports for SERC-W have been considered in the reserve margin calculations for the reporting area. Most of these contracts are 10-year agreements for the winter- and summer-peaking seasons. All imports and exports in SERC-W are firm agreements for both generation and transmission that range from one to 20 years. The SERC-W entities, most of which are members of the SPP Reserve Sharing Group, are dependent on certain imports, transfers, or contracts to meet load. Group participants within SPP generally transfer reserves into the SERC-W Area to supply generation or replace the largest generation contingency. These reserves are not relied on in the resource adequacy assessment or for capacity or Planning Reserve Margins. System operators generally coordinate reserve scheduling and transmission.

Neighboring balancing areas have interchange agreements to ensure needed imports are available during critical peak events. Under these agreements, both Real-time and day-ahead personnel are in place to coordinate imports as necessary. From a transmission perspective, Entergy coordinates with neighboring areas to ensure that adequate transfer capabilities will be available for the upcoming season's Expected imports.[147]

Transmission and System Enhancements

Currently, utilities in SERC-W do not expect any significant transmission facility outages that would impact BES reliability. A three-phase project is currently underway to construct a new 230-kV transmission line and install a new 230/115-kV autotransformer in lower Plaquemines Parish of southeastern Louisiana. The project will provide an additional transmission source to help support the underlying area's load during a single-contingency event. Loss of a single 115-kV transmission element could result in a long radial configuration causing low voltages and elements exceeding their thermal capability. Without this improvement, and due to the radial configuration during the contingency, local nonconsequential load loss in the extreme southeastern Louisiana area is required in order to eliminate any thermal and voltage violations. Phases 1 and 2 of this project have been successfully completed. However, routing issues and landowner opposition are expected to delay the final phase of the project into the second quarter of 2014 or beyond. There is also a single Extra High Voltage (EHV) connection on the western end with a neighboring system that provides some limited support, but can be constrained by autotransformer and underlying 138-kV transmission circuit limitations. Another project is underway to install additional transformer capacity at the EHV source and construct a new 230-kV transmission line from the western EHV source down to the primary load center in the western area. This project is scheduled for completion in 2016 and will address both future reliability needs and congestion issues.

Entergy is constructing a project that interconnects a new generator in the Amite South region of southern Louisiana. Utilities in SERC-W have no plans to install additional UVLS schemes, SPSs, or Remedial Action Schemes (RASs). However, Entergy is planning on modifying its existing UVLS scheme in the western area of Texas to replace its existing SCADA-based scheme with a microprocessor relay-based scheme to help improve the efficiency and reliability of the existing UVLS.

Entergy has adopted an automated critical clearing time methodology by using POM-TS software that automatically generates the critical clearing times for generating units. This will help analyze stability limits on the system under planning and operational conditions and determine the stability margin on the system. In addition, Entergy is using optimal power flow (OPF) for reactive power planning and management, which helps to assess the reactive power needs of the system. Entergy is also planning to deploy a total of 41 phasor measurement units (PMUs) to monitor abnormal system conditions and disturbances. The data obtained from the PMUs is then used in model validation and investigating corrective actions. Louisiana Generating, LLC is systematically upgrading communications with relay devices. This will assist in quickly evaluating events and system restoration.

Long-Term Reliability Issues

Utilities in SERC-W report that resource adequacy and operational concerns are mainly associated with water levels and extended generating unit outages. Scenario assessments for weather and hydro flows have been incorporated into reserve margin studies. Current operational plans mitigate the impact of drought in 2015 and beyond.

Mitigation plans also include availability and responsiveness of DR programs. For extended generating unit outages, securing a short-term capability will not have an impact on resource adequacy.

The EPA MATS regulation will have an impact on retirement or retrofitting of some generating units. Outages for planned maintenance and retrofits are carefully coordinated well in advance and—according to current timelines—will not result in reliability concerns within the SERC-W Assessment Area.

[147] Coordination is executed via participation in intra-regional (SERC Near-term Study Group [NTSG] and SERC Long-term Study Group [LTSG]) and inter-regional (ERAG MRSWS) working groups and coordination studies for the near-term and long-term capacity and resource impacts.

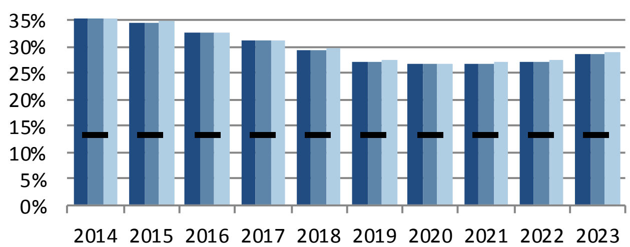
SPP

The Southwest Power Pool (SPP) Assessment Area is a NERC RE that covers 370,000 square miles and encompasses all or part of Arkansas, Kansas, Louisiana, Mississippi, Missouri, New Mexico, Oklahoma, and Texas. The SPP RE reporting footprint includes the MRO entity members that are part of the SPP Planning Coordinator, which consists of the Nebraska entities. SPP's footprint consists of 20 BA Areas including 48,368 miles of transmission lines, 915 generating plants, and 2,481 substations.

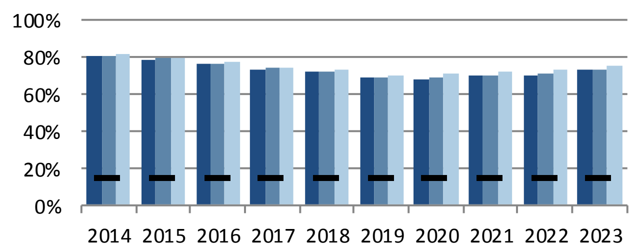
Planning Reserve Margins

SPP-Summer		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ANTICIPATED		35.71%	34.67%	32.68%	31.08%	29.49%	27.15%	26.66%	26.72%	27.14%	28.64%
PROSPECTIVE		35.67%	34.62%	32.62%	31.03%	29.43%	27.08%	26.59%	26.65%	27.06%	28.56%
ADJUSTED POTENTIAL		35.72%	34.78%	32.82%	31.28%	29.68%	27.33%	26.94%	27.02%	27.43%	28.93%
NERC REFERENCE	-	**13.60%**	**13.60%**	**13.60%**	**13.60%**	**13.60%**	**13.60%**	**13.60%**	**13.60%**	**13.60%**	**13.60%**
SPP-Winter		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ANTICIPATED		80.46%	79.00%	75.95%	73.77%	71.81%	68.66%	68.36%	69.61%	70.51%	72.93%
PROSPECTIVE		80.95%	79.48%	76.41%	74.22%	72.44%	69.28%	68.97%	70.22%	71.10%	73.52%
ADJUSTED POTENTIAL		81.55%	80.07%	77.00%	74.79%	73.21%	70.03%	71.00%	72.60%	73.48%	75.89%
NERC REFERENCE	-	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**

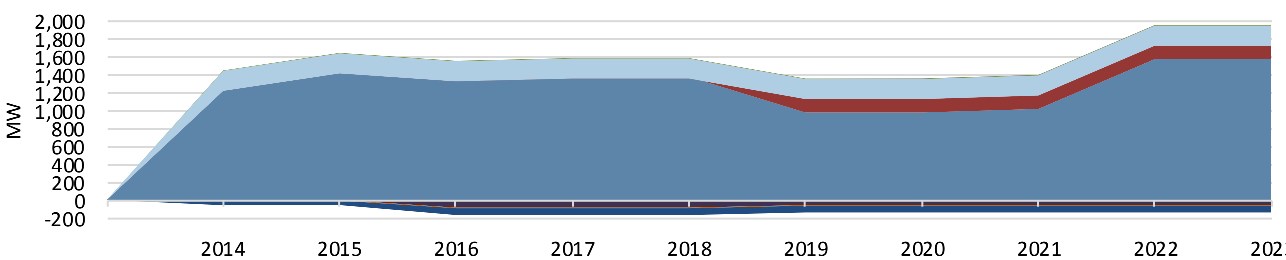
Summer



Winter



Cumulative 10-Year Planned Capacity Change



SPP		2013 Existing Capacity (MW)	2013 Existing Share (%)	2023 Planned Capacity (MW)	2023 Planned Share (%)	2023 Planned Change (MW)	2023 Planned & Conceptual Capacity (MW)	2023 Planned & Conceptual Share (%)	2023 Planned & Conceptual Change (MW)
Coal		30,026	41.3%	29,969	40.2%	-57	29,969	39.1%	-57
Petroleum		1,345	1.8%	1,336	1.8%	-8	1,336	1.7%	-8
Gas		35,046	48.2%	36,626	49.2%	1,580	38,461	50.2%	3,415
Nuclear		2,755	3.8%	2,906	3.9%	151	2,906	3.8%	151
Hydro		1,762	2.4%	1,686	2.3%	-76	1,686	2.2%	-76
Pumped Storage		0	0.0%	0	0.0%	0	0	0.0%	0
Geothermal		0	0.0%	0	0.0%	0	0	0.0%	0
Wind		1,698	2.3%	1,922	2.6%	224	2,252	2.9%	554
Biomass		26	0.0%	32	0.0%	5	32	0.0%	5
Solar		35	0.0%	36	0.0%	1	36	0.0%	1
TOTAL		**72,693**	**100.0%**	**74,514**	**100.0%**	**1,821**	**76,678**	**100.0%**	**3,985**

BOUNDARY CHANGE

The SPP RC is coordinating with Entergy, CLECO, Lafayette Utilities System, Louisiana Energy and Power Authority, and MISO for the transition of those entities to the MISO RC footprint and eventually into the MISO BA Area and the MISO Market. This transition began in June 2013 and will conclude in December 2013. This transition into the MISO Market and MISO BA is expected to result in significant changes in flows as compared to what has historically been observed and managed using existing congestion management processes. SPP and MISO are evaluating ways to mitigate reliability concerns from these operational changes by improving how flows are accounted for and reviewing congestion management techniques for potential enhancements. These additional coordination activities are expected to continue to ensure the reliable operation of the interconnected transmission system.

Demand, Resources, and Planning Reserve Margins

The SPP Assessment Area's target reserve margin is 13.6 percent, which has not changed since the *2012LTRA*.[148] The assessment area is projecting adequate Planning Reserve Margins above the SPP target (NERC Reference Margin Level) throughout the assessment period. [149] Due to the modest 10-year projections for annual demand growth, the existing and planned generation in the SPP footprint will provide sufficient Planning Reserve Margins each year of the assessment period.

SPP RE is showing a decrease in Total Internal Demand from 2012 to 2013. This decrease in Total Internal Demand is primarily due to a methodology change in SPP RE forecasting. Beginning with the 2012–2013 winter assessment, SPP RE reported a coincident peak demand forecast based on the Model Development Working Group (MDWG) modeling data submitted by individual entities. Previously, SPP RE reported a noncoincident Total Internal Demand forecast based on aggregated member data. SPP RE will continue to use the MDWG model for future demand forecasts. The High-Priority Incremental Load Study, which began in April 2013, indicates that the SPP Assessment Area is experiencing an increase in oil and gas drilling that is causing substantial load growth in northern Oklahoma, southwestern Kansas, Texas, and New Mexico.

Continued annual growth in Energy Efficiency and conservation and DR programs is expected through 2023; however, the overall impact of these programs is relatively small. DR programs in the SPP RE footprint are voluntary and are primarily targeted for summer peak load reduction use. For the most part, SPP RE members include their own DR and Energy Efficiency programs as reductions in their load forecasts. The utilization of DR resources is not vital to meeting the energy and capacity obligations of the SPP Region.

