NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2012 Long-Term Reliability Assessment

November 2012

RELIABILITY | ACCOUNTABILITY

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This assessment was prepared by NERC in its capacity as the Electric Reliability Organization[1] and provides an independent view of the 10-year reliability outlook for the North American BPS,[2] while identifying trends, emerging issues, and potential risks. Additional insight will be offered regarding resource adequacy and operating reliability, as well as an overview of projected electricity demand growth for individual assessment areas. The 10-year period observed in this assessment is from 2013-2022, with the 2013 summer as the initial season. Information and data for the 2012 summer and 2012/2013 winter seasons are provided in NERC's seasonal reliability assessments.[3] This new approach eliminates overlap between seasonal and long-term assessments.

Additional inquiries regarding the information, data, and analysis in this assessment may be directed to the NERC Reliability Assessment Staff:

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[1] Section 39.11(b) of the U.S. FERC's regulations provide that: "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."

[2] 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 account for 80 percent of all electricity supply interruptions to end-use customers.

[3] NERC *2012 Summer Reliability Assessment* and *2012/2013 Winter Reliability Assessment*: http://www.nerc.com/page.php?cid=4|61.

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.[4,5] 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 for North America, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.[6]

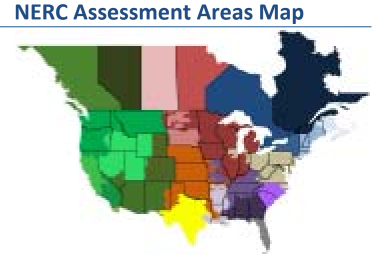
Reliability Standards are the planning and operating rules that electric utilities follow to support and maintain a reliable electric system. These standards are developed by the industry using a balanced, open, fair and inclusive process accredited by the American National Standards Institute (ANSI). 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, through reliability assessment, NERC can independently assess where reliability issues may arise as well as identify emerging risks. This information, along with NERC recommendations, is then 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 of the overall reliability and adequacy of the North American BPS, which is divided into 26 assessment areas, both within and across the eight Regional Entity boundaries, as shown by the corresponding table and maps above.[7] To prepare these assessments, NERC collects and consolidates data from the eight Regional Entities, including forecasts for on-peak demand and energy, demand response, resource capacity, and transmission projects. The use of this bottom-up approach accounts for virtually all electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico. The information is analyzed to identify notable trends, emerging issues, and potential concerns regarding future electricity supply, as well as the overall adequacy of the BPS to meet future demand. Reliability assessments are developed with the intention of informing industry, policy makers, and regulators and to aid NERC in achieving its mission—to ensure the reliability of the North American BPS.

[4] H.R. 6 as approved by of the One Hundred Ninth Congress of the United States, the Energy Policy Act of 2005: http://www.gpo.gov/fdsys/pkg/BILLS-109hr6enr/pdf/BILLS-109hr6enr.pdf.

[5] 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.

[6] As of June 18, 2007, the U.S. Federal Energy Regulatory Commission (FERC) granted NERC the legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the bulk power system, and made compliance with those standards mandatory and enforceable. In Canada, NERC presently has memorandums of understanding in place with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, and Saskatchewan, and with the Canadian National Energy Board. NERC standards are mandatory and enforceable in British Columbia, Ontario, New Brunswick, and Nova Scotia. NERC has an agreement with Manitoba Hydro making reliability standards mandatory for that entity, and Manitoba has adopted legislation setting out a framework for standards to become mandatory for users, owners, and operators in the province. 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 and 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 and enforceable in that jurisdiction.

[7] A larger map of the assessment area boundaries is included in Appendix IV of this assessment.

Assessment Preparation and Design

The *2012 Long-Term Reliability Assessment* (*2012LTRA*) is published in accordance with Title 18, § 39.11 of the Code of Federal Regulations,[8] also referred to as Section 215 of the Federal Power Act, which instructs NERC to conduct periodic assessments of the BPS. NERC's obligation to produce a long-term reliability assessment is further described by Section 803 of NERC's Rules of Procedure,[9] which calls for the development of an annual long-term report with a 10-year planning horizon.

NERC prepared the *2012 Long-Term Reliability Assessment* 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 was submitted in June 2012, and periodic updates occurred throughout the development of the report. Any other data sources included by NERC staff are identified accordingly.

NERC uses a RAS peer review process in preparing both seasonal and long-term reliability assessments to leverage the knowledge and experience of subject matter experts representing NERC Regions, as well as the electricity industry at large. This process provides an essential balance that ensures the validity of data and information provided by the Regional Entities. Each regional self-assessment is assigned to subcommittee members from other Regions to provide a comprehensive review that is discussed and verified by the subcommittee in open meetings. The review process enables all RAS members the opportunity to verify that each Regional Entity produces quality assessments that are accurate and offer a comprehensive assessment for each assessment area. A complete draft of the document is further reviewed by the PC and the Member Representatives Committee (MRC), fully vetting all findings and conclusions. Prior to release, the assessment is submitted to the NERC Board of Trustees (BOT) for final review and approval.

The *2012LTRA* is arranged as follows:

- An "Executive Summary" presents notable findings and highlights brought forward from NERC's reference case projections for the long-term outlook. This section also provides an overview of NERC-wide reliability issues that have been recognized by the industry as important emerging issues that need to be addressed. Additionally, highlights of the projected resource adequacy are provided for the 26 assessment areas, along with area-specific impacts and potential vulnerabilities.
- The "Key Reliability Findings" section includes highlights identified from the *2012LTRA* Reference case. The reference case incorporates known policy and regulation changes expected to take effect throughout the 10-year timeframe, assuming a variety of factors such as economic growth, weather patterns, and system equipment behavior. This section provides NERC's independent assessment of the *2012LTRA* Reference case and recommendations to further identify, study, or manage reliability concerns.
- The "Emerging Reliability Issues in Focus" section supports the development of scenarios—the analysis of which can indicate the sensitivity of the reference case to changes in pre-specified 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 understandings of potential impacts to the BPS, the likelihood of those impacts, and regional implications are important characteristics to NERC's reliability assessment process.
- The "Demands, Resources, and Reserve Margins" section provides summary tables and corresponding analysis of projections of the electricity supply, demand, and transmission throughout North America.
- The "Regional Reliability Assessments" section includes summary tables and corresponding text that provide a more comprehensive and granular reliability outlook for each assessment area.

[8] http://www.gpo.gov/fdsys/pkg/CFR-2010-title18-vol1/pdf/CFR-2010-title18-vol1-sec39-11.pdf.
[9] NERC Rules of Procedure: http://www.nerc.com/page.php?cid=1|8|169.

Report and Data Assumptions

Forecasts cannot precisely predict the future. Instead, many forecasts report a baseline or "most likely" outcome and a range of possible outcomes based on probabilities around the baseline or midpoint. Each NERC Region is responsible for providing projections for NERC's seasonal and long-term reliability assessments. Projections 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] Generally, future generation projections are often derived from generation queues and other area-specific resource planning processes, while load projections are typically based on a non-coincident 50/50 peak demand forecast probability. Additional information is available in Appendix IV and V of this assessment.

When aggregating this data to provide overall projections for the United States, Canada, or North America as a whole, NERC strives to ensure these projections are as accurate as possible to aid the industry, regulators, and policy makers.

The *2012LTRA* reference case for electricity supply and internal demand projections are as follows:

- Data updates are included until September 2012. Any subsequent revisions or corrections may not be included or otherwise represented in this assessment.
- Average or normal weather conditions.
- Based on the economic conditions and outlook at the time of analysis.
- Generating and transmission equipment availability is based on historic performance.
- Planned outages and additions to or upgrades of generation and transmission will be completed as scheduled.
- Demand reductions expected from direct control load management and interruptible demand contracts will be available if and when they are needed.
- Other peak demand-side management and demand response programs are included in net internal demand forecasts.
- Electricity transfers between Regions are contractually arranged and occur as projected.
- Federal, state, and provincial laws and regulations in effect at the time of data and information collection.

In the *2011 Long-Term Reliability Assessment*, NERC indicated that the Environmental Protection Agency's (EPA) Cross-State Air Pollution Rule (CSAPR), combined with other environmental regulations, could directly impact power supply decisions and grid reliability. On August 21, 2012, the D.C. Circuit Court vacated the CSAPR,[11] which had originally required 23 states to reduce annual SO_2 and NO_X emissions. Final data submission for this assessment may not reflect the full impact of the vacated rule. The data collected for the *2012LTRA* is generally based on the assumption that this rule would remain in effect. 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. Moreover, the likely drivers behind retirement decisions will be the combination of other federal and state environmental rules, changing fuel costs (i.e., lower natural gas prices), and other economic decisions. The status of these assumptions is represented in the reference case assessed in this report.

[10] Additional information on the methods and assumption used by each Assessment Area are available through the following link: http://www.nerc.com/files/2012LTRA_PartII.pdf.

[11] 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 http://www.epa.gov/airtransport/.

Enhancements

A number of enhancements have been made to the *2012 Long-Term Reliability Assessment* in support of stakeholder comments, the Reliability Assessment Improvement Plan,[12] guidance from the Board of Trustees, and the Reliability Assessment Subcommittee's efforts to obtain additional information needed to sufficiently perform the long-term reliability assessment. This year, enhancements include:

- **An enhanced view of generator retirements and retrofits**
  - A supplemental request for information and data on known and potential generator retirements and retrofits in the next 10 years (see Appendix IX for more information)
- **Probabilistic indices to supplement the *Long-Term Reliability Assessment***
  - The biannual probabilistic assessment report is designed to complement the *Long-Term Reliability Assessment* by providing additional probabilistic statistics of Loss of Load Hours (LOLH) and Expected Unserved Energy (EUE). The analysis will provide results for the third and fifth year of the *2012 Long-Term Reliability Assessment*—2014 and 2016 results (see Appendix VIII for more information)
- **Regional vulnerabilities and emerging issues identified in the report**
  - Emerging issues are developed for each assessment area that provide a more granular view on Region-specific issues that potentially affect long-term BPS reliability
- **Risk-type evaluations of key reliability findings and emerging reliability issues**
  - Evaluations of risks to operating reliability (security) compared to those that impact resource adequacy
  - Preliminary support for the Reliability Issues Steering Committee (RISC) framework as this will evolve into future reliability assessments
- **A Regional Methods and Assumptions document**
  - A separate document is published that details methods and assumptions used in the development of the seasonal and long-term reliability assessments for each NERC Assessment Area. This information is modified only as frequently as the Assessment Area changes or enhances the process for assessing reliability. This document is published to support the *2012 Long-Term Reliability Assessment* and can be found on the NERC website.[13]
- **Modified 10-year assessment period**
  - The 10-year period observed in this assessment is from 2013-2022, with the 2013 summer as the initial season. Information and data for the 2012 summer and 2012/2013 winter seasons are provided in NERC's seasonal reliability assessments.[14] This new approach eliminates overlap between seasonal and long-term assessments.

[12] Reliability Assessment Improvement Plan : http://www.nerc.com/files/Reliability%20Improvement%20Report%20RAITF%20100208.pdf .
[13] 2012 LTRA Methods and Assumptions: http://www.nerc.com/files/2012LTRA_PartII.pdf.
[14] NERC *2012 Summer Reliability Assessment* and *2012/2013 Winter Reliability Assessment*: http://www.nerc.com/page.php?cid=4|61.

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Executive Summary

In preparing this assessment, NERC has evaluated key reliability indicators, including peak demand and energy forecasts, resource adequacy, transmission development, changes in overall system characteristics and operating behavior, and other influential or regulatory issues that may impact 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. Emerging reliability challenges will drive a transformational change for the industry that could potentially result in a dramatically different resource mix with reliance on natural gas and renewable generation, a need for enhanced modeling, a new risk and probabilistic framework built to address reliability challenges, and growing critical infrastructure and protection concerns—both physical and cyber.

One of the most significant overarching findings of this report is a rapid change in resource mix in several areas across North America. While the key factors driving this evolutionary change vary by region, fuel price economics, environmental regulations, and renewable requirements are the most significant factors affecting the pace of change. Fundamentally, substantial modifications to the bulk power system require a great deal of time to design, site, permit, and ultimately construct. As projected in this report, a majority of new generation, as well as older generation expected to retire, will contribute to a significant resource shift. As resources change both in system characteristics and geography, the transmission system will be challenged to develop a more robust grid that is not only resilient to resource shifts, but also other more extreme conditions.

With the exception of the challenges identified in Electric Reliability Council of Texas (ERCOT), the electricity industry has prepared plans for the 2013-2022 assessment period in an effort to provide reliable electric service across North America. As identified in previous assessments, capacity resources in ERCOT have drifted to a level below reliability targets. In other assessment areas, potential impacts of issues that are not yet fully understood could affect the implementation of current plans.

While the highlights of this report are presented independently, they are cross-cutting, and interdependencies between many of these issues present unique challenges to the electricity industry. Growth in flexible resources, such as demand response and quick-start natural gas power generators, and increased transmission plans to integrate renewable resources distant from load centers are encouraging trends. However, fundamental changes to planning and operating strategies must consider evolving risks such as increased dependency on natural gas, uncertainties of variable and renewable generation, and new vectors of penetration for emerging cyber and physical security threats. The confluence of these risks are critically interdependent and must be strategically managed, monitored, and mitigated in order to preserve the reliability of the BPS.

2012 Key Reliability Findings:

Significant Fossil-Fired Generator Retirements Over Next Five Years

Due largely to the unique confluence of final and potential environmental regulations, low natural gas prices, and other economic factors, about 71 GW of fossil-fired generation is projected to retire by 2022, with over 90 percent retiring by 2017. With the exception of ERCOT, the retirement of this capacity does not pose significant resource adequacy concerns. Reserve Margins are likely to be reduced, but to levels that are still above targets. However, retirements over the next three to four years may raise issues related to system stability and the need for transmission enhancements, which if not addressed could cause reliability concerns in some areas.

Increased Risk of Capacity Deficiencies in ERCOT as Planning Reserve Margins Projected to Fall Below Targets

Starting as early as next year, the Electric Reliability Council of Texas (ERCOT) Planning Reserve Margin is anticipated to be 13.4 percent, which is below the NERC Reference Margin Level and ERCOT planning target of 13.75 percent. At these levels, the risk of insufficient generation resources to meet peak demand increases beyond reliability targets.

Resources Sufficient to Meet Reliability Targets in Most Areas

For the majority of the bulk power system, Planning Reserve Margins appear sufficient to maintain reliability through the long-term horizon. However, there are significant challenges facing the electric industry that may shift industry projections adding considerable uncertainty to the long term assessment. Future uncertainties include electricity market changes, fuel-prices (natural gas in particular), potential environmental regulations, and renewable portfolio standards.

Increased Dependence on Natural Gas for Electricity Generation

Increased dependence on natural gas for electricity in some areas has increased the need for all gas users, electric system planners and operators, and policy makers to focus more sharply on the interaction between the electric and gas industries. The adoption of highly efficient combined-cycle technology by the electric power industry and the emergence of shale gas have altered the relative economics of gas-fired generation. As a result, the dependence on natural gas by the electric power sector has increased significantly. Trends in fuel-mix changes highlighted in this assessment identify gas-fired generation as the primary choice for new capacity with almost 100 GW of Planned and Conceptual capacity expected over the next 10 years, which represents almost half of all new generation capacity.

Long-Term Generator Maintenance Outages for Environmental Retrofits

A significant generation retrofit effort is expected over the next 10 years in order to comply with federal and state-level environmental regulations. A majority of environmental controls are expected to be put in place to meet air regulations by April 2016. In total, 339 unit-level retrofits on fossil-fired generation will be needed, totaling about 160 GW. However, there is still significant uncertainty in the forecasted values as maintenance schedules have not yet been fully evaluated by all areas.

Renewable Resource Additions Introduce New Planning and Operational Challenges

Renewable resources are growing in importance in many areas of North America as the number of new facilities continues to increase. The share of capacity from renewable resources will continue to grow, especially as significant additions are projected for both wind and solar throughout North America. In 2012, renewable generation, including hydro, made up 15.6 percent of all on-peak capacity resources and is expected to reach almost 17 percent in 2022. Contributing to this growth is approximately 20 GW of on-peak Future-Planned capacity and an additional 21.5 GW of on-peak Conceptual capacity. It is vital that these variable resources are integrated reliably and in a way that supports the continued performance of the BPS and addresses both planning and operational challenges.

Transmission Growth to Accommodate New and Distant Resources

As recent as five years ago, transmission was being constructed at a rate of about 1,000 circuit miles per year. In the last five years, over 2,300 circuit miles were constructed per year, more than doubling actual builds in the previous five years. With the current plans in place, that rate is expected to increase to 3,600 miles per year over the next five years. NERC-wide, almost a quarter of new transmission is specifically linked to the integration of renewable generation.

Increases in Demand-Side Management Help Offset Future Resource Needs

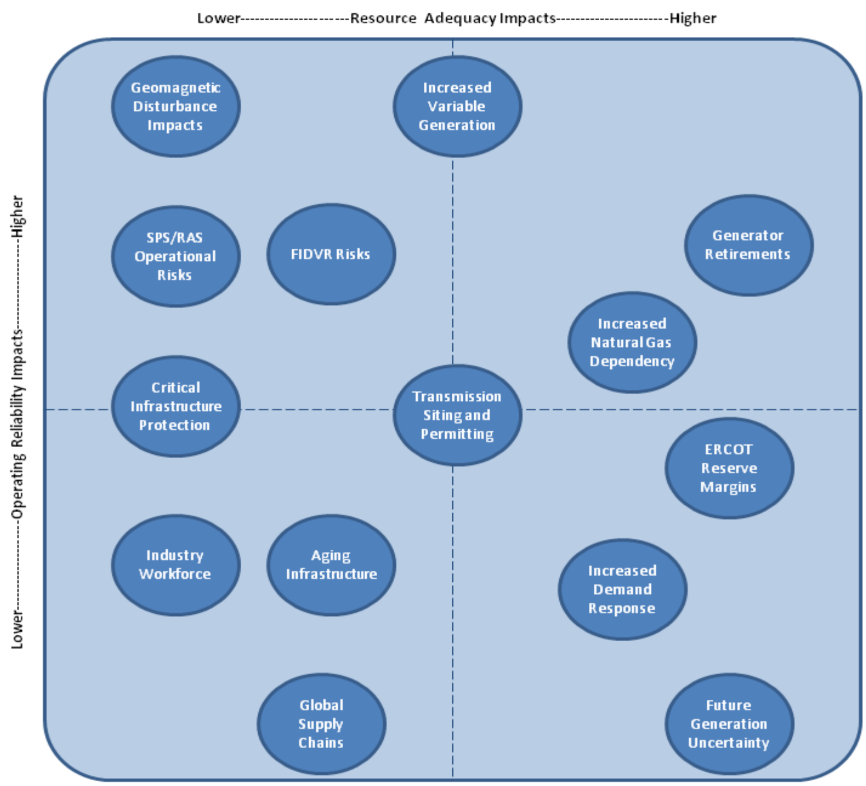
All areas are projecting at least some increased availability of Demand-Side Management (DSM) over the next 10 years to reduce peak demands, contributing either to the deferral of new generating capacity or improving operator flexibility in day-ahead or real-time time operations. NERC-wide, DSM is projected to total roughly 80,000 MW by 2022 (or about 7 percent of the on-peak resource portfolio), offsetting approximately six years of peak demand growth. However, unlike traditional generating resources with many decades of historic data for analysis, the long-term projections of DSM involve greater forecasting uncertainty—particulary with Demand Response resources.

Future Reliability Challenges and Emerging Issue Risk Types

A comprehensive reliability assessment of the North American BPS requires considerations of emerging issues and future risks to reliability. While NERC is in the process of developing a strategic framework to address and prioritize high-risk issues, it is important to recognize how different risks can be exposed and what the potential impact could be to reliability.

Emerging risks identified in the current and past long-term reliability assessment reports are shown in Figure 1. Two fundamental and measurable characteristics of BPS reliability form the foundation of the concepts described in this document—*resource adequacy* and *operating reliability* (or system security). Each issue in Figure I includes the potential to impact these two characteristics differently; therefore, the impacts to system reliability can be different and must be well understood. The results are the product of combined industry surveys, engineering judgment, and NERC's independent assessment.

Figure 1: Future Reliability Challenges and Emerging Issues as a Function of Resource Adequacy versus Operating Reliability Impacts



By understanding these risks, the electricity industry can be more effective in mitigating adverse impacts. With resource adequacy impacts, the ability of the BPS to supply the aggregate electrical demand and energy requirements is compromised. Operating reliability impacts include all other system disturbances that result in the unplanned or uncontrolled interruption of customer demand, regardless of cause. Impacts that spread over a wide area of the grid are referred to as cascading outages—the uncontrolled successive loss of system elements triggered by an incident at any location.

Going forward, an enhanced framework for developing strategic and tactical recommendations will help NERC and the industry effectively focus resources on the critical issues needed to best improve the reliability of the BPS. The Reliability Issues Steering Committee (RISC) is an advisory committee that reports directly to the NERC Board of Trustees and triages and provides front-end, high-level leadership and accountability for nominated issues of strategic importance to reliability. Ultimately, the recommendations will improve efficiency of NERC Reliability Standards development, engage high-level stakeholder leadership, and promote reliability excellence.[15]

[15] RISC Website: http://www.nerc.com/page.php?cid=1|117|428.

Key Reliability Findings

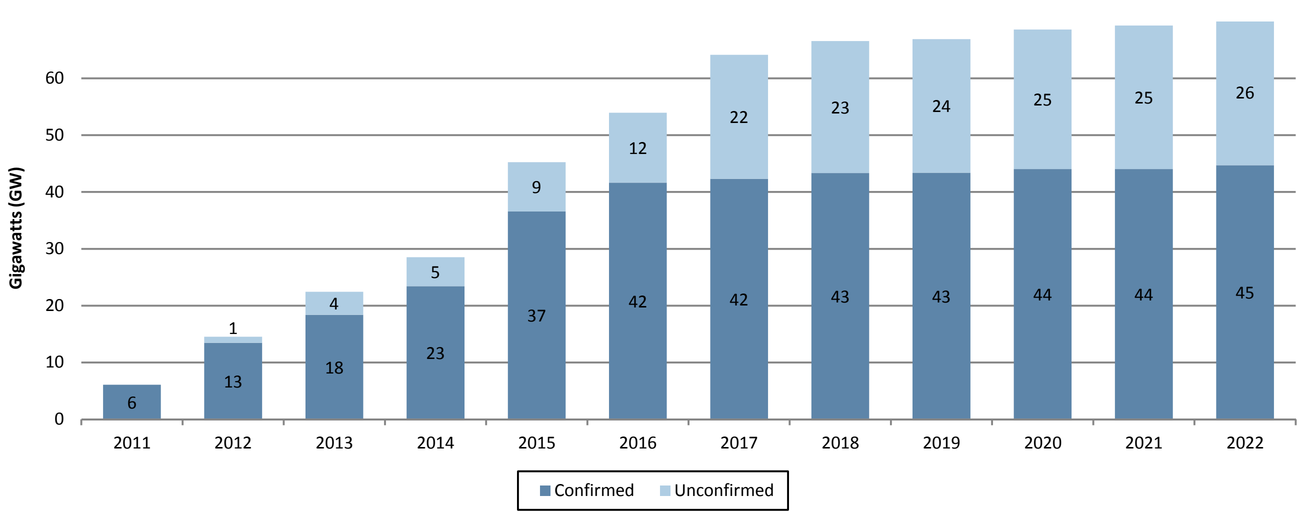
Each year, the Long-Term Reliability Assessment (LTRA) forms the basis for the NERC reference case. This reference case incorporates known policy and regulation changes that are expected to take effect throughout the 10-year timeframe, assuming a variety of factors such as economic growth, weather patterns, and system equipment behavior. This section provides NERC's independent assessment of the 2012 reference case and discusses key findings and challenges of managing reliability concerns.

Significant Fossil-Fired Generator Retirements Over Next Five Years

Largely due to the unique confluence of final and potential federal environmental regulations, low natural gas prices, and other economic factors, approximately 71 GW of fossil-fired generation[16] is projected to retire by 2022, with over 90 percent retiring by 2017. Over the past three years, significant uncertainty surrounding fossil-fired generation retirements has been the most prominent emerging reliability issue assessed by NERC and the electric power industry. For the first time, coal-fired generation is projected to decline over the 10-year assessment period. While significant fossil-fired generation retirements were expected (based on a 2011 NERC assessment), the magnitude of retirements remains uncertain due to generator owners not revealing or announcing plans for unit retirements until recently.

For the *2012LTRA* Reference case, approximately 44 GW of fossil-fired capacity retirements has been confirmed to retire in the next 10 years (Figure 2). Confirmed retirements are those that have been announced or otherwise included in a given Planning Coordinator's resource plans. Additionally, unconfirmed retirement projections have been reported, reaching a total of 26 GW by 2022, a majority of which are projected to retire by 2017 (Figure 3). Projected retirements were forecast by individual assessment areas based on reasonable expectations. For many assessment areas, existing studies and analyses were applied as a basis for retirement projections over and above the amount that has already been confirmed. Some assessment areas did not fully project additional retirements beyond confirmed amounts included in the reference case as insufficient information was available to make a determination.[17] For assessment areas that did not submit supplemental retirement data, the *2012LTRA* Reference case data was applied. Uncertainties still exist and more generators may retire than what is projected in this assessment.

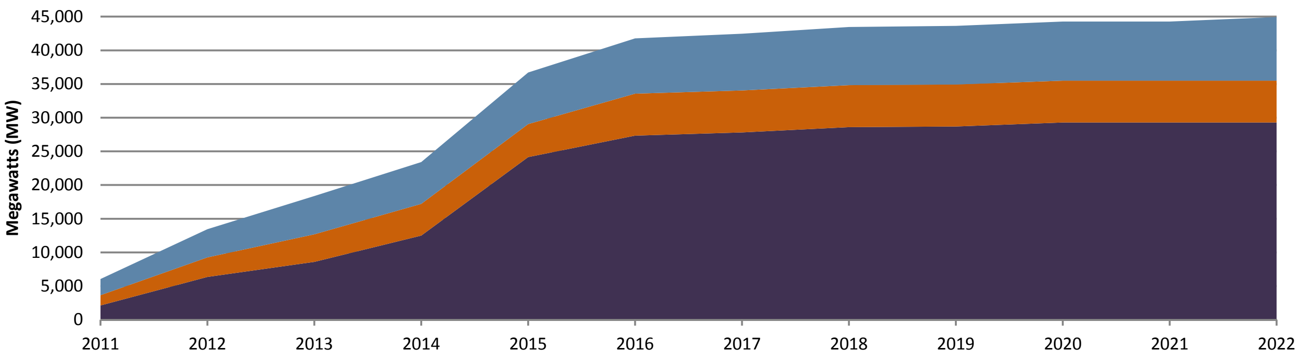
Figure 2: NERC-Wide Cumulative Summer Fossil-Fired Capacity Resource Retirements



[16] NERC reviews the impacts of both controlled and variable resources in this assessment. Variable resources differ from conventional controllable resources, such as fossil-fired resources in a fundamental way: their fuel source (wind, sunlight, andmoving water) cannot presently be controlled or stored. Unlike coal or natural gas, which can be extracted from the earth, delivered to plants thousands of miles away, and stockpiled for use when needed, variable fuels must be used when and where they are available.

[17] ERCOT, FRCC, NPCC-New England, NPCC-Ontario, and SERC Assessment Areas

Figure 3: NERC-Wide Confirmed Retirements by Fuel Type (Summer Capacity)



Capacity Type		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Coal		2,131	6,380	8,597	12,496	23,615	26,719	27,198	27,971	28,067	28,650	28,650	28,650
Petroleum		1,531	2,880	4,088	4,719	4,909	6,221	6,221	6,221	6,221	6,221	6,221	6,221
Gas		2,405	4,195	5,565	6,086	7,530	7,919	8,121	8,365	8,417	8,493	8,493	8,611
Total		**6,067**	**13,454**	**18,250**	**23,301**	**36,054**	**40,858**	**41,539**	**42,556**	**42,705**	**43,364**	**43,364**	**43,482**

In the *2011 Long-Term Reliability Assessment*, NERC projected capacity losses due to retirements and derates associated with environmental control impacts to generator ratings.[18] Based on the results of the Moderate Case, 36 GW of incremental capacity in coal, oil, and gas-fired generation was identified for either retirement or for capacity reductions to support additional station loads (deratings) by 2018. In the Strict Case, capacity reductions amount to approximately 59 GW. For retirements only, the study indicated a range of 7 GW to 18 GW for 2015 and 32 GW to 54 GW for 2018 (Moderate to Strict Cases represent the ranges).[19] Confirmed and unconfirmed retirements in the *2012LTRA* Refernce case show significantly more generators retiring than had previously been projected by NERC for 2015; however, 2018 projections are more in line with last year's study. This is believed to be due largely to a decrease in natural gas prices as well as the extended compliance period associated with the EPA Mercury and Air Toxics Standard (MATS).[20,21]

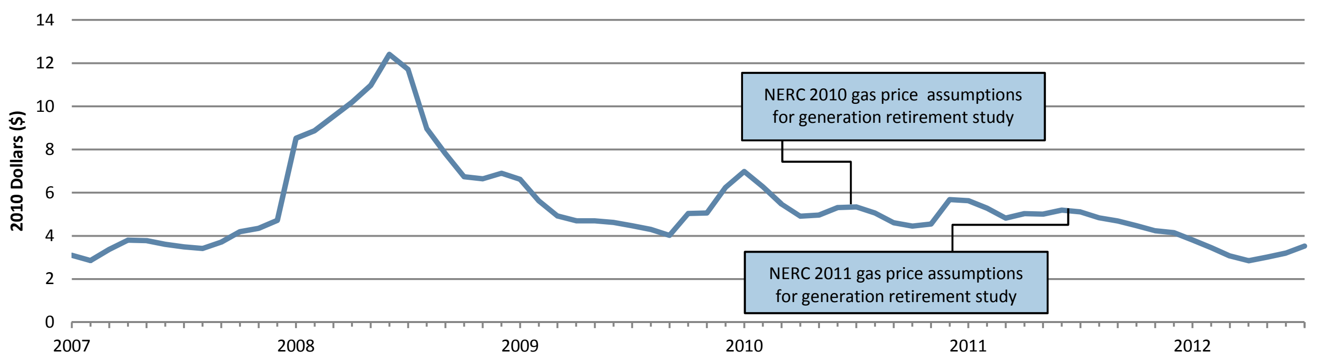
On December 16, 2011, the Environmental Protection Agency (EPA) issued a rule to reduce emissions of toxic air pollutants from power plants. Specifically, MATS will reduce emissions from existing and planned coal- and oil-fired generators by requiring the installation of environmental controls. These controls typically involve the addition of dry sorbent injection[22] or a scrubber on units to control emission levels. Generation owners will ultimately be charged with deciding between investing in the plant to ensure compliance, or closing it permenantly.

Adding to the regulatory constraint, low natural gas in recent years offers incentives for plant owners to convert existing plants from coal to gas. Retirement decisions for existing coal- and oil-fired units are often highly sensitive to the replacement costs for that capacity—which, in effect is fuel cost dependent. Therefore, the option of converting these existing units to natural gas becomes a more economically attractive alternative as gas prices decline. According to the 2011 NERC study on potential generator retirements, a $2 downward swing on natural gas prices could potentially double the amount of retired coal-fired generation as part of the NERC scenario analysis.[23] Henry Hub natural gas prices have dropped

[18] Extraction from *2011 Long-Term Reliability Assessment*: http://www.nerc.com/files/EPA%20Section.pdf.
[19] Derates associated with generator retrofits are embedded within the 2012 LTRA reference case for projected capacity resources and generator ratings and have been considered as part of the overall assessment.
[20] http://www.epa.gov/mats/.
[21] National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units, http://www.gpo.gov/fdsys/pkg/FR-2012-02-16/pdf/2012-806.pdf.
[22] http://www.eia.gov/todayinenergy/detail.cfm?id=5430.
[23] Based on Henry Hub Prices, *2011 Long-Term Reliability Assessment*, Table 35: Projected 2018 Coal Retirements Based on Gas-Price Sensitivity: http://www.nerc.com/files/2011%20LTRA_Final.pdf.

almost $2 since NERC's 2011 study on generation retirements, providing obvious incentives and greater economic benefits to switch from coal or oil to gas generation (Figure 4).

Figure 4: Monthly Average Electric Generation Natural Gas Prices 2007–July 2012 (2010 dollars per million Btu)[24]

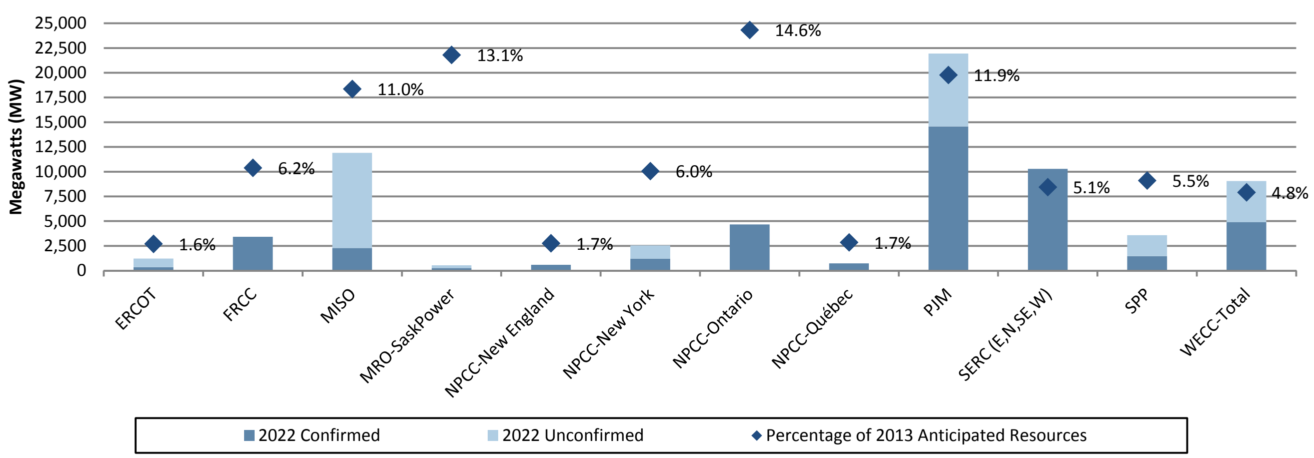


Other reasons for generation retirements include economic-related decisions for continuing the operation of a given plant. Decisions may be impacted by the plant's age, past investment in environmental controls, and other regional-specific issues such as fuel mix, renewable portfolio standards, and impacts of other proposed environmental regulations.

While facility retirements are expected NERC-wide—including in the United States and Canada—some assessment areas will be impacted more than others will. It is important to note that absolute retirement impacts will only cause a resource adequacy concern if retirements cause the Planning Reserve Margin to fall below the targets.[25] For example, PJM is projected to retire the largest amount of fossil-fired capacity by 2022; however, even with 15 GW of generator retirements confirmed, Planning Reserve Margins do not fall below the NERC Reference Margin Level until 2020. The plans for new generation in PJM, along with available reserves, allow PJM the flexibility required to maintain resource adequacy through the long term.

PJM, MISO, and the SERC Assessment Areas are projecting the highest amount of retirements (over 10 GW), as well as the highest percentage relative to total capacity resources—11.9 percent, 11 percent, and 5.1 percent, respectively (Figure 5). Ontario is also projected to retire 14.2 percent of its total capacity by 2014 (Table 1).

Figure 5: NERC-Wide Confirmed and Projected Fossil-Fired Capacity Retirements for 10-Year Period



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[24] U.S. Department of Energy – Energy Information Administration: http://www.eia.gov/dnav/ng/hist/n3045us3m.htm.

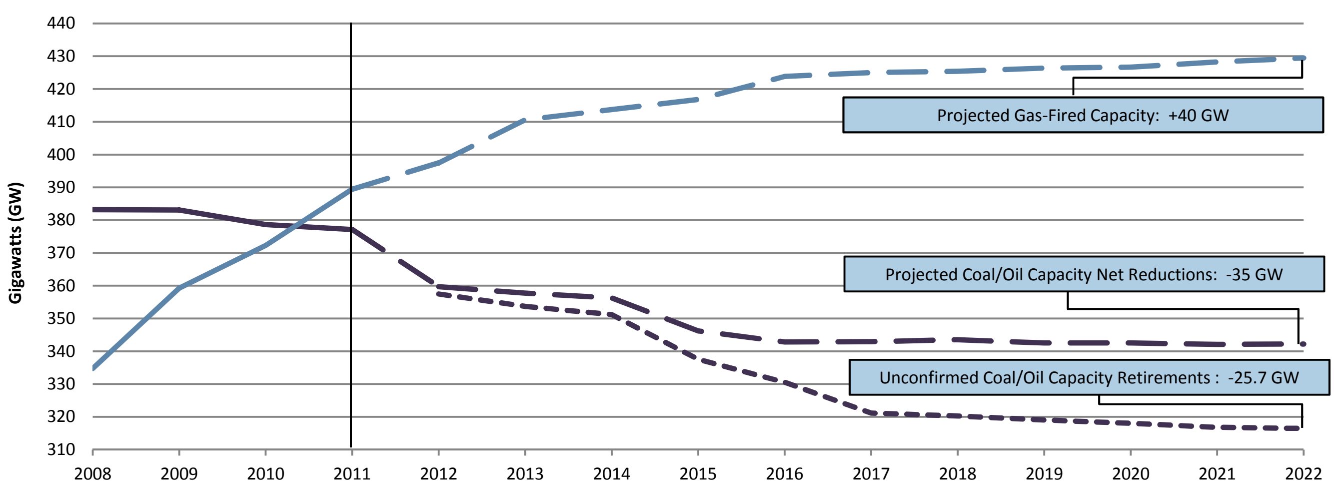
[25] Targets are based on resource planning analysis or regulatory criteria within Regions, NERC Assessment Areas, or Canadian provinces. In some cases, these targets are mandatory. The target for each assessment area is applied as the NERC Reference Margin Level.

Table 1: Cumulative NERC-Wide Confirmed and Unconfirmed Fossil-Fired Capacity Retirements[26]

Assessment Area	Certainty	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ERCOT	Confirmed	342	342	342	342	342	342	342	342	342	342	342	342
	Unconfirmed	-	0	0	0	0	0	0	871	871	871	871	871
FRCC	Confirmed	957	1,344	2,599	2,599	2,611	3,321	3,345	3,345	3,345	3,421	3,421	3,421
	Unconfirmed	-	0	0	0	0	0	0	0	0	0	0	0
MISO	Confirmed	1,012	2,170	2,281	2,281	2,281	2,281	2,281	2,281	2,281	2,281	2,281	2,281
	Unconfirmed	-	252	364	364	364	364	9,626	9,626	9,626	9,626	9,626	9,626
MRO-SaskPower	Confirmed	0	0	201	201	262	262	262	262	262	262	262	262
	Unconfirmed	-	0	0	0	0	0	0	0	0	0	278	278
NPCC-New England	Confirmed	0	0	0	587	587	587	587	587	587	587	587	587
	Unconfirmed	-	0	0	0	0	0	0	0	0	0	0	0
NPCC-New York	Confirmed	219	1,204	1,204	1,204	1,204	1,204	1,204	1,204	1,204	1,204	1,204	1,204
	Unconfirmed	-	0	1,342	1,342	1,342	1,342	1,342	1,342	1,342	1,342	1,342	1,342
NPCC-Ontario	Confirmed	920	920	920	2,699	4,002	4,112	4,290	4,494	4,546	4,546	4,546	4,664
	Unconfirmed	-	0	0	0	0	0	0	0	0	0	0	0
NPCC-Québec	Confirmed	450	730	730	730	730	730	730	730	730	730	730	730
	Unconfirmed	-	0	0	0	0	0	0	0	0	0	0	0
PJM	Confirmed	0	1,367	1,601	3,518	12,215	14,578	14,578	14,578	14,578	14,578	14,578	14,578
	Unconfirmed	-	0	1,038	1,931	4,289	7,373	7,373	7,373	7,373	7,373	7,373	7,373
SERC (E,N,SE,W)	Confirmed	977	3,401	4,882	5,605	7,550	9,172	9,467	10,280	10,280	10,280	10,280	10,280
	Unconfirmed	-	0	0	0	0	0	0	0	0	0	0	0
SPP	Confirmed	0	0	130	130	676	926	926	926	926	926	926	1,457
	Unconfirmed	-	496	700	737	1,305	1,851	2,108	2,108	2,108	2,116	2,116	2,116
WECC-Total	Confirmed	1,190	1,972	3,485	3,530	4,132	4,132	4,316	4,316	4,316	4,899	4,899	4,899
	Unconfirmed	-	340	613	722	1,366	1,366	1,366	1,911	2,204	3,213	3,655	4,150
TOTAL-NERC	**Confirmed**	**6,067**	**13,450**	**18,375**	**23,426**	**36,592**	**41,647**	**42,328**	**43,345**	**43,397**	**44,056**	**44,056**	**44,705**
TOTAL-NERC	**Unconfirmed**	**-**	**1,088**	**4,057**	**5,096**	**8,666**	**12,296**	**21,815**	**23,231**	**23,524**	**24,541**	**25,261**	**25,756**
TOTAL-NERC	**TOTAL**	**6,067**	**14,538**	**22,432**	**28,521**	**45,259**	**53,943**	**64,143**	**66,576**	**66,921**	**68,597**	**69,316**	**70,460**

For all these reasons, NERC is projecting approximately 64.1 GW of capacity to be retired by 2017 and 70.5 GW by 2022. With the exception of ERCOT, the retirement of this capacity does not pose significant resource adequacy concerns. Rather, issues related to supporting system stability and transmission enhancements required as a result of retiring generation are likely to cause some reliability concerns in areas that are impacted by large generator retirements (Figure 6).

Figure 6: NERC-Wide Confirmed and Projected Fossil-Fired Capacity Retirements (with 2011 as a base-year)[27]



[26] Net On-Peak summer capacity.

[27] Natural gas and coal/oil projections projections are aggregated from *2012 LTRA* reference case data and represent net changes (i.e., there are increases in capacity throughout the assessment period as well). Capacity changes are due to a combination of capacity retirements, derates, and maintenance outages. Unconfirmed retirements of oil and coal were provided through a supplemental data request. Details on this request are provided in Appendix IX. The *2012LTRA* Reference case indicates approximaterly 32 GW of gas-fired capacity is projected from 2012-2022. This figure has a base-year of 2011, with over 40 GW projected from 2011-2022.

The retirement of larger and/or strategically situated generating units will cause changes to the power flows and the performance of the bulk power system. 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.

System planners and operators must understand and study impacts of every generator that may be retired; in market areas, this analysis is performed with a retirement request of the market participant. Federal environmental rule compliance deadlines will challenge the electric industry's planning horizons and processes. Transmission lines and facilities, as well as power plants, are often planned and constructed over a long period of time. Therefore, sufficient time is needed so that plans can be developed and implemented to accommodate generator retirements. If these decisions are made in a time frame that does not allow for building new generation capacity or transmission enhancements, overall system reliability could be adversely affected.

The lack of certainty has left system planners with little information on how the system might be changed in the future. For example, in many of the deregulated market areas, the ISO/RTO, performing the Planning Coordinator function, has little insight into the retirement decisions of generators serving the market. Many of the ISO/RTOs have challenges in identifying generators that will retire, because the market rules or criteria do not require generators to inform the system operator until 90 days prior to the requested retirement date or termination of an interconnection agreement. However, those areas with a forward capacity market structure are able to foresee market participant withdrawals up to three years in the future. For example, in PJM, almost 15 GW of existing fossil-fired generation did not bid into the capacity market. While this capacity has not all been officially announced to retire, the PJM planning process, along with this assessment, does not include this generation in future reliability analyses. Areas without this capability or other methods to provide planning coordination with sufficient lead time to determine reliability impacts are left with significant uncertainty as to the amount and timing of retirements.

As a result of generator uncertainties, transmission plans needed to accommodate generator retirements are impacted. System planners' responsibilities include analyzing expected future changes in generation and transmission assets, such as the retirement of a generating unit; customer demand; and emerging reliability issues. For example, once a system planner learns that a power company intends to retire a generating unit, the system planner generally studies the electric system to assess whether the retirement would cause reliability challenges and then identifies solutions to mitigate any impacts. The solutions could be in the form of replacement capacity (generation or demand-side resources), new transmission lines, or other equipment, each with its own associated permitting and construction timelines.

Other compounding issues, such as dependency on gas-fired generation, significant generator retrofit maintenance outages, and an increasing need for system flexibility, will pose continued challenges for planners and operators of the performance of the BPS. As more gas-fired generation is brought on-line in the bulk power system, gas dependency issues must be addressed. Increased gas-fired capacity may require additional gas pipeline infrastructure, increased coordination with pipeline operators, and developing operational strategies to minimize potential fuel delivery issues. These issues were highlighted in a recent NERC report[28] on gas and electric interdependencies and are also highlighted later in this report.

When a Planning Coordinator receives a deactivation request from a Generator Owner, it simulates power flows and stability of the bulk power system and assesses resource adequacy based on forecast system conditions. Detailed modeling studies analyze system configurations against NERC and Regional Reliability Standards to identify transmission overloads, voltage limitations, system stability, and other reliability performance conditions. The Planning Coordinator is required to develop plans and implement solutions for each potential violation, which could otherwise lead to overloads, equipment failure, instability, and, in the most extreme circumstances, uncontrolled, widespread cascading outages.

[28] 2011 NERC Special Assessment Report: A Primer of the Natural Gas and Electric Power Interdependency in the United States: http://www.nerc.com/files/Gas_Electric_Interdependencies_Phase_I.pdf

Based on information gathered from stakeholders and the Regional Entities, a large amount of retirements occurring over a short period may cause reliability concerns. In some cases, these reliability issues could result in violations of NERC Reliability Standards and, therefore, pose a threat to reliability if not addressed. System impact studies, conducted by Planning Coordinators, will be able to identify impacts and potential mitigation strategies to address the announced and planned retirement of facilities.

Overall, generation retirements need to be evaluated and analyzed in an integrated fashion. While the high degree of uncertainty surrounding retirement decisions continues to be exceedingly difficult, power system planners must continue not only to study the effects of individual generator impacts, but also to recognize the cumulative impacts of multiple generator retirements.

Risk Assessment Summary

Impacted Assessment Area(s)	PJM MISO SERC
Impact Type	Resource Adequacy - Significant generator retirements can cause capacity deficiencies and may affect the power system's ability to meet peak demands.
Magnitude of Impact	Operating Reliability – Local transmission reliability impacts due to large plant retirements
	44 GW of Fossil-Fired Generation Confirmed to Retire
	24 GW of Fossil-Fired Generation Projected to Retire
Likelihood of Impact	Confirmed retirement capacity is very likely to retire based on the current schedule. However, it is possible that these plans change in the future depending on changes in regulations, technologies, and fuel prices.
	Short terms; a majority of the retirements are expected by 2016

Recommendations

NERC	NERC should continue to monitor retirements and emerging reliability issues stemming from significant generator retirements in the *Long-Term Reliability Assessments*.
Generator Owners and Operators	Generator Owners and Operators that are disconnected from wide-area planning functions (e.g., generator owners operating in an ISO/RTO), should provide Planning Coordinators timely and accurate information about the retirement plans for their units in order to adequately assess any reliability concerns. While changes to market rules are not necessarily needed, discussions should occur and expectations should be shared with independent authorities on reliability.
Planning Coordinators	All Planning Coordinators should employ available tools and processes to ensure that BPS reliability is maintained through any resource transition. Regional wholesale competitive market operators should ensure markets are functioning effectively to support the development of new replacement capacity where needed.

Increased Risk of Capacity Deficiencies in ERCOT as Planning Reserve Margins Projected to Fall Below Targets

Starting as early as next year, the Electric Reliability Council of Texas (ERCOT)[29] Planning Reserve Margin is projected to be below the NERC Reference Margin Level. Specifically, for 2013 the Anticipated Reserve Margin of 13.4 percent is below the ERCOT planning target (NERC Reference Margin Level) of 13.75 percent.[30] At these levels, the risk of insufficient generation resources to meet peak demand increases beyond the accepted target. Throughout the 10-year assessment period, the Planning Reserve Margin continues to degrade and is projected to fall below five percent by 2017 and approximately zero by 2020 if more resources are not acquired. By not meeting the Planning Reserve Margin target of 13.75 percent, ERCOT is unable to meet a "one-event-in-ten" planning target.[31] With ERCOT Planning Reserve Margins below the NERC Reference Margin Level, ERCOT does not appear to have sufficient resources during the summer peak to maintain target resource adequacy levels at any point throughout the assessment period (Figure 7 and Table 2).

Figure 7: ERCOT Summer Planning Reserve Margins

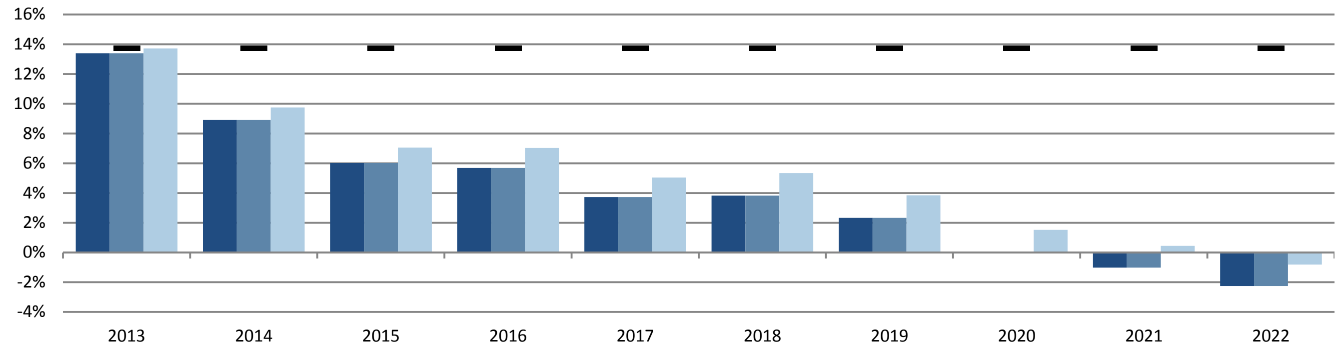


Table 2: ERCOT Planning Reserve Margins

ERCOT-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		13.40%	8.91%	6.02%	5.69%	3.72%	3.82%	2.33%	0.04%	-1.02%	-2.26%
PROSPECTIVE		13.40%	8.91%	6.02%	5.69%	3.72%	3.82%	2.33%	0.04%	-1.02%	-2.26%
ADJUSTED POTENTIAL		13.72%	9.75%	7.06%	7.03%	5.04%	5.34%	3.84%	1.52%	0.44%	-0.82%
NERC REFERENCE	-	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**

ERCOT-Winter		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		53.03%	52.33%	47.01%	48.32%	40.96%	42.49%	40.71%	39.72%	37.78%	32.35%
PROSPECTIVE		53.03%	52.33%	47.01%	48.32%	40.96%	42.49%	40.71%	39.72%	37.78%	32.35%
ADJUSTED POTENTIAL		55.34%	57.43%	53.33%	56.81%	49.02%	52.00%	50.20%	49.10%	47.03%	41.24%
NERC REFERENCE	-	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**

The projected capacity deficiencies may result in an increased probability of interruptions of firm load to maintain reliability. Reserve margins are calculated using a 50/50 peak demand forecast.[32] Therefore, these values represent what is considered a normal summer with a normal electric peak demand. However, the onset of extreme and sustained hot temperatures may cause ERCOT to initiate rotating outages to maintain the reliability of the interconnection and prevent uncontrolled, cascading outages. As reserve margins decrease below reliability targets, the probability of rotating outages

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[29] The Electric Reliability Council of Texas (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 bulk power system within ERCOT.

[30] The ERCOT Planning Target of 13.75 percent is a planning target applied based on a probabilistic analysis performed by ERCOT. See *2010 ERCOT Long Term System Assessment*: http://www.ercot.com/content/news/presentations/2010/ERCOT%202010%20Long%20Term%20System%20Assessment.pdf ERCOT's Planning Target is included as the NERC Reference Margin Level in this assessment.

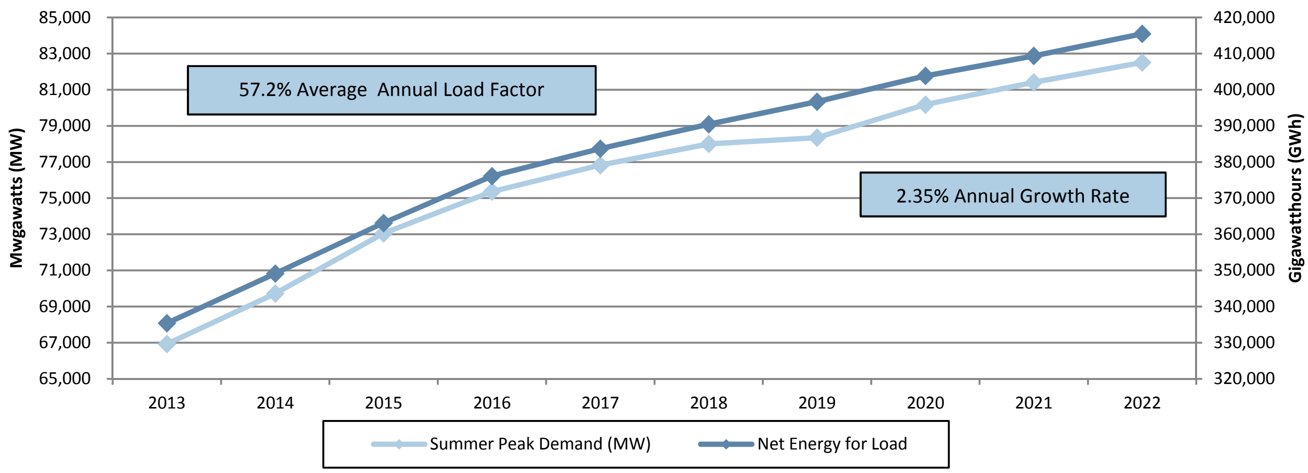
[31] Reliability planning for the bulk power system, or resource adequacy planning, has historically been based strictly on Loss of Load Expectation (LOLE), or the number of firm load shed events an electric system expects over a period of one or more years. The electric power industry has for decades used an LOLE of 1 day of firm load shed in 10 years as the primary, if not sole means for setting target reserve margins and capacity requirements in such resource adequacy analyses. While this is not a regulatory requirement in ERCOT, this planning criteria is the generally accepted industry standard for maintaining sufficient resources to meet peak demands.

[32] Forecasts cannot precisely predict the future. Instead, many forecasts report a baseline or most likely outcome, and a range of possible outcomes based on probabilities around the baseline or midpoint. Actual demand may deviate from the midpoint projections due to variability in key factors that drive electricity use. For these forecasts, there is generally a long-run 50 percent probability that actual demand will be higher than the forecast midpoint and a long-run 50 percent probability that it will be lower.

increases. Meeting resource adequacy targets in ERCOT over the next 10 years will largely be a function of the extent and frequency of extreme and prolonged weather events and whether timely capacity additions can be integrated. Most importantly, current forecasts do not appear to be sufficient to meet a "normal" peak demand forecast.[33]

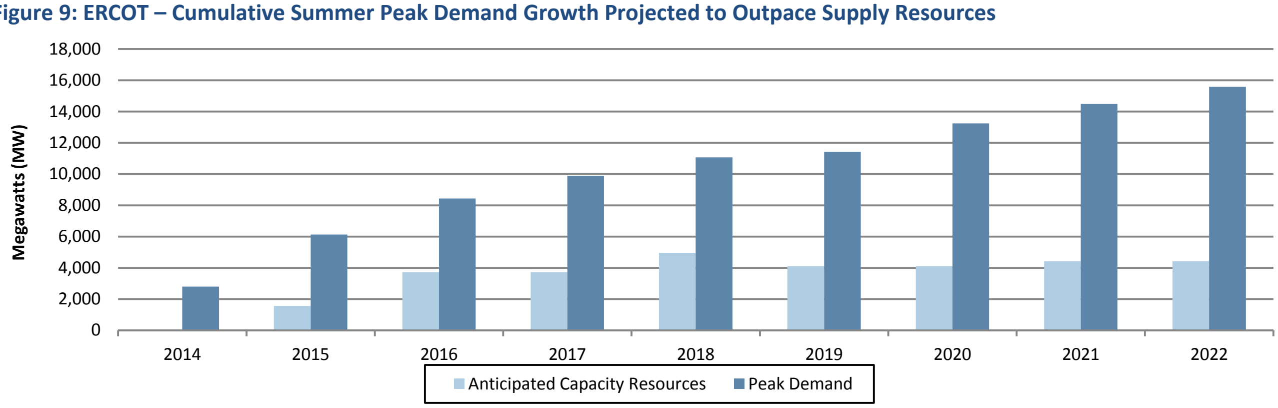
With significant demand growth expected in Texas, even slight deviations from the peak demand forecast can significantly impact the area's flexibility on peak. Over the next 10 years, peak demand in ERCOT is expected to increase by almost 16,000 MW (or 23 percent), which is the largest growth across all NERC assessment areas (Figure 8).

Figure 8: ERCOT – Highest 10-Year Projection for Peak Demand and Energy Growth



The expectation that Planning Reserve Margins will be below the NERC Reference Margin Level is a result of limited knowledge of plans for future generation development and retirements, especially due to uncertainty in ERCOT's marketplace. Uncertainty in the supply of future resources is causing significant reliability concerns as projected resources cannot keep up with the large peak demand growth (Figure 9).

Figure 9: ERCOT – Cumulative Summer Peak Demand Growth Projected to Outpace Supply Resources



It is important to note that resource adequacy and its impact on the Planning Reserve Margin is at the forefront of policy maker discussions in Texas, and there are a number of proposals to incent more generation development as well as other non-traditional resources. The projections for Planning Reserve Margin deficits will vary as solutions are implemented. A project has been created to discuss the options, opinions, and concerns by the Public Utility Commission of Texas (PUCT).[34]

[33] ERCOT Planning – 2012 Long-Term Demand and Energy Forecast http://www.ercot.com/content/news/presentations/2012/2012%20Long-Term%20Hourly%20Peak%20Demand%20and%20Energy%20Forecast.pdf

[34] See Project No. 40000 at the Public Utility Commission of Texas.

Since ERCOT operates within its own interconnection, opportunities to import more power from neighboring areas are limited. The amount of capacity imports considered Firm by ERCOT is just under 600 MW. Assistance from outside entities is restricted to a maximum of approximately 1,100 MW. While there are some transmission projects being considered to increase the transfer capabilities between ERCOT and Eastern and Western Interconnections,[35] these projects are too early in development to be considered for this assessment (Table 3).

Table 3: ERCOT Capacity Transactions (Summer Peak)

ERCOT-Summer	2013	2022
Expected Imports	0	0
Firm Imports	598	598
TOTAL IMPORTS	598	598
Expected Exports	0	0
Firm Exports	317	0
TOTAL EXPORTS	317	0
TOTAL NET CAPACITY TRANSACTIONS	**281**	**598**

Short of building more generation within ERCOT or relying on future transmission projects to increase transfer capabilities, there are additional opportunities to procure more demand-side resources in the future.

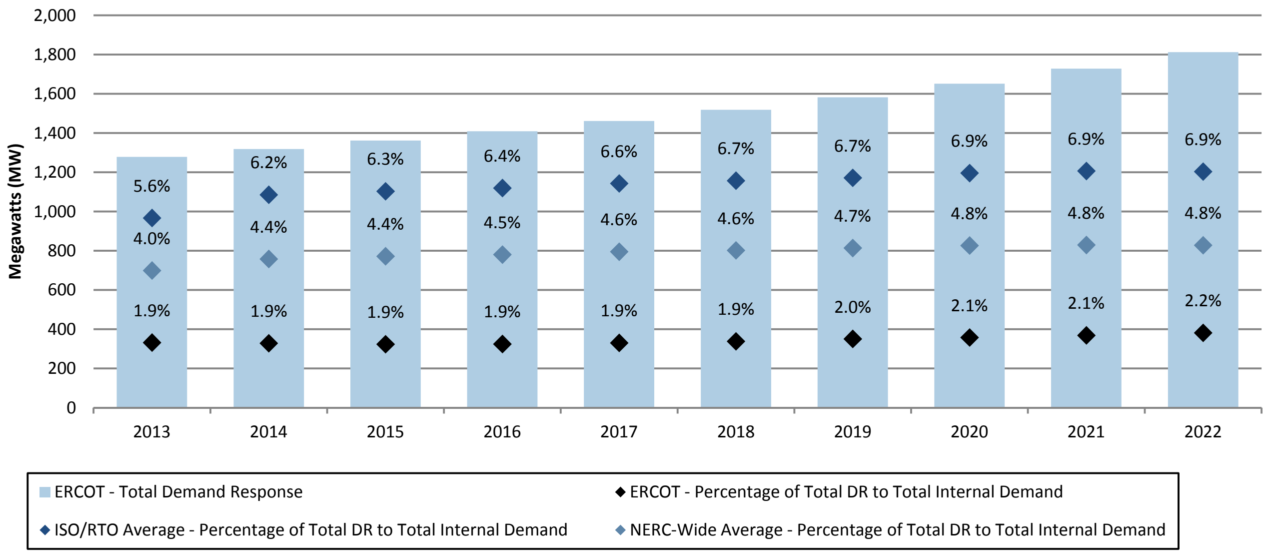
Demand-Side Management (DSM) programs, which include Conservation, Energy Efficiency (EE), and a variety of Demand Response (DR) programs, provide the industry with the ability to reduce peak demand and to potentially defer the need for some future generation capacity. EE concentrates on end-use energy solutions and targets permanent reduction of electricity consumption, attempting to reduce the demand for power. DR works to change the timing of energy use from peak to off-peak periods by transmitting changes in prices, load control signals, or other incentives to end users to reflect existing production and delivery costs.

Currently, ERCOT has almost 1,300 MW of expected dispatchable and controllable demand response available for market operations. Load Resources (LRs)[36,37,] provide Responsive Reserve Service (RRS) and Emergency Response Service (ERS) designed to be deployed in the late stages of a grid emergency prior to shedding involuntary Firm load and represents contractually committed interruptible load.[38,39] Additional demand response exists in ERCOT, but market rules currently limit the amount commercially available. This commercially available amount equates to approximately 2 percent of the forecast Total Internal Demand for the assessment area. This is significantly less than both the NERC-wide average, which is approximately 4 percent, and the ISO/RTO average, which is approximately 5.5 percent and will increase to 7 percent by 2022.

ERCOT also has an almost untapped resource market in the residential sector. Increasing demand response capabilities can provide some significant benefits in the short-term. Since demand response can be “installed” in a relatively short time frame, these resources have the potential to provide ERCOT operators with the flexibility that is needed during peak demand periods in the upcoming years. The increasing amount of smart meters and other smart grid technology in the state of Texas may also provide additional demand-side resources, which will help to partially offset potentially insufficient generation resources (Figure 10).[40]

[35] http://www.tresamigasllc.com/.
[36] Categorized as Load as a Capacity Resource Demand Response in this assessment.
[37] http://www.ercot.com/content/mktinfo/dam/kd/ERCOT Percent20Methodologies Percent20for Percent20Determining Percent20Ancillary Percent20Service Percent20Requir.zip.
[38] The 886 MW represent LR participation in RRS capacity during the peak month of August 2011 across the peak hours (3-6 PM).
[39] See Section 3.14.3 of the current ERCOT protocols:http://www.ercot.com/content/mktrules/nprotocols/current/03-051012_Nodal.doc.
[40] ERCOT Advanced Metering Initiative: http://www.ercot.com/services/projects/current/80027_01/index

Figure 10: ERCOT – Demand Response Mix Less Than Industry Averages



While some enhancements have already been made—such as increasing the scarcity pricing cap—ERCOT, along with the Public Utility Commission of Texas (PUCT), continues to identify and evaluate potential solutions to incentivize new capacity resources. Some of these potential solutions include developing more demand-side management resources with more demand response programs and increasing conservation capabilities, implementing state-mandated resource adequacy targets, and enhancing existing market mechanisms, which may include further increasing scarcity pricing or integrating a capacity component to the market structure.

The ongoing resource adequacy challenges in ERCOT are dynamic. The state regulator (PUCT) continues to be proactive in developing solutions that will be most beneficial to the electric stakeholders across Texas.[41] Most recently, changes in wholesale market rules for ERCOT were adopted in an effort to increase incentives for new capacity investments and to ensure reliability targets can be met.[42]

Ultimately, the resource adequacy concerns in ERCOT are more likely to impact the reliability of the BPS during peak conditions or in an extreme event. Since capacity deficiencies are likely to result in having to implement emergency operating procedures—which may include shedding firm load—uncontrolled cascading of the BPS is unlikely. However, the likelihood of this impact is highly dependent on weather conditions and resulting impacts to peak demand, especially in the summer. If actual peak demand increases beyond the summer forecast, the potential for rotating system outages grows. Prolonged extreme conditions also increase the last several days during the summer peak season.

[41] Resource Adequacy docket at the Public Utility Commission of Texas (Docket No. 40000)
[42] http://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.508/25.508.pdf

Risk Assessment Summary

Impacted Assessment Area(s)	ERCOT
Impact Type	Resource Adequacy - Significant generator retirements and lack of new resources can cause capacity deficiencies and may affect the power system's ability to meet peak demands.
Magnitude of Impact	Degrading Reserve Margins: Anticipated Reserve Margin below NERC Reference Margin Level in every year and is zero by 2020 unless more capacity is added
	Rotating System Outages: Capacity deficiencies can trigger emergency operating procedures that may include the shedding of firm load.
Likelihood of Impact	With ERCOT Planning Reserve Margins projected to be below the NERC Reference Margin Level in 2013, the probability of a capacity deficiency is increased and will continue to increase throughout the assessment period unless more capacity is added.

Recommendations

NERC	NERC should continue to assess plans and actions to address resource adequacy issues. Seasonal reliability assessments will provide a better short-term view on the preparations to maintain reliability through the upcoming season.
ERCOT	ERCOT should consider alternative solutions to resource adequacy issues and provide a strategic plan outlining the measures it is taking to increase reserve margins and ensure reliability.
	ERCOT should continue to provide information to the PUCT for continued development of policies in support of a solution to incease capacity resources.
Regulators	NERC strongly recommends that the PUCT and ERCOT identify and implement near-term and long-term solutions to decrease the likelihood of a capacity deficiency. While there has been a significant amount of work done at the PUCT on addressing this issue,[43] there has been little progress on bringing new resources online.

[43] Texas Public Utility Commission Proceeding to Ensure Resource Adequacy in Texas, http://www.puc.texas.gov/industry/projects/electric/40000/40000.aspx

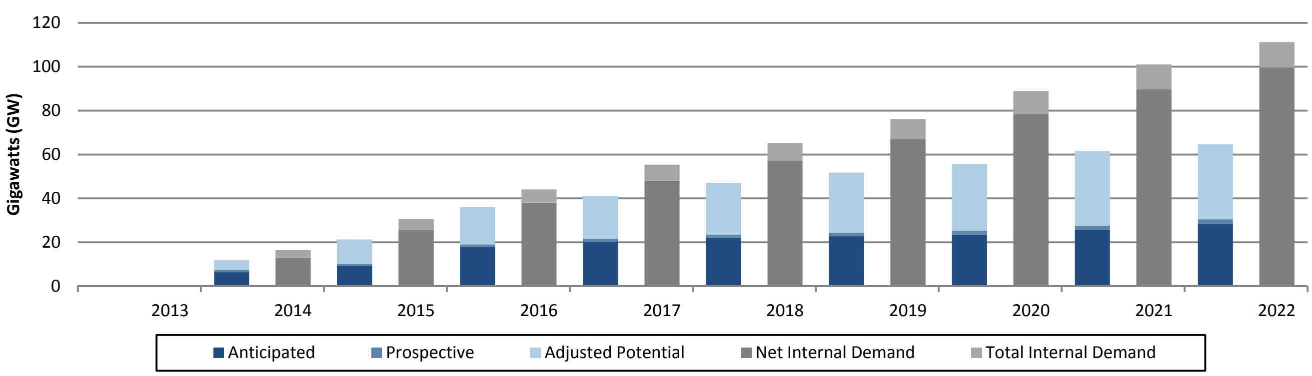
Resources Sufficient to Meet Reliability Targets in Most Areas

NERC assesses resource adequacy by evaluating each Assessment Area's Planning Reserve Margins—a deterministic method based on traditional capacity planning.[44] For the majority of the bulk power system, Planning Reserve Margins appear sufficient to maintain reliability during the long-term horizon. However, there are significant challenges facing the electric industry that may shift industry projections and cause the NERC reference case to change, adding considerable uncertainty not only in the long term, but in the short term as well. Where markets exist, signals for new capacity must be effective for planning purposes, which can impact necessary lead times to construct new generation, as well as any associated transmission. A transition to reduce environmental impacts through policy, specifically through regulatory compliance deadlines, could ultimately conflict with existing planning and approval processes—both regional and interregional.

Supply and Planning Reserve Margin projections in this assessment do not necessarily take into account all retirements of generators due to all potential environmental regulations and other industry risks. While some generators have already announced and planned for retirement, the majority of vulnerable generation resources have not finalized plans. A significant amount of generation retirements can have a considerable impact on Planning Reserve Margins if new resources and associated transmission cannot be constructed or acquired before the compliance deadlines. The results would drive on-peak Planning Reserve Margins lower than forecasted in this assessment. The uncertainty inherent in future generation retirements is representative of the future supply forecast as well. Without a firm understanding of future generation retirements, plans for replacement capacity are left uncertain (Figure 11).

Long-term uncertainty can increase due to the growth in demand response, as well as shorter lead times for bringing on-line natural gas and renewable generation capacity. All of these drivers contribute to future uncertainty as system planners can defer large capacity development projects for longer periods of time, allowing decisions to be made at a later time without an impact to reliability.

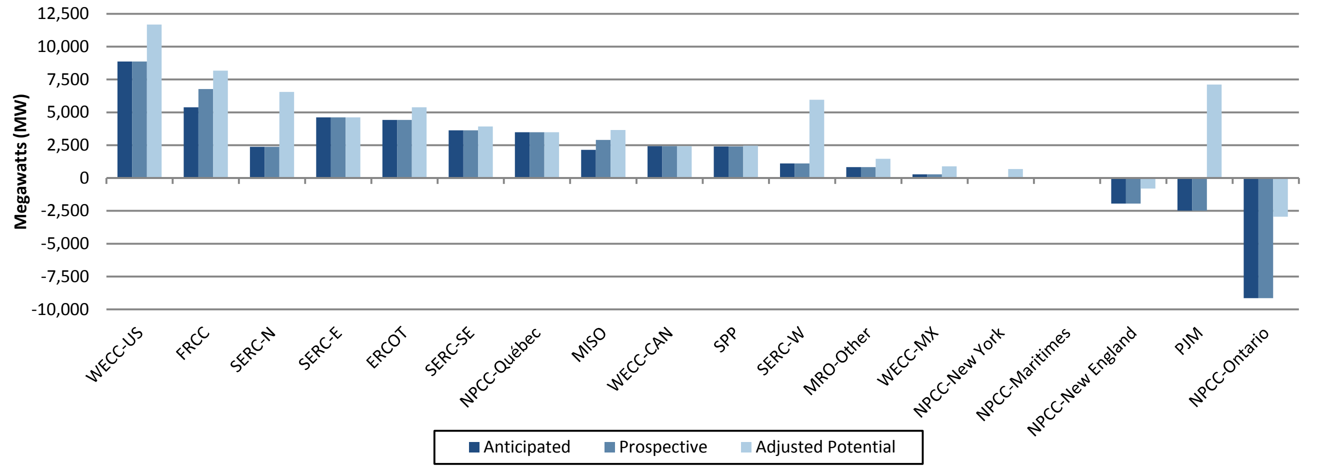
Figure 11: Net Cumulative Change in Supply and Demand Forecasts; Supply Categories Show Different Degrees of Resource Uncertainty; Demand Growth Outpaces Supply



However, the long lead times for developing and constructing transmission are difficult to align with the shorter lead times for resources. Although generating plant in-service lead times have been significantly reduced (excluding environmental permitting processes), transmission planning and approval necessary to integrate these new resources have not experienced a similar lead-time reduction (Figure 12).

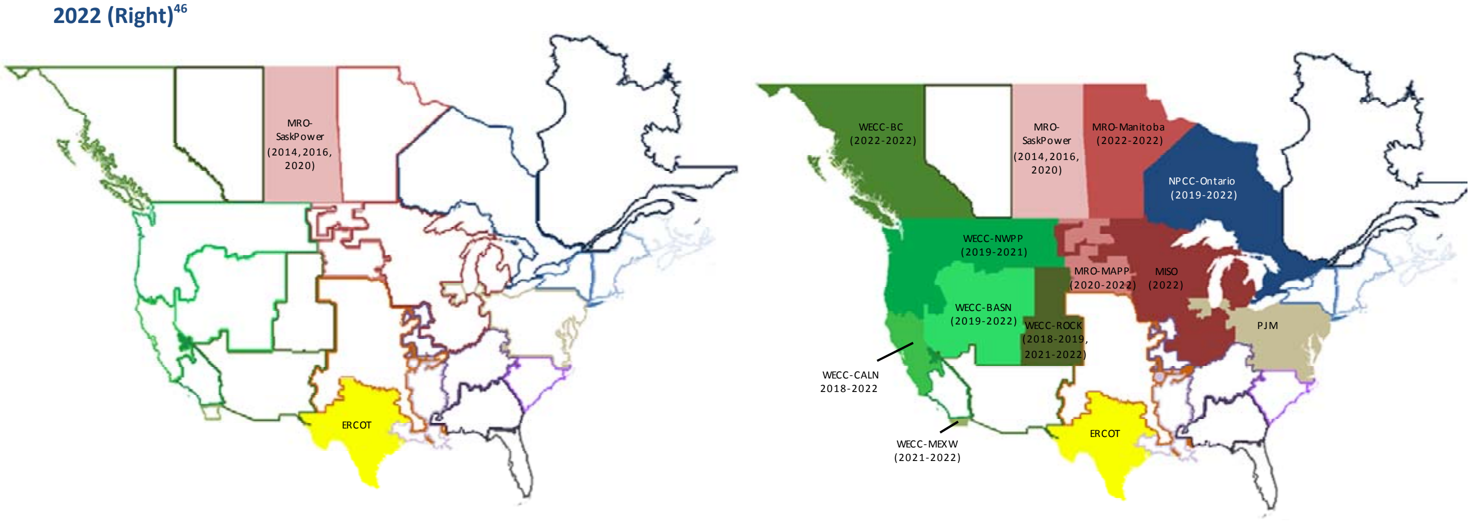
[44] Planning Reserve Margins in this report represent margins calculated for planning purposes (Planning Reserve Margins) not operational reserve margins that reflect real-time operating conditions. See *Estimated Demand, Resources, and Reserve Margins* for specific values.

Figure 12: Future Net 10-Year Capacity Change by Assessment Area



As mentioned earlier in this report, Planning Reserve Margins in ERCOT are projected to significantly decline over the assessment period. Additionally, the approximately 5,000 MW of projected resources does not appear to be sufficient to keep pace with peak demand growth. A considerable amount of Conceptual resources (which are included only as Adjusted Potential Resources), appears to be the primary reason that Ontario, PJM, and the WECC assessment areas fall below the NERC Reference Margin Level (Figure 13).

Figure 13: Assessment Areas with Anticipated Reserve Margins that fall below the NERC Reference Margin Level by 2014[45] (Left) and 2022 (Right)[46]



In general, long-term planning (beyond five years) is inherently uncertain due to, among other things, varying market practices and regulatory conditions, such as environmental regulations. In the areas where Anticipated Resources fall short of meeting the NERC Reference Margin Level, Adjusted Potential Resources must be accelerated, if necessary. However, Adjusted Potential Resources carry a higher degree of uncertainty because these resources are in the early stages of

[45] When evaluating system requirements for new generation, SaskPower utilizes a mostlikely load forecast accounting for load risk to project demand requirements. This is not based on a 50/50 probability. For the purpose of this study, utilization of a less conservative 50/50 load forecast probability would result in higher reserve margins ranging from approximately 16 to 23 percent. Furthermore, for the purpose of this assessment, the NERC Reference Margin Level is 11 percent (lower end of probabilistic EUE range) throughout the assessment period. Saskatchewan has planned for adequate resources to meet anticipated load throughout the assessment period.

[46] Assessment Areas with no dates in parenthesis maintain Anticipated Reserve Margins that are above the NERC Reference Margin Level throughout the assessment period.

development. Therefore, considerable progress in resource development must be made in order to bring these resources online. Engineering studies, siting and permitting, and construction represent the activities required before these resources can have reasonable expectation of going into service. Should peak demand grow faster than projected, additional Conceptual resources should be developed, as they likely will be needed to maintain resource adequacy.

Risk Assessment Summary

Impacted Assessment Area(s)	ERCOT
	MISO
	MRO
	NPCC-Ontario
	PJM
	WECC
Impact Type	Resource Adequacy - Lower than anticipated capacity additions can contribute to a capacity shortage
Magnitude of Impact	With the exception of ERCOT, all other impacted areas have at least five years to enhance plans to ensure sufficient resources are constructed or procured.
Likelihood of Impact	The likelihood of an event that impacts reliability is greatly reduced if proper planning processes sufficiently reflect resource uncertainties
	Conceptual resources are generally in early planning stages and have a high degree of uncertainty associated with project completion

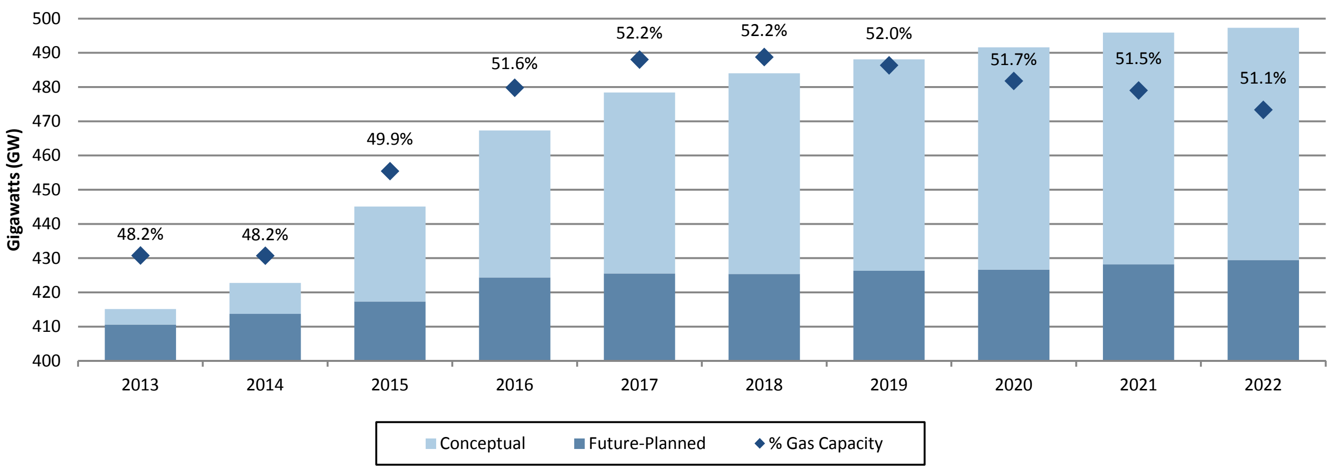
Recommendations

NERC	NERC should consider evaluating generator uncertainties using a probabilistic risk basis, rather than a deterministic approach in its reliability assessment.

Increased Dependence on Natural Gas for Electricity Generation

The growth in natural gas demand within the electric sector has important implications on other gas-consuming sectors, such as commercial and residential heating or industrial manufacturing. Increased dependence on natural gas in the electric sector has increased the need for all gas consumers, electric system planners and operators, and policy makers to focus more sharply on the interaction between the electric and gas industries. For a variety of reasons, including the adoption of highly efficient combined-cycle technology by the electric power industry and the emergence of shale gas, both of which have altered the relative economics of gas-fired generation, the dependence on natural gas by the electric power sector has increased significantly. Trends in fuel-mix changes highlighted in this assessment identify gas-fired generation as the premier choice for new capacity with almost 100 GW expected over the next 10 years, which represents almost half of all new generation capacity (Figure 14).

Figure 14: NERC-Wide Future Gas-Fired Capacity Serves Over Half the Projected Peak Total Internal Demand by 2016



Increasing gas-fired generation to meet electric loads in the future does not come without dependency risks. Increased dependence on natural gas can amplify the bulk power system's exposure to disruptions of fuel supply, transportation, and delivery. In order to accommodate a significant amount of gas-fired generation, BPS planners must understand the different functions gas-fired generation will perform (i.e., baseload and midrange support versus load following and peaking support). Risks to reliability must also be addressed through the three primary timeframes of system planning and operations: Long and Short-Term Planning (1–10 years), Operational Planning (1 day–1 year), and Operations (1 day–real-time) (Table 4).

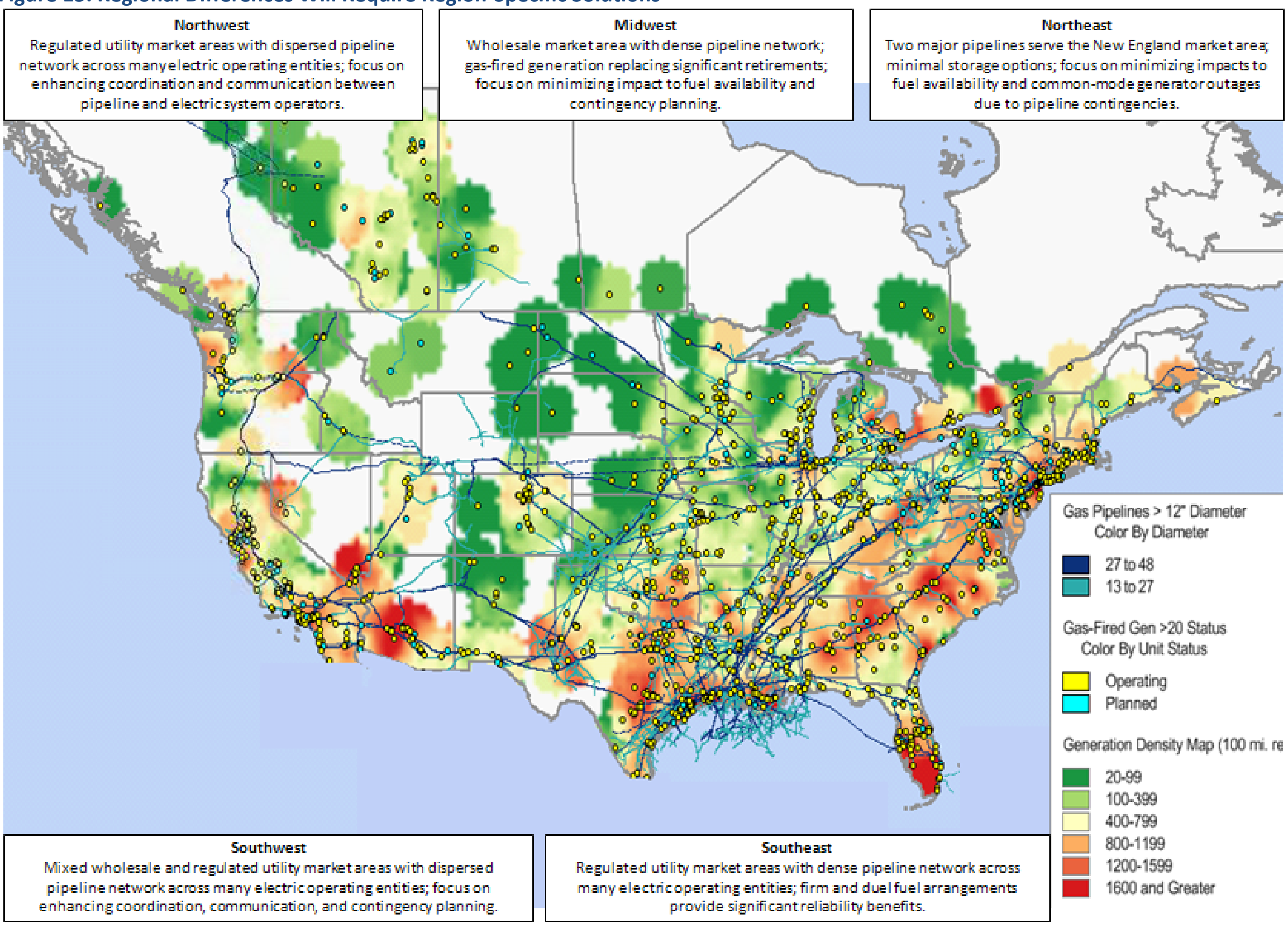
Table 4: Reliability Considerations for Accommodating Large Amounts of Gas-Fired Generation

Long- and Short- Term Planning	Operational Planning	Operations
Gas supply and fuel security	Seasonal and day-ahead observability	Information sharing and visibility
Dual-fuel capabilities	Coordinated operational procedures	Communication and information exchange
Fuel transportation expectations	Coordinated outage schedules	Emergency operating procedures
Generator availability	Increasing flexibility	
Resource planning		
Reliability assessment and resource adequacy studies		

NERC's Phase II effort on gas dependency targets these very issues. The report focuses on the different risks that can affect BPS reliability, identifying practices that minimize vulnerabilities, and identifying approaches where coordinated inter-industry efforts could provide enhanced system reliability.

A key area of focus is the need for increased coordination between the two industries, particularly at a regional level. It is important to understand the fundamental differences between how the two industries plan for the long term, communicate with each respective stakeholder, and operate within different regulatory frameworks. While solutions to mitigate increasing risks will be vast and Region-specific, NERC should ensure that enhancements to planning processes will account for expected uncertainty in gas-fired generation performance as well as potential contingencies on the pipeline network. Furthermore, operational procedures should include a certain level of formalized coordination with the gas pipeline industry, with specific attention on emergency operating procedures during extreme events. Each Region will have unique issues to resolve; therefore, efforts to reduce these risks will vary. These new challenges include a reduction of fuel supply diversification within the power industry, incorporating risks into planning processes and operational procedures, and the need to adapt fuel procurement, transportation, and storage strategies (Figure 15).

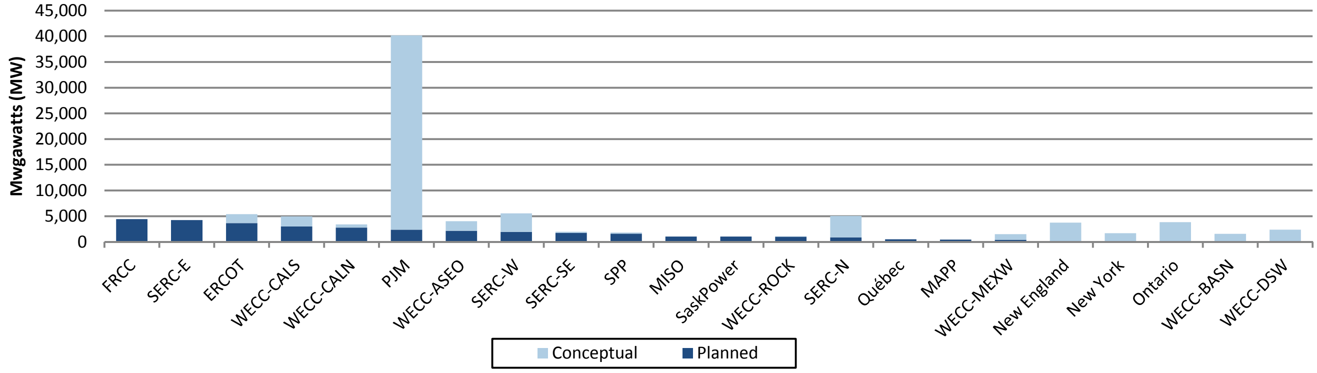
Figure 15: Regional Differences Will Require Region-Specific Solutions[47]



The amount of gas-fired capacity additions also contributes to the regional differences and vulnerabilities that could impact BPS reliability in the future. With natural gas as the premier fuel for new generation, gas-fired capacity additions are largely a function of forecasted peak demand increases and the amount of coal and oil-fired generation within a given assessment area. With significant generator retirements expected in the forecast, PJM is projecting approximately 40,000 MW of new gas-fired generation; however, over 37,000 MW are Conceptual and still in the early planning stages (Figure 16). No more than 5,000 MW are either Planned or Conceptual in all other areas.

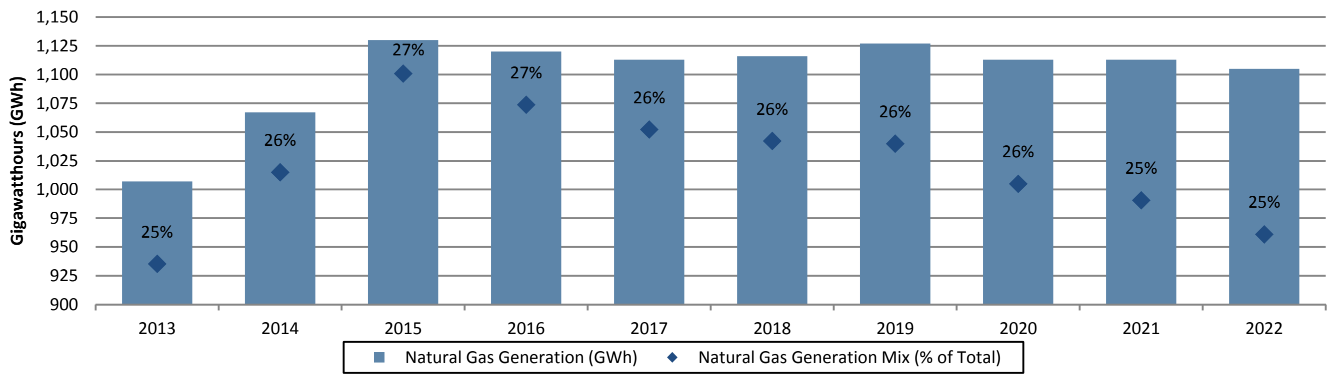
[47] Source: Ventyx Velocity Suite, An ABB Company; modified by NERC staff to reflect NERC footprint. Text boxes added by NERC staff.

Figure 16: Future Gas-Fired Capacity Serves Over Half the Projected Peak Demand



Historically, the power industry has relied heavily on fuel diversification for generating electricity. While there are regional differences, diversification strategies have had a number of significant benefits for the power industry. However, with the projected increases in capacity of gas-fired generation along with the projected reductions in coal capacity, gas-fired generation will be called upon more often. Gas-fired generation will be used to meet base, intermediate, and peak load requirements, effectively increasing overall capacity factors. According to its *2012 Annual Energy Outlook*,[48] the Energy Information Administration (EIA) is projecting an approximately 110 GWh increase in gas-fired generation, effectively increasing gas-fired generation to over 27 percent of all electric generation in 2015 and trailing off to 25 percent in the long term (Figure 17).

Figure 17: Gas-Fired Generation Significantly Increases Over Next Three Years



As shown in the NERC Phase I study on increasing gas dependencies, reliability challenges are more likely to occur during the winter season.[49] While electric generation is generally able to schedule and secure gas during the summer to meet seasonal peak demand, this flexibility decreases during winter months when pipelines tend to peak and firm transportation customers have scheduled their full entitlements. Cold weather can also be responsible for increased infrastructure and supply disruptions, which are generally caused by freezing. Risks to gas well-heads, generators, and pipeline infrastructure due to freezing can expose the electric industry to significant capacity shortages. It is important to understand that while firm gas transportation significantly decreases the likelihood that fuel delivery will be curtailed, extreme events, such as well-head freeze-offs causing decreased gas production (a “force majeure” event),[50] could potentially lead to common-mode failures of a significant amount of gas-fired generators. Additionally, pipeline customers with gas use is designated as

[48] U.S. Energy Information Administration's (EIA's) Annual Energy Outlook 2012 (AEO2012): www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf.

[49] 2011 Special Assessment Report: A Primer of the Natural Gas and Electric Power Interdependency in the United States, http://www.nerc.com/files/Gas_Electric_Interdependencies_Phase_I.pdf

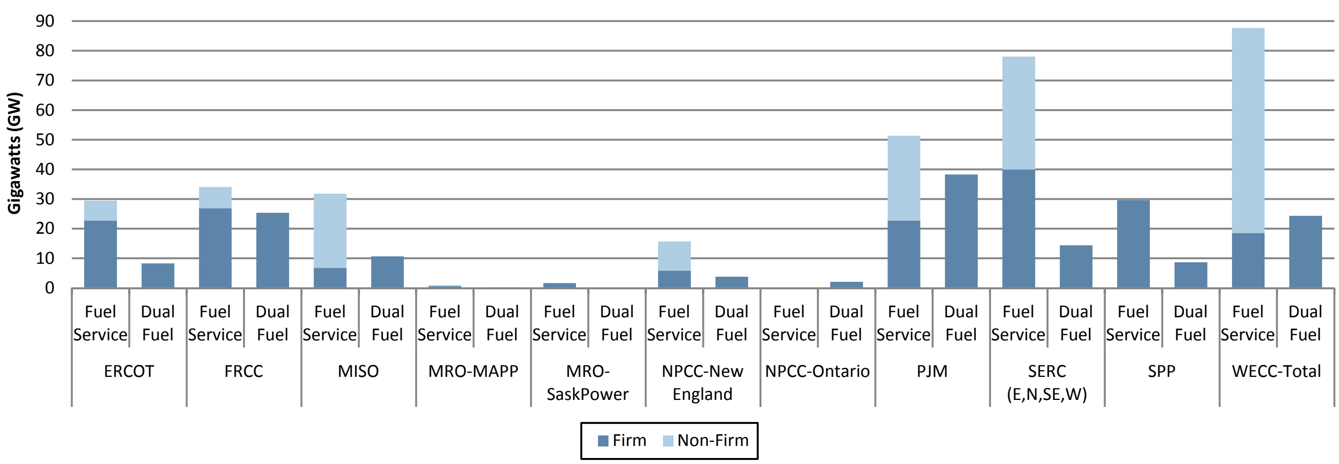
[50] Such agreements in fuel contracts relieve the lessee from liability for breach, if the party's performance is impeded as the result of a natural cause that could not have been anticipated or prevented. This act of God must completely prevent performance and must be unanticipated.

"human use" (typically local distribution companies and some commercial customers) always receive priority over electric generation, which during emergencies and restoration efforts can have an impact to gas-fired generation—even with pipelines that have Firm capacity rights.

Dual fuel capabilities and a variety of storage options may help bridge the gap between the uncertainties of gas availability during extreme events and maintaining a reliable source of capacity available to meet seasonal peak demands. Ultimately, the right balance of firm pipeline capacity, dual-fuel capabilities, and a variety of storage options will be regionally dependent. Factors such as market structure, geography, fuel mix, and pipeline infrastructure will determine the extent of gas dependency risks as well as what solutions are available.

Improvements in system reliability may be realized from having sufficient back-up, dual-fuel switching capabilities. Obstacles to achieving such benefits include operational preparedness and state, federal, and provincial environmental regulations, which effectively limit the amount of oil that can be burned. Current policies and rules that regulate back-up oil use and emissions for electric generation may need to be evaluated to ensure dual-fuel capability can be maintained during emergencies or other extreme conditions. Additionally, planning processes should consider back-up fuel inventories, changes in ramp and unit power capabilities, and the time requirements for fuel switch-over. Without considering this information, the amount of available dual-fuel generation projected to be available may be overstated. Currently, 125 GW of gas-fired generation has dual-fuel capabilities, and 58 percent of gas-fired generation is tied to firm supply, transportation, and delivery (Figure 18).

Figure 18: NERC-Wide Gas-Fired Generation Fuel Services and Dual Fuel Capabilities[51]



In early February 2011, a cold-weather event impacted a significant amount of electric generation in Texas, Arizona, and New Mexico.[52] While much of the impact was related to insufficient weatherization, there were some issues with gas supply and transportation. For the southwest as a whole, 67 percent of the generator failures (by MWh) were due directly to weather-related causes, including frozen sensing lines, frozen equipment, frozen water lines, frozen valves, blade icing, and low temperature cutoff limits. At least another 12 percent were indirectly attributable to the weather (occasioned by natural gas curtailments to gas-fired generators and difficulties in fuel switching). Natural gas production losses stemmed principally from three causes: gas well-head freeze-offs, icy roads limiting field crew's access to remote well-head sites, and rolling electric blackouts or customer curtailments impacting gas production equipment.

[51] This analysis shows results of where fuel service is known. Areas which did not provide results, and may have unknown fuel service, are not shown.

[52] Joint FERC / NERC Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011, http://www.ferc.gov/legal/staff-reports/08-16-11-report.pdf.

While extreme cold weather is less common in the Southwest, these conditions can arise every few years, without substantial warning. Significant progress has been made to both the gas and electric industries' preparations for managing extreme cold weather events. Weatherization and enhanced emergency operating procedures have been implemented because of the event and will be highlighted in the *2012/2013 Winter Reliability Assessment*.[53]

It is inherent in the electric industry's role of providing reliable electricity to its customers to manage risks. However, it is important to recognize that reliability comes at a cost, and the electric industry must maintain reliability, regardless of the constantly shifting resource mix. The issue of deciding between reliability and cost must be addressed appropriately by all participants of both industries. Industry regulators have a paramount responsibly to find common ground.

NERC will soon release a second phase of its ongoing assessment of the increased dependency on natural gas-fired generation.[54] In its role of continuing to assess the reliability of the BPS through periodic and special reliability assessments, NERC realized the necessity to identify more specific reliability needs. The NERC Phase II effort on increasing gas dependency focuses on the different vulnerabilities that can affect BPS reliability, identifying ways that could minimize those vulnerabilities, and identifying approaches in which coordinated inter-industry activities could provide enhanced system reliability. While solutions will be vast and Region-specific, NERC must ensure that enhancements to planning processes are made to account for any expected uncertainty in gas-fired generation performance as well as potential contingencies on the pipeline network. Furthermore, operational procedures must include a certain level of formalized coordination with the gas pipeline industry, with specific focus on emergency procedures during extreme events.

Risk Assessment Summary

Impacted Assessment Area(s)	ERCOT
	NPCC-New England
	MISO
	PJM
Impact Type	Resource Adequacy - Significant (common-mode) generator outages can cause capacity deficiencies.
	Operating Reliability - Transmission system impacts could manifest from significant gas-fired generator outages.
Magnitude of Impact	During extreme cold weather conditions, gas-fired generation with neither firm transportation nor dual-fuel capabilities may not be available to produce electricity.
	A significant gas supply or pipeline disruption can cause a substantial portion of gas-fired generation to be unavailable.
Likelihood of Impact	Highly dependent on winter weather conditions
	Increase in gas generation and capacity is expected by 2015
	In the past 40 years, at least one significant event has occurred during each 10-year period—at least two major events occurred between 2002 and 2011.

Recommendations

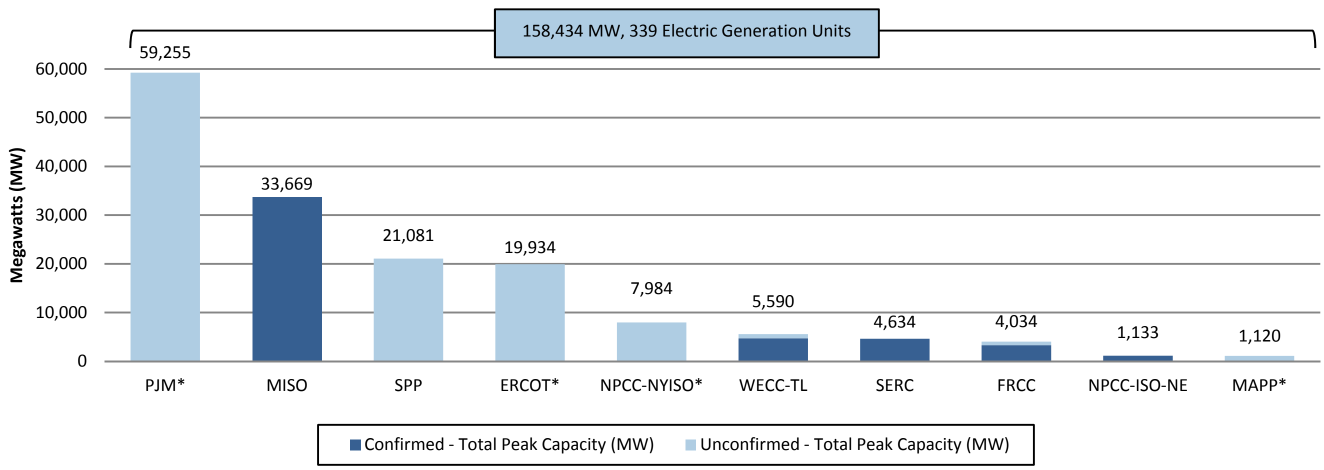
NERC	Identify guidelines, recommendations, alerts, or enhancements to reliability standards that support minimizing risks associated with natural gas dependencies.
	Consider incorporating fuel risks and capacity impacts into resource adequacy and reliability assessments.
	Enhance seasonal assessments of gas-fired generation availability by identifying fuel transportation types and dual-fuel reliability metrics.
	Assess industry plans and procedures to mitigate severe fuel disruptions.
Planning Coordinators, Reliability Coordinators and Balancing Authorities	Enhancements to BPS planning processes that account for uncertainty in gas-fired generation performance should be considered.
	Operational procedures should include a certain level of formalized coordination with the gas supply and pipeline industry, as well as emergency procedures during extreme events
Regulators	State regulators should evaluate the associated risks of gas supply and transportation disruptions and ensure these risks are consistent with a level of risk that is known, expected and planned.
	Current policies and rules that regulate back-up oil use and emissions for electric generation may need to be evaluated to ensure dual-fuel capability can be maintained during emergencies or extreme conditions.

[53] NERC reliability assessment reports: http://www.nerc.com/page.php?cid=4|38.
[54] NERC Gas and Electric Interdependency activities: Phase I and II study scope: http://www.nerc.com/docs/pc/ras/Draft2011GasStudyScope.pdf.

Long-Term Generator Maintenance Outages for Environmental Retrofits

A significant retrofit effort is expected over the next 10 years in order to comply with federal and state-level environmental regulations. A majority of environmental controls are expected to be put in place to meet air regulations by April 2016. In total, 339 unit-level foss-fired generation retrofits will be needed, totaling about 160 GW.[55] However, there is still significant uncertainty in the "unconfirmed" values as maintenance schedules have not yet been fully evaluated by all areas (Figure 19).

Figure 19: NERC-Wide Confirmed & Unconfirmed (Projected) Maintenance Outages for Environmental Control Retrofits through 2016



Complying with proposed environmental regulations may result in generation capacity not being available during shoulder months and off-peak times during the operating day in the near-term (2013–2016).[56] Within this timeframe, some generators may not have enough time to acquire permits, procure engineering services, design equipment, and systematically shut down units for the purpose of retrofitting, while concurrently meeting reliability goals. Deactivations or temporary de-ratings associated with generating unit retrofits may avoid the need to procure replacement resources, but they introduce additional complexities with scheduling outages to avoid temporary shortages that may occur if too much capacity is taken out of service at the same time.

The challenge of timing and scheduling numerous major construction projects, both generation and transmission, to maintain system reliability and avoid having key facilities unavailable at the same time, include:

- Compressed timelines
- Uncertainty related to scope of materials, equipment needs, and availability of skilled labor for these projects
- Market forces outside of the entity's control that could impact cost and delivery times of long lead items (fans, large motors, transformers, fabricated equipment, etc.)
- Outage durations, some as long as 12 weeks at a time, to cover tie-ins and fan upgrades for baghouses and SCRs
- Conflicts in outage windows due to the coordination of new compliance-related projects/outages and existing transmission construction programs and outages, located internally and externally to an area's service territory
- Managing reliability risks for units that will share common environmental controls such as common scrubbers or baghouses

[55] These values do not include retrofits that would be needed to meet 316(b) compliance, as this rule has not yet been finalized and plans have not yet been established. Additionally, areas marked with a (*) were unable to provide this data at this time as the information is not available. In these cases, estimates from NERC's *2011 Long-Term Reliability Assessment* were used and potential retrofits for 316(b) are included.

[56] The shoulder months of the electric year are from March 1 through May 30 and October 1 through November 30.

Generators that are required to retrofit their plants with environmental controls and have chosen to remain online must be in compliance with MATS by 2016 or submit a request for a waiver or extension—specifically, an Administrative Order.[57] With a significant amount of retrofits to be completed from now (late 2012) through 2016, reduced system flexibility during off-peak periods could be encountered. Given the window for completing retrofits, many affected units may need to take long-term maintenance outages concurrently. Taking multiple units out of service for extended outage periods can aggravate resource adequacy and reduce system flexibility and dispatch options, especially during seasons considered "off-peak". Therefore, outage and retirement coordination must be a priority for the industry. If a reliability critical generator cannot come into compliance with the MATS by April 2016, it may request from the EPA an Administrative Order to come into compliance by as late as April 2017, following the pathway described in the December 16, 2011 policy document.

The EPA will rule on a generator's requests for an Administrative Order (AO) to operate in noncompliance with the EPA's Mercury and Air Toxics Standards (MATS).[58] As stated in the EPA Policy Memorandum, on a case-by-case basis, the EPA may rely on identification or analysis of reliability risks upon the advice and counsel of reliability experts, including, but not limited to FERC, RTO/ISOs, Planning Authorities, NERC, and state public service or utility commissions. However, the decision to grant an AO to an owner/operator rests entirely with EPA. NERC, in concert with the Regional Entities, may be requested by the EPA to provide a reliability assessment in relation to a pending AO request. This assessment may include review of the recommendations, a resource adequacy assessment of the given area, gathering of additional information, and additional study if required. Further, it may include all requirements for a reliable power system, including impacts on Planning Reserve Margins, effects on local, regional, and interconnection-wide operational reliability, and review of the expected operating procedures that system planners and operators will use to address NERC Reliability Standards. These studies include a measure of resource adequacy, power flow, transient stability, and system restoration plans. Plans for transmission outage coordination (inter- and intra-regional) may also be needed to implement necessary transmission upgrades. To the extent that potential violations to NERC Reliability Standards are identified, FERC may also provide comments to serve as guidance for EPA on whether there might be a violation of a Reliability Standard.[59]

Compressed compliance deadlines may challenge the electric industry's planning horizons, existing planning processes, and typical construction schedules. Successful implementation of environmental regulation compliance will be highly dependent on the ability of units needed for reliability to obtain the necessary time needed to comply with certain requirements. Given the timelines for compliance, many of the affected units may need to take maintenance outages concurrently. The need to take multiple units out of service on extended scheduled outages can exacerbate resource adequacy concerns and reduce needed flexibility, even during off-peak periods. Outage coordination must be a priority to avoid resource adequacy concerns during maintenance periods.

The timelines for retrofits vary by technology. Some retrofit technologies, such as flue gas desulfurization (FGD) and selective catalyst reduction (SCR), are riskier than others because of the length of time it takes to complete the work compared to the deadlines for compliance. It may be possible to receive an additional one-year AO beyond the first-year extension, extending the compliance deadline into 2017. This second-year extension will likely be limited to unique cases, but does offer the flexibility that is needed to ensure generators that are critical for reliability can operate.

Existing authorities should be used to provide extensions where justified. Unit outages for maintenance due to retrofits will affect both the capability to retrofit existing plants to meet required emission targets and the ability of industry to coordinate the necessary outages in order to perform the retrofit. For example, to meet the MATS rule, one possible retrofit solution is to install an air scrubber. It takes approximately 18 months—including planning and installation—for an air scrubber to be installed into an existing facility, as scrubbing equipment is unique to each generator (Figure 20).

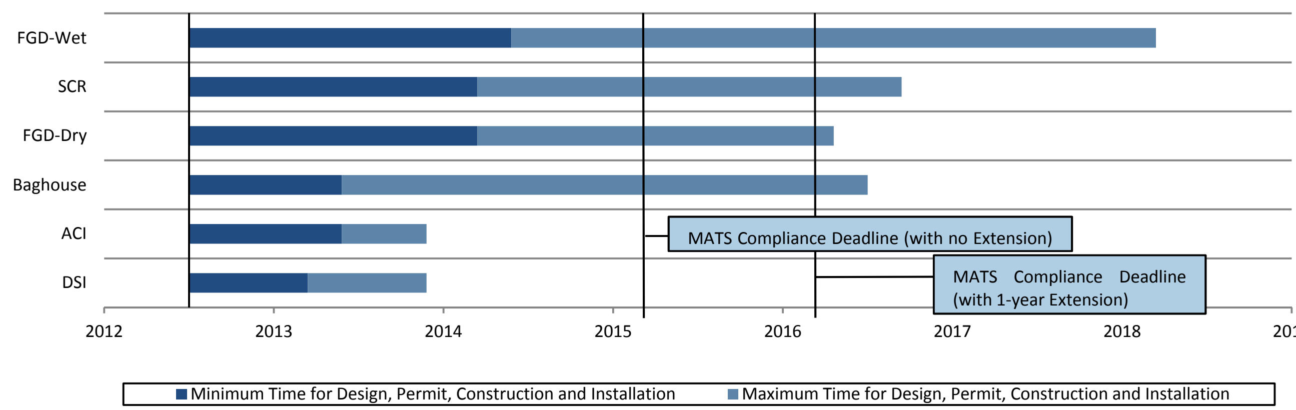
[57] http://www.epa.gov/mats/pdfs/EnforcementResponsePolicyforCAA113.pdf

[58] The EPA's Enforcement Response Policy For Use Of Clean Air Act Section 113(a) Administrative Orders In Relation To Electric Reliability And The Mercury and Air Toxics Standard (Dec. 16, 2011), http://www.epa.gov/compliance/resources/policies/civil/erp/mats-erp.pdf.

[59] The Commission's Role Regarding the EPA's Mercury and Air Toxics Standards: http://www.ferc.gov/whats-new/comm-meet/2012/051712/E-5.pdf.

However, scrubbers are not expected to be the premier choice for environmental controls at this point in time as some Regions have indicated that direct sorbent injection (DSI) has been selected for a majority of known retrofits (activated carbon injection (ACI) has also been selected). Therefore, longer-term maintenance outages spanning over a year are only expected for a fraction of retrofits.

Figure 20: Retrofit Project Timelines Relative to MATS Compliance Deadlines



With the limited outage windows before the 2016 compliance deadline, it will be increasingly important for the outage coordination groups to have as much information as possible. In MISO, the development of a monthly maintenance margin will aid in outage scheduling and will be updated seasonally to reflect current information.[60] As part of MISO's efforts to best manage an expected influx of outage requests associated with recent environmental regulations, MISO conducted an outage limit analysis to determine acceptable monthly outage levels that can be allowed to maintain reliable transmission operations.[61]

MISO's supply chain analysis,[62] conducted by The Brattle Group, concluded that the March 2015 timeline requires more construction than the industry has seen in the past and the greatest unknown risk is the amount of skilled labor available to perform the retrofits. In addition, the type of technology necessary to bring a unit into compliance may require lengthy unit outages that may run past the compliance deadline.

In PJM, significant uncertainty remains in the projections for maintenance outages. However, PJM will continue to coordinate closely with BPS owners and operators in the area to analyze the impact of retiring generation, planned outage to perform retrofits, and transmission maintenance outages required to reliably take retiring units out of service. Generation Owners have indicated that while 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.

In SPP, it is expected that the impact of retrofits will constrain the availability and increase the costs of qualified labor, materials, and heavy equipment. These constraints, as well as the need to coordinate outage scheduling and complete localized transmission reinforcement projects, will likely result in the compliance deadlines for certain units be extended. SPP RTO is maintaining regular contact with individual entities to ensure that any specialized assessments can be completed in time to identify and address circumstances in which additional time may be warranted. Surveys are still being completed regarding expected retrofit and retirement plans, and SPP RTO expects to complete an initial analysis of this issue by the end of the year.

[60] https://www.midwestiso.org/Library/Repository/Communication%20Material/Power%20Up/EPA_Outage%20Limits%20Analysis.pdf.
[61] https://www.midwestiso.org/Library/Repository/Communication%20Material/Power%20Up/EPA_Outage%20Limits%20Analysis.pdf.
[62] https://www.midwestiso.org/Library/Repository/Communication Percent20Material/Key Percent20Presentations Percent20and Percent20Whitepapers/Supply Percent20Chain Percent20and Percent20Outage Percent20Analysis Percent20of Percent20MISO Percent20Coal Percent20Retrofits Percent20for Percent20MATS.pdf

Risk Assessment Summary

Impacted Assessment Area(s)	MISO
	PJM
	SPP
Impact Type	Resource Adequacy - Longer than expected maintenance outages can result in off-peak resource adequacy concerns.
	Operating Reliability - The aggregated impact of multiple unit outages, combined with unforeseen system stresses, can impact system stability.
Magnitude of Impact	339 generation unit retrofits, comprising of almost 160 GW of capacity
Likelihood of Impact	Dependent on delays in retrofits and scheduled maintenance
	While there are often procedures to manage and coordinate generator outages, unforeseen events can reduce the system operator's ability to perform corrective actions.

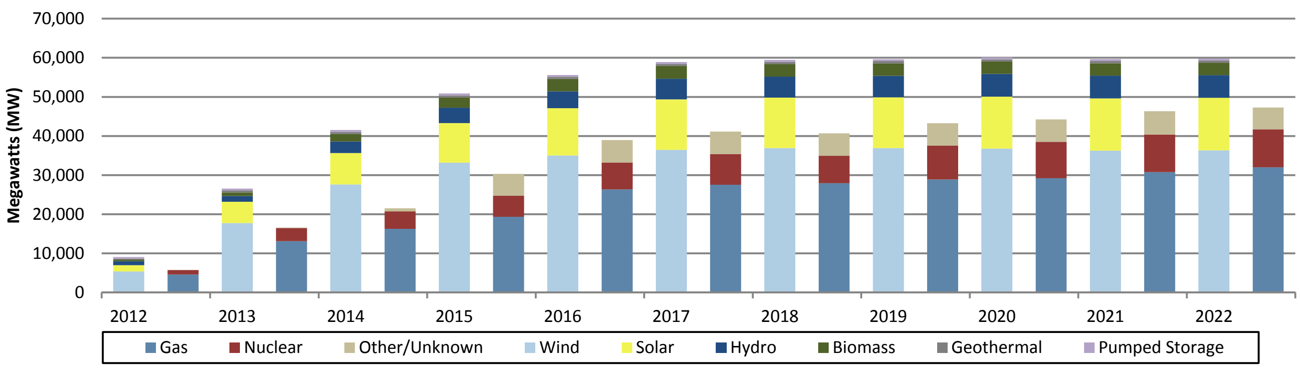
Recommendations

NERC	NERC should evaluate the retrofit efforts of generators in North America within its seasonal reliability assessment.
Regulators	ERCOT should continue to consider alternative solutions to the resource adequacy issues.
	Regulators should provide extensions where justified by independent authorities on electric reliability.

Renewable Resource Additions Introduce New Planning and Operational Challenges

Renewable resources are growing in importance in many areas of North America as the number of new facilities continues to increase. Nameplate renewable capacity (including wind, solar, hyro, biomass, geothermal, and pumped storage) will grow by approximately 60 GW by 2022, outpacing any other resource (Figure 21). Wind contribution during the peak is typically only a fraction of the nameplate capacity, which grows by over 36 GW during the assessment period. Solar and bioass will grow by 13.4 and 3.1 GW, respectively. A majority of the 580 GW of geothermal capacity additions will occur in the first two years of the assessment period (by 2014). The same case applies to pumped storage resources, which will grow to 466 MW by 2014 and remain constant through 2022.

Figure 21: Cumulative Future-Planned Nameplate Renewable Capacity Additions Compared to Non-Renewable Capacity Additions

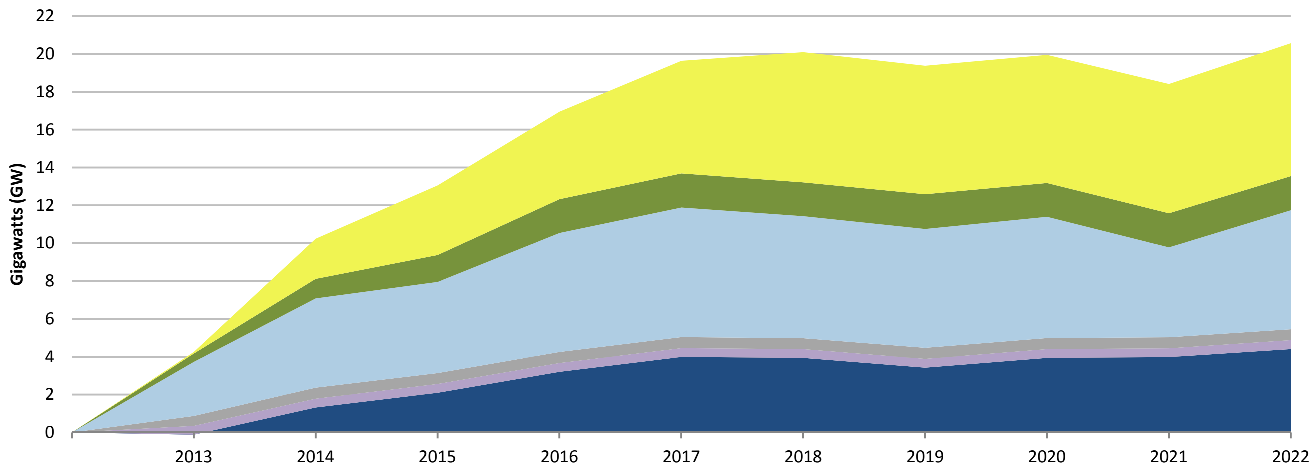


Overall capacity contribution from renewable resources will continue to grow, especially as significant additions are projected for both wind and solar throughout North America. In 2012, renewable generation, including hydro, made up 15.6 percent of all on-peak capacity resources and is expected to reach almost 17 percent in 2022 (Figure 22). Contributing to this growth is approximately 20 GW of on-peak planned capacity and an additional 21.5 GW of on-peak Conceptual capacity. It is vital that these variable resources are integrated reliably and in a way that supports the continued performance of the BPS and addresses both planning and operational challenges.[63]

Managing the variability of wind and solar resources will require more flexibility in the power system. The changes in the bulk power system flows from both the variable generation and demand response implementation must be better understood. The NERC Integrating Variable Generation Task Force (IVGTF) has completed significant work over the past three years to address enhanced planning and operational reliability considerations when accommodating large amounts of variable generation.[64] The scope of work has addressed not only system-specific considerations, but also those from a regional and North American perspective.

[63] Accommodating High Levels of Variable Generation: Summary Report: http://www.nerc.com/files/Special%20Report%20%20Accommodating%20High%20Levels%20of%20Variable%20Generation.pdf.
[64] Completed variable generation assessments and recommendations produced by the IVGTF: http://www.nerc.com/page.php?cid=4|61

Figure 22: On-Peak Future-Planned Renewable Capacity – Cumulative Net Change



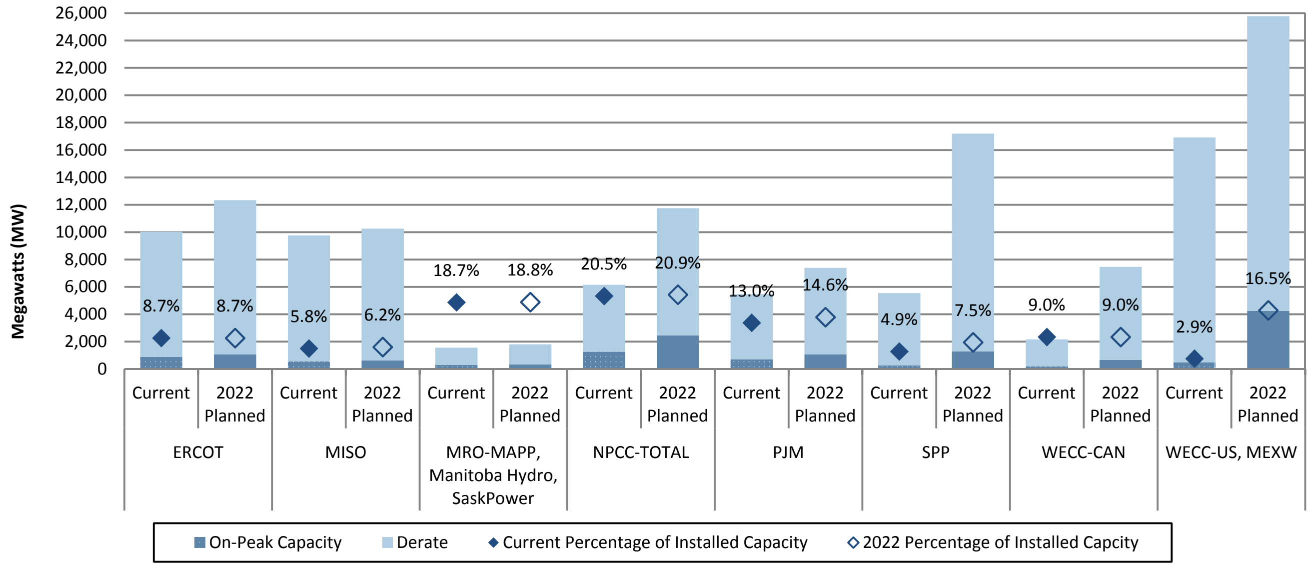
		Current		2022 Planned			2022 Planned & Conceptual		
		Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Hydro		124,332	77.50%	128,742	71.01%	4,410	131,175	58.50%	6,843
Pumped Storage		21,697	13.53%	22,162	12.22%	465	22,627	10.09%	930
Geothermal		2,584	1.61%	3,333	1.84%	749	4,082	1.82%	1,498
Wind		5,219	3.25%	11,505	6.35%	6,286	32,105	14.32%	26,886
Biomass		4,780	2.98%	6,736	3.72%	1,956	8,692	3.88%	3,912
Solar		1,809	1.13%	8,833	4.87%	7,025	25,555	11.40%	23,747
TOTAL		**160,420**	**100.00%**	**181,311**	**100.00%**	**20,891**	**224,235**	**100.00%**	**63,815**

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. Because wind power output is often inversely correlated with demand in some regions, capacity output of wind plants during times of peak demand generally amounts to a fraction of nameplate capacity (Figure 23). For example, the "expected on-peak capacity" can account for as little as 3 percent of a given area's entire nameplate wind capacity. As noted by NERC in prior assessments, consistent methods to determine on-peak wind capacity are needed to ensure uniform measurement and resource adequacy assumptions.[65] 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 are generally in the range of 5 to ten percent of the wind energy nameplate capacity.[66] Currenly, only MISO and ERCOT have a probabilistic basis for determining this factor. More consistency is being achieved due to more experience with larger portfolios of wind generation.

[65] Currently, Regions and subregions (in particular, difference operating entities) use different methods to determine expected on-peak values of wind capacity. The Integration of Variable Generation Task Force is addressing this issue. The report *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning* is available on the NERC website at: http://www.nerc.com/files/IVGTF1-2.pdf

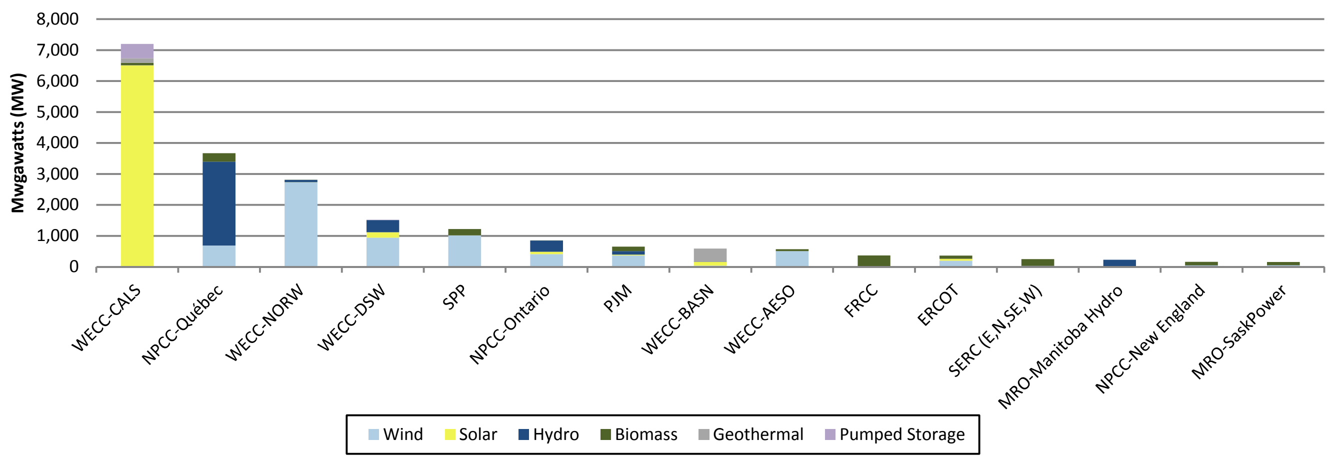
[66] http://www.nerc.com/docs/pc/ivgtf/ieee-capacity-value-task-force-confidential%20%282%29.pdf

Figure 23: On-Peak Renewable Capacity – Cumulative Net Change[67]



From an assessment area perspective, southern California is expecting the most future renewable on-peak capacity with over 13 GW of new solar capacity. Significant on-peak wind capacity is projected in both the United States and Canada, totaling an increase of over 7.4 GW in WECC alone (Figure 23).

Figure 24: On-Peak Renewable Capacity – Planned Additions by 2022[68]



Solar generation will see more growth in both nameplate and on-peak capacity during the next 10 years (Figure 25). Plans for approximately 13.4 GW of nameplate capacity are projected to come into service, primarily in the WECC-CALS and WECC-DSW subregions. Regional planners in these areas continue to assess the growing impacts of this variable resource into the generation mix. One notable difference is the expected on-peak capacity that can be reliably counted on to serve peak demand. Across the dense installations of solar capacity in the Southwest, the two WECC assessment areas are counting on approximately half of the installed capacity to serve peak demand.

[67] For WECC-CAN, the metric the on-peak wind capacity is based actual performance for the last three winter seasons, as reported in the 2010-2012 LTRA reference cases. WECC is currently developing an enhanced approach to determine capacity contributions from variable generation.
[68] This figure includes only those areas with significant renewable capacity additions and does not include capacity additions classified as Conceptual.

Figure 26: Solar Additions Primarily in the WECC-CALS and WECC-DSW Assessment Areas

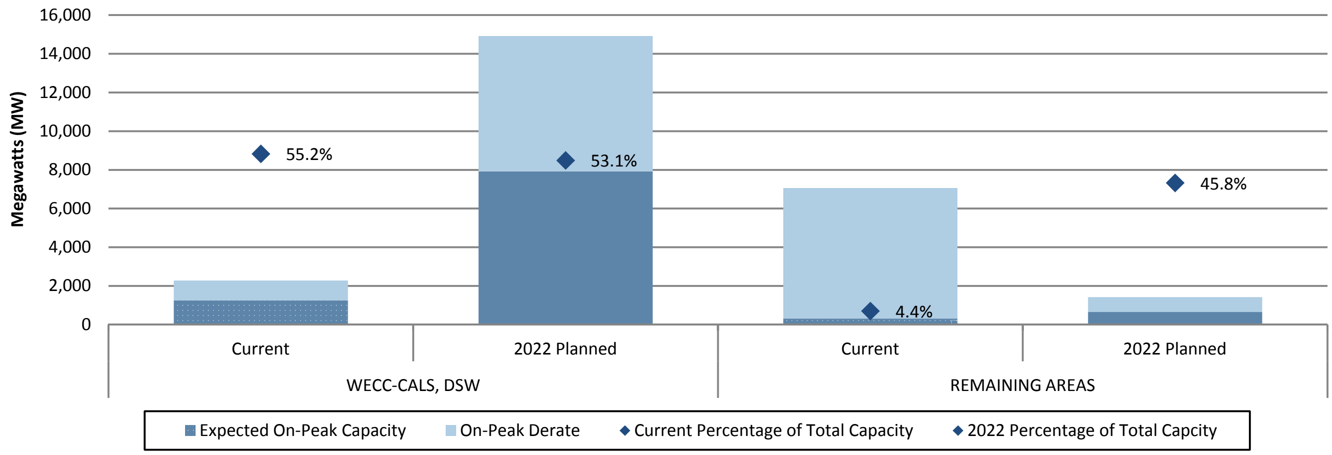
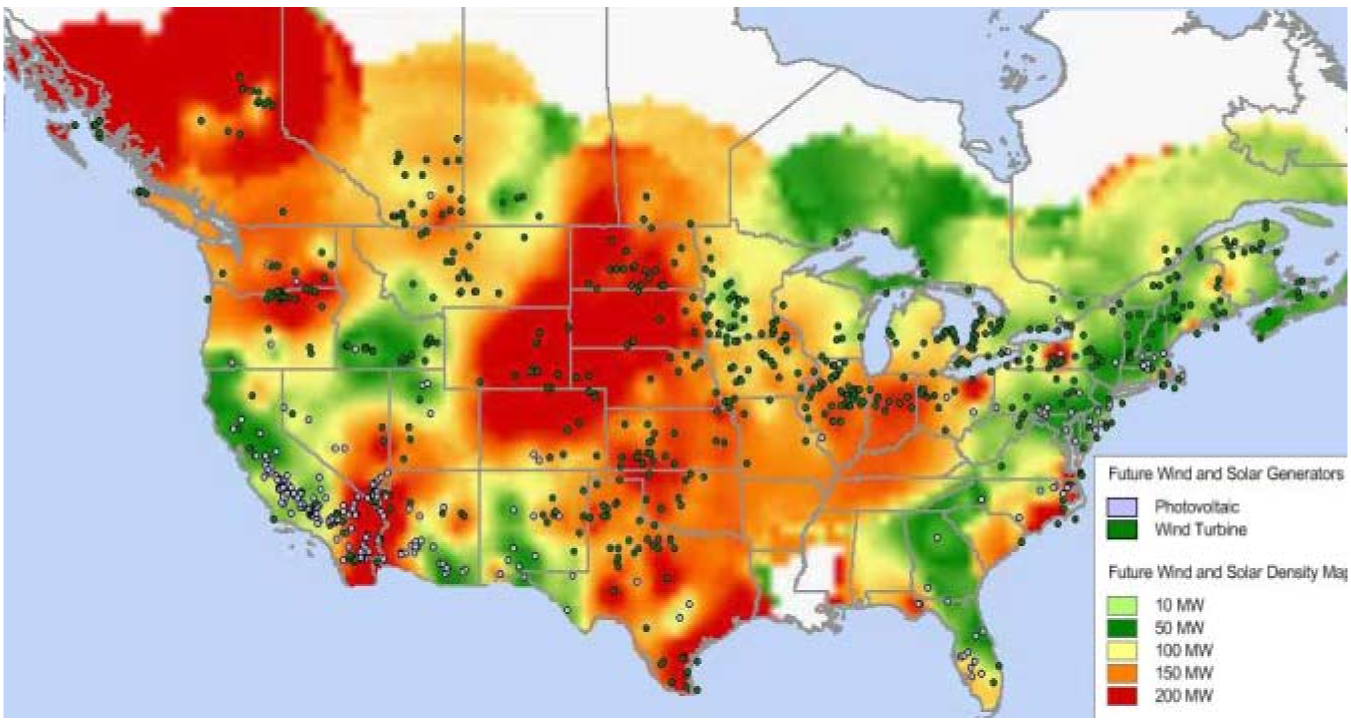


Figure 27: Density Map of Future Wind and Solar Installed Capacity Additions[69]



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 bulk power system reliability. Power system planning is intended to ensure that a reliable and robust power system is available to the power system operator within the planning horizon. The industry has already begun development of new planning methods and techniques that consider the characteristics of variable generation assets to improve system reliability. These tools need to be expedited to ensure the reliable operation of the bulk power system. New models need to take into account new technologies, such as storage, variable demand such as demand response, and incorporation of flexible resources. For example, storage technologies, if 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, if economical.

[69] Source: Ventyx Velocity Suite, An ABB Company, modified by NERC staff to reflect NERC footprint.

Areas integrating wind resources have projected increases in transmission congestion, particularly when demand is low. As wind resources are less predictable and follow the availability of their fuel (wind) rather than dispatch instructions from operators or market based systems for traditional “controlled fuel” plants, different patterns in the use of transmission capacity can emerge from this new variable fuel paradigm. In some cases, renewable resource availability may not be correlated to demand, being available during the nighttime, for example, rather than during daily peak periods. Energy storage may provide potential support by converting this energy to stored capacity. Further, some Regions report challenges in managing the power system under the high variability of wind resources and report the need to provide additional ancillary services (such as operating reserves) as specific challenges (see NERC’s *2012 Summer Reliability Assessment*).[70]

Power system planners are already familiar with designing a system that can be operated reliably while accommodating a certain amount of variability and uncertainty, particularly as it relates to system demand and, to a lesser extent, to conventional generation. However, large-scale integration of variable generation can significantly alter familiar system conditions due to increased supply variability and uncertainty. This presents new challenges to power system operators, and planners will need to design a system that can accommodate variable generation in large quantities, providing operators with the resources needed. In addition, system variability occurs from distribution system connected renewables (also called embedded generation). Embedded generation capacity is less visible to system operators and introduces additional variability to the perceived local demand forecast and load served.

Forecasting of variable generation resources is important in all timeframes, and there are many uses for longer-range forecasts from days and weeks (e.g., transmission outage planning and minimum generation issues) to years (e.g., integrated resource planning, where resource flexibility and ramping capabilities should be increasingly valued, and the generation mix if not appropriately planned can raise bigger challenges/issues during operating timeframe). Such longer-term schedules are adjusted as they get closer to real-time and the critical operating impacts to bulk power system reliability tend to be closer to real time.

Regional differences will exist; however, this is largely an interconnection-wide issue as policy and mandates requiring energy from renewable generation expand. As policy and regulations on greenhouse gas emissions, notably CO_2, and mandated Renewable Portfolio Standards (RPS) are being developed by states and provinces throughout North America, and as the economics of renewable resources continue to improve, the addition of renewable generation into the bulk power system is expected to grow considerably in the near future. The level of commitment to renewable resources offers benefits such as new generation resources, fuel diversification, and greenhouse gas reductions. However, renewable commitments present significant new challenges that need to be properly addressed to maintain bulk power system reliability.

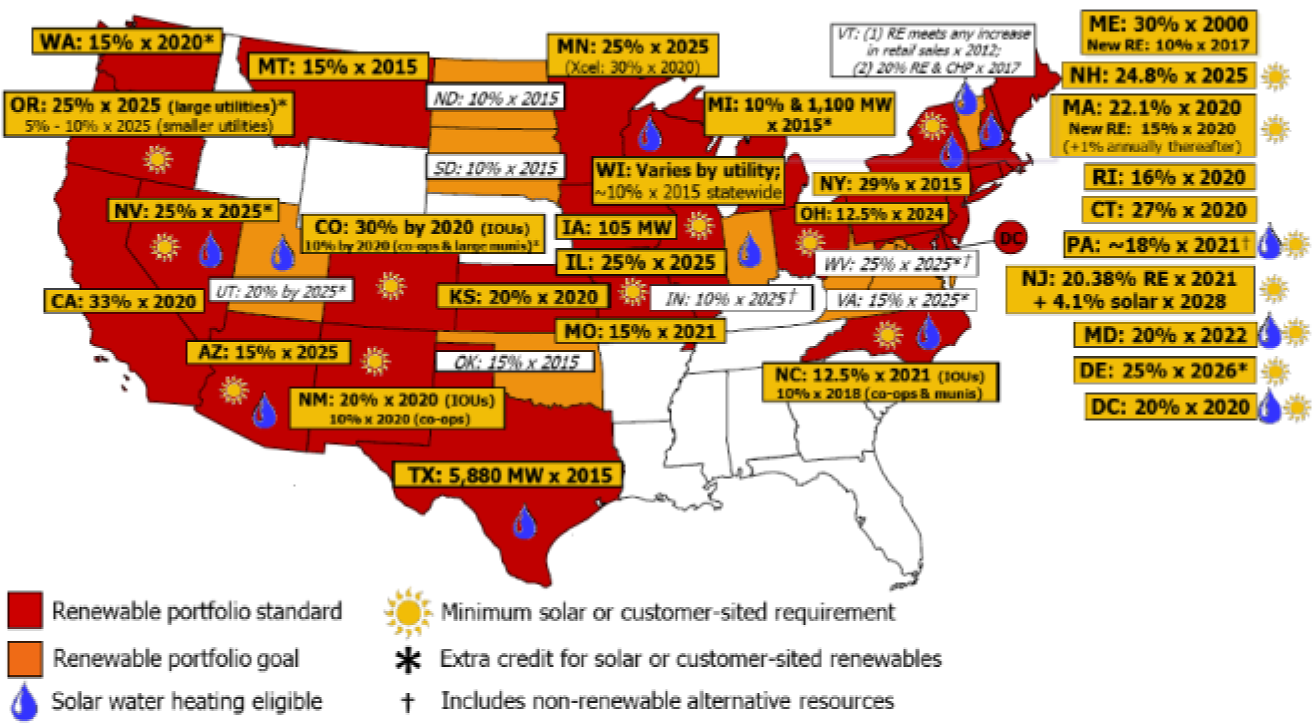
Provincial and state Renewable Portfolio Standards (RPS) will increase renewable resources located where wind power densities and solar development are favorable. Congress is also considering a federal RPS. Grid expansion is needed to support the dispersed nature of renewable resources. The limited timeframe provided to meet RPS mandates requires that current transmission siting and permitting processes be expedited. Federal, state, and provincial CO_2 legislation is pending throughout North America.

In the United States, a number of Regional and state activities have resulted in a variety of renewable portfolio standards. In 2010, NERC’s Planning Committee created the Reliability Impacts of Climate Change Initiatives Task Force (RICCITF)[71] to

[70] *2012 Summer Reliability Assessment*: http://www.nerc.com/files/2012SRA.pdf
[71] 2010 Special Reliability Assessment: Reliability Impacts of Climate Change Initiatives: Technology Assessment and Scenario Development, http://www.nerc.com/files/RICCI_2010.pdf

review CO_2 legislative and regulatory impacts on BPS reliability.[72] Further, NERC staff prepared a report documenting industry concerns and reliability considerations (Figure 28).[73]

Figure 28: Renewable Portfolio Targets in Most of the United States[74]



Individual state, provincial, and regional initiatives may not significantly affect BPS reliability. However, these combined initiatives will begin to come to fruition concurrently with federal climate change policies underway in North America. Industry planners should recognize and address potential impacts to meet the following climate change initiatives without compromising system reliability.

- **State and Provincial Renewable Portfolio Standards**: Renewable Portfolio Standards typically require load-serving entities in a given area to acquire a certain percentage of their energy supply from renewable resources by a target year (for example, 20 percent by 2020). Twenty-nine U.S. states and three Canadian provinces have some kind of renewable portfolio standard in place. NERC has studied the reliability consideration resulting from accommodating high levels of variable renewable resources.[75]
- **Other State and Provincial Climate Goals**: All remaining Canadian provinces and six U.S. states have some form of policy in place to address climate change and greenhouse gas emissions, either through specific capacity or energy goals for electric generation or other means.
- **Regional Initiatives**: Initiatives such as the Regional Greenhouse Gas Initiative in the Northeast (RGGI) and Western Climate Initiative (WCI) have created multi-state and cross-border partnerships to reduce greenhouse gas emissions on a regional basis.[76]
- **U.S. Federal Climate Change Legislation**: The U.S. Senate and House of Representatives, as well as the EPA, have considered in the recent past various legislative proposals to reduce carbon dioxide (CO_2) emissions.

[72] http://www.nerc.com/filez/riccitf.html
[73] http://www.nerc.com/files/2008-Climate-Initiatives-Report.pdf
[74] Source: Database of State Incentives for Renewables & Efficiency: http://www.dsireusa.org/.
[75] Numerous special assessments on accommodating high-levels of variable generation: http://www.nerc.com/page.php?cid=4|61
[76] Regional Greenhouse Gas Initiative (http://www.rggi.org/) and Western Climate Initiative (http://www.westernclimateinitiative.org/)

As states and provinces begin adopting a variety of approaches to greenhouse gas emission regulation, the prospect grows for federal regulation. Further, an April 2007 United States Supreme Court decision[77] determined greenhouse gas regulation fell under the purview of the U.S. Environmental Protection Agency.

Transmission

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

- Whether government renewable policies or mandates exist;
- Level of variable generation mandated and available variable generation in remote locations;
- Time horizon across which capital investments in variable generation are to be made; and
- Geographic footprint across which the investments occur.

In order to ensure reliability, transmission is needed to achieve the following:

- Interconnect variable energy resources planned in remote Regions
- 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 area to equalize supply and demand

Transmission system expansion is vital to unlocking the capacity available from variable generation. In those Regions with a competitive generation marketplace, regulatory targets such as Renewable Portfolio Standards 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 a key driver 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.

Transmission expansion, including greater connectivity between Balancing Authorities, and coordination on a broader regional basis, is a tool that can aggregate variable generators and lead to the reduction of overall variability. Sufficient transmission capacity serves to accommodate the output of individual variable and conventional generation plants across a broader geographical region. Large balancing areas or participation in wider-area balancing management may be needed to enable high levels of variable resources. As long as existing transmission pathways are not congested, transmission expansion may not be required to achieve the benefits of larger balancing areas. Shared ramping capability and ancillary services between adjacent areas also provide additional reliability benefits, depending on how existing and planned inter-area transmission assets are used.

Currently, high-voltage transmission overlay expansions are being conceptualized in various parts of the NERC footprint. High-Voltage Alternating Current (HVAC), High-Voltage Direct Current (HVdc) transmission, or a hybrid of both provides expansion alternatives for this overlay approach. HVAC can interconnect to the existing AC grid to support new generation and load centers as the grid evolves. However, for very long, over-ground distances (wind sites are often hundreds of miles away from demand centers), dedicated HVdc may be a more suitable solution. In addition to long distances, offshore applications also offer technical challenges that can preclude HVAC cables. With the advent of voltage-source converter (VSC) technologies, additional HVdc benefits (e.g., reactive power control voltage and frequency control) have proven useful in other renewable energy projects, such as offshore wind plants, and can be useful in many other generation projects as well.

[77] http://www.supremecourtus.gov/opinions/06pdf/05-1120.pdf

Risk Assessment Summary

Impacted Assessment Area(s)	ERCOT
	MISO
	SPP
	WECC
Impact Type	Resource Adequacy - Large and unexpected down ramps can contribute to a capacity shortage.
	Operating Reliability - Distributed and variable generation can have unforeseen impacts to system stability and voltage support if not sufficiently modeled.
Magnitude of Impact	Sufficient transmission is needed to reliably interconnect 80 GW of projected renewable generation on-peak capacity.
	Renewables are expected to provide 20 percent of expected on-peak capacity in 2022. This value reflects de-rates for nameplate renewable resources.
Likelihood of Impact	The likelihood of an event that impacts reliability is greatly reduced if proper planning processes, operational procedures, and operator training have been implemented.
	Increasing operator experience with variable resource characteristics and behaviors should enhance system operators' ability to manage unpredicted events.

Recommendations

NERC	The IVGTF should complete their work on planning and operating requirements for integrating large amounts of variable generation.[78] • NERC should address recommendations for adopting probabilistic approaches for determining capacity contributions of variable generation.[79] • NERC should enhance its Reliability Standards by organizing Standard Authorization Requests or supporting existing standard development processes that have been identified by the Integration of Variable Generation Task Force: o Distributed Resources[80] o Standard Models[81] o Interconnection Requirements[82] • NERC should develop metrics that measure flexibility needs for variable generation.[83] • Recommendations for operational planning and real-time operations o Forecasting[84] o Operating Criteria and Ancillary Services[85] o Operating Practices, Procedures, and Tools[86]
Generator Owners and Operators	Variable Generator Owners should explore whether their resources have the technical abilities of providing enhanced (ancillary) services to the BPS.
Planning and Reliability Coordinators	Requirements for operational flexibility and reliability criteria should be re-examined for systems with large amounts of variable resources.

[78] http://www.nerc.com/filez/ivgtf.html
[79] http://www.nerc.com/files/IVGTF1-2.pdf
[80] http://www.nerc.com/files/IVGTF_TF-1-8_Reliability-Impact-Distributed-Resources_Final-Draft_2011%20%282%29.pdf
[81] http://www.nerc.com/files/Standards%20Models%20for%20Variable%20Generation.pdf
[82] http://www.nerc.com/files/2012_IVGTF_Task_1-3.pdf
[83] http://www.nerc.com/files/IVGTF_Task_1_4_Final.pdf
[84] http://www.nerc.com/files/Varialbe%20Generationn%20Power%20Forecasting%20for%20Operations.pdf
[85] http://www.nerc.com/files/IVGTF2-3.pdf
[86] http://www.nerc.com/files/IVGTF2-4.pdf

Transmission Growth to Accommodate New and Distant Resources

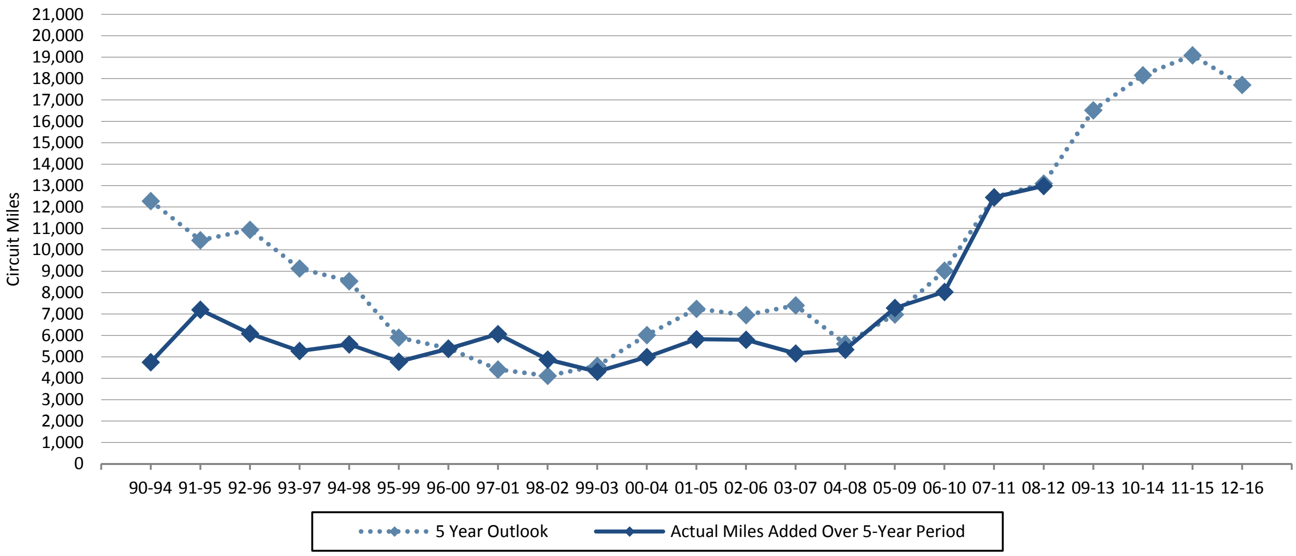
The future reliability of the BPS is largely dependent on the ability to site, permit, and build new transmission assets in a timely manner. The existing electric transmission systems and planned additions over the next 10 years appear adequate to reliably meet customer electricity requirements. However, delays to transmission construction due to permitting and siting have been observed and continue to inhibit the industry from constructing new and potentially vital transmission infrastructure. While these deferments do not currently pose a reliability concern, the importance of a secure transmission infrastructure is amplified when one considers the significant addition of variable generation resources, pending environmental legislation in both the United States and Canada, and increased demand projections throughout North America in the assessment's 10-year horizon. It is important that local, state, provincial, and federal regulators work together to develop timely and effective solutions to minimize potential delays. The process to site new transmission continues to be difficult, time-consuming, and expensive due to local opposition and environmental concerns, especially when lines are planned to cross state borders. Negotiations still delay and, in some cases, stop needed projects from being built. As a result, transmission permitting, siting, and construction can take significantly longer (i.e., 7–10 years) than permitting, siting, and construction of generation.

NERC continues to monitor the progress of transmission projects across North America. While transmission planning is dynamic (i.e., a project is needed one year, but can be deferred due to a change in demand forecasts), plans should reflect realistic expectations in order to reliably support system needs in the future. For example, ERCOT plans to install a significant amount of transmission circuit miles by 2013. Once in-service, these lines will provide ERCOT with better methods to manage existing and potential congestion problems and will support recently completed Competitive Renewable Energy Zone (CREZ) projects in Western Texas. Large transmission line additions and upgrades are also projected within the MISO footprint, with more than half of these upgrades resulting from a need to reliably integrate renewable generation resources. Minor additions are expected throughout the MRO Assessment Areas to integrate hydropower resources in Manitoba and improve reliability in the MAPP Assessment Area while accommodating for projected load growth in SaskPower.

An analysis of the past 16 years shows that planned transmission (greater than 200 kV)[87] during the next five years would nearly triple the average circuit miles that have historically been constructed during a five-year period. Through this analysis period, the number of actual miles constructed over five-year periods has roughly averaged 7,100 circuit miles. During the next five years, about 18,700 miles are planned, which continues to exceed recent historical averages.[88] However, during the previous and consecutive five-year periods (2003–07 through 2007–11), industry was successful in meeting its projections. From 2006 through the end of 2011, industry has exceeded the average transmission additions (circuit miles), constructing the most transmission during a five-year period since the 1991-1995 period[89] (Figure 29). As recent as five years ago, transmission was being constructed at a rate of about 1,000 circuit miles per year. In the last five years, over 2,300 circuit miles were constructed per year, more than doubling actual builds in the previous five years. With the current plans in place, that rate is expected to increase to 3,600 miles per year over the next five years.

[87] Transmission data prior to 2009 is limited to 200 kV and above.
[88] Significant recent and projected transmission additions are still well below additions made 40-50 years ago when much of the current grid was built
[89] 1990 is the first year this type of data was digitized. Previously data was not collected on five-year plans.

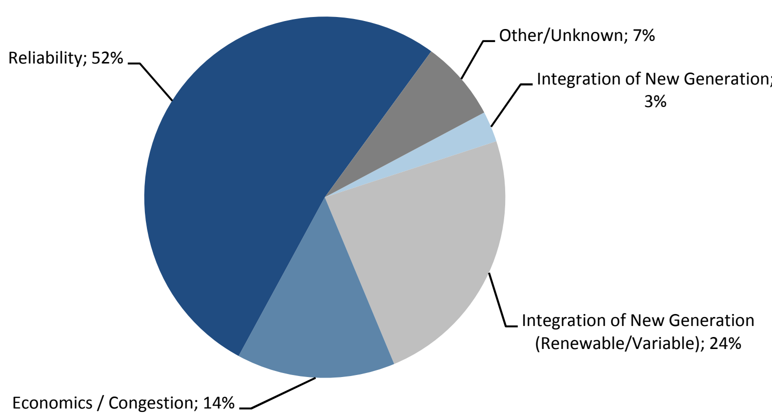
Figure 29: Historical Actual Miles Added for Rolling Five-Year Periods and Projected Five-Year Plans, 200kV and Above[90]



Stakeholders within the electric industry continually assess the ability of their internal transmission system and interconnections with other systems not only to meet regional requirements, but also to meet compliance with NERC Reliability Standards. Once a set of transmission alternatives has been identified, the project can take up to ten or more years to complete from project identification to final certification and energization of elements. 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.

NERC-wide, almost a quarter of new transmission is specifically linked to the integration of renewable generation. Therefore, areas with larger increases in projected renewables are generally the areas with significant transmission additions. Projected transmission additions in ERCOT, MISO, and WECC are largely due to the future renewable additions that are expected over the next 10 years (Figure 30 and Table 30).

Figure 30: New Transmission Projects (by Circuit Miles) Driven by Reliability and the Integration of Renewable Resources



[90] Historic data has been revised for some areas based on the original submission of erroneous data for existing and planned circuit miles.

Table 31: Planned Transmission Additions by Assessment Area, 2012-2022 (Circuit Miles 100kV and Above)

	Existing		2010-2011	Current	2012-2017		2018-2022		2022 Total Projected	
Assessment Area/Country	2010 Year-End	2011 Year-End	Line Additions	Under Construction	Planned	Conceptual	Planned	Conceptual	E+UC+P	E+UC+P+C
ERCOT	29,107	29,465	358	946	4,757	800	29	391	35,197	36,388
FRCC	11,973	12,031	58	46	249	0	200	97	12,526	12,623
MISO	50,144	44,500	-5,644	161	1,838	63	1,069	0	47,568	47,631
MRO-MAPP	10,314	10,266	-49	230	716	107	0	0	11,211	11,318
NPCC-New England	8,496	8,106	-390	182	458	218	8	18	8,753	8,989
NPCC-New York	10,990	10,992	2	0	138	0	30	0	11,160	11,160
PJM	45,472	51,649	6,177	118	709	131	1,267	134	53,743	54,008
SERC-E	21,995	22,180	185	33	276	87	189	189	22,678	22,954
SERC-N	21,303	21,600	297	254	332	21	13	57	22,198	22,276
SERC-SE	27,316	27,672	356	108	305	66	374	0	28,459	28,525
SERC-W	13,604	14,295	691	72	414	26	79	92	14,860	14,978
SPP	32,857	32,881	24	638	1,613	47	180	103	35,311	35,460
WECC-US	103,371	104,359	988	199	4,093	4,501	1,921	2,598	110,572	117,672
TOTAL-US	386,942	389,995	3,053	2,988	15,895	6,066	5,358	3,678	414,236	423,981
MRO-Manitoba	7,295	7,485	190	0	237	0	1,076	80	8,798	8,878
MRO-SaskPower	4,997	5,083	86	0	323	222	0	0	5,406	5,628
NPCC-Maritimes	5,056	5,082	26	0	13	203	0	283	5,095	5,581
NPCC-Ontario	17,713	17,931	218	93	0	180	0	599	18,024	18,803
NPCC-Québec	23,100	22,787	-313	412	68	546	129	599	23,395	24,539
WECC-Canada	21,489	22,946	1,457	0	1,970	0	706	0	25,623	25,623
TOTAL-CANADA	79,650	81,314	1,664	505	2,611	1,151	1,911	1,560	86,341	89,051
WECC-MEXW	1,425	1,458	33	0	255	0	132	0	1,845	1,845
TOTAL-MEXICO	1,425	1,458	33	0	255	0	132	0	1,845	1,845
TOTAL-NERC	**468,017**	**472,767**	**4,750**	**3,492**	**18,761**	**7,217**	**7,401**	**5,239**	**502,421**	**514,877**

In the United States, the recent issuance of FERC Order 1000 reforms the Commission's electric transmission planning and cost allocation requirements for public utility transmission providers. While the rule provides a framework for cost allocation and requires certain considerations that need to be addressed, the potential benefit the order brings is in its inter-regional transmission planning reform. While many Regions already perform inter-regional planning, the order facilitates the evaluation of large, interconnection-wide issues.