Since 2009, three voluntary customer DR programs have been implemented in the SPP footprint. Westar Energy launched a program in 2009 for residential and small to mid-size commercial customers. The program has more than 32,000 customers enrolled and a load reduction capacity of 27 MW. By the end of 2015, Westar anticipates the enrollment of 90,000 participants and a potential load reduction capability of 90 MW. In 2010, Oklahoma Gas & Electric began a program that installed 40,000 residential-customer smart meters and provides up to 84 MW of DR during peak hours. The newest program, Kansas City Board of Public Utilities' residential customer thermostat program, will provide a demand reduction of approximately 3 MW, with 3,500 subscribers expected by the end of 2013.

SPP RE does not expect to have any reliability issues because of the modest amount (approximately 400 MW) of projected retirements. With new generation projected to come into service during the assessment period, there are no operational or planning concerns at this time. There have been no project cancellations. While some derates were reported from the previous year's assessment, they were not material.

[148] SPP's target Reserve Margin of 13.6 percent also serves as NERC's Reference Reserve Margin.

[149] In 2010, NERC created a Reliability Assessment Procedure that realigned the reporting areas for the REs. Beginning in 2011, SPP RE assumed the reporting responsibilities of the Nebraska entities (NPPD, OPPD, and LES) that are part of the SPP Planning Coordinator. The realignment of footprints increased the demand forecast for the SPP RE footprint.

SPP RE relies on members to provide the information needed to model all load and generation, including any changes to generation ratings and long-term outage plans. SPP RE does not designate units for seasonal availability or have specific criterion to address behind-the-meter generation, although individual entities may net the generation from their load.

The expected on-peak capacity values for variable generation are determined by historical performance guidelines.[150] The net capability for wind is determined on a monthly basis, and there are eight steps that outline the process for establishing net capability. Wind facilities that have been in commercial operation for three years or less must include the most recently available data. If MW values are not available, estimates based on wind data correlated with reference towers outside a 50-mile radius of the facility's location must be approved by the SPP RTO Generation Working Group (GWG).

The net capability for solar resources is also determined on a monthly basis via the same eight-step process applicable to wind resources. Solar data that is correlated beyond 200 miles of the reference measuring device must also be approved by SPP RTO GWG. [151]

SPP RTO evaluates operational procedures on an ongoing basis to determine if any improvements can be made for efficiency and reliability. Because of the level of wind resources in the footprint, SPP RTO is investigating the addition of wind into its automatic, security-constrained dispatch calculations. This would allow SPP RTO to better manage local congestion issues in which wind is the primary impacting resource. It is anticipated that SPP RTO would then be able to better manage system reliability by using quicker and more effective control actions.

For 2014, SPP RE members report 3,184 MW of firm imports, 25 MW of Expected imports, 2,252 MW of firm exports, and 49 MW of Expected exports. For the assessment period, 2014 has the highest reported number of imports and exports. All of these capacity transactions have firm transmission service contracts with terms between three to 10 years. On-Peak capacity transactions do not have a significant impact on operational reliability due to the volume of internal generation capacity available within the SPP Assessment Area.

SPP RE members, along with some members of the SERC Region, jointly participate in a Reserve Sharing Group. Group members receive contingency reserve assistance from each other and do not require support from generation resources outside the SPP RE Region.[152] The SPP RE's Operating Reliability Working Group sets the Reserve Sharing Group's Minimum Daily Contingency Reserve Requirement. The Reserve Sharing Group maintains a minimum first Contingency Reserve equal to the generating capacity of the largest unit scheduled to be on-line plus 50 percent of the capacity of the next largest generating unit scheduled to be on-line. SPP sets aside the Transmission Reserve Margin (TRM) to allow for loss of the most impacting generation on each flowgate. This ensures that reserve assistance among members is viable.

Transmission and System Enhancements

SPP RE has identified several transmission reliability upgrades. The following list, which is arranged by state (although some projects may cross state lines), shows a description, location, and in-service date for these identified upgrades.

ARKANSAS

- 18 miles of 345-kV transmission line from Flint Creek to Shipe Road in northwestern Arkansas in 2014
- 55 miles of 345-kV transmission line from Shipe Road to Osage Creek (passing near East Rogers) in northwestern Arkansas in 2015

[150] SPP Criteria - Section 12.0.

[151] 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.

[152] While the RSG does have generation-owning members outside the SPP footprint, that generation is not expected to provide support into SPP except for intra-hour contingency events.

KANSAS

- 114 miles double-circuit, 345-kV transmission line from Spearville to Clark County to Thistle in southwestern Kansas in 2014
- 78 miles double-circuit, 345-kV transmission line from Thistle to Wichita in southern Kansas in 2014
- 58 miles of 345-kV transmission line from Elm Creek to Summit in northern central Kansas in 2016

OKLAHOMA

- 100 miles of 345-kV transmission line from Seminole to Muskogee in central Oklahoma in 2013
- 122 miles of double-circuit, 345-kV transmission line from Hitchland to Woodward District EHV in northwestern Oklahoma in 2014
- 107 miles of double-circuit, 345-kV transmission line from Thistle to Woodward District EHV in northwest Oklahoma and southwest Kansas in 2014
- 76 miles of 345-kV transmission line from northwestern Texarkana to Valliant in southeastern Oklahoma in 2015
- 93 miles of 345-kV transmission line from Elk City to Gracemont in western Oklahoma in 2018
- 5 miles of 345-kV transmission line from Arcadia to Redbud in central Oklahoma in 2019
- 126 miles of 345-kV transmission line from Woodward District EHV to Tatonga to Mathewson to Cimarron in northwestern Oklahoma in 2021

MISSOURI

- 30 miles of 345-kV transmission line from Iatan to Nashua in northwestern Missouri in 2015
- 181 miles of 345-kV transmission line from Sibley to Mullin's Creek to Nebraska City in northwestern Missouri and southeastern Nebraska in 2017

NEBRASKA

- 40 miles of 345-kV transmission line from Neligh to Hoskins in north-central Nebraska in 2016
- 222 miles of 345-kV transmission line from Gentleman to Cherry County to Holt County in northwestern Nebraska in 2018

TEXAS

- 305 miles of 345-kV transmission line from Woodward District EHV in western Oklahoma to Tuco in the Texas Panhandle in 2014

The most congested flowgates and areas in the SPP Region are identified on a monthly basis. Some of these congested flowgates are considered long-term transmission constraints. SPP has identified several long-term constraints in two areas and proposed transmission solutions to help alleviate them.

In the Texas Panhandle, the interface monitoring the Southwest Public Service North–South lines and the flowgate monitoring Osage–Canyon East 115-kV for the loss of the Deaf Smith–Bushland 230-kV are expected to be relieved with the installation of the new 305-mile Tuco–Woodward 345-kV line in spring 2014. In spring 2015, the same flowgate monitoring Osage–Canyon East 115-kV is also expected to be relieved with the installation of the new Castro County–Newhart 115-kV line. Another constraint in the Texas Panhandle is the flowgate monitoring the Grapevine 230/115-kV transformer for the loss of Elk City–Sweetwater 230-kV line, which is expected to be alleviated by installation of 38-mile Bowers–Howard 115-kV line in late 2014.

In June 2015, a top long-term constraint in the Kansas City area (i.e., the flowgate monitoring Pentagon–Mund 115-kV for the loss of 87th Street–Craig 345-kV line) is expected to be alleviated by installation of a new 31-mile Iatan–Nashua 345-kV line.

For the purpose of improving reliability, there are several significant transmission projects involving upgrades to existing transmission lines. In north-central Oklahoma, 41 miles of 69-kV line will be converted to 138-kV from Cottonwood to Crescent and from Cashion to Dover. In western Oklahoma, 44 miles of 69-kV line from Anadarko to Franklin will be converted to 138-kV. In southwestern Oklahoma, the 33-mile, Lindsay Flood Tap–Cornville 69-kV line will be converted to 138-kV. In central Oklahoma, 32 miles of 69-kV line will be converted to 138-kV in the Cushing area.

In Kansas, there will be a 48-mile rebuild of a 115-kV line from St. John to Medicine Lodge and 32 miles of 138-kV line from Medicine Lodge to Harper in south-central Kansas in the first five years of the assessment period. During the last five years of the assessment period, Kansas entities plan to rebuild the 34-mile, Harper–Clearwater 138-kV line in this same area. Kansas entities also plan to rebuild 41 miles of 115-kV line from Chapman–Abilene Energy Center to North Street in north-central Kansas.

In the Texas Panhandle, a 45-mile, 69-kV line will be converted to 115-kV during the first five years of the assessment. In east Texas during the same time period, 44 miles of 69-kV line will be converted to 138-kV. During the last five years of the assessment period, these lines and an additional 35-mile line to Dallam are planned for conversion to 230-kV.

The following are considered to be interregional, interconnection-related projects:

STEGALL PROJECT

Add a 345/115-kV transformer at Basin Electric's Stegall substation and build a 22-mile, 115-kV line from Stegall to Scotts Bluff. This project will address low voltage at Victory Hill in southwestern Nebraska due to the loss of the Stegall 345/230-kV transformer. This project is expected to be in-service in 2015.

MESSICK PROJECT

Add a new 500/230-kV transformer and substation at Messick. The transformer will tie together Entergy and Cleco's systems. The project addresses the overloads of the SWEPCO International Paper–Wallace and International Paper–Mansfield 138-kV lines due to the loss of the Dolet Hills–Shreveport 345-kV. This project is expected to be in-service in 2015.

SHIPE ROAD–EAST ROGERS–KINGS RIVER PROJECT

This multi-stage project includes a new 345-kV line in northwestern Arkansas that will connect to the underlying 161-kV system. The Kings River 161-kV termination to the existing system involves interconnecting to Entergy's system. This project is needed to address overloads on the 161-kV system in northwestern Arkansas due to the loss of the Flint Creek–Brookline 345-kV. This project is expected to be in-service in 2016.

GENTLEMAN–CHERRY COUNTY–HOLT PROJECT

This is a 345-kV, multi-line project running through a large portion of central Nebraska. The Cherry County–Holt 345-kV line segment is proposed to interconnect with a Western Area Power Administration (WAPA) 345-kV line. This project is driven by reliability and economic needs and the need to meet renewable policies in Nebraska and other areas in the SPP footprint. This project is expected to be in-service in 2018.

SPP identified several reliability projects that were delayed but are expected to be in-service during the assessment period. Mitigation plans and operator actions have been put into place to alleviate any reliability concerns.

In September 2012, the Centennial Wind Farm SPS was approved, eliminating the need to curtail the existing wind farms in northwestern Oklahoma under the Category B contingency for the loss of either the Woodward District EHV or the loss of Tatonga–Northwest 345-kV line. This SPS is scheduled for removal once the expansion to the Woodward District EHV substation is completed in 2014. The plans are to expand the Woodward District EHV substation to a breaker and a half scheme, install a second 345/138-kV transformer, and construct new 345-kV lines out of this substation that will facilitate the operation of all wind farms presently connected to the system. These new 345-kV lines will connect to Hitchland, Tuco, and Thistle.

In September 2011, the Ensign Wind Farm SPS was approved. The SPS was designed to detect an overload on the MKEC Station–Cudahay 115-kV line that would then trip generation from the Ensign Wind Farm and alleviate the overload. This SPS is scheduled to be removed in 2014. The construction of a second North Judson Large–Spearville line will eliminate the single contingency exposure to overloading the MKEC Station–Cudahay line and make it possible to retire the SPS.

SPP RTO expects to implement its Day 2 market (i.e., Integrated Marketplace) for its RTO footprint on March 1, 2014. This market will centralize unit commitment across 16 BA Areas and consolidate operations into a single BA—known as the SPP RTO Consolidated BA. SPP RTO will provide a five-minute, security-constrained economic dispatch in order to provide Real-time balancing activities, while also providing centralized commitment of resources through the end of the operating horizon. This structure will better allow SPP RTO to manage the variability of load and resources and provide additional flexibility in dealing with short-term reliability issues.

SPP RTO is also investigating centralizing the data gathering from several PMU systems within the footprint to enhance reliability analysis and situational awareness. At this time, SPP RTO is in the early stages of investigating appropriate smart grid programs.

Long-Term Reliability Issues

Current drought conditions in the western portion of the SPP RE Area are projected to continue into the assessment period. As most of the SPP RE heavily water dependent resources are located in the eastern half of the footprint, is not expected to experience significant drought conditions, this area is less affected by droughts.

SPP's increase in installed variable generation, which is composed almost entirely of wind generation, will continue to cause operational challenges. These challenges arise because local area transmission congestion can occur as transmission projects are constructed and interconnected prior to completion of the planned transmission upgrades. In addition, SPP's reliability-focused studies are based on deterministic criteria and do not necessarily capture wind generation outlet constraints given limited power flow models and current assumptions about reduced wind output. The SPP RTO Consolidated BA will provide balancing benefits for the widespread installed wind generation. Impending unit retirements are not expected to impact reliability outside of the local area. SPP RE has sufficient capacity and is expected to continue to be sufficient despite resource retirements.

SPP's Operational Planning group performs bi-annual system planning studies in order to capture potential reliability impacts of retirements and retrofits. Analysis results that reveal reliability concerns are then 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 take into account load forecasts, known transmission, and known generation outages. Local issues are reported to the SPP Transmission Operators involved. Since SPP RE has sufficient capacity, the impacts of long-term maintenance outages are expected to be more economic in nature. Based on the results of studies up to this point, it is expected that there will be adequate time to perform necessary generator retrofits. These retrofits are expected to impact the economics of generation supply more than the ability to reliably serve load across the Region. Local issues may require uneconomic generation to be designated "must run" during long-term outages, but reliability is expected to be maintained.

Due to oil and natural gas drilling, parts of Texas, Oklahoma, Kansas, and New Mexico are experiencing substantial load growth on the transmission system. From a transmission perspective, these loads are difficult to plan for because drilling facilities can be quickly established, causing an unplanned increase in demand. This leaves very little time to complete transmission projects to serve the pump loads when needed. Economic, regulatory, and geological issues can affect where, when, and for how long new wells will be installed and operated. SPP and TOs rely on communication with entities adding load to the transmission system to project where and to what extent this load growth will occur in the future. SPP is enhancing applicable planning processes in order to plan transmission projects to support these loads.

Most of the EHV transmission system across North American and the SPP Region was constructed in the 30-year period between 1950 and 1980, with little or no consideration to broader regional, interregional, or national needs. Because of

SPP's geographic location in the Eastern Interconnection and ties with the Western Interconnection and ERCOT, SPP is uniquely situated to play a key role in the strategic processes necessary to identify critical corridors via rightsizing key lines during rebuilds, reconfiguring grid topology, and potential converting select lines from ac to dc operation to manage congestion and improve overall grid efficiency across North America. Assessment and evaluation of this issue has just begun; therefore, the *2013LTRA* reference case does not consider the potential impacts of aging infrastructure replacement and corridor planning in the SPP Region.

As noted in *2012LTRA*, several HVdc lines are being planned to traverse the SPP Region. On April 9, 2013, FERC approved an interconnection agreement between Tres Amigas, LLC and Southwestern Public Service Co. with SPP as a signatory. Phase I of the Tres Amigas project is expected to consist of a 750-MW, two-node intertie between the Western and Eastern Interconnections. Construction will include the expansion of Southwestern Public Service Co.'s Eddy County substation and a 73-mile, 345-kV line. The project is planned to be operational in the summer of 2016.[153]

A Clean Line Energy project, the Plain–Eastern line, is a 3,500-MW capacity, 700-mile HVdc facility that will begin in western Oklahoma and end in western Tennessee. [154] A second Clean Line Energy project, the Grain Belt Express Line,[155] will consist of an approximately 700-mile HVdc transmission line that will begin in western Kansas and extend eastward through Missouri. Both of the Clean Line Energy projects remain in the planning stages.

As these projects move closer to construction and commercial operation, SPP may be faced with a large number of transmission requests. SPP may not be able to approve all of the requests until additional transmission facilities are built. However, SPP's current processes should prevent any reliability impacts to the BES. The *2013LTRA* reference case does not consider the commercial realization of these projects.

SPP's planning processes have identified a number of transmission projects needed for reliability purposes, and it is expected that those projects will be completed as scheduled or mitigation plans will be developed. The most significant transmission challenges facing portions of the SPP footprint are related to an increase in oil and gas drilling. New oil and gas drilling facilities are built faster than they can be captured in SPP's planning processes and models. SPP also continues to have an influx of variable generation resources, leading to operational challenges. However, SPP is enhancing planning processes to better capture the impacts of the oil and gas projects and variable generation. Given the Region's generation capacity, transmission infrastructure, and enhancements being made to processes and models, SPP is expected to be able to meet any challenges—including environmental regulations—that may arise during the next decade.

[153] Tres Amigas LLC.
[154] Plains & Eastern Clean Line.
[155] Grain Belt Express Clean Line.

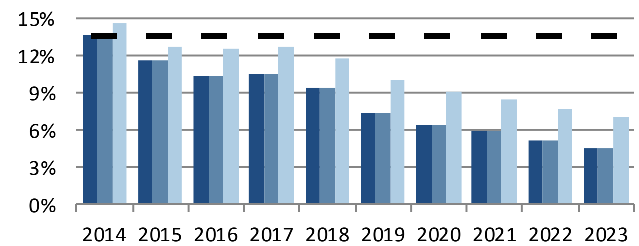
TRE-ERCOT

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 and operates as a single BA. ERCOT is a summer-peaking Region that is responsible for about 85 percent of the electric load in Texas 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.

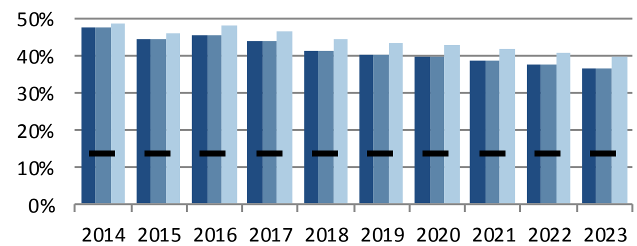
Planning Reserve Margins

TRE-ERCOT-Summer		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ANTICIPATED		13.74%	11.59%	10.34%	10.46%	9.34%	7.36%	6.44%	5.91%	5.11%	4.43%
PROSPECTIVE		13.74%	11.59%	10.34%	10.46%	9.34%	7.36%	6.44%	5.91%	5.11%	4.43%
ADJUSTED POTENTIAL		14.58%	12.71%	12.53%	12.71%	11.75%	9.98%	9.04%	8.49%	7.67%	6.97%
NERC REFERENCE	-	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**
TRE-ERCOT-Winter		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ANTICIPATED		47.60%	44.33%	45.44%	43.76%	41.29%	40.42%	39.76%	38.60%	37.65%	36.81%
PROSPECTIVE		47.60%	44.33%	45.44%	43.76%	41.29%	40.42%	39.76%	38.60%	37.65%	36.81%
ADJUSTED POTENTIAL		48.73%	45.95%	48.26%	46.58%	44.31%	43.72%	43.03%	41.85%	40.87%	40.01%
NERC REFERENCE	-	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**

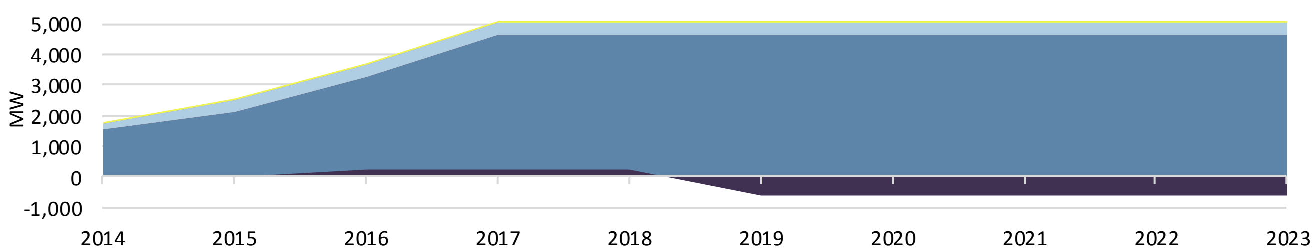
Summer



Winter



Cumulative 10-Year Planned Capacity Change



TRE-ERCOT		2013 Existing Capacity (MW)	2013 Existing Share (%)	2023 Planned Capacity (MW)	2023 Planned Share (%)	2023 Planned Change (MW)	2023 Planned & Conceptual Capacity (MW)	2023 Planned & Conceptual Share (%)	2023 Planned & Conceptual Change (MW)
Coal		17,806	24.5%	17,196	22.3%	-610	18,046	20.8%	240
Petroleum		0	0.0%	0	0.0%	0	0	0.0%	0
Gas		48,089	66.1%	52,741	68.3%	4,652	59,891	68.9%	11,802
Nuclear		5,150	7.1%	5,150	6.7%	0	5,150	5.9%	0
Hydro		479	0.7%	479	0.6%	0	479	0.6%	0
Pumped Storage		0	0.0%	0	0.0%	0	0	0.0%	0
Geothermal		0	0.0%	0	0.0%	0	0	0.0%	0
Wind		918	1.3%	1,318	1.7%	399	2,472	2.8%	1,553
Biomass		211	0.3%	211	0.3%	0	211	0.2%	0
Solar		74	0.1%	124	0.2%	50	637	0.7%	564
TOTAL		**72,727**	**100.0%**	**77,219**	**100.0%**	**4,491**	**86,886**	**100.0%**	**14,159**

Demand, Resources, and Planning Reserve Margins

The ERCOT target reserve margin, adopted as the NERC Reference Margin Level, is 13.75 percent and is based on the loss-of-load probability (LOLP) study that was completed in 2010. ERCOT's target reserve margin has not changed since the release of the 2012 long-term assessment. ERCOT stakeholders are reviewing an updated reserve margin value based on the 2012 LOLP study[156], and a decision by the ERCOT Board on the final value is expected by the end of 2013.[157]

The Anticipated Reserve Margin falls below the ERCOT Target Reserve Margin beginning in summer 2014. The depleting Reserve Margin in ERCOT is due to generation resource additions not having kept pace with the higher than normal load growth experienced in recent years. The generation market in ERCOT is unregulated and generators make resource decisions based on market dynamics. Generation investors state that a combination of lack of long-term contracting with buyers, low market heat rates, and low gas prices are hindering decisions to build new generation. For its part, the PUCT and ERCOT are working through to study, and facilitate revisions to, market protocols and pricing rules to bolster the reserve margin. To incent new generator construction, improvements such as increases in system-wide Energy Offer caps, rising of Energy Offer floors, and adjustments to Emergency Response Service to include distributed generator participation, are among the results so far. Several proposed initiatives focus on DR resources, such as revising market rules to stimulate greater participation of weather-sensitive loads in the Emergency Response Service program. The PUCT has directed ERCOT to draft rules for incorporation of an interim energy market funding solution called the Operating Reserve Demand Curve (ORDC). The PUCT will continue efforts regarding possible setting of a mandated reserve margin level in the ERCOT region.