Projected transmission circuit mile additions are an indicator of the relative strengthening of the existing bulk power transmission system. Although the addition of transmission circuit miles is encouraging, the associated increased use of transmission systems due to increased demand growth, generation additions (including geographically distant generation), capacity deficiencies, and the increasingly competitive bulk power market must also be considered when evaluating overall system reliability (Figure 32 and Figure 33).

Figure 32: NERC-Wide Cumulative Transmission Additions by Project Status and Expected In-Service Year

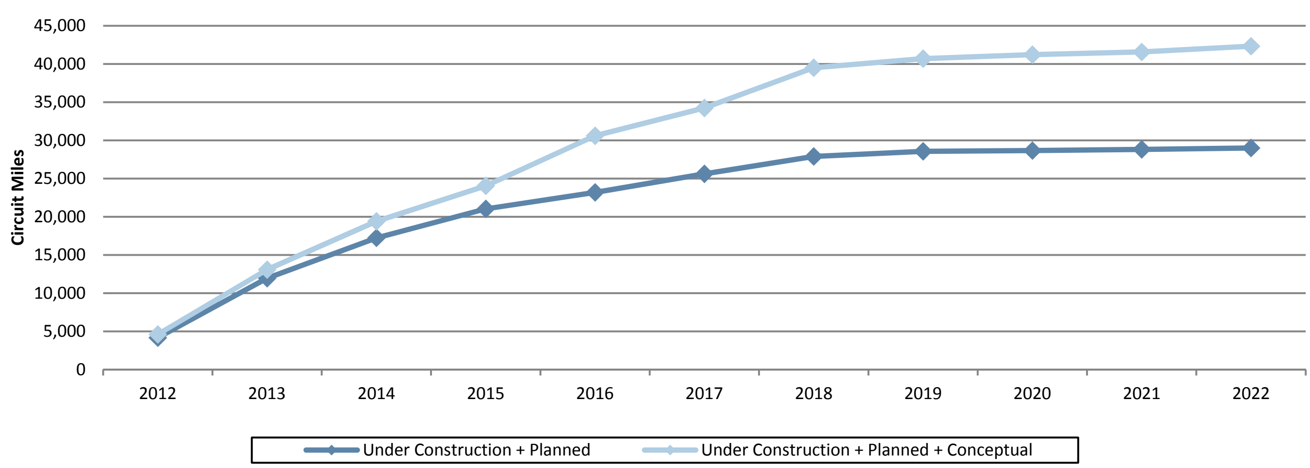
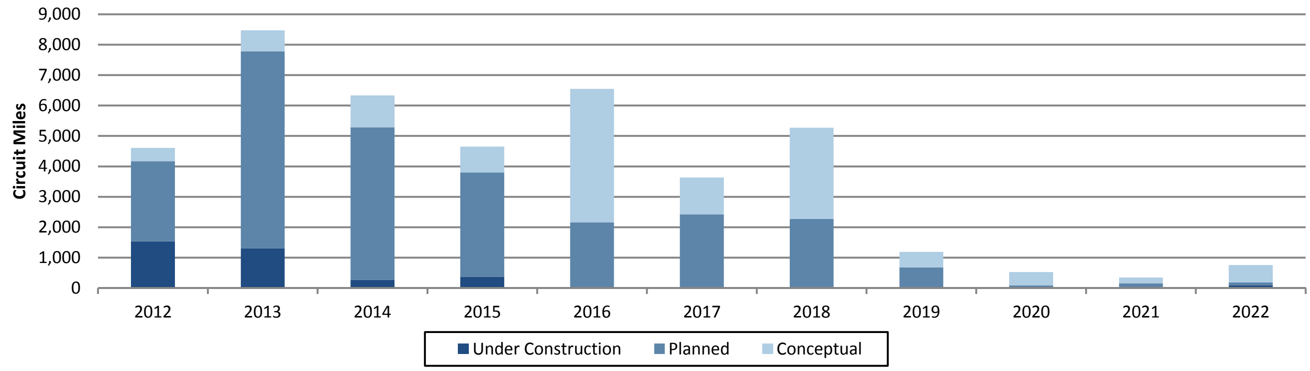


Figure 33: NERC-Wide Transmission Additions by Project Status per Year



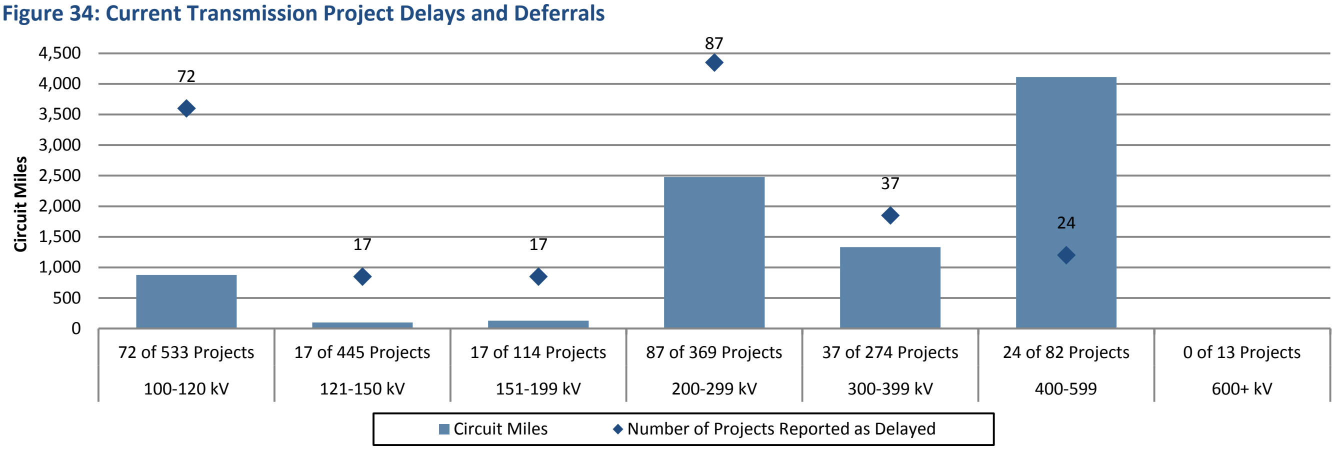
From 2012-2022, the industry has under construction and planned transmission facilities that will add approximately 29,600 circuit miles to the existing[91] North American transmission infrastructure.

NERC continues to monitor the progress of transmission projects across North America. While transmission planning is dynamic (i.e., project is needed one year, but can be deferred due to a change in demand forecasts), plans should reflect realistic expectations in order to reliably support system needs in the future.

Along with the status of transmission plans, NERC gathers information on key drivers that are delaying the construction of individual transmission line and infrastructure development projects. Deferrals based on reassessments of load growth have been the primary reason for delays of new transmission and upgrades of existing transmission infrastructure. Results from recent transmission studies in these areas show that some large transmission projects, such as the Potomac-Appalachian Transmission Highline (PATH) project in PJM, are no longer necessary to maintain grid reliability and have been put on hold.

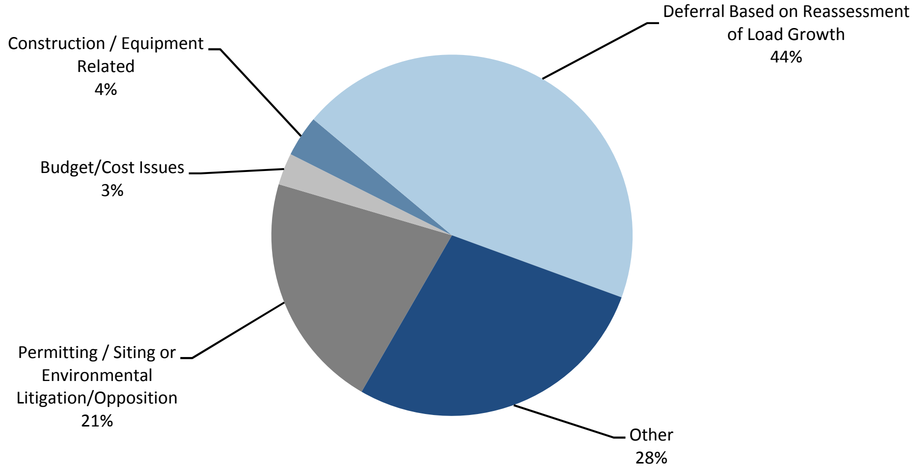
Across North America, 230 transmission projects consisting of almost 5,000 circuit miles are currently considered delayed or deferred.[92] A majority of the delays in transmission projects are observed at the 200-299 kV class (approximately 2,500 circuit miles). Additionally, 72 projects at the 100-199 kV class, totaling less than 900 circuit miles, are currently delayed or deferred. Because these lower voltage lines are typically built in less rural areas, siting and permitting issues may present more of a challenge. Permitting, siting, and other regulatory issues account for 21 percent of transmission project delays (Figure 34 and Figure 35).

Figure 34: Current Transmission Project Delays and Deferrals



[91] Existing circuit miles as reported for December 31, 2011.
[92] The total of circuit miles reported as delayed to NERC by assessment area is 4,915 miles.

Figure 35: Reasons for Transmission Project Delays and Deferrals



Transmission lines are the critical link between generation and bulk power system customers. As demand grows and generation is built in areas remote from the demand, more capacity on the transmission system is needed to meet demand. As more and more power is moved over transmission lines, congestion can have a significant impact on reliability. As these lines reach their capacity, for example, it is more difficult for them to make up the difference when neighboring lines are forced out of service. Under-investment in transmission puts additional strain on existing resources, which raises the risk of system disturbances, lengthens restoration time when outages do occur, and limits access to remote generation.

The benefits of more transmission are also far-reaching. New transmission can reduce installed capacity and reserve requirements, reduce losses, increase transfer capabilities, and provide diversification of renewable generation over a large geographical region.

Risk Assessment Summary

Impacted Assessment Area(s)	All Regions
Impact Type	Resource Adequacy - A constrained and limited transmission system could potentially affect resource deliverability and cause generator de-rates.
	Operating Reliability - Increased stress to transmission systems can cause a decrease in the performance of transmission facilities.
Magnitude of Impact	15,000 circuit miles Planned over next five years
	26,000 circuit miles Planned over next ten years
Likelihood of Impact	Increased delays could impede the industry's transmission plans
	Since less than 10 percent of all circuit miles are currently delayed or deferred, actual additions may not meet expectations.

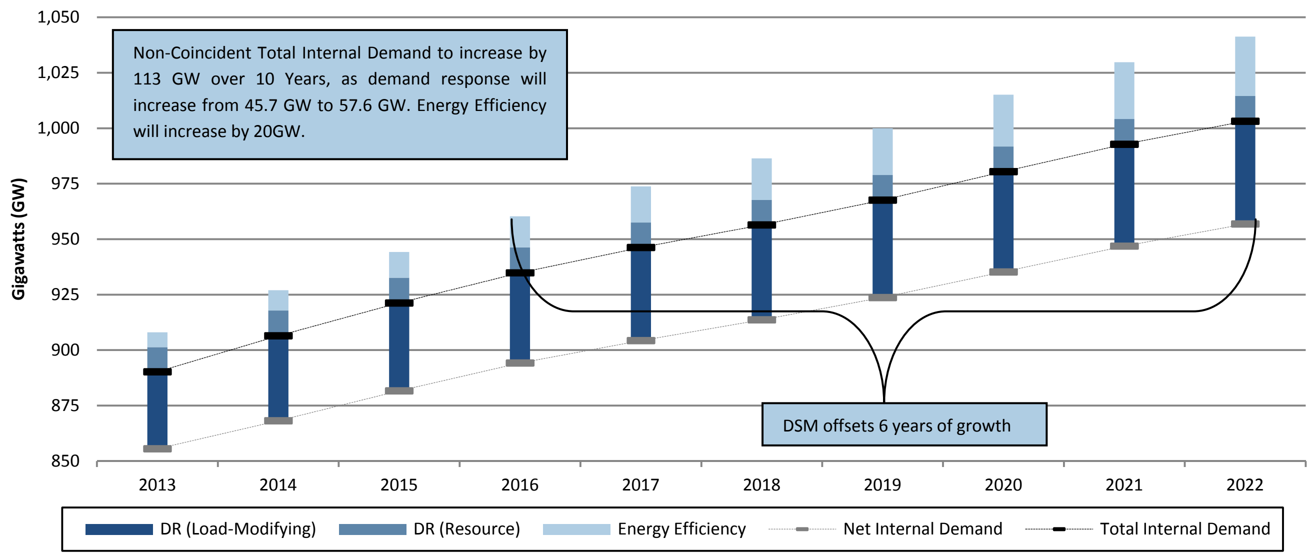
Recommendations

NERC	NERC should expand its understanding of projected transmission resource acquisition strategies being employed throughout North America. Therefore, categorization of transmission additions should be considered to fully appreciate transmission resource requirements. NERC should identify transmission assessment metrics to determine if future projects are sufficient to meet projected resource plans.
	NERC should continue to provide information and support to NERC stakeholders on the need for new transmission in North America.
Regulators	Regulators need to continue their support for additional transmission resources. Further, they should revise their existing processes to expedite the licensing of transmission projects needed to maintain reliability.

Increases in Demand-Side Management Help Offset Future Resource Needs

All areas are projecting at least some increased availability of DSM over the next 10 years to reduce peak demands, contributing either to the deferral of new generating capacity or improving operator flexibility in the day-ahead or real-time time periods. NERC-wide, DSM is projected to total roughly 80,000 MW by 2022 (or about 7 percent of the on-peak resource portfolio), offsetting approximately six years of peak demand growth (Figure 36).

Figure 36: Demand-Side Management Offsets Six Years of Peak Demand Growth

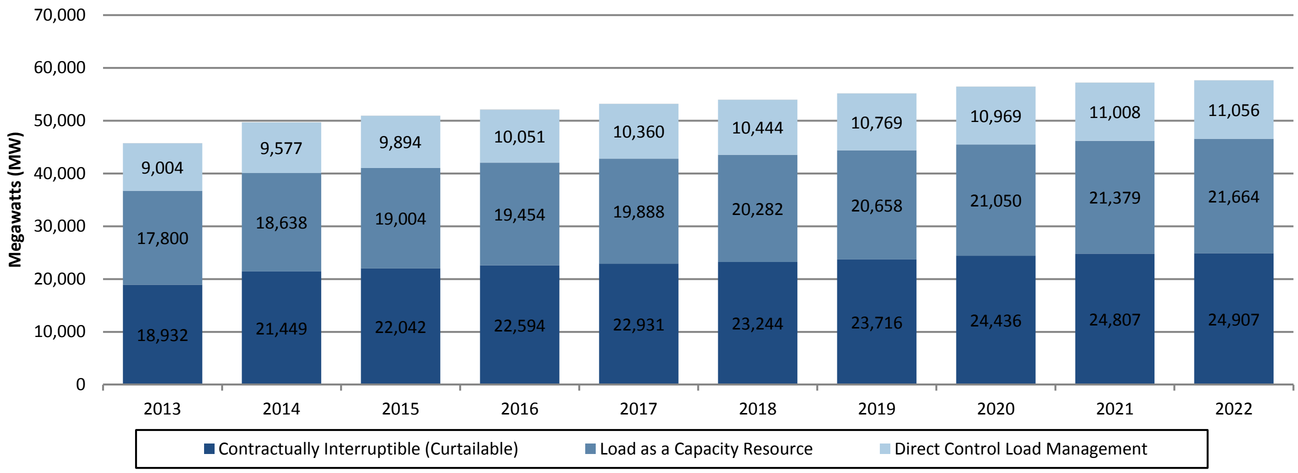


However, DSM is not an unlimited resource and may provide limited demand reductions during pre-specified time periods (generally during peak or adverse system conditions). Some Regions—such as ERCOT, FRCC, NPCC, and WECC—have been using DSM for many years, while others have less penetration. Historical performance data from these Regions may also provide a way to analyze the benefits from these resources.[93] The structure of DSM programs (e.g., performance requirements, measurement and verification applicability, and resource criteria) may be indicative of how well these programs perform when needed. The shared experiences and lessons learned from these high-penetration areas should benefit the North American BPS in providing more planning and operating flexibility.

In terms of DR (Dispatchable and Controllable), total expected capacity is anticipated to increase from approximately 46,000 MW to 59,000 MW by 2022. Year-over-year increases are projected to remain steady through the 10-year period, compared to previous years where projections would plateau after three or four years (Figure 37).

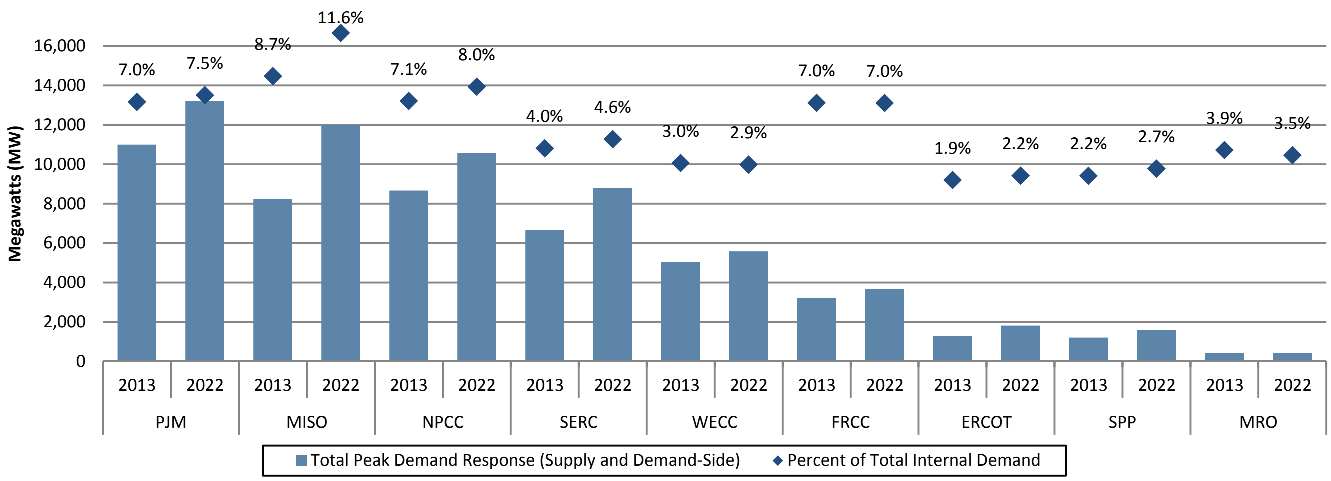
[93] NERC Demand Response Availability Data System (DADS) is collecting Demand Response performance data on a semi-annual basis. The goal of the DADS is to collect Demand Response enrollment and event information to measure its actual performance including its contribution to improved reliability. Ultimately, this analysis can provide industry with a basis for projecting contributions of dispatchable and non-dispatchable Demand Response supporting forecast adequacy and operational reliability. For more information, visit the DADS website at: http://www.nerc.com/page.php?cid=4|357.

Figure 37: NERC-Wide Dispatchable, Controllable Demand Response Increases Steadily over 10 Years



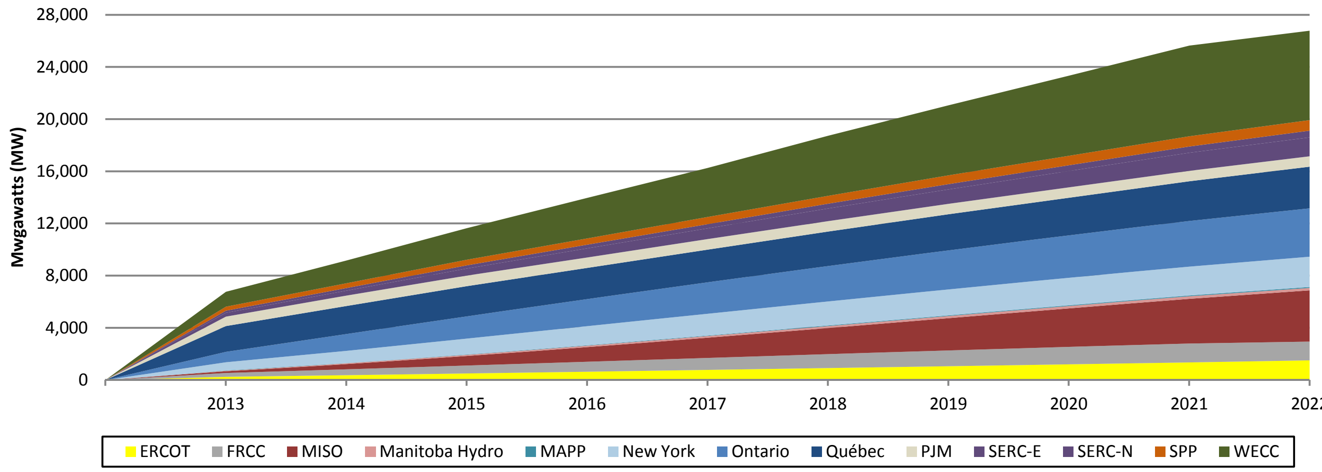
From an assessment area perspective, PJM, MISO, and NPCC administer the most DR and represent over half of the total DR NERC-wide. These relatively large demand response participation values represent about 8 percent of the Total Internal Demand for each of the areas, with MISO projected to increase to nearly 12 percent by 2022 (Figure 38).

Figure 38: NERC-Wide Dispatchable, Controllable Demand Response Increases over 10 Years



Through EE and Conservation, permanent replacement or more efficient operation of electrical devices results in demand reductions across all hours of use, rather than event-driven, targeted demand reductions. In the next 10 years, EE across all NERC Regions is expected to reduce demand by over 19,000 MW during the NERC-wide summer peak. While most assessment areas show increases compared to last year, significant EE is projected in WECC, NPCC, and MISO. As a result of implementing EE programs, the electric industry in North America has deferred new generating capacity by approximately two years. The ability to implement EE programs relatively quickly provides the industry with another short-term solution to help defer any anticipated capacity shortfalls. Successful integration of EE into resource planning requires close coordination between those responsible for EE and those in bulk system planning to ensure appropriate capacity values are estimated while meeting reliability objectives (Figure 39).

Figure 39: Growth in Energy Efficiency Supports Deferral of Capacity Needs[94]



The type of EE programs (industrial, commercial, and residential) influence the total capacity (MW) reduction depending on the time of day and desired reduction. Load forecasting is a critical component to understanding the overall peak reduction observed or projected. Tracking and validating EE programs is vital to increasing the accuracy of forecasts. In some areas, experience with these demand-side resources has improved. For example, in ISO-NE demand-side resources can participate just like traditional generation resources in the Forward Capacity Market.[95] The ability to demonstrate effective performance of these resources illustrates the confidence exhibited by system planners and operators in using demand-side resources to fulfill capacity obligations and maintain the same level of reliability.

Potential drivers for the continued expansion of EE programs in the future are Renewable Portfolio Standards (RPS), which commonly include provisions for energy-reducing actions to account for a portion of the renewable resource requirement (generally no more than 5 percent of total energy use). Other policy drivers include the American Recovery and Reinvestment Act of 2009,[96] which includes provisions for significant investments in energy and climate-related initiatives; the American Clean Energy and Security Bill of 2009,[97] which established credits for reduced carbon emissions; the Climate Change Plan for Canada;[98] and several regional, state, and provincial initiatives.[99]

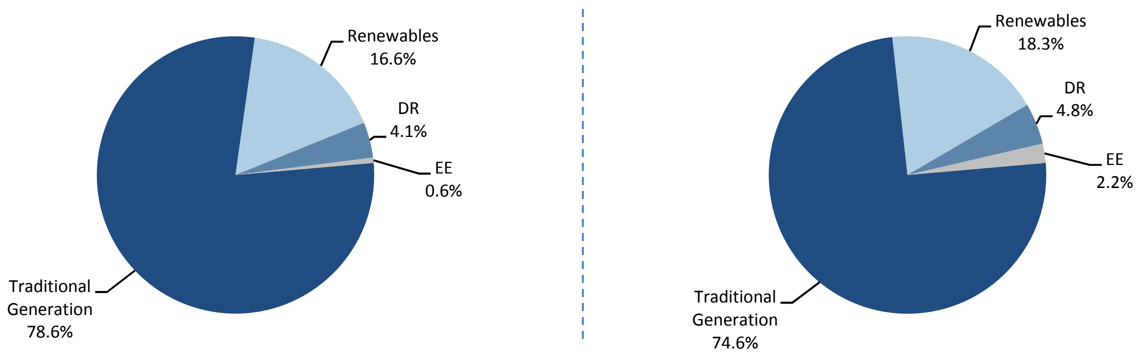
Uncertainty exists not only in how much peak demand reduction will actually be realized at the particular time when DR is needed and deployed, but also in the long-term sustainability of these resources.[100] Unlike traditional generating resources with many decades of historic data for analysis, the long-term projections of DR involve greater forecasting uncertainty. Because participation in DR programs is highly dependent on a number of economic variables and incentives, it is challenging to forecast how much DR will be available beyond three or four years.[101]

As DSM is increasingly deployed in response to climate change initiatives or mandates, it will become a larger portion of the overall resource portfolio. During the next decade, DR will increase to approximately 4.8 percent of the total resource mix, and EE will account for 2.2 percent. Climate change initiatives at the state/provincial level, along with consumer-led efforts to reduce energy consumption, will broaden the size and scope of DSM programs. Both EE and DR can make significant

[94] NPCC-New England did not provide separate EE data.
[95] http://www.iso-ne.com/nwsiss/grid_mkts/how_mkts_wrk/cap_mkt/index.html
[96] http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=111_cong_bills&docid=f:h1enr.txt.pdf
[97] http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=111_cong_bills&docid=f:h2454pcs.txt.pdf
[98] http://dsp-psd.pwgsc.gc.ca/Collection/En56-183-2002E.pdf
[99] Reliability Impacts of Climate Change Initiatives report: http://www.nerc.com/files/RICCI_2010.pdf
[100] Refer to the *2010 Long-Term Reliability Assessment*, Emerging Reliability Issues: Uncertainty of Sustained Participation in Demand Response Programs section http://www.nerc.com/files/2010_LTRA_v2-.pdf
[101] In most cases, actual forecasting of Demand Response is not performed, per se. Rather, projections are based on resource requirements and the amount of capacity contracted during a given commitment period--usually between one and three years.

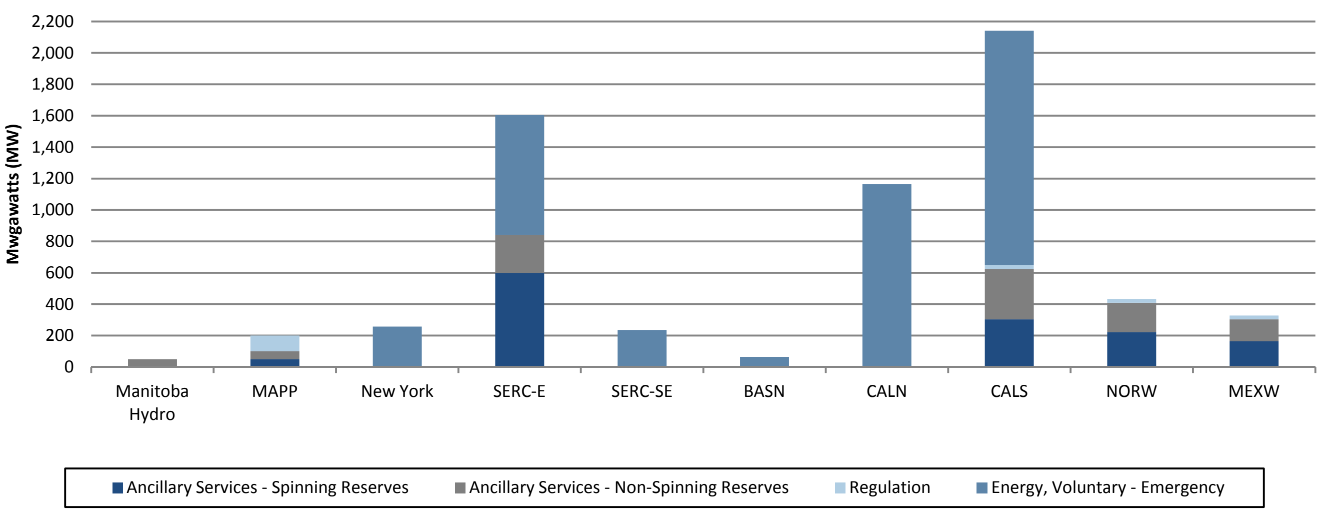
contributions to a reduction in greenhouse gases, with EE providing ongoing benefits and DR driving energy use to time periods when lower or non-carbon-emitting resources are available. DR can also enable the integration of renewable resources by supporting a variety of new operating characteristics associated with variable resources. Therefore, broader industry experience is needed as the certainty, locality, and characteristics of DSM become increasingly important to reliability of the BPS (Figure 40).

Figure 40: Growth in Energy Efficiency Supports Deferral of Resource Needs in 2013 (Left) and 2022 (Right)



While many similarities exist between DR and generating capacity, key differences in terms of availability, performance, and sustainability may appear as a given system becomes more stressed. Less-understood attributes of these resources, such as response fatigue[102] or economic-based participation rates, must be carefully monitored to ensure they do not pose reliability issues in the future. DR is increasingly being used to balance system load and to relieve resource adequacy and transmission reliability issues. Decreased or insufficient participation could lead to operational challenges where peak demand cannot be met by current generation or transmission resources. In 2013, just over 7,000 MW of DR NERC-wide is projected to support operational and emergency flexibility through the provision of ancillary services. There is virtually no increase in these values through the 10-year period (Figure 41).

Figure 41: Demand Response Used for Ancillary Services and Emergencies Increases Operator Flexibility[103]



[102] Response fatigue is a characteristic of demand resources that initially participate in Demand-Side Management programs because of the financial incentives. Once the electric supply to their equipment has actually been interrupted a number of times, the inconvenience outweighs the cost savings and the resource may potentially withdraw from the programs.

[103] Assessment areas not shown did not report any Demand Response used for Ancillary Services to be used during the peak.

The Reliability Assessments Subcommittee identified the following assumptions while reviewing this concern for consideration as an emerging reliability issue:

- DR participation plateaus in the long term
- Potential increase in frequency of use within the short term
- Character differences in traditional generation resources versus DR resources

The increased penetration of DR raises operational challenges in numerous areas of day-to-day operation of the BPS. Should DR be unable to deliver the required reduction in demand as committed, real-time operations may be challenged to ensure that adequate resources are available (contingency reserve) and that transmission facilities are operated within their defined limits to maintain BPS reliability.

Any analysis of DR fatigue should also be in effort to determine whether measure type. Moreover, load reduction versus customer-owned generation or temperature-sensitive load versus non-temperature-sensitive load (e.g., HVAC versus lighting, etc.) plays a significant role in the issue of DR fatigue.

DR fatigue issues also concern baseline estimation. The difference between the baseline and the resource's actual load is commonly used to determine the performance of a DR resource. However, if a DR resource is both responding to high-energy prices *and* participating in a capacity market (jointly enrolled participation), the resource will not be available to reduce load, should Emergency Operating Procedures (EOPs) be invoked at a time when the DR resource is actively reducing load for the price-responsive program. If the DR resource is already reducing load when EOPs are called, the amount of load reduction available from those DR resources could actually be lower than their capacity market obligation. This is especially an issue if the system operator is not aware that the load relief was unavailable. Additionally, if a DR resource is responding often to price signals, it becomes unclear how the baseline should be estimated. Establishing a baseline method for DR resources gives the system operator an accurate, real-time picture of available DR.

In addition to baseline estimation issues, analysis should include data quality and meter accuracy issues that have been encountered in estimating actual DR reductions. Telemeter data provides effective and reliable metering solutions that provide near real-time meter information in order to assess actual performance. Follow-on action can then be taken by the system operator once the initial dispatch signals were given. System operators must know how much DR actually responded. Further, system operators may be able to track or identify actions by DR resources through feeder, substation, or pricing node data.

These issues become even more important as system operators begin to use DR more to control transmission constraints, provide ancillary services, and manage contingency reserves. Program-specific details to the maximum interruption frequency must be fully considered. For example, several DR programs limit the amount of times service can be interrupted from the customer within a given time period (e.g., per day, month, or season). Where these limits exist, reductions in peak demand may not be obtainable by the system operator if extreme weather conditions were to persist for a prolonged period of time during the peak season. More experience and data analysis associated with DR performance will be required to establish the long-term availability, effectiveness, and customer acceptance of these programs.

The trend of increased use of DR programs to meet projected peak demands gives system planners the confidence that the trend will continue in the future. If DR programs fail to deliver committed load shedding, additional generation resources and transmission facilities may need to be planned and constructed to deal with an unplanned contingency response. Additionally, expected transmission and generation resources may not be online due to scheduled or unscheduled maintenance, further complicating the issue if DR programs are planned as fixed reductions in load.

These results and findings of any analysis on DR fatigue should assist system planners in developing guidelines for treatment of DR resources within both short and long-term planning studies. The assumptions regarding performance and availability of DR need to be developed and incorporated into various types of traditional transmission planning studies such as steady state, short circuit, thermal, and voltage analyses.

Risk Assessment Summary

Impacted Assessment Area(s)	PJM
	MISO
	NPCC
	SERC
	WECC
Impact Type	Resource Adequacy - Unavailability and non-performance of expected DR during peak periods can contribute to a capacity shortage
	Operating Reliability - DR can have unforeseen impacts to system stability and voltage support if not sufficiently modeled
Magnitude of Impact	80 GW of DSM (DR and EE) are projected to be available by 2022
	DR projected up to 12 percent of peak demand
Likelihood of Impact	The likelihood of an event that impacts reliability is greatly reduced if proper planning processes, operational procedures, and operator training have been implemented
	Increasing operator experience with demand response characteristics and behaviors should enhance system operators' ability to manage unpredicted events

Recommendations

NERC	NERC should continue to monitor the Demand Response Availability Data System (DADS) data to identify availability and performance trends that may indicate potential planning risks.
	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 reliability targets and provide ancillary services.

Progress Since 2011

NERC identified six key findings in the *2011 Long-Term Reliability Assessment*[104] that could affect long-term reliability, unless the electric industry took action to address and mitigate the impacts. The 2011 key findings were based on observations and analyses of supply and demand projections submitted by the Regional Entities, a NERC staff independent assessment, and other stakeholder input and comments.

The magnitude of these issues necessitates complex planning and effective strategies whose effects may not be realized for several years. While significant progress has been made since last year, continued action is still needed on all of the issues identified in last year's report to ensure a reliable bulk power system for the future. NERC continues to monitor and assess these issues based on industry progress through its annual reliability assessments, as well as through any special reliability assessments that may be needed as determined by the NERC Planning Committee.

While significant progress has been made over the past year for many of these issues, others have not yet been resolved, and continue to exacerbate power system planning and operations.

2011 Key Finding #1: A decrease in Future and Conceptual generation resources is projected reduce Planning Reserve Margins in some areas—resource adequacy in ERCOT shows signs of concern; however, most areas appear to have adequate resource plans to meet projected peak demands.

Developments in 2012:

- Overall, most areas are projecting decreased Planning Reserve Margins compared to last year, but still at levels above the NERC Reference Margin Levels.
- Projected resource adequacy concerns in ERCOT have worsened, as targets are not projected to be met by next year.
- Decreased Reserve Margin concerns in only some areas remain in 2012 and are a key finding in this report. This is due to shorter lead times for bringing on-line natural gas and renewable generation capacity, as well as the growth in demand response. All of these drivers contribute to future uncertainty as system planners can defer large capacity development projects for longer periods of time, which allows decisions to be made at a later time without an impact to reliability.
- In 2012, NERC issued a Pilot Probabilistic Assessment to determine if added value could be obtained from enhanced resource adequacy metrics. In September, the Planning Committee approved the implementation of a continent-wide biannual assessment of probabilistic indices.

2011 Key Finding #2: Existing and proposed environmental regulations in the United States may significantly affect bulk power system reliability, depending on the scope and timing of the rule implementation and the mechanisms in place to preserve reliability.

Developments in 2012:

- On December 21, 2011, the Environmental Protection Agency (EPA) released the Mercury and Air Toxics final rule pursuant to its authority under Section 112 of the Clean Air Act. Enhanced flexibility for generator compliance was included by allowing an additional year for modifications and provisions for extension requests. The proactive engagement among system planners, EPA, DOE and FERC has significantly aided the implementation of solutions to address the potential impacts associated with expected retirements and retrofits. Most importantly, should a reliability concern arise, additional safeguards are in place to ensure the continued operation of a given generator deemed critical to system reliability.[105] However, significant concerns still remain in the industry's efforts to coordinate a large environmental retrofit effort, as well as constructing the necessary transmission upgrades as a result of accommodating a shifting resource mix.

[104] *2011 Long-Term Reliability Assessment:* http://www.nerc.com/files/2011%20LTRA_Final.pdf
[105] See Key Findings section for more information on tools in place to ensure reliability.

- On August 21, 2012, the D.C. Circuit Court vacated the Cross-State Air Pollution Rule (CSAPR),[106] which had originally required 23 states to reduce annual SO_2 and NO_X emissions. Since then, the EPA has appealed for full court review.
- On June 27, 2012, the EPA revised an agreement that now calls for the agency to take final action by June 27, 2013, to implement cooling-water rules for existing power plants under Section 316(b) of the Clean Water Act. The extension will allow the federal agency time to review public comments received on controls required to protect aquatic life and on a survey to help determine benefits of the rule.

2011 Key Finding #3: The growing dependence on natural gas as a primary fuel source of on-peak capacity must be considered in planning. Operational measures must be in place to minimize interdependency risks, particularly during off-peak periods as more gas-fired generation is expected to provide base-load functions.

Developments in 2012:

- NERC continues to assess the reliability of the BPS through periodic and special reliability assessments. The NERC Phase II effort on gas dependency targets dependency risks by determining the different vulnerabilities that can affect BPS reliability, identifying ways that could minimize those vulnerabilities, and identifying approaches where coordinated inter-industry activities could provide enhanced system reliability.
- In 2012, NERC issued a lesson learned document on gas and electric interdependencies as a result of key findings from the *Report on Outages and Curtailments during the Southwest Cold Weather Event of February 1-5, 2011*.
- During August of 2012, FERC held a series of five regional conferences, which addressed local situations directly with electric grid operators, utilities, power generators, natural gas pipeline operators, natural gas producers, and natural gas distributors.
- The NERC Phase II effort on gas dependency targets dependency issues by determining the different vulnerabilities that can affect BPS reliability, identifying ways that could minimize those vulnerabilities, and identifying approaches where coordinated inter-industry activities could provide enhanced system reliability. The report is scheduled to be released by the end of 2012.

2011 Key Finding #4: Significant growth in wind and solar generation continues to be projected and surpasses the NERC-wide on-peak capacity forecasts of all other types of generations. Tools, training, and transmission remain key to successful planning and operations.

Developments in 2012:

- NERC will issue three special reliability assessments on accommodating high levels of variable generation, which include reports and recommendations for interconnection requirements, system operator communications, and probabilistic methods for resource adequacy.
- NERC will also issue a joint report with the California Independent System Operator (CAISO), which focuses on challenges and solutions aimed at the area's growing resource mix of variable generation.

2011 Key Finding #5: Significant increases in Demand-Side Management continue to offset future resource needs, while dispatchable and controllable demand response can expand flexibility for operators.

Developments in 2012:

- Compared to last year's projections, planners anticipate significant growth in Demand-Side Management.
- Smart meter integration in the residential sector, increased retail and wholesale demand response programs, and state-sponsored initiatives have further enabled demand-side resources from participating in economic and reliability-based programs.

[106] 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 http://www.epa.gov/airtransport/.

2011 Key Finding #6: Transmission growth as a result of increased plans for integrating and delivering new resources (i.e., renewables); constructed transmission is on pace with projections.

Developments in 2012:

- Numerous transmission projects are planned and designed specifically for the integration of new renewable generation.
- In recent years, higher-than-average plans have been met with the construction of significant transmission.
- Five years ago, transmission was constructed at a rate of about 1,000 circuit miles per year. In the last five years, more than 2,300 circuit miles came into service each year, which more than doubled actual builds in the previous five years. The current plans further increase that rate to 3,600 miles per year over the next five years.

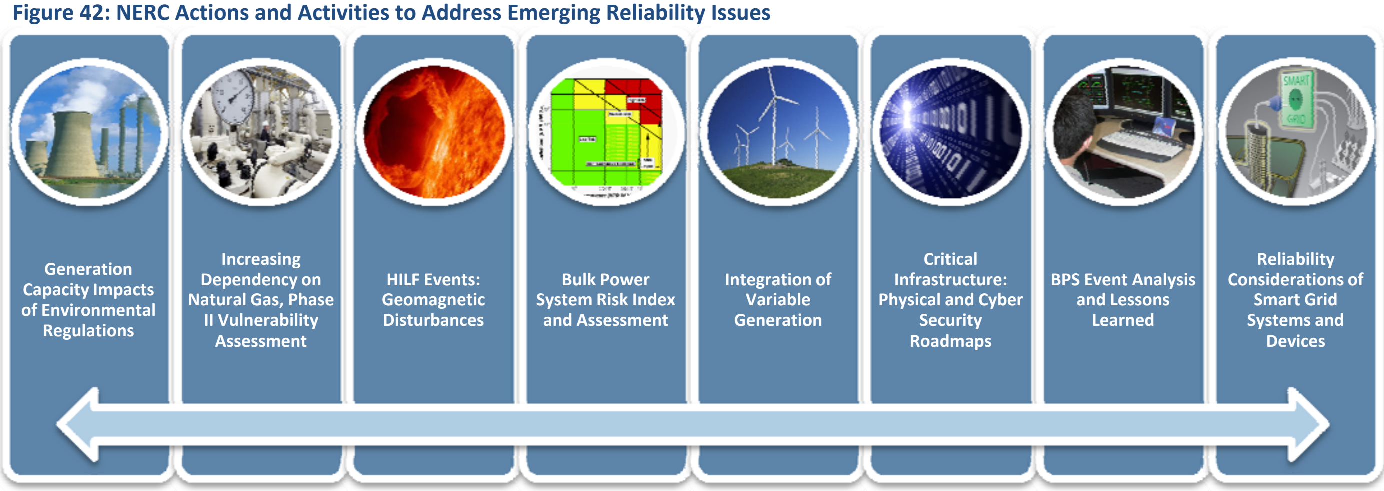
Emerging Reliability Issues in Focus

The NERC Reliability Assessment and Performance Analysis (RAPA) program reviews, assesses, and reports on the overall electric reliability of the interconnected bulk power system in North America. As part of this assessment, the program identifies and analyzes the impact of key issues and trends that may affect reliability in the future, such as market practices, industry developments, potential technical challenges, technology implications, and policy changes.

Each year, the NERC *Long-Term Reliability Assessment* forms the basis for the NERC reference case. This reference case incorporates known policy and regulation changes expected to take effect throughout the 10-year timeframe, assuming a variety of factors such as economic growth, weather patterns, and system equipment behavior. A set of scenarios can be developed from risk assessment of emerging reliability issues. These scenarios can then be compared to the reference case to measure and identify any significant changes to the BPS that may be required to maintain reliability.

For this reason, NERC investigated each of these emerging reliability issues through structured technical committees and leveraged the expertise of the electric industry's broad knowledge base. Over the next decade, the electric industry will face a number of significant emerging reliability issues. The confluence of these issues will drive a transformational change for the industry, potentially resulting in a dramatically different resource mix with significantly increased reliance on natural gas and renewable generation, a need for enhanced and sophisticated modeling, a new risk and probabilistic framework built to address reliability challenges, and growing critical infrastructure and protection concerns—both physical and cyber. Many of these change elements are critically interdependent, and industry action must be closely coordinated to ensure continued reliability. As a result, numerous NERC activities are currently ongoing, which exemplifies the industry's commitment to understand, resolve, and make recommendations that support enhancing future reliability (Figure 42).

Figure 42: NERC Actions and Activities to Address Emerging Reliability Issues



Since 2007, the Reliability Assessment Subcommittee (RAS) of the NERC Planning Committee (PC) has identified a number of issues of strategic importance to the industry and surveyed industry participants to rank these issues based on their probability of occurrence and their impact to the reliable operation on the BPS over both the one-to-five-year and six-to-ten-year time frame. A number of recommendations based on emerging reliability issues identified in the *LTRA* were developed to support long-term reliability risks and challenges; however, not all have been fully addressed.

In August 2012, the NERC Board of Trustees approved the charter and start-up of the Reliability Issues Steering Committee (RISC), which is an advisory committee to the board that provides front-end, high-level leadership, prioritization, and accountability for issues of strategic importance to BPS reliability. The RISC assists the Board, NERC standing committees, NERC staff, regulators, Regional Entities, and industry stakeholders in establishing a common understanding of the scope, priority, and goals for the development of solutions to address these issues. In some cases, that includes recommending reliability solutions other than the development of new or revised standards and offering high-level stakeholder leadership engagement and input on issues that enter the standards process. The recommendations will improve efficiency of Reliability Standards development, engage high-level stakeholder leadership, and promote reliability excellence.[107]

The issues surveyed by the RAS in 2012, as well as other identified reliability issues from the *2007-2011 Long-Term Reliability Assessments* will be submitted on behalf of NERC staff, the PC, and the industry for review, analysis, and prioritization of action by the RISC.

2012 Emerging Reliability Issues

For the *2012 Long-Term Reliability Assessment*, NERC gathered emerging issues previously identified in other assessments as well as issues identified and assessed in a survey submitted to the technical committees and based on RAS identification. For many reasons, it is difficult for NERC to evaluate every emerging issue that can potentially impact reliability in the future—including unforeseen and unpredictable events. Each year the RAS identifies a set of issues that are of particular concern. RAS identified eight issues for use in a risk assessment survey. A risk assessment was performed on these issues and detailed with additional information provided in Appendix V. The voting members of the Planning Committee, Operating Committee, and Members Representative Committee provided their input on risk, which was defined as determining likelihood of occurrence and consequence. They categorized each issue as high-impact, medium-impact, or low-impact to reliability and identified other characteristics of the impact.

Across North America, several issues affecting BPS reliability are regional. Because some Regions are more vulnerable to certain risks than others, the possibility of a risk impacting the power system can vary. Looking at regionally aggregated overall likelihood can be misleading as the possibility of an impact for one given area can be very high, but for another it can be very low. By aggregating these two areas, the overall likelihood can significantly mask impacts that may be regionally focused.

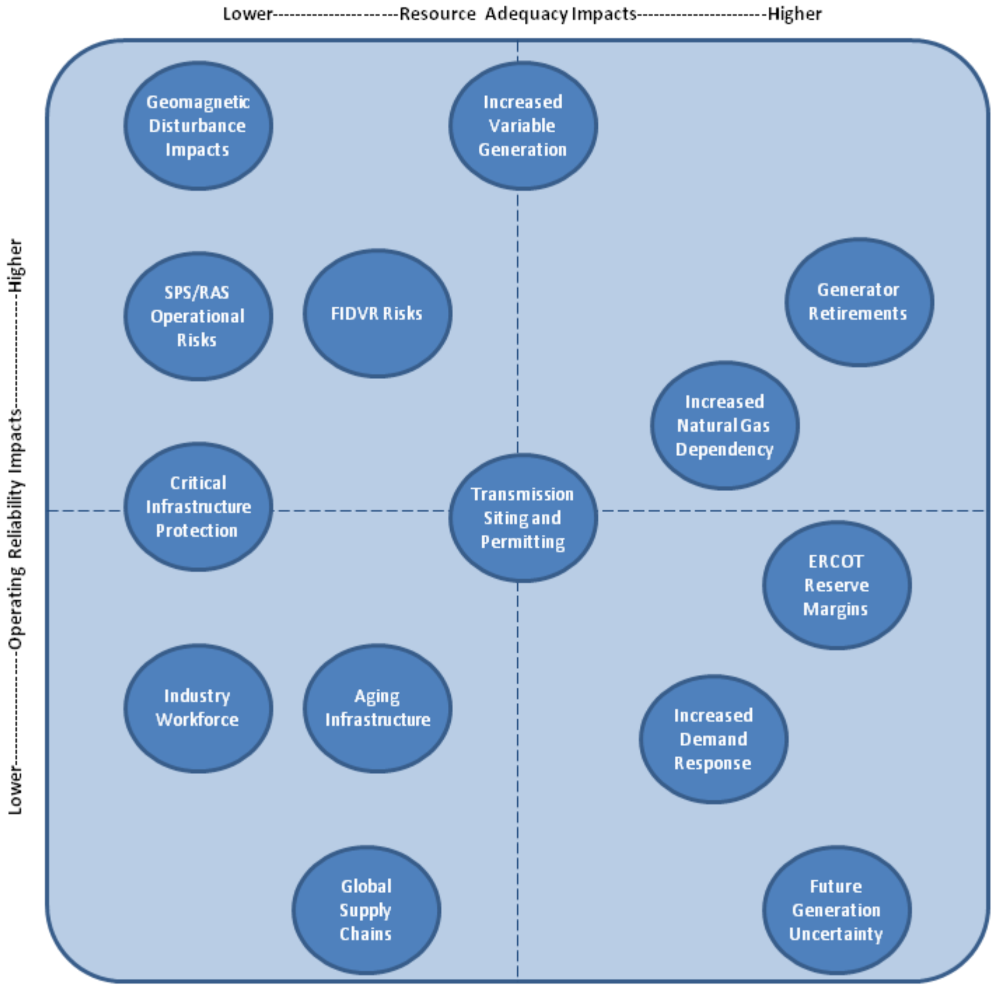
Two fundamental and measurable characteristics of BPS reliability form the foundation of the concepts described in this document—*resource adequacy*[108] and *operating reliability*[109] (or system security). Each issue has the potential to impact these two characteristics differently; therefore, the impacts to system reliability can be different and must be well-understood. While not considered in the figure below, integrating the likelihood of occurrence for each impact can provide a greater understanding of expected reliability consequences.

On the impact side, a greater understanding of expected reliability consequences can be easily assessed. For example, signifiacnt generator retirements have a greater impact on resource adequacy compared to operating reliability. Conversely, transmission facility-related impacts, such as geomagnetic disturbances and misoperation of Special Protection Systems (SPS), have a greater impact on operating reliability, as these issues have a direct impact to system stability and the performance of the transmission system under stressed conditions.

The results in the figure below are the product of combined industry surveys on emerging reliability issues, key findings from this report, engineering judgment, and prior independent assessments released by NERC (Figure 43).

[107] RISC Website: http://www.nerc.com/page.php?cid=1|117|428.
[108] Defined as the ability of the bulk power system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
[109] Defined as the ability of the bulk power system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements from credible contingencies.

Figure 43: Future Reliability Challenges and Emerging Issues as a Function of Resource Adequacy versus Operating Reliability Impacts



In order to minimize these risks, the electric power industry must understand what the impact will be. With resource adequacy impacts, the ability of the BPS to supply the aggregate electrical demand and energy requirements is compromised. While shedding firm load is a likely impact, system operators should take controlled actions or procedures to maintain a continual balance between supply and demand. When supply is insufficient to meet all the demand, rotating outages or controlled interruption of customer demand is needed to maintain a balance with available supplies while maintaining the overall reliability of the interconnected system.

All other system disturbances that result in the unplanned or uncontrolled interruption of customer demand, regardless of cause are considered as operating reliability impacts. When these interruptions are contained within a localized area, they are considered unplanned interruptions or disturbances. When they spread over a wide area of the grid, they are referred to as cascading outages—the uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an exposed area. The outage in 1965 and 2003 in the Northeast, as well as the most recent 2011 event in the Southwest, were uncontrolled cascading outages.

Emerging Issues Risk Impact Scale

Extremely Low	Low	Medium	High	Extremely High
0%-20%	21%-40%	41%-60%	61%-80%	81%-100%

Emerging Reliability Issues, Impact, and Risk Type

Reliability Issue	Onset Time	Impact Type	Key Finding	Associated Risks	Impact to Resource Adequacy	Impact to Real-Time Operations	Impact to Long-Term Planning
Significant Generator Retirements and Environmental Control Retrofit Outages	1-4 years	Resource Adequacy Real-Time Operations Long-Term Planning	• 65 GW of Retirements Projected • 44 GW confirmed at the time of publication	• Insufficient capacity to meet demand • Less flexibility to meet higher than forecasted demand			
Accommodating Variable Resources in System Operations	Occurring and Increasing	Real -Time Operations Long-Term Planning	• 21 GW of Planned variable on-peak capacity added by 2022 • 46 GW of Conceptual variable on-peak capacity added by 2022	• Unplanned system contingencies could develop • Insufficient capacity to meet demand • Real and reactive power system mismatches could develop			
Increased Dependency on Natural Gas	Occurring and Increasing	Resource Adequacy Real-Time Operations Long-Term Planning	• Potential impacts to long-term reliability, operational planning, and real-time operations	• Committed capacity unavailable for dispatch when needed • Insufficient planning of fuel contingencies and mitigation • Potential for wide-spread common-mode outages			
Geomagnetic Disturbance Impacts to System Operations and Communications	Any	Real-Time Operations Long-Term Planning	Potential impacts to system operations and equipment Assessments underway to determine impact severity	• Unplanned system contingencies could develop • Solar Storm Forecast Warning • Frequency of coronal mass ejections			
Transmission Siting and Permitting	Occurring	Long-Term Planning	30,000 miles of transmission under construction + planned to be added from 2012-2022	• Capacity unable to reach demand • Unplanned system contingencies could develop without transmission reinforcements			
Potential Operational Risks Associated with Interaction of Special Protection Schemes/Remedial Action Schemes	Occurring	Real-Time Operations	Special Protection Schemes a leading cause of 2011 Pacific Southwest Outage	• Unforeseen operational impacts with increased interaction of Special Protection System /Remedial Action Scheme			
Global Supply Chains and Fuel Reliability	Any	Resource Adequacy Real-Time Operations	Political Instability in countries supplying critical energy components	• Loss of capacity due to loss of fuel • Potential for wide-spread common-mode outages			
Assessment of Fault-Induced Delayed Voltage Recovery (FIDVR) Simulation	Any	Real-Time Operations	Planning Coordinators should study the impacts from FIDVR-related events	• System contingencies could develop that have not been fully analyzed and evaluated			
Coordinated Cyber / Physical Attacks on Critical Infrastructure	Occurring	Real-Time Operations	Potential impacts to system operations and equipment	• Unplanned system contingencies could develop			
Electricity Industry Workforce	Occurring	Long-Term Planning	Upcoming retirements of large numbers of veteran industry planners, operators, trades workers	• Reduction in experienced industry resources and knowledge • Insufficient knowledge transfer efforts			
Aging Infrastructure	Occurring	Real-Time Operations Long-Term Planning	Infrastructure installed in the 1960s and 1970s (and in some cases earlier) is reaching the end of its projected lifecycle.	• Infrastructure installed in the 1970s is reaching the end of its projected lifecycle.			

Emerging Reliability Issue Summaries

Selected emerging reliability issues are summarized below. Additional detail is provided in Appendix V.

Significant Generator Retirements and Environmental Control Retrofit Outages

Largely due to the combination of low natural gas prices and environmental regulations, a significant amount of generation is expected to retire over the next four years. Overall, generation retirements need to be evaluated and analyzed in an integrated fashion. While the high degree of uncertainty surrounding retirement decisions continues to be exceedingly difficult, power system planners must continue not only to study the effects of individual generator impacts, but also recognize the cumulative impacts of multiple generator retirements.

In the United States, several regulations that directly affect the electric industry are either final or in the process of being proposed by the U.S. Environmental Protection Agency (EPA). The most significant proposed EPA rules have been in development for over 10 years and are currently undergoing court-ordered revisions that must be implemented within mandatory time frames. A significant retrofit effort is expected over the next 10 years in order to comply with federal and state-level environmental regulations. Environmental controls are expected to be put in place to meet newly finalized Clean Air Act rules by the end of 2016. While federal water rules (i.e., Section 316 (b) of the Clean Water Act: Cooling Water Intake Structures) may also affect retirements and outage scheduling, regulations have not yet been finalized.

Accommodating Variable Resources in System Operations

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. To manage this increased uncertainty, the system operator must have access to advanced variable generation forecasting techniques and have access to sufficient flexible resources to mitigate the added variability and uncertainty associated with the large-scale integration of variable generation. In this respect, operating criteria, forecasting, commitment, scheduling, dispatch and balancing practices, procedures, and tools must be enhanced to assist operators in maintaining BPS reliability. Improved operating practices, procedures and tools are critical in order to integrate variable generation into the power system, as well as improve the control performance and reliability characteristics of the power system. System resources supporting reliability, such as flexible generation and responsive load, are finite. Operating practices, procedures, and tools that maximize the effective use of limited responsive resources improve reliability and facilitate variable generation integration.

Increased Dependency on Natural Gas

The majority of new North American generating capacity projected for the next 10 years will rely on natural gas as its primary fuel. With a shift to unconventional gas production in North America, the potential to increase availability of supply makes gas-fired generation a premier choice for new generating capacity in the future, overtaking and replacing coal-fired capacity. However, increased dependence on natural gas for generating capacity can amplify the BPS's exposure to interruptions in natural gas fuel supply and delivery. Mitigating strategies—such as storage, firm fuel contracting, alternate pipelines, dual-fuel capability, access to multiple natural gas basins, nearby plants using other fuels, or additional transmission lines from other areas—can contribute to managing this risk.

In the future, the electric sector will be responsible for most of the growth in natural gas demand. The combination of this growth in gas demand within the electric sector and its changing status among the gas-consuming sectors has significantly increased the interdependences of the two industries and increased the focus on the interface between them. A key element of this interface focus is the need for increased coordination between the two industries, particularly at a regional level.

Geomagnetic Disturbance Impacts to System Operations and Communications

In February 2012, NERC reported that the most likely result from a strong geomagnetic disturbance (GMD) is voltage collapse. NERC also found that particularly large geomagnetically induced current (GIC) flows can result in transformer damage and may ultimately result in the failure of some transformers. The risk of the introduction of GIC into the BPS may be at greater for Regions that are situated in the northern latitudes and have high ground conductivity. Depending on the duration and severity of the occurrence, GIC can impact real-time operations and equipment. Real-time operations could be impacted when reactive demands increase as transformers experience thermal heating from geomagnetically induced currents. If reactive demands and geomagnetic currents are not properly monitored, situations could develop in which an uncontrolled cascade of the BPS due to the introduction of geomagnetically induced currents ultimately results in voltage collapse.

The industry is well-equipped to face a small number of transformer failures; however, due to the concerns about an extreme GMD event causing a larger-than-expected number of failures, it is imperative that the nature of the reliability risk be quantified before a corrective action is developed. Therefore, the industry should consider vulnerability assessments, equipment testing, operational procedure enhancements, and appropriate measures for grid and facility hardening to address potential impacts.

Transmission Siting and Permitting

Siting difficulties have always been an issue for utilities. However, with increasing plans for new transmission, ensuring transmission can sufficiently be built within a specified time period has increased the importance of this issue. Siting of new bulk power transmission lines brings with it unique challenges due to the high visibility, their span through multiple states and provinces, and, potentially, the amount of coordination required among multiple regulating agencies and authorities. Lack of consistent and agreed-upon cost allocation approaches (specific to transmission construction), coupled with public opposition due to land use and property valuation concerns, have, at times, have resulted in long delays in transmission construction. When construction is delayed, special operating procedures to maintain BPS reliability may be needed.

Potential Operational Risks Associated with Interaction of Special Protection System / Remedial Action Scheme

Special Protection Systems (SPS) and Remedial Action Schemes represent a planning and operation alternative to the addition of new transmission facilities. Although an SPS is less costly and faster to install than building new facilities, it has the risk of potentially failing to operate and adds planning and operational complexity. System operators need to be aware of the potential impacts associated with an SPS or remedial action scheme. 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.[110] Accordingly, the objective of this emerging issue is to: (1) evaluate historical and future trends in SPS identification and deployment; (2) identify limitations of SPS deployment and proliferation; (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 the ability for a given power plant, or group of power plants, to produce electricity and, therefore, cause significant reliability concerns.

Of specific concern are global supply chains that are made up of weak chains (e.g., political uncertainty and instability, war-stricken states, weak ties to North American foreign affairs). Currently, there are two known potential supply chains of specific concern to the electric power industry: scarcity of rare earth metals for nuclear generation and liquefied natural gas imports from the Middle East.

[110] NERC Southwest Blackout Event Reports: http://www.nerc.com/page.php?cid=5%7C407.

Assessment of Fault-Induced Delayed Voltage Recovery (FIDVR)

Fault-Induced Delayed Voltage Recovery (FIDVR) events are characterized by a depressed voltage for 5 to 30 seconds following a fault. These events are of concern because they show a temporary loss of voltage control in an area, and they pose a risk of cascading to a larger area, especially if another unexpected event occurs while the voltage is depressed. These events have been studied and are believed to be initiated by the stall of low inertia induction motors during the fault. Motors at risk of stalling include compressor-driven loads such as air conditioners. The subject of FIDVR events and their causes and solutions is covered in a NERC report on this topic.[111]

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, although 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.

Electric Industry Workforce

The demand for industry workers to plan, maintain, and operate the BPS increases with the growing need for new infrastructure investments in electric generation, delivery, and use technologies and the rising need for technology innovation. 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, but with the increased need to plan, design, and operate the BPS to accommodate a variety of new technologies and processes, there is still substantial interest in training and hiring workers to support industry needs and knowledge transfer.

Aging Infrastructure

Over the past decades, the majority of transmission investment was directed toward constructing new facilities to meet customer load demands, and comparatively little capital investment was expended for refurbishing existing facilities. The aging transmission system infrastructure has many challenges, such as the availability of spare parts, the obsolesce of older equipment, the ability to maintain equipment due to outage scheduling restrictions, and the aging of the work force and lost knowledge due to personnel retirements. Considering the diversity of equipment technologies and installation dates, potential for increased failure rates should be evaluated. However, implementation of any replacement strategy and in-depth training programs require additional capital investment, engineering and design resources, and construction labor resources, all of which are in relatively short supply.

[111] http://www.nerc.com/docs/pc/tis/FIDV_R_Tech_Ref_V1-1_PC_Approved.pdf.

Projected Demand, Resources, and Reserve Margins (2013–22)

The following section of the report represents the NERC-wide reference case and 10-year forecasts of Planning Reserve Margins, capacity resources, seasonal peak demands, and transmission.

Planning Reserve Margins

The electric industry has prepared plans to ensure the generation and delivery of reliable electricity throughout North America. Based on NERC's three different categories of Planning Reserve Margins (metrics used to measure the ability of a system's resources to meet customer demands based on current capacity plans and load forecasts), nearly all assessment areas will remain above the NERC Reference Margin Level throughout the 5-year (2017) assessment. The 10-year (2022) assessment shows a considerable decrease in Planning Reserve Margins, equating to more assessment areas being below the NERC Reference Margin Level (Figure 44, Figure 45).

Figure 44: 2017 NERC-Wide Peak Season Planning Reserve Margins

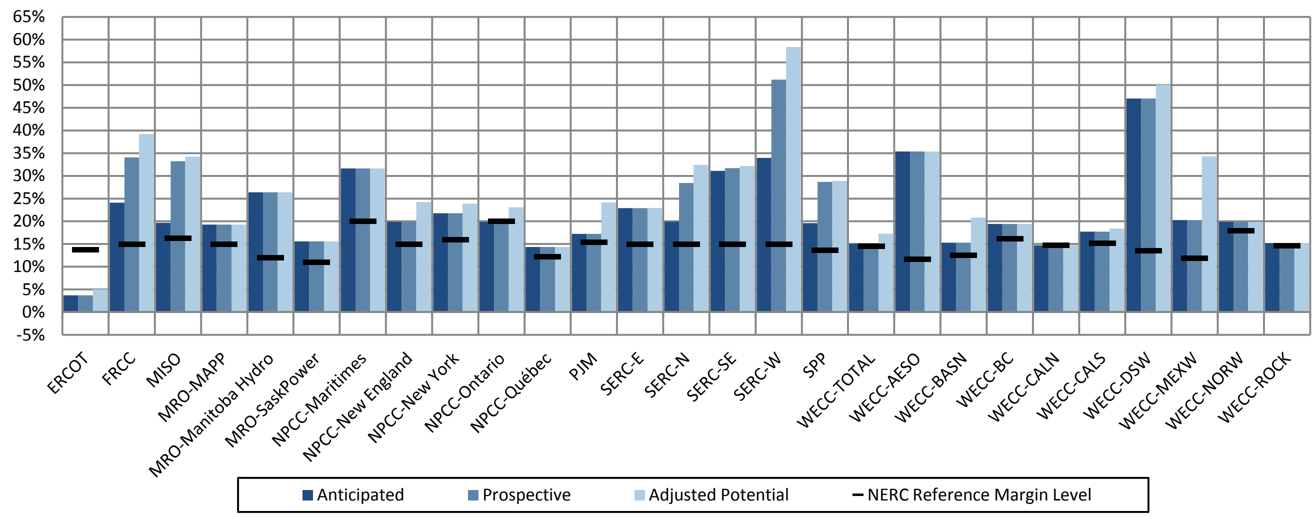
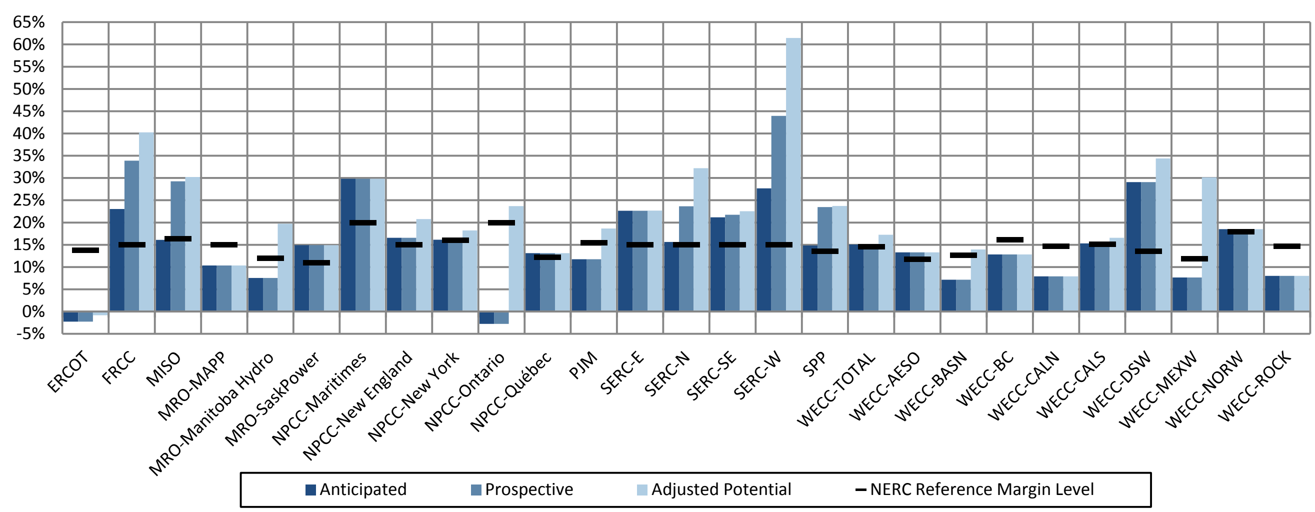


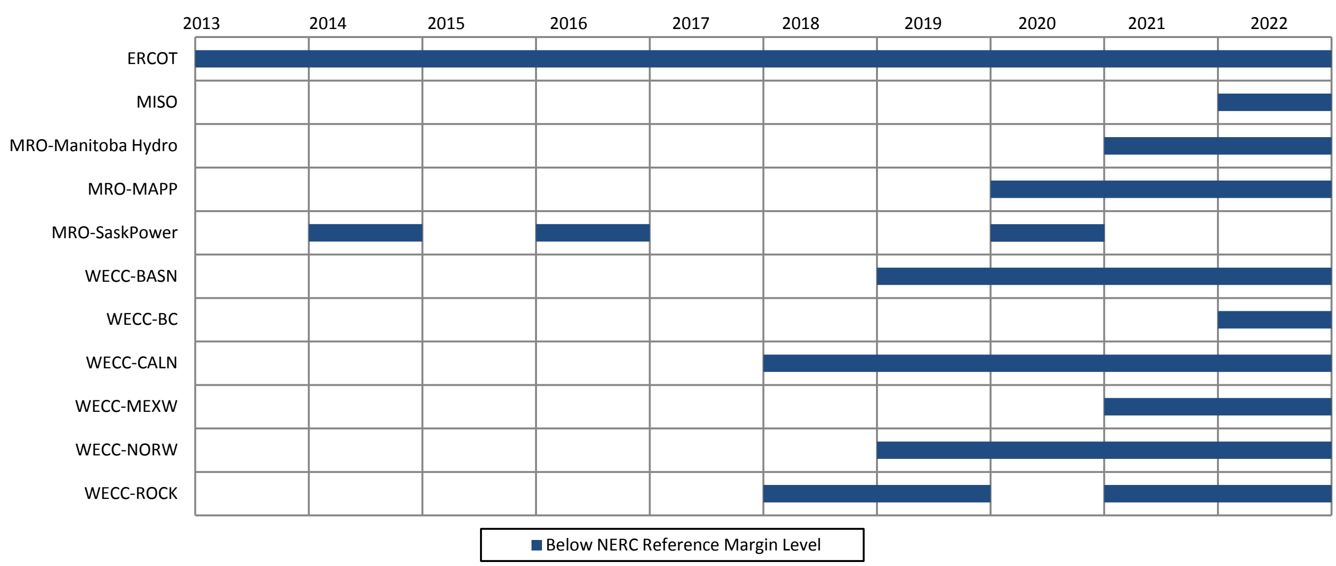
Figure 45: 2022 NERC-Wide Peak Season Planning Reserve Margins



Significant challenges face the electric industry. These challenges may shift industry projections and cause the NERC reference case to change, which would add considerable uncertainty—not only in the long term, but in the short-term, as well. Where markets exist, signals for new capacity must be effective for planning purposes and must reflect the lead times necessary to construct new generation and any associated transmission. Regulations aimed at controlling environmental impacts caused by higher-emission generating plants create additional concerns for industry planners, as regulatory compliance deadlines could conflict with existing capacity plans and approval processes. Potential impacts could be both local and regional and must be addressed accordingly.

The ERCOT Assessment Area will face resource adequacy challenges throughout the long-term outlook due to the uncertainty of plans for new capacity—demand continues to grow at a compound annual growth rate of 2.35 percent. Although ERCOT and the Public Utility Commission of Texas (PUCT) have been proactive, new market rules and increased demand response impacts have not been in place long enough to curb the continued decline of Planning Reserve Margins.[112] Planning Reserve Margins remain below the NERC Reference Margin Level of 13.75 percent throughout the assessment period, turning negative in the latter years. Uncertainty surrounding plans for future capacity is the most notable issue that may result in the need for emergency actions. Until new capacity projects come online, the use of interruptible load, voltage reduction, or the implementation of other ERCOT-specific Energy Emergency Alerts (EEA) plans may become necessary. Impacts could be exacerbated by extreme weather conditions, such as drought and heat waves that have become an ongoing concern in recent years. This would result in the highest recorded peak demand for the area during the 2011 summer. Although improved 2012 spring rainfall has temporarily alleviated drought conditions, the potential for extreme heat and corresponding increase in demand remains a monumental concern that will only be mitigated by securing additional capacity or demand-side management resources. Adequacy concerns in ERCOT could be further exacerbated by the potential for more stringent emission requirements from the MATS rule, which could result in additional project delays or cancellations of new capacity (Figure 46).

Figure 46: Assessment Areas with Anticipated Reserve Margins that fall below the NERC Reference Margin Level by 2022



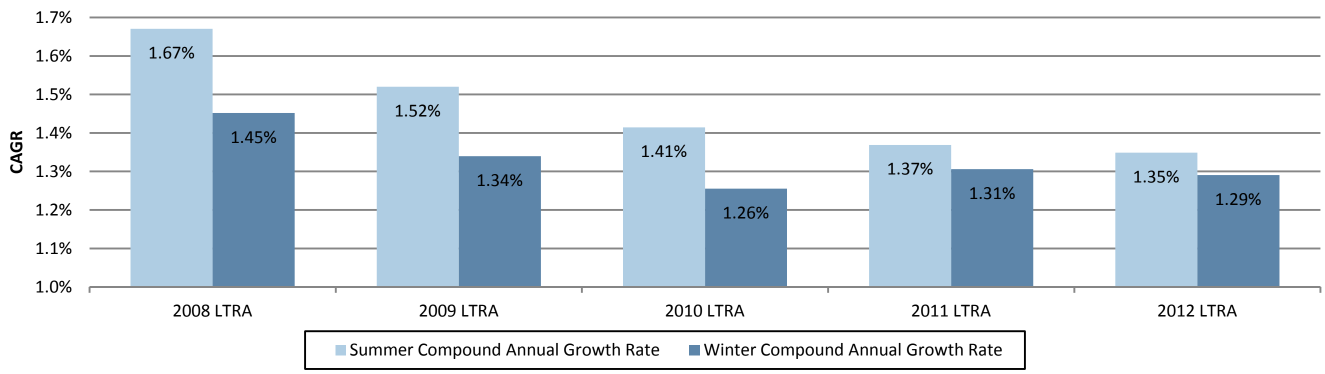
As the Ontario Assessment Area phases out all remaining coal-fired capacity by 2014, the province must manage a shifting resource mix. Plans call for an increased dependence on nuclear resources. Several refurbished units are expected to return to service after prolonged outages, with all of the coal units retired or converted to cleaner fuels. Retired units have been replaced by new gas units, renewable generation, and restarted nuclear units. With these changing conditions, Planning Reserve Margins remain adequate through 2017 but significantly decrease thereafter, becoming negative in the final years of the outlook. Additional conceptual resources will be necessary, including scheduled refurbishments at both the Bruce and Darlington nuclear plants, along with potential nuclear new-build at the Darlington site.

[112] The actions taken need evaluation time. While there have been no significant announcements of new generation yet, the work of the PUCT and ERCOT participants continues.

Demand

The North American electricity demand growth for the summer season during the next decade (2013–2022) remains essentially unchanged from last year's outlook. NERC-wide, the 10-year compound annual growth rate (CAGR) for on-peak summer demand is 1.35 percent—slightly lower than what was reported in the *2011 Long-Term Reliability Assessment*. The 10-year growth outlook for winter demand also remains steady at 1.29 percent. There is a 0.02 percent decline compared to a year earlier, but demand still remains above its lowest outlook in 2010 (Figure 47).

Figure 47: NERC-Wide Compound Annual Growth Rate of Seasonal Total Internal Demand



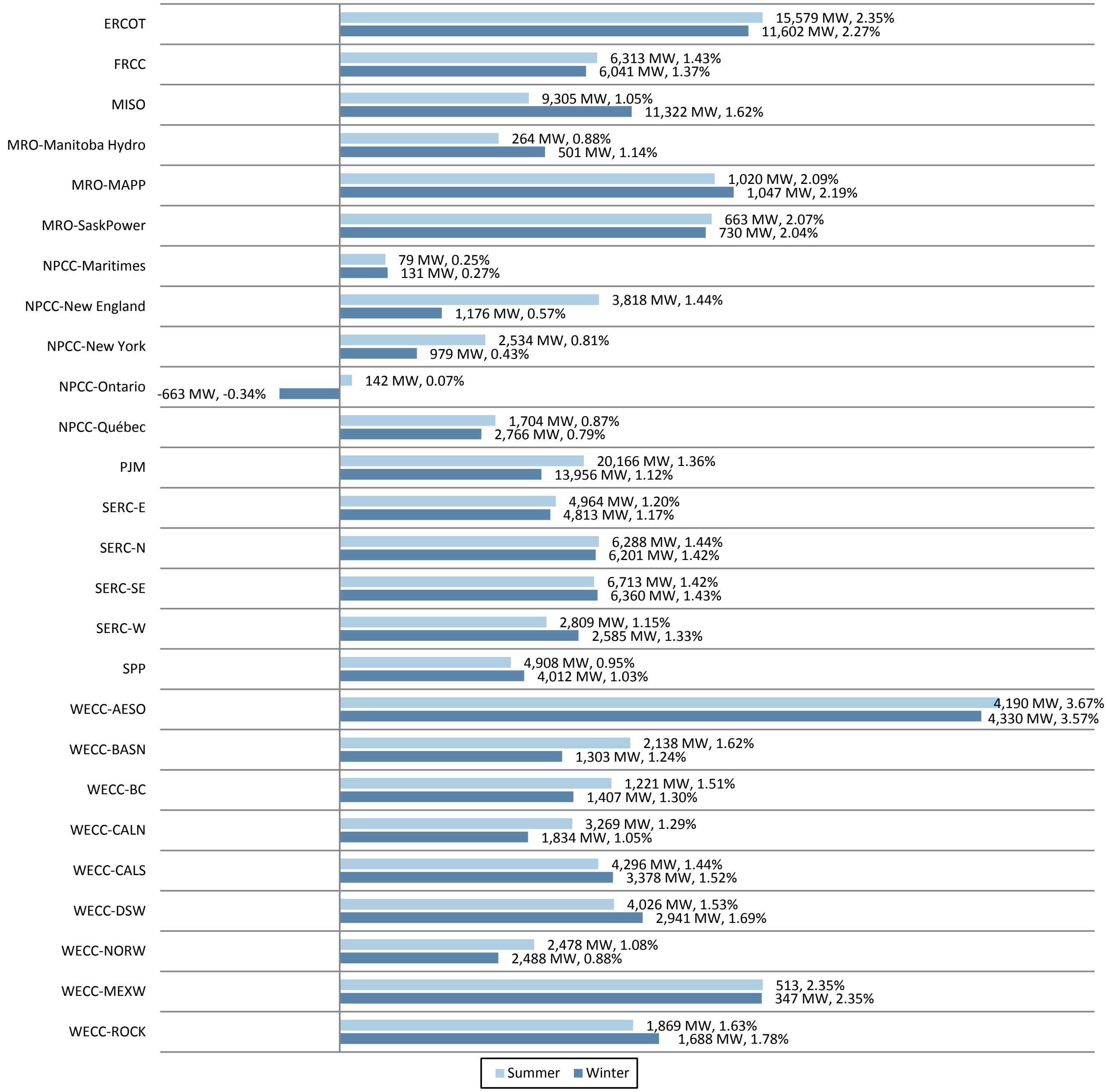
Peak load forecasts provide a future view on electricity infrastructure needs. According to the *2012LTRA* reference case, the demand growth for the summer season has reached its lowest level since NERC began reporting this data in 1967. This slower growth outlook will have important implications on the need for new capacity resources.

Despite a slower growth forecast for North America as a whole, several assessment areas project significant electricity demand growth during the next decade, including Alberta (WECC-AESO) and ERCOT. Alberta covers the third-largest proven oil reserves in the world (over 170 billion barrels), and the extraction of these oil sands by surface mining will create substantial load growth—both to support mining operations and corresponding population increases. The Alberta Assessment Area projects average growth of over 3.5 percent annually, totaling over 4 GW by 2022. Continued population growth throughout Texas is largely responsible for increasing electricity demand in load centers during the 10-year outlook.

Although Canada as a whole projects moderate economic growth and corresponding electricity demand growth in the coming decade, Ontario will lag behind in the near term. High commodity prices—in particular oil—will benefit other parts of Canada over Ontario's manufacturing and export-based economy. During the 10-year period, Ontario's economy is expected to continue to undergo structural change. As the economy matures, there is likely to be a transition from an energy-intense industrial process-based economy to one with a larger service sector and specialized or high-value-added manufacturing, which could lead to a less energy-intense economy. Demand conservation is another underlying driver for slower demand growth. Accordingly, the NPCC-Ontario Assessment Area is expecting flat demand growth for the 10-year summer outlook with negative growth during the winter.

Most of the remaining assessment areas are planning for moderate demand growth over the 10-year period, attributing mostly local economic conditions as primary determinants (Figure 48).

Figure 48: Peak Demand Growth (MW) and Compound Annual Growth Rate (%) of Total Internal Demand by Assessment Area



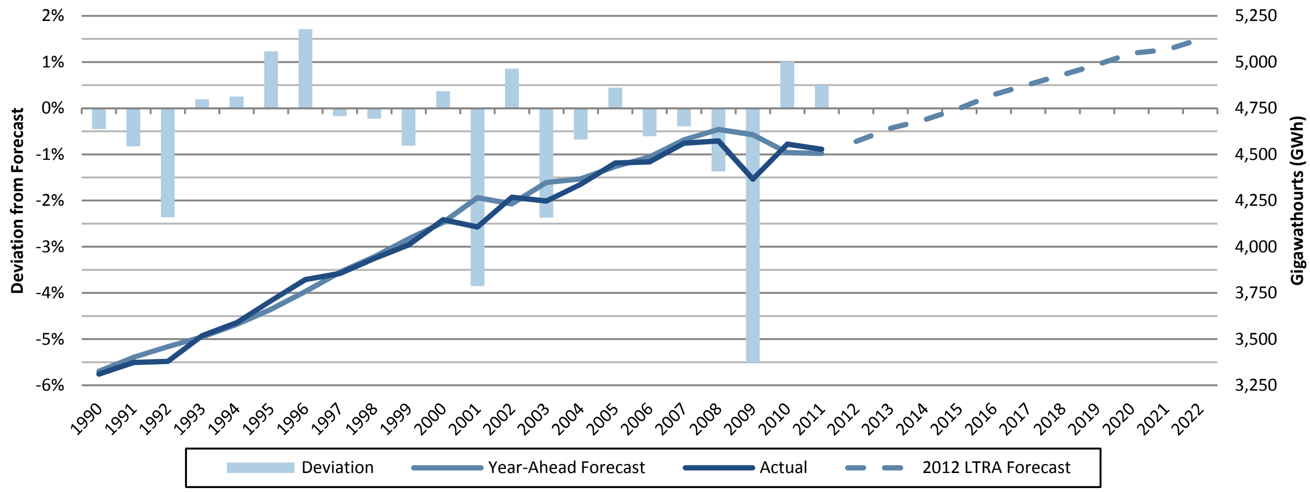
Load Forecast Uncertainty

Forecasting electricity demand has become more complicated in recent years, and this issue was addressed thoroughly in the *2011 Long-Term Reliability Assessment*.[113] Conclusions highlighted the challenges of redefining methods based on customer and utility behavior, the current state and outlook of the North American economy, and new developments in long-term weather projections. These challenges continue to make load forecasting more complex and are highlighted by the year-ahead outlook for NERC-wide Net Energy for Load (NEL), a measurement of annual generation in megawatt-hours

[113] *2011 Long-Term Reliability Assessment*. Load Forecasting Uncertainty. P. 107. http://www.nerc.com/files/2011%20LTRA_Final.pdf.

(MWh). Although year-ahead projections were extremely accurate during the 1990s when economic growth was relatively stable, the mild recession during the early 2000s largely contributed to the actual NEL falling below the forecast. Similarly, the 2008 recession caused actual demand to drop significantly, which further supports the high correlation between economic conditions and electricity use (Figure 49).

Figure 49: Net Energy for Load – Forecast vs. Actual



While unstable economic conditions have added complexity to load forecasting in recent years, utility integration of smart grid-related technologies has also had an influence. Electricity use with smart grid programs has encouraged consumers to reduce or otherwise change their electricity usage during peak periods in response to time-based rates or other forms of financial incentives. Continued enrollment in large-scale demand-side management programs by industrial and commercial customers will bear an even greater impact on load forecasts. As demand-side management programs continue to evolve, load forecasting methods will need to adapt accordingly to ensure demand projections remain a dependable source of information for industry planners.

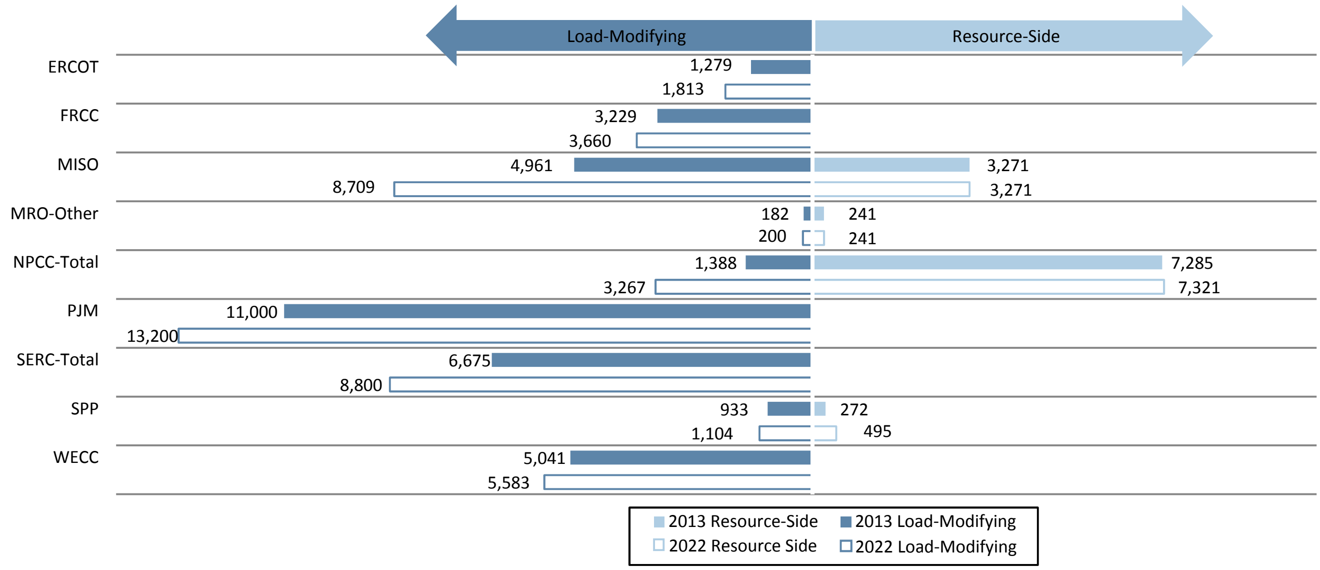
Demand-Side Management

The use of demand-side resources is expected to expand throughout North America, continuing the trend NERC has observed since initially collecting this data in the 1980s. In recent years, as various new demand response and energy efficiency programs have been introduced, NERC has strived to modify data collection and presentation as necessary to keep up with an industry that continues to evolve. Additional information regarding how NERC collects and reports demand response is included in Appendix V and VII in this assessment.

As increased demand-side management in recent years has provided more flexibility for system operators, continued penetration of these programs is forecast throughout the assessment period. However, it is important to consider how each area forecasts the future availability of demand response during peak demand periods. Generally, most demand response programs involve short-term contracts between participants that provide increased certainty during the first three years. In subsequent years, expected performance is based on area-specific assumptions.

Demand Response as a percentage of Total Internal Demand is highest in the NPCC-New England Assessment Area, amounting to 10.1 percent in 2013. Projections are for a 5 percent increase during the next 10 years. By 2022, nearly 5 GW of load-modifying and resource-side demand response is projected to be available during the summer peak. Similarly, MISO is planning for over 3.7 GW in additional load-modifying demand response during the assessment period (Figure 50).

Figure 50: NERC-Wide Demand Response: 10-Year Outlook

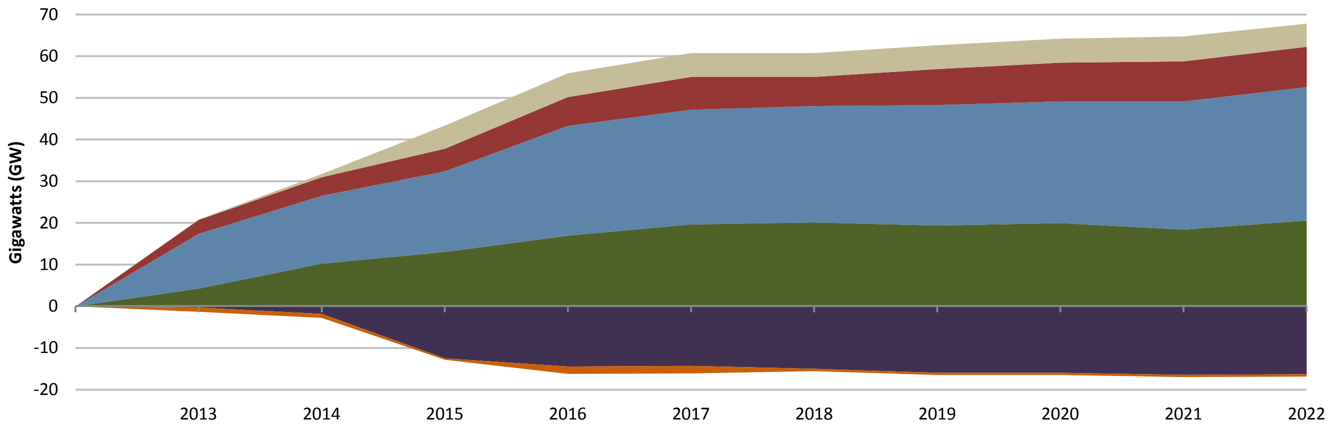


In many cases, DR—especially load categorized as a resource—can offer more flexibility to operators and provide redispatching options used to maintain reliability. Specifically, demand response programs in the industrial and commercial sectors are even more impactful and usually involve contracts that require participants to respond when called upon by system operators. Contract lengths rarely extend beyond three years with provisions, which limits the number of times a participant will be called to respond in a given year. However, planners should consider the potential reliability consequences of over-dependence on these large-scale demand response programs. Specifically, prolonged cases of extreme demand could trigger the repeated use of demand response, ultimately causing customers to forego future participation in these programs.

Generation

Projections for future generation are based on several factors and can vary by NERC Region or Assessment Area. The economic outlook, fuel prices, regulations, and load forecasts are all volatile and have important implications in regard to decisions to build new capacity. According to the *2012LTRA* reference case, a net of 51.3 GW of on-peak generation is expected to be added during the 10-year NERC-wide outlook (Figure 51).

Figure 51: NERC-Wide Capacity: 10-Year Outlook[114]



	Current		2022 Planned			2022 Planned & Conceptual		
	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Coal	307,201	29.78%	290,915	26.86%	-16,286	278,775	22.61%	-28,426
Petroleum	52,498	5.09%	51,954	4.80%	-544	51,377	4.17%	-1,121
Gas	397,464	38.53%	429,462	39.65%	31,998	529,328	42.94%	131,863
Nuclear	113,821	11.03%	123,525	11.41%	9,704	136,361	11.06%	22,540
Other/Unknown	271	0.03%	5,840	0.54%	5,569	12,683	1.03%	12,412
Renewables	160,420	15.55%	181,311	16.74%	20,891	224,235	18.19%	63,815
TOTAL	**1,031,676**	**100.00%**	**1,083,007**	**100.00%**	**51,332**	**1,232,759**	**100.00%**	**201,083**

Coal

Projections for coal-fired generation in the *2012LTRA* Reference case point to a decline during the 10-year outlook. In 2012, coal's total on-peak contribution is approximately 30 percent—a slight decrease compared to 2011. Its share will continue to decline, falling to under 27 percent in 2022, due to the projected retirements of over 16 GW throughout the next decade. Conceptual plans for newer coal plants, some of which include carbon capture and storage (CCS) technologies, could partially offset retirements by adding approximately 7 GW. Economic decisions caused by impacts—both direct and indirect—of environmental regulations, coupled with presently inexpensive natural gas prices, are two key factors that contribute to a shifting capacity mix. Coal retirements are widely projected throughout North America, with reliability impacts dependent on each assessment area's resource mix.

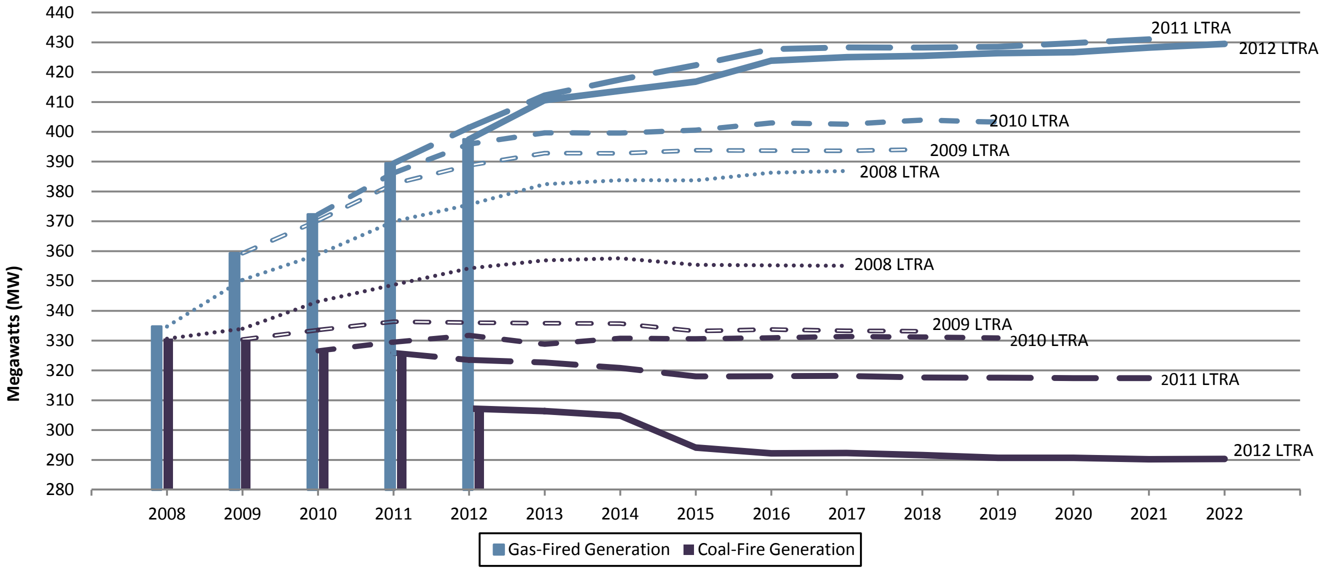
The reference case includes some consideration for federal and state regulations that are expected to impact coal-fired capacity in the United States. This includes regulation that supports the Clean Air Act[115] but does not include the full extent of these impacts. The age of a coal plant can impact retirement decisions spurred in part by environmental regulations with impending costs to either retrofit applicable units with expensive environmental control equipment, or close the plant permanently. Moreover, the potential investment in retrofit equipment generally becomes less economical if fewer years remain on the life of a given plant. The potential investment in retrofit equipment generally becomes less economical if fewer years remain on the life of a given plant. In NPCC, the New England Assessment Area includes over 6 GW of fossil-fueled generating units (primarily coal or oil) that are at least 40 years old, creating conditions more susceptible to unit retirements than retrofits. The New York Assessment Area has also reported 1,200 MW of confirmed retirements.

On an assessment-area basis, Ontario and PJM anticipate the most significant reduction in coal during the 10-year outlook, with unit retirement projections amounting to 3.4 GW and 12.7 GW, respectively. In Ontario, two coal-fired units totaling 980 MW were closed in 2011, with the remaining 9 units in the province to be taken offline by the end of 2014. The PJM

[114] Represents the "non-coincident" NERC-wide on-peak capacity for each assessment area.
[115] http://www.epa.gov/air/caa/; http://www.epa.gov/airtransport/; http://www.epa.gov/airquality/powerplanttoxics/index.html.

projections indicate 14 units (1.3 GW) will shut down during 2012 with 60 additional units (9.8 GW) to close by 2015. Unit retirements in the latter years of the 10-year outlook are less certain, and reliability impacts are still being analyzed (Figure 52).

Figure 52: NERC-Wide Coal- and Gas-Fired Generation Outlook: *2008-2012LTRA* Reference Case Comparison



According to reference cases from the last four long-term reliability assessments, NERC-wide coal capacity on peak declined by approximately 23.5 GW, from 330.6 GW in 2008 to 307.1 GW in 2012. Most of this decline in coal occurred during 2011, as the finalization of several environmental regulations—specifically air-related regulations—clearly impacted decisions of plant owners and industry planners throughout the United States. Alternatives to coal have also become more prominent in recent years. State and provincial renewable energy requirements and goals have created more localized policy incentives to encourage more contribution of renewables in the capacity mix. For example, the Atikokan Generating Station, a coal plant in the NPCC-Ontario Assessment Area, is undergoing conversion to biomass that is expected to take place by 2014. Additionally, the role of coal has been further diminished by the relatively new capability to run existing gas-fired units as baseload generation with a higher capacity factor (instead of only during peak periods).

Natural Gas

As coal's contribution continues to decline, gas-fired capacity is projected to outpace all other forms of generation in growth, except for renewable, adding 32 GW by 2022 in the *2012LTRA* Reference case. Conceptual projections amount to an additional 68 GW, which is indicative of the industry's high expectations for gas-fired generation to account for a majority of capacity introduced during the 10-year outlook.

The conversion to—or development of—new gas-fired units has become an attractive alternative to coal with the current affordability of natural gas and the added benefit of relatively lower emissions. New gas-fired units also have relatively low capital costs, with a lead time of only two years compared to coal or nuclear plants, whose lead times range from 5 to 12 years. In many cases, existing coal-fired plant sites are being converted to gas-fired plants. In Ontario, plans are in place to convert at least two units from coal to natural gas by 2014, with several other coal units currently under consideration. Several coal plants in the WECC Assessment Area are also projecting unit conversions to natural gas as alternatives to retrofitting or retiring coal units.

The extensive growth in gas-fired capacity may not be caused entirely by the enduring decline in coal—the ease of converting a coal-fired plant to a gas-fired plant may help alleviate reliability concerns that are inherent to large base-load retirements. The use of existing facilities (such as transmission, cooling towers, and other on-site facilities) makes converting a plant especially economical and ensures the continued generation of reactive power used to serve nearby loads.

From a reliability aspect, the increase in gas-fired generation compliments the inherent variability of renewable resources that are also experiencing continued growth. As wind and solar resources contribute more to service load at times of peak demand, gas-fired units can be ramped up or down as necessary, thus allowing operators more flexibility to offset renewable variability.

Nuclear

NERC-wide, nuclear additions are projected to add 10.4 GW of on-peak capacity by 2022. Unit uprates account for a significant portion of these additions and are partially offset by plans to take units offline for refurbishment in the later years of the assessment. The contribution from nuclear power remains relatively stable throughout the 10-year outlook. This is partially due to the continued operation of plants built over 40 years ago. In the United States, the Nuclear Regulatory Commission (NRC) has provided operating license renewals for 71 of the total fleet of 104 reactors, while an additional 15 applications are currently under review. The Canadian Nuclear Safety Commission (CNSC) maintains similar regulatory oversight of seven nuclear power plants at five sites in Canada.

For the first time in almost three decades, the NRC voted in February 2012 to grant a combined construction and operating license to four units in the SERC Region. Units 3 and 4 at the Vogtle Nuclear Power Plant in the SERC-SE Assessment Area are expected to come online by the end of 2017, providing 2.2 GW of additional capacity. Units 2 and 3 of the VC Summer Plant in SERC-E are also expected to be operating as soon as 2016 and 2019, respectively, with each reactor providing 1.1 GW of capacity. Finally, the Bellefonte Unit 1 reactor is included in the Tennessee Valley Authority (TVA) Integrated Resource Plan and for the purpose of this assessment is categorized as Future-Planned, with an in-service date of June 2020. License approval from the NRC is currently suspended.

In Canada, the Point Lepreau nuclear plant (totaling 660 MW) is projected to return to service by the end of 2012 after a four-year extended outage and will serve as the single largest unit and only nuclear facility in the Maritimes Assessment Area.

In NPCC-Ontario, nuclear generation will remain the largest contributor, providing over half the electricity in the area. Two units at the Bruce A Nuclear Generating Station are currently undergoing refurbishments that will add 1,500 MW upon completion. In the final years of the 10-year outlook, plans call for the refurbishment of several units at the Bruce and Darlington Nuclear Generating Stations. The Pickering Nuclear Generating Station (Units 5, 6, 7, and 8) is scheduled for retirement by 2016 but is currently licensed through 2020, and extending the operating life of the four units is currently under review, with a decision expected by the end of 2013.

In the NPCC-Québec Assessment Area, the recently announced closure of the Gentilly-2 generating station is scheduled for December 2012 and is incorporated into the *2012LTRA* Reference case.

Renewables

Contribution from renewable resources will continue to grow, as significant capacity additions are projected for both wind and solar throughout North America. In 2012, renewable generation—including hydro as a share of total on-peak contribution—is 15.6 percent and expected to reach almost 17 percent by the end of 2022. Projections for new solar in WECC—especially Southern California and Arizona, (WECC-CALS and WECC-DSW Assessment Areas)—account for most of the 7 GW of NERC-wide solar additions during the next 10 years. WECC also has aggressive plans for 13.4 GW of new wind generation projected throughout the assessment period. In the NPCC Region, the Ontario and Québec Assessment Areas will more than double current wind capacity during the next decade, adding approximately 5.2 GW. SPP planners expect the addition of 11.6 GW of planned wind projects. PJM and ERCOT have project plans totaling 2,298 MW and 1,918 MW of installed wind capacity, respectively. Non-hydro renewable capacity additions are currently supported by federal tax credits and state Renewable Portfolio Standards (RPS); however, changes in the political landscape in the United States could put the federal tax credits in jeopardy.

Additions of biomass capacity are most substantial in FRCC and most of the SERC Region. Biomass is projected to remain the largest renewable resource in the FRCC Assessment Area, growing from 374 MW to 736 MW during the 10-year outlook. Planned additions for biomass capacity in the SERC-E, SERC-SE, and SERC-W Assessment Areas amount to 216 MW. Similar additions are also planned in the PJM, MRO-SaskPower, and NPCC-Maritimes Assessment Areas.

Uprates and additions in the NPCC-Québec Assessment Area account for nearly half of the hydropower additions during the 10-year outlook. Specifically, the commissioning of several new hydropower generating stations will add 2,160 MW to Hydro-Québec's capacity mix, with an additional 500 MW of capacity uprates at existing plants.

NERC-Wide Summary Tables

Table Notes

- All values are in megawatts, unless noted otherwise.
- CAGR: Compound Annual Growth Rate
- Net Internal Demand excludes all load-modifying Demand Response; primary demand statistic for all NERC Planning Reserve Margin calculations.
- Reference: NERC Reference Margin Level as assigned by each NERC Region. If no Reference Margin Level is provided, NERC applies a 15 percent and 10 percent level for thermal and hydro systems, respectively. The Reference Margin Level is subject to change by season or year. For additional information, see respective assessment area section.

Demand, Resources, and Reserve Margins: 2013 Summer

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			NERC
Assessment Areas/Country	Net Internal	Total Internal	Anticipated	Prospective	Adj. Potential	Anticipated	Prospective	Adj. Potential	Reference
ERCOT	65,649	66,928	74,448	74,448	74,656	13.40%	13.40%	13.72%	13.75%
FRCC	43,041	46,270	54,823	58,732	60,439	27.37%	36.46%	40.42%	15.00%
MISO	89,318	94,279	108,007	119,723	119,903	20.92%	34.04%	34.24%	16.30%
MRO-MAPP	4,904	4,995	6,344	6,344	6,344	29.36%	29.36%	29.36%	15.00%
NPCC-New England	26,629	27,765	35,265	35,265	35,329	32.43%	32.43%	32.67%	15.00%
NPCC-New York	33,696	33,696	42,127	42,127	42,150	25.02%	25.02%	25.09%	16.00%
PJM	145,254	156,254	184,882	184,882	186,581	27.28%	27.28%	28.45%	15.40%
SERC-E	41,805	43,733	52,271	52,271	52,285	25.03%	25.03%	25.07%	15.00%
SERC-N	43,808	45,750	54,020	57,939	57,939	23.31%	32.26%	32.26%	15.00%
SERC-SE	47,900	49,799	62,107	62,407	62,549	29.66%	30.29%	30.58%	15.00%
SERC-W	25,015	25,921	34,335	38,854	38,864	37.26%	55.32%	55.36%	15.00%
SPP	54,247	55,180	65,335	70,419	70,524	20.44%	29.81%	30.01%	13.60%
WECC-BASN	12,667	13,776	16,154	16,154	16,154	27.53%	27.53%	27.53%	12.60%
WECC-CALN	25,841	26,645	29,757	29,757	29,757	15.16%	15.16%	15.16%	14.71%
WECC-CALS	29,311	31,319	34,012	34,012	34,086	16.04%	16.04%	16.29%	15.14%
WECC-DSW	27,034	27,576	39,623	39,623	39,804	46.57%	46.57%	47.24%	13.50%
WECC-NORW	24,310	24,380	28,919	28,919	28,920	18.96%	18.96%	18.96%	17.90%
WECC-ROCK	11,434	11,904	14,285	14,285	14,288	24.93%	24.93%	24.96%	14.65%
TOTAL-UNITED STATES	751,862	786,170	936,713	966,160	970,572	24.59%	28.50%	29.09%	15.00%
MRO-Manitoba Hydro	3,210	3,210	4,597	4,597	4,597	43.21%	43.21%	43.21%	12.00%
MRO-SaskPower	3,184	3,275	3,628	3,628	3,628	13.93%	13.93%	13.93%	11.00%
NPCC-Maritimes	3,104	3,435	6,597	6,597	6,597	112.52%	112.52%	112.52%	20.00%
NPCC-Ontario	23,301	23,301	31,938	31,938	31,938	37.07%	37.07%	37.07%	19.70%
NPCC-Québec	21,115	21,115	31,821	31,821	31,821	50.71%	50.71%	50.71%	9.60%
WECC-AESO	10,903	10,941	12,994	12,994	12,994	19.18%	19.18%	19.18%	12.24%
WECC-BC	8,449	8,449	11,975	11,975	11,975	41.74%	41.74%	41.74%	12.51%
TOTAL-CANADA	73,266	73,726	103,550	103,550	103,550	41.34%	41.34%	41.34%	10.00%
WECC-MEXW	2,203	2,203	2,641	2,641	2,641	19.89%	19.89%	19.89%	11.86%
TOTAL-MÉXICO	2,203	2,203	2,641	2,641	2,641	19.89%	19.89%	19.89%	11.86%
TOTAL-NERC	**827,330**	**862,098**	**1,042,904**	**1,072,351**	**1,076,763**	**26.06%**	**29.62%**	**30.15%**	**15.00%**

Demand, Resources, and Reserve Margins: 2013/2014 Winter

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			NERC
Assessment Areas/Country	Net Internal	Total Internal	Anticipated	Prospective	Adj. Potential	Anticipated	Prospective	Adj. Potential	Reference
ERCOT	50,263	51,734	76,915	76,915	78,081	53.03%	53.03%	55.34%	13.75%
FRCC	43,049	46,367	58,229	61,616	62,777	35.26%	43.13%	45.83%	15.00%
MISO	69,663	72,572	109,462	121,135	121,156	57.13%	73.89%	73.92%	16.30%
MRO-MAPP	4,858	4,858	6,673	6,673	6,673	37.37%	37.37%	37.37%	15.00%
NPCC-New England	21,383	22,510	37,848	37,848	38,098	77.00%	77.00%	78.17%	15.00%
NPCC-New York	24,929	24,929	42,883	42,883	43,216	72.02%	72.02%	73.36%	16.00%
PJM	121,160	132,160	184,925	184,925	186,623	52.63%	52.63%	54.03%	15.40%
SERC-E	42,042	43,582	54,712	54,712	54,726	30.14%	30.14%	30.17%	15.00%
SERC-N	43,734	45,713	68,909	72,900	72,900	57.56%	66.69%	66.69%	15.00%
SERC-SE	44,652	46,534	64,449	64,749	64,806	44.34%	45.01%	45.14%	15.00%
SERC-W	19,731	20,497	42,929	47,197	47,207	117.57%	139.20%	139.25%	15.00%
SPP	40,983	41,714	61,197	66,023	67,069	49.32%	61.10%	63.65%	13.60%
WECC-BASN	10,842	11,134	13,760	13,760	13,760	26.91%	26.91%	26.91%	13.49%
WECC-CALN	18,407	18,664	22,557	22,557	22,557	22.55%	22.55%	22.55%	11.86%
WECC-CALS	22,360	23,229	34,561	34,561	34,635	54.57%	54.57%	54.90%	11.03%
WECC-DSW	17,845	18,124	34,086	34,086	34,253	91.01%	91.01%	91.95%	13.96%
WECC-NORW	30,217	30,270	36,285	36,285	36,285	20.08%	20.08%	20.08%	19.90%
WECC-ROCK	9,565	9,833	14,023	14,023	14,259	46.61%	46.61%	49.08%	15.68%
TOTAL-UNITED STATES	635,683	664,424	964,403	992,850	999,083	51.71%	56.19%	57.17%	15.00%
MRO-Manitoba Hydro	4,661	4,661	5,996	5,996	5,996	28.63%	28.63%	28.63%	12.00%
MRO-SaskPower	3,580	3,671	4,125	4,125	4,125	15.24%	15.24%	15.24%	11.00%
NPCC-Maritimes	5,169	5,421	6,878	6,878	6,878	33.06%	33.06%	33.06%	20.00%
NPCC-Ontario	22,192	22,192	32,060	32,060	32,074	44.47%	44.47%	44.53%	18.60%
NPCC-Québec	37,810	37,810	42,483	42,483	42,483	12.36%	12.36%	12.36%	10.00%
WECC-AESO	11,664	11,664	13,831	13,831	13,831	18.58%	18.58%	18.58%	11.71%
WECC-BC	11,416	11,416	13,384	13,384	13,384	17.24%	17.24%	17.24%	16.16%
TOTAL-CANADA	96,492	96,835	118,757	118,757	118,770	23.07%	23.07%	23.09%	10.00%
WECC-MEXW	1,494	1,494	2,434	2,434	2,434	62.92%	62.92%	62.92%	10.71%
TOTAL-MÉXICO	1,494	1,494	2,434	2,434	2,434	62.92%	62.92%	62.92%	10.71%
TOTAL-NERC	**733,669**	**762,753**	**1,085,594**	**1,114,040**	**1,120,287**	**47.97%**	**51.85%**	**52.70%**	**15.00%**

Demand, Resources, and Reserve Margins: 2014 Summer

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			NERC
Assessment Areas/Country	Net Internal	Total Internal	Anticipated	Prospective	Adj. Potential	Anticipated	Prospective	Adj. Potential	Reference
ERCOT	68,403	69,721	74,498	74,498	75,074	8.91%	8.91%	9.75%	13.75%
FRCC	43,618	46,857	55,343	60,273	63,001	26.88%	38.18%	44.44%	15.00%
MISO	90,707	96,129	108,139	119,855	120,036	19.22%	32.13%	32.33%	16.30%
MRO-MAPP	5,024	5,117	6,370	6,370	6,370	26.79%	26.79%	26.79%	15.00%
NPCC-New England	26,877	28,275	35,160	35,160	35,498	30.82%	30.82%	32.07%	15.00%
NPCC-New York	33,914	33,914	42,077	42,077	42,129	24.07%	24.07%	24.22%	16.00%
PJM	146,642	159,842	185,879	185,879	188,912	26.76%	26.76%	28.83%	15.40%
SERC-E	42,412	44,457	52,658	52,658	52,672	24.16%	24.16%	24.19%	15.00%
SERC-N	44,387	46,542	55,142	59,061	59,061	24.23%	33.06%	33.06%	15.00%
SERC-SE	48,738	50,838	62,901	63,201	63,443	29.06%	29.68%	30.17%	15.00%
SERC-W	25,257	26,166	34,943	39,462	40,172	38.35%	56.24%	59.05%	15.00%
SPP	54,794	55,732	66,086	71,170	71,280	20.61%	29.89%	30.09%	13.60%
WECC-BASN	13,025	14,144	15,909	15,909	16,355	22.14%	22.14%	25.57%	12.60%
WECC-CALN	26,154	26,971	30,031	30,031	30,031	14.82%	14.82%	14.82%	14.71%
WECC-CALS	29,901	31,896	36,162	36,162	36,236	20.94%	20.94%	21.19%	15.14%
WECC-DSW	27,252	27,847	39,110	39,110	39,551	43.51%	43.51%	45.13%	13.50%
WECC-NORW	24,609	24,694	29,042	29,042	29,043	18.02%	18.02%	18.02%	17.90%
WECC-ROCK	11,619	12,107	14,164	14,164	14,167	21.91%	21.91%	21.93%	14.65%
TOTAL-UNITED STATES	763,332	801,249	943,615	974,083	983,032	23.62%	27.61%	28.78%	15.00%
MRO-Manitoba Hydro	3,238	3,238	4,607	4,607	4,607	42.26%	42.26%	42.26%	12.00%
MRO-SaskPower	3,335	3,426	3,762	3,762	3,762	12.79%	12.79%	12.79%	11.00%
NPCC-Maritimes	3,138	3,469	6,610	6,610	6,610	110.64%	110.64%	110.64%	20.00%
NPCC-Ontario	23,080	23,080	30,023	30,023	30,035	30.08%	30.08%	30.14%	18.60%
NPCC-Québec	21,550	21,550	31,755	31,755	31,755	47.36%	47.36%	47.36%	10.00%
WECC-AESO	11,510	11,548	13,765	13,765	13,765	19.59%	19.59%	19.59%	12.24%
WECC-BC	8,684	8,684	12,218	12,218	12,218	40.70%	40.70%	40.70%	12.51%
TOTAL-CANADA	74,535	74,995	102,739	102,739	102,751	37.84%	37.84%	37.86%	10.00%
WECC-MEXW	2,260	2,260	2,923	2,923	2,923	29.35%	29.35%	29.35%	11.86%
TOTAL-MÉXICO	2,260	2,260	2,923	2,923	2,923	29.35%	29.35%	29.35%	11.86%
TOTAL-NERC	**840,127**	**878,504**	**1,049,277**	**1,079,745**	**1,088,707**	**24.90%**	**28.52%**	**29.59%**	**15.00%**

Demand, Resources, and Reserve Margins: 2014/2015 Winter

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			NERC
Assessment Areas/Country	Net Internal	Total Internal	Anticipated	Prospective	Adj. Potential	Anticipated	Prospective	Adj. Potential	Reference
ERCOT	50,533	52,063	76,976	76,976	79,552	52.33%	52.33%	57.43%	13.75%
FRCC	44,228	47,568	61,341	63,983	64,399	38.69%	44.67%	45.61%	15.00%
MISO	74,965	78,143	109,692	121,524	121,704	46.32%	62.11%	62.35%	16.30%
MRO-MAPP	4,999	4,999	6,713	6,713	6,713	34.28%	34.28%	34.28%	15.00%
NPCC-New England	21,285	22,670	37,197	37,197	37,570	74.75%	74.75%	76.51%	15.00%
NPCC-New York	24,999	24,999	41,530	41,530	42,194	66.13%	66.13%	68.78%	16.00%
PJM	121,571	134,771	185,881	185,881	188,914	52.90%	52.90%	55.39%	15.40%
SERC-E	42,408	43,977	55,191	55,191	55,205	30.14%	30.14%	30.18%	15.00%
SERC-N	44,212	46,433	68,909	72,900	72,900	55.86%	64.89%	64.89%	15.00%
SERC-SE	45,103	47,197	65,284	65,584	65,742	44.75%	45.41%	45.76%	15.00%
SERC-W	20,042	20,835	43,537	47,805	48,515	117.23%	138.53%	142.07%	15.00%
SPP	41,345	42,010	61,824	66,651	67,756	49.53%	61.21%	63.88%	13.60%
WECC-BASN	10,913	11,215	13,513	13,513	13,959	23.82%	23.82%	27.91%	13.49%
WECC-CALN	18,707	18,977	24,470	24,470	24,470	30.81%	30.81%	30.81%	11.86%
WECC-CALS	22,893	23,753	34,228	34,228	34,302	49.51%	49.51%	49.83%	11.03%
WECC-DSW	18,095	18,380	34,397	34,397	34,569	90.09%	90.09%	91.04%	13.96%
WECC-NORW	30,507	30,577	36,683	36,683	36,683	20.24%	20.24%	20.25%	19.90%
WECC-ROCK	9,709	9,978	13,318	13,318	13,631	37.17%	37.17%	40.39%	15.68%
TOTAL-UNITED STATES	646,514	678,545	970,684	998,544	1,008,779	50.14%	54.45%	56.03%	15.00%
MRO-Manitoba Hydro	4,712	4,712	6,039	6,039	6,039	28.18%	28.18%	28.18%	12.00%
MRO-SaskPower	3,738	3,829	4,161	4,161	4,161	11.33%	11.33%	11.33%	11.00%
NPCC-Maritimes	5,166	5,420	6,893	6,893	6,893	33.45%	33.45%	33.45%	20.00%
NPCC-Ontario	21,890	21,890	29,908	29,908	30,192	36.63%	36.63%	37.92%	19.80%
NPCC-Québec	38,062	38,062	42,971	42,971	42,971	12.90%	12.90%	12.90%	10.50%
WECC-AESO	12,162	12,162	15,685	15,685	15,685	28.97%	28.97%	28.97%	11.71%
WECC-BC	11,738	11,738	13,869	13,869	13,869	18.15%	18.15%	18.15%	16.16%
TOTAL-CANADA	97,467	97,812	119,526	119,526	119,811	22.63%	22.63%	22.92%	10.00%
WECC-MEXW	1,532	1,532	2,617	2,617	2,617	70.84%	70.84%	70.84%	10.71%
TOTAL-MÉXICO	1,532	1,532	2,617	2,617	2,617	70.84%	70.84%	70.84%	10.71%
TOTAL-NERC	**745,513**	**777,889**	**1,092,828**	**1,120,688**	**1,131,207**	**46.59%**	**50.32%**	**51.74%**	**15.00%**

Demand, Resources, and Reserve Margins: 2015 Summer

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			NERC
Assessment Areas/Country	Net Internal	Total Internal	Anticipated	Prospective	Adj. Potential	Anticipated	Prospective	Adj. Potential	Reference
ERCOT	71,692	73,054	76,006	76,006	76,751	6.02%	6.02%	7.06%	13.75%
FRCC	44,459	47,758	57,181	61,286	63,188	28.62%	37.85%	42.13%	15.00%
MISO	91,096	96,929	108,443	120,916	121,853	19.04%	32.73%	33.76%	16.30%
MRO-MAPP	5,135	5,230	6,430	6,430	6,430	25.21%	25.21%	25.21%	15.00%
NPCC-New England	27,193	28,840	34,997	34,997	35,510	28.70%	28.70%	30.59%	15.00%
NPCC-New York	34,151	34,151	42,077	42,077	42,209	23.21%	23.21%	23.59%	16.00%
PJM	149,968	163,168	180,473	180,473	188,445	20.34%	20.34%	25.66%	15.40%
SERC-E	42,750	44,903	52,658	52,658	52,672	23.18%	23.18%	23.21%	15.00%
SERC-N	44,952	47,303	55,142	59,061	59,061	22.67%	31.39%	31.39%	15.00%
SERC-SE	49,227	51,431	62,913	63,213	63,456	27.80%	28.41%	28.90%	15.00%
SERC-W	25,623	26,563	34,970	39,489	41,173	36.48%	54.12%	60.69%	15.00%
SPP	54,788	55,766	66,237	71,321	71,440	20.90%	30.17%	30.39%	13.60%
WECC-BASN	13,354	14,482	15,999	15,999	16,445	19.81%	19.81%	23.15%	12.60%
WECC-CALN	26,471	27,298	31,313	31,313	31,313	18.29%	18.29%	18.29%	14.71%
WECC-CALS	30,467	32,472	36,278	36,278	36,351	19.07%	19.07%	19.31%	15.14%
WECC-DSW	27,551	28,179	40,140	40,140	40,708	45.69%	45.69%	47.75%	13.50%
WECC-NORW	24,872	24,967	29,613	29,613	29,613	19.06%	19.06%	19.06%	17.90%
WECC-ROCK	11,827	12,330	14,165	14,165	14,172	19.77%	19.77%	19.83%	14.65%
TOTAL-UNITED STATES	775,577	814,823	945,034	975,433	990,788	21.85%	25.77%	27.75%	15.00%
MRO-Manitoba Hydro	3,207	3,207	4,944	4,944	4,944	54.15%	54.15%	54.15%	12.00%
MRO-SaskPower	3,444	3,535	3,840	3,840	3,840	11.51%	11.51%	11.51%	11.00%
NPCC-Maritimes	3,117	3,448	6,538	6,538	6,538	109.76%	109.76%	109.76%	20.00%
NPCC-Ontario	22,859	22,859	29,725	29,725	29,962	30.03%	30.03%	31.07%	19.80%
NPCC-Québec	21,642	21,642	32,489	32,489	32,489	50.12%	50.12%	50.12%	10.50%
WECC-AESO	12,039	12,077	14,613	14,613	14,613	21.38%	21.38%	21.38%	12.24%
WECC-BC	8,834	8,834	11,957	11,957	11,957	35.36%	35.36%	35.36%	12.51%
TOTAL-CANADA	75,142	75,602	104,107	104,107	104,344	38.55%	38.55%	38.86%	10.00%
WECC-MEXW	2,317	2,317	2,923	2,923	2,923	26.17%	26.17%	26.17%	11.86%
TOTAL-MÉXICO	2,317	2,317	2,923	2,923	2,923	26.17%	26.17%	26.17%	11.86%
TOTAL-NERC	**853,036**	**892,742**	**1,052,064**	**1,082,463**	**1,098,055**	**23.33%**	**26.90%**	**28.72%**	**15.00%**

Demand, Resources, and Reserve Margins: 2015/2016 Winter

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			NERC
Assessment Areas/Country	Net Internal	Total Internal	Anticipated	Prospective	Adj. Potential	Anticipated	Prospective	Adj. Potential	Reference
ERCOT	53,378	54,972	78,473	78,473	81,845	47.01%	47.01%	53.33%	13.75%
FRCC	44,790	48,172	60,166	62,831	63,270	34.33%	40.28%	41.26%	15.00%
MISO	75,354	78,773	109,996	122,623	123,597	45.97%	62.73%	64.02%	16.30%
MRO-MAPP	5,074	5,074	6,840	6,840	6,840	34.82%	34.82%	34.82%	15.00%
NPCC-New England	21,193	22,825	37,531	37,531	38,259	77.09%	77.09%	80.53%	15.00%
NPCC-New York	25,053	25,053	41,480	41,480	43,325	65.57%	65.57%	72.93%	16.00%
PJM	123,711	136,911	180,744	180,744	188,715	46.10%	46.10%	52.55%	15.40%
SERC-E	42,934	44,520	55,091	55,091	55,105	28.32%	28.32%	28.35%	15.00%
SERC-N	44,685	47,166	68,909	72,900	72,900	54.21%	63.14%	63.14%	15.00%
SERC-SE	45,615	47,814	65,303	65,603	65,760	43.16%	43.82%	44.16%	15.00%
SERC-W	20,209	20,992	43,564	47,832	49,528	115.57%	136.69%	145.08%	15.00%
SPP	41,225	42,040	61,972	66,798	67,995	50.33%	62.04%	64.94%	13.60%
WECC-BASN	11,167	11,472	13,711	13,711	14,190	22.78%	22.78%	27.07%	13.49%
WECC-CALN	18,937	19,212	24,395	24,395	24,395	28.82%	28.82%	28.82%	11.86%
WECC-CALS	23,235	24,106	34,020	34,020	34,094	46.42%	46.42%	46.74%	11.03%
WECC-DSW	18,431	18,721	34,917	34,917	34,938	89.45%	89.45%	89.57%	13.96%
WECC-NORW	30,763	30,843	37,163	37,163	37,163	20.80%	20.80%	20.80%	19.90%
WECC-ROCK	9,918	10,189	13,244	13,244	13,637	33.54%	33.54%	37.50%	15.68%
TOTAL-UNITED STATES	655,672	688,855	967,521	996,199	1,015,559	47.56%	51.94%	54.89%	15.00%
MRO-Manitoba Hydro	4,723	4,723	6,106	6,106	6,106	29.28%	29.28%	29.28%	12.00%
MRO-SaskPower	3,859	3,950	4,377	4,377	4,377	13.43%	13.43%	13.43%	11.00%
NPCC-Maritimes	5,165	5,419	6,832	6,832	6,832	32.29%	32.29%	32.29%	20.00%
NPCC-Ontario	21,500	21,500	31,038	31,038	31,821	44.36%	44.36%	48.01%	19.20%
NPCC-Québec	38,527	38,527	43,197	43,197	43,197	12.12%	12.12%	12.12%	11.40%
WECC-AESO	12,801	12,801	17,568	17,568	17,568	37.24%	37.24%	37.24%	11.71%
WECC-BC	11,943	11,943	14,320	14,320	14,320	19.90%	19.90%	19.90%	16.16%
TOTAL-CANADA	98,517	98,863	123,438	123,438	124,221	25.30%	25.30%	26.09%	10.00%
WECC-MEXW	1,571	1,571	2,750	2,750	2,750	75.07%	75.07%	75.07%	10.71%
TOTAL-MÉXICO	1,571	1,571	2,750	2,750	2,750	75.07%	75.07%	75.07%	10.71%
TOTAL-NERC	**755,760**	**789,289**	**1,093,709**	**1,122,387**	**1,142,531**	**44.72%**	**48.51%**	**51.18%**	**15.00%**

Demand, Resources, and Reserve Margins: 2016 Summer

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			NERC
Assessment Areas/Country	Net Internal	Total Internal	Anticipated	Prospective	Adj. Potential	Anticipated	Prospective	Adj. Potential	Reference
ERCOT	73,957	75,366	78,166	78,166	79,159	5.69%	5.69%	7.03%	13.75%
FRCC	45,242	48,594	56,591	60,718	62,643	25.08%	34.21%	38.46%	15.00%
MISO	91,556	97,811	108,564	121,037	121,974	18.58%	32.20%	33.22%	16.30%
MRO-MAPP	5,406	5,503	6,512	6,512	6,512	20.46%	20.46%	20.46%	15.00%
NPCC-New England	27,520	29,400	33,349	33,349	34,506	21.18%	21.18%	25.39%	15.00%
NPCC-New York	34,345	34,345	42,077	42,077	42,725	22.51%	22.51%	24.40%	16.00%
PJM	152,491	165,691	180,821	180,821	190,190	18.58%	18.58%	24.72%	15.40%
SERC-E	43,235	45,436	53,675	53,675	53,689	24.15%	24.15%	24.18%	15.00%
SERC-N	45,537	47,974	55,142	59,061	60,706	21.09%	29.70%	33.31%	15.00%
SERC-SE	49,823	52,045	65,326	65,626	65,868	31.12%	31.72%	32.20%	15.00%
SERC-W	25,937	26,881	35,171	39,690	41,476	35.60%	53.03%	59.91%	15.00%
SPP	55,368	56,364	66,084	71,167	71,287	19.35%	28.53%	28.75%	13.60%
WECC-BASN	13,607	14,765	16,067	16,067	16,834	18.08%	18.08%	23.72%	12.60%
WECC-CALN	27,072	27,904	31,406	31,406	31,408	16.01%	16.01%	16.02%	14.71%
WECC-CALS	30,796	32,821	36,535	36,535	36,713	18.63%	18.63%	19.21%	15.14%
WECC-DSW	28,035	28,679	41,473	41,473	42,100	47.93%	47.93%	50.17%	13.50%
WECC-NORW	25,155	25,270	30,917	30,917	30,918	22.91%	22.91%	22.91%	17.90%
WECC-ROCK	12,048	12,563	14,222	14,222	14,225	18.04%	18.04%	18.07%	14.65%
TOTAL-UNITED STATES	787,129	827,411	952,097	982,518	1,002,933	20.96%	24.82%	27.42%	15.00%
MRO-Manitoba Hydro	3,244	3,244	4,949	4,949	4,949	52.56%	52.56%	52.56%	12.00%
MRO-SaskPower	3,533	3,624	4,071	4,071	4,071	15.22%	15.22%	15.22%	11.00%
NPCC-Maritimes	3,110	3,441	6,542	6,542	6,542	110.34%	110.34%	110.34%	20.00%
NPCC-Ontario	22,638	22,638	28,801	28,801	29,455	27.22%	27.22%	30.11%	19.20%
NPCC-Québec	21,883	21,883	33,505	33,505	33,505	53.11%	53.11%	53.11%	11.40%
WECC-AESO	12,604	12,642	16,182	16,182	16,182	28.39%	28.39%	28.39%	12.24%
WECC-BC	8,913	8,913	11,909	11,909	11,909	33.62%	33.62%	33.62%	12.51%
TOTAL-CANADA	75,925	76,385	105,959	105,959	106,613	39.56%	39.56%	40.42%	10.00%
WECC-MEXW	2,374	2,374	2,924	2,924	3,264	23.16%	23.16%	37.50%	11.86%
TOTAL-MÉXICO	2,374	2,374	2,924	2,924	3,264	23.16%	23.16%	37.50%	11.86%
TOTAL-NERC	**865,428**	**906,170**	**1,060,979**	**1,091,401**	**1,112,810**	**22.60%**	**26.11%**	**28.58%**	**15.00%**

Demand, Resources, and Reserve Margins: 2016/2017 Winter

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			NERC
Assessment Areas/Country	Net Internal	Total Internal	Anticipated	Prospective	Adj. Potential	Anticipated	Prospective	Adj. Potential	Reference
ERCOT	54,363	56,028	80,633	80,633	85,247	48.32%	48.32%	56.81%	13.75%
FRCC	45,297	48,797	61,167	64,260	65,126	35.04%	41.86%	43.77%	15.00%
MISO	75,854	79,521	110,117	122,744	123,718	45.17%	61.82%	63.10%	16.30%
MRO-MAPP	5,335	5,335	6,882	6,882	6,882	29.00%	29.00%	29.00%	15.00%
NPCC-New England	21,097	22,960	35,869	35,869	37,076	70.02%	70.02%	75.74%	15.00%
NPCC-New York	25,149	25,149	41,480	41,480	44,379	64.94%	64.94%	76.46%	16.00%
PJM	125,367	138,567	180,823	180,823	190,191	44.24%	44.24%	51.71%	15.40%
SERC-E	43,395	44,993	56,253	56,253	56,267	29.63%	29.63%	29.66%	15.00%
SERC-N	45,226	47,967	68,909	72,900	74,972	52.37%	61.19%	65.77%	15.00%
SERC-SE	46,266	48,485	67,652	67,952	68,109	46.22%	46.87%	47.21%	15.00%
SERC-W	20,694	21,493	43,765	48,033	49,831	111.49%	132.11%	140.80%	15.00%
SPP	41,812	42,644	61,891	66,717	67,895	48.02%	59.56%	62.38%	13.60%
WECC-BASN	11,416	11,721	13,204	13,204	13,982	15.67%	15.67%	22.48%	13.49%
WECC-CALN	19,220	19,498	23,350	23,350	23,351	21.49%	21.49%	21.50%	11.86%
WECC-CALS	23,441	24,332	32,805	32,805	32,984	39.95%	39.95%	40.71%	11.03%
WECC-DSW	18,827	19,117	35,197	35,197	35,613	86.95%	86.95%	89.16%	13.96%
WECC-NORW	31,053	31,148	38,188	38,188	38,189	22.98%	22.98%	22.98%	19.90%
WECC-ROCK	10,214	10,486	14,425	14,425	14,606	41.22%	41.22%	43.00%	15.68%
TOTAL-UNITED STATES	664,025	698,239	972,612	1,001,717	1,028,420	46.47%	50.86%	54.88%	15.00%
MRO-Manitoba Hydro	4,781	4,781	6,124	6,124	6,124	28.09%	28.09%	28.09%	12.00%
MRO-SaskPower	3,959	4,050	4,421	4,421	4,421	11.68%	11.68%	11.68%	11.00%
NPCC-Maritimes	5,185	5,444	6,838	6,838	6,838	31.88%	31.88%	31.88%	20.00%
NPCC-Ontario	21,153	21,153	28,332	28,332	29,197	33.94%	33.94%	38.02%	20.00%
NPCC-Québec	38,845	38,845	44,201	44,201	44,201	13.79%	13.79%	13.79%	12.20%
WECC-AESO	13,382	13,382	18,043	18,043	18,043	34.83%	34.83%	34.83%	11.71%
WECC-BC	12,050	12,050	14,466	14,466	14,466	20.05%	20.05%	20.05%	16.16%
TOTAL-CANADA	99,355	99,706	122,426	122,426	123,291	23.22%	23.22%	24.09%	10.00%
WECC-MEXW	1,610	1,610	2,902	2,902	3,243	80.27%	80.27%	101.41%	10.71%
TOTAL-MÉXICO	1,610	1,610	2,902	2,902	3,243	80.27%	80.27%	101.41%	10.71%
TOTAL-NERC	**764,990**	**799,555**	**1,097,940**	**1,127,045**	**1,154,953**	**43.52%**	**47.33%**	**50.98%**	**15.00%**

Demand, Resources, and Reserve Margins: 2017 Summer

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			NERC
Assessment Areas/Country	Net Internal	Total Internal	Anticipated	Prospective	Adj. Potential	Anticipated	Prospective	Adj. Potential	Reference
ERCOT	75,360	76,821	78,166	78,166	79,159	3.72%	3.72%	5.04%	13.75%
FRCC	45,802	49,244	56,849	61,404	63,756	24.12%	34.06%	39.20%	15.00%
MISO	92,022	98,729	110,127	122,600	123,537	19.68%	33.23%	34.25%	16.30%
MRO-MAPP	5,461	5,560	6,514	6,514	6,514	19.28%	19.28%	19.28%	15.00%
NPCC-New England	27,797	29,895	33,324	33,324	34,531	19.88%	19.88%	24.23%	15.00%
NPCC-New York	34,550	34,550	42,077	42,077	42,800	21.79%	21.79%	23.88%	16.00%
PJM	154,233	167,433	180,821	180,821	191,470	17.24%	17.24%	24.14%	15.40%
SERC-E	43,707	45,939	53,720	53,720	53,734	22.91%	22.91%	22.94%	15.00%
SERC-N	45,987	48,660	55,142	59,061	60,891	19.91%	28.43%	32.41%	15.00%
SERC-SE	50,551	52,789	66,278	66,578	66,820	31.11%	31.70%	32.18%	15.00%
SERC-W	26,252	27,199	35,171	39,690	41,579	33.98%	51.19%	58.38%	15.00%
SPP	55,927	57,055	66,889	71,973	72,091	19.60%	28.69%	28.90%	13.60%
WECC-BASN	13,923	15,081	16,054	16,054	16,822	15.30%	15.30%	20.82%	12.60%
WECC-CALN	27,376	28,211	31,403	31,403	31,405	14.71%	14.71%	14.72%	14.71%
WECC-CALS	31,191	33,254	36,723	36,723	36,931	17.74%	17.74%	18.40%	15.14%
WECC-DSW	28,510	29,157	41,917	41,917	42,778	47.03%	47.03%	50.05%	13.50%
WECC-NORW	25,445	25,560	30,499	30,499	30,500	19.86%	19.86%	19.87%	17.90%
WECC-ROCK	12,235	12,763	14,094	14,094	14,099	15.20%	15.20%	15.24%	14.65%
TOTAL-UNITED STATES	796,328	837,899	955,768	986,617	1,009,416	20.02%	23.90%	26.76%	15.00%
MRO-Manitoba Hydro	3,286	3,286	4,949	4,949	4,949	50.60%	50.60%	50.60%	12.00%
MRO-SaskPower	3,630	3,721	4,285	4,285	4,285	18.02%	18.02%	18.02%	11.00%
NPCC-Maritimes	3,116	3,447	6,547	6,547	6,547	110.09%	110.09%	110.09%	20.00%
NPCC-Ontario	22,471	22,471	26,937	26,937	27,657	19.88%	19.88%	23.08%	20.00%
NPCC-Québec	22,008	22,008	33,911	33,911	33,911	54.08%	54.08%	54.08%	12.20%
WECC-AESO	13,108	13,146	15,962	15,962	15,962	21.77%	21.77%	21.77%	12.24%
WECC-BC	9,043	9,043	11,920	11,920	11,920	31.81%	31.81%	31.81%	12.51%
TOTAL-CANADA	76,663	77,123	104,510	104,510	105,230	36.32%	36.32%	37.26%	10.00%
WECC-MEXW	2,431	2,431	2,924	2,924	3,264	20.27%	20.27%	34.27%	11.86%
TOTAL-MÉXICO	2,431	2,431	2,924	2,924	3,264	20.27%	20.27%	34.27%	11.86%
TOTAL-NERC	**875,421**	**917,453**	**1,063,202**	**1,094,051**	**1,117,910**	**21.45%**	**24.97%**	**27.70%**	**15.00%**

Demand, Resources, and Reserve Margins: 2017/2018 Winter

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			NERC
Assessment Areas/Country	Net Internal	Total Internal	Anticipated	Prospective	Adj. Potential	Anticipated	Prospective	Adj. Potential	Reference
ERCOT	57,204	58,869	80,633	80,633	85,247	40.96%	40.96%	49.02%	13.75%
FRCC	45,752	49,298	61,238	64,346	65,227	33.85%	40.64%	42.57%	15.00%
MISO	76,172	80,104	111,680	124,307	125,281	46.61%	63.19%	64.47%	16.30%
MRO-MAPP	5,412	5,412	6,884	6,884	6,884	27.20%	27.20%	27.20%	15.00%
NPCC-New England	21,011	23,090	35,869	35,869	37,076	70.71%	70.71%	76.46%	15.00%
NPCC-New York	25,153	25,153	41,480	41,480	44,379	64.91%	64.91%	76.44%	16.00%
PJM	126,462	139,662	180,831	180,831	191,479	42.99%	42.99%	51.41%	15.40%
SERC-E	43,879	45,487	56,253	56,253	56,267	28.20%	28.20%	28.23%	15.00%
SERC-N	45,723	48,659	68,909	72,900	74,972	50.71%	59.44%	63.97%	15.00%
SERC-SE	46,743	48,978	68,641	68,941	69,098	46.85%	47.49%	47.83%	15.00%
SERC-W	21,106	21,908	43,765	48,033	49,934	107.36%	127.58%	136.59%	15.00%
SPP	42,205	43,069	62,716	67,543	68,724	48.60%	60.04%	62.83%	13.60%
WECC-BASN	11,640	11,945	13,362	13,362	14,140	14.79%	14.79%	21.47%	13.49%
WECC-CALN	19,409	19,689	24,156	24,156	24,158	24.46%	24.46%	24.47%	11.86%
WECC-CALS	23,770	24,697	32,984	32,984	33,192	38.76%	38.76%	39.64%	11.03%
WECC-DSW	19,187	19,477	35,299	35,299	35,928	83.98%	83.98%	87.25%	13.96%
WECC-NORW	31,355	31,450	37,735	37,735	37,735	20.35%	20.35%	20.35%	19.90%
WECC-ROCK	10,398	10,672	14,882	14,882	15,160	43.12%	43.12%	45.80%	15.68%
TOTAL-UNITED STATES	672,581	707,619	977,319	1,006,439	1,034,881	45.31%	49.64%	53.87%	15.00%
MRO-Manitoba Hydro	4,845	4,845	6,124	6,124	6,124	26.39%	26.39%	26.39%	12.00%
MRO-SaskPower	4,068	4,159	4,701	4,701	4,701	15.57%	15.57%	15.57%	11.00%
NPCC-Maritimes	5,201	5,462	6,846	6,846	6,846	31.63%	31.63%	31.63%	20.00%
NPCC-Ontario	20,719	20,719	28,121	28,121	29,886	35.73%	35.73%	44.25%	20.00%
NPCC-Québec	39,189	39,189	44,817	44,817	44,817	14.36%	14.36%	14.36%	12.20%
WECC-AESO	13,856	13,856	18,755	18,755	18,755	35.36%	35.36%	35.36%	11.71%
WECC-BC	12,073	12,073	14,419	14,419	14,419	19.44%	19.44%	19.44%	16.16%
TOTAL-CANADA	99,951	100,303	123,785	123,785	125,550	23.85%	23.85%	25.61%	10.00%
WECC-MEXW	1,648	1,648	2,901	2,901	3,241	76.03%	76.03%	96.69%	10.71%
TOTAL-MÉXICO	1,648	1,648	2,901	2,901	3,241	76.03%	76.03%	96.69%	10.71%
TOTAL-NERC	**774,180**	**809,570**	**1,104,004**	**1,133,124**	**1,163,672**	**42.60%**	**46.36%**	**50.31%**	**15.00%**

Demand, Resources, and Reserve Margins: 2018 Summer

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			NERC
Assessment Areas/Country	Net Internal	Total Internal	Anticipated	Prospective	Adj. Potential	Anticipated	Prospective	Adj. Potential	Reference
ERCOT	76,483	78,002	79,406	79,406	80,569	3.82%	3.82%	5.34%	13.75%
FRCC	46,152	49,643	56,921	61,491	63,858	23.33%	33.24%	38.36%	15.00%
MISO	92,447	99,611	110,152	122,624	123,561	19.15%	32.64%	33.66%	16.30%
MRO-MAPP	5,543	5,643	6,516	6,516	6,516	17.57%	17.57%	17.57%	15.00%
NPCC-New England	27,973	30,275	33,324	33,324	34,531	19.13%	19.13%	23.44%	15.00%
NPCC-New York	34,868	34,868	42,077	42,077	42,800	20.68%	20.68%	22.75%	16.00%
PJM	155,832	169,032	180,829	180,829	192,121	16.04%	16.04%	23.29%	15.40%
SERC-E	44,103	46,358	53,720	53,720	53,734	21.80%	21.80%	21.84%	15.00%
SERC-N	46,504	49,288	55,142	59,061	61,671	18.57%	27.00%	32.61%	15.00%
SERC-SE	51,023	53,256	66,269	66,569	66,812	29.88%	30.47%	30.94%	15.00%
SERC-W	26,556	27,505	35,171	39,690	42,281	32.44%	49.46%	59.22%	15.00%
SPP	56,539	57,591	66,913	71,997	72,115	18.35%	27.34%	27.55%	13.60%
WECC-BASN	14,148	15,306	16,037	16,037	16,805	13.35%	13.35%	18.78%	12.60%
WECC-CALN	27,670	28,507	31,413	31,413	31,415	13.53%	13.53%	13.54%	14.71%
WECC-CALS	31,577	33,666	36,382	36,382	36,691	15.22%	15.22%	16.19%	15.14%
WECC-DSW	29,106	29,686	42,514	42,514	43,327	46.07%	46.07%	48.86%	13.50%
WECC-NORW	25,675	25,797	30,331	30,331	30,333	18.14%	18.14%	18.14%	17.90%
WECC-ROCK	12,431	12,970	14,094	14,094	14,108	13.38%	13.38%	13.49%	14.65%
TOTAL-UNITED STATES	804,630	847,005	957,212	988,076	1,013,248	18.96%	22.80%	25.93%	15.00%
MRO-Manitoba Hydro	3,221	3,221	4,949	4,949	4,949	53.66%	53.66%	53.66%	12.00%
MRO-SaskPower	3,618	3,709	4,285	4,285	4,285	18.41%	18.41%	18.41%	11.00%
NPCC-Maritimes	3,128	3,459	6,558	6,558	6,558	109.65%	109.65%	109.65%	20.00%
NPCC-Ontario	22,583	22,583	25,858	25,858	28,368	14.50%	14.50%	25.62%	20.00%
NPCC-Québec	22,125	22,125	34,764	34,764	34,764	57.13%	57.13%	57.13%	12.20%
WECC-AESO	13,522	13,560	15,929	15,929	15,929	17.80%	17.80%	17.80%	12.24%
WECC-BC	9,167	9,167	12,470	12,470	12,470	36.03%	36.03%	36.03%	12.51%
TOTAL-CANADA	77,364	77,824	104,813	104,813	107,322	35.48%	35.48%	38.72%	10.00%
WECC-MEXW	2,488	2,488	2,923	2,923	3,264	17.50%	17.50%	31.18%	11.86%
TOTAL-MÉXICO	2,488	2,488	2,923	2,923	3,264	17.50%	17.50%	31.18%	11.86%
TOTAL-NERC	**884,482**	**927,317**	**1,064,948**	**1,095,812**	**1,123,834**	**20.40%**	**23.89%**	**27.06%**	**15.00%**

Demand, Resources, and Reserve Margins: 2018/2019 Winter

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			NERC
Assessment Areas/Country	Net Internal	Total Internal	Anticipated	Prospective	Adj. Potential	Anticipated	Prospective	Adj. Potential	Reference
ERCOT	57,459	59,202	81,873	81,873	87,337	42.49%	42.49%	52.00%	13.75%
FRCC	46,305	49,908	61,461	64,844	66,001	32.73%	40.04%	42.54%	15.00%
MISO	76,692	80,891	111,704	124,331	125,306	45.65%	62.12%	63.39%	16.30%
MRO-MAPP	5,522	5,522	6,886	6,886	6,886	24.70%	24.70%	24.70%	15.00%
NPCC-New England	20,929	23,210	35,869	35,869	37,076	71.38%	71.38%	77.15%	15.00%
NPCC-New York	25,265	25,265	41,480	41,480	44,379	64.18%	64.18%	75.65%	16.00%
PJM	127,644	140,844	182,401	182,401	193,693	42.90%	42.90%	51.74%	15.40%
SERC-E	44,382	46,003	56,343	56,343	56,357	26.95%	26.95%	26.98%	15.00%
SERC-N	46,176	49,266	68,909	72,900	75,852	49.23%	57.88%	64.27%	15.00%
SERC-SE	47,434	49,665	68,526	68,826	68,983	44.46%	45.10%	45.43%	15.00%
SERC-W	21,410	22,215	43,765	48,033	51,156	104.42%	124.35%	138.94%	15.00%
SPP	42,726	43,590	62,960	67,787	69,138	47.36%	58.65%	61.82%	13.60%
WECC-BASN	11,818	12,123	13,896	13,896	14,678	17.58%	17.58%	24.20%	13.49%
WECC-CALN	19,618	19,898	24,309	24,309	24,505	23.91%	23.91%	24.91%	11.86%
WECC-CALS	24,099	25,051	33,789	33,789	34,098	40.21%	40.21%	41.49%	11.03%
WECC-DSW	19,540	19,830	35,713	35,713	36,341	82.77%	82.77%	85.98%	13.96%
WECC-NORW	31,607	31,705	38,343	38,343	38,344	21.31%	21.31%	21.31%	19.90%
WECC-ROCK	10,602	10,877	14,578	14,578	15,074	37.50%	37.50%	42.18%	15.68%
TOTAL-UNITED STATES	679,228	715,065	982,805	1,012,200	1,045,206	44.69%	49.02%	53.88%	15.00%
MRO-Manitoba Hydro	4,801	4,801	6,124	6,124	6,124	27.56%	27.56%	27.56%	12.00%
MRO-SaskPower	4,054	4,145	4,701	4,701	4,701	15.97%	15.97%	15.97%	11.00%
NPCC-Maritimes	5,226	5,489	6,861	6,861	6,861	31.28%	31.28%	31.28%	20.00%
NPCC-Ontario	20,700	20,700	27,189	27,189	30,150	31.35%	31.35%	45.65%	20.00%
NPCC-Québec	39,487	39,487	45,399	45,399	45,399	14.97%	14.97%	14.97%	12.20%
WECC-AESO	14,351	14,351	18,081	18,081	18,081	25.99%	25.99%	25.99%	11.71%
WECC-BC	12,223	12,223	14,409	14,409	14,409	17.88%	17.88%	17.88%	16.16%
TOTAL-CANADA	100,842	101,196	122,764	122,764	125,725	21.74%	21.74%	24.68%	10.00%
WECC-MEXW	1,687	1,687	2,649	2,649	2,989	57.02%	57.02%	77.20%	10.71%
TOTAL-MÉXICO	1,687	1,687	2,649	2,649	2,989	57.02%	57.02%	77.20%	10.71%
TOTAL-NERC	**781,757**	**817,948**	**1,108,218**	**1,137,614**	**1,173,920**	**41.76%**	**45.52%**	**50.16%**	**15.00%**

Demand, Resources, and Reserve Margins: 2019 Summer

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			NERC
Assessment Areas/Country	Net Internal	Total Internal	Anticipated	Prospective	Adj. Potential	Anticipated	Prospective	Adj. Potential	Reference
ERCOT	76,769	78,351	78,556	78,556	79,719	2.33%	2.33%	3.84%	13.75%
FRCC	46,803	50,356	57,848	62,693	65,337	23.60%	33.95%	39.60%	15.00%
MISO	92,932	100,565	110,152	122,624	123,561	18.53%	31.95%	32.96%	16.30%
MRO-MAPP	5,643	5,746	6,518	6,518	6,518	15.50%	15.50%	15.50%	15.00%
NPCC-New England	28,111	30,605	33,324	33,324	34,531	18.54%	18.54%	22.84%	15.00%
NPCC-New York	35,204	35,204	42,077	42,077	42,838	19.52%	19.52%	21.68%	16.00%
PJM	157,660	170,860	182,399	182,399	193,691	15.69%	15.69%	22.85%	15.40%
SERC-E	44,636	46,908	55,103	55,103	55,117	23.45%	23.45%	23.48%	15.00%
SERC-N	47,044	50,090	55,142	59,061	62,451	17.21%	25.54%	32.75%	15.00%
SERC-SE	51,707	53,948	66,154	66,454	66,696	27.94%	28.52%	28.99%	15.00%
SERC-W	26,910	27,863	35,171	39,690	43,580	30.70%	47.49%	61.95%	15.00%
SPP	57,338	58,378	66,970	72,054	72,189	16.80%	25.67%	25.90%	13.60%
WECC-BASN	14,392	15,550	15,895	15,895	16,667	10.44%	10.44%	15.80%	12.60%
WECC-CALN	27,998	28,834	30,534	30,534	30,536	9.06%	9.06%	9.07%	14.71%
WECC-CALS	31,948	34,090	36,810	36,810	37,129	15.22%	15.22%	16.22%	15.14%
WECC-DSW	29,622	30,204	41,934	41,934	43,162	41.56%	41.56%	45.71%	13.50%
WECC-NORW	25,901	26,034	30,600	30,600	30,602	18.14%	18.14%	18.15%	17.90%
WECC-ROCK	12,626	13,176	14,247	14,247	14,263	12.84%	12.84%	12.97%	14.65%
TOTAL-UNITED STATES	813,244	856,761	959,432	990,572	1,018,587	17.98%	21.81%	25.25%	15.00%
MRO-Manitoba Hydro	3,271	3,271	4,852	4,852	4,852	48.34%	48.34%	48.34%	12.00%
MRO-SaskPower	3,665	3,756	4,285	4,285	4,285	16.89%	16.89%	16.89%	11.00%
NPCC-Maritimes	3,140	3,471	6,558	6,558	6,558	108.84%	108.84%	108.84%	20.00%
NPCC-Ontario	22,891	22,891	24,777	24,777	27,827	8.24%	8.24%	21.57%	20.00%
NPCC-Québec	22,307	22,307	34,799	34,799	34,799	56.00%	56.00%	56.00%	12.20%
WECC-AESO	13,936	13,974	15,669	15,669	15,669	12.43%	12.43%	12.43%	12.24%
WECC-BC	9,289	9,289	12,369	12,369	12,369	33.16%	33.16%	33.16%	12.51%
TOTAL-CANADA	78,498	78,958	103,308	103,308	106,359	31.61%	31.61%	35.49%	10.00%
WECC-MEXW	2,545	2,545	2,923	2,923	3,535	14.86%	14.86%	38.90%	11.86%
TOTAL-MÉXICO	2,545	2,545	2,923	2,923	3,535	14.86%	14.86%	38.90%	11.86%
TOTAL-NERC	**894,287**	**938,265**	**1,065,664**	**1,096,804**	**1,128,480**	**19.16%**	**22.65%**	**26.19%**	**15.00%**

Demand, Resources, and Reserve Margins: 2019/2020 Winter

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			NERC
Assessment Areas/Country	Net Internal	Total Internal	Anticipated	Prospective	Adj. Potential	Anticipated	Prospective	Adj. Potential	Reference
ERCOT	57,575	59,318	81,013	81,013	86,477	40.71%	40.71%	50.20%	13.75%
FRCC	46,910	50,570	62,340	65,725	66,884	32.89%	40.11%	42.58%	15.00%
MISO	77,174	81,649	111,704	124,331	125,306	44.74%	61.10%	62.37%	16.30%
MRO-MAPP	5,623	5,623	6,866	6,866	6,866	22.11%	22.11%	22.11%	15.00%
NPCC-New England	20,859	23,330	35,869	35,869	37,076	71.96%	71.96%	77.75%	15.00%
NPCC-New York	25,422	25,422	41,480	41,480	44,757	63.17%	63.17%	76.06%	16.00%
PJM	128,818	142,018	182,401	182,401	193,693	41.60%	41.60%	50.36%	15.40%
SERC-E	45,016	46,648	57,661	57,661	57,675	28.09%	28.09%	28.12%	15.00%
SERC-N	46,697	49,932	68,909	72,900	76,732	47.57%	56.11%	64.32%	15.00%
SERC-SE	48,097	50,338	68,506	68,806	68,964	42.43%	43.06%	43.38%	15.00%
SERC-W	21,118	21,923	43,765	48,033	51,975	107.24%	127.45%	146.12%	15.00%
SPP	43,360	44,223	63,127	67,954	69,307	45.59%	56.72%	59.84%	13.60%
WECC-BASN	11,940	12,245	13,935	13,935	14,919	16.71%	16.71%	24.94%	13.49%
WECC-CALN	19,767	20,048	24,348	24,348	24,544	23.18%	23.18%	24.17%	11.86%
WECC-CALS	24,438	25,440	32,161	32,161	32,470	31.60%	31.60%	32.87%	11.03%
WECC-DSW	19,945	20,235	35,184	35,184	36,614	76.41%	76.41%	83.57%	13.96%
WECC-NORW	31,862	31,971	37,851	37,851	37,852	18.80%	18.80%	18.80%	19.90%
WECC-ROCK	10,796	11,072	14,612	14,612	15,140	35.35%	35.35%	40.23%	15.68%
TOTAL-UNITED STATES	685,417	722,005	981,734	1,011,131	1,047,251	43.23%	47.52%	52.79%	15.00%
MRO-Manitoba Hydro	4,878	4,878	6,027	6,027	6,027	23.55%	23.55%	23.55%	12.00%
MRO-SaskPower	4,107	4,198	4,701	4,701	4,701	14.47%	14.47%	14.47%	11.00%
NPCC-Maritimes	5,228	5,492	6,861	6,861	6,861	31.25%	31.25%	31.25%	20.00%
NPCC-Ontario	21,063	21,063	25,160	25,160	28,528	19.45%	19.45%	35.44%	20.00%
NPCC-Québec	39,812	39,812	45,505	45,505	45,505	14.30%	14.30%	14.30%	12.20%
WECC-AESO	14,759	14,759	18,140	18,140	18,140	22.91%	22.91%	22.91%	11.71%
WECC-BC	12,373	12,373	14,474	14,474	14,474	16.98%	16.98%	16.98%	16.16%
TOTAL-CANADA	102,219	102,575	120,869	120,869	124,237	18.24%	18.24%	21.54%	10.00%
WECC-MEXW	1,725	1,725	2,774	2,774	3,386	60.83%	60.83%	96.29%	10.71%
TOTAL-MÉXICO	1,725	1,725	2,774	2,774	3,386	60.83%	60.83%	96.29%	10.71%
TOTAL-NERC	**789,361**	**826,305**	**1,105,377**	**1,134,775**	**1,174,874**	**40.03%**	**43.76%**	**48.84%**	**15.00%**

Demand, Resources, and Reserve Margins: 2020 Summer

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			NERC
Assessment Areas/Country	Net Internal	Total Internal	Anticipated	Prospective	Adj. Potential	Anticipated	Prospective	Adj. Potential	Reference
ERCOT	78,524	80,176	78,556	78,556	79,719	0.04%	0.04%	1.52%	13.75%
FRCC	47,581	51,191	57,847	62,695	65,339	21.58%	31.76%	37.32%	15.00%
MISO	93,419	101,530	110,152	122,624	123,561	17.91%	31.26%	32.27%	16.30%
MRO-MAPP	5,735	5,840	6,518	6,518	6,518	13.65%	13.65%	13.65%	15.00%
NPCC-New England	28,257	30,930	33,324	33,324	34,531	17.93%	17.93%	22.20%	15.00%
NPCC-New York	35,526	35,526	42,077	42,077	42,838	18.44%	18.44%	20.58%	16.00%
PJM	159,593	172,793	182,399	182,399	193,691	14.29%	14.29%	21.37%	15.40%
SERC-E	45,200	47,487	55,379	55,379	55,393	22.52%	22.52%	22.55%	15.00%
SERC-N	47,653	50,868	56,402	60,321	63,711	18.36%	26.58%	33.70%	15.00%
SERC-SE	52,396	54,645	66,135	66,435	66,865	26.22%	26.79%	27.61%	15.00%
SERC-W	27,198	28,153	35,171	39,690	43,730	29.32%	45.93%	60.79%	15.00%
SPP	57,971	59,239	67,496	72,580	72,737	16.43%	25.20%	25.47%	13.60%
WECC-BASN	14,628	15,786	15,719	15,719	16,685	7.46%	7.46%	14.07%	12.60%
WECC-CALN	28,324	29,160	31,011	31,011	31,014	9.49%	9.49%	9.49%	14.71%
WECC-CALS	32,472	34,666	37,485	37,485	37,909	15.44%	15.44%	16.74%	15.14%
WECC-DSW	30,183	30,764	40,664	40,664	42,234	34.72%	34.72%	39.93%	13.50%
WECC-NORW	26,151	26,295	30,895	30,895	30,895	18.14%	18.14%	18.14%	17.90%
WECC-ROCK	12,840	13,404	14,837	14,837	14,842	15.56%	15.56%	15.59%	14.65%
TOTAL-UNITED STATES	823,652	868,453	962,068	993,209	1,022,214	16.81%	20.59%	24.11%	15.00%
MRO-Manitoba Hydro	3,348	3,348	4,602	4,602	5,232	37.45%	37.45%	56.26%	12.00%
MRO-SaskPower	3,716	3,807	4,285	4,285	4,285	15.29%	15.29%	15.29%	11.00%
NPCC-Maritimes	3,163	3,494	6,558	6,558	6,558	107.33%	107.33%	107.33%	20.00%
NPCC-Ontario	23,010	23,010	23,867	23,867	28,509	3.72%	3.72%	23.90%	20.00%
NPCC-Québec	22,503	22,503	34,905	34,905	34,905	55.11%	55.11%	55.11%	12.20%
WECC-AESO	14,336	14,374	15,619	15,619	15,619	8.95%	8.95%	8.95%	12.24%
WECC-BC	9,427	9,427	11,626	11,626	11,626	23.33%	23.33%	23.33%	12.51%
TOTAL-CANADA	79,504	79,964	101,461	101,461	106,734	27.62%	27.62%	34.25%	10.00%
WECC-MEXW	2,602	2,602	2,923	2,923	3,535	12.35%	12.35%	35.85%	11.86%
TOTAL-MÉXICO	2,602	2,602	2,923	2,923	3,535	12.35%	12.35%	35.85%	11.86%
TOTAL-NERC	**905,758**	**951,019**	**1,066,452**	**1,097,594**	**1,132,482**	**17.74%**	**21.18%**	**25.03%**	**15.00%**

Demand, Resources, and Reserve Margins: 2020/2021 Winter

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			NERC
Assessment Areas/Country	Net Internal	Total Internal	Anticipated	Prospective	Adj. Potential	Anticipated	Prospective	Adj. Potential	Reference
ERCOT	58,210	60,039	81,330	81,330	86,794	39.72%	39.72%	49.10%	13.75%
FRCC	47,509	51,218	63,335	66,720	67,879	33.31%	40.44%	42.88%	15.00%
MISO	77,498	82,252	111,704	124,331	125,306	44.14%	60.43%	61.69%	16.30%
MRO-MAPP	5,718	5,718	6,866	6,866	6,866	20.07%	20.07%	20.07%	15.00%
NPCC-New England	20,797	23,445	35,863	35,863	37,070	72.44%	72.44%	78.25%	15.00%
NPCC-New York	25,627	25,627	41,480	41,480	44,757	61.86%	61.86%	74.65%	16.00%
PJM	130,219	143,419	182,401	182,401	193,693	40.07%	40.07%	48.74%	15.40%
SERC-E	45,557	47,201	57,942	57,942	57,956	27.19%	27.19%	27.22%	15.00%
SERC-N	47,211	50,584	70,169	74,160	77,992	48.63%	57.08%	65.20%	15.00%
SERC-SE	48,943	51,193	68,499	68,799	69,144	39.96%	40.57%	41.28%	15.00%
SERC-W	21,726	22,539	43,765	48,033	52,125	101.44%	121.09%	139.92%	15.00%
SPP	43,930	44,794	63,774	68,600	70,175	45.17%	56.16%	59.74%	13.60%
WECC-BASN	12,026	12,331	13,968	13,968	15,128	16.15%	16.15%	25.79%	13.49%
WECC-CALN	19,919	20,198	23,971	23,971	24,165	20.34%	20.34%	21.32%	11.86%
WECC-CALS	24,941	25,994	30,223	30,223	30,637	21.18%	21.18%	22.84%	11.03%
WECC-DSW	20,263	20,553	36,364	36,364	38,149	79.46%	79.46%	88.27%	13.96%
WECC-NORW	32,075	32,195	37,625	37,625	37,626	17.30%	17.30%	17.31%	19.90%
WECC-ROCK	10,922	11,200	13,156	13,156	13,581	20.45%	20.45%	24.35%	15.68%
TOTAL-UNITED STATES	693,092	730,501	982,436	1,011,834	1,049,044	41.75%	45.99%	51.36%	15.00%
MRO-Manitoba Hydro	4,981	4,981	5,777	5,777	6,317	15.97%	15.97%	26.81%	12.00%
MRO-SaskPower	4,164	4,255	4,701	4,701	4,701	12.91%	12.91%	12.91%	11.00%
NPCC-Maritimes	5,247	5,513	6,861	6,861	6,861	30.75%	30.75%	30.75%	20.00%
NPCC-Ontario	21,234	21,234	25,125	25,125	30,085	18.33%	18.33%	41.69%	20.00%
NPCC-Québec	40,079	40,079	45,906	45,906	45,906	14.54%	14.54%	14.54%	12.20%
WECC-AESO	15,162	15,162	18,746	18,746	18,746	23.64%	23.64%	23.64%	11.71%
WECC-BC	12,523	12,523	14,330	14,330	14,330	14.43%	14.43%	14.43%	16.16%
TOTAL-CANADA	103,391	103,747	121,446	121,446	126,946	17.46%	17.46%	22.78%	10.00%
WECC-MEXW	1,764	1,764	2,770	2,770	3,382	57.05%	57.05%	91.72%	10.71%
TOTAL-MÉXICO	1,764	1,764	2,770	2,770	3,382	57.05%	57.05%	91.72%	10.71%
TOTAL-NERC	**798,246**	**836,012**	**1,106,653**	**1,136,050**	**1,179,373**	**38.64%**	**42.32%**	**47.75%**	**15.00%**

Demand, Resources, and Reserve Margins: 2021 Summer

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			NERC
Assessment Areas/Country	Net Internal	Total Internal	Anticipated	Prospective	Adj. Potential	Anticipated	Prospective	Adj. Potential	Reference
ERCOT	79,682	81,410	78,873	78,873	80,036	-1.02%	-1.02%	0.44%	13.75%
FRCC	48,273	51,933	59,941	65,247	68,351	24.17%	35.16%	41.59%	15.00%
MISO	93,957	102,559	110,152	122,624	123,561	17.24%	30.51%	31.51%	16.30%
MRO-MAPP	5,821	5,928	6,518	6,518	6,518	11.97%	11.97%	11.97%	15.00%
NPCC-New England	28,414	31,255	33,318	33,318	34,525	17.26%	17.26%	21.51%	15.00%
NPCC-New York	35,913	35,913	42,077	42,077	42,838	17.16%	17.16%	19.28%	16.00%
PJM	161,438	174,638	182,399	182,399	193,691	12.98%	12.98%	19.98%	15.40%
SERC-E	45,848	48,149	56,007	56,007	56,021	22.16%	22.16%	22.19%	15.00%
SERC-N	48,167	51,345	56,402	60,321	64,491	17.10%	25.23%	33.89%	15.00%
SERC-SE	53,343	55,600	65,848	66,148	66,579	23.44%	24.01%	24.81%	15.00%
SERC-W	27,472	28,435	35,450	39,969	44,759	29.04%	45.49%	62.93%	15.00%
SPP	58,716	59,904	67,715	72,799	72,956	15.33%	23.98%	24.25%	13.60%
WECC-BASN	14,836	15,994	15,814	15,814	16,779	6.59%	6.59%	13.10%	12.60%
WECC-CALN	28,652	29,487	31,293	31,293	31,295	9.22%	9.22%	9.22%	14.71%
WECC-CALS	32,997	35,243	38,010	38,010	38,434	15.19%	15.19%	16.48%	15.14%
WECC-DSW	30,720	31,305	39,790	39,790	41,441	29.52%	29.52%	34.90%	13.50%
WECC-NORW	26,414	26,561	31,204	31,204	31,206	18.13%	18.13%	18.14%	17.90%
WECC-ROCK	13,093	13,615	14,656	14,656	14,660	11.94%	11.94%	11.97%	14.65%
TOTAL-UNITED STATES	833,758	879,275	965,464	997,065	1,028,141	15.80%	19.59%	23.31%	15.00%
MRO-Manitoba Hydro	3,428	3,428	4,377	4,377	5,007	27.69%	27.69%	46.06%	12.00%
MRO-SaskPower	3,784	3,875	4,394	4,394	4,394	16.11%	16.11%	16.11%	11.00%
NPCC-Maritimes	3,175	3,506	6,558	6,558	6,558	106.54%	106.54%	106.54%	20.00%
NPCC-Ontario	23,390	23,390	22,787	22,787	28,820	-2.58%	-2.58%	23.21%	20.00%
NPCC-Québec	22,662	22,662	35,306	35,306	35,306	55.79%	55.79%	55.79%	12.20%
WECC-AESO	14,727	14,765	15,621	15,621	15,621	6.07%	6.07%	6.07%	12.24%
WECC-BC	9,553	9,553	10,983	10,983	10,983	14.97%	14.97%	14.97%	12.51%
TOTAL-CANADA	80,719	81,179	100,027	100,027	106,689	23.92%	23.92%	32.17%	10.00%
WECC-MEXW	2,659	2,659	2,923	2,923	3,535	9.94%	9.94%	32.94%	11.86%
TOTAL-MÉXICO	2,659	2,659	2,923	2,923	3,535	9.94%	9.94%	32.94%	11.86%
TOTAL-NERC	**917,136**	**963,113**	**1,068,414**	**1,100,015**	**1,138,365**	**16.49%**	**19.94%**	**24.12%**	**15.00%**

Demand, Resources, and Reserve Margins: 2021/2022 Winter

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			NERC
Assessment Areas/Country	Net Internal	Total Internal	Anticipated	Prospective	Adj. Potential	Anticipated	Prospective	Adj. Potential	Reference
ERCOT	59,031	60,917	81,330	81,330	86,794	37.78%	37.78%	47.03%	13.75%
FRCC	48,169	51,921	64,893	68,824	70,529	34.72%	42.88%	46.42%	15.00%
MISO	78,022	83,064	111,704	124,331	125,306	43.17%	59.35%	60.60%	16.30%
MRO-MAPP	5,814	5,814	6,866	6,866	6,866	18.10%	18.10%	18.10%	15.00%
NPCC-New England	20,750	23,565	35,863	35,863	37,070	72.83%	72.83%	78.65%	15.00%
NPCC-New York	25,794	25,794	42,833	42,833	46,110	66.06%	66.06%	78.76%	16.00%
PJM	131,636	144,836	182,401	182,401	193,693	38.56%	38.56%	47.14%	15.40%
SERC-E	46,144	47,797	58,720	58,720	58,734	27.25%	27.25%	27.28%	15.00%
SERC-N	47,891	51,397	70,169	74,160	78,872	46.52%	54.85%	64.69%	15.00%
SERC-SE	49,770	52,029	68,113	68,413	68,758	36.86%	37.46%	38.15%	15.00%
SERC-W	21,891	22,707	44,044	48,312	53,154	101.20%	120.69%	142.81%	15.00%
SPP	44,470	45,334	63,966	68,793	70,368	43.84%	54.69%	58.24%	13.60%
WECC-BASN	12,158	12,463	13,565	13,565	14,792	11.57%	11.57%	21.67%	13.49%
WECC-CALN	20,070	20,348	23,848	23,848	23,946	18.82%	18.82%	19.31%	11.86%
WECC-CALS	25,300	26,403	32,182	32,182	32,596	27.20%	27.20%	28.84%	11.03%
WECC-DSW	20,490	20,780	36,572	36,572	37,479	78.49%	78.49%	82.91%	13.96%
WECC-NORW	32,391	32,512	37,468	37,468	37,470	15.67%	15.67%	15.68%	19.90%
WECC-ROCK	11,165	11,401	14,162	14,162	14,586	26.85%	26.85%	30.64%	15.68%
TOTAL-UNITED STATES	700,956	739,081	988,701	1,018,645	1,057,124	41.05%	45.32%	50.81%	15.00%
MRO-Manitoba Hydro	5,089	5,089	5,552	5,552	6,182	9.10%	9.10%	21.48%	12.00%
MRO-SaskPower	4,239	4,330	4,828	4,828	4,828	13.90%	13.90%	13.90%	11.00%
NPCC-Maritimes	5,264	5,530	6,861	6,861	6,861	30.34%	30.34%	30.34%	20.00%
NPCC-Ontario	21,441	21,441	26,014	26,014	32,364	21.33%	21.33%	50.95%	20.00%
NPCC-Québec	40,317	40,317	45,906	45,906	45,906	13.86%	13.86%	13.86%	12.20%
WECC-AESO	15,618	15,618	18,034	18,034	18,034	15.47%	15.47%	15.47%	11.71%
WECC-BC	12,673	12,673	14,401	14,401	14,401	13.64%	13.64%	13.64%	16.16%
TOTAL-CANADA	104,640	104,997	121,597	121,597	128,577	16.21%	16.21%	22.88%	10.00%
WECC-MEXW	1,803	1,803	2,771	2,771	3,382	53.67%	53.67%	87.59%	10.71%
TOTAL-MÉXICO	1,803	1,803	2,771	2,771	3,382	53.67%	53.67%	87.59%	10.71%
TOTAL-NERC	**807,399**	**845,882**	**1,113,069**	**1,143,013**	**1,189,083**	**37.86%**	**41.57%**	**47.27%**	**15.00%**

Demand, Resources, and Reserve Margins: 2022 Summer

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			NERC
Assessment Areas/Country	Net Internal	Total Internal	Anticipated	Prospective	Adj. Potential	Anticipated	Prospective	Adj. Potential	Reference
ERCOT	80,694	82,507	78,873	78,873	80,036	-2.26%	-2.26%	-0.82%	13.75%
FRCC	48,923	52,583	60,203	65,509	68,613	23.06%	33.90%	40.25%	15.00%
MISO	94,875	103,584	110,152	122,624	123,561	16.10%	29.25%	30.24%	16.30%
MRO-MAPP	5,906	6,015	6,518	6,518	6,518	10.36%	10.36%	10.36%	15.00%
NPCC-New England	28,583	31,583	33,318	33,318	34,525	16.56%	16.56%	20.79%	15.00%
NPCC-New York	36,230	36,230	42,077	42,077	42,838	16.14%	16.14%	18.24%	16.00%
PJM	163,220	176,420	182,399	182,399	193,691	11.75%	11.75%	18.67%	15.40%
SERC-E	46,386	48,697	56,889	56,889	56,903	22.64%	22.64%	22.67%	15.00%
SERC-N	48,778	52,038	56,402	60,321	64,491	15.63%	23.66%	32.21%	15.00%
SERC-SE	54,249	56,512	65,741	66,041	66,471	21.18%	21.74%	22.53%	15.00%
SERC-W	27,764	28,730	35,450	39,969	44,822	27.68%	43.96%	61.44%	15.00%
SPP	58,985	60,088	67,740	72,823	72,981	14.84%	23.46%	23.73%	13.60%
WECC-BASN	14,756	15,914	15,813	15,813	16,816	7.17%	7.17%	13.96%	12.60%
WECC-CALN	29,077	29,912	31,375	31,375	31,378	7.90%	7.90%	7.91%	14.71%
WECC-CALS	33,319	35,615	38,422	38,422	38,846	15.31%	15.31%	16.59%	15.14%
WECC-DSW	31,013	31,602	40,035	40,035	41,683	29.09%	29.09%	34.40%	13.50%
WECC-NORW	26,711	26,858	31,656	31,656	31,656	18.51%	18.51%	18.51%	17.90%
WECC-ROCK	13,251	13,771	14,313	14,313	14,315	8.02%	8.02%	8.03%	14.65%
TOTAL-UNITED STATES	842,721	888,660	967,375	998,976	1,030,143	14.79%	18.54%	22.24%	15.00%
MRO-Manitoba Hydro	3,474	3,474	4,377	4,377	5,007	25.98%	25.98%	44.11%	12.00%
MRO-SaskPower	3,847	3,938	4,505	4,505	4,505	17.10%	17.10%	17.10%	11.00%
NPCC-Maritimes	3,183	3,514	6,558	6,558	6,558	106.02%	106.02%	106.02%	20.00%
NPCC-Ontario	23,442	23,442	22,791	22,791	28,996	-2.78%	-2.78%	23.69%	20.00%
NPCC-Québec	22,818	22,818	35,306	35,306	35,306	54.73%	54.73%	54.73%	12.20%
WECC-AESO	15,093	15,131	16,375	16,375	16,375	8.50%	8.50%	8.50%	12.24%
WECC-BC	9,670	9,670	11,015	11,015	11,015	13.91%	13.91%	13.91%	12.51%
TOTAL-CANADA	81,528	81,988	100,928	100,928	107,762	23.80%	23.80%	32.18%	10.00%
WECC-MEXW	2,716	2,716	2,924	2,924	3,535	7.65%	7.65%	30.17%	11.86%
TOTAL-MÉXICO	2,716	2,716	2,924	2,924	3,535	7.65%	7.65%	30.17%	11.86%
TOTAL-NERC	**926,965**	**973,364**	**1,071,227**	**1,102,827**	**1,141,441**	**15.56%**	**18.97%**	**23.14%**	**15.00%**

Demand, Resources, and Reserve Margins: 2022/2023 Winter

	Demand (MW)		Capacity Resources (MW)			Planning Reserve Margins (%)			NERC
Assessment Areas/Country	Net Internal	Total Internal	Anticipated	Prospective	Adj. Potential	Anticipated	Prospective	Adj. Potential	Reference
ERCOT	61,450	63,336	81,330	81,330	86,794	32.35%	32.35%	41.24%	13.75%
FRCC	48,656	52,408	64,893	68,824	70,529	33.37%	41.45%	44.95%	15.00%
MISO	78,789	83,894	111,704	124,331	125,306	41.78%	57.80%	59.04%	16.30%
MRO-MAPP	5,904	5,904	6,866	6,866	6,866	16.29%	16.29%	16.29%	15.00%
NPCC-New England	20,711	23,686	35,863	35,863	37,070	73.16%	73.16%	78.99%	15.00%
NPCC-New York	25,908	25,908	42,833	42,833	46,110	65.33%	65.33%	77.98%	16.00%
PJM	132,916	146,116	182,401	182,401	193,693	37.23%	37.23%	45.73%	15.40%
SERC-E	46,730	48,395	59,595	59,595	59,609	27.53%	27.53%	27.56%	15.00%
SERC-N	48,256	51,914	70,569	74,560	79,272	46.24%	54.51%	64.28%	15.00%
SERC-SE	50,627	52,894	68,106	68,406	68,751	34.52%	35.12%	35.80%	15.00%
SERC-W	22,262	23,082	44,044	48,312	53,217	97.85%	117.02%	139.05%	15.00%
SPP	44,862	45,726	64,137	68,963	70,538	42.96%	53.72%	57.23%	13.60%
WECC-BASN	12,132	12,437	13,582	13,582	14,571	11.96%	11.96%	20.10%	13.49%
WECC-CALN	20,220	20,498	23,330	23,330	23,502	15.38%	15.38%	16.23%	11.86%
WECC-CALS	25,454	26,607	30,703	30,703	31,117	20.62%	20.62%	22.25%	11.03%
WECC-DSW	20,775	21,065	36,929	36,929	38,169	77.75%	77.75%	83.72%	13.96%
WECC-NORW	32,638	32,759	39,876	39,876	39,878	22.18%	22.18%	22.18%	19.90%
WECC-ROCK	11,283	11,521	13,443	13,443	13,458	19.14%	19.14%	19.27%	15.68%
TOTAL-UNITED STATES	709,572	748,149	990,204	1,020,148	1,058,450	39.55%	43.77%	49.17%	15.00%
MRO-Manitoba Hydro	5,162	5,162	5,552	5,552	6,182	7.54%	7.54%	19.75%	12.00%
MRO-SaskPower	4,310	4,401	4,953	4,953	4,953	14.93%	14.93%	14.93%	11.00%
NPCC-Maritimes	5,285	5,552	6,861	6,861	6,861	29.82%	29.82%	29.82%	20.00%
NPCC-Ontario	21,529	21,529	26,858	26,858	33,380	24.75%	24.75%	55.04%	20.00%
NPCC-Québec	40,575	40,575	45,906	45,906	45,906	13.14%	13.14%	13.14%	12.20%
WECC-AESO	15,994	15,994	18,124	18,124	18,124	13.32%	13.32%	13.32%	11.71%
WECC-BC	12,823	12,823	14,467	14,467	14,467	12.82%	12.82%	12.82%	16.16%
TOTAL-CANADA	105,679	106,037	122,721	122,721	129,873	16.13%	16.13%	22.89%	10.00%
WECC-MEXW	1,841	1,841	2,772	2,772	3,384	50.59%	50.59%	83.81%	10.71%
TOTAL-MÉXICO	1,841	1,841	2,772	2,772	3,384	50.59%	50.59%	83.81%	10.71%
TOTAL-NERC	**817,092**	**856,027**	**1,115,697**	**1,145,641**	**1,191,707**	**36.54%**	**40.21%**	**45.85%**	**15.00%**

ERCOT

Planning Reserve Margins

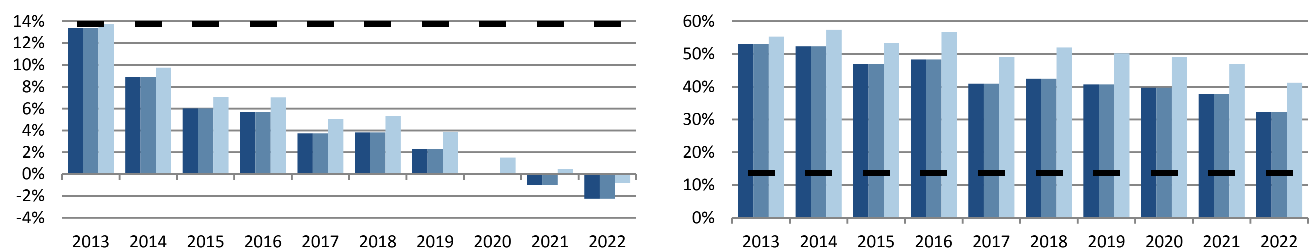
Based on current information regarding Future-Planned generation, the ERCOT Region will not maintain adequate Planning Reserve Margins throughout the assessment period. The Anticipated, Prospective and Adjusted Potential Reserve Margins are expected to be below the NERC Reference Margin Level of 13.75 percent as early as the 2013 summer. The Total Potential Resources Reserve Margin is forecast to drop below the NERC Reference Margin Level in 2014. The Anticipated and Prospective Reserve Margins for 2013 are forecast to be 13.4 percent. Given expected load growth and limited knowledge of future generation development and retirements, Reserve Margins are expected to decline through the end of the assessment period (ERCOT-Table 1 and ERCOT-Figure 1).

ERCOT-Table 1: Planning Reserve Margins

ERCOT-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		13.40%	8.91%	6.02%	5.69%	3.72%	3.82%	2.33%	0.04%	-1.02%	-2.26%
PROSPECTIVE		13.40%	8.91%	6.02%	5.69%	3.72%	3.82%	2.33%	0.04%	-1.02%	-2.26%
ADJUSTED POTENTIAL		13.72%	9.75%	7.06%	7.03%	5.04%	5.34%	3.84%	1.52%	0.44%	-0.82%
NERC REFERENCE	-	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**

ERCOT-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		53.03%	52.33%	47.01%	48.32%	40.96%	42.49%	40.71%	39.72%	37.78%	32.35%
PROSPECTIVE		53.03%	52.33%	47.01%	48.32%	40.96%	42.49%	40.71%	39.72%	37.78%	32.35%
ADJUSTED POTENTIAL		55.34%	57.43%	53.33%	56.81%	49.02%	52.00%	50.20%	49.10%	47.03%	41.24%
NERC REFERENCE	-	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**	**13.75%**

ERCOT-Figure 1: Summer (Left) and Winter[116] (Right) Planning Reserve Margins



Expectations that reserve margins will be below the minimum NERC Reference Margin Level are a result of limited knowledge of plans for future generation development and retirements, especially due to uncertainty in the generation marketplace. With no administrative requirement for market participants to notify ERCOT of their long-term generation development plans, generation additions and retirements beyond those that are currently being reviewed for interconnection to the transmission system are not known and cannot be included in this assessment. Additionally, the exclusion of hydro generation capacity during the peak further reduces Planning Reserve Margins throughout the assessment period.

Historically, in both internal and external assessments, ERCOT has assumed hydro generation capacity to be unavailable during the peak. Recent ERCOT internal discussions have led ERCOT staff to believe the inclusion of all hydro generation capacity is appropriate. Texas Reliability Entity (TRE) does not currently share this view and is awaiting a technically justifiable approach for inclusion (either total or partial), of the hydro capacity values during the peak. The inclusion or exclusion of ERCOT's 544 MW of hydro generation capacity has important implications for the area's Anticipated Reserve Margins and its proximity to the NERC Reference Margin Level. Accordingly, TRE and ERCOT staff will continue to work together to determine a technically justifiable resolution, which may require changes in ERCOT stakeholder procedures.

[116] Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.

The Public Utility Commission of Texas (PUCT) is responsible for ensuring that the market design promotes an adequate level of resources required to serve expected loads. There is no requirement for any entity to plan for – or ensure – adequate levels of future resource additions. The ERCOT market design provides an opportunity for any interested stakeholder to develop new generation and bid into the electricity market.

Given adequate time for development of new generation, regulatory or market changes resulting in idling or retirement of generation facilities are not expected to have a significant impact on projected Reserve Margins. However, due to environmental requirements and regulatory changes that result in significant accelerated reductions in overall resource capacity or regulatory constraints that impede the development of new resources, reduced system reliability due to the impact on Reserve Margins is expected. Regulatory uncertainty gives resource owners added reason to retire existing resources without providing sufficient assurance on future market conditions to developers of new resources. This increases the risk of reduced system reliability.

Demand

Total Internal Demand is forecast to grow at a compounded annual rate of 2.32 percent for the 2013–2022 assessment period (ERCOT-Table 2). The reduction in load forecast growth projections compared to a year earlier, results from changes in the long-range economic forecast, which is obtained from Moody's.[117] The Moody's base-case economic forecast was used to provide forecast, non-farm employment values for 2013–2022. A normal weather year was determined based on actual weather data from 1997 to 2011. Reported peak demands represent the coincident demand for ERCOT.

ERCOT-Table 2: Demand Outlook

ERCOT-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	65,649	80,694	15,045	22.9%	2.32%
Load-Modifying Demand Response	1,279	1,813	534	41.7%	3.95%
TOTAL INTERNAL DEMAND	**66,928**	**82,507**	**15,579**	**23.3%**	**2.35%**
ERCOT-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	50,263	61,450	11,187	22.3%	2.26%
Load-Modifying Demand Response	1,471	1,886	415	28.2%	2.80%
TOTAL INTERNAL DEMAND	**51,734**	**63,336**	**11,602**	**22.4%**	**2.27%**

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. The extreme hot weather conditions experienced over the entire ERCOT Interconnection during the summer of 2011 impacted the calculation of average weather conditions,[118] resulting in higher expected peak loads in future years. In the near term, this change in average weather conditions will increase forecast peak loads by approximately 1.2 percent.

Demand-Side Management

Load Resources (LRs) providing Responsive Reserve Service (RRS)[119] are projected to provide 886 MW of dispatchable, contractually committed Demand Response during summer peak hours in 2013 and future years (ERCOT-Table 3).[120,121]

[117] http://www.moodys.com/.
[118] http://www.ercot.com/content/meetings/rpg/keydocs/2012/0817/2011_Long-Term_Load_Forecast_Model_Descript.pdf.
[119] Categorized as Load as Capacity Resource Demand Response in this assessment.
[120] http://www.ercot.com/content/mktinfo/dam/kd/ERCOT Percent20Methodologies Percent20for Percent20Determining Percent20Ancillary Percent20ServicePercent 20Requir.zip
[121] The 886 MW represent LR participation in RRS capacity during the peak month of August 2011 across the peak hours (3-6 PM).

ERCOT-Table 3: Demand-Side Management

ERCOT-Summer	Short-Term 2013	2014	2015	2022	10-Year Change	2022 Share of Total Internal Demand
Direct Control Load Management (DCLM)	0	0	0	0	0	0.00%
Contractually Interruptible (Curtailable)	393	432	476	927	534	1.12%
Critical Peak-Pricing (CPP) with Control	0	0	0	0	0	0.00%
Load as a Capacity Resource	886	886	886	886	0	1.07%
TOTAL LOAD-MODIFYING DEMAND RESPONSE	1,279	1,318	1,362	1,813	534	2.20%
TOTAL ENERGY EFFICIENCY	240	366	498	1,506	1,266	1.83%
TOTAL DEMAND-SIDE MANAGEMENT	**1,519**	**1,684**	**1,860**	**3,319**	**1,800**	**4.02%**

Emergency Response Service (ERS, formerly known as Emergency Interruptible Load Service or EILS)[122] is designed to be deployed in the late stages of a grid emergency prior to shedding involuntary Firm load and represents contractually committed interruptible load.[123] Based on the results of the latest bid selection process, ERCOT planned to procure approximately 393 MW of ERS load for the 2013 summer peak. For the 10-year outlook, this procurement is expected to increase by 10 percent per year, reaching 927 MW by 2022. Measurement and verification procedures for the LRs and ERS programs are defined in the Performance Monitoring section of the ERCOT Protocols.[124]

In addition to these two Demand Response programs (LRs and ERS), several Transmission Service Providers (TSP) have their own contractual arrangements with loads that can respond to instructions to reduce their energy usage. The recent implementation of the Demand Response Availability System (DADS) will provide ERCOT better understanding regarding the expected magnitude of load MW in the TSP-based Demand Response programs. ERCOT is working to better coordinate activation of these loads included in the TSP Demand Response programs with ERCOT system operations.

Recent legislation requires utilities to provide Energy Efficiency programs sufficient to reduce their incremental peak demand growth by at least 20 percent each year. These programs include Low Income Weatherization, Energy Star (New Homes), Air Conditioning Efficiency Programs, Air Conditioning Installer Training, Retro-Commissioning, Hard-to-Reach, Load Management, Multifamily Water & Space Heating, Texas SCORE/City Smart, Trees for Efficiency, and Third Party. The incremental effect of this level of reduction is included as New Conservation (Energy Efficiency) in this assessment. The impact of current Energy Efficiency is reported to the PUCT on an annual basis. ERCOT does not verify or measure the impact of Energy Efficiency programs.

Utility savings, as measured and verified by an independent contractor, have exceeded the goals set by the utilities.[125] In a recent assessment, utility programs implemented after electric utility industry restructuring in Texas had produced 301 MW of peak demand reduction and 536 GWh of electricity savings for 2010.[126] This demand reduction is accounted for within the load forecast, and only the incremental portion, which is expected to increase from 240 MW in 2013 to 1,506 MW in 2022, is included as a demand adjustment for the summer seasons during the assessment period.

Generation

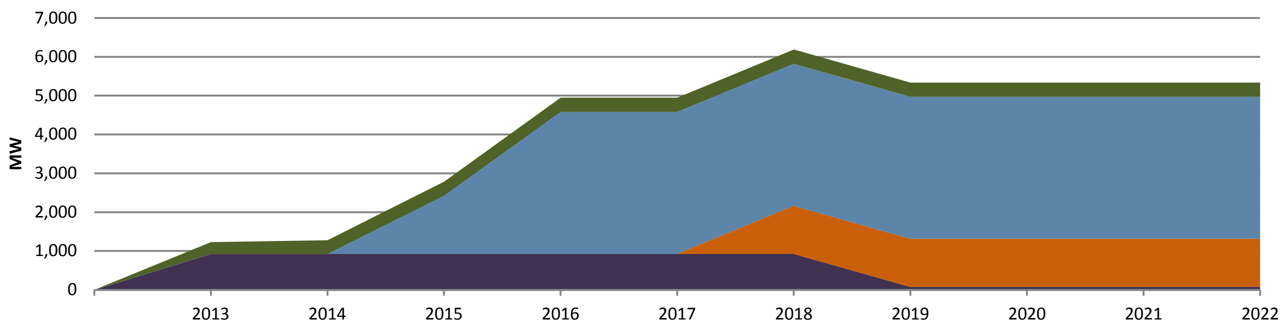
Existing-Certain generation capacity in ERCOT, as currently reported by the generation resource owners, is 73,018 MW (ERCOT-Table 4). The primary fuel sources for generation in ERCOT are natural gas and coal. Since the 2011 summer season, 1,597 MW of generation capacity has been added or will return to service. The generation capacity consists of 1,260 MW of gas generation (which includes 553 MW of mothballed units returned to service), 275 MW of coal generation, 35 MW of wind generation (with nameplate capacity of 402 MW), and 27 MW of solar generation. There are 2,962 MW of "switchable" generation that can operate in the ERCOT system or in the adjacent (not synchronously interconnected) Southwest Power Pool Region. ERCOT counts all of the switchable generation capacity as Existing-Certain capacity, except for 317 MW, which is obligated to serve load outside of ERCOT through the year 2020.

[122] Categorized as Contractually Interruptible (curtailable) Demand Response in this assessment.
[123] See Section 3.14.3 of the current ERCOT protocols:http://www.ercot.com/content/mktrules/nprotocols/current/03-051012_Nodal.doc
[124] http://www.ercot.com/content/mktrules/nprotocols/current/08-020111_Nodal.doc
[125] http://www.texasefficiency.com/images/documents/Publications/Reports/EnergyEfficiencyAccomplishments/eummotreport2010.pdf
[126] http://www.puc.state.tx.us/industry/projects/rules/38578/EUMMOT_EEIP_June_2_2011.pdf

ERCOT-Table 4: Capacity Outlook[127]

ERCOT-Summer	Current		2022 Planned			2022 Planned & Conceptual		
	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Coal	18,215	24.9%	18,290	23.3%	75	20,580	24.5%	2,365
Petroleum	138	0.2%	1,378	1.8%	1,240	1,378	1.6%	1,240
Gas	48,355	66.2%	52,012	66.4%	3,657	53,756	63.9%	5,401
Nuclear	5,150	7.1%	5,150	6.6%	0	5,150	6.1%	0
Other/Unknown	0	0.0%	0	0.0%	0	0	0.0%	0
Renewables	1,160	1.6%	1,525	1.9%	365	3,230	3.8%	2,070
TOTAL	**73,018**	**100.0%**	**78,355**	**100.0%**	**5,337**	**84,095**	**100.0%**	**11,076**

ERCOT-Figure 2: Summer Net Capacity Change



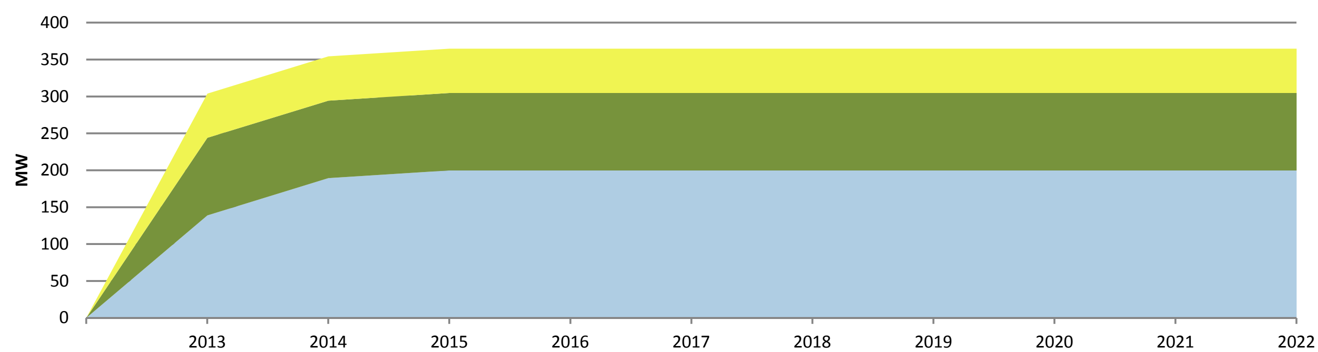
Before a new power project is included in reserve margin calculations, a binding Interconnection Agreement (IA) must exist between the resource owner and the Transmission Service Provider (TSP). Additionally, thermal units must have an air permit issued from the appropriate state and federal agencies specifying the conditions for operation. Future-Planned Resources expected through the assessment period (2013–2022) include 3,657 MW of gas-fired generation, 75 MW[128] of coal-fired generation, 1,240 MW of petroleum coke-fueled generation, 60 MW of solar generation, 105 MW of biomass generation, and 200 MW of on-peak wind generation (2,098 MW of wind derate on-peak). There is 1,224 MW of on-peak wind generation (11,260 MW of wind derate on-peak) considered as Conceptual capacity for the 2013-2022 assessment period (ERCOT-Table 5, ERCOT-Figure 2, ERCOT-Table 6, ERCOT-Figure 3, ERCOT-Table 6).

[127] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.
[128] Future-Planned coal unit retirements nearly offset Future-Planned unit additions, resulting in only 75 MW of added coal capacity by 2022.

ERCOT-Table 5: Renewable Capacity Outlook[129]

		Current		2022 Planned			2022 Planned & Conceptual		
ERCOT-Summer		Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Hydro		0	0.0%	0	0.0%	0	0	0.0%	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		873	75.3%	1,073	70.4%	200	2,297	71.1%	1,424
Biomass		213	18.4%	318	20.9%	105	318	9.8%	105
Solar		74	6.4%	134	8.8%	60	615	19.0%	541
TOTAL		**1,160**	**100.0%**	**1,525**	**100.0%**	**365**	**3,230**	**100.0%**	**2,070**

ERCOT-Figure 3: Summer Net Renewable Capacity Change



One 925 MW thermal generation project was expected to become available prior to the 2012 summer season. However, this project has been delayed and is now expected to be available in March 2013. ERCOT has been notified that the Cobisa-Greenville gas-fired plant (1,792 MW), tentatively scheduled to be on-line by 2016, has been indefinitely delayed. In addition, a gas plant that was expected to be on-line prior to the summer of 2014 has been delayed and is now expected in January 2015. 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.

ERCOT Table 6: Renewable Capacity Outlook: On-Peak Vs. Installed

	Current				2022 Planned			
ERCOT-Summer	Wind	Solar	Hydro	Biomass	Wind	Solar	Hydro	Biomass
Installed Capacity	10,035	74	544	213	12,333	134	544	318
On-Peak Derate	9,162	0	544	0	11,260	0	544	0
EXPECTED ON-PEAK OUTPUT	873	74	0	213	1,073	134	0	318

In order to gain additional insight into any impediments to investment in generation resources in ERCOT, the Region commissioned The Brattle Group to conduct a review of current market conditions and the impact on generation development.[130] The primary report high-level recommendations are for the Public Utility Commission of Texas (PUCT) and ERCOT to: (1) evaluate and define resource adequacy objectives for the BPS; and then (2) choose a policy path to meet those objectives, based on the advantages and disadvantages of each option identified. ERCOT has not been formally notified of any resource retirements, although one resource owner has publicly announced that they will retire the J.T. Deely coal-fired plant (845 MW) by the end of 2018. This expected retirement is included in this assessment.

Given the current market design, in which no party has a requirement to develop or maintain generation resources, ERCOT will study the potential impact of any announced unit retirements and will 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

[129] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.
[130] Operations and System Planning document titles "The Brattle Group Report": http://www.ercot.com/news/presentations/index#.

reliability and market impact 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.

There are no planned unit uprates or non-traditional resources included in the Future-Planned, Future-Other, or Conceptual resources. Several units with a total capacity of 553 MW that had been idled (or mothballed) by the respective owners have returned to service since last summer. As ERCOT has not been notified that these units will return back to mothballed status, the units are considered to be available throughout the assessment period. However, given that the units are older, less efficient, and previously determined not to be cost-effective by the owners, it is unlikely that these units will remain completely available throughout the assessment period. Essentially, the summer season appears to provide an economic viability opportunity for these units to return to service for the summer seasons but return to mothball status during off-peak periods.

Two storage facilities (76 MW of batteries considered as Conceptual resources) are currently being reviewed by ERCOT staff for possible interconnection before 2013. The facilities have publicly announced plans but have not completed the ERCOT process to be included in Planned or Existing-Certain Capacity categories.

ERCOT has a number of resources categorized as behind-the-meter (or Private-Use Network) generation. The capacity from these resources provided to the grid is assessed on a regular basis; operational data from the summer of 2011 indicates that these resources are able to provide 4,390 MW during peak hours. Previously ERCOT had surveyed behind-the-meter generation owners to determine what capacity may be available to the ERCOT grid, but ERCOT staff recently determined that using actual availability provided a more technically acceptable value. ERCOT will work with owners of behind-the-meter generation to ensure that changes in the aggregate capability of these resources are appropriately quantified in future resource assessments.

Of the Existing-Certain generation capacity, 108 MW is biomass and 74 MW is solar. ERCOT counts these resources as available on-peak. There are 544 MW of hydro generation capacity in ERCOT; internally (i.e., within ERCOT internal assessments) this capacity is expected on-peak but for this NERC assessment hydro generation capacity has been derated to zero (0) MW, as has been done historically. Of the 9,829 MW of existing wind generation capacity and 2,298 MW of Future-Planned wind generation capacity, 855 MW of Existing and 200 MW of Future-Planned is included in the expected on-peak resources, respectively. The currently approved Effective Load Carrying Capability (ELCC) of wind resources in ERCOT is 8.7 percent. The ELCC of wind generation is determined as part of the ERCOT Region Target Reserve Margin evaluation using a Loss of Load Probability Monte Carlo model.[131]

ERCOT has significant experience maintaining operational reliability with significant and increasing levels of interconnected variable generation. Using a combination of state-of-the-art wind generation forecasts and flexible levels of ancillary services, ERCOT will effectively manage available wind and solar generation to support system reliability utilizing current procedures. Continuing development of wind resources along the Texas coast, which exhibit generation patterns that are more correlated with summer peak loads than wind sited in inland western portions of Texas, is also expected to increase the overall reliability benefit from wind generation. An evaluation of possible differences in a locational-based wind ELCC is in progress.

With only 74 MW of registered solar resources in ERCOT (not including smaller solar resources that do not participate in the wholesale energy market) and only 60 MW of solar resources included in the Future-Planned Category, the variability of these resources will not adversely affect the reliability of the grid. As future solar generation becomes more prevalent in ERCOT, it will become necessary to develop an estimate of the ELCC of solar resources and to develop a process for forecasting solar resources.

[131] Item 14 documents located at http://www.ercot.com/calendar/2010/11/20101104-TAC give more details.

Less than 1 percent of the ERCOT generation capacity is hydro (544 MW). These facilities are typically operated as run-of-river or planned release due to downstream needs and not operated specifically to produce electricity. However, these resources may be available during peak conditions, either to provide energy or to provide ancillary services, ensuring units are available to provide energy to serve Firm load.

Capacity Transactions

ERCOT is a separate interconnection with only asynchronous ties to the Southwest Power Pool (SPP) and Mexico's Comisión Federal de Electricidad (CFE). ERCOT does not share reserves with other Regions. There are two asynchronous ties between ERCOT and SPP, providing a sum of 820 MW of transfer capability and three asynchronous ties between ERCOT and Mexico, with a total of 280 MW of transfer capability.

ERCOT 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. Under peak conditions for the assessment period, ERCOT is expected to have 458 MW of imports from SPP and 123 MW from CFE. Of the imports from SPP, 48 MW is tied to a long-term contract for a purchase of Firm power from specific generation. The remaining imports of 410 MW from SPP and 123 MW from CFE represent one-half of the asynchronous tie transfer capability, included to reflect emergency support arrangements. Total Firm imports amount to 598 MW throughout the 2013–2022 outlook (ERCOT-Table-7).

ERCOT-Table 7: Projected Capacity Transactions

ERCOT-Summer	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Expected Imports	0	0	0	0	0	0	0	0	0	0
Firm Imports	598	598	598	598	598	598	598	598	598	598
TOTAL IMPORTS	598	598	598	598	598	598	598	598	598	598
Expected Exports	0	0	0	0	0	0	0	0	0	0
Firm Exports	317	317	317	317	317	317	317	317	0	0
TOTAL EXPORTS	317	317	317	317	317	317	317	317	0	0
TOTAL NET CAPACITY TRANSACTIONS	**281**	**281**	**281**	**281**	**281**	**281**	**281**	**281**	**598**	**598**

Additional asynchronous tie capacity between ERCOT and other Regions is being developed by independent market participants. The Southern Cross[132] and the Tres Amigas[133] projects could add a combined 3,000–6,000 MW of import and export capacity between ERCOT and other Regions (SERC, WECC and SPP). Both of these projects are in the market subscription stage; if either project garners sufficient market subscriptions to become viable, a target project completion date will be set, additional studies regarding the impact of the project will be conducted, and the additional tie capacity will be included in future assessments.

Several SPP members own 317 MW of a power plant located in ERCOT, resulting in a Firm export of that amount from ERCOT to SPP. This contract is currently expected to terminate before the peak season of 2020. There are no known non-firm contracts signed or pending, or any other contracts that are known to be under negotiation or study (outside of the two projects described in the previous paragraph).

Transmission

There are currently 4,974 circuit miles of 345 kV transmission additions planned in ERCOT during the 2013–2022 assessment period. This total includes the transmission improvements designed to connect five designated Competitive Renewable Energy Zones (CREZ) in west Texas to major load centers in Texas.[134] The CREZ project alone includes more than 2,300 circuit miles of 345 kV transmission right-of-way. Six of the new rights-of-way will include series compensation, mostly located at intermediary substations. The CREZ project will include approximately 1,400 MVars of Static Var Compensators (SVC), 4,000 MVars of shunt reactors, and 1,000 Mvars of shunt capacitors. This project also includes upgrades of several circuits, many immediately west of Fort Worth and northwest of San Antonio, where the CREZ circuits

[132] http://www.southerncrosstransmission.com/project_documents/southern_cross_fact_sheet.pdf
[133] http://www.tresamigasllc.com/index.php
[134] http://www.texascrezprojects.com/default.aspx

connect with existing infrastructure. All of these improvements are scheduled to be completed by the end of 2013. It is expected that these new and upgraded circuits will eliminate the existing West-to-North Dynamic Stability limit, which limits power flows from the West Zone to the North Zone. ERCOT is reviewing the proposed configurations to see if new interface limits may occur during and after the CREZ line construction.

Existing and projected transmission lines for the ERCOT Assessment Area are as follows (ERCOT-Table 8):

ERCOT-Table 8: Existing and Projected Transmission

ERCOT	AC(Circuit Miles)	DC(Circuit Miles)	Total(Circuit Miles)
EXISTING	29,465	0	29,465
Currently Under Construction	946	0	946
Planned - Completed within First Five Years	4,757	0	4,757
Planned - Completed within Second Five Years	29	0	29
2022 TOTAL (UNDER CONSTRUCTION & PLANNED)	35,197	0	35,197
Conceptual - Completed within First Five Years	800	0	800
Conceptual - Completed within Second Five Years	391	0	391
2022 TOTAL (UNDER CONSTRUCTION, PLANNED & CONCEPTUAL)	**36,388**	**0**	**36,388**

A new 345 kV transmission line with series compensation is planned to connect the Laredo Area with the Lower Rio Grande Valley Area. The line will support the high load growth projected for the Lower Rio Grande Valley Area, as well as provide longer-term benefits for the Laredo Area. It is projected to be in service by the summer peak of 2016. This project will increase the limit of power flows between the rest of ERCOT and the Lower Rio Grande Valley region.

Current transmission plans during the assessment period include the installation of thirty-four 345/138 kV autotransformers to support load growth and the reliability of the ERCOT Interconnection.

There is a transmission constraint commonly referred to as the North-to-Houston Voltage Stability Limit and considered an Interconnection Reliability Operating Limit (IROL) that is managed daily. At this point, there has been no information regarding the future mitigation of that IROL. ERCOT is reviewing the September 8, 2011 Southwest Blackout Event[135] recommendations to determine whether any procedural changes may be necessary regarding IROL identification, as well as other aspects of the report.[136] ERCOT does not have any additional transmission constraints that are expected to significantly impact reliability.

A major planned circuit connecting the Fayetteville and Zenith substations (west of Houston) has been cancelled. This project was endorsed by ERCOT in 2010 based on aggregate reduction of market prices due to reduced congestion into the Houston Area. This project was not required in order to maintain adequate system reliability. Following project endorsement, the PUCT changed the economic planning criteria for transmission in ERCOT, eliminating the consideration of market prices from the process. This change resulted in the cancellation of the Fayetteville to Zenith project. ERCOT planning studies will continue to review the possible need for additional transmission projects in and around the major load centers, including Houston.

No project delays or long-term outages that are expected to affect system reliability are known at this time. Outage analysis in the Operations Planning and Operations horizons ensure that system outages, transmission or generation, are only taken if they do not compromise system reliability.

ERCOT ensures that adequate transmission is planned and constructed to support new generation and increasing loads through a coordinated planning process, including long-range studies, mid-term transmission planning, and stability analyses over a range of planning horizons and system conditions. The ERCOT Five-Year Transmission Plan study[137] and

[135] http://www.ferc.gov/legal/staff-reports/04-27-2012-ferc-nerc-report.pdf.
[136] Recommendations in Appendix B starting on page 116 of the report located at http://www.nerc.com/files/AZOutage_Report_01MAY12.pdf
[137] This study is not available to the public. A description of the process used to develop this study is included within the "ERCOT Regional Planning Group – Chapters and Procedures." http://www.ercot.com/content/committees/other/rpg/keydocs/2012/RPG_Charter_and_Procedure_20090716_Approved.pdf.
Charter and Procedures

additional voltage stability studies through the 2015 summer peak network conditions identify limiting elements under contingency. Based on the results of these studies, ERCOT proposes projects as needed to mitigate any system deficiencies.

Reactive margins are analyzed in the planning horizon. In the operating horizon, reactive margins are maintained in the major metropolitan areas through real-time analysis. Areas of dynamic and static reactive power limitations are Corpus Christi, Houston, Dallas/Fort Worth, and Lower Rio Grande Valley. Operating Procedure Manual for the Transmission and Security Operating Procedure 6.1, Voltage Control, describes the procedure to monitor the system and to prevent voltage collapse using an on-line voltage stability analysis tool.[138]

ERCOT plans for a 5 percent voltage stability margin for NERC Category B contingencies and a 2.5 percent margin for NERC Category C contingencies.[139] ERCOT planning criteria are intended to maintain sufficient dynamic reactive capability to maintain system voltages within the range for which generators are expected to remain on-line. Potential problems are reported to ERCOT System Planning and the affected Transmission Planners (TPs) to develop corresponding transmission projects to resolve the lack of voltage stability margin and to Transmission Operators for their reassessment for the operating horizon.

Significant substation equipment installed or planned for the ERCOT Region includes:

- 300 Mvar Static Var Compensator (SVC) at the Tesla 345kV Station (CREZ-related)
- 2 x 300 Mvar SVC at the Brown 345kV Station (CREZ-related)
- 300 Mvar SVC at the Parker 345kV Station (CREZ-related)
- 200 Mvar SVC at Hamilton 138kV Station (CREZ-related)

Vulnerability Assessment

Given recent rainfall, drought conditions in ERCOT are significantly less severe than they were in 2011. There are no immediate concerns regarding the impact of reduced water levels or increased water temperatures on generation resources. However, ERCOT continues to work with resource owners to closely monitor the availability of water resources at generating plants. ERCOT is also working with several national laboratories on an analysis of the potential impact of a multi-year sustained drought on system needs as part of the long-term transmission planning process. The results of this analysis will be included in the internal ERCOT Long-Term System Assessment scheduled to be completed in December 2012.

Unit outages are reviewed and approved or denied in the outage scheduling process. In addition, as part of the analysis of the impact of changing environmental regulations, ERCOT is working directly with resource owners to assess the potential impact of extended outages to install additional emissions control technologies. At this time, there are no known extended outages that are expected to have an impact on system reliability. This is primarily due to regulatory uncertainty and the required analysis that will need to be completed to determine the affected unit economic viability.

The Renewable Portfolio Standard (RPS)[140] for Texas (including areas of Texas that are outside of ERCOT) is 5,880 MW of installed renewable capacity by 2015 and 10,880 MW of installed capacity by 2025. Each entity that serves load is required to obtain sufficient renewable energy credits from renewable resource owners (one credit for each megawatt produced from a renewable resource) to represent their market share of energy sales times the renewable capacity goal. The 2025 target has already been met. These targets may be changed by the state legislature, which convenes at the start of every odd-numbered year.

A wind integration study completed for ERCOT in 2008 indicated that the current nodal operating procedures, with purchases of suitable amounts of ancillary services, would be appropriate for levels of integrated wind generation capacity

[138] http://www.ercot.com/content/mktrules/guides/procedures/Transmission Percent20and Percent20Security Percent20Operating Percent20Procedure Percent20V1Rev16.doc
[139] See Section 4.1.1 of the ERCOT Planning Guides: http://www.ercot.com/content/mktrules/guides/planning/current/04-090111.doc
[140] http://www.puc.state.tx.us/rules/statutes/Pura09.pdf; Section 39.904

up to 15,000 MW. This level is greater than the current RPS targets, even for 2025, and greater than the amount of wind capacity in the Existing-Certain and Future-Planned categories. ERCOT has implemented a wind power forecasting system to allow ERCOT system operators to identify and take appropriate action when wind resource schedules may not track expected changes in wind production. ERCOT has also implemented a wind ramp forecasting tool that provides a probabilistic assessment of the magnitude and likelihood of a significant change in aggregate wind output over upcoming operating periods. In addition, ERCOT evaluates the impact of increased installed wind generation on ancillary services requirements on an ongoing basis.[141]

Levels of solar resources currently in the interconnection queue are unlikely to have an adverse impact on system reliability. ERCOT works with market stakeholders to ensure that procedures and processes are sufficient to reliably integrate variable resources through operating practices. The Emerging Technologies Working Group has been established to track issues[142] and make recommendations regarding the integration of new technologies, particularly variable resources.

There are no anticipated reliability concerns resulting from unresponsive or unavailable Demand Response. There are specific measurement and verification procedures for the coordinated Demand Response programs.[143] Both LRs and ERS products are subject to unannounced load-shed testing, to be followed by an additional test if the first is unsuccessful. A second consecutive unsuccessful test subjects the resource to suspension. In addition, these resources are monitored using after-the-fact metering and are subject to payment reductions and suspension from the program for failing to meet availability requirements.

These Demand Response programs (LRs and ERS) are utilized in the event of a sudden loss of generation (LRs) or in the event of an imminent shortage of system-wide generation (LRs and ERS). Response from these resources has been satisfactory in previous events in which they were utilized.

Similarly, there are no expected reliability concerns related to high levels of Demand Response resources. ERCOT currently limits the Demand Response participation of LRs at 50 percent of the hourly RRS procurement, for which the minimum requirement is 2,800 MW. This participation limit is reviewed on a regular basis. LRs are deployed automatically via Under Frequency Relays in response to frequency excursions below 59.7 Hz or through manual deployment during system emergencies such as Energy Emergency Alerts.

There are no anticipated reliability concerns with distributed resource integration at this time.

ERCOT plans grid enhancements as needed on a continuous basis and does not plan for additional Under-Voltage Load Shedding (UVLS) schemes as a reliability tool. UVLS deployments are intended to provide a “safety net” in case other operating actions are not sufficient to resolve under-voltage problems. UVLS schemes generally are not relied upon to maintain the overall system stability following NERC Category B and C events,[144] and system reinforcements may be made to limit the amount of load shed that may occur under certain NERC Category D events.

ERCOT works with transmission service providers to minimize the use of Special Protection Systems (SPS) and Remedial Action Plans (RAP).[145] When utilized, these measures will improve rather than adversely impact system reliability and possibly reduce system costs. These measures are typically designed to be temporary—utilized only until a system improvement eliminates the need for the SPS or RAP.[146]

[141] http://www.ercot.com/content/mktinfo/dam/kd/ERCOT Percent20Methodologies Percent20for Percent20Determining Percent20Ancillary Percent20Service Percent20Requir.zip
[142] http://www.ercot.com/content/meetings/tac/keydocs/2010/1104/15._ETIP_draft_v10_102210.doc
[143] As defined in the Performance Monitoring section of the ERCOT Protocols. (http://www.ercot.com/content/mktrules/nprotocols/current/08-020111_Nodal.doc).
[144] http://www.nerc.com/page.php?cid=2|20.
[145] A RAP is a predetermined operator action to maintain reliability in a defined adverse operating condition. See Section 4.3.1 of the ERCOT Operating Guides for additional information: http://www.ercot.com/content/mktrules/guides/noperating/current/04-121411.doc
[146] A list of current SPSs and RAPs in ERCOT is available on the ERCOT website: https://mis.ercot.com/pps/tibco/mis/Pages/Grid+Information/Long+Term+Planning

ERCOT works with transmission service providers to develop options in the event of large emergencies. As an example, areas where load transfers can be implemented are reviewed on an ad hoc basis, and in some cases additional transmission equipment to allow such block-load transfers has been installed. Additionally, transmission service providers supply ERCOT with a list of NERC Category D contingencies, which are studied annually.

ERCOT is working with transmission service providers and university researchers to evaluate ways to utilize Phasor Measurement Unit (PMU) data. Current initiatives seek to utilize PMU data to validate aspects of planning stability models and to increase real-time operational awareness.

There are currently over 4.4 million advanced meters being used for customer load settlement in the ERCOT Region. Retail electric service providers are beginning to provide time-of-use rates, although at this point most of these offerings are simply two or three different periods in a day. The potential exists for these load resources to grow into an aggregate size that has an impact on market prices and system reliability. ERCOT will continue to coordinate with the PUCT, with transmission service providers, and retail electric service providers to forecast the potential impact associated with the advanced meter data use, and to quantify the participation of market-driven customer Demand Response in real-time operations.

ERCOT has Operating Guides to address relay misoperations and the defined requirements for registered entities to follow in the event of relay misoperations. Registered entities are required to follow TRE's procedure for misoperations as well. In addition, ERCOT has established the System Protection Working Group, made up of ERCOT market participants with knowledge of relay operations, to investigate relay misoperations and disseminate lessons learned.

ERCOT continues to review the potential impact of changing environmental regulations on system reliability. ERCOT is coordinating directly with resource owners to understand their individual compliance strategies and to aggregate these activities to evaluate the system-wide impact. It is unknown at this time if the recently finalized Mercury and Air Toxics Standard (MATS) will result in retirement of existing coal-fired capacity or if existing coal-fired generation capacity will be retrofitted with additional emissions control technologies. Because the Cross-State Air Pollution Rule (CSAPR) was stayed prior to implementation, and the EPA proposed rule revisions that may or may not be implemented depending on the ruling of the D.C. Court of Appeals, it is not known if the CSAPR predecessor, the Clean Air Interstate Rule (CAIR), will have a near-term impact on available resources. However, the combined impact of sustained low natural gas prices, current economic and market conditions, regulatory uncertainty, and other environmental regulations could result in decisions by resource owners to retire units. If these decisions are made in a time frame that does not allow for market investment in new generation resources, overall system reliability will be adversely affected.

Representatives of the Texas Commission on Environmental Quality (TCEQ)[147] have informed ERCOT that the emissions requirements in the MATS rule for Future-Planned and Conceptual solid-fuel units are more stringent than those included in recently finalized air permits for several new plants. This discrepancy could force these new units to reapply for air permits and could result in project delays or cancellations.

A review of the impact of proposed environmental regulations on the ERCOT system completed in June 2011 noted the potential impact of upgrade requirements on old gas-steam generation units.[148] As these units are only utilized during peak load conditions, they do not generate sufficient revenue to warrant even minor capital additions. As a result, any retrofit requirement (such as potential entrainment/impingement limitations resulting from proposed Clean Water Act Section 316 (b) implementation) could lead to significant retirements of gas-steam units. The report cited above noted as much as 9,800 MW of vulnerable generation capacity. Much of this generation is located in or near urban centers; retirement of these units would result in a need for new generation and, potentially, new generation and transmission to increase import

[147] http://www.tceq.state.tx.us/.
[148] http://www.ercot.com/content/news/presentations/2011/ERCOT_Review_EPA_Planning_Final.pdf

capability into these affected load centers. Redevelopment of existing brownfield generation facilities could reduce the need for new transmission, but such redevelopment could be hindered by limited existing gas pipeline infrastructure and by air quality permitting requirements.

ERCOT recently commissioned Black and Veatch to conduct a review of the potential impact of gas curtailment on the ERCOT grid.[149] The study indicates a significant amount of redundancy and robustness in gas supply to generation facilities. While the greatest risk to generation loss was found to be the result of freezing weather, even in extreme weather the regional pipeline capacity was found to be adequate to meet current generation demands.

Plans for Accommodating Generator Retirements and Environmental Control Retrofits

Each individual generator owner/operator has to evaluate the environmental regulations to determine their applicability and the risk and impact to specific sites. If there is an impact noted a financial evaluation of the various options available to the owner/operator (e.g. wet limestone scrubber, dry sorbent injection, selective non-catalytic reduction, closed-loop cooling tower, baghouse, etc) would occur. Additional in-depth review of near- and long-term markets and the companies individual strategies associated with those markets would need to occur to evaluate economic viability. At this point, no resources owners have informed ERCOT of the need to retrofit or retire existing generation in order to comply with recently finalized environmental regulations. ERCOT performed two assessments of the potential impacts of environmental regulations on resources. Reports describing the methodologies and results of these studies are available on the ERCOT web site[150,151]. The reports assess the potential impacts of environmental regulatory changes based on ERCOT reviews of published nation-wide impact studies of the proposed regulations. In addition, ERCOT met with environmental experts from several of the generating entities in the ERCOT Region. Using information obtained from these reviews, ERCOT developed scenarios based on likely compliance requirements and future market conditions and evaluated the economic value of affected generating units. It should be noted that there is a great degree of uncertainty in the environmental regulation implementation horizon that hinders efforts to develop firm plans for resource owners and ERCOT.

ERCOT has not recently formally received nor requested any updated specific plans from generator owner/operators to achieve compliance with the environmental standards. Some owners have informally noted that compliance will be achieved through low capital cost plant changes and fuel switching. As noted in an ERCOT assessment[152], the compliance requirements of the regulations and the compliance schedules will have a significant impact on system reliability.

ERCOT has not recently received nor requested any specific plans to achieve compliance with the environmental standards. There is a general concern by Texas RE that lack of sufficient planning, largely due to uncertainty regarding the environmental regulations, by and between the generator owners/operators and ERCOT, may result in a significant demand on internal and external personnel resources and, possibly, equipment necessary to provide compliance.

The installation of environmental controls or other facility enhancements may require an extended outage for each associated generating unit. If the compliance schedule to implement the solutions is overly restrictive, a significant number of units may request to be unavailable at the same time, possibly resulting in ERCOT not being able to approve all the outages necessary and still maintain system reliability. As was shown in December 2011, when Luminant announced the idling of coal-fired Monticello Units 1 and 2[153] due to CSAPR, ERCOT study methodologies indicated that the units were not required for transmission reliability but could cause ERCOT to drop below its Target Reserve Margin. ERCOT decisions avoided subjecting Luminant to possible litigation as a result of probable EPA regulation violations by not finding the Luminant units necessary to maintain reliability of the ERCOT Interconnection. The finding followed the current local rules associated with determining "reliability must run" unit designation and there have been limited changes to those rules

[149] http://www.ercot.com/content/news/presentations/2012/BV Percent20ERCOT Percent20Gas Percent20Study Percent20Report Percent20March Percent202012.pdf
[150] http://www.ercot.com/content/news/presentations/2011/ERCOT_Review_EPA_Planning_Final.pdf
[151] http://www.ercot.com/content/news/presentations/2011/ERCOT_CSAPR_Study.pdf
[152] http://www.ercot.com/content/news/presentations/2011/ERCOT_Review_EPA_Planning_Final.pdf
[153] http://www.luminant.com/news/spotlight/detail.aspx?FtID=23

since December 2011. However, ERCOT rules were changed to allow ERCOT to recall "mothballed" units for imminent emergencies. In August 2012 Luminant provided a suspension of operations notice to ERCOT indicating that the Monticello Units 1 and 2 would be offline starting December 2012 for a minimum of six (6) months and no more than seven (7) months due to low energy prices within the ERCOT market not environmental regulations. ERCOT subsequently removed the units from the preliminary Seasonal Assessment of Resource Adequacy for the ERCOT 2012/2013 winter[154].The spring and early summer of 2013 will help ERCOT evaluate impact on the system of an unexpected extended outage above and beyond what normally may occur.

Since there have been no retirement announcements transmission needs have not been identified at this time. However, even at system reserve margin levels at or near the current Target Reserve Margin for ERCOT of 13.75 percent, it is possible that unit retirements could result in significant local congestion. Generation within urban load centers can be operated during peak load periods to limit the amount of power provided by distant generation. The retirement of intra-urban generation resources would result in the need to import more power to serve load, leading to potential overloads and increased reactive power requirements. Given the locations of the potential generation retirements caused by the pending regulations, the two areas of specific concern for transmission reliability are the Dallas/Fort Worth region and the Houston region. A detailed study would be required in order to determine the most cost-effective improvements to maintain transmission system reliability in the ERCOT Region following a significant retirement of generation capacity.

At this point, with limited information available, it is not known whether any possible projects will be completed by 2016. An evaluation of each unit retirement will need completion to determine if a project is needed and what project timeframe will be required. One Transmission Operator in the ERCOT Region, ONCOR, has recently adjusted its planning criteria to accommodate the possibility of no generation being available at an entire site regardless of the reason (market or environmental reasons)[155]. Although not specifically related to the pending environmental regulations, the ONCOR idea addresses the impact of generation loss in an area that results in transmission upgrades and is viewed as a positive proactive planning step in the right direction to address possible issues with environmental regulation impacts. The ONCOR plan to mitigate the congestion condition extends to 2018.

The Public Utility Commission of Texas is currently reviewing additional options to incentivize generation to be built within the ERCOT Region.[156,157] There have been some recent rules changes but more efforts are ongoing to reach the full potential of options.

No announcements have been made by resource owners in the ERCOT region regarding plant retrofits or retirements of resources due to recently finalized environmental regulations.

As noted above, ERCOT has completed two assessments of the potential system impacts due to environmental regulations. Texas RE affirms that ERCOT needs to coordinate more aspects of the environmental impacts, such as outage coordination, internal and external personnel constraints, and, possibly, equipment availability constraints with resource owners to fully understand the developing compliance strategies, and to assess impacts of these compliance actions on grid operations and resource adequacy. Texas RE will monitor ERCOTs progress as the regulatory uncertainty is further clarified and refined.

Standing and Emerging Reliability Issues

Environmental Regulations

The impact of environmental regulations on the ERCOT system was delayed due to the court stay of the Cross-State Air Pollution Rule (CSAPR). Without that stay, the regulations likely would have affected system reliability in 2012. At this point

[154] http://www.ercot.com/content/news/presentations/2012/SARA-Winter2012-13_Preliminary.pdf
[155] http://www.ercot.com/content/meetings/rpg/keydocs/2012/0817/OncorERCOTRPGOdessaNPresentation08172012.pdf
[156] http://www.ercot.com/content/news/presentations/2012/The%20Brattle%20Group%20Presentation%20for%20PUCT%20July%2027%202012%20Work.pdf
[157] http://interchange.puc.state.tx.us/WebApp/Interchange/application/dbapps/filings/pgControl.asp?TXT_UTILITY_TYPE=A&TXT_CNTRL_NO=40000&TXT_ITEM_MATCH=1&TXT_ITEM_NO=&TXT_N_UTILITY=&TXT_N_FILE_PARTY=&TXT_DOC_TYPE=ALL&TXT_D_FROM=&TXT_D_TO=&TXT_NEW=true

the CSAPR predecessor, CAIR, impacts have not been fully evaluated. The Mercury and Air Toxics Standard (MATS) required compliance by 2015 (or within two years of that date with possible compliance extensions). Other regulations (Clean Water Act (Section 316(b)), Coal Combustion Residuals Disposal (CCRD)) may take effect later in this decade.

The impact of proposed environmental regulation on resource adequacy is a standing reliability issue of national interest that has been studied by NERC, ERCOT, and other concerned stakeholders. 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, , and the Coal Combustion Residuals Disposal, as well as the existing CAIR regulations may require retrofits or upgrades or otherwise increase production costs to a point at which retirement of those units may be more plausible than continued operation.

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 that unit. Preliminary ERCOT studies for the impact of EPA regulation, not including CSAPR, suggest that 9,800 MW of legacy gas units are at highest risk of accelerated retirement. The combined impact of sustained low natural gas prices, the CAIR, MATS rule, and other regulatory uncertainty may result in the retirement of solid-fuel units as well.

Accelerated generation retirements without accelerated development of new generation resources will further decrease the Reserve Margin within ERCOT. The Reserve Margin in ERCOT is forecast to fall below the required 13.75 percent level in 2013 even without these accelerated retirements.

Preliminary ERCOT studies, which were performed prior to the issuance and subsequent vacating 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 emissions 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 likely to see less-than-favorable economics for continued operation. ERCOT studies suggest that over 9,800 MW of gas-fired generation near or around the Dallas and Houston Areas may be affected by EPA regulations including Section 316(b) of the Clean Water Act. In addition, ERCOT completed an assessment of the proposed inclusion of Texas in the CSAPR. The assessment found that, if the rule were 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. If potential retirements occur as projected in various ERCOT studies, reactive support and/or new import paths will be required in the Dallas/Fort Worth and Houston metropolitan areas.

As potential retirements occur as forecast in ERCOT studies, and market conditions do not attract incremental or replacement generation, then Reserve Margins within the ERCOT Region will not be satisfactory during the 10-year horizon. The PUCT has held a number of workshops and regulatory discussions regarding resource adequacy. Redevelopment of existing generation sites would be likely to minimize the need for additional transmission investment. However, many legacy gas plants are located within EPA air quality non-attainment zones. In addition, pipeline requirements of new generation may exceed the capability of pipeline infrastructure at legacy gas plant locations.

If potential retirements occur as forecast in ERCOT studies and incremental or replacement generation is not constructed, then ERCOT will face lower Reserve Margins, decreased ramping capability, and increased transmission congestion. The unavailability of generation due to 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 are implemented.

It is not clear when resource owners will finalize their compliance strategies due to the uncertainties in the implementation of environmental regulations and the need to verify the effectiveness of available environmental control technologies to the final approved regulations; until these compliance strategies are evaluated in aggregate, the impact 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 4^{th}- or 5^{th}-year extensions. It is unknown how changing market dynamics will affect compliance strategies.

The proposed EPA regulations (Clean Water Act Section 316 (b), MATS, and CCRD) have the potential to expedite retirement of legacy generation units and exacerbate resource adequacy issues in ERCOT over the next 10 years.

These regulations may reduce the economic viability of coal facilities with higher emissions rates and over 9,800 MW of legacy gas generation. From a transmission perspective, these potential generation retirements would require new import paths and significant reactive support in the Dallas/Fort Worth and Houston metropolitan areas. From an operational perspective, accelerated retirements, as modeled, would further impact the Planning Reserve Margin shortfall in the ERCOT Region over the assessment period (currently projected to fall below the required 13.75 percent in 2013 without any additional retirements).

Operating Variable Resources

Following the designation of Competitive Renewable Energy Zones (CREZ) and completion of the transmission improvements to serve these areas, the trend of rapid development of renewable energy resources within ERCOT is likely to continue over the next 10 years. Operating the system with increasing amounts of renewable energy presents reliability challenges in longer-term horizons.

Reliable system operation with increasing amounts of renewable energy is a standing issue. This issue has become a core issue in ERCOT. The Emerging Technologies Working Group has developed a process that tracks issues and their solutions associated with renewable integration on an ongoing basis.[158] This issue was also addressed in a study performed by General Electric: ERCOT Wind Impact/Integration Analysis.[159]

The resource mix in the LTRA will change with increasing amounts of renewable energy resources. These variable resources present a range of issues that can affect reliability, including changes to load-serving requirements for dispatchable generation (net load patterns may be different from historical load patterns); the impact on system forecasting capabilities; and system stability impact. Variable generation can be highly locational, often resulting in the need to move power a significant distance from generator to load.

Within the 10-year horizon, ERCOT may have to modify its ancillary services procurement practices and its reliability unit commitment procedures. New ancillary services may need to be developed. Generation resources that may not be needed for a significant amount of energy across the year may need reliability-must-run arrangements to support system reliability. However, these process changes will not be required to integrate renewable resources. Based on the study completed in 2008, at least 3,000 MW of additional wind generation beyond Existing Certain and Future-Planned projections would be required in order for these changes to be necessary or cost-effective.

Increasing amounts of renewable energy may require additional regulating capacity including, but not limited to, increased system ramping capability, additional resources, or both to maintain system frequency in real time.

Studies are required to determine if additional thermal resources will need to be committed, or if alternative transmission improvements are necessary to ensure reliable integration of increasing amounts of renewable energy resources. The studies will be completed by ERCOT staff and ERCOT stakeholders as more renewable resources are projected to be added to the system.

[158] http://www.ercot.com/gridinfo/etts/.
[159] http://www.ercot.com/content/news/presentations/2008/Wind_Generation_Impact_on_Ancillary_Services_-_GE_Study.zip.

Currently, localized congestion and Special Protection Systems within generation “pockets” of renewable energy can cause the curtailment of otherwise economic renewable energy. The CREZ process resulted in plans for a 345 kV transmission infrastructure to support the delivery of over 18,000 MW of energy. These transmission circuits are scheduled to be completed by the end of 2013.

Variable generation is typically highly locational. Specifically designed transmission improvements are usually required to move renewable energy from resources to load. The CREZ transmission plan includes over 2,300 new miles of 345 kV right-of-way, 1,400 Mvars of SVCs, 4,000 Mvars of shunt reactors, and approximately 1,000 Mvars of shunt capacitors. This transmission infrastructure is designed to support the delivery of over 18,000 MW of renewable wind energy.

Real-time energy balance and frequency maintenance with an increasing proportion of wind energy and other intermittent resources on the ERCOT system will require updated or revised ancillary service requirements. The GE study indicates that current operations processes and practices are adequate for wind levels up to approximately 15,000 MW. The report conclusions state that beyond that amount, a thorough review of operations practices will likely be required to minimize system costs while maintaining adequate system reliability. The impact of increased solar integration has not been assessed.

The diversity benefits from integration of wind resources in the Texas Panhandle (the northernmost CREZ) are unknown. It is unknown if solar resources will be more prevalent in the urban centers, near the load, or in extreme western and southwestern Texas, where solar insolation can be as much as 30 percent greater.

The ERCOT Region, with almost 10,000 MW of wind generation installed and an additional 2,000 MW currently planned (based on current interconnection agreements) over the next 10 years, must continue to refine its planning and operational procedures to ensure reliable integration of renewable resources. The CREZ, currently under construction, was designed to have adequate transmission capacity for 18,000 MW of renewable energy. As CREZ reaches its designed capacity for renewable resources, ERCOT will continue to monitor the adequacy of its balancing and ancillary service procurement process under increasing proportions of renewable energy to load. ERCOT currently has less than 100 MW of large-scale solar generation. Further study of the expected impact of solar development is required.

FRCC

Planning Reserve Margins

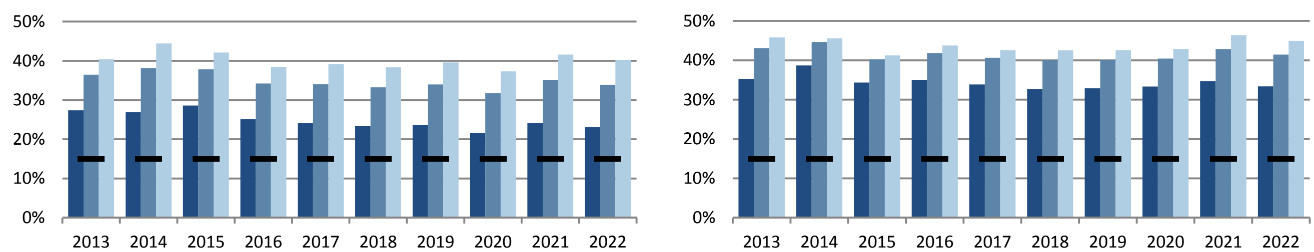
FRCC is projecting adequate Planning Reserve Margins throughout the assessment period (2013–2022). The NERC Reference Margin Level of 15 percent (FRCC-Table 1 and FRCC-Figure 1)[160] was established by FRCC for the entire Region for the entire assessment period. Based on the expected load and generation capacity, the calculated reserve margin is above the NERC Reference Margin Level percent for all summer seasons when demand response (load management and interruptible loads) are treated as load-modifying.

FRCC-Table 1: Planning Reserve Margins

FRCC-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		27.37%	26.88%	28.62%	25.08%	24.12%	23.33%	23.60%	21.58%	24.17%	23.06%
PROSPECTIVE		36.46%	38.18%	37.85%	34.21%	34.06%	33.24%	33.95%	31.76%	35.16%	33.90%
ADJUSTED POTENTIAL		40.42%	44.44%	42.13%	38.46%	39.20%	38.36%	39.60%	37.32%	41.59%	40.25%
NERC REFERENCE	-	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**

FRCC-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		35.26%	38.69%	34.33%	35.04%	33.85%	32.73%	32.89%	33.31%	34.72%	33.37%
PROSPECTIVE		43.13%	44.67%	40.28%	41.86%	40.64%	40.04%	40.11%	40.44%	42.88%	41.45%
ADJUSTED POTENTIAL		45.83%	45.61%	41.26%	43.77%	42.57%	42.54%	42.58%	42.88%	46.42%	44.95%
NERC REFERENCE	-	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**

ERCOT-Figure 1: Summer (Left) and Winter[161] (Right) Planning Reserve Margins



A rebound in the economy could potentially increase the demand, energy, and load projections that would realign them with previously reported projections. There is also potential for the passage of pending environmental or regulatory regulations that lead to timing challenges in the retrofitting or building of replacement generation. Unit retirements caused by challenges in complying with environmental rules or other reasons, could result in unscheduled generation outages and corresponding reductions in Planning Reserve Margins.

Demand

The 10-year demand forecast for FRCC is projected to have a CAGR of 1.43 percent (FRCC-Table 2). This outlook is similar to the 2011 forecast, with projected population growth essentially negated by ongoing impacts from the recent economic recession and increased federal and state Energy Efficiency standards.

[160] The FRCC target is 20 percent for Investor-Owned Utilities.

[161] Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.

FRCC-Table 2: Demand Outlook

FRCC-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	43,041	48,923	5,882	13.7%	1.43%
Load-Modifying Demand Response	3,229	3,660	431	13.3%	1.40%
TOTAL INTERNAL DEMAND	**46,270**	**52,583**	**6,313**	**13.6%**	**1.43%**

FRCC-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	43,049	48,656	5,607	13.0%	1.37%
Load-Modifying Demand Response	3,318	3,752	434	13.1%	1.38%
TOTAL INTERNAL DEMAND	**46,367**	**52,408**	**6,041**	**13.0%**	**1.37%**

Overall projections of load growth for most entities remain at levels below earlier forecasts. The *2012 Annual Energy Outlook* from the U.S. Department of Energy's Energy Information Agency (EIA) indicated that recovery from the recent recession will exhibit the weakest growth of any since 1960.[162] As such, near-term increases in demand are not expected to realign with the more robust projections that were anticipated in projections made prior to the 2008 economic recession.

Load growth across individual Load Serving Entities (LSEs) in the Region is proportional with the level of load growth seen across the FRCC Assessment Area.

Demand-Side Management

The 2013 summer Net Internal Demand (NID) forecast includes the effects of 3,229 MW of potential demand reductions from the use of load management (2,616 MW) and interruptible demand (613 MW).

The 2022 summer NID forecast includes the effects of 3,660 MW of potential demand reductions from the use of load management (3,028 MW) and interruptible demand (632 MW). Load management is projected to increase at a steady rate of 50 MW per year over the forecast horizon, while interruptible demand is projected to essentially remain constant (FRCC-Table 3).

FRCC-Table 3: Demand-Side Management[163]

FRCC-Summer	Short-Term 2013	Short-Term 2014	Short-Term 2015	2022	10-Year Change	2022 Share of Total Internal Demand
Direct Control Load Management (DCLM)	2,616	2,669	2,720	3,028	412	5.76%
Contractually Interruptible (Curtailable)	613	570	579	632	19	1.20%
Critical Peak-Pricing (CPP) with Control	0	0	0	0	0	0.00%
Load as a Capacity Resource	0	0	0	0	0	0.00%
TOTAL LOAD-MODIFYING DEMAND RESPONSE	3,229	3,239	3,299	3,660	431	6.96%
TOTAL ENERGY EFFICIENCY	303	461	617	1,443	1,140	2.74%
TOTAL DEMAND-SIDE MANAGEMENT	**3,532**	**3,700**	**3,916**	**5,103**	**1,571**	**9.70%**

All Load Serving Entities (LSE) within FRCC treat Demand Response as load-modifying and not as a capacity resource. Demand reduction is used primarily to shave the peak demand.

There is currently no Renewable Portfolio Standard (RPS) in Florida. A draft rule was submitted by the Florida Public Service Commission staff to the Florida Legislature for consideration;[164] however, the Florida Legislature has not established Renewable Portfolio Standards in Florida.

There are a variety of Energy Efficiency programs implemented by entities throughout FRCC. These programs can include commercial and residential audits (surveys) with incentives for duct testing and repair, high-efficiency appliances (air conditioning, water heater, heat pumps, refrigeration, etc.) rebates and high-efficiency lighting rebates. Total Energy Efficiency programs in FRCC are incorporated into the load forecast, increasing from 303 MW to 1,143 MW over the 10-year period.

[162] The U.S. Energy Information Administration's (EIA's) *Annual Energy Outlook 2012* (*AEO2012*): http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf.
[163] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.
[164] http://www.psc.state.fl.us/utilities/electricgas/RenewableEnergy/2009_FPSC_Draft_RPS_Rule.pdf.

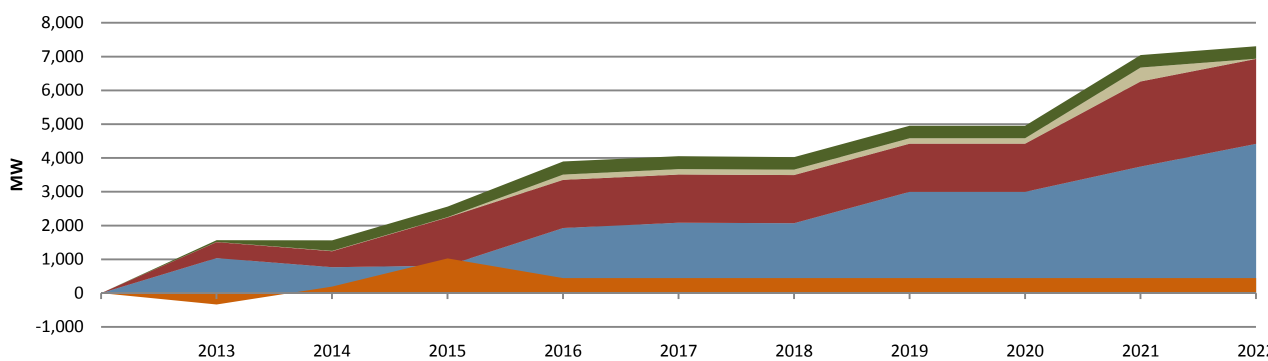
Generation

FRCC supply-side resources considered for the summer assessment are categorized as Existing-Certain, Existing-Other, and Existing-Inoperable. FRCC counts on 51,170 MW of Existing-Certain resources, of which 44 MW are hydro and 374 MW are Biomass. Current solar capacity is projected at 8 MW; however, most of this capacity is derated with approximately 5.8 MW considered as a Firm resource available during peak demand and the remainder being utilized as an energy-only resource. Derated hydro capacity is 44 MW. Approximately 183 MW of Existing-Other merchant plant capability is potentially available as future resources of FRCC members and others, with another 2,019 MW of Existing-Other resources placed into Inactive Reserves or Operational Standby for future operations by FRCC members. Of Existing-Certain capacity, generation fueled by natural gas is the primary source of fuel, supplying nearly 60 percent of capacity, while coal and oil will each account for nearly 16.2 percent. Nuclear generation will contribute about 4.8 percent (FRCC-Table 4, FRCC-Figure 2).

FRCC-Table 4: Capacity Outlook[165]

	Current		2022 Planned			2022 Planned & Conceptual		
FRCC-Summer	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Coal	8,430	16.2%	8,428	14.1%	-2	8,428	14.1%	-2
Petroleum	8,458	16.2%	8,906	14.9%	448	8,906	14.9%	448
Gas	32,325	62.0%	36,741	61.3%	4,416	36,741	61.3%	4,416
Nuclear	2,529	4.8%	5,046	8.4%	2,517	5,046	8.4%	2,517
Other/Unknown	3	0.0%	8	0.0%	5	8	0.0%	5
Renewables	426	0.8%	796	1.3%	371	796	1.3%	371
TOTAL	**52,170**	**100.0%**	**59,925**	**100.0%**	**7,754**	**59,925**	**100.0%**	**7,754**

FRCC-Figure 2: Summer Net Capacity Change



The majority of growth in Future-Planned resources is projected to come from plants fueled either by natural gas or nuclear. The construction of new natural gas facilities from 2013-2022 is projected to add over 7,754 MW over the coming decade. Similarly, increases in nuclear capacity over the same time period will come mostly from the uprate of existing units; however, approximately 2,517 MW of new nuclear capacity is scheduled for operation by 2022.

No significant unit retirements, deferments, or derates have been scheduled over the long-term planning horizon. However, there is approximately 850 MW of capacity not included in the forecast due to an extended unit outage. This capacity outage has been replaced with power contracts to meet any obligation-to-serve requirements, as mandated by the Florida Public Service Commission. The capacity outages discussed here is scheduled to return to service in 2014 with no reliability impacts.

There are several plants in FRCC that are either undergoing capacity uprates or have plans to for them in the near-term. Most of these uprates involve modernization of plant equipment. The potential impacts resulting from the temporary unavailability of generation has been mitigated by the short-term activation of off-line capacity that was staged in inactive reserves. Ongoing and future coordination will help to maintain adequate Planning Reserve Margins.

[165] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

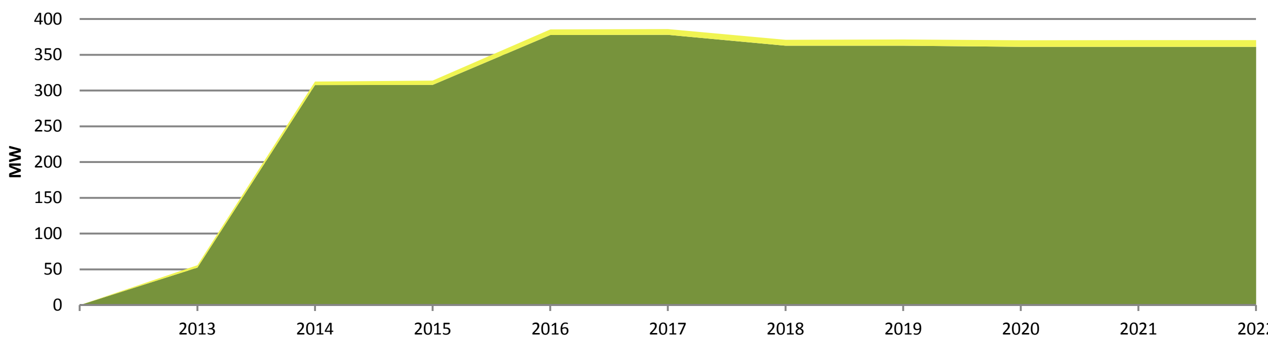
Variable Generation Outlook

Firm capacity from biomass currently supplies about 374 MW during seasonal peak demands, while variable resources such as hydro and solar will contribute about 44 MW and 8 MW, respectively. Approximately 11 MW of hydro is derated and not available during system peak, while the derated capacity from solar amounts to 48 MW (FRCC-Table 5 and FRCC-Figure 2). Even though such derated capacity cannot be used in the calculation of reserve margins, this non-Firm portion of capacity can be utilized as an energy-only resource.

FRCC-Table 5: Renewable Capacity Outlook[166]

	Current		2022 Planned			2022 Planned & Conceptual		
FRCC-Summer	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Hydro	44	10.2%	44	5.5%	0	44	5.5%	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	374	88.0%	736	92.4%	361	736	92.4%	361
Solar	8	1.8%	17	2.2%	9	17	2.2%	9
TOTAL	**426**	**100.0%**	**796**	**100.0%**	**371**	**796**	**100.0%**	**371**

FRCC-Figure 2: Summer Net Renewable Capacity Change



Only the minimum firm capacity from intermittent or energy-limited resources is included in the calculation of seasonal reserve margins. Accordingly, the inherent uncertainty caused by this variability is applied such that the potential unavailability of these resources will not impact reliability (FRCC-Table 6). Currently, no further operational changes are needed or planned to accommodate the integration of variable resources during the long-term planning horizon.

FRCC-Table 6: Variable Generation Outlook

	Current				2022 Planned			
FRCC-Summer	Wind	Solar	Hydro	Biomass	Wind	Solar	Hydro	Biomass
Installed Capacity	0	55	55	374	0	82	55	736
On-Peak Derate	0	47	11	0	0	65	11	0
EXPECTED ON-PEAK OUTPUT	0	8	44	374	0	17	44	736

Capacity Transactions

There are 1,340 MW of generation under Firm contract available to be imported from SERC-SE Assessment Area through the end of 2014, with the Firm imports decreasing to 200 MW in subsequent years. Additional capacity transactions include approximately 870 MW from member-owned generation that will be dynamically dispatched from the SERC-SE Assessment Area. These purchases have Firm transmission service to ensure deliverability to FRCC. Total expected Firm imports amount to 2,206 MW until 2016 and drop to 866 MW before increasing to 1,066 MW through the final years of the assessment period (FRCC-Table 7).

[166] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

FRCC has 143 MW of generation under Firm contract to be exported only during the summer season into the SERC-SE Assessment Area throughout 2020. These sales have Firm transmission service to ensure deliverability into the SERC-SE Assessment Area.

FRCC-Table 7: Projected Capacity Transactions

FRCC-Summer	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Expected Imports	0	0	0	0	0	0	0	0	0	0
Firm Imports	2,206	2,206	2,206	866	966	1,066	1,066	1,066	1,066	1,066
TOTAL IMPORTS	2,206	2,206	2,206	866	966	1,066	1,066	1,066	1,066	1,066
Expected Exports	0	0	0	0	0	0	0	0	0	0
Firm Exports	143	143	143	143	143	143	143	143	143	143
TOTAL EXPORTS	143	143	143	143	143	143	143	143	143	143
TOTAL NET CAPACITY TRANSACTIONS	**2,063**	**2,063**	**2,063**	**723**	**823**	**923**	**923**	**923**	**923**	**923**

Neither non-Firm resources nor expected transactions are included in the assessment for the calculation of reserve margins.

FRCC does not rely on external resources for emergency imports and reserve sharing. However, there are emergency power contracts in place between SERC members and FRCC entities.

Transmission

Transmission constraints in central Florida may require remedial actions, depending on system conditions creating increased west-to-east flow across the central Florida metropolitan load areas until the permanent solutions are constructed. No interconnection-related issues have been identified or are anticipated through the assessment period within FRCC. The FRCC planning process identified the following four transmission projects in central Florida as necessary for providing enhanced reliability during the assessment period:

- Intercession City to Gifford 230 kV (new 12-mile line)
- Holopaw to Poinsett 230 kV transmission line (rebuild)
- Tenoroc to Interstate to FiberTek to West 230 kV transmission line (reconductor)
- McIntosh to Lake Agnes 230 kV transmission line (rebuild)

There are no foreseen project delays in meeting the in-service date of any planned transmission facilities that have an impact on the long-term reliability during this assessment period. Any 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., SVC, FACTS controllers, HVdc, etc.) additions are expected through 2022.

A list of existing and projected transmission additions is provided below (FRCC-Table 8):

FRCC-Table 8: Existing and Projected Transmission

FRCC	AC (Circuit Miles)	DC (Circuit Miles)	Total (Circuit Miles)
EXISTING	12,031	0	12,031
Under Construction	46	0	46
Planned - Completed within First Five Years	249	0	249
Planned - Completed within Second Five Years	200	0	200
2022 TOTAL (UNDER CONSTRUCTION & PLANNED)	12,526	0	12,526
Conceptual - Completed within First Five Years	0	0	0
Conceptual - Completed within Second Five Years	97	0	97
2022 TOTAL (UNDER CONSTRUCTION, PLANNED & CONCEPTUAL)	**12,623**	**0**	**12,623**

All Future-Planned generation within the FRCC Region is thoroughly studied by the interconnecting Transmission Service Provider (TSP). The TSP will then submit the results of their study to FRCC’s Transmission Working Group (TWG) for additional third-party screening in accordance with the applicable TPL series of NERC Reliability Standards. This additional screening assures that all Future-Planned generation is deliverable (if requested), reliable, and does not adversely impact the BPS within FRCC.

The *FRCC Long Range Study 2012-2021*[167] did not identify any reactive power-limited areas that would impact the BPS through 2021. FRCC has not identified the need to develop specific criteria to establish a voltage stability margin.

The FRCC expects the BPS to perform adequately over various system operating conditions with the ability to deliver the resources to meet the load requirements at the time of both the summer and winter peak demand. The results of the annual Long-Range Study, which evaluated the steady-state summer, winter peak and select off-peak load conditions under different operating scenarios, indicates that any concerns with thermal overloads or voltage conditions can be managed successfully by operator intervention or by planned system expansion to serve the forecast demand. The scenarios analyzed included the unavailability of major generating units within the FRCC. Therefore, various dispatch scenarios were evaluated to ensure generating resources within the FRCC are deliverable by meeting NERC Reliability Standards under these dispatch scenarios. No localized pockets of reactive power-limited areas were identified on the BPS within FRCC in the current long-range study.

Vulnerability Assessment

One 800 MW class unit is scheduled to be unavailable during a defined period within the study horizon. Based on the FRCC Long-Range Study, the unavailability of this unit is not anticipated to cause any reliability concerns. In addition, FRCC does not foresee any issues associated with long-term/extended drought conditions, the unavailability of demand resources, or an increase in variable or distributed generation.

There are currently no plans for additional Under-Voltage Load Shed (UVLS) within FRCC. There is currently about 940 MW of UVLS armed within FRCC. These UVLS relays are designed to respond to local low-voltage conditions that could be caused by a Category C or D multiple contingency events. Two new permanent Special Protection Systems were installed within FRCC. The Special Protection Systems are designed to protect BES facilities under certain generation dispatch scenarios and specific multiple contingency events.

Based on past operating experience with the impact of hurricanes on the fuel supply infrastructure within the Region, the FRCC developed a *Generating Capacity Shortage Plan*.[168] This plan can distinguish between generating capacity shortages caused by abnormally high system loads and unavailable generating facilities from those caused by short-term, generating fuel or availability constraints. Since a significant portion of electric generation within Florida uses remotely supplied natural gas, the plan specifically distinguishes generating capacity shortages by primary causes (e.g., hurricanes and abnormally high loads) in order to provide a more effective regional coordination. The FRCC Operating Committee (OC) has also developed *FRCC Communications Protocols – Reliability Coordinator, Generator Operators and Natural Gas Transportation Service Providers* to enhance the existing coordination between the FRCC Reliability Coordinator and the natural gas pipeline operators in response to FERC Order 698. In addition, the FRCC Operating Reliability Subcommittee (ORS), through its Fuel Reliability Working Group, periodically reviews and assesses the current fuel supply infrastructure in terms of reliability for generating capacity.

FRCC entities 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 FRCC. However, at this time there are no FACTS devices installed within the Region. FRCC Transmission Owners (TOs) consider enhancements to existing transmission planning tools (e.g., enhancements to existing software, new software, etc.) to address the expected planning needs of the future.

Entities within FRCC are taking many steps to reduce protection system misoperations. Some major steps are:

[167] This study is not available to the public due to the inclusion of CEII information.
[168] https://www.frcc.com/handbook/Shared%20Documents/EOP%20-%20Emergency%20Preparedness%20and%20Operations/FINAL%20FRCC%20Generating%20Capacity%20Shortage%20Plan.pdf.

- Improving documentation and actively communicating throughout the Region, by reviewing test procedures and commissioning procedures to ensure there are no “gaps,” then sharing these methods with all entities within the Region;
- Improving the relay setting preparation process by sharing data through the FRCC working groups and using field-measured line impedances where practical;
- Reviewing corrective action plans for effectiveness;
- Reviewing NERC and FRCC lessons learned and discussing practical examples;
- Reviewing and implementing vendor service bulletins, including Firmware upgrades, and discussing misoperations with peers.

Procedures have been put in place to reduce human error affecting misoperations, by implementing settings with written, vetted procedures and considering field implementation as a last line of defense to abate human error.

Many entities within FRCC have implemented a capital improvement process, replacing legacy relays with microprocessor relays as each entity’s capital budget allows. Entities are refining maintenance by adjusting maintenance practices and maintenance cycles as necessary and applying full-functional testing by direct current injection whenever practical.

FRCC entities thoroughly investigate misoperations to determine the root cause, monitor Protection Systems (alarm contacts, relay voltages, etc.) and review all normal protective system operations for agreement with expected operation-per-settings calculations.

The Florida 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. The DC Circuit Court of Appeals placed a stay on CSAPR in late 2011, and ultimately vacated in August 2012.

The EPA’s Mercury and Air Toxics Standard (MATS) became effective on April 16, 2012, and requires compliance within three years, with the possibility of a one or two year extension under specific circumstances. Numerous entities around the country have challenged MATS in the D.C. Circuit; it will likely be more than a year before these challenges are resolved. Accordingly, it is still unknown the full impact that MATS or CSAPR, or replacement rules, will have on the long range reliability of the BPS in the FRCC region.

Standing and Emerging Reliability Issues

FRCC has identified one new emerging issue dealing with generation capacity with the potential for serious impact affecting the short-term time frame. Generation capacity could be severely impacted by EPA regulations requiring potential early retirement of existing units and/or unit output derates. The regulations could potentially impact the BPS by requiring new transmission facilities to be constructed to accommodate replacement generation to serve the forecast load with insufficient construction lead time. In the referenced case, resource capacity will decrease to account for potential unit retirement and/or derates. Additional issues that potentially could arise from EPA regulations are the uncertainties of sufficient time frame to replace generation capacity, materials required to retrofit units, and operational issues resulting from alternative dispatch patterns.

MISO

Planning Reserve Margins

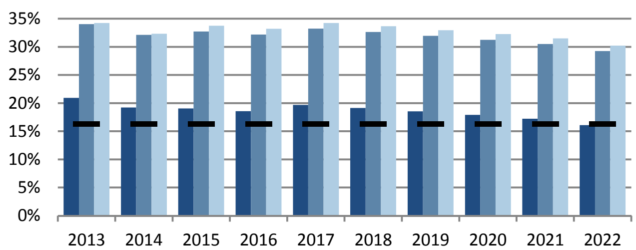
MISO has adequate Planning Reserve Margins throughout the assessment period to meet MISO's Planning Reserve Margin Requirement (PRMR) of 16.3 percent, also applied as the NERC Reference Margin Level (MISO-Table 1 and MISO-Figure 1).

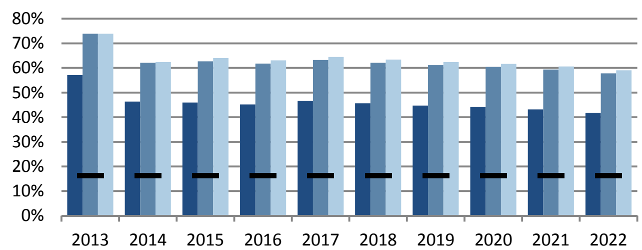
MISO-Table 1: Planning Reserve Margins

MISO-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		20.92%	19.22%	19.04%	18.58%	19.68%	19.15%	18.53%	17.91%	17.24%	16.10%
PROSPECTIVE		34.04%	32.13%	32.73%	32.20%	33.23%	32.64%	31.95%	31.26%	30.51%	29.25%
ADJUSTED POTENTIAL		34.24%	32.33%	33.76%	33.22%	34.25%	33.66%	32.96%	32.27%	31.51%	30.24%
NERC REFERENCE	-	**16.30%**	**16.30%**	**16.30%**	**16.30%**	**16.30%**	**16.30%**	**16.30%**	**16.30%**	**16.30%**	**16.30%**

MISO-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		57.13%	46.32%	45.97%	45.17%	46.61%	45.65%	44.74%	44.14%	43.17%	41.78%
PROSPECTIVE		73.89%	62.11%	62.73%	61.82%	63.19%	62.12%	61.10%	60.43%	59.35%	57.80%
ADJUSTED POTENTIAL		73.92%	62.35%	64.02%	63.10%	64.47%	63.39%	62.37%	61.69%	60.60%	59.04%
NERC REFERENCE	-	**16.30%**	**16.30%**	**16.30%**	**16.30%**	**16.30%**	**16.30%**	**16.30%**	**16.30%**	**16.30%**	**16.30%**

MISO-Figure 1: Summer (Left) and Winter[169] (Right) Planning Reserve Margins





The Planning Reserve Margin does not fall below the NERC Reference Margin Level during the assessment period. Anticipated Resources may also increase as Existing-Other and Future-Other resources are reclassified to Existing-Certain through MISO's Module E process. This will occur as needed to keep up with load growth while maintaining the PRMR in the final years of the assessment period.

MISO continues to evaluate potential challenges that may exist due to Environmental Protection Agency (EPA) regulations and the gas infrastructure system, which are not included in the Planning Reserve Margins above. EPA regulations may deteriorate projected reserve levels as early as 2015 due to increased retirements to MISO's coal fleet. In addition, as these retired coal units are replaced by other fuel sources, like gas, MISO must evaluate the possible strain on the gas infrastructure system to meet this increased demand. This impact is not included in the Planning Reserve Margins provided below. For more detailed information on the potential impact on reliability due to these and other issues, please read the Emerging Issues section.

Demand

The Total Internal Demand for MISO points to a 10-year CAGR of 1.05 percent, slightly higher than projected one year ago.[170] A diversity factor of 4.61 percent was estimated for 2012. Applying this diversity factor for the period 2013-2022, MISO is able to estimate a Total Internal Demand[171] of 94,279 MW and 103,584 MW for the 2013 and 2022 summers, respectively (MISO-Table 2).[172]

[169] Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.
[170] The 2011 LTRA projections shown in Figure 3-1 do not include Duke Energy Ohio or Duke Energy Kentucky load due to their exits from MISO effective January 1, 2012.
[171] This forecast doesn't include the Entergy and its six utility operating companies which will be integrated into MISO footprint by December 2013. The 2011 LTRA forecast was for the period 2011-2021.
[172] MISO projects a high load scenario (90/10) Total Internal Demand of 99,620 MW 109,452 MW for the 2013 and 2022 summers, based on the load forecast uncertainty analysis.

MISO-Table 2: Demand Outlook

MISO-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	89,318	94,875	5,557	6.2%	0.67%
Load-Modifying Demand Response	4,962	8,709	3,747	0.0%	0.00%
TOTAL INTERNAL DEMAND	**94,279**	**103,584**	**9,305**	**9.9%**	**1.05%**

MISO-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	69,663	78,789	9,126	13.1%	1.38%
Load-Modifying Demand Response	2,909	5,105	2,197	0.0%	0.00%
TOTAL INTERNAL DEMAND	**72,572**	**83,894**	**11,322**	**15.6%**	**1.62%**

Approximately 6,000 MW of unrestricted non-coincident peak load was removed from MISO due to the exit of the Duke companies.

The Entergy operating companies Entergy Arkansas, Inc.; Entergy Gulf States Louisiana, LLC; Entergy Louisiana, LLC; Entergy Mississippi, Inc.; Entergy New Orleans, Inc.; and Entergy Texas, Inc. intend to join MISO in December 2013. Total Internal Demand and Net Energy Load for Entergy are not included in the above sections as the current Module E Capacity Tracking[173] tool does not capture the information. MISO is not including Entergy in the *2012LTRA* analysis.

Demand-Side Management

MISO currently separates Load-Modifying Demand Response resources into two separate categories: Interruptible Load (IL) and Direct Control Load Management (DCLM). IL is the magnitude of customer demand (usually industrial) that, in accordance with contractual arrangements, can be interrupted at the time of peak by direct control of the system operator (remote tripping) or by action of the customer at the direct request of the system operator. MISO projects IL resources to be 3,883 MW and 6,816 MW for 2013 and 2022, respectively.

DCLM is the magnitude of customer service (usually residential) that can be interrupted at the time of peak by direct control of the applicable system operator. DCLM is typically used for “peak shaving.” During the first year MISO projects DCLM of 1,078 MW, and for the final year of the assessment, MISO projects DCLM of 1,893 MW. Total Demand Response projections for MISO resulted in a CAGR of 6.45 percent from 2013 to 2022 (MISO-Table 3).

MISO-Table 3: Demand-Side Management

	Short-Term					
MISO-Summer	2013	2014	2015	2022	10-Year Change	2022 Share of Total Internal Demand
Direct Control Load Management (DCLM)	0	0	0	0	0	0.00%
Contractually Interruptible (Curtailable)	0	0	0	0	0	0.00%
Critical Peak-Pricing (CPP) with Control	0	0	0	0	0	0.00%
Load as a Capacity Resource	3,271	3,271	3,271	3,271	0	3.16%
TOTAL RESOURCE-SIDE DEMAND RESPONSE	3,271	3,271	3,271	3,271	0	3.16%
Direct Control Load Management (DCLM)	1,078	1,178	1,268	1,893	814	1.83%
Contractually Interruptible (Curtailable)	3,883	4,244	4,565	6,816	2,933	6.58%
Critical Peak-Pricing (CPP) with Control	0	0	0	0	0	0.00%
Load as a Capacity Resource	0	0	0	0	0	0.00%
TOTAL LOAD-MODIFYING DEMAND RESPONSE	4,962	5,422	5,833	8,709	3,747	8.41%
TOTAL ENERGY EFFICIENCY	131	382	720	3,922	3,790	3.79%
TOTAL DEMAND-SIDE MANAGEMENT	**8,364**	**9,075**	**9,824**	**15,902**	**7,538**	**15.35%**

Per MISO’s Emergency Operating Procedures (RTO-EOP-002), MISO must declare a Maximum Generation Emergency Event Step 2b[174] to gain access to IL and DCLM resources, whereby MISO instructs local Balancing Authorities to reduce load via load-modifying resources as defined in Module E of MISO’s tariff.[175]

[173] MISO market participants use the Module E Capacity Tracking (MECT) tool to submit its forecasted Demand and Resources at each Commercial Pricing Node for the upcoming planning years.
[174] Emergency Operating Procedures: https://www.misoenergy.org/MarketsOperations/ReliabilityOperatingProcedures/Pages/ReliabilityOperating Procedures.aspx.
[175] Model E of MISO Tariff (https://www.misoenergy.org/Library/Tariff/Pages/Tariff.aspx) and Resource Adequacy BPM 011 (https://www.misoenergy.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx).

Generation

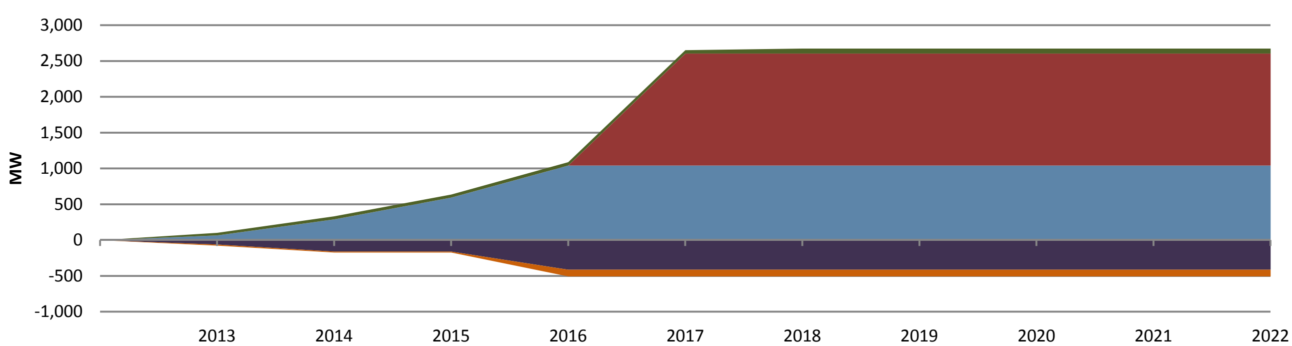
MISO has Existing-Certain resources totaling 101,060 MW for expected summer rated on-peak capacity within its market footprint. Additionally, there is 11,536 MW and 1,588 MW of Existing-Other and Existing-Inoperable capacity, respectively. Since the 2011 summer season, 79 MW of Existing-Certain resources have come into service. This includes 70 MW of wind and 9 MW of gas expected summer rated capacity. The predominant source of fuel in MISO is coal at approximately 55 percent of total existing resources, followed by gas-fired and nuclear generation, totaling 28 and 8 percent, respectively.

Throughout the assessment time frame, MISO anticipates a net total summer rated capacity of 2,197 MW of Future-Planned resources, which includes 202 MW of planned retirements before the 2013 summer season, 71 MW of new wind, 1,069 MW of new natural gas, and 1,563 MW of new nuclear(MISO-Table 4 and MISO-Figure 2).

MISO-Table 4: Capacity Outlook[176]

	Current		2022 Planned			2022 Planned & Conceptual		
MISO	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Coal	55,824	55.2%	55,411	53.6%	-414	55,411	53.6%	-414
Petroleum	4,853	4.8%	4,761	4.6%	-92	4,761	4.6%	-92
Gas	28,298	28.0%	29,367	28.4%	1,069	29,367	28.4%	1,069
Nuclear	8,013	7.9%	9,576	9.3%	1,563	9,576	9.3%	1,563
Other/Unknown	0	0.0%	0	0.0%	0	0	0.0%	0
Renewables	4,134	4.1%	4,204	4.1%	71	4,204	4.1%	71
TOTAL	**101,122**	**100.0%**	**103,319**	**100.0%**	**2,197**	**103,319**	**100.0%**	**2,197**

MISO-Figure 2: Summer Net Capacity Change



Included in total Future-Planned resources are a facility upgrade of an Existing-Certain natural gas combined-cycle plant of 51 MW, a facility replacement of an Existing-Certain coal facility to natural gas with an increase in capacity of 253 MW, and a facility replacement of an Existing-Certain coal and natural gas facility to a natural gas combined-cycle facility with an increase in capacity of 116 MW

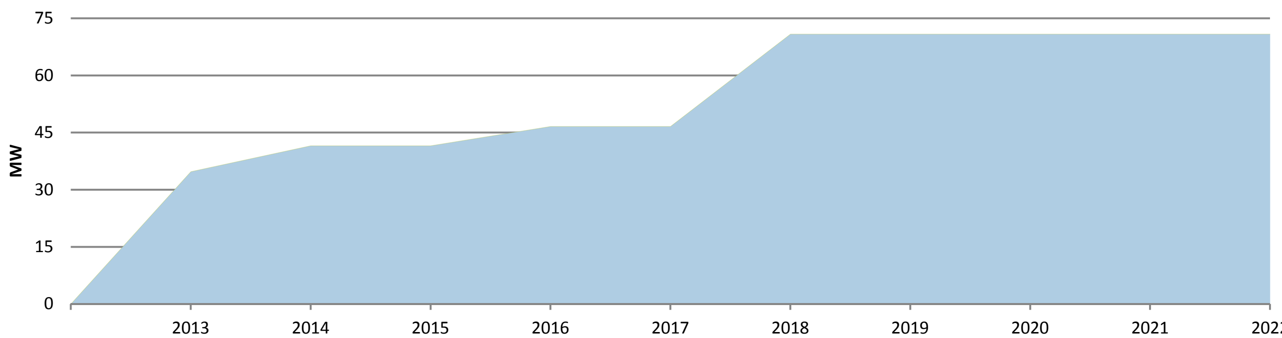
Since the 2011 summer season, MISO's existing capacity was negatively impacted by 4,726 MW of summer rated capacity due to the departure of Duke Energy Ohio and Duke Energy Kentucky from the MISO market on January 1, 2012. The predominant source of fuel from the Duke exit is coal at 78 percent of total Duke Energy Ohio and Duke Energy Kentucky resources. Next is gas at 15 percent and oil at 8 percent. MISO also experienced unit retirements totaling 556 MW in 2011 and 750 MW in 2012 of summer rated capacity since the last reporting year, which was 49 percent coal, 30 percent gas, and 21 percent oil. In addition to membership changes and unit retirements, 160 MW of wind, 10 MW of hydro, and 8 MW of oil resources were pseudo-tied out of MISO since the prior year (MISO-Table 5 and MISO-Figure 2).

[176] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

MISO-Table 5: Renewable Capacity Outlook[177]

MISO-Summer	Current Capacity	Current Share	2022 Planned Capacity	2022 Planned Share	2022 Planned Change	2022 Planned & Conceptual Capacity	2022 Planned & Conceptual Share	2022 Planned & Conceptual Change
Hydro	790	19.1%	790	18.8%	0	790	18.8%	0
Pumped Storage	2,288	55.4%	2,288	54.4%	0	2,288	54.4%	0
Geothermal	0	0.0%	0	0.0%	0	0	0.0%	0
Wind	563	13.6%	634	15.1%	71	634	15.1%	71
Biomass	492	11.9%	492	11.7%	0	492	11.7%	0
Solar	0	0.0%	0	0.0%	0	0	0.0%	0
TOTAL	**4,134**	**100.0%**	**4,204**	**100.0%**	**71**	**4,204**	**100.0%**	**71**

MISO-Figure 2: Summer Net Renewable Capacity Outlook



MISO expects 148 MW of Existing-Certain and 20 MW of Existing-Other resources to retire before the 2013 summer season, of which the impact on reliability is negligible. This includes 106 MW of coal, 47 MW of gas, and 14 MW of oil resources. In addition, throughout the assessment period, MISO expects 1,099 MW of Existing-Inoperable resources to be removed from suspended or mothballed status and be in service by 2015, which has a positive impact on the Prospective Capacity Resources Reserve Margin of 1 percentage point, keeping the Prospective Reserve Margin above 30 percent in 2015.

Behind-the-meter generation is held flat at the current summer expectation of 3,271 MW throughout the assessment period. Without behind-the-meter generation, MISO's 2022 Anticipated and Prospective Reserve Margins would decrease by 4 percentage points and 3 percentage points, respectively.

The majority of MISO's non-intermittent resources have an Expected Summer on-peak capacity (summer rating) equal to their 2012 Generator Verification Test Capacity (GVTC). More information on the GVTC may be found in the Resource Adequacy Business Practice Manual (BPM) on MISO's website. When a test is not available, the non-intermittent units' Maximum Output from MISO's Commercial Model is utilized.

MISO's wind resources expected on-peak capacity is arrived at by applying a 14.7 percent wind capacity credit to the resources nameplate capacity, and other intermittent resources are given its UCAP rating per the Module E process. The variable capacity outlook for MISO is listed below (MISO-Table 6).

MISO-Table 6: Renewable Capacity Outlook: On-Peak Vs. Installed

MISO-Summer	Current Wind	Current Solar	Current Hydro	Current Biomass	2022 Planned Wind	2022 Planned Solar	2022 Planned Hydro	2022 Planned Biomass
Installed Capacity	10,791	0	875	599	11,273	0	875	599
On-Peak Derate	10,228	0	85	106	10,873	0	85	106
EXPECTED ON-PEAK CAPACITY	563	0	790	492	634	0	790	492

[177] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

Capacity Transactions

MISO only reports Firm power imports that are in the MISO market. The forecast imports are held flat at 3,557 MW throughout the assessment time frame (MISO-Table 7). All these imports are Firm and fully backed by Firm transmission and Firm generation. No imports are based on partial path reservations.

MISO-Table 7: Projected Capacity Transactions

MISO-Summer	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Expected Imports	0	0	0	0	0	0	0	0	0	0
Firm Imports	3,557	3,557	3,557	3,557	3,557	3,557	3,557	3,557	3,557	3,557
TOTAL IMPORTS	3,557	3,557	3,557	3,557	3,557	3,557	3,557	3,557	3,557	3,557
Expected Exports	0	0	0	0	0	0	0	0	0	0
Firm Exports	0	0	0	0	0	0	0	0	0	0
TOTAL EXPORTS	0	0	0	0	0	0	0	0	0	0
TOTAL NET CAPACITY TRANSACTIONS	**3,557**	**3,557**	**3,557**	**3,557**	**3,557**	**3,557**	**3,557**	**3,557**	**3,557**	**3,557**

Transmission

MISO has 273 miles of greater-than-100-kV transmission line under construction, over 90 percent of which is for reliability. MISO expects 1,316 miles of greater-than-100-kV planned transmission line to be in service within five years, of which 530 miles are for the integration of variable/renewable resources, while the remainder is for reliability. As well, 1,571 miles of greater-than-100-kV planned transmission line are expected to be in service within 10 years, of which 866 miles are for the integration of variable/renewable resources, while the remainder is for reliability. All of these projects total 1,844 miles of under-construction or planned transmission expected within the study time frame (MISO-Table 8).

MISO-Table 8: Existing and Projected Transmission

MISO	AC (Circuit Miles)	DC (Circuit Miles)	Total (Circuit Miles)
EXISTING	43,291	1,209	44,500
Currently Under Construction	161	0	161
Planned - Completed within First Five Years	1,838	0	1,838
Planned - Completed within Second Five Years	1,069	0	1,069
2022 TOTAL (UNDER CONSTRUCTION & PLANNED)	46,359	1,209	47,568
Conceptual - Completed within First Five Years	63	0	63
Conceptual - Completed within Second Five Years	0	0	0
2022 TOTAL (UNDER CONSTRUCTION, PLANNED & CONCEPTUAL)	**46,422**	**1,209**	**47,631**

Currently, MISO does not anticipate delays in meeting target in-service dates. These projects are anticipated to come into service during the 2012-2022 period to enable reliable and efficient transmission service for MISO. There is no potential reliability impact in not meeting target in-service dates of transmission identified. MISO does not anticipate any existing, significant transmission lines or transformers being out of service through the assessment period. MISO does not have any transmission constraints that could significantly impact reliability.

Vulnerability Assessment

MISO is involved in a variety of smart grid initiatives that will provide increased grid intelligence, use energy in smarter ways, and provide the Region with even greater reliability, efficiency, and sustainability.

MISO uses industry-leading, wide-area uses visualization tools to give system operators a clearer look at system conditions. One of these tools, synchrophasors, provides more precise grid measurements by using data collected from monitors called Phasor Measurement Units (PMUs). PMU measurements are taken at a very high speed (typically 30 observations per second, compared to once every 4 seconds using current technology). PMU measurements are time stamped to time-align (or synchronize) data from widely dispersed locations in the power system network.

In order to plan for 2013 installations, MISO has begun reaching out to Transmission and Generation Owners to identify and confirm additional sites. The placement strategy for 2013 sites will be slightly different from the original placement approach. The new strategy will focus on generator model validation, Transient Stability Analysis, Voltage Stability Analysis, and monitoring of system interfaces.

Plans for Accommodating Generator Retirements and Environmental Control Retrofits

MISO conducts quarterly surveys of asset owners' EPA compliance strategies. From the second quarter 2012 survey, 67 out of 103 units totaling 21,893 MW of summer rated capacity will be retrofitting using the dry sorbent injection (DSI) and/or activated carbon injection (ACI) options (MISO-Table 9). Units using these options should have ample time to meet the deadline. Of the remaining units, 8,009 MW will install a combination of FGD, baghouse/fabric filter (FF), and potentially SCR. Most of these units are in the design, permit and constructions phases and should have time to meet the compliance deadline. However, there are a few that have not begun some phases of the retrofit. This could require extensions of the compliance deadline for these units. Additionally, 3,564 MW of capacity has not been committed to a particular technology. The majority of the undecided units are testing for DSI viability. If proven not viable, options become limited and the units will likely require extensions.

MISO-Table 9: Environmental Retrofits by Technology, Resource Type, and Supply Category

Resource Type	Technology	Number of Units	Summer Rating (MW) EC	Summer Rating (MW) EO	Winter Rating (MW) EC	Winter Rating (MW) EO
Coal	DSI and/or ACI	**64**	20,218	1,456	20,403	1,462
	FGD	**18**	7,936	74	7,961	74
	FF	**1**	52	-	44	-
	TBD	**17**	3,557	7	3,587	7
Gas	DSI and/or ACI	**2**	174	45	177	45
	FGD	**2**	151	-	193	-
	FF	**-**	-	-	-	-
	TBD	**-**	-	-	-	-
Biomass	DSI and/or ACI	**1**	18	1	18	1
	FGD	**-**	-	-	-	-
	FF	**-**	-	-	-	-
	TBD	**-**	-	-	-	-
TOTAL		**105**	**32,106**	**1,583**	**32,383**	**1,589**

A larger number of units will have "no action required" to comply with the Mercury Air Toxics Standard (MATS) then initially anticipated in the 2011 EPA study effort. In that study, approximately 9,500 MW of capacity was categorized with no action required. However, in the second-quarter survey, asset owners responded "no action required" to meet the MATS amounted to 19,864 MW of capacity. The exact reason for the increase in the no action required category is not known. However, the majority of the increase takes place at units with an electrostatic precipitator (ESP). This technology should be sufficient to meet the particulate matter removal required for MATS, which uses the emission limit for filterable particulate matter instead of total particulate matter.

The remaining units have retired, will be retired, or are in consideration for retirement. From the survey, asset owners have retired 1,706 MW and indicate the intent to retire an additional 2,400 MW of summer rated capacity with another 7,028 MW of capacity on the bubble (MISO-Table 10). If units that did not respond to the survey are included, the retirement figure could reach 12,223 MW. MISO will continue to survey asset owners quarterly.

MISO-Table 10: Retirement Decisions by Resource Type and Supply Category

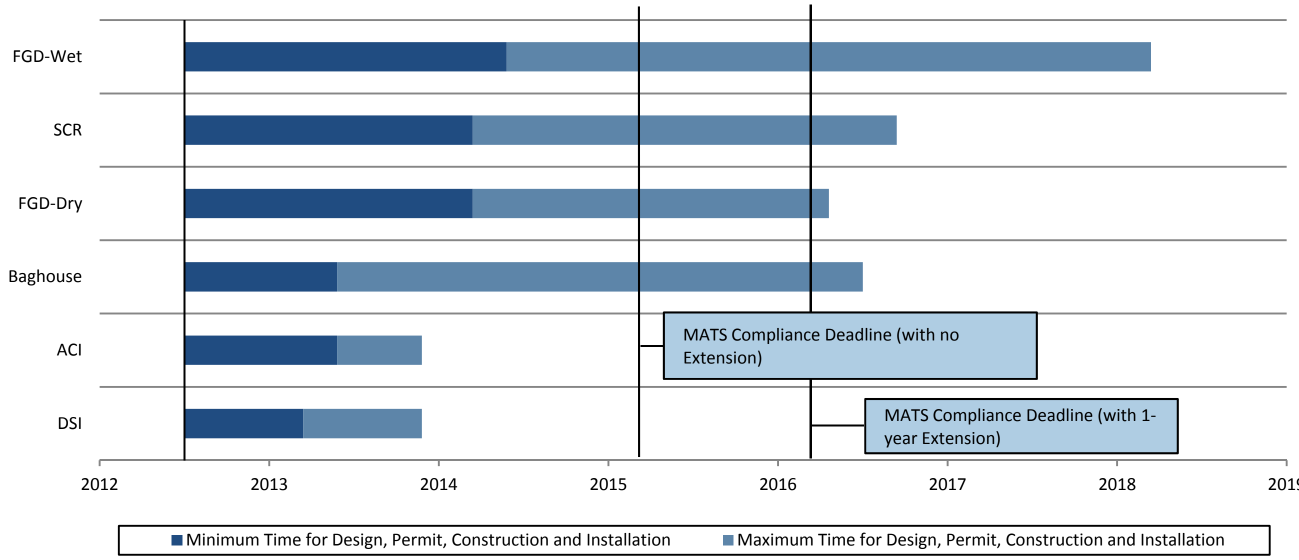
Resource Type	Retirement Decision	Number of Units	Summer Rating (MW) Other	Summer EC	Summer EO	Summer FP	Summer FO	Winter Rating (MW) Other	Winter EC	Winter EO	Winter FP	Winter FO
Coal	Already Retired	**27**	1,706	-	-	-	-	1,706	-	-	-	-
	Retire	**19**	-	1,022	564	106	394	-	1,040	564	106	394
	TBD for Retire	**49**	-	6,502	176	-	-	-	6,520	176	-	-
	No Action Required	**42**	-	14,719	3,351	-	-	-	14,900	3,371	-	-
	No Response to Survey	**15**	-	482	37	-	-	-	485	37	-	-
Gas	Already Retired	**-**	-	-	-	-	-	-	-	-	-	-
	Retire	**1**	-	158	156	-	-	-	158	156	-	-
	TBD for Retire	**4**	-	295	-	-	-	-	373	-	-	-
	No Action Required	**4**	-	372	4	-	-	-	374	4	-	-
	No Response to Survey	**-**	-	-	-	-	-	-	-	-	-	-
Oil	Already Retired	**-**	-	-	-	-	-	-	-	-	-	-
	Retire	**-**	-	-	-	-	-	-	-	-	-	-
	TBD for Retire	**4**	-	55	-	-	-	-	66	-	-	-
	No Action Required	**-**	-	-	-	-	-	-	-	-	-	-
	No Response to Survey	**1**	-	-	24	-	-	-	-	24	-	-
Behind-the-meter-Generation	Already Retired	**-**	-	-	-	-	-	-	-	-	-	-
	Retire	**-**	-	-	-	-	-	-	-	-	-	-
	TBD for Retire	**-**	-	-	-	-	-	-	-	-	-	-
	No Action Required	**4**	417	-	-	-	-	417	-	-	-	-
	No Response to Survey	**17**	625	-	-	-	-	625	-	-	-	-
Firm Capacity Transactions	Already Retired	**-**	-	-	-	-	-	-	-	-	-	-
	Retire	**-**	-	-	-	-	-	-	-	-	-	-
	TBD for Retire	**-**	-	-	-	-	-	-	-	-	-	-
	No Action Required	**1**	1,002	-	-	-	-	1,002	-	-	-	-
	No Response to Survey	**-**	-	-	-	-	-	-	-	-	-	-

MISO performed EPA analysis using the Electric Generation Expansion Analysis System (EGEAS) software to determine whether retirement or retrofitting would be the most economic option for each generator impacted by the regulations.[178]

The timelines for retrofits vary by technology. Some retrofit technologies - flue gas desulfurization (FGD) and selective catalyst reduction (SCR) - are riskier than others because of the length of time it takes to complete the work and the deadlines for compliance (Figure 3a). It may be possible to receive an additional one-year extension beyond the first year extension, extending the compliance deadline into 2017. This second year extension will likely be limited to unique cases (MISO-Table 11).

[178] A full summary of the analysis is documented in section 4.2 of MISO's MTEP 11 report: https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP11/MTEP11%20Report.pdf.

MISO-Table 11: Retrofit Timeline for Various Control Technologies



MISO coordinates the timing of generator (and transmission) outages on the MISO system to maintain reliability. Outage coordination could be affected with the limited number of outage windows. Revisions to the tariff need to take place to address this issue.

Currently, outages in MISO can be rescheduled based on one of the following:

- An emergency
- To maintain nuclear plant interface requirements
- To maintain the Transmission System within System Operating Limits using normal operating procedures or restore the Transmission System to normal operating conditions following a single contingency
- The potential for contingencies to significantly affect Transmission System reliability of metropolitan areas

With the limited outage windows before the 2015 compliance deadline, it will be increasingly important for the outage scheduling group to have has much information as possible. MISO would like to add a fifth rescheduling option to the tariff pertaining to the monthly maintenance margin. The monthly maintenance margin was developed to aid the outage scheduling group and will be updated seasonally.[179]

Standing and Emerging Issues

Environmental Regulations

As a result of the Environmental Protection Agency (EPA) compliance work from 2010-2011, an EPA compliance strategy was developed that would end with possible tariff and market evaluation and adjustments. Several areas of concern that would be included in the EPA compliance strategy were discussed at various stakeholder meetings. Those concerns can be described in four categories: resource adequacy, outage coordination, meeting compliance deadlines, and natural gas infrastructure. Two of the four categories are their own emerging reliability issues: Outage Coordination and Gas and Electric Interdependencies.

The likely impact of this issue will steadily increase as the compliance deadline of 2015 approaches, and MISO anticipates resource adequacy issues to emerge throughout the 2013-2015 period as MISO's market participants determine whether to retire or retrofit units.

[179] https://www.midwestiso.org/Library/Repository/Communication%20Material/Power%20Up/EPA_Outage%20Limits%20Analysis.pdf.

The EPA has proposed four regulations that would have potentially profound effects on the power industry's ability to deliver electricity reliably. This compliance may require billions of dollars of investment in new or upgraded facilities to ensure safe and reliable electric service for consumers in the MISO footprint. As a result, MISO may face a capacity shortage if the proposed EPA regulations go into effect.

In the initial evaluation of the impact of the EPA rules on the MISO system, studies were conducted with the Electric Generation Expansion Analysis System (EGEAS) software package developed by the Electric Power Research Institute (EPRI) commonly used by utility generation planners. MISO performed more than 400 sensitivity screens using the EGEAS capacity expansion model to identify the units most at risk for retirement. The sensitivities consisted of variation in costs for natural gas, cost uncertainty risk and retrofit compliance. The results of the EGEAS analysis produced two scenarios, which were 2.9 GW of coal fleet capacity at risk for retirement and 12.6 GW at risk for retirement.

Since the initial evaluation, the four rules have been revised. In response to the revisions, MISO sent out second-quarter surveys to its market participants in 2012 to determine the resource adequacy impact of the EPA regulations. Surveys will continue go out every quarter. From the survey, 4.3 GW of coal capacity responded with the intent to retire, while another 6.3 GW of coal capacity is still in the decision-making stages. If the number of units that did not respond to the survey is included, there is a possibility of 11.9 GW of coal capacity retiring.

If the 4 GW of retirements is experienced, MISO will be able to meet its Planning Reserve Margin Requirements (PRMR) throughout the assessment period. Of the 4 GW of retirements from the survey, 1,706 MW have already retired or have exited the MISO market for reasons unknown to MISO. This leaves 2,400 MW of capacity with the intent to retire during the assessment period. Of this 2,400 MW, 106 MW are Future-Planned retirements, which leaves 2,294 MW. That 2,294 MW is categorized as 1,180 MW of Existing-Certain resources, 720 MW of Existing-Other resources, and 394 MW of Future-Other resources. If these resources retire, MISO has adequate resources to meet its PRMR (target reserve level).

If the 12 GW of retirements is experienced, MISO will be able to meet its Planning Reserve Margin Requirements throughout the assessment period; however, this will be done by relying heavily on Existing-Other resources, which may be subject to fuel availability issues, leading to higher average forced outage rates, transmission limitations, etc. More investigation into resource utilization type is required to understand the true reliability impact. Of the 12 GW of potential retirements, 10,956 MW is included in the LTRA data. Of this 10,596 MW, 106 MW are Future-Planned retirements, which leaves 10,490 MW. That 10,490 MW is categorized as 8,514 MW of Existing-Certain resources, 957 MW of Existing-Other resources, 394 MW of Future-Other resources, and 625 MW of behind-the-meter generation. If these resources retire, the Anticipated Reserve Margins for 2015 and 2022 will be 9.7 percent and 7.1 percent, respectively, and the Prospective Reserve Margin will be 21.9 percent and 18.9 percent, respectively. At this level of retirement, MISO may not have adequate resources to reliably serve load.

For additional information on the impact of EPA retirements on Loss of Load expectation within MISO, see the MTEP 12 report posted on MISO's website.[180]

From the initial EPA study work, it was shown that most of the impact on transmission reliability cost would be relatively small ($30 / kW) and could be implemented within the 2015 period if upgrades are committed early. The upgrades include capacitor bank installations, short lower voltage transmission line additions, modest reconductoring jobs or transformer upgrades at existing stations. However, for some unique situations transmission upgrades would be more involved and would require the need for an extension.

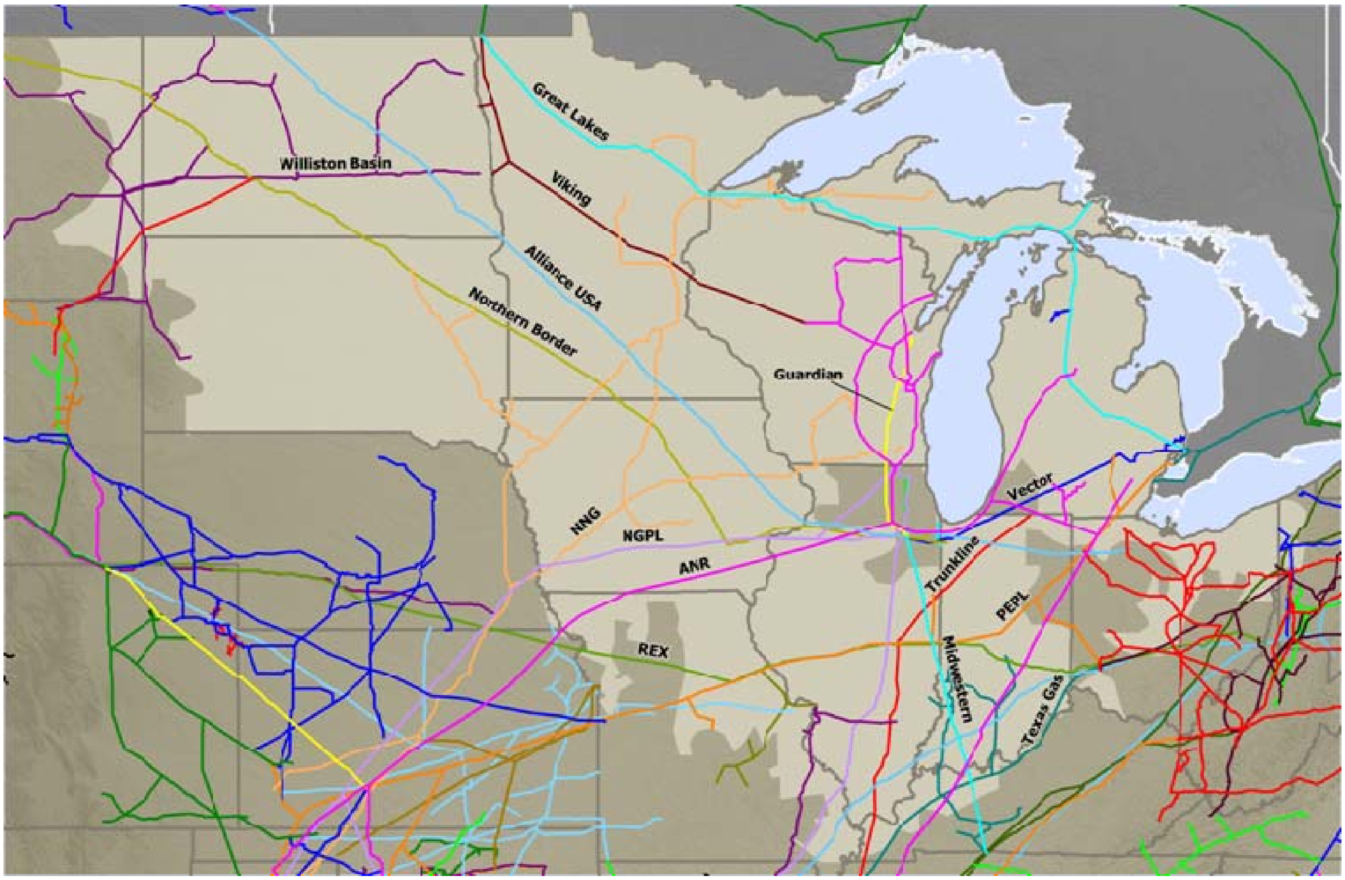
[180] MTEP 12: https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MTEP12.aspx.

MISO is developing a methodology for tracking and projecting emissions. The tool is expected to be complete by the time the CSAPR rule is implemented. Tracking emissions will help MISO staff anticipate potential issues that may arise from the management of the allowances by generating-owning members.

Gas and Electric Interdependencies

New and proposed regulatory compliance obligations will potentially cause the retirement of an estimated 12.6 GW of coal-fired capacity in MISO, causing a shift in the Region's fuel mix. Natural gas-fired plants are expected to replace much of the retired capacity. To prepare for this eventuality, MISO studied gas supply, storage, and pipeline infrastructure to assess how the shift in the electric fuel mix may impact the gas and electric industries over the next 20 years (MISO-Figure 4).

MISO-Figure 4: Overview of MISO Region Major Pipelines



This study[181] demonstrates sufficient gas supply but inadequate mainline capacity to serve the 12.6 GW retirement scenario. Over 65 percent of the pipelines have insufficient capacity to fully meet the needs of the existing units operating at expected capacity factors under the 12.6 GW retirement scenarios. Pipelines sourcing gas supply from the Gulf Coast have significantly higher levels of insufficient capacity compared to southwest and mid-continent pipeline sources. Additionally, shale gas supplies in proximity to MISO will need pipeline flow changes and infrastructure build-out. This analysis is a first step for both the natural gas and electric power industries to better communicate the potential future pipeline capacity availability for gas-fired power generation needs. A collaborative effort among the two industries and regulators is needed to refine pragmatic and practical capacity solutions to meet the future capacity requirements of gas-fired power generation.

[181] https://www.midwestiso.org/Library/Repository/Communication Percent20Material/Key Percent20Presentations Percent20and Percent20Whitepapers/Natural Percent20Gas- Electric Percent20Infrastructure Percent20Interdependency Percent20Analysis_022212_Final Percent20Public.pdf.

MISO performed historical outage analysis for gas-fired units with lack-of-fuel cause codes in the Generation Availability Data System (GADS). The first cause code is for lack of fuel where the operator is not in control of contracts, supply lines, or delivery of fuels and the second cause code is for lack of fuel with interruptible supply of the fuel part of the fuel contract. Since capacity factors for gas-fired units have historically been low, MISO was able to dispatch base generation units—specifically coal units. However, with increased coal retirements due to EPA regulations, MISO expects to see higher outage rates for gas-fired units.

MISO also performed additional analysis to determine the resulting capacity factors on the gas Combustion Turbines (CTs) and Combined Cycles (CCs) over the 20-year time horizon using the Electric Generation Expansion Analysis System (EGEAS) model, based on a 2011 starting gas price of $2.50/MMBtu and 12.6 GW retirement scenario. For more study analysis on this issue, please refer to the MTEP 12 report posted on MISO's website.[182]

EPA Regulations and Supply Chain

MISO evaluated the risks associated with equipment and labor procurement (supply chain) for various Environmental Protection Agency (EPA) Mercury and Air Toxics Standards (MATS) rule compliance strategies. MISO's supply chain analysis,[183] conducted by The Brattle Group, concluded that the March 2015 timeline requires more construction than the industry has seen in the past, and the greatest unknown risk is the amount of skilled labor available to perform the retrofits. In addition, the type of technology necessary to bring a unit into compliance may require lengthy unit outages that may run past the compliance deadline.

Outage Management Under New EPA Regulations

As part of MISO's efforts to best manage an expected influx of outage requests associated with recent environmental regulations, MISO conducted an outage limit analysis to determine acceptable monthly outage levels that can be allowed to maintain reliable transmission operations.[184]

[182] https://www.midwestiso.org/Pages/Home.aspx.

[183] https://www.midwestiso.org/Library/Repository/Communication Percent20Material/Key Percent20Presentations Percent20and Percent20Whitepapers/Supply Percent20Chain Percent20and Percent20Outage Percent20Analysis Percent20of Percent20MISO Percent20Coal Percent20Retrofits Percent20for Percent20MATS.pdf

[184] https://www.midwestiso.org/Library/Repository/Communication%20Material/Power%20Up/EPA_Outage%20Limits%20Analysis.pdf.

MRO-Manitoba Hydro

Planning Reserve Margins

Manitoba is projecting adequate Planning Reserve Margins for the entire assessment period. As a predominately hydro region, Manitoba has both an energy criterion and a capacity Reserve Margin criterion. The capacity Reserve Margin criterion requires a minimum 12 percent reserve above the forecast peak demand. This same criterion is also applied as the NERC Reference Margin Level. Manitoba Hydro uses a series of probabilistic adequacy analysis, with an objective LOLE of 0.1 days per year over a 10-year planning horizon, to review the suitability of the NERC Reference Margin Level above the forecast peak demand.

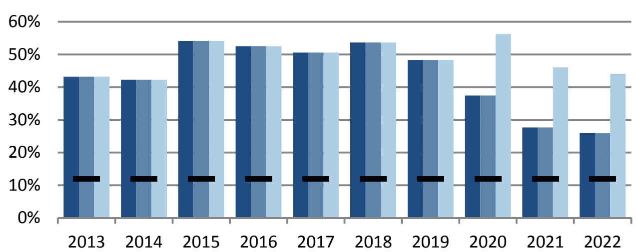
Manitoba Hydro uses an integrated resource planning process with a 35-year planning horizon to plan to meet the long-term needs of the Province of Manitoba. The Anticipated and Prospective Reserve Margins for the winter peak are projected to be below the Reference Margin Level during the 2021-2022 winter seasons. There are expected export sales that are contingent upon Conceptual resources being built. The Anticipated and Prospective Reserve Margins include these expected export sales in their calculations; however, they do not include the expected Conceptual resources. Without the Conceptual resources being built, expected exports would not be realized, and the Anticipated and Prospective Reserve Margins will remain above the NERC Reference Margin level during the winter seasons for the final two years of the assessment period. Should the Conceptual resources be built and the sales realized, Adjusted Potential Reserve Margins are projected to remain well above the NERC Reference Margin Level (MRO-Manitoba Hydro-Table 1 and MRO-Manitoba Hydro-Figure 1).

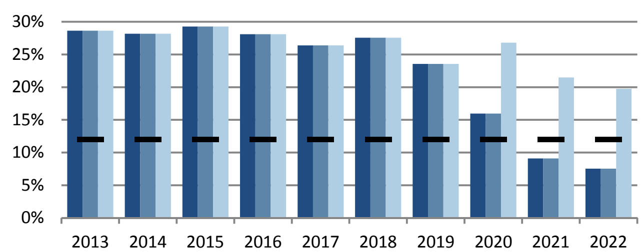
MRO-Manitoba Hydro-Table 1: Planning Reserve Margins

Manitoba Hydro-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		43.21%	42.26%	54.15%	52.56%	50.60%	53.66%	48.34%	37.45%	27.69%	25.98%
PROSPECTIVE		43.21%	42.26%	54.15%	52.56%	50.60%	53.66%	48.34%	37.45%	27.69%	25.98%
ADJUSTED POTENTIAL		43.21%	42.26%	54.15%	52.56%	50.60%	53.66%	48.34%	56.26%	46.06%	44.11%
NERC REFERENCE	-	**12.00%**	**12.00%**	**12.00%**	**12.00%**	**12.00%**	**12.00%**	**12.00%**	**12.00%**	**12.00%**	**12.00%**

Manitoba Hydro-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		28.63%	28.18%	29.28%	28.09%	26.39%	27.56%	23.55%	15.97%	9.10%	7.54%
PROSPECTIVE		28.63%	28.18%	29.28%	28.09%	26.39%	27.56%	23.55%	15.97%	9.10%	7.54%
ADJUSTED POTENTIAL		28.63%	28.18%	29.28%	28.09%	26.39%	27.56%	23.55%	26.81%	21.48%	19.75%
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-Figure 1: Summer (Left) and Winter[185] (Right) Planning Reserve Margins





Assessment projections show ample resources over the next five years, assuming the nearly completed Wuskwatim Generating Station is placed into service by the end of 2012. Beyond the next five years, new resources are likely required, and assessment projections depend on those resources coming into service as planned.

Demand

The compound annual growth rate (CAGR) for Total Internal Demand forecast is 1.14 percent for the winter season and 0.88 percent for the summer season during the 10-year outlook. The slight increase compared to last year's forecast is

[185] Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.

attributed to higher growth in the residential and commercial sectors, namely from a projected increase in population (MRO-Manitoba-Table 2).

MRO-Manitoba Hydro-Table 2: Demand Outlook

MRO-Manitoba Hydro-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	3,210	3,474	264	8.2%	0.88%
Load-Modifying Demand Response	0	0	0	0.0%	0.00%
TOTAL INTERNAL DEMAND	**3,210**	**3,474**	**264**	**8.2%**	**0.88%**

MRO-Manitoba Hydro-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	4,661	5,162	501	10.8%	1.14%
Load-Modifying Demand Response	0	0	0	0.0%	0.00%
TOTAL INTERNAL DEMAND	**4,661**	**5,162**	**501**	**10.8%**	**1.14%**

Manitoba Hydro does not expect any significant long-term demand forecast change during the assessment period due to entity acquisitions or exits. Based on the 2011 Economic and Energy Price Outlook, no significant long-term demand change is forecast.

The peak load forecast model has been improved since the *2011 LTRA* with the inclusion hourly data by sector. While the previous model included hourly data at the total system level to determine the load shape for the entire system, the modified approach considers individual load shape all six sectors (Residential All-Electric, Residential Standard, General Service Mass Market, Top Consumers, Distribution Losses, and Transmission Losses). Load growth for each sector is incorporated in the model to determine future load shape and projected peak for the entire system.

Manitoba has a very stable population and a diversified economy with slow but steady growth across the assessment area. The largest customers are in the smelting, chemicals, and pipeline industries and have been operating for decades. Future load growth could be driven by new industries in the area, but are not anticipated at this time.

Demand-Side Management

During the first year of the assessment, the Demand Response used for Ancillary Services–Non Spinning Reserves is 50 MW in 2013. Energy Efficiency and Conservation programs will account for 42 MW for 2013.

During the final year of the assessment, the Demand Response used for Ancillary Services–Non Spinning Reserves remains unchanged at 50 MW. Contractually Interruptible demand response remains unchanged at 225 MW throughout the assessment period. Energy efficiency and conservation programs are projected to increase from 42 MW in 2013 to 419 MW in 2022 (MRO-Manitoba Hydro-Table 3).

MRO-Manitoba Hydro-Table 3: Demand-Side Management

	Short-Term					
MRO-Manitoba Hydro-Winter	2013/14	2014/15	2015/16	2022/23	10-Year Change	2022/23 Share of Total Internal Demand
Direct Control Load Management (DCLM)	0	0	0	0	0	0.00%
Contractually Interruptible (Curtailable)	225	225	225	225	0	6.48%
Critical Peak-Pricing (CPP) with Control	0	0	0	0	0	0.00%
Load as a Capacity Resource	0	0	0	0	0	0.00%
TOTAL RESOURCE-SIDE DEMAND RESPONSE	225	225	225	225	0	6.48%
Direct Control Load Management (DCLM)	0	0	0	0	0	0.00%
Contractually Interruptible (Curtailable)	0	0	0	0	0	0.00%
Critical Peak-Pricing (CPP) with Control	0	0	0	0	0	0.00%
Load as a Capacity Resource	0	0	0	0	0	0.00%
TOTAL LOAD-MODIFYING DEMAND RESPONSE	0	0	0	0	0	0.00%
TOTAL ENERGY EFFICIENCY	42	66	88	194	152	5.58%
TOTAL DEMAND-SIDE MANAGEMENT	**267**	**291**	**313**	**419**	**152**	**12.06%**

The Energy Efficiency or conservation growth pattern for Demand Response is expected to be minimal. Current Demand Response implementations are limited to interruptible customer load and are not expected to expand at this time. Demand Response programs are only being used during system contingencies or emergencies. The interruptible customer load may only be used to reduce peak demand if planning and/or contingency reserve obligations are in jeopardy of not being met.

Manitoba Hydro's current Power Smart portfolio includes customer service, cost-recovery, incentive-based and rate-based initiatives, and programs customized to meet the specific energy needs of the residential, commercial, and industrial markets. This portfolio, consisting of Energy Efficiency, conservation, load management, and customer self-generation programs, is designed to help customers conserve energy, reduce energy bills and protect the environment. No specific state or regulatory drivers affect Demand-Side Management (DSM) in Manitoba.

The driver behind all current Dispatchable and Controllable Demand Response programs in place at Manitoba Hydro is to provide operational flexibility for the system operator under emergency conditions. These Demand Response programs are all interruptible customer load for which the industrial customers receive reduced electricity rates in exchange for these services. No significant developments, policy changes, or enhanced implementations to the current programs are expected. The Demand Response program used for Ancillary Services (Non-Spinning Reserves) in place at Manitoba Hydro is the Curtailable Customer Load Option R. Manitoba Hydro has an agreement with a large industrial customer to carry 50 MW of Non-Spinning Reserves in the form of a curtailable customer load.

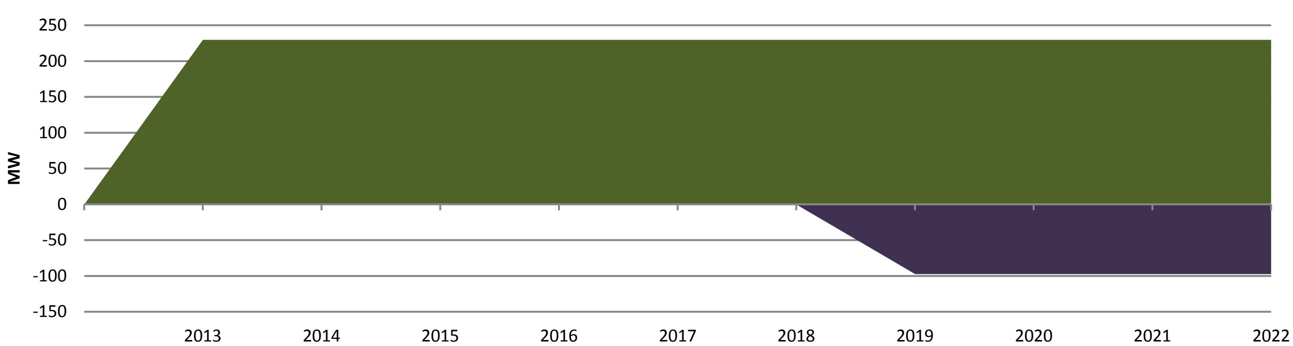
Generation

Current resources in Manitoba total 5,524 MW, with hydro as the primary fuel source in the assessment area. Since last year's assessment, 11 MW of nameplate capacity (hydro) from Kelsey upgrades have been added to Existing-Certain resources (MRO-Manitoba Hydro-Table 4 and MRO-Manitoba Hydro-Figure 2).