ERCOT expects tight reserves throughout the 10 year outlook. Based on current information regarding resource availability and anticipated demand levels, there is a significant chance that ERCOT will need to declare an Energy Emergency Alert (EEA) during a number of the future years and issue corresponding public appeals for conservation. The ERCOT system would likely have insufficient resources available to serve customer demand, if a higher-than-normal number of forced generation outages occur during a period of high demand or if record-breaking weather conditions similar to the summer of 2011 lead to even higher-than-expected peak demands. In these scenarios, the EEA declarations may be followed by a need to institute rotating outages to maintain the integrity of the system as a whole.

Total Internal Demand (TID) and Net Internal Demand (NID) are forecasted to grow at a compounded annual rate of 1.38 percent during the assessment period. This forecast is lower than the compounded growth rate provided in the previous LTRA of 2.3 percent for the 2012–2022 period. The reduction in year-on-year load forecast growth projections is the result of changes in the Moody's long-range economic forecast for the ERCOT Region. Moody's low-case economic forecast is used to provide forecasted non-farm employment values for 2013 through 2023 and a normal weather year is determined based on actual weather data from 1998–2012. Reported peak demands represent the coincident demand for the ERCOT Region. There are no expected changes in the footprint of the ERCOT Interconnection. There have been no significant changes in the forecasting process since the previous LTRA.

Sharyland Utilities purchased Cap Rock Electric Cooperative and has begun to move load that was previously served in SPP into ERCOT. There are no footprint changes associated with this load and transmission assets transfer. These loads are already included in the ERCOT long-term load forecast.

Odessa North area (West Texas) experienced unprecedented load growth due to oil and natural gas production and mid-stream processing. Recent reports indicate that the Midland–Odessa economy grew 13.5 percent in 2011 and retail sales

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[156] 2012 ERCOT Loss of Load Study Assumptions and Methodology.

[157] Stakeholders have voted at a Wholesale Market Subcommittee (WMS) meeting to increase the Target Reserve Margin (TRM) to 16.1 percent. It has been reviewed and approved by the Technical Advisory Committee (TAC). In its July meeting, the ERCOT Board of Directors considered the revised TRM but decided to delay voting on a final TRM number. Presumably this delay would allow more time for the Public Utility Commission of Texas to complete its current projects related to Resource Adequacy in Texas. It is anticipated that a decision will be made by the end of 2013.

were up 26 percent. Surrounding counties are also experiencing increased economic activity and continue to drive high load growth averaging 40 percent in the area yearly. Because of the economies associated with oil and natural gas exploration and production in this area, load growth is expected to continue into the future. County-level forecast of economic and demographic data was obtained from Moody's and was incorporated in the ERCOT long-term load forecast.[158]

There are two DR services administered by ERCOT: Load Resources (LRs) and Emergency Response Service (ERS). Load Resources (LRs) providing the Responsive Reserves ancillary service is a contractually committed Load-Modifying Demand as a Capacity Resource to ERCOT. Emergency Response Service (ERS) is a 10-minute DR and distributed generation service designed to be deployed in the late stages of a grid emergency, prior to shedding involuntary firm load, and represents Load-Modifying Contractually Interruptible (Curtailable) Demand. All DR programs are counted as LMRs in ERCOT.

Load Resource participation serves as part of the system-wide procurement of the Responsive Reserve Service (RRS)[159] used for ancillary service and is limited to 50 percent of the total RRS requirement. Load Resources providing the Responsive Reserves ancillary service is a contractually committed Demand-Side Load as a Capacity Resource to ERCOT. In 2012, ERCOT increased the total RRS (provided by Generation Resources and Load Resources) participation cap from 2,300 to 2,800 MW based on the analysis conducted by the ERCOT Dynamic Working Group. This cap is not expected to change, and ERCOT therefore does not envision any significant change in the level of this DR product (current procurement is slightly below the maximum 1,400 MW cap).

ERS is provided by loads and distributed generators that are contractually obligated to deploy in the event of notification by ERCOT during system emergency conditions prior to shedding involuntary firm load. In its six-year history, ERS has grown from zero MW to its current level of more than 500 MW; participation in the service has been increasing at a rate of approximately 10 percent per year. However, ERS is subject to a cost cap imposed by the PUCT ($50 million annually), and its growth through the assessment period could be affected by the cost cap. It is reasonable to expect the 10 percent growth rate to continue and potentially increase throughout the next several years, but absent an increase in the cost cap (which would require a rulemaking action), the procured capacity can be expected to level off somewhere below 1,000 MW during the assessment period. Based on market participant projections, it is likely that there may be an increase in ERS participation by distributed generation resources.

Utility savings, as measured and verified by an independent contractor, have exceeded the goals set by the utilities[160]. In a recent assessment, utility programs implemented after electric utility industry restructuring in Texas had produced 270 MW of peak demand reduction and 529 GWh of electricity savings in 2011 which exceeded the statewide legislative Energy Efficiency goals for the ninth straight year[161]. Between 1999 and 2011, the utilities' programs have produced 1,936 MW of peak demand reduction and 4,639 GWh of electricity savings. This historical demand reduction is accounted for within the load forecast and only the expected incremental portion, which is expected to increase from 392 MW in 2013 to 1,238 MW in 2023, is included as a demand adjustment for the summer seasons during the assessment period.

In addition to the ERCOT-managed DR programs, several Transmission Service Providers (TSPs) have individual, contractual programs with loads that can respond to instructions to reduce total energy usage. These programs were expected to attract approximately 250 MW of additional DR capacity for the summer of 2013 and are subject to concurrent deployment with existing ERCOT-directed DR programs, pursuant to agreements between ERCOT ISO and the TSPs.

DSM program amendments include updating the avoided cost calculations to account for the transition to a nodal market design in the ERCOT; increasing the demand reduction goals to 30 percent of annual growth in demand beginning in 2013

[158] Odessa North Congestion Update.
[159] ERCOT Methodologies for Determining Ancillary Service Requirements.
[160] Energy Efficiency Accomplishments of Texas Investor Owned Utilities - Calendar Year 2012.
[161] Energy Efficiency Accomplishments of Texas Investor Owned Utilities - Calendar Year 2011.

and moving to four-tenths of summer-weather adjusted peak in subsequent years; setting the bonus at a maximum of 10% of total net benefits; adding provisions for utility self-delivered programs; revising load management programs by requiring more coordination with ERCOT; increasing the set-aside for targeted low-income programs to 10 percent of the utility's budget; formalizing the Energy Efficiency implementation project (EEIP) process; revising the customer protection standards and applicable definitions to allow behavioral programs; and adding an opt-out provision for industrial customers taking service at distribution voltage. These amendments constitute a competition rule subject to judicial review as specified in Public Utility Regulatory Act (PURA) §39.001(e).[162] PUCT Project Number 39674 is assigned to this proceeding.[163]

All of these programs and services are subject to regulatory uncertainty, which has increased as the PUCT has evaluated the role of DR in the market design as it relates to resource adequacy. Among the options that have been considered are expansion of Ancillary Services and conversion of ERS to an Ancillary Service procured in the Day-Ahead Market (instead of three times per year for four-month contract terms, as is the case today).

ERCOT continues to monitor the continuing drought conditions. While reservoir levels are not expected to drop below power plant physical intake limits during any given year, potential risks to generation capacity exist if Texas remains in widespread drought conditions.

ERCOT has been notified that the Cobisa–Greenville gas-fired plant (1,792 MW), tentatively scheduled to be on-line by 2017, has been indefinitely delayed. ERCOT has not been notified of any other project deferments. However, the status of Future-Planned gas-fired resources is being reviewed frequently; current market conditions caused by low natural gas prices are not conducive to gas generation market investment. In order to gain additional insight into any impediments to investment in generation resources in the ERCOT region, ERCOT commissioned the Brattle Group to conduct a review of current market conditions and the impact on generation development.[164]

ERCOT was notified of two recent retirements, including the Lower Colorado River Authority's 425 MW Ferguson natural gas plant, which was taken out of service in September 2013. This capacity will be replaced by a 540 MW combined-cycle gas-fired plant, expected to be in service by summer 2014. Additional retirements include two Leon Creek gas-fired units, previously categorized as mothballed and permanently shut down in April 2013. Although there has been no formal notification to ERCOT, the owner of the J. T. Deely coal-fired plant (845 MW) has publicly announced plans to retire the plant by the end of 2018.[165] This expected retirement is included in this assessment. Upon receipt of a notification of retirement, ERCOT will study the potential impacts of the retirement, and will work with the resource owner to finalize reliability-must-run contracts in the event that the unit is required to maintain system reliability. ERCOT will develop analyses of reliability and market impacts of potential expected retirements as needed and make this information available to market participants so that developers and investors can better assess future market opportunities.

Some ERCOT generators are considering the addition of thermal energy storage onto their resources to increase the summer capability of the resources.[166] In 2012, 36 MW of batteries came on-line in ERCOT, and developers are evaluating opportunities to install additional batteries on the system. In addition, a number of compressed air energy storage (CAES) projects are being proposed for ERCOT, such as the Chamisa project near Tulia, Texas.[167] Furthermore, ERCOT created a new category of seasonal outage resources.[168] A Nodal Protocol Revision Request (NPRR) to modify the Protocols to allow the Resource Entity to designate its resources to be mothballed in non-summer months but operational in summer

[162] Public Utility Regulatory Act - Title II, Texas Utility Code.
[163] PUCT Project Number 39674.
[164] ERCOT Investment Incentives and Resource Adequacy (The Brattle Group).
[165] Reuters - UPDATE 1-CPS Energy to shut 871-MW Texas coal-fired plant.
[166] Generator Storage: Tapping Texas' Hidden, Flexible, Peak Capacity.
[167] EPA Air Permits.
[168] NPRR514, Seasonal Generation Resource (Luminant Wholesale Market Subcommittee).

months[169] was approved by the ERCOT Board at the May meeting. Regarding behind-the-meter generation, ERCOT surveyed Private Use Networks (PUN) Generator owners for updates to grid output capacity since conducting the last operational data analysis for 2011. This generation source is now forecasted to supply 4,331 MW to the system.

ERCOT currently uses 8.7 percent as the Effective Load Carrying Capacity (ELCC) contribution of wind generation. This capacity contribution was approved by the ERCOT Board of Directors in November 2010. The ELCC of wind generation is determined as part of the evaluation of the target reserve margin for the ERCOT Region. Using a LOLP Monte Carlo model, the reliability impacts of wind generation are compared to average dispatchable generation capacity of the ERCOT fleet to determine the ratio of wind reliability benefits to that of a thermal unit. ERCOT currently assumes that 100 percent of solar capacity is available on peak due to the small installed capacity amount (75 MW) and expects that the variability of these resources would not adversely affect grid reliability. However, in anticipation of greater solar generation prevalence, ERCOT is developing an estimate of the solar ELCC. For hydro, the peak capacity contribution is 88 percent based on a new methodology being considered by stakeholders that uses the average capacity available during the 20 highest peak load hours over each of the preceding three years. Biomass generation is assigned a peak capacity contribution value of 100 percent.

ERCOT has been incorporating variable resources into its operating procedures and has significant experience maintaining operational reliability with significant and increasing levels of interconnected variable generation. Recently, ERCOT implemented an additional procedure in the control room for large ramp periods using the ERCOT Large Ramp Alert System (ELRAS) tool in the operator procedures. These tools and operating practices have been implemented to aid ERCOT in managing the integration of variable resources and the reliability of the grid.

The 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. Presently, there are two asynchronous ties between ERCOT and SPP with a total of 820 MW of transfer capability and three asynchronous ties between ERCOT and Mexico with a total of 280 MW of transfer capability. The ERCOT Region does not rely on external resources to meet demand under normal operating conditions; however, under emergency support agreements, it may request external resources for emergency services over the asynchronous ties or by block transfer of discrete loads.

ERCOT includes imports of 410 MW from SPP and 218 MW from CFE, which represent 50 percent of the asynchronous tie transfer capability to reflect emergency support arrangements. Of the imports from SPP, 48 MW is tied to a long-term contract for a purchase of firm power from specific generation. In 2014, Sharyland Utilities will expand one of the dc ties and increase its capacity by 150 MW, providing an additional 78 MW of imports from CFE. Including this addition, import capacity provides 0.8-0.9 percent toward the target reserve margin calculation during peak demands.

Several SPP members own 317 MW of a power plant located in the ERCOT Region through 2020, resulting in a firm export of that amount from ERCOT to SPP. There are no known nonfirm contracts signed or pending. In the future, switchable units attached to both ERCOT and MISO may participate in the MISO capacity market. The Gateway and Frontier generators will be able to participate in the Midwest ISO capacity auction in December 2013. If any of these resources are selected for MISO from the auction, they will be excluded from ERCOT resources in future LTRAs.

Transmission and System Enhancements

The recently updated ERCOT future transmission projects list includes the additions or upgrades of 5,640 miles of 138-kV and 345-kV transmission circuits, 7,063 MVA of 345/138-kV autotransformer capacity, and 10,416 Mvar of reactive capability projects that are planned in the ERCOT Region between 2013 and 2022.

[169] ERCOT Board Report.

In the Lower Rio Grande Valley (LRGV), a new 345-kV import line and an upgrade of the two existing 345-kV import lines are part of a project to increase the overall import capability into the area by 2016. Additionally, a new 163-mile, 345-kV line from the Lobo station, near Laredo, to the North Edinburgh station is expected to be completed by 2016. This new line will provide a third 345-kV import circuit into the LRGV from outside of the area. These projects are needed to meet the load growth demands in the area. Currently, demand in the LRGV is supported by the two existing 345-kV lines, three smaller 138-kV lines, and approximately 1,700 MW of natural gas generation at four plants. The area also has some hydro and wind generation and an asynchronous tie with the Mexico system. Because the area is dependent on such a small number of resources, maintenance outages must be carefully planned in order to be able to reliably serve the area. Similarly, the area is vulnerable to contingency events in which multiple pieces of equipment are out due to maintenance or equipment failure.

A new Cross Valley 345-kV, 106-mile line from the North Edinburg station, located on the west side of the LRGV, to the Loma Alta station, located on the east side of the LRGV, is expected to be in-service before the summer peak of 2016. This new line will support load growth in the cities, including Brownsville, along the eastern side of the LRGV. Part of the LRGV import project includes the installation of a new composite core conductor on each of the existing 345-kV import lines into the area. The reconductoring will occur while the lines are energized as they cannot be taken out of service for extended periods of time due to the Region's dependence on the import power they provide. This is accomplished by constructing a temporary transmission circuit phase parallel to the actual line, bypassing the section the construction crews are working on.

Elsewhere on the ERCOT system, the Competitive Renewable Energy Zone (CREZ) projects are expected to resolve the West–North stability limit constraint once all of the transmission lines associated with the projects are in place by the end of 2013.

Multiple transmission upgrades in the Odessa North area (West Texas) scheduled to be completed prior to the summer of 2013 are expected to reduce congestion and improve reliability in the area. Oncor is seeking approval to construct a new 138-kV, 80-mile transmission line from Permian Basin Switching Station to Culberson Switching Station, which is projected to be in-service by summer 2016. This line will effectively create a transmission loop that serves existing customers and the future load growth anticipated in the area.

Power imports into the Houston area are expected to be constrained until new import lines are constructed or new generation is built within the area in the 10-year planning horizon. Currently, there is enough import capability and generation to meet the demand in Houston. However, the anticipated load growth in the ERCOT Long-term Forecast for the Houston region indicates that a new import path will most likely be needed before 2022. ERCOT will continue evaluating Houston import options and ensure that the results are incorporated in short-term study horizons.

In West Texas, the revitalization of the Permian Basin oil fields has increased electric demand at unprecedented rates in some areas, causing a substantial amount of congestion on some transmission elements. In South Texas, the development of the Eagle Ford Shale fields has caused the need for transmission system improvements. Constraints in both areas are expected to persist until the planned long-term solutions that are expected to be in-service between 2013 and 2015.[170]

In 2014, the existing Railroad dc tie connection between ERCOT and CFE will double in capacity to 300 MW. Additionally, 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 transmission access to several Regions adjacent to ERCOT, and the associated

[170]Details of the plans for the Permian Basin area can be found at: Presentation to ERCOT Regional Planning Group (Oncor - ODESSA UPDATE). Details of the plans for the Eagle Ford Shale area can be found at: ERCOT Meeting Minutes.

increase in import capability will improve resource adequacy in the Region. The additional dc tie capacity is being proposed for commercial purposes.

There are no project delays or outages that are expected to impact long-term reliability during the assessment period. Outage analysis in the Operations Planning and Operations horizons ensures that system outages, transmission, or generation are only taken if they do not compromise system reliability.

By the end of 2013, dynamic reactive devices will be installed in four substations within ERCOT. Two devices are in the North-Central weather zone, which includes the Dallas–Fort Worth area and are 600 Mvar capacitive and 530 Mvar reactive and 300 Mvar capacitive and 265 Mvar reactive, respectively. Another device is being installed in the North weather zone and is 300 Mvar capacitive and 100 Mvar reactive. The fourth device is being installed in the West weather zone and is 200 Mvar capacitive and 50 Mvar reactive. Based on the 2012 *Report on Existing and Potential Electric System Constraints and Needs*, additional reactive devices will be needed by 2022.[171] With these devices included, the ERCOT Region is projected to add over 3,705 Mvar of reactive devices and 6,711 Mvar of capacitive devices by 2022.

A stability assessment indicated that an N-1-1 Element contingency (loss of two 345-kV circuits) in South Texas could potentially depress the voltage below 0.8 per unit, if it occurred during peak load conditions. An existing UVLS scheme with less than 300 MW of load in the area can improve the voltage recovery to prevent a cascading event. The Lobo–North Edinburg 345-kV line project is planned to be in-service by 2016 to resolve this issue in the long term.[172] Additionally, an existing UVLS scheme with less than 200 MW of load in the Laredo area will prevent a local voltage collapse for an extreme contingency.

There are no current plans to install SPS in lieu of planned bulk power transmission facilities. ERCOT is reviewing SPSs for retirement-based exit criteria and anticipates that several are targeted prior to summer 2013.

As a part of the collaborative effort funded by DOE under the Synchrophasor Project, PMUs are being installed in ERCOT. This fast-responding, new technology is an essential part of integrating renewables and assisting the control room with wide-area monitoring. This effort has engaged various other entities, including ERCOT TSPs (ONCOR, American Electric Power (AEP), and Sharyland), Electric Power Group (EPG) as the software application vendor, the Center for the Commercialization of Electric Technology (CCET) as coordinator, and University of Texas at Arlington (UT-Arlington) as research collaborator. A total of 33 PMUs are being installed in the ERCOT Region as a part of this project.

Additionally, FACTs, phase shifters, series compensated lines, STATCOMs, and SVCs are being used within the ERCOT Interconnection. Houston and Dallas–Ft. Worth have SVCs to support a severe (i.e., NERC Category C) contingency, while phase shifters are used to manage flows in local areas. Series compensated lines are being added to improve transfer limits for CREZ and other import lines.

Some LSEs in the ERCOT Region have implemented smart grid products. Those LSEs and others are known to be expanding existing products and evaluating new products and services. These smart grid products, many of which are enabled by smart meter implementation, are based entirely on bilateral agreements between the LSEs and their customers and are therefore not dispatchable by ERCOT. However, deployment of these services can potentially have a significant impact on ERCOT operations and load forecasting. As such, ERCOT is taking an active approach toward collecting data on the products and services in order to evaluate the MW values of their DR and price response actions.

Under PUCT rules, LSEs are required to provide ERCOT with "…complete information on load response capabilities that are self-arranged or pursuant to bilateral agreements between LSEs and their customers."[173] ERCOT will request data from the

[171] ERCOT: Report on Existing and Potential Electric System Constraints and Needs (December 2012).
[172] ERCOT Presentation: Lower Rio Grande Valley.
[173] PUC Substantive Rule 25.505 ()(5).

LSEs for customers enrolled in various DR and load management products. LSEs will submit the data to ERCOT beginning with the summer of 2013, enabling ERCOT to evaluate the impact of retail response to various pricing events. Surveys can then be repeated annually to provide a measurement of the growth of retail load response.

Long-Term Reliability Issues

ERCOT, as part of a long-term transmission planning study funded by DOE, has been reviewing the impact of extensive wind generation added to the grid (49 GW by 2016). Additional analysis is ongoing.[174] In 1999, as part of the restructuring of the electric market, the Texas Legislature passed a law requiring retail electric providers to invest in, acquire, or purchase a total of at least 2,800 MW of clean energy by 2009. In 2005, the Texas Legislature expanded this RPS to 5,880 MW by 2015 and 10,000 MW by 2025. ERCOT already surpassed this amount of installed renewable capacity (10,556 MW), and developed many operational and planning tools to handle these additions to the grid.

The bulk of DR currently in ERCOT is large commercial and industrial load. It has provided more than the required MW when called upon. Measurement and verification procedures for these programs are defined in the Performance Monitoring section of the ERCOT Protocols.[175] As the ERCOT market adds more DR in the future, potential unresponsiveness will have to be addressed.

ERCOT is following the installation of distributed energy resources in the grid. Currently, the amount is not enough to be a concern (less than 200 MW). As the ERCOT market adds more distributed energy resources in the future, the potential of system reliability impacts will have to be addressed.

Drought and environmental regulation are the two emerging reliability issues of the highest level priority at ERCOT. Both of these issues became focal points for the state in 2011 when the lack of rainfall and introduction of CSPAR came to the frontlines.

ERCOT is working with generators to determine the generation limitations during extreme drought conditions. ERCOT surveyed generators to identify the most at-risk resources. The last survey showed no current concern of drought, but the Region continues to monitor the issue.[176] The new Panda Sherman and Panda Temple Power plants will use recycled sewage for cooling purposes to help conserve the state's water supply.

Drought could be a potential issue in any given year. Multi-year cycles of drought conditions increase the probability that the following year will have more problems as the baseline storage has to be refilled in addition to having sufficient rainfall for the current year's needs. If multiple resources were unable to run due to lack of water to cool the units, resource adequacy in that given year would be at risk. These affected generation resources would fall into the unavailable category, resulting in a reduced reserve margin. Constant review and vigilance is taken by ERCOT in order to identify areas in which resources are at risk of derating or shutdown. 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. If additional resources are added into an area that is historically known for drought, it can exacerbate the resource adequacy situation. Also, an extended, multi-year drought would aggravate the problem.

Concerning environmental regulations, the EPA has proposed new regulations that, if implemented, may degrade the economic viability of certain generation resources. Specifically, the Clean Water Act (Section 316(b)), the MATS, CSAPR, and the Coal Combustion Residuals Disposal (CCDR) regulations may require retrofits, upgrades, or otherwise increase production costs to a point at which retirement of units may be more plausible than continued operation. The near-term

[174] ERCOT Panhandle Renewable Energy Zone Study
[175] ERCOT Market Rules.
[176] ERCOT 2013 Summer Presentation.

impact of environmental regulations on the ERCOT system was delayed due to the court stay of the CSAPR. Without that stay, the regulations likely would have affected system reliability in 2012. If the court finds for the EPA and allows the rule to stand, the CSAPR will probably impact unit availability. The MATS required compliance by 2015 (or within two years of that date with possible compliance extensions). Other regulations (e.g., Clean Water Act (Section 316(b)) and CCDR) may take effect later in this decade. During the 10-year horizon, Generator Owners whose cost of compliance is greater than or equal to the present value of the future predicted stream of revenue associated with a certain generator may opt to retire the unit.