MRO-Manitoba Hydro-Table 4: Capacity Outlook[186]

	Current		2022/23 Planned			2022/23 Planned & Conceptual		
Manitoba Hydro-Winter	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
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	395	7.2%	395	7.0%	0	395	6.3%	0
Nuclear	0	0.0%	0	0.0%	0	0	0.0%	0
Other/Unknown	0	0.0%	0	0.0%	0	0	0.0%	0
Renewables	5,032	91.1%	5,262	93.0%	230	5,892	93.7%	860
TOTAL	**5,524**	**100.0%**	**5,657**	**100.0%**	**133**	**6,287**	**100.0%**	**763**

MRO-Manitoba Hydro-Figure 2: Winter Net Capacity Change[187]



Future-Planned hydro generation includes an addition of 22 MW from Kelsey upgrades and 208 MW from the construction of the Wuskwatim Generating Station (both 2012). Also in 2012, an additional 16.5 MW from the St. Leon wind farm is included. Manitoba Hydro's assessment includes 630 MW of conceptual capacity from the Keeyask Generating Station from 2019 to 2020. It is expected that in 2019, the coal unit at the Brandon Generating Station will be retired (approximately 95 MW). Manitoba Hydro uses an integrated resource planning process with a 35-year planning horizon to plan to meet the long-term needs of the Province of Manitoba. Units that are taken out of service during the summer and winter peaks

[186] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

[187] Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.

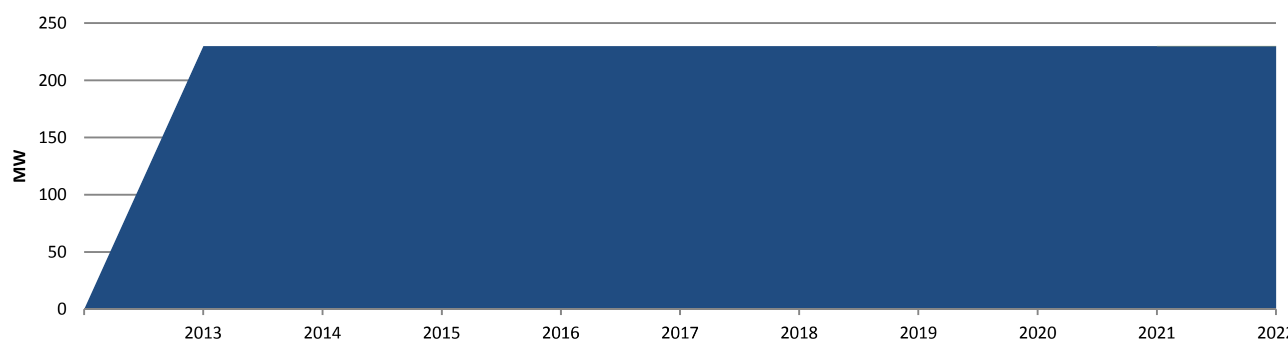
range between 5 MW and 147 MW over the assessment period. Approximately 8 MW of behind-the-meter generation per year is included in the assessment period.

For the 2011 resource adequacy study, wind generation was modeled as a simple load modifier with zero capacity value in the winter (December, January, and February), and an 8 percent capacity credit (19 MW) in the other months. The hydro capacity expected in the on-peak ranges from 4,929 MW to 5,008 MW, depending on the month, as median head conditions vary through the year. The maximum is 5,089 MW, based on nameplate capacity net of station service (MRO-Manitoba Hydro-Table 4 and MRO-Manitoba Hydro-Figure 3). The expected on-peak wind capacity for the summer is 8 percent of the nameplate capacity, and 0 percent for winter on-peak capacity. The expected hydro on-peak values are determined using testing and data processing procedures in accordance with the Midwest Reliability Organization (MRO) Generator Testing Guidelines[188] approved on March 29, 2007.

MRO-Manitoba Hydro-Table 4: Renewable Capacity Outlook[189]

	Current		2022/23 Planned			2022/23 Planned & Conceptual		
Manitoba Hydro-Winter	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Hydro	5,032	100.0%	5,262	100.0%	230	5,892	100.0%	860
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	**5,032**	**100.0%**	**5,262**	**100.0%**	**230**	**5,892**	**100.0%**	**860**

MRO-Manitoba Hydro-Figure 3: Winter Net Renewable Capacity Change[190]



The expected on-peak capacity that a unit can sustain is computed using the test results. These values are adjusted for ambient conditions and do not include any capacity utilized for station service. For reservoir hydro units, the values are corrected to the five-year median head for each month, while for run-of-river hydro units, the calculation is the average net integrated hourly capability for all hours of historical operation for each month (MRO-Manitoba Hydro-Table 5).

MRO-Manitoba Hydro-Table 5: Renewable Capacity Outlook: On-Peak Vs. Installed

	Current				2022/23 Planned			
MRO-Manitoba Hydro-Winter	Wind	Solar	Hydro	Biomass	Wind	Solar	Hydro	Biomass
Installed Capacity	259	0	5,170	0	275	0	5,400	0
On-Peak Derate	257	0	0	0	272	0	0	0
EXPECTED ON-PEAK OUTPUT	1	0	5,170	0	3	0	5,400	0

Operational procedures will be adjusted gradually as the wind penetration level is increased in the Manitoba Hydro footprint. The potential operational impact of increased wind includes reserve increases and automatic generation control (AGC) sensitivity. Wind forecasting methodologies have been studied for increasing levels of wind penetration, and various

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188 http://www.midwestreliability.org/03_reliability/06_gtrtf/Documents/MRO_Generator_Testing_Guidelines.pdf

189 "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

190 Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.

recommendations have been made for improvements, depending on the level of penetration studied. Recommendations for improvement include a probabilistic-based forecast approach, as well as decreasing the forecast time step to sub-hourly intervals.

Capacity Transactions

All of Manitoba Hydro's dependable exports and imports are backed by contracts. Manitoba Hydro has between 325 and 550 MW of Firm on-peak capacity exports and between 350 and 500 MW of Firm on-peak capacity imports in the winter and between 725 and 1080 MW of on-peak capacity exports in the summer and associated Firm transmission reservations during the assessment period (MRO-Manitoba Hydro-Table 6). Manitoba Hydro does not have any capacity imports during the summer. These contractual agreements have Firm transmission reservations associated with them with agreements that have staggered terms. Manitoba Hydro does not project any capacity transactions beyond the contract terms; however, in some cases contracts are expected to be rolled over with similar terms. Some future capacity export transactions are contingent upon additional resources being built.

MRO-Manitoba Hydro-Table 6: Projected Capacity Transactions

MRO-Manitoba Hydro-Winter	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
Expected Imports	200	200	200	200	200	200	200	200	200	200
Firm Imports	500	500	350	350	350	350	350	350	350	350
TOTAL IMPORTS	700	700	550	550	550	550	550	550	550	550
Expected Exports	0	0	0	0	0	0	0	250	475	475
Firm Exports	550	550	325	325	325	325	325	325	325	325
TOTAL EXPORTS	550	550	325	325	325	325	325	575	800	800
TOTAL NET CAPACITY TRANSACTIONS	**150**	**150**	**225**	**225**	**225**	**225**	**225**	**-25**	**-250**	**-250**

The Manitoba Hydro system is interconnected to three external systems: the MISO system to the south in the United States, and two other Canadian electric power systems, Saskatchewan Power Corporation and Ontario Independent Electricity System Operator. In a resource adequacy assessment, Manitoba Hydro considers non-Firm import as reserve sharing only from the United States (Western MISO Region), but not from other neighboring Canadian utilities. The reserve sharing with the United States is assumed to be possible only if the Western MISO Region system has adequate resource, meaning that the LOLE of Western MISO Region system is not worse than 0.1 days per year.

Transmission

Transmission projects expected to be completed in the Manitoba Assessment Area during the long-term outlook for this assessment are listed in Appendix II. Additionally, a summary of existing and projected transmission additions is provided below (MRO-Manitoba Hydro-Table 7).

MRO-Manitoba Hydro-Table 8: Existing and Projected Transmission

MRO-Manitoba Hydro	AC (Circuit Miles)	DC (Circuit Miles)	Total (Circuit Miles)
EXISTING	6,340	1,145	7,485
Currently Under Construction	0	0	0
Planned - Completed within First Five Years	237	0	237
Planned - Completed within Second Five Years	243	833	1,076
2022 TOTAL (UNDER CONSTRUCTION & PLANNED)	6,820	1,978	8,798
Conceptual - Completed within First Five Years	0	0	0
Conceptual - Completed within Second Five Years	80	0	80
2022 TOTAL (UNDER CONSTRUCTION, PLANNED & CONCEPTUAL)	**6,900**	**1,978**	**8,878**

A fourth transformer addition at Cornwallis Station is required and planned to provide Firm capacity to the Brandon Area due to restricted operation of the Brandon Unit 5 coal-fired generator. New provincial legislation aimed at greenhouse gas reduction only allows operation of the coal unit under emergency or drought conditions. There are plans to extend Cornwallis Station to accommodate a fourth 230-115 kV transformer and a new 230 kV breaker. Also planned are upgrades and re-routing of 115 kV transmission lines BE3 (Brandon–Brandon Victoria), CB3 (Cornwallis–Brandon), MR11 (Raven Lake–Brandon Victoria), and CB4 (Cornwallis–Brandon). Installation of the fourth transformer and associated transmission line upgrades are estimated to be in service by May 2013. A new 500/230 kV Riel Station consists of establishing a new station, which will involve:

- Installing a 230 kV to 500 kV transformer bank

- Sectionalizing the existing Dorsey–Forbes 500 kV line
- Sectionalizing two existing 230 kV lines (Ridgeway–St. Vital lines R32V and R33V and Ridgeway–Richer Line R49R)

Winnipeg Area Transmission Refurbishments consist of an estimated 113 miles of 230 kV transmission lines that will be upgraded to carry higher loading. Several new 230/115 kV and 66 kV transformers are being added to the system. The sites include Rockwood, Transcona, Stanley, and Neepawa stations. The Rosser–Parkdale–Selkirk 115 kV Transmission System project consists of development of the new 230/115 kV Rockwood Station supplied from the sectionalized Ashern–Rosser 230 kV transmission line A3R (Ashern–Rosser). A 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 Scotland (now called Stafford) Station rebuild is required in order to provide additional capacity to the core Winnipeg Area and to facilitate the replacement of aging equipment at Scotland Station. The Scotland 138 kV and 115-66 kV Terminal Station is going to be rebuilt. This will involve reusing four 138-66 kV transformers, two 115-66 kV transformers, installing two new 125 MVA 115-66 kV transformers, and new 66 kV and 115 kV ring buses. In addition, the 138 kV transmission systems between Pointe Du Bois, Slave Falls, and Scotland will be converted to 115 kV so that the former Winnipeg Hydro transmission can be integrated into the Manitoba Hydro 115 kV system. Pointe Du Bois 138-66 kV Bank 7 will be replaced by a new 115-66 kV 60 MVA bank to accommodate the voltage conversion. Finally, the termination of lines YH33 (Laverendrye–Harrow) and VS27 (St. Vital–Scotland) will be relocated from Harrow to the new Stafford Station. The scheduled in-service date is estimated to be 2014.

Pointe du Bois transmission line replacement consists of retiring four 66 kV Pointe du Bois–Rover transmission lines on two parallel sets of steel towers that cover 77 miles. The lines were first installed in 1910 and have reached the end of their life. They will be replaced 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:

- Advance construction of a new 115 kV switchyard at Pointe du Bois.
- Installing a new 66 kV Line from Ridgeway to Rover, including terminations at both stations
- Salvaging two 115-66 kV banks at Transcona Station.
- Increasing the rating of 115 kV Slave Falls transmission lines designated S1 & S2 (Slave Falls–Scotland).

Manitoba Hydro is planning to establish a new 230-66 kV station at Neepawa and tap the existing line D54C (Dorsey–Cornwallis). This project has been delayed for two years due to budget constraints.

The deferral of the Neepawa 230-66 kV Station combined with the proposed new pipeline load in the area increases the risk of under-voltage conditions for outages of either line MR11 (Ravern Lake–Brandon Victoria) or BN5 (Brandon–Neepawa). Operating guides will be put in place as required. Brandon Generating Station Unit 5 was modified in December 2010 to permit synchronous condenser operation, which provides additional local area voltage support.

The Bipole III transmission line from Keewatinoow Converter Station in the north to the Riel Converter Station near Winnipeg will have sufficient capacity to support the Future-Planned Keeyask 630 MW generation plant. The Bipole III routing project on the west side of the province includes:

- ±500 kV HVdc transmission line, about 833 miles long, from Keewatinoow Converter Station to Riel Converter Station
- 2,000 MW converter station at Keewatinoow near the future Conawapa Generating Station
- five ac transmission lines each approximately 19 miles in length to connect the Keewatinoow Converter Station to the existing northern ac collector system
- 2,000 MW converter station at Riel, including 4 x 250 Mvar synchronous compensators

Other significant substation equipment to be added within the Manitoba Assessment Area includes:

- Brandon Generating Station 54 Mvar 115 kV capacitor (4th) (October 2012)
- Riel 230 kV 3 X 73.4 Mvar capacitors (May 2014)

- Keewatinoow and Riel—2000 MW converters at each station (October 2017)
- Riel synchronous condensers (4 X 250 Mvar) (October 2017)
- Dorsey 150 Mvar line reactor—new (May 2018)
- Dorsey bank 51, second stage 73.4 Mvar tertiary capacitors (May 2018)
- Riel 2nd 230/500 kV transformer bank with 2 x 73.4 Mvar tertiary capacitors (May 2019)

Vulnerability Assessment

Several factors could potentially impact the performance adequacy of the Manitoba Hydro system. The primary concerns include extended drought conditions, increased generating unit forced outage rates, and load forecast uncertainty in load forecast beyond that anticipated.

Manitoba Hydro considers extended drought conditions in planning resources and evaluating system resource adequacy. Manitoba Hydro uses an energy criterion for extended drought conditions. The criterion requires adequate energy resources to supply Firm energy demand in the event that the lowest recorded coincident river flow conditions on the available historic hydraulic flow record are repeated. In addition, hydro units are modeled as energy limited resources in the probabilistic resource adequacy study with the energy limits for the applicable cases based on drought or extreme drought conditions.

Generating unit forced outages are considered in the probabilistic resource adequacy studies. Sensitivity analysis on the hydro units forced outage rates of the hydro units that predominate in Manitoba Hydro's system indicates low impact on Planning Reserve Margin Requirements.

Generally, a higher reserve capacity is required in order to maintain a specified level of reliability for an uncertain load than for a known load. Uncertainties in the economy, weather, and temperature would impact the accuracy of forecast load. Probabilistic resource adequacy studies on the Manitoba Hydro system indicate that the load forecast uncertainty negatively impacts Manitoba Hydro's system resource adequacy.

Manitoba does not have a Renewable Portfolio Standard (RPS). Considering that Manitoba's typical energy production is already 98 percent renewable, the potential for a provincial RPS is very low.

Manitoba Hydro currently has approximately 200 MW of Demand Response under Options A, C, E and R of its Curtailable Rates Program. Due to modeling complexities combined with uncertainty as to the customer's long-term commitments to the Curtailable Rates program, these Demand Response resources were not considered in the pending 2012 resource adequacy study. While this assumption is conservative for now, its appropriateness will be reviewed for future LOLE studies. There are no resource adequacy concerns for unavailable/unresponsive Demand Response programs in Manitoba Hydro. The most significant operational concern for this scenario is the need to carry contingency reserves elsewhere when the non-spinning reserves normally available as Demand Response are unresponsive. In addition, when interruptible customer load is unavailable, system operators will have to rely more heavily on emergency energy purchases prior to shedding Firm load under severe system contingencies.

The most likely increase in variable generation in the foreseeable future is wind-related. The addition of new resources would help with resource adequacy issues, and the addition of plausible amounts of wind generation does not raise any significant operational concerns, given the significant operating flexibility of the existing hydro resources.

Currently Manitoba Hydro does not have any Under-Voltage Load Shedding (UVLS) relays installed and has no plans to install any in the 10-year planning horizon.

A new SPS is planned to be installed at Grand Rapids Generating Station. When north-to-south transfers are high in Manitoba, there is potential to thermally overload one or more of the Grand Rapids Generating Station outlet lines when one of the four generator outlet line trips. The SPS will convert one of the Generating Station units to a synchronous condenser within two minutes of an outlet line tripping, thus preventing line overload while maintaining dynamic var reserves. This will be a permanent solution.

A new SPS is also planned to be installed at Raven Lake Station on 115 kV line MR11 (Raven Lake–Brandon Victoria). When north-to-south transfers in Manitoba are high, there is potential to thermally overload this line for loss of the 230 kV line C28R (Cornwallis–Reston). Over-current tripping of line MR11 will be initiated to alleviate the thermal overload issue. This will be a permanent solution.

Manitoba Hydro has conducted an assessment of vulnerabilities considering low probability extreme weather events and other hazards, such as fires. These low probability events could result in catastrophic outages. Manitoba Hydro has evaluated the risks of these extreme disturbances and associated consequences and has determined that the consequences are too great to be ignored. To mitigate these low-probability and high-impact events and improve system reliability, an additional transmission line located on a separate corridor and associated facilities is planned to provide an alternative north-to-south transmission route and power injection point in the south of Manitoba. Reliability enhancement against fire risks is also in progress.

Manitoba Hydro has already deployed Static Var Compensators (SVCs) at several stations to improve system reliability. A number of Phasor Measurement Units (PMUs) have also been deployed at various points on Manitoba Hydro system, and a data analysis tool is being used to process the collected data to improve system simulation models and fine tune controls. Future plans include the use of PMU data for real-time visualization and decision support tools for system operators. Short-term plans to increase reliability through the use of technology include dynamic security assessment, dynamic equipment ratings, advanced equipment monitoring, and fault current mitigation.

There are no significant smart grid programs currently planned at the distribution level that would impact reliability of the transmission in the bulk power system.

Manitoba Hydro's generation portfolio is dominated by over 95 percent hydro-powered generation. Future plans for new hydro generation to satisfy reliability concerns do not experience the same environmental limitations as the fossil fuel-based alternatives. No significant future environmental regulations will have an impact on reliability.

Operation of the coal-fired Brandon Generating Station is restricted to use for emergency preparedness only, for reliability and staff training purposes. There is sufficient time to perform required retrofits on the coal-fired Brandon Generating Station when the greenhouse gas regulations are introduced and clarified, since it is anticipated that enough lead time will be given to allow for appropriate mitigation.

Plans for Accommodating Generator Retirements and Environmental Control Retrofits

Operation of the coal-fired Brandon Generating Station is restricted to use for emergency preparedness only, for reliability and staff training purposes. There is sufficient time to perform required retrofits on the coal-fired Brandon Generating Station when the greenhouse gas regulations are introduced and clarified, since it is anticipated that enough lead time will be given to allow for appropriate mitigation.

The Climate Change and Emissions Reductions Act was enacted by the Province of Manitoba. Since January 1, 2010, provisions under the act have restricted the use of coal generation electricity except in support of emergency operations and drought. In addition to meeting any emergencies, the one remaining coal unit, Brandon Unit #5, may be also be operated to provide for staff training and unit testing to ensure that the unit is maintained in a ready state.

The Government of Canada has a national Greenhouse Gas Emissions Reporting Program (GHGRP). This program applies to the industrial greenhouse gas emitters in Canada. Starting in 2009, all facilities that emit the equivalent of 50,000 tonnes or more of greenhouse gases in carbon dioxide equivalent units per year are required to report their emissions.

Manitoba Hydro has a comprehensive greenhouse gas management strategy to reduce emissions. Actions taken to date include retiring four coal units, converting and additional two coal units to gas-fired operation, developing new hydropower and wind, and increasing the efficiency of our generation and transmission system. Another key component of this strategy is Manitoba Hydro's long-term commitment to demand-side efficiency improvements through its PowerSmart programs.

Current plans count on the one remaining coal-fired unit, Brandon Unit #5, until 2019. However, depending on various considerations, the unit may continue to provide emergency services beyond this time frame.

There are no anticipated reliability impacts associated with the US environmental regulatory requirements for Manitoba Hydro.

Standing and Emerging Reliability Issues

Each of the three reliability issues identified above is further assessed below.

1. Critical Infrastructure Protection – Extreme Weather Event

This was reported in the *2011 LTRA*; NERC's Technical Committees set up several task forces to investigate high-impact, low-probability events (Spare Equipment data TF and Severe Impact Restoration TF).

The *2012LTRA* Reference case incorporates plans to address the reliability issue. A severe event, such as a naturally occurring hazard (tornado, ice storm), could severely limit the north-to-south transfer capability in Manitoba, which could result in long-duration rotating blackouts in Manitoba.

Significant loss of transmission due to a corridor loss or station loss can restrict the ability of large amounts of generation to serve load.

This issue directly affects transmission adequacy. Generation-to-load transfer capability would be severely diminished for a duration that depends on the underlying cause.

This type of event includes loss of an entire substation and/or loss of a transmission corridor. These events could be caused by extreme weather (fire, tornado, ice storms) or sabotage. These events could cripple operation of the Bulk Electric System (BES) in Manitoba. Manitoba Hydro has operated to protect against a severe disturbance when the likelihood of an extreme weather event has increased to a certain threshold. For example, Manitoba Hydro has developed a "Hydro Proximity Report" application that monitors storm events and their proximity to key infrastructure. If the "Hydro Proximity Report" indicates that a tornado or other strong wind event is threatening key infrastructure, Manitoba Hydro will reduce transfers to ensure that the severe event will not cause Manitoba Hydro to lose its interconnection ties.

Additional Information – Preparedness for Extreme Weather Events

Severe events, such as loss of an entire substation or transmission corridor, are low in probability but can have major consequences, such as long-duration rotating blackouts. An assessment of the vulnerability of Manitoba's facilities to extreme weather and other disturbances was conducted, and it was determined the risk was too great to be ignored. To date, Manitoba Hydro has not experienced any reliability issues associated with high-impact, low-probability events. To mitigate these potential reliability concerns, plans are in place to construct an additional north-to-south transmission line on a separate corridor by 2017. Until these facilities are in place, severe weather is monitored in the operating horizon. Power transfers on the north-to-south flow facilities are reduced if the severe weather is threatening key infrastructure. Loss of these facilities at reduced loading will prevent cascade tripping.

2. Geomagnetic Disturbances

This was reported in the *2011LTRA*. The NERC Planning Committees set up a task force to investigate the impact of geomagnetic disturbances on the grid.

The *2012LTRA* Reference case does not include any specific plans to address the issue. A severe geomagnetic disturbance is forecast to occur roughly coincidental with the peak of sunspot activity that occurs every 12 to 13 years. The last peak in sunspot activity occurred between 2000 and 2003. The next peak is forecast between 2013 and 2016. The geomagnetic disturbance causes dc current to flow in neutral grounded transformers, which can saturate the banks and lead to shortages of reactive power. Manitoba Hydro analysis conducted to date has indicated that geomagnetic disturbance could impact parts of Manitoba Hydro's 230 kV northern network. The potential impact has not been quantified.

The DC current caused by geomagnetic disturbances can cause transformer equipment damage or misoperation of Static Var Compensators. Manitoba Hydro has developed special equipment specifications and test procedures to minimize this possibility. Monitoring equipment is placed strategically to quantify the magnitude of DC current and notify system operators. Research is underway to develop better analysis tools for determining whether further mitigation is warranted or new operating procedures are required.

Manitoba Hydro has developed operating procedures to minimize the impact of a geomagnetic disturbance. These procedures are implemented once the Reliability Coordinator notifies Manitoba Hydro that an upcoming event has met or exceeded thresholds (per Geomagnetic Disturbance Procedure RTO-OP-053-r4). The Reliability Coordinator receives indices from Boulder, Colorado that indicate the intensity of the geomagnetic disturbance.

3. Integration of Variable Generation

Integration of Variable Generation is a standing issue. This was reported in the 2011 LTRA. The NERC Planning Committee has set up the Integration of Variable Generation Task Force.

The reference case does not include any specific plans to address the issue.

Interconnection of additional variable generation in neighboring Regions to Manitoba changes during the 10-year horizon.

Long-term planning studies indicate potentially significant loop flow in Manitoba due to U.S.-connected wind generation. The loop flow could cause thermal overloads or reduced reactive power reserves in southern Manitoba. In addition, area control error could increase due to the lack of fast-acting regulating reserves in neighboring Regions.

In most studies, transmission is being added only to address Firm capacity levels of variable generation (e.g., 10 to 40 percent of nameplate), which means a significant proportion of the output is non-Firm. Re-dispatch may not be available in the planning horizon to address transmission adequacy issues.

The proliferation of variable resources like wind has introduced complexity into the operating environment. Many wind plants do not build facilities to allow Firm transmission of their wind energy. Loop flow and congestion caused by wind resources outside Manitoba Hydro's service area are the operational issues that arise from integration of these resources. As such, operating guides that curtail wind resources and other resources are used as a mitigating strategy to ensure reliable operations when transmission capacity is exceeded.

MRO-MAPP

Planning Reserve Margins

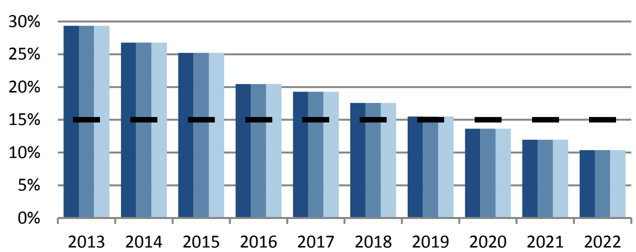
MAPP is projecting adequate Planning Reserve Margins during the 2013–2022 assessment period. All Planning Reserve Margin categories (Anticipated, Prospective, and Adjusted Potential) exceed the NERC Reference Margin Level of 15 percent due to the area's strong generation portfolio and Demand-Side Management programs through 2019 (MRO-MAPP-Table 1 and MRO-MAPP-Figure 1).

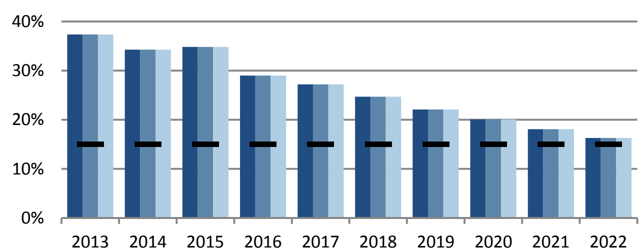
MRO-MAPP-Table 1: Planning Reserve Margins

MAPP-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		29.36%	26.79%	25.21%	20.46%	19.28%	17.57%	15.50%	13.65%	11.97%	10.36%
PROSPECTIVE		29.36%	26.79%	25.21%	20.46%	19.28%	17.57%	15.50%	13.65%	11.97%	10.36%
ADJUSTED POTENTIAL		29.36%	26.79%	25.21%	20.46%	19.28%	17.57%	15.50%	13.65%	11.97%	10.36%
NERC REFERENCE	-	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**

MAPP-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		37.37%	34.28%	34.82%	29.00%	27.20%	24.70%	22.11%	20.07%	18.10%	16.29%
PROSPECTIVE		37.37%	34.28%	34.82%	29.00%	27.20%	24.70%	22.11%	20.07%	18.10%	16.29%
ADJUSTED POTENTIAL		37.37%	34.28%	34.82%	29.00%	27.20%	24.70%	22.11%	20.07%	18.10%	16.29%
NERC REFERENCE	-	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**

MRO-MAPP-Figure 1: Summer (Left) and Winter[191] (Right) Planning Reserve Margins





The Anticipated Reserve Margin falls below the NERC Reference Margin Level in 2020 and reaches 10.36 percent in 2022. This is a common situation in MAPP, which has traditionally planned to meet the NERC Reference Margin Level at least five to six years in advance, without considerations for additional Firm contracts or new peaking capacity units that have less certainty in the final years of the 10-year assessment. MAPP will provide more accurate plans for 2020–2022 in future long-term assessments, as load projections become more accurate, long-term contracts are executed, and new generation resources are planned. MAPP does not anticipate any scenarios that would lead to a significant detraction from these projections for this assessment period.

Demand

The forecasted 10-year compound annual growth rate for Total Internal Demand remains flat at 2.09 percent for the summer and 2.19 percent for the winter, increasing from 4,995 MW in 2013 to 6,015 MW in 2022 for the peak season (MRO-MAPP-Table 2). This amounts to a 2.09 percent CAGR for the summer demand.

MRO-MAPP-Table 2: Demand Outlook

MRO-MAPP-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	4,904	5,906	1,002	20.4%	2.09%
Load-Modifying Demand Response	91	109	18	19.3%	1.98%
TOTAL INTERNAL DEMAND	**4,995**	**6,015**	**1,020**	**20.4%**	**2.09%**

MRO-MAPP-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	4,858	5,904	1,047	21.5%	2.19%
Load-Modifying Demand Response	0	0	0	0.0%	0.00%
TOTAL INTERNAL DEMAND	**4,858**	**5,904**	**1,047**	**21.5%**	**2.19%**

[191] Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.

Certain load-centers (e.g., large cities) are no longer included in the MRO-MAPP Assessment Area. These changes to the assessment area did not have much of an impact on demand growth, which remained essentially unchanged since the *2011LTRA*. There were no changes or enhancements this year to the forecasting methods used by MAPP last year. 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 forecast 10-year annual growth rate of 6.9 percent for Total Internal Demand. This growth rate is primarily due to the downtown area development of City of Rochester and the expansion of the Mayo Clinic. MAPP continues to monitor the potential impact to demand that may be attributed to the increasing development in the oil and gas production in the Bakken Formation in western North Dakota and eastern Montana. In April 2008, the U.S. Geological Survey (USGS) estimated that the Bakken Formation is larger than all other current USGS oil assessments of the lower 48 states and is the largest “continuous” oil accumulation ever assessed by the USGS.

Demand-Side Management

The total on-peak amount of Demand Response and Energy Efficiency/Conservation projected to be available for 2013 is 129 MW. The total on-peak amount of Demand Response and Energy Efficiency/Conservation projected to be available during the tenth year of the assessment (2022) is 190 MW. The growth pattern for Demand Response is a flat 1 percent throughout the assessment period. The growth pattern for Energy Efficiency / Conservation has more than triple during this assessment period, growing from approximately 22 MW in 2013 to 66 MW in 2022 (MRO-MAPP-Table 3).

MRO-MAPP-Table 3: Demand-Side Management

	Short-Term					
MRO-MAPP-Summer	2013	2014	2015	2022	10-Year Change	2022 Share of Total Internal Demand
Direct Control Load Management (DCLM)	5	5	5	5	0	0.09%
Contractually Interruptible (Curtailable)	10	10	10	10	0	0.17%
Critical Peak-Pricing (CPP) with Control	0	0	0	0	0	0.00%
Load as a Capacity Resource	0	0	0	0	0	0.00%
TOTAL RESOURCE-SIDE DEMAND RESPONSE	16	16	16	16	0	0.26%
Direct Control Load Management (DCLM)	86	88	90	104	18	1.73%
Contractually Interruptible (Curtailable)	5	5	5	5	0	0.08%
Critical Peak-Pricing (CPP) with Control	0	0	0	0	0	0.00%
Load as a Capacity Resource	0	0	0	0	0	0.00%
TOTAL LOAD-MODIFYING DEMAND RESPONSE	91	93	95	109	18	1.81%
TOTAL ENERGY EFFICIENCY	22	26	31	66	44	1.10%
TOTAL DEMAND-SIDE MANAGEMENT	**129**	**135**	**142**	**190**	**61**	**3.16%**

There have not been any significant changes regarding dispatchable and controllable Demand Response, or Demand Response used for ancillary services in MAPP. The amount of DSM in these areas remains flat.

Generation

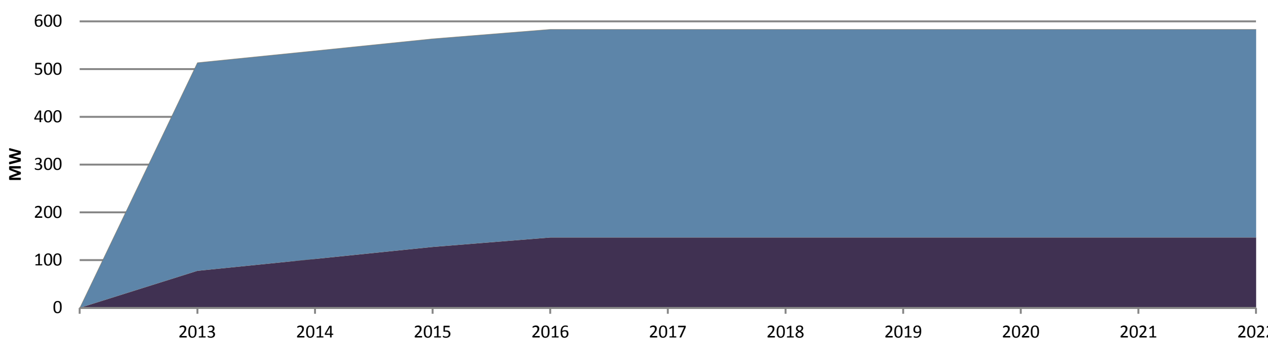
Current capacity amounts to 7,319 MW. There is currently no capacity categorized as Existing-Other or Existing-Inoperable. The primary fuel sources in MAPP are coal, hydro, natural gas, followed by oil and wind. Added capacity since the *2011LTRA* amounts to only about 50 MW.

There are 584 MW of Future-Planned and Conceptual resources projected to come on-line throughout the assessment time frame (MRO-MAPP Table 4 and MRO-MAPP Figure 2).

MRO-MAPP-Table 4: Capacity Outlook[192]

		Current		2022 Planned			2022 Planned & Conceptual		
MRO-MAPP-Summer		Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Coal		3,174	43.4%	3,322	42.0%	148	3,322	42.0%	148
Petroleum		597	8.2%	597	7.6%	0	597	7.6%	0
Gas		999	13.7%	1,435	18.2%	436	1,435	18.2%	436
Nuclear		60	0.8%	60	0.8%	0	60	0.8%	0
Other/Unknown		41	0.6%	41	0.5%	0	41	0.5%	0
Renewables		2,448	33.4%	2,448	31.0%	0	2,448	31.0%	0
TOTAL		**7,319**	**100.0%**	**7,903**	**100.0%**	**584**	**7,903**	**100.0%**	**584**

MRO-MAPP-Figure 2: Summer Net Capacity Change



There have been no significant unit retirements, deferments, derates, or other negative impact to Existing-Certain capacity in the prior year.

MAPP is not projecting any significant new generation, generator uprates, units taken out of service, units brought back in service, or long-term outages over the assessment period. There has been no change in behind-the-meter generation, or changes in other "non-traditional" resources in the previous year.

Of the total existing capacity, 251 MW of wind generation is expected on-peak, with a nameplate rating of 1,100 MW. To determine wind expected peak, MAPP utilizes a methodology that is based on a median of actual wind output. The same four peak hours per day for each day of the month are used. The four peak hours may change from month to month. This data set consists of 10 years of data or the life of the wind farm. Additionally, there are 2,193 MW of hydro and 3 MW of biomass Existing-Certain Capacity Resources in MAPP (MRO-MAPP-Table 5).

MRO-MAPP-Table 5: Renewable Capacity Outlook[193]

	Current		2022 Planned			2022 Planned & Conceptual		
MRO-MAAP-Summer	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Hydro	2,193	89.6%	2,193	89.6%	0	2,193	89.6%	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	251	10.3%	251	10.3%	0	251	10.3%	0
Biomass	3	0.1%	3	0.1%	0	3	0.1%	0
Solar	0	0.0%	0	0.0%	0	0	0.0%	0
TOTAL	**2,448**	**100.0%**	**2,448**	**100.0%**	**0**	**2,448**	**100.0%**	**0**

No abnormal operating conditions or restrictions due to the integration of variable resources are expected to impact reliability during the assessment period. Hydro conditions are expected to be normal, with reservoir levels back to a normal level after several seasons of low water (MRO-MAPP-Table 6).

MRO-MAPP-Table 6: Renewable Capacity Outlook

Current	2022 Planned

[192] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

[193] *Ibid*.

MRO-MAPP-Summer	Wind	Solar	Hydro	Biomass	Wind	Solar	Hydro	Biomass
Installed Capacity	1,104	0	2,357	3	1,104	0	2,357	3
On-Peak Derate	853	0	164	0	853	0	164	0
EXPECTED ON-PEAK OUTPUT	251	0	2,193	3	251	0	2,193	3

Capacity Transactions

MAPP is projecting total Firm imports of 307 MW in 2013, increasing to 318 MW by 2022. Additionally, MAPP is projecting total Firm exports of 1,517 MW in 2013, decreasing to 1,424 by 2022. Net capacity transactions remain negative throughout the assessment period (MRO-MAPP-Table 7).

MRO-MAPP-Table 7: Projected Capacity Transactions

MRO-MAPP-Summer	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Expected Imports	0	0	0	0	0	0	0	0	0	0
Firm Imports	307	313	319	312	314	316	318	318	318	318
TOTAL IMPORTS	307	313	319	312	314	316	318	318	318	318
Expected Exports	0	0	0	0	0	0	0	0	0	0
Firm Exports	1,517	1,522	1,493	1,424	1,424	1,424	1,424	1,424	1,424	1,424
TOTAL EXPORTS	1,517	1,522	1,493	1,424	1,424	1,424	1,424	1,424	1,424	1,424
TOTAL NET CAPACITY TRANSACTIONS	**-1,210**	**-1,209**	**-1,174**	**-1,112**	**-1,110**	**-1,108**	**-1,106**	**-1,106**	**-1,106**	**-1,106**

No emergency MW imports are required to meet the reserve margin target in MAPP.

Transmission

MAPP has 230 miles of greater-than-100 kV transmission line under construction and 716 miles of planned transmission projects above 100 kV that are expected to be in service within five years (MRO-MAPP-Table 8). These projects are anticipated to come into service during the 2013–2022 study period to enable reliable and efficient transmission service for the MAPP Assessment Area. There is no potential reliability impact in not meeting target in-service dates of transmission identified. MAPP does not anticipate any existing, significant transmission lines or transformers being out of service through the assessment period. MAPP does not have any transmission constraints that could significantly impact reliability. One transmission project was noted to have permitting delays, but the delays are not expected to impact reliability. Sufficient transmission is being built to support its Future-Planned generation. During the assessment period, several significant transformers are also planned to be upgraded.

MRO-MAPP-Table 8: Existing and Projected Transmission

MRO-MAPP	AC (Circuit Miles)	DC (Circuit Miles)	Total (Circuit Miles)
EXISTING	10,266	0	10,266
Currently Under Construction	230	0	230
Planned - Completed within First Five Years	716	0	716
Planned - Completed within Second Five Years	0	0	0
2022 TOTAL (UNDER CONSTRUCTION & PLANNED)	11,211	0	11,211
Conceptual - Completed within First Five Years	107	0	107
Conceptual - Completed within Second Five Years	0	0	0
2022 TOTAL (UNDER CONSTRUCTION, PLANNED & CONCEPTUAL)	**11,318**	**0**	**11,318**

Vulnerability Assessment

With MAPP's current generation capacity margin and average to high water levels, there are no resource adequacy or operational concerns. Renewable Portfolio Standards (RPS) are not projected to impact reliability in the assessment period.

There are no expectations to install additional Under-Voltage Load Shedding (UVLS) schemes in MAPP. MAPP does not have a regional UVLS requirement. Although Special Protection Systems or Remedial Action Schemes are sometimes utilized in MAPP, none are projected to be installed in lieu of planned bulk power transmission facilities.

MAPP relies on the Balancing Authorities to plan for catastrophic/hi-impact, low-frequency (HILF) events. Currently, there is no regional plan in place.

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

MAPP and MAPP Members continue to work with the MRO and its Subject Matter Expert (SME) teams and their application guides for protection and control to reduce the amount of relay protection misoperations.

The pending future environmental regulations may have an impact on reliability in the MAPP Assessment Area. However, the extent of the reliability impact on the MAPP Assessment Area is unknown until all impacted Generator Owners have announced their plans for compliance with the EPA regulation. MAPP continues both internally and in collaboration with stakeholders to maximize preparedness for the impact of this and other regulations.

Plans for Accommodating Generator Retirements and Environmental Control Retrofits

MAPP generators report that they are in compliance with current EPA regulations and Existing Units will be in compliance by the required dates for newly finalized EPA regulations. A few smaller IC units have been retired due to the new regulations, since it would have been cost prohibitive to retrofit the units to meet the regulations.

Generally, MAPP generators are already in compliance or plan to be so by the effective date of EPA regulations. One member reports, emission control technologies have been recently installed and mercury control technology will be optimized 4th quarter 2012 to determine if additional controls will be needed.

One MAPP member has reported it already made the required preparations for integrating its future generation additions. All physical onsite preps have been completed and the permitting and licensing requirements are in process.

MPC reports, the completion of a new 345 kV transmission line at the end of 2013 will allow additional energy from a compliant unit to be brought into Minnkota's service area.

As stated, HUC has retired old generation and new generation is being installed currently.

Heartland has sufficient resource to meet all of its demand and planning margin requirements for the foreseeable future. No new resources, supply or demand side, are planned at this time.

WAPA reports there are plans to uprate the Fort Randall units, which would result in a 28% increase in capacity/unit. However at this time it is unfunded.

Minnkota reports its units are in compliance (earlier than the required date), and is not aware of the need for the assessment.

HUC has done its own internal assessment as to the reliability impact of the new environmental regulations and the current generation plan is the result of that assessment. HUC will perform its own assessments if necessary. Any/all plans are discussed through coordinated meetings with HUC's balancing authority (GRE) prior to implementation.

Standing and Emerging Reliability Issues

Integration of Variable Resources – Planning Perspective

One of the emerging issues within MAPP is the integration of variable resources, such as wind turbines. Many states in MAPP have a renewable energy mandate or goal. It is expected 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. The integration does not cause undo reliability issues on its own, but it does change the nature of how the BPS is operated.

As the amount of wind resources increases, its 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 will need to be dedicated into 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, resource adequacy may become a concern if additional regulations or rules (clean energy standards, carbon reduction) are implemented. Additionally, economic factors may increase the amount of intermittent resources found on the system, such as higher gas prices or lower construction costs for the intermittent resources.

Transmission In-Service Dates

Another emerging issue that impacts MAPP as well as other Assessment Areas is the complex process for getting transmission projects built. Transmission projects that do not get built, or get 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. A Loss of Load Expectation (LOLE) study may reveal constrained interfaces within MAPP. 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

Planning Reserve Margins

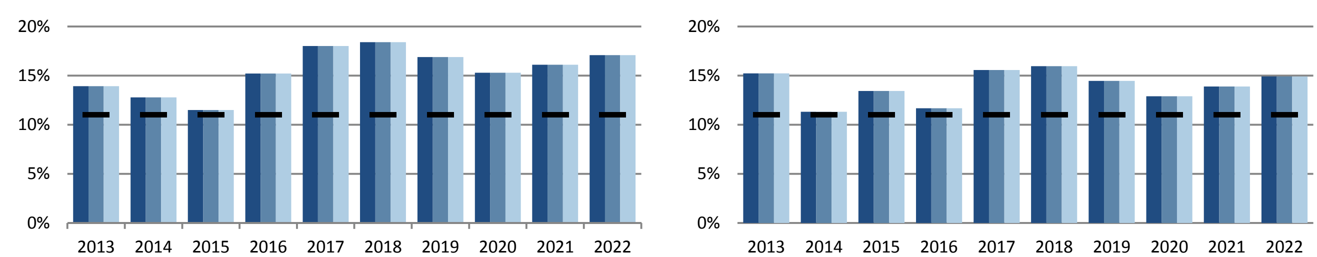
Saskatchewan is projecting adequate Planning Reserve Margins based on Expected Unserved Energy (EUE) analysis. Saskatchewan's criteria for adding new generation resources are also based on EUE. Saskatchewan performs an annual probabilistic analysis to determine the requirement for adding new generation resources. The probabilistic EUE value equates to an approximate 11 to 18 percent reserve margin based on the deterministic calculation (MRO-SaskPower-Table 1 and MRO-SaskPower-Figure 1). When evaluating system requirements for new generation, SaskPower utilizes a most likely load forecast accounting for load risk to project demand requirements. This is not based on a 50/50 probability. For the purpose of this study, utilization of a less conservative 50/50 load forecast probability would result in higher reserve margins ranging from approximately 16 to 23 percent. Furthermore, for the purpose of this assessment, the NERC Reference Margin Level is 11 percent (lower end of probabilistic EUE range) throughout the assessment period. Saskatchewan has planned for adequate resources to meet anticipated load throughout the assessment period.

MRO-SaskPower-Table 1: Planning Reserve Margins

SaskPower-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		13.93%	12.79%	11.51%	15.22%	18.02%	18.41%	16.89%	15.29%	16.11%	17.10%
PROSPECTIVE		13.93%	12.79%	11.51%	15.22%	18.02%	18.41%	16.89%	15.29%	16.11%	17.10%
ADJUSTED POTENTIAL		13.93%	12.79%	11.51%	15.22%	18.02%	18.41%	16.89%	15.29%	16.11%	17.10%
NERC REFERENCE	-	**11.00%**	**11.00%**	**11.00%**	**11.00%**	**11.00%**	**11.00%**	**11.00%**	**11.00%**	**11.00%**	**11.00%**

SaskPower-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		15.24%	11.33%	13.43%	11.68%	15.57%	15.97%	14.47%	12.91%	13.90%	14.93%
PROSPECTIVE		15.24%	11.33%	13.43%	11.68%	15.57%	15.97%	14.47%	12.91%	13.90%	14.93%
ADJUSTED POTENTIAL		15.24%	11.33%	13.43%	11.68%	15.57%	15.97%	14.47%	12.91%	13.90%	14.93%
NERC REFERENCE	-	**11.00%**	**11.00%**	**11.00%**	**11.00%**	**11.00%**	**11.00%**	**11.00%**	**11.00%**	**11.00%**	**11.00%**

MRO-SaskPower-Figure 1: Summer (Left) and Winter[194] (Right) Planning Reserve Margins



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

Demand

The forecasted compound annual growth rates (CAGR) Total Internal Demand is 2.12 percent for the summer and 2.04 percent for the winter during the 10-year outlook (MRO-SaskPower-Table 2).

[194] Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.

MRO-SaskPower-Table 2: Demand Outlook

MRO-SaskPower-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	3,184	3,847	663	20.8%	2.12%
Load-Modifying Demand Response	91	91	0	0.0%	0.00%
TOTAL INTERNAL DEMAND	**3,275**	**3,938**	**663**	**20.2%**	**2.07%**

MRO-SaskPower-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	3,580	4,310	730	20.4%	2.08%
Load-Modifying Demand Response	91	91	0	0.0%	0.00%
TOTAL INTERNAL DEMAND	**3,671**	**4,401**	**730**	**19.9%**	**2.04%**

Saskatchewan does not anticipate any significant 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 in place to meet resource reliability requirements should a sudden economic change cause a need for new capacity. There were no changes or enhancements made to the forecasting methods used by SaskPower. Load growth is due primarily to economic growth in the industrial sector.

Demand-Side Management

It is expected that 150 MW of Demand Response and Energy Efficiency/Conservation will be available during the first year of the assessment. It is expected that 253 MW of Demand Response and Energy Efficiency/Conservation will be available during the tenth year of the assessment. Approximately 10 MW of additional Energy Efficiency/Conservation is expected to be available each year throughout the assessment period (MRO-SaskPower-Table 3).

MRO-SaskPower-Table 3: Demand-Side Management

	Short-Term					
MRO-SaskPower-Winter	2013/14	2014/15	2015/16	2022/23	10-Year Change	2022/23 Share of Total Internal Demand
Direct Control Load Management (DCLM)	0	0	0	0	0	0.00%
Contractually Interruptible (Curtailable)	91	91	91	91	0	2.07%
Critical Peak-Pricing (CPP) with Control	0	0	0	0	0	0.00%
Load as a Capacity Resource	0	0	0	0	0	0.00%
TOTAL LOAD-MODIFYING DEMAND RESPONSE	91	91	91	91	0	2.07%
TOTAL ENERGY EFFICIENCY	0	0	0	0	0	0.00%
TOTAL DEMAND-SIDE MANAGEMENT	**91**	**91**	**91**	**91**	**0**	**2.07%**

Saskatchewan considers Demand Response to be a capacity resource used for peak shaving. The primary driver for DSM programs in Saskatchewan is the economic incentive (difference in cost between providing the DSM program and the cost of serving the load). Increases in DSM will come from growth of existing programs.

There are no new Demand Response programs or Ancillary Services being incorporated for the assessment period.

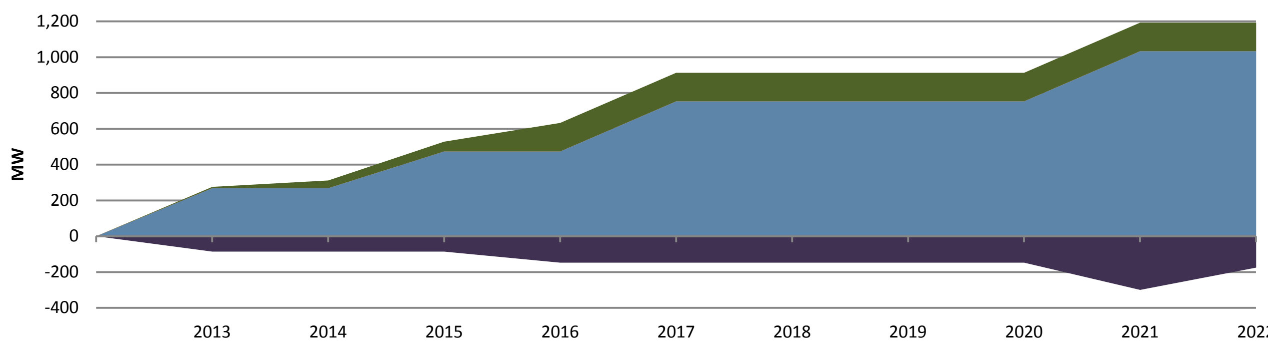
Generation

The primary sources of fuel in Saskatchewan are coal, hydro, and natural gas. Since 2011, 89 MW of natural gas generation has been added in Saskatchewan. Throughout the assessment period, a total nameplate capacity of 1,742 MW of Future-Planned resources are projected to come on-line (365 MW of refurbished coal, 1,034 MW of gas, 230 MW (nameplate) wind, 106 MW of biomass resources), and about 7 MW of additional hydro resources. Saskatchewan manages unit retirements within its resource planning process so that there are no reliability issues related to unit retirements during the assessment period. Unit retirements (coal) during the assessment period include 62 MW in 2013 and 61 MW in 2015 (MRO-SaskPower-Table 3 and MRO-SaskPower-Figure 2).

MRO-SaskPower-Table 4: Capacity Outlook[195]

MRO-SaskPower-Winter		Current Capacity	Current Share	2022/23 Planned Capacity	2022/23 Planned Share	2022/23 Planned Change	2022/23 Planned & Conceptual Capacity	2022/23 Planned & Conceptual Share	2022/23 Planned & Conceptual Change
Coal		1,671	42.4%	1,496	30.2%	-175	1,496	30.2%	-175
Petroleum		0	0.0%	0	0.0%	0	0	0.0%	0
Gas		1,361	34.6%	2,395	48.3%	1,034	2,395	48.3%	1,034
Nuclear		0	0.0%	0	0.0%	0	0	0.0%	0
Other/Unknown		0	0.0%	0	0.0%	0	0	0.0%	0
Renewables		907	23.0%	1,066	21.5%	159	1,066	21.5%	159
TOTAL		**3,939**	**100.0%**	**4,957**	**100.0%**	**1,018**	**4,957**	**100.0%**	**1,018**

MRO-SaskPower-Figure 2: Winter Net Capacity Change[196]

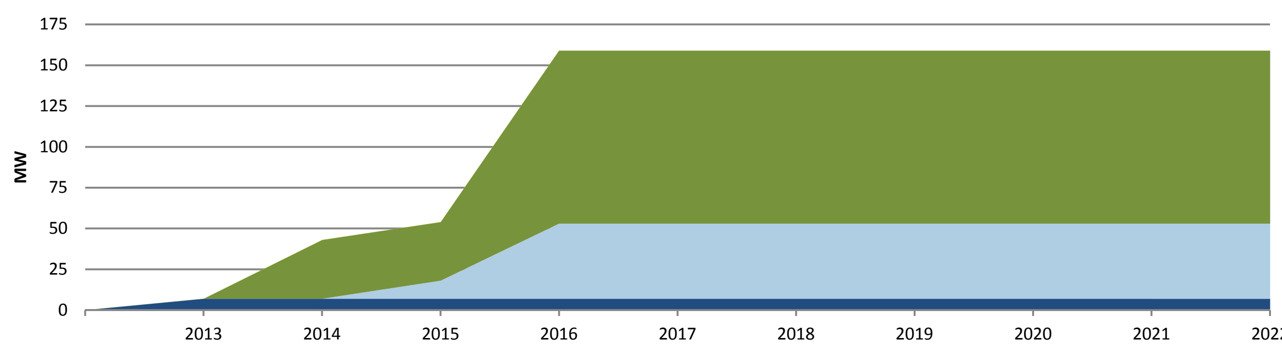


By the final year of the assessment period, about 86 MW (out of 428 MW nameplate capacity) of wind is expected to be available to meet the winter peak, which is over twice the 2013 amount. During the next ten years, 106 MW of biomass is also expected to be added.

MRO-SaskPower-Table 5: Renewable Capacity Outlook[197]

MRO-SaskPower-Winter		Current Capacity	Current Share	2022/23 Planned Capacity	2022/23 Planned Share	2022/23 Planned Change	2022/23 Planned & Conceptual Capacity	2022/23 Planned & Conceptual Share	2022/23 Planned & Conceptual Change
Hydro		857	94.5%	864	81.1%	7	864	81.1%	7
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	4.4%	86	8.0%	46	86	8.0%	46
Biomass		10	1.1%	116	10.9%	106	116	10.9%	106
Solar		0	0.0%	0	0.0%	0	0	0.0%	0
TOTAL		**907**	**100.0%**	**1,066**	**100.0%**	**159**	**1,066**	**100.0%**	**159**

MRO-SaskPower-Figure3: Winter Net Renewable Capacity Change[198]



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[195] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.
[196] Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.
[197] *Ibid.*
[198] *Ibid.*

For the assessment period, Saskatchewan plans for 10 percent of wind nameplate capacity to be available to meet summer peak demand and 20 percent of wind nameplate capacity to be available to meet winter peak demand. The wind available to meet peak requirements is based on the historical actual wind generation over a four-hour period during the peak for each day. On-peak expected values for hydro assume nameplate net generation less expected seasonal derates due to water conditions. Saskatchewan plans for 100 percent of biomass nameplate capacity to be available to meet demand based on a base-load contract. Operational procedures for the assessment period will not be impacted because of integrating variable resources (MRO-SaskPower-Table 6).

MRO-SaskPower-Table 6: Variable Generation

	Current				2022/23 Planned			
MRO-SaskPower-Winter	Wind	Solar	Hydro	Biomass	Wind	Solar	Hydro	Biomass
Installed Capacity	198	0	860	10	428	0	867	186
On-Peak Derate	158	0	2	0	342	0	2	70
EXPECTED ON-PEAK OUTPUT	40	0	857	10	86	0	864	116

Capacity Transactions

Saskatchewan does not anticipate any Firm imports or exports for the assessment period. Saskatchewan does not rely on emergency imports to meet its demand.

Transmission

Major projects expected to be completed in the MRO-SaskPower Assessment Area during the long-term outlook for this assessment are listed in Appendix II and summarized below (MRO-SaskPower-Table7). Additional details and descriptions of particular projects needed to meet transmission adequacy and load growth in the area are included below.

MRO-SaskPower-Table 7: Existing and Projected Transmission

NPCC-Maritimes	AC (Circuit Miles)	DC (Circuit Miles)	Total (Circuit Miles)
EXISTING	5,082	0	5,082
Currently Under Construction	0	0	0
Planned - Completed within First Five Years	13	0	13
Planned - Completed within Second Five Years	0	0	0
2022 TOTAL (UNDER CONSTRUCTION & PLANNED)	5,095	0	5,095
Conceptual - Completed within First Five Years	203	0	203
Conceptual - Completed within Second Five Years	50	0	50
2022 TOTAL (UNDER CONSTRUCTION, PLANNED & CONCEPTUAL)	**5,348**	**0**	**5,348**

Autotransformer Additions

- Planned addition of two 230-138 kV autotransformers in the Tantallon Area (eastern Saskatchewan) in late 2012 and 2013.
- The existing 230-138 kV autotransformer in the Tantallon Area will be moved to the Peebles area (eastern Saskatchewan).
- Planned addition of two 230-138 kV autotransformers in the Fleet Street Area (southeastern Saskatchewan) in late 2012 and 2013.
- The existing 230-138 kV autotransformer in the Fleet Street Area will be moved to the Kennedy Area (eastern Saskatchewan).
- Planned addition of two 230-138 kV autotransformers in the Boundary Dam Area (southeastern Saskatchewan) in late 2013 and 2014.
- The existing 230-138 kV autotransformer in the Boundary Dam Area will be utilized as a system spare or moved to another location in Saskatchewan.
- Conceptual addition of 230-138 kV autotransformers in the Condie, Regina, Moose Jaw, North Battleford, Wolverine, and Lloydminster Areas (dispersed in Saskatchewan) in late 2016.

Transmission Line Additions

- Planned addition of a 40 km 230 kV transmission line in the Saskatoon-Martinsville Area (central Saskatchewan) in late 2013.

- Planned addition of a 110 km 230 kV transmission line in the Saskatoon-Wolverine Area (central Saskatchewan) in late 2013.
- Planned addition of 50 km of 138 kV transmission line and salvage of 65 km of 138 kV line in the Elstow-Wolverine Area (central Saskatchewan) in late 2013.
- Planned addition of a 225 km 230 kV transmission line in the Moose Jaw-Swift Current Area (central Saskatchewan) in late 2016.
- Planned addition of 225 km of 138 kV transmission line and salvage of 200 km of 138 kV line in the Moose Jaw-Swift Current Area (central Saskatchewan) in late 2016.
- Planned addition of a 135 km 230 kV transmission line in the Peebles-Tantallon Area (eastern Saskatchewan) in late 2013.
- Conceptual addition of a 160 km 230 kV transmission line in the Beatty-Wolverine Area (north-central Saskatchewan) in late 2016.
- Conceptual addition of a 70 km 230 kV transmission line in Condie-Pasqua Area (south-central Saskatchewan) in late 2016.
- Conceptual addition of a 130 km 230 kV transmission line in North Battleford-Saskatoon Area (south-central Saskatchewan) in late 2016.

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.

Sufficient transmission lines are being constructed to support the Future-Planned resources that are projected to come on-line during the assessment period. Saskatchewan is planning for the addition of a Static Var System (SVS) in the Swift Current Area (southwestern Saskatchewan) in late 2013.

Vulnerability Assessment

Saskatchewan has no resource adequacy or operational concerns during the assessment period. Currently there are plans to install one UVLS scheme in the Tantallon Area in late 2012. This scheme is being installed to mitigate potential low voltages under certain generation dispatch scenarios caused by an N-1 outage (until planned transmission reinforcement in 2015 is in place) and a few N-2 outages. These outages are in the southeastern portion of the province. The planned UVLS scheme targets approximately 40 MVA of load to be shed. This equates to approximately 1 percent of the projected total Saskatchewan 2013 winter peak load. The planned 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 in the Tantallon Area that will reinforce the Tantallon Area voltage. This line has a projected in-service date of mid-2015. The UVLS scheme may then be used to mitigate potential low voltages for N-1-1 and N-2 outages under certain generation dispatch scenarios.

Special Protection Systems in Saskatchewan are typically implemented on a temporary basis until transmission facilities can be added. The following Special Protection Systems are planned in Saskatchewan to address N-2 outages of 230 kV double circuits:

- 230 kV double circuit between the Boundary Dam and Regina Areas.
- Planned in-service date of 2014
- This scheme is intended to be temporary until 2015, when planned generation unit retirements and projected industrial load growth in the southeastern portion of the province materializes.
- 230 kV double circuits in the Nipawin Area.
- Planned in-service date of 2014.
- Permanent for the assessment period.

- 230 kV double circuit between the Saskatoon and Beatty Areas.
- Planned in-service date of 2015.
- This scheme is intended to be temporary until 2016, when the Conceptual Beatty to Wolverine 230 kV line is in service.

Saskatchewan has emergency preparedness plans as mandated by provincial and federal requirements to address catastrophic events in general. Saskatchewan does not specifically plan its system for high-impact, low-frequency events, but assessments may be done on as-needed basis, taking into account the reliability benefit versus cost. In general, the Saskatchewan BES is designed to be fail-safe for most types of contingencies and to be restored as soon as possible. However, operation of the Saskatchewan system would be performed on a best-efforts basis under the types of catastrophic emergency conditions provided as examples. Resources would be offset by planning reserves and external markets as much as possible. If necessary, operational measures would include interruptible load contracts, public appeals, and rotating outages.

Earthquakes and hurricanes are historically not a concern for Saskatchewan. Fuel disruptions are minimized as much as possible by historical system design practices, and Saskatchewan has a diverse energy mix of resources. Coal resources have Firm contracts and are adjacent to generating facilities, and stockpiles are maintained at each facility in the event that mine operations are unable to meet the required demand of the generating facility. Natural gas resources have Firm transportation contracts with large natural gas storage facilities located within the province backing those contracts up. Coordination meetings between the electric system and the natural gas transportation system are held to discuss operational and planning issues. These meetings enable both systems to be informed of any issues relating to security of supply for natural gas transportation. Hydro facilities/reservoirs are fully controlled by Saskatchewan, and long-term hydrological conditions are monitored. Geomagnetic induced currents have historically not been a problem for Saskatchewan. Loss of a major import path has not historically been a concern for Saskatchewan, as it typically does not rely on imports to serve load.

Saskatchewan evaluates new technologies as they become available and uses them if economical. Saskatchewan does not have any significant smart grid programs that affect the BES. Current efforts are primarily focused on the distribution system. Protection systems are maintained and tested on an on-going basis, and misoperations are evaluated for lessons learned.

No environmental or regulatory restrictions have been identified at this time that could potentially impact reliability in Saskatchewan for the assessment period. Greenhouse gas regulations are expected to become an issue as specific regulations are introduced and clarified. The consequence of such regulations is expected to have a low impact on reliability, because it is anticipated that enough lead time will be given to allow for appropriate mitigation.

Plans for Accommodating Generator Retirements and Environmental Control Retrofits

Currently there are no greenhouse gas emission programs or criteria for Saskatchewan. For the assessment period, Saskatchewan has plans to retire five coal-fired generating units. Up to three of the units will be replaced by clean coal generating units. Studies have been performed based on possible greenhouse gas regulations. Analysis to support decision-making will conducted once the regulations are known. Ultimately, no potential reliability impacts or improvements that would arise on the Saskatchewan system have been identified due to the recent US environmental regulatory requirements.

Standing and Emerging Reliability Issues

Greenhouse gas regulation is expected to become an issue in the short-term (one- to five-year period) as specific regulations are introduced and clarified. The consequence of such regulations is expected to have a low impact on reliability, because it is anticipated that enough lead time will be given to allow for appropriate mitigation. Saskatchewan currently relies, in part, on greenhouse gas emitting generation sources such as coal and natural gas. The potential impact of greenhouse gas regulations would be to reduce Saskatchewan's ability to rely on carbon-emitting fuel sources for future generation requirements. Saskatchewan has developed future scenario plans to deal with anticipated greenhouse gas emissions regulations. Saskatchewan has not yet experienced any reliability issues related to greenhouse gas regulations and is expected to effectively mitigate any future reliability issues related to greenhouse gas regulations. Mitigation will either be reducing greenhouse emissions or replacement of generation.

NPCC-Maritimes

Planning Reserve Margins

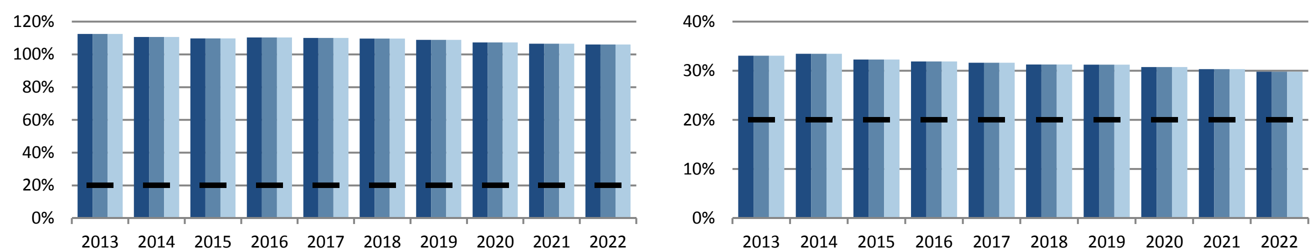
The NERC Reference Margin Level for the Maritimes Assessment Area is 20 percent throughout the assessment period (NPCC-Maritimes-Table 1 and MRO-Maritimes Figure 1).

NPCC-Maritimes-Table 1: Planning Reserve Margins – NPCC-Maritimes

NPCC-Maritimes-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		112.5%	110.6%	109.8%	110.3%	110.1%	109.6%	108.8%	107.3%	106.5%	106.0%
PROSPECTIVE		112.5%	110.6%	109.8%	110.3%	110.1%	109.6%	108.8%	107.3%	106.5%	106.0%
ADJUSTED POTENTIAL		112.5%	110.6%	109.8%	110.3%	110.1%	109.6%	108.8%	107.3%	106.5%	106.0%
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		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		33.1%	33.4%	32.3%	31.9%	31.6%	31.3%	31.2%	30.8%	30.3%	29.8%
PROSPECTIVE		33.1%	33.4%	32.3%	31.9%	31.6%	31.3%	31.2%	30.8%	30.3%	29.8%
ADJUSTED POTENTIAL		33.1%	33.4%	32.3%	31.9%	31.6%	31.3%	31.2%	30.8%	30.3%	29.8%
NERC REFERENCE	-	**20.00%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**

NPCC-Maritimes-Figure 1: Summer (Left) and Winter[199] (Right) Planning Reserve Margins



Renewable portfolio standards in the area led to the construction of the existing generation mix. Peak demands in the area have declined from historic highs and combined with the addition of generation resources associated with renewable portfolio standards. All Planning Reserve Margins exceed the NERC Reference Margin Level for the duration of the assessment period.

Demand

The forecast CAGR for peak demand is 0.25 and 0.27 percent for the summer and winter seasons, respectively (NPCC-Maritimes-Table 2). This indicates that aggregated growth will be effectively offset by the sum of any DSM projections or load losses included in the sub-area forecasts.

NPCC-Maritimes-Table 2: Demand Outlook

NPCC-Maritimes-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	3,104	3,183	79	2.5%	0.28%
Load-Modifying Demand Response	331	331	0	0.0%	0.00%
TOTAL INTERNAL DEMAND	**3,435**	**3,514**	**79**	**2.3%**	**0.25%**

NPCC-Maritimes-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	5,169	5,285	116	2.2%	0.25%
Load-Modifying Demand Response	252	267	15	6.0%	0.64%
TOTAL INTERNAL DEMAND	**5,421**	**5,552**	**131**	**2.4%**	**0.27%**

Load growth in the southeastern corner of New Brunswick, though not specifically identified in the load projections, has outpaced the rest of the assessment area.

Demand-Side Management

Current and projected Energy Efficiency effects are incorporated directly into the load forecast, while Demand Response is counted as a load modifier. Moreover, Demand Response is not used for peak shaving. It is used to reduce demand during

[199] Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.

emergencies and is not backed by capacity reserves. Contractually interruptible (curtailable) Demand Response is projected to account for 252 MW in 2013, increasing to 267 MW in 2022 (NPCC-Maritimes-Table 3).

NPCC-Maritimes-Table 3: Demand-Side Management

NPCC-Maritimes-Winter	Short-Term 2013/14	2014/15	2015/16	2022/23	10-Year Change	2022/23 Share of Total Internal Demand
Direct Control Load Management (DCLM)	0	0	0	0	0	0.00%
Contractually Interruptible (Curtailable)	252	254	254	267	15	7.60%
Critical Peak-Pricing (CPP) with Control	0	0	0	0	0	0.00%
Load as a Capacity Resource	0	0	0	0	0	0.00%
TOTAL LOAD-MODIFYING DEMAND RESPONSE	252	254	254	267	15	7.60%
TOTAL ENERGY EFFICIENCY	0	0	0	0	0	0.00%
TOTAL DEMAND-SIDE MANAGEMENT	**252**	**254**	**254**	**267**	**15**	**7.60%**

Jurisdictions within the Maritimes Area have established Energy Efficiency corporations or government agencies whose mandate is 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 utilize 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 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.

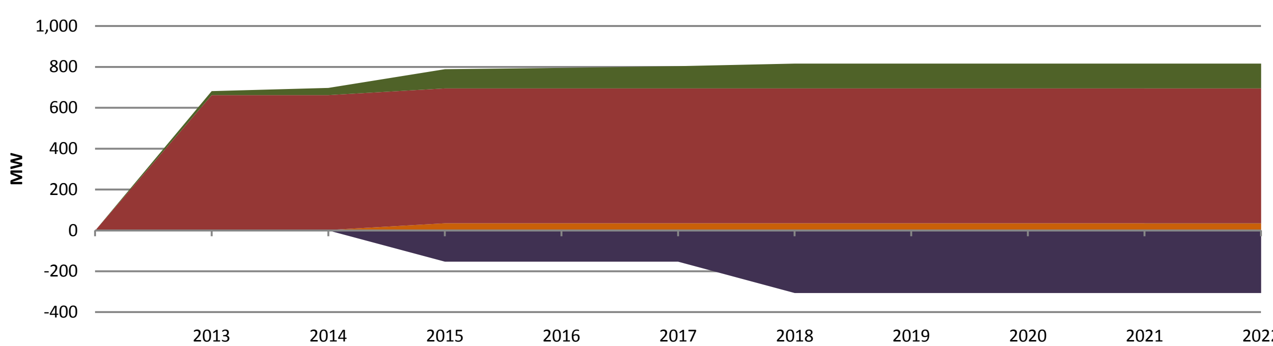
Generation

The primary sources of fuel in the Maritimes Assessment Area are oil and coal, followed by hydro, natural gas, and nuclear. Other capacity sources include wind and biomass (NPCC-Maritimes-Table 4 and NPCC-Maritimes-Figure 2).

NPCC-Maritimes-Table 4: Capacity Outlook[200]

NPCC-Maritimes-Winter	Current Capacity	Current Share	2022/23 Planned Capacity	Share	Change	2022/23 Planned & Conceptual Capacity	Share	Change
Coal	1,714	25.0%	1,408	21.0%	-306	1,408	21.0%	-306
Petroleum	1,857	27.1%	1,892	28.2%	35	1,892	28.2%	35
Gas	829	12.1%	829	12.4%	0	829	12.4%	0
Nuclear	660	9.6%	660	9.8%	0	660	9.8%	0
Other/Unknown	0	0.0%	0	0.0%	0	0	0.0%	0
Renewables	1,796	26.2%	1,917	28.6%	121	1,917	28.6%	121
TOTAL	**6,856**	**100.0%**	**6,706**	**100.0%**	**-149**	**6,706**	**100.0%**	**-149**

NPCC-Maritimes-Table 4: Winter Net Capacity Change[201]



[200] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

[201] Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.

Since 2011, 49 MW of Existing-Certain capacity fueled by existing natural gas units in combined-cycle mode was added at Nova Scotia's Tufts Cove plant. Another 40 MW of wind generation capacity derated to 14 MW of Existing-Certain capacity was installed at two sites.

The return to service of the 660 MW Point Lepreau Nuclear Generating Station was a major Future-Planned capacity addition during 2012. There are no Conceptual projects planned during this assessment period. The retirement of the 299 MW oil-fired Dalhousie Plant in New Brunswick is scheduled for May 31, 2012. This retirement justifies the addition of a 345 kV breaker at the Belledune 345 kV terminal and reconfiguration of the Eel River 230 kV terminal. From a resource adequacy perspective, the reliability impact of this capacity reduction is more than offset by the return to service of the 660 MW Point Lepreau Nuclear Generating Station, expected to occur by October 1, 2012.

The refurbishment of the Point Lepreau Nuclear Generating Station will result in a 25 MW uprate of the plant's net capacity. This small uprate has no significant long-term reliability impact.

The return to service of the 660 MW Point Lepreau plant will more than offset the capacity loss associated with the retirement of the Dalhousie Plant. The impact of the retirement of Nova Scotia's Lingan generators in 2015 and 2018 is expected to be offset by installation of wind and biomass units and an expected purchase from Nalcor, a Newfoundland and Labrador utility.

There are no 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.

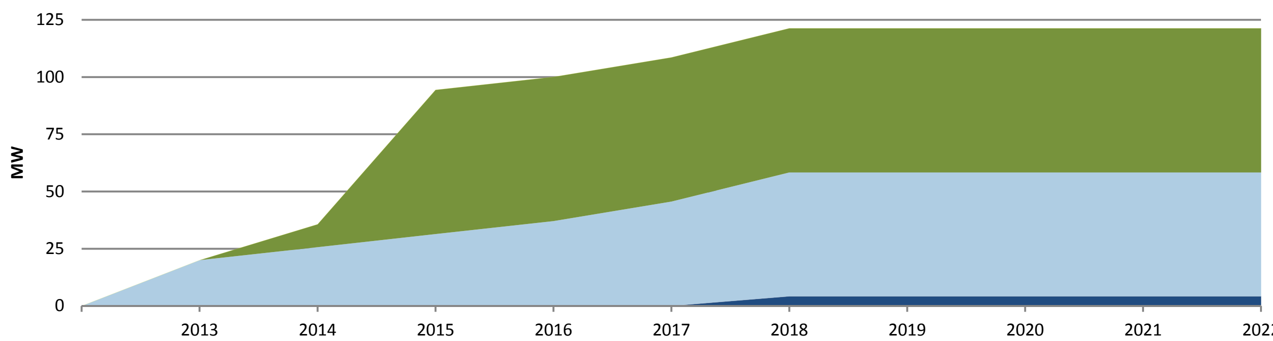
The Maritimes Assessment Area has no non-traditional (e.g., storage, flywheels, batteries) resources. Wind projects included with capacities modeled in resource adequacy calculations for New Brunswick and northern Maine (40 percent of nominal capacity during the winter peak period) are based on results from the September 2005 NBSO report "Maritimes Wind Integration Study."[202] This report showed that the effective capacity from wind projects and their contribution to Loss of Load Expectation (LOLE) was equal to or better than their seasonal capacity factors. The NPCC Maritimes Area "2010 Comprehensive Review of Resource Adequacy"[203] indicated that the area can achieve less than the target maximum of 0.1 days per year of LOLE, even with zero wind installed, while still exceeding its 20 percent NERC Reference Reserve Margin. Renewable capacity for the Maritimes Assessment Area is shown below (NPCC-Maritimes-Table 5 and NPCC-Maritimes-Figure 2)

[202] http://www.nbso.ca/Public/_private/2005 Percent20Maritime Percent20Wind Percent20Integration Percent20Study Percent20_Final_.pdf.
[203] https://www.npcc.org/Library/Resource Percent20Adequacy/Forms/Public Percent20List.aspx.

NPCC-Maritimes-Table 5: Renewable Capacity Outlook[204]

NPCC-Maritimes-Winter	Current		2022 Planned			2022 Planned & Conceptual		
	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Hydro	1,337	74.4%	1,341	69.9%	4	1,341	69.9%	4
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	318	17.7%	372	19.4%	54	372	19.4%	54
Biomass	141	7.9%	204	10.7%	63	204	10.7%	63
Solar	0	0.0%	0	0.0%	0	0	0.0%	0
TOTAL	**1,796**	**100.0%**	**1,917**	**100.0%**	**121**	**1,917**	**100.0%**	**121**

NPCC-Maritimes-Figure 2: Winter Net Renewable Capacity Change[205]



The Maritimes Assessment Area projects no solar power installations. With very few small exceptions, hydro and biomass generators are not derated during peak periods.

Currently, wind generators are accredited with on-peak capacity, based on observed or expected seasonally adjusted capacity factors. Hydro and biomass units are expected to be fully available during peak periods, and on-peak capacity is equal to their demonstrated unit capability (NPCC-Maritimes-Table 6). The Maritimes Area is currently reviewing and assessing previously used methods for attributing on-peak wind capacity.

NPCC-Maritimes-Table 6: Renewable Capacity Outlook: On-Peak Vs. Installed

NPCC-Maritimes-Winter	Current				2022/23 Planned			
	Wind	Solar	Hydro	Biomass	Wind	Solar	Hydro	Biomass
Installed Capacity	816	0	1,339	148	964	0	1,343	211
On-Peak Derate	498	0	2	7	592	0	2	7
EXPECTED ON-PEAK OUTPUT	318	0	1,337	141	372	0	1,341	204

Plans are underway for the individual jurisdictions within the Maritimes Assessment 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 available for system operators to dispatch accordingly.

Capacity Transactions

The Maritimes Assessment Area has included Firm imports, which are projected to begin in 2018, from the Newfoundland utility Nalcor (NPCC-Maritimes-Table 7). In 2018, development of the Muskrat Falls Generation Project in the Canadian province of Newfoundland and Labrador includes the installation of a High Voltage Direct Current (HVdc) undersea cable link (Maritime Link).

[204] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

[205] Years represent initial year for each winter season. For example: 2013 represents the 2013/2014 winter season.

NPCC-Maritimes-Table 7: Projected Capacity Transactions

NPCC-Maritimes-Winter	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
Expected Imports	0	0	0	0	0	155	155	155	155	155
Firm Imports	0	0	0	0	0	0	0	0	0	0
TOTAL IMPORTS	0	0	0	0	0	155	155	155	155	155
Expected Exports	0	0	0	0	0	0	0	0	0	0
Firm Exports	0	0	0	0	0	0	0	0	0	0
TOTAL EXPORTS	0	0	0	0	0	0	0	0	0	0
TOTAL NET CAPACITY TRANSACTIONS	**0**	**0**	**0**	**0**	**0**	**155**	**155**	**155**	**155**	**155**

The Expected Firm Import will commence in 2018 and extends well beyond the assessment period. The Maritimes Assessment Area does not depend on emergency imports from other areas to meet the NERC Reserve Margin Reference Level.

Transmission

Three major new transmission line additions are in Conceptual stages during the review period. In New Brunswick, a new 345kV circuit between the Coleson Cove and Salisbury terminals is being considered to improve transmission service to southeastern New Brunswick, which has experienced relatively higher load growth compared to the remainder of the province. New Brunswick and Nova Scotia are studying a project to twin the existing 100-mile-long 345 kV transmission line between Salisbury, New Brunswick, and Onslow, Nova Scotia. This project is under study for 2016 and will allow for increased integration of renewable energy in the Maritimes Area. In 2018, potential development of the Muskrat Falls Generation Project in the Canadian province of Newfoundland and Labrador would see the installation of a High Voltage Direct Current (HVdc) undersea cable link (Maritime Link) between that province and Nova Scotia. Existing and projected transmission additions are listed in the table below (NPCC-Maritimes-Table 8).

NPCC-Maritimes-Table 8: Existing and Projected Transmission

NPCC-New England	AC (Circuit Miles)	DC (Circuit Miles)	Total (Circuit Miles)
EXISTING	7,890	216	8,106
Currently Under Construction	182	0	182
Planned - Completed within First Five Years	458	0	458
Planned - Completed within Second Five Years	8	0	8
2022 TOTAL (UNDER CONSTRUCTION & PLANNED)	8,537	216	8,753
Conceptual - Completed within First Five Years	78	140	218
Conceptual - Completed within Second Five Years	18	0	18
2022 TOTAL (UNDER CONSTRUCTION, PLANNED & CONCEPTUAL)	**8,633**	**356**	**8,989**

Conceptual 345 kV line reinforcements from Coleson Cove to Onslow would alleviate existing constraints that limit capacity transfers between New Brunswick and Nova Scotia to non-Firm or short-term transactions.

The 2012 retirement of the Dalhousie Plant in NB requires the addition of a new 345 kV breaker at the New Brunswick Belledune terminal to improve local reliability. The plant retirement also made it necessary for the 240 kV terminal at Eel River NB to be reconfigured to allow a single feed to two 240/138 kV parallel transformers to be split. A refurbishment of one of two HVdc stations between the Maritimes Area and Hydro Québec at Eel River New Brunswick is being tentatively planned for 2014. A new 37.5 Mvar capacitor is being constructed at the Norton terminal in southern New Brunswick. This will help maintain voltages in the area during contingency conditions. No new circuit miles are involved in any of these projects. The construction periods for the planned projects mentioned above are all of short duration and can be scheduled during times that will not significantly affect the reliability of the area.

Currently projected for the 2016 time frame, further study to determine need and timing will be completed prior to construction of the Coleson Cove to Salisbury to Onslow 345 kV circuits. The Maritime Link Project and the retirement of a comparable-sized unit will be timed to coincide so that the project will not have an impact on overall reliability.

Being of small size and spread over a multitude of sites, additions to the generation complement in the Maritimes Area of small wind farms and biomass-fueled projects will not require major transmission reinforcement.

A new 37.5 Mvar capacitor is being constructed at the Norton terminal in southern New Brunswick, and a second 36 Mvar capacity bank will be added at Bridgewater in southwest Nova Scotia in 2013. From 2013 to 2022, changes to the HVdc system in the Maritimes will include the proposed 2014 refurbishment of the 350 MVA Eel River HVdc Station on the New Brunswick tie to Québec and the proposed 2018 addition of an HVdc tie between Nova Scotia and the province of Newfoundland and Labrador (Maritime Link).

Vulnerability Assessment

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

The approximately 1,330 MW hydro-electric power supply system in the Maritimes Area is predominantly run off 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.

Because of the relative size of the area's largest generating units compared to its aggregated load, the area carries substantial reserve capacity. Long-term outages to individual units do not cause undue stress from a technical perspective. Because the area peaks in winter as opposed to neighboring jurisdictions that peak in summer, 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 Québec.

Renewable Portfolio Standards (RPSs) have lead to the development of substantially more wind generation capacity than any other renewable generation type. Reduced frequency response is associated with wind generation and may, with increasing levels in the future, require displacement with conventional generation during light load periods. If required by system operators, wind farms in the Maritimes Area must provide controls that will enable curtailment. In New Brunswick, while increasing RPS requirements to 40 percent of New Brunswick energy by 2020, the government has recently announced that there is enough large-scale wind capacity on the system and that it will shift the focus of the standard to concentrate on less-intermittent hydro (including sources outside the Maritimes Area), wood-based biomass, and small-scale wind developments, but new projects have been identified to date. In Nova Scotia, wind generation capacity is expected to increase with the addition of a government-mandated Community Feed-in Tariff. The Renewable Electricity Standard target is 40 percent by 2020 and is expected to be achieved largely with hydro energy imports through the Maritimes Link Project. Nova Scotia Power has commissioned a renewables integration study with General Electric, the results of which should provide insight into the resource adequacy and operational issues related to increased renewables.

Demand Response in the Maritimes Area consists primarily of interruptible customer load equivalent to 5 percent of peak load for the 2012/2013 winter season. Performance of these customers is metered in real time to ensure compliance with operator instructions. In addition to interruptible load, Nova Scotia implements a 5 percent voltage reduction at selected substations and reduces their demand by approximately 1 MW to 5 MW.

There are no 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 is required to fully understand the cost and technical implications related to possible transmission upgrades and new operational demands on existing infrastructure.

In the New Brunswick sub-area, the government has acknowledged the need to develop less-intermittent sources of renewable energy. With the significant amount of large-scale wind energy currently being balanced on their system, the next phase of renewable energy development will focus on smaller-scale projects with a particular emphasis on non-intermittent 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.

At this time, there are no plans to install more Under-Voltage Load Shedding (UVLS) in the Maritimes Area.

Collectively, UVLS in New Brunswick can shed up to 25 percent of load. UFLS in the Maritimes Area will conform to NPCC Directory 12 requirements calling for 30 percent of area load available to be shed by 2012.

Neither UVLS nor UFLS are used in resource adequacy analysis in the Maritimes Assessment Area. Additional SPS schemes could be implemented in addition to proposed bulk power transmission facilities. At this time, no specific applications are planned for the Maritimes Area during the assessment period.

Scenarios of high load growth, significant resource outages, and zero wind availability (loss of source) are studied for NPCC Comprehensive Reviews of Resource Adequacy. The Comprehensive Area Transmission Reviews require that system performance be studied under stressful conditions such as N-1-1 conditions, extreme contingencies (complete loss of entire generating stations, HVdc ties, etc.), and extreme conditions (weather or loss of fuel) to test the "strength" of the system.

Regional cooperation to mitigate the effects of increases in variable generation has led to a regional research initiative known as PowerShift Atlantic. This initiative will attempt to ease variable generation balancing issues using smart grid technology. Automatic direct control of individual loads will offset changing output from variable resources.

All relay protection misoperations are investigated, and if the relay is found to be faulty, it is replaced. If the settings are found to be in error, they are corrected. If human error was the cause (accidental trips, etc.), the staff involved is trained to avoid the problem in the future. If the relay is misapplied, a new relay scheme is installed to the correct the problem. All of these approaches are taken to reduce the potential for future misoperation.

Renewable Portfolio Standards have mandated increased levels of variable generation in the area, and these have been included in resource adequacy reviews. Within the Nova Scotia sub-area, increasingly stringent air-emissions hard caps have been accounted for in the assessment.

To reduce emissions associated with energy production, governments in the Maritimes Area have introduced Renewable Portfolio Standards, leading to a large-scale development of wind energy resources in the area. The Maritimes Area examines cases in which a complete absence of wind in the area occurs due to weather conditions. The conclusion is that the area is not overly reliant on wind generation to meet its 20 percent reserve criterion (the level at which it has been shown that the area meets the NPCC resource adequacy reliability criterion). 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 greenhouse gas emissions are expected and could limit the future utilization of fossil-fueled generation. System Operators in the Maritimes Area are tracking such developing standards and are conducting analyses regarding their impact on future resource adequacy.

No resource deficiencies are forecast and there is no over-reliance on wind to meet area Reserve Margin targets. To avoid an over-abundance of variable generation in the province, the Government of New Brunswick is now concentrating on development of non-intermittent renewable resources. Nova Scotia Power has augmented the supply of renewables with dispatchable biomass. Additionally, the Nova Scotia government has added provisions to the proposed 2020 RES targets that would allow imported renewable hydro energy from the Newfoundland and Labrador utility Nalcor. Nova Scotia Power has commissioned a renewables integration study with General Electric, and the results of the study should provide insight into the resource adequacy and operational issues related to increased renewables.

The 660 MW Point Lepreau nuclear generator is the single largest unit in the area, and upon its return in October 2012, it will have been out of service for four and a half years. During that period, the area met its reserve requirements in part by contracting winter replacement capacity from neighboring areas. During off-peak periods, capacity contracts were unnecessary. Sufficient capacity exists for the Maritimes Area to meet its target Reserve Margin, should the return to service of Point Lepreau be further delayed. Therefore, long-term maintenance outages in the Maritimes Area are not expected to cause any reliability issues during the assessment period.

With the completion of the Point Lepreau refurbishment in 2012, no other major retrofits are currently scheduled in the Maritimes Area during the assessment period.

Standing and Emerging Reliability Issues

Currently, there are two emerging reliability issues being examined in the Maritimes Area: increasing load in southeastern New Brunswick and additional renewable resources throughout the area.

Increasing Southeastern New Brunswick Load

The issue may require transmission reinforcements within the midterm time frame, which is between four and eight years.

Load growth in the southeastern area of New Brunswick has been more rapid than other areas in the province. Voltages and thermal loading on lines are approaching unacceptable levels during 345 kV contingencies for various operating scenarios.

The effect on resource adequacy is minimal. Generation is unaffected, and the higher loads are included in forecasts used for resource adequacy studies. The impact on LOLE is captured by modeling a reduction in tie transfer capabilities between sub-areas. The 2011 NPCC Interim Review of Resource Adequacy showed that LOLE values do not exceed the NPCC limit of 0.1 days per year of resource adequacy.

The issue could affect BPS reliability by threatening voltage instability and potentially overloading circuits during contingencies in the Assessment Area.

The low voltages and overloads of parallel circuits during contingencies would be moderate but localized and not likely to create problems in neighboring Regions. To address this issue, construction of a new 103-mile-long 345 kV transmission line twinning existing circuits between the Coleson Cove NB and Salisbury NB terminals is being considered. The new line would increase the transmission capacity in the area, alleviating contingency-related overloads and improving area voltages.

The 2012LTRA reference case will not be affected by this issue, and although the load growth and potential voltage issues are localized to southeastern New Brunswick for 345kV outages feeding that area, 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 interconnection of new resources in the area is not considered an issue and would likely help mitigate this emerging issue, as a lack of generating resources situated in this area contributes to the problem. Ultimately, the issue seems to become problematic for 345 KV contingencies when New Brunswick loads are at near-peak levels and there are high southern or northern New Brunswick generation dispatches during periods of high exports from New Brunswick to Prince Edward Island or Nova Scotia.

Addition of Renewable Resources in the Area

Addition of renewable resources, particularly in Nova Scotia, is classified as an emerging issue that may require bulk power enhancements within the midterm time frame of four and eight years. Nova Scotia’s Renewable Electricity Standard (RES) seeks to displace significant amounts of fossil-fueled generation with renewable resources. By 2015, 25 percent of the province’s electricity sales will be supplied by renewable energy sources, and by 2020 the target is 40 percent. The issue actually enhances resource adequacy, provided existing traditional resources are not prematurely retired as a result of the new capacity.

The addition of renewable resources could affect BPS reliability if increasing amounts of variable or low-mass slow-speed units are added without considering the reduction of frequency response during certain system contingencies or without sufficient transmission enhancements to prevent voltage or thermal performance issues. The emergence of any of these issues could limit operation of, or the amount of, new renewable generation added to the system.

The issue has not currently affected transmission adequacy, but depending on the location and amount of generation added, it could in the future, since “surplus” transmission capacity is used up to interconnect the new facilities or, on the contrary, congestion is relieved. The process of completing System Impact Studies prior to interconnecting new generation should identify whether transmission adequacy is an issue on a case-by-case basis. The lack of transmission enhancement could delay the development of new renewable resources.

The LTRA case is affected by this issue as Reserve Margins increase due to increasing capacity versus load. Although much of the new renewable capacity is derated to “expected” on-peak values, the actual capacity contribution will be verified through experience with actual operation and further study. In addition, many of the new resources being considered have short timelines, which makes long-term projections less reliable as project plans are introduced, cancelled, or modified in response to changing government incentive policies.

Many of the sites chosen for new renewable generation facilities are located near the energy sources or are sited near existing transmission infrastructure. There is potential for such additions across the entire Maritimes Area.

The variable intermittent nature and low inertia of some renewable resources (in particular wind, by far the most prevalent type) combined with a possible lack of transmission resources in the area of a project site may limit development of these resources.

The intermittent nature of many renewable resources is a major consideration for generation dispatchers on a daily basis. The low inertia effects on system frequency response will be felt mostly during off-peak, light-load periods when high-mass units have been displaced by low-mass, new renewable resources.

NPCC-New England

Planning Reserve Margins

ISO New England expects to have adequate Planning Reserve Margins throughout the assessment period (2013–2022). The amount of Anticipated and Prospective Resources in the 2013 summer is 35,265 MW, which results in an Anticipated Reserve Margin of 32.4 percent of the reference demand forecast of 26,629 MW during the summer season.

Planning Reserve Margin considerations for this assessment newly reflect Seasonal Claimed Capability (which could be higher than the Capacity Supply Obligation (CSO)) of all ISO-NE generators, as well as demand resources and imports that have assumed CSOs under the ISO-NE's Forward Capacity Market (FCM). Consideration for generator Seasonal Claimed Capabilities has not been included in determining the capacity projections in long-term assessments since 2008, when ISO-NE started to use CSOs in the LTRA to reflect the capacity purchased under the FCM. Prior to the 2008 assessment, all generator capabilities in the LTRA were based on the Seasonal Claimed Capability. The reason for reflecting the generator Seasonal Claimed Capabilities in this and future LTRAs is that when the energy prices are lucrative (which is always the case during annual peak demand conditions), generating resources offer the energy market up to, and sometimes more than, their Seasonal Claimed Capability. The LTRA would undercount New England capacity if ISO-NE only reflected the CSOs in the LTRA.

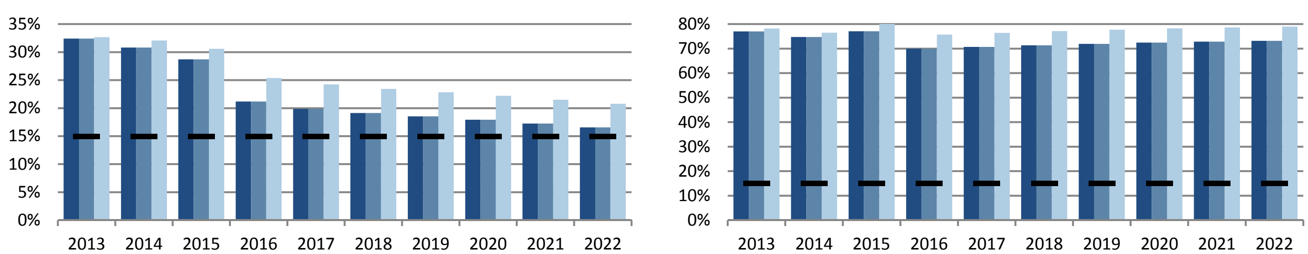
This Reserve Margin during the annual peak reflects the Seasonal Claimed Capability of all ISO-NE generators, as well as demand resources and imports that have Capacity Supply Obligations (CSOs) as a result of ISO-NE's Forward Capacity Market (FCM) auctions. The Adjusted Potential Capacity Resources are slightly higher at 35,329 MW, resulting in a Reserve Margin of 32.67 percent. The Reserve Margins decrease steadily through the assessment period. By 2022, the Anticipated and Prospective Reserve Margins reach a low of 16.56 percent and the Adjusted Potential Reserve Margin decreases to 20.79 percent (NPCC-New England-Table 1 and NPCC-New England-Figure 1).

NPCC-New England-Table 1: Planning Reserve Margins – NPCC-New England

NPCC-New England-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		32.43%	30.82%	28.70%	21.18%	19.88%	19.13%	18.54%	17.93%	17.26%	16.56%
PROSPECTIVE		32.43%	30.82%	28.70%	21.18%	19.88%	19.13%	18.54%	17.93%	17.26%	16.56%
ADJUSTED POTENTIAL		32.67%	32.07%	30.59%	25.39%	24.23%	23.44%	22.84%	22.20%	21.51%	20.79%
NERC REFERENCE	-	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**

NPCC-New England-Winter		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		77.00%	74.75%	77.09%	70.02%	70.71%	71.38%	71.96%	72.44%	72.83%	73.16%
PROSPECTIVE		77.00%	74.75%	77.09%	70.02%	70.71%	71.38%	71.96%	72.44%	72.83%	73.16%
ADJUSTED POTENTIAL		78.17%	76.51%	80.53%	75.74%	76.46%	77.15%	77.75%	78.25%	78.65%	78.99%
NERC REFERENCE	-	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**

NPCC-New England-Figure 1: Summer (Left) and Winter[206] (Right) Planning Reserve Margins



New England did not provide a specific Planning Reserve Margin target level and as a thermal system—a NERC Reference Margin Level of 15 percent is applied. ISO New England projects its capacity needs to meet the NPCC once-in-10-year Loss

[206] Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.

of Load Expectation (LOLE) resource planning reliability criterion. The amount of capacity needs can and do vary from year to year depending on expected system conditions.

There is a potential for lower-than-anticipated reserve margins if significant retirements due to environmental regulations result in lost capacity that cannot be replaced quickly enough by new resources.

Demand

The 2013 summer peak demand forecast is 27,765 MW, and the Net Internal Demand, which takes into account 1,136 MW of passive demand resources (Energy Efficiency), is 26,629 MW.

This year's forecast of the 10-year summer Total Internal Demand compound annual growth rate (CAGR) based on Total Internal Demand is 1.44 percent, which is slightly higher than the 2011 projection of 1.30 percent. The reason for this increase is changes in the economic forecast.

The forecast 10-year winter Total Internal Demand CAGR is 0.57 percent, which is approximately the same as last year's growth rate (NPCC-New England-Table 2). The winter peak is less weather-sensitive than the summer peak; is closely linked to residential demand and is less impacted by the recession.[207]

NPCC-New England-Table 2: Demand Outlook

NPCC-New England-Summer	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	26,629	28,583	1,954	7.3%	0.79%
Load-Modifying Demand Response	1,136	3,000	1,864	164.1%	11.39%
TOTAL INTERNAL DEMAND	**27,765**	**31,583**	**3,818**	**13.8%**	**1.44%**

NPCC-New England-Winter	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	21,383	20,711	-672	-3.1%	-0.35%
Load-Modifying Demand Response	1,127	2,975	1,848	164.0%	11.39%
TOTAL INTERNAL DEMAND	**22,510**	**23,686**	**1,176**	**5.2%**	**0.57%**

This year's forecast of the 10-year net annual energy CAGR is 0.98 percent, which is the same as last year's forecast.

Demand-Side Management

DSM in ISO-NE's BPS consists of active demand resources and passive demand resources. Active demand resources consist of real-time Demand Response 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).[208] Some assets in the real-time Demand Response 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 verifiable reductions in the total amount of electrical energy used during on-peak hours.

The amount of summer active Demand Resources[209] in 2013 is projected to be 1,681 MW and the amount of passive Demand Resources[210] is 1,136 MW. In the winter, the amount of active and passive DR is 1,536 MW and 1,127 MW, respectively (NPCC-New England-Table 3).

[207] The winter peak is also somewhat dependent on electric heating demand, while the summer peak is directly dependent on air conditioning demand. A much larger number of homes in New England have air conditioning versus electric heat.
[208] OP-4 (located at http://www.iso-ne.com/rules_proceds/operating/isone/op4/index.html) is used by ISO-NE operators when resources are insufficient to meet the anticipated load plus Operating Reserve Requirement.
[209] Active Demand Resources in New England are considered Demand Response that is treated as a resource for this assessment.
[210] Passive Demand Resources in New England are treated as load-modifying Demand Response for this assessment.

NPCC-New England-Table 3: Demand-Side Management

NPCC-New England-Summer	Short-Term 2013	2014	2015	2022	10-Year Change	2022 Share of Total Internal Demand
Direct Control Load Management (DCLM)	0	0	0	0	0	0.00%
Contractually Interruptible (Curtailable)	0	0	0	0	0	0.00%
Critical Peak-Pricing (CPP) with Control	0	0	0	0	0	0.00%
Load as a Capacity Resource	1,681	1,999	1,919	1,919	238	6.08%
TOTAL RESOURCE-SIDE DEMAND RESPONSE	1,681	1,999	1,919	1,919	238	6.08%
Direct Control Load Management (DCLM)	0	0	0	0	0	0.00%
Contractually Interruptible (Curtailable)	0	0	0	0	0	0.00%
Critical Peak-Pricing (CPP) with Control	0	0	0	0	0	0.00%
Load as a Capacity Resource	1,136	1,398	1,647	3,000	1,864	9.50%
TOTAL LOAD-MODIFYING DEMAND RESPONSE	1,136	1,398	1,647	3,000	1,864	9.50%
TOTAL ENERGY EFFICIENCY	0	0	0	0	0	0.00%
TOTAL DEMAND-SIDE MANAGEMENT	**2,817**	**3,397**	**3,566**	**4,919**	**2,102**	**15.57%**

In 2022, the amount of summer active DR is projected to be 1,919 MW and the passive DR is 3,000 MW. In the winter, the projected active and passive amounts are 1,795 MW and 2,975 MW, respectively.

The active DR is based on the Capacity Supply Obligations (CSO) obtained through ISO-NE's Forward Capacity Market (FCM) three years in advance. The CSOs increase from 1,681 MW in 2013 to 1,999 WM in 2014 and then decrease slightly to 1,919 MW in 2015. At that point, since there are no further auction results, the CSOs are assumed to remain the same through the end of the reporting period.

Energy Efficiency is also secured by means of FCM CSOs. However, this year ISO-New England developed a new Energy Efficiency forecasting methodology that takes into account the potential impact of growing Energy Efficiency (EE)/conservation initiatives in the Region to project the amount of EE beyond the years when the FCM CSOs have already been procured. EE has been increasing and is projected to continue growing throughout the study period, but at a continually decreasing rate. The amount of EE in 2013 is 1,136 MW, increasing by 23 percent to 1,398 MW in 2014 and by 18 percent to 1,647 MW in 2015. By 2022, the growth rate of EE is projected to be around 6 percent per year, and about 3,000 MW of EE is expected to be available.

Both passive and active demand resources are treated as capacity in New England's FCM. 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 DR was dispatched and 644 MW responded. On another OP-4 occurrence on the morning of December 19, 2011, active DR reduced the load by 380 MW (out of 504 MW dispatched).

Generation

ISO-NE's Existing Certain capacity in summer 2012 is 31,969 MW. Natural gas-fired generation represents the largest component of ISO New England's total installed capacity, followed oil-fired generation, nuclear generation, and coal.

A total of 196 MW of new generation has been installed since the 2011 summer. Most of that capacity consists of a 130 MW gas-fired combustion turbine. In addition, a wind facility with a 62 MW summer rating (217 MW nameplate) went commercial. As explained later in this section, the on-peak capacity of intermittent generators such as wind, hydro, and solar units is based on actual generation during the summer or winter reliability hours. Therefore, the capacity as a percentage of nameplate varies from resource to resource.

ISO-NE has a total of 184 MW of capacity in the Future-Planned Category, all of which is expected to be in service by summer 2013 and consists primarily of biomass (84 MW), wind (42 MW, with a nameplate capability of 228 MW), landfill gas (28 MW), and fuel cell (18 MW) projects. Conceptual capacity[211] amounts to a total of 6,037.[212] A 20 percent confidence factor is applied to that value to reflect the percentage of queue projects that have historically gone into commercial

[211] All of the capacity in ISO-NE's generator interconnection queue that is not included in the Future-Planned Category.
[212] Includes all Conceptual additions with in-service dates from summer 2012 to summer 2017. Does not include conceptual retirements.

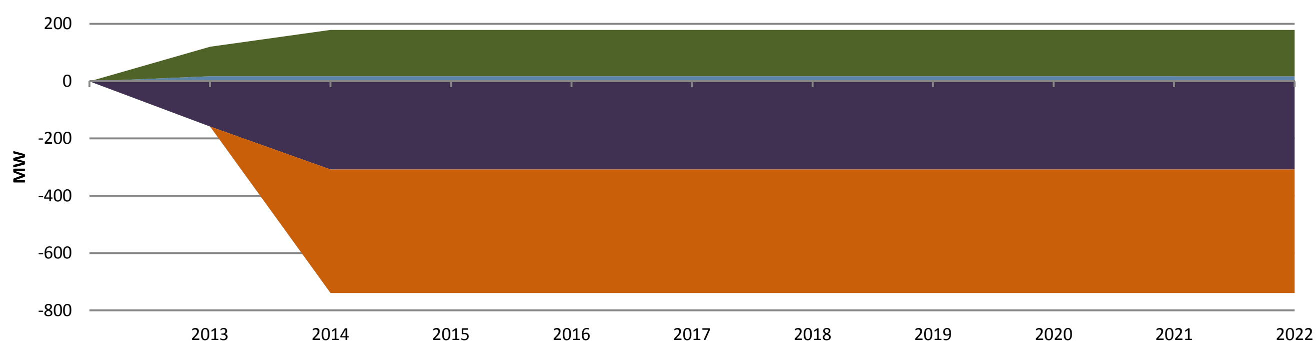
operation. The queue projects include primarily natural gas (3,734 MW), wind (1,991 MW nameplate), and biomass facilities (159 MW). Hydro-electric uprates, oil-fired peaking units, and solar projects make up the remaining 153 MW (NPCC-New England-Table 4 and NPCC-New England Figure 2)

AES Thames, a 181 MW coal plant located in southeastern Connecticut, ceased operation in early 2011. In addition, Salem Harbor units 1 and 2 (158 MW) were shut down as of December 31, 2011, and Salem Harbor Units 3 and 4 (587 MW) are scheduled to retire by June 1, 2014.

NPCC-New England-Table 4: Capacity Outlook[213]

	Current		2022 Planned			2022 Planned & Conceptual		
NPCC-New England-Summer	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Coal	2,484	7.8%	2,176	6.9%	-307	2,176	5.8%	-307
Petroleum	6,895	21.6%	6,463	20.6%	-432	6,505	17.4%	-390
Gas	13,772	43.1%	13,790	43.9%	18	17,525	46.8%	3,753
Nuclear	4,628	14.5%	4,628	14.7%	0	4,628	12.4%	0
Other/Unknown	0	0.0%	0	0.0%	0	0	0.0%	0
Renewables	4,191	13.1%	4,352	13.9%	161	6,613	17.7%	2,422
TOTAL	**31,969**	**100.0%**	**31,410**	**100.0%**	**-560**	**37,447**	**100.0%**	**5,478**

NPCC-New England-Figure 2: Summer Net Renewable Capacity Change



The retirements of both AES Thames and Salem Harbor have been included in the Planning Reserve Margin calculations, and the Reserve Margin remains above the 15 percent Reference Reserve Margin throughout the long-term assessment period. ISO-NE ensures that it has adequate capacity up to three years in advance with its Forward Capacity Auctions and Annual Reconfiguration Auctions. With respect to local loads, there is adequate capacity and transmission within the Connecticut sub-area where AES Thames is located. Since the Salem Harbor plant is located in the Boston sub-area, ISO-NE performed a reliability review to determine the impact of the retirement of the full plant. It was 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 Transmission Owners have developed plans to perform 115 kV transmission line reconductoring projects on portions of five lines prior to the plant retirement. These upgrades are expected to be completed in May 2014.

ISO-NE has small amounts (less than 5 MW total) of non-traditional resources providing regulation service through a pilot program. These include battery storage, flywheels, electric thermal storage heating, and aggregated load control. After the pilot program concludes, these resource types will remain eligible to provide regulation service. There is no current expectation that these resources will or will not 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.

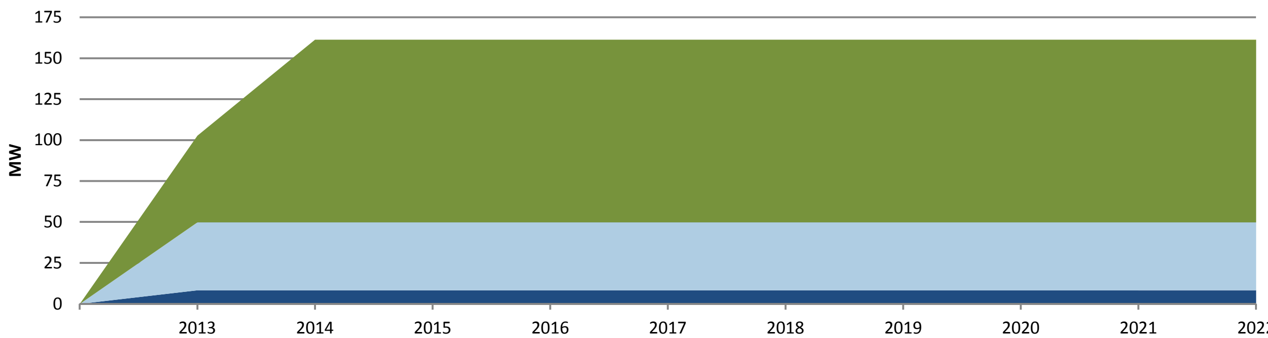
[213] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

As of summer 2012, ISO-NE has 97 MW of on-peak wind capacity, with a total nameplate capability of 566 MW. The amount of on-peak solar capacity is 5 MW, with a nameplate capability of 18 MW. For 2013, on-peak hydro-electric capacity is 1,483 MW, derated from a maximum capacity of 2,043 MW, and biomass capacity is 907 MW (NPCC-New England-Table 5, NPCC-New England-Figure 3, and NPCC-New England-Table 6).

NPCC-New England-Table 5: Renewable Capacity Outlook[214]

	Current		2022 Planned			2022 Planned & Conceptual		
NPCC-New England-Summer	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Hydro	1,483	35.4%	1,492	34.3%	8	1,512	22.9%	29
Pumped Storage	1,698	40.5%	1,698	39.0%	0	1,773	26.8%	75
Geothermal	0	0.0%	0	0.0%	0	0	0.0%	0
Wind	97	2.3%	139	3.2%	42	2,129	32.2%	2,032
Biomass	907	21.6%	1,019	23.4%	112	1,177	17.8%	270
Solar	5	0.1%	5	0.1%	0	21	0.3%	16
TOTAL	4,191	100.0%	4,352	100.0%	161	6,613	100.0%	2,422

NPCC-New England-Figure 3: Summer Net Renewable Capacity Change



NPCC-New England-Table 6: Renewable Capacity Outlook: On-Peak Vs. Installed

	Current				2022 Planned			
NPCC-New England-Summer	Wind	Solar	Hydro	Biomass	Wind	Solar	Hydro	Biomass
Installed Capacity	566	18	2,043	907	794	18	2,051	1,019
On-Peak Derate	469	13	560	0	656	13	560	0
EXPECTED ON-PEAK OUTPUT	97	5	1,483	907	139	5	1,492	1,019

ISO-NE continues to integrate new power supply sources—including new 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 through our Energy Management System (EMS). To facilitate system operation with potentially large amounts of wind power, ISO-NE Operating Procedure No. 14[215] was developed and implemented. 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.

Capacity Transactions

Firm summer capacity imports increase from 1,746 MW in 2013 to 1,768 MW in 2015 before eventually falling to 89 MW for the final years of the assessment. The capacity imports for those years reflect the results of the appropriate FCAs. Since the FCA imports are based on one-year contracts, beginning in 2016 the imports reflect only known, long-term ICAP contracts. If the imports beyond the 2015 summer do not clear in future FCM commitment periods, the lost capacity will be replaced by other supply or Demand-Side resources (NPCC-New England-Table 7).

[214] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.
[215] Appendix F – Wind Plant Operators Guide (OP-14F): http://www.iso-ne.com/rules_proceds/operating/isone/op14/.

NPCC-New England-Table 7: Projected Capacity Transactions

NPCC-New England-Summer	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Expected Imports	0	0	0	0	0	0	0	0	0	0
Firm Imports	1,746	1,851	1,768	120	95	95	95	95	89	89
TOTAL IMPORTS	1,746	1,851	1,768	120	95	95	95	95	89	89
Expected Exports	0	0	0	0	0	0	0	0	0	0
Firm Exports	100	100	100	100	100	100	100	100	100	100
TOTAL EXPORTS	100	100	100	100	100	100	100	100	100	100
TOTAL NET CAPACITY TRANSACTIONS	**1,646**	**1,751**	**1,668**	**20**	**-5**	**-5**	**-5**	**-5**	**-11**	**-11**

For the 2012 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 is held constant through the assessment period.

Transmission

There are several transmission projects that are projected to come on-line during the assessment period that are important to the continuation of, or enhancement to, system or sub-area reliability. These projects are the results of progress made by the ISO and regional stakeholders in analyzing the transmission system in New England, developing back-stop solutions to address existing and projected transmission system needs, and implementing these solutions. 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 SEMA project. The new paths that are part of MPRP, many components of which are under construction, will provide basic infrastructure necessary to increase the ability to move power into Maine from New Hampshire and improve the ability of the transmission system within Maine to move power into the local load pockets as necessary. NEEWS consists of a series of projects that have been identified to improve system reliability, including in Springfield and Rhode Island, and increases total transfer capability across the New England east-to-west and west-to-east interfaces. The Long-Term Lower SEMA project eliminates the criteria violations in the lower southeastern Massachusetts Area, which includes Cape Cod. Individual 345kV projects, most of which are components of the major projects described above, are listed in the following table, which also includes line upgrades (NPCC-New England-Table 8).

NPCC-New England-Table 8: Planned and Under Construction Transmission Projects

Status	Terminal Origin Location	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Capacity Rating (MW)	Expected In-Service
Under Construction	Larrabee Road S/S	Surowiec S/S	17	300 - 399	2,151	2014
Under Construction	Kent County	West Farnum S/S	21.4	300 - 399	1,353	2013
Under Construction	Manchester	Meekville Jct.	2	300 - 399	2,420	2013
Under Construction	North Bloomfield S/S	Conn/Mass Border	11.9	300 - 399	2,420	2013
Under Construction	Agawam S/S	Ludlow S/S	16.8	300 - 399	2,420	2013
Under Construction	Orrington S/S	Albion Road S/S	59	300 - 399	2,151	2014
Under Construction	Surowiec S/S	Raven Farm S/S	12.4	300 - 399	2,151	2013
Under Construction	Maguire Road S/S	South Gorham S/S	21	300 - 399	2,151	2013
Under Construction	Maguire Road S/S	Three Rivers Switchyard	19.2	300 - 399	2,151	2013
Under Construction	Albion Road S/S	Coopers Mills S/S	21	300 - 399	2,151	2014
Under Construction	Larrabee Road S/S	Coopers Mills S/S	34.3	300 - 399	2,151	2014
Planned	Carver	Bourne	17.9	300 - 399	2,169	2013
Planned	ANP Blackstone	NEA Bellingham Tap	1.2	300 - 399	1,882	2013
Planned	Card S/S	Lake Road S/S	29.3	300 - 399	2,420	2015
Planned	Lake Road S/S	Con/RI Border	7.6	300 - 399	2,420	2015
Planned	West Farnum S/S	Con/RI Border	17.7	300 - 399	2,172	2015
Planned	Millbury S/S	West Farnum S/S	20.7	300 - 399	2,172	2015
Planned	Frost Bridge S/S	North Bloomfield S/S	35.4	300 - 399	2,420	2017

Currently, there are no transmission constraints preventing the system from being operated in a manner that ensures the reliability of the New England-wide system. The proposed projects with the target in-service dates are expected to enhance the long-term reliability of the New England bulk power supply system. There are no major interconnection-related projects or issues at this time. Existing and projected transmission additions are included in the table below (NPCC-New England-Table 9).

NPCC-New England-Table 9: Existing and Projected Transmission

NPCC-New England	AC (Circuit Miles)	DC (Circuit Miles)	Total (Circuit Miles)
EXISTING	7,890	216	8,106
Currently Under Construction	182	0	182
Planned - Completed within First Five Years	458	0	458
Planned - Completed within Second Five Years	8	0	8
2022 TOTAL (UNDER CONSTRUCTION & PLANNED)	8,537	216	8,753
Conceptual - Completed within First Five Years	78	140	218
Conceptual - Completed within Second Five Years	18	0	18
2022 TOTAL (UNDER CONSTRUCTION, PLANNED & CONCEPTUAL)	**8,633**	**356**	**8,989**

Presently there are no significant concerns over meeting the target in-service dates of any of the transmission projects. However, if the implementation of these projects is delayed, interim measures will be taken, such as issuing gap requests for proposals (RFPs) to install temporary generation in a specific area of the system.

No additional significant substation equipment such as SVC, FACTS controllers, or HVdc is currently planned to be added to the system.

Vulnerability Assessment

The New England Area is currently not experiencing a drought. However, in the event that the assessment area was to experience an extended drought, some traditional hydro-electric stations could be temporarily capacity or energy-constrained. Other fossil stations could also be temporarily capacity limited due to lack of cooling water or other (heat-related) environmental issues.

Due to the relatively small contribution to overall capacity from hydro-electric facilities (1,483 MW, or 4.6 percent), any potential reduction in hydro-electric energy production due to regional drought conditions could be readily supplemented by increased levels of other types of fossil-based generation.

There are no existing or potential significant long-term generator outages that are anticipated to impact reliability during the assessment period.

The New England states' Renewable Portfolio Standards (RPS) include technology classes for new and existing resources, and Load Serving Entities (LSEs) must provide their customers with a specified percentage of electric energy generated by each class each year. Renewables designated as "new" resources (typically Class I RPS resources) are state-specific but typically include wind, solar, hydro-electric, biomass, landfill gas, and ocean thermal. Although the required percentage for new renewable resources varies by state, it increases each year and accounts for most of the growth of RPS targets in New England. The RPS percentage targets for new resources in 2021 for the five New England states with RPSs range from 10 percent for Maine to 20 percent for Connecticut, with New Hampshire, Rhode Island and Massachusetts at 12, 14 and 16 percent, respectively. It is assumed that these targets will be met by generators in the ISO-NE generator interconnection queue, which had 2,577 MW of renewable projects as of April 1, 2012. Wind makes up approximately 85 percent of that potential renewable capacity.

Concerns exist over the resultant impact from compliance with state RPS and the potential build-out of these new renewable resources. Because of concerns over the increasing amount of wind capacity, ISO-NE completed a major wind integration study to identify the detailed operational issues of integrating large amounts of wind resources into the New England power grid. ISO-NE is currently implementing the recommendations of this study, including the development of a centralized wind power forecasting system.

Although the amount of ISO-NE's solar capacity is still small (18 MW nameplate), the number of solar projects has increased significantly in recent years and is likely to continue growing due to incentives that all the New England states have in place. Currently, it is estimated that New England actually has about 125 MW of nameplate solar capacity. However, only about 15 percent of that is registered in ISO-NE's energy and capacity markets, with the rest remaining behind the meter.

The implementation of the FCM has enhanced the integration of demand resources into system operations. ISO New England has two real-time demand resource programs that can be used to manage load and reserves as part of implementation of ISO-NE OP-4. The first program is focused on load response and is utilized in the early stages of OP-4. The second is emergency generation (RTEG), which is accessed in a later action of OP-4. All of these resources are audited annually in both the summer and winter for their ability to perform. Based on DR audits in summer 2011 and the response of active DR during the July 22, 2011 OP-4 event, ISO-NE expects that approximately 95 percent of DR capacity will perform when triggered. In addition, each demand resource submits the hourly status of their capability to the ISO, and the system operators are able to view that capability in real time. Finally, the operators are provided with telemetry from each resource to monitor the real-time performance of the resources in relation to their capacity supply obligations.

Due to the fact that distributed generation (DG) must be integrated into the local electric company's distribution systems, it must comply with the interconnection standards applicable to such systems. This distributed generation is traditionally not a major concern for BPS operation, although relatively large DG projects can be studied by ISO-NE. ISO-NE does not anticipate any operational problems or reliability concerns resulting from the levels of distributed generation enrolled within its Demand Response programs.[216] The FCM qualification process requires additional information for projects that include the use of DG to ensure that they comply with the definition of DG within FCM.

In December 2010, ISO-NE completed the New England Wind Integration Study (NEWIS), a major study of integrating wind resources into the New England electric system. The study found that the large-scale integration of wind resources is feasible, but the Region will need to continue addressing a number of issues. Those issues include the need to: 1) ensure revenues for other types of generation to maintain system reliability; 2) increase system flexibility and improve market design to provide incentives for dispatchable resources; 3) provide increased operating reserve and regulation; 4) evaluate the accuracy of methods for calculating wind capacity; 5) develop transmission to interconnect wind resources and bring the energy to load centers in New England; 6) develop an accurate means of forecasting wind generation output; and 7) update interconnection requirements for wind generation.

The results of NEWIS will serve as the basis for regional policies and practices by ISO-NE, wind project owners, and interconnecting transmission owners, and may result in changes to the ISO-NE tariff, operating procedures, and manuals. ISO-NE will continue to work with stakeholders through the usual stakeholder processes to implement the study's findings, which may require modifying market and reliability rules necessary to facilitate the large-scale integration of future wind resources.

The majority of actions to be implemented in the near term were derived from the NEWIS-identified technical requirements for interconnection.[217] The balance of the integration efforts will be prioritized and completed through ISO-NE's stakeholder process.

The Wind Power Forecast Integration Project (WPFIP) is the first phase in the progression of steps necessary to fully integrate wind power into the ISO-NE system. Currently in New England, variable energy resources (VERs) perform their own forecast of generation for each hour of the next operating day, which they submit to ISO-NE as a self-schedule (forecast) on the day preceding the operating day. Phase 1 of the WPFIP will replace this self-scheduled forecast with a centralized forecasting system, as described above. Phase 2 of the WPFIP will make it possible to dispatch wind plants in a manner similar to that of other ISOs that have integrated wind power into their dispatch process. Integration into real-time dispatch means that wind plants will submit economic offers and be able to set prices at their local bus, and transmission congestion will be managed in a transparent and automated process (versus the typically manual process that is currently

[216] Within New England, the capacity and load relief benefits from triggering distributed generation, Real-Time Emergency Generation (RTEG), is only attainable through the invocation of ISO-NE Operating Procedure No. 4 – *Action during a Capacity Deficiency* (OP-4) – Action 6 of 11.

[217] GE Energy Application and Systems Engineering, et al., *Technical Requirements for Wind Generation Interconnection and Integration* (November 3, 2009), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2009/newis_report.pdf.

used for real-time self-scheduled resources). Phase 2 of the WPFIP will also include closer coupling with the short-term outage scheduling process and will include publishing of the aggregate week-ahead wind power forecast (similar to the manner in which a week-ahead load forecast is published) in order for the market participants to be able to incorporate this information into their decision-making processes and market strategies.

At this time, there are no plans to install more Under-Voltage Load Shedding (UVLS) in New England. Currently, northern New England has the potential to arm 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 facility already out of service. Presently, two significant projects have the attribute of either completely eliminating the need for the UVLS or significantly reducing the likelihood of depending on such schemes. These projects are the Vermont Southern Loop Project and the Maine Power Reliability Program (MPRP). The Vermont Southern Loop Project was completed in late 2010 and the MPRP project is scheduled to be completed in 2014.

There are no Special Protection Systems that are proposed to be installed in lieu of proposed regulated transmission facilities to address system reliability needs in New England in the assessment time frame. However, two new, temporary Special Protection Systems 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 2014), these two temporary Special Protection Systems will be removed.

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 flexible alternating-current transmission systems (FACTS) and high-voltage direct current (HVdc) will facilitate the integration of variable resources in the Region and reliably improve the economical operation of the power system. Because much of the potential for wind development is remote from load centers, additional transmission development will be required. Some of these transmission improvements will likely use HVdc technology, which is economical over long distances, and FACTS, which makes better use of limited transmission facilities. 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. 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 Transmission Owners a significantly expanded base of Phasor Measurement Units (PMUs), Phasor Data Concentrators, and greatly enhanced phasor data analytical tools. The SIDU project will supplement 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 it will serve as the smart grid technology platform upon which advanced analysis and visualization tools can be deployed. 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 are conducting smart grid pilot programs or projects in New England 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 Long-Term Reliability Assessment period.

New England relies upon the facility owners to investigate relay protection misoperations with cooperation and technical support from ISO-NE. The facility owners will then determine the cause of the misoperation and implement corrective actions for that facility and other facilities that have the same concern. New England has a number of forums that allow the equipment owners to share information they feel may be useful to other equipment owners in preventing similar events.

ISO-NE routinely reviews the existing, pending, and promulgating environmental regulation for their potential impact on existing or future capacity. Under the workloads associated with its Strategic Planning Initiative, ISO-NE has identified several regional power stations that may be retired due to the economics of compliance with pending state and federal air and water regulations.

Emerging environmental regulations will very likely require large capital investments that may be uneconomic for many older fossil-fueled resources. While the exact form and timing of the regulations remain uncertain, it is highly likely that substantial compliance investments will be required by owners of existing New England resources to continue operations. This could lead to a significant quantity of older generation choosing to retire rather than comply.

Approximately 7.9 GW of coal- and oil-fired capacity located in New England is subject to the final Mercury and Air Toxics Standards (MATS). Many coal-fired units have or are planning needed retrofit controls to comply with existing state regulations, and most oil-fired units are expected to utilize a safe harbor exemption to continue operation beyond the April 2015 compliance deadline. Overall, less than 1 GW of affected capacity in New England is expected to retire due to non-compliance with the MATS.

A total of 12.1 GW of thermal station generating capacity using once-through cooling in the Region is subject to the proposed Clean Water Act Section 316(b) cooling water rule and will likely be required to modify existing cooling water intake structures by 2020 to minimize loss of fish and other aquatic life. A smaller subset of this affected capacity with water withdrawals greater than 125 million gallons per day (estimated at 5.6 GW) will likely need to convert to closed-cycle cooling in the same time frame. ISO-NE estimates that between 1 and 3 GW of affected capacity in New England may retire by 2020 due to non-compliance with CWA Section 316(b).

Currently, the procedures that are in place to maintain system reliability include reliability agreements and out-of-merit unit commitment. 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 assessment area's dependence on natural gas-fired resources. If all of New England's older oil units were to seek retirement, new capacity would be required to satisfy the Installed Capacity Requirement.

ISO-NE has initiated and is aggressively promoting a regional dialogue focused on solutions that can avert undesirable outcomes. ISO-NE has initiated a study to better quantify the implications of this issue. This analysis will complement the 2010 economic planning studies. For more information, reference the Standing and Emerging Reliability Issues section.

At this time there are no planned outages for generator environmental retrofits that would impact reliability. Many environmental retrofits needed for MATS have already been placed into service or are planned well ahead of the April 2015 compliance deadline. Remaining retrofits are expected to be completed during traditional outage periods.

Plans for Accommodating Generator Retirements and Environmental Control Retrofits

ISO-NE has received notification of the retirement of Salem Harbor units 3 & 4, with a combined capability of 587 MW. The retirement is to take effect on June 1, 2014.

Between 2012 and 2021, environmental regulations could require generators to incur significant capital costs for retrofits. The added pollution control equipment could restrict operation and the cost of compliance could render some of these generators non-price competitive, resulting in the retirement of additional generation. The compliance retrofits could include adding post-combustion control devices, modifying cooling water intakes, switching to closed-cycle cooling systems, or switching fuels. ISO-NE estimates that, in total, these regulations would affect over 12.1 GW of installed capacity across New England.

Because new environmental requirements are in flux and are being phased in over the next decade, assessing the potential impacts that the resulting regulations could have on generators and the power system poses some challenges. First, the capital investments some generation owners will need to make are uncertain for complying with the Mercury and Air Toxics

Standards (MATS) of the US EPA Clean Air Act (CAA) and the Cooling Water Intake 316(b) Rule of the Clean Water Act (CWA). Other unknowns include the timing, magnitude, and location of unit retirements that could result from generators opting not to comply with these regulations.

As part of the Strategic Planning Initiative, ISO-NE is collecting and analyzing data to identify the units expected to face significant capital investments because of upcoming regulatory requirements and to assess the potential resulting impacts on transmission system operations. The ISO has also initiated a study to better quantify the implications of the likely retirement of several generating units and their potential replacements. The ISO is identifying generators that already have environmental remediation measures in place or may require relatively minor upgrades and those at risk for retirement. The actual compliance timelines will depend on the timing and substance of the final regulations and site-specific circumstances of the electric generating facilities. Most of the at-risk capacity would face compliance or retirement decisions—and Forward Capacity Market positioning decisions—starting late in this decade, extending into the early part of the next decade.

A total of 12.1 GW of fossil and nuclear capacity are subject to the proposed Cooling Water Intake Rule, which is expected to be finalized in June 2013. This rule directly affects a total of 5.6 GW of fossil-fueled and nuclear facilities with 125 MGD or higher once-through cooling water systems, which likely will be obligated to convert to closed-cycle cooling systems between 2018 and 2024. The ISO estimates that approximately 1 GW to 3 GW of the 5.6 GW subject to the additional requirements of EPA's preferred option[218] may retire between 2018 and 2020, rather than retrofit to closed-cycle cooling systems.

The MATS rule affects coal- and oil-fired steam units over 25 MW. The final MATS rule will have a relatively modest impact on New England generators. Although 7.9 GW will be affected, less than 1 GW of environmental retirements are anticipated by 2015. Most oil-fired generators are expected to continue operating after 2015, and limited additional pollution control retrofits are required for the remaining coal-fired generators, which have mostly completed or are implementing retrofits.

Compliance with environmental requirements will require the coordination of construction schedules and maintenance outages at affected generators to avoid diminishing system reliability. ISO-NE schedules planned outages up to approximately two years in advance. At this time, three outages related to environmental retrofits, totaling approximately 1,100 MW, have been scheduled during the assessment period.

Since 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. It was 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 Transmission Owners have developed plans to perform 115 kV transmission line reconductoring projects on portions of five lines in the North Shore area prior to the plant retirement. These upgrades are expected to be completed in May 2014.

There are no major interconnection-related projects at this time.

To ensure resource adequacy for the system, the amount of capacity the system requires in a given year is determined through the Installed Capacity Requirement (ICR) calculation, which accounts for uncertainties, contingencies, and resource performance under a wide range of existing and future system conditions. The ICR is the amount of capacity that must be obtained through supply-side and demand-side resources in the Forward Capacity Market. Through the FCM, which consists of a series of auctions and bilateral trading periods, specific resources are procured and committed for meeting the ICR, and

[218] EPA's preferred entrainment-mitigation option requires electric power generating facilities with 125 MGD or higher once-through cooling water systems to prepare and submit an entrainment-characterization study for determining whether they would need to retrofit to closed-cycle cooling systems. These facilities would need to follow an expedited schedule for submitting CWIS performance data to regulators.

other key values are identified. Purchased capacity resources must be available in the specified timeframe to ensure the region has adequate resources.

The FCM's Forward Capacity Auctions are designed to procure capacity roughly three years (40 months) in advance of the commitment period. This lead time allows capacity suppliers to develop new capacity resources and enables the ISO to plan for these new resources.

The results of the most recent Forward Capacity Auction show that New England will have adequate resources through 2015/2016, assuming that resources meet their capacity supply obligations. Most recent increases in capacity have come from both demand resources and imports from neighboring regions, and approximately 6,600 MW of proposed generation are in the ISO Generator Interconnection Queue. The ISO remains optimistic that adequate demand and supply resources will be procured and installed in time to meet the physical capacity needs that will be established by the ICRs for future years.

Because additional retirements may occur, ISO-NE is working with stakeholders to identify issues and find the means of meeting future capacity needs. The ISO is studying the potential retirement of aging units as part of its Strategic Planning Initiative. The capacity mix in New England currently operates with about 6 GW of fossil-fueled generating units (primarily coal or oil) that are older than 40 years. That amount increases to 8.5 GW by 2020. Existing and pending environmental initiatives that require reduced air emissions and controlled water withdrawals and discharges are placing increased economic pressure on aging coal-and oil-fired units to add environmental controls or to reduce run times. Given their age and lack of operating revenues and the new capital investment that may be required, many of these coal and oil units are likely to retire in the latter half of the decade and be replaced with efficient and relatively clean-burning natural-gas-fired units. The ISO is conducting studies to assess the economic and reliability effects of retiring aging, environmentally challenged generating units and their likely replacement with natural-gas-fired generation, variable renewable resources, and imports from the neighboring Canadian regions.

ISO-NE is performing a Strategic Transmission Analysis, which is assessing potential transmission issues associated with generator retirements and examining "broad" transmission system requirements to integrate renewable resources for the 2020 study year. Some portions of the study will be complete in 2012, which include interim reports, and the remainder of the study is scheduled for 2013.

The initial study system conditions include the integration of demand resources and the retirement of oil and coal generating units more than 50 years old. The study also assumes the repowering of existing old coal- and oil-fired generators with natural gas, which would not require a major expansion of the transmission system. Therefore, the Strategic Transmission Analysis focuses on the ability of wind, other supplemental capacity, or a combination of all resources to address the reliability needs resulting from the potential removal of generators, both simultaneously and in smaller clusters.

Standing and Emerging Reliability Issues

Since early 2011, ISO-NE, the New England states and market participants have engaged in a Strategic Planning Initiative (SPI) focused on the future of the wholesale electricity sector in New England. ISO-NE launched the SPI to highlight key risks to the efficient operation of the wholesale electric markets and reliability of the BPS. As part of the SPI, ISO-NE sought feedback from the Region's stakeholders on the nature and urgency of the risks. Following these discussions, a broad consensus was reached regarding the risks facing the Region. ISO-NE has suggested a path forward to both mitigate these risks and lay the groundwork for an electricity system driven by public policy goals, economic factors, and new technologies.

As part of its SPI, ISO-NE has identified five key risks to the efficient operation of the wholesale electric markets and reliability of the BPS.[219] These five risks, which are both standing and emerging, are:

- **Resource Performance and Flexibility** – related to the uncertain performance and/or constrained operational accessibility of demand resources and aging supply resources, and the need to increase system flexibility.
- **Increased Reliance on Natural Gas-Fired Capacity** – related to the reliance on natural-gas-only resources, as sufficient gas may not be available to meet power system needs during periods of very high seasonal demand, under other stressed system conditions, or when facing contingencies associated with natural gas supply/transportation system infrastructure.
- **Retirement of Generators** – related to the economic and policy factors that will result in the potential exit of a substantial portion of existing, older fossil-fuel capacity.
- **Integration of a Greater Level of Variable Resources** – related to the need for a steady increase in system flexibility as more variable resources, primarily renewable energy resources are added to the system over the next several years.
- **Alignment of Markets with Planning** – related to the need to better align— from timing and analytic perspectives— wholesale market procurements with transmission planning processes to allow reliability needs to be met through either market resources or backstop transmission solutions.

The following discussion will relate to the first three issues listed above: 1) Resource Performance and Flexibility, 2) Increased Reliance on Natural Gas-Fired Capacity, and 3) Retirement of Generators. The other two issues are equally important, but ISO-NE determined that the first three issues are the highest priority risks that may impact system reliability in the near term, while the other two issues are longer term in nature.

1: Resource Performance and Flexibility

Recent experience has indicated that the current fleet of resources in New England could be better matched to existing and likely future system operational needs. Current contingencies assumed in operations and planning are large relative to the size of the New England system. In practice, since there are limited readily-available, off-line reserve resources, the commitment of additional resources for on-line reserves is required at times. Moreover, the system has limited flexibility given the current market incentives and unit performance characteristics. The current circumstances include the slow response and decreased reliability of older thermal units; the relatively narrow operational band of more responsive, newer combined-cycle units; the frequent participation in energy markets of capacity that is responsive but energy-limited, rendering it unavailable to serve as reserves or provide ramping functions; and the constrained operational accessibility to certain classes of demand resources that can only be dispatched in emergency conditions.

Although this issue does not directly impact resource adequacy from a supply/demand balance perspective, it leads to conditions that increase the complexity of reliable system operations and will likely decrease the efficiency of the wholesale markets. Reliability will be impacted due to increased commitment and out-of-merit dispatch, the potential rejection of "economic delist bids" due to local reliability concerns, and sanctionable violations of NERC Reliability Criteria. ISO-NE expects that the operational challenges related to unit performance and flexibility will increase in severity and frequency with the retirement of uneconomic generating capacity.

The resulting impact on the transmission system is likely to be negligible. However, the LTRA Reserve Margins may be impacted depending on remedial measures, such as the derating of units to reflect lower availability, which may result in a reduction in capacity. The extent of the potential impact is unknown at this time.

The results of studies regarding this issue and implementation of mitigation measures may impact the specific technology types and operating characteristics of new resource development and procurement.

[219] The risks and the path toward mitigation can be found in more detail on the ISO-NE web site under the Strategic Planning Initiative directory located at: http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/index.html.

Contingencies that are larger and more frequent than those currently assumed in ISO-NE operations and planning could increase the vulnerability of New England's electric grid. Increased ramping requirements for both the morning and evening load pick-ups (and drop-offs) could also exacerbate this issue.

2: Increased Reliance on Natural Gas-Fired Capacity

On several occasions over the past 10 years, New England has faced challenging operating conditions related to the availability of the Region's gas-fired generating capacity (e.g., 2004 Cold Snap, 2009 Sable Island Outage, January 2011 cold weather, and April/May 2011 liquefied natural gas shortages). These operating conditions were linked to disruptions in natural gas supply or transportation infrastructure, regional and global natural gas market conditions, and natural gas availability for power generation under peak "cold snap" natural gas demand conditions. These natural gas-related operational and economic risks are already in evidence.

As discussed within the next issue, it is expected that the upcoming unit/station retirements will heighten this gas dependence risk. The Region will lose (coal and oil-fired) capacity that currently provides fuel diversity under constrained gas availability conditions, and the residual and replacement capacity may be primarily natural gas-fired, or may be of a resource type that does not provide operational certainty under constrained gas availability conditions.

In support of ISO-NE's SPI concerning natural gas, a high-level, deterministic assessment was performed in 2011 to assess the ability of the regional gas supply and delivery systems to serve seasonal electric power sector demands based on the economic dispatch of all generation. The study assessed the gas supply available for New England's gas-fired power generation through 2020 on peak winter and peak summer days. The analysis considered the gas demands of existing generators as well as a scenario assuming that a portion of the non-gas-fired capacity in the assessment area retires and is replaced with new natural gas-fired capacity.

The 2011 Natural Gas Study[220] concluded that the natural gas pipeline capacity is insufficient during winter for satisfying the economical gas needs for New England's power plants during the next decade.

With existing natural gas-fired capacity in place, the existing natural gas infrastructure is insufficient to meet electric power system demand (for natural gas) for all study years (i.e., the winter of 2011/12 through the winter of 2019/20) for all electric system demand scenarios. In the later years of the study, deficiencies reach approximately 625,000 dekatherms per day (Dth/day) in some years in the reference case, to as much as 1,375,000 Dth/day in the maximum electric demand scenario. A gas deficit of 240,000 Dth/day is estimated to be equivalent to a shortage of 1,000 MW/day, with an assumed full-load heat rate of 10,000 Btu/kWh. No shortages are expected under reference system conditions during the summer peak because gas local distribution company demand in the summer is minimal, opening up substantial capacity on the natural gas system in quantities that generally exceed increased summertime power generation demand.

The study also considered natural gas system contingencies for the same assumptions of natural gas and power system demand. These results and findings are considered Critical Energy Infrastructure Information (CEII).

While the study shows gas-fired electric generators would have shortfalls in fuel supply and thus seasonal unit availability, replacement or supplemental (coal- and oil-fired) capacity may soon not be available to the ISO for mitigation purposes. However, power system reliability can be preserved in a number of ways. Alternate sources of electric energy could be used when gas supply shortage events are projected, including dual-fuel generating units using fuels other than natural gas, and imports from neighboring systems, such as Canada. In addition, the Region is showing growth in Energy Efficiency, and increased renewable sources of energy will likely develop in the Region. Firm contracting for gas supply and transportation may also help in mitigation, but "Firm" is still "not-Firm" under force majeure scenarios.

[220] http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2012/gas_study_public.pdf.

The procurement of non-Firm natural gas supply and transportation within the electric sector may result in the loss of single-fuel gas-fired stations, thus changing the topology of the integrated electric generation and transmission grid. It is unknown at this time whether the end result would be an increase or decrease in existing transmission interface constraints, or the development of new constraints. In addition, the potential unit reductions and unavailability could directly decrease seasonal Reserve Margins over the study period.

As noted earlier, because the Region is so dependent upon natural gas-fired generation, any contingency on the regional gas grid or upstream of New England's gas grid may temporarily impact fuel deliveries into and throughout the Region. These contingencies could be in the form of "force majeure" on regional gas infrastructure or originate as a result of planned or unplanned maintenance.

3: Retirement of Generators

One of the near-term risks is the potential for substantial unit retirements before the planned long-term changes can influence resource development decisions. From a market perspective, the retirement of existing uneconomic capacity is an efficient outcome and was contemplated in the design of Forward Capacity Market (FCM). The concern, then, is not with retirements per se; rather, ISO-NE has identified unit retirements as a strategic risk due to their potential magnitude in a relatively short time frame, and the interaction between unit retirements and existing challenges associated with the performance, flexibility, and high gas dependence of the existing fleet.

The capacity mix in New England—a system with summer peak requirements of roughly 30 gigawatts (GW)—includes over 6 GW of fossil-fueled generating units (primarily coal or oil) that exceed 40 years in age, which run at heat rates exceeding 10,000 Btu/kWh. Oil-fired generation, representing 22 percent of existing capacity in the Region, operates at an average capacity factor of less than 1 percent, but during system peaks provides almost 20 percent of the Region's energy. Under current fuel prices and other market conditions, this group of resources faces economic challenges. These units may effectively need to recover all variable and fixed costs, including any new capital investments, from energy markets whose prices are dictated in many hours by currently low natural gas prices from highly efficient, new generating facilities. In other words, even without new capital investment requirements, a significant portion of the Region's generating fleet is at risk of retirement.

Studies are currently being conducted to assess the resultant reliability impact from both resource adequacy and transmission security perspectives. While the studies are still unfinished due to the ever-changing regulatory environment, the most likely outcomes are shortfalls in summer capacity margins, loss of mitigation measure during winter peak operations, and possible, various impact on transmission as a result of critical unit/station retirements. The studies are targeted for approval and publication by the end of 2012.

The direct result of the unit retirements would be a decrease in seasonal Reserve Margins over the study period, barring a quick influx of replacement capacity. The results of new capacity integration studies and implementation of other mitigation measures to remediate other SPI risk factors may dictate or impact the specific technology types and operating characteristics of new resources.

New capital investment requirements associated with emerging U.S. Environmental Protection Agency (EPA) rules related to mercury/air toxics and cooling water standards could precipitate unit retirements in the latter half of the decade. Any changes to the proposed regulatory compliance dates moving forward may become problematic. As the long-term changes will not be in place in time to influence new resource development, the Region must either consider near-term enhancements to the current structures or allow the existing processes to manage the transition.

NPCC-New York

Planning Reserve Margins

The New York Balancing Authority (NYBA) is projecting adequate Planning Reserve Margins from 2013–2022, based upon the current NYBA Installed Reserve Margin (included in this assessment as the NERC Reference Margin Level) (NPCC-New York-Table 1 and NPCC-New York-Figure 1).

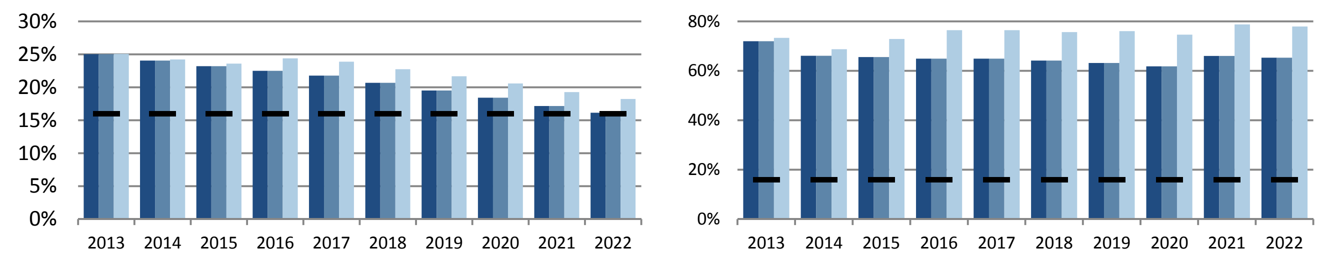
The current Installed Reserve Margin (IRM) requirement for the NYBA Area that covers the period from May 2012 to April 2013 (2012 Capability Year) is 16 percent. This requirement is based upon an annual study conducted by the New York State Reliability Council (NYSRC) Installed Capacity Subcommittee (ICS).

NPCC-New York-Table 1: Planning Reserve Margins

NPCC-New York-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		25.02%	24.07%	23.21%	22.51%	21.79%	20.68%	19.52%	18.44%	17.16%	16.14%
PROSPECTIVE		25.02%	24.07%	23.21%	22.51%	21.79%	20.68%	19.52%	18.44%	17.16%	16.14%
ADJUSTED POTENTIAL		25.09%	24.22%	23.59%	24.40%	23.88%	22.75%	21.68%	20.58%	19.28%	18.24%
NERC REFERENCE	-	**16.00%**	**16.00%**	**16.00%**	**16.00%**	**16.00%**	**16.00%**	**16.00%**	**16.00%**	**16.00%**	**16.00%**

NPCC-New York-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		72.02%	66.13%	65.57%	64.94%	64.91%	64.18%	63.17%	61.86%	66.06%	65.33%
PROSPECTIVE		72.02%	66.13%	65.57%	64.94%	64.91%	64.18%	63.17%	61.86%	66.06%	65.33%
ADJUSTED POTENTIAL		73.36%	68.78%	72.93%	76.46%	76.44%	75.65%	76.06%	74.65%	78.76%	77.98%
NERC REFERENCE	-	**16.00%**	**16.00%**	**16.00%**	**16.00%**	**16.00%**	**16.00%**	**16.00%**	**16.00%**	**16.00%**	**16.00%**

NPCC-New York-Figure 1: Summer (Left) and Winter[221] (Right) Planning Reserve Margins



Demand

The 2011 LTRA forecast compound average growth rate (CAGR) was 0.66 percent from 2012 to 2021, compared to 0.81 percent for this assessment period (2013-2022).

NPCC-New York-Table 2: Demand Outlook

NPCC-New York-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	33,696	36,230	2,534	7.5%	0.81%
Load-Modifying Demand Response	0	0	0	0.0%	0.00%
TOTAL INTERNAL DEMAND	**33,696**	**36,230**	**2,534**	**7.5%**	**0.81%**

NPCC-New York-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	24,929	25,908	979	3.9%	0.43%
Load-Modifying Demand Response	0	0	0	0.0%	0.00%
TOTAL INTERNAL DEMAND	**24,929**	**25,908**	**979**	**3.9%**	**0.43%**

The primary differences between the forecasts are the recovery from the recession in the short term as well as a reduction in the estimate of peak demand associated with Energy Efficiency programs.

Demand-Side Management

Demand Response resources expected to be available on-peak for the first year of the assessment include 2,165 MW (summer 2013) of Special Case Resources and 257 MW (summer 2013) of Emergency Demand Response Program (EDRP)

[221] Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.

resources. These numbers are reported in the "2012 Load and Capacity Data Report."[222] The 2013 forecast of peak demand impact of Energy Efficiency programs is 343 MW (NPCC-New York-Table 3).

The Demand Response resources are held constant over the 10-year assessment period of the NERC LTRA. The cumulative forecast Energy Efficiency impact on peak demand is 1,674 MW by 2017 and 2,324 MW by 2022. The growth of peak demand impact is 650 MW during the second five years of the forecast.

NPCC-New York-Table 3-Demand-Side Management

	Short-Term					
NPCC-New York-Summer	2013	2014	2015	2022	10-Year Change	2022 Share of Total Internal Demand
Direct Control Load Management (DCLM)	0	0	0	0	0	0.00%
Contractually Interruptible (Curtailable)	0	0	0	0	0	0.00%
Critical Peak-Pricing (CPP) with Control	0	0	0	0	0	0.00%
Load as a Capacity Resource	2,165	2,165	2,165	2,165	0	5.98%
TOTAL RESOURCE-SIDE DEMAND RESPONSE	2,165	2,165	2,165	2,165	0	5.98%
TOTAL ENERGY EFFICIENCY	624	932	1,210	2,324	1,700	6.41%
TOTAL DEMAND-SIDE MANAGEMENT	**2,789**	**3,097**	**3,375**	**4,489**	**1,700**	**12.39%**

The projected levels of Demand Response resources are held constant beyond 2012. The inclusion of Special Case Resources in this manner is an appropriate assumption for planning purposes as these resources can be added or removed with short lead times and are driven by market conditions.

No significant developments or policy implementations are known at this time.

The NYBA's market rules allow for aggregations of demand side resources to provide operating reserves and regulation service.

Generation

The NYBA Area currently enjoys a diverse fuel supply (NPCC-New York-Table 4 and NPCC-New York-Figure 2). Since the last reporting year, new resources totaling 633 MW have come on-line. These include 549 MW of natural gas, 52 MW of wind, and 32 MW of solar. Additionally, there are 182 MW of unit uprates scheduled for 2012. The most significant generator uprate is the 168 MW uprate of a nuclear facility. The NYBA expects the reliance on natural gas as the fuel for new generation to increase over time, and that fuel diversity will decrease as a result.

No current Future-Planned resources are confirmed to come on-line during the assessment period at this time. There are a total of 2,537 MW of Conceptual resources in the NYISO interconnection queue that are at various stages of study that may come on-line over the assessment period. These include 2,198 MW of natural gas, 312 MW of nameplate wind capacity, 21 MW of biomass, and 6 MW of hydro-electric resources.

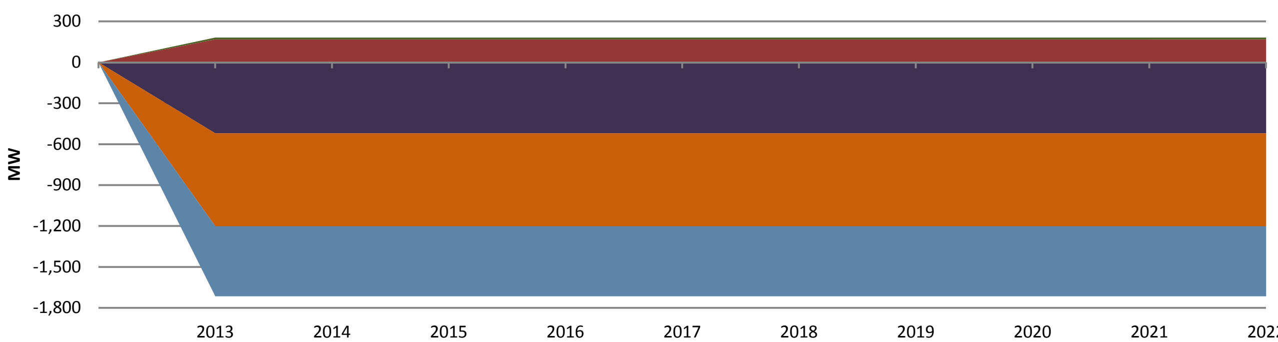
There are a significant number of generators retiring/mothballing that are impacting the NYBA Area this year. Since last year, 1,804 MW of generator retirement/mothball notices have been received. 88 MW of generation retired in 2011. The remaining 1,716 MW are scheduled to retire/mothball during 2012.

[222] http://www.nyiso.com/public/markets_operations/services/planning/documents/index.jsp.

NPCC-New York-Table 4-Capacity Outlook[223]

	Current		2022 Planned			2022 Planned & Conceptual		
NPCC-New York-Summer	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Coal	2,370	6.4%	1,850	5.2%	-520	1,850	4.9%	-520
Petroleum	9,152	24.8%	8,470	24.0%	-682	8,470	22.4%	-682
Gas	14,133	38.3%	13,620	38.6%	-513	15,817	41.8%	1,684
Nuclear	5,431	14.7%	5,599	15.9%	168	5,599	14.8%	168
Other/Unknown	0	0.0%	0	0.0%	0	0	0.0%	0
Renewables	5,771	15.7%	5,786	16.4%	14	6,125	16.2%	353
TOTAL	**36,858**	**100.0%**	**35,325**	**100.0%**	**-1,533**	**37,861**	**100.0%**	**1,003**

NPCC-New York-Figure 2-Summer Net Capacity Change



When the NYISO receives a generator retirement/mothball notice, the NYISO conducts an impact study to determine if reliability issues will arise when the unit shuts down. If no need is determined, then the unit may retire/mothball as planned. However, if a need is determined to exist, follow-up studies are required. If the need is on the local transmission system, the local transmission owner is required to resolve the reliability need. The solution may be that the unit remains on-line as a must-run unit for reliability. If the local transmission owner provides a solution to maintain reliability, the unit may then retire/mothball as planned, providing that the solution is in place prior to the retirement/mothballing date. If the solution will not be in place per the unit's shutdown schedule, the unit may be required to remain in service until the transmission owner's solution is fully implemented. The NYISO would determine the course of action in consultation with the NYS PSC and NYISO stakeholders. Following implementation of the solution, the unit may then enter the retired/mothballed status.

If the Reliability Need is determined to be on the BPS, the NYISO's Comprehensive System Planning Process (CSPP) will study the need in detail as part of the development of NYISO's Comprehensive Reliability Plan (CRP). If the Reliability Needs Assessment (RNA) identifies any violation of Reliability Criteria for bulk power transmission facilities, the NYISO will report a Reliability Need, quantified by an amount of compensatory megawatts or Mvars, and designate one or more Responsible Transmission Owners to develop a regulated backstop solution to address each identified need. In addition, after approval of the RNA, the NYISO will request market-based and alternative regulated proposals from interested parties to address the identified Reliability Need.

Proposed solutions that are submitted in response to an indentified Reliability Need are evaluated in the CRP process and must satisfy Reliability Criteria, including resource adequacy and system security. However, the solutions submitted to the NYISO for evaluation in the CRP do not have to be in the same amounts of compensatory MW/Mvar or the locations reported in the RNA. There are various combinations of resources and transmission upgrades that could meet the needs identified in the RNA. The reconfiguration of transmission facilities and/or modifications to operating protocols identified in the solution phase could result in changes and/or modifications of the needs identified in the RNA.

[223] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

There is only one significant generator uprate occurring over the assessment period. The Nine-Mile nuclear facility will uprate by 168 MW. This will generally have a positive impact on system reliability as nuclear units typically have a very low forced outage rate and scheduled refueling outages are outside peak demand times. The impact will be more noticeable on the operational side as the rated summer capability after the uprate will be 1,309 MW. This exceeds the current 1,200 MW single contingency loss that has been in place for operating reasons and has required that the system carry 1,800 MW of reserves (600 MW 10-minute sync, 600 MW 10-minute non-sync, and 600 MW 30-minute). Operating procedures have been updated to increase the amount of reserves the NYBA carries when the uprate goes into service.