Preliminary ERCOT studies that did not include CSAPR suggest that 9,800 MW of legacy gas units are at highest risk of accelerated retirement. In addition, ERCOT completed an assessment of the proposed inclusion of Texas in the CSAPR. The assessment found that, if the rule was implemented as scheduled on January 1, 2012, the generators' compliance plans indicated that 1,200 to 1,400 MW of generation would be unavailable year-round and an additional 1,800 to 4,800 MW would be unavailable during the off-peak months. Preliminary ERCOT studies, which were performed prior to the issuance of the CSAPR and assumed implementation of the Clean Air Transport Rule, suggest that coal plants within the Region should continue to be economically viable to operate, unless low natural gas prices and increased carbon emission fees occur with the pending regulations. Low natural gas prices are present now due to increased production or possible production of shale plays within the continental United States. Gas plants in the ERCOT Region, facing the imposition of closed-loop cooling tower requirements as a part of Section 316(b) of the Clean Water Act, are more likely to see less than favorable economics for continued operation. In summary, the combined impact of sustained low natural gas prices, the CSAPR, MATS rule, and other regulatory uncertainties may result in the retirement of both gas and solid-fuel units.

The PUCT has held a number of workshops and regulatory discussions regarding resource adequacy. Redevelopment of existing generation sites would likely minimize the need for additional transmission investment. However, many legacy gas plants are located within EPA air quality nonattainment zones. In addition, pipeline requirements of new generation may exceed the capability of pipeline infrastructure at legacy gas plant locations. It is unclear when resource owners will finalize their environmental compliance strategies due to the uncertainties in the implementation of environmental regulations and the need to test the effectiveness of environmental control technologies; until these compliance strategies are evaluated in aggregate, the impacts to system reliability cannot be fully quantified. If additional time is required for resource owners to complete their strategies to comply with the MATS rule, they will need to inform the EPA and ERCOT well in advance of the regulatory deadline in order to qualify for the four- or five-year extensions. It is unknown how changing market dynamics will affect compliance strategies.

If implement and unaccompanied by accelerated development of new generation, these environmental regulations will further decrease the reserve margin within the ERCOT Region. As noted above, the reserve margin in the ERCOT Region is forecasted to fall below the required 13.75 percent level in 2014, even without these accelerated retirements. If potential retirements occur as forecasted in ERCOT studies, reactive support or new import paths will be required in the Dallas–Fort Worth and Houston metropolitan areas. If potential retirements occur as forecasted in ERCOT studies and incremental or replacement generation is not constructed, ERCOT will face lower reserve margins, decreased ramping capability, and increased transmission congestion. The unavailability of generation due to the CSAPR and MATS would increase capacity insufficiency and the need for emergency actions (including rotating outages) not only during the peak months but also during the off-peak months until retrofits or alternative resources were implemented.

ERCOT is working with Generation Owners to determine the impact of environmental rules on potential retirement of generation. A study on environmental scenarios was completed when the draft Cross-State Air Pollution Rule (CSPAR) was released in 2011.[177] To address and mitigate reliability issues as conditions arise, ERCOT reviews the impact of the

[177] 2011 Long-Term Interim Report - Volume 2.

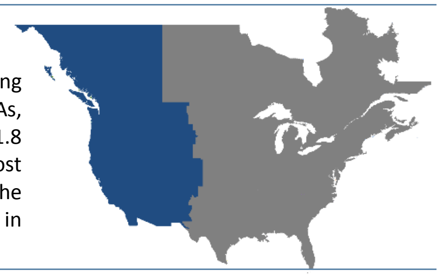
retirement of resources on the ERCOT grid and performs transmission reliability analyses. If the reliability analyses identify any deficiencies, resources are given a reliability-must-run contract to temporarily keep them operational until the implementation of the transmission projects to mitigate the deficiencies.

ERCOT will study the potential impacts of unit retirements and work with resource owners to finalize reliability-must-run contracts in the event that units are required to maintain system reliability. ERCOT will develop analyses of reliability and market impacts of potential expected retirements as needed and make this information available to market participants so that developers and investors can accurately assess future market opportunities.

With respect to maintenance outage impacts caused by environmental control requirements, the ERCOT system has excess generation in the shoulder months to handle such outages under most weather conditions. Reliability could be impacted in situations of unseasonably warm weather and unplanned or planned resource outages. System reliability may be impacted if unit outages for installation of environmental equipment enter into or go beyond the summer season. In 2011, ERCOT conducted a study to quantify the impact of retrofits on reliability.[178] A potential risk exists that not enough vendors are available to serve all the markets under the time constraints given.

[178] ERCOT retrofit impacts on reliability.

WECC

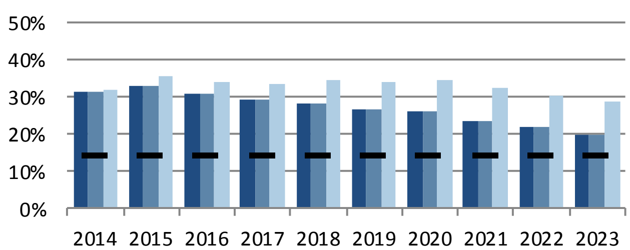


The Western Electricity Coordinating Council (WECC) is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members, which include 39 BAs, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and approximately 81 million people, it is geographically the largest and most diverse of the NERC Regional Reliability Organizations. 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 in between.

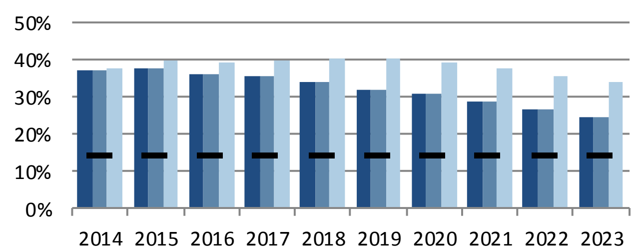
Planning Reserve Margins

WECC-TOTAL-Summer		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ANTICIPATED		31.18%	33.03%	30.72%	29.29%	28.02%	26.44%	26.02%	23.37%	21.76%	19.93%
PROSPECTIVE		31.18%	33.03%	30.72%	29.29%	28.02%	26.44%	26.02%	23.37%	21.76%	19.93%
ADJUSTED POTENTIAL		31.95%	35.39%	34.20%	33.68%	34.41%	34.03%	34.57%	32.16%	30.49%	28.64%
NERC REFERENCE	-	**14.70%**	**14.70%**	**14.70%**	**14.70%**	**14.70%**	**14.70%**	**14.70%**	**14.70%**	**14.70%**	**14.70%**
WECC-TOTAL-Winter		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ANTICIPATED		37.07%	37.61%	36.33%	35.83%	33.95%	32.06%	30.62%	28.69%	26.41%	24.72%
PROSPECTIVE		37.07%	37.61%	36.33%	35.83%	33.95%	32.06%	30.62%	28.69%	26.41%	24.72%
ADJUSTED POTENTIAL		37.83%	39.62%	39.46%	39.86%	40.35%	40.15%	39.47%	37.82%	35.44%	33.76%
NERC REFERENCE	-	**14.50%**	**14.50%**	**14.50%**	**14.50%**	**14.50%**	**14.50%**	**14.50%**	**14.50%**	**14.50%**	**14.50%**

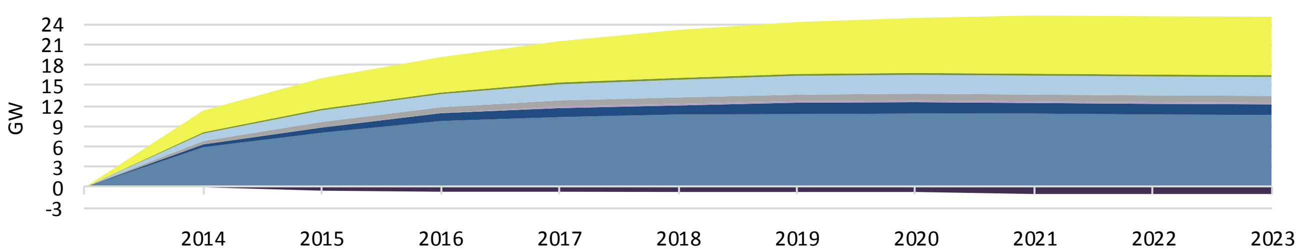
Summer



Winter



Cumulative 10-Year Planned Capacity Change



	2013 Existing		2023 Planned			2023 Planned & Conceptual		
WECC-TOTAL	Capacity (MW)	Share (%)	Capacity (MW)	Share (%)	Change (MW)	Capacity (MW)	Share (%)	Change (MW)
Coal	38,798	19.7%	37,787	17.1%	-1,011	37,787	16.0%	-1,011
Petroleum	1,047	0.5%	1,047	0.5%	0	1,047	0.4%	0
Gas	89,870	45.6%	100,534	45.4%	10,664	111,762	47.3%	21,892
Nuclear	9,553	4.8%	9,553	4.3%	0	9,553	4.0%	0
Hydro	42,577	21.6%	44,131	19.9%	1,554	44,728	18.9%	2,152
Pumped Storage	4,441	2.3%	4,688	2.1%	248	4,688	2.0%	248
Geothermal	2,597	1.3%	3,602	1.6%	1,005	3,713	1.6%	1,116
Wind	5,381	2.7%	8,174	3.7%	2,793	9,544	4.0%	4,163
Biomass	1,279	0.6%	1,555	0.7%	276	1,582	0.7%	303
Solar	1,718	0.9%	10,343	4.7%	8,625	12,080	5.1%	10,361
TOTAL	**197,261**	**100.0%**	**221,415**	**100.0%**	**24,155**	**236,484**	**100.0%**	**39,223**

BOUNDARY CHANGE[179]

In 2013, there was a small change in the footprint of two of the WECC subregions. Valley Electric Association, Inc. moved from Nevada Power within the DSW to the California ISO in the CALS subregion.

Planning Reserve Margins

The Planning Reserve Margins,[180] or target margins, were derived using the 2014 load forecast and the same method as the 2013 *Power Supply Assessment* (PSA).[181] The PSA uses a Building Block Method[182] for developing the Planning Reserve Margins and has four elements: Contingency reserves, Operating reserves, Reserves for forced outages, and Reserves for one-year-in-10 weather events.

By the summer of 2023, the difference between WECC's Anticipated Resources (212,078 MW) and WECC's Net Internal Demand (173,095 MW) is anticipated to be 38,983 MW (22.5 percent margin). As the expected resources exceed target margins, it is reasonable to assume that only a portion of the reported resource additions will ultimately enter commercial service within the planning horizon.

WECC does not have an interconnection-wide formal Planning Reserve Margin standard. As previously mentioned, the WECC annual PSA summer and winter reserve target margins are developed using a Building Block Method.

As depicted in the table at the beginning of this section, the Planning Reserve Margins for the WECC Region remain above NERC Reference Margin Level throughout the 2014–2023 planning horizon. Individual subregions do drop below their Reference Margins in future years, but the reported Conceptual resources will exceed these potential 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 zonal reserve target margins throughout the entire period. These target margins are applied as the NERC Reference Margin Level for each WECC subregion.

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 distributed or behind-the-meter generation 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 3.1 percent from 2011 to 2012, mostly due to warmer than normal temperatures in 2012. The Total Internal Demand for the summer season is projected to increase by 1.7 percent per year for the 2014–2023 time frame, which is unchanged from the 1.7 percent projected last year for the 2013–2022 period. The annual energy load is projected to increase by 1.5 percent per year for the 2014–2023 time frame, which is a decrease from the 1.6 percent projected last year for the 2013–2022 period.

The WECC Total Internal Demand forecast includes summer DR that varies from 4,531 MW in 2014 to 5,273 MW in 2023. The direct control DSM capability is located mostly in the CALN and CALS subregions, totaling 2,810 MW in 2014 and 3,162

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[179] For long-term planning, the WECC Region is divided into nine assessment areas: Alberta, Canada (AESO); California-North (CALN); Northwest US (NORW); Basin (BASN); California-South (CALS); Rockies (ROCK); British Columbia, Canada (BC); Desert Southwest (DSW); WECC-Mexico (MEXW).

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

[181] WECC's Power Supply Assessments.

[182] Elements of the Building Block Target are detailed in NERC's Attachment II: Long-Term Reliability Assessment – Methods and Assumptions.

MW in 2023. DSM programs in other subregions are also increasing. The most prevalent DR 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 DR development activity within WECC is taking place in California; California ISO (CAISO) is actively engaged with stakeholders in developing viable wholesale DR products with direct market participation capability. Also of note is CAISO's new DR 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.[183]

Overall DR 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 LSEs during high-power cost periods but in general are only activated during periods in which local power supply issues arise. Generally, DR programs in WECC have limitations, such as having a limited number of times they can be activated.[184]

All of the BAs within the Western Interconnection provided the generation data for this assessment, and WECC staff—under the direction of the WECC Loads and Resources Subcommittee (LRS)—processed the data. The reported generation additions generally reflect extractions from generation queues.

Distributed energy resources, including rooftop solar and behind-the-meter generation, currently represents an insignificant portion of both the existing and planned resources. As the load served by these resources is not included in the actual or forecast peak demands and energy loads, these resources are excluded from the resource adequacy calculation.

Since the *2012LTRA*, expected available nonrenewable summer capacity has increased by 2,355 MW, and renewable summer capacity (nameplate) has increased by 5,941 MW. Thermal plant additions were largely gas-fired combined-cycle plants, while renewable additions were largely wind farms. Gross Future-Planned additions are expected to total 34,474 MW (including 10,664 MW natural gas-fired, 10,254 MW wind powered, and 10,665 MW solar resources), with Conceptual additions totaling 19,497 MW (including 11,228 MW natural gas-fired, 5,029 MW wind powered, and 2,147 MW solar resources).

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,[185] it is expected that future LTRA information will report additional retirements and fuel conversions as more plant owners establish their preferred approaches for addressing the recent Maximum Achievable Control Technology regulations. California regulations essentially specify that existing long-term contracts with coal-fired plants will be allowed to run to expiration, though not renewed.[186] 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 been reported for this year's LTRA. Current information regarding the California OTC is available on the California Energy Commission's website.[187] It is expected that any capacity reductions will be offset by new plants that may or may not be reflected in the current Conceptual resources data.

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[183] California ISO Demand Response Initiatives.

[184] NERC's assessment process assumes that DR may be shared among LSEs, BAs, and subregions. However, DSM sharing is not a contractual arrangement. Consequently, reserve margins may be overstated as they do not reflect DR that could potentially be unavailable to respond to external energy emergencies. Energy efficiency and conservation programs vary by location and are generally offered by the LSEs. The reduction to demand associated with these programs is reflected in the load forecasts supplied by the BAs.

[185] Environmental Controls and the WECC Coal Fleet.

[186] CEC Emission Performance Standards.

[187] CEC Once-Through Cooling.

The 2,250-MW San Onofre Nuclear Generating Station (SONGS) in southern California experienced premature wear in the steam tubes for both of the plant's units, which were shut down for repairs.[188] In June of this year, Southern California Edison, the majority owner and operator of the plant, announced that after considering options to repair the SONGS units, it determined that none were cost-effective and the plant will be retired.[189]

The Existing-Certain and Future-Planned resources projected for the 2014 summer peak period total 199,015 MW and reflect the monthly shaping of variable generation and the seasonal ratings of conventional resources. The resources not counted toward on-peak capacity include 39,150 MW of variable generation derates and 6,678 MW of inoperable and scheduled generation outages. The Expected 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 the 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.[190] 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 34,474 MW as the gross Future-Planned capacity projected to 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 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 regarding the issue on its website.[191] Increased wind penetration is expected to worsen the operating reserve situation. Solar generation has not yet reached a level sufficient to create significant operational issues.

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 the MRO. One WECC entity reports a 101 MW diversity exchange credit with its counterpart in SPP, but the exchange is not reflected in this assessment. WECC does not model emergency generation as being available to meet the NERC Reference Margin.

Inter-subregional transfers are derived from resource allocation computer simulations that incorporate transmission constraints among various path-constrained zones within WECC.[192] The WECC resource allocation model places conservative transmission limits on paths between 19 load groupings (zones) when calculating the transfers between these areas. These load zones were developed for WECC's PSA studies. The aggregation of PSA load zones into WECC subregions may obscure differences in adequacy or deliverability between zones within the subregion.

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

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[188] SONGS capacity was reported as Inoperable and excluded for this reliability assessment.
[189] Information on the status of SONGS.
[190] Details concerning the hourly blocks can be found in the Long-Term Reliability Assessment – Methods and Assumptions document.
[191] BPA Wind Activities.
[192] 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.

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. When examining all Adjusted-Potential Resources, all subregions maintain adequate reserves (above respective targets) throughout the assessment period.

Transmission and System Enhancements

WECC is spread over a wide geographic area, with significant distances between generation and load centers. In addition, the northern portion of the assessment area is winter-peaking, while the southern portion 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. Due to the inter-subregional transmission constraints, reliability in the Western Interconnection is best examined at a subregional level.

The addition of 15,458 circuit miles of ac transmission line and 535 circuit miles of dc transmission have been reported through 2023. A large number of transmission projects have been reported to WECC. Some of these projects are duplicative in nature and may have a proposed path similar to another project. As WECC does not vet the new projects or identify minimum transmission addition needs, reported additions may not closely reflect transmission additions that could occur during the assessment period. A delay of these projects may impact the timing and location of resource additions but should not adversely impact system reliability. The WECC Transmission Project Information Portal[193] provides a single location where interested parties can find basic information about major transmission projects in the Western Interconnection.

WECC's Transmission Expansion Planning Policy Committee's (TEPPC) Subregional Coordination Group analyzed the development status of the major reported transmission projects and identified 30 projects with a high probability of being in service by 2023. Information regarding the projects is available in the group's report *2022 Common Case Transmission Assumptions* (CCTA).[194]

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*.[195] 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.

After the July 2 and August 10, 1996 disturbances that caused cascading transmission and generation outages and a widespread loss of customer load within WECC, the technical groups evaluating those events recommended a number of action items to enhance interconnected system reliability. One of those action items was that WECC member systems evaluate the need for UVLS and report to WECC regarding the implementation of UVLS on their individual systems.

Other documents that supported the call for UVLS studies were the NERC's *Survey of Voltage Collapse Phenomenon* (published in August 1991), the NERC Planning Standards (approved in September 1997), and WECC's *Policy Regarding Extreme Contingencies and Unplanned Events*.[196] The WECC policy, in particular, places strong emphasis on the application

[193] WECC Transmission Project Information Portal.
[194] 2022 Common Case Transmission Assumptions (CCTA).
[195] WECC's Project Coordination and Path Rating Processes.
[196] WECC Policy Regarding Extreme Contingencies and Unplanned Events.

of Safety Nets to protect the system from unplanned events outside the performance levels defined under the WECC Reliability Criteria. Under-voltage load shedding (UVLS) is one of the Safety Net schemes identified under the WECC policy.

To assist member systems on how to perform UVLS studies to comply with the WECC mandate, the Technical Studies Subcommittee (TSS) formed an Under-Voltage Load Shedding Task Force (UVLSTF) with the direction to:

- Develop guidelines to help the member systems determine if they would benefit from UVLS as a Remedial Action Scheme (RAS) or as a Safety Net;
- Prepare application guidelines to design UVLS systems; and
- Develop methodologies to study and implement UVLS.

WECC addressed the UVLS issue in the *Under-Voltage Load Shedding Guidelines* document, which was approved by WECC's TSS on April 28, 2010.[197] The installation of additional UVLS will depend on currently undetermined actions by individual system operators and LSEs.

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 SPSs or RASs. In addition, transmission operators may install SPSs or RASs to address localized transmission overloads related to single- and multiple-contingency transmission outages. The future use of such relatively inexpensive schemes in lieu of costly transmission facility additions—and whether they will be permanent or temporary additions—will depend on as-yet-undetermined system conditions.

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

Long-Term Reliability Issues

Reliability within the Western Interconnection may be adversely impacted by events that are independent of the planning margin and transmission facility information presented in this assessment. Due to the fluid nature of entity responses to these events, the timing and locations of potential impacts, if any, on service to customers cannot be ascertained with a high level of certainty. Some specific events that have a potential for adverse impacts are discussed below.

A significant portion of the assessment area's annual energy generation is from hydroelectric resources. Portions of the hydroelectric resources are run-of-river facilities that are impacted in a relatively short time frame by reduced precipitation. Other hydroelectric resources are associated with dams that may store enough water to support near-normal generation for a few months to several years. In addition, much of the hydroelectric generation is located in areas with river run-offs that are affected by local snow melt conditions. These varying conditions, combined with other factors such as maximum or minimum river flow restrictions and other water-use requirements, such as irrigation, often result in complex hydroelectric system operational planning processes that may significantly impact both energy production and peak hydroelectric resource capability.

As noted previously, light load-period, minimum-generation conflicts exist between northwestern wind and hydro generation. The unique Northwest condition, an economic issue rather than a reliability issue, could occur in other WECC subregions if wind resource penetration increases to a presently unidentified extent. Solar penetration is less problematic relative to low nighttime and weekend load issues and is not expected to be a concern during the assessment period.

[197] WECC Under voltage Load Shedding Guidelines.

Another issue associated with the integration of variable resources relates to their impact on operating reserve requirements. Various entities, including the California Energy Commission, have commissioned studies related to this issue.[198] To date, the adverse impacts associated with operating reserves appear to be largely limited to economic issues but, conceivably, operating reserve ramp-rate limitations could lead to slight resource mix adjustments.

RPSs have resulted in significant increases in installed wind-powered generation and planned wind and solar generation additions. The largest proportion of these additions is due to California's RPS, which requires that 33 percent of the state's annual energy usage be supplied by renewable resources by 2020. WECC's TEPPC is actively evaluating long-term regional transmission needs that factor in the expanding role of these variable generation resources. Further information regarding that work is available on WECC's website.[199]

Due to limited size and program design, a lack of DR action during activation events has not been an issue and, due to the limited growth in such programs, is generally not expected to be a significant issue during the assessment period. It should be noted that CISO is actively engaging stakeholders in developing viable wholesale DR products with direct market participation capability. CISO's website presents current information about its DR initiative.[200]

Historically, distributed generation has not been a significant resource in WECC. While the assessment area has experienced an increase in distributed solar generation, any associated impact has been essentially limited to the local power distribution facilities. Further expansion of solar distributed generation is not expected to significantly impact the interconnected power system.