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 Demand Response Programs.

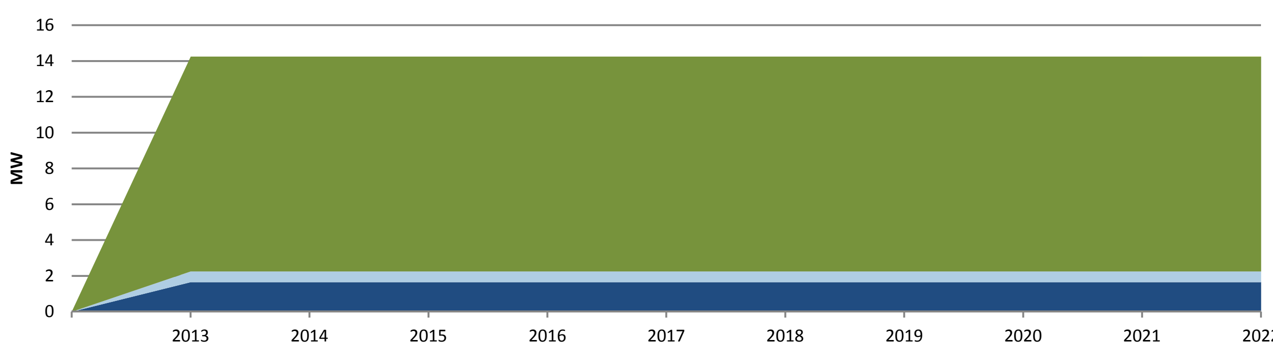
There are only two "non-traditional" resources in the NYBA's markets. A 20 MW flywheel and an 8 MW storage battery are listed in the 2012 Gold Book. There is no impact over the assessment period.

The assumed capacity on-peak for variable resources such as wind, solar, and run-of-river hydro included in this assessment is determined using an expected capability for each resource class based upon unit historic operating data and engineering judgment. On-peak land-based wind resources are rated at 131 MW (nameplate capacity of 1,314 MW). On-peak solar resources are expected at 3 MW (nameplate capacity of 32 MW). On-peak run-of-river hydro resources are expected at 3,827 MW. Biomass landfill gas resources are expected on-peak with a rated capacity of 403 MW (NPCC-New York-Table 5, NPCC-New York-Figure 3, and NPCC-New York-Table 6).

NPCC-New York-Table 5: Renewable Capacity Outlook[224]

	Current		2022 Planned			2022 Planned & Conceptual		
NPCC-New York-Summer	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Hydro	3,827	66.3%	3,829	66.2%	2	3,835	62.6%	8
Pumped Storage	1,407	24.4%	1,407	24.3%	0	1,407	23.0%	0
Geothermal	0	0.0%	0	0.0%	0	0	0.0%	0
Wind	131	2.3%	132	2.3%	1	444	7.3%	313
Biomass	403	7.0%	415	7.2%	12	435	7.1%	33
Solar	3	0.1%	3	0.1%	0	3	0.1%	0
TOTAL	**5,771**	**100.0%**	**5,786**	**100.0%**	**14**	**6,125**	**100.0%**	**353**

NPCC-New York-Figure 3: Summer Net Renewable Capacity Change



[224] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

NPCC-New York-Table 6: Renewable Capacity Outlook: On-Peak Vs. Installed

	Current				2022 Planned			
NPCC-New York-Summer	Wind	Solar	Hydro	Biomass	Wind	Solar	Hydro	Biomass
Installed Capacity	1,311	32	4,282	403	1,317	32	4,285	415
On-Peak Derate	1,180	28	454	0	1,186	28	456	0
EXPECTED ON-PEAK OUTPUT	131	3	3,827	403	132	3	3,829	415

Hourly unit output data is collected for the summer peak hours (2–5 PM) over the June 1 through August 31 period. A derating factor is then calculated for each resource. The unit-specific capacity factors calculated are used in the NYISO's capacity markets and energy markets. However, for reliability studies and planning assessments a more conservative approach is used. Wind resources are assumed to operate at approximately a 10 percent capacity factor and solar resources are expected to operate at a 65 percent capacity factor. Run-of-river hydro resources are given an assumed derate factor of 45 percent to account for the uncertainty in the amount of water available at peak. Biomass and landfill gas resources are modeled with the unit's rated capability and an associated forced outage rate.

Capacity Transactions

Unforced Capacity Deliverability Rights (UDRs) are rights associated with new incremental controllable transmission projects that provide a transmission interface to a NYCA 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 (660 MW transmission capability with 320 MW Firm capacity rights) is scheduled to be in service for May 2013. Capacity transactions associated with a UDR are considered confidential market data. Only net capacity import/export totals can be provided to maintain market confidentiality.

External capacity (ICAP) purchases and sales are administered by the NYISO. An annual study is performed to determine the maximum level of capacity imports from neighboring control areas allowed without violating the LOLE criteria. Firm imports decline slightly from 2,270 MW in 2013 to 2,220 MW in 2022 while expected imports remain unchanged at 1,353 MMW throughout the assessment period (NPCC-New York-Table 7). Except for grandfathered contracts, these Import Rights are allocated on a first-come, first-serve 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.

NPCC-New York-Table 7: Projected Capacity Transactions

NPCC-New York-Summer	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Expected Imports	1,353	1,353	1,353	1,353	1,353	1,353	1,353	1,353	1,353	1,353
Firm Imports	2,270	2,220	2,220	2,220	2,220	2,220	2,220	2,220	2,220	2,220
TOTAL IMPORTS	3,623	3,573	3,573	3,573	3,573	3,573	3,573	3,573	3,573	3,573
Expected Exports	0	0	0	0	0	0	0	0	0	0
Firm Exports	0	0	0	0	0	0	0	0	0	0
TOTAL EXPORTS	0	0	0	0	0	0	0	0	0	0
TOTAL NET CAPACITY TRANSACTIONS	**3,623**	**3,573**	**3,573**	**3,573**	**3,573**	**3,573**	**3,573**	**3,573**	**3,573**	**3,573**

Only Firm contracts longer than one year are considered in planning studies and reliability assessments. These are reviewed annually in the preparation of the annual Gold Book publication.

Only the known duration of any Firm contracts of at least one year are considered in planning studies and reliability assessments.

The NYBA does not rely on emergency imports to maintain reliability. However, transfer capability is reserved on the ties with our neighbors in our planning studies to allow for emergency imports as one potential emergency operating procedure step in the event of a system emergency. These imports would be external to the NYBA.

Transmission

The Hudson Transmission Project (HTP) is a new tie-line between PJM and NYISO from PSE&G's Bergen 230 kV substation to ConEdison'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 will be capable of transferring 660 MW but has Firm capacity withdrawal rights from PJM of 320 MW. The project is currently under construction with a planned in-service date of May 2013. Additional local transmission owner plans include sub-transmission system reinforcements throughout the state. Existing and projected transmission additions are summarized below (NPCC-New York-Table 8).

NPCC-New York-Table 8: NPCC-New York-Table 8: Existing and Projected Transmission

NPCC-New York	AC (Circuit Miles)	DC (Circuit Miles)	Total (Circuit Miles)
EXISTING	10,926	66	10,992
Currently Under Construction	0	0	0
Planned - Completed within First Five Years	138	0	138
Planned - Completed within Second Five Years	30	0	30
2022 TOTAL (UNDER CONSTRUCTION & PLANNED)	11,094	66	11,160
Conceptual - Completed within First Five Years	0	0	0
Conceptual - Completed within Second Five Years	0	0	0
2022 TOTAL (UNDER CONSTRUCTION, PLANNED & CONCEPTUAL)	**11,094**	**66**	**11,160**

Historically the most congested transmission paths in New York are Central East, Leeds–Pleasant Valley, and Dunwoodie–Shore Road. Central East and Leeds–Pleasant Valley constraints 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 Road 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 during the assessment period.

The NYISO Minimum Interconnection Standard provides that sufficient transmission is constructed to provide reliable access by any given proposed generation project to the New York State Transmission System. In addition, any generation developer seeking to qualify as an Installed Capacity Supplier must meet the NYISO Deliverability Interconnection Standard, which may require the construction of transmission.

The NYISO's role in the interconnection process is that of process administrator, project and system evaluator, and arbiter to ensure that the Project Developer and Transmission Owner collaborate in good faith to keep the project moving forward in a non-discriminatory manner. The process includes the identification and cost allocation of system upgrades necessary for the safe and reliable interconnection to the BPS. This process includes:

- Interconnection Request submission, review, validation and approval;
- Scoping of project, including NYISO receipt of necessary technical data for each;
- Scoping of Feasibility Study(ies), including execution of study agreement and NYISO receipt of necessary technical data;
- Conducting Feasibility Study(ies) with final report meeting with Developer and Transmission Owner;
- Scoping of System Reliability Impact Study(ies), including execution of study agreement and NYISO receipt of necessary technical data;
- Conducting System Reliability Impact Study(ies) with final report meeting with Developer and Transmission Owner;
- Scoping of Facilities Study(ies), including execution of study agreement and NYISO receipt of necessary technical data;
- Conducting Class Year Facilities Study(ies) with system facilities upgrades and capacity deliverability cost allocation, with final report meeting with Developer and Transmission Owner;
- Submission and approval of Class Year Facilities Study(ies) to NYISO Market Participant governance working groups, sub-committees and Operating Committee;
- Decisions of Project Developers to accept or not accept their Project Cost Allocations for system upgrades; and
- Interconnection Agreements provided to Developer, including proof of continued site control and the achievement of development milestones, to be filed with FERC.

As part of the DOE Smart Grid Investment Grant, 888 Mvar of smart grid-enabled capacitor banks will be installed at various sub-transmission voltage levels throughout the state by the end of 2012, and 39 phasor measurement units (PMUs) will be installed at bulk power stations throughout New York by June 2013.

Vulnerability Assessment

The NYBA Area 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 are subject to water levels that may vary greatly on a month-to-month basis based upon weather conditions—snowfall amounts, temperature, and 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.

There are no expected long-term generator outages over the assessment period. Demand Response resources are modeled conservatively in planning studies to account for the possibility of these resources being unavailable or non-responsive. The NYBA does not rely on distributed generation for reliability.

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. There are no planned installations of additional UVLS schemes or Special Protection Systems (SPS) in the NPCC-New York Assessment Area.

The NYISO evaluates extreme contingencies as required by the New York State Reliability Council, such as the loss of all transmission circuits on a common right-of-way, or the sudden loss of a fuel delivery system (i.e., gas pipeline contingencies). The NYISO also evaluates extreme system conditions such as extreme weather or loss of gas supply (i.e., shortage).

Should natural gas supply shortages arise in New York State in the winter, natural gas-fired units could be forced to burn other fuels or curtail operations. Many of the dual-fuel units are the larger and older steam units located in load pockets and would impact reliability needs in multiple ways if they were to retire and if replacement capacity with dual-fuel capability was not available. The real challenge on a going-forward basis will be to maintain the benefits that fuel diversity, in particular dual fuel capability, provides today. This will be especially critical in New York City and Long Island, which are entirely dependent on oil- and gas-fired units, many of which have interruptible gas transportation contracts. In terms of operational strategy, the NYSRC has adopted the following local reliability rule where a single gas facility refers to a pipeline or storage facility:

I-R3. Loss of Generator Gas Supply (New York City & Long Island)

"The NYS BPS shall be operated so that the loss of a single gas facility does not result in the loss of electric load within the New York City and Long Island zones." The NYISO categorizes generation capacity fuel types into three supply risks: Low, Moderate, and High.

The greatest risk to fuel supply interruption occurs during the winter months when both natural gas and heating fuel oils are competing to serve electrical and heating loads. Fortunately in New York, peak electrical loads occur during the summer months when demand is approximately 9,000 MW greater than the winter peak. As such, New York can meet the winter peak of roughly 25,000–26,000 MW with sufficient generation without exposure to significant fuel risks. Even with a forced outage rate of 10 percent, there is sufficient generation in the low to moderate fuel risk categories to meet the winter electrical peak.

On June 25, 2007, FERC Order 698 incorporated by reference NAESB (North American Energy Standards Board) standards to "establish communication protocols between interstate pipelines and power plant operators and transmission owners and operators." The NYISO has met this requirement with the establishment of communication systems to receive notices of system events, including Operational Flow Orders from interstate pipelines serving generators in New York, and by establishing communication systems to send Energy Emergency Alerts to the Interstate Pipelines. The NYISO will also notify Local Distribution Companies in the event of a system alert. These communication protocols are documented in Attachment BB of the NYISO Open Access Transmission Tariff.

New York has a long history in the active development of 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 the NYISO since 1999 has resulted in the retirement of older plants equaling approximately 4,000 MW of capacity and the addition of over 9,300 MW of new efficient generating capacity. In turn, these changes have led to a marked reduction of power plant emissions and a significant improvement in the efficiency of the generation fleet.

Notwithstanding the progress toward achieving New York's clean energy and environmental goals, various environmental initiatives are either in place or pending that will affect the operation of the existing fleet. Environmental initiatives that may affect generation resources may be driven by either or both the state and federal programs. Since the prior LTRA, the USEPA has promulgated several regulations that could affect most of the thermal fleet of generators in NYCA. Similarly, the 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 the state.

The NYISO performs analysis 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 versus coal has challenged the viability of some 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 potentially may require retrofitting environmental control technologies. Therefore Generator Owners will likely need to address the retirement versus retrofit question. These environmental initiatives are NYSDEC's Reasonably Available Control Technology for Oxides of Nitrogen (NOx RACT), Best Available Retrofit Technology (BART), Best Technology Available (BTA) for cooling water intake structures, the USEPA's Mercury and Air Toxics Standards (MATS), and the Cross State Air Pollution Rule (CSAPR), which is currently under review in court.

NOx RACT

The NYS DEC finalized new regulations for the control of emissions of nitrogen oxides (NOx) from fossil-fueled power plants (Part 227-2). The regulations establish presumptive emissions 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, and installing emissions reduction equipment such as low NOx burners or combustors, selective catalytic reduction units, or retirement. Generators were required to file permit applications and a RACT analysis with NYSDEC by January 1, 2012. Compliance with approved plans is required by July 1, 2014. The plans have been reviewed. Several generators have requested that their submittals be considered Competitive Business Information; however, NYSDEC has denied these requests.

Reviewing the plans that are public, the rule applies to approximately 28,000 MW of capacity, of which approximately 4,000 MW is involved in emissions reduction projects. Some of these projects are underway, and the NYISO is informed that the balance should be able to be accomplished prior to the July 2014 compliance date.

BART

The NYSDEC recently promulgated a new regulation: Part 249, Requirements for the Applicability, Analysis, and Installation of Best Available Retrofit Technology (BART) Controls. The regulation applies to fossil-fueled electric generating units with approximately 8,200 MW of capacity built between August 7, 1962 and August 7, 1977, and is necessary for New York State to comply with provisions of the federal Clean Air Act that are designed to improve visibility in National Parks. The regulation requires an analysis to determine the impact of an affected unit's emissions on visibility in national parks. If the impact is greater than a prescribed minimum, then emissions reductions must be made at the affected unit. The compliance deadline is January 1, 2014. Emissions control of sulfur dioxide (SO2), nitrogen oxides (NOx) and particulate matter (PM) may be necessary. Compliance plans were filed with NYSDEC in October 2011. In April, USEPA announced that it had accepted some plans, was awaiting further administrative actions on other plans and had declared specific lower emissions limits for other plans. Several small units have chosen to retire, representing a capacity loss of less than 50 MW. Other plants will achieve the required emissions reductions through the use of cleaner fuels, while others are undertaking retrofit projects. Approximately 500 MW of capacity may be needed to undertake a major emissions reduction project or switch to cleaner fuels, or shut down.

BTA

The NYS DEC has finalized its policy document "Best Technology Available (BTA) for Cooling Water Intake Structures." The policy applies to plants that use once-through cooling with design intake capacity greater than 20 million gallons/day. The policy prescribes reductions in fish mortality and 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 is applied at the time that the generating facility's State Pollution Discharge Elimination System (SPDES) Permit is renewed, which is theoretically a five-year period.

Generators with approximately 18,000 MW of capacity are subject to this policy. Of that total, generators with 4,000-7,000 MW may need to retrofit their cooling water intake technology. If cooling tower retrofits are required, compliance deadlines will be project-specific.

Mercury and Air Toxics Standards

The USEPA announced the final rule in December 2011. The final rule replaced what had been known as the Maximum Achievable Control Technology, or MACT Rule. The rule establishes limits for Hazardous Air Pollutants (HAPs)—for acid gases, Hydrogen Chloride (HCl), Hydrogen Fluoride (HF), Mercury (Hg), and Particulate Matter. Alternative limits were also established. These limits apply to coal- and oil-fired generators. The compliance date is March 2015. The NYS DEC may provide an additional year to comply if necessary. Further, reliability critical units can qualify for another year to achieve compliance if retrofitting emissions control technology is required or if the reliability improvement project will take an additional year to comply. 11,331 MW of capacity in New York will be affected by this regulation. The USEPA established a subcategory for limited use oil-fired generators. Units that maintain a capacity factor on oil that is less than 8 percent will be more lightly regulated. No oil-fired EGUs exceeded the 8 percent Capacity Factor when firing oil in 2009 and 2010. While these units will remain subject to MATS, it is not expected that significant emissions control retrofit projects will be required at these units.

A review of emissions records was done to determine the best level of emissions reductions that has been shown to be sustainable. These emissions levels were compared to those necessary to comply with MATS for coal-fired units. This review shows that most of the coal-fired units in New York are already capable or nearly capable of complying with MATS. In addition, NYS DEC has promulgated Part 246: Mercury Reduction Program for Coal-Fired Electric Utility Steam Generating Units, which establishes emissions limitations that are currently in effect in New York to reduce mercury emissions. Phase II of this regulation requires additional reductions from coal-fired boilers in 2015. The Phase II emissions limitations are more stringent than the USEPA MATS limits.

CSAPR

The USEPA finalized the Cross State Air Pollution Rule (CSAPR) in December 2011. The rule is designed to reduce interstate transport of emissions of SO2, 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 emissions allowances and limited trading programs. The regulation establishes emissions budgets for each affected state. The emissions budget is then divided on a pro-rata basis determined by historic heat input for existing facilities. There are set-asides to provide allowances to new fossil generators. The use of emissions allowances will be expected to increase offering prices for generation from affected facilities. The final rule was placed under a stay by the United States District Court. However, for the stay, the rule would be in effect currently with another reduction in the SO2 cap scheduled for 2014. While this rule is currently the subject of an appeal, the NYISO has included the impact from the rule in its analysis because the Clean Air Act requires the USEPA to address interstate pollution transport in some form. CSAPR is the USEPA'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 CAIR remain in effect until such time as a replacement rule is implemented. In December when the District Court stayed the CSAPR rule, it ordered that CAIR be reinstated. CAIR as promulgated has a significant reduction in allowable emissions scheduled for 2015. It is reasonable to assume that a national program will be in effect for limiting emissions of SO_2 and NOx via a cap-and-trade program in the early part of the planning horizon. The CSAPR rule will be used to evaluate the potential impact of that program.

The CSAPR rule applies to most of the fossil-fueled fleet with nameplate capacity greater than 25 MW. The rule will require the use of allowances in numbers equivalent to actual emissions tonnages for three categories: SO_2, Annual NOx, and for Ozone Season NOx. The annual budget for each of the states in the program has been established by USEPA through the use of long-range transport models to identify sources and sinks for impact of emissions on areas in other states. The budget of allowances for each of the three categories is distributed based upon each affected unit's pro-rata share of historic heat input. A small set-aside is established for new units, and recently retired units continue to receive allowances for a limited time period. The rule calls for a two-phase reduction of SO_2, while the limits for Annual NOx and Ozone Season NOx are fixed. The program limits the amount of allowances that can be obtained through trading with Generator Owners in other states. The total of the budget plus allowed traded allowances is known at the "Assurance Level." Should a state's emissions exceed the Assurance Level, two additional allowances would need to be surrendered for each ton of excess emissions. This penalty would be pro-rated across all emitters who exceeded their direct allocation plus the allowed trading percentages.

Historic emissions and inventories of installed emissions control equipment have been reviewed to estimate the level of additional emissions reductions required. As detailed in the figure below, with optimum operation of existing environmental control equipment and fuel switching, New York State should be able operate within the Assurance Level.

The NYISO has conducted the analysis described above to identify generating units that are subject to 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 then was extended to identify the amounts of capacity that are subject to multiple environmental requirements. The bi-annual Reliability Needs Assessment conducts scenario evaluations. In particular, the results of an analysis of the NYISO "zones at risk" are compared to the amount of capacity that could be considered at risk for unplanned retirement due to the need for capital expenditures to retrofit environmental control technology.

GE conducted a study of the amount of time necessary for NOx emissions control retrofits. The study concluded that required retrofit installations could be covered within the time frame of major turbine/generator overhaul. It is reasonable to expect that other outages necessary for emissions control technology retrofits would require similar time periods for equipment tie-in. Given the time horizon for outage scheduling and the capacity balance in NYBA Area, it is reasonable to conclude that bulk system reliability will not be negatively affected.

Plans for Accommodating Generator Retirements and Environmental Control Retrofits

The NYISO has reviewed compliance plans that have been filed by generators for NYSDEC's NOx RACT and BART programs, as well as, USEPA notices on acceptance or modifications to those plans. The plans were obtained from NYSDEC through a Freedom of Information Law request.

The generators are not required to file compliance plans with NYSDEC for MATS compliance. They are however, required to notify the NYISO by March of 2013 if they intend to seek additional time to comply with MATS. To date, no such notifications have been received.

The USEPA recently announced that it will take another year to finalized regulations for cooling water systems that use public waters. In the interim, NYSDEC will continue to administer its Best Technology Available Policy on a case by case basis as permits are renewed. The NYISO meets periodically with NYSDEC to review the status of permit renewals.

A three-judge panel of the United States Court of Appeals for the District of Columbia Circuit vacated CSAPR and the Transport Rule Federal Implementation Plans, in an order issued August 21, 2012. The Court remanded the proceeding to the EPA and ordered it to continue to administer CAIR pending a valid replacement. Consequently, generators have not announced any compliance plans relative to this program. The table below has been updated to reflect increases in New York's CSAPR Allowance Budget that have been announced by USEPA, as well as, to take into account recently announced retirements (NPCC-New York-Table 9).

NPCC-New York-Table 9: NY State Emission Allocation under CSAPR

	2012 SO2	2014 SO2	Annual NOX	Ozone Season NOX
A. Allocation for Units Proposed to be In-Service	26,060	19598	16,334	7,898
B. Retired Units [2] + Non-EGU Allocations [3] + Miscellaneous [4]	9,510	7407	4,954	2,264
C. New Unit Set-Aside	726	551	434	207
D. Total Allocation (A+B+C)	36,296	27,556	21,722	10,369
E. Trading Variability for 2014 (18% Annual, 21% Ozone Season)	N/A	4960	3,910	2,177
F. 2014 Assurance Level (D+E)	**N/A**	**32,516**	**25,632**	**12,546**
Historic Emissions				
G. 2011 Emissions from Units Proposed to be In-Service		24,020	17,153	8,533
H. Estimated 2011 In-Service Unit Emissions - Best Demonstrated Performance (2011 Actual Heat Input Lowest Annual Emissions Rate from 2006-2011)		14,972	13,076	6,765
I. 2011 "New Unit" Emissions		11	134	58

[1] Linked Cogeneration Facility is not included.
[2] Retired Units Include: Poletti, Projec Orange, Greenidge, Westober, Ogdensburg Cogen, Astoria Generating ST2 and 4, Glenwood ST 4 and 5, Far Rockaway ST4, Dunkirk 1-4, and AES Cayuga.
[3] Three (3) Consolidated Edison Steam System Boilers were given allocations.
[4] EPA calculation and rounding error.

The NYISO's Draft 2012 Reliability Needs Assessment[225] considers a scenario where all coal fired units are retired. The study can be found on the NYISO website.[226] The study found that the retirement of all coal units would accelerate the year of need to 2019 from 2020. The table below identifies the programs, their current status, compliance dates, quantities of capacity affected and announced and estimated quantities of capacity that is expected to undergo retrofits of environmental control equipment (NPCC-New York-Table 10).

NPCC-New York-Table 10: Other Environmental Regulation Status, Compliance Deadlines, and Potential Impacts in New York

Rule/Legislation	Status	Compliance Deadline	Approximate Capacity Affected	Potential Retrofits
Nox RACT	In Effect	Jun-14	26,700	6,000 MW
			238 Units	23 Units
BART	In Effect	Jan-14	8,600 MW	1,800 MW
			19 Units	5 Units
MATS	In Effect	Mar-15	10,300 MW	400 MW
			28 Units	2 Units
BTA	In Effect	Upon Permit Renewal	16,900 MW	4,400 MW -7,300 MW
			39 Units	-
CSAPR	Stayed While in Litigation	January 2012 and January 2014	25,000 MW	2,400 MW
			156 Units	11
RGGI	In Effect	In Effect	25,000 MW	-
			158 Units	-

Generator Owners and Operators have not informed the NYISO that they will be unable to meet the compliance deadlines established in these programs. The NYISO has procedures in place to approve outages and will use these procedures to maintain reliability of the system during the periods of retrofit installations.

[225] The draft RNA will not be final until the Board approves the report in September.
[226] http://www.nyiso.com/public/markets_operations/committees/meeting_materials/index.jsp?com=mc.

The Astoria 345/138 kV transformer and phase angle regulator were installed in 2012 between Astoria Annex 345 kV and Astoria East 138 kV to maintain reliability on the non-bulk system in response to the mothballing of generation units Astoria 2 and Astoria 4. Non-bulk transmission needs have been identified in Western New York in association with the mothballing of the Dunkirk coal plant. Transmission solutions have not yet been finalized. Transmission needs relating to the integration of new generation are addressed on a class year basis in accordance with the NYISO Open Access Transmission Tariff.

Following the completion of the NYISO 2012 Reliability Needs Assessment, the NYISO will request market solutions (including transmission, generation, or demand response) to address any reliability needs.

Standing and Emerging Reliability Issues

The NYBA identified two issues in the 2011 NERC LTRA narrative that could continue to impact reliability over the long-term assessment period. They were a) the impact of federal and state environmental regulations, and b) project lead times. For this report, the two issues remain as standing reliability issues.

The potential impact to system reliability due to state and federal environmental regulations is a standing reliability issue as discussed in last year's NERC LTRA. There are five major environmental initiatives that have requirements that may potentially require retrofitting environmental control technologies.

The timing of reliability impacts will vary with the compliance date of various environmental initiatives. Generator units affected by BART must comply by January 1, 2014. BTA policy rules will be applied at the time the State Pollution Discharge Elimination System Permit is renewed, which is theoretically over a five-year period. Compliance deadlines will be project-specific. Units that must comply with the Mercury and Air Toxic Standards have until March 2015. Units subject to the NOx RACT regulations have until July 1, 2014 to comply. Units subject to CSAPR regulations must comply in 2015.

The primary drivers are to reduce the amount of power plant emissions into the environment and to increase the efficiency of the generation fleet by encouraging the building and utilization of more efficient, more environmentally friendly resources.

Environmental regulations may lead some generation resources to retire, as the cost to meet the new regulations may not be economical for some units. Depending upon the regulation, as low as 500 MW to as much as 28,000 MW may be affected. The impact will depend upon the amount and location of the retiring generation.

BPS reliability could be affected if critical units that support the BPS are retired. However, as the NYBA, the NYISO has the authority to designate the Responsible TO or Responsible TOs to proceed with a regulated backstop solution in order to maintain system reliability in the event that market-based solutions do not materialize to meet a reliability need in a timely manner. The impact on BPS reliability due to generator retirements is for the most part localized, where following the retirement the transmission in the affected area is relied upon more heavily to serve load in that area. Certain generator retirements or combinations of retirements may result in the need for significant transmission upgrades absent other generator or Demand Response solutions.

The bulk power transmission facilities could be affected if critical units that support the BPTF are retired. However, the NYBA has the authority to designate the Responsible TO or Responsible TOs to proceed with a regulated backstop solution in order to maintain system reliability in the event that market-based solutions do not materialize to meet a reliability need in a timely manner. The impact would be dependent upon the criticality of the need being resolved.

If generation units ultimately retire as a result of environmental issues, the Planning Reference Margin would be adjusted accordingly. This would also affect the total MW of generation capacity and the fuel mix of the resources reported. Generation retirements would affect the total MW of generation capacity and the fuel mix of the resources reported and would also have the potential to impact the entire Assessment Area.

When reliability needs are identified, solutions (generation, transmission, or Demand-Side measures) are solicited through the NYISO's Comprehensive System Planning Process. Competitive market-based solutions are given first priority because of their reduced risk to rate-paying consumers**.** Given the potentially short notice period coupled with the potentially significant impact, gap solutions or regulated backstop solutions may be necessary in some situations if market solutions do not respond in time.

If generation units shut down in response to the regulations, the vulnerability of the system may increase due to the decrease in resources. The NYISO would respond by invoking regulatory backstop solutions or gap solutions as required by the circumstances.

The project lead time issue was identified in the *2012 Long-Term Reliability Assessment*. Long project lead times may affect reliability over the assessment period depending upon the impact of the environmental initiatives on the NYBA Area's fleet.

Considerable lead time is required for power infrastructure project execution, given the time frames needed to finance, permit, and construct major energy projects. The planning horizons of policy makers and regulators should encompass the time required for the electric industry to address new laws and changes in regulatory requirements.

Resource adequacy is a function of the amount of generation resources available to meet the system load. If resources are not added in a timely manner to meet projected demand, reliability may be negatively impacted. The impact would vary depending upon the timing and scope of the need.

This issue may affect the BPS reliability if projects critical to maintaining reliability are delayed because of the process.

This issue may affect the bulk power transmission facilities if projects critical to maintaining reliability are delayed because of the process. The impact would depend upon the timing and scope of the need.

The estimated in-service dates for Conceptual resources may be pushed back further due to time considerations (assuming the project moves forward to construction). This would affect the Adjusted Potential Reference Margin Level with minimal impact on the overall assessment.

When reliability needs are identified, solutions (generation, transmission, or Demand-Side measures) are solicited through the NYISO's Comprehensive System Planning Process. Competitive market-based solutions are given first priority because of their reduced risk to rate-paying consumers. Ultimately, if generation units are not built in a timely manner to meet system demand, the impact to BPS reliability may increase.

NPCC-Ontario

Planning Reserve Margins

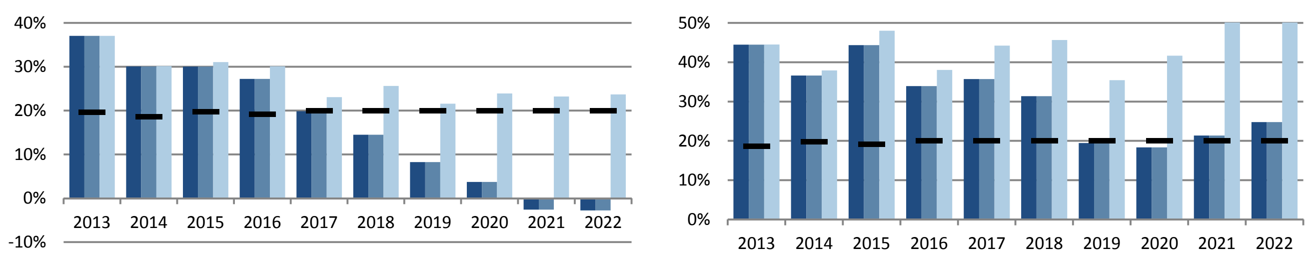
Ontario is projecting adequate Planning Reserve Margins throughout the assessment period (2013– 2022). The required reserve levels are determined based on probabilistic methods deemed by NPCC to be acceptable for meeting regional Loss of Load Expectation (LOLE) criteria. The target Reserve Margin levels for the first four years vary from 19.7 percent in 2013 to 19.2 percent in 2016. The OPA target Reserve Margin of 20 percent is applied from 2017–2022 (NPCC-Ontario-Table 1 and NPCC-Ontario-Figure 1). These targets are applied as the NERC Reference Margin Level throughout the assessment period.

NPCC-Ontario Table 1: Planning Reserve Margins

NPCC-Ontario-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		37.07%	30.08%	30.03%	27.22%	19.88%	14.50%	8.24%	3.72%	-2.58%	-2.78%
PROSPECTIVE		37.07%	30.08%	30.03%	27.22%	19.88%	14.50%	8.24%	3.72%	-2.58%	-2.78%
ADJUSTED POTENTIAL		37.07%	30.14%	31.07%	30.11%	23.08%	25.62%	21.57%	23.90%	23.21%	23.69%
NERC REFERENCE	-	**19.70%**	**18.60%**	**19.80%**	**19.20%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**

NPCC-Ontario-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		44.47%	36.63%	44.36%	33.94%	35.73%	31.35%	19.45%	18.33%	21.33%	24.75%
PROSPECTIVE		44.47%	36.63%	44.36%	33.94%	35.73%	31.35%	19.45%	18.33%	21.33%	24.75%
ADJUSTED POTENTIAL		44.53%	37.92%	48.01%	38.02%	44.25%	45.65%	35.44%	41.69%	50.95%	55.04%
NERC REFERENCE	-	**18.60%**	**19.80%**	**19.20%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**	**20.00%**

NPCC-Ontario-Figure 1: Summer (Left) and Winter[227] (Right) Planning Reserve Margins



The Adjusted Potential Planning Reserve Margins remains above the required Reserve Margin for all 10 years. The supply mix and the system demand affect the level of Planning Reserve Margin Requirements. On February 17, 2011, the Government of Ontario issued a Supply Mix Directive that specified the government's goals, including a target of renewable capacity. The cumulative renewable resources target by end of 2018 is 10,700 MW for renewables such as wind, solar, and bio energy, and 9,000 MW for hydro-electric capacity. These resources would be accommodated through transmission expansion and by maximizing the use of the existing transmission and distribution systems. The amount of variable generation such as wind, solar, and run-of-river hydro is expected to increase over time, and the integration of these variable generation resources will influence the level of planning reserve that is required for the long term.

In assessing reserves for the next decade, the IESO has made allowance for long-term refurbishment outages for the nuclear units at the Bruce and Darlington Nuclear Generating Stations. To extend their lives, these units will be out of service for about three years while being refurbished. There is considerable uncertainty about when these refurbishment outages will actually occur, as a number of options exist for extending life expectancy. Until formal programs are established by the station owners, the IESO will continue to assume nuclear reductions occur in sequence in the latter half of the 10-year period. As the supply mix continues to change, the level of planning reserve will need to be reassessed. In addition to generation, the projected demand with respect to its load shape and the expected peak values can also influence the level of Planning Reserve Margins.

[227] Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.

Anticipated and Prospective Planning Reserve Margins are projected to be below the NERC Reference Margin Level in 2017. However, the Total Potential and Adjusted Potential Reserve Margins are expected to stay above the target margin for the entire period. Some of the Bruce and Darlington units will be out of service for refurbishment in this time frame.

Ontario's planning process considers expected and potential unit refurbishments or retirements and proposes ways to meet resulting resource requirements. Specific considerations include the procurement of conservation programs, renewable resources, new gas-fired units, and refurbished nuclear resources. In addition, the process considers the transmission expansion that would be required to integrate all of the above-mentioned resources. Other options include developing greater coordination and flexibility related to nuclear refurbishment outages and converting existing coal stations to alternate fuels. Mitigation of reliability concerns is to be supported through ongoing monitoring, assessment, measurement, and verification.

The IESO and the OPA recognize the potential for certain adverse conditions (such as extended forced outages, drought conditions, and particular fuel interruptions) to result in higher than expected resource unavailability, and therefore establish planning reserves sufficient to handle 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 adverse situations, the 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.

Demand

This year's electricity Net Energy for Load forecast net of conservation has an average annual growth rate of -0.3 percent over the period 2012-2022 compared to last year's average growth of -0.1 percent for the years 2011-2021. The rate of growth for overall consumption is lower than the peak growth rates. Initially conservation was aimed at reducing peaks, but as those peak reduction opportunities are realized, conservation and embedded generation will start impacting overall energy demand. Peak demand for the summer season grows by only 0.7 percent between 2013 and 2022 (NPCC-Ontario-Table 2).

NPCC-Ontario-Table 2: Demand Outlook

NPCC-Ontario-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	23,301	23,442	142	0.6%	0.07%
Load-Modifying Demand Response	0	0	0	0.0%	0.00%
TOTAL INTERNAL DEMAND	**23,301**	**23,442**	**142**	**0.6%**	**0.07%**

NPCC-Ontario-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	22,192	21,529	-663	-3.0%	-0.34%
Load-Modifying Demand Response	0	0	0	0.0%	0.00%
TOTAL INTERNAL DEMAND	**22,192**	**21,529**	**-663**	**-3.0%**	**-0.34%**

With the underlying drivers being very similar to last year, the forecasts' growth rates remain similar as well. Although Canada is expected to post respectable growth over the forecast, Ontario will lag the nation's growth in the near term. High commodity prices—in particular oil—will benefit other parts of Canada over 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.

Over the forecast horizon Ontario's economy will continue to undergo structural change. As the economy matures, there is a transition from an energy-intense industrial process based economy to one with a larger service sector and specialized or high-value-added manufacturing. This will lead to a less energy-intense economy.

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.

Load growth has been relatively flat in recent years, and this trend is expected to continue as Ontario demand is subject to two opposing forces. Pushing higher peak and energy demands are population growth and economic expansion. Acting to restrain that underlying growth are increased conservation initiatives, increased embedded generation capacity and, for peaks in particular, time-of-use rates.

Within Ontario there has been some localized variation in demand. The Toronto and southwest part of the province make up the vast majority of the provincial demand and in essence drive the provincial numbers. Changes in the industrial composition in the north have had a significant impact on demand patterns and will continue throughout the forecast. The northwest part of the province has been in decline due to reductions in the forestry and pulp and paper sectors. The northeast has more mines and has benefited from strong commodity prices and raw material demands from emerging nations. These underlying trends are expected to continue. There is significant potential for mineral extraction in the Ring of Fire Area of northern Ontario, which could be a source of significant load growth. At present this potential impact is speculative and has not been factored into the forecast.

Demand-Side Management

The IESO treats Demand Response as a resource and conservation as a decrement to demand. In 2013 there is just over 1,500 MW of effective Demand Response Capacity available during peak periods. At the time of the 2013 peak, conservation impact is estimated to be roughly 500 MW higher when compared to 2012.

In the final year of the forecast, effective Demand Response Capacity is expected to be 1,687 MW. Also at the final year, total incremental peak conservation savings (or Energy Efficiency) are projected to be 3,710 MW (NPCC-Ontario-Table 3).

NPCC-Ontario-Table 3: Projected Demand-Side Management

	Short-Term					
NPCC-Ontario-Summer	2013	2014	2015	2022	10-Year Change	2022 Share of Total Internal Demand
Direct Control Load Management (DCLM)	0	0	0	0	0	0.00%
Contractually Interruptible (Curtailable)	0	0	0	0	0	0.00%
Critical Peak-Pricing (CPP) with Control	0	0	0	0	0	0.00%
Load as a Capacity Resource	1,529	1,665	1,668	1,687	158	7.20%
TOTAL RESOURCE-SIDE DEMAND RESPONSE	1,529	1,665	1,668	1,687	158	7.20%
TOTAL ENERGY EFFICIENCY	793	1,285	1,734	3,710	2,917	15.82%
TOTAL DEMAND-SIDE MANAGEMENT	**2,322**	**2,950**	**3,402**	**5,397**	**3,075**	**23.02%**

The growth in Demand Response Capacity is relatively small over the forecast but plateaus in 2015–16.

Demand Response programs in Ontario are treated as a supply resource with discounted capacities associated with the unique characteristics of each program (e.g., voluntary/Firm contracts). The OPA manages contracts for the majority of the Demand Response programs scheduled to be activated over the forecast time frame. Programs with Firm contracts to reduce demand during periods of high demand/tight supply are expected to provide a reliable and verifiable supply resource. Most Demand Response programs are market-based and are triggered by market prices or supply cushion conditions.

Energy Efficiency and conservation are decremented from demand. These programs are run and delivered by distributors and the OPA. As well, changing efficiency standards and building codes also contribute to conservation savings. The savings are projected to grow throughout the forecast.

The capacity of Demand Response programs is relatively static throughout the forecast, with only some small incremental growth.

The IESO does not have ancillary service Demand Response programs.

Generation

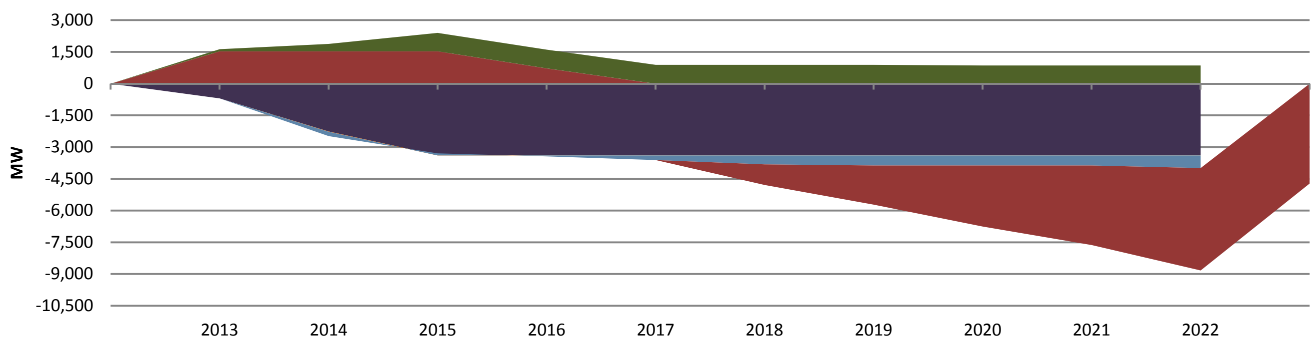
At the time of this assessment in 2012, the total Existing-Certain Capacity Resources connected to the IESO-controlled grid is 29,500 MW. The Existing-Other and Existing-Inoperable capacity amounts to 4,800 MW and 28 MW, respectively.

The primary sources of fuel in Ontario are nuclear, gas or oil, water, and coal. More than 50 percent of the electrical energy is generated with nuclear. Coal-fired generation will cease operation by the end of 2014. More than 5,600 MW of gas-fired generation has been added over the last 10 years. About 1,500 MW of grid-connected wind is in operation, with another 200 MW in final stages of commissioning. Future-Planned projections indicate an increase in renewable capacity, to 7,011 MW by 2022 (NPCC-Ontario-Table 4 and NPCC-Ontario-Figure 2).

NPCC-Ontario-Table 4: Capacity Outlook[228]

	Current		2022 Planned			2022 Planned & Conceptual		
NPCC-Ontario-Summer	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Coal	3,377	11.2%	0	0.0%	-3,377	0	0.0%	-3,377
Petroleum	2,148	7.1%	2,134	7.7%	-14	2,134	7.5%	-14
Gas	6,439	21.4%	6,439	23.3%	0	10,274	36.1%	3,834
Nuclear	12,011	39.9%	12,011	43.5%	0	7,290	25.6%	-4,721
Other/Unknown	0	0.0%	0	0.0%	0	0	0.0%	0
Renewables	6,156	20.4%	7,011	25.4%	855	8,782	30.8%	2,627
TOTAL	**30,131**	**100.0%**	**27,595**	**100.0%**	**-2,536**	**28,480**	**100.0%**	**-1,651**

NPCC-Ontario-Figure 2: Summer Net Capacity Change



Since last year, 227 MW of wind and 438 MW of gas generation have come into service. There are 8,782 MW of Future-Planned and Conceptual renewables resources that are expected to come on-line throughout the assessment time frame. Of this, about 200 MW are expected to come from the coal to biomass conversion at the Atikokan Generating Station, which is expected to take place by 2014. The remaining new capacity is mostly comprised of generation from the Feed-In Tariff (FIT) and microFIT programs, and from the Green Energy Investment Agreement. The Future-Planned and Conceptual renewable resources will meet the Government of Ontario's target of 10,700 MW of renewables other than hydro-electric and 9,000 MW of hydro-electric capacity by 2018. Two units at Bruce A Nuclear Generating Station are being refurbished and are expected to add 1,500 MW. In the latter half of the 10-year period, a number of nuclear units at Bruce and Darlington Nuclear Generating Stations will be expected to undergo refurbishment.

Two more coal units at Nanticoke Generating Station with a total capacity of 980 MW were shut down in December 2011. The remaining nine coal-fired units across four facilities in the province will be phased out by 2014. Pickering Nuclear Generating Station is scheduled for retirement by 2016, but the technical feasibility of extending the operating life of the Pickering generating units is being studied with a decision expected within next year. If feasible, it would provide the option to continue to operate the units at Pickering Nuclear Generating Station through to 2020. In September 2011, a 280 MW gas plant under construction in Mississauga was cancelled. This project had been scheduled to be in service by the third quarter of 2014. There is work currently underway to determine relocation options for this plant. No other major generation or transmission projects have been cancelled or significantly deferred that affect reliability.

By 2014, all coal-fired energy in the province will be phased out. Plans are moving forward for the conversion to biomass of the 205 MW Atikokan Generation Station in northwestern Ontario. In addition, two units at the Thunder Bay Generating Station in northwestern Ontario are candidates for conversion to natural gas over the period leading up to 2014.

[228] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

Conversion of some or all of the remaining coal-fired units at Lambton and Nanticoke to natural gas will be assessed, in conjunction with other options, under a range of different scenarios.

Ontario Power Generation's Lower Mattagami expansion project, which is currently under construction, will add 438 MW of hydro-electric capacity to Ontario's electricity system. In addition, by 2013 the new Niagara Tunnel will allow OPG to generate a further 1.6 billion kilowatt-hours of electricity annually.

About 1,500 MW of nuclear capacity is expected to be brought back into service from the re-start of units 1 and 2 at Bruce A Nuclear Generating Station in the short term. In the years following the 2014 coal phase-out, the province's next reliability challenge will be to carefully manage the renewal of its nuclear fleet. The technical feasibility of extending the operating life of the units at Pickering Nuclear Generating Station is being studied, and an update is expected within next year. If feasible, it would provide the option to continue to operate the units at Pickering Nuclear Generating System through to 2020. Units at Bruce B and Darlington Nuclear Generating Station are expected to reach the end of their service lives over the next decade. To extend their lives, these units will be taken out of service for refurbishment. Supply options for maintaining resource adequacy over this time period are under review and include, among others, new gas generation or conversion of some or all of the Lambton and Nanticoke coal-fired units to natural gas.

Over the assessment time frame, the level of renewables penetration will be expected to increase significantly through the FIT and microFIT programs. This in turn will increase the level of behind-the-meter generation. Much of this generation could be variable in nature, which adds more volatility as on-grid demand is impacted both by underlying demand and by 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 hydro-electric 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 that 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 medium-term storage providing frequency regulation and ramping capabilities and can help improve system reliability. Long-term 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. Energy storage can also defer transmission and distribution system upgrades if installed in the right location.

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.

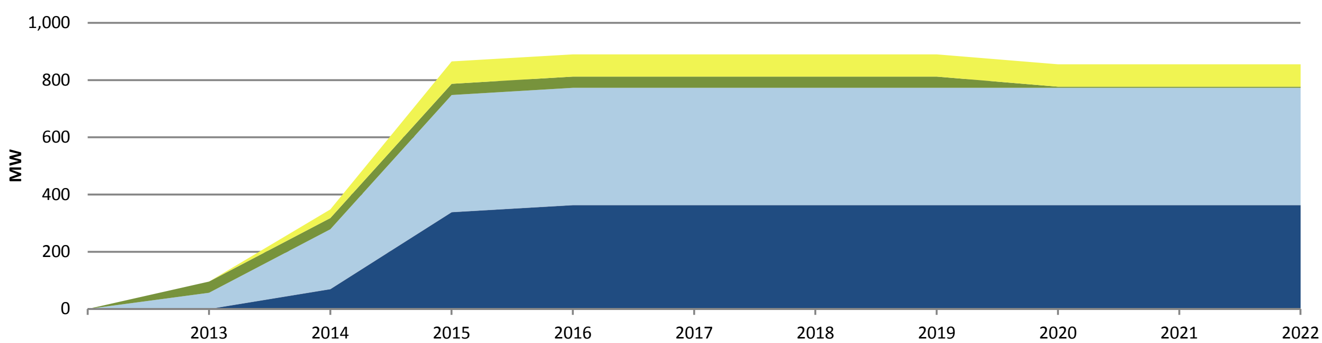
Fourteen percent of the installed wind capacity is assumed to be available at the time of summer peak, and 32 percent is assumed to be available at the time of winter peak. Monthly Wind Capacity Contribution (WCC) values are used to forecast the contribution from wind generators. WCC values (percent 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. The WCC values are updated annually.

Ontario's solar capacity value is forecast to be 30 percent of installed for the summer peak and 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 in the evening around dinner time. The values are based on historical modeled photovoltaic output data at the time of summer and winter peaks. The renewable capacity outlook is included in below (NPCC-Ontario-Table 5, NPCC-Ontario-Figure 3, and NPCC-Ontario-Table 6).

NPCC-Ontario-Table 5: Renewable Capacity Outlook[229]

	Current		2022 Planned			2022 Planned & Conceptual		
NPCC-Ontario-Summer	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Hydro	5,794	94.1%	6,157	87.8%	363	6,500	74.0%	706
Pumped Storage	91	1.5%	91	1.3%	0	91	1.0%	0
Geothermal	0	0.0%	0	0.0%	0	0	0.0%	0
Wind	227	3.7%	637	9.1%	410	1,429	16.3%	1,202
Biomass	43	0.7%	47	0.7%	4	204	2.3%	161
Solar	0	0.0%	78	1.1%	78	558	6.4%	558
TOTAL	**6,156**	**100.0%**	**7,011**	**100.0%**	**855**	**8,782**	**100.0%**	**2,627**

NPCC-Ontario-Figure3: Renewable Capacity Outlook



On average, the assumed capacity contribution for biomass generation ranges from 64 to 98 percent of installed capacity. Hydro-electric generation output forecast is based on median historical values of hydro-electric production and contribution to operating reserve during weekday peak demand hours. Through this method, routine maintenance and actual forced outages of the generating units are implicitly accounted for in the historical data. Market data starting from May 2002 is used, with new values calculated annually as additional years of market experience are acquired. The assumed capacity contributions for hydroelectric is 71 percent in the summer and 75 percent for the winter.

The hydro-electric forecast may be adjusted to account for the impact of project-related long-duration outages that occur less frequently than regular maintenance. The hydro-electric performance is monitored on a monthly basis, and adjustments may also be made to the forecast values when water conditions drive expectations of higher or lower output that deviates from median values by approximately 500 MW for two consecutive months. The project-related long-duration outages may include hydro facility expansions and major equipment replacements and/or repairs.

NPCC-Ontario-Table 6: Renewable Capacity Outlook: On-Peak Vs. Installed[230]

	Current				2022 Planned			
NPCC-Ontario-Summer	Wind	Solar	Hydro	Biomass	Wind	Solar	Hydro	Biomass
Installed Capacity	1,725	0	7,832	47	4,651	260	8,347	49
On-Peak Derate	1,498	0	2,038	4	4,014	182	2,190	2
EXPECTED ON-PEAK OUTPUT	227	0	5,794	43	637	78	6,157	47

[229] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.
[230] Note: The table above shows only the expected grid-connected renewable generation resources in Ontario. A substantial amount of renewable generation is embedded and is included in the demand forecast. About 9 percent of wind, 28 percent of biomass and 81 percent of solar are expected to be embedded in the distribution networks.

Centralized forecasting for variable resources such as solar and wind is an initiative designed to allow for better forecasting of energy production to ensure a more accurate unit commitment occurs. A centralized forecast is being developed for all grid-connected variable resources with a full implementation set to be complete by the first quarter of 2013. Forecasting for embedded variable resources will be developed in 2013. Additionally, the IESO's Renewable Integration Initiative (RII) will facilitate the dispatching of renewable energy, with implementation expected in the fourth quarter of 2013. Variable generation dispatch will allow for greater flexibility and help alleviate occurrences of surplus base-load generation.

Capacity Transactions

No Firm imports into Ontario, exports to other Regions or emergency generation are considered in this *2012LTRA* Reference case. However, for use during daily operation, operating agreements between the IESO and neighboring jurisdictions in NPCC, RFC, and MRO include contractual provisions for emergency imports directly by the IESO. IESO also participates in a shared activation of reserve group, which includes PJM, NYISO, ISO-NE, and New Brunswick.

Transmission

A new 110 mile 500 kV double-circuit line from the Bruce Power complex to Milton Switching Station (SS) 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 together with approximately 500 MW of existing wind generating capacity, as well as a further 1,200 MW of new renewable generating capacity that is forecast for development within the area. With the new generating facilities, the combined generation in the Bruce Area is projected to exceed 8,100 MW. New dynamic voltage control facilities at Nanticoke and Detweiler will improve the transfer capability from the Bruce Area. A summary of existing and projected transmission is included below (NPCC-Ontario-Table 7).

NPCC-Ontario-Table 7: Existing and Projected Transmission

NPCC-Ontario	AC (Circuit Miles)	DC (Circuit Miles)	Total (Circuit Miles)
EXISTING	17,931	0	17,931
Currently Under Construction	93	0	93
Planned - Completed within First Five Years	0	0	0
Planned - Completed within Second Five Years	0	0	0
2022 TOTAL (UNDER CONSTRUCTION & PLANNED)	18,024	0	18,024
Conceptual - Completed within First Five Years	180	0	180
Conceptual - Completed within Second Five Years	283	0	283
2022 TOTAL (UNDER CONSTRUCTION, PLANNED & CONCEPTUAL)	**18,487**	**0**	**18,487**

The existing Bruce SPS will be enhanced not only to accommodate the two new 500 kV circuits between the Bruce complex and Milton SS, but also 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 re-preparation 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 in spring of 2012 and was placed in service in the second quarter.

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

Four phase angle regulators (PARs) are now operational and regulating flow over the Ontario-Michigan interconnections. The operation of these PARs helps control inter-jurisdictional loop flows and assists in the management of system congestion.

The transmission lines east of Mississagi TS and the north-south corridor have experienced increased congestion due to the continuing addition of new renewable resources and reduced demand. It is expected that congestion will further increase with projects in the area, both proposed and under construction becoming operational. To help incorporate the future

Lower Mattagami expansion projects and other renewable generation resources and to reduce likelihood of congestion, Hydro One installed series compensation on the 500 kV north-south lines at Nobel SS and dynamic reactive compensation facilities at Porcupine TS. To further improve the north-south transfer capability, Hydro One will install static reactive compensation facilities at Porcupine TS, Pinard TS, and Hanmer TS and dynamic reactive compensation facilities at Kirkland Lake TS. All the static and dynamic compensation facilities are going in service gradually, with the last one scheduled for 2013.

The Government of Ontario's Long-Term Energy Plan (LTEP) specifies five priority transmission projects to accommodate renewable generation to serve new load and support reliability. Furthermore, in a Supply Mix Directive on February 17, 2011, the OPA was required to include the five priority projects as part of long-term planning:

- Devices to enhance transfer capability, such as series or static var compensation, or other similar devices, in southwestern Ontario
- Enhance the East-West Tie along the east shore of Lake Superior through a new line
- Upgrade existing lines west of London
- A new line west of London
- New line to Pickle Lake

Northwestern Ontario (northwest) is connected to the rest of the province by the double circuit 230 kV East-West Tie. The Region has significant amounts of hydro-electric generation as well as other resources such as coal, gas, and biomass. As part of the coal shutdown, Atikokan and Thunder Bay (totaling 500 MW of generation capacity) will cease coal-fired operation by 2014. To maintain supply security in this area under the wide range of possible system and water conditions, additional resources located in the northwest or increased westbound transfer capability into this Region through the East-West Tie are required. The conversion of Atikokan to biomass and Thunder Bay to gas operation, as indicated in the LTEP, is part of the solution. The expansion of the East-West Tie is to provide a long-term reliable and cost-effective supply to the northwest. The line is anticipated to be in service no sooner than 2017.

A new supply line to Pickle Lake is currently being planned as part of a potential suite of options that may be required to serve growing load and maintain reliability in the system north of Dryden. Load in and north of this area is forecast to grow substantially over the next 10 to 15 years, and it is expected that new supply to the area will be required around 2015. Various options, both 230 kV and 115 kV are being studied, with lengths up to 300 km. These options will have some capability to support growth in the Red Lake Area to provide operational flexibility to enable refurbishment of end-of-life equipment, and to serve new load for mining operations in the area known as the Ring of Fire. The Ring of Fire Area is approximately 350 km northeast of Pickle Lake. If the new supply line to Pickle Lake is delayed, load that is being planned for connection after 2015 will not be able to connect until the new line is available. Studies have identified the need for incremental reactive capability throughout the region north of Dryden to support load growth, and there may also be the need for reactive devices at strategic locations in the bulk system at and west of Mackenzie TS.

The LTEP includes three transmission projects to accommodate additional renewable generation in southwestern Ontario: two upgrade projects and one new transmission line project. The two upgrade projects consist of a reactive compensation project and a line re-conductoring project. For the reactive compensation project, the OPA has recommended installation of an SVC with a capacitive capacity of 350 Mvar and connecting to the 500kV voltage level at the Milton Station. An in-service date of spring 2015 has been established for this project. The planned line re-conductoring project will consist of re-conductoring approximately 70 km of 230 kV transmission line between Lambton TS and Longwood TS. The two upgrade projects are intended to maximize the capability of the existing system and increase capability to incorporate additional renewable resources in a shorter time frame than a new transmission line can be built. A new transmission line west of London is targeted to be completed in 2017.

Ontario will monitor the progress of the continued operation of nuclear units at Pickering Nuclear Generating System. Pickering Nuclear Generating System units connect directly to the 230 kV system at Cherrywood TS, east of the Greater Toronto Area. The retirement of Pickering Nuclear Generating Station would require an additional 230 kV supply source for the Pickering and Oshawa Areas. Plans are currently being developed for construction of the Clarington 500/230 kV Transformer Station by as early as 2015.

As demand increases in the western part of the Greater Toronto Area, the loading on the 500/230 kV transformers at Claireville TS and Trafalgar TS will exceed their capacity by about the middle of this decade. An additional 500 to 230 kV supply source would be required to relieve the loading on the existing autotransformers. Installation of 500/230 kV transformers later in this decade at the 500 kV Milton Switching Station is one of the options under consideration.

The transmission projects that are under various stages of construction and the planned projects will address the transmission constraints identified. The transmitters 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 resulting from delays in obtaining required approvals or delays in construction may result in increased congestion or Special Protection Systems (post-contingency generation rejection) in the interim.

System reinforcements are also being considered in a number of regional areas throughout the province, such as Kitchener-Waterloo-Cambridge-Guelph, York Region, and Ottawa, in order to maintain a reliable local supply of electricity. The OPA's regional planning approach addresses project delays. Regional planning 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.

Vulnerability Assessment

As described in section 5, hydro-electric generation capacity contributions are based on median historical values of hydro-electric production plus operating reserve provided during weekday peak demand hours. Hydro-electric production is monitored on a monthly basis, and due allowance is made for deviations from the median historical conditions.

Units at Bruce B and Darlington Nuclear Generating Stations are expected to reach the end of their service lives in the latter half of the 10-year period. To extend the life of these units, they will have to be taken out of service sequentially for about three years for refurbishment. A number of options are being considered, and the timing of the refurbishment plan is not yet finalized.

The Government of Ontario in its Long-Term Energy Plan (LTEP) specified the target for large-scale development of renewable energy projects and implementation of conservation. The renewable resources target for wind, solar, and bioenergy is 10,700 MW by 2018, accommodated through transmission expansion and maximizing the use of the existing system. Ontario will grow its clean energy portfolio through the continuation of programs like the Feed-in Tariff (FIT) and microFIT.

Ontario will continue to grow its hydro-electric capacity, with a target of 9,000 MW by 2018. This will be achieved through the development of new facilities and through significant investments to maximize the use of Ontario's existing facilities.

The IESO includes a quantity of Demand Response termed the "Reliably Available Capacity" in its reliability analysis. This does not represent the total registered capacity of Demand Response programs. For market-based programs, the IESO utilizes historical information to ascertain the amount of Demand Response capacity that is typically bid into the market at the time of the weekly peak demand. For programs that have contracts, the IESO uses both historical information and contract information in order to determine the quantity of Reliably Available Capacity.

Over the assessment time frame, the level of renewables penetration is expected to increase through the FIT and microFIT programs. As a result, there will be significant increases in generation connected to the distribution systems, as well as additions to the IESO-controlled grid. Most of this generation will be variable in nature, which adds more volatility as on-grid demand is impacted both by underlying demand and by variable generation within the distribution system.

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, occurrences of surplus base-load generation will continue until the middle of the decade. An increasing number of mitigation options to reduce surplus will need to be utilized. Surplus base-load conditions are expected to significantly reduce when the nuclear refurbishment programs begin.

There are a number of initiatives (such as centralized forecasting and dispatch of renewable generation) being implemented, as described in section 5, to mitigate the challenges posed by variable generation and distributed generation.

There are no wide-area UVLS programs in Ontario, and there are no plans to install any UVLS schemes in the future.

The majority of the Special Protection Systems 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 northeast load and generation rejection SPS that mitigates the effects of contingencies involving the single-circuit 500 kV lines that service this area. This SPS is designed to achieve a post-contingency match between the load and available generation in the area to prevent possible separation and islanding of a portion of the north-east system.

Following the 1998 ice storm and prior to the 2002 opening of Ontario's competitive markets for electricity, Ontario's Emergency Planning Task Force (EPTF) was created. It is chaired by the IESO and comprises the major electricity sector players including the provincial government's Ministry of Energy. The EPTF oversees an emergency management team called the Crisis Management Support Team (CMST) to manage any crisis and mitigate the impact on public health and safety due to an extended electricity system emergency. Ontario runs an annual program of Reliability and Emergency Management workshops, including tabletop drills. Additionally, major integrated exercises are staged in which both the operational response and emergency management processes are activated. The CMST also performs regular test activations.

During the nine-day capacity and energy emergency that followed the August 2003 blackout, the CMST managed the emergency via 31 conference calls and was instrumental in producing media messages, facilitating the government's appeal and direction for reduced demand, and obtaining the necessary environmental variances to secure additional supply.

The 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 to calculate a limited set of operating security limits in southern Ontario, in the northeast and the east. There are plans to extend the use of this tool to the entire province by the end of 2013. The limits calculated by the tool are used to plan and schedule outages and to re-prepare the power system following a forced outage.

A web-based online outage requests tool was introduced last fall for market participants to submit their outages directly into the Integrated Outage Management System. The new tool replaces a manual process and is a marked improvement in efficiency, with validation and alerts for short notice requests built into the online tool.

As of March 2012, 4.7 million smart meters have been installed across the province, and 70 local distribution companies and 4.36 million meters were enrolled with the Meter Data Management and Repository (MDM/R). The MDM/R system actively processes smart meter data and produces time of use (TOU) billing quantities for customer invoices. The smart meter customers are charged TOU rates, where the price of electricity depends on when it is used relative to peak demand periods.

The IESO reviews all relay protection misoperations and works with Transmission Operators to ensure that timely assessments and repairs are completed for reliable operation of the IESO-controlled grid.

Over the last two years, about 3,000 MW of coal-fired generation from six coal units at two generating stations has been shutdown. The current installed capacity of coal-fired generation in Ontario amounts to about 3,500 MW. The phase-out of the remaining coal-fired generation by the end of 2014 is underway. In the intervening period, the Ontario government has implemented greenhouse gas emissions targets for coal-powered generation to ensure that between 2012 and 2014, annual emissions are two-thirds lower than 2003 levels.

Ontario Power Generation, the owner of the coal units, is making significant reductions in CO_2 emissions from coal in a manner consistent with government direction. OPG's strategy will achieve the required reductions in emissions while making sure the coal units are available to meet peak electricity demand.

As described in section 5, a number of nuclear units at Darlington and Bruce B Nuclear Generating Stations will be on refurbishment outage at different times over the assessment period. At this stage, these outages are not expected to have any reliability issues as plans are in place—these plans are reviewed on an ongoing basis with changes in assumptions.

Retrofits are required for conversion from coal to other fuels such as gas or biomass. The plans allow sufficient time for conversions.

Standing and Emerging Reliability Issues

Demand Forecasting Models

Maintaining accuracy of demand forecasting models is an emerging issue. Demand forecasting continues to evolve and is becoming more complex due to a number of driving factors. Conservation has had a significant impact on demand and continues to make it difficult for system planners and operators to capture or estimate the impact of conservation programs and initiatives. Similarly, embedded generation is starting to require more attention from load forecasters as the amount of embedded generation capacity is expected to show a dramatic increase. The fact that much of the embedded generation will be variable in nature adds a new degree of volatility as on-grid demand is impacted both by underlying demand and by variable generation within the distribution system. The correlation of end-use consumption uncertainty with distributed generation uncertainty is not a trivial modeling exercise. Lastly, the evolution of the smart grid and smart grid technologies will unlock greater Demand Response and increase the complexity of operating the electricity grid.

The issue requires industry attention over the next 10 years. The consequence of variance in demand forecasting will be moderated as the industry develops the means and processes to track and evaluate the individual programs' performance. Improved data collection and new models and tools will enable the industry to more accurately identify and assess the impact of these initiatives on the power system.

Asset Renewal - A Systematic Approach for Continuous Modernization of Aging Energy Infrastructure

Asset renewal is a standing issue. Much of the current power system infrastructure, whether generation, transmission, or distribution equipment, is aging and needs to be refurbished, replaced, or upgraded to comply with new standards and to meet demand. A long-term plan is required to coordinate the renewal of infrastructure to manage reliability, environmental, and cost impact.

In the latter half of the 10-year period, a number of nuclear units at Bruce and Darlington Nuclear Generating Stations will be expected to undergo refurbishment. The Pickering Nuclear Generating Station is scheduled for retirement within the next decade. Coal units will cease burning coal by 2014, with conversion to other fuels being considered as just one of several mitigating options. Some transmission and distribution components are over 80 years old and require upgrading. Although many companies have sustainment 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 non-electrical infrastructure developments.

NPCC-Québec

Planning Reserve Margins

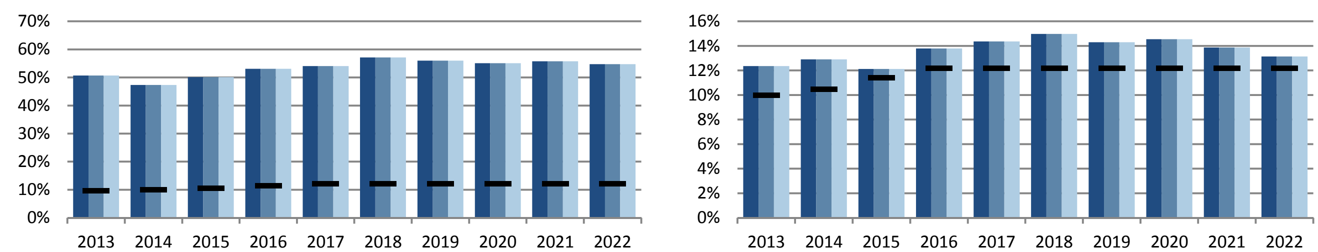
The Québec Area is projecting adequate Planning Reserve Margins throughout the long-term assessment period, varying between 12.1 and 15 percent. For the first year considered in this assessment, the 2013/2014 winter peak, the Anticipated Reserve Margin is 12.36 percent, which is above the NERC Reference Reserve Margin of 10 percent. Québec's Anticipated Reserve Margin for the 2012/2013 winter is projected to be 10.8 percent, also above the NERC Reference Margin Level 9.6 percent.[231] The NERC Reference Reserve Margin Levels are drawn from the most recent Québec Balancing Authority Area Comprehensive Review of Resource Adequacy, which was approved by NPCC's Reliability Coordinating Committee on November 29, 2011. These levels vary between 9.6 and 12.2 percent during the 10-year assessment (NPCC-Québec-Table 1 and NPCC-Québec-Figure 1).

NPCC-Québec-Table 1: Planning Reserve Margins[232]

NPCC-Québec-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		50.71%	47.36%	50.12%	53.11%	54.08%	57.13%	56.00%	55.11%	55.79%	54.73%
PROSPECTIVE		50.71%	47.36%	50.12%	53.11%	54.08%	57.13%	56.00%	55.11%	55.79%	54.73%
ADJUSTED POTENTIAL		50.71%	47.36%	50.12%	53.11%	54.08%	57.13%	56.00%	55.11%	55.79%	54.73%
NERC REFERENCE	-	**9.60%**	**10.00%**	**10.50%**	**11.40%**	**12.20%**	**12.20%**	**12.20%**	**12.20%**	**12.20%**	**12.20%**

NPCC-Québec-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		12.36%	12.90%	12.12%	13.79%	14.36%	14.97%	14.30%	14.54%	13.86%	13.14%
PROSPECTIVE		12.36%	12.90%	12.12%	13.79%	14.36%	14.97%	14.30%	14.54%	13.86%	13.14%
ADJUSTED POTENTIAL		12.36%	12.90%	12.12%	13.79%	14.36%	14.97%	14.30%	14.54%	13.86%	13.14%
NERC REFERENCE	-	**10.00%**	**10.50%**	**11.40%**	**12.20%**	**12.20%**	**12.20%**	**12.20%**	**12.20%**	**12.20%**	**12.20%**

NPCC-Québec-Figure 1: Summer (Left) and Winter[233] (Right) Planning Reserve Margins



The Planning Reserve Margins projected in this assessment are adequate and result mostly from the commissioning of additional resources, most of which are new hydro projects, such as La Sarcelle Generating Station, the Romaine River Complex (Romaine 1, 2, 3, and 4), additional capacity at Sainte-Margerite-3 Generating Station, and wind and biomass resources. Moreover, an additional amount of Demand Response programs contributes to this adequate level of projected reserve margins.

For this assessment, the Gentilly-2 nuclear station will be out of service for decommissioning at the end of 2012. The Tracy and La Citière thermal generating stations have also been permanently retired.

Demand

The compound annual growth rate (CAGR) forecast for Total Internal Demand is 0.79 percent during the next 10 years (2013/2014 – 2022/2023 winter seasons), which is slightly lower than the one percent growth rate forecast reported in the 2011 LTRA (NPCC-Québec-Table 2). As for the Net Energy for Load (NEL), the average growth rate forecast is also 0.8 percent, compared to a 0.6 percent growth rate forecasted last year.

231 Additional information on the 2012/2013 winter season can be found in the NERC *Winter Reliability Assessment*: http://www.nerc.com/page.php?cid=4|61.

232 Winter years represent the first year of the winter season (For example, the 2013 column represents the 2013/2014 winter season).

233 Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.

NPCC-Québec-Table 2: Demand Outlook

NPCC-Québec-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	21,115	22,818	1,704	8.1%	0.87%
Load-Modifying Demand Response	0	0	0	0.0%	0.00%
TOTAL INTERNAL DEMAND	**21,115**	**22,818**	**1,704**	**8.1%**	**0.87%**

NPCC-Québec-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	37,810	40,575	2,766	7.3%	0.79%
Load-Modifying Demand Response	0	0	0	0.0%	0.00%
TOTAL INTERNAL DEMAND	**37,810**	**40,575**	**2,766**	**7.3%**	**0.79%**

The Net Internal Demand for the 2013/2014 winter peak peak is projected to be 37,810 MW, which is 267 MW higher than the forecasted 2012/2013 winter peak demand. The demand forecast methods used in this assessment have not changed from previous years. Additionally, there have been no footprint changes and no entity acquisitions or exits.

Demand-Side Management

The only Demand Response programs in the Québec Area specifically designed for peak-load reduction during winter operating periods are interruptible demand programs (for large industrial customers) totaling 1,660 MW for the 2013/2014 winter period, decreasing to 1,300 MW by the final year of the assessment (NPCC-Québec-Table 3). It is usually used in situations when load is expected to reach high levels or when resources are not expected to be sufficient to meet load at peak periods. Demand Response is relatively stable over the assessment period, with a maximum reached for the 2013/2014 winter peak period.

NPCC-Québec-Table 3: Projected Demand-Side Management

	Short-Term					
NPCC-Québec-Winter	2013/14	2014/15	2015/16	2022/23	10-Year Change	2022/23 Share of Total Internal Demand
Direct Control Load Management (DCLM)	250	250	250	250	0	0.62%
Contractually Interruptible (Curtailable)	1,660	1,439	1,439	1,300	-360	3.20%
Critical Peak-Pricing (CPP) with Control	0	0	0	0	0	0.00%
Load as a Capacity Resource	0	0	0	0	0	0.00%
TOTAL RESOURCE-SIDE DEMAND RESPONSE	1,910	1,689	1,689	1,550	-360	3.82%
TOTAL ENERGY EFFICIENCY	1,980	2,150	2,300	3,190	1,210	7.86%
TOTAL DEMAND-SIDE MANAGEMENT	**3,890**	**3,839**	**3,989**	**4,740**	**850**	**11.68%**

Total Energy Efficiency/Conservation is included in the forecast load and accounts for 1,980 MW at the 2013/2014 winter peak period. Energy Efficiency is growing throughout the entire period of the assessment. The total on-peak Demand Response and Energy Efficiency/Conservation for the 2022/2023 winter period is projected to be approximately 4,740 MW.

On a yearly basis, Hydro-Québec Distribution presents its Energy Efficiency Plan Update, "Plan global en efficacité énergétique," to the Québec Energy Board (regulatory body in Québec) for the next and upcoming years. This plan focuses on energy conservation measures and includes programs tailored to residential customers, commercial and institutional markets, small and medium industrial customers, and large-power customers. Examples of programs and tools for promoting energy savings for the residential customers include old refrigerator recycling, electronic thermostats, low-energy lighting, etc. The provincial government, through its Ministry of Natural Resources, also implements Energy Efficiency/Conservation programs, mainly in the area of building standards and housing insulation.

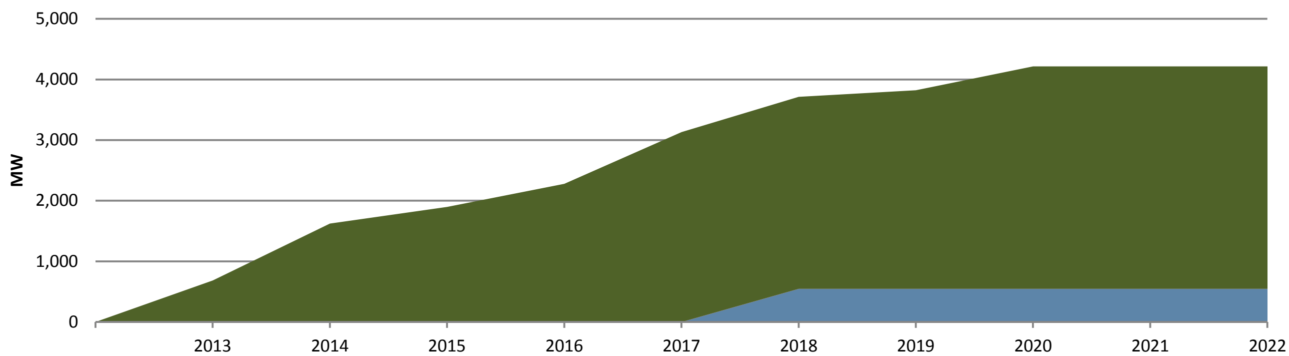
Generation

At the time of this assessment, available resources for the next winter in the Québec Area are evaluated at 39,502 MW, most of which are hydropower generation (97 percent). Wind and biomass resources, which are owned and operated by Independent Power Producers (IPPs) and under long-term power purchase agreements with Hydro-Québec Distribution and Hydro-Québec Production, account for two percent of the available capacity. Hydro-Québec Production also operates one fuel oil generating station (for peaking purposes), which represents about one percent of the total available capacity (NPCC-Québec-Table 4 and NPCC-Québec-Figure 2).

NPCC-Québec-Table 4: Capacity Outlook[234]

NPCC-Québec-Winter	Current		2022/23 Planned			2022/23 Planned & Conceptual		
	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
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%	547	1.3%	547	547	1.3%	547
Nuclear	0	0.0%	0	0.0%	0	0	0.0%	0
Other/Unknown	0	0.0%	0	0.0%	0	0	0.0%	0
Renewables	39,066	98.9%	42,418	97.7%	3,353	42,418	97.7%	3,353
TOTAL	**39,502**	**100.0%**	**43,401**	**100.0%**	**3,900**	**43,401**	**100.0%**	**3,900**

NPCC-Québec-Figure 2: Winter Net Capacity Change[235]



The Existing-Certain capacity increased by an amount of 1,240 MW since the previous assessment, of which 720 MW are from hydropower generation and 520 MW from wind and biomass.

TransCanada Energy's 547MW natural gas combined-cycle generating station in Bécancour is mothballed and accounts for the total Existing-Inoperable resources. Each summer, Hydro-Québec Distribution must decide whether to mothball the Bécancour power plant for an additional year or to re-start it for the coming year. Although this plant is expected to be mothballed until December 2017, it could be re-started sooner if needed.

As mentioned above, the Gentilly 2 nuclear station (675 MW) will be out of service for decommissioning at the end of 2012. Two thermal generating stations have also been permanently retired since the last assessment—Tracy (450 MW) and La Citière (280 MW). In the previous assessment, the Tracy power plant was mothballed over the entire assessment period.

The temporary unit shutdown and retirements described above are offset by the commissioning of new resources. The last two units of La Sarcelle Hydro Generating Station (50 MW each) are to be commissioned during the 2012/2013 winter period. The Romaine-2 (622 MW) and Romaine-1 (260 MW) Hydro Generating Station are under construction and are expected to be commissioned for the 2014/2015 and 2016/2017 winter peak periods respectively. The added capacity at Sainte-Margerite-3 is expected to be commissioned for the 2017/2018 winter peak period, adding 440 MW of capacity. Two other generating stations at the Romaine Complex (Romaine-3 and Romaine-4) are expected to be commissioned later during the assessment period (2017/2018 and 2020/2021), adding 668 MW of capacity to the system. Finally, existing power plant retrofitting will add close to 500 MW of new capacity by the 2020/2021 winter peak period.

In recent years, Hydro-Québec Distribution has launched several calls for tenders and electricity purchase programs for new renewable supplies, which will also be commissioned in the next years:

- 2,290 MW of wind power to be commissioned between 2012 and 2015.

[234] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

[235] Years represent initial year for each winter season. For example: 2013 represents the 2013/2014 winter season.

- 125 MW generated by small hydro plants (50 MW and less) developed in partnership with local and First Nations communities, will be commissioned between 2012 and 2014.
- 300 MW generated from biomass to be commissioned between 2012 and 2016.

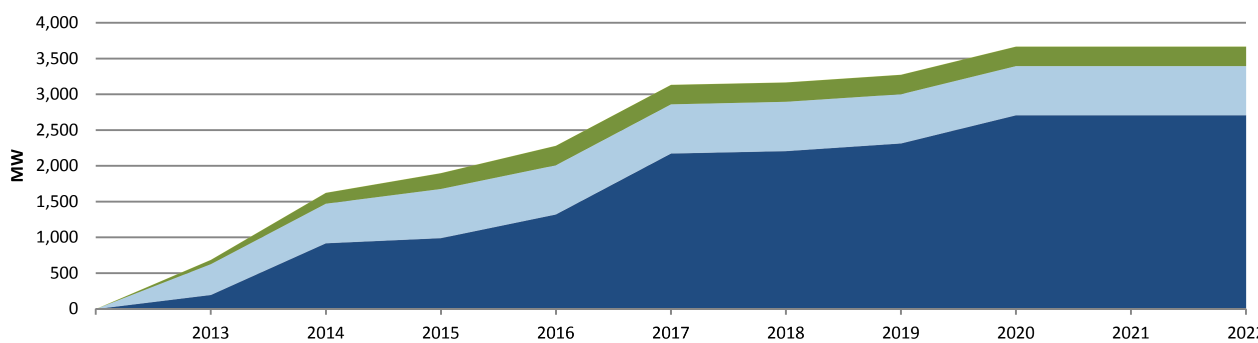
As for behind-the-meter generation, it is negligible and is included in the load forecast. For hydro resources, maximum capacity is set equal to the power that each plant can generate at its maximum rating during two full hours, while expected on-peak capacity is set equal to maximum capacity minus scheduled maintenance outages and restrictions.

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, which represents 490 MW and 973 MW respectively for the 2012/2013 (current) and 2022/2023 winter periods. The maximum wind capacity is equal to contractual capacity, which generally equals to its nameplate capacity. For summer peak periods, the expected on-peak wind capacity is set to zero as wind resources are completely derated (NPCC-Québec-Table 5 and NPCC-Québec-Figure 3).

NPCC-Québec-Table 5: Renewable Capacity Outlook[236]

	Current		2022/23 Planned			2022/23 Planned & Conceptual		
NPCC-Québec-Winter	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Hydro	38,315	98.1%	40,971	96.6%	2,656	40,971	96.6%	2,656
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	490	1.3%	973	2.3%	483	973	2.3%	483
Biomass	261	0.7%	474	1.1%	213	474	1.1%	213
Solar	0	0.0%	0	0.0%	0	0	0.0%	0
TOTAL	**39,066**	**100.0%**	**42,418**	**100.0%**	**3,353**	**42,418**	**100.0%**	**3,353**

NPCC-Québec-Figure 3: Winter Net Renewable Capacity Change[237]



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

- Wind generation variability on system load and interconnection ramping.
- Frequency and voltage regulation problems.
- Increase of start-ups/shutdowns of hydroelectric units due to load following coupled with wind variability; efficiency losses in generating units also expected.
- Reduction of low-load operation flexibility due to low inertial response of wind generation coupled to must-run hydroelectric generation.

[236] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.
[237] Years represent initial year for each winter season. For example: 2013 represents the 2013/2014 winter season.

Capacity Transactions

Expected capacity purchases are planned by Hydro-Québec Distribution as needed for the Québec internal demand. These purchases are set at 1,100 MW throughout the assessment period and may be supplied by resources located in Québec or in neighboring markets. In this regard, Hydro-Québec Distribution has designated the Massena–Châteauguay (1,000 MW) and Dennison–Langlois (100 MW) interconnections' transfer capacity to meet its resource requirements during winter peak periods. These purchases are not backed by firm long-term contracts. However, on a yearly basis, Hydro-Québec Distribution proceeds with short-term capacity purchases (UCAP) in order to meet its capacity requirements if needed.

The Québec Area will support firm capacity sales totaling 398 MW to New England and Ontario (Cornwall) during the 2013/2014 winter peak, backed by Firm contracts for both generation and transmission, but which will decline to 145 MW in 2020 (NPCC-Québec-Table 7). Moreover, 228 MW of Firm exports for the 2014/2015 winter period and 500 MW for the 2015/2016 winter peak are committed for neighboring area's needs.

NPCC-Québec-Table 7: Projected Capacity Transactions

NPCC-Québec-Winter	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
Expected Imports	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100
Firm Imports	0	0	0	0	0	0	0	0	0	0
TOTAL IMPORTS	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100
Expected Exports	0	0	0	0	0	0	0	0	0	0
Firm Exports	398	626	676	151	151	151	151	145	145	145
TOTAL EXPORTS	398	626	676	151	151	151	151	145	145	145
TOTAL NET CAPACITY TRANSACTIONS	**702**	**474**	**424**	**949**	**949**	**949**	**949**	**955**	**955**	**955**

The Québec Area does not rely on any emergency capacity imports to meet its Reserve Margin Reference Level.

Transmission

This section briefly describes the BPS transmission additions anticipated to be in service during the assessment period. A summary of existing and projected additions is included below (NPCC-Québec-Table 8). Descriptions for each project of particular importance are also included below.

NPCC-Québec-Table 8: Existing and Projected Transmission

NPCC-Québec	AC (Circuit Miles)	DC (Circuit Miles)	Total (Circuit Miles)
EXISTING	21,273	1,514	22,787
Currently Under Construction	412	0	412
Planned - Completed within First Five Years	68	0	68
Planned - Completed within Second Five Years	129	0	129
2022 TOTAL (UNDER CONSTRUCTION & PLANNED)	21,881	1,514	23,395
Conceptual - Completed within First Five Years	452	93	546
Conceptual - Completed within Second Five Years	599	0	599
2022 TOTAL (UNDER CONSTRUCTION, PLANNED & CONCEPTUAL)	**22,932**	**1,607**	**24,539**

The Romaine River Hydro Complex Integration

Construction of the first phase of transmission infrastructures for the Romaine River Hydro Complex project has now begun. The generating stations will be integrated on a 735 kV infrastructure initially operated at 315 kV. Romaine-2 and Romaine-1 will be integrated in 2014/2016 at Arnaud 735/315 kV substation. Romaine-3 and Romaine-4 will be integrated in 2017/2020 at Montagnais 735/315 kV substation.

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

The Bout-de-l'Île 735-kV Section

Hydro-Québec TransÉnergie is adding a new 735 kV section at Bout-de-l'Île (east end of Montréal Island) substation. This was originally a 315/120 kV station. The Boucherville–Duvernay 735 kV line (line 7009), which passes by Bout-de-l'Île, will be looped into the new station. A new -300/+300 Mvar Static Var Compensator 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 will absorb load growth in the eastern part of 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 Northern Pass Project

This project to increase interconnection transfer capability between Québec and New England by 1,200 MW is now being studied. The project involves construction of a ±300 kV dc transmission line about 46 miles long from Des Cantons 735/230 kV substation to the Canadian-U.S. border. This line will be extended into the United States to a substation built in Franklin, New Hampshire.

The project in Québec also includes the construction of two 600 MW converters at Des Cantons and a 300 kV dc switchyard. Permitting for this project is presently ongoing but the initial commissioning date of 2015 may be delayed.

Wind Generation Integration Projects

A number of wind transmission projects with voltages ranging from 120 kV to 315 kV are either under construction or in planning stages in order to integrate wind generation planned to come on-line in the next few years. These wind generation projects are distributed in many areas of the Province of Québec, but most are near the shores of the Gaspésie Peninsula, along the Gulf of St. Lawrence down to the New Brunswick border.

Projects on the main system include 735 kV series compensation additions, and the addition of a second SVC at Bout-de-l'Île substation after the addition of the previously mentioned 735 kV section, and an SVC at Jacques-Cartier substation. Nominal current upgrades will also be done on some existing series compensation, and a thermal capacity upgrade will be done on two 735 kV lines. However, the future construction of the Chamouchouane–Bout-de-l'Île 735 kV line (see below) will replace a number of the above-mentioned projects.

Chamouchouane – Bout-de-l'Île 735 kV Line

The large generation additions and transmission services coming up over the next years require, as shown above, a number of system additions to maintain reliability. Moreover, planning studies have shown that to optimize the different solutions and to significantly reduce marginal losses on the system due to this new generation, a new 735 kV line from Chamouchouane substation on the eastern James Bay subsystem to Bout-de-l'Île substation in Montréal (about 230 miles) is required. Planning, permitting and construction delays are such that the line is scheduled for the 2017/2018 winter peak period. This optimization will result in replacing some of the above-mentioned projects, and in other cases will result in reducing additional equipment that was previously planned. The new line will also reduce transfers on other parallel lines on the Manicouagan–Québec 735 kV interface, thus optimizing operation flexibility and reducing losses.

Public information meetings have begun on this project. Final line route has not been determined yet and government authorization processes are ongoing.

Other 735 kV Conceptual Projects

A new 735/315 kV transformer station near the existing Arnaud 735 kV station is being projected for 2018. This station, tentatively named Arnaud-2, will be about 9.3 miles from Arnaud. It will be integrated into the Churchill Falls–Manicouagan subsystem using two existing lines and one new 15-km (9.3 mi.) 735 kV line from Arnaud Station. Two 735/315 kV, 1650 MVA transformers and six 315 kV line feeders will complete the station. Two double-circuit 315 kV lines will eventually feed the Alouette Aluminum Smelter Complex, replacing the 161 kV feeders now in service.

A new 735/315 kV transformer station is being projected 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 miles) 735 kV line is projected from Abitibi 735 kV Station on the 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. It is projected to be in service in fall 2018.

Regional Projects Under Construction

There are a number of regional projects now underway. The three most important are listed here:

- Limoilou 230/25 kV substation in Québec City; in service fall 2012
- St-Bruno 315/25 kV substation south of Montréal; in service fall 2013
- Bécancour 230 and 120 kV system reinforcement; Bécancour Industrial Park, in service fall 2012

Upcoming Regional Projects

Other regional substation and/or line projects are now in the planning/permitting stages. There are about a dozen regional transmission projects in the Montréal and Québec City Areas and another dozen in other areas within service dates from 2012 to 2018.

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. Moreover, there are no project delays or temporary service outages for any transmission facilities (lines or transformers) that will impact long-term reliability during the assessment period.

The Hydro-Québec system has sufficient transmission being constructed to support all Future-Planned generation forecast to come on-line during the assessment period.

Vulnerability Assessment

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

A total of 1,500 MW is targeted by Under-Voltage Load Shedding (UVLS) in the Québec Area. It has been designed to operate following contingencies involving the loss of two or more 735 kV lines. These contingencies do not require more than 1,500 MW of load shedding, although UVLS operates on a pre-defined pool of 2,500 MW located in the Montréal Area. The NPCC Comprehensive Review Assessment of the Québec Transmission System for 2012 (the last Comprehensive Review to date) conducted by Hydro-Québec TransÉnergie (acting as Transmission Planner) shows that UVLS is adequate to preserve system stability after the contingencies for which it is designed.

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. The number of automatic actions needed to stabilize the system increases with the severity of the contingencies, but the whole analysis indicates a stable and well-damped system response for all contingencies. This assessment indicates that no voltage or reactive power problems having an adverse impact on the BPS are anticipated under complementary contingency requirements. No additional load is expected to be assigned to UVLS during the next 10 years.

Hydro-Québec maintains a permanent emergency plan in case of catastrophic events. This stems from a number of federal and provincial legislation, rules, procedures and municipal by-laws. At the corporate level, Order #24 "Service Continuity and Emergency Measures" and Corporate Policy "Our Security" form the basis on which the plan is built. The Corporate Plan is prepared by the Industrial Security Group at Hydro-Québec. It includes the plan's objectives, risks covered by the plan, the organization around the plan (Steering Committee and Coordinating Committee), communications, and updating. Risks cover a large array of situations, for example, rupturing of a dam or dike, a nuclear incident, extensive damage to transmission lines and stations, forest fires, unavailability of computer systems or telecommunications systems, biological risks, cyber criminality, terrorism, etc. The plan also provides links with the Québec Civil Security Organization and other civil, military, or medical organizations. This Corporate Plan directs Hydro-Québec's divisions to elaborate and maintain their own sectorial plan according to their field of activities.

Hydro-Québec TransÉnergie's Plan is based on eight different types of risk that the system has a probability of experiencing. These risk types are associated with criteria determining their impact on the system. Studies have determined the probability of occurrence and an impact level on a scale from 1 to 9 is associated with the risk type.

For each risk type, a file has been developed defining the risk, possible source events, potential impact, risk evaluation (probability of occurrence), mitigation procedures, post-mortem and follow-up requirements.

The planning process for catastrophic events completes system planning as required by NPCC's Regional Reliability Reference Directory #1–Design and Operation of the BPS and by NERC's Transmission Planning Standards. These standards define a number of system events that must be assessed under specified conditions. For NPCC, this includes an Extreme Contingency Assessment with, for example, loss of the entire capability of a generating station, loss of all transmission circuits in a common right-of-way, the sudden dropping of a large load or major load center, or the sudden loss of fuel delivery systems to multiple plants. Not all of these events apply to TransÉnergie. For example, only one natural gas-fired plant exists in the Québec Area, generating 547 MW, so that a pipeline failure is of little consequence to the system in this case. However, since bulk transmission is 735 kV, TransÉnergie physically limits the number of 735 kV lines in a common right-of-way to a maximum of two lines, because the loss of a right-of-way has a definite impact. Sudden dropping of large load centers, loss of generation stations, and loss of a 735 kV switching station are extreme events covered by Special Protection Systems, which limit the event's impact on the system.

In the case of an extreme contingency leading to a system blackout, there is an automatic device called SPSR (French acronym for "System Separation Solution") that acts locally at a number of 735 kV stations to close in sacrificial Zinc Oxide surge arrestors before the system dismantles. System collapse is accompanied by over voltages that would damage equipment if not dampened by the surge arrestors. This makes it possible to restore the system in minimum time with maximum equipment availability after a blackout. The surge arrestors themselves must be replaced after such an event.

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

TransÉnergie's system consists of an extensive 735 kV network underlain with 315 kV, 230 kV, and 120 kV subsystems totaling close to 22,800 circuit 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 with 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. Special Protection Systems to provide additional reliability (for extreme events) are presently in use and will continue to be used. These include Remote Generation Rejection and Load Shedding, Under-Voltage Remote Load Shedding, and Under-Frequency Load Shedding. It is not planned that Special Protection Systems or Remedial Action Schemes will be installed in lieu of planned bulk power transmission facilities in the Québec Area.

Other technologies such as synchronous condensers, Static Var Compensators (SVCs), 735 kV series compensation, multi-band power system stabilizers (MBPSS), 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.

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 on-line reporting and provides priceless post-mortem 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).

Simulation tools are constantly being developed by TransÉnergie for planning purposes. These load forecasting tools, including local weather forecasts provided by TransÉnergie staff. These efforts contribute to the TransÉnergie Operation Planning Department that receives assistance from Hydro-Québec's Research Institute (IREQ) as well as the Université de Liège in Belgium, working to develop a number of system simulation software packages for in-house use. These include on-line dynamic security assessments (DSA), voltage sensitivity due to load and generation variations, massive stability simulations, voltage stability, real-time load modeling, and research on motor load modeling. DSA applications have been the object of joint (TransÉnergie and IREQ) IEEE papers.

Another project looks at regulation systems and SPS improvement in order to upgrade transfer capability and improve system reliability. This includes installation of MBPSSs in a great number of generating stations, new regulation circuits for the dynamic shunt compensation equipment, new relaying for Special Protection Systems, new control strategies for HVdc converters, development of severity indices for angular and voltage stability, etc. The project is also studying the possibility of introducing a type of global regulation for dynamic shunt equipment (as opposed to regulation based on local parameters) implying Measurement Units, a Data Concentrator, and Control Units, all linked by synchronized digital communications.

During the past year, no new smart grid programs were fully implemented at Hydro-Québec. The IMAGINE project is ongoing. IMAGINE involves automated maintenance and enhanced processing of monitoring data. Altogether, 94 substations are now connected to two remote maintenance centres, one in Montréal and one in Québec City. 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. Fault location data will be shared with Hydro-Québec Distribution, which will reduce recovery time. This project will also help Hydro-Québec meet NERC CIP requirements pertaining to cyber assets by providing an automated inventory of protection and control device passwords. The IMAGINE investment is over-budget for initiatives that are also accomplished through IREQ, Hydro-Québec's research center, with the help of industrial partners.

TransÉnergie is also working with IREQ to prepare the smart transmission grid of the future. In 2010, the main outlines of an adaptive power grid were sketched out. The grid would be equipped with controllers, sensors, analysis systems and other devices necessary to monitor equipment continuously and manage the system and its components in real time. Related projects include the ACOR grid response improvement program, which is designed to increase system capacity, reliability, and security by means of advanced protections and controls.

All relay operations are submitted to systematic and thorough analysis by TransÉnergie's "Analyses et comportement du réseau principal et des réseaux régionaux" (Bulk and Regional System Behavior and Analysis) unit, where primary causes of relay operations are studied and determined. When misoperations do occur, corrective actions and recommendations are issued and transposed to other installations when required. This is done through Maintenance Notices issued to Maintenance Units. Recommendation follow-up is certified through the SADA system (SPS and Protection Analysis System).

Concerning protection equipment durability, a TransÉnergie working group makes sure that data pertaining to control systems and protection systems are up-to-date at all times. A log sheet containing replacement priorities (on a scale of 1 to 9) and timelines for protection equipment is also kept up-to-date. A yearly follow-up is done to re-evaluate priorities and account for the work done and remaining. Evaluations of problematic systems are kept on file for ongoing referencing.

Finally, as a member of the Western Climate Initiative[238], the province of Québec implemented a cap-and-trade system in 2012, with the first compliance period planned to start January 1, 2013. Given the proportion of renewable generation in the Québec Area, this new regulation will not impact the Québec Area's reliability.

Standing and Emerging Reliability Issues

This section briefly discusses some important issues that may impact system reliability during the assessment period. There is no doubt that developments during recent years have contributed to a more reliable system. However, sustainable system reliability may be challenged by several issues. Two of them are considered as standing reliability issues and are described and analyzed below.

Wind Plant Integration to Grid

As a separate NERC Interconnection, the Québec subregion 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 it is required to set operating limits related to post-contingency frequency behavior.

Through 2015, Hydro-Québec will have integrated around 3,350 MW of nameplate wind capacity. This kind of large-scale integration of wind capacity on the system has triggered a need for frequency support by wind plants. In order to maintain actual system performance, TransÉnergie (the System 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. TransÉnergie is presently in the process of quantifying its inertia emulation needs. This is an ongoing interactive process with manufacturers. TransÉnergie is now in the process of procuring and validating manufacturers' inertia emulation model functions for wind plants. Inertia emulation is required for Hydro-Québec Distribution's wind generation resulting from the second and third calls for tenders, totaling 2,290 MW of capacity. Further studies will have to be made if wind capacity integration is extended in the mid-term.

Equipment Aging and Sustainability

Equipment aging and sustainability have been standing issues at TransÉnergie for more than 15 years (line and station equipment). 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 when the equipment is approaching the end of its life cycle. This risk assessment considers the probability of a major failure and its impact on the transmission system and on TransÉnergie as an asset owner. The strategy put forward in 2007 was presented to the Québec Energy Board and authorized by the Board with an accompanying annual budget.

Issues that could impact reliability in the context of equipment aging are the following:

- Significant investment cuts
- Personnel and equipment availability for maintenance outages as well as new projects
- System availability for outages

At this time, there is no major concern regarding these issues that could have an impact on the BPS.

[238] The Western Climate Initiative is a collaboration of independent jurisdictions working together to identify, evaluate, and implement emissions trading policies to tackle climate change at a regional level. http://www.mddep.gouv.qc.ca/changements/plan_action/index-en.htm

PJM

Planning Reserve Margins

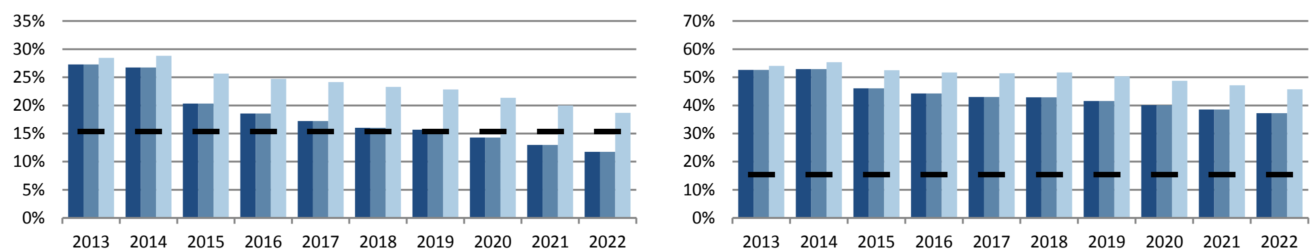
The PJM RTO will have adequate Planning Reserve Margins for all three categories throughout the 2019 summer season. It is expected that some Conceptual queued units will eventually become planned and placed in service to make up the amount below the NERC Reference Margin Level, beginning in 2020. The current PJM RTO Reserve Requirement is 15.6 percent through May 31, 2013. For the remainder of the assessment period, the PJM Reserve Requirement is 15.4 percent, applied as the NERC Reference Margin Level throughout this long-term assessment (PJM-Table 1 and PJM-Figure 1).[239]

PJM-Table 1: Planning Reserve Margins

PJM-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		27.28%	26.76%	20.34%	18.58%	17.24%	16.04%	15.69%	14.29%	12.98%	11.75%
PROSPECTIVE		27.28%	26.76%	20.34%	18.58%	17.24%	16.04%	15.69%	14.29%	12.98%	11.75%
ADJUSTED POTENTIAL		28.45%	28.83%	25.66%	24.72%	24.14%	23.29%	22.85%	21.37%	19.98%	18.67%
NERC REFERENCE	-	**15.40%**	**15.40%**	**15.40%**	**15.40%**	**15.40%**	**15.40%**	**15.40%**	**15.40%**	**15.40%**	**15.40%**

PJM-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		52.63%	52.90%	46.10%	44.24%	42.99%	42.90%	41.60%	40.07%	38.56%	37.23%
PROSPECTIVE		52.63%	52.90%	46.10%	44.24%	42.99%	42.90%	41.60%	40.07%	38.56%	37.23%
ADJUSTED POTENTIAL		54.03%	55.39%	52.55%	51.71%	51.41%	51.74%	50.36%	48.74%	47.14%	45.73%
NERC REFERENCE	-	**15.40%**	**15.40%**	**15.40%**	**15.40%**	**15.40%**	**15.40%**	**15.40%**	**15.40%**	**15.40%**	**15.40%**

PJM-Figure 1: Summer (Left) and Winter[240] (Right) Planning Reserve Margins



The PJM Reliability Pricing Model (RPM) or Forward Capacity Market provides:

- procurement of capacity three years before it is needed through a competitive auction;
- locational pricing for capacity that reflects limitations on the transmission system's ability to deliver electricity into an area and to account for the differing need for capacity in various areas of PJM;
- a variable resource requirement to help set the price for capacity;
- a backstop mechanism to ensure that sufficient resources will be available to preserve system reliability.

The Anticipated Capacity Reserve Margin falls below the PJM required reserve margin in 2020. The adjusted potential resources Reserve Margin is above the PJM requirement through the assessment period. The major contributing factor to the shortfall is significant retirements. It is expected that generator developers will make up the shortfall in those future years. Continued use of the PJM RPM will ensure that the Planning Reserve Margin is met at least three years into the future. A potential issue that could lead to incorrect projections is significant load growth well beyond what is expected. Also, planned units not coming on-line would affect the PJM reserve margin in the long-term future, but the RPM is anticipated to provide adequate resources in the three-year near term when that time horizon is experienced.

[239] For more information, see the 2011 PJM Reserve Requirement Study: http://www.pjm.com/planning/resource-adequacy-planning/~/media/planning/res-adeq/2011-rrs-study.ashx.

[240] Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.

Demand

Summer peak load growth for the PJM RTO is projected to average 1.36 percent per year over the next 10 years. The PJM RTO summer peak is forecast to be 176,420 MW in 2022, a 10-year increase of 20,166 MW (PJM-Table 2). Annualized 10-year growth rates for individual PJM transmission zones range from 0.9 percent to 1.9 percent.

PJM-Table 2: Demand Outlook

PJM-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	145,254	163,220	17,966	12.4%	1.30%
Load-Modifying Demand Response	11,000	13,200	2,200	20.0%	2.05%
TOTAL INTERNAL DEMAND	**156,254**	**176,420**	**20,166**	**12.9%**	**1.36%**
PJM-Winter	**2013/14**	**2022/23**	**10-Year Change**		**CAGR**
NET INTERNAL DEMAND	121,160	132,916	11,756	9.7%	1.03%
Load-Modifying Demand Response	11,000	13,200	2,200	20.0%	2.05%
TOTAL INTERNAL DEMAND	**132,160**	**146,116**	**13,956**	**10.6%**	**1.12%**

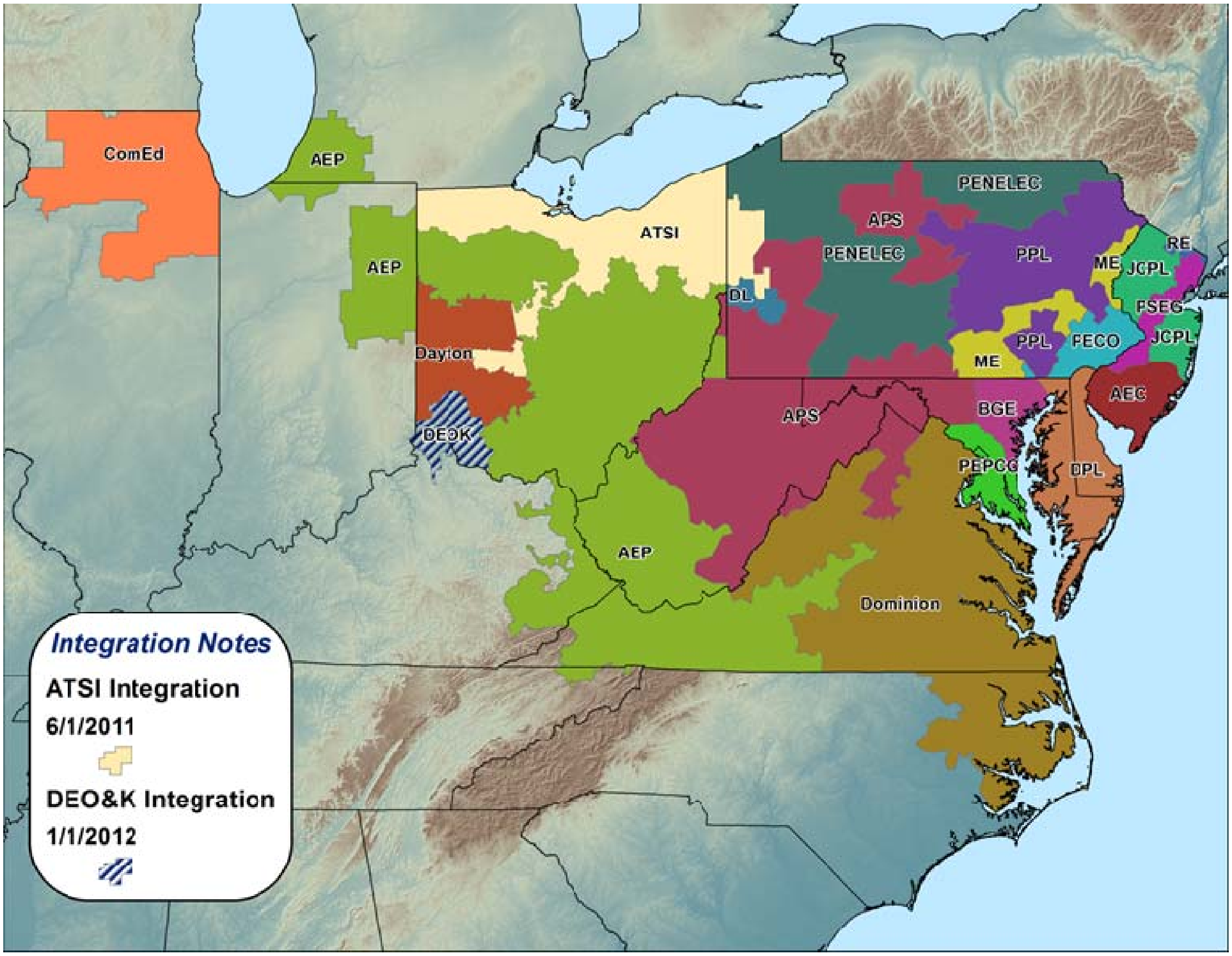
A downward revision to the near-term economic outlook for both the United States and PJM Area resulted in lower peak and energy forecasts in the 2012 load forecast compared to the 2011 load forecast. This is tied to revised assumptions regarding the timing of the recovery of the U.S. economy. While growth in later years accelerates, the historic growth rate will not be restored until past the assessment period.

This year's forecast reflects PJM's adoption of an independent consultant's recommendation to replace the load model's previous economic driver (Gross Metropolitan Product) with a variable that incorporates six economic measures (Gross Domestic Product, Gross Metropolitan Product, Real Personal Income, Population, Households, and Non-Manufacturing Employment). A summary report of economic assumptions used in the 2012 load forecast provided by Moody's Analytics states that:

> *Mid-Atlantic and Virginia Areas are expected to be among the fastest growing in the PJM service territory. Long-term growth in these metro areas will be driven by highly educated labor forces, favorable demographics, productivity growth, and for some Virginia metro areas, plentiful and affordable housing, and relatively low costs. Metro areas in Ohio and Pennsylvania are expected to grow more slowly. Expansion in those states will be more restrained as regions transition away from manufacturing toward more services-oriented economies.*

No footprint changes are included in these calculations. East Kentucky Power Cooperative (EKPC) has announced its intention to join PJM on June 1, 2013. EKPC is a not-for-profit, member-owned cooperative providing wholesale electricity to 16 owner-member distribution cooperatives that serve 520,000 homes, farms, and businesses across 87 of the 120 counties in Kentucky. EKPC owns and operates four major power plants with a total generating capacity of about 3,000 megawatts, as well as approximately 2,800 miles of high-voltage transmission line. Peak load was 2,889 MW. No other entity acquisitions or exits are anticipated. A map of the current PJM footprint is provided on the next page (PJM-Figure 2).

PJM-Figure 2: PJM Footprint



PJM-Table 3: PJM Entities

AEC - Atlantic City Electric	Dayton - Dayton Power and Light	ME - Metropolitan Edison
AEP - American Electric Power Service Corporation	DEOK - Duke Ohio and Kentucky	PECO - PECO Energy Company
APS - Allegheny Power	DL - Duquesne Light Company	PENELEC - Pennsylvania Electric
ATSI - American Transmission Systems Incorporated	Dominion – Virginia Electric Power Company	PEPCO - Potomac Electric Power Company
BGE - Baltimore Gas and Electric	DPL - Delmarva Power and Light	PPL - PPL Electric Utilities
ComEd - Commonwealth Edison Company	JCPL - Jersey Central Power and Light	PSEG - Public Service Electric and Gas

Demand-Side Management

Last year PJM had 11,600 MW of Demand-Side resources available during the summer peak period. PJM expects similar amounts for this year's summer peak period. Because PJM has a shorter history with accepting Demand Response and Energy Efficiency, the forecasts are conservative. Accordingly, Demand Response will remain slightly below was available during the 2011 peak. The Energy Efficiency will increase from 728 MW in 2013 to 804 MW in 2022 (PJM-Table 3).

PJM-Table 4: Projected Demand-Side Management

PJM-Summer	Short-Term 2013	2014	2015	2022	10-Year Change	2022 Share of Total Internal Demand
Direct Control Load Management (DCLM)	1,000	1,000	1,000	1,000	0	0.57%
Contractually Interruptible (Curtailable)	5,000	7,200	7,200	7,200	2,200	4.08%
Critical Peak-Pricing (CPP) with Control	0	0	0	0	0	0.00%
Load as a Capacity Resource	5,000	5,000	5,000	5,000	0	2.83%
TOTAL LOAD-MODIFYING DEMAND RESPONSE	11,000	13,200	13,200	13,200	2,200	7.48%
TOTAL ENERGY EFFICIENCY	728	804	804	804	76	0.46%
TOTAL DEMAND-SIDE MANAGEMENT	**11,728**	**14,004**	**14,004**	**14,004**	**2,276**	**7.94%**

Demand-Side resources accepted through the Forward Capacity Market are DSM that is dispatched like generator resources and is treated as such. The more typical type of Demand-Side resource is the kind that is retained for use by the PJM operators during capacity emergencies, and it reduces load.

Energy Efficiency programs are included in the 2013–2022 load forecasts with approval for use in the PJM Reliability Pricing Model (RPM). Energy Efficiency is included as a capacity resource in the RPM Market but is limited to a maximum of four years. The Energy Efficiency then becomes part of the load forecast. Measurement and verification of Energy Efficiency programs are governed by rules specified in PJM Manual 18B.[241] To demonstrate the value of an Energy Efficiency resource, resource providers must comply with the measurement and verification standards defined in this manual by establishing Measurement and Verification (M&V) plans, providing post-installation M&V reports, and undergoing an M&V audit.

There are some minor concerns related to the amount of information available to PJM, which can be used to determine the amount of DR to dispatch during emergency conditions. PJM has filed tariff changes with FERC that will require more robust reporting of the DR operational capability in real time for Curtailment Service Providers. PJM does not have a reliability concern, but the additional information will help avoid the dispatch of DR that may not be necessary to meet the need of the emergency conditions. PJM has addressed the issue of availability by creating three different DR products: Limited DR (10 days for six hours per day), Extended Summer DR (unlimited days during summers for 10 hours per day) and Annual DR (unlimited days for 10 hours per day), and requiring the necessary amount of annual capacity (DR or generation) to fulfill the PJM reliability requirements. DSM used for reserves is limited by the RFC standard BAL-002-RFC-02 to 25 percent of the 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.

Generation

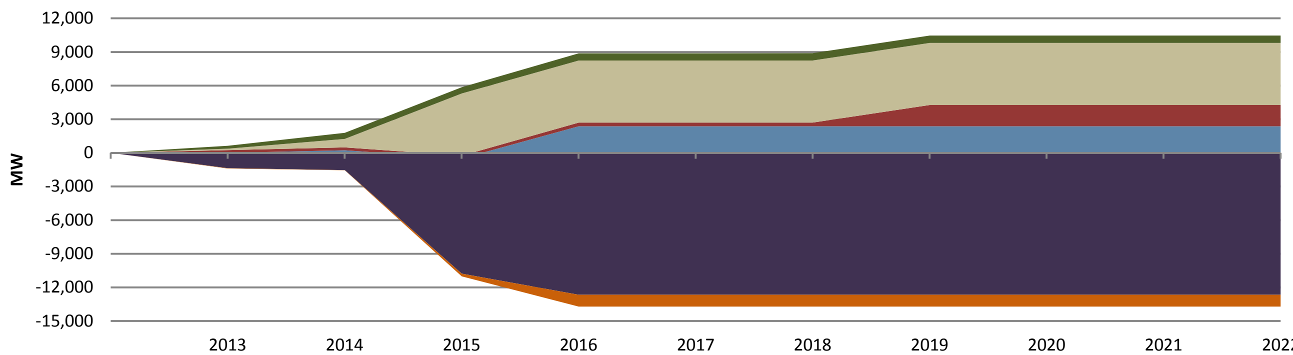
The predominant source of fuel in PJM is coal at approximately 42 percent. Next is natural gas at 26 percent and nuclear at 18 percent. Since the 2011 assessment, along with the DOEK generation, PJM added 1,608 MW of natural gas generation, 117 MW of existing nuclear generation uprates are included, and 280 MW of nameplate wind generation with 42 MW counted as Existing-Certain. In addition, 70 MW of nameplate solar generation with 27 MW counted as Existing-Certain (PJM-Table 6, PJM-Figure 3, and PJM-Table 7). No capacity resource changes are expected though the summer of 2012. All capacity changes in PJM occur only on June 1 of each year (PJM-Table 5 and PJM-Figure 4).

[241] http://www.pjm.com/~/media/documents/manuals/m18b.ashx.

PJM-Table 5: Capacity Outlook[242]

PJM-Summer	Current Capacity	Current Share	2022 Planned Capacity	2022 Planned Share	2022 Planned Change	2022 Planned & Conceptual Capacity	2022 Planned & Conceptual Share	2022 Planned & Conceptual Change
Coal	78,105	42.1%	65,455	35.9%	-12,650	67,310	28.9%	-10,795
Petroleum	11,739	6.3%	10,683	5.9%	-1,056	10,688	4.6%	-1,051
Gas	52,395	28.3%	54,763	30.1%	2,368	92,554	39.8%	40,160
Nuclear	33,666	18.2%	35,566	19.5%	1,900	38,427	16.5%	4,761
Other/Unknown	0	0.0%	5,542	3.0%	5,542	5,916	2.5%	5,916
Renewables	9,519	5.1%	10,173	5.6%	654	17,857	7.7%	8,338
TOTAL	**185,424**	**100.0%**	**182,182**	**100.0%**	**-3,242**	**232,752**	**100.0%**	**47,329**

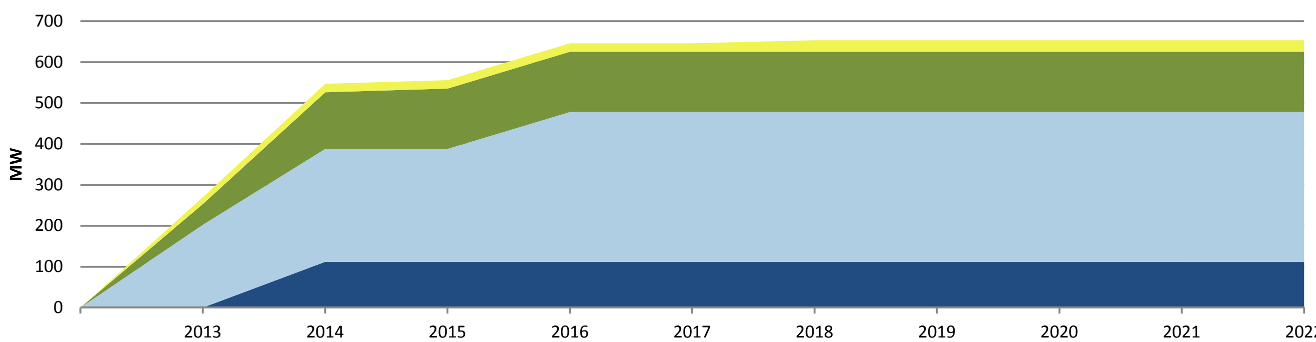
PJM-Figure 3: Summer Net Capacity Change



PJM-Table 6: Renewable Capacity Outlook[243]

PJM-Summer	Current Capacity	Current Share	2022 Planned Capacity	2022 Planned Share	2022 Planned Change	2022 Planned & Conceptual Capacity	2022 Planned & Conceptual Share	2022 Planned & Conceptual Change
Hydro	2,677	28.1%	2,789	27.4%	112	2,989	16.7%	312
Pumped Storage	5,145	54.0%	5,145	50.6%	0	5,145	28.8%	0
Geothermal	0	0.0%	0	0.0%	0	0	0.0%	0
Wind	711	7.5%	1,078	10.6%	366	6,936	38.8%	6,225
Biomass	943	9.9%	1,090	10.7%	147	1,438	8.1%	494
Solar	42	0.4%	71	0.7%	28	1,349	7.6%	1,306
TOTAL	**9,519**	**100.0%**	**10,173**	**100.0%**	**654**	**17,857**	**100.0%**	**8,338**

PJM-Figure 4: Summer Net Renewable Capacity Change



[242] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.
[243] *Ibid*.

PJM-Table 7: Renewable Capacity Outlook: On-Peak Vs. Installed

	Current				2022 Planned			
PJM-Summer	Wind	Solar	Hydro	Biomass	Wind	Solar	Hydro	Biomass
Installed Capacity	5,472	106	2,677	943	7,391	175	2,789	1,090
On-Peak Derate	4,761	64	0	0	6,313	104	0	0
EXPECTED ON-PEAK OUTPUT	711	42	2,677	943	1,078	71	2,789	1,090

PJM had a total increase of 5,007 MW since last summer almost completely due to the addition of DEOK generation. Generation additions and retirements in the rest of PJM almost netted out. A new natural gas combined-cycle unit at Dresden was added at 545 MW. Kearny natural gas units 13 and 14 were added for 267 MW. A new natural gas combined-cycle unit named Virginia City was added in AEP for 585 MW.

Martins Creek 4 oil unit was uprated 70 MW in PPL. Susquehanna nuclear units 1 and 2 in PPL were uprated 45 MW each. A net of 568 MW of uprates and derates also occurred.

Benning 15 and 16, totaling 548 MW of oil generation, were retired in the Baltimore Gas and Electric (BGE) footprint. Gorsuch units 1–4, totaling 189 MW of coal generation, were retired in AEP. The Buzzard Point East and West oil CTs totaling 210 MW were retired in Pepco. The Hudson 1 natural gas unit at 322 MW was retired in PSE&G. Also in PSE&G the Kearny 10 and 11 natural gas units were retired for a loss of 250 MW. The State Line 3 and 4 units were retired from ComEd, totaling 515 MW.

No units were brought back into service since the last assessment. PJM has no on-going long-term outages of generation. There are no significant project deferrals or cancellations; occasional delays are expected but should not cause any reliability problems. Behind-the-meter generation is not considered as capacity in PJM. It offsets load that is also behind the meter.

The Laurel Mountain Energy Storage Facility consists of eight Smart Grid Stabilization System Lithium Ion battery modules for a total output of 27.4 MW on the same site as the Laurel Mountain Wind Farm located at Laurel Mountain, West Virginia. A two MW (300 kilowatt hours of storage) battery for frequency regulation has been installed on the same property as the Paradise Solar project in Deptford, New Jersey.

PJM uses the maximum generator capability expected capacity on-peak (Existing-Certain). This capability may only be available for a limited period of time, but PJM requires that units be able to produce this amount over the peak hours. PJM requires annual verification of this capability. Variable resources are only counted partially for PJM resource adequacy studies. Both wind and solar initially utilize class average capacity factors, which are 13 percent for wind and 38 percent for solar. Performance over the peak period is tracked, and the class average capacity factor is supplanted with historic information. After three years of operation only historic performance over the peak period is used to determine the individual unit's capacity factor. No enhancements have been made as to how expected on-peak capacity values are calculated for each resource in PJM. PJM does not anticipate any reliability concerns resulting from minimum demand and over generation. Intermittent resources can be required to disconnect. Established procedures address reliability concerns caused by over-generation.

Capacity Transactions

All transactions are Firm for both specific generation and transmission (PJM-Table 8). Firm contacts are mostly long-term, but some are shorter in the one- to three-year time frames. All transactions are assumed to continue through the entire assessment period unless a termination date has been specified. While it is possible that the termination dates could be extended, experience shows that the transaction usually ends on the date contracted. PJM has no reliance on outside assistance for emergency imports. There is no emergency generation needed to be available to meet PJM Reserve Margin Requirement.

PJM-Table 8: Projected Capacity Transactions

PJM-Summer	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Expected Imports	0	0	0	0	0	0	0	0	0	0
Firm Imports	1,453	1,453	1,453	1,453	1,453	1,453	1,453	1,453	1,453	1,453
TOTAL IMPORTS	1,453	1,453	1,453	1,453	1,453	1,453	1,453	1,453	1,453	1,453
Expected Exports	0	0	0	0	0	0	0	0	0	0
Firm Exports	1,236	1,236	1,236	1,236	1,236	1,236	1,236	1,236	1,236	1,236
TOTAL EXPORTS	1,236	1,236	1,236	1,236	1,236	1,236	1,236	1,236	1,236	1,236
TOTAL NET CAPACITY TRANSACTIONS	**217**	**217**	**217**	**217**	**217**	**217**	**217**	**217**	**217**	**217**

Transmission

Today, as part of its ongoing RTO responsibilities, PJM's Regional Transmission Expansion Plan (RTEP) protocol comprises a process that considers the aggregate effects of many system trends: long-term growth in electricity use, generating plant retirements, broader generation development patterns—including the evolution of renewable resources—as well as Demand-Side response (DSR) programs and Energy Efficiency (EE) programs. A summary of expected and existing transmission additions is included below (PJM-Table 9).

PJM-Table 9: Existing and Projected Transmission

PJM	AC (Circuit Miles)	DC (Circuit Miles)	Total (Circuit Miles)
EXISTING	51,583	66	51,649
Currently Under Construction	118	0	118
Planned - Completed within First Five Years	709	0	709
Planned - Completed within Second Five Years	1,267	0	1,267
2022 TOTAL (UNDER CONSTRUCTION & PLANNED)	53,677	66	53,743
Conceptual - Completed within First Five Years	131	0	131
Conceptual - Completed within Second Five Years	134	0	134
2022 TOTAL (UNDER CONSTRUCTION, PLANNED & CONCEPTUAL)	**53,942**	**66**	**54,008**

This process culminates in one recommended plan (one RTEP) for the entire PJM footprint that is submitted to PJM's independent Board of Managers (PJM Board) for consideration and approval. Under contractual agreement, the PJM Board's approval then obligates transmission-owning utilities in PJM to build the facilities specified in the RTEP. This includes construction of new transmission lines and other facilities as well as upgrades to existing transmission assets.

The RTO Perspective

PJM operates and plans the transmission system region-wide, as a whole, ignoring corporate and state boundaries when taking operational action or making planning decisions. By planning for future reliability needs on a region-wide rather than a utility-by-utility or state-by-state basis, PJM's RTEP process helps focus on transmission upgrades that meet Reliability Criteria and increase economic efficiency more effectively. PJM's existing RTEP Protocol[244] has been applied by PJM so as to evaluate reliability and market efficiency driving transmission expansion plans today using bright line triggers.

Baseline Reliability Upgrades

PJM's baseline reliability assessments identify areas where the electric power system, forecast over a specific time, would not be in compliance with NERC Reliability Standards. These baseline assessments lead to recommendations for enhancement plans, referred to as baseline transmission network upgrades, to ensure compliance with those standards. Fundamentally, the construction of baseline transmission upgrades is required to ensure that the PJM system remains in compliance with NERC Reliability Standards. This baseline then serves as the basis for the analysis of subsequent requests for transmission service and interconnection.

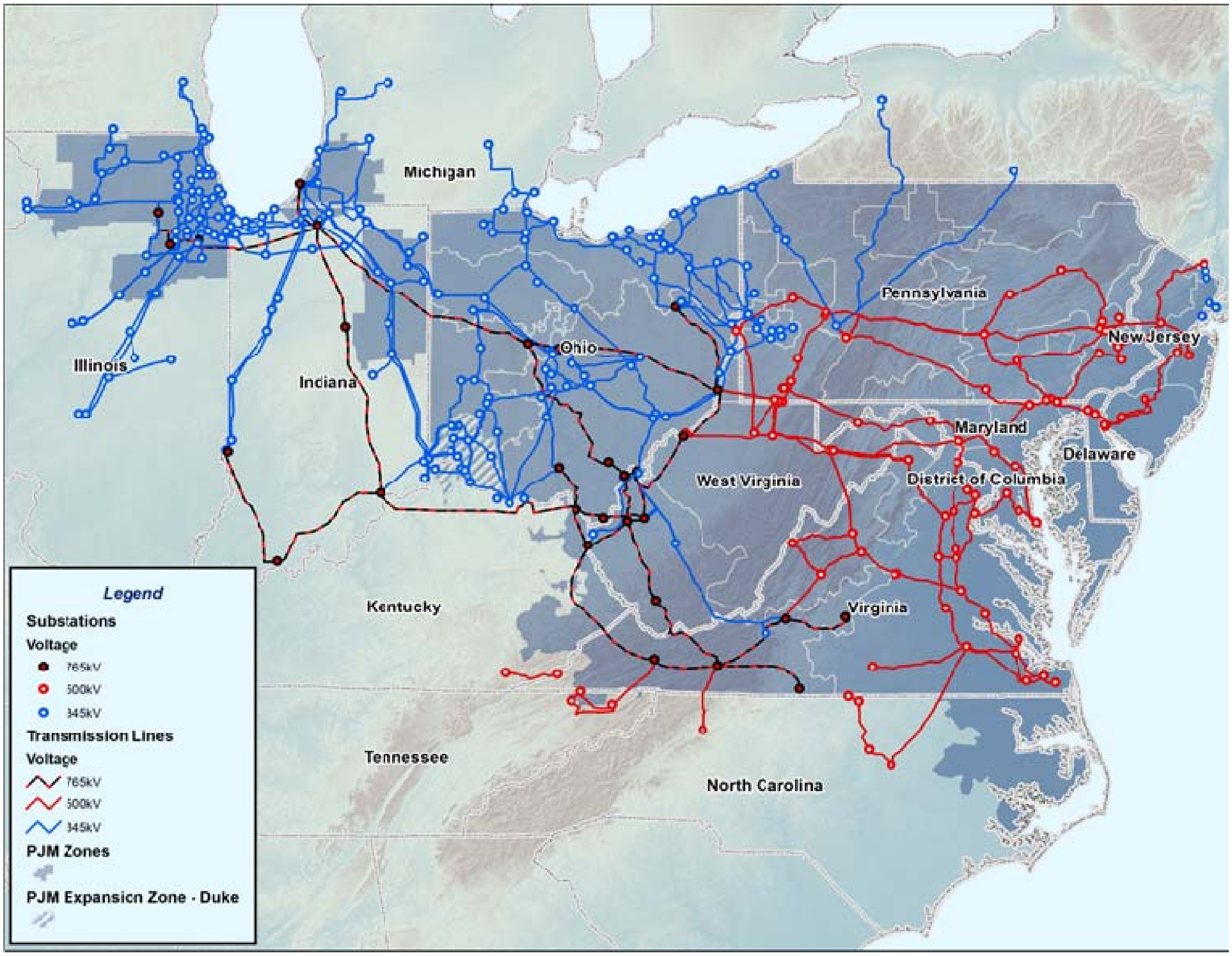
Scope of Upgrades Discussed

In 2011 alone, the PJM Board approved approximately 400 individual Bulk Electric System (BES) upgrades. However, to put reasonable parameters around the scope and length of this report, the upgrades discussed here are generally those whose

[244] As codified in Schedule 6 of PJM's Operating Agreement (http://www.pjm.com/documents/~/media/documents/agreements/oa.ashx) and described in detail in the PJM manuals (http://www.pjm.com/documents/manuals.aspx).

costs exceed $5 million. A complete list of all approved RTEP upgrades, a brief description of facility and driver, and current status can be found on PJM's website.[245] The map on the next page presents major transmission infrastructure in the PJM Assessment Area footprint (PJM-Figure 5).

PJM-Figure56: Existing Backbone Transmission



TrAIL

The 500 kV Trans Allegheny Interstate Line (TrAIL) was placed in service on May 23, 2011, improving reliability into such congested areas as Washington, D.C., Baltimore, and northern Virginia. The TrAIL line was built in three segments, connecting substations in southwestern Pennsylvania, northern West Virginia and northern Virginia as shown on Map 1.3. Built by and jointly owned by Allegheny Energy (now FirstEnergy) and Dominion, the 220-mile TrAIL line was the first high-voltage backbone transmission line approved by the PJM Board through PJM's planning process to enter commercial operation.

MAPP Abeyance

The Mid-Atlantic Power Pathway (MAPP), shown on Map 1.3, was placed in abeyance by the PJM Board on August 18, 2011. PJM 2011 RTEP generator sensitivity analysis indicated that the need for the line has moved out several years, beyond

[245] http://www.pjm.com/planning/ rtep-upgrades-status/construct-status.aspx.

2015, but as early as 2019. The PJM Board has also directed PJM to perform additional sensitivity analyses as part of the 2012 RTEP cycle of analysis—including the impact of May 2012 RPM auction results—to assess the need to further address MAPP abeyance.

Susquehanna–Roseland

In 2007 the PJM Board approved the Susquehanna–Roseland 500 kV line, shown on Map 1.3, to resolve numerous overloads on critical 230 kV circuits across eastern Pennsylvania and northern New Jersey beginning in 2012. PJM's 2008 RTEP Retool validated the required June 1, 2012 in-service date in light of 23 single contingency Reliability Criteria thermal violations and NERC Category C double-circuit tower line contingency thermal violations. PJM's 2009 RTEP Retool analysis for 2012 also included an assessment of the continued need for the Susquehanna–Roseland 500 kV line. Based on the identification of 13 single contingency thermal overloads and 10 double-circuit tower line outage overloads, PJM re-validated the line's June 1, 2012 in-service date.

PJM conducted additional analysis in 2011 to assess the impact of delays to the construction. Originally required to be in service by June 1 2012, regulatory delays have pushed the expected in-service date to June 1, 2015. Updated analysis using the 2011 load forecast confirmed double-circuit tower line (DCTL) violations beginning in summer 2012. The near-term solution is to operate to the DCTL violations in real-time operation and adjust generation and implement Demand-Side Response (DSR) as required to maintain grid reliability. Updated studies also show that Hudson Unit 1, previously designated as a reliability-must-run unit, is not required to maintain reliability and will be released.

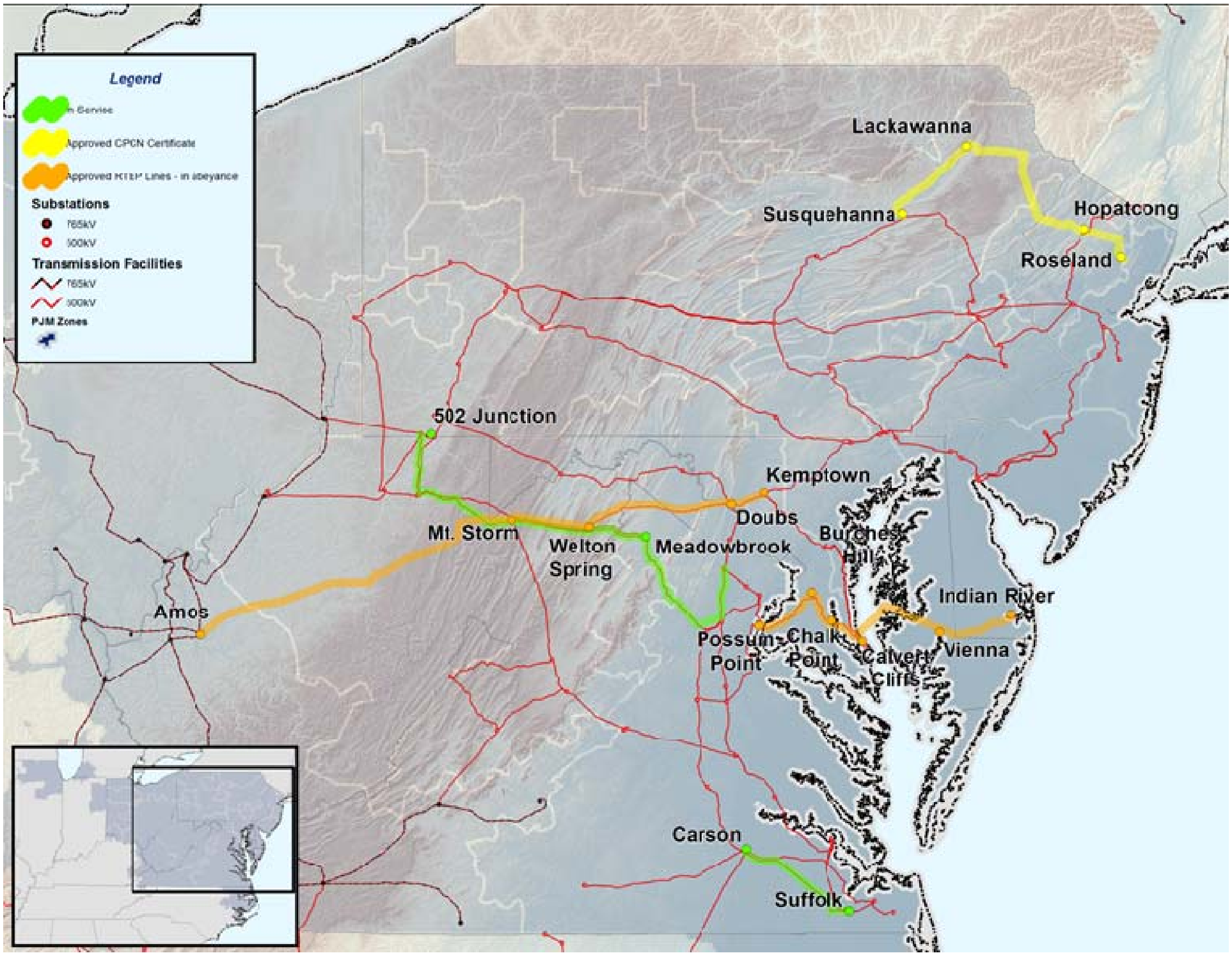
PATH Abeyance

Analysis performed during the 2010 RTEP cycle required an in-service date of June 1, 2015 for the PATH Line as shown on Map 1.3. The PJM Board issued a statement on February 28, 2011, suspending the PATH line.

PJM staff performed an updated analysis based on the 2011 RTEP assumptions that included generation deliverability and load. Additional analysis performed on a 2017 study year case with 2011 RTEP assumptions examined the impact on the PATH abeyance from Warren Generation, Global Insights load forecast, RPS, at-risk generation and state DSR/EE goals. The 2011 RTEP analysis suggests that the need for the PATH line has moved several years beyond 2015. Based on these analyses the PJM Board decided to continue to hold the project in abeyance and requested that the Transmission Owners suspend development activities. Furthermore, the PJM Board has directed staff to perform additional analysis using the 2012 RTEP assumptions and incorporating May RPM base residual auction results.

The map on the next page presents transmission upgrades that were underway in early 2012 (PJM-Figure 6).

PJM-Figure 6: Significant Transmission Upgrades



PJM evaluates transmission congestion continuously. When congestion costs become uneconomical related to the cost of transmission construction, transmission enhancement is considered. The PJM Board has the final say on whether a project is developed to mitigate congestion charges. PJM has a number of projects to tap lines for generation interconnection or for load serving. See the map of PJM above to see where significant transmission is being added. There are no interconnection-related projects or issues in PJM. There are no project delays or temporary service outages for transmission facilities (lines or transformers) that will impact reliability during the assessment period. The potential reliability impact of not meeting target in-service dates for projects is under constant review to identify alternate plans or mitigating operational actions that should be taken in the event of project delays. Available mitigating measures include re-dispatch of generation, operating procedures, and temporary Special Protection Schemes.

In PJM, generation-seeking capacity revenue must expand the transmission system so as to enable their deliverability to the PJM system. Therefore, sufficient transmission will exist for any new capacity project in PJM.

Static Var Compensators (SVC) to be Installed:

- Frost Bridge 138 kV; FirstEnergy (AP); 70 Mvar; 6/1/12
- Meadowbrook 500 kV; Primary Power; 600 Mvar; 6/1/14
- Mt. Storm 500 kV; Primary Power; 250 Mvar; 6/1/14
- Hunterstown 500 kV; FirstEnergy (ME); 500 Mvar; 6/1/14

- Altoona 230 kV; FirstEnergy (ME); 250 Mvar; 6/1/14

Fast Switching Capacitors

- Mansfield 345 kV; FirstEnergy (PN); 100 Mvar; 6/1/14
- Jack's Mountain 500 kV; FirstEnergy (PN); 100 Mvar; 6/1/17
- Jack's Mountain 500 kV; FirstEnergy (PN); 500 Mvar; 6/1/17

HVdc

- Bergen 230 kV (PSE&G-NJ)–49th Street 345 kV (ConEd–NY) 670 MW; 6/1/13

Vulnerability Assessment

PJM has very little hydro generation, and reservoir levels are adequate. PJM expects no problems with warm cooling water. Any one specific generator outage, even if it is long-term, can be replaced with other resources available within PJM.

Significant development of wind, solar, and biomass has already occurred in PJM. Much of this development is in response to existing Renewable Portfolio Standards (RPS). The challenges of integrating this variable generation will grow as more and more generation of this type is added. Demand-Side resources are not of significant size to be of great concern for unresponsiveness. Penalties exist to make unresponsiveness financially unattractive. Distributed generation has been increasing in PJM, especially solar installations, which are mostly connected to lower voltage lines. No special operating procedures are required. PJM has developed a Wind Power Forecast tool and visualization to assist operations.

No additional Under-Voltage Load Shedding (UVLS) schemes are planned. No new Special Protection Systems are planned. PJM does not include planning for catastrophic/high-impact, low-frequency (HILF) events.

Significant smart grid programs include:

- Synchrophasor data may be integrated into operational, planning, and study tools by 2022, and it is anticipated the data will be used in real-time operational decision making.
- PJM's transmission system will include FACTS devices, SVCs, Statcoms, and other technologies that will enable inverter-based generation to reliably connect to the system.
- Dynamic line ratings.
- In addition to renewable integration, PJM anticipates seeing more energy storage deployed across the grid in the form of batteries, thermal storage, flywheels, and perhaps even compressed air. It is possible some of these technologies will also be treated as transmission assets to help defer line upgrades.
- Automated Voltage Control (AVC) that will optimize the voltage schedule across the PJM footprint.
- Some form of automated/optimized restoration tool.
- On-line transient stability analysis tool that also recommends preventative control actions to operators.

Smart grid devices that may enhance reliability include synchrophasor implementation, which can help with better modeling and better real-time awareness of what's happening in the system and how the health of the system is trending. In addition, PJM's advanced technology pilot programs give PJM the opportunity to better understand the upcoming technologies, such as aggregated Demand Response and electric vehicle charging, along with their benefits and their challenges. PJM will have better insight into ways to optimize all the assets on the system.

Smart grid applications that may have a reliability concern include:

- It will take time to be comfortable with synchrophasor data and what it means. Great care and testing and analysis need to be taken while operators are still getting familiar with what the synchrophasor data means.
- The paradigm switch of load following generation and the need for load shaping, where possible (e.g., smart charging), and shifting, also better load forecasting and modeling.

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

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 the short-term impact and long-term projections through 2018. PJM is communicating with interconnected Transmission Owners, as required, to address local reliability issues, and is also communicating with 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 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 reliably take retiring units out of service. Generation Owners have indicated that while 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.

Standing and Emerging Reliability Issues

Retirement of capacity because of the environmental regulations and diminishing amounts of blackstart resources.

Retirement of Generation

The concern about generator retirements due to stricter environmental regulations is a standing issue that has previously been investigated by the NERC Reliability Assessment Subcommittee.

Because of the way that PJM plans their resources for the three-year-in-advance period, it is not likely to be an issue in the near term but may become an issue if interconnection of new resources does not match the retirement of existing resources. Drivers are the new, stricter environmental regulations. While some Generator Owners wait to see how quickly and strictly these new rules will be enforced, others are more transparent, announcing the future retirements far in advance. PJM RPM requires that units be removed at least three years in advance to avoid severe penalties. Loss of large generating resources can affect PJM's resource adequacy in obvious ways. At this time, loss of resources in the three-year time frame has amounted to approximately 10,000 MW. It is difficult to tell how much will be lost past that time frame. While it isn't thought that PJM would violate its reserve margin requirement, PJM may be operating closer to it. Replacement resources could be in different locations from the locations of retiring units, which could load up the transmission system more.

No changes to the reference case would be needed to model this issue because changes to resources as a result of this issue would happen in the future. Loss of resources would affect the entire PJM system. The method for retiring units in PJM allows for PJM to delay unit retirements if reliability issues exist.[246] See Manual 14d Section 9 – Generator Deactivations. Strict requirements for adherence to the new environmental regulations may cause reserve margins to get close to the required values. Some flexibility to allow for cost-effective replacement of resources is needed. Movement

[246] http://www.pjm.com/~/media/documents/manuals/m14d.ashx.

away from the existing coal fuel supply infrastructure will burden other fuel supplies and supply chains, like the transportation and storage of natural gas.

Loss of Blackstart Resources

The concern about blackstart resource retirements is an emerging issue that has been discussed but not analyzed. The time frame for this issue is today since PJM is already seeing fewer blackstart resources available. PJM establishes a minimum blackstart unit threshold of three units for each restoration zone. Drivers for the blackstart resources going away are maintenance and retrofit costs associated with keeping some of the older blackstart resources running. Other cost increases include retrofitting to comply with the new environmental regulations and, though significantly diminished, the cost associated with CIP compliance. Many blackstart unit owners also complain that the reimbursed costs received from PJM are not adequate.

Loss of blackstart resources will not affect reserve margins significantly. Blackstart resources are usually small units that contribute little to installed capacity. While not directly affecting reliability in PJM, loss of blackstart resources would lengthen a blackout. Transmission adequacy would not be affected by the loss of blackstart resources. Different cranking paths may need to be used, but the amounts of power transferred are small.

No changes to the reference case would be needed to model this issue. Since location of blackstart resources is considered Critical Energy Infrastructure information (CEII), location information will not be disclosed.

A blackstart generator replacement process exists but has proved to be ineffective. See Manual 14d Section 10 “Blackstart Replacement Process.”[247] Since some of the blackstart resource retirements are related to the enforcement of stricter environmental regulations, strict adherence to those regulations and their time frames can exacerbate the blackstart availability issue.

[247] http://www.pjm.com/~/media/documents/manuals/m14d.ashx.

SERC-E

Planning Reserve Margins

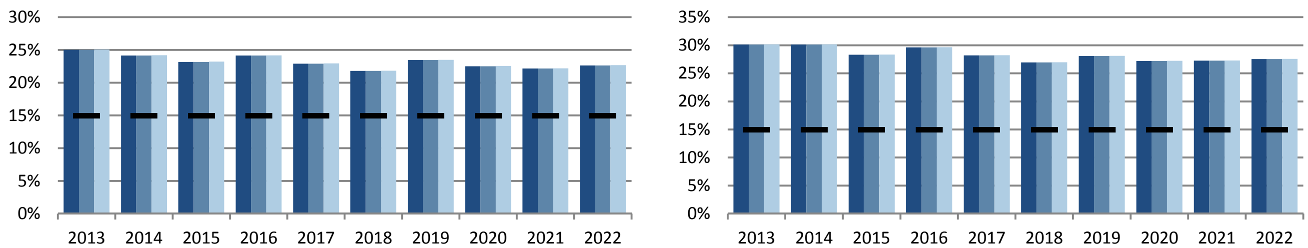
Reserves will provide adequate and reliable power supply throughout this assessment period. All Planning Reserve Margins are projected to remain above the NERC Reference Margin Level from 2013–2022 (SERC-E-Table 1 and SERC-E-Figure 1).

SERC-E-Table 1: Planning Reserve Margins

SERC-E-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		25.03%	24.16%	23.18%	24.15%	22.91%	21.80%	23.45%	22.52%	22.16%	22.64%
PROSPECTIVE		25.03%	24.16%	23.18%	24.15%	22.91%	21.80%	23.45%	22.52%	22.16%	22.64%
ADJUSTED POTENTIAL		25.07%	24.19%	23.21%	24.18%	22.94%	21.84%	23.48%	22.55%	22.19%	22.67%
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		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		30.14%	30.14%	28.32%	29.63%	28.20%	26.95%	28.09%	27.19%	27.25%	27.53%
PROSPECTIVE		30.14%	30.14%	28.32%	29.63%	28.20%	26.95%	28.09%	27.19%	27.25%	27.53%
ADJUSTED POTENTIAL		30.17%	30.18%	28.35%	29.66%	28.23%	26.98%	28.12%	27.22%	27.28%	27.56%
NERC REFERENCE	-	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**

SERC-E-Figure 1: Summer (Left) and Winter[248] (Right) Planning Reserve Margins



SERC does not require specific Reserve Margin criteria or "targets" for SERC-E. Therefore, NERC applies the 15 percent Reference Margin Level throughout the assessment period. SERC utilities in North Carolina include renewables in their portfolios to meet the requirements of the Renewable Energy and Energy Efficiency Portfolio Standard (REPS). Under this standard, investor-owned utilities in North Carolina will be required to meet up to 12.5 percent of their energy needs through renewable energy resources or Energy Efficiency measures by 2021. Rural electric cooperatives and municipal electric suppliers are subject to a 10 percent REPS requirement.[249] Variable resources are assessed for their availability to meet the needs of customers reliably and economically, based on the requirements of the standard and maintaining flexibility in making long-term resource decisions. Reporting results show that utilities are planning for reserves in the range of 12 to 15 percent for the upcoming period.

No operational problems are anticipated that would detract from these projections. For the forecast and any extreme peaks, Reserve Margins are such that loss of multiple units can be accommodated without threatening reliability. The VACAR reserve sharing agreement[250] is also available to support recovery from such extreme events. Beyond these measures, transmission Reserve Margins can also be utilized to secure market purchases to maintain reliability. As stated in annual integrated resource plan filings with the North Carolina Utilities Commission (NCUC), various entities are evaluating a wide range of factors in order to ensure reliable and cost-effective service to customers. Over the next 10 years, entities will be evaluating numerous factors, such as new environmental requirements, renewable energy, new generation technologies and rising commodity costs.

[248] Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.
[249] http://www.ncuc.commerce.state.nc.us/reps/reps.htm
[250] The VACAR-South Reliability Coordinator area includes portions of two southeastern states (North Carolina and South Carolina). There are five Balancing Authorities in SERC-E; Alcoa Power Generating, Inc. – Yadkin Division, Duke Energy Carolinas, Progress Energy Carolinas, South Carolina Electric & Gas Company, and South Carolina Public Service Authority.

Demand

Entities are projecting reductions in demand growth rates when compared to forecasts a year earlier. The compound annual growth rate (CAGR) for Total Internal Demand is projected to be 1.2 percent, slightly lower than last year's 10-year forecast (SERC-E-Table 2). Most entities are not expecting significant change in growth. However, differences are accounted for through lower load projections. Entities in the area have experienced a shift in load-serving responsibilities among entities in the area due to contractual agreements scheduled between 2013 and 2019.

SERC-E-Table 2: Demand Outlook

SERC-E-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	41,805	46,386	4,581	11.0%	1.16%
Load-Modifying Demand Response	1,928	2,311	383	19.9%	2.03%
TOTAL INTERNAL DEMAND	**43,733**	**48,697**	**4,964**	**11.4%**	**1.20%**

SERC-E-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	42,042	46,730	4,688	11.2%	1.18%
Load-Modifying Demand Response	1,540	1,665	125	8.1%	0.87%
TOTAL INTERNAL DEMAND	**43,582**	**48,395**	**4,813**	**11.0%**	**1.17%**

Some entities in the reporting area are currently assessing their forecasting models for the most recent regional and local economic projections. This information will come from vendors such as Economy.com and IHS Global Insight. Weather projections were taken from various sources, such as the National Oceanic and Atmospheric Administration (NOAA), or individual company databases. Projections in this reporting area are expected to be normal. However, energy sales projections, which serve as a primary driver of the load forecast for some entities, are lower based on revised economic growth assumptions. No other significant changes or enhancements were reported for this year's forecasting methods.

Demand-Side Management

Demand Response and Energy Efficiency is projected to be 1,928 MW and 581 MW respectively for the 2013 reporting period.

Approximately 2,310 MW of Demand Response and 299 MW of Energy Efficiency are projected to be available on-peak by 2022. These programs are used to reduce the effects of period peaks and are considered part of the utilities' resource planning. Demand Response is projected to account for 4.40 and 4.75 percent of Total Internal Demand in 2013 and 2022, respectively. Demand Response is projected to increase to 1,928 MW in 2013. Additionally, Energy Efficiency is projected to account for 0.70 and 2.97 percent of Total Internal Demand for 2013 and 2022, respectively (SERC-E-Table 3). Projections are intended to reduce peak demand on entity systems within the reporting area.

SERC-E-Table 3: Projected Demand-Side Management

	Short-Term					
SERC-E-Summer	2013	2014	2015	2022	10-Year Change	2022 Share of Total Internal Demand
Direct Control Load Management (DCLM)	858	969	1,064	1,201	343	2.47%
Contractually Interruptible (Curtailable)	967	968	981	1,002	35	2.06%
Critical Peak-Pricing (CPP) with Control	14	19	19	19	5	0.04%
Load as a Capacity Resource	89	89	89	89	0	0.18%
TOTAL LOAD-MODIFYING DEMAND RESPONSE	1,928	2,045	2,153	2,311	383	4.75%
TOTAL ENERGY EFFICIENCY	299	375	549	1,444	1,146	2.97%
TOTAL DEMAND-SIDE MANAGEMENT	**2,227**	**2,420**	**2,702**	**3,755**	**1,529**	**7.71%**

Entities continue to assess the effects of newly approved Energy Efficiency programs installed on the system since 2010. However, a variety of existing programs that support Energy Efficiency and Demand Response are also offered to customers in this reporting area. Some of the programs that include current Energy Efficiency and DSM programs are interruptible capacity programs, load control curtailing programs, residential air conditioning direct loads programs, energy products loan programs, standby generator controls programs, residential time-of-use programs, Demand Response programs (interruptible and related rate structures), Power Manager Power Share conservation programs, residential Energy Star rates programs, the Good Cents new home program, the commercial Good Cents program, the thermal storage cooling program, the H20 Advantage water heater program, general service and industrial time-of-use programs, and hourly pricing for incremental load interruptible programs. They are also used to reduce the effects of period peaks and are considered part of the utilities' resource planning. The commitments to these programs are part of a long-term, balanced energy strategy to meet future energy needs. Load response will be measured by trending real-time load data from telemetry and statistical models that identify the difference between the actual consumption and the projected consumption absent the curtailment event. As stated above, entities include renewables in their portfolios to meet the requirements of the REPS of North Carolina.

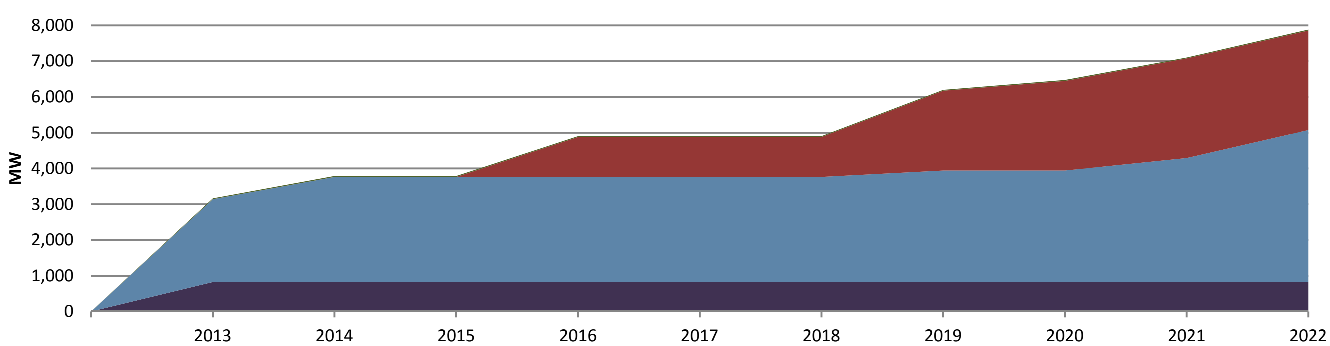
Generation

Companies within the SERC-E reporting area expect to have 48,218 MW of Existing-Certain, 0 MW of Existing-Other, 0 MW of Existing-Inoperable, 3,167 MW of Future-Planned, and 14 MW of Conceptual resources on-peak for 2013. Additionally, 7,888 MW of Future-Planned resources and 14 MW of Conceptual resources are expected to be added in 2013. This capacity is projected to help meet demand during this time period. Coal is the primary source of fuel within this area. Entities have added the 20 MW of Biomass and 5 MW of Solar Existing-Certain resources since the previous long-term reporting period (SERC-E Table 5 and SERC-E Figure 3). However, entities have reported 656 MW of unit retirements since the previous long-term reporting period. Additionally, 1,191 MW of unit retirements have been reported to occur during the 2013 to 2022 period (SERC-E-Table 4 and SERC-E-Figure 2). Internal company discussions of these retirements have included mitigation measures that must be explored and considered as part of any decision to retire existing generating units. This capacity will be offset in part by the addition of 4,251 MW of combined-cycle units by 2022 and 2,234 MW of nuclear generation (1,117 MW in 2016 and 2019).