WECC contains a significant number of coal-fired power plants that may be affected by new emissions regulations. WECC LRS has not studied the overall impact of environmental regulations; however, WECC TEPPC prepared a scenario analysis that addresses a potential retirement of 5,400 MW of coal-fired resources.[201] Additionally, some information regarding the issue is available in NERC's *Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations*.[202]

In August 2011, the Canadian federal government published draft regulations that would require existing and new coal-fired units to reach CO_2 emissions levels equivalent to natural gas-fired, combined-cycle plants. For existing plants, the requirements enforceable once a plant reached the end of its useful life (approximately 45 years). Any new unit built after 2015 will need to reach the set emissions levels by 2025.

The two Canadian provinces within WECC, Alberta and British Columbia, will be impacted differently by this regulation. As British Columbia has no coal-fired generation or plans to build any coal-fired facilities, it will not be affected. This regulation will affect the retirement of existing units in Alberta, as well as the addition of coal-fired capacity. In Alberta, about 1,000 MW of existing coal-fired capacity will reach the end of its useful life by 2020. The majority of this capacity is expected to retire, as retrofitting to meet the required emissions levels is prohibitively expensive. The Alberta market, however, is expected to manage the development of new generation to replace retired capacity during the next decade, and resource adequacy is not expected to be significantly reduced.

The WECC-Mexico subregion does not contain coal-fired power plants. It is expected that future coal-fired plant retirements and repowerings in other WECC subregions will occur on a schedule that meshes with associated resource and transmission facility addition schedules.

[198] Research Evaluation of Wind Generation, Solar Generation, and Storage Impact on the California Grid.
[199] WECC Transmission Expansion Planning.
[200] California ISO - Demand Response Initiative.
[201] WGG Coal Retirement Case.
[202] Resource Adequacy Impacts of Potential U.S. Environmental Regulations.

As noted in the Generation section of this assessment, the California State Water Resources Control Board's policy on OTC mitigation is intended to cause a substantial amount of California capacity to retire or be refitted to reduce environmental impacts. Mechanisms are built into the OTC policy to consider any reliability concerns of California energy agencies or CISO. The principal issues are associated with local reliability concerns that are not addressed in this WECC-wide assessment. In southern California, the air quality mandates imposed on the South Coast Air Quality Management District by the federal Clean Air Act continue to place constraints on new power plant development and on repowering of existing OTC facilities. The state energy agencies and CISO are assisting the California Air Resources Board to assess the minimum capacity requirements of southern California and the need for offsets to facilitate permitting of these capacity additions. Such capacity additions are closely related to OTC policy-induced repowering or the retirement of older OTC facilities.

WECC staff has identified long-term reliability issues concerning changes in the mix of generation types expected in future years through either resource retirements or additions. Many existing resources could be retired as environmental standards increase. A related concern is the expected reliance on natural gas-fired generation used to replace these retired units.

Generation retirements or repowerings in California that are associated with the OTC standard may be affected by the early retirement of SONGS. This issue and others associated with the retirement of SONGS are being addressed by state regulators and CISO.

Generation fueled by natural gas is expected to be the choice for most, if not all, future conventional generation. A subsequent increase in demand could have an impact on fuel deliverability as pipelines may be fully contracted. Entities with the Western Interconnection are actively studying the potential reliability impacts of dependence on natural gas-fired generation.

Appendix I: List of Acronyms

Abbreviation	Term
A/C	Air Conditioning
AEP	American Electric Power
AESO	Alberta Electric System Operator (WECC subregion)
AFC	Available Flowgate Capability
ASM	Ancillary Services Market
ATCLLC	American Transmission Company, LLC
ATR	AREA Transmission Review (of NYISO)
AWEA	American Wind Energy Association
BA	Balancing Authorities
BASN	Basin (WECC subregion)
BC	British Columbia (WECC subregion)
BCF	Billion cubic feet
BCFD	Billion cubic feet per day
CAGR	Compound Annual Growth Rate
CALN	California-North (WECC subregion)
CALS	California-South (WECC subregion)
CANW	WECC-Canada (WECC subregion, includes AESO and BC)
CFL	Compact Fluorescent Light
CMPA	California-Mexico Power Area
COI	California-Oregon Intertie
COS	Coordinated Outage [transmission] System
CPUC	California Public Utilities Commission
CRO	Contingency Reserve Obligation
CRPP	Comprehensive Reliability Planning Process (of NYISO)
DADRP	Day-Ahead Demand Response Program
DC	Direct Current
DCLM	Direct Controlled Load Management
DFW	Dallas/Fort Worth
DLC	Direct Load Control
DOE	U.S. Department of Energy
DSG	Dynamics Study Group
DSI	Direct-served Industry
DSM	Demand-Side Management
DSW	Desert Southwest (WECC subregion)
DVAR	D-VAR® reactive power compensation system
EDRP	Emergency Demand Response Program
EE	Energy Efficiency
EEA	Energy Emergency Alert
EECP	Emergency Electric Curtailment Plan
EIA	Energy Information Agency (U.S. Department of Energy)
EILS	Emergency Interruptible Load Service (of ERCOT)
EISA	Energy Independence and Security Act of 2007 (USA)
ELCC	Effective Load-carrying Capability
EMTP	Electromagnetic Transient Program
ENS	Energy Not Served
EOP	Emergency Operating Procedure
ERAG	Eastern Interconnection Reliability Assessment Group
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
FCITC	First Contingency Incremental Transfer Capability
FCM	Forward Capacity Market
FERC	U.S. Federal Energy Regulatory Commission
FP	*Future-Planned*
FO	*Future-Other*
FRCC	Florida Reliability Coordinating Council
GADS	Generating Availability Data System
GDP	Gross Domestic Product
GGGS	Gerald Gentleman Station Stability

Abbreviation	Term
GHG	Greenhouse Gas
GRSP	Generation Reserve Sharing Pool (of MAPP)
GTA	Greater Toronto Area
GWh	Gigawatt hours
HDD	Heating Degree Days
HVac	Heating, Ventilating, and Air Conditioning
IA	Interchange Authority
ICAP	Installed Capacity
ICR	Installed Capacity Requirement
IESO	Independent Electric System Operator (in Ontario)
IOU	Investor Owned Utility
IPSI	Integrated Power System Plan
IRM	Installed Reserve Margin
IROL	Interconnection Reliability Operating Limit
IRP	Integrated Resource Plan
ISO	Independent System Operator
ISO-NE	ISO New England, Inc.
kV	Kilovolts (one thousand volts)
LaaRs	Loads acting as a Resource
LCR	Locational Installed Capacity Requirements
LDC	Liquidated Damage Contract
LFU	Load Forecast Uncertainty
LNG	Liquefied Natural Gas
LOLE	Loss-of-load expectation
LOLP	Loss of load probability
LOOP	Loss of off-site power
LRP	Long Range Plan
LSE	Load-serving Entities
LTRA	Long-Term Reliability Assessment
LTSG	Long-term Study Group
MAAC	Mid-Atlantic Area Council
Maf	Million acre-feet
MAIN	Mid-America Interconnected Network, Inc.
MAPP	Mid-Continent Area Power Pool
MCRSG	Midwest Contingency Reserve Sharing Group
MEXW	WECC-Mexico (WECC Subregion)
MISO	Midwest Independent Transmission System Operator
MPRP	Maine Power Reliability Program
MRO	Midwest Reliability Organization
MVA	MegaVolt Ampere
Mvar	MegaVolt Ampere reactive
MW	Megawatts (millions of watts)
MWEX	Minnesota Wisconsin Export
NB	New Brunswick
NDEX	North Dakota Export Stability Interface
NEEWS	New England East West Solution
NERC	North American Electric Reliability Corporation
NIETC	National Interest Electric Transmission Corridor
NOPSG	Northwest Operation and Planning Study Group
NORW	Northwest (WECC subregion)
NPCC	Northeast Power Coordinating Council, Inc.
NPDES	National Pollutant Discharge Elimination System
NPPD	Nebraska Public Power District
NSPI	Nova Scotia Power Inc.
NTSG	Near-term Study Group
NWPP	Northwest Power Pool Area (WECC subregion)
NYISO	New York Independent System Operator
NYPA	New York Planning Authority
NYRSC	New York State Reliability Council, LLC
OASIS	Open Access Same Time Information Service

Abbreviation	Term
OATT	Open Access Transmission Tariff
OP	Operating Procedure
OPA	Ontario Power Authority
OPPD	Omaha Public Power District
ORWG	Operating Reliability Working Group
OTC	Operating Transfer Capability
OVEC	Ohio Valley Electric Corporation
PA	Planning Authority
PACE	PacifiCorp East
PAR	Phase Angle Regulators
PC	NERC Planning Committee
PCAP	Pre-Contingency Action Plans
PCC	Planning Coordination Committee (of WECC)
PJM	PJM Interconnection
PRB	Powder River Basin
PRC	Public Regulation Commission
PRSG	Planned Reserve Sharing Group
PSA	Power Supply Assessment
PUCN	Public Utilities Commission of Nevada
QSE	Qualified Scheduling Entities
RA	Resource Adequacy
RAP	Remedial Action Plan (of ERCOT)
RAR	Resource Adequacy Requirement
RAS	Reliability Assessment Subcommittee
RC	Reliability Coordinator
RCC	Reliability Coordinating Committee
RFC	ReliabilityFirst Corporation
RFP	Request For Proposal
RGGI	Regional Greenhouse Gas Initiative
RIS	Resource Issues Subcommittee
RMR	Reliability Must Run
RMRG	Rocky Mountain Reserve Group
ROCK	Rockies (WECC subregion)
RP	Reliability Planner
RPM	Reliability Pricing Mode
RRS	Reliability Review Subcommittee
RSG	Reserve Sharing Group
RTEP	Regional Transmission Expansion Plan (for PJM)
RTO	Regional Transmission Organization
RTP	Real-time Pricing
RTWG	Renewable Technologies Working Group
SA	Security Analysis
SasKPower	Saskatchewan Power Corporation
SCADA	Supervisory Control and Data Acquisition
SCC	Seasonal Claimed Capability
SCD	Security Constrained Dispatch
SCDWG	Short Circuit Database Working Group
SCEC	State Capacity Emergency Coordinator (of FRCC)
SCR	Special Case Resources
SEMA	Southeastern Massachusetts
SEPA	State Environmental Protection Administration
SERC	SERC Reliability Corporation
SMUD	Sacramento Municipal Utility District
SOL	System Operating Limits
SPP	Southwest Power Pool
SPS	Special Protection System
SPS	Special Protection Schemes
SRIS	System Reliability Impact Studies
SRWG	System Review Working Group
STATCOM	Static Synchronous Compensator
STEP	SPP Transmission Expansion Plan

Abbreviation	Term
SVC	Static Var Compensation
TCF	Trillion Cubic Feet
TFCP	Task Force on Coordination of Planning
THI	Temperature Humidity Index
TIC	Total Import Capability
TID	Total Internal Demand
TLR	Transmission Loading Relief
TOP	Transmission Operator
TPL	Transmission Planning
TRE	Texas Regional Entity
TRM	Transmission Reliability Margins
TS	Transformer Station
TSP	Transmission Service Provider
TSS	Technical Studies Subcommittee
TVA	Tennessee Valley Authority
UFLS	Under Frequency Load Shedding Schemes
UVLS	Under-voltage load shedding
VArb	Voltampere reactive
VACAR	Virginia and Carolinas (subregion of SERC)
VER	Variable energy resource
VSAT	Voltage Stability Assessment Tool
WALC	Western Area Lower Colorado
WECC	Western Electricity Coordinating Council
WTHI	Weighted Temperature-Humidity Index
WUMS	Wisconsin-Upper Michigan Systems

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