SERC-E-Table 4: Capacity Outlook[251]

	Current		2022 Planned			2022 Planned & Conceptual		
SERC-E-Summer	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Coal	16,775	34.8%	17,600	31.4%	825	17,600	31.3%	825
Petroleum	1,967	4.1%	1,967	3.5%	0	1,967	3.5%	0
Gas	11,682	24.2%	15,934	28.4%	4,252	15,934	28.4%	4,252
Nuclear	11,456	23.7%	14,242	25.4%	2,786	14,242	25.4%	2,786
Other/Unknown	107	0.2%	107	0.2%	0	107	0.2%	0
Renewables	6,256	13.0%	6,281	11.2%	25	6,295	11.2%	39
TOTAL	**48,243**	**100.0%**	**56,131**	**100.0%**	**7,888**	**56,145**	**100.0%**	**7,902**

SERC-E-Figure 2: Summer Net Capacity Change



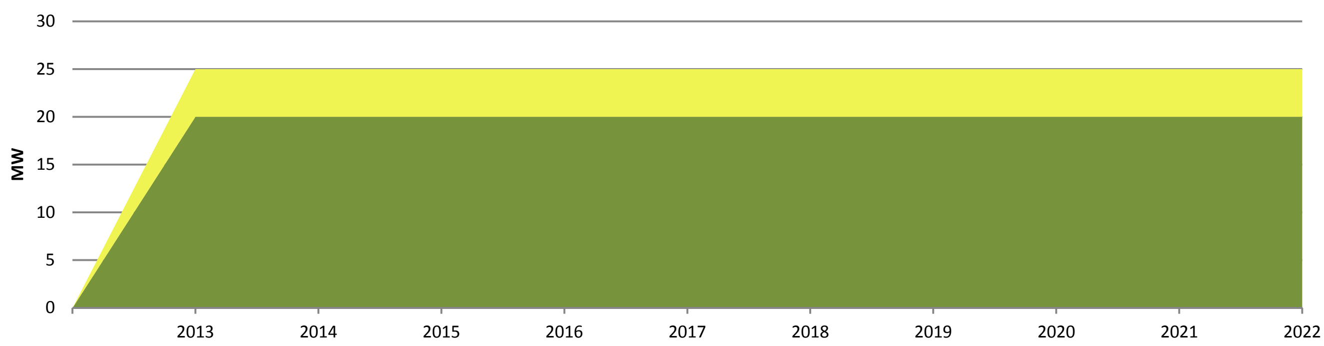
There are no new generator uprates in service, and no generation taken out of service for maintenance during the period. SERC methods of data collection do not identify specific uprates or derates throughout the year. Rather, entities reporting to SERC make changes to unit generation continuously throughout the year. Additionally, there is no behind-the-meter generation reported for the period. However, 387 MW of Other/Unknown resources and 200 MW of capacity from standby generator programs and interruptible services are anticipated during this time.[252]

[251] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.
[252] Includes resources categorized as Existing-Other, which are not included in the above table.

SERC-Table 5: Renewable Capacity Outlook[253]

SERC-E-Summer		Current		2022 Planned			2022 Planned & Conceptual		
		Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Hydro		3,087	49.3%	3,087	49.1%	0	3,087	49.0%	0
Pumped Storage		3,044	48.7%	3,044	48.5%	0	3,044	48.4%	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		97	1.5%	117	1.9%	20	127	2.0%	30
Solar		28	0.5%	33	0.5%	5	37	0.6%	9
TOTAL		**6,256**	**100.0%**	**6,281**	**100.0%**	**25**	**6,295**	**100.0%**	**39**

SERC-Figure 3: Net Renewable Capacity Change



Variable resources are limited within this area and are not commonly planned in peak maximum capacity calculations. However, they are assessed for their availability to meet the needs of customers reliably and economically, based on the requirements of the regulatory standards and their ability to maintain flexibility for long-term resource decisions. These resources may be given a reduced capacity contribution for Reserve Margin based on an estimated hourly energy profile (SERC-Table 6). As required, entities will continue to evaluate these and other renewable resources as part of its integrated resource planning process. In addition, no immediate changes in entity planning procedures are needed. This is due to adding small increments of variable resources yearly to meet the REPS 12.5 percent target by 2021.

SERC-Table 6: Renewable Capacity Outlook: On-Peak Vs. Installed

SERC-E-Summer	Current				2022 Planned			
	Wind	Solar	Hydro	Biomass	Wind	Solar	Hydro	Biomass
Installed Capacity	0	28	3,087	97	0	33	3,087	117
On-Peak Derate	0	0	0	0	0	0	0	0
EXPECTED ON-PEAK OUTPUT	0	28	3,087	97	0	33	3,087	117

Capacity Transactions

Utilities within the SERC-E reporting area expect the capacity imports and exports listed in the table below (SERC-E-Table 7). These transactions have been accounted for in the Reserve Margin calculations for the reporting area. Most of the contracts in the area are agreements for a 10-year period for the winter and summer peaking seasons. These transactions are external and internal to the Region and the reporting area. All purchases are backed by Firm contracts for both generation and transmission and are not considered to be based on partial path reservations. Of the imports/exports shown below, very few are associated with Liquidated Damages Contracts (LDCs), in which the contracts are considered 100 percent "make-whole."

[253] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

SERC-E-Table 7: Projected Capacity Transactions

SERC-E	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Expected Imports	0	0	0	0	0	0	0	0	0	0
Firm Imports	1,003	815	815	715	760	760	850	850	850	850
TOTAL IMPORTS	1,003	815	815	715	760	760	850	850	850	850
Expected Exports	0	0	0	0	0	0	0	0	0	0
Firm Exports	117	167	167	167	167	167	167	167	167	67
TOTAL EXPORTS	117	167	167	167	167	167	167	167	167	67
TOTAL NET CAPACITY TRANSACTIONS	**886**	**648**	**648**	**548**	**593**	**593**	**683**	**683**	**683**	**783**

To meet Reserve Margins during the period, entities within the SERC-E reporting area do not rely on resources outside the Region for emergency imports, reserve sharing, or outside assistance/external resources. Most entities within this area participate in reserve sharing agreements (RSAs) with other VACAR utilities. Collectively, members of the VACAR RSA, under their current agreement, hold 1.5 times the largest single contingency (1,135 MW) in the VACAR RSA Area to meet Reserve Margin targets. The Reserve Sharing Group is expected to have adequate reserves throughout the operating period. Total emergency MW from these imports was not reported but are available as needed.

Transmission

In-service dates for existing transmission projects are not at risk during the reporting period. If delays occur that would result in reliability concerns, mitigating actions would be developed accordingly. Mitigating measures include re-dispatch of generation, operating procedures, and Special Protection Systems. On an ongoing basis, companies review/confirm completion dates and monitor the construction status of all projects. Transmission projects planned to address a potential System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) problem commonly receive the highest priority for resources. A summary of existing and projected transmission additions is included below (SERC-E-Table 8)

SERC-E-Table 8: Existing and Projected Transmission

SERC-E	AC (Circuit Miles)	DC (Circuit Miles)	Total (Circuit Miles)
EXISTING	22,180	0	22,180
Currently Under Construction	33	0	33
Planned - Completed within First Five Years	276	0	276
Planned - Completed within Second Five Years	189	0	189
2022 TOTAL (UNDER CONSTRUCTION & PLANNED)	22,678	0	22,678
Conceptual - Completed within First Five Years	87	0	87
Conceptual - Completed within Second Five Years	189	0	189
2022 TOTAL (UNDER CONSTRUCTION, PLANNED & CONCEPTUAL)	**774**	**0**	**774**

New construction efforts are focused on completing facilities ahead of seasonal peak periods. Close coordination between construction management and operations planning ensures schedule requirements and completion requirements are well-understood. Several large-scale construction projects are planned and will be implemented in phases around seasonal peak load periods to mitigate reliability concerns associated with line clearances and non-routine operating arrangements during higher seasonal load periods. Additionally, no significant transmission facility outages are anticipated to be out of service during the period.

Regional studies are also performed on a routine basis both internally and externally. Coordinated single transfer capability studies with external utilities are performed quarterly by the SERC Near-Term Study Group (NTSG). Projected seasonal import and export capabilities are consistent with those identified in these assessments. Constraints that are external to the SERC subregion are evaluated as part of the SERC East-RFC Seasonal Study Group efforts. No transmission constraints have been identified that are anticipated to significantly impact reliability.

To address the need to maintain and enhance reliability, Progress Energy Corporation (PEC) is currently implementing a special transmission project in response to NERC's recommendation to utilities entitled "Consideration of Actual Field Conditions in Determination of Facility Ratings." The entity is using Light Detection and Ranging, (LiDAR) technology to analyze these conditions. Results from the project are currently being assessed, and the project is scheduled to be completed by the end of 2014. Any concerns that are identified will be mitigated through an immediate remediation strategy.

Other Transmission Operators in the SERC-E reporting area are also subject to the NERC recommendation. None report any negative transmission reliability or adequacy concerns.

Shifts from the use of coal to natural gas as a generation fuel source due to decreasing costs of natural gas have led to non-typical transmission line power loadings. However, none of the Transmission Operators in the SERC-E reporting area report any negative impact on transmission adequacy. Entities will continue to consider new Demand-Side Management tools, SVC technology, and potential applications of smart grid technology.

Vulnerability Assessment

Resource adequacy studies help determine entity Reserve Margins in the reporting area. The study recognizes, among other factors (such as load forecast uncertainty due to economics and weather), generator unavailability, deliverability of resources to load, and the benefit of interconnection with neighboring systems. Uncertainties may also be addressed through capacity margin objectives and practices in other resource assessments at the operational level. These studies may be performed annually using input provided from Generator Operators. As conditions warrant, entities may see the need to perform additional assessments to mitigate challenging conditions on the system. Entities report that historical studies have determined that a minimum Planning Reserve Margin of 12 percent is adequate for reliability. The latest studies have identified that future generation is needed to achieve planning adequate reserves. Entities will account for this in their long-term generation plans. Plans will also account for new environmental requirements, renewable energy, new generation technologies, and rising commodity costs. No other concerns are known at this time, and operational problems are not anticipated for the period.

Additionally, a study was done on the eastern North Carolina coastal area (Jacksonville, Havelock, and Morehead City) that resulted in a long-term project to install a large Static Var Compensator at the Jacksonville 230 kV substation. Similarly, another dynamic study was recently performed in the western area of North Carolina that validated the existing procedure to operate a minimum complement of generators at various load/import levels to ensure adequate dynamic reactive resources are available for this area.

In order to address reliability issues in the future, utilities have considered using Under-Voltage Load Shedding (UVLS) schemes on their system. However, none of these programs are expected to be installed on the system during the time of this assessment. Additionally, there are no Special Protection Systems or Remedial Action Schemes within SERC-E and none planned for the assessment period.

Utilities have addressed planning processes for catastrophic events in many ways. Some companies have procedures in place for system restoration, as well as capacity and emergency action plans. Other companies follow the practice of maintaining several days' worth of fuel oil at facilities in the event of natural gas disruptions. Resource portfolios are also used to address the issue. Portfolios are diversified with multiple resources mitigating the impact of a major import path disruption. Sophisticated internal real-time systems have been developed by the utilities within the reporting area to track and analyze gas pipeline issues. These systems can monitor the impact of disruptions to major pipelines or the loss of a major import path as part of a contingency analysis process. Depending on the advance notice, either operating plans can be adjusted or emergency procedures can be implemented. For the projected summer peaks, Reserve Margins are such that the loss of multiple units can be accommodated without threatening reliability. Purchased power sources utilize Firm transmission and are sufficiently limited in quantity compared to total resources. The VACAR reserve-sharing agreement is also available to support recovery from such extreme events. Beyond these measures, transmission Reserve Margin can also be utilized to secure market purchases to maintain reliability.

The utilities within SERC-E have procedures in place to identify and review misoperations caused by protection systems. When a misoperation occurs on the transmission system, corrective action is implemented to prevent recurrence. If needed, other locations are also reviewed for problems of a similar nature. Misoperations caused by protection systems are reviewed on an annual basis for possible trends.

Currently, utilities in the area are not aware of any environmental or regulatory restrictions that could impact reliability during the reporting period. They will continue to assess system studies and develop generation mitigation plans as needed to account for new environmental requirements.

Standing and Emerging Reliability Issues

To minimize reliability concerns on the system, entities regularly study and review annual and seasonal assessments. These assessments serve to develop a seasonal strategy for maintaining adequate system operating performance. Entities are also active participants within the SERC NTSG, which regularly performs annual reliability studies for summer and winter peak conditions, as well as quarterly OASIS studies for summer, fall, winter, and spring conditions. Transmission maintenance schedules are carefully reviewed and evaluated to address reliability concerns, and to permit as much prioritized maintenance as can be accommodated prior to seasonal peak periods. Likewise, new construction efforts are focused on completing facilities ahead of seasonal peak periods. Annual planning activities continue to address both near- and long-term facility needs.

Overall, there are no known or projected significant conditions or generator outages that would reduce capacity in the area. Entities in the SERC-E reporting area are not aware of any near-term environmental or regulatory restrictions that could impact reliability and continue to assess the potential reliability effects of pending future environmental regulations.

The utilities in the SERC-E Area have identified an emerging issue in regard to Fault Induced Delayed Voltage Recovery (FIDVR), which is the phenomenon whereby system voltage remains at significantly reduced levels for several seconds after a transmission, sub-transmission, or distribution fault has been cleared. Significant load loss due to motor protective device action can result, as can significant loss of generation, with a potential secondary effect of high system voltage due to load loss. If the BES voltage does not recover to 90 percent of the pre-contingency system voltage in a few seconds, the FIDVR can initiate further tripping of load and generation. Longer periods of depressed voltage below such levels can cause damage to customer and electric system equipment.

Planning studies have not been able to foresee FIDVR events very accurately due to an inaccurate modeling of loads. Uncorrected, this modeling deficiency has a two-fold detrimental effect. First, it can result in studies that do not adequately identify potential FIDVR events. Second, it can give false confidence in mitigation plans designed to prevent FIDVR events. Several groups of experts are actively developing better dynamic load models for aggregate induction motor load using results of extensive single-phase air conditioning performance tests and detailing analyses of actual FIDVR events. Although SERC-E has not experienced a significant reliability impact associated with FIDVR, some utilities in SERC-E have already installed SVCs (or plan to) as a mitigating measure for potential FIDVR issues.

SERC-N

Planning Reserve Margins

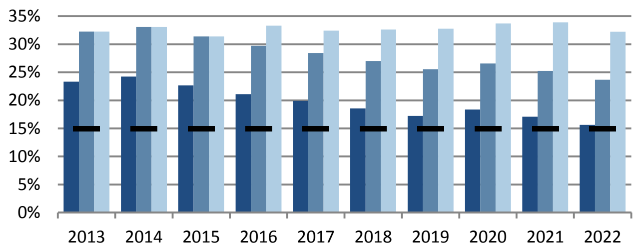
As a result of lower loads in the first few years, coupled with additional capacity, the SERC-N Assessment Area is projecting adequate Anticipated Planning Reserve Margins ranging between 15.63 and 24.23 percent during the assessment period (SERC-N-Table 1 and SERC-N-Figure 1).

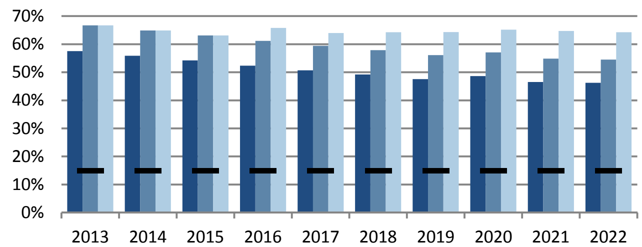
SERC-N-Table 1: Planning Reserve Margins

SERC-N-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		23.31%	24.23%	22.67%	21.09%	19.91%	18.57%	17.21%	18.36%	17.10%	15.63%
PROSPECTIVE		32.26%	33.06%	31.39%	29.70%	28.43%	27.00%	25.54%	26.58%	25.23%	23.66%
ADJUSTED POTENTIAL		32.26%	33.06%	31.39%	33.31%	32.41%	32.61%	32.75%	33.70%	33.89%	32.21%
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		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		57.56%	55.86%	54.21%	52.37%	50.71%	49.23%	47.57%	48.63%	46.52%	46.24%
PROSPECTIVE		66.69%	64.89%	63.14%	61.19%	59.44%	57.88%	56.11%	57.08%	54.85%	54.51%
ADJUSTED POTENTIAL		66.69%	64.89%	63.14%	65.77%	63.97%	64.27%	64.32%	65.20%	64.69%	64.28%
NERC REFERENCE	-	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**

SERC-N-Figure 1: Summer (Left) and Winter[254] (Right) Planning Reserve Margins





SERC does not require specific Reserve Margin criteria or "targets" for SERC-N. Therefore, NERC applies the 15 percent Reference Margin Level throughout the assessment period. Additionally, some individual entity criteria are established based on state public service commissions or their Balancing Authority's criteria, such as most severe single contingency, cost of unserved energy, unit availability, import availability/capability, load forecast, and loss of load probability studies (such as 0.1 day per year). Other utilities report that Planning Reserve Margins are established with the objective of minimizing overall cost of reliability to the customer, while not exposing customers to significant risk. To achieve this goal, planning reserves are calculated on a probabilistic assessment of reliability, which includes uncertainty related to weather, economic growth, unit availability, and transmission capability to determine expected costs at various levels of reliability. Using this analysis, a target level of planning reserves is selected such that the cost of additional reserves plus the cost of reliability events to the customer is minimized. This target (optimal) Reserve Margin is then adjusted to reduce risks and enhance reliability to produce the final level of planning reserves. Entities internally report planning reserves in the range of 12 to 15 percent during the assessment period.

Assessment projections are anticipated to be adequate, assuming typical weather and operating conditions. Given these circumstances, no significant detractions from this forecast are anticipated.

Demand

The Total Internal Demand in SERC-N is projected to grow by approximately 1.44 percent during the 10-year assessment. This growth is slightly higher compared to the 2011 forecast (SERC-N-Table 2).

[254] Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.

SERC-N-Table 2: Demand Outlook

SERC-N-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	43,808	48,778	4,970	11.3%	1.20%
Load-Modifying Demand Response	1,942	3,260	1,318	67.9%	5.92%
TOTAL INTERNAL DEMAND	**45,750**	**52,038**	**6,288**	**13.7%**	**1.44%**

SERC-N-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	43,734	48,256	4,522	10.3%	1.10%
Load-Modifying Demand Response	1,979	3,658	1,679	84.8%	7.06%
TOTAL INTERNAL DEMAND	**45,713**	**51,914**	**6,201**	**13.6%**	**1.42%**

Increases are believed to be primarily due to a perception of improved economic outlook. However, continuing low economic forecasts and growing levels of Demand Response and Energy Efficiency programs are expected to limit demand growth in the coming years. Assumptions have been adjusted for normal weather and current economic conditions for both the United States and regional economies. Since the start of the economic recession, some entities have significantly adjusted their long-term models and revised their near-term hourly forecast models.

Demand-Side Management

Demand Response and Energy Efficiency are projected to be 1,942 MW and 149 MW, respectively, available on-peak for the 2013 reporting period, increasing to approximately 3,260 MW of Demand Response and 516 MW of Energy Efficiency by 2022 (SERC-N-Table 3). The Demand Response and Energy Efficiency average annual growth rates for the 2013–2022 reporting period are 7.5 percent and 27.4 percent respectively. Demand Response programs allow entities within the reporting area to reduce demand and control voltage as needed for reliability purposes, mainly during summer peaks. Demand Response is projected to account for 4.2 percent of Total Internal Demand in 2013, a substantial increase from 0.3 percent in 2011. Presently the primary source of Demand Response in the area is the direct load control (DLC) program and the interruptible product portfolio. DLC includes a program with interruptible load contracted to a third party and verified by the utility. Program participants have contractually agreed to reduce their loads within minutes of a request. Estimates used in operational planning take into account the amount of load available and not the sum of total load under contract. Other Demand Response products utilize control devices on air conditioning units and water heaters in residences. Entities are planning for increased demand reductions from the following in the upcoming years: interruptible demand and load control capabilities, distributor-operated voltage regulation programs, Demand Response pricing products, and two-way direct load control.

SERC-N-Table 3: Projected Demand-Side Management

	Short-Term					
SERC-N-Summer	2013	2014	2015	2022	10-Year Change	2022 Share of Total Internal Demand
Direct Control Load Management (DCLM)	194	204	221	137	-57	0.26%
Contractually Interruptible (Curtailable)	992	1,000	1,003	1,003	11	1.93%
Critical Peak-Pricing (CPP) with Control	0	0	0	0	0	0.00%
Load as a Capacity Resource	756	951	1,127	2,120	1,364	4.07%
TOTAL LOAD-MODIFYING DEMAND RESPONSE	1,942	2,155	2,351	3,260	1,318	6.26%
TOTAL ENERGY EFFICIENCY	149	199	243	516	367	0.99%
TOTAL DEMAND-SIDE MANAGEMENT	**2,091**	**2,354**	**2,594**	**3,776**	**1,685**	**7.26%**

New Energy Efficiency is projected to be 0.3 percent of Total Internal Demand during 2013 and increase to 1.0 percent by 2022. Programs such as customer cost-saving energy surveys and audit evaluations, customer education, responsive pricing, residential/commercial conservation, electric thermal storage incentives, new construction (heat pump and geothermal), energy efficient homes, air-source heat-pumps (replacing older resistance heat), low-income weatherization, low-income assistance, HVAC system improvements, industrial compressed-air systems, and various advanced lighting and third-party verification/measurement groups are currently in operation within the area for residential and commercial customers. Commercial/industrial/direct-served industry consumers have programs for efficiency improvements in HVAC, lighting, motors and controls, and other electrical-intensive equipment. Entities in the area are predicting an additional 1,400 MW of controllable Demand Response reductions by the end of 2012.

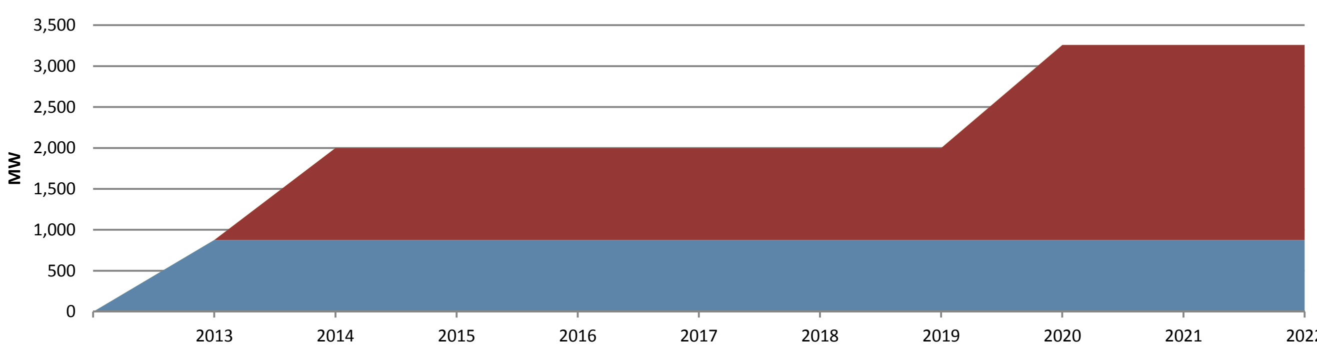
Generation

Companies within SERC-N expect to have 53,084 MW of Existing-Certain, 3,919 MW of Existing-Other, 0 MW of Existing-Inoperable, 878 MW of net Future-Planned resources including retirements, and 0 MW of Conceptual resources on-peak for 2013. Net Future-Planned resources of 3,260 MW and Conceptual resources of 4,170 MW are expected to be added by 2022. Coal is the primary source of fuel within this area. There are no new Existing-Certain Resource additions since the prior season. For 2012, 71 MW is planned to be on inactive reserve, 412 MW is scheduled to be on 8 weeks of planned maintenance beginning the first week of September, 167 MW is scheduled to be on planned maintenance for the last week of September, and 352 MW will be retired. A total of 3,021 MW of retirements have been announced for the 2013–2022 reporting period. In accordance with an EPA settlement, four units (approximately 480 MW) are scheduled to idle in the spring of 2012[255] and retire by the end of 2015; six units (111 MW each) will be out of service by August 1, 2015; 2,078 MW will be retired in 2016, and 938 MW will be retired in 2019 (SERC-N-Table 4, SERC-N-Figure 2, and SERC-N-Table 5). The ability for utilities to reliably meet demand is not expected to be impacted by these planned retirements. Scenario planning studies are routinely done to assess the impact on system reliability and adequacy for possible unit retirements during the planning window. The results of those studies are used in the annual planning process and as input to the ongoing development of generating fleet strategic plans. Planning actions in response to the retirements include consideration of additional resource needs in Integrated Resource Plans, reinforcement of the transmission system including uprating a number of lines, and evaluation of needs for static and dynamic var support, such as for major cities with high concentrations of air conditioning load.

SERC-N-Table 4: Capacity Outlook[256]

	Current		2022 Planned			2022 Planned & Conceptual		
SERC-N-Summer	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Coal	21,657	40.1%	21,657	37.8%	0	21,657	35.3%	0
Petroleum	111	0.2%	111	0.2%	0	111	0.2%	0
Gas	18,060	33.5%	18,938	33.1%	878	23,108	37.6%	5,048
Nuclear	7,113	13.2%	9,495	16.6%	2,382	9,495	15.5%	2,382
Other/Unknown	0	0.0%	0	0.0%	0	0	0.0%	0
Renewables	7,022	13.0%	7,022	12.3%	0	7,022	11.4%	0
TOTAL	**53,962**	**100.0%**	**57,222**	**100.0%**	**3,260**	**61,392**	**100.0%**	**7,430**

SERC-N-Figure 2: Summer Net Capacity Change



There are 2 MW of new generator uprates scheduled to be in service. However, 20 MW are scheduled to be taken out of service for planned maintenance during the peak demand months of 2012, and 6 MW will be brought back in service yearly for the peak-demand summer months of 2013–2015. As an average over the period, behind-the-meter generation is reported to be 13 MW of Other/Unknown resources.

[255] http://www.epa.gov/compliance/resources/cases/civil/caa/tvacoal-fired.html
[256] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

SERC-N-Table 5: Renewable Capacity Outlook[257]

	Current		2022 Planned			2022 Planned & Conceptual		
SERC-N - Summer	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Hydro	5,325	75.8%	5,325	75.8%	0	5,325	75.8%	0
Pumped Storage	1,652	23.5%	1,652	23.5%	0	1,652	23.5%	0
Geothermal	0	0.0%	0	0.0%	0	0	0.0%	0
Wind	28	0.4%	28	0.4%	0	28	0.4%	0
Biomass	17	0.2%	17	0.2%	0	17	0.2%	0
Solar	0	0.0%	0	0.0%	0	0	0.0%	0
TOTAL	**7,022**	**100.0%**	**7,022**	**100.0%**	**0**	**7,022**	**100.0%**	**0**

Variable resources are limited within this area. However, there are some purchases sourced from wind that are included in the transfer amount and a small amount of solar supply that is part of a customer-owned generation buy-back program. The capacity values of wind contracts are usually based on applicable contract terms (SERC-N-Table 6).

SERC-N-Table 6: Renewable Capacity Outlook: On-Peak Vs. Installed

	Current				2022 Planned			
SERC-N-Summer	Wind	Solar	Hydro	Biomass	Wind	Solar	Hydro	Biomass
Installed Capacity	179	0	5,325	17	179	0	5,325	17
On-Peak Derate	152	0	0	0	152	0	0	0
EXPECTED ON-PEAK OUTPUT	28	0	5,325	17	28	0	5,325	17

A typical assumed contribution at the time of the system peak is 12 percent of the nameplate ratings of the associated wind generators (this factor is consistent with the credit applied by RTOs to other wind resources in that same geographical area). The contribution from customer-owned solar resources is based on the solar insolation values for the area at the time of the period peak. Entities will continue to evaluate these and other renewable resources as part of their integrated resource planning processes. No changes in planning procedures are needed for these small increments of variable resources.

Capacity Transactions

Utilities within SERC-N expect the imports and exports listed below for the period. These imports and exports have been accounted for in the Reserve Margin calculations for the reporting area. Most of the contracts in the area are agreements for a 10-year period for the winter and peaking seasons. The majority of these imports/exports are backed by Firm contracts for both generation and transmission, and do not include "make-whole provisions." However, more than half of the imports reported by entities within SERC-N during the peak month are not backed by a Firm contract. Non-Firm contracts are not included in SERC-N Planning Reserve Margins. Total imports and exports will remain constant throughout the assessment period at 1,640 MW and 1,582 MW, respectively (SERC-N-Table 7)

SERC-N-Table 7: Projected Capacity Transactions

SERC-N - Summer	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Expected Imports	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333
Firm Imports	307	307	307	307	307	307	307	307	307	307
TOTAL IMPORTS	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640
Expected Exports	156	156	156	156	156	156	156	156	156	156
Firm Exports	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426
TOTAL EXPORTS	1,582	1,582	1,582	1,582	1,582	1,582	1,582	1,582	1,582	1,582
TOTAL NET CAPACITY TRANSACTIONS	**58**	**58**	**58**	**58**	**58**	**58**	**58**	**58**	**58**	**58**

Contingency reserves and emergency imports are obtained from a variety of resources, such as Midwest ISO (under Attachment RR of the Midwest ISO ancillary services market tariff), PJM, and the TVA-EKPC-E.ON.US Contingency Reserve Sharing Group (TCRSG). The TCRSG consists of three Balancing Authorities that are internal to the area and is intended to provide immediate response to contingencies. This assists the group with complying with the Disturbance Control Standard (DCS) and preventing the curtailment of native load. Even though some entities rely on outside resources for imports, there are others within the area that do not depend on short-term outside purchases or transfers from other regions or reporting areas to meet demand requirements. Purchase agreements for imports do not include emergency MW arrangements.

[257] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

Transmission

Two significant transmission projects in the SERC-N Area are Blackberry–Sportsman Acres (in service in 2013) and Franks–Barnett (in service in 2016). Currently, there are no major concerns with meeting in-service dates for transmission improvements or specific projects needed to maintain reliability. Additionally, there is adequate transmission to support the reported Future-Planned generation. If necessary, local area generation may be re-dispatched or transmission elements reconfigured to alleviate next contingency overloads. Entities also have the option to invoke NERC Transmission Limited Resource (TLR) procedures in scenarios that are not easily remedied by a local area solution. A summary of existing and projected transmission additions is included below (SERC-N-Table 8).

SERC-N-Table 8: Existing and Projected Transmission

SERC-N	AC (Circuit Miles)	DC (Circuit Miles)	Total (Circuit Miles)
EXISTING	21,600	0	21,600
Currently Under Construction	254	0	254
Planned - Completed within First Five Years	332	0	332
Planned - Completed within Second Five Years	13	0	13
2022 TOTAL (UNDER CONSTRUCTION & PLANNED)	22,198	0	22,198
Conceptual - Completed within First Five Years	21	0	21
Conceptual - Completed within Second Five Years	57	0	57
2022 TOTAL (UNDER CONSTRUCTION, PLANNED & CONCEPTUAL)	**676**	**0**	**676**

Entities in the area continue to evaluate and consider new technologies that can be utilized to improve BPS reliability. An example of this is TVA's Clay, Mississippi, a fourth-generation GIS 500/161 kV substation, which is scheduled to be placed in service prior to the 2012 summer peak. This project will provide enhanced reliability for load in the vicinity.

Vulnerability Assessment

Resource adequacy assessments covering the next 36 months are performed monthly to assist in identifying limitations or constraints that may impact seasonal adequacy. Long-term adequacy assessments based on 20-year capacity plans are also performed to make decisions relative to resource acquisitions, renewable portfolio standard legislations, and project development timelines to ensure system reliability. No system reliability concerns for the period have been identified in the latest resource adequacy studies. Resource availability, fuel availability, and hydro and reservoir conditions are expected to be normal during the period. In addition, there are no issues due to the distribution of generation or the unavailability of Demand Response. The contributions of Demand Response programs are included in long-range capacity planning studies. Programs are based on the particular program impact, historical trends of effectiveness in the region, dependability, and system cost-effectiveness, for use in summer peak adequacy assessments. Entities are monitoring adjustments and results to these studies as a consequence of new and potential environmental regulations.

No additional UVLS schemes are planned for installation during the assessment period, but TVA is considering an additional scheme in addition to two existing UVLS protection schemes already in place to limit potential wider area under-voltage events. The non-coincident peak demand served from the substations equipped with UVLS totals approximately 450 MW. No Special Protection Systems or Remedial Action Schemes are planned for the time period.

Entities regularly participate in emergency system drills to ensure that operators are trained and properly prepared for catastrophic events. The transmission planning processes prepare for the loss of up to all units at any given generating station as part of assessments. Planners disseminate that information to system operations. Entities also rely on reserve sharing, Purchasing and Selling Entities (PSEs), and coordination with Balancing Authorities, through capacity and energy emergency plans. Planned unit maintenance outages or derates may be delayed or canceled in the event of a significant loss in capacity, and voluntary load shedding and energy emergency criteria will be enacted if necessary.

Some entities use risk analysis processes to identify the contingencies that have the greatest impact on their resource adequacy over the long term. Specific outage events are not modeled in that analysis but may be considered during sensitivity studies as part of the annual capacity planning effort. If resource inadequacies (such as catastrophic events) cause the Reserve Margin to be reduced, the entity then may anticipate the use of purchases from the short-term markets as a necessary addition to appropriate operational actions to ensure system reliability.

For the operational planning horizon, in the event of a catastrophic event such as a hurricane causing pipeline outages, supply/transportation could be re-routed to other pipeline legs (routes), thereby bypassing the restriction or outage. Entities also have backhaul transportation contracts in place that could be utilized to source and deliver supply. If a storage facility allows, supply could be wheeled (an interruptible service) across the storage facility to other pipeline interconnects.

Most smart grid efforts to date have been on the scale of demonstration projects. A summary of TVA's current research and programs can be found on TVA's web site.[258] LG&E and KU Energy plans to invest approximately $14 million in smart grid enabling technologies by 2014. These investments provide for a variety of enhanced capabilities for system monitoring and operation. No reliability improvements or issues have been identified as a direct result of these investments.

Entities have established proactive programs to minimize the likelihood of relay protection misoperations. Recent evaluations have revealed problems with increases in 'unknown' causes, carrier failure, calculations and settings, and relay applications. Remedial measures include maintenance programs to periodically calibrate and test relays, investigations of every relay misoperation, goals to remedy misoperations within two years, relay replacement programs to replace obsolete relays, improved implementation processes, and improved identification of mutual coupling effects.

Utilities in the area are aware of the potential for environmental/regulatory restrictions to impact generating resource operations. These can include emissions restrictions as well as cooling water source temperature regulation, which can lead to plant derates. Routine internal communications practices will alert operational planners at the onset to any potential environmental/regulatory impact to plant operations. Such limitations are factored into operational planning analysis.

There are currently no anticipated unit retirements that significantly impact system reliability, nor any indication that there will be insufficient time to perform any required retrofits. Entities will continue to conduct scenario planning studies to assess the impact on system reliability and adequacy for possible unit retirements during the period. The results of those studies are used in annual planning and provide input to ongoing development of generation fleet strategic plans. The effects of possible future long-term maintenance outages on off-peak reliability are uncertain. Ongoing mitigation plans are developed to reduce system reliability risks. Mitigations may include purchases, new generation, or reliance on reserves. However, for every new regulation that is promulgated, entities will continue to adapt their operations as needed (e.g., install controls, etc.) such that they comply with new regulatory requirements and do not affect reliability.

Standing and Emerging Reliability Issues

As stated in the previous section, utilities are aware of the risks associated with the current and pending environmental regulations/limitations and have established operational procedures to avoid or mitigate system reliability impact. Long-term adequacy assessments based on 20-year capacity plans are performed to make decisions relative to resource acquisitions and project development timelines to ensure system reliability. Resource adequacy assessments covering the next 36 months are performed monthly to assist in identifying limitations or constraints that may impact seasonal adequacy. Entities monitor adjustments and results to the studies as a consequence of environmental regulations.

Ongoing mitigation plans are developed to reduce system reliability risks. Mitigations may include purchases, new generation, or reliance on reserves. However, as for every regulation, entities will continue to adapt their operations as needed (e.g., install controls, etc.) such that they comply with new regulatory requirements and do not affect reliability.

There are currently no anticipated unit retirements that significantly impact system reliability, nor any indication that there will be insufficient time to perform any required retrofits. Entities will continue to conduct scenario planning studies to assess the impact on system reliability and adequacy for various assumptions of possible unit retirements during the period. The results of those studies are used in annual planning and provide input to ongoing development of generation fleet

[258] http://www.tva.gov/environment/technology/epri.htm.

strategic plans. The effects of possible future, long-term maintenance outages on off-peak reliability are believed to be negligible.

Utilities within the SERC-N Area have experienced two reliability issues: severe weather-related damage such as that caused by the very severe tornadic activity in April 2011; and the effects of substantial reconstruction efforts required after a significant event occurs. While severe weather-related damage is a standing issue for the SERC-N Area, the reconstruction efforts are an emerging issue. No long-term reliability impact is expected due to the storm damage from the spring storms. The assessment impact is generally the same for both reliability issues.

Severe weather events are generally unpredictable, and two or more such events could lead to uncertainty in the ability to maintain adequate reserves. The unprecedented April 2011 storm events in SERC-N removed from service and damaged approximately 90 TVA transmission lines. Such widespread damage can challenge reserves of restoration materials.

In recent years, utilities within the reporting area have experienced pressure in maintaining margin reserves due to restoration activities, maintenance schedules, high-water threats from the Mississippi River, and hot weather.

SERC-SE

Planning Reserve Margins

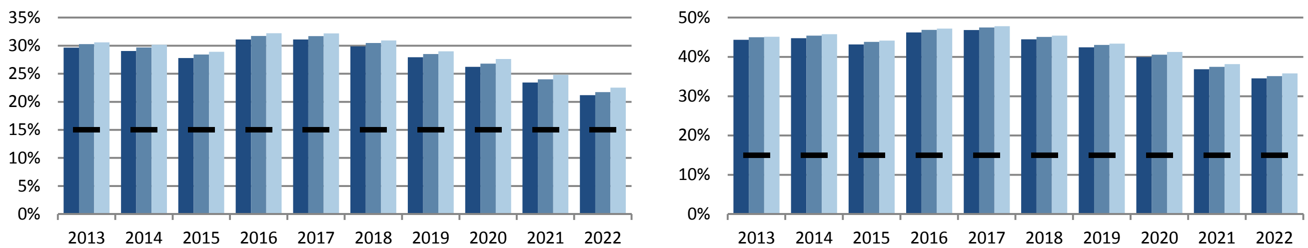
During the assessment period, the SERC-SE Assessment Area is projecting adequate Anticipated Capacity Resource Reserve Margins falls as low as 21.18 percent in the final year of the assessment period, above the NERC Reference Margin Level (SERC-SE-Table 1).

SERC-SE-Table 1: Planning Reserve Margins

SERC-SE-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		29.66%	29.06%	27.80%	31.12%	31.11%	29.88%	27.94%	26.22%	23.44%	21.18%
PROSPECTIVE		30.29%	29.68%	28.41%	31.72%	31.70%	30.47%	28.52%	26.79%	24.01%	21.74%
ADJUSTED POTENTIAL		30.58%	30.17%	28.90%	32.20%	32.18%	30.94%	28.99%	27.61%	24.81%	22.53%
NERC REFERENCE	-	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**

SERC-SE-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		44.34%	44.75%	43.16%	46.22%	46.85%	44.46%	42.43%	39.96%	36.86%	34.52%
PROSPECTIVE		45.01%	45.41%	43.82%	46.87%	47.49%	45.10%	43.06%	40.57%	37.46%	35.12%
ADJUSTED POTENTIAL		45.14%	45.76%	44.16%	47.21%	47.83%	45.43%	43.38%	41.28%	38.15%	35.80%
NERC REFERENCE	-	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**

SERC-SE-Figure 1: Summer (Left) and Winter[259] (Right) Planning Reserve Margins



Long-term demand is expected to grow even though the levels of economic activity and production are lower than pervious assessments. Additional contributing factors to adequate margins are the addition of resources and the expiration or acquisition of Firm purchase contracts. Utilities do not adhere to any targets or Reserve Margin criteria. However, the state of Georgia requires maintaining at least 13.5 percent near-term (fewer than three years) and 15 percent long-term (three years or more) Reserve Margin levels for investor-owned utilities. All entities indicate that projected Reserve Margins remain above 15 percent, the NERC Reference Margin Level.

Reserves for the period are anticipated to be adequate due to reductions in load forecast resulting from the recent recession and economic downturn, assuming typical weather and operating conditions.

Demand

Entities within the SERC-SE Assessment Area are projecting a 1.42 percent growth rate, a slight decrease compared to the 2011 LTRA (SERC-SE-Table 2).

SERC-SE-Table 2: Demand Outlook

SERC-SE-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	47,900	54,249	6,349	13.3%	1.39%
Load-Modifying Demand Response	1,899	2,263	364	19.2%	1.97%
TOTAL INTERNAL DEMAND	**49,799**	**56,512**	**6,713**	**13.5%**	**1.42%**

SERC-SE-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	44,652	50,627	5,975	13.4%	1.41%
Load-Modifying Demand Response	1,882	2,267	385	20.5%	2.09%
TOTAL INTERNAL DEMAND	**46,534**	**52,894**	**6,360**	**13.7%**	**1.43%**

[259] Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.

The change is mostly driven by the slower-than-expected recovery from the recession as compared to last year. The assumptions in SERC-SE's economic forecast indicate that it is in the recovery phase, even though recovery has been slow. The economic fundamentals of the Region are still strong. Forecasters are anticipating that when the job market recovers, the housing market will follow and this will lead to a period of self-sustaining load growth. Normal weather assumptions are used to forecast the load shapes for various classes. Economic assumptions are captured from analytical vendors for the area. The recession affected short-term growth for energy and peak demand forecast. Adjustments were needed to reflect lower energy sales, milder temperatures, and the slow economic recovery, as well as to capture a more attainable consumer forecast.

Demand-Side Management

The Demand Response available on-peak is projected to be 1,899 MW for 2013 and 2,263 MW by 2022 (SERC-SE-Table 3). Entities currently reflect Energy Efficiencies in the load forecasts. These programs allow entities within the reporting area to have better ability to control various amounts of load and capacity when needed for reliability purposes. Extreme real-time pricing response is considered as a capacity resource. Distribution efficiency programs consist of adding capacitors on distribution circuits to reduce line losses and to smooth out voltage drop across the circuit. In addition, Conservation Voltage Reduction activation reduces the voltage on the distribution circuit at the voltage regulator or load tap transformer, reducing the customer's demand. Additional objectives of some of the programs are as follows:

- Help reduce the need to build or purchase capacity.
- Respond to volatile wholesale energy markets.
- Improve the efficiency (load factor) as well as the utilization of generation, transmission, and distribution systems.
- Provide low-cost energy to member cooperatives.
- Increase off-peak kWh sales.

SERC-SE-Table 3: Projected Demand-Side Management

	Short-Term					
SERC-SE	2013	2014	2015	2022	10-Year Change	2022 Share of Total Internal Demand
Direct Control Load Management (DCLM)	626	825	848	912	286	1.61%
Contractually Interruptible (Curtailable)	1,188	1,188	1,267	1,252	64	2.22%
Critical Peak-Pricing (CPP) with Control	0	0	0	0	0	0.00%
Load as a Capacity Resource	85	87	89	99	14	0.18%
TOTAL LOAD-MODIFYING DEMAND RESPONSE	1,899	2,100	2,204	2,263	364	4.00%
TOTAL ENERGY EFFICIENCY	0	0	0	0	0	0.00%
TOTAL DEMAND-SIDE MANAGEMENT	**1,899**	**2,100**	**2,204**	**2,263**	**364**	**4.00%**

There is no significant change in the amount of Demand Response since last year's reporting period. Demand Response is projected to account for 3.8 to 4 percent of Total Internal Demand from 2013 to 2022. Additionally, Demand Response is projected to increase by 12.5 percent in 2013 from the 2011 long-term assessment period. Currently, entities include Energy Efficiencies in load forecasts and it is not reported separately in this assessment. Additional Energy Efficiency programs are being considered for residential, commercial and industrial customers in the area. Over 500 programs are being reviewed for consideration for future implementation, but not all programs will be implemented. After a program is approved by the Public Service Commission for implementation and after the implementation begins, a general evaluation plan is developed into a more detailed evaluation plan through a bid process with consultants who have the expertise to develop and perform thorough program evaluations.

Demand Response programs within the area consist of programs ranging from customer stand-by generation, real-time pricing/critical-peak pricing (reduce energy use based on price signaling), and interruptible demand programs (requests customers to reduce energy use), to direct load control programs (energy provider reduces customer energy use). Various utilities have residential Energy Efficiency programs that may include educational presentations, home energy audits, home inspector programs, compact fluorescent light bulbs, electric water heater incentives, heat pump incentives, Energy Efficient new home programs, Energy Star-rated appliance promotions, appliance recycling programs, loans or financing options/incentives, weatherization, programmable thermostats, and ceiling insulation. Commercial programs may include energy audits, lighting programs, and plan review services.

Other programs, such as business assistance/audits, weatherization assistance for low-income customers, residential energy audits, and comfort advantage Energy Efficient home programs promote reduced energy use and supply information and develop Energy Efficiency presentations for various customers and organizations. Some entities are beginning to work with states' energy divisions on Energy Efficiency planning efforts. Training seminars addressing Energy Efficiency, HVAC sizing, and energy-related end-use technologies are also offered to educate customers.

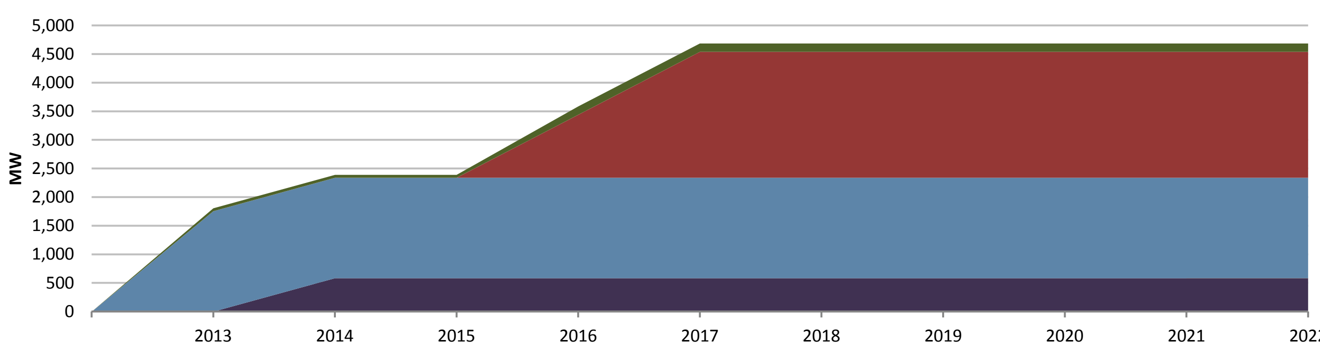
Generation

Companies within the SERC-SE Area expect to have 62,312 MW of Existing-Certain, 300 MW of Existing-Other, 0 MW of Existing-Inoperable, 1,807 MW of Future-Planned, and 142 MW of Conceptual resources on-peak respectively for 2013. Additionally, 4,688 MW of Future-Planned resources and 430 MW of Conceptual resources are expected to be added in 2022. The major additions to the area include Plant Ratcliffe IGCC and Plant Vogtle Units 3 and 4. The Vogtle units represent the first new nuclear units constructed in over 30 years in the United States and will begin operation in 2016 and 2017, respectively. This capacity is projected to help meet demand during this time period. Gas is the primary source of fuel within this area. An additional 841 MW of Existing-Certain resources have been added since the prior season. Gas-fired Future-Planned resources are projected to increase by 130 MW during the summer of 2012. Entities have reported 107 MW of unit retirements during 2012 and 1,032 MW of unit retirement throughout the period. There may be a reliability concern involving the uncertainty in generating resource availability in 2015 and beyond introduced by the recent implementation of EPA MATS rules and other pending environmental rules. Entities in the area are working to assess resource availability and potential unit retirements. Additional transmission enhancements have been identified and will be re-assessed during the spring planning cycle for possible inclusion in the 10-year expansion plans (SERC-SE-Table 4 and SERC-SE Figure 2).

SERC-SE-Table 4: Capacity Outlook[260]

	Current		2022 Planned			2022 Planned & Conceptual		
SERC-SE-Summer	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Coal	24,604	38.9%	25,189	37.1%	585	25,189	36.8%	585
Petroleum	1,017	1.6%	1,017	1.5%	0	1,017	1.5%	0
Gas	26,763	42.3%	28,520	42.0%	1,757	28,738	42.0%	1,975
Nuclear	5,818	9.2%	8,018	11.8%	2,200	8,018	11.7%	2,200
Other/Unknown	13	0.0%	13	0.0%	0	19	0.0%	6
Renewables	5,063	8.0%	5,209	7.7%	146	5,416	7.9%	352
TOTAL	**63,278**	**100.0%**	**67,966**	**100.0%**	**4,688**	**68,396**	**100.0%**	**5,118**

SERC-SE-Figure 2: Summer Net Capacity Change



New generator uprates are not reported to be in service during the period. In addition, no generation is expected to be brought back into service. Entities are currently working through solutions in order to address potential unit unavailability

[260] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

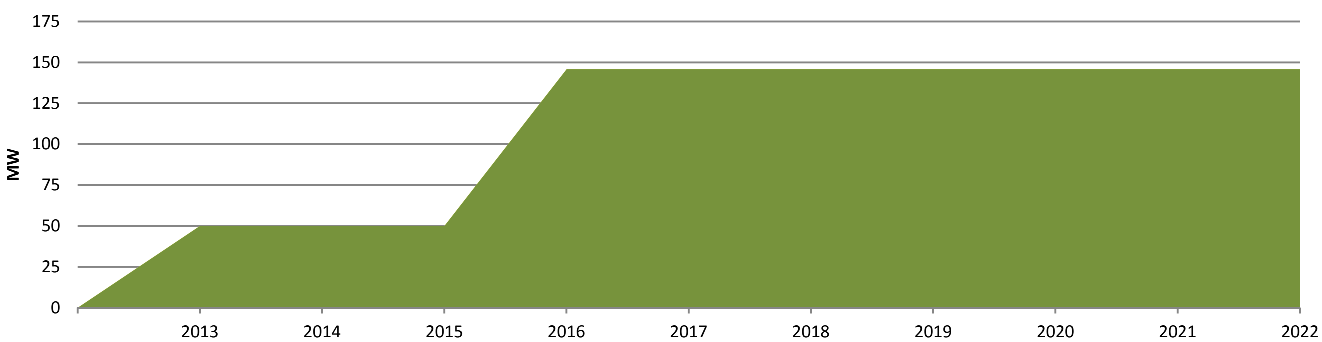
that may occur in the future. Behind-the-meter generation and Other/Unknown resources are also not anticipated during the period.

Only Firm Capacity Resources are counted toward the Planning Reserve Margins at peak in calculations. However, Future-Planned biomass generation is included in the Integrated Resource Plans at less than the nameplate capacity for converted boilers, and at nameplate capacity for units receiving new boilers. Landfill gas facilities are included at their nameplate ratings. Contracts with external parties for these resources usually require proof of capacity and allow for capacity payment penalties for excessive unavailability and derating events (SERC-Table 5 and SERC-Figure 3).

SERC-SE-Table 5: Renewable Capacity Outlook[261]

	Current		2022 Planned			2022 Planned & Conceptual		
SERC-SE-Summer	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Hydro	3,360	66.4%	3,360	64.5%	0	3,360	62.0%	0
Pumped Storage	1,632	32.2%	1,632	31.3%	0	1,632	30.1%	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	1.3%	213	4.1%	146	419	7.7%	352
Solar	4	0.1%	4	0.1%	0	4	0.1%	0
TOTAL	**5,063**	**100.0%**	**5,209**	**100.0%**	**146**	**5,416**	**100.0%**	**352**

SERC-SE-Figure 3: Summer Net Renewable Capacity Change



Currently, entities are enhancing their methods for incorporating variable resources into their planning processes. Variable resources are currently evaluated by analyzing their historical or projected output profiles (SERC-Table 6). The result will be a determination of the comparative capacity value to that of a typical combustion turbine on the system.

SERC-SE-Table 6: Renewable Capacity Outlook: On-Peak Vs. Installed

	Current				2022 Planned			
SERC-SE-Summer	Wind	Solar	Hydro	Biomass	Wind	Solar	Hydro	Biomass
Installed Capacity	0	4	3,360	67	0	4	3,360	213
On-Peak Derate	0	0	0	0	0	0	0	0
EXPECTED ON-PEAK OUTPUT	0	4	3,360	67	0	4	3,360	213
SHARE OF ON-PEAK CAPACITY	**0.00%**	**0.01%**	**5.31%**	**0.11%**	**0.00%**	**0.01%**	**5.02%**	**0.32%**

Capacity Transactions

Utilities within SERC-SE expect the following imports and exports listed below for the period. These imports and exports have been accounted for in the Reserve Margin calculations for the reporting area. The majority of the contracts in the area are yearly Firm agreements typically lasting five or more years. All imports and exports were reported to be backed by Firm contracts for both generation and transmission, but none are associated with LDCs or are considered "make whole." Once the contract ends, the unit's capacity is changed from Existing-Certain to Existing-Other. Firm imports amount to 850 MW in 2013 and ultimately drop to 446 MW in 2022. Exports fall from 2,862 MW in 2013 to 1,705 MW in 2022 (SERC-SE-Table 7).

[261] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

Projected Capacity Transactions

SERC-SE-Summer	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Expected Imports	0	0	0	0	0	0	0	0	0	0
Firm Imports	850	900	900	825	825	825	825	825	546	446
TOTAL IMPORTS	850	900	900	825	825	825	825	825	546	446
Expected Exports	0	0	0	0	0	0	0	0	0	0
Firm Exports	2,862	2,703	2,690	1,399	1,547	1,555	1,671	1,690	1,697	1,705
TOTAL EXPORTS	2,862	2,703	2,690	1,399	1,547	1,555	1,671	1,690	1,697	1,705
TOTAL NET CAPACITY TRANSACTIONS	**-2,012**	**-1,803**	**-1,790**	**-574**	**-722**	**-730**	**-846**	**-865**	**-1,151**	**-1,259**

Reporting entities maintain emergency reserve sharing agreements with organizations internal to the area and other contract agreements with neighboring utilities provide capacity for outages of specific generation. Total emergency MW from these imports were not reported, but are available as needed. Overall, entities are not dependent on outside imports or transfers to meet the demands of its load.

Transmission

Currently, there are no concerns with meeting in-service dates for transmission improvements or specific projects needed to maintain reliability. Significant projects in SERC-SE that have been finalized are:

- Dresden–Heard County 500 kV Transmission Line
- Thomson Primary–Vogtle 500 kV Transmission Line
- Greene County–Bassett Creek 230 kV Transmission Line
- Pinckard–Holmes Creek–Highland City 230 kV Transmission Line

A summary of existing and projected transmission additions is included in the table below (SERC-SE-Table 8).

SERC-SE-Table 8: Existing and Projected Transmission

SERC-SE	AC (Circuit Miles)	DC (Circuit Miles)	Total (Circuit Miles)
EXISTING	27,672	0	27,672
Currently Under Construction	108	0	108
Planned - Completed within First Five Years	305	0	305
Planned - Completed within Second Five Years	374	0	374
2022 TOTAL (UNDER CONSTRUCTION & PLANNED)	28,459	0	28,459
Conceptual - Completed within First Five Years	66	0	66
Conceptual - Completed within Second Five Years	0	0	0
2022 TOTAL (UNDER CONSTRUCTION, PLANNED & CONCEPTUAL)	**853**	**0**	**853**

Entities consistently evaluate the transmission system through operating studies and a model construction process. These evaluations address any potential delays in construction and are used to determine switching procedures, operating procedures, or near-term improvements that may be necessary should an in-service date of a bulk facility be adjusted. The Reliability Coordinator and Transmission Operators also work with impacted entities to coordinate construction and outage schedules to maintain reliable operations.

To address reliability concerns for the 10-year planning horizon, entities are conducting comprehensive reliability assessments consistent with NERC planning criteria and developing transmission expansion plans to address identified constraints in advance of reliability needs. Transmission projects identified in the expansion plans will be constructed to coincide with the integration of new and retirement of existing generation resources, load growth, and other Firm service requirements. Potential additional transmission enhancements have been identified due to EPA regulations and will be reassessed during the spring planning cycle for possible inclusion in the 10-year expansion plans. Significant outage coordination is underway to ensure that all projects can be completed by the required in-service dates without affecting system reliability. These spring planning assessments may also lead to requests associated with MATS rule implementation requirements to 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 2015 implementation of MATS. At this time, entities in the area do not have plans to add new technologies or significant substation equipment. Companies will continue to assess potential applications for these technologies in assessing reliability needs during annual expansion planning processes and are prepared to deploy these technologies in suitable applications.

Vulnerability Assessment

Resource adequacy is determined by extensive analysis of costs associated with expected unserved energy, market purchases, and new capacity. These costs are balanced to identify a minimum cost point that is the optimum Reserve Margin level. No system reliability concerns for the period have been identified in the latest resource adequacy studies. Fuel availability and hydro and reservoir conditions are expected to be normal throughout the reporting period. Assessments are currently in progress to assess the effects of the EPA regulations on generation availability in 2015 and beyond. Additionally, the variable resources that have been procured as energy resources are not presently relied upon to meet resource adequacy requirements. However, some entities are in the process of enhancing their methods to incorporate variable resources. Currently, variable resources are evaluated by analyzing their historical or projected output profiles. The result will be a determination of the comparative capacity value to that of a typical combustion turbine on the system. Demand Response is not a factor, and Renewable Portfolio Standard requirements do not currently exist in the service territory.

A 2,250 MW UVLS scheme currently exists in northern Georgia. The scheme was installed to help meet three-phase faults with breaker failure contingencies. There are no future plans to install more schemes.

Utilities within the reporting area use various tactics to prepare for catastrophic events. Company-specific processes and guidelines for coal, natural gas, and transmission usage are areas that companies consider to be most critical. To address the coal concerns, several resource adequacy studies were conducted to evaluate the ability to meet peak demand while considering the historic and probabilistic limitations of import interfaces. Transmission studies are regularly performed. Loss-of-pipeline, extreme events (TPL-003 and TPL-004), and infrastructure security are taken into consideration. The purpose is to assess vulnerability for catastrophic events and develop appropriate mitigation plans. The general conclusion is that the system is capable of weathering many potential catastrophic events with minimal impact on neighboring systems.

There are three existing Special Protection Systems in the SERC-SE Area. They are located at Plant Daniel (230kV), Plant Crist (115kV) and Plant Wilson (230kV). Plant Wilson's SPS will be retired by 2015 when the breaker replacement project is complete. SERC reviews each SPS every five years as well as any SPS retirement.

Currently in SERC-SE, entities are proceeding with various smart grid projects to help enhance the reliability of the transmission system. These projects include replacing older electromechanical relays with microprocessor relays, installing transformer equipment monitors, automating transmission line switches, installing digital fault recorders (DFRs) and installing human machine interfaces (HMI's) in substations.

The utilities in SERC-SE have procedures in place to identify and review misoperations caused by protection systems. When a misoperation occurs on the transmission system, corrective action is implemented to prevent recurrence. If needed, other locations are also reviewed for similar problems. Misoperations caused by protection systems are reviewed on an annual basis for possible trends.

As stated in the above sections, a reliability concern involves uncertainty in generating resource availability in 2015 and beyond, introduced by the recent implementation of EPA MATS rules and other pending environmental rules. All entities in the area are fully engaged in assessing resource availability and potential unit retirements. Resource adequacy, expansion plans and models will be updated if the decisions for the retirement of various units become available. Potential transmission enhancements have been identified from recent assessments and will be re-assessed in future expansion plans. These assessments may also lead to requests associated with MATS implementation requirements to operating units beyond 2015 as needed to maintain reliability. Plans also include the Reliability Coordinator and Transmission Operators coordination efforts to decide construction and outage schedules to maintain reliable operations.

Standing and Emerging Reliability Issues

A significant reliability concern involves the uncertainty of generating resource availability in 2015 and beyond, introduced by the recent implementation of EPA MATS rules and other pending environmental rules being promulgated. The SBA Planning Authority is working with Load Serving Entities and Generator Operators to assess resource availability and potential unit retirements. Potential additional transmission enhancements have been identified and will be re-assessed during future expansion plans. These assessments may also lead to requests associated with MATS implementation requirements to 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 2015 implementation of MATS. The Reliability Coordinator and Transmission Operators are working with impacted entities to coordinate construction and outage schedules to maintain reliable operations.

SERC-W

Planning Reserve Margins

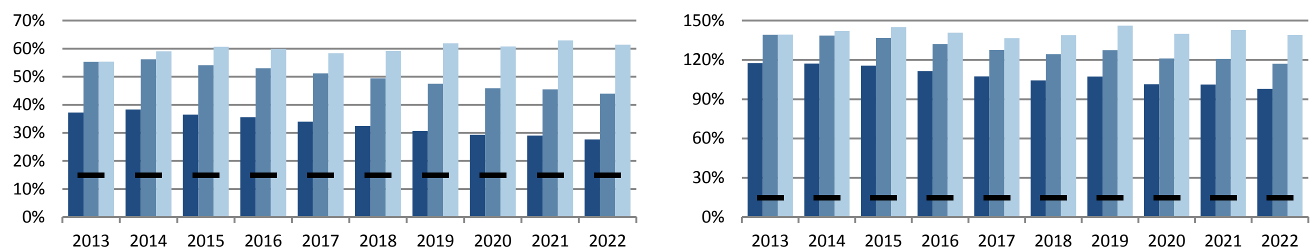
The reporting area is projecting adequate Anticipated Capacity Resource Reserve Margins from 2013 to 2022, ranging between 26.1 and 35.5 percent. None of the Planning Reserve Margins are projected to fall below the NERC Reference Margin Level of 15 percent (SERC-W-Table 1 and SERC-W-Figure 1).

SERC-W-Table 1: Planning Reserve Margins

SERC-W-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		37.26%	38.35%	36.48%	35.60%	33.98%	32.44%	30.70%	29.32%	29.04%	27.68%
PROSPECTIVE		55.32%	56.24%	54.12%	53.03%	51.19%	49.46%	47.49%	45.93%	45.49%	43.96%
ADJUSTED POTENTIAL		55.36%	59.05%	60.69%	59.91%	58.38%	59.22%	61.95%	60.79%	62.93%	61.44%
NERC REFERENCE	-	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**

SERC-W-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		117.6%	117.2%	115.6%	111.5%	107.4%	104.4%	107.2%	101.4%	101.2%	97.8%
PROSPECTIVE		139.2%	138.5%	136.7%	132.1%	127.6%	124.3%	127.5%	121.1%	120.7%	117.0%
ADJUSTED POTENTIAL		139.3%	142.1%	145.1%	140.8%	136.6%	138.9%	146.1%	139.9%	142.8%	139.0%
NERC REFERENCE	-	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**	**15.00%**

SERC-W-Figure 1: Summer (Left) and Winter[262] (Right) Planning Reserve Margins



Contributing factors to adequate margins exist and owned resources, limited and long-term purchase contracts, as well as potential deactivations and anticipated unit outages to plan and procure resources needed to meet the target Reserve Margin when developing plans for the season. Individual entity criteria also help establish resource adequacy by allocations assigned as a member of the SPP Reserve Sharing Group, Balancing Authority's most severe single contingency, load forecasts, reserve requirements using historical allocations, and Loss of Load Expectation studies (0.1 day per year). There are no other anticipated reliability concerns for the period.

Demand

Entities in the SERC-W Assessment Area project decreases in growth rates when comparing the 2013 long-term forecast (1.15 percent) to the 2011 forecast (1.30 percent) (SERC-W-Table 2).

SERC-W-Table 2: Demand Outlook

SERC-W-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	25,015	27,764	2,749	11.0%	1.17%
Load-Modifying Demand Response	906	966	60	6.6%	0.72%
TOTAL INTERNAL DEMAND	**25,921**	**28,730**	**2,809**	**10.8%**	**1.15%**

SERC-W-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	19,731	22,262	2,531	12.8%	1.35%
Load-Modifying Demand Response	766	820	54	7.0%	0.76%
TOTAL INTERNAL DEMAND	**20,497**	**23,082**	**2,585**	**12.6%**	**1.33%**

The modest decrease in growth is due to lower economic projections received from vendors as they adjusted forecasts to reflect a longer recovery from the recession. Decreases also reflect a reduction in the long-term outlook for retail electric sales due to this forecast. Typical weather conditions are used to forecast the load shapes for the residential, commercial,

[262] Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.

and governmental classes. The forecast assumes a gradual economic recovery. Entities in the area regularly develop load scenarios for outage planning purposes. These load scenarios include load forecasts based on high and low scenarios for energy sales and scenarios for alternative capacity factors. No significant changes are reflected in this year's assumptions.

Demand-Side Management

Demand Response is expected to be 906 MW for 2013 and 966 MW by 2022. Currently, there are no Energy Efficiency contributions projected during this reporting period. Demand Response accounts for approximately 3.5 and 3.4 percent of Total Internal Demand in 2013 to 2022, respectively (SERC-W-Table 3). Demand Response is projected to increase 3.4 percent from 2011 to 2013. There is no significant change in the amount of load reduction programs since last year. DSM programs among the utilities in the reporting area include interruptible load programs for larger customers, Direct Control Load Management programs for agricultural customers, and a range of conservation/load management programs for all customer segments. There are no significant changes in the amount and availability of load management and interruptible demand since last year.

SERC-W-Table 3: Projected Demand-Side Management

	Short-Term					
SERC-W-Summer	2013	2014	2015	2022	10-Year Change	2022 Share of Total Internal Demand
Direct Control Load Management (DCLM)	0	0	0	0	0	0.00%
Contractually Interruptible (Curtailable)	906	909	940	966	60	3.36%
Critical Peak-Pricing (CPP) with Control	0	0	0	0	0	0.00%
Load as a Capacity Resource	0	0	0	0	0	0.00%
TOTAL LOAD-MODIFYING DEMAND RESPONSE	906	909	940	966	60	3.36%
TOTAL ENERGY EFFICIENCY	0	0	0	0	0	0.00%
TOTAL DEMAND-SIDE MANAGEMENT	**906**	**909**	**940**	**966**	**60**	**3.36%**

Energy Efficiency programs are implemented to distribution cooperatives and the residential sector. A variety of programs ranging from home energy audits, CFL lighting, and Energy Star-rated washing machines and dishwashers, to Energy Star-rated heat pumps and air conditioners, weatherization and high efficiency water heaters have been added to company portfolios over the years. Utilities plan to offer these types of programs as long as they are determined to be cost-effective. Annual measurement and verification (M&V) programs measure energy savings and costs for each of these Energy Efficiency programs. Information from these M&V programs will be used to fine-tune Energy Efficiency programs and determine their cost-effectiveness. The current forecast includes Energy Efficiency programs that have received regulatory approval. As programs advance, they will be incorporated into retail sales and load forecasts. M&V for interruptible Demand Response programs for larger customers are conducted on a customer-by-customer basis. These include an annual review of customer information and Firm load requirements. Compliance is determined by a review of customer load data as related to the terms and conditions of the electric rate schedule. Companies adhere to measurement and verification requirements set forth by state regulators.

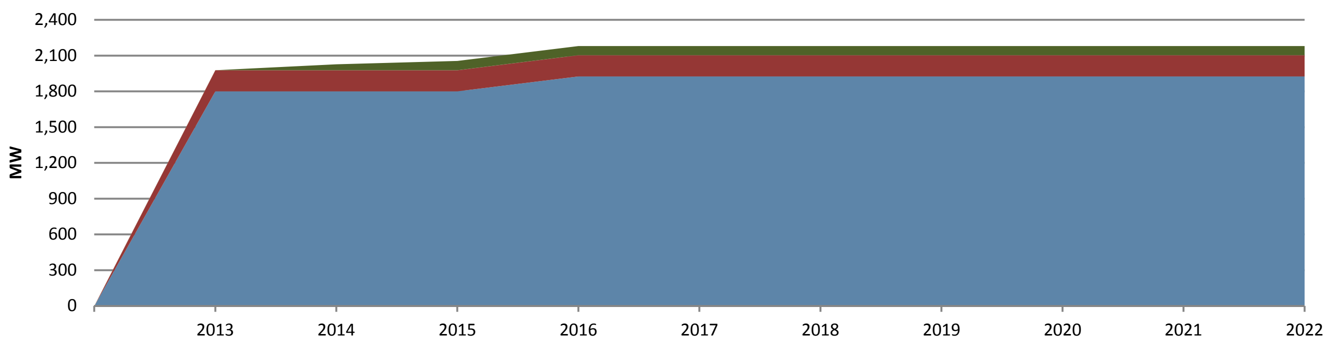
Generation

Companies within SERC-W expect to have 34,175 MW of Existing-Certain, 4,519 MW of Existing-Other, 0 MW of Existing-Inoperable, 1,978 MW of Future-Planned, and 10 MW of Conceptual resources on-peak for 2013 (SERC-W-Table 4 and SERC-W-Figure 2). Additionally, 2,181 MW of Future-Planned resources and 4,853 MW of Conceptual resources are expected to be added in 2022. This capacity is projected to help meet demand during this time period. Oil, gas, and dual fuel units are the primary sources of fuel within this area. No Existing-Certain resources have been added since the previous long-term reporting period. Entities have reported no unit retirements since the previous long-term reporting period. However, 93 MW of unit retirements will occur in 2013. No significant negative impact to reliability due to capacity limitations is anticipated for the period.

SERC-W-Table 4: Capacity Outlook[263]

SERC-W-Summer		Current Capacity	Current Share	2022 Planned Capacity	2022 Planned Share	2022 Planned Change	2022 Planned & Conceptual Capacity	2022 Planned & Conceptual Share	2022 Planned & Conceptual Change
Coal		6,300	17.3%	6,300	16.3%	0	6,300	14.5%	0
Petroleum		41	0.1%	41	0.1%	0	41	0.1%	0
Gas		24,494	67.2%	26,420	68.4%	1,926	30,046	69.1%	5,552
Nuclear		5,324	14.6%	5,502	14.2%	178	5,627	12.9%	303
Other/Unknown		0	0.0%	0	0.0%	0	0	0.0%	0
Renewables		311	0.9%	388	1.0%	77	1,490	3.4%	1,179
TOTAL		**36,470**	**100.0%**	**38,651**	**100.0%**	**2,181**	**43,504**	**100.0%**	**7,034**

SERC-W-Figure 3: Summer Net Capacity Change

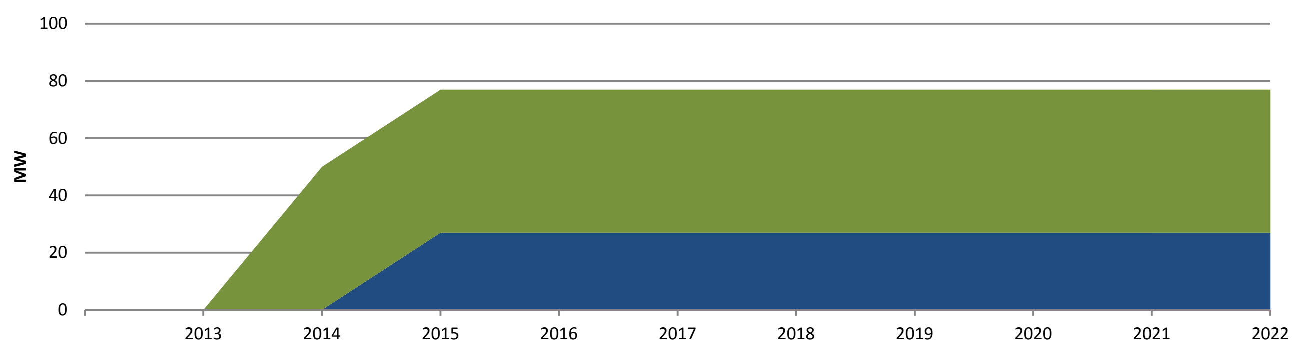


There are also no new generator uprates or generation taken out of service during the period. However, a 57 MW natural gas unit will be brought back into service for the period. Behind-the-meter generation and Other/Unknown resources are also not expected to be in service for the period.

SERC-W-Table 5: Renewable Capacity Outlook[264]

SERC-W-Summer		Current Capacity	Current Share	2022 Planned Capacity	2022 Planned Share	2022 Planned Change	2022 Planned & Conceptual Capacity	2022 Planned & Conceptual Share	2022 Planned & Conceptual Change
Hydro		311	100.0%	338	87.1%	27	607	40.8%	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	1.5%	23
Biomass		0	0.0%	50	12.9%	50	860	57.7%	860
Solar		0	0.0%	0	0.0%	0	0	0.0%	0
TOTAL		**311**	**100.0%**	**388**	**100.0%**	**77**	**1,490**	**100.0%**	**1,179**

SERC-W-Figure 4: Summer Net Renewable Capacity Change



Due to an insignificant amount of variable generation connected to the distribution system, there are no concerns about integrating these resources onto the system. Currently, entities are studying potential approaches for incorporating variable

[263] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

[264] *Ibid*.

resources into their planning processes. Wind agreements are used as a tool to allow operators to enhance reliability and can be used in situations such as curtailing for TLR and managing minimum generation problems. An energy forecasting package is used to predict wind farm output given meteorological data collected at the wind farms. No issues are anticipated for the period.

SERC-W-Table 6: Renewable Capacity Outlook: On-Peak Vs. Installed

	Current				2022 Planned			
SERC-W-Summer	Wind	Solar	Hydro	Biomass	Wind	Solar	Hydro	Biomass
Installed Capacity	0	0	311	0	0	0	338	50
On-Peak Derate	0	0	0	0	0	0	0	0
EXPECTED ON-PEAK OUTPUT	0	0	311	0	0	0	338	50

Capacity Transactions

Utilities within SERC-W expect the following imports and exports listed below for the period. These imports and exports have been accounted for in the Reserve Margin calculations for the reporting area. Most of the contracts in the area are agreements for a 10-year period for the winter and summer peaking seasons. Once the contract ends, the unit's capacity is changed from Existing-Certain to Existing-Other.

SERC-W-Table 7: Projected Capacity Transactions

SERC-W-Summer	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Expected Imports	0	0	0	0	0	0	0	0	0	0
Firm Imports	50	50	50	50	50	50	50	50	50	50
TOTAL IMPORTS	50	50	50	50	50	50	50	50	50	50
Expected Exports	0	0	0	0	0	0	0	0	0	0
Firm Exports	2,304	1,746	1,746	1,671	1,671	1,671	1,671	1,671	1,392	1,392
TOTAL EXPORTS	2,304	1,746	1,746	1,671	1,671	1,671	1,671	1,671	1,392	1,392
TOTAL NET CAPACITY TRANSACTIONS	**-2,254**	**-1,696**	**-1,696**	**-1,621**	**-1,621**	**-1,621**	**-1,621**	**-1,621**	**-1,342**	**-1,342**

Reporting entities in the area are dependent on certain imports, transfers, or contracts to meet the load demands. Most entities are members of the Southwest Power Pool (SPP) Reserve Sharing Group. Group participants within SPP generally transfer reserves into the area to either replace (largest contingency) or supply generation to the area. These reserves are not relied on in the resource adequacy assessment, or for capacity or Reserve Margins. System operators generally coordinate the scheduling and transmitting of the reserves. Total emergency MW from these imports was not reported.

Transmission

Entities within the reporting area are not expecting any delays in meeting in-service dates for projects scheduled for the summer assessment period. Some of the significant projects that are planned or have been recently completed in SERC-W are:

- Acadiana Load Pocket Project Phases 1 and 2: Completed in June, 2012. Project creates a new 230 kV overlay in the Acadiana Area of south Louisiana.
- Ouachita Transmission Projects: Completed in June, 2012. Projects included increasing 500-115 kV transformer capacity in northern Louisiana, upgrades of various 115 kV lines around the Sterlington Area, and the addition of a 2nd 500-115 kV transformer at the Baxter Wilson substation in Mississippi.
- Grenada/Winona/Greenwood Area Improvement Project: Completed in June, 2012. Project included the construction of a new Tillatoba–South Grenada 230 kV line and a 230-115 kV transformer at South Grenada.
- Holland Bottoms Project: Completed in May 2012. Project included the addition of 500-161 and 500-115 kV transformers in the northeast Little Rock Area of Arkansas and the construction of a new 161 kV transmission line from Holland Bottoms to the Hamlet substation north of the Little Rock Area.
- Nelson to Moss Bluff 230 kV line: Completed in May, 2012. Project included the construction of a new 230 kV line in the Lake Charles Area of southern Louisiana.
- Northeast Louisiana Improvement Project Phases 1 and 2: Projected in service by summer 2013 and summer 2014, respectively. Project includes construction of new 230 kV line (to operate at 115 kV initially) from the Monroe Area of northern Louisiana to the Delhi Area in order to increase transmission capacity in the Area.

- Getwell to Church Road 230 kV line: Projected in-service date by summer 2013. Project includes the construction of a new 230 kV line between Church Road and Getwell substations in north Mississippi and create a 230 kV loop in the Area.

SERC-W-Table 8: Existing and Projected Transmission

SERC-W	AC (Circuit Miles)	DC (Circuit Miles)	Total (Circuit Miles)
EXISTING	14,295	0	14,295
Currently Under Construction	72	0	72
Planned - Completed within First Five Years	414	0	414
Planned - Completed within Second Five Years	79	0	79
2022 TOTAL (UNDER CONSTRUCTION & PLANNED)	14,860	0	14,860
Conceptual - Completed within First Five Years	26	0	26
Conceptual - Completed within Second Five Years	92	0	92
2022 TOTAL (UNDER CONSTRUCTION, PLANNED & CONCEPTUAL)	**683**	**0**	**683**

Additionally, there are no significant transmission facility outages or significant projects that are expected to impact BES reliability. Utilities in SERC-W continue to identify and develop plans to construct or upgrade transmission facilities to meet reliability needs and incorporate new generation resources in the area for both the near-term and long-term planning horizons. Transmission projects are planned to be constructed to support the Future-Planned generation in the SERC-W Area. Prior to approval of any proposed maintenance outages, studies are completed to identify any impact on reliability. In addition, 2012 near-term summer preliminary results indicate that with operating guides in place, imports into the Area exceed 2,000 MW for all paths studied. To enhance the system, entities continue to research new technologies such as dynamic voltage devices (SVC/Statcom) to provide voltage support to the Area. However, no additional SVC/Statcom or other specialized devices are expected to be added during the long-term period. Some utilities in SERC-W are involved in adding PMUs as part of an ongoing DOE project. The project will allow a greater visualization of the transmission system for transmission system operators. Twelve PMUs were installed in 2011, with an additional 23 PMUs planned to be installed throughout the transmission system in 2012.

Vulnerability Assessment

Existing and owned resources, limited and long-term purchase contracts, potential deactivations, and anticipated unit outages are considered when developing the one-year and 10-year resource plan. The latest resource adequacy studies do not show concerns for reliability of the system. Resource availability, fuel availability, and hydro conditions are expected to be normal during the summer, except for possible hydro limitations in Texas. Energy production in Texas may be limited due to existing drought conditions, unless above-normal rainfall is experienced during winter and spring months. Studies in these areas account for these conditions. Loss-of-load studies are performed annually for the current year based on updated load forecasts and unit availability data. The long-term test of resource adequacy is met by achieving a 16.85 percent Planning Reserve Margin.

Demand Response, distributed generation, variable renewable resources and Renewable Portfolio Standards (RPS) are not currently explicitly considered in the resource adequacy assessment. However, an RFP was recently conducted for Louisiana to identify and select renewable energy resources that meet the requirements of the Louisiana Public Service Commission's Pilot Program and approved Implementation Plan. These plans are consistent with the objectives of Entergy's Systems Strategic Resource Plan. Selections have been made, and ESI will be entering into discussions for the execution of definitive agreements associated with the proposals on the primary selection list.

Studies are being conducted for 2012 and 2018 summer time periods to identify additional static and dynamic reactive support requirements in the Nine Mile Area. Based on the study results, recommendations may be to install SVCs or capacitor banks, change transformer tap settings, or add new transmission facilities to ensure adequate reactive requirements are met. UVLS programs are also used to maintain voltage stability and protect against BES cascading events. An existing 250 MW UVLS scheme is used in the western area of Texas. No additional UVLS schemes are planned for the reporting area. In addition, no Special Protection Schemes are expected to be installed for the SERC-W Area in lieu of planned bulk power transmission facilities.

Resource and transmission planning activities consider contingency events to help entities prepare for catastrophic events. Close relationships with neighboring utilities and regular emergency operating drills are important practices of utilities. Entities within this reporting area are routinely exposed to hurricanes, and detailed emergency response plans have been developed for dealing with the consequences of hurricane damage to area electrical systems. One way that catastrophic events are mitigated is that gas-fired power plants do not rely on a single pipeline for transportation of natural gas. Likewise, most entities do not heavily rely on imports outside the reporting areas due to the loss of a major import that could negatively affect reliability.

Utilities within SERC-W have procedures in place to identify and review misoperations associated with transmission protection systems. In the event of a misoperation on the transmission system, investigations, including root cause analysis, are performed to determine corrective actions and implementation plans. Corrective action plans may cause an entity to evaluate other facilities for similar causes of misoperation.

There are no environmental or regulatory restrictions projected within the reporting area that will affect reliability for the period. The CSAPR rules, which have been stayed by federal courts, were not expected to result in any new reliability-must-run (RMR) units in SERC-W. In the event that there were insufficient allowances to operate existing RMR units at historical levels, it was possible to run these units at reduced production levels while ensuring grid reliability. Additional flexibility was expected with the October 2011 proposed revision. The increased flexibility allowed by this revision created additional possibilities for compliance, including interstate allowance purchases. Prior to the proposed October limits, some utilities in SERC-W had identified potential transmission upgrades in which acceleration of existing transmission projects was being considered. These are existing BES projects in various stages of planning, design, and construction. However, with the proposed October 2011 limits, no BES projects were identified in which acceleration prior to 2012 was required. Off-peak maintenance outages are not expected to affect reliability in the SERC-W Area.

Beyond the impact of CSAPR itself, utilities in the SERC-W Area do not anticipate a significant, immediate impact to system reliability due to the combined effects of CSAPR and other emerging environmental regulations. While the short implementation period allowed for CSAPR created concerns, other emerging rules are expected to have varying implementation dates that will provide adequate time for planning and execution of control projects. In addition, coal plants, which will be most affected by emerging regulations, are positioned relatively well in regard to their capacity and age, such that most projected environmental projects are currently estimated to be economically viable and are not expected to drive early retirements.

Utilities within SERC-W report that the deadlines created by the final EGU MACT rule could be problematic for the installation deadlines of major pollution control equipment for individual plants. This problem could also be compounded by the uncertainty over regional haze state implementation plan requirements. When plans are approved by the EPA, another layer of technology installments would be required. Utilities in the SERC-W Area believe that for coal plants, these are issues of timing, permitting, state public service commission approval, and rational project management, not retirement. The most immediate threat to reliability is likely to be in the 2020 time frame when units will be required to implement 316(b) controls and address any reductions driven by lower National Ambient Air Quality Standards (NAAQS). However, utilities in the SERC-W Area do not anticipate the suite of EPA regulations to result in significant facility retirements or generation reductions.

Standing and Emerging Reliability Issues

The CSAPR rules, which have been stayed, were not expected to result in any new reliability-must-run (RMR) units in SERC-W. In the event that there were insufficient allowances to operate existing RMR units at historical levels, it was still possible to run these units at reduced production levels while still ensuring grid reliability. Additional flexibility was expected with the October 2011 proposed revision. The increased flexibility allowed by this revision created addition possibilities for compliance, including interstate allowance purchases. Prior to the proposed October limits, some utilities in SERC-W had identified potential transmission upgrades in which acceleration of existing transmission projects was being considered.

These are current BES projects in various stages of planning, design, and construction. However, with the proposed October limits, no BES projects were identified in which acceleration prior to 2012 was required.

Beyond the impact of CSAPR itself, utilities in the SERC-W Area do not anticipate a significant, immediate impact to system reliability due to the combined effects of CSAPR and other emerging environmental regulations. While the short implementation period allowed for CSAPR created concerns, other emerging rules are expected to have varying implementation dates that will provide adequate time for planning and execution of control projects. In addition, coal plants, which will be most affected by emerging regulations, are positioned relatively well in regard to their capacity and age, such that most projected environmental projects are currently estimated to be economically viable and are not expected to drive early retirements.

Utilities note that depending on the deadlines created by the final EGU MACT rule, applicable deadlines for the installation of major pollution control equipment could be problematic for individual plants. This potential problem is compounded by the uncertainty over regional haze state implementation plan requirements, which when eventually approved by EPA, could require another layer of technology to be installed. Utilities believe that for coal plants, these are issues of timing, permitting, state public service commission approval, and rational project management, not retirement. The most immediate threat to reliability is likely to be in the 2020 time frame, when units will be required to implement 316(b) controls and will need to address any reductions driven by lower National Ambient Air Quality Standards (NAAQS). However, utilities do not anticipate the suite of EPA regulations to result in significant facility retirements or generation reductions.

SPP

Planning Reserve Margins

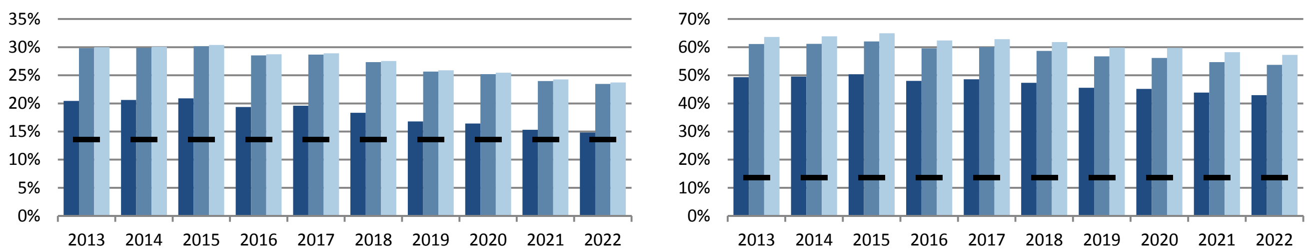
SPP criteria require members to maintain a minimum capacity margin of 12 percent. The SPP RTO is projected to have adequate Planning Reserve Margins throughout the assessment period well above SPP's required Reserve Margin of 13.6 percent, which is also used as the NERC Reference Margin Level. This level of adequacy is supported by the existing and planned generation within the SPP RTO footprint, along with the modest annual demand growth projections during the next 10 years.

SPP-Table 1: Planning Reserve Margins

SPP-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		20.44%	20.61%	20.90%	19.35%	19.60%	18.35%	16.80%	16.43%	15.33%	14.84%
PROSPECTIVE		29.81%	29.89%	30.17%	28.53%	28.69%	27.34%	25.67%	25.20%	23.98%	23.46%
ADJUSTED POTENTIAL		30.01%	30.09%	30.39%	28.75%	28.90%	27.55%	25.90%	25.47%	24.25%	23.73%
NERC REFERENCE	-	**13.60%**	**13.60%**	**13.60%**	**13.60%**	**13.60%**	**13.60%**	**13.60%**	**13.60%**	**13.60%**	**13.60%**

SPP-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		49.32%	49.53%	50.33%	48.02%	48.60%	47.36%	45.59%	45.17%	43.84%	42.96%
PROSPECTIVE		61.10%	61.21%	62.04%	59.56%	60.04%	58.65%	56.72%	56.16%	54.69%	53.72%
ADJUSTED POTENTIAL		63.65%	63.88%	64.94%	62.38%	62.83%	61.82%	59.84%	59.74%	58.24%	57.23%
NERC REFERENCE	-	**13.60%**	**13.60%**	**13.60%**	**13.60%**	**13.60%**	**13.60%**	**13.60%**	**13.60%**	**13.60%**	**13.60%**

SPP-Figure 1: Summer (Left) and Winter[265] (Right) Planning Reserve Margins



Although CSAPR was vacated in August 2012, other federal environmental regulations, which have compliance dates beginning in 2014 could cause the retirement of coal and gas units in the SPP RTO footprint. While the loss of base-load generation does not jeopardize SPP RTO's ability to meet the reserve margin requirements for the footprint, these retirements and/or outage scheduling may cause localized issues. Further discussion on the EPA regulations will take place later in this assessment.

Demand

The projected compound annual growth rate (CAGR) for the SPP RTO is approximately 1 percent from 2013 to 2022.

SPP-Table 2: Demand Outlook

SPP-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	54,247	58,985	4,738	8.7%	0.93%
Load-Modifying Demand Response	933	1,104	170	18.3%	1.88%
TOTAL INTERNAL DEMAND	**55,180**	**60,088**	**4,908**	**8.9%**	**0.95%**

SPP-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	40,983	44,862	3,879	9.5%	1.01%
Load-Modifying Demand Response	731	864	132	18.1%	1.86%
TOTAL INTERNAL DEMAND	**41,714**	**45,726**	**4,012**	**9.6%**	**1.03%**

The 2012 projected annual growth rate is slightly higher than the 2011 projections, primarily due to load growth in one large member's service territory. Throughout the rest of the SPP RTO footprint, economic growth is just now showing signs of slowing, even though the recession has been ongoing across the United States for several years.

[265] Each year represents the initial year of the winter season. For example: 2013 represents the 2013/2014 winter season.

Demand-Side Management

For 2013, SPP RTO projects 910 MW of Contractually Interruptible DR, 85 MW of Direct Control Load Management (DCLM) counted as a resources, 182 MW of load-modifying DCLM, and 28 MW of Load as a Capacity Resource. An additional 307 MW of new conservation (Energy Efficiency) is also projected. Total Demand Response is projected to increase from 1,513 MW in 2013 to 2,408 MW in 2022.

SPP-Table 3: Projected Demand-Side Management

SPP-Summer	Short-Term 2013	Short-Term 2014	Short-Term 2015	2022	10-Year Change	2022 Share of Total Internal Demand
Direct Control Load Management (DCLM)	85	94	104	175	89	0.29%
Contractually Interruptible (Curtailable)	187	271	286	320	133	0.53%
Critical Peak-Pricing (CPP) with Control	0	0	0	0	0	0.00%
Load as a Capacity Resource	0	0	0	0	0	0.00%
TOTAL RESOURCE-SIDE DEMAND RESPONSE	272	365	390	495	223	0.82%
Direct Control Load Management (DCLM)	182	191	200	208	26	0.35%
Contractually Interruptible (Curtailable)	723	719	750	868	145	1.44%
Critical Peak-Pricing (CPP) with Control	0	0	0	0	0	0.00%
Load as a Capacity Resource	28	28	28	28	0	0.05%
TOTAL LOAD-MODIFYING DEMAND RESPONSE	933	938	977	1,104	170	1.84%
TOTAL ENERGY EFFICIENCY	307	369	423	809	502	1.35%
TOTAL DEMAND-SIDE MANAGEMENT	**1,513**	**1,672**	**1,791**	**2,408**	**895**	**4.01%**

For 2022, SPP RTO projects 1,188 MW of Contractually Interruptible DR, 208 MW of Demand-Side DCLM, 175 MW of Supply Side DCLM, 28 MW of Load as a Capacity Resource, and 809 MW of new conservation (Energy Efficiency). SPP RTO projects a yearly increase in Demand Response programs until the year 2018 when the projections become more variable due to the discontinuation of certain programs.

Westar Energy launched its voluntary Demand Response program, Watt Saver, in September 2009. Watt Saver is open to single- and multi-family residential customers as well as small and medium commercial customers who receive a free Honeywell Utility Pro programmable thermostat and access to an online energy management system. From June through September, Watt Saver participants agree to allow Westar to cycle their central air conditioners or heat pumps (on and off in 15-minute intervals) in a coordinated effort to reduce energy demand during peak times. These cycling events normally last between four and six hours and run between noon and 8:00 p.m. Cycling events occur infrequently and only on standard work days. In 2011, Westar implemented the program six times. Currently, more than 32,000 Westar customers are enrolled in the program, which provides an estimated 27 MW of load reduction capability. Westar anticipates enrollment of 90,000 participants with a potential load reduction capability of 90 MW by the end of 2016.

SPP RTO member Oklahoma Gas and Electric (OG&E) installed approximately 40,000 smart meters on customer homes in Norman, Oklahoma in 2010, 2011, and 2012. The information delivery infrastructure was also installed to carry information to and from the customers and OG&E. This program will provide OG&E with 84 MW of Demand Response during peak hours.

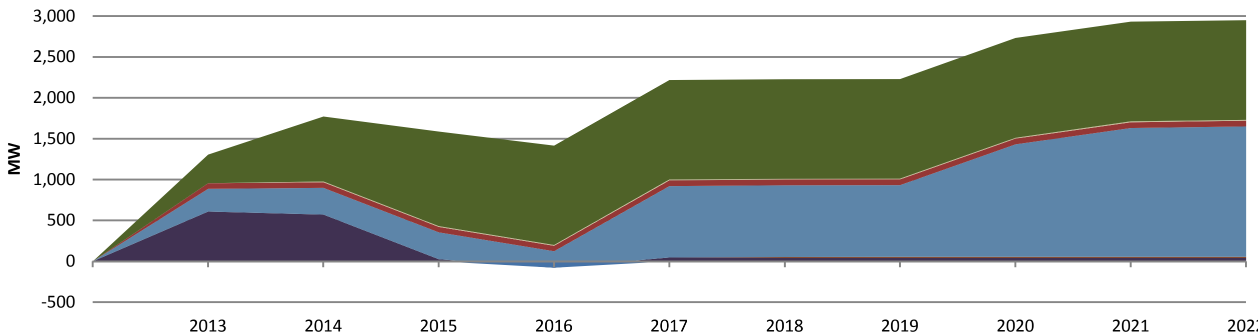
In January 2012, Kansas City Board of Public Utilities (KCBPU) started a voluntary program in which they will install a free Honeywell UtilityPro thermostat in customers’ homes. Participating customers agree to allow KCBPU to raise the temperature in their home or business by up to two degrees. This will allow KCBPU to reduce summer electricity demand during periods of peak use and extreme heat. These peak events typically last no more than four hours and begin on a weekday afternoon and end in early evening. KCBPU expects to enroll 6,000 customers by the end of 2013, which will provide a demand reduction of approximately 10 MW.

Generation

For the current year 2012, SPP RTO forecasts 63,896 MW of Existing-Certain and 5,083 MW of Existing- Other. The primary fuel sources in the SPP RTO footprint are gas (46 percent) and coal (43 percent). Several new generation units have been added to the SPP RTO fleet since the 2011 long-term reliability assessment, including 308 MW of wind, 552 MW of gas, and 168 MW of coal.

SPP-Table 4: Capacity Outlook[266]

SPP-Summer	Current		2022 Planned			2022 Planned & Conceptual		
	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Coal	27,334	42.5%	27,380	40.7%	46	27,380	39.7%	46
Petroleum	1,919	3.0%	1,927	2.9%	9	1,927	2.8%	9
Gas	29,395	45.7%	30,990	46.0%	1,595	31,200	45.3%	1,805
Nuclear	2,409	3.7%	2,480	3.7%	71	2,626	3.8%	217
Other/Unknown	40	0.1%	50	0.1%	10	50	0.1%	10
Renewables	3,291	5.1%	4,511	6.7%	1,220	5,730	8.3%	2,439
TOTAL	**64,388**	**100.0%**	**67,338**	**100.0%**	**2,951**	**68,913**	**100.0%**	**4,525**



Future-Planned Expected on-peak capacity from renewable plants increases from 350 MW in 2013 to 1,220 MW in 2022. These reported renewable resource additions in the SPP RTO do not reflect merchant wind farm development in process, incremental needs that may result from Renewable Energy Standard mandates or goals within the SPP RTO region, or public announcements for additional renewable expansion by SPP RTO members. The SPP RTO has requests to interconnect approximately 14,109 MW of Future-Planned generation (mostly wind) to the SPP RTO grid via the generation interconnection queue.

Variable generation of 13,900 MW nameplate capacity comprises the majority of the Conceptual resources. SPP Criteria Section 12.0[267] discusses capacity values and how they are calculated for the Region based on a wind farm's historical performance. The SPP RTO applies a 10 percent confidence factor to all Conceptual capacity unless otherwise reported by SPP RTO members. Therefore, Conceptual Capacity Resources are forecast to be 1,045 MW in 2013, increasing to 1,575 MW in 2022.

For the reporting of Future and Conceptual Capacity Resources, the SPP RTO uses the Generation Interconnection and Transmission Service Request study processes as defined in the SPP OATT. According to the OATT, when the interconnection request is submitted, the interconnection customer must request either energy resource interconnection service or Network Resource interconnection service. Any interconnection customer requesting Network Resource interconnection service may also request that it be concurrently studied for energy resource interconnection service. This remains an option up to the point when an interconnection facility study agreement is executed. Interconnection customers may then elect to proceed with Network Resource interconnection service or to proceed under a lower level of interconnection service to the extent that only certain upgrades will be completed. In the NERC LTRA, the SPP RTO includes active requests that are currently in the generation queue to be studied, in addition to the member-reported Future, Planned, and Conceptual resources.

SPP RTO projects 929 MW of generation retirements over the 2013–2022 assessment time frame, not including retirements or derates that may occur in response to developing EPA regulations. The retirement of units is scheduled as follows: 130

[266] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.
[267] SPP Criteria: http://www.spp.org/publications/CRITERIA%20and%20Appendices%2001-25-2011Current.pdf.

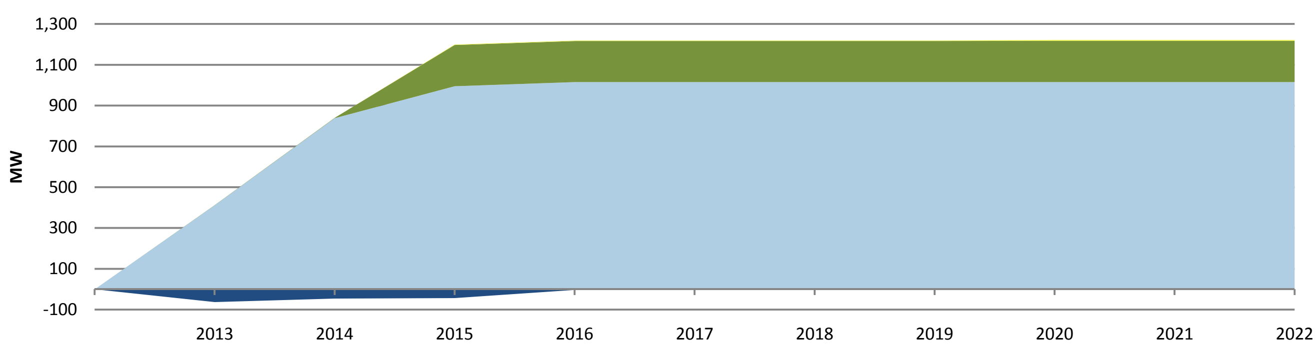
MW in 2013, 18 MW in 2015, 250 MW in 2016, and 531 MW in 2022. SPP RTO does not expect to have any reliability issues because of the projected retirements. With the new generation projected there are no operational or planning concerns at this time. There have been no project cancellations, and while some derates were reported from the previous year's assessment, they were not material.

The planned and conceptual renewable resources for the year 2022 are as follows: 2,505 MW of expected on-peak wind capacity with a maximum nameplate capacity of 28,069 MW, 13 MW of expected on-peak solar capacity with a maximum nameplate capacity of 90 MW, 2,673 MW of expected on-peak hydro capacity with a maximum nameplate capacity of 2,785 MW, and 221 MW of expected on-peak biomass capacity. The expected on-peak capacity values for this variable generation are determined by guidelines established in the SPP Criteria Section 12.0.

SPP-Table 5: Renewable Capacity Outlook[268]

	Current		2022 Planned			2022 Planned & Conceptual		
SPP-Summer	Capacity	Share	Capacity	Share	Change	Capacity	Share	Change
Hydro	2,676	81.3%	2,673	59.2%	-3	2,673	46.6%	-3
Pumped Storage	319	9.7%	319	7.1%	0	319	5.6%	0
Geothermal	0	0.0%	0	0.0%	0	0	0.0%	0
Wind	273	8.3%	1,289	28.6%	1,016	2,505	43.7%	2,232
Biomass	19	0.6%	221	4.9%	202	221	3.9%	202
Solar	5	0.2%	10	0.2%	5	13	0.2%	8
TOTAL	**3,291**	**100.0%**	**4,511**	**100.0%**	**1,220**	**5,730**	**100.0%**	**2,439**

SPP-Figure 3: Summer Net Renewable Capacity Change



SPP-Table 6: Renewable Capacity Outlook: On-Peak Vs. Installed

	Current				2022 Planned			
SPP-Summer	Wind	Solar	Hydro	Biomass	Wind	Solar	Hydro	Biomass
Installed Capacity	5,537	50	2,827	19	17,194	100	2,824	231
On-Peak Derate	5,264	45	152	0	15,905	90	152	10
EXPECTED ON-PEAK OUTPUT	273	5	2,676	19	1,289	10	2,673	221

SPP RTO evaluates operational procedures on an ongoing basis to determine if there are available improvements in efficiencies 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 where wind is the primary impacting resource. It is anticipated that SPP RTO would then be able to manage system reliability by quicker and more effective control actions.

Capacity Transactions

SPP RTO members reported the following imports and exports for 2013–2022 (SPP-Table 7). These are Firm contracts that are backed by Firm transmission and generation.

[268] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

SPP-Table 7: Projected Capacity Transactions

SPP-Summer	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Expected Imports	0	0	0	0	0	0	0	0	0	0
Firm Imports	2,247	2,408	2,408	2,408	2,458	2,458	2,488	2,488	2,488	2,488
TOTAL IMPORTS	2,247	2,408	2,408	2,408	2,458	2,458	2,488	2,488	2,488	2,488
Expected Exports	50	50	50	50	50	50	50	50	50	50
Firm Exports	2,338	2,307	1,997	1,997	2,067	2,034	2,034	2,034	2,034	2,043
TOTAL EXPORTS	2,388	2,357	2,047	2,047	2,117	2,084	2,084	2,084	2,084	2,093
TOTAL NET CAPACITY TRANSACTIONS	**-141**	**50**	**361**	**361**	**341**	**374**	**404**	**404**	**404**	**395**

SPP RTO members and some members of SERC have formed a Reserve Sharing Group. Group members receive contingency reserve assistance from each other; however, due to the high Reserve Margin in the SPP RTO footprint, group participants within SPP generally transfer reserves into SERC. Therefore, the group does not require support from generation resources located outside the SPP RTO region. The SPP RTO’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 one-half of the capacity of the next-largest generating unit scheduled to be on-line.

Transmission

Appendix II lists the BPS transmission projects SPP RTO has defined as Under Construction, Planned, or Conceptual that are projected to be in service during the assessment time frame. Existing and projected transmission projects are summarized below (SPP-Table 8).

SPP-Table 8: Existing and Projected Transmission

SPP	AC (Circuit Miles)	DC (Circuit Miles)	Total (Circuit Miles)
EXISTING	32,881	0	32,881
Currently Under Construction	638	0	638
Planned - Completed within First Five Years	1,613	0	1,613
Planned - Completed within Second Five Years	180	0	180
2022 TOTAL (UNDER CONSTRUCTION & PLANNED)	35,311	0	35,311
Conceptual - Completed within First Five Years	47	0	47
Conceptual - Completed within Second Five Years	103	0	103
2022 TOTAL (UNDER CONSTRUCTION, PLANNED & CONCEPTUAL)	**35,460**	**0**	**35,460**

There are several significant transmission projects involving upgrades to existing transmission lines for reliability purposes.

- In north-central Oklahoma, 45 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 from Anadarko to Franklin will be converted to 138 kV. In southwestern Oklahoma, the 33-mile Lindsay Flood Tap to Cornville 69 kV line will be converted to138 kV.
- 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. Additionally, in the last five years of the assessment period, the Kansas entities plan to rebuild the 33-mile Harper to Clearwater 138 kV line in this same Area. In the north-central Kansas Area, the 35-mile Clifton to Knob Hill 115 kV line will also be rebuilt. Kansas entities plan to rebuild 41 miles of 115 kV from Chapman–Abilene Energy Center to North Street in north-central Kansas.
- In the Texas panhandle, the 45-mile 69 kV Potter to Channing line will be converted to 115 kV during the first five years of the assessment. During the next five years of the assessment period, this line and an additional 35-mile line to Dallam is planned for conversion to 230 kV. In east Texas, 33 miles of 69 kV will be converted to 138 kV from Martinsville to Tempson.
- In Missouri, the 34-mile 161 kV line from Idalia to Poplar Bluff will be rebuilt.

The following projects are considered interregional interconnection-related projects:

- Stegall Project: Add a second 345/230 kV transformer at Stegall. The installation of this transformer requires a 3.3-mile tie line between the Stegall 230 kV and 345 kV substation. This project is to address low voltage at Victory Hill in southwest Nebraska for the loss of the first Stegall 345/230 kV.

- Gentleman–Cherry County–Holt: This project is a 345 kV multiline project through a large portion of central Nebraska. The Cherry County–Holt 345 kV line segment is proposed to interconnect with a WAPA 345 kV line. The construction of this project is driven by reliability needs, economic needs, and the need to meet renewable policies both in Nebraska and other areas in the SPP footprint.

The SPP RTO has sufficient transmission being constructed to meet the needs of the reported Future-Planned generation.

Appendix III contains a list of transformers projected to be in service during the assessment period.

Vulnerability Assessment

The impact of a long-term drought in the SPP RTO footprint would result in some loss of generation due to the unavailability of hydro generation and the loss of generation cooling water supplies. However, it is not anticipated that a long-term drought would impact reliability during the assessment period because SPP's geography is diverse and large portions of generation are not dependent upon single watersheds.

With the D.C. Circuit Court's decision to vacate CSAPR in August 2012, that regulation will no longer impact the SPP RTO footprint. However, the EPA's MATS regulation could result in generator retirements in the SPP footprint during the assessment period, and more detailed studies of the localized reliability impact will be conducted in response to official notifications of these retirements. In addition, there is a need to undertake coordination of outage scheduling around the compliance dates for new EPA standards, which may result in the need for limited compliance extensions. At this time and based on information provided to SPP RTO from members in March 2012, there are currently no scheduled long-term generator outages that could result in reliability concerns in the SPP RTO footprint.

EPA regulations may reduce the overall capacity margin within the SPP RTO, but some portion of that capacity is expected to be replaced due to an increase in renewable resources because of Renewable Portfolio Standards and state mandates. However, the replacement of that capacity with variable renewable technologies then raises reliability concerns of maintaining adequate frequency response, balancing control, and other reserve requirements. SPP RTO is participating in various standard development and research projects to determine any new requirements that may be necessary.

The projected level of Demand Response is not expected to have a significant impact on reliability during the next 10 years.

SPP RTO is evaluating the need for further requirements or standards that may be necessary to preserve reliability with increased levels of distributed, renewable generation such as rooftop solar and wind. The frequency response, balancing controls, and reserve requirement implications are the concern with these technologies.

SPP RTO is investigating the impact of requiring new variable generation installations to possess dispatch ability controls in order to allow the variable generation to respond to automatic security constrained dispatch instructions.

The SPP RTO only has one Under-Voltage Load Shedding program in western Arkansas within the AEP-West footprint. This program targets about 186 MW of load shed during peak summer conditions to protect the BPS from under-voltage events.

The SPP RTO has seven Special Protection Systems that are approved to be in place from 18 months to five years, based on the reliability need. All SPS requests are reviewed and approved by SPP's System Protection and Control Working Group, the Operating Reliability Working Group, and the Transmission Working Group.

SPP RTO has one SPS that was implemented in fall 2011 that is expected to be in service for three years. An automatic control system (ACS) was implemented to curtail a wind farm output to limit the flow on the MKEC Station–Cudahay line to 90 percent of the line rating under normal conditions. The SPS system would alleviate any overloads in the event of a system contingency or the failure of the ACS system. This temporary solution will be replaced with a permanent solution with the construction of a second 115 kV North Judson Large to Spearville line, which would eliminate the single contingency exposure to overloading the MKEC Station–Cudahay line. No SPS in SPP RTO was installed in place of planned bulk power transmission facilities.

While SPP RTO does not have a planning process in place at this time for catastrophic events, it does assess and study selected events as required by TPL-003 and TPL-004.

SPP RTO expects to implement its Day 2 market for its RTO footprint on March 1, 2014. This market, otherwise known as the Integrated Marketplace, will centralize unit commitment across 16 Balancing Authority (BA) Areas and consolidate operations to a single BA, known as the SPP RTO Consolidated Balancing Authority. 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. It is expected that 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 Phasor Measurement Units (PMU) systems within the footprint in order to enhance reliability analysis and situational awareness.

At this time, SPP RTO is in the early stages of investigating appropriate smart grid programs.

On a quarterly basis, SPP RTO reviews several years of SPP RTO Protection System misoperations data looking for trends that could be used to help reduce the number of misoperations in the future.

In December 2011, the U.S. Court of Appeals issued a stay of CSAPR that allowed SPP RTO staff to conduct a reliability impact assessment of the EPA MATS and CSAPR regulations (EPA Assessment) in early 2012. That assessment was based on members' preliminary expectations of how they currently plan to comply with both the CSAPR and the MATS. The EPA assessment indicated that for the years 2013 and 2015, outages associated with retrofits, deratings, revised dispatch, and retirements as a result of members' current expectations to comply with these regulations does have the potential for localized reliability violations but should not present footprint-wide negative reliability implications resulting from the assumptions used in the EPA's model.[269] Further, SPP analyzed the resource adequacy of the Region based on member EPA rules compliance expectations and, assuming no other negative circumstances in the SPP RTO footprint, resource adequacy appears to be sufficient. These conclusions could change if individual entities' underlying compliance planning changes.

Standing and Emerging Issues

Even with the decision to vacate CSAPR, the standing reliability issue that SPP RTO is most concerned about for the 10-year assessment period is the impact of the EPA MATS regulation as well as other developing environmental regulations on reserve margins and localized grid stability. On-going discussions with SPP RTO and EPA have recognized that ways of managing retrofits continues to be explored and these are being proactively managed. The SPP Operational Reliability Working Group has been tasked with oversight of a long-term outage coordination study to determine the impact of long-term outages to facilitate new environmental capture technologies and the expected retirements due to regulations. It is expected that the impact of these retirements and retrofits will begin to be experienced by 2015. The compressed compliance time frame provided for MATS will constrain the availability and increase the costs of qualified labor, materials and heavy equipment. These constraints, as well as the need to coordinate outage scheduling and complete localized transmission reinforcement projects, will likely demand that the compliance deadlines for certain units be extended. SPP RTO is maintaining regular contact with individual entities to ensure that any specialized assessments can be completed in time to identify and address circumstances in which additional time may be warranted. SPP RTO expects to complete an initial analysis of this issue by the end of 2012.

Capacity margins would be expected to decline throughout the SPP footprint, with at least some replacement capacity coming in the form of additional wind installations. However, wind as replacement capacity is subject to variability, inertia,

[269] The impacts identified in the study for 2013 will no longer be applicable with the CSAPR decision, but SPP RTO believes the MATS regulation will have similar impacts beginning in 2015 due to the four year compliance timeframe from the December 2011 finalization date of MATS.

and dispatch ability concerns. Lower capacity margins increase the exposure of the area to regional events such as those caused by extreme cold weather, droughts, widespread flooding, etc.

SPP RTO is also concerned about the dispatch ability of wind-powered resources. SPP RTO has been identified as an area rich with the hub height winds (the appropriate wind profile needed for the production of wind generation). While additional wind resources provide positive growth to the SPP RTO capacity margin, they also bring the issues associated with having a variable fuel supply. Also, without adequate requirements in place, new wind resources will not be equipped with the necessary primary frequency response, dispatch ability, or adequate voltage regulation controls. SPP RTO is participating in various forums to understand the implications and necessary actions to provide the appropriate requirements not just for wind resources, but all new generation technologies. There could be anywhere from 10,000 to 24,000 MW of nameplate wind resources forecast to be built within the SPP Region over the next 10 years. This includes wind that SPP RTO concludes to be Future-Planned and Conceptual. SPP's Integrated Transmission Planning process is taking into account the additional transmission needs of new wind resources.

Finally, SPP RTO and other affected parties are reviewing studies performed by Clean Line Energy for HVdc lines proposed to traverse across SPP from west to east. The first project, the Plain and Eastern line, is a 3,500 MW capacity, 700-mile HVdc facility that is planned to begin in western Oklahoma and end in western Tennessee.[270] The second Clean Line Energy project, the Grain Belt Express Line, is a 3,500 MW, 700-mile HVdc facility planned between Kansas and Missouri

SPP and other affected parties are also reviewing studies performed by Tres Amigas for its proposed construction of an HVdc transmission facility that will link America's three primary electric transmission grids: the Eastern Interconnect (SPP, MRO, etc.), the Western Interconnect (WECC) and Texas (ERCOT).[271]

Both Clean Line Energy projects and the Tres Amigas project are in the planning stages. No Firm in-service dates are known for the Clean Line projects, but Tres Amigas expects Phase 1 (750 MW) of its project to be in service by March 2015. As stated above, SPP has begun the technical evaluation of these projects. Should the proposed facilities be constructed and placed in service, 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 impact to the BES.

[270] http://www.plainsandeasterncleanline.com/site/home
[271] http://tresamigasllc.com/index.php

WECC

Planning Reserve Margins

The Planning Reserve Margins, or target margins, were derived using the 2013 load forecast and the same method as the 2011 Power Supply Assessment (PSA).[272] The PSA uses a building block method for developing the Planning Reserve Margins and has four elements:

- Contingency reserves
- Operating reserves
- Reserves for forced outages
- Reserves for one-year-in-ten weather events

By the summer of 2022, the difference between WECC's Anticipated Resources (194,401 MW) and WECC's Net Internal Demand (168,973 MW) is anticipated to be 25,429 MW (15.0 percent margin). This would be 759 MW above the target margin. Since the expected capacity resources result in margins that 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 subregional tables, found at the end of the WECC section, the Anticipated, Prospective, and Adjusted Potential Reserve Margins for the WECC Assessment Area remain above NERC Reference Margin Level throughout the 2013–2022 planning horizon. However, individual subregions do drop below the target in future years.

NERC's assessment process treats Demand Response (DR) programs as sharable between Load-Serving Entities (LSE), Balancing Authorities (BA), and subregions. However, DR programs in WECC generally have limitations, such as having a limited number of times they can be called. Some can only be called during a declared local emergency. Consequently, Planning Reserve Margins may be overstated, as these margins do not consider the potential unavailability of DR for external energy emergencies. Many LSEs within WECC largely treat DR as a safety net that is available if circumstances such as unexpected generator-forced outages or extreme temperature events result in unexpected low operating margins.

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 (1-2 years), but most projections provide at least a 10-year outlook. WECC's PSA uses a study period of 10 years and uses 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 resources (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.

Demand

Total Internal Demand for the summer, the peak season for the entire WECC Assessment Area, decreased by 0.8 percent from 2010 to 2011. Summer temperatures in both 2010 and 2011 were normal to slightly warmer than normal which indicates actual demand reduction is associated with the continued slow economic recovery. The projected 2013 and 2022 Total Internal Demand forecasts and compound annual growth rates are presented in the following tables.

[272] WECC's Power Supply Assessment: http://www.wecc.biz/Planning/ResourceAdequacy/PSA/Documents/Forms/AllItems.aspx.

Demand Outlook – WECC Total

WECC-Total-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	144,936	168,973	24,036	16.6%	1.72%
Load-Modifying Demand Response	5,041	5,583	542	10.8%	1.14%
TOTAL INTERNAL DEMAND	**149,977**	**174,556**	**24,578**	**16.4%**	**1.70%**

WECC-Total-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	132,006	150,429	18,423	14.0%	1.46%
Load-Modifying Demand Response	2,018	2,385	367	18.2%	1.87%
TOTAL INTERNAL DEMAND	**134,024**	**152,814**	**18,790**	**14.0%**	**1.47%**

The Total Internal Demand for the summer season is projected to increase by 1.7 percent per year for the 2013–2022 timeframe, which is unchanged from the 1.7 percent projected last year for the 2012–2021 period. The annual energy load is projected to increase by 1.6 percent per year for the 2013–2022 timeframe, which is unchanged from the 1.6 percent projected last year for the 2012–2021 period.

Demand-Side Management

The total WECC internal demand forecast includes summer DR that varies from 5,041 MW in 2013 to 5,583 MW in 2022. The direct control DSM capability is located mostly in the CALN and CALS subregions, totaling 2,812 MW in 2013 and 3,131 MW in 2022, but 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 such as mining. The most significant current DR development activity within WECC is occurring in California where the California ISO (CISO) is actively engaged with stakeholders in developing viable wholesale DR products with direct market participation capability. Also of note is the CISO's new DR product implementation that facilitates the participation of existing retail demand programs in the CISO market. Further information regarding these initiatives is available at the CISO website.[273]

Projected Demand-Side Management – WECC Total

WECC-Total-Summer	Short-Term 2013	2014	2015	2022	10-Year Change	2022 Share of Total Internal Demand
Direct Control Load Management (DCLM)	2,023	2,103	2,125	2,144	121	1.12%
Contractually Interruptible (Curtailable)	1,836	1,923	1,971	2,023	187	1.06%
Critical Peak-Pricing (CPP) with Control	7	12	13	16	9	0.01%
Load as a Capacity Resource	1,175	1,099	1,115	1,400	225	0.73%
TOTAL LOAD-MODIFYING DEMAND RESPONSE	5,041	5,137	5,224	5,583	542	2.92%
TOTAL ENERGY EFFICIENCY	1,150	1,749	2,418	6,859	5,709	3.59%
TOTAL DEMAND-SIDE MANAGEMENT	**6,191**	**6,886**	**7,642**	**12,442**	**6,251**	**6.51%**

Generation

The generation data for this assessment was provided by all of the BAs within the Western Interconnection and was processed by WECC staff under the direction of the WECC Loads and Resources Subcommittee (LRS). The reported generation additions generally reflect extractions from generation queues.

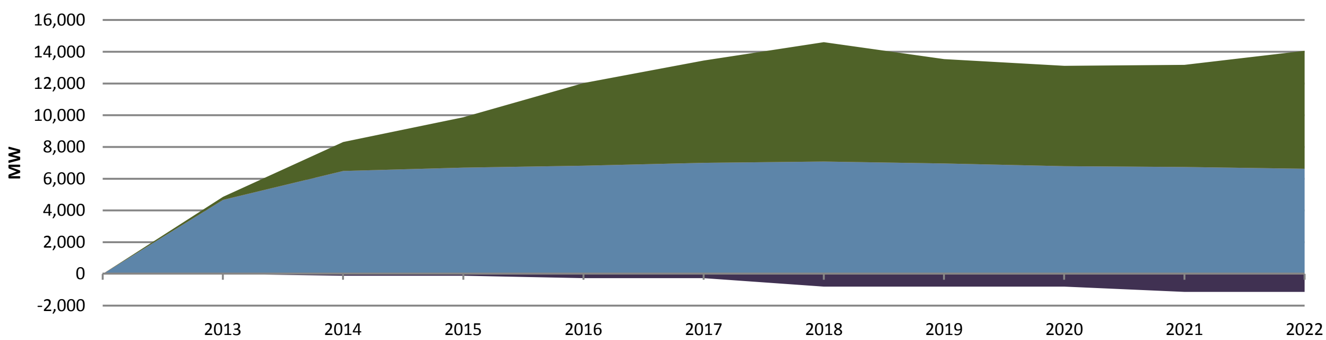
Distributed generation, including rooftop solar and behind-the-meter generation, represents an insignificant portion of both the existing and planned resources. As noted previously, these resources are excluded from the resource adequacy calculation (i.e., they are not included as resources). The current resource mix by fuel type includes natural gas, hydro-powered, and coal-fired generation at 87,769 MW, 61,439 MW, and 35,069 MW, respectively.

Since last year's assessment, expected available capacity increased by 363 MW. Thermal plant additions were largely gas-fired combined-cycle plants, while renewable additions were largely wind farms.

[273] CAISO Demand Response Initiatives: http://www.caiso.com/1893/1893e350393b0.html.

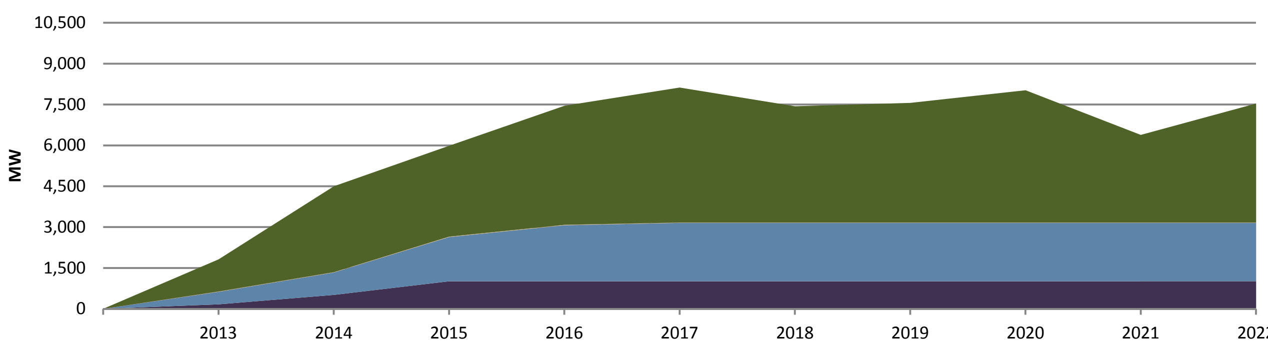
Capacity Outlook– WECC-US[274]

WECC-US-Summer	Current Capacity	Current Share	2022 Planned Capacity	2022 Planned Share	2022 Planned Change	2022 Planned & Conceptual Capacity	2022 Planned & Conceptual Share	2022 Planned & Conceptual Change
Coal	29,333	17.9%	28,188	16.1%	-1,145	28,188	15.3%	-1,145
Petroleum	1,084	0.7%	1,084	0.6%	0	1,004	0.5%	-80
Gas	79,303	48.5%	85,055	48.4%	5,752	91,811	49.8%	12,508
Nuclear	9,553	5.8%	9,553	5.4%	0	9,553	5.2%	0
Other/Unknown	52	0.0%	52	0.0%	0	52	0.0%	0
Renewables	44,229	27.0%	51,655	29.4%	7,426	53,615	29.1%	9,386
TOTAL	**163,553**	**100.0%**	**175,586**	**100.0%**	**12,033**	**184,222**	**100.0%**	**20,669**



Capacity Outlook– WECC-CAN[275,276]

WECC-CAN-Winter	Current Capacity Mix	Current Share of Total	2022/23 Planned Capacity Mix	2022/23 Planned Share of Total	2022/23 Planned Change	2022/23 Planned & Conceptual Capacity Mix	2022/23 Planned & Conceptual Share of Total	2022/23 Planned & Conceptual Change
Coal	5,811	21.6%	6,655	19.4%	844	6,655	18.4%	844
Petroleum	0	0.0%	0	0.0%	0	0	0.0%	0
Gas	6,794	25.2%	8,904	26.0%	2,110	10,781	29.9%	3,988
Nuclear	0	0.0%	0	0.0%	0	0	0.0%	0
Other/Unknown	22	0.1%	26	0.1%	4	26	0.1%	4
Renewables	14,282	53.1%	18,653	54.5%	4,371	18,653	51.6%	4,371
TOTAL	**26,909**	**100.0%**	**34,238**	**100.0%**	**7,329**	**36,115**	**100.0%**	**9,206**



Gross Future-Planned additions are 12,033 MW for the United States, and 7,329 MW for Canada. Conceptual additions amount to 20,669 MW and 9,206 MW for the United States and Canada, respectively.

Three utilities attributed coal-fired plant retirements totaling 1,050 MW and fuel conversions totaling 295 MW to existing air emissions regulations. Based on information related to western coal-fired plant environmental regulation cost

[274] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.
[275] *Ibid*.
[276] Years represent initial year for each winter season. For example: 2013 represents the 2013/2014 winter season.

exposure,[277] it is expected that next year's LTRA information will report additional retirements and fuel conversion as more plant owners establish their preferred approaches to address the recent Maximum Achievable Control Technology regulations. 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.[278]

It is expected that the WECC Region will not experience significant resource capability changes due to plant rating changes, plants being temporarily removed from service, new "non-traditional" resource acquisitions, or changes in behind-the-meter generation.

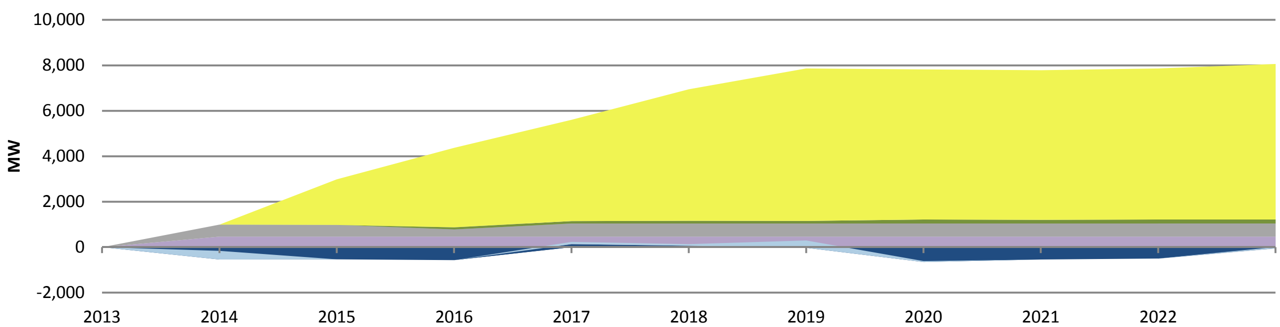
The projected summer peak-period Existing-Certain and Future-Other resources value 2013 of 182,873 MW reflects the monthly shaping of variable generation and the seasonal ratings of conventional resources. The resources not counted toward on-peak capacity include 45,791 MW of variable generation derates and 10,264 MW of scheduled outages. Hydro derates reflect an assumed adverse hydro condition and is dispatched economically limited to a specified annual energy output. Wind derates are based on wind capability curves created using three years' worth of one-hour interval wind speed data while solar production curves were created using two years of solar insolation data.

The individual BAs report the net Future-Planned Capacity Resources projected to be placed into service by the end of this assessment period as 19,361 MW.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 issue. Increased wind generation has also exacerbated high generation issues in the Bonneville Power Administration (BPA) Area during light load and high hydro-electric generation conditions. BPA is working on long-term solutions to this issue and makes current information regarding the issue available on its website.[279] Increased wind penetration is expected to exacerbate the operating reserve situation.

[277] Environmental Controls and the WECC Coal Fleet: http://www.wecc.biz/committees/BOD/TEPPC/TAS/SWG/10March2011/Lists/Minutes/1/WGG_Coal_Plant_Database_Documentation_Final.pdf.
[278] CEC Once-Through Cooling: http://www.energy.ca.gov/siting/once_through_cooling.html.
[279] BPA Wind Activities http://transmission.bpa.gov/wind/.

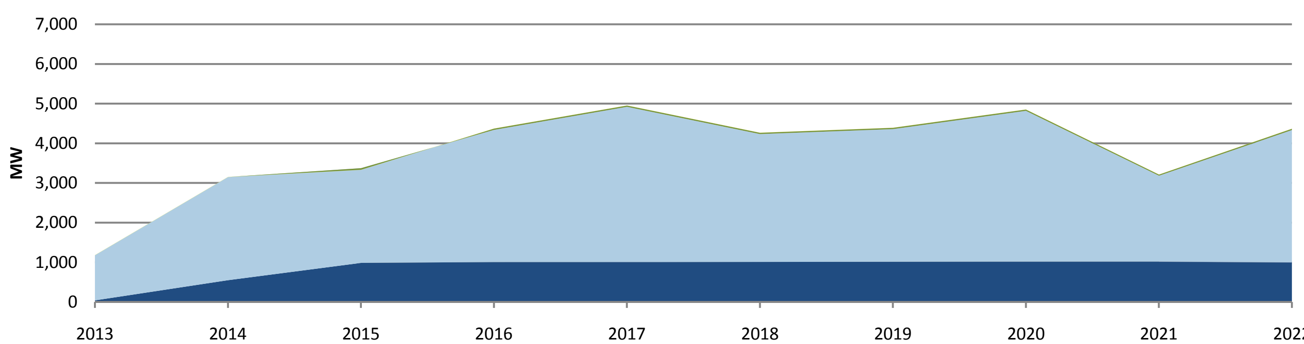
Renewable Capacity Outlook[280]

WECC-US-Summer	Current Capacity	Current Share	2022 Planned Capacity	2022 Planned Share	2022 Planned Change	2022 Planned & Conceptual Capacity	2022 Planned & Conceptual Share	2022 Planned & Conceptual Change
Hydro	34,505	78.0%	34,457	66.7%	-48	34,481	64.3%	-24
Pumped Storage	4,872	11.0%	4,887	9.5%	15	5,277	9.8%	405
Geothermal	2,087	4.7%	2,478	4.8%	392	3,227	6.0%	1,141
Wind	317	0.7%	371	0.7%	54	411	0.8%	94
Biomass	802	1.8%	977	1.9%	175	980	1.8%	178
Solar	1,646	3.7%	8,485	16.4%	6,839	9,239	17.2%	7,592
TOTAL	**44,229**	**100.0%**	**51,655**	**100.0%**	**7,426**	**53,615**	**100.0%**	**9,386**



WECC-CAN-Winter	Current Capacity	Current Share	2022/23 Planned Capacity	2022/23 Planned Share	2022/23 Planned Change	2022/23 Planned & Conceptual Capacity	2022/23 Planned & Conceptual Share	2022/23 Planned & Conceptual Change
Hydro	12,836	89.9%	13,835	74.2%	999	13,835	74.2%	999
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	1,173	8.2%	4,513	24.2%	3,341	4,513	24.2%	3,341
Biomass	273	1.9%	305	1.6%	31	305	1.6%	31
Solar	0	0.0%	0	0.0%	0	0	0.0%	0
TOTAL	**14,282**	**100.0%**	**18,653**	**100.0%**	**4,371**	**18,653**	**100.0%**	**4,371**

Renewable Capacity Outlook[281]



[280] "Current" represents Existing-Certain and Future-Planned projections for the 2012 summer (for summer-peaking assessment areas) or 2012/2013 winter (for winter-peaking assessment areas). "Share" represents the share (percent) of total Existing-Certain and Future-Planned capacity projected for the peak season.

[281] Years represent initial year for each winter season. For example: 2013 represents the 2013/2014 winter season.

WECC-Total-Table 8: Renewable Capacity Outlook: On-Peak Vs. Installed

	Current				2022 Planned			
WECC-TotalL-Summer	Wind	Solar	Hydro	Biomass	Wind	Solar	Hydro	Biomass
Installed Capacity	17,249	2,725	66,984	1,944	30,649	15,738	69,032	3,287
On-Peak Derate	16,893	1,079	19,969	872	29,511	6,144	20,574	2,029
EXPECTED ON-PEAK OUTPUT	356	1,646	47,016	1,072	1,138	9,595	48,458	1,257

Capacity Transactions

WECC does not rely on imports from outside the Assessment Area when calculating peak demand reliability margins. The Assessment Area also does not model exports to areas outside of WECC. However, imports may be scheduled across three back-to-back dc ties with the Southwest Power Pool, Inc. (SPP) and five back-to-back dc ties with the Midwest Reliability Organization (MRO). One WECC entity reports a 101 MW diversity exchange credit with its counterpart in SPP, but this exchange is not reflected in this assessment. WECC does not model “emergency generation” as being available to meet the NERC Reference Margin Level.

Inter-subregional transfers are derived from resource allocation computer simulations that incorporate transmission constraints among various path-constrained zones within WECC. The WECC resource allocation model places conservative transmission limits on paths between 20 load groupings (bubbles) when calculating the transfers between these areas. These load bubbles were developed for WECC’s PSA studies. The aggregation of PSA load bubbles into WECC subregions may obscure differences in adequacy or deliverability between bubbles within the subregion. Hence, the resource data for the individual subregions include transfers between subregions that are either plant-contingent transfers or reflect projected economic transfers with a high probability of occurrence. The plant-contingent transfers represent both joint-plant ownership and plant-specific transfers from one subregion to another.

The projected economic 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 Firm purchases that may occur between subregions.

Despite the fact that 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 using the adjusted potential resource mixes, all of the subregions are able to maintain adequate reserves.

A process similar to the one used to determine regional and subregional target margins was used to determine the inter-subregional transfers. The various area bubbles used were combined into the appropriate WECC subregions, and the excess or deficit capacity was summed for each of the WECC subregions. The excess or deficit capacity was then used to calculate the amount of projected purchases or projected sales transactions between the various subregions.

Western entities participate in shorter-term power markets for which forecasts are not available. This is a primary reason the WECC analysis uses the simulation process described above to determine the projected transfer values. The Western Systems Power Pool contract, which contains liquidated damage provisions, is heavily relied upon as the template for such transactions.

Transmission

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 loading on numerous transmission lines, but that full loading is deemed not to adversely impact reliability. Due to the inter-subregional transmission constraints, reliability in the Western Interconnection is best examined at a subregional level.

AC transmission line additions through 2022 have been reported at 15,841 circuit miles and 535 circuit miles of DC transmission. The reported existing and projected transmission additions are compiled in the following table (WECC-Total-Table 8).

WECC-Total-Table 8: Existing and Projected Transmission

WECC-Total	AC (Circuit Miles)	DC (Circuit Miles)	Total (Circuit Miles)
EXISTING	127,019	1,744	128,763
Currently Under Construction	199	0	199
Planned - Completed within First Five Years	5,784	535	6,319
Planned - Completed within Second Five Years	4,501	0	4,501
2022 TOTAL (UNDER CONSTRUCTION & PLANNED)	137,503	2,279	139,782
Conceptual - Completed within First Five Years	2,759	0	2,759
Conceptual - Completed within Second Five Years	2,598	0	2,598
2022 TOTAL (UNDER CONSTRUCTION, PLANNED & CONCEPTUAL)	**142,860**	**2,279**	**145,139**

There are a large number of transmission projects that have been reported to WECC. Some of these projects are duplicative in nature and may have a proposed path similar to another project. Since WECC does not vet the reported new projects and does not identify minimum transmission addition needs, the above tabulation may not closely reflect transmission additions that could occur during the assessment period. A delay of these projects could impact the timing and location of resource additions but should not adversely impact system reliability. The subregion sections of this assessment may identify some projects that could impact local area reliability. The WECC Transmission Project Information Portal[282] 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 has analyzed the development status of reported major transmission projects and identified 30 projects that have a high probability of being in service by 2022. Information regarding the projects is available in the group's report *2022 Common Case Transmission Assumptions* (CCTA).[283]

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 *Policies and Procedures for Project Coordination Review, Project Rating Review, and Progress Reports*.[284] 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.

WECC has signed an agreement with the U.S. Department of Energy to receive a $53.9 million grant for the Western Interconnection Synchrophasor Program (WISP). The funding allows an accelerated installation of more than 250 new Phasor Measurement Units (PMUs) in the Western Interconnection. The PMUs are designed to alert operators to existing and potential problems on the grid and improve the ability to integrate and manage intermittent renewable resources in the west. The synchrophasor infrastructure and associated software applications and tools are expected to improve situational awareness, system-wide modeling, performance analysis, and wide-area monitoring and controls. Further information regarding the WISP program is available on the WECC website.[285]

Growth in demand combined with increases in projected new generation has resulted in the need for significant transmission system upgrades and expansion. Because of the longer lead time required for transmission permitting and

[282] WECC Transmission Project Information Portal: http://www.wecc.biz/PLANNING/TRANSMISSIONEXPANSION/MAP/Pages/.
[283] 2022 Common Case Transmission Assumptions (CCTA): http://www.wecc.biz/committees/BOD/TEPPC/External/SCG_CCTA_Report.pdf.
[284] WECC's Overview of Policies and Procedures for Project Coordination Review, Project Rating Review and Progress Reports: http://www.wecc.biz/committees/StandingCommittees/PCC/Shared%20Documents/ProjectCoordination_ProjectRating_ProgressReports_approved%203-11.aspx.
[285] WECC WISP web site: http://www.wecc.biz/awareness/Pages/WISP.aspx.

construction, network planning focuses on establishing a flexible grid infrastructure. This is being done with the goal of accommodating internal power movement from generation sources to load centers.

Planning efforts continue on a number of major system reinforcements, including supply into the Fort Saskatchewan and Fort McMurray Areas of northeast Alberta. This reinforcement will likely be a combination of 500 kV and 240 kV developments. Planning efforts are also continuing on reinforcing the main north-south transmission grid in Alberta. The Edmonton–Calgary Transmission Reinforcement project calls for two high-capacity lines between the north and south of the province to reinforce the backbone of the grid. It is anticipated that this project will be in-service by the end of 2014.

Alberta Electric System Operator (AESO) has an Under-Voltage Load Shedding (UVLS) scheme. There are approximately 300 MW of load currently connected to the UVLS. Activation of the scheme is not expected to adversely impact other load within the AESO subregion.

A Calgary-Area transmission must-run procedure addresses 240 kV transmission grid-loading issues and ensures voltage stability margins are maintained. The transmission must-run procedure is an ancillary service contract with generators that is required to address contingencies in areas of inadequate transmission to help provide voltage support to the transmission system in southern Alberta (near Calgary) and assist in maintaining overall system security.

Transmission owners in the subregion have started construction on significant grid reinforcements and enhancements to support intra-regional power transfers and exports of wind generation.

Power flow studies have been conducted by the transmission planning authorities, and in some cases where there have been critical contingencies identified, mitigation measures (e.g., adding reactive sources) or new facilities (e.g., adding a new transformer) have been proposed. Because some of these improvements are driven by future load growth or requests not yet firmed up by the customers, some of these measures have not yet escalated to the project level, and no specific date for their completion has been assigned.

Because of the longer time required for transmission permitting and construction, it is recognized that network planning should focus on establishing a flexible grid infrastructure. This is being done with the goal of accommodating internal power movement from generation sites to load centers.

Analysis of WECC's 2011 PSA results indicates that economic diversity exchanges may result in full loading of the transmission interconnections between the United States and Canadian portions of the NWPP during winter peak periods. British Columbia (WECC-BC) is traditionally a net exporter with projected exports expected to remain relatively constant throughout the study period.

The WECC-BC subregion relies on hydro-electric generation for 90 percent of its energy production. British Columbia Hydro and Power Authority (BCHA) is responsible for the planning, operation, and maintenance of British Columbia's publicly-owned transmission system. BCHA is addressing constraints between remote hydro plants and the Lower Mainland (LM) and Vancouver Island (VI) load centers.

A key transmission constraint in the WECC-BC subregion is the Interior-to-Lower Mainline (IML) path. The ILM Transmission Project[286] is the province's largest expansion project in 30 years. In August 2008, the British Columbia Utility Commission approved the ILM Project, which is a new 500 kV line between the Nicola and Meridian substations, with a projected in-service date in 2014.

BCHA is planning to rely on the existing 905 MW conventional steam plant located in the major load center and the 1,250 MW Canadian entitlement from the Northwestern United States (WECC-NWPP) to meet the Lower Mainland resource requirements in the interim period.

[286] Interior to Lower Mainland (ILM) Transmission Project: http://www.bchydro.com/energy_in_bc/projects/ilm.html.

BCHA has UVLS schemes installed for the LM and V I systems to prevent voltage collapse. These schemes monitor the voltage at the key substations in LM and VI a and the Var reserves at VI transmission synchronous condensers and Burrard Generation Station. If the voltages and the Var reserves are lower than the settings, the selected loads in LM and VI will be removed from service. The maximum load-shedding amount is about 1,690 MW. At this time, BCHA does not anticipate the installation of any additional UVLS schemes.

The 500 kV bulk transmission systems in northern California consist of three parallel 500 kV lines that traverse the state from the California–Oregon border in the north and continue south to the Vincent substation in southern California. This system transfers power between California and other states in the northwest. The interconnection at the northern end is identified as Path 66, or the California–Oregon Intertie. The system also interconnects with northern California hydro-electric generation for delivery to population centers in the San Francisco Bay Area and the Central Valley Area. Further south, the 500 kV lines interconnect with a large number of generation resources in central California. At the Vincent substation, the 500 kV lines interconnect with the Southern California Edison (SCE) 500 kV transmission system. That interconnection point is identified as Path 26.

The Reliability Assessment section of the CISO's 2011–2012 Transmission Plan[287] examined power flow studies, transient stability analysis, and voltage stability studies to identify facilities that indicate the potential of not meeting applicable performance requirements. For the backbone system assessment (500 kV and select 230 kV facilities), conventional and governor power flow studies and stability studies were performed to evaluate the system performance under normal conditions and following the contingencies of power system equipment of voltage levels 230 kV and above. For the local area non-simultaneous assessments, conventional and governor power flow studies were performed under normal system conditions and contingency system conditions of power system equipment of voltage levels 60 kV through 230 kV. These assessments were performed for eight local Pacific Gas & Electric Company service territory areas.

The California-South (CALS) subregion is connected to the California-North subregion by three 500 kV transmission lines. Additional California-South interconnections include a 500 kV dc transmission line to north-central Oregon, a 500 kV dc transmission line to the Intermountain Power Plant in central Utah, a few 230 kV ties to Baja California, Mexico, and numerous 500 kV and lower voltage ties to Arizona and southern Nevada. These numerous interconnections allow the subregion to be a net importer of significant amounts of power. As discussed in the California-North transmission assessment narrative, the CISO prepares an annual transmission plan. That plan addresses San Diego Gas & Electric Company's (SDG&E) service territory and seven local SCE service territory areas. In June, SDG&E placed into service a new 500 kV transmission line linking San Diego and Imperial Valley. The line, initially rated at 800 MW, will help support the CALS Area during the San Onofre nuclear plant outage. Ultimately, the line will support the transfer of up to 1,000 MW of power from the renewable-rich Imperial Valley Area.

Transmission providers from the Desert Southwest subregion, along with other stakeholders from southern California, are actively engaged in the Southwest Transmission Expansion Planning (STEP) group. The goal of this group is to collaborate in the planning, coordination, and implementation of a robust transmission system interconnecting Arizona, southern Nevada, Mexico, and southern California that is capable of supporting a competitive, efficient, and seamless west-wide wholesale electricity market while meeting established reliability standards. The STEP group has developed three projects resulting from the study efforts to upgrade the transmission path from Arizona to southern California and southern Nevada. The three projects will increase the transmission path capability by about 3,000 MW. The first set of upgrades was completed in 2006 and increased the transfer capacity by 505 MW. The second set of upgrades will increase the transfer capacity by 1,245 MW, and many of the upgrades have been completed. The final set of upgrades is the Palo Verde–Devers #2 500 kV transmission line (PVD2) addition. The final set of upgrades encountered complications in 2007 with the Arizona Corporation Commission's refusal to grant a permit for the construction of the PVD2 line. In May 2009, SCE dropped the

[287] CISO 2011-2012 Transmission Plan: http://www.caiso.com/Documents/Board-approvedISO2011-2012-TransmissionPlan.pdf.

Arizona portion of the proposed line and announced that it would proceed to construct the California portion. During the years that the line has been proposed, the resource situation changed drastically, and SCE now believes that the California portion of the line is useful for central station solar projects being planned for the eastern portion of the state.[288]

For the Northwest subregion, additional time required for transmission permitting and construction requires recognition that network planners should focus on establishing a flexible interconnected transmission infrastructure. This is being accomplished with the goals of accommodating anticipated transfers among systems, addressing several areas of constraint within Washington, Oregon, Montana, northern Idaho, and other areas within the Assessment Area, and integrating new generation. Projects at various stages of planning and implementation include approximately 758 miles of 500 kV transmission lines.

Maintaining the capability to import power into the Northwest subregion during infrequent extreme cold weather periods continues to be an important component of transmission planning and operations. Under certain transmission system outage conditions, the Northwest subregion depends on an automatic Under-Frequency Load Shedding (UFLS) scheme to support maximum import transfer capabilities.

Some BAs have taken steps to help make the transmission queue assessment processes more efficient. For example, BPA instituted a process called the Network Open Season (NOS) for allowing resources placement in its transmission queue. Under the NOS, those seeking transmission capacity are asked to sign Precedent Transmission Service Agreements (PTSA) that commit them to taking service at a specified time and under specified terms. At one time, BPA's transmission queue was over 18,000 MW. After the first phase of the 2008 NOS, there were 6,410 MW worth of transmission requests made and PTSAs signed by customers. The PSTA contract is still contingent on BPA's ability to offer new service at its embedded cost rate and is subject to BPA's completion of the required environmental work prior to construction of new facilities.

Tri-State Generation and Transmission is proposing a project in southern Colorado called the San Luis Valley Electric System Improvement project. The project would involve the construction of an 80-mile 230 kV transmission line between the Walsenburg substation and the San Luis Valley substation. The San Luis Valley's existing electrical system has reached its limit due to continued residential and irrigation growth. One major concern is that the radial nature of the existing 230 kV transmission system does not provide the reliability benefits of redundant service. The other major problem currently experienced on the transmission system is a drop in voltage that occurs when the load on the electric system in the valley is above 65 MW. This line will provide the power delivery infrastructure to increase the reliability and capacity of the existing transmission system and support proposed renewable energy development in the area.

The Western Area Power Administration (WAPA) is upgrading several 115 kV transmission lines to 230 kV over the next several years to increase transfer capabilities and help maintain the operating transfer capability between southeastern Wyoming and northeastern Colorado.

There were no significant transmission additions in the WECC-Mexico subregion.

Vulnerability Assessment

Hydro systems within the Western Interconnection are exposed to drought conditions that may adversely impact electric power generation. The adverse impact includes both reduced energy generation and reduced operating flexibility in maximizing generation during high-peak demand periods. However, since the bulk of the river flows are driven by snowfall, system operators have sufficient time to prepare operational plans consistent with seasonal river runoff forecasts.

Due to the strength of the interconnected power grid, WECC has not experienced significant reliability issues related to long-term generator outages, and possible future long-term plant outages are not a concern relative to long-term reliability planning.

[288] Palo Verde-Devers: http://www.cpuc.ca.gov/environment/info/aspen/dpv2/dpv2.htm.

Renewable Portfolio Standards (RPS) have resulted in significant increases in installed wind-powered generation and planned wind and solar generation additions. 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 the WECC website.[289]

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, however, that the CISO is actively engaging stakeholders in developing viable wholesale DR products with direct market participation capability. The CISO's website presents current information about its Demand Response initiative.[290]

Distributed generation has historically 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, and further expansion of solar-distributed generation is not expected to significantly impact the interconnected power system.

As noted in the preceding RPS discussion, entities within the Assessment Area are addressing long-term transmission effects related to increased variable generation. It is expected that processes to address other operational issues, such as over-generation during light load periods, will be addressed by affected entities on a when-needed and where-needed basis (e.g., Bonneville Power Administration's over-generation issue).[291]

After the July 2 and August 10, 1996 disturbances that caused cascading outages of transmission and generation 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 should evaluate the need for UVLS and report to WECC regarding the implementation of UVLS on their individual systems.

Other documents supporting the call for UVLS studies were the NERC report "Survey of Voltage Collapse Phenomenon (August 1991)," the NERC Planning Standards (approved September 1997) and the WECC "Policy Regarding Extreme Contingencies and Unplanned Events".[292] The WECC policy in particular places strong emphasis on the application of Safety Nets to protect the system from unplanned events outside the performance levels defined under the WECC Reliability Criteria. 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 a direction to:

- Develop guidelines for the member systems to determine if they would benefit from UVLS either as a Remedial Action Scheme or as a Safety Net
- Prepare application guidelines to design UVLS systems
- Develop methodologies to study and implement UVLS

WECC addressed the UVLS issue in the "Under-Voltage Load Shedding Guidelines" document approved by WECC's Technical Studies Subcommittee April 28, 2010.[293]

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 SPS or remedial action scheme. The future use of such

[289]WECC Regional Transmission Expansion Planning: http://www.wecc.biz/Planning/TransmissionExpansion/RTEP/Pages/default.aspx.
[290]California ISO - Demand Response Initiative: http://www.caiso.com/1893/1893e350393b0.html.
[291]BPA Wind Activities: http://transmission.bpa.gov/wind/.
[292]Approved October 1997; see Appendix C.
[293]WECC Undervoltage Load Shedding Guidelines http://www.wecc.biz/library/Documentation%20Categorization%20Files/Guidelines/Undervoltage%20Load%20Shedding%20Guidelies%20-%20Guideline.pdf.

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.

WECC has not established a planning process that addresses high-impact, low-probability events. However, various entities within WECC do take such possibilities into consideration, depending on conditions most pertinent to their respective geographic areas. For example, transmission planners in northern areas consider loading on transmission lines under severe ice storm conditions. High-wind areas are also addressed in facility designs, as is earthquake potential, etc.

LSEs within WECC have been rapidly expanding the use of smart meters and the associated interface equipment. The impact of such facilities relative to power system reliability has 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. The CISO's website presents its smart grid initiatives, which are typical of activities within the assessment area.[294]

WECC's in-house power system disturbance investigations have identified relay protection misoperation as a factor in reduced system reliability. On June 22, 2011, WECC's Board of Directors approved PRC-003-WECC-CRT-1, Analysis, Reporting, and Mitigation of Transmission and Generation Protection Systems and Remedial Action Schemes Misoperations Procedure.[295] The procedure was developed to meet NERC Reliability Standard PRC-003-1, R1. It is expected that the mandatory compliance criteria will lead to a reduction in the adverse reliability effects related to relay protection misoperations.

WECC has not assessed the possible interconnection-wide effects of pending future environmental regulations. Several coal-fired plants have significant exposure to emissions limitations, and some have been or are scheduled to be shut down during the assessment period, while others are in discussion or litigation regarding emissions issues. In addition, several California power plants are subject to once-through cooling (OTC) limitations that may result in plant closures. The resource data used for this assessment reflect some capacity retirements due to existing clean air and once-through cooling initiatives but do not reflect possible retirements due to potential environmental regulations. California's OTC initiative includes provisions for stakeholder input regarding reliability issues associated with the plant shutdown scheduling, and it is expected that the initiative will be implemented on a schedule that will avoid any adverse reliability impact. It is not expected that long-term maintenance outages associated with coal-plant emissions equipment retrofits will affect reliability, and it is not expected that retrofit time schedules will lead to off-peak reliability issues. However, extended retrofit shutdowns coupled with unexpected, unseasonable severe weather could result in somewhat localized capacity issues.

Standing and Emerging Reliability Issues

The WECC LRS has identified four emerging reliability issues that may impact entity activities in the Western Interconnection. The Subcommittee has discussed the emerging issues in general terms but has not attempted to associate likelihood or consequences to the four issues, which vary by subregion. Since none of these issues have currently identified time frames associated with specific adverse consequences that cannot be mitigated in a reasonable manner, an impact on adverse reliability resource adequacy is not expected to occur. Due to the fluid nature of entity responses to these issues, the timing and locations of potential impact, if any, on transmission adequacy during the assessment period cannot be ascertained with a high level of certainty.

Impact of Federal and State Environmental Regulations

WECC contains a significant number of coal-fired power plants that may be affected by new emissions regulations. The overall impact of environmental regulations has not been studied by the subcommittee, but some information regarding

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[294] California ISO - Smart Grid: http://www.caiso.com/green/greensmartgrid.html.

[295] WECC Relay Misoperation Criterion: http://www.wecc.biz/Standards/Development/WECC-0059/Shared%20Documents/Final%20to%20SC%20for%20Concurrent%20Posting/WECC-0059%20Relay%20Misoperation%20Criterion%20Effective%2010-1-2011.pdf.

the issue is available in the "Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations" section of the *2011 LTRA*[296]

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 would come into force once a plant reached the end of its useful life (approx. 45 years), and any new unit built after 2015 would 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. British Columbia has no coal-fired generation and will not be affected, as it has no plans to build new coal-fired facilities. However, 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 currently prohibitively expensive. The Alberta market, however, is expected to manage the development of new generation to replace retired capacity over the next decade, and resource adequacy is not expected to be significantly reduced.

The WECC-Mexico subregion does not contain coal-fired power plants.

California State Water Resources Control Board policy on OTC mitigation is intended to cause a substantial amount of California capacity to retire or be re-fitted to reduce environmental impact. Mechanisms are built into the OTC policy to consider any reliability concerns of California state energy agencies or the 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 possibly on repowering of existing OTC facilities. The state energy agencies and CISO are assisting the California Air Resources Board to assess 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 retirement of older OTC facilities. In summary, state environmental impact reduction policies are being implemented with an awareness of reliability concerns, and all of the appropriate entities are collaborating to conduct planning assessments aspiring to simultaneously achieve these goals.

Integration of Variable Resources

The WECC LRS discussed light load period minimum generation conflicts between northwest wind and hydro generation. The unique northwest condition, which was essentially an economic issue rather than a reliability issue, could occur in other WECC subregions if their 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 within a foreseeable time period.

Delays in Transmission Siting

Transmission siting delay issues can relate to both new transmission lines and to reconstructions and/or upgrades to existing lines, and both may be driven by either demand growth or by generation delivery needs. Regardless, siting delays may have reliability implications that need to be addressed by the appropriate transmission planners and their associated governmental authorities. The "not in my back yard" philosophy coupled with firmly entrenched environmental study requirements essentially guarantees transmission development time frames that extend beyond those most desirable to developers and are expected to recur through the LTRA time frame. While siting delays may ultimately adversely impact resource development, evolving conditions relative to smart grid enhancements may significantly transform WECC's stability-limited transmission system. Additional transforming events may include ongoing building of new gas-fired generation closer to load centers and increased rooftop solar power generation.

[296]Resource Adequacy Impacts of Potential U.S. Environmental Regulations: http://www.nerc.com/files/EPA_Scenario_Final_v2.pdf.

WECC Subregional Tables

Planning Reserve Margins – WECC-AESO

WECC-AESO-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		19.18%	19.59%	21.38%	28.39%	21.77%	17.80%	12.43%	8.95%	6.07%	8.50%
PROSPECTIVE		19.18%	19.59%	21.38%	28.39%	21.77%	17.80%	12.43%	8.95%	6.07%	8.50%
ADJUSTED POTENTIAL		19.18%	19.59%	21.38%	28.39%	21.77%	17.80%	12.43%	8.95%	6.07%	8.50%
NERC REFERENCE	-	**12.24%**	**12.24%**	**12.24%**	**12.24%**	**12.24%**	**12.24%**	**12.24%**	**12.24%**	**12.24%**	**12.24%**

WECC-AESO-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		18.58%	28.97%	37.24%	34.83%	35.36%	25.99%	22.91%	23.64%	15.47%	13.32%
PROSPECTIVE		18.58%	28.97%	37.24%	34.83%	35.36%	25.99%	22.91%	23.64%	15.47%	13.32%
ADJUSTED POTENTIAL		18.58%	28.97%	37.24%	34.83%	35.36%	25.99%	22.91%	23.64%	15.47%	13.32%
NERC REFERENCE	-	**11.71%**	**11.71%**	**11.71%**	**11.71%**	**11.71%**	**11.71%**	**11.71%**	**11.71%**	**11.71%**	**11.71%**

Planning Reserve Margins – WECC-BASN

WECC-BASN-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		27.53%	22.14%	19.81%	18.08%	15.30%	13.35%	10.44%	7.46%	6.59%	7.17%
PROSPECTIVE		27.53%	22.14%	19.81%	18.08%	15.30%	13.35%	10.44%	7.46%	6.59%	7.17%
ADJUSTED POTENTIAL		27.53%	25.57%	23.15%	23.72%	20.82%	18.78%	15.80%	14.07%	13.10%	13.96%
NERC REFERENCE	-	**12.60%**	**12.60%**	**12.60%**	**12.60%**	**12.60%**	**12.60%**	**12.60%**	**12.60%**	**12.60%**	**12.60%**

WECC-BASN-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		26.91%	23.82%	22.78%	15.67%	14.79%	17.58%	16.71%	16.15%	11.57%	11.96%
PROSPECTIVE		26.91%	23.82%	22.78%	15.67%	14.79%	17.58%	16.71%	16.15%	11.57%	11.96%
ADJUSTED POTENTIAL		26.91%	27.91%	27.07%	22.48%	21.47%	24.20%	24.94%	25.79%	21.67%	20.10%
NERC REFERENCE	-	**13.49%**	**13.49%**	**13.49%**	**13.49%**	**13.49%**	**13.49%**	**13.49%**	**13.49%**	**13.49%**	**13.49%**

Planning Reserve Margins – WECC-BC

WECC-BC-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		41.74%	40.70%	35.36%	33.62%	31.81%	36.03%	33.16%	23.33%	14.97%	13.91%
PROSPECTIVE		41.74%	40.70%	35.36%	33.62%	31.81%	36.03%	33.16%	23.33%	14.97%	13.91%
ADJUSTED POTENTIAL		41.74%	40.70%	35.36%	33.62%	31.81%	36.03%	33.16%	23.33%	14.97%	13.91%
NERC REFERENCE	-	**12.51%**	**12.51%**	**12.51%**	**12.51%**	**12.51%**	**12.51%**	**12.51%**	**12.51%**	**12.51%**	**12.51%**

WECC-BC-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		17.24%	18.15%	19.90%	20.05%	19.44%	17.88%	16.98%	14.43%	13.64%	12.82%
PROSPECTIVE		17.24%	18.15%	19.90%	20.05%	19.44%	17.88%	16.98%	14.43%	13.64%	12.82%
ADJUSTED POTENTIAL		17.24%	18.15%	19.90%	20.05%	19.44%	17.88%	16.98%	14.43%	13.64%	12.82%
NERC REFERENCE	-	**16.16%**	**16.16%**	**16.16%**	**16.16%**	**16.16%**	**16.16%**	**16.16%**	**16.16%**	**16.16%**	**16.16%**

Planning Reserve Margins – WECC-CALN

WECC-CALN-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		15.16%	14.82%	18.29%	16.01%	14.71%	13.53%	9.06%	9.49%	9.22%	7.90%
PROSPECTIVE		15.16%	14.82%	18.29%	16.01%	14.71%	13.53%	9.06%	9.49%	9.22%	7.90%
ADJUSTED POTENTIAL		15.16%	14.82%	18.29%	16.02%	14.72%	13.54%	9.07%	9.49%	9.22%	7.91%
NERC REFERENCE	-	**14.71%**	**14.71%**	**14.71%**	**14.71%**	**14.71%**	**14.71%**	**14.71%**	**14.71%**	**14.71%**	**14.71%**

WECC-CALN-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		22.55%	30.81%	28.82%	21.49%	24.46%	23.91%	23.18%	20.34%	18.82%	15.38%
PROSPECTIVE		22.55%	30.81%	28.82%	21.49%	24.46%	23.91%	23.18%	20.34%	18.82%	15.38%
ADJUSTED POTENTIAL		22.55%	30.81%	28.82%	21.50%	24.47%	24.91%	24.17%	21.32%	19.31%	16.23%
NERC REFERENCE	-	**11.86%**	**11.86%**	**11.86%**	**11.86%**	**11.86%**	**11.86%**	**11.86%**	**11.86%**	**11.86%**	**11.86%**

Planning Reserve Margins – WECC-CALS

WECC-CALS-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		16.04%	20.94%	19.07%	18.63%	17.74%	15.22%	15.22%	15.44%	15.19%	15.31%
PROSPECTIVE		16.04%	20.94%	19.07%	18.63%	17.74%	15.22%	15.22%	15.44%	15.19%	15.31%
ADJUSTED POTENTIAL		16.29%	21.19%	19.31%	19.21%	18.40%	16.19%	16.22%	16.74%	16.48%	16.59%
NERC REFERENCE	-	**15.14%**	**15.14%**	**15.14%**	**15.14%**	**15.14%**	**15.14%**	**15.14%**	**15.14%**	**15.14%**	**15.14%**

WECC-CALS-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		54.57%	49.51%	46.42%	39.95%	38.76%	40.21%	31.60%	21.18%	27.20%	20.62%
PROSPECTIVE		54.57%	49.51%	46.42%	39.95%	38.76%	40.21%	31.60%	21.18%	27.20%	20.62%
ADJUSTED POTENTIAL		54.90%	49.83%	46.74%	40.71%	39.64%	41.49%	32.87%	22.84%	28.84%	22.25%
NERC REFERENCE	-	**11.03%**	**11.03%**	**11.03%**	**11.03%**	**11.03%**	**11.03%**	**11.03%**	**11.03%**	**11.03%**	**11.03%**

Planning Reserve Margins – WECC-DSW

WECC-DSW-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		46.57%	43.51%	45.69%	47.93%	47.03%	46.07%	41.56%	34.72%	29.52%	29.09%
PROSPECTIVE		46.57%	43.51%	45.69%	47.93%	47.03%	46.07%	41.56%	34.72%	29.52%	29.09%
ADJUSTED POTENTIAL		47.24%	45.13%	47.75%	50.17%	50.05%	48.86%	45.71%	39.93%	34.90%	34.40%
NERC REFERENCE	-	**13.50%**	**13.50%**	**13.50%**	**13.50%**	**13.50%**	**13.50%**	**13.50%**	**13.50%**	**13.50%**	**13.50%**

WECC-DSW-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		91.01%	90.09%	89.45%	86.95%	83.98%	82.77%	76.41%	79.46%	78.49%	77.75%

PROSPECTIVE		91.01%	90.09%	89.45%	86.95%	83.98%	82.77%	76.41%	79.46%	78.49%	77.75%
ADJUSTED POTENTIAL		91.95%	91.04%	89.57%	89.16%	87.25%	85.98%	83.57%	88.27%	82.91%	83.72%
NERC REFERENCE	-	**13.96%**	**13.96%**	**13.96%**	**13.96%**	**13.96%**	**13.96%**	**13.96%**	**13.96%**	**13.96%**	**13.96%**

Planning Reserve Margins – WECC-MEXW

WECC-MEXW-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		19.89%	29.35%	26.17%	23.16%	20.27%	17.50%	14.86%	12.35%	9.94%	7.65%
PROSPECTIVE		19.89%	29.35%	26.17%	23.16%	20.27%	17.50%	14.86%	12.35%	9.94%	7.65%
ADJUSTED POTENTIAL		19.89%	29.35%	26.17%	37.50%	34.27%	31.18%	38.90%	35.85%	32.94%	30.17%
NERC REFERENCE	-	**11.86%**	**11.86%**	**11.86%**	**11.86%**	**11.86%**	**11.86%**	**11.86%**	**11.86%**	**11.86%**	**11.86%**

WECC-MEXW-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		62.92%	70.84%	75.07%	80.27%	76.03%	57.02%	60.83%	57.05%	53.67%	50.59%
PROSPECTIVE		62.92%	70.84%	75.07%	80.27%	76.03%	57.02%	60.83%	57.05%	53.67%	50.59%
ADJUSTED POTENTIAL		62.92%	70.84%	75.07%	101.41%	96.69%	77.20%	96.29%	91.72%	87.59%	83.81%
NERC REFERENCE	-	**10.71%**	**10.71%**	**10.71%**	**10.71%**	**10.71%**	**10.71%**	**10.71%**	**10.71%**	**10.71%**	**10.71%**

Planning Reserve Margins – WECC-NORW

WECC-NORW-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		18.96%	18.02%	19.06%	22.91%	19.86%	18.14%	18.14%	18.14%	18.13%	18.51%
PROSPECTIVE		18.96%	18.02%	19.06%	22.91%	19.86%	18.14%	18.14%	18.14%	18.13%	18.51%
ADJUSTED POTENTIAL		18.96%	18.02%	19.06%	22.91%	19.87%	18.14%	18.15%	18.14%	18.14%	18.51%
NERC REFERENCE	-	**17.90%**	**17.90%**	**17.90%**	**17.90%**	**17.90%**	**17.90%**	**17.90%**	**17.90%**	**17.90%**	**17.90%**

WECC-NORW-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		20.08%	20.24%	20.80%	22.98%	20.35%	21.31%	18.80%	17.30%	15.67%	22.18%
PROSPECTIVE		20.08%	20.24%	20.80%	22.98%	20.35%	21.31%	18.80%	17.30%	15.67%	22.18%
ADJUSTED POTENTIAL		20.08%	20.25%	20.80%	22.98%	20.35%	21.31%	18.80%	17.31%	15.68%	22.18%
NERC REFERENCE	-	**19.90%**	**19.90%**	**19.90%**	**19.90%**	**19.90%**	**19.90%**	**19.90%**	**19.90%**	**19.90%**	**19.90%**

Planning Reserve Margins – WECC-ROCK

WECC-ROCK-Summer		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ANTICIPATED		24.93%	21.91%	19.77%	18.04%	15.20%	13.38%	12.84%	15.56%	11.94%	8.02%
PROSPECTIVE		24.93%	21.91%	19.77%	18.04%	15.20%	13.38%	12.84%	15.56%	11.94%	8.02%
ADJUSTED POTENTIAL		24.96%	21.93%	19.83%	18.07%	15.24%	13.49%	12.97%	15.59%	11.97%	8.03%
NERC REFERENCE	-	**14.65%**	**14.65%**	**14.65%**	**14.65%**	**14.65%**	**14.65%**	**14.65%**	**14.65%**	**14.65%**	**14.65%**

WECC-ROCK-Winter		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
ANTICIPATED		46.61%	37.17%	33.54%	41.22%	43.12%	37.50%	35.35%	20.45%	26.85%	19.14%
PROSPECTIVE		46.61%	37.17%	33.54%	41.22%	43.12%	37.50%	35.35%	20.45%	26.85%	19.14%
ADJUSTED POTENTIAL		49.08%	40.39%	37.50%	43.00%	45.80%	42.18%	40.23%	24.35%	30.64%	19.27%
NERC REFERENCE	-	**15.68%**	**15.68%**	**15.68%**	**15.68%**	**15.68%**	**15.68%**	**15.68%**	**15.68%**	**15.68%**	**15.68%**

Demand Outlook – WECC-AESO

WECC-AESO-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	10,903	15,093	4,190	38.4%	3.68%
Load-Modifying Demand Response	38	38	0	0.0%	0.00%
TOTAL INTERNAL DEMAND	**10,941**	**15,131**	**4,190**	**38.3%**	**3.67%**

WECC-AESO-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	11,664	15,994	4,330	37.1%	3.57%
Load-Modifying Demand Response	0	0	0	0.0%	0.00%
TOTAL INTERNAL DEMAND	**11,664**	**15,994**	**4,330**	**37.1%**	**3.57%**

Demand Outlook – WECC-BASN

WECC-BASN-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	12,667	14,756	2,089	16.5%	1.71%
Load-Modifying Demand Response	1,109	1,158	49	4.4%	0.48%
TOTAL INTERNAL DEMAND	**13,776**	**15,914**	**2,138**	**15.5%**	**1.62%**

WECC-BASN-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	10,842	12,132	1,290	11.9%	1.26%
Load-Modifying Demand Response	292	305	13	4.5%	0.49%
TOTAL INTERNAL DEMAND	**11,134**	**12,437**	**1,303**	**11.7%**	**1.24%**

Demand Outlook – WECC-BC

WECC-BC-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	8,449	9,670	1,221	14.5%	1.51%
Load-Modifying Demand Response	0	0	0	0.0%	0.00%
TOTAL INTERNAL DEMAND	**8,449**	**9,670**	**1,221**	**14.5%**	**1.51%**

WECC-BC-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	11,416	12,823	1,407	12.3%	1.30%

Load-Modifying Demand Response	0	0	0	0.0%	0.00%
TOTAL INTERNAL DEMAND	**11,416**	**12,823**	**1,407**	**12.3%**	**1.30%**

Demand Outlook – WECC-CALN

WECC-CALN-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	25,841	29,077	3,236	12.5%	1.32%
Load-Modifying Demand Response	804	835	31	3.9%	0.42%
TOTAL INTERNAL DEMAND	**26,645**	**29,912**	**3,267**	**12.3%**	**1.29%**

WECC-CALN-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	18,407	20,220	1,813	9.9%	1.05%
Load-Modifying Demand Response	257	278	21	8.2%	0.88%
TOTAL INTERNAL DEMAND	**18,664**	**20,498**	**1,834**	**9.8%**	**1.05%**

Demand Outlook – WECC-CALS

WECC-CALS-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	29,311	33,319	4,008	13.7%	1.43%
Load-Modifying Demand Response	2,008	2,296	288	14.3%	1.50%
TOTAL INTERNAL DEMAND	**31,319**	**35,615**	**4,296**	**13.7%**	**1.44%**

WECC-CALS-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	22,360	25,454	3,094	13.8%	1.45%
Load-Modifying Demand Response	869	1,153	284	32.7%	3.19%
TOTAL INTERNAL DEMAND	**23,229**	**26,607**	**3,378**	**14.5%**	**1.52%**

Demand Outlook – WECC-DSW

WECC-DSW-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	27,034	31,013	3,979	14.7%	1.54%
Load-Modifying Demand Response	542	589	47	8.7%	0.93%
TOTAL INTERNAL DEMAND	**27,576**	**31,602**	**4,026**	**14.6%**	**1.53%**

WECC-DSW-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	17,845	20,775	2,930	16.4%	1.70%
Load-Modifying Demand Response	279	290	11	3.9%	0.43%
TOTAL INTERNAL DEMAND	**18,124**	**21,065**	**2,941**	**16.2%**	**1.69%**

Demand Outlook – WECC-MEXW

WECC-MEXW-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	2,203	2,716	513	23.3%	2.35%
Load-Modifying Demand Response	0	0	0	0.0%	0.00%
TOTAL INTERNAL DEMAND	**2,203**	**2,716**	**513**	**23.3%**	**2.35%**

WECC-MEXW-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	1,494	1,841	347	23.2%	2.35%
Load-Modifying Demand Response	0	0	0	0.0%	0.00%
TOTAL INTERNAL DEMAND	**1,494**	**1,841**	**347**	**23.2%**	**2.35%**

Demand Outlook – WECC-NORW

WECC-NORW-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	24,310	26,711	2,401	9.9%	1.05%
Load-Modifying Demand Response	70	147	77	110.0%	8.59%
TOTAL INTERNAL DEMAND	**24,380**	**26,858**	**2,478**	**10.2%**	**1.08%**

WECC-NORW-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	30,217	32,638	2,420	8.0%	0.86%
Load-Modifying Demand Response	53	121	68	128.3%	9.61%
TOTAL INTERNAL DEMAND	**30,270**	**32,759**	**2,488**	**8.2%**	**0.88%**

Demand Outlook – WECC-ROCK

WECC-ROCK-Summer	2013	2022	10-Year Change		CAGR
NET INTERNAL DEMAND	11,434	13,251	1,817	15.9%	1.65%
Load-Modifying Demand Response	470	520	50	10.6%	1.13%
TOTAL INTERNAL DEMAND	**11,904**	**13,771**	**1,867**	**15.7%**	**1.63%**

WECC-ROCK-Winter	2013/14	2022/23	10-Year Change		CAGR
NET INTERNAL DEMAND	9,565	11,283	1,718	18.0%	1.85%
Load-Modifying Demand Response	268	238	-30	-11.2%	-1.31%
TOTAL INTERNAL DEMAND	**9,833**	**11,521**	**1,688**	**17.2%**	**1.78%**

Net Transactions – WECC-AESO

WECC-AESO	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
Expected Imports	0	0	0	0	0	0	0	0	0	0
Firm Imports	0	0	0	0	0	0	0	0	0	0

TOTAL IMPORTS	0	0	0	0	0	0	0	0	0	0
Expected Exports	0	0	0	0	0	0	0	0	0	0
Firm Exports	600	600	600	600	600	600	600	600	600	600
TOTAL EXPORTS	600	600	600	600	600	600	600	600	600	600
TOTAL NET CAPACITY TRANSACTIONS	**-600**	**-600**	**-600**	**-600**	**-600**	**-600**	**-600**	**-600**	**-600**	**-600**

Net Transactions – WECC-BASN

WECC-BASN	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Expected Imports	0	0	0	0	0	0	0	0	0	0
Firm Imports	4,313	4,313	4,313	4,313	4,313	4,313	4,313	4,313	4,313	4,313
TOTAL IMPORTS	4,313	4,313	4,313	4,313	4,313	4,313	4,313	4,313	4,313	4,313
Expected Exports	0	0	0	0	0	0	0	0	0	0
Firm Exports	2,760	2,760	2,760	2,760	2,760	2,760	2,760	2,760	2,760	2,760
TOTAL EXPORTS	2,760	2,760	2,760	2,760	2,760	2,760	2,760	2,760	2,760	2,760
TOTAL NET CAPACITY TRANSACTIONS	**1,553**	**1,553**	**1,553**	**1,553**	**1,553**	**1,553**	**1,553**	**1,553**	**1,553**	**1,553**

Net Transactions – WECC-BC

WECC-BC	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
Expected Imports	0	0	0	0	0	0	0	0	0	0
Firm Imports	600	600	600	600	600	600	600	600	600	600
TOTAL IMPORTS	600	600	600	600	600	600	600	600	600	600
Expected Exports	0	0	0	0	0	0	0	0	0	0
Firm Exports	800	800	800	800	800	800	800	800	800	800
TOTAL EXPORTS	800	800	800	800	800	800	800	800	800	800
TOTAL NET CAPACITY TRANSACTIONS	**-200**	**-200**	**-200**	**-200**	**-200**	**-200**	**-200**	**-200**	**-200**	**-200**

Net Transactions – WECC-CALN

WECC-CALN	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Expected Imports	0	0	0	0	0	0	0	0	0	0
Firm Imports	4,200	4,100	4,200	4,200	4,200	4,200	3,400	3,900	4,200	4,200
TOTAL IMPORTS	4,200	4,100	4,200	4,200	4,200	4,200	3,400	3,900	4,200	4,200
Expected Exports	0	0	0	0	0	0	0	0	0	0
Firm Exports	100	100	100	100	100	100	100	100	100	100
TOTAL EXPORTS	100	100	100	100	100	100	100	100	100	100
TOTAL NET CAPACITY TRANSACTIONS	**4,100**	**4,000**	**4,100**	**4,100**	**4,100**	**4,100**	**3,300**	**3,800**	**4,100**	**4,100**

Net Transactions – WECC-CALS

WECC-CALS	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Expected Imports	0	0	0	0	0	0	0	0	0	0
Firm Imports	6,931	7,481	6,977	6,862	6,879	6,862	6,862	6,862	6,862	6,862
TOTAL IMPORTS	6,931	7,481	6,977	6,862	6,879	6,862	6,862	6,862	6,862	6,862
Expected Exports	0	0	0	0	0	0	0	0	0	0
Firm Exports	3,529	3,564	3,782	4,783	4,783	5,181	4,677	4,043	3,588	3,206
TOTAL EXPORTS	3,529	3,564	3,782	4,783	4,783	5,181	4,677	4,043	3,588	3,206
TOTAL NET CAPACITY TRANSACTIONS	**3,402**	**3,917**	**3,195**	**2,079**	**2,096**	**1,681**	**2,185**	**2,819**	**3,274**	**3,656**

Net Transactions – WECC-DSW

WECC-DSW	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Expected Imports	0	0	0	0	0	0	0	0	0	0
Firm Imports	2,271	2,306	2,524	3,539	3,051	3,937	3,432	2,902	2,323	2,065
TOTAL IMPORTS	2,271	2,306	2,524	3,539	3,051	3,937	3,432	2,902	2,323	2,065
Expected Exports	0	0	0	0	0	0	0	0	0	0
Firm Exports	4,023	4,806	4,068	3,953	3,953	3,953	3,953	4,617	4,380	3,953
TOTAL EXPORTS	4,023	4,806	4,068	3,953	3,953	3,953	3,953	4,617	4,380	3,953
TOTAL NET CAPACITY TRANSACTIONS	**-1,752**	**-2,500**	**-1,544**	**-414**	**-902**	**-16**	**-521**	**-1,715**	**-2,057**	**-1,888**

Net Transactions – WECC-MEXW

WECC-MEXW	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Expected Imports	0	0	0	0	0	0	0	0	0	0
Firm Imports	0	0	0	0	0	0	0	0	0	0
TOTAL IMPORTS	0	0	0	0	0	0	0	0	0	0
Expected Exports	0	0	0	0	0	0	0	0	0	0
Firm Exports	0	0	0	0	0	0	0	0	0	0
TOTAL EXPORTS	0	0	0	0	0	0	0	0	0	0
TOTAL NET CAPACITY TRANSACTIONS	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Net Transactions – WECC-NORW

WECC-NORW	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
Expected Imports	0	0	0	0	0	0	0	0	0	0
Firm Imports	4,100	4,000	4,000	4,000	4,500	4,000	5,400	5,400	5,400	4,000
TOTAL IMPORTS	4,100	4,000	4,000	4,000	4,500	4,000	5,400	5,400	5,400	4,000
Expected Exports	0	0	0	0	0	0	0	0	0	0

Firm Exports	0	0	0	0	0	0	0	0	0	0
TOTAL EXPORTS	0	0	0	0	0	0	0	0	0	0
TOTAL NET CAPACITY TRANSACTIONS	**4,100**	**4,000**	**4,000**	**4,000**	**4,500**	**4,000**	**5,400**	**5,400**	**5,400**	**4,000**

Net Transactions – WECC-ROCK

WECC-ROCK	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Expected Imports	0	0	0	0	0	0	0	0	0	0
Firm Imports	400	634	400	400	400	400	400	1,064	827	400
TOTAL IMPORTS	400	634	400	400	400	400	400	1,064	827	400
Expected Exports	0	0	0	0	0	0	0	0	0	0
Firm Exports	274	531	531	531	531	531	531	531	531	531
TOTAL EXPORTS	274	531	531	531	531	531	531	531	531	531
TOTAL NET CAPACITY TRANSACTIONS	**126**	**103**	**-131**	**-131**	**-131**	**-131**	**-131**	**533**	**296**	**-131**

Appendix I: NERC Reference Case –Annual Demand Tables

Annual Net Internal Demand - Summer

Assessment Area/Country	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	10-Year Change		CAGR
ERCOT	65,649	68,403	71,692	73,957	75,360	76,483	76,769	78,524	79,682	80,694	15,045	22.92%	2.32%
FRCC	43,041	43,618	44,459	45,242	45,802	46,152	46,803	47,581	48,273	48,923	5,882	13.67%	1.43%
MISO	89,318	90,707	91,096	91,556	92,022	92,447	92,932	93,419	93,957	94,875	5,557	6.22%	0.67%
MRO-MAPP	4,904	5,024	5,135	5,406	5,461	5,543	5,643	5,735	5,821	5,906	1,002	20.44%	2.09%
NPCC-New England	26,629	26,877	27,193	27,520	27,797	27,973	28,111	28,257	28,414	28,583	1,954	7.34%	0.79%
NPCC-New York	33,696	33,914	34,151	34,345	34,550	34,868	35,204	35,526	35,913	36,230	2,534	7.52%	0.81%
PJM	145,254	146,642	149,968	152,491	154,233	155,832	157,660	159,593	161,438	163,220	17,966	12.37%	1.30%
SERC-E	41,805	42,412	42,750	43,235	43,707	44,103	44,636	45,200	45,848	46,386	4,581	10.96%	1.16%
SERC-N	43,808	44,387	44,952	45,537	45,987	46,504	47,044	47,653	48,167	48,778	4,970	11.35%	1.20%
SERC-SE	47,900	48,738	49,227	49,823	50,551	51,023	51,707	52,396	53,343	54,249	6,349	13.25%	1.39%
SERC-W	25,015	25,257	25,623	25,937	26,252	26,556	26,910	27,198	27,472	27,764	2,749	10.99%	1.17%
SPP	54,247	54,794	54,788	55,368	55,927	56,539	57,338	57,971	58,716	58,985	4,738	8.73%	0.93%
WECC-BASN	12,667	13,025	13,354	13,607	13,923	14,148	14,392	14,628	14,836	14,756	2,089	16.49%	1.71%
WECC-CALN	25,841	26,154	26,471	27,072	27,376	27,670	27,998	28,324	28,652	29,077	3,236	12.52%	1.32%
WECC-CALS	29,311	29,901	30,467	30,796	31,191	31,577	31,948	32,472	32,997	33,319	4,008	13.67%	1.43%
WECC-DSW	27,034	27,252	27,551	28,035	28,510	29,106	29,622	30,183	30,720	31,013	3,979	14.72%	1.54%
WECC-NORW	24,310	24,609	24,872	25,155	25,445	25,675	25,901	26,151	26,414	26,711	2,401	9.88%	1.05%
WECC-ROCK	11,434	11,619	11,827	12,048	12,235	12,431	12,626	12,840	13,093	13,251	1,817	15.89%	1.65%
TOTAL-UNITED STATES	751,862	763,332	775,577	787,129	796,328	804,630	813,244	823,652	833,758	842,721	90,859	12.08%	1.28%
MRO-Manitoba Hydro	3,210	3,238	3,207	3,244	3,286	3,221	3,271	3,348	3,428	3,474	264	8.24%	0.88%
MRO-SaskPower	3,184	3,335	3,444	3,533	3,630	3,618	3,665	3,716	3,784	3,847	663	20.81%	2.12%
NPCC-Maritimes	3,104	3,138	3,117	3,110	3,116	3,128	3,140	3,163	3,175	3,183	79	2.55%	0.28%
NPCC-Ontario	23,301	23,080	22,859	22,638	22,471	22,583	22,891	23,010	23,390	23,442	142	0.61%	0.07%
NPCC-Québec	21,115	21,550	21,642	21,883	22,008	22,125	22,307	22,503	22,662	22,818	1,704	8.07%	0.87%
WECC-AESO	10,903	11,510	12,039	12,604	13,108	13,522	13,936	14,336	14,727	15,093	4,190	38.43%	3.68%
WECC-BC	8,449	8,684	8,834	8,913	9,043	9,167	9,289	9,427	9,553	9,670	1,221	14.45%	1.51%
TOTAL-CANADA	73,266	74,535	75,142	75,925	76,663	77,364	78,498	79,504	80,719	81,528	8,262	11.28%	1.19%
WECC-MEXW	2,203	2,260	2,317	2,374	2,431	2,488	2,545	2,602	2,659	2,716	513	23.29%	2.35%
TOTAL-MÉXICO	2,203	2,260	2,317	2,374	2,431	2,488	2,545	2,602	2,659	2,716	513	23.29%	2.35%
TOTAL-NERC	**827,330**	**840,127**	**853,036**	**865,428**	**875,421**	**884,482**	**894,287**	**905,758**	**917,136**	**926,965**	**99,635**	**12.04%**	**1.27%**

Annual Net Internal Demand – Winter

Assessment Area/Country	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	10-Year Change		CAGR
ERCOT	50,263	50,533	53,378	54,363	57,204	57,459	57,575	58,210	59,031	61,450	11,187	22.26%	2.26%
FRCC	43,049	44,228	44,790	45,297	45,752	46,305	46,910	47,509	48,169	48,656	5,607	13.02%	1.37%
MISO	69,663	74,965	75,354	75,854	76,172	76,692	77,174	77,498	78,022	78,789	9,126	13.10%	1.38%
MRO-MAPP	4,858	4,999	5,074	5,335	5,412	5,522	5,623	5,718	5,814	5,904	1,047	21.55%	2.19%
NPCC-New England	21,383	21,285	21,193	21,097	21,011	20,929	20,859	20,797	20,750	20,711	-672	-3.14%	-0.35%
NPCC-New York	24,929	24,999	25,053	25,149	25,153	25,265	25,422	25,627	25,794	25,908	979	3.93%	0.43%
PJM	121,160	121,571	123,711	125,367	126,462	127,644	128,818	130,219	131,636	132,916	11,756	9.70%	1.03%
SERC-E	42,042	42,408	42,934	43,395	43,879	44,382	45,016	45,557	46,144	46,730	4,688	11.15%	1.18%
SERC-N	43,734	44,212	44,685	45,226	45,723	46,176	46,697	47,211	47,891	48,256	4,522	10.34%	1.10%
SERC-SE	44,652	45,103	45,615	46,266	46,743	47,434	48,097	48,943	49,770	50,627	5,975	13.38%	1.41%
SERC-W	19,731	20,042	20,209	20,694	21,106	21,410	21,118	21,726	21,891	22,262	2,531	12.83%	1.35%
SPP	40,983	41,345	41,225	41,812	42,205	42,726	43,360	43,930	44,470	44,862	3,879	9.47%	1.01%
WECC-BASN	10,842	10,913	11,167	11,416	11,640	11,818	11,940	12,026	12,158	12,132	1,290	11.90%	1.26%
WECC-CALN	18,407	18,707	18,937	19,220	19,409	19,618	19,767	19,919	20,070	20,220	1,813	9.85%	1.05%
WECC-CALS	22,360	22,893	23,235	23,441	23,770	24,099	24,438	24,941	25,300	25,454	3,094	13.84%	1.45%
WECC-DSW	17,845	18,095	18,431	18,827	19,187	19,540	19,945	20,263	20,490	20,775	2,930	16.42%	1.70%
WECC-NORW	30,217	30,507	30,763	31,053	31,355	31,607	31,862	32,075	32,391	32,638	2,420	8.01%	0.86%
WECC-ROCK	9,565	9,709	9,918	10,214	10,398	10,602	10,796	10,922	11,165	11,283	1,718	17.96%	1.85%
TOTAL-UNITED STATES	635,683	646,514	655,672	664,025	672,581	679,228	685,417	693,092	700,956	709,572	73,889	11.62%	1.23%
MRO-Manitoba Hydro	4,661	4,712	4,723	4,781	4,845	4,801	4,878	4,981	5,089	5,162	501	10.76%	1.14%
MRO-SaskPower	3,580	3,738	3,859	3,959	4,068	4,054	4,107	4,164	4,239	4,310	730	20.39%	2.08%
NPCC-Maritimes	5,169	5,166	5,165	5,185	5,201	5,226	5,228	5,247	5,264	5,285	116	2.24%	0.25%
NPCC-Ontario	22,192	21,890	21,500	21,153	20,719	20,700	21,063	21,234	21,441	21,529	-663	-2.99%	-0.34%
NPCC-Québec	37,810	38,062	38,527	38,845	39,189	39,487	39,812	40,079	40,317	40,575	2,766	7.31%	0.79%
WECC-AESO	11,664	12,162	12,801	13,382	13,856	14,351	14,759	15,162	15,618	15,994	4,330	37.12%	3.57%
WECC-BC	11,416	11,738	11,943	12,050	12,073	12,223	12,373	12,523	12,673	12,823	1,407	12.32%	1.30%
TOTAL-CANADA	96,492	97,467	98,517	99,355	99,951	100,842	102,219	103,391	104,640	105,679	9,187	9.52%	1.02%
WECC-MEXW	1,494	1,532	1,571	1,610	1,648	1,687	1,725	1,764	1,803	1,841	347	23.23%	2.35%
TOTAL-MÉXICO	1,494	1,532	1,571	1,610	1,648	1,687	1,725	1,764	1,803	1,841	347	23.23%	2.35%
TOTAL-NERC	**733,669**	**745,513**	**755,760**	**764,990**	**774,180**	**781,757**	**789,361**	**798,246**	**807,399**	**817,092**	**83,423**	**11.37%**	**1.20%**

Annual Total Internal Demand – Summer

Assessment Area/Country	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	10-Year Change		CAGR
ERCOT	66,928	69,721	73,054	75,366	76,821	78,002	78,351	80,176	81,410	82,507	15,579	23.28%	2.35%
FRCC	46,270	46,857	47,758	48,594	49,244	49,643	50,356	51,191	51,933	52,583	6,313	13.64%	1.43%
MISO	94,279	96,129	96,929	97,811	98,729	99,611	100,565	101,530	102,559	103,584	9,305	9.87%	1.05%
MRO-MAPP	4,995	5,117	5,230	5,503	5,560	5,643	5,746	5,840	5,928	6,015	1,020	20.42%	2.09%
NPCC-New England	27,765	28,275	28,840	29,400	29,895	30,275	30,605	30,930	31,255	31,583	3,818	13.75%	1.44%
NPCC-New York	33,696	33,914	34,151	34,345	34,550	34,868	35,204	35,526	35,913	36,230	2,534	7.52%	0.81%
PJM	156,254	159,842	163,168	165,691	167,433	169,032	170,860	172,793	174,638	176,420	20,166	12.91%	1.36%
SERC-E	43,733	44,457	44,903	45,436	45,939	46,358	46,908	47,487	48,149	48,697	4,964	11.35%	1.20%
SERC-N	45,750	46,542	47,303	47,974	48,660	49,288	50,090	50,868	51,345	52,038	6,288	13.74%	1.44%
SERC-SE	49,799	50,838	51,431	52,045	52,789	53,256	53,948	54,645	55,600	56,512	6,713	13.48%	1.42%
SERC-W	25,921	26,166	26,563	26,881	27,199	27,505	27,863	28,153	28,435	28,730	2,809	10.84%	1.15%
SPP	55,180	55,732	55,766	56,364	57,055	57,591	58,378	59,239	59,904	60,088	4,908	8.90%	0.95%
WECC-BASN	13,776	14,144	14,482	14,765	15,081	15,306	15,550	15,786	15,994	15,914	2,138	15.52%	1.62%
WECC-CALN	26,645	26,971	27,298	27,904	28,211	28,507	28,834	29,160	29,487	29,912	3,267	12.26%	1.29%
WECC-CALS	31,319	31,896	32,472	32,821	33,254	33,666	34,090	34,666	35,243	35,615	4,296	13.72%	1.44%
WECC-DSW	27,576	27,847	28,179	28,679	29,157	29,686	30,204	30,764	31,305	31,602	4,026	14.60%	1.53%
WECC-NORW	24,380	24,694	24,967	25,270	25,560	25,797	26,034	26,295	26,561	26,858	2,478	10.16%	1.08%
WECC-ROCK	11,904	12,107	12,330	12,563	12,763	12,970	13,176	13,404	13,615	13,771	1,867	15.68%	1.63%
TOTAL-UNITED STATES	786,170	801,249	814,823	827,411	837,899	847,005	856,761	868,453	879,275	888,660	102,490	13.04%	1.37%
MRO-Manitoba Hydro	3,210	3,238	3,207	3,244	3,286	3,221	3,271	3,348	3,428	3,474	264	8.24%	0.88%
MRO-SaskPower	3,275	3,426	3,535	3,624	3,721	3,709	3,756	3,807	3,875	3,938	663	20.24%	2.07%
NPCC-Maritimes	3,435	3,469	3,448	3,441	3,447	3,459	3,471	3,494	3,506	3,514	79	2.30%	0.25%
NPCC-Ontario	23,301	23,080	22,859	22,638	22,471	22,583	22,891	23,010	23,390	23,442	142	0.61%	0.07%
NPCC-Québec	21,115	21,550	21,642	21,883	22,008	22,125	22,307	22,503	22,662	22,818	1,704	8.07%	0.87%
WECC-AESO	10,941	11,548	12,077	12,642	13,146	13,560	13,974	14,374	14,765	15,131	4,190	38.30%	3.67%
WECC-BC	8,449	8,684	8,834	8,913	9,043	9,167	9,289	9,427	9,553	9,670	1,221	14.45%	1.51%
TOTAL-CANADA	73,726	74,995	75,602	76,385	77,123	77,824	78,958	79,964	81,179	81,988	8,262	11.21%	1.19%
WECC-MEXW	2,203	2,260	2,317	2,374	2,431	2,488	2,545	2,602	2,659	2,716	513	23.29%	2.35%
TOTAL-MÉXICO	2,203	2,260	2,317	2,374	2,431	2,488	2,545	2,602	2,659	2,716	513	23.29%	2.35%
TOTAL-NERC	**862,098**	**878,504**	**892,742**	**906,170**	**917,453**	**927,317**	**938,265**	**951,019**	**963,113**	**973,364**	**111,266**	**12.91%**	**1.36%**

Annual Total Internal Demand – Winter

Assessment Area/Country	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	10-Year Change		CAGR
ERCOT	51,734	52,063	54,972	56,028	58,869	59,202	59,318	60,039	60,917	63,336	11,602	22.43%	2.27%
FRCC	46,367	47,568	48,172	48,797	49,298	49,908	50,570	51,218	51,921	52,408	6,041	13.03%	1.37%
MISO	72,572	78,143	78,773	79,521	80,104	80,891	81,649	82,252	83,064	83,894	11,322	15.60%	1.62%
MRO-MAPP	4,858	4,999	5,074	5,335	5,412	5,522	5,623	5,718	5,814	5,904	1,047	21.55%	2.19%
NPCC-New England	22,510	22,670	22,825	22,960	23,090	23,210	23,330	23,445	23,565	23,686	1,176	5.22%	0.57%
NPCC-New York	24,929	24,999	25,053	25,149	25,153	25,265	25,422	25,627	25,794	25,908	979	3.93%	0.43%
PJM	132,160	134,771	136,911	138,567	139,662	140,844	142,018	143,419	144,836	146,116	13,956	10.56%	1.12%
SERC-E	43,582	43,977	44,520	44,993	45,487	46,003	46,648	47,201	47,797	48,395	4,813	11.04%	1.17%
SERC-N	45,713	46,433	47,166	47,967	48,659	49,266	49,932	50,584	51,397	51,914	6,201	13.56%	1.42%
SERC-SE	46,534	47,197	47,814	48,485	48,978	49,665	50,338	51,193	52,029	52,894	6,360	13.67%	1.43%
SERC-W	20,497	20,835	20,992	21,493	21,908	22,215	21,923	22,539	22,707	23,082	2,585	12.61%	1.33%
SPP	41,714	42,010	42,040	42,644	43,069	43,590	44,223	44,794	45,334	45,726	4,012	9.62%	1.03%
WECC-BASN	11,134	11,215	11,472	11,721	11,945	12,123	12,245	12,331	12,463	12,437	1,303	11.70%	1.24%
WECC-CALN	18,664	18,977	19,212	19,498	19,689	19,898	20,048	20,198	20,348	20,498	1,834	9.83%	1.05%
WECC-CALS	23,229	23,753	24,106	24,332	24,697	25,051	25,440	25,994	26,403	26,607	3,378	14.54%	1.52%
WECC-DSW	18,124	18,380	18,721	19,117	19,477	19,830	20,235	20,553	20,780	21,065	2,941	16.23%	1.69%
WECC-NORW	30,270	30,577	30,843	31,148	31,450	31,705	31,971	32,195	32,512	32,759	2,488	8.22%	0.88%
WECC-ROCK	9,833	9,978	10,189	10,486	10,672	10,877	11,072	11,200	11,401	11,521	1,688	17.17%	1.78%
TOTAL-UNITED STATES	664,424	678,545	688,855	698,239	707,619	715,065	722,005	730,501	739,081	748,149	83,725	12.60%	1.33%
MRO-Manitoba Hydro	4,661	4,712	4,723	4,781	4,845	4,801	4,878	4,981	5,089	5,162	501	10.76%	1.14%
MRO-SaskPower	3,671	3,829	3,950	4,050	4,159	4,145	4,198	4,255	4,330	4,401	730	19.89%	2.04%
NPCC-Maritimes	5,421	5,420	5,419	5,444	5,462	5,489	5,492	5,513	5,530	5,552	131	2.42%	0.27%
NPCC-Ontario	22,192	21,890	21,500	21,153	20,719	20,700	21,063	21,234	21,441	21,529	-663	-2.99%	-0.34%
NPCC-Québec	37,810	38,062	38,527	38,845	39,189	39,487	39,812	40,079	40,317	40,575	2,766	7.31%	0.79%
WECC-AESO	11,664	12,162	12,801	13,382	13,856	14,351	14,759	15,162	15,618	15,994	4,330	37.12%	3.57%
WECC-BC	11,416	11,738	11,943	12,050	12,073	12,223	12,373	12,523	12,673	12,823	1,407	12.32%	1.30%
TOTAL-CANADA	96,835	97,812	98,863	99,706	100,303	101,196	102,575	103,747	104,997	106,037	9,202	9.50%	1.01%
WECC-MEXW	1,494	1,532	1,571	1,610	1,648	1,687	1,725	1,764	1,803	1,841	347	23.23%	2.35%
TOTAL-MÉXICO	1,494	1,532	1,571	1,610	1,648	1,687	1,725	1,764	1,803	1,841	347	23.23%	2.35%
TOTAL-NERC	**762,753**	**777,889**	**789,289**	**799,555**	**809,570**	**817,948**	**826,305**	**836,012**	**845,882**	**856,027**	**93,274**	**12.23%**	**1.29%**

Appendix II: NERC-Wide Transmission Additions, Upgrades, and Retirements

Table Notes

- Includes 100 kV and above transmission additions, upgrades, and retirements with in-service dates from 2012-2022, as reported by each NERC Assessment Area.
- Line length in circuit miles is presented in terms of net change; relining, rerating and other upgrades typically result in no change in line length, while retired lines result in negative circuit miles (unless otherwise noted).
- Project status categories are defined below:
  - UC: Project Under Construction
  - P: New Planned Project
  - U: Planned Upgrade of Existing Line
  - C: New Conceptual Project
  - R: Retirement of Existing Line

Assessment Area	Transmission Project Name	Status	Terminal Origin Locaction	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Current (AC/DC)	Capacity Rating (MVA)	In-Service Year
ERCOT	00TPIT0004	C	DeCordova	Benbrook	27.0	300-399	AC	Unknown	2018
ERCOT	00TPITno07	C	Loma Alta Substation	Rio Hondo Substation	35.0	300-399	AC	Unknown	2018
ERCOT	05TPIT0065	P	Highway 32	Wimberley	4.0	121-150	AC	Unknown	2014
ERCOT	06TPIT0036	C	Ennis Switch	Ennis	6.3	121-150	AC	Unknown	2018
ERCOT	06TPIT0042	C	Lake Wichita Switch	Wichitia Falls Switch	6.3	121-150	AC	Unknown	2018
ERCOT	06TPIT0043	C	Sherry	Liggett	13.0	121-150	AC	Unknown	2014
ERCOT	06TPIT0047	C	Elkton	Tyler	5.0	121-150	AC	Unknown	2018
ERCOT	06TPIT0068	C	Hamilton Road	Picacho	8.7	121-150	AC	Unknown	2018
ERCOT	06TPIT0082	C	Buena Vista	Picacho	3.0	121-150	AC	Unknown	2018
ERCOT	06TPIT0083	C	Del Rio	Buena Vista	3.0	121-150	AC	Unknown	2018
ERCOT	06TPIT0084	C	Hamilton Road	Del Rio	3.0	121-150	AC	Unknown	2018
ERCOT	06TPIT0112	P	Lakeway Substation	Lakeway Substation	0.9	121-150	AC	Unknown	2012
ERCOT	06TPIT0143	C	Temple Switch	Temple SE	4.4	121-150	AC	Unknown	2014
ERCOT	07TPIT0001	C	Liggett	Trinity Switch	12.8	300-399	AC	Unknown	2018
ERCOT	07TPIT0012	C	Trinity Switch	Richland	0.5	121-150	AC	Unknown	2018
ERCOT	07TPIT0014	C	Plano West	Richardson Tap	1.9	121-150	AC	Unknown	2020
ERCOT	07TPIT0017	C	Handley	Hurst	18.7	121-150	AC	Unknown	2012
ERCOT	07TPIT0027	UC	CPS Lytle	ETT Lytle	4.0	121-150	AC	Unknown	2012
ERCOT	07TPIT0050	P	Decker Switchyard	Techridge Substation	4.5	121-150	AC	Unknown	2013
ERCOT	07TPIT0060	P	Howard Lane Substation	Techridge Substation	1.7	121-150	AC	Unknown	2015
ERCOT	07TPIT0069	C	Sterrett	Sardis	2.0	121-150	AC	Unknown	2022
ERCOT	07TPIT0073	C	Venus	Webb	11.3	300-399	AC	Unknown	2020
ERCOT	07TPIT0083	C	Picacho	CFE	8.8	121-150	AC	Unknown	2018
ERCOT	07TPIT0115	C	Elgiin Switch	Taylor	11.4	121-150	AC	Unknown	2018
ERCOT	07TPIT0119	C	Lavon Switch	Allen Switch	8.9	121-150	AC	Unknown	2018
ERCOT	07TPIT0122	C	Royse	Dalrock	6.8	121-150	AC	Unknown	2018
ERCOT	07TPIT0126	P	Tricorner	Seagoville	9.4	300-399	AC	Unknown	2014
ERCOT	07TPIT0138	C	Oats (GPL)	Garland Bobtown Tap	1.5	121-150	AC	Unknown	2018
ERCOT	07TPIT0140	C	Trinidad	Watermill	52.0	300-399	AC	Unknown	2014
ERCOT	07TPIT0234	C	Collin Switch	NW. Carrollton	19.3	300-399	AC	Unknown	2022
ERCOT	07TPIT0236	C	N. Terrell Tap	Rose Hill	8.7	121-150	AC	Unknown	2014
ERCOT	08TPIT0007	C	Austin Ranch	Hebron	0.7	121-150	AC	Unknown	2018
ERCOT	08TPIT0018	UC	Uvalde	Castroville	77.5	121-150	AC	Unknown	2012
ERCOT	08TPIT0033	P	Gilleland Substation	Techridge Substation	8.0	300-399	AC	Unknown	2015
ERCOT	08TPIT0034	P	McNeil Substation	Summit Substation	2.0	121-150	AC	Unknown	2012
ERCOT	08TPIT0069	C	Lake Creek	East Waco	10.5	121-150	AC	Unknown	2018
ERCOT	08TPIT0097	UC	Rhome	Roanoke	16.6	121-150	AC	Unknown	2013
ERCOT	08TPIT0104	C	Elgin Switching Station	Elgin	5.9	121-150	AC	Unknown	2014
ERCOT	08TPIT0107	C	Leon	Flat Creek	19.5	121-150	AC	Unknown	2012
ERCOT	08TPIT0109	C	Payne	Collin Switching Station	31.8	121-150	AC	Unknown	2020
ERCOT	08TPIT0111	C	Lufkin Switching Station	Texas Foundries Tap	0.7	121-150	AC	Unknown	2018
ERCOT	08TPIT0153	C	Elkton	Athens North Tap	29.1	121-150	AC	Unknown	2014
ERCOT	09TPIT0011	C	Cagnon	Hill Country	19.5	300-399	AC	Unknown	2020
ERCOT	09TPIT0012	C	Hill Country	Skyline	11.0	300-399	AC	Unknown	2016
ERCOT	09TPIT0037	P	Blossom	Harmony Hills/Skyline	0.1	121-150	AC	Unknown	2014
ERCOT	09TPIT0043	C	Coppell	North Lake	4.8	121-150	AC	Unknown	2018
ERCOT	09TPIT0044	C	E. Richardson	Apollo	2.3	121-150	AC	Unknown	2013
ERCOT	09TPIT0046	C	N. Midlothian	Midlothian TXI Tap	6.2	121-150	AC	Unknown	2018
ERCOT	09TPIT0047	C	N. Waco	NE. Waco	1.9	121-150	AC	Unknown	2020
ERCOT	09TPIT0050	C	Rowlett	Garland Bobtown Tap	4.1	121-150	AC	Unknown	2018
ERCOT	09TPIT0051	C	Saldo Switch	Cedar Valley Switch	7.0	121-150	AC	Unknown	2018
ERCOT	09TPIT0066	C	Boggy Creek	Boggy Creek	3.5	121-150	AC	Unknown	2018
ERCOT	09TPIT0073	P	Switch 1377 at Jupiter	Switch 6612 at Apollo	2.0	121-150	AC	Unknown	2012
ERCOT	09TPIT0074	P	Switch 1378 at Jupiter	Switch 931 at Lawler Tap	1.5	121-150	AC	Unknown	2012
ERCOT	09TPIT0076	P	Switch 932atLawler Tap	Switch 6832 at College	2.0	121-150	AC	Unknown	2012
ERCOT	09TPIT0117	C	Stryker Creek	Dialville	15.2	121-150	AC	Unknown	2014
ERCOT	09TPIT0118	C	Fisher Road	Wichita Falls	1.5	121-150	AC	Unknown	2020
ERCOT	09TPIT0120	C	Sun Switch	Sacroc	12.8	121-150	AC	Unknown	2012
ERCOT	09TPIT0121	C	Sun Switch	Sacroc	1.8	121-150	AC	Unknown	2012
ERCOT	09TPIT0122	C	Shamburger	Tyler NW	6.3	121-150	AC	Unknown	2020
ERCOT	10TPIT0001	C	Trumbo	Leon Creek/Pleasanton	0.1	121-150	AC	Unknown	2016
ERCOT	10TPIT0009	C	Trinity Switch	Hurst	4.0	121-150	AC	Unknown	2018
ERCOT	10TPIT0010	C	Coppell	Roanoke	17.0	121-150	AC	Unknown	2012
ERCOT	10TPIT0013	C	Apollo	East Richardson	1.4	121-150	AC	Unknown	2013

Assessment Area	Transmission Project Name	Status	Terminal Origin Locaction	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Current (AC/DC)	Capacity Rating (MVA)	In-Service Year
ERCOT	10TPIT0017	C	Allen Switch	Collin Junction	9.0	121-150	AC	Unknown	2014
ERCOT	10TPIT0018	C	Austin Ranch	Colony	4.6	121-150	AC	Unknown	2012
ERCOT	10TPIT0019	C	Everman	Cleburne Switch	8.5	121-150	AC	Unknown	2020
ERCOT	10TPIT0020	P	Anna Switch	Krum W. Switch	140.0	300-399	AC	Unknown	2013
ERCOT	10TPIT0024	P	Stoney Ridge Substation	Stoney Ridge Substation	0.1	121-150	AC	Unknown	2012
ERCOT	10TPIT0025	P	Rinard Creek substation	Rinard Creek Substation	0.1	121-150	AC	Unknown	2015
ERCOT	10TPIT0028	C	Escondido	West Batesville	46.2	121-150	AC	Unknown	2018
ERCOT	10TPIT0032	C	Arco (TMPA)	Krugerville	5.6	121-150	AC	Unknown	2012
ERCOT	10TPIT0038	P	Switch 8832 at College	Switch 1364 at Brand	4.2	121-150	AC	Unknown	2013
ERCOT	10TPIT0041	P	Temple Switch	Salado Switch	15.2	300-399	AC	Unknown	2012
ERCOT	10TPIT0049	P	Koppe Bridge	Wellborn	5.8	121-150	AC	Unknown	2012
ERCOT	10TPIT0063	P	Geronimo	CMC	5.5	121-150	AC	Unknown	2014
ERCOT	10TPIT0086	P	East Abilene	Putnam	32.0	121-150	AC	Unknown	2012
ERCOT	10TPIT0091	C	Elm Mott	Waco Northcrest	3.6	121-150	AC	Unknown	2020
ERCOT	10TPIT0095	P	VH Braunig	Grandview	2.1	121-150	AC	Unknown	2012
ERCOT	11TPIT0001	P	Lobo	Rio Bravo	30.0	300-399	AC	Unknown	2016
ERCOT	11TPIT0002	P	Lobo	North Edinburg	163.0	300-399	AC	Unknown	2016
ERCOT	11TPIT0008	P	Rainey St Substation	Rainey St Substation	0.1	121-150	AC	Unknown	2017
ERCOT	11TPIT0009	P	Dunlap Substation	Dunlap Substation	0.1	121-150	AC	Unknown	2014
ERCOT	11TPIT0011	P	Northeast Substation	Northeast Substation	0.1	121-150	AC	Unknown	2017
ERCOT	11TPIT0012	C	Euless	Grapevine Ball Street	5.9	121-150	AC	Unknown	2020
ERCOT	11TPIT0015	C	Sherry	Grand Prairie	11.4	121-150	AC	Unknown	2015
ERCOT	11TPIT0024	C	various	various	5.8	121-150	AC	Unknown	2012
ERCOT	11TPIT0028	C	Allen Switch	West Plano Switch	3.5	121-150	AC	Unknown	2018
ERCOT	11TPIT0032	C	NW Carrollton	Collin	16.9	121-150	AC	Unknown	2014
ERCOT	11TPIT0033	C	Saginaw	American MFG Tap	1.4	121-150	AC	Unknown	2020
ERCOT	11TPIT0047	P	Twin Buttes	Brown	0.2	300-399	AC	Unknown	2012
ERCOT	11TPIT0050	C	Roanoke Switch	Elizabeth Creek	3.8	121-150	AC	Unknown	2015
ERCOT	11TPIT0050	C	Hicks Switch	Elizabeth Creek	10.0	121-150	AC	Unknown	2015
ERCOT	11TPIT0065	C	Ector Co. North Switch	Moss	20.5	121-150	AC	Unknown	2012
ERCOT	11TPIT0072a	UC	Garrott	Midtown	1.5	121-150	AC	Unknown	2012
ERCOT	11TPIT0072b	UC	Midtown	Polk	1.0	121-150	AC	Unknown	2012
ERCOT	11TPIT0076	P	Cottonwood	Dermott	74.2	300-399	AC	Unknown	2012
ERCOT	11TPIT0081	UC	Switch 7512 at Plastipak	Switch 8702 at Shiloh	1.5	121-150	AC	Unknown	2012
ERCOT	11TPIT0085	P	Doedyns	Sioux	5.5	121-150	AC	Unknown	2013
ERCOT	11TPIT0101	P	Reno	Rhome	13.9	121-150	AC	Unknown	2012
ERCOT	11TPIT0110b	P	Weslaco Switch	Valverde	4.5	121-150	AC	Unknown	2012
ERCOT	11TPIT0111	P	Thompson Creek	Koppe Bridge	17.0	121-150	AC	Unknown	2012
ERCOT	11TPIT0114	P	Alberta Switch	Doedyns	3.1	121-150	AC	Unknown	2013
ERCOT	11TPIT0179	C	Hicks Switch	Elizabeth Creek	10.0	121-150	AC	Unknown	2015
ERCOT	12TPIT0004	C	Sulpher Springs	OW Sommers/Kirby	0.1	121-150	AC	Unknown	2018
ERCOT	12TPIT0009	P	Masterson Rd.	Cagnon/Valley/Howard	20.0	121-150	AC	Unknown	2018
ERCOT	12TPIT0015	P	Barney Davis	Laguna	4.2	121-150	AC	Unknown	2014
ERCOT	12TPIT0026	P	Odessa	North McCamey	59.6	300-399	AC	Unknown	2013
ERCOT	12TPIT0027	P	Bakersfield	North McCamey	15.9	300-399	AC	Unknown	2013
ERCOT	12TPIT0028	P	Twin Buttes	Big Hill	31.0	300-399	AC	Unknown	2012
ERCOT	12TPIT0029	P	Big Hill	Kendall	274.0	300-399	AC	Unknown	2013
ERCOT	12TPIT0036	P	Brown	Newton	98.6	300-399	AC	Unknown	2012
ERCOT	12TPIT0037	P	Newton	Killeen Switch	27.9	300-399	AC	Unknown	2012
ERCOT	12TPIT0038	P	Brown	Killeen Switch	126.5	300-399	AC	Unknown	2012
ERCOT	12TPIT0043	UC	Bluff Creek	Brown	86.6	300-399	AC	Unknown	2012
ERCOT	12TPIT0044	UC	Central Bluff	Brown	96.1	300-399	AC	Unknown	2012
ERCOT	12TPIT0046	UC	ZENITH	Gertie	10.0	300-399	AC	Unknown	2012
ERCOT	12TPIT0047	UC	Kluge	Addicks	6.1	121-150	AC	Unknown	2012
ERCOT	12TPIT0047b	UC	ZENITH	ADDICKS	1.5	121-150	AC	Unknown	2012
ERCOT	12TPIT0047c	UC	CAMRON	KLUGE	4.6	121-150	AC	Unknown	2012
ERCOT	12TPIT0049	P	Cottonwood	Silverton	64.5	300-399	AC	Unknown	2013
ERCOT	12TPIT0051	P	Silverton	Nazareth	46.0	300-399	AC	Unknown	2013
ERCOT	12TPIT0052	P	Nazareth	Hereford	25.5	300-399	AC	Unknown	2013
ERCOT	12TPIT0056	P	Grelton	Long Draw	55.4	300-399	AC	Unknown	2013
ERCOT	12TPIT0057	P	Grelton	Odessa	49.9	300-399	AC	Unknown	2013
ERCOT	12TPIT0058	P	Long Draw	Scurry	50.7	300-399	AC	Unknown	2013
ERCOT	12TPIT0059	P	Sand Bluff	Divide	37.0	300-399	AC	Unknown	2013
ERCOT	12TPIT0060	P	Berkat	Sandbluff	28.9	300-399	AC	Unknown	2013
ERCOT	12TPIT0061	P	Sand Bluff	Long Draw	77.4	300-399	AC	Unknown	2013
ERCOT	12TPIT0068	C	South Bend Switch	Morris Sheppard	18.2	121-150	AC	Unknown	2013
ERCOT	12TPIT0072	P	Ferguson	Wirtz	4.0	121-150	AC	Unknown	2012

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ERCOT	12TPIT0078	C	Southeast Nacogdoches	Lufkin Switch	13.0	300-399	AC	Unknown	2022
ERCOT	12TPIT0079	C	Roanoke Switch	Coppell	19.6	121-150	AC	Unknown	2013
ERCOT	12TPIT0081	P	Merida	Medina Base	0.1	121-150	AC	Unknown	2013
ERCOT	12TPIT0082	P	Hotwells	Ball Park/Deely	0.1	121-150	AC	Unknown	2012
ERCOT	12TPIT0083	P	S 8512 at Firewheel	Lookout	1.3	121-150	AC	Unknown	2012
ERCOT	12TPIT0085	P	Switch 8622 at Apollo	Lookout	2.8	121-150	AC	Unknown	2012
ERCOT	12TPIT0095b	UC	TXGULF	West Columbia	27.5	121-150	AC	Unknown	2012
ERCOT	12TPIT0115	P	Bullick Hollow	Marshall Ford/Balcones	2.3	121-150	AC	Unknown	2012
ERCOT	12TPIT0116	P	Scarscale	El Dorado/S.Houston	0.9	121-150	AC	Unknown	2012
ERCOT	12TPIT0118	C	Elkton	S Tyler	2.8	121-150	AC	Unknown	2012
ERCOT	12TPIT0128	P	WA Parish	Sienna	4.2	121-150	AC	Unknown	2012
ERCOT	12TPIT0134	P	St Jo	Capps Corner	8.6	121-150	AC	Unknown	2012
ERCOT	12TPIT0135	P	Spring	Bridgeport Switch	33.3	121-150	AC	Unknown	2013
ERCOT	12TPIT0136	UC	El Gato	Sioux	5.4	121-150	AC	Unknown	2012
ERCOT	12TPIT0141	C	Dinero	Dinero	0.5	121-150	AC	Unknown	2012
ERCOT	12TPIT0165	P	Fairbanks	Deihl	3.6	121-150	AC	Unknown	2012
ERCOT	12TPIT0165a	P	Deihl	White Oak	4.1	121-150	AC	Unknown	2012
ERCOT	12TPIT0167	P	Crockett	Northside	2.5	121-150	AC	Unknown	2012
ERCOT	12TPIT0169	P	Bellaire	Ulrich	3.4	121-150	AC	Unknown	2012
ERCOT	12TPIT0170	P	Airline	White Oak	3.0	121-150	AC	Unknown	2012
ERCOT	12TPIT0171	P	HO Clarke	Knight	3.9	121-150	AC	Unknown	2012
ERCOT	12TPIT0172	P	Western Dawson	Patricia	7.5	300-399	AC	Unknown	2012
ERCOT	12TPIT0173	P	Austin	Kirby	2.8	121-150	AC	Unknown	2012
ERCOT	12TPIT0178	P	EXTER	HASTINGS	0.1	121-150	AC	Unknown	2012
ERCOT	12TPIT0185	C	Airline	Cabaniss	5.5	121-150	AC	Unknown	2014
ERCOT	13TPIT0011	C	Palo Alto	Leon Creek/Chavaneaus	0.1	121-150	AC	Unknown	2013
ERCOT	13TPIT0016	P	Greens Prairie	Wellborn	4.0	121-150	AC	Unknown	2013
ERCOT	13TPIT0018	P	Bakersfield	Big Hill	112.0	300-399	AC	Unknown	2013
ERCOT	13TPIT0019	P	Riley	Edith Clarke	86.6	300-399	AC	Unknown	2013
ERCOT	13TPIT0020	P	Tesla	Edith Clarke	110.4	300-399	AC	Unknown	2013
ERCOT	13TPIT0021	P	Cottonwood	Edith Clarke	178.0	300-399	AC	Unknown	2013
ERCOT	13TPIT0022	P	Tesla	Riley	131.2	300-399	AC	Unknown	2013
ERCOT	13TPIT0030	P	Dermott	Clear Crossing	180.6	300-399	AC	Unknown	2013
ERCOT	13TPIT0032	P	Edith Clarke	Clear Crossing	158.4	300-399	AC	Unknown	2013
ERCOT	13TPIT0033	P	Clear Crossing	West Shackleford	67.6	300-399	AC	Unknown	2013
ERCOT	13TPIT0035	P	Willow Creek	Dermott Switch	220.0	300-399	AC	Unknown	2013
ERCOT	13TPIT0036	P	Krum West	Riley	322.8	300-399	AC	Unknown	2013
ERCOT	13TPIT0039	P	Hicks Switch	Willow Creek	80.4	300-399	AC	Unknown	2013
ERCOT	13TPIT0042	P	White Deer	Hereford	91.2	300-399	AC	Unknown	2013
ERCOT	13TPIT0045	P	Blumenthal	Kendall CTEC/Mt. Top	8.4	121-150	AC	Unknown	2017
ERCOT	13TPIT0046	P	Flatonia	Yoakum Gartner Road	27.7	121-150	AC	Unknown	2013
ERCOT	13TPIT0047	P	Parkway	EC Mornhinweg	8.0	121-150	AC	Unknown	2014
ERCOT	13TPIT0048	UC	Scurry County South	West Shackelford	204.0	300-399	AC	Unknown	2013
ERCOT	13TPIT0049	UC	West Shackelford	C1 - Sam C2 Navarro	402.0	300-399	AC	Unknown	2013
ERCOT	13TPIT0050	P	Silverton	White Deer	68.2	300-399	AC	Unknown	2013
ERCOT	13TPIT0051	P	Gray	Tesla	218.0	300-399	AC	Unknown	2013
ERCOT	13TPIT0054	P	Gray	White Deer	80.0	300-399	AC	Unknown	2013
ERCOT	13TPIT0055	P	Silverton	Tesla	170.0	300-399	AC	Unknown	2013
ERCOT	13TPIT0058	P	Summit Substation	Williamson Substation	3.5	121-150	AC	Unknown	2014
ERCOT	13TPIT0059	C	Cedar Crest	Industrial	3.2	121-150	AC	Unknown	2020
ERCOT	13TPIT0060	C	Cedar Hill Switch	Mountain Creek	11.4	121-150	AC	Unknown	2014
ERCOT	13TPIT0061	C	Terrell Switch	North Terrell Tap	7.9	121-150	AC	Unknown	2015
ERCOT	13TPIT0066	P	GPI	EC Mornhinweg	2.7	121-150	AC	Unknown	2012
ERCOT	13TPIT0068	P	Helotes	Grissom	0.5	121-150	AC	Unknown	2012
ERCOT	13TPIT0069	P	Panther Springs	Hill Country/Stonegate	0.1	121-150	AC	Unknown	2013
ERCOT	13TPIT0077	P	Kendall	Paleface	56.9	121-150	AC	Unknown	2013
ERCOT	13TPIT0079	P	Alvin	North Alvin	2.1	121-150	AC	Unknown	2014
ERCOT	13TPIT0092	C	Killeen Switch	Harker Heights	15.0	121-150	AC	Unknown	2013
ERCOT	13TPIT0094	C	Lamesa	Ackerly	21.5	121-150	AC	Unknown	2013
ERCOT	13TPIT0099	P	League City	Magnolia	3.6	121-150	AC	Unknown	2013
ERCOT	13TPIT0106	P	Killeen SS	Ding Dong	23.8	121-150	AC	Unknown	2013
ERCOT	13TPIT0108	P	Nelson Sharpe	Ajo	37.0	300-399	AC	Unknown	2013
ERCOT	13TPIT0109	P	Ajo	Rio Hondo	66.7	300-399	AC	Unknown	2013
ERCOT	13TPIT0119	P	Vanderbilt	Ricebird	52.0	121-150	AC	Unknown	2013
ERCOT	13TPIT0121	C	Tilden	TBD	48.0	121-150	AC	Unknown	2013
ERCOT	13TPIT0129	P	George West	Tilden	20.6	121-150	AC	Unknown	2013
ERCOT	13TPIT0130	C	San Miguel	Fashing	20.6	121-150	AC	Unknown	2013

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ERCOT	13TPIT0131	C	Oaks	Fashing	38.0	121-150	AC	Unknown	2013
ERCOT	13TPIT0135	C	Holt Switch	Goldsmith Substation	5.0	121-150	AC	Unknown	2013
ERCOT	13TPIT0137	C	Odessa North Switch	Goldsmith Substation	17.3	121-150	AC	Unknown	2013
ERCOT	13TPIT0139	C	Olinger	Greenville Interchange	25.0	121-150	AC	Unknown	2013
ERCOT	13TPIT0141	P	NORTON	HACHER/ENPROD	2.0	121-150	AC	Unknown	2013
ERCOT	13TPIT0143	P	El Campo Substation	Nada Substation	17.5	121-150	AC	Unknown	2013
ERCOT	13TPIT0149	P	Oaks	TBD	5.7	121-150	AC	Unknown	2013
ERCOT	13TPIT0152	C	Wink Switch	Loving	16.6	121-150	AC	Unknown	2013
ERCOT	13TPIT0153	C	Moss	Odessa EHV	14.2	121-150	AC	Unknown	2013
ERCOT	13TPIT0158	P	Bruni	MEC Bruni	0.6	121-150	AC	Unknown	2013
ERCOT	13TPIT0162	P	Colorado City	Oncor Breaker Station	2.1	121-150	AC	Unknown	2013
ERCOT	13TPIT0163	C	0	Jan-1900	0.3	121-150	AC	Unknown	2013
ERCOT	14TPIT0003	C	Ranchtown	Helotes/Menger Creek	0.1	121-150	AC	Unknown	2015
ERCOT	14TPIT0004	P	Highway 123	Cushman/New Berlin	6.2	121-150	AC	Unknown	2014
ERCOT	14TPIT0010	C	Handley	Pantego	3.8	121-150	AC	Unknown	2017
ERCOT	14TPIT0011	C	Midland East	Windwood	1.7	121-150	AC	Unknown	2020
ERCOT	14TPIT0012	C	Mountain Creek	Norwood	7.2	121-150	AC	Unknown	2014
ERCOT	14TPIT0013	C	Norwood	East Levee	6.6	121-150	AC	Unknown	2012
ERCOT	14TPIT0014	C	NW Carrollton	Lakepointe (TNMP)	2.1	121-150	AC	Unknown	2014
ERCOT	14TPIT0015	C	Troup	Tyler Grande	13.3	121-150	AC	Unknown	2012
ERCOT	14TPIT0016	C	West Mesquite	Prairie Creek	2.8	121-150	AC	Unknown	2014
ERCOT	14TPIT0020	P	SpencerInt.PSS/EBus982	Pockrus SubPSS/E Bus917	3.3	121-150	AC	Unknown	2015
ERCOT	14TPIT0021	P	Buttercup Substation	Whitestone Substation	2.3	121-150	AC	Unknown	2014
ERCOT	14TPIT0024	P	Lon Hill	Sand Dollar	11.5	300-399	AC	Unknown	2015
ERCOT	14TPIT0025	P	Nopalito	Sand Dollar	14.5	300-399	AC	Unknown	2016
ERCOT	14TPIT0026	P	Sand Dollar	Las Brisas	2.0	300-399	AC	Unknown	2015
ERCOT	14TPIT0029	C	Lake Creek	Robinson	8.3	121-150	AC	Unknown	2018
ERCOT	14TPIT0037	C	Martin Lake	Mount Enterprise	1.2	300-399	AC	Unknown	2012
ERCOT	14TPIT0038	P	Northland Substation	Mag Plant Substation	4.1	121-150	AC	Unknown	2014
ERCOT	14TPIT0040	P	Springwoods	Rayford/Louetta	3.1	121-150	AC	Unknown	2014
ERCOT	14TPIT0041	P	Coliseum	Kirby	4.2	121-150	AC	Unknown	2014
ERCOT	14TPIT0042	P	Five Points	Broadview	9.4	121-150	AC	Unknown	2014
ERCOT	14TPIT0043	C	Skyline	Tri_Conty/Wiederstein	0.1	121-150	AC	Unknown	2014
ERCOT	14TPIT0047	C	W.Denton,N Denton	Arco, Pockrus, Teasley	30.0	121-150	AC	Unknown	2014
ERCOT	14TPIT0050	P	Lon Hill	North Edinburg	122.9	300-399	AC	Unknown	2014
ERCOT	14TPIT0052	C	Midland East	Stanton East	18.6	121-150	AC	Unknown	2014
ERCOT	14TPIT0053	C	Moss	Westover	3.4	121-150	AC	Unknown	2014
ERCOT	14TPIT0054	C	Odessa	Odessa North	7.2	121-150	AC	Unknown	2020
ERCOT	14TPIT0055	C	Seagoville	Wilmer	10.9	121-150	AC	Unknown	2014
ERCOT	14TPIT0056	C	Northaven	Welch	6.0	121-150	AC	Unknown	2014
ERCOT	14TPIT0057	C	Cedar Hill Switch	Mayfield Tap North	4.3	121-150	AC	Unknown	2013
ERCOT	14TPIT0058c	P	JORDAN	BARHIL	0.9	121-150	AC	Unknown	2014
ERCOT	14TPIT0058d	P	JORDAN	NORTON	0.9	121-150	AC	Unknown	2014
ERCOT	14TPIT0058k	P	BENDER	DUNCAN	1.9	121-150	AC	Unknown	2013
ERCOT	14TPIT0058l	P	CROSBY	BENDER	7.9	121-150	AC	Unknown	2013
ERCOT	14TPIT0061	P	Atkins Substation	Briarcrest Substation	3.4	121-150	AC	Unknown	2014
ERCOT	14TPIT0070	P	LaPalma	Palo Alto	12.0	121-150	AC	Unknown	2014
ERCOT	15TPIT0003	P	Sand Dollar	Las Brisas	2.0	300-399	AC	Unknown	2016
ERCOT	15TPIT0004	C	Converse	Deely/Skyline	0.1	121-150	AC	Unknown	2015
ERCOT	15TPIT0007	C	Green Mountain	Stonegate	11.5	121-150	AC	Unknown	2015
ERCOT	15TPIT0015	P	Hastings	Friendswood	7.3	121-150	AC	Unknown	2014
ERCOT	15TPIT0018	P	Kerrville Stadium	Raymond F Barker	10.1	121-150	AC	Unknown	2015
ERCOT	15TPIT0021	P	PHRobinson	South Shore	5.6	121-150	AC	Unknown	2015
ERCOT	15TPIT0022	P	Dobbin	Highway 6	23.0	121-150	AC	Unknown	2015
ERCOT	15TPIT0024	P	Lon Hill	Nelson Sharpe	20.8	300-399	AC	Unknown	2015
ERCOT	15TPIT0025	C	Monticello SES	Monticello Tap	20.1	121-150	AC	Unknown	2015
ERCOT	15TPIT0026	P	Wellborn Susbstation	Millican Substation	3.6	121-150	AC	Unknown	2015
ERCOT	16TPIT0003	P	Longneck	Princeton	3.5	121-150	AC	Unknown	2016
ERCOT	16TPIT0005	P	Farm West	Princeton	7.5	121-150	AC	Unknown	2016
ERCOT	16TPIT0006	P	Climax	Longneck	7.5	121-150	AC	Unknown	2016
ERCOT	16TPIT0007	P	McNeil Substation	Mag Plant Substation	3.2	121-150	AC	Unknown	2016
ERCOT	16TPIT0009	P	Five Points	Westside	3.8	121-150	AC	Unknown	2016
ERCOT	16TPIT0010	C	Hill Country	Bulverde/Stonegate	0.1	121-150	AC	Unknown	2016
ERCOT	16TPIT0016	P	Dobbin	Fish Creek	15.5	121-150	AC	Unknown	2016
ERCOT	16TPIT0023	C	South McAllen	Stewart Road	9.8	121-150	AC	Unknown	2016
ERCOT	16TPIT0024	C	Hamilton Road	Uvalde	53.7	121-150	AC	Unknown	2016
ERCOT	16TPIT0030	P	Loma Alta	N Edinburgh	106.5	300-399	AC	Unknown	2016

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FRCC	Manatee-Bobwhite	P	Manatee	Bob White	25.0	200-299	AC	1,195.0	2014
FRCC	Bunnell-St. Johns	P	St. Johns	Pellicer	21.5	200-299	AC	759.0	2016
FRCC	Myakka-Englewood	P	Myakka	Englewood	3.3	121-150	AC	357.0	2012
FRCC	Coconut Grove Injection	P	Galloway	Coconut Grove	3.0	121-150	AC	353.0	2020
FRCC	Buckingham 230kV injection	P	Orange River	Collier	1.0	200-299	AC	759.0	2017
FRCC	Garden-Gratigny	P	Gratigny	Country Club	4.5	121-150	AC	287.0	2016
FRCC	Line18Intercon GRECPlant-GVL	P	GREC Plant	Hague Switch Station	0.8	121-150	AC	282/282	2012
FRCC	Greenland Energy Center to Nocatee	P	Greenland Energy	Nocatee	4.4	200-299	AC	668/832	2017
FRCC	LCEC Lake Trafford - Lehigh South Tap	P	Lake Trafford	Lehigh South Tap	13.0	121-150	AC	277/326	2015
FRCC	LCEC Immokalee West - Immokalee	P	Immokalee West	Immokalee	2.7	121-150	AC	396/404	2016
FRCC	LCEC Ave Maria - Carnestown	P	Ave Maria	Carnestown	5.7	121-150	AC	396/404	2019
FRCC	Kathleen to Zephyrhills North	UC	Kathleen	Zephyrhills N	13.0	200-299	AC	919/1000	2013
FRCC	Intercession to Gifford	UC	Intercession City	Gifford	12.0	200-299	AC	1260/1370	2013
FRCC	Central Plaza to 51st St	UC	Central Plaza	51st St	1.8	100-120	AC	392/427	2012
FRCC	Brooksville W.-Brooksville (Rebuild)	UC	Brooksville West	Tangerine	5.1	100-120	AC	392/427	2012
FRCC	115 kV Line Rebuild	P	Havana	Bradfordville West	10.5	100-120	AC	Unknown	2013
FRCC	Atwater-Quincy - 115 kV Line Rebuild	P	Atwater	Quincy	10.9	100-120	AC	Unknown	2014
FRCC	Switch-115 kV Line Rebuild	P	Brooksville West	Weeki Wachee	3.3	100-120	AC	Unknown	2014
FRCC	Jasper-Wrights Chapel Rebuild	P	Jasper	Wrights Chapel	9.6	100-120	AC	460.0	2015
FRCC	115 kV Line Rebuilds	UC	Brooksville	Tangerine	4.0	100-120	AC	392/427	2016
FRCC	Lecanto - Inverness - New 115 kV Line	P	Lecanto	Inverness	11.0	100-120	AC	Unknown	2015
FRCC	Brooksville West - Brooksville - New	P	Brooksville West	Brooksville	0.0	200-299	AC	919/1000	2019
FRCC	Deltona to Orange City- New 115 kV	UC	DELTONA	ORANGE CITY	6.2	100-120	AC	392/427	2013
FRCC	Liberty to Brickyard Tap - new 115 kV	P	BRICKYARDTP1	LIBERTY	23.6	100-120	AC	392/427	2014
FRCC	23_1485_MXA	P	CASSADAGA	MONASTERY	3.3	100-120	AC	203/248	2013
FRCC	24_1485_MXA	P	DELTONA	MONASTERY	4.1	100-120	AC	203/248	2013
FRCC	72_1016_MXA	P	DELEON SPRGS	DELAND WEST	8.3	100-120	AC	300/326	2013
FRCC	236_1123_MXA	P	ORANGE CTY W	HIGHBANKS	3.0	100-120	AC	392/427	2015
FRCC	237_1123_MXA	P	DELTONA	HIGHBANKS	2.0	100-120	AC	300/326	2015
FRCC	278_1662_MXA	P	ORANGE CITY	ORANGE CTY W	1.5	100-120	AC	392/427	2015
FRCC	279_1662_MXA	P	DELTONA	ORANGE CTY W	5.0	100-120	AC	300/326	2015
FRCC	171_1099_MXA	P	DELAND EAST	LK WINNEMISS	3.6	100-120	AC	159/214	2016
FRCC	172_1099_MXA	P	LK HELEN	LK WINNEMISS	3.6	100-120	AC	218/262	2016
FRCC	269_1801T2_MJP	P	HIGGINS 115.00	MORGAN RD SW 115.00	17.0	100-120	AC	160/230	2017
FRCC	270_1801T2_MJP	P	GRIFFIN 115.00	MORGAN RD SW 115.00	27.8	100-120	AC	160/230	2017
FRCC	314_1801T2_MJP	P	MORGAN RD 115.00	MORGAN RD SW 115.00	5.5	100-120	AC	460.0	2015
FRCC	New 230 kV & Disston 230/115 kV	UC	DISSTON	NORTHEAST	4.2	200-299	AC	919/1000	2013
FRCC	88_2154_MXA	P	CITRUS CENT	INTERCESSION CITY	1.6	200-299	AC	1260/1370	2015
FRCC	91_2154_MXA	P	CITRUS CENT	DUNDEE	18.6	200-299	AC	1260/1370	2015
FRCC	Unnamed / Name Unknown	C	Gilchrist Gen Station	Gilchrist E. Switch	10.0	200-299	AC	1,195.0	2017
FRCC	PRECO SR. 70	P	S.R. 70	S.R. 70 Tap	3.0	121-150	AC	115.0	2014
FRCC	CEC Birley	P	Birley	Branford	6.0	100-120	AC	Uknown	2018
FRCC	CEC Brannan Field	P	Brannan Field	Black Creek	0.3	100-120	AC	Uknown	2020
FRCC	LCEC North Trail	P	North Trail	Lee	5.8	121-150	AC	Uknown	2014
FRCC	Unnamed	P	Sub 14 115	Sub 17 115	3.6	100-120	AC	230.0	2012
FRCC	Unnamed / Name Unknown	P	Sub 14 115	Sub 7 115	6.0	100-120	AC	232.0	2013
FRCC	Unnamed / Name Unknown	P	Hopkins-Crawfordville	Sub 5 230	8.0	200-299	AC	458.0	2013
FRCC	Unnamed / Name Unknown	P	Sub 21 115	Sub 17 115	6.0	100-120	AC	232.0	2012
FRCC	Polk 2-5 CC	C	Aspen	Polk	23.5	200-299	AC	1,119.0	2017
FRCC	Polk 2-5 CC	C	Aspen	Mines	15.0	200-299	AC	1,119.0	2017
FRCC	Polk 2-5 CC	C	Aspen	FishHawk (Circuit 1)	6.0	200-299	AC	1,195.0	2017
FRCC	Polk 2-5 CC	C	Aspen	FishHawk (Circuit 2)	6.0	200-299	AC	1,195.0	2017
FRCC	Polk 2-5 CC	C	Polk	Mines	12.0	200-299	AC	1,119.0	2017
FRCC	NO NAME OR NAME UNKNOWN	C	Bayside Power Station	Bayside Biomass	0.7	200-299	AC	729.0	2020
FRCC	Clearview-Himes 138kV circuit	P	Clearvw	Himes	8.2	121-150	AC	329.0	2018
FRCC	Wheeler Road to Thonotosassa	P	WHEELER	THONOTOSASSA	8.3	200-299	AC	1,119.0	2022
FRCC	Pebbledale to Willow Oak	P	PEBB	WILLOW	11.0	200-299	AC	1,119.0	2022
FRCC	Willow Oak to Wheeler Road	P	WILLOW	WHEELER	20.0	200-299	AC	1,093.0	2022
FRCC	Davis Rd-Dale Mabry	P	Davis Rd	Dlmbry	13.0	200-299	AC	1,119.0	2019
FRCC	Polk 2-5 CC	C	Aspen	FishHawk (Circuit 1)	6.0	200-299	AC	1,195.0	2017
FRCC	Polk 2-5 CC	C	Aspen	FishHawk (Circuit 2)	6.0	200-299	AC	1,195.0	2017
FRCC	Polk 2-5 CC	C	Polk	Mines	12.0	200-299	AC	1,119.0	2017
FRCC	Wheeler Road to Thonotosassa	P	WHEELER	THONOTOSASSA	8.3	200-299	AC	1,118.6	2016
FRCC	Clearview-Himes 138kV circuit	P	Clearvw	Himes	8.2	121-150	AC	329.0	2016
FRCC	Pebbledale to Willow Oak	P	PEBB	WILLOW	11.0	200-299	AC	1,118.6	2018
FRCC	Polk to FishHawk 230kV Ckt	P	POLKPLNT	FISHHAWK	30.5	200-299	AC	1,118.6	2018
FRCC	Willow Oak to Wheeler Road	P	WILLOW	WHEELER	20.0	200-299	AC	1,093.5	2018

Assessment Area	Transmission Project Name	Status	Terminal Origin Locaction	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Current (AC/DC)	Capacity Rating (MVA)	In-Service Year
FRCC	Davis Rd-Dale Mabry	P	Davis Rd	Dlmbry	13.0	200-299	AC	1,118.6	2019
MISO	Canal-Dunn Road 138 kV	P	Canal	Dunn Road	7.6	121-150	AC	290	2012
MISO	Bemidji-Grand Rapids 230 kV Line	P	Boswell	Wilton	72.0	200-299	AC	495	2012
MISO	Fargo,NDStCloud-MonticelloMN area	UC	Alexandria SS	Quarry (St. Cloud)	65.0	300-399	AC	2085	2013
MISO	Fargo,NDStCloud-MonticelloMN area	UC	Bison	Alexandria SS	130.0	300-399	AC	2085	2015
MISO	Rockdale-West Middleton 345 kV	P	Cardinal (W Middleton)	Rockdale/Albion	35.0	300-399	AC	1,195.0	2013
MISO	Monroe County - Council Creek	P	Monroe County (XEL)	Council Creek (ATC)	17.3	151-199	AC	445	2013
MISO	Crooked Lake - Enterprise Park	P	Crooked Lake	Enterprise Park	4.0	100-120	AC	316	2012
MISO	LaSalle Area Development	P	N. LaSalle	Wedron Fox River	25.0	121-150	AC	266	2012
MISO	LaSalle Area Development	P	Ottawa	Wedron Fox River	8.0	121-150	AC	266	2013
MISO	New Northeast-Oak Grove	UC	Northeast	Oak Grove	5.0	121-150	AC	287/287	2012
MISO	SE Twin Cities-Rochester	P	Hampton Corner	North Rochester	36.0	300-399	AC	2050	2015
MISO	SE TwinCities-Rochester	P	North Rochester	Northern Hills	12.6	151-199	AC	400	2012
MISO	SE TwinCities-Rochester	P	North Rochester	Chester	14.0	151-199	AC	400	2015
MISO	SE TwinCities-Rochester	P	North Rochester	North La Crosse	82.0	300-399	AC	2050	2014
MISO	Brookings, SD - SE Twin Cities 345 kV	P	Brookings County	Lyon County 345 kV	48.1	300-399	AC	2066	2015
MISO	Brookings, SD - SE Twin Cities 345 kV	P	Lyon County	Cedar Mountain	51.9	300-399	AC	2066	2013
MISO	Brookings, SD - SE Twin Cities 345 kV	P	Lyon County	Cedar Mountain	51.9	300-399	AC	2066	2013
MISO	Brookings, SD - SE Twin Cities 345 kV	P	Cedar Mountain	Helena	62.2	300-399	AC	2066	2013
MISO	Brookings, SD - SE Twin Cities 345 kV	P	Cedar Mountain	Helena	62.2	300-399	AC	2066	2013
MISO	Brookings, SD - SE Twin Cities 345 kV	P	Helena	Lake Marion	26.6	300-399	AC	2066	2014
MISO	Brookings, SD - SE Twin Cities 345 kV	P	Lake Marion	Hampton Corner	18.5	300-399	AC	2066	2014
MISO	Brookings, SD - SE Twin Cities 345 kV	P	Lyon County	Hazel	23.5	300-399	AC	2066	2015
MISO	Brookings, SD - SE Twin Cities 345 kV	P	Hazel	Minnesota Valley	6.0	200-299	AC	1558	2015
MISO	Brookings, SD - SE Twin Cities 345 kV	P	Cedar Mountain	Franklin	5.0	100-120	AC	336	2014
MISO	Gibson (Cinergy)-AB Brown-Reid	UC	AB Brown(Vectren)	Reid (BREC)	25.7	300-399	AC	1430/1430	2012
MISO	Hazleton - Salem	P	Salem	Hazleton	81.0	300-399	AC	1195	2012
MISO	Lewis Fields	P	Lewis Fields	Hiawatha	8.5	151-199	AC	1.0	2012
MISO	Morgan Valley (Beverly)	P	Morgan Valley	Beverly	7.9	151-199	AC	335	2013
MISO	Ashland to Rochelle 138	P	Rochelle	Ridgeway	1.0	121-150	AC	282	2012
MISO	Ashland to Rochelle 138	P	Ridgeway	Ashland	1.3	121-150	AC	282	2012
MISO	Bloomington-Hanna 345 kV	C	Bloomington	Pritchard	15.0	300-399	AC	1386	2014
MISO	Bloomington-Hanna 345 kV	C	Pritchard	Franklin Twp	24.0	300-399	AC	956	2014
MISO	Bloomington-Hanna 345 kV	C	Franklin Twp	Hanna	2.8	300-399	AC	1386	2014
MISO	Qualitech to Pittsboro new 138kv line	P	Qualitech	Pittsboro Jct	3.3	121-150	AC	306	2013
MISO	Marshalltown-Franklin	P	Eldora	Iowa Falls Industrial	2.0	151-199	AC	1.0	2012
MISO	Tahoe	P	Tahoe	Wixom	2.6	100-120	AC	351.0	2013
MISO	Clear Lake-Woodmin 115 kV	P	Clear Lake	Woodmin	7.5	100-120	AC	175.0	2012
MISO	Required Gen Int. RequestG362	P	Pleasant Valley	Byron	25.0	151-199	AC	447.0	2012
MISO	AEP Sullivan to DEM Brookston 765	C	DEM Brookston	AEP Sullivan	126.0	600+	AC	4008	2018
MISO	DEM Brookston to Greentown 765	C	DEM Brookston	Greentown	66.0	600+	AC	3576	2018
MISO	Ellendale to Big Stone South	P	Big Stone South	Ellendale	145.0	300-399	AC	Unknown	2019
MISO	Big Stone South to Brookings	P	Big Stone South	Brookings 345 kV double	65.0	300-399	AC	Unknown	2017
MISO	Big Stone South to Brookings	P	Big Stone	Big Stone South	2.0	200-299	AC	Unknown	2017
MISO	Big Stone South to Brookings	P	Big Stone	Big Stone South	2.0	200-299	AC	Unknown	2017
MISO	Meradosia to Ipava	C	Meredosia	Ipava	43.0	300-399	AC	1793	2018
MISO	Meradosia to Pawnee	C	Meredosia	Pawnee	58.0	300-399	AC	1793	2018
MISO	Pana to Mt. Zion	C	Mt. Zion	Pana	30.0	300-399	AC	1793	2020
MISO	Mt. Zion to Kansas	C	Mt. Zion	Kansas	52.0	300-399	AC	1793	2020
MISO	Rising to Sidney 345 kV line	C	Rising	Sidney	27.0	300-399	AC	1793	2017
MISO	Kansas to Sugar Creek	C	Kansas	Sugar Creek	23.7	300-399	AC	1793	2020
MISO	Thomas Hill - Adair - Ottumwa 345	C	Ottumwa	Thomas Hill	105.0	300-399	AC	1793	2017
MISO	Beaver - Davis Besse #2 345kV Line	P	Beaver	Davis Besse	50.0	300-399	AC	Unknown	2014
MISO	Washington Street Substation	P	Line 1364 (new tap)	Washington Street Sub	0.2	121-150	AC	Unknown	2012
MISO	Nortwest Cape Area 345/161 kV Sub	C	Lutesville	Northwest Cape	11.0	300-399	AC	1793	2016
MISO	St. Cloud Loop	P	Benton Co	Mayhew Lake	4.0	100-120	AC	361.0	2012
MISO	New 345kV Supply at Fargo Sub	P	Fargo	Maple Ridge	20.0	300-399	AC	1793	2016
MISO	Essar	P	Boswell	Essar Mine Sub (Calumet)	16.0	200-299	AC	423	2012
MISO	Essar	P	Essar steel plant sub	Shannon	8.0	200-299	AC	423	2015
MISO	Essar	P	Blackberry	Essar Mine Sub (Calumet)	16.0	200-299	AC	465	2012
MISO	Essar	P	Essar Mine Sub)	Essar steel plant	2.5	200-299	AC	465	2012
MISO	Skibo	C	Skibo	Hoyt Lakes	3.0	121-150	AC	202	2012
MISO	Sartell (SEA) 3.0 mile, 115 kV line	P	Sartell	Le Sauk	3.0	100-120	AC	Unknown	2012
MISO	Northport (BENCO) 1 mile, dbl ckt	P	Northport	Northport Tap	1.0	100-120	AC	Unknown	2013
MISO	St. Lawrence Substation&Tap-MVEC	P	St. Lawrence	St. Lawrence Tap	0.5	100-120	AC	Unknown	2017
MISO	South Minneapolis	P	Hiawatha	Midtown	1.3	100-120	AC	360.0	2012
MISO	Dubuque Co -Spring Green 345 kV	C	Spring Green	Dubuque Co	75.1	300-399	AC	2110	2020

Assessment Area	Transmission Project Name	Status	Terminal Origin Locaction	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Current (AC/DC)	Capacity Rating (MVA)	In-Service Year
MISO	Dubuque Co - Spring Green 345 kV	C	Spring Green	Cardinal	28.0	300-399	AC	2110	2020
MISO	Ariel Substation (formerly Holland)	P	Ariel (formerly Holland)	Wheeler	0.1	100-120	AC	Unknown	2012
MISO	Ariel Substation (formerly Holland)	P	Ariel (formerly Holland)	Troy	0.1	100-120	AC	Unknown	2012
MISO	St Antoine-Essex #2 120 kV	C	St Antoine	Essex	5.1	100-120	AC	Unknown	2015
MISO	Raun-Sioux City 345 kV Line	C	Raun	WAPA Sioux City	23.0	300-399	AC	Unknown	2016
MISO	North Alton Substation Supply	P	Wood River-N. Staunton	Tap to Supply N.Alton	4.0	121-150	AC	240	2015
MISO	North Alton Substation Supply	P	Wood River-Stallings	Tap to Supply N. Alton	4.0	121-150	AC	240	2014
MISO	Warrenton-Lincoln Bulk 161 kV Line	C	Warrenton	Lincoln 138-34.5 kV Bulk	10.0	151-199	AC	280	2016
MISO	Bondville-S.W. Campus	P	Bondville	S.W. Campus	8.0	121-150	AC	411	2014
MISO	Quincy Area 345/138 kV Substation	C	Palmyra	Quincy	10.0	300-399	AC	1793	2017
MISO	Newton-Hutsonville-Merom 345 kV	C	Hutsonville Plant	Merom	12.0	300-399	AC	1793	2018
MISO	Quincy-Meredosia 345 kV Line	C	Quincy Area	Meredosia	40.0	300-399	AC	1793	2018
MISO	Fargo-Oak Grove 345 kV Line	C	Fargo	Oak Grove	70.0	300-399	AC	Unknown	2018
MISO	Dickinson 115 kV Loop	P	Dickinson Basin	Dickinson West	5.0	100-120	AC	120	2014
MISO	Dickinson 115 kV Loop	P	North Dickinson	Dickinson West	3.0	100-120	AC	120	2014
MISO	28L reroute	P	Boswell	Nashwaulk	7.5	100-120	AC	144	2012
MISO	N. Lake Geneva-S. Lake Geneva	C	South Lake Geneva	North Lake Geneva	5.0	121-150	AC	293.0	2016
MISO	N LaCrosse-N Madison-Cardinal 345	C	North LaCrosse	North Madison	136.3	300-399	AC	2110	2018
MISO	N LaCrosse-N Madison-Cardinal 345	P	North Madison	Cardinal	20.5	300-399	AC	2110	2018
MISO	Michigan Thumb Wind Zone	P	Rapson (formerly Wyatt)	Baker (formerly Reese)	56.0	300-399	AC	Unknown	2013
MISO	Michigan Thumb Wind Zone	P	Rapson (formerly Wyatt)	Baker (formerly Reese)	56.0	300-399	AC	Unknown	2013
MISO	Michigan Thumb Wind Zone	P	Rapson (formerly Wyatt)	Greenwood	65.0	300-399	AC	Unknown	2015
MISO	Michigan Thumb Wind Zone	P	Rapson (formerly Wyatt)	Greenwood	65.0	300-399	AC	Unknown	2015
MISO	Michigan Thumb Wind Zone	P	Greenwood	Fitz (formerly Saratoga)	19.0	300-399	AC	Unknown	2015
MISO	Michigan Thumb Wind Zone	P	Greenwood	Fitz (formerly Saratoga)	19.0	300-399	AC	Unknown	2015
MISO	West Adair-Palmyra Tap 345 kV Line	C	Adair	Palmyra Tap	63.4	300-399	AC	1793	2018
MISO	Sheldon - Webster 345 kV line	C	Sheldon	Webster	120.0	300-399	AC	1739	2016
MISO	Reqd. for Gen Interconnection	C	Barnhart	Plymouth #4	5.9	121-150	AC	348	2018
MISO	Reqd. for Gen Interconnection	C	Plymouth #4	Howards Grove	3.1	121-150	AC	348	2018
MISO	Reqd. for Gen Interconnection	C	Howards Grove	Erdman	6.6	121-150	AC	348	2018
MISO	Reqd. for Gen Interconnection	C	Barnhart	Branch River	35.5	300-399	AC	1096	2018
MISO	Reqd. for Gen Interconnection	C	Branch River	Forest Jct	12.9	300-399	AC	883	2018
MISO	Reqd. for Gen Interconnection	C	Branch River	Point Beach	1.0	300-399	AC	1096	2018
MISO	Reqd. for Gen Interconnection	C	Branch River	Sheboygan Energy Center	1.0	300-399	AC	1096	2018
MISO	Webster - Hazleton 345 kV line	C	Black Hawk	Webster	91.3	300-399	AC	1739	2015
MISO	Webster - Hazleton 345 kV line	C	Black Hawk	Hazleton	24.0	300-399	AC	1200	2018
Manitoba	Transcona 230-66 Station	P	R32V tap	Transcona	1.0	200-299	AC	658.1	2012
Manitoba	Canexus Upgrade	P	Brandon	Maple Leaf	3.9	100-120	AC	73.0	2012
Manitoba	Transcona 230-66 Station	P	R33V tap	Transcona	1.0	200-299	AC	658.1	2012
Manitoba	Cornwallis Bank Addition	P	Brandon G.S.	Cornwallis	0.2	100-120	AC	189.3	2013
Manitoba	Neepawa 230-66 Station	P	D54C tap	Neepawa 230/66 station	1.0	200-299	AC	564.5	2013
Manitoba	R1 Line Voltage Chng	P	Pointe du Bois	Slave Falls	0.0	121-150	AC	81.7	2014
Manitoba	R2 Line Voltage Chng	P	Pointe du Bois	Slave Falls	0.0	121-150	AC	81.7	2014
Manitoba	S1 Line Voltage Chng	P	Pointe du Bois	Slave Falls	0.0	121-150	AC	95.4	2014
Manitoba	S2 Line Voltage Chng	P	Pointe du Bois	Slave Falls	0.0	121-150	AC	95.4	2014
Manitoba	R1 Line Voltage Chng	P	Pointe du Bois	Slave Falls	6.3	100-120	AC	68.1	2014
Manitoba	R2 Line Voltage Chng	P	Pointe du Bois	Slave Falls	6.3	100-120	AC	68.1	2014
Manitoba	S1 Line Voltage Chng	P	Pointe du Bois	Slave Falls	86.3	100-120	AC	85.3	2014
Manitoba	S2 Line Voltage Chng	P	Pointe du Bois	Slave Falls	86.3	100-120	AC	85.3	2014
Manitoba	Dorsey-Portage 2nd T/L	P	Dorsey	Portage	43.5	200-299	AC	564.5	2015
Manitoba	Rockwood	P	Rockwood	CP17 tap	1.1	100-120	AC	170.3	2015
Manitoba	Rockwood	P	Rockwood	CP17 tap	1.1	100-120	AC	170.3	2015
Manitoba	Rockwood	P	Rockwood	RP16 tap	1.6	100-120	AC	170.3	2015
Manitoba	Pointe du Bois	P	Pointe du Bois	Whiteshell	34.0	100-120	AC	257.3	2015
Manitoba	Lett-St. Vital T/L	P	Letellier	St Vital	77.7	200-299	AC	658.1	2015
Manitoba	Manigotagan Station	P	Pine Falls	Manigotagan	49.7	100-120	AC	127.0	2015
Manitoba	Lav-St. Vital T/L	P	LaVerendrye	St Vital	21.1	200-299	AC	658.1	2015
Manitoba	Bipole 3 / Conawapa	P	Henday	Conawapa Constr Power	0.0	200-299	AC	768.8	2017
Manitoba	Bipole 3 / Conawapa	P	Keewatinoow	Riel	833.3	400-599	DC	2,000.0	2018
Manitoba	Bipole 3 / Conawapa	P	Keewatinoow	Henday	18.2	200-299	AC	768.8	2018
Manitoba	Bipole 3 / Conawapa	P	Keewatinoow	Henday	18.2	200-299	AC	768.8	2018
Manitoba	Bipole 3 / Conawapa	P	Keewatinoow	Henday	18.2	200-299	AC	768.8	2018
Manitoba	Bipole 3 / Conawapa	P	Keewatinoow	Henday	18.2	200-299	AC	768.8	2018
Manitoba	Bipole 3 / Conawapa	P	Conawapa	Long Spruce	34.7	200-299	AC	1,029.2	2018
Manitoba	Keeyask	P	Radisson	Keeyask G.S.	23.6	121-150	AC	461.3	2018
Manitoba	Manitoba-US tie	P	Dorsey	Riel	30.9	400-599	AC	3,746.4	2019
Manitoba	Keeyask	P	Keeyask G.S.	Keeyask S.S.	2.0	121-150	AC	436.2	2019

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Manitoba	Keeyask	P	Keeyask G.S.	Keeyask S.S.	2.0	121-150	AC	436.2	2019
Manitoba	Keeyask	P	Keeyask G.S.	Keeyask S.S.	2.0	121-150	AC	436.2	2019
Manitoba	Keeyask	P	Keeyask	Radisson	23.6	121-150	AC	461.3	2019
Manitoba	Keeyask	P	Keeyask	Radisson	23.6	121-150	AC	461.3	2019
Manitoba	St.Vital-Steinbach	P	St. Vital	Steinbach	27.8	200-299	AC	420.0	2020
Manitoba	Manitoba-US tie	C	Riel	Shannon	80.0	200-299	AC	1,732.0	2022
MAPP	AMES Plant - NE Ankeny 161 kV Line	C	AMES Plant 161 kV Sub.	NE Ankeny 161 kV Sub.	22.0	151-199	AC	332.0	2013
MAPP	AVS-NESET 345	P	AVS 345	NESET 345	190.0	300-399	AC	1,200.0	2016
MAPP	Snake Creek-Neset 115	P	Snake Creek 115	Neset 115	160.0	100-120	AC	140.0	2014
MAPP	Blaisdell-Berhold 115	P	Blaisdell 115	Berthold 115	15.0	100-120	AC	140.0	2013
MAPP	S.Gap-Watford City 115	C	S.Gap 115	Watford City 115	40.0	100-120	AC	140.0	2013
MAPP	Culbertson-Grenora	C	Culbertson 115	Grenora 115	45.0	100-120	AC	140.0	2014
MAPP	CapX	UC	Brookings County, SD	Hampton, MN	230.0	300-399	AC	1,000.0	2015
MAPP	CENTER-GRAND FORKS 345 KV LINE	P	CENTER 345 KV SUB	PRAIRIE 345 KV SUB	250.0	300-399	AC	1,206.0	2013
MAPP	BEMIDJI - CASS LAKE 230 KV LINE	P	WILTON 230 KV SUB	CASS LAKE 230 KV SUB	19.0	200-299	AC	641.0	2012
MAPP	CASS LAKE - BOSWELL 230 KV LINE	P	CASS LAKE 230 KV SUB	BOSWELL 230 KV SUB	51.0	200-299	AC	641.0	2012
MAPP	Big Bend-Lower Brule	P	Lower Brule dbl ckt	Big Bend	2.1	200-299	AC	Unknown	2016
MAPP	Big Bend-Lower Brule	P	Lower Brule	Fort Thompson	9.3	200-299	AC	Unknown	2016
MAPP	Big Bend-Lower Brule	P	Lower Brule	Reliance	19.5	200-299	AC	Unknown	2016
SaskPower	Unnamed / Name Unknown	P	Aberdeen Switch St.	Martinsville Switch St.	25.0	200-299	AC	765.0	2013
SaskPower	Unnamed / Name Unknown	P	Aberdeen Switch St.	Wolverine Switch St.	68.0	200-299	AC	765.0	2013
SaskPower	Unnamed / Name Unknown	P	Elstow Switch St.	Wolverine Switch St.	31.0	121-150	AC	382.0	2013
SaskPower	Unnamed / Name Unknown	P	Elstow Switch St.	Wolverine Switch St.	0.0	121-150	AC	166.0	2013
SaskPower	Unnamed / Name Unknown	P	Pasqua Switch Station	Swift Current Switch St.	140.0	200-299	AC	765.0	2016
SaskPower	Unnamed / Name Unknown	P	Pasqua Switch Station	Swift Current Switch St.	0.0	121-150	AC	134.0	2016
SaskPower	Unnamed / Name Unknown	P	Pasqua Switch Station	Swift Current Switch St.	140.0	121-150	AC	382.0	2016
SaskPower	Unnamed / Name Unknown	P	Peebles Switch St.	Tantallon Switch St.	84.0	200-299	AC	765.0	2013
SaskPower	Unnamed / Name Unknown	C	Beatty Switching Station	Wolverine Switch St.	99.0	200-299	AC	765.0	2016
SaskPower	Unnamed / Name Unknown	C	Condie Switching Station	Pasqua Switching Station	43.0	200-299	AC	765.0	2016
SaskPower	Unnamed / Name Unknown	C	Brada Switching Station	Martinsville Switch St.	80.0	200-299	AC	765.0	2016
Maritimes	Coleson Cove to Salisbury 345 kV	C	Coleson Cove	Salisbury	103.0	300-399	AC	1,076.0	2016
Maritimes	New Minas Sub	P	Canaan Road	Prospect Road	2.5	121-150	AC	170.0	2012
Maritimes	Harbour East	P	Dartmouth East	Eastern Passage	10.6	121-150	AC	170.0	2013
Maritimes	NS/NB Tie	C	Onslow	Salisbury	100.0	300-399	AC	1,076.0	2016
Maritimes	NS - NL Tie	C	Newfoundland	Nova Scotia	100.0	200-299	DC	Unknown	2018
Maritimes	Y-104	C	West Royalty	Church Road	50.0	121-150	AC	189.0	2017
New England	Rochester Area	P	Rochester Substation	North Rochester Sub.	6.9	100-120	AC	238.0	2015
New England	MPRP	P	Orrington	Coopers Mills	54.0	100-120	AC	380.0	2014
New England	MPRP	P	Larrabee Road	Middle St	5.7	100-120	AC	282.0	2014
New England	MPRP	P	Middle St	Lewiston Lower	1.2	100-120	AC	282.0	2014
New England	MPRP	P	Larrabee Road	Livermore Falls	24.1	100-120	AC	282.0	2013
New England	MPRP	P	Livermore Falls	Rumford IP	20.4	100-120	AC	282.0	2013
New England	Section 241 Somerset Co. Reinforce	P	Wyman Hydro	Rice Rips Tap	39.0	100-120	AC	282.0	2012
New England	Greater Rhode Island Upgrades	P	Brayton Point Station	Somerset	3.4	100-120	AC	Unknown	2014
New England	Central/Western MA upgrades	P	Millbury	Tower	6.9	100-120	AC	259.0	2013
New England	Merrimack Valley/North Shore	P	King St	West Amesbury	7.2	100-120	AC	232.0	2012
New England	Central/Western MA upgrades	P	Otter River	East Winchendon	5.7	100-120	AC	262.0	2016
New England	Worcester Area Upgrades	P	North Bloomingdale	Vernon	3.6	100-120	AC	179.0	2012
New England	Greater Rhode Island Upgrades	P	Somerset	Bell Rock	3.7	100-120	AC	Unknown	2014
New England	Boston Area Enhancements	P	West Walpole	Holbrook	0.0	100-120	AC	Unknown	2014
New England	Mid Cape Reliability Project	C	Canal	Barnstable	0.0	100-120	AC	Unknown	2013
New England	Greater Boston - North	C	Wakefield	Everett	0.0	100-120	AC	Unknown	2015
New England	Greater Boston - Western Suburbs	C	Woburn	Hartwell Ave	6.4	100-120	AC	Unknown	2015
New England	Pittsfield/Greenfield Area	P	Northfield Mt. Sub.	Erving Substation	1.2	100-120	AC	696.0	2014
New England	Stamford Area	C	Glenbrook Substation	Southend S/S	0.0	100-120	AC	Unknown	2022
New England	Lyman Substation	C	Holyoke Fairmont South	Lyman Substation	0.0	100-120	AC	Unknown	2022
New England	Granite/Middlesex	C	Granite S/S	Middlesex S/S	16.0	200-299	AC	496.0	2022
New England	Long Term Lower SEMA	P	Carver	Bourne	17.9	300-399	AC	2,169.0	2014
New England	NEEWs	P	West Farnum S/S	CT/RI Border	17.7	300-399	AC	2,172.0	2015
New England	NEEWs	P	Millbury S/S	West Farnum S/S	20.2	300-399	AC	2,172.0	2015
New England	NEEWs	UC	Kent County	West Farnum S/S	21.4	300-399	AC	1,353.0	2013
New England	NEEWs	P	Card S/S	Lake Road S/S	29.3	300-399	AC	2,420.0	2015
New England	NEEWs	P	Lake Road S/S	CT/RI Border	7.6	300-399	AC	2,420.0	2017
New England	NEEWs	P	Frost Bridge S/S	North Bloomfield S/S	35.4	300-399	AC	2,420.0	2016
New England	NEEWs	P	Manchester	Meekville Jct.	2.7	300-399	AC	2,420.0	2013
New England	NEEWs	P	North Bloomfield S/S	CT/MA Border	12.0	300-399	AC	2,420.0	2013
New England	NEEWs	UC	Agawam S/S	Ludlow S/S	16.9	300-399	AC	2,420.0	2013
New England	MPRP	UC	Orrington S/S	Albion Road S/S	59.0	300-399	AC	2,151.0	2013

Assessment Area	Transmission Project Name	Status	Terminal Origin Locaction	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Current (AC/DC)	Capacity Rating (MVA)	In-Service Year
New England	MPRP	UC	Albion Road S/S	Coopers Mills S/S	21.0	300-399	AC	2,151.0	2014
New England	MPRP	UC	Larrabee Road S/S	Coopers Mills S/S	34.3	300-399	AC	2,151.0	2014
New England	MPRP	UC	Larrabee Road S/S	Surowiec S/S	17.0	300-399	AC	2,151.0	2012
New England	MPRP	UC	Surowiec S/S	Raven Farm S/S	12.4	300-399	AC	2,151.0	2013
New England	MPRP	P	Maguire Road S/S	South Gorham S/S	21.0	300-399	AC	2,151.0	2012
New England	MPRP	P	Maguire Road S/S	Three Rivers Switchyard	19.2	300-399	AC	2,151.0	2013
New England	Greater Boston N-S. Central	P	Scobie S/S	PSNH/NGRID Border	10.8	300-399	AC	2,420.0	2016
New England	Northern Pass Transmission Project	C	Quebec/NH Border	Franklin	140.0	300-399	DC	Unknown	2016
New England	Northern Pass Transmission Project	C	Franklin	Deerfield	40.0	300-399	AC	Unknown	2016
New England	8300 Line Configuration	P	Grand Isle S/S	Mill River	0.1	100-120	AC	340.0	2013
New England	Lakewood Reinforcement	P	Lake Road S/S	Section 833B Tap	4.0	100-120	AC	282.0	2013
New England	Merrimack Valley/N.Shore Reliability	P	Mystic	Everett	0.5	100-120	AC	153.0	2012
New England	Greater Boston - South	P	Medway #65	Border with Milford	2.0	100-120	AC	325.0	2013
New England	Greater Boston - South	P	Border with Bellingham	Border with Milford	2.0	100-120	AC	325.0	2013
New England	NEEWs	P	ANP Blackstone	NEA Bellingham Tap	1.2	100-120	AC	Unknown	2012
New England	Greater Boston - North	C	Woburn	Tewsbury	0.0	300-399	AC	Unknown	2016
New England	Greater Boston - North	C	Woburn	N. Cambridge	0.0	100-120	AC	Unknown	2016
New England	Greater Boston - Western Suburbs	C	Woburn	Burlington	3.7	100-120	AC	Unknown	2013
New England	Greater Boston - Central	C	Mystic	Chelsea	0.0	100-120	AC	Unknown	2016
New England	Greater Boston - Central	C	Mystic	Woburn	0.0	100-120	AC	Unknown	2016
New England	Greater Boston - Central	C	Needham	Baker Street	0.0	100-120	AC	Unknown	2016
New England	Greater Boston - Western Suburbs	C	Sudbury	Hudson	0.0	100-120	AC	Unknown	2016
New England	Mid Cape Reliability Project	C	Bourne	Falmouth Tap	0.0	100-120	AC	Unknown	2015
New England	Mid Cape Reliability Project	C	Bourne	Oak Street	0.0	100-120	AC	Unknown	2015
New England	Mid Cape Reliability Project	C	Oak Street	Barnstable	0.0	100-120	AC	Unknown	2015
New England	Long Term Lower SEMA	P	Carver	Oak Street	30.7	300-399	AC	2,169.0	2012
New England	NEEWs	P	Agawam S/S	CT/MA Border	6.0	300-399	AC	2,420.0	2013
New England	Western New Hampshire Solution	C	Fitzwilliam S/S	Monadnock S/S	2.5	100-120	AC	Unknown	2016
New England	Southern New Hampshire Solution	C	Scobie S/S	Huse Rd. S/S	6.0	100-120	AC	Unknown	2016
New England	Seacost New Hampshire Solution	C	Madbury S/S	Portsmouth S/S	13.0	100-120	AC	Unknown	2016
New England	Seacost New Hampshire Solution	C	Scobie S/S	Chester S/S	6.0	100-120	AC	Unknown	2016
New England	SWCT Advanced Solutions	C	Glenbrook S/S	South End S/S	1.8	100-120	AC	Unknown	2022
New England	Line Configuration	P	Coopers Mills	Highland Substation	0.0	100-120	AC	Unknown	2013
New England	Central Vermont Solution	P	West Rutland	Coolidge	27.0	300-399	AC	Unknown	2016
New England	Cental Vermont Soluton	P	Coolidge	Ascutney	15.0	100-120	AC	Unknown	2016
New York	Unnamed / Name Unknown	P	Quebec - NY	Astoria Annex 345kV	0.0	300-399	DC	Unknown	2016
New York	Unnamed / Name Unknown	P	St. Pool	High Falls	5.6	100-120	AC	1,114.0	2020
New York	Unnamed / Name Unknown	P	High Falls	Kerhonkson	10.0	100-120	AC	1,114.0	2020
New York	Unnamed / Name Unknown	P	Kerhonkson	Honk Falls	9.9	100-120	AC	1,114.0	2020
New York	Unnamed / Name Unknown	P	Modena	Galeville	4.6	100-120	AC	1,114.0	2020
New York	Unnamed / Name Unknown	P	Galeville	Kerhonkson	9.0	100-120	AC	1,851.0	2013
New York	Unnamed / Name Unknown	P	Shoreham	Brookhaven	0.0	121-150	AC	1,851.0	2013
New York	Unnamed / Name Unknown	P	Shoreham	Wildwood	1.0	121-150	AC	1,851.0	2013
New York	Unnamed / Name Unknown	P	Wildwood	Brookhaven	6.3	121-150	AC	3,124.0	2013
New York	Unnamed / Name Unknown	P	Holbrook	Holtsville GT	0.0	121-150	AC	3,124.0	2013
New York	Unnamed / Name Unknown	P	Holbrook	West Bus	0.2	121-150	AC	3,124.0	2013
New York	Unnamed / Name Unknown	P	West Bus	Holtsville GT	0.1	121-150	AC	3,124.0	2013
New York	Unnamed / Name Unknown	P	Sill Rd	Holtsville GT	0.0	121-150	AC	3,124.0	2013
New York	Unnamed / Name Unknown	P	Sill Rd	West Bus	9.4	121-150	AC	3,124.0	2013
New York	Unnamed / Name Unknown	P	West Bus	Holtsville GT	0.1	121-150	AC	3,124.0	2013
New York	Unnamed / Name Unknown	P	Pilgrim	Holtsville GT	0.0	121-150	AC	2,087.0	2013
New York	Unnamed / Name Unknown	P	Pilgrim	West Bus	11.7	121-150	AC	2,087.0	2013
New York	Unnamed / Name Unknown	P	Riverhead	Wildwood	10.6	121-150	AC	1,399.0	2014
New York	Unnamed / Name Unknown	P	Moses	Willis	0.0	200-299	AC	876.0	2013
New York	Unnamed / Name Unknown	P	Moses	Willis	37.1	200-299	AC	876.0	2013
New York	Unnamed / Name Unknown	P	Moses	Willis	37.1	200-299	AC	876.0	2013
New York	Unnamed / Name Unknown	P	Oakdale	Fraser	56.9	300-399	AC	2,100.0	2012
New York	Unnamed / Name Unknown	P	Oakdale	Clarks Corners	21.2	300-399	AC	2,020.0	2012
New York	Unnamed / Name Unknown	P	Spier	Rotterdam	32.7	100-120	AC	Unknown	2015
New York	Unnamed / Name Unknown	P	Burns	Corporate Drive	4.0	121-150	AC	Unknown	2014
New York	Unnamed / Name Unknown	P	BPS Station	Rochester	3.8	300-399	AC	2,177.0	2016
New York	Unnamed / Name Unknown	UC	Wood Street	Carmel	1.3	100-120	AC	Unknown	2012
New York	Unnamed / Name Unknown	UC	Wood Street	Katonah	11.7	100-120	AC	Unknown	2012
New York	Unnamed / Name Unknown	UC	Greenbush	Hudson	0.0	100-120	AC	Unknown	2012
New York	Unnamed / Name Unknown	UC	Greenbush	Klinekill Tap	20.3	100-120	AC	Unknown	2012
New York	Unnamed / Name Unknown	UC	Klinekill Tap	Hudson	6.1	100-120	AC	Unknown	2012
Ontario	Unnamed / Name Unknown	UC	Allanburg TS	Middleport TS	93.0	200-299	AC	964.0	2022

Assessment Area	Transmission Project Name	Status	Terminal Origin Locaction	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Current (AC/DC)	Capacity Rating (MVA)	In-Service Year
Ontario	East-West Tie	C	Lakehead TS	Wawa TS	240.0	200-299	AC	Unknown	2017
Ontario	London West	C	London	Sarnia/Chatham	43.0	200-299	AC	Unknown	2017
Ontario	Unnamed / Name Unknown	C	Dryden area	Pickle Lake	180.0	200-299	AC	Unknown	0
Québec	Eastmain-1-A - La Sarcelle	UC	La Sarcelle	Eastmain-1	63.4	300-399	AC	885.2	2012
Québec	Lac Alfred Wind Project	UC	Lac Alfred W.F.	Rimouski Tap	18.6	300-399	AC	1,454.2	2012
Québec	Bloom Lake Mining Project	UC	Mines Bloom Lake	Bloom Lake Tap	1.1	300-399	AC	1,115.0	2012
Québec	Des Moulins Wind Project	UC	Des Moulins W.F.	Antoine-Lemieux Tap	1.9	200-299	AC	594.1	2012
Québec	Line 2359 Dismantlement	UC	Francheville T.S.	Sorel T.S.	0.0	200-299	AC	Unknown	2012
Québec	Francheville 230 kV Project	UC	Francheville T.S.	L2356 Tower 6	2.0	200-299	AC	Unknown	2012
Québec	New Richmond Wind Project	UC	New Richmond W.F.	Cascapédia Tap	6.6	200-299	AC	701.7	2012
Québec	Limoilou 230/25 kV Project	UC	Québec/Stadacona	Limoilou T.S.	0.6	200-299	AC	470.0	2012
Québec	Eleonore Mining 120 kV Project	UC	Eastmain-1	Mines Opinaca	39.5	100-120	AC	195.4	2012
Québec	St-Robert-Bellarmin Wind Project	UC	St-Robert-Bellarmin W.F.	Bolduc T.S.	20.5	100-120	AC	313.0	2012
Québec	Montérégie Wind Project	UC	Montérégie W.F.	St-Rémi Tap	0.3	100-120	AC	Unknown	2012
Québec	Neubois 120/25 kV T.S. Project	UC	Ste-Marie	Neubois T.S.	29.8	100-120	AC	366.1	2012
Québec	Neubois 120/25 kV T.S. Project	UC	Ste-Marie T.S.	Scott T.S.	0.0	100-120	AC	Unknown	2012
Québec	De l'Érable Wind Project	UC	De l'Érable W.F.	Kingsey Tap	7.5	100-120	AC	Unknown	2012
Québec	Sheldrake Private Hydro Project	UC	Sheldrake G.S.	Sheldrake Tap	2.8	151-199	AC	309.7	2012
Québec	Québec Lithium	UC	Québec Lithium (HV)	Québec Lithium Tap	0.9	100-120	AC	255.0	2012
Québec	Seigneurie-de-Beaupré Wind	UC	Seigneurie-de-Beaupré	Beaupré Tap	9.3	300-399	AC	Uknown	2013
Québec	Charlevoix 315 kV T.S. Looping	UC	Charlevoix T.S.	Bersimis/Laurentides 315	3.7	300-399	AC	877.3	2013
Québec	St-Bruno 315/25 kV T.S. project	UC	St-Bruno T.S.	St-Bruno Tap	1.2	300-399	AC	1,107.8	2013
Québec	Bélanger 315/25 kV T.S. Project	P	Bélanger 315/25 T.S.	Bélanger Tap	2.5	300-399	AC	Unknown	2013
Québec	Bélanger 315/25 kV T.S. Project	R	Bélanger 120/25 T.S.	Montréal-Nord T.S.	0.0	100-120	AC	Unknown	2013
Québec	Charlesbourg 230/25 kV T.S. project	C	Charlesbourg T.S.	Charlesbourg Tap	7.5	200-299	AC	697.2	2013
Québec	Arnaud Mining Project	C	Mines Arnaud	Mines Arnaud Tap	0.6	151-199	AC	Unknown	2013
Québec	Massif-du-Sud Wind Project	UC	Massif-du-Sud	Massif-du-Sud Tap	13.0	100-120	AC	Unknown	2013
Québec	Joanna 120 kV Mining Project	C	Mines Joanna	Joanna Tap	0.9	100-120	AC	231.0	2013
Québec	St-Damase Wind Project (Third call)	P	St-Damase	St-Damase Tap	0.3	100-120	AC	Unknown	2013
Québec	Viger-Denonville Wind (3rd call)	P	Viger-Denonville	Denonville Tap	0.1	100-120	AC	Unknown	2013
Québec	Lachenaie 315/25 T.S. project	P	Lachenaie T.S.	Lachenaie Tap	0.6	300-399	AC	1,113.4	2013
Québec	Val-Jalbert Private Hydro Integration	P	Val-Jalbert G.S.	Val-Jalbert Tap	0.1	151-199	AC	Unknown	2013
Québec	Blainville 315/25 kV T.S. project	P	Blainville T.S.	Blainville Tap	7.2	300-399	AC	Unknown	2014
Québec	Pierre-Le Gardeur 315/120 kV Project	P	Pierre-Le Gardeur 315	Mauricie Tap	0.4	300-399	AC	1,113.4	2014
Québec	Pierre-Le Gardeur 315/120 kV Project	P	Pierre-Le Gardeur 120	120 kV system	1.0	100-120	AC	Unknown	2014
Québec	Mauricie-Lanaudière 315 kV Project	C	Lanaudière T.S.	Mauricie Tap	3.1	300-399	AC	Unknown	2014
Québec	Pierre-Le Gardeur 315/120 kV	C	Pierre-Legardeur120 T.S.	St-Sulpice 120 T.S.	17.4	100-120	AC	Unknown	2014
Québec	Lefrançois 315/25 kV T.S. Project	C	Lefrançois T.S.	Lefrançois Tap	2.5	300-399	AC	877.3	2014
Québec	Rivière-du-Moulin Wind Project	P	Rivière-du-Moulin	Rivière-du-Moulin Tap	15.5	300-399	AC	Unknown	2014
Québec	Romaine Complex Hydro Project	UC	La Romaine-2	Arnaud	162.2	300-399	AC	2,980.6	2014
Québec	Romaine Complex Hydro Project	UC	La Romaine-2	La Romaine-2 G.S.	1.7	300-399	AC	Unknown	2014
Québec	Aux Outardes 735 kV Project	P	Micoua	Aux Outardes	9.3	600+	AC	6,954.9	2014
Québec	Chigoubiche 161/25 kV T.S.	R	Chigoubiche T.S.	St-Félicien T.S.	0.0	151-199	AC	Unknown	2014
Québec	Black Rock Metal Project	C	Black Rock	Black Rock Tap	15.6	151-199	AC	310.0	2014
Québec	Obatogamau T.S. Retirement	R	Obatogamau T.S.	Obatogamau Tap	0.0	151-199	AC	Unknown	2014
Québec	Crevier Project	C	Normandin T.S.	Crevier (HV client)	49.4	151-199	AC	310.0	2014
Québec	Vent-du-Kempt Wind Project	P	Vent-du-Kempt	Vent-du-Kempt Tap	6.2	100-120	AC	230.8	2014
Québec	Bedford 230/120 kV Upgrade Project	C	St-Césaire 120 T.S.	Bedford 120 T.S.	43.5	100-120	AC	Unknown	2014
Québec	Temiscouata Wind Project (Third call)	P	Temiscouata	Temiscouata Tap	0.4	100-120	AC	Unknown	2014
Québec	Palmarolle 120 kV Reinforcement	UC	Palmarolle T.S.	Figuery T.S.	24.9	100-120	AC	366.1	2014
Québec	Alcoa Baie Comeau Aluminum Project	C	Alcoa	Hauterive T.S.	25.5	151-199	AC	570.3	2015
Québec	Duchesnay 315/25 kV T.S. Project	P	Duchesnay T.S.	Duchesnay Tap	6.2	300-399	AC	1,113.4	2015
Québec	Northern Pass Project	C	Des Cantons735/300 T.S.	Québec - US Border	93.2	300-399	DC	Unknown	2015
Québec	Limoilou 230/25 kV Project	C	Québec	Limoilou T.S.	5.3	200-299	AC	Unknown	2015
Québec	Limoilou 230/25 kV Project	C	Limoilou T.S.	Stadacona T.S.	0.5	200-299	AC	Unknown	2015
Québec	Alouette Phase 3 Aluminum Smelter	C	Alouette	Arnaud T.S.	17.5	151-199	AC	1,140.9	2015
Québec	Grande-Baie Project Rio Tinto Alcan	C	Saguenay T.S.	Grande-Baie	50.0	151-199	AC	570.0	2015
Québec	Renard Mining Project	C	Mines Renard	Nikamo T.S.	103.1	151-199	AC	195.0	2015
Québec	La lièvre 120/25 kV T.S. Project	C	High Falls (Brookfiled)	La lièvre T.S.	5.0	100-120	AC	Unknown	2015
Québec	Dumont Mining Project	C	Figuery T.S.	Mines Dumont	10.0	100-120	AC	366.1	2015
Québec	Waswanipi 315/25 kV T.S.	C	Waswanipi T.S.	Waswanipi Tap	1.2	300-399	AC	Unknown	2015
Québec	Romaine Complex Hydro Project	P	Romaine-1	Romaine-2	17.4	300-399	AC	Unknown	2016
Québec	Romaine Complex Hydro Project	P	Romaine-1	Romaine-1 G.S.	0.6	300-399	AC	Unknown	2016
Québec	Baie-St-Paul 315/25 kV T.S. Project	C	Baie-St-Paul T.S.	Baie-St-Paul Tap	6.2	300-399	AC	1,022.0	2016
Québec	Maniwaki-Paugan 120 kV Line Project	C	Maniwaki T.S.	Paugan G.S.	7.5	100-120	AC	Unknown	2016
Québec	Mont-Laurier-Maniwaki 120 kV Line	C	Maniwaki T.S.	Mont-Laurier T.S.	30.3	100-120	AC	Unknown	2016
Québec	St-Jérôme Project	C	Grand-Brûlé T.S.	St-Jérôme T.S.	49.7	100-120	AC	Unknown	2016

Assessment Area	Transmission Project Name	Status	Terminal Origin Location	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Current (AC/DC)	Capacity Rating (MVA)	In-Service Year
Québec	Chamouchouane-Montréal 735 kV	C	Chamouchouane 735 kV	Bout-de-l'Ile 735 kV	229.9	600+	AC	Unknown	2017
Québec	Romaine Complex Hydro Project	P	Montagnais T.S.	Romaine-4	108.7	300-399	AC	Unknown	2017
Québec	Romaine Complex Hydro Project	P	Romaine-3	Romaine-4	19.9	300-399	AC	Unknown	2017
Québec	Vimont 315/25 kV T.S. Project	C	Vimont 315 T.S.	Vimont Tap	0.4	300-399	AC	Unknown	2017
Québec	De Lorimier 315/25 kV T.S. Project	C	Viger	De Lorimier 315 T.S.	3.7	300-399	AC	Unknown	2017
Québec	De Lorimier 315/25 kV T.S. Project	C	Viger	De Lorimier 315 T.S.	3.7	300-399	AC	Unknown	2017
Québec	De Lorimier 315/25 kV T.S. Project	R	Notre-Dame 120 T.S.	De Lorimier 120 T.S.	0.0	100-120	AC	Unknown	2017
Québec	Fleury 315/25 kV T.S. Project	C	Fleury 315/25 T.S.	Charland T.S.	7.5	300-399	AC	Unknown	2017
Québec	Fleury 315/25 kV T.S. Project	C	Fleury 315/25 T.S.	Beaumont T.S.	2.5	300-399	AC	Unknown	2017
Québec	Fleury 315/25 kV T.S. Project	R	Fleury 120/25 T.S.	Reed T.S.	0.0	100-120	AC	Unknown	2017
Québec	Fleury 315/25 kV T.S. project	R	Fleury 120/25 T.S.	Charland T.S.	0.0	100-120	AC	Unknown	2017
Québec	Abitibi subregion reinforcement	C	Abitibi 735 kV	Duchemin 735/315 kV	88.2	600+	AC	2,980.6	2018
Québec	Abitibi subregion reinforcement	C	Duchemin 315 kV	Lebel 315 kV	11.2	300-399	AC	Unknown	2018
Québec	Abitibi subregion reinforcement	C	Lebel 315 kV	Poularies 315 kV	211.3	300-399	AC	Unknown	2018
Québec	Arnaud-2 project	C	Arnaud	Arnaud-2	9.3	600+	AC	2,980.6	2018
Québec	Alouette reinforcement	C	Arnaud-2	Alouette	15.5	300-399	AC	Unknown	2018
Québec	Alouette reinforcement	C	Arnaud-2	Alouette	0.0	151-199	AC	Unknown	2018
Québec	Alouette reinforcement	C	Arnaud-2	Alouette	15.5	300-399	AC	Unknown	2018
PJM	Capital Ave	C	Capital Ave	Capital Ave Substation	0.1	121-150	AC	159.0	2012
PJM	Chums Corner	C	Chums Corner Jct	Chums Corner Substation	1.1	121-150	AC	159.0	2012
PJM	Eagle's Landing	C	Eagle's Landing Jct	Eagle's Landing Sub.	0.1	121-150	AC	159.0	2012
PJM	Fausett	C	Fausett Jct	Fausett Substation	0.1	121-150	AC	159.0	2012
PJM	Hawthorne	C	Hawthorne Jct	Hawthorne Substation	0.0	121-150	AC	159.0	2012
PJM	Maines Rd	C	Maines Rd Jct	Maines Rd Substation	0.1	121-150	AC	159.0	2012
PJM	Ryno	C	Ryno Jct	Ryno Substation	0.1	121-150	AC	159.0	2012
PJM	Scenic Lake	C	Scenic Lake Jct	Scenic Lake Substation	0.1	121-150	AC	159.0	2012
PJM	Egan	C	Egan Jct	Egan Substation	2.5	121-150	AC	159.0	2012
PJM	Forest Grove	C	Forest Grove Jct	Forest Grove Substation	1.0	121-150	AC	159.0	2012
PJM	Haakwood	C	Haakwood Jct	Haakwood Substation	0.0	121-150	AC	159.0	2012
PJM	Snyder	C	Snyder Jct	Snyder Substation	0.0	121-150	AC	159.0	2012
PJM	Unnamed / Name Unknown	C	Wheatland	Bloomington	61.0	300-399	AC	1,200.0	2012
PJM	Unnamed / Name Unknown	C	Brookston	Frankfort	53.0	300-399	AC	1,793.0	2016
PJM	Unnamed / Name Unknown	C	Thorntown	Qualitech	23.0	300-399	AC	1,793.0	2016
PJM	Unnamed / Name Unknown	C	Brookston	Reynolds	0.5	300-399	AC	1,793.0	2016
PJM	Unnamed / Name Unknown	C	Avon Industrial Park	A new Distr. Sub.	2.6	300-399	AC	306.0	2020
PJM	St. Antoin - Essex #2	C	St Antoine	Essex #2	5.1	100-120	AC	240.0	2015
PJM	Quaker - Southfield #2	C	CTL 18	Southfield	0.4	100-120	AC	242.0	2015
PJM	n1174	C	Carlos Junction	Dans Mountain	5.0	121-150	AC	Unknown	2013
PJM	n1174	C	Ridgeley	Dans Mountain	5.0	121-150	AC	Unknown	2013
PJM	n1350	C	Sutton	Sutton Dam	0.1	121-150	AC	Unknown	2015
PJM	n1350	C	Sutton Hill	Sutton Dam	0.1	121-150	AC	Unknown	2015
PJM	Unnamed / Name Unknown	C	Broadview	Clark	5.0	121-150	AC	278/338	2019
PJM	Unnamed / Name Unknown	C	Broadview	East Springfield	3.5	121-150	AC	160/192	2019
PJM	Unnamed / Name Unknown	C	Broadview	Tangy	3.5	121-150	AC	160/192	2019
PJM	Unnamed / Name Unknown	C	Broadview	Urbana	5.0	121-150	AC	278/338	2019
PJM	Unnamed / Name Unknown	C	Midway	Wauseon	0.0	121-150	AC	151/166	2018
PJM	Unnamed / Name Unknown	C	Napoleon	Richland	0.0	121-150	AC	151/166	2018
PJM	Unnamed / Name Unknown	C	Richland	Stryker	0.0	121-150	AC	151/166	2018
PJM	Line 701 Upgrade	C	West Nyack	Harings Corner	0.3	121-150	AC	236.0	2018
PJM	Z75 Extension	C	Toytota	Scott	14.0	121-150	AC	287.0	2016
PJM	Quaker - Southfield #2	C	Quaker	CTL 18	7.1	100-120	AC	320.0	2015
PJM	Pere Marquette - Keystone 230	C	Pere Marquette	Keystone	75.0	200-299	AC	576.0	2015
PJM	n1647	C	U2-041	East Lima / Marysville	0.0	300-399	AC	Unknown	2012
PJM	n1397	C	Browns Run	Rhodes Lane	0.1	400-599	AC	Unknown	2015
PJM	n1397	C	Yukon	Rhodes Lane	0.1	400-599	AC	Unknown	2015
PJM	b1267.1	P	Coldspring	Erdman	10.3	100-120	AC	Unknown	2015
PJM	b1267.1	P	Coldspring	Erdman	10.3	100-120	AC	Unknown	2015
PJM	b0729	P	Perryman	Harford	0.4	100-120	AC	Unknown	2013
PJM	b0729	P	Perryman	Harford	0.4	100-120	AC	Unknown	2013
PJM	b1084	P	Deer Park	Northwest	3.0	100-120	AC	Unknown	2014
PJM	b1729	P	Burton	Oakwood	3.5	100-120	AC	Unknown	2014
PJM	Unnamed / Name Unknown	P	Rutland	Algonquin	5.5	121-150	AC	376.0	2012
PJM	Unnamed / Name Unknown	P	Rutland	Algonquin	5.5	121-150	AC	376.0	2012
PJM	Unnamed / Name Unknown	P	Qualitech	Pittsboro	3.3	121-150	AC	306.0	2013
PJM	Unnamed / Name Unknown	P	Ridgeway	Ashland	1.3	121-150	AC	282.0	2012
PJM	Unnamed / Name Unknown	P	Ridgeway	Rochelle	1.0	121-150	AC	282.0	2012
PJM	Unnamed / Name Unknown	P	Vincennes	Vigo Street	2.3	121-150	AC	287.0	2012

Assessment Area	Transmission Project Name	Status	Terminal Origin Locaction	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Current (AC/DC)	Capacity Rating (MVA)	In-Service Year
PJM	toi1340.2	P	Plum	Universal	7.3	121-150	AC	Unknown	2022
PJM	s0059	P	East Petersburg	Howmet	0.9	121-150	AC	193.0	2013
PJM	s0059	P	Dillersville	Howmet	1.6	121-150	AC	193.0	2013
PJM	b0210.1	P	Orchard	Cumberland	2.7	200-299	AC	Unknown	2013
PJM	b1172	P	Hopewell	Bull Hill	5.0	200-299	AC	Unknown	2012
PJM	s0169	P	Dickerson	Edwards Ferry	1.0	200-299	AC	Unknown	2013
PJM	s0169	P	Pleasant View	Edwards Ferry	1.0	200-299	AC	Unknown	2013
PJM	b1309	P	Lakeside	Northwest	11.5	200-299	AC	Unknown	2013
PJM	b1312	P	Charlottesville	Hollymeade	1.0	200-299	AC	Unknown	2014
PJM	b1312	P	Gordonsville	Hollymeade	1.0	200-299	AC	Unknown	2014
PJM	b1215	P	Trowbridge	Winfall	0.0	200-299	AC	Unknown	2014
PJM	b1332	P	Cannon Branch	Cloverhill	2.0	200-299	AC	Unknown	2015
PJM	b1332	P	Liberty	Cloverhill	5.8	200-299	AC	Unknown	2015
PJM	b1321	P	North Anna	Oak Green	28.2	200-299	AC	Unknown	2015
PJM	b1331	P	Shawboro	Aydlett	16.0	200-299	AC	Unknown	2015
PJM	b1508.1	P	Harrisonburg	Endless Caverns	19.8	200-299	AC	Unknown	2015
PJM	b1697	P	Idylwood	Clark	4.0	200-299	AC	Unknown	2016
PJM	b1794	P	Hornertown	Battleboro	33.0	200-299	AC	Unknown	2016
PJM	b1794	P	Rocky Mount	Battleboro	8.6	200-299	AC	Unknown	2016
PJM	b1125	P	Buzzard Point	Ritchie	10.8	200-299	AC	Unknown	2014
PJM	b1813.3	P	West Pocono	North Pocono	10.6	200-299	AC	648.0	2017
PJM	b1813.6	P	Jenkins	West Pocono	14.7	200-299	AC	648.0	2016
PJM	b1813.8	P	Paupack	North Pocono	21.9	200-299	AC	648.0	2015
PJM	n3053.4	P	Eldred	W3-022	0.0	200-299	AC	648.0	2014
PJM	Unnamed / Name Unknown	P	Speed	New Albany SW (LGEE)	1.9	300-399	AC	1,244.0	2012
PJM	Unnamed / Name Unknown	P	Sugar Creek	Kansas (NIPS)	35.0	300-399	AC	1,793.0	2019
PJM	Reynolds_BurrOak_Hiple_345kV_Line	P	Reynolds	Burr Oak	47.0	300-399	AC	1314-1773	2019
PJM	Reynolds_BurrOak_Hiple_345kV_Line	P	Burr Oak	Hiple	53.0	300-399	AC	1314-1773	2019
PJM	n1323	P	Mt. Storm	Bismark	1.0	400-599	AC	Uknown	2012
PJM	n1323	P	Doubs	Bismark	1.0	400-599	AC	Uknown	2012
PJM	b1188	P	Loudoun	Brambleton	1.0	400-599	AC	Uknown	2014
PJM	b1188	P	Pleasant View	Brambleton	1.0	400-599	AC	Uknown	2014
PJM	Unnamed / Name Unknown	P	Greentown	Reynold (NIPS)	66.0	600+	AC	3,576.0	2018
PJM	b1674	P	Englishtown	Wyckoff Street	15.0	100-120	AC	140.0	2013
PJM	b1608	P	Everets	Mainesburg	0.0	100-120	AC	Uknown	2015
PJM	b1608	P	Mansfield	Mainesburg	0.0	100-120	AC	Uknown	2015
PJM	b1277	P	Osterburg East	Bedford North	5.7	100-120	AC	229/278	2013
PJM	Michigan Region 4 Thumb Loop	P	Wyatt	Rapson 1	2.0	100-120	AC	196.0	2015
PJM	Michigan Region 4 Thumb Loop	P	Rapson	Harbor Beach	2.0	100-120	AC	137.0	2015
PJM	b0838	P	Softshell	Bonnyman	24.0	121-150	AC	669.0	2014
PJM	b0840	P	Twin Branch	East Elkhart	18.0	121-150	AC	205.0	2013
PJM	b1032.2	P	Biers Run	Hopetown	3.0	121-150	AC	389.0	2015
PJM	b1032.2	P	Biers Run	Circleville	20.0	121-150	AC	389.0	2015
PJM	b1032.3	P	Hopetown	Delano	3.0	121-150	AC	389.0	2015
PJM	b1034.1	P	South Canton	West Canton	4.1	121-150	AC	251.0	2014
PJM	b1034.2	P	West Canton	Wayview	0.0	121-150	AC	251.0	2014
PJM	b1034.1	P	Wagenhals	Wayview	9.0	121-150	AC	251.0	2014
PJM	b1035	P	West Millersport	Gahanna	15.0	121-150	AC	359.0	2014
PJM	b1052	P	Hyatt	Sawmill	5.3	121-150	AC	388.0	2014
PJM	b1430	P	Benton Harbor	Riverside	0.0	121-150	AC	167.0	2015
PJM	b1430	P	East Watervliet	Benton Harbor / Hartford	5.0	121-150	AC	296.0	2015
PJM	b1466.1	P	Adams	Seaman / Waverly	0.0	121-150	AC	150.0	2014
PJM	b1466.5	P	Seaman	Highland	17.4	121-150	AC	223.0	2014
PJM	b1466.7	P	Hillsboro	Highland	3.0	121-150	AC	223.0	2014
PJM	b1467.2	P	Laporte Jct	Olive / Michigan City	0.0	121-150	AC	156.0	2015
PJM	b1470.1 /s0350	P	Sundial	Baileysville	6.4	121-150	AC	296.0	2015
PJM	b1470.3 /s0350	P	Sundial	Kanawha River	0.0	121-150	AC	223.0	2015
PJM	b1470.3 /s0350	P	Sundial	Baileysville	0.0	121-150	AC	223.0	2015
PJM	b1490	P	Robison Park	Auburn	15.0	121-150	AC	388.0	2015
PJM	b1490	P	Kendallville	Albion / Garrett North	0.0	121-150	AC	251.0	2015
PJM	b1662	P	Pemberton	Cherry Creek	4.0	121-150	AC	251.0	2015
PJM	b1663	P	Jacksons Ferry	Wythe	28.0	121-150	AC	388.0	2015
PJM	b1666	P	Findlay Tap	Fostoria Central	0.0	121-150	AC	150 / 167	2015
PJM	b1666	P	Findlay Tap	New Liberty / N.Findlay	0.0	121-150	AC	150 / 167	2015
PJM	b1666	P	Findlay Tap	Findlay Center/NE Findlay	0.0	121-150	AC	205.0	2015
PJM	b1667	P	Melmore	Tiffin Center	7.2	121-150	AC	Uknown	2015
PJM	b1667	P	Tiffin Center	Fremont Center	12.6	121-150	AC	Uknown	2015
PJM	b1667	P	Melmore	Greenlawn	0.0	121-150	AC	205.0	2015

Assessment Area	Transmission Project Name	Status	Terminal Origin Locaction	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Current (AC/DC)	Capacity Rating (MVA)	In-Service Year
PJM	b1667	P	Melmore	West End Fostoria	0.0	121-150	AC	167.0	2015
PJM	b1667	P	Melmore	Howard	0.0	121-150	AC	167.0	2015
PJM	b1781	P	Trail Fork	Baileysville	0.0	121-150	AC	302.0	2013
PJM	b1781	P	Trail Fork	Tazewell	0.0	121-150	AC	302.0	2013
PJM	b1783	P	Lonesome Pine	Tazewell / Bluefield	0.0	121-150	AC	251.0	2015
PJM	b1783	P	South Bluefield	S.Princeton / Bluefield	0.0	121-150	AC	205 / 251	2015
PJM	b1818	P	Lincoln	Allen	4.5	121-150	AC	Uknown	2016
PJM	b1818	P	Sterling	Allen	4.5	121-150	AC	Uknown	2016
PJM	b1818	P	Milan	Allen	4.5	121-150	AC	Uknown	2016
PJM	b1818	P	Timber Switch	Allen	4.5	121-150	AC	Uknown	2016
PJM	s0251	P	Vassell	Delaware	17.4	121-150	AC	251.0	2014
PJM	s0352	P	Ware Road	Waverly / Adams-Seaman	0.0	121-150	AC	150.0	2012
PJM	s0353	P	I. U. Purdue	Spy Run / Robison Park	6.5	121-150	AC	Uknown	2014
PJM	s0353.3	P	Industrial Park	Spy Run / McKinley	0.0	121-150	AC	296 /251	2014
PJM	b0873	P	Glasgow	Mount Pleasant	12.0	121-150	AC	Uknown	2013
PJM	b0879	P	Wye Mills	Church	7.0	121-150	AC	Uknown	2015
PJM	b0737	P	Indian River	Bishop	12.0	121-150	AC	Uknown	2012
PJM	toi355	P	Wye Mills	Easton	4.0	121-150	AC	Uknown	2018
PJM	s0198	P	Albright	Altamont	0.0	121-150	AC	Uknown	2014
PJM	s0180	P	Greenbrier	Harts Run	0.0	121-150	AC	Uknown	2013
PJM	s0198	P	Mt. Zion	Altamont	0.0	121-150	AC	Uknown	2014
PJM	b1023.3	P	Osage	502 Junction	7.0	121-150	AC	Uknown	2013
PJM	b0674	P	Osage	Whiteley	12.0	121-150	AC	Uknown	2013
PJM	s0110	P	Pursley	Holbrook	5.0	121-150	AC	Uknown	2016
PJM	s0180	P	Ronceverte	Harts Run	0.0	121-150	AC	Uknown	2013
PJM	b1023.3	P	Whiteley	502 Junction	6.0	121-150	AC	Uknown	2013
PJM	s0110	P	Whiteley	Holbrook	5.0	121-150	AC	Uknown	2016
PJM	0	P	Ashtabula	Stacy	10.0	121-150	AC	103/133	2013
PJM	b1281	P	Avery	Hayes	6.3	121-150	AC	149/194	2014
PJM	Unnamed / Name Unknown	P	Barberton	South Akron	8.1	121-150	AC	232/281	2017
PJM	Unnamed / Name Unknown	P	Bluebell	New Berlin Lake Area Sub	1.0	121-150	AC	102/132	2015
PJM	b1691	P	Bluebell	South Akron	31.6	121-150	AC	163/197	2016
PJM	Unnamed / Name Unknown	P	Chamberlin	Shalersville	2.5	121-150	AC	278/338	2014
PJM	Unnamed / Name Unknown	P	Delta	Fulton	1.0	121-150	AC	278/343	2013
PJM	b1692	P	East Akron	Knox	0.3	121-150	AC	185/189	2013
PJM	s0370	P	East Springfield	London	15.5	121-150	AC	199/240	2014
PJM	Unnamed / Name Unknown	P	Fulton	Swanton	1.0	121-150	AC	278/343	2013
PJM	b1585	P	Galion	Longview	0.0	121-150	AC	200/242	2012
PJM	b1281	P	Greenfield	Hayes	4.4	121-150	AC	149/194	2014
PJM	b1281	P	Greenfield	Hayes	4.4	121-150	AC	278/338	2014
PJM	s0369	P	London	Tangy	38.6	121-150	AC	199/240	2014
PJM	Unnamed / Name Unknown	P	Mayfield	Stacy	10.0	121-150	AC	103/133	2013
PJM	Unnamed / Name Unknown	P	Niles	New Berlin Lake Area Sub	1.0	121-150	AC	102/132	2015
PJM	b1290	P	Niles	Salt Springs #2	3.2	121-150	AC	278/339	2013
PJM	b1692	P	Sammis	Knox	0.3	121-150	AC	185/189	2013
PJM	b1398.3	P	Mickleton	Deptford	1.7	200-299	AC	Uknown	2015
PJM	b0497	P	Conastone	Graceton	8.6	200-299	AC	Uknown	2014
PJM	b0877	P	Vienna	Steele	28.0	200-299	AC	Uknown	2017
PJM	b0750	P	Vienna	Loretto	16.0	200-299	AC	Uknown	2018
PJM	b0750	P	Loretto	Piney Grove	6.0	200-299	AC	Uknown	2018
PJM	b0673	P	Elko	Carbon Center Jct	5.8	200-299	AC	Uknown	2016
PJM	b1153	P	Conemaugh	Seward	2.4	200-299	AC	719/882	2014
PJM	b0910	P	Jenkins	Stanton	8.6	200-299	AC	648.0	2014
PJM	b0717	P	Brunner Island	West Shore	16.0	200-299	AC	648.0	2013
PJM	b1154	P	West Orange	Roseland	4.5	200-299	AC	Uknown	2014
PJM	b1154	P	West Orange	Roseland	4.5	200-299	AC	Uknown	2014
PJM	b1154	P	Roseland	Sewaren	29.8	200-299	AC	Uknown	2014
PJM	b1155	P	Camden	Burlington	13.7	200-299	AC	Uknown	2014
PJM	b1155	P	Camden	Cuthbert Blvd.	4.5	200-299	AC	Uknown	2014
PJM	b1304.1	P	Hudson	Kearny	2.0	200-299	AC	Uknown	2014
PJM	b1304.1	P	Roseland	Kearny	21.9	200-299	AC	Uknown	2014
PJM	b1304.3	P	Bergen	Athenia	10.0	200-299	AC	Uknown	2015
PJM	b1398	P	Gloucester	Cuthbert Blvd.	4.5	200-299	AC	Uknown	2015
PJM	b1398.3	P	Mickleton	Gloucester	9.0	200-299	AC	Uknown	2015
PJM	b1787	P	Cox's Corner	Lumberton	4.3	200-299	AC	Uknown	2016
PJM	n1035	P	Athenia	Bergen	10.0	200-299	AC	Uknown	2014
PJM	b1032.1	P	Don Marquis	Biers Run	0.0	300-399	AC	1,219.0	2015

Assessment Area	Transmission Project Name	Status	Terminal Origin Locaction	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Current (AC/DC)	Capacity Rating (MVA)	In-Service Year
PJM	b1032.1	P	Biers Run	Bixby	0.0	300-399	AC	1,235.0	2015
PJM	b1817	P	East Elkhart	Cook / Hiple	0.0	300-399	AC	1,409.0	2016
PJM	b1819	P	Robison Park	Sorenson	24.0	300-399	AC	Uknown	2016
PJM	s0251	P	Vassell	Hyatt	0.0	300-399	AC	1,409.0	2014
PJM	s0251	P	Vassell	Corridor	0.0	300-399	AC	1,235.0	2014
PJM	s0251	P	Vassell	Corridor	8.0	300-399	AC	1,409.0	2014
PJM	n1650	P	Kewanee	Nelson TSS155	51.0	300-399	AC	Uknown	2012
PJM	n1651	P	Kewanee	Collins	85.0	300-399	AC	Uknown	2012
PJM	Unnamed / Name Unknown	P	Allen Junction	Fulton	0.0	300-399	AC	1370/1646	2013
PJM	b1282	P	Beaver	Hayes	32.9	300-399	AC	1542/1878	2014
PJM	b1283	P	Chamberlin	Hanna	0.7	300-399	AC	1380/1646	2014
PJM	Unnamed / Name Unknown	P	Chamberlin	Shalersville	9.5	121-150	AC	617/751	2014
PJM	b1282	P	Davis Besse	Hayes	32.0	300-399	AC	1542/1878	2014
PJM	Unnamed / Name Unknown	P	Fulton	Midway	0.0	300-399	AC	1370/1646	2013
PJM	Unnamed / Name Unknown	P	Fulton	North Star Steel	0.0	300-399	AC	1370/1646	2013
PJM	n2176	P	G689	Highland	1.3	300-399	AC	1559/1899	2014
PJM	n2176	P	G689	Sammis	1.3	300-399	AC	1559/1899	2014
PJM	b1283	P	Hanna	Mansfield	0.7	300-399	AC	1380/1646	2014
PJM	Michigan Region 4 Thumb Loop	P	Baker	Rapson 1	63.9	300-399	AC	2,568.0	2013
PJM	Michigan Region 4 Thumb Loop	P	Baker	Rapson 2	63.9	300-399	AC	2,568.0	2013
PJM	Michigan Region 4 Thumb Loop	P	Rapson	Greenwood	55.0	300-399	AC	2,568.0	2015
PJM	Michigan Region 4 Thumb Loop	P	Rapson	Banner	33.2	300-399	AC	2,568.0	2015
PJM	Michigan Region 4 Thumb Loop	P	SE Sandusky	Greenwood	21.8	300-399	AC	2,568.0	2015
PJM	Michigan Region 4 Thumb Loop	P	Greenwood	Fitz 2	13.2	300-399	AC	2,568.0	2015
PJM	Michigan Region 4 Thumb Loop	P	Greenwood	Fitz 3	13.2	300-399	AC	2,568.0	2015
PJM	Michigan Region 4 Thumb Loop	P	Belle River	Fitz 1	3.5	300-399	AC	2,568.0	2015
PJM	Michigan Region 4 Thumb Loop	P	Belle River	Fitz 2	3.5	300-399	AC	2,568.0	2015
PJM	s0104	P	Cranberry	Cabot	0.1	400-599	AC	2800/3600	2012
PJM	s0104	P	Cranberry	Wylie Ridge	0.1	400-599	AC	2800/3600	2012
PJM	b0284.1	P	Conemaugh	Jacks Mountain	0.0	400-599	AC	2,932.0	2017
PJM	b0284.1	P	Jacks Mountain	Juniata	0.0	400-599	AC	2,932.0	2017
PJM	b0284.1	P	Jacks Mountain	Juniata	0.0	400-599	AC	2,932.0	2017
PJM	b0284.1	P	Keystone	Jacks Mountain	0.0	400-599	AC	2,932.0	2017
PJM	b0478	P	Susquehanna	Roseland	146.0	400-599	AC	3,005.0	2015
PJM	b0478	P	Susquehanna	Roseland	146.0	400-599	AC	Uknown	2015
PJM	b1659.14	P	Dumont	Sorenson	7.0	600+	AC	6,249.0	2015
PJM	b1659.14	P	Marysville	Sorenson	7.0	600+	AC	6,249.0	2015
PJM	s0251	P	Vassell	Kammer / Maliszewski	0.0	600+	AC	4257/4174	2014
PJM	TOI152	P	Westport	Wilkens Ave	3.0	100-120	AC	Uknown	2014
PJM	Gratiot Wind Park	UC	Titibawassee	Begole	5.0	121-150	AC	394.0	2012
PJM	AB Brown to Reid 345kv	UC	Reid	Brown	24.5	300-399	AC	1,400.0	2012
PJM	s0356	UC	Wayman Switch	Sand Hill / Kammer	0.0	121-150	AC	205.0	2012
PJM	Birchwood	UC	Birchwood Jct	Birchwood Substation	0.0	121-150	AC	159.0	2012
PJM	Ratigan	UC	Ratigan Jct	Ratigan Substation	0.1	121-150	AC	159.0	2012
PJM	Unnamed / Name Unknown	UC	Noblesville Gen. Station	Geist	0.6	200-299	AC	319.0	2012
PJM	s0124	UC	Fredrickburg	Garrisonville	1.0	200-299	AC	Uknown	2012
PJM	s0124	UC	Possum Point	Garrisonville	1.0	200-299	AC	Uknown	2012
PJM	b1071	UC	Landstown	Virginia Beach	11.0	200-299	AC	Uknown	2012
PJM	b1096	UC	Loudoun	Middleburg	10.0	200-299	AC	Uknown	2013
PJM	s0121	UC	Loudoun	Cochran Mill	1.0	200-299	AC	Uknown	2014
PJM	s0121	UC	Pleasant View	Cochran Mill	1.0	200-299	AC	Uknown	2014
PJM	b0503	UC	Carson	Forbes	2.8	121-150	AC	Uknown	2012
PJM	b0503	UC	Oakland	Carson	2.0	121-150	AC	Uknown	2013
PJM	Unnamed / Name Unknown	UC	Cranberry	Hoytdale	2.2	121-150	AC	278/338	2012
PJM	Unnamed / Name Unknown	UC	Cranberry	Maple	0.6	121-150	AC	278/338	2012
PJM	Unnamed / Name Unknown	UC	Cranberry	Pine #1	2.2	121-150	AC	278/338	2012
PJM	Unnamed / Name Unknown	UC	Cranberry	Pine #2	0.6	121-150	AC	278/338	2012
PJM	b0814	UC	Essex	Kearny	2.0	121-150	AC	Uknown	2013
PJM	b1100	UC	Bayonne	Marion	4.4	121-150	AC	Uknown	2012
PJM	Simpson – Batavia	UC	Simpson	Batavia	22.3	121-150	AC	345.0	2012
PJM	s0178	UC	Bradford/Clay Tap	Clay	0.0	200-299	AC	328.0	2013
PJM	s0178	UC	Colora/Clay Tap	Clay	7.0	200-299	AC	463.0	2013
PJM	b0526	UC	Richie	Benning	5.3	200-299	AC	Uknown	2012
PJM	toi334.2	UC	Arsenal	Logans Ferry	12.0	300-399	AC	Uknown	2016
PJM	DWSD SubA Trf 3 Addition	P	Waterman Bus 3	Zug B Bus 102	1.0	100-120	AC	343.0	2013
PJM	Unnamed / Name Unknown	X	Somerset	O19	0.1	100-120	AC	Uknown	0
PJM	Unnamed / Name Unknown	X	Amos	Welton Spring	175.0	600+	AC	6,500.0	0

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PJM	Unnamed / Name Unknown	X	Welton Spring	Kemptown	100.0	600+	AC	6,500.0	0
PJM	Unnamed / Name Unknown	X	Amos	Welton Spring	175.0	600+	AC	6,500.0	0
PJM	Unnamed / Name Unknown	X	Welton Spring	Kemptown	100.0	600+	AC	6,500.0	0
SERC-E	Mull 100 kV Lines	U	Hickory Tie	Newton Tie Tap	0.0	100-120	AC	200.0	2012
SERC-E	Swain 161-66 kV Tie Station	UC	West Mill Tie	Swain Tie	17.0	151-199	AC	275.0	2013
SERC-E	Pinewood 100 kV Lines	U	Lawsons Fork Tie	Pinewood Ret Tap	0.0	100-120	AC	225.0	2014
SERC-E	Beulah 100 kV Lines	U	Stamey Tie	EU # 18 Tap	0.0	100-120	AC	375.0	2014
SERC-E	Mayo 100 kV Lines	U	Dan River Steam Sta	Madison Tie	0.0	100-120	AC	225.0	2013
SERC-E	Monroe 100 kV Lines	U	Lancaster Mn	Monroe Mn	0.0	100-120	AC	175.0	2014
SERC-E	Oaklawn 100 kV Lines	U	Lakewood Tie	Bancroft Ret Tap	0.0	100-120	AC	375.0	2014
SERC-E	Odell 100 kV Lines	U	Winecoff Tie	Westfork Sw Sta	0.0	100-120	AC	225.0	2014
SERC-E	Caesar 230 kV Lines (Pisgah - Shiloh)	U	Shiloh Sw Sta	Pisgah Tie	0.0	200-299	AC	850.0	2013
SERC-E	London Creek 230 kV Lines	U	Riverview Sw Sta	Peach Valley Tie	0.0	200-299	AC	750.0	2020
SERC-E	Oakvale 100 kV Lines	U	Oakvale Tie	Shady Grove Tie	0.0	100-120	AC	375.0	2018
SERC-E	Greenville-Kinston Dupont 230 kV	C	Greenville	Kinston DuPont	30.0	200-299	AC	615.0	2017
SERC-E	Harris - RTP 230 kV line	P	Harris	RTP	22.0	200-299	AC	1,195.0	2014
SERC-E	Asheboro-Asheboro East 115kV, S.	U	Asheboro	Asheboro East	0.0	100-120	AC	308.0	2016
SERC-E	Asheboro-Asheboro East 115kV, N.	U	Asheboro	Asheboro East (2)	0.0	100-120	AC	308.0	2019
SERC-E	Asheville-Enka 115 kV line	P	Asheville	Enka (2)	10.0	100-120	AC	320.0	2012
SERC-E	Folkstone 230 kV, Loop-in 230 kV line	P	Folkstone	Castle Hayne/Jacksonville	16.0	100-120	AC	308.0	2012
SERC-E	A M Williams-Cainhoy	P	A M Williams	Cainhoy	11.0	200-299	AC	352.0	2014
SERC-E	Urquhart-Graniteville	U	Urquhart	Graniteville (2)	0.0	200-299	AC	950.0	2016
SERC-E	VC Summer-Killian	P	VC Summer	Killian	38.0	200-299	AC	950.0	2015
SERC-E	VC Summer #2-Lake Murray	P	VC Summer #2	Lake Murray (2)	23.0	200-299	AC	950.0	2015
SERC-E	VC Summer-VC Summer #2	UC	VC Summer	VC Summer #2	1.0	200-299	AC	950.0	2013
SERC-E	VC Summer-VC Summer #2	UC	VC Summer	VC Summer #2 (2)	1.0	200-299	AC	950.0	2013
SERC-E	Lyles-Denny Terrace	P	Lyles	Denny Terrace	3.0	200-299	AC	950.0	2015
SERC-E	Pepperhill-Summerville	P	Pepperhill	Summerville	7.0	200-299	AC	950.0	2014
SERC-E	VC Summer #2-St. George	P	VC Summer #2	St. George	135.0	200-299	AC	950.0	2018
SERC-E	VC Summer-VC Summer #2	P	VC Summer	VC Summer #2 (3)	1.0	200-299	AC	950.0	2018
SERC-E	AM WIlliams-Cainhoy	P	AM WIlliams	Cainhoy (2)	9.0	200-299	AC	510.0	2017
SERC-E	Belvedere-Stevens Creek	R	Belvedere	Stevens Creek	0.0	100-120	AC	130.0	2013
SERC-E	Belvedere-Stevens Creek	P	Belvedere	Stevens Creek	8.0	100-120	AC	474.0	2013
SERC-E	VC Summer-Parr	R	VC Summer	Parr	0.0	200-299	AC	475.0	2013
SERC-E	VC Summer-Parr	R	VC Summer	Parr (2)	0.0	200-299	AC	475.0	2013
SERC-E	Canadys-St. George	R	Canadys	St. George	0.0	200-299	AC	352.0	2018
SERC-E	Canadys-St. George	P	Canadys	St. George	8.0	200-299	AC	950.0	2018
SERC-E	St. George-Summerville	U	St. George	Summerville	0.0	200-299	AC	950.0	2018
SERC-E	Saluda Hydro-Ga Pac	U	Saluda Hydro	Ga Pac	0.0	100-120	AC	474.0	2018
SERC-E	Lyles-Denny Terrace	R	Lyles	Denny Terrace	0.0	100-120	AC	187.0	2015
SERC-E	Lyles-Denny Terrace	R	Lyles	Denny Terrace	0.0	200-299	AC	510.0	2015
SERC-E	Lyles-Denny Terrace	P	Lyles	Denny Terrace	3.0	100-120	AC	377.0	2015
SERC-E	Lyles-Williams Street	U	Lyles	Williams Street	0.0	100-120	AC	237.0	2015
SERC-E	Killian-Blythewood	P	Killian	Blythewood	7.0	100-120	AC	472.0	2014
SERC-E	Lake Murray-Saluda Hydro	U	Lake Murray	Saluda Hydro	0.0	100-120	AC	236.0	2015
SERC-E	Lake Murray-McMeekin	U	Lake Murray	McMeekin	0.0	100-120	AC	236.0	2015
SERC-E	Pomaria-V C Summer	P	Pomaria	V C Summer (2)	8.0	200-299	AC	956.0	2014
SERC-E	V C Summer-Winnsboro	P	V C Summer	Winnsboro	14.0	200-299	AC	956.0	2013
SERC-E	Winnsboro-Richburg	P	Winnsboro	Richburg	27.0	200-299	AC	956.0	2014
SERC-E	Richburg-Flat Creek	P	Richburg	Flat Creek	32.0	200-299	AC	956.0	2015
SERC-E	Pomaria-Sandy Run	C	Pomaria	Sandy Run	55.0	200-299	AC	956.0	2016
SERC-E	Sandy Run-Orangeburg	C	Sandy Run	Orangeburg	34.0	200-299	AC	956.0	2017
SERC-E	Orangeburg-St. George	C	Orangeburg	St. George	26.0	200-299	AC	956.0	2018
SERC-E	St. George-Varnville	C	St. George	Varnville	38.0	200-299	AC	956.0	2019
SERC-E	Bucksville-Garden City	P	Bucksville	Garden City	15.0	100-120	AC	797.0	2016
SERC-E	Proposed Watauga 230kV Sub-Boone	P	Proposed Watauga	Boone Step-Down Sub	2.0	100-120	AC	156.0	2019
SERC-E	Boone Step-Down Sub-Blowing Rock	UC	Boone Step-Down Sub	Blowing Rock Sub (None)	6.0	100-120	AC	92.0	2014
SERC-E	Blowing Rock Sub-New Blowing Rock	P	Blowing Rock Sub	New Blowing Rock Sub	1.0	100-120	AC	102.0	2014
SERC-E	Horse Gap Sub-New Watauga 230kV	P	Horse Gap Sub	New Watauga 230kV Sub	17.0	200-299	AC	402.0	2020
SERC-E	Hudson Sub-Oak Hill Sub	P	Hudson Sub	Oak Hill Sub	4.0	100-120	AC	156.0	2016
SERC-E	Beaver Creek Sub-United Chemi-Con	P	Beaver Creek Sub	United Chemi-Con Sub	8.0	100-120	AC	92.0	2015
SERC-E	Boone Step-Down Sub-Boone	P	Boone Step-Down Sub	Boone Step-Down Sub	9.0	100-120	AC	92.0	2016
SERC-E	Elizabeth 100 kV Lines	U	Kenilworth Ret	N Charlotte	0.0	100-120	AC	425.0	2015
SERC-E	Lyles-Denny Terrace	P	Lyles	Denny Terrace	3.0	200-299	AC	950.0	2015
SERC-E	Charlotte Street-Hagood Junction	P	Charlotte Street	Hagood Junction	5.0	100-120	AC	237.0	2012
SERC-E	Hagood-Accabee	P	Hagood	Accabee	1.0	100-120	AC	176.0	2012
SERC-E	Charlotte Street-Hagood Junction	R	Charlotte Street	Hagood Junction	0.0	100-120	AC	176.0	2012
SERC-E	Hagood-Faber Place	P	Hagood	Faber Place (2)	6.0	100-120	AC	237.0	2017

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SERC-E	Winyah-Bucksville	C	Winyah	Bucksville	32.0	200-299	AC	956.0	2015
SERC-E	Cross-Wassamassaw	C	Cross	Wassamassaw (2)	18.0	200-299	AC	956.0	2018
SERC-E	Bucksville-Conway	C	Bucksville	Conway	7.0	200-299	AC	956.0	2018
SERC-E	Red Bluff-Nixons Crossroads	C	Red Bluff	Nixons Crossroads (2)	14.0	100-120	AC	239.0	2019
SERC-E	Wassamassaw-St. George	C	Wassamassaw	St. George	22.0	200-299	AC	956.0	2019
SERC-E	Aiken Hampton-Aiken #3	U	Aiken Hampton	Aiken #3	0.0	100-120	AC	227.0	2014
SERC-E	Aiken Hampton-Aiken Transmission	U	Aiken Hampton	Aiken Transmission	0.0	100-120	AC	237.0	2015
SERC-E	Mt Pleasant-Bayview	U	Mt Pleasant	Bayview	0.0	100-120	AC	237.0	2014
SERC-E	Yemassee-Burton	U	Yemassee	Burton (2)	0.0	100-120	AC	352.0	2015
SERC-E	St Andrews-Queensboro	U	St Andrews	Queensboro	0.0	100-120	AC	237.0	2015
SERC-E	Cherokee 100 kV Lines	U	Cliffside Steam Station	1st Tap	0.0	100-120	AC	182.0	2013
SERC-E	Faber Place - Hagood Junction 115kV	U	Faber Place	Hagood Junction	0.0	100-120	AC	237.0	2017
SERC-E	Faber Place - Hagood Junction 115kV	U	Faber Place	Hagood Junction	0.0	100-120	AC	237.0	2017
SERC-E	Hagood - Bee Street 115kV Upgrade	U	Hagood	Bee Street	0.0	100-120	AC	352.0	2014
SERC-E	Faber Place - Hagood 115kV Upgrade	U	Faber Place	Hagood	0.0	100-120	AC	237.0	2014
SERC-E	Faber Place - Hagood 115kV #2	P	Faber Place	Hagood (2)	5.0	100-120	AC	237.0	2017
SERC-E	Hagood Junction - Hagood 115kV	P	Hagood Junction	Hagood	0.5	100-120	AC	237.0	2012
SERC-E	Hamlin-Isle of Palms 115kV Sub.Cable	UC	Hamlin	Isle of Palms	8.0	100-120	AC	237.0	2013
SERC-E	Lyles - Saluda River 115 kV	U	Lyles	Saluda River	0.0	100-120	AC	237.0	2015
SERC-E	Lake Murray - Saluda River 115 kV	U	Lake Murray	Saluda River	0.0	100-120	AC	237.0	2015
SERC-E	Raeford 230 kV	P	Richmond Co. Plant	Ft.Bragg Woodruff St Sub.	6.0	200-299	AC	1,195.0	2018
SERC-N	Apache Flats-Scruggs	P	Apache Flats	Scruggs	2.0	151-199	AC	286.0	2015
SERC-N	Rogersville-Holman	P	Rogersville	Holman	7.0	151-199	AC	286.0	2013
SERC-N	Willow Springs-Summersville East	P	Willow Springs	Summersville East	0.0	151-199	AC	203.0	2013
SERC-N	Summersville East-Sweetwater	P	Summersville East	Sweetwater	0.0	151-199	AC	203.0	2013
SERC-N	Mansfield-Mountain Grove	UC	Mansfield	Mountain Grove	22.0	151-199	AC	286.0	2012
SERC-N	Cabool-Mountain Grove	UC	Cabool	Mountain Grove	10.0	151-199	AC	286.0	2012
SERC-N	Cabool-Willow Springs	UC	Cabool	Willow Springs	14.0	151-199	AC	286.0	2012
SERC-N	Blackberry-Neosho	UC	Blackberry	Neosho	0.0	300-399	AC	870.0	2013
SERC-N	Blackberry-Morgan	UC	Blackberry	Morgan	0.0	300-399	AC	870.0	2013
SERC-N	Blackberry-Sportsman Acres	UC	Blackberry	Sportsman Acres	93.0	300-399	AC	1,369.0	2013
SERC-N	Cedar Crest-Locust Grove	P	Cedar Crest	Locust Grove	0.0	151-199	AC	204.0	2012
SERC-N	Cedar Crest-Talequah	P	Cedar Crest	Talequah	0.0	151-199	AC	204.0	2012
SERC-N	Cedar Crest-Lowery	P	Cedar Crest	Lowery	12.0	151-199	AC	204.0	2012
SERC-N	Cedar Crest-Lowery	P	Cedar Crest	Lowery	12.0	151-199	AC	286.0	2012
SERC-N	Cedar Crest-Peggs	P	Cedar Crest	Peggs	4.0	151-199	AC	286.0	2012
SERC-N	Bristow-Okemah	UC	Bristow	Okemah	0.0	121-150	AC	174.0	2013
SERC-N	Pharoah-Okemah	UC	Pharoah	Okemah	0.0	121-150	AC	174.0	2013
SERC-N	Gypsy-Stroud	P	Gypsy	Stroud	21.1	121-150	AC	122.0	2014
SERC-N	Stroud-Warwick	P	Stroud	Warwick	12.0	121-150	AC	245.0	2014
SERC-N	Wheaton-Cassville	P	Wheaton	Cassville	15.0	151-199	AC	286.0	2015
SERC-N	Maries-Dixon	P	Maries	Dixon	5.0	151-199	AC	286.0	2018
SERC-N	Enon-Lake St. Louis	P	Enon	Lake St. Louis	5.0	151-199	AC	372.0	2014
SERC-N	Lake St Louis-Dardenne	P	Lake St Louis	Dardenne	3.0	151-199	AC	372.0	2014
SERC-N	Rolla (South)-Yancy Mills	P	Rolla (South)	Yancy Mills	7.0	100-120	AC	122.0	2012
SERC-N	Luther-Warwick Tap	P	Luther	Warwick Tap	7.4	121-150	AC	245.0	2013
SERC-N	Davidson-Pin Hook	U	Davidson	Pin Hook	0.0	400-599	AC	2,598.0	2013
SERC-N	Shelby-Lagoon Creek	U	Shelby	Lagoon Creek	0.0	400-599	AC	2,598.0	2012
SERC-N	Wilson-Pin Hook	U	Wilson	Pin Hook	0.0	400-599	AC	2,598.0	2013
SERC-N	Widows Creek-Oglethorpe	U	Widows Creek	Oglethorpe (2)	0.0	151-199	AC	299.0	2012
SERC-N	Widows Creek-Oglethorpe	U	Widows Creek	Oglethorpe (3)	0.0	151-199	AC	299.0	2012
SERC-N	Volunteer-East Knox	UC	Volunteer	East Knox	13.0	151-199	AC	450.0	2015
SERC-N	Gallatin-Angeltown	UC	Gallatin	Angeltown	19.0	151-199	AC	410.0	2012
SERC-N	Choctaw-French Camp	U	Choctaw	French Camp	0.0	400-599	AC	2,598.0	2015
SERC-N	Unionville-Rally Hill	UC	Unionville	Rally Hill	18.0	151-199	AC	299.0	2012
SERC-N	West Point-Clay	UC	West Point	Clay	0.0	400-599	AC	2,598.0	2012
SERC-N	MEC-Nucor	P	MEC	Nucor	2.0	151-199	AC	371.0	2015
SERC-N	Wolf Creek-Clinton County 161 kV	C	Wolf Creek	Clinton County	9.0	151-199	AC	292.0	2019
SERC-N	Grahamville-Joppa DOE C33	P	Grahamville	Joppa DOE C33 (2)	2.0	151-199	AC	346.0	2012
SERC-N	Hardin County-Elizabethtown	P	Hardin County	Elizabethtown (2)	1.0	121-150	AC	296.0	2014
SERC-N	Paddys West-Speed 345kV	C	Paddys West	Speed	11.0	300-399	AC	1,195.0	2012
SERC-N	2nd Grahamville-Wickliffe kV	C	Grahamville	Wickliffe (2)	20.0	151-199	AC	889.0	2017
SERC-N	Shelby-Cordova	UC	Shelby	Cordova (2)	23.0	400-599	AC	1,732.0	2012
SERC-N	Sub. 79-Sub. 86	UC	Sub. 79	Sub. 86	11.0	151-199	AC	421.0	2013
SERC-N	Airport-South	U	Airport	South	0.0	151-199	AC	532.0	2022
SERC-N	Airport-Murfreesboro Road	U	Airport	Murfreesboro Road	0.0	151-199	AC	532.0	2022
SERC-N	Battlefield-Craighead	P	Battlefield	Craighead	1.0	151-199	AC	532.0	2016

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SERC-N	Battlefield-Sharondale	P	Battlefield	Sharondale	3.0	151-199	AC	532.0	2016
SERC-N	Elza-Huntsville	U	Elza	Huntsville	0.0	151-199	AC	237.0	2012
SERC-N	Wheeler-Mt. Pleasant	U	Wheeler	Mt. Pleasant	0.0	151-199	AC	334.0	2012
SERC-N	Rebuild / Reconductor Line	UC	Farley	Guntersville	17.0	151-199	AC	367.0	2012
SERC-N	Marshall-Calvert	U	Marshall	Calvert	0.0	151-199	AC	697.0	2013
SERC-N	Marshall-Calvert	U	Marshall	Calvert (2)	0.0	151-199	AC	697.0	2013
SERC-N	Madison-Farley	U	Madison	Farley	0.0	121-150	AC	410.0	2012
SERC-N	ServerCorr-Clayton Village	UC	ServerCorr	Clayton Village	14.0	151-199	AC	423.0	2013
SERC-N	East Point-Arab	U	East Point	Arab	0.0	151-199	AC	318.0	2013
SERC-N	Johnsonville FP-Monsanto	U	Johnsonville FP	Monsanto	0.0	151-199	AC	208.0	2013
SERC-N	Marshall-C33	U	Marshall	C33	0.0	151-199	AC	237.0	2014
SERC-N	Ardmore-Park City	U	Ardmore	Fayetteville	0.0	151-199	AC	232.0	2014
SERC-N	Decatur-Priceville	U	Decatur	Guntersville	0.0	151-199	AC	334.0	2013
SERC-N	Guntersville-Goose Pond	U	Guntersville	Goose Pond	0.0	151-199	AC	334.0	2012
SERC-N	Calvert-South Calvert	U	Calvert	South Calvert (2)	0.0	151-199	AC	237.0	2012
SERC-N	Marshall-Benton	U	Marshall	Benton	0.0	151-199	AC	307.0	2013
SERC-N	Marshall-Mayfield	U	Marshall	Mayfield	0.0	151-199	AC	410.0	2014
SERC-N	Fayette-South Jessamine 138 kV Line	C	Fayette	South Jessamine	7.3	121-150	AC	267.0	2019
SERC-N	W. Berea-Three Links Junction 138 kV	P	West Berea	Three Links Junction	7.5	121-150	AC	267.0	2020
SERC-N	Starkville-Clayton Village	P	Starkville	Clayton Village	4.6	151-199	AC	371.0	2013
SERC-N	Matanzas	P	Matanzas	Ohio Co	0.0	121-150	AC	210.0	2013
SERC-N	Matanzas	P	Matanzas	Green River	0.0	121-150	AC	210.0	2013
SERC-N	New Albany 345kV	P	New Albany	Paddys West	0.3	300-399	AC	1,146.0	2013
SERC-N	New Albany 345kV	P	New Albany	Northside	0.3	300-399	AC	1,146.0	2013
SERC-N	Midway 138kV	C	Midway	Adams	0.0	121-150	AC	166.0	2015
SERC-N	Midway 138kV	C	Midway	Tyrone	0.0	121-150	AC	166.0	2015
SERC-N	Baldor-Westville	P	Baldor	Westville	4.0	151-199	AC	122.0	2012
SERC-N	Holman-Crossway	P	Holman	Crossway	9.0	151-199	AC	286.0	2012
SERC-N	Franks-Barnett	P	Franks	Barnett	50.0	300-399	AC	1,369.0	2016
SERC-N	Turkey Creek-Warsaw East	P	Turkey Creek	Warsaw East	7.0	151-199	AC	286.0	2014
SERC-N	March-Crossway	P	March	Crossway	12.0	151-199	AC	122.0	2013
SERC-N	St. Francis-St. Francis Tap	P	St. Francis	St. Francis Tap	4.3	300-399	AC	870.0	2013
SERC-N	Fredericktown-Lutesville	P	Fredericktown	Lutesville	16.2	151-199	AC	122.0	2014
SERC-N	Jasper-Lamar	P	Jasper	Lamar	13.0	151-199	AC	319.0	2012
SERC-N	Kingdom City-Mexico North	P	Kingdom City	Mexico North	20.0	151-199	AC	286.0	2015
SERC-N	Enon-Enon Tap	P	Enon	Enon Tap	0.3	300-399	AC	1,382.0	2016
SERC-N	Maries-Rolla North Wye	P	Maries	Rolla North Wye	20.8	151-199	AC	286.0	2014
SERC-N	Oak Ridge-Eufala	C	Oak Ridge	Eufala	10.0	121-150	AC	245.0	2015
SERC-N	Stillwell-Baldor	P	Stillwell	Baldor	15.3	151-199	AC	122.0	2012
SERC-N	Carthage-Philbert	C	Carthage	Philbert	3.5	151-199	AC	286.0	2019
SERC-N	Jasper-Philbert	C	Jasper	Philbert	16.7	151-199	AC	286.0	2019
SERC-N	Sedalia-Windsor Tap	P	Sedalia	Windsor Tap	1.0	151-199	AC	286.0	2013
SERC-N	Barnett-Eldon	P	Barnett	Eldon	0.0	151-199	AC	204.0	2016
SERC-N	Warwick Tap-Warwick	P	Warwick Tap	Warwick	7.4	121-150	AC	228.0	2013
SERC-N	Notch-Redwood	P	Notch	Redwood	30.0	151-199	AC	286.0	2013
SERC-SE	Barry-Chickasaw	U	Barry	Chickasaw	0.0	200-299	AC	1,243.0	2015
SERC-SE	Gaston-East Pelham	U	Gaston	East Pelham	0.0	200-299	AC	502.0	2022
SERC-SE	North Crichton S.S.-South Mobile	U	North Crichton S.S.	South Mobile	0.0	100-120	AC	184.0	2014
SERC-SE	North Crichton S.S.-South Mobile	U	North Crichton S.S.	South Mobile (2)	0.0	100-120	AC	184.0	2014
SERC-SE	Big Creek T.S.-Lyndell D.S.	P	Big Creek T.S.	Lynndell D.S.	8.0	100-120	AC	290.0	2014
SERC-SE	North Mobile-Crichton #1	U	North Mobile	Crichton #1	0.0	100-120	AC	290.0	2015
SERC-SE	Schillinger Road-Lott Road Tap	P	Schillinger Road	Lott Road Tap	2.0	100-120	AC	290.0	2014
SERC-SE	Leeds-Westbury	U	Leeds	Westbury	0.0	100-120	AC	270.0	2018
SERC-SE	North Brewton TS-North Brewton DS	P	North Brewton TS	North Brewton DS	6.0	100-120	AC	290.0	2020
SERC-SE	Wire Road-Wire Road Tap	P	Wire Road	Wire Road Tap	4.0	100-120	AC	216.0	2021
SERC-SE	Opelika #1-Opelika #3	U	Opelika #1	Opelika #3	0.0	100-120	AC	138.0	2021
SERC-SE	North Mobile-Racetrack D.S.	P	North Mobile	Racetrack D.S.	2.0	100-120	AC	290.0	2014
SERC-SE	Old Pascagoula Tap-Old Pascagoula	P	Old Pascagoula Tap	Old Pascagoula Rd	2.0	100-120	AC	138.0	2012
SERC-SE	Kimberly Clark-Blakeley Island	U	Kimberly Clark	Blakeley Island	0.0	100-120	AC	341.0	2019
SERC-SE	McIntosh-Jackson TS (New miles)	P	McIntosh	Jackson TS (New miles)	2.0	100-120	AC	216.0	2013
SERC-SE	Springdale D.S.-Springhill D.S.	U	Springdale D.S.	Springhill D.S.	0.0	100-120	AC	216.0	2016
SERC-SE	Michael Blvd D.S.-Michael Blvd Tap	U	Michael Blvd D.S.	Michael Blvd Tap	0.0	100-120	AC	138.0	2015
SERC-SE	Wolf Ridge D.S. Tap-Springhill D.S.	U	Wolf Ridge D.S. Tap	Springhill D.S.	0.0	100-120	AC	216.0	2015
SERC-SE	Barnwell Tap-Barnwell	U	Barnwell Tap	Barnwell	0.0	100-120	AC	216.0	2012
SERC-SE	Racetrack D.S.-Lott Road	P	Racetrack D.S.	Lott Road	4.0	100-120	AC	290.0	2014
SERC-SE	Anniston Tap-Golden Springs	U	Anniston Tap	Golden Springs	0.0	100-120	AC	216.0	2012
SERC-SE	Henry Dam-Cedar Bend	U	Henry Dam	Cedar Bend	0.0	100-120	AC	159.0	2015

Assessment Area	Transmission Project Name	Status	Terminal Origin Locaction	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Current (AC/DC)	Capacity Rating (MVA)	In-Service Year
SERC-SE	So. Tuscaloosa-Holt	U	So. Tuscaloosa	Holt	0.0	100-120	AC	341.0	2016
SERC-SE	Anniston-Oxanna	U	Anniston	Oxanna	0.0	100-120	AC	216.0	2014
SERC-SE	Anniston-Greenbrier	P	Anniston	Greenbrier	1.0	100-120	AC	216.0	2014
SERC-SE	31st Avenue-South Tuscaloosa	U	31st Avenue	South Tuscaloosa	0.0	100-120	AC	341.0	2015
SERC-SE	Demopolis-Selma	U	Demopolis	Selma	0.0	100-120	AC	216.0	2019
SERC-SE	Barnwell Tap-Turkey Hill	P	Barnwell Tap	Turkey Hill	3.0	100-120	AC	216.0	2018
SERC-SE	Silverhill-Fish River Tap	U	Silverhill	Fish River Tap	0.0	100-120	AC	216.0	2018
SERC-SE	Plantation Pipeline (Akron)-Akron	P	Plantation Pipeline	Akron	1.0	100-120	AC	383.0	2014
SERC-SE	Colonial Pipeline Tap-Colonial	U	Colonial Pipeline Tap	Colonial Pipeline	0.0	100-120	AC	138.0	2019
SERC-SE	Pinckard TS-Slocomb TS	U	Pinckard TS	Slocomb TS	0.0	100-120	AC	336.0	2013
SERC-SE	North Selma-Inter Paper Tap	P	North Selma	Inter Paper Tap	7.0	100-120	AC	216.0	2014
SERC-SE	Slocomb TS-AL/FL State Line	U	Slocomb TS	AL/FL State Line	0.0	100-120	AC	336.0	2014
SERC-SE	Snowdoun TS-Pike Co	U	Snowdoun TS	Pike Co	0.0	200-299	AC	807.0	2014
SERC-SE	Autaugaville 6-Autaugaville 8	P	Autaugaville 6	Autaugaville 8	1.0	200-299	AC	1,614.0	2013
SERC-SE	South Montg-Pinedale	U	South Montg	Pinedale	0.0	100-120	AC	216.0	2013
SERC-SE	Pinedale-ECI Halstead	U	Pinedale	ECI Halstead	0.0	100-120	AC	216.0	2013
SERC-SE	Montg SS-South Montg	U	Montg SS	South Montg	0.0	200-299	AC	403.0	2013
SERC-SE	Cedar Bend-North Cedar Bend Tap	U	Cedar Bend	North Cedar Bend Tap	0.0	100-120	AC	138.0	2015
SERC-SE	Bynum-Anniston	U	Bynum	Anniston	0.0	100-120	AC	454.0	2014
SERC-SE	Tap 115kV TL from Fayette Highway	P	Fayette HW-Hunt Oil	Airport DS	2.0	100-120	AC	216.0	2017
SERC-SE	Bellamy SS-Cuba	U	Bellamy SS	Cuba	0.0	100-120	AC	154.0	2021
SERC-SE	Demopolis TS-Cemex	U	Demopolis TS	Cemex	0.0	100-120	AC	154.0	2021
SERC-SE	Big Sandy Tap-Englewood Tap	U	Big Sandy Tap	Englewood Tap	0.0	100-120	AC	138.0	2016
SERC-SE	Moundville-North Moundville	P	Moundville	North Moundville	5.0	100-120	AC	383.0	2015
SERC-SE	Englewood Tap-Moundville	P	Englewood Tap	Moundville	9.0	100-120	AC	383.0	2014
SERC-SE	Englewood Tap-South Tuscaloosa	P	Englewood Tap	South Tuscaloosa	18.0	100-120	AC	383.0	2016
SERC-SE	Moundville-Colonial Pipeline	P	Moundville	Colonial Pipeline	6.0	100-120	AC	383.0	2019
SERC-SE	Epes-Eutaw	P	Epes	Eutaw	23.0	100-120	AC	341.0	2014
SERC-SE	O'Hara-McDonough Primary	P	O'Hara	McDonough Primary	20.0	200-299	AC	602.0	2018
SERC-SE	South Dahlonega-Palmer Creek	P	South Dahlonega	Palmer Creek	10.0	200-299	AC	602.0	2019
SERC-SE	Vogtle-Thomson	P	Vogtle	Thomson	60.0	400-599	AC	2,701.0	2016
SERC-SE	Kraft-McIntosh (white)	U	Kraft	McIntosh (white)	0.0	200-299	AC	1,024.0	2012
SERC-SE	Blanford/Meldrim-McIntosh (white)	U	Blanford/Meldrim	McIntosh (white)	0.0	200-299	AC	1,024.0	2014
SERC-SE	Blanford/Meldrim-McIntosh (black)	U	Blanford/Meldrim	McIntosh (black) (2)	0.0	200-299	AC	1,024.0	2014
SERC-SE	Austin Drive-River Road	U	Austin Drive	River Road	0.0	100-120	AC	216.0	2016
SERC-SE	Bark Camp-Gainesville #1	U	Bark Camp	Gainesville #1	0.0	100-120	AC	216.0	2013
SERC-SE	Bremen-Possum Branch	U	Bremen	Possum Branch	0.0	100-120	AC	255.0	2019
SERC-SE	Brunswick-Stonewall Junct.	U	Brunswick	Stonewall Junct.	0.0	100-120	AC	216.0	2018
SERC-SE	Cornish Mountain-Sigman Road	U	Cornish Mountain	Sigman Road	0.0	100-120	AC	301.0	2018
SERC-SE	Daniel Siding-Little Ogeechee	U	Daniel Siding	Little Ogeechee	0.0	100-120	AC	369.0	2017
SERC-SE	Dawsonville-Leach Road	U	Dawsonville	Leach Road	0.0	100-120	AC	216.0	2013
SERC-SE	Decatur-Kirkland	U	Decatur	Kirkland	0.0	100-120	AC	188.0	2016
SERC-SE	Douglasville-Post Road	U	Douglasville	Post Road	0.0	100-120	AC	140.0	2016
SERC-SE	Douglasville-West Marietta	U	Douglasville	West Marietta	0.0	100-120	AC	255.0	2021
SERC-SE	East Social Circle-Social Circle	U	East Social Circle	Social Circle	0.0	100-120	AC	255.0	2020
SERC-SE	Hampton-McDonough Pri	U	Hampton	McDonough Pri	0.0	100-120	AC	301.0	2015
SERC-SE	Horse Creek-Ludowici	U	Horse Creek	Ludowici	0.0	100-120	AC	216.0	2017
SERC-SE	Jack McDonough-Northwest	U	Jack McDonough	Northwest	0.0	200-299	AC	602.0	2013
SERC-SE	Jack McDonough-Northwest	U	Jack McDonough	Northwest (2)	0.0	200-299	AC	602.0	2013
SERC-SE	Jack McDonough-West Marietta	P	Jack McDonough	West Marietta	4.0	100-120	AC	255.0	2018
SERC-SE	Jesup-Rayonier	U	Jesup	Rayonier	0.0	100-120	AC	216.0	2017
SERC-SE	McConnell Road-South Acworth	U	McConnell Road	South Acworth	0.0	100-120	AC	301.0	2021
SERC-SE	O'Hara-Corinth Road	U	O'Hara	Corinth Road	0.0	100-120	AC	255.0	2021
SERC-SE	Porterdale-S. Covington Tap	U	Porterdale	S. Covington Tap	0.0	100-120	AC	138.0	2013
SERC-SE	South Griffin-Jackson	U	South Griffin	Jackson	0.0	100-120	AC	216.0	2013
SERC-SE	W. Brunswick-Altamaha	P	W. Brunswick	Altamaha	8.0	100-120	AC	216.0	2016
SERC-SE	East Point-College Park #3	U	East Point	College Park #3	0.0	100-120	AC	255.0	2017
SERC-SE	Mountain View-Barnett Road	U	Mountain View	Barnett Road	0.0	100-120	AC	255.0	2021
SERC-SE	Morrow-Ellenwood	U	Morrow	Ellenwood	0.0	100-120	AC	417.0	2016
SERC-SE	Parkaire-Roswell	P	Parkaire	Roswell	5.0	100-120	AC	301.0	2018
SERC-SE	Berkeley Lake-Spruill Road	U	Berkeley Lake	Spruill Road	0.0	200-299	AC	682.0	2018
SERC-SE	Grady-Moreland Avenue	U	Grady	Moreland Avenue	0.0	100-120	AC	293.0	2012
SERC-SE	Northside Drive-Northwest	U	Northside Drive	Northwest	0.0	100-120	AC	301.0	2013
SERC-SE	Atkinson-Northside Drive	U	Atkinson	Northside Drive	0.0	100-120	AC	188.0	2013
SERC-SE	Northside Drive-Spring Street	U	Northside Drive	Spring Street	0.0	100-120	AC	269.0	2013
SERC-SE	North Americus-North Tifton	U	North Americus	North Tifton	0.0	100-120	AC	124.0	2014
SERC-SE	First Avenue-North Columbs	U	First Avenue	North Columbs	0.0	100-120	AC	216.0	2021

Assessment Area	Transmission Project Name	Status	Terminal Origin Locaction	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Current (AC/DC)	Capacity Rating (MVA)	In-Service Year
SERC-SE	Bull Creek-Victory Drive	U	Bull Creek	Victory Drive	0.0	100-120	AC	216.0	2015
SERC-SE	Americus-North Americus	U	Americus	North Americus	0.0	100-120	AC	155.0	2021
SERC-SE	Blackshear Jct.-Offerman	U	Blackshear Jct.	Offerman	0.0	100-120	AC	216.0	2019
SERC-SE	Bemiss-Pine Grove Primary	U	Bemiss	Pine Grove Primary	0.0	100-120	AC	216.0	2021
SERC-SE	Lassiter Road-North Marietta	U	Lassiter Road	North Marietta	0.0	100-120	AC	341.0	2013
SERC-SE	Dean Forest-Kraft	U	Dean Forest	Kraft	0.0	200-299	AC	866.0	2015
SERC-SE	Dean Forest-GSW	P	Dean Forest	GSW	5.0	200-299	AC	1,018.0	2015
SERC-SE	Boulevard-Dean Forest	U	Boulevard	Dean Forest	0.0	100-120	AC	433.0	2015
SERC-SE	Boulevard-Dean Forest	U	Boulevard	Dean Forest (2)	0.0	200-299	AC	866.0	2015
SERC-SE	Dorchester-Little Ogeechee	U	Dorchester	Little Ogeechee	0.0	200-299	AC	1,205.0	2017
SERC-SE	Dorchester-West Brunswick	P	Dorchester	West Brunswick	45.0	200-299	AC	1,018.0	2017
SERC-SE	Dorchester-Walthoursville	P	Dorchester	Walthoursville	8.0	100-120	AC	216.0	2017
SERC-SE	Sylvania-Deal Branch	U	Sylvania	Deal Branch	0.0	100-120	AC	124.0	2019
SERC-SE	Bethabara-East Walton	P	Bethabara	East Walton	8.0	200-299	AC	602.0	2017
SERC-SE	Bostwick-East Walton	P	Bostwick	East Walton	4.0	200-299	AC	602.0	2017
SERC-SE	East Walton-Jack's Creek	P	East Walton	Jack's Creek	9.0	200-299	AC	602.0	2017
SERC-SE	East Walton-Rockville	P	East Walton	Rockville	40.0	400-599	AC	3,464.0	2017
SERC-SE	Cumming-Sharon Springs	P	Cumming	Sharon Springs	7.0	200-299	AC	602.0	2018
SERC-SE	Burnt Church-Tradeport Industrial	UC	Burnt Church	Tradeport Industrial	12.0	100-120	AC	216.0	2013
SERC-SE	Daniel Siding-Burnt Church	U	Daniel Siding	Burnt Church	0.0	100-120	AC	216.0	2016
SERC-SE	Lords-Toomsboro	P	Lords	Toomsboro	4.0	100-120	AC	124.0	2014
SERC-SE	Ingram-Peeksville	P	Ingram	Peeksville	7.0	100-120	AC	216.0	2018
SERC-SE	Barry-Crist	U	Barry	Crist	0.0	200-299	AC	693.0	2015
SERC-SE	Lansing Smith-Laguna Beach	P	Lansing Smith	Laguna Beach	14.0	200-299	AC	602.0	2013
SERC-SE	Laguna Beach-Santa Rosa	P	Laguna Beach	Santa Rosa	21.0	200-299	AC	602.0	2015
SERC-SE	Lansing Smith-Laguna Beach	U	Lansing Smith	Laguna Beach	0.0	100-120	AC	301.0	2012
SERC-SE	Champion-Molino	U	Champion	Molino	0.0	100-120	AC	251.0	2012
SERC-SE	Callaway-Gaskin	U	Callaway	Gaskin	0.0	100-120	AC	216.0	2022
SERC-SE	Pine Forest-Champion	U	Pine Forest	Champion	0.0	100-120	AC	251.0	2012
SERC-SE	Pinckard-Holmes Creek	U	Pinckard	Holmes Creek	0.0	100-120	AC	336.0	2013
SERC-SE	Laguna Beach-Santa Rosa	P	Laguna Beach	Santa Rosa (2)	21.0	200-299	AC	602.0	2015
SERC-SE	Bayou Marcus-Beach Haven	U	Bayou Marcus	Beach Haven	0.0	100-120	AC	124.0	2018
SERC-SE	Wright-Sullivan	U	Wright	Sullivan	0.0	100-120	AC	251.0	2022
SERC-SE	Wright-Fort Walton	U	Wright	Fort Walton	0.0	100-120	AC	251.0	2022
SERC-SE	Wiggins SS-Wiggins 5th Ave	U	Wiggins SS	Wiggins 5th Ave	0.0	100-120	AC	216.0	2017
SERC-SE	Hattiesburg SW-Hwy 11	U	Hattiesburg SW	Hwy 11	0.0	100-120	AC	216.0	2014
SERC-SE	Hattiesburg SW-West Hattiesburg	U	Hattiesburg SW	West Hattiesburg	0.0	100-120	AC	216.0	2014
SERC-SE	Orange Grove-Chevron PRCP	P	Orange Grove	Chevron PRCP	5.0	100-120	AC	251.0	2022
SERC-SE	Orange Grove-Bayou Casotte	U	Orange Grove	Bayou Casotte	0.0	100-120	AC	251.0	2022
SERC-SE	Kemper IGCC-Lauderdale East	UC	Kemper IGCC	Lauderdale East	18.0	200-299	AC	752.0	2012
SERC-SE	Kemper IGCC-Lauderdale West	UC	Kemper IGCC	Lauderdale West	20.0	200-299	AC	752.0	2013
SERC-SE	Lauderdale East-Vimville	UC	Lauderdale East	Vimville	6.0	200-299	AC	602.0	2013
SERC-SE	Vimville-Sweatt	UC	Vimville	Sweatt	14.0	200-299	AC	602.0	2013
SERC-SE	Sweatt-Stonewall	U	Sweatt	Stonewall	0.0	100-120	AC	216.0	2012
SERC-SE	Meridian NE-Vimville	UC	Meridian NE	Vimville	9.0	100-120	AC	216.0	2014
SERC-SE	Hurricane Creek-Wiggins SS	U	Hurricane Creek	Wiggins SS	0.0	100-120	AC	216.0	2016
SERC-SE	Laurel North Amaranth-Heidelberg	U	Laurel North Amaranth	Heidelberg	0.0	100-120	AC	216.0	2014
SERC-SE	Plant Daniel-Moss Point East	U	Plant Daniel	Moss Point East	0.0	200-299	AC	865.0	2012
SERC-SE	Orange Grove-Moss Point East	U	Orange Grove	Moss Point East	0.0	200-299	AC	752.0	2022
SERC-SE	Hattiesburg North-Petal George St.	U	Hattiesburg North	Petal George St.	0.0	100-120	AC	155.0	2014
SERC-SE	Goshen-Waynesboro	U	Goshen	Waynesboro	0.0	100-120	AC	255.0	2016
SERC-SE	North Marietta-Marietta #5	U	North Marietta	Marietta #5	0.0	100-120	AC	325.0	2013
SERC-SE	Crisp #2-Crisp #8	C	Crisp #2	Crisp #8	12.0	100-120	AC	216.0	2014
SERC-SE	Bonaire Primary-Fort Valley 115kV	U	Bonaire Primary	Peach Blossum	0.0	100-120	AC	216.0	2017
SERC-SE	Prentiss-Jeff Davis SS	UC	Prentiss	Jeff Davis SS	7.0	151-199	AC	296.0	2012
SERC-SE	Moselle-South Hoy	P	Moselle	South Hoy	23.0	151-199	AC	296.0	2013
SERC-SE	Miflin Switch-Josephine TP	P	Miflin Switch	Josephine TP	5.0	100-120	AC	300.0	2013
SERC-SE	Texasville Jct-Judson	UC	Texasville Jct	Judson	16.0	100-120	AC	210.0	2012
SERC-SE	Selma Jct-Selma	P	Selma Jct	Selma	1.0	100-120	AC	86.0	2012
SERC-SE	Wayne Farms Jct-Wayne Farms	C	Wayne Farms Jct	Wayne Farms	4.0	100-120	AC	86.0	2012
SERC-SE	Owls Head Jct-Owls Head	C	Owls Head Jct	Owls Head	2.0	100-120	AC	86.0	2012
SERC-SE	Gulf Coast Airport Jct-Gulf Coast	P	Gulf Coast Airport Jct	Gulf Coast Airport	1.0	100-120	AC	86.0	2012
SERC-SE	APAC Jct-APAC	C	APAC Jct	APAC	1.0	100-120	AC	86.0	2012
SERC-SE	Millers Crossroad Jct-Millers	C	Millers Crossroad Jct	Millers Crossroad	1.0	100-120	AC	86.0	2012
SERC-SE	Freeport 230-Freeport 115	C	Freeport 230	Freeport 115	1.0	200-299	AC	586.0	2013
SERC-SE	Oak Grove-Jay	P	Oak Grove	Jay	24.0	100-120	AC	218.0	2013
SERC-SE	Gantt 230-Dublin	C	Gantt 230	Dublin	37.0	100-120	AC	218.0	2013

Assessment Area	Transmission Project Name	Status	Terminal Origin Locaction	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Current (AC/DC)	Capacity Rating (MVA)	In-Service Year
SERC-SE	Josephine TP-Florida Ave	P	Josephine TP	Florida Ave	1.0	100-120	AC	300.0	2013
SERC-SE	East Point - Willingham Dr. 115kV	U	East Point	Willingham	0.0	100-120	AC	255.0	2017
SERC-SE	McConnell Road-South Acworth	U	McConnell Road	South Acworth	0.0	100-120	AC	301.0	2020
SERC-SE	Dresden-Heard County	UC	Dresden	Heard County	6.0	400-599	AC	3,429.0	2014
SERC-SE	Barry-North Mobile	U	Barry	North Mobile (2)	0.0	100-120	AC	301.0	2016
SERC-SE	Fish River Tap-Fairhope	U	Fish River Tap	Fairhope	0.0	100-120	AC	216.0	2018
SERC-SE	Fairhope-Point Clear	U	Fairhope	Point Clear	0.0	100-120	AC	216.0	2018
SERC-SE	Ellicott TS-SSAB	P	Ellicott TS	SSAB	6.0	200-299	AC	807.0	2021
SERC-SE	SSAB-Kushla S.S.	U	SSAB	Kushla S.S.	0.0	200-299	AC	693.0	2021
SERC-SE	Ellicott TS-Georgetown D.S.	U	Ellicott TS	Georgetown D.S.	0.0	200-299	AC	693.0	2021
SERC-SE	Co line Rd-PSDF	U	Co line Rd	PSDF	0.0	200-299	AC	907.0	2019
SERC-SE	McIntosh-Yemassee	U	McIntosh	Yemassee (10)	0.0	100-120	AC	286.0	2019
SERC-SE	Vogtle-Wilson	U	Vogtle	Wilson	0.0	200-299	AC	1,018.0	2019
SERC-SE	Waynesboro-Wilson	U	Waynesboro	Wilson	0.0	200-299	AC	866.0	2020
SERC-SE	Wadley-Waynesboro	U	Wadley	Waynesboro	0.0	200-299	AC	718.0	2019
SERC-SE	East Point-Willingham Drive	U	East Point	Willingham Drive	0.0	100-120	AC	255.0	2017
SERC-SE	S. Columbus-Dawson Pri/Ft.Ben,AL	U	South Columbus	Dawson Pri/Ft. Ben, AL	0.0	100-120	AC	124.0	2015
SERC-SE	American Cyanamid-Avalon	P	American Cyanamid	Avalon	4.0	100-120	AC	251.0	2018
SERC-SE	Crist-Escambia Chemical Tap	U	Crist	Escambia Chemical Tap	0.0	100-120	AC	251.0	2013
SERC-SE	Escambia Chemical Tap-Air Products	U	Escambia Chemical Tap	Air Products	0.0	100-120	AC	251.0	2013
SERC-SE	Escambia Chemical Tap-American Cy	U	Escambia Chemical Tap	American Cyanamid	0.0	100-120	AC	251.0	2013
SERC-SE	Greenwood-Highland City	U	Greenwood	Highland City	0.0	100-120	AC	301.0	2022
SERC-SE	Highland City-Callaway	P	Highland City	Callaway	4.0	200-299	AC	602.0	2013
SERC-SE	Gaston-Yellowdirt	U	Gaston	Yellowdirt	0.0	200-299	AC	602.0	2012
SERC-SE	Bonaire-Waterford	U	Bonaire	Waterford	0.0	100-120	AC	216.0	2013
SERC-SE	Gaston-Roopville	U	Gaston	Roopville (2)	0.0	200-299	AC	602.0	2012
SERC-SE	Autaugaville 6-Autuagaville 8	P	Autaugaville 6	Autuagaville 8 (2)	1.0	200-299	AC	1,614.0	2013
SERC-SE	Enterprise-South Enterprise TS	P	Enterprise	South Enterprise TS	5.0	100-120	AC	216.0	2015
SERC-SE	Co Line Rd-ECI Prattville	P	Co Line Rd	ECI Prattville	7.0	100-120	AC	216.0	2021
SERC-SE	GKN Wesland-Hall Climate Tap	U	GKN Wesland	Hall Climate Tap	0.0	100-120	AC	216.0	2019
SERC-SE	Meridian NE-Hawkins Crossing	U	Meridian NE	Hawkins Crossing	0.0	100-120	AC	216.0	2012
SERC-SE	McManus-West Brunswick	U	McManus	West Brunswick	0.0	100-120	AC	301.0	2014
SERC-SE	Arnold Mill-Hopewell	P	Arnold Mill	Hopewell	12.0	200-299	AC	509.0	2021
SERC-SE	Highway 54 - Ebenezer Road	P	Highway 54	Ebenezer Road	6.0	100-120	AC	255.0	2019
SERC-SE	Highway 54-Tyrone	P	Highway 54	Tyrone	6.0	100-120	AC	255.0	2019
SERC-SE	Golden Springs-Cheaha Tap	U	Golden Springs	Cheaha Tap	0.0	100-120	AC	216.0	2017
SERC-SE	North Cedar Bend Tap-Rainbow City	U	North Cedar Bend Tap	Rainbow City	0.0	100-120	AC	159.0	2015
SERC-SE	Barnwell-Point Clear	U	Barnwell	Point Clear	0.0	100-120	AC	216.0	2014
SERC-SE	North Brewton TS-Crist S.P.	P	North Brewton TS	Crist S.P.	56.0	200-299	AC	907.0	2021
SERC-SE	Gorgas-Jaspter TS Tap	U	Gorgas	Jaspter TS Tap	0.0	151-199	AC	303.0	2017
SERC-SE	Jasper TS-Jasper SS	P	Jasper TS	Jasper SS	1.0	151-199	AC	303.0	2017
SERC-SE	Jasper TS-Parkland SS	U	Jasper TS	Parkland SS	0.0	151-199	AC	303.0	2017
SERC-SE	PSDF-County Line Rd	U	PSDF	County Line Rd	0.0	200-299	AC	577.0	2015
SERC-SE	PSDF-Gaston	U	PSDF	Gaston	0.0	200-299	AC	907.0	2019
SERC-SE	Greene County-North Selma	U	Greene County	North Selma	0.0	200-299	AC	907.0	2020
SERC-SE	Greenwood-Shipyard	U	Greenwood	Shipyard	0.0	100-120	AC	289.0	2021
SERC-SE	Marianna-Highland City	U	Marianna	Highland City	0.0	100-120	AC	251.0	2013
SERC-SE	Milligan Tap-Milligan	P	Milligan Tap	Milligan	1.0	100-120	AC	155.0	2012
SERC-SE	Sinai Cemetery-Woodruff Tap	U	Sinai Cemetery	Woodruff Tap	0.0	100-120	AC	320.0	2015
SERC-SE	South Crestview-Airport	P	South Crestview	Airport	5.0	100-120	AC	155.0	2013
SERC-SE	North Brewton-Crist SP	P	North Brewton	Crist SP	56.0	200-299	AC	907.0	2021
SERC-SE	Cairo #1 to Brumbley Creek	C	Cairo # 1	Brumbley Creek	4.1	100-120	AC	124.0	2013
SERC-SE	Elberton #1 to Elberton #2	C	Elberton #1	Elberton #2	2.6	100-120	AC	124.0	2014
SERC-SE	Griffin #1 to Griffin #2	C	Griffin #1	Griffin #2	1.6	100-120	AC	124.0	2014
SERC-SE	Alcovy Road to SKC	U	Alcovy Road	SKC	0.0	100-120	AC	255.0	2015
SERC-SE	Mitchell - Moultrie	U	Mitchell	Lester	0.0	100-120	AC	216.0	2015
SERC-SE	McIntosh Sw to McIntosh South	P	McIntosh Sw	McIntosh South	1.5	100-120	AC	218.0	2012
SERC-SE	Fortson to Talbot County #1	U	Fortson	Talbot County #1	0.0	200-299	AC	807.0	2016
SERC-SE	Athena to Union Point	U	Athena	Union Point	0.0	100-120	AC	216.0	2021
SERC-SE	Palmyra - Slappy Dr 115kV Line	U	Albany #2	Slappy Drive	0.0	100-120	AC	216.0	2021
SERC-SE	Bonaire-Peach Blossom	U	Bonaire	Peach Blossom	0.0	100-120	AC	216.0	2015
SERC-SE	Bowen-Cartersville	U	Bowen	Cartersville	0.0	100-120	AC	255.0	2014
SERC-SE	Cherokee Rd-Ujnion Point	U	Cherokee Rd	Ujnion Point	0.0	100-120	AC	216.0	2021
SERC-SE	Deal Branch-Sylvania	U	Deal Branch	Sylvania	0.0	100-120	AC	124.0	2016
SERC-SE	Doublas/Lakeland-Pine Grove	P	Doublas/Lakeland	Pine Grove	15.0	200-299	AC	602.0	2019
SERC-SE	Douglasville-Factory Shoals/Groover	U	Douglasville	Factory Shoals/Groover	0.0	100-120	AC	207.0	2021
SERC-SE	Douglasville-Post Road/Aneewakee	U	Douglasville	Post Road/Aneewakee	0.0	100-120	AC	255.0	2021

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SERC-SE	East Point-Camp Creek	U	East Point	Camp Creek	0.0	200-299	AC	596.0	2018
SERC-SE	First Avenue-Victory Drive	U	First Avenue	Victory Drive	0.0	100-120	AC	199.0	2015
SERC-SE	Fortson-Talbot #2	U	Fortson	Talbot #2	0.0	200-299	AC	433.0	2016
SERC-SE	Franklin Jct-Mulberry Jct	P	Franklin Jct	Mulberry Jct	14.0	200-299	AC	807.0	2015
SERC-SE	Hickory Level-W Villa Rica	U	Hickory Level	W Villa Rica	0.0	100-120	AC	216.0	2019
SERC-SE	Leach Road-Bark Camp	U	Leach Road	Bark Camp	0.0	100-120	AC	216.0	2013
SERC-SE	Ludowici Pri-West Brunswick	U	Ludowici Pri	West Brunswick	0.0	100-120	AC	216.0	2018
SERC-SE	Marietta/Roswell Rd.-Marietta #4	U	Marietta/Roswell Rd.	Marietta #4	0.0	100-120	AC	269.0	2021
SERC-SE	McIntosh-Jasper	U	McIntosh	Jasper	0.0	100-120	AC	301.0	2016
SERC-SE	Meldrim-River	U	Meldrim	River	0.0	100-120	AC	255.0	2018
SERC-SE	Statesboro Pri-Langston	U	Statesboro Pri	Langston	0.0	100-120	AC	216.0	2016
SERC-SE	Thalmann-West Brunswick	U	Thalmann	West Brunswick	0.0	200-299	AC	1,205.0	2018
SERC-SE	Thalmann SS J-Cypress Point	U	Thalmann SS J	Cypress Point	0.0	100-120	AC	216.0	2019
SERC-SE	Arnold Mill - Hopewell	P	Arnold Mill	Hopewell	12.0	200-299	AC	602.0	2021
SERC-SE	Danial Siding - Riceboro	U	Danial Siding	Riceboro	0.0	100-120	AC	216.0	2021
SERC-SE	South Acworth - Woodstock	U	South Acworth	Woodstock	0.0	100-120	AC	255.0	2020
SERC-SE	Lassiter Road - North Marietta	U	Lassiter Road	North Marietta	0.0	100-120	AC	255.0	2017
SERC-W	Acadiana Area Improvement-Phase 2	UC	Labbe	Sellers Road	15.0	200-299	AC	829.0	2012
SERC-W	Upgrade walnut Grove - Swartz	U	Walnut Grove	Swartz	0.0	100-120	AC	276.0	2012
SERC-W	Upgrade Sterlington to Log Cabin 115	U	Bastrop	Log Cabin	0.0	100-120	AC	259.0	2012
SERC-W	upgrade North Bastrop - Log Cabin	U	North Bastrop	Log Cabin	0.0	100-120	AC	178.0	2012
SERC-W	Tillatoba-South Grenada	UC	Tillatoba	South Grenada	19.0	200-299	AC	500.0	2012
SERC-W	Lakeover-Northpark	U	Lakeover	Northpark	0.0	100-120	AC	231.0	2012
SERC-W	Cedar Hill-Plantation	U	Cedar Hill	Plantation	0.0	121-150	AC	478.0	2013
SERC-W	Plantation-Conroe	U	Plantation	Conroe	0.0	121-150	AC	478.0	2013
SERC-W	Jasper-Sam Rayburn Dam	U	Jasper	Sam Rayburn Dam	0.0	121-150	AC	275.0	2013
SERC-W	Snakefarm - Kenner Upgrade Line	U	Snakefarm	Kenner	0.0	100-120	AC	360.0	2012
SERC-W	SE LA Coastal Improvement-Phase 3	P	Oakville	Alliance	10.0	200-299	AC	515.0	2012
SERC-W	Iron Man to Tezcuco 230 kV line	P	Bayou Steel	Tezcuco	10.0	200-299	AC	520.0	2018
SERC-W	Springridge Rd-Wynndale	P	Springridge Rd	Wynndale	25.0	100-120	AC	260.0	2013
SERC-W	Church Rd-Getwell	P	Church Rd	Getwell	16.0	200-299	AC	520.0	2013
SERC-W	Getwell-Senatobia Industrial	C	Getwell	Senatobia Industrial	26.0	200-299	AC	520.0	2016
SERC-W	Holland Bottoms-Hamlet	UC	Holland Bottoms	Hamlet	20.0	151-199	AC	558.0	2012
SERC-W	Jonesboro-Hergett	U	Jonesboro	Hergett	0.0	151-199	AC	246.0	2012
SERC-W	Benton North-Benton South	UC	Benton N	Benton S	6.0	100-120	AC	175.0	2012
SERC-W	Westar Transmission Service	U	Monette	Paragould	0.0	100-120	AC	246.0	2012
SERC-W	Nelson-Moss Bluff 230 kV	P	Nelson	Moss Bluff (2)	7.0	200-299	AC	779.0	2012
SERC-W	Hot Springs Hamilton-Bismarck	P	HS Hamilton	Carpenter	10.0	100-120	AC	260.0	2015
SERC-W	Arcadia-Sailes 230kV (Op.@115kV)	P	Arcadia	Sailes	15.0	100-120	AC	261.0	2019
SERC-W	Mt. Olive to Arcadia Project Phase 2	P	Mt. Olive	Arcadia	15.0	100-120	AC	261.0	2019
SERC-W	NE Louisiana Improvement - Phase 2	P	Oakridge	Dunn	15.0	100-120	AC	261.0	2013
SERC-W	Sterlington to Downsville 115 kV line	U	Sterlington	Downsville	0.0	100-120	AC	239.0	2019
SERC-W	Northeast LA Improvement - Phase 3	U	Sterlington	Dunn	0.0	100-120	AC	262.0	2017
SERC-W	NE Louisiana Improvement - Phase 1	P	Swartz	Oakridge	15.0	100-120	AC	260.0	2013
SERC-W	Golden Meadow-Leeville 115 kV	U	Golden Meadow	Leeville	0.0	100-120	AC	239.0	2013
SERC-W	Raceland	C	Raceland	Waterford	4.0	200-299	AC	519.0	2018
SERC-W	Terrabone-Humph230kV(Op.@115)	C	Terrebone	Humphrey	15.0	100-120	AC	239.0	2018
SERC-W	Valentine to Clovelly 115 kV upgrade	U	Valentine	Clovelly	0.0	100-120	AC	239.0	2017
SERC-W	Lakeover-Northpark	UC	Lakeover	Northpark (2)	12.0	100-120	AC	231.0	2012
SERC-W	China-Stowell	C	China	Stowell	18.0	121-150	AC	265.0	2018
SERC-W	China-Amelia	P	China	Amelia (2)	10.0	200-299	AC	797.0	2016
SERC-W	Eastgate-Dayton Bulk	U	Eastgate	Dayton Bulk	0.0	121-150	AC	422.0	2013
SERC-W	Grimes-Bentwater	U	Grimes	Bentwater	0.0	121-150	AC	422.0	2020
SERC-W	Grimes-Mt. Zion	U	Grimes	Mt. Zion	0.0	121-150	AC	339.0	2019
SERC-W	Mt. Zion-Huntsville	U	Mt. Zion	Huntsville	0.0	121-150	AC	340.0	2020
SERC-W	Hartburg-Chisholm Road	C	Hartburg	Chisholm Road	12.0	200-299	AC	1,039.0	2017
SERC-W	Hickory Ridge-Eastgate	U	Hickory Ridge	Eastgate	0.0	121-150	AC	422.0	2016
SERC-W	McLewis-Helbig	U	McLewis	Helbig	0.0	200-299	AC	685.0	2012
SERC-W	McLewis-Helbig	U	McLewis	Helbig	0.0	200-299	AC	785.0	2018
SERC-W	Sabine-Port Neches Bulk	U	Sabine	Port Neches Bulk	0.0	121-150	AC	422.0	2017
SERC-W	Sabine-Linde	U	Sabine	Linde	0.0	121-150	AC	422.0	2018
SERC-W	Splendora-Apollo	U	Splendora	Apollo	0.0	121-150	AC	478.0	2016
SERC-W	Toledo Bend-Newton Bulk	U	Toledo Bend	Newton Bulk	0.0	121-150	AC	265.0	2013
SERC-W	West Memphis - Birmingham Steel	U	West Memphis	Birmingham Steel	0.0	400-599	AC	2,598.0	2012
SERC-W	Sheridan South 500 kV FG Upgrade	U	Sheridan	Mabelvale	0.0	400-599	AC	2,598.0	2014
SERC-W	Sheridan South 500 kV FG Upgrade	U	Sheridan	White Bluff	0.0	400-599	AC	2,598.0	2014
SERC-W	Sheridan South 500 kV FG Upgrade	U	Sheridan	El Dorado	0.0	400-599	AC	2,598.0	2014
SERC-W	Pine Bluff Voltage Support	P	White Bluff	PB Arsenal D	0.0	200-299	AC	532.0	2015

Assessment Area	Transmission Project Name	Status	Terminal Origin Locaction	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Current (AC/DC)	Capacity Rating (MVA)	In-Service Year
SERC-W	Pine Bluff Voltage Support	P	Woodward	PB Arsenal D	0.0	200-299	AC	532.0	2015
SERC-W	Jim Hill Area Upgrades	P	Doniphan	Datto	15.0	151-199	AC	364.0	2017
SERC-W	Trumann-Trumann West - Upgrade	U	Trumann	Trumann West	0.0	151-199	AC	335.0	2016
SERC-W	Norfork-Calico Rock : Upgrade 161 kV	U	Calico Rock	Norfork	0.0	151-199	AC	335.0	2016
SERC-W	NLR Westgate - NLR Levy:	U	NLR Westgate	NLR Levy	0.0	100-120	AC	239.0	2013
SERC-W	AECC L&D 2 to Gillett 115 kV	P	L&D #2	Gillett	30.0	100-120	AC	260.0	2016
SERC-W	Calico Rock-Melbourne	U	Calico Rock	Melbourne	0.0	151-199	AC	335.0	2014
SERC-W	Woodward-WestPine Bluff	U	Woodward	Pine Bluff West	0.0	100-120	AC	319.0	2015
SERC-W	Woodward - Pine Bluff W.	U	PB McCamant	Pine Bluff West	0.0	100-120	AC	319.0	2015
SERC-W	Camden McGuire -Camden N. 115 KV	P	Camden McGuire	Camden N	4.0	100-120	AC	260.0	2014
SERC-W	LV Bagby-Reed:230kV(operate @115)	P	LV Bagby	Reed S	260.0	100-120	AC	260.0	2014
SERC-W	HS EHV - HS Industrial: Upgrade	U	HS EHV	HS Industrial	0.0	100-120	AC	239.0	2015
SERC-W	HS Industrial-HS Union Carbide:	U	HS Industrial	HS Union Carbide	0.0	100-120	AC	239.0	2015
SERC-W	HS Union Carbide - HS East	U	HS Union Carbide	HS East	0.0	100-120	AC	239.0	2015
SERC-W	Woodward-Pine Bluff Watson Chapel	U	Woodward	PB Watson Chapel	0.0	100-120	AC	390.0	2014
SERC-W	Arklahoma No. 2 to HS EHV East	U	Arklahoma	HS EHV (2)	0.0	100-120	AC	390.0	2017
SERC-W	Arklahoma No. 1 to HS EHV West	U	Aklahoma	HS EHV	0.0	100-120	AC	390.0	2017
SERC-W	Quitman to Bee Branch	U	Quitman	Bee Branch	0.0	151-199	AC	223.0	2017
SERC-W	Mabelvale - LR Kanis 115 kV	U	Mabelvale	LR Kanis	0.0	100-120	AC	266.0	2018
SERC-W	Mayflower - Morgan 115 kV Line:	U	Mayflower	Morgan	0.0	100-120	AC	398.0	2019
SERC-W	Holland Bottoms-Jacksonville N.	U	Holland Bottoms	Jacksonville N	0.0	100-120	AC	398.0	2018
SERC-W	Russellville E-Russellville N.Recon.116	U	Russellville East	Russellville North	0.0	151-199	AC	446.0	2018
SERC-W	LR West - LR Palm: Recon. 115 kV	U	LR West	LR Palm	0.0	100-120	AC	239.0	2018
SERC-W	NLR Westgate-LRGaines: Recon.115	U	NLR Westgate	LR Gaines	0.0	100-120	AC	255.0	2018
SERC-W	Paragould-Paragould S: Recon 161kV	U	Paragould	Paragould South	0.0	151-199	AC	335.0	2020
SERC-W	LR Boyle Park-LR West: Upgrades	U	LR Boyle Park	LR West	0.0	100-120	AC	260.0	2020
SERC-W	LR Mann Road - LR Chicot: Upgrades	U	LR Mann Rd	LR Chicot	0.0	100-120	AC	319.0	2020
SERC-W	Mabelvale-Bryant: Reconductor 115	U	Mabelvale	Bryant	0.0	100-120	AC	239.0	2018
SERC-W	LR South-LR Rock Creek: upgrade	U	LR South	LR Rock Creek	0.0	100-120	AC	398.0	2018
SERC-W	Upgrade Cheetah-Hot Springs Village	U	Cheetah	HS Village	0.0	100-120	AC	239.0	2018
SERC-W	LR Kanis - LR Markham: Reconductor	U	LR Kanis	LR Markham	0.0	100-120	AC	319.0	2018
SERC-W	Gum Springs to Amity	C	Gum Springs	(add breakers)Amity	40.0	100-120	AC	260.0	2018
SERC-W	Jonesboro-Jonesboro SPA Reconduct	U	Jonesboro	Jonesboro SPA	0.0	151-199	AC	546.0	2020
SERC-W	Baxter Wilson-S.E. Vicksburg	U	Baxter Wilson	S.E. Vicksburg	0.0	100-120	AC	260.0	2015
SERC-W	Franklin-McComb	P	Franklin	McComb	24.0	100-120	AC	398.0	2017
SERC-W	McComb-Tylertown	U	McComb	Tylertown	0.0	100-120	AC	199.0	2017
SERC-W	Murphy Tap-Belzoni Tap	P	Murphy Tap	Belzoni Tap	7.6	100-120	AC	108.0	2015
SERC-W	Jacinto-Splendora	U	Jacinto	Splendora	0.0	121-150	AC	478.0	2015
SERC-W	Jacinto-Cleveland	U	Jacinto	Cleveland	0.0	121-150	AC	478.0	2017
SERC-W	Toledo Bend-Leach	U	Toledo Bend	Leach	0.0	121-150	AC	265.0	2017
SERC-W	Leach-Newton Bulk	U	Leach	Newton Bulk	0.0	121-150	AC	287.0	2018
SERC-W	Sabine-Big Three	U	Sabine	Big Three	0.0	200-299	AC	685.0	2017
SERC-W	Buna-Evadale	U	Buna	Evadale	0.0	121-150	AC	287.0	2020
SERC-W	Rayburn-Mill Creek	U	Rayburn	Mill Creek	0.0	121-150	AC	287.0	2020
SERC-W	Porter-Apollo	U	Porter	Apollo	0.0	121-150	AC	286.0	2021
SERC-W	New Caney-Hickory Ridge	U	New Caney	Hickory Ridge	0.0	121-150	AC	478.0	2022
SERC-W	Amelia Bulk-Helbig	U	Amelia Bulk	Helbig	0.0	200-299	AC	785.0	2021
SERC-W	Gulfway-VFW Park	U	Gulfway	VFW Park	0.0	200-299	AC	685.0	2018
SERC-W	Moril-Delcambre	U	Moril	Delcambre	0.0	121-150	AC	251.0	2017
SERC-W	Willow Glen-Webre	U	Willow Glen	Webre	0.0	400-599	AC	1,732.0	2012
SERC-W	Bloomfield-Bosco	P	Bloomfield	Bosco	4.0	121-150	AC	250.0	2013
SERC-W	Bloomfield-Colton	C	Bloomfield	Colton	3.0	121-150	AC	225.0	2019
SERC-W	Moril-Hopkins	U	Moril	Hopkins	0.0	121-150	AC	381.0	2013
SERC-W	Champagne-Plaisance	U	Champagne	Plaisance	0.0	121-150	AC	287.0	2013
SERC-W	Gonzales-Sorrento	U	Gonzales	Sorrento	0.0	121-150	AC	260.0	2014
SPP	Hitchland Project	P	Hitchland	Moore County	50.0	200-299	AC	452.0	2012
SPP	Channing Project	P	Channing	Potter County	70.0	100-120	AC	146.0	2012
SPP	Johnson Draw	P	Johnson Draw	Amfrac/Mapco	0.1	100-120	AC	146.0	2012
SPP	Johnson Draw	P	Johnson Draw	Gaines	4.8	100-120	AC	164.0	2012
SPP	Johnson Draw	P	Taylor Switch	Johnson Draw	4.8	100-120	AC	164.0	2012
SPP	Johnson Draw	P	Higg	Johnson Draw	0.1	100-120	AC	146.0	2012
SPP	Hitchland - Ochiltree Project	P	Hitchland	Ochiltree Intg.	32.0	200-299	AC	452.0	2012
SPP	Carlsbad Ocotillo	P	Pecos	Ocotillo	5.8	100-120	AC	146.0	2012
SPP	Leighton Area Reliability Project	U	57th & Garland	84th & Leighton	0.0	100-120	AC	372.0	2012
SPP	Broken Bow to Broken Bow Wind	UC	Broken Bow	Broken Bow Wind	9.0	100-120	AC	95.0	2012
SPP	OU SW to Canadian SW 138kV	UC	OU Switchyard	Canadian Switchyard	11.0	121-150	AC	183.0	2012
SPP	Roswell-Capitan	P	Roswell Intg	Capitan Substation	5.7	100-120	AC	146.0	2012

Assessment Area	Transmission Project Name	Status	Terminal Origin Locaction	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Current (AC/DC)	Capacity Rating (MVA)	In-Service Year
SPP	Sooner to Cleveland	UC	Sooner	Cleveland	35.2	300-399	AC	1,793.0	2012
SPP	East Clovis Conversion	P	Pleasant Hill	Curry County	1.5	100-120	AC	146.0	2012
SPP	Anadarko SW 138 kV	UC	Anadarko SW	Georgia Tap	5.0	121-150	AC	212.0	2012
SPP	Sunnnyside to Hugo	UC	Sunnyside	Hugo	120.0	300-399	AC	1,793.0	2012
SPP	Johnston County	UC	Caney Creek	Johnston County	25.0	121-150	AC	287.0	2012
SPP	ALP	UC	Bonin	Labbe	1.4	200-299	AC	693.0	2012
SPP	Heizer to Mullegren	P	Heizer	Mullegren	0.3	100-120	AC	Uknown	2012
SPP	Clay Center Jct-New Clay Center	UC	Clay Center Jct	New Clay Center SS	8.8	100-120	AC	262.0	2012
SPP	KSU-North Manhattan-Wildcat 115kV	UC	KSU-Wildcat	North Manhattan	2.0	100-120	AC	262.0	2012
SPP	Turk to NW Texarkana	UC	Turk	NW Texarkana	33.0	300-399	AC	1,336.0	2012
SPP	Massard - Oak Park	UC	Massard	Oak Park	0.5	121-150	AC	194.0	2012
SPP	Franklin SW to OU SW 138kV	UC	Franklin Switchyard	OU Switchyard	22.0	121-150	AC	183.0	2012
SPP	Rose Hill-Sooner 345kV	UC	Rose Hill	Sooner	100.0	300-399	AC	1,882.0	2012
SPP	Twin Church to South Sioux City	UC	Twin Church	South Sioux City	11.0	100-120	AC	240.0	2012
SPP	Twin Church to South Sioux City	UC	Twin Church	South Sioux City	7.0	100-120	AC	240.0	2012
SPP	GI L1369	P	Substation F	St. Libory Junction	7.0	100-120	AC	180.0	2012
SPP	Gill W-Waco 138kV	UC	Gill W	Waco	1.9	121-150	AC	314.0	2012
SPP	Reeding to Twin Lakes	UC	Reeding	Twin Lakes Switchyard	7.0	121-150	AC	144.0	2012
SPP	Meeker to Hammett 138kV	P	Meeker Switchyard	Hammett Substation	10.0	121-150	AC	183.0	2013
SPP	Central Lincoln Reliability Project	UC	17th & Holdrege	21st & N	1.3	100-120	AC	179.0	2013
SPP	Central Lincoln Reliability Project	R	20th & Pioneers	29th & Leighton	0.0	100-120	AC	121.0	2013
SPP	Central Lincoln Reliability Project	UC	21st & N	30th & A	1.5	100-120	AC	179.0	2013
SPP	Central Lincoln Reliability Project	UC	30th & A	56th & Everett	2.5	100-120	AC	186.0	2013
SPP	Randall County Intg.	P	Randall County	Amarillo South	8.5	200-299	AC	452.0	2013
SPP	Cherry St. Intg.	P	Harrington	Cherry St. Intg.	5.3	200-299	AC	452.0	2013
SPP	Cherry St. Intg.	P	Nichols	Cherry St. Intg.	6.4	100-120	AC	146.0	2013
SPP	Cherry St. Intg.	P	Cherry St. Intg.	Cherry St. substation	0.1	100-120	AC	146.0	2013
SPP	Pleasant Hill	P	Pleasant Hill	Curry County	0.2	100-120	AC	146.0	2013
SPP	Pleasant Hill	P	Pleasant Hill	Curry County	3.0	100-120	AC	146.0	2013
SPP	McAlester City to Dustin	P	McAlester City	Dustin	6.0	121-150	AC	321.0	2013
SPP	Cherry St. Intg.	P	Cherry St. Intg.	Hastings	4.0	100-120	AC	146.0	2013
SPP	Cherry St. Intg.	P	East Plant	Hastings	4.9	100-120	AC	146.0	2013
SPP	Goodyear-MacVicar-17th&Fairlawn	P	Goodyear	MacVicar	4.0	100-120	AC	262.0	2013
SPP	Seminole to Muskogee	UC	Seminole	Muskogee	100.0	300-399	AC	1,793.0	2013
SPP	Newhart Intg.	P	Potter County	Newhart Intg.	68.0	200-299	AC	452.0	2013
SPP	Cherry St. Intg.	P	Cherry St. Intg.	Northwest	8.3	100-120	AC	146.0	2013
SPP	Pleasant Hill	P	Pleasant Hill	Norton	0.2	100-120	AC	146.0	2013
SPP	Osbourne to Osbourne Tap	P	Osbourne	Osbourne Tap	2.0	151-199	AC	512.0	2013
SPP	Fairfax-Pawnee	P	Fairfax KAMO	Pawnee Sw. Station	16.3	121-150	AC	305.0	2013
SPP	Newhart Intg.	P	Newhart Intg.	Plant X	36.0	200-299	AC	452.0	2013
SPP	Axtell to Post Rock	UC	Axtell	Post Rock	125.0	300-399	AC	1,792.0	2013
SPP	Cherry St. Intg.	P	Cherry St. Intg.	Potter County	6.0	200-299	AC	452.0	2013
SPP	OG&E Renfrow interconnect	P	Wakita	Renfrow	25.0	121-150	AC	106.0	2013
SPP	Muncie to Armourdale Line	P	Muncie Substation	Armourdale Substation	0.1	151-199	AC	318.0	2013
SPP	Muncie to Center City Line	P	Muncie Substation	Center City Substation	0.1	151-199	AC	318.0	2013
SPP	Clarks to Central City No.	P	Clarks	Central City No.	12.0	100-120	AC	80.0	2014
SPP	TransCanada-Burns 138kV	P	Burns Tap	TC-Burns	9.0	121-150	AC	314.0	2014
SPP	TransCanada-Riley 115kV	P	New Clay Center SS	TC-Riley	10.0	100-120	AC	262.0	2014
SPP	Pleasant Hill	P	Pleasant Hill	FEC Clovis (Intg. #3)	3.0	100-120	AC	146.0	2014
SPP	Newhart Intg.	P	Newhart	Kress	18.0	100-120	AC	146.0	2014
SPP	Goodyear-MacVicar-17th&Fairlawn	P	MacVicar	17th & Fairlawn	4.0	100-120	AC	262.0	2014
SPP	Woodward EHV to Border	P	Woodward EHV	Border	72.0	300-399	AC	1,793.0	2014
SPP	Plainview City	P	Plainview City	Cox	10.0	100-120	AC	146.0	2014
SPP	Shipe Road to E. Centerton	P	Shipe Road	E. Centerton	9.0	151-199	AC	512.0	2014
SPP	Border to Hitchland	P	Border Substation	Hitchland	220.0	300-399	AC	3,586.0	2014
SPP	Woodward EHV to Hitchland	P	Woodward EHV	Hitchland	13.5	300-399	AC	1,793.0	2014
SPP	Newhart Intg.	P	Newhart	Lamton	19.0	100-120	AC	146.0	2014
SPP	Woodward EHV to Medicine Lodge	P	Woodward EHV	Medicine Lodge	115.0	300-399	AC	1,793.0	2014
SPP	Valliant to NW Texarkana	P	Valliant	NW Texarkana	76.0	300-399	AC	1,793.0	2014
SPP	Hitchland-Woodward	P	Hitchland	OGE Woodward Sub.	30.0	300-399	AC	1,800.0	2014
SPP	TUCO-Woodward	P	TUCO	OGE Woodward Sub.	180.0	300-399	AC	1,355.0	2014
SPP	Plainview City	P	Kress Intg.	Plainview City	18.0	100-120	AC	146.0	2014
SPP	Flint Creek to Shipe Road	P	Flint Creek	Shipe Road	18.0	300-399	AC	1,336.0	2014
SPP	Newhart Intg.	P	Newhart Intg.	Swisher County	19.0	200-299	AC	452.0	2014
SPP	Newhart Intg.	P	Newhart	Castro	24.0	100-120	AC	146.0	2014
SPP	Wolcott to Nearman Line	P	Wolcott Substation	Nearman Substation	5.0	151-199	AC	1,170.0	2014
SPP	SW Reliability Project	P	SW 7th & Bennet	40th & Rokeby	5.4	100-120	AC	372.0	2015

Assessment Area	Transmission Project Name	Status	Terminal Origin Locaction	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Current (AC/DC)	Capacity Rating (MVA)	In-Service Year
SPP	GREENWOOD-LONEJACK	P	GREENWOOD	LONE JACK	4.7	151-199	AC	233.0	2015
SPP	IATAN-NASHUA	P	IATAN	NASHUA	30.0	300-399	AC	2,546.0	2015
SPP	Stegall / WAPA to Stegall/BEPC	P	Stegall / WAPA	Stegall/ BEPC	3.3	200-299	AC	Unknown	2015
SPP	Kinsley	C	Kinsley	various options	35.0	100-120	AC	Unknown	2015
SPP	Monett	P	Monett Sub #383	South of Monett, MO	9.2	151-199	AC	268.0	2016
SPP	Shipe Road to E. Rogers	P	Shipe Road	E. Rogers	9.0	300-399	AC	1,336.0	2016
SPP	E. Rogers to Osage Creek	P	E. Rogers	Osage Creek	32.0	300-399	AC	1,336.0	2016
SPP	Fisher to Barber Substation	C	Fisher Substation	Barber Substation	2.5	151-199	AC	1,170.0	2016
SPP	Kaw to Barber Transmission Line	C	Kaw Substation	Barber Substation	2.0	151-199	AC	585.0	2016
SPP	Speaker to Kaw Transmission Line	C	Speaker Substation	Kaw Substation	3.0	151-199	AC	585.0	2016
SPP	Kaw-West to Speaker Line	C	Kaw-West Sub	Speaker Sub	4.0	151-199	AC	585.0	2016
SPP	CEDARNILES-CLARE	P	CEDAR NILES	CLARE	4.8	151-199	AC	293.0	2017
SPP	SIBLEY-MARYVILLE	P	SIBLEY	MARYVILLE	105.0	300-399	AC	1,792.0	2017
SPP	MARYVILLE-NEBRASKA	P	MARYVILLE	NEBRASKA	70.0	300-399	AC	1,792.0	2017
SPP	Speaker to Everett Transmission Line	C	Speaker Substation	Everett Substation	3.0	151-199	AC	585.0	2017
SPP	Everett to Quindaro Line	C	Everett Substation	Quindaro Substation	4.5	151-199	AC	585.0	2017
SPP	Woodward EHV to Woodring	C	Woodward EHV	Woodring	95.0	300-399	AC	1,793.0	2020
SPP	Twin Lakes to OG&E Crescent 138kV	UC	Twin Lakes Switchyard	OG&E Crescent Sub.	7.0	121-150	AC	183.0	2012
SPP	Anadarko SW to Washita	UC	Anadarko SW	Washita	1.0	121-150	AC	183.0	2012
SPP	Loco SW to Healdton-Butler Jct.	P	Loco SW	Healdton-Butler Jct.	13.0	121-150	AC	183.0	2013
SPP	Elk City to Russell SW 138kV	P	Elk City Substation	Russell Switchyard	46.0	121-150	AC	183.0	2015
SPP	Cache to Grandfield 138kV	P	Cache Switchyard	Grandfield Switchyard	58.0	121-150	AC	183.0	2016
SPP	Anadarko to OU	P	Anadarko Switchyard	OU Switchyard	11.1	121-150	AC	106.0	2016
SPP	Snyder SW to Paradise	P	Snyder Switchyard	Paradise Substation	9.9	121-150	AC	183.0	2016
SPP	South Joplin	P	Stateline #439	Reinmiller #393	12.0	151-199	AC	428.0	2017
SPP	Snyder SW to Russell	P	Snyder Switchyard	Russell Switchyard	44.0	121-150	AC	106.0	2017
SPP	Anadarko to Paradise	P	Anadarko Switchyard	Paradise Substation	40.0	121-150	AC	212.0	2018
WECC-US	Sundance–Pinal Central 230 kV Line	P	Coolidge	Coolidge	6.0	200-299	AC	1,200.0	2014
WECC-US	Sun Valley – Trilby Wash 230 kV Line	P	Buckeye AZ	Surprise AZ	15.0	200-299	AC	1,200.0	2014
WECC-US	TS2– Palm Valley 230 kV Line	P	Surprise AZ	Goodyear AZ	12.0	200-299	AC	1,200.0	2015
WECC-US	TS2– Trilby Wash 230 kV Line	P	Surprise AZ	Surprise AZ	12.0	200-299	AC	1,200.0	2015
WECC-US	North Gila - TS8 230 kV Line	P	Yuma AZ	Yuma AZ	11.0	200-299	AC	Unknown	2014
WECC-US	Delaney - Palo Verde 500 kV Line	P	Maricopa Co. AZ	Wintersburg AZ	15.0	400-599	AC	1,000.0	2013
WECC-US	Palo Verde - North Gila 500 kV line	P	Wintersburg AZ	Yuma AZ	115.0	400-599	AC	1,200.0	2014
WECC-US	Sun Valley – Morgan 500 kV Line	P	Buckeye AZ	Peoria AZ	40.0	400-599	AC	1,200.0	2016
WECC-US	Delaney - Sun Valley 500 kV Line	P	Maricopa Co. AZ	Buckeye AZ	28.0	400-599	AC	Unknown	2014
WECC-US	West Station-Portland #2 115	P	West Station 115 kV bus	Portland 115 kV bus	16.0	100-120	AC	222.0	2012
WECC-US	Reader-Rattlesnake Butte 115 kV Line	P	Reader 115 Sub	Rattlesnake Butte115Sub	36.0	100-120	AC	222.0	2012
WECC-US	Baculite Mesa-Overton 115kV rebuild	P	Baculite Mesa 115 kV	Overton 115 kV bus	4.0	100-120	AC	222.0	2012
WECC-US	Pueblo-West Station 115 kV Rebuild	P	Pueblo 115 kV bus	West Station 115 kV bus	5.0	100-120	AC	222.0	2013
WECC-US	Greenhorn-Reader 115 kV Rebuild	P	Greenhorn 115 kV bus	Reader 115 kV bus	5.0	100-120	AC	222.0	2013
WECC-US	La Junta Interconnect	P	La Junta BHCE 115 kV	La Junta TSGT 115 kV bus	1.0	100-120	AC	222.0	2014
WECC-US	Teckla-Osage 230 kV line	P	Teckla 230 kV bus	Osage 230 kV bus	60.0	200-299	AC	554.0	2014
WECC-US	Osage-Lange 230 kV line	P	Osage 230 kV bus	Lange 230 kV bus	75.0	200-299	AC	554.0	2015
WECC-US	Lower Monumental-Central Fer	P	Clyde, WA	Central Ferry, WA	38.0	400-599	AC	3949/4936	2022
WECC-US	Big Eddy-Knight 500kV	P	The Dalles, OR	Goldendale, WA	28.0	400-599	AC	3949/4936	2013
WECC-US	Castle Rock-Troutdale 500 kV line	P	Castle Rock, WA	Troutdale, OR	70.0	400-599	AC	Unknown	2015
WECC-US	Rocky Reach-Chelan #1 Rebuild	C	Rocky Reach	Chelan #1	29.0	100-120	AC	Unknown	2021
WECC-US	Entiat Valley Tap	P	Entiat	Crum Canyon	7.5	100-120	AC	281.0	2012
WECC-US	Happy Jack-North Range 115 kV Line	P	Happy Jack Sub	North Range Sub	1.0	100-120	AC	222.0	2012
WECC-US	Corlett-Swan Ranch 115 kV Line	P	Corlett Sub	Swan Ranch Sub	3.0	100-120	AC	222.0	2013
WECC-US	Swan Ranch-Cheyenne South 115 kV	P	Swan Ranch Sub	Cheyenne South Sub	6.0	100-120	AC	222.0	2013
WECC-US	Pump Station No.9	P	New Bowdoin Sub	Pump Station No. 9	48.0	100-120	AC	150.0	2012
WECC-US	Douglas-Rapids 230-kV Line	P	Douglas Switchyard	Rapids Switchyard	15.0	200-299	AC	555.0	2013
WECC-US	Afton-Airport-Jornada 115 kV Line	C	Las Cruces, NM	Las Cruces, NM	30.0	100-120	AC	156.6	2015
WECC-US	Santa Teresa-Montoya 115 kV Line	P	El Paso, Tx	El Paso,Tx	10.3	100-120	AC	156.6	2012
WECC-US	Organ (LE1)-Arroyo 115 kV Line	P	Las Cruces, NM	Las Cruces, NM	6.6	100-120	AC	156.6	2012
WECC-US	Organ (LE1)-Jornada 115 kV Line	P	Las Cruces, NM	Las Cruces, NM	6.6	100-120	AC	156.6	2012
WECC-US	Wheeler Rd Tap-Ruff Reconductor	C	Sand Dunes Larson	Ruff Tap	8.0	100-120	AC	202.0	2012
WECC-US	Rocky Ford Dover 115 kV	C	Rocky Ford	Larson (Dover)	8.5	100-120	AC	202.0	2014
WECC-US	Wanapum _ Priest Rapids Mid Way	C	Wanapum	Midway	23.9	200-299	AC	797.0	2018
WECC-US	Columbia Rocky Ford 230 kV line	C	Columbia	Larson	30.5	200-299	AC	797.0	2013
WECC-US	Hemingway-Boardman Transm	C	Walters Ferry, ID	Bowmont, ID	13.0	200-299	AC	565.0	2016
WECC-US	Gateway West Transm.	C	Shoshone, ID	Pocatello, ID	0.0	300-399	AC	1,386.0	2019
WECC-US	Gateway West Transm.	C	American Falls, ID	Pocatello, ID	32.0	300-399	AC	1,386.0	2019
WECC-US	Gateway West Transm.	C	Shoshone, ID	Pocatello, ID	0.0	300-399	AC	2,079.0	2019
WECC-US	Gateway West Transm.	C	Shoshone, ID	American Falls, ID	84.0	400-599	AC	3,000.0	2019

Assessment Area	Transmission Project Name	Status	Terminal Origin Locaction	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Current (AC/DC)	Capacity Rating (MVA)	In-Service Year
WECC-US	Gateway West Transm.	C	Shoshone, ID	Walters Ferry, ID	126.0	400-599	AC	3,000.0	2021
WECC-US	Gateway West Transm.	C	Hollister, ID	Shoshone, ID	34.0	400-599	AC	3,000.0	2019
WECC-US	Gateway West Transm.	C	Hollister, ID	Walters Ferry, ID	161.0	400-599	AC	3,000.0	2019
WECC-US	Gateway West Transm.	C	Downey, ID	American Falls, ID	55.0	400-599	AC	3,000.0	2019
WECC-US	Hemingway-Boardman Transm	C	Walters Ferry, ID	Boardman, OR	300.0	400-599	AC	3,000.0	2016
WECC-US	Midpoint-Boise Bench: Loop Justice	P	Midpoint, ID	DRAM, ID	0.0	200-299	AC	351.0	2012
WECC-US	Midpoint-Boise Bench: Loop Justice	P	Midpoint, ID	King, ID	24.0	200-299	AC	351.0	2012
WECC-US	Midpoint-Boise Bench: Loop Justice	P	King, ID	DRAM, ID	80.0	200-299	AC	351.0	2012
WECC-US	Langley Gulch Generation Project	UC	S. of New Plymouth, ID	Caldwell, ID	20.0	121-150	AC	339.0	2012
WECC-US	Barren Ridge Renewable	C	Barren Ridge CA	Rinaldi CA	76.0	200-299	AC	650.0	2015
WECC-US	Barren Ridge Renewable	C	Haskell CA	Castaic CA	12.0	200-299	AC	950.0	2015
WECC-US	Barren Ridge Renewable	C	Barren Ridge CA	Haskell CA	61.0	200-299	AC	950.0	2015
WECC-US	Scattergood-Olympic 230kV Line 1	P	Scattergood Gen St.	Olympic Receiving Station	12.0	200-299	AC	500.0	2014
WECC-US	Los Alamos Service Area Cap.Upgrade	C	Norton	STA	12.0	100-120	AC	285.0	2015
WECC-US	Hooper Springs-Lanes Creek 115 kV	P	Caribu County, ID	Caribu County, ID	32.0	121-150	AC	Unknown	2014
WECC-US	Montana Alberta Tie Line	P	120S	Montana	326.0	200-299	AC	300.0	2012
WECC-US	VARS (Thunderbird - Iron Mt. #1)	C	Las Vegas NV	Las Vegas NV	16.0	200-299	AC	810.0	2018
WECC-US	VARS (Harry Allen - NW fold #1)	C	Las Vegas NV	Las Vegas NV	1.0	200-299	AC	810.0	2018
WECC-US	VARS project (NW - Iron Mt. #1)	C	Las Vegas NV	Las Vegas NV	16.0	200-299	AC	810.0	2018
WECC-US	Mead - Amaragosa 500kV	C	Boulder City NV	Lathrop WellsNV	110.0	400-599	AC	3,000.0	2012
WECC-US	Harry Allen - Northwest #2 500kV	C	Las Vegas NV	Las Vegas NV	28.0	400-599	AC	3,000.0	2018
WECC-US	Northwest - Amargosa 500kV	C	Las Vegas NV	Lathrop WellsNV	75.0	400-599	AC	3,000.0	2014
WECC-US	VEA/NVE230kV Intercon@ NW	P	Las Vegas NV	Mercury NV	75.0	200-299	AC	1,200.0	2012
WECC-US	Sunrise500kV(Sunrise-Winterwood 1	P	Las Vegas NV	Las Vegas NV	1.0	200-299	AC	1,200.0	2018
WECC-US	Sunrise500kV(Sunrise-Winterwood 2	P	Las Vegas NV	Las Vegas NV	1.0	200-299	AC	1,200.0	2018
WECC-US	Sunrise 500kV(Sunrise - Equestrian #1	P	Las Vegas NV	Las Vegas NV	18.0	200-299	AC	810.0	2018
WECC-US	Sunrise 500kV(Sunrise - Equestrian #2	P	Las Vegas NV	Las Vegas NV	18.0	200-299	AC	810.0	2018
WECC-US	Sunrise 500kV(Sunrise - Clark #1)	P	Las Vegas NV	Las Vegas NV	4.0	200-299	AC	810.0	2018
WECC-US	Pecos - Brooks 230 kV Line	P	Las Vegas NV	Las Vegas NV	5.0	200-299	AC	810.0	2018
WECC-US	Sunrise 500 kV (Mead-HA fold #1)	P	Las Vegas NV	Las Vegas NV	8.0	400-599	AC	3,000.0	2018
WECC-US	Sunrise 500 kV (Mead - HA fold #2)	P	Las Vegas NV	Las Vegas NV	8.0	400-599	AC	3,000.0	2018
WECC-US	Harry Allen / Eldorado 500kV #1	P	Las Vegas NV	Las Vegas NV	0.0	400-599	AC	Unknown	2015
WECC-US	Harry Allen / Eldorado 500kV #3	P	Las Vegas NV	Las Vegas NV	0.0	400-599	AC	Unknown	2016
WECC-US	Path 18 46 MW Upgrade	P	Mill Creek, MT	AMPS Substation, ID	0.0	200-299	AC	337 - 383	2013
WECC-US	Mountain States Trans. Intertie(MSTI)	P	Townsend, MT	Midpoint, ID	460.0	400-599	AC	1,500.0	2017
WECC-US	500 kV Upgrade	P	Broadwater or Colstrip	Garrison- BPA Existing	0.0	400-599	AC	2200/3000	2017
WECC-US	Tonasket/Aeneas 115-KV Line	C	Tonasket Switchyard	Aeneas Substation	16.1	100-120	AC	100.0	2013
WECC-US	So. Pateros-Twisp 115-kV Line	P	Watson Draw Tap Switch	Gold Creek Substation	13.7	100-120	AC	100.0	2013
WECC-US	No. Pateros-Twisp 115-kV Line	P	Gold Creek Substation	Twisp Switchyard	14.5	100-120	AC	100.0	2013
WECC-US	Red Butte/Central to St George	P	Central, UT	St.George,UT	20.0	121-150	AC	600.0	2019
WECC-US	Windstar-Aeolus 230 kV #1 line	P	Windstar,WY	Carbon County, WY	76.0	200-299	AC	888.0	2015
WECC-US	Windstar-Aeolus 230 kV #2 line	P	Windstar,WY	Carbon County, WY	122.0	200-299	AC	888.0	2015
WECC-US	DJ-Aeolus 230 kV line rebuild w/1272	P	Aeolus, WY	Dave Johnston Sub.,WY	70.0	200-299	AC	888.0	2015
WECC-US	Three Peaks-Hurricane-St George 345	P	Sigurd, UT	Hurricane, Utah	170.0	300-399	AC	1,163.0	2019
WECC-US	Clover-Limber 500 kV at 345 kV	P	Mona, UT	Tooele County,UT	65.0	300-399	AC	3,681.5	2013
WECC-US	Limber-Oquirrh 2-345 kV lines	P	Tooele County, UT	South Jordan, UT	32.0	300-399	AC	1,396.0	2013
WECC-US	Sigurd-Red Butte 345 kV #2 line	P	Sigurd, UT	Central,UT	165.0	300-399	AC	1,163.0	2014
WECC-US	Oquirrh-Terminal 345 kV line	P	South Jordan, UT	SLC,UT	28.0	300-399	AC	1,332.0	2014
WECC-US	Aeolus-Clover 500 kV line#1	P	Carbon County, WY	Mona, UT	400.0	400-599	AC	3,681.5	2018
WECC-US	Aeolus-Anticline/Bridger 500 kV #1	P	Carbon County, WY	Rock Springs, WY	154.0	400-599	AC	3,681.5	2015
WECC-US	Anticline/Bridger-Populus 500 kV #1	P	Rock Springs, WY	Downey, ID	203.0	400-599	AC	3,681.5	2015
WECC-US	Wallula to McNary 230 kV Line	P	Wallula	McNary	30.0	200-299	AC	500.0	2013
WECC-US	Vantace to Pomona	P	Vantage	Pomona Heights	40.0	200-299	AC	500.0	2013
WECC-US	Embarcadero-Potrero 230kV (T1032)	C	Embarcadero	Potrero	3.0	200-299	AC	Unknown	2012
WECC-US	Midway-Morro Bay 230kV (T1093A)	C	Midway	San Luis Obispo Solar	68.0	200-299	AC	Unknown	2012
WECC-US	Rio Oso-Atlantic (T1001)	C	Rio Oso	Gold Hill	28.5	200-299	AC	Unknown	2012
WECC-US	Tesla-Newark 230kV Path (T670A)	C	Telsa Substation	Newark Substation	54.0	200-299	AC	1,366.0	2013
WECC-US	Bay Area Bulk Project (T073)	C	Collinsvills, CA	Pittsburg, CA	8.0	200-299	AC	800/2146	2016
WECC-US	Contra Costa - Moraga 230kV (T991)	C	Contra Costa Sub.	Moraga Substation	54.0	200-299	AC	683.0	2014
WECC-US	Pittsburg - Tesla 230kV (T984)	C	Pittsburg Substation	Telsa Substation (	62.0	200-299	AC	683.0	2014
WECC-US	Vaca Dixon - Lakeville 230kV (T603B)	C	Vaca Dixon (Vacaville)	Lakeville Sub. (Petaluma)	80.0	200-299	AC	658.0	2014
WECC-US	CAN/PAC NW– N Cal. (T1051)	C	Selkirk BC	Collinsville CA	2,500.0	400-599	AC	3,000.0	2016
WECC-US	Central California Clean Energy(T971)	C	Bakersfield, Ca	Fresno, Ca	280.0	400-599	AC	2,146.0	2017
WECC-US	Atwater-Merced Reliability (T1026)	P	Cressey	Gallo	12.0	100-120	AC	Unknown	2012
WECC-US	Bay Meadows 4/0 Cu (T249)	P	San Mateo	Bay Meadows	4.5	100-120	AC	Unknown	2012
WECC-US	Gold Hill - Horseshoe (T444D)	P	Placer	Horseshoe	16.0	100-120	AC	Unknown	2012
WECC-US	Midway - Renfro 115 kV (T1090)	P	Midway	Renfro	33.0	100-120	AC	Unknown	2012
WECC-US	Missouri Flat - Gold Hill (T444C)	P	Missouri Flat	Gold Hill	25.0	100-120	AC	Unknown	2012

Assessment Area	Transmission Project Name	Status	Terminal Origin Locaction	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Current (AC/DC)	Capacity Rating (MVA)	In-Service Year
WECC-US	S. San Matero Cap Increase (T920A)	P	Ames	Ravenswood&San Matero	44.0	100-120	AC	Unknown	2014
WECC-US	Newark - Ravenwood (T982)	P	Newark Substation)	Ravenswood Substation	18.0	200-299	AC	1,366.0	2014
WECC-US	Horizon Phase 1	P	Horizon	Keeler	1.5	200-299	AC	900.0	2012
WECC-US	Blue Lake - Gresham 230 kV Line	P	Blue Lake	Gresham	6.1	200-299	AC	900.0	2017
WECC-US	Cascade Crossing	P	Coyote Springs	Bethel	200.0	400-599	AC	1,500.0	2017
WECC-US	Sandia-North Line	C	North	Montano	2.3	100-120	AC	200.0	2014
WECC-US	Rio Puerco P. 2 bisection@Rio Puerco	P	San Juan	B-A	0.0	300-399	AC	Unknown	2014
WECC-US	Dixon - Horseshoe 230 kV Line	UC	Fort Collins CO	Loveland CO	10.0	200-299	AC	472.0	2012
WECC-US	Eldorado - Plainview 115kV	P	Eldorado	Plainview	4.0	100-120	AC	150.0	2013
WECC-US	Niwot - Gunbarrel 230kV	P	Niwot	Gunbarrel	2.3	200-299	AC	Unknown	2012
WECC-US	Rifle - Parachute	P	Rifle	Parachute	21.0	200-299	AC	576.0	2015
WECC-US	Pawnee - Daniels Park 345kV	P	Pawnee	Daniels Park	124.0	300-399	AC	1,200.0	2018
WECC-US	Kitsap County	P	Manchester WA	Long Lake WA	0.3	100-120	AC	320.0	2012
WECC-US	Pierce County	P	Sumner WA	Puyallup WA	3.0	100-120	AC	Unknown	2012
WECC-US	Kitsap County	P	Manchester WA	Poulsbo WA	15.0	100-120	AC	Unknown	2018
WECC-US	Whatcom County	P	Sumas WA	Everson WA	10.0	100-120	AC	314.0	2018
WECC-US	Whatcom County	P	Ferndale WA	Custer WA	8.0	100-120	AC	Unknown	2018
WECC-US	King County	P	Kenmore WA	Kirkland WA	4.0	100-120	AC	Unknown	2021
WECC-US	North King County	P	Kirkland WA	Sammamish WA	5.2	100-120	AC	314.0	2013
WECC-US	South King County	P	Sumner WA	Auburn WA	2.3	100-120	AC	314.0	2017
WECC-US	South King County	P	Sumner WA	Auburn WA	2.5	100-120	AC	314.0	2017
WECC-US	South King County	P	Federal Way WA	Puyallup WA	6.3	100-120	AC	314.0	2017
WECC-US	South King County	P	Berrydale WA	Enumclaw WA	18.0	100-120	AC	314.0	2017
WECC-US	Pierce and Thurston Counties	P	Puyallup WA	Lacey WA	15.0	100-120	AC	314.0	2015
WECC-US	Thurston County	P	Lacey WA	Yelm WA	15.0	100-120	AC	Unknown	2015
WECC-US	King County	P	Renton WA	Bellevue WA	7.0	100-120	AC	314.0	2017
WECC-US	King County	P	Berrydale WA	Snoqualmie WA	10.0	100-120	AC	314.0	2017
WECC-US	Thurston County	P	Lacey WA	Lacey WA	10.0	200-299	AC	Unknown	2013
WECC-US	Pierce County	P	Sumner WA	Puyallup WA	8.0	200-299	AC	733.0	2014
WECC-US	King County	P	Sammamish WA	Renton WA	16.0	200-299	AC	Unknown	2017
WECC-US	Kitmat Kemano (35%) Series Comp.	P	Kitimat, BC	Kemano, BC	0.0	200-299	AC	Unknown	2014
WECC-US	Devers - Mirage 230 kV	C	Palm Springs CA	Mirage CA	15.0	200-299	AC	1,240.0	2019
WECC-US	Eldorado-Ivanpah Transmission (EITP)	C	Boulder City NV	Primm NV	35.0	200-299	AC	Unknown	2013
WECC-US	Colorado River - Devers 500 kV	C	Colorado River CA	Devers CA	115.0	400-599	AC	2,700.0	2013
WECC-US	Devers - Valley 500 kV	C	Valley CA	Devers CA	42.0	400-599	AC		2013
WECC-US	San Joaquin Cross Valley Loop	P	Rector CA	Springville CA	38.0	200-299	AC	3,230.0	2014
WECC-US	Tehachapi Renewable Segments 4-11	P	Tehachapi CA	Mira Loma CA	250.0	400-599	AC	3,950.0	2015
WECC-US	Sunrise Powerlink (-Sycamore 230kV)	UC	Suncrest	Sycamore Canyon	28.0	200-299	AC	1,326.0	2012
WECC-US	Sunrise Powerlink	UC	Suncrest	Sycamore Canyon	28.0	200-299	AC	1,326.0	2012
WECC-US	Sunrise Powerlink (IV-Central 500kV)	UC	Imperial Valley	Suncrest	91.0	400-599	AC	2,598.0	2012
WECC-US	Dixie-Oreana RTI Zone1 Collector 345	C			301.0	300-399	AC	1,000.0	2016
WECC-US	Blackhawk - Amaragosa 500kV	C	Carson City, NV	Las Vegas NV	265.0	400-599	AC	3,000.0	2018
WECC-US	Robinson - Midpoint 500kV (GBT)	C	Twin Falls ID	Ely NV	280.0	400-599	AC	3,000.0	2014
WECC-US	Cal Sub - Bordertown 120kV	P	Bordertown, NV	Verdi, CA	12.0	100-120	AC	200.0	2014
WECC-US	Carson Lake	P	Carson Lake, NV	Fallon, NV	20.0	200-299	AC	200.0	2013
WECC-US	East Tracy – Blackhawk 345 kV Line	P	Reno NV	Dayton NV	17.0	300-399	AC	600.0	2012
WECC-US	Tracy-Ft. Sage 345 kV Line	P	Reno NV	Doyle CA	50.0	300-399	AC	600.0	2018
WECC-US	Robinson - Harry Allen 500 kV Line	P	Ely NV	Las Vegas NV	250.0	400-599	AC	3,000.0	2013
WECC-US	Robinson - Eldorado 500kV Line (GBT)	P	Ely NV	Boulder City NV	230.0	400-599	AC	3,000.0	2014
WECC-US	Blackhawk- Mira Loma 345 kV Line	P	Dayton NV	Reno NV	15.0	300-399	AC	600.0	2018
WECC-US	Ball to Pfister	P	Gilbert AZ	Queen Creek AZ	8.0	200-299	AC	875.0	2019
WECC-US	Southeast Valley Project	P	Maricopa AZ	Mesa AZ	0.0	200-299	AC	1,405.0	2014
WECC-US	Pfister to Abel	P	Queen Creek AZ	Florence AZ	12.0	200-299	AC	875.0	2014
WECC-US	Desert Basin-Pinal South Project	P	Casa Grande, AZ	Coolidge AZ	21.0	200-299	AC	833.0	2014
WECC-US	Southeast Valley Project	P	Maricopa AZ	Mesa AZ	87.0	400-599	AC	1,405.0	2014
WECC-US	SUNZIA SOUTHWEST TRANSMISSION	P	Corona, NM	Coolidge, AZ	500.0	400-599	AC	3,000.0	2016
WECC-US	Vail - Irvington 345 kV	C	Vail, AZ	Tucson, AZ	11.0	300-399	AC	1,195.0	2022
WECC-US	Irvington - South 345 kV	C	Tucson, AZ	Sahuarita, AZ	16.0	300-399	AC	1,195.0	2022
WECC-US	Tortolita - North Loop 345 kV	C	Red Rock, AZ	Marana, AZ	15.0	300-399	AC	1,195.0	2022
WECC-US	Vail - South 345 kV	C	Vail, AZ	Sahuarita, AZ	14.0	300-399	AC	1,195.0	2022
WECC-US	Springerville - Greenlee 345 kV	C	Springerville, AZ	Greenlee, AZ	110.0	300-399	AC	1,195.0	2022
WECC-US	Tortolita - South 345 kV	C	Red Rock, AZ	Sahuarita, AZ	68.0	300-399	AC	1,195.0	2022
WECC-US	Tortolita - Winchester 500 kV	C	Red Rock, AZ	Benson, AZ	80.0	400-599	AC	Unknown	2022
WECC-US	Westwing - South #2	C	Phoenix, AZ	Sahuarita, AZ	68.0	400-599	AC	Unknown	2022
WECC-US	Pinal Central - Tortolita 500 kV	P	Nine Mile Corner, AZ	Red Rock, AZ	38.0	400-599	AC	1,732.0	2014
WECC-US	Hughson-Grayson	P	Hughson	Grayson	11.5	100-120	AC	163.0	2012
WECC-US	Hughson-Grayson	P	Grayson	Taylor	16.0	100-120	AC	163.0	2012
WECC-US	Almond 2 PP	UC	Almond	Grayson	0.3	100-120	AC	163.0	2012

Assessment Area	Transmission Project Name	Status	Terminal Origin Locaction	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Current (AC/DC)	Capacity Rating (MVA)	In-Service Year
WECC-US	Pagosa-Ignacio 115 kV Line	C	Pagosa Springs, CO	To Be Determined	37.0	100-120	AC	166.0	2016
WECC-US	East Montrose-South Canal 115 kV	C	Montrose, CO	Montrose County, CO	8.0	100-120	AC	166.0	2016
WECC-US	Santa Rosa-Gladstone 230kV Tie Line	C	So. of Gladstone, NM	Santa Rosa, NM	80.0	200-299	AC	Unknown	2018
WECC-US	Lamar - Front Range Transmission	C	Lamar, CO area	Denver, CO area	500.0	300-399	AC	Unknown	2018
WECC-US	Lamar - Front Range Transmission	C	Lamar, CO area	Denver, CO area	500.0	300-399	AC	Unknown	2018
WECC-US	Oneok 115 kV Project	P	Yuma County, CO	To Be Determined	20.0	100-120	AC	166.0	2012
WECC-US	Bromley-Prairie Center 115 kV Line	P	Brighton, CO	Brighton, CO	4.0	100-120	AC	166.0	2012
WECC-US	Plaza - Waverly 69-115kV conversion	P	Plaza, CO	Waverly, CO	30.5	100-120	AC	Unknown	2013
WECC-US	Big Sandy-Lincoln-Midway 230kV Line	P	Limon, CO	S. of Colorado Springs, CO	56.0	200-299	AC	Unknown	2013
WECC-US	Shiprock-Kiffen Canyon 230 kV Line	P	Shiprock, NM	La Plata County, CO	40.0	200-299	AC	613.0	2015
WECC-US	Shiprock-Kiffen Canyon 230 kV Line	P	Shiprock, NM	La Plata County, CO	40.0	200-299	AC	613.0	2015
WECC-US	Calumet-Walsenburg 230 kV Line	P	Huerfano County, CO	Pueblo, CO	7.0	200-299	AC	613.0	2015
WECC-US	San Luis Valley-Calumet 230 kV Line	P	Alamosa County, CO	Huerfano County, CO	93.0	200-299	AC	(2) 613	2017
WECC-US	San Luis Valley-Calumet 230 kV Line	P	Alamosa County, CO	Huerfano County, CO	93.0	200-299	AC	(2) 613	2017
WECC-US	Sidney-Peetz Logan 230kV Line	P	Sidney, NB	Peetz, CO	5.0	200-299	AC	Unknown	2017
WECC-US	Sidney-Peetz Logan 230kV Line	P	Sidney, NB	Peetz, CO	5.0	200-299	AC	Unknown	2017
WECC-US	Big Sandy - Calhan 230 kV	P	Limon, CO	Calhan, CO	55.0	200-299	AC	Unknown	2017
WECC-US	Big Sandy - Calhan 230 kV	P	Limon, CO	Calhan, CO	55.0	200-299	AC	Unknown	2017
WECC-US	Burlington-Wray 230 kV Line	P	Burlington, CO	Wray, CO	56.0	200-299	AC	613.0	2015
WECC-US	Calumet-Comanche 345 kV Line	P	Huerfano County, CO	Pueblo, CO	43.0	300-399	AC	(2) 1700	2015
WECC-US	Richard Lake - Waverly 115 kV Line	UC	Richard Lake CO	Wellington CO	8.0	100-120	AC	166.0	2012
WECC-US	Valley Farms-Oracle	C	Valley Farms	Oracle	39.5	100-120	AC	Unknown	2018
WECC-US	Tucson-Nogales	C	Tucson	Nogales	20.4	100-120	AC	Unknown	2020
WECC-US	Saguaro-Tucson	C	Saguaro	Tucson	35.4	100-120	AC	Unknown	2021
WECC-US	Nogales-Apache	C	Nogales	Apache	59.2	100-120	AC	Unknown	2022
WECC-US	Saguaro-Oracle	C	Saguaro	Oracle	0.0	100-120	AC	Unknown	2022
WECC-US	Coolidge-Valley Farms	C	Coolidge	Valley Farms	5.2	100-120	AC	Unknown	2015
WECC-US	ED5-Saguaro Northern	C	ED5	Saguaro	17.1	100-120	AC	Unknown	2016
WECC-US	ED5-Saguaro Southern	C	ED5	Saguaro	17.0	100-120	AC	Unknown	2016
WECC-US	Parker-Headgate Rock	C	Parker	Headgate Rock	14.0	151-199	AC	Unknown	2016
WECC-US	Headgate Rock-Bouse	C	Headgate Rock	Bouse	18.0	151-199	AC	Unknown	2016
WECC-US	Empire-ED5	P	Empire	ED5	9.2	100-120	AC	Unknown	2012
WECC-US	ED4-ED5	P	ED4	ED5	9.1	100-120	AC	Unknown	2013
WECC-US	ED4-ED2	P	ED4	ED2	9.2	100-120	AC	Unknown	2014
WECC-US	Thornton Road-Empire	UC	Casa Grande	Empire	13.2	100-120	AC	Unknown	2012
WECC-CAN	Hanna Area Reinforcement	P	28S	132S	23.0	200-299	AC	1,275.0	2012
WECC-CAN	Heartland Reinforcement	P	12S	13S	17.0	200-299	AC	754.0	2013
WECC-CAN	Hanna Area Reinforcement	P	946S	801S	4.0	200-299	AC	1,103.0	2013
WECC-CAN	Hanna Area Reinforcement	P	946S	963S	22.0	200-299	AC	1,103.0	2013
WECC-CAN	Hanna Area Reinforcement	P	650S	932S	37.0	200-299	AC	1,103.0	2013
WECC-CAN	Hanna Area Reinforcement	P	932S	959S	42.0	200-299	AC	1,103.0	2013
WECC-CAN	Hanna Area Reinforcement	P	959S	946S	54.0	200-299	AC	1,103.0	2013
WECC-CAN	South Alberta Reinforcement	P	59S	237S	150.0	200-299	AC	Unknown	2015
WECC-CAN	South Alberta Reinforcement	P	Whitla	244S	55.0	200-299	AC	1,275.0	2014
WECC-CAN	South Alberta Reinforcement	P	324S	244S	85.0	200-299	AC	1,275.0	2014
WECC-CAN	South Alberta Reinforcement	P	103S	Journault	19.0	200-299	AC	1,103.0	2016
WECC-CAN	South Alberta Reinforcement	P	491S	312S	24.0	200-299	AC	1,275.0	2016
WECC-CAN	South Alberta Reinforcement	P	312S	103S	24.0	200-299	AC	1,275.0	2016
WECC-CAN	South Alberta Reinforcement	P	Journault	Whitla	60.0	200-299	AC	1,103.0	2015
WECC-CAN	South Alberta Reinforcement	P	Journault	120S	32.0	200-299	AC	1,103.0	2014
WECC-CAN	Foothills Area Development	P	SS-65	74S	11.0	200-299	AC	Unknown	2015
WECC-CAN	Foothills Area Development	P	237S	SS-65	29.0	200-299	AC	Unknown	2015
WECC-CAN	Foothills Area Development	P	237S	42S	60.9	200-299	AC	Unknown	2017
WECC-CAN	Heartland Reinforcement	P	12S	89S	50.0	400-599	AC	3,500.0	2013
WECC-CAN	Fort McMurray Reinforcement	P	GENESEE AB	939S	304.0	400-599	AC	3,500.0	2017
WECC-CAN	Fort McMurray Reinforcement	P	939S	951S	304.0	400-599	AC	3,500.0	2017
WECC-CAN	Edmonton to Calgary Reinforcement	P	12S	28S	310.0	400-599	DC	3,000.0	2014
WECC-CAN	Edmonton to Calgary Reinforcement	P	GENESEE AB	102S	225.0	400-599	DC	3,000.0	2014
WECC-CAN	Invermere to Goldon 230 kV line	P	Invermere, BC	Kicking Horse	120.0	200-299	AC	1,357.0	2012
WECC-CAN	Vancouver City Central(2L20 & 2L44)	P	Cathedral Square	Sperling (via Mt Pleasant)	8.2	200-299	AC		2012
WECC-CAN	West End Substation	P	Horne Payne	West End	10.4	200-299	AC		2019
WECC-CAN	Metro North Reinforcement	P	Como Lake	Murrin (via Horne Payne)	26.8	200-299	AC		2018
WECC-CAN	Dawson Creek / Chetwynd(DCAT)	P	Sundance, BC	Bear Mountain, BC	60.2	200-299	AC	2,386.0	2013
WECC-CAN	Northwest Transmission Line (NTL)	P	Skeena, BC	Bob Quinn, BC	340.0	200-299	AC	3,004.0	2014
WECC-CAN	Fraser Valley W Reinforcement	P	Ingledow, BC	Mclellan (via Fleetwood)	16.0	200-299	AC		2014
WECC-CAN	5L91 (50%) Series Compensation	P	Ashton Creek, BC	Selkirk, BC	0.0	400-599	AC		2018
WECC-CAN	5L98 (50%) Series Compensation	P	Nichola, BC	Vassuax Lake, BC	0.0	400-599	AC		2018
WECC-CAN	5L5 and 5L6 (Site C to PCN)	P	Site C, BC	Peace Canyon	0.0	400-599	AC		2020

Assessment Area	Transmission Project Name	Status	Terminal Origin Locaction	Terminal End Location	Length (Circuit Miles)	Operating Voltage (kV)	Current (AC/DC)	Capacity Rating (MVA)	In-Service Year
WECC-CAN	500 kV Line (5L83) Project	P	Nicola BC	Meridian BC	153.0	400-599	AC	3,000.0	2014
WECC-CAN	5L71 & 5L72 (50%) Series Comp.	P	Mica, BC	Nicola, BC	0.0	400-599	AC		2014
WECC-MX	La Jovita	P	La Jovita MX	Presidente Juarz MX	38.0	200-299	AC	430.0	2012
WECC-MX	Valle de Puebla	P	Valle de Puebla	Tecnologico MX	5.8	200-299	AC	388.0	2012
WECC-MX	Valle de Puebla	P	Valle de Puebla	Sanchez Taboada MX	12.3	200-299	AC	388.0	2012
WECC-MX	Parque Industrial	P	Parque Industrial	Cerro Prieto II MX	33.6	200-299	AC	388.0	2012
WECC-MX	La Jovita	P	La Jovita MX	Lomas MX	30.0	200-299	AC	430.0	2018
WECC-MX	El Cañon	P	El Cañon MX	El Ciprés MX	52.0	200-299	AC	430.0	2018
WECC-MX	La Jovita	P	La Jovita MX	El Ciprés MX	35.0	200-299	AC	430.0	2013
WECC-MX	El Centenario	P	El Centenario MX	La Rosita MX	8.0	200-299	AC	388.0	2013
WECC-MX	El Centenario	P	El Centenario MX	Sanchez Taboada MX	8.0	200-299	AC	388.0	2013
WECC-MX	La Jovita	P	La Jovita MX	La Herradura MX	50.0	200-299	AC	430.0	2015
WECC-MX	Cucapah	P	Cucapah	Mexicali MX	14.3	200-299	AC	388.0	2014
WECC-MX	Cucapah	P	Cucapah	Sanchez Taboada MX	14.3	200-299	AC	388.0	2014
WECC-MX	Cucapah	P	Cucapah	Cerro Prieto II MX	14.9	200-299	AC	388.0	2014
WECC-MX	Cucapah	P	Cucapah	La Rosita MX	20.5	200-299	AC	388.0	2014
WECC-MX	Ensenada	P	Ensenada	La Herradura MX	49.7	400-599	AC	800.0	2018

Appendix III: NERC-Wide Projected Transformer Projects

Table Notes

- Includes transformer projects that are under construction, planned, or conceptual, with in-service dates from 2012-2022, as reported by each NERC Assessment Area.

Appendix III: NERC-Wide Projected Transformer Projects

Assessment Area	Transformer Project Name	High-Side Voltage(kV)	Low-Side Voltage(kV)	In-Service (Month-Year)	Description
ERCOT	Wellborn Switching Sub	138	69	Sep-2013	Install (3) Breaker ring to include (2) 138 lines and (1) 138/69 auto transformer relocated from Greens Prairie
ERCOT	Mountain Top-Blanco-Devil's Hill	138	69	Dec-2012	Close the 69-kV switch (SW 458) at the Blanco substation(7482) to loop the load located at the Blanco substation. Upgrade the capacity of the 138-69-kV auto-transformer (T2) at the Devil's Hill substation(7493) from 20-MVA to 45-MVA.
ERCOT	Oran 138/69 kV autotransformer	138	69	Dec-2012	Install second 138/69 kV autotransformer
ERCOT	Cumby Switch	138	69	May-2013	Replace existing 138/69 kV autotransformer
ERCOT	Melon Creek: Install 138/69 KV Auto	138	69	Mar-2015	Construct Melon Creek substation on Airco to Rincon 138 kV line with 138/69 kV, 93 MVA, auto. Build new 69 kV line from Melon Creek to Tatton. Rebuild 69 kV line from Refugio to Tatton.
ERCOT	Whitney 2nd Auto	138	69	Oct-2012	Replace 60 MVA, 138/69 kV auto with 75 MVA auto
ERCOT	Illinois #4, Build new three breaker ring bus & add 138/69 kV auto	138	69	Feb-2012	Rebuild 69 kV line from Ft. Lancaster to Hamilton Rd. with 795 ACSS, double circuit capable as alternative to CREZ project of rebuilding Sonora to Hamilton 138 kV line
ERCOT	Lytle: Add 138/69 kV Auto	138	69	Dec-2012	Add CPS Lytle to ETT Lytle 795 ACSR 138 kV line and 93 MVA 69/138 kV autotransformer at Lytle
ERCOT	Seaton Auto	138	69	Jun-2015	Upgrade 138/69 kV auto to 100 MVA
ERCOT	Bonham Switching Station 138/69 kV autotransformer replacement	138	69	May-2018	Replace existing 138/69 kV autotransformer
ERCOT	Leon Switch #2 138/69 kV autotransformer replacement	138	69	May-2018	Replace existing 138/69 kV autotransformer
ERCOT	Pleasant Valley second 138/69 kV autotransformer	138	69	May-2019	Install second 138/69 kV autotransformer
ERCOT	Royse 138/69 kV autotransformer	138	69	May-2020	Install larger autotransformer
ERCOT	Choate Station and Autotransformer	138	69	Jan-2013	Build new Choate substation where Pawnee to Four Corners 138 kV and Kenedy to Charco 69 kV lines cross and add a 150 MVA 139/69 kV autotransformer
ERCOT	Fashing Autotransformer	138	69	Mar-2013	Expand Fashing station to have 138 kV and add a 150 MVA 138/69 kV autotransformer at Fashing.
ERCOT	Magruder: Add 138/69 kV, 187 MVA, auto, 3 breaker 138 kV ringbus, 1 69 kV lowside breaker	138	69	Sep-2014	Reconductor Victoria to North Victoria and North Victoria to Magruder 69 kV line to 1590 ACSR. Install 138/69 kV, 187 MVA, autotransformer at Magruder on the Victoria to Thomaston 138kV line.
ERCOT	Ranchito: Build 138 kV station with 138 KV Auto and Ring Bus	138	69	Dec-2017	Construct 345 kV line from LaPalma to Ranchito to South McAllen and add 345/138/69 kV substation adjacent to existing Cavazos 69 kV substation with 600 MVA 345/138 kV autotransformer
ERCOT	Pearsall auto upgrade	138	69	May-2012	Upgrade the 50 MVA138/69 kV autotransformer.
ERCOT	Laguna: Add 138/69 kV Auto	138	69	Mar-2014	Construct new 138 kV line and add tranformation at Laguna to remove contingency overloads during off-peak maintenance
ERCOT	Greens Bayou Autotransformer Upgrade	345	138	May-2013	Replace existing 400MVA Greens Bayou autotransformer A2 with 800MVA autotransformer.
ERCOT	Obrien Autotransformer Upgrade	345	138	May-2013	Replace existing 400MVA Obrien autotransformer A3 with 800MVA autotransformer.
ERCOT	Zorn Autotransformer Addition	345	138	May-2013	Add a new 345-138 kV 478 MVA autotransformer at the Zorn substation (7042).
ERCOT	Cedar Hill Switch second 345/138 kV autotransformer	345	138	May-2019	Install autotransformer
ERCOT	PH Robinson Autotransformer A3	345	138	Mar-2012	Install temporary 600MVA Autotransformer A3 at PH Robinson
ERCOT	Anna Switch 345/138 kV autotransformer replacement	345	138	May-2012	Replace #1 autotransformer
ERCOT	Southeast Nacogdoches 345/138 kV autotransformer	345	138	May-2012	Replace existing 345/138 kV autotransformer with larger autotransformer

Appendix III: Projected Transformer Projects

Assessment Area	Transformer Project Name	High-Side Voltage(kV)	Low-Side Voltage(kV)	In-Service (Month-Year)	Description
ERCOT	Cagnon - Install a Third 345kV Autotransformer	345	138	Sep-2012	Install one 600 MVA autotransformer.
ERCOT	Killeen Switch	345	138	Dec-2012	Install circuit breakers and second 345/138 kV autotransformer
ERCOT	Willow Valley Switch	345	138	Jun-2013	Install 345/138 kV autotransformer
ERCOT	Forney Sw. Sta. Second 600 MVA, 345/138 kV Autotransformer	345	138	May-2014	Add second 345/138 autotransformer
ERCOT	Cagnon - Install a Fourth 345kV Autotransformer	345	138	Jun-2014	Install one 600 MVA autotransformer.
ERCOT	Hicks Switch Autotransformer	345	138	May-2015	Install 345/138 kV autotransformer
ERCOT	Collin 345/138 kV autotransformer	345	138	May-2016	Install second 345/138 kV autotransformer
ERCOT	Sargent Road 345/138 kV autotransformer	345	138	May-2016	Install second 345/138 kV autotransformer
ERCOT	Norwood Switch autotransformer	345	138	May-2016	Replace #1 345/138 kV autotransformer
ERCOT	Loma Alta 345kV station and autotransformer	345	138	May-2018	Construct a 345 substation and connect to the existing Loma Alta 138 substation.
ERCOT	Trinity Switch 345/138 kV autotransformer	345	138	May-2018	Create Trinity Switch and install a 600 MVA 345/138 kV autotransformer
ERCOT	Lavon 345/138 kV Switching Station	345	138	May-2018	Construct 345/138 kV switching station
ERCOT	North Lake 345/138 kV autotransformer	345	138	May-2018	Install a 345/138 kV autotransformer
ERCOT	Renner	345	138	May-2020	Replace existing 345/138 kV autotransformer with larger autotransformer
ERCOT	Kendall Autotransformer Addition	345	138	Jul-2012	Replace the existing 345-138 kV 478MVA autotransformer with an 672 MVA autotransformer at the Kendall substation (7150).
ERCOT	Dunlap 138/345kV Autotransformer Project	345	138	Mar-2013	Install a 138/345 kV 672 MVA autoxfmr at Dunlap, configuring a Dunlap to Lost Pines 345 kV circuit, add a new 345kV line from Dunlap to Austrop and combine 138kv Dunlap to Decker and Decker to Techridge into one single circuit bypassing Decker.
ERCOT	Frontera: Build 345 kV station with 345/138 kV	345	138	Oct-2017	Construct 345 kV line from Frontera to Del Sol
ERCOT	Ranchito, New SS with 345/138 kV autotransformer	345	138	Dec-2017	Construct 345 kV line from LaPalma to Ranchito to South McAllen and add 345/138/69 kV substation adjacent to existing Cavazos 69 kV substation with 600 MVA 345/138 kV autotransformer
ERCOT	South McAllen, new SS with 345/138 kV autotransformer	345	138	Dec-2017	Add Frontera to South McAllen 345 kV line with bundled 1590 ACSR and double circuit capable structures and 345/138 kV substations at Frontera and South McAllen
ERCOT	2nd Lewisville Auto	345	138	Mar-2012	Install (2nd) 345/138 kV autotransformer at Lewisville station
ERCOT	Jack County Auto	345	138	Jun-2013	Install 345/138 kV, 700 MVA auto at Jack County
ERCOT	Dobbin switching station	345	138	Feb-2015	Construct 345/138 kV switching station in CNP's Roans Prairie to Kuykendahl line
ERCOT	Kendall Autotransformer Replacement	345	138	Jun-2012	Replace the existing 345/138 kV 336 MVA autotransformer with an 800 MVA autotransformer at the Kendall Substation (7152).
ERCOT	Mont Belvieu Area Upgrades	345	138	May-2014	Build new 345/138kV JORDAN substation. Install new 800 MVA autotransformer.
ERCOT	Central Bluff Switch	345	138	Dec-2011	Construct 345 kV switching station with 345/138 kV autotransformer
ERCOT	North McCamey Autotransformer Addition	345	138	Jan-2014	Add two new 345-138 kV 800 MVA autotransformer at the North McCamey substation (76595).
FRCC	NO PROJECTS TO REPORT	-	-	-	No Projected Transformer Projects
MISO	Fargo, ND - St Cloud/Monticello, MN area 345 kV project	345	115	05-2013	Bison - AlexandriaSS - Waite Park - Monticello 345 ckt 1, Sum rate 2085
MISO	Rockdale-West Middleton 345 kV	345	138	06-2013	Construct a new 345/138 kV substation at Cardinal (next to the existing West Middleton sub), install a 345/138 kV 500 MVA transformer at Cardinal, construct 47.9 miles overhead 345 kV line from Albion to Cardinal/West Middleton, modifications to the existing West Middleton substation, construct a new Albion 345 kV switching station. Facility costs listed in the facility table are for the southern route.

Assessment Area	Transformer Project Name	High-Side Voltage(kV)	Low-Side Voltage(kV)	In-Service (Month-Year)	Description
MISO	Rockdale-West Middleton 345 kV	345	138	06-2013	Construct a new 345/138 kV substation at Cardinal (next to the existing West Middleton sub), install a 345/138 kV 500 MVA transformer at Cardinal, construct 47.9 miles overhead 345 kV line from Albion to Cardinal/West Middleton, modifications to the existing West Middleton substation, construct a new Albion 345 kV switching station. Facility costs listed in the facility table are for the southern route.
MISO	Monroe County - Council Creek 161 kV line projects	161	138	12-2014	Monroe County - Council Creek 161 kV line, Council Creek 161/138 kV transformer; Council Creek-Petenwell uprate 138 kV
MISO	Weeds Lake	345	138	12-2014	Loop the 345kV Argenta - Robinson Park 345kV circuit into a new 345/138kV EHV substation called Weeds Lake. Build 4 new (approximately 6 miles) 138kV circuits to loop the two Argenta-Milham 138kV lines into the substation.
MISO	Westwood Bk1 Limiting Equipment	345	138	06-2015	Replace 1600A 138kV breaker with 3000A to allow full xfr rating.
MISO	SE Twin Cities - Rochester, MN - LaCrosse, WI 345 kV project	345	161	12-2012	Construct Hampton Corner-North Rochester-Chester-North LaCrosse 345 kV line, North Rochester - N. Hills 161 kV line, North Rochester-Chester 161 kV line, Hampton Corner 345/161 transformer, North Rochester 354/161 transformer, North LaCrosse 345/161 transformer
MISO	SE Twin Cities - Rochester, MN - LaCrosse, WI 345 kV project	345	161	03-2014	Construct Hampton Corner-North Rochester-Chester-North LaCrosse 345 kV line, North Rochester - N. Hills 161 kV line, North Rochester-Chester 161 kV line, Hampton Corner 345/161 transformer, North Rochester 354/161 transformer, North LaCrosse 345/161 transformer
MISO	G519 - Mesaba	230	115	07-2014	Network Upgrades associated with 600 MW coal gasification generating facility at the propsoed Mesaba generating station. There is a G477 alternate site which is not described here.
MISO	Candidate MVP Portfolio 1 - Brookings, SD - SE Twin Cities 345 kV	345	115	11-2013	Brookings Cty-Lyon Cty (Single Ckt 345 kV); Lyon Cty-Cedar Mountain-Helena (Double Ckt 345 kV); Helena-Chub Lake-Hampton Corner (Single Ckt 345 kV); Lyon Cty-Hazel (Single Ckt 345 kV); Hazel-Minnesota Valley (Single Ckt 345 kV, initially operate at 230 kV); Cedar Mountain-Franklin (Single Ckt 115 kV)
MISO	Candidate MVP Portfolio 1 - Brookings, SD - SE Twin Cities 345 kV	345	115	04-2014	Brookings Cty-Lyon Cty (Single Ckt 345 kV); Lyon Cty-Cedar Mountain-Helena (Double Ckt 345 kV); Helena-Chub Lake-Hampton Corner (Single Ckt 345 kV); Lyon Cty-Hazel (Single Ckt 345 kV); Hazel-Minnesota Valley (Single Ckt 345 kV, initially operate at 230 kV); Cedar Mountain-Franklin (Single Ckt 115 kV)
MISO	Candidate MVP Portfolio 1 - Brookings, SD - SE Twin Cities 345 kV	345	230	12-2014	Brookings Cty-Lyon Cty (Single Ckt 345 kV); Lyon Cty-Cedar Mountain-Helena (Double Ckt 345 kV); Helena-Chub Lake-Hampton Corner (Single Ckt 345 kV); Lyon Cty-Hazel (Single Ckt 345 kV); Hazel-Minnesota Valley (Single Ckt 345 kV, initially operate at 230 kV); Cedar Mountain-Franklin (Single Ckt 115 kV)
MISO	Candidate MVP Portfolio 1 - Brookings, SD - SE Twin Cities 345 kV	345	115	07-2013	Brookings Cty-Lyon Cty (Single Ckt 345 kV); Lyon Cty-Cedar Mountain-Helena (Double Ckt 345 kV); Helena-Chub Lake-Hampton Corner (Single Ckt 345 kV); Lyon Cty-Hazel (Single Ckt 345 kV); Hazel-Minnesota Valley (Single Ckt 345 kV, initially operate at 230 kV); Cedar Mountain-Franklin (Single Ckt 115 kV)
MISO	Replace Arcadian 345/138 kV transformer	345	138	06-2020	Replace Arcadian 345/138 kV transformer #3 with a 500 MVA transformer.
MISO	Hazleton - Salem 345 kV line with a 2nd Salem 345/161 kV 448 MVA transformer.	345	161	05-2013	Build a new Hazleton - Salem 345 kV line. Expand the Hazleton 345kV bus to a 5 position ring and expand the Salem 345kV ring to allow for a 2nd Salem 345/161 kV 448 MVA transformer. (option 1) The route will follow the existing Hazleton-Dundee-Liberty-Lore 161kV route.
MISO	Coffey (formerly Lewis Fields) 161 kV substation which taps the SwampFX - Coggon 115 kV line	161	115	12-2014	Construct a new Coffey (formerly Lewis Fields) substation with 161/115kV transformer & a single 161kV line to feed to Hiawatha and 2 115kV lines to Swamp Fox & Coggon. Future configuration will allow for a single 115kV line to feed to Swamp Fox and 2 161kV lines to Hiawatha & Coggon. A new ~9 mile 161 kV line from Hiawatha to Coffeybe built.
MISO	Coffey (formerly Lewis Fields) 161 kV substation which taps the SwampFX - Coggon 115 kV line	161	115	12-2014	Construct a new Coffey (formerly Lewis Fields) substation with 161/115kV transformer & a single 161kV line to feed to Hiawatha and 2 115kV lines to Swamp Fox & Coggon. Future configuration will allow for a single 115kV line to feed to Swamp Fox and 2 161kV lines to Hiawatha & Coggon. A new ~9 mile 161 kV line from Hiawatha to Coffeybe built.
MISO	Build a new 345 kV Morgan Valley (Beverly) substation which taps the Arnold -Tiffin 345 kV line	345	161	12-2014	Build a new 345 kV Morgan Valley (Beverly) Tap substation and tapped to 345 kV line Arnold - Tiffin at 40% distance away from Arnold. Add a new 335 MVA 345/161 kV transformer and build a new 161 kV line connecting the new substation to Beverly 161 kV bus. Tap Arnold-Fairfax 161kV line for in and out feeds from Morgan Valley
MISO	RTU / SCADA Re-direction Program	345	138	06-2013	Install and/or upgrade RTU's and SCADA points throughout system
MISO	Qualitech 345/138KV Transformer and breakers	345	138	06-2013	Qualitech Sub- Install one 345/138kv, 300Mva Xtr and 2-345kv Bkrs and 1-138kv Bkr to provide second 138kv source to proposed Hendricks Co 138kv system

Appendix III: Projected Transformer Projects

Assessment Area	Transformer Project Name	High-Side Voltage(kV)	Low-Side Voltage(kV)	In-Service (Month-Year)	Description
MISO	Hancock 230/120kV Transformer	230	120	12-2015	Cut the Wixom-Quaker 230kV circuit into Hancock Station, install a 230/120kV transformer.
MISO	Petersburg 345/138kV East and West Autotransformers and 345 kV breaker	345	138	06-2013	Replace and upgrade existing East and West 345/138kV autotransformer at Petersburg Substation. Add 345kV breaker.
MISO	South Bloomington - Install new 560 MVA 345 /138 Xfmr	345	138	06-2015	South Bloomington Area 345/138 kV Substation - Install 345/138 kV, 560 MVA Transformer. Extend new 345 kV line approximately 5 miles from Brokaw Substation to South Bloomington Substation. Install 1-138 kV PCB at South Bloomington Substation, and 2-345 kV PCB's at Brokaw Substation
MISO	North Mankato 115 kV project	345	115	04-2013	1) New 345/115 kV TR at the proposed Helena 345 kV switching station. 2) New 115 kV line from Helena - St. Thomas. 3) New 115/69 kV substation near St. Thomas. 4) New 69 kV switchig station at Lesueur Tap.
MISO	Proposed MVP Portfolio 1 - Reynolds to Greentown 765 kV line	765	345	06-2018	Reynolds to Greentown 765 kV line
MISO	Proposed MVP Portfolio 1 - Ellendale to Big Stone South	345	230	12-2019	Big Stone to Ellendale 345 kV line
MISO	Proposed MVP Portfolio 1 - Big Stone South to Brookings	345	230	12-2017	Brookings to Big Stone 345 kV line (double ckt capable)
MISO	Proposed MVP Portfolio 1 - Big Stone South to Brookings	345	230	12-2017	Brookings to Big Stone 345 kV line (double ckt capable)
MISO	Proposed MVP Portfolio 1 - Big Stone South to Brookings	345	230	12-2015	Brookings to Big Stone 345 kV line (double ckt capable)
MISO	Proposed MVP Portfolio 1 - Pana - Mt. Zion - Kansas - Sugar Creek 345 kV line	345	138	11-2018	Pana to Mt. Zion to Kansas to Sugar Creek 345 kV line. Install transformers at Mt. Zion and Kansas
MISO	Proposed MVP Portfolio 1 - Pana - Mt. Zion - Kansas - Sugar Creek 345 kV line	345	138	11-2018	Pana to Mt. Zion to Kansas to Sugar Creek 345 kV line. Install transformers at Mt. Zion and Kansas
MISO	Proposed MVP Portfolio 1 - Adair - Ottumwa 345	345	161	11-2018	Adair Substation - New 560 MVA, 345/161 kV Transformer. New 71 mile 345 kV line from Adair to Ottumwa with 3000 A summer emergency capability
MISO	Proposed MVP Portfolio 1 - Adair - Ottumwa 345	345	161	06-2017	Adair Substation - New 560 MVA, 345/161 kV Transformer. New 71 mile 345 kV line from Adair to Ottumwa with 3000 A summer emergency capability
MISO	Nortwest Cape Area 345/161 kV Substation	345	161	06-2016	Install 560 MVA, 345/161 kV Transformer. Provide 345 kV supply from 11 mile 345 kV line extension from Lutesville Substation
MISO	New 345kV Supply at Fargo Substation	345	138	12-2016	Tap existing 345kV line from Duck Creek to Tazewell and create new Maple Ridge Substation ($6.5M) Build a new supply line to the Fargo Substation by extending 20 miles of 345kV from the new Maple Ridge Substation ($50.1M) Create Fargo Station and install 560 MVA 345/138kV Transformer ($9.4M)
MISO	Sag clearance 2012	345	138	12-2012	Identify and remediate inherent sag limitations on heavily loaded METC trasmission lines throughout the system.
MISO	Breaker Replacement Program 2012	345	120	12-2012	Replace defective, damaged, or over dutied breakers throughout system.
MISO	NERC Relay Loadability Compliance 2012	345	120	12-2012	Upgrade relays throughout system
MISO	Potential Device Replacement 2012	345	120	12-2012	Replace aging potential devices
MISO	Relay Betterment Program 2012	345	120	12-2012	Replace aging and electromechanical relays throughout the system. Add OPGW where needed.
MISO	Sub 39: Second 345-161 kV Xfmr	345	161	06-2016	Add a second 345-161 kV xfmr. Expand 345 kV and 161 kV buses.

Assessment Area	Transformer Project Name	High-Side Voltage(kV)	Low-Side Voltage(kV)	In-Service (Month-Year)	Description
MISO	Sidney Transformer Addition	345	138	06-2013	Sidney 345/138 kV Substation - Install a second 345/138kV, 560 MVA Transformer and establish 345 kV ring bus
MISO	Baldwin-Grand Tower-N.W. Cape 345 kV Line	345	138	12-2018	New 69 mile, single-circuit line (possible double circuit), 3000 A SE capability (Baldwin-Grand Tower - 45 miles; Grand Tower-N.W. Cape - 24 miles). Grand Tower 345/138 kV Substation - 1-560 MVA transformer, 345 kV Ring bus
MISO	Proposed MVP Portfolio 1 - Palmyra Tap -Quincy-Meredosia - Ipava & Meredosia-Pawnee 345 kV Line	345	138	11-2016	Palmyra Tap to Quincy to Meredosia to Ipava 345 line and Meredosia to Pawnee 345 kV line. Install additional transformers at Quincy, Meredosia and Pawnee.
MISO	Proposed MVP Portfolio 1 - Palmyra Tap -Quincy-Meredosia - Ipava & Meredosia-Pawnee 345 kV Line	345	138	11-2017	Palmyra Tap to Quincy to Meredosia to Ipava 345 line and Meredosia to Pawnee 345 kV line. Install additional transformers at Quincy, Meredosia and Pawnee.
MISO	Proposed MVP Portfolio 1 - Palmyra Tap -Quincy-Meredosia - Ipava & Meredosia-Pawnee 345 kV Line	345	138	11-2016	Palmyra Tap to Quincy to Meredosia to Ipava 345 line and Meredosia to Pawnee 345 kV line. Install additional transformers at Quincy, Meredosia and Pawnee.
MISO	Proposed MVP Portfolio 1 - Fargo-Galesburg-Oak Grove 345 kV Line	345	138	12-2016	Fargo-Galesburg-Oak Grove 345 kV Line - New 70 mile, 3000 A summer emergency capability line. 345 kV PCBs: 3-Fargo, 1-Oak Grove. 3-Galesburg. 560 MVA xfmr at Galesburg
MISO	Proposed MVP Portfolio 1 - N LaCrosse-N Madison-Cardinal - Dubuque area 345-kV	345	138	12-2018	N LaCrosse- N Madison - Cardinal 345-kV & Dubuque County - Cardinal 345 kV line and Transformers needed for stepdown
MISO	Proposed MVP Portfolio 1 - N LaCrosse-N Madison-Cardinal - Dubuque area 345-kV	345	138	12-2018	N LaCrosse- N Madison - Cardinal 345-kV & Dubuque County - Cardinal 345 kV line and Transformers needed for stepdown
MISO	Proposed MVP Portfolio 1 - N LaCrosse-N Madison-Cardinal - Dubuque area 345-kV	345	138	12-2018	N LaCrosse- N Madison - Cardinal 345-kV & Dubuque County - Cardinal 345 kV line and Transformers needed for stepdown
MISO	Proposed MVP Portfolio 1 - N LaCrosse-N Madison-Cardinal - Dubuque area 345-kV line	345	161	12-2018	N LaCrosse- N Madison - Cardinal 345-kV & Dubuque County - Cardinal 345 kV line and Transformers needed for stepdown
MISO	Cass Lake -Nary-Helga -Bemidji 115	230	115	12-2012	Capacity upgrade: Cass Lake-Bemidji 115 kV
MISO	Proposed MVP Portfolio 1 - Michigan Thumb Wind Zone	345	120	12-2013	The proposed transmission line will connect into a new station to the south and west of the Thumb area that will tap three existing 345 kV circuits; one between the Manning and Thetford 345 kV stations, one between the Hampton and Pontiac 345 kV stations and one between the Hampton and Thetford 345 kV stations. Two new 345 kV circuits will extend from this new station, to be called Baker (formerly Reese), up to a new station, to be called Rapson (formerly Wyatt or Wyatt East) that will be located to the north and east of the existing 120 kV Wyatt station. In order to support the existing 120 kV system in the northern tip of the Thumb, the two existing 120 kV circuits between the Wyatt and Harbor Beach stations, one that connects directly between Wyatt and Harbor Beach and that connects Wyatt to Harbor Beach through the Seaside station, will be cut into the new Rapson station. From the Rapson station, two 345 kV circuits will extend down the east side of the Thum to the existing Greenwood 345 kV station and then continue south to the point where the existing three ended Pontiac to Greenwood to Belle River 345 kV circuit combines. To facilitate connection to the existing transmission system a new 345 kV station, to be called Fitz (formerly Saratoga), is included in the plan at a site due south of the existing Greenwood station and just north of where the existing three ended Pontiac to Greenwood to Belle River 345 kV circuit combines. The Fitz station will then tap the existing Pontiac to Belle River to Greenwood 345 kV circuit and the existing Belle River to Blackfoot 345 kV circuit. Transformation from the 345 kV facilities to the 120 kV facilities will be necessary to maintain continuity to the existing system in and around the Sandusky area. The existing 120 kV facilities between the site that will facilitate the new 345 kV to 120 kV transformation can be utilized to facilitate a connection between the new 345 kV to 120 kV transformation and the existing 120 kV facilities in the Sandusky area.

Assessment	Transformer Project	High-Side Voltage(kV)	Low-Side Voltage(kV)	In-Service (Month-Year)	Description

Area	Name				
MISO	Proposed MVP Portfolio 1 - Michigan Thumb Wind Zone	345	120	12-2013	The proposed transmission line will connect into a new station to the south and west of the Thumb area that will tap three existing 345 kV circuits; one between the Manning and Thetford 345 kV stations, one between the Hampton and Pontiac 345 kV stations and one between the Hampton and Thetford 345 kV stations. Two new 345 kV circuits will extend from this new station, to be called Baker (formerly Reese), up to a new station, to be called Rapson (formerly Wyatt or Wyatt East) that will be located to the north and east of the existing 120 kV Wyatt station. In order to support the existing 120 kV system in the northern tip of the Thumb, the two existing 120 kV circuits between the Wyatt and Harbor Beach stations, one that connects directly between Wyatt and Harbor Beach and that connects Wyatt to Harbor Beach through the Seaside station, will be cut into the new Rapson station. From the Rapson station station, two 345 kV circuits will extend down the east side of the Thum to the existing Greenwood 345 kV station and then continue south to the point where the existing three ended Pontiac to Greenwood to Belle River 345 kV circuit combines. To facilitate connection to the existing transmission system a new 345 kV station, to be called Fitz (formerly Saratoga), is included in the plan at a site due south of the existing Greenwood station and just north of where the existing three ended Pontiac to Greenwood to Belle River 345 kV circuit combines. The Fitz station will then tap the existing Pontiac to Belle River to Greenwood 345 kV circuit and the existing Belle River to Blackfoot 345 kV circuit. Transformation from the 345 kV facilities to the 120 kV facilities will be necessary to maintain continuity to the existing system in and around the Sandusky area. The existing 120 kV facilities between the site that will facilitate the new 345 kV to 120 kV transformation can be utilized to facilitate a connection between the new 345 kV to 120 kV transformation and the existing 120 kV facilities in the Sandusky area.
MISO	Proposed MVP Portfolio 1 - Michigan Thumb Wind Zone	345	120	12-2013	The proposed transmission line will connect into a new station to the south and west of the Thumb area that will tap three existing 345 kV circuits; one between the Manning and Thetford 345 kV stations, one between the Hampton and Pontiac 345 kV stations and one between the Hampton and Thetford 345 kV stations. Two new 345 kV circuits will extend from this new station, to be called Baker (formerly Reese), up to a new station, to be called Rapson (formerly Wyatt or Wyatt East) that will be located to the north and east of the existing 120 kV Wyatt station. In order to support the existing 120 kV system in the northern tip of the Thumb, the two existing 120 kV circuits between the Wyatt and Harbor Beach stations, one that connects directly between Wyatt and Harbor Beach and that connects Wyatt to Harbor Beach through the Seaside station, will be cut into the new Rapson station. From the Rapson station station, two 345 kV circuits will extend down the east side of the Thum to the existing Greenwood 345 kV station and then continue south to the point where the existing three ended Pontiac to Greenwood to Belle River 345 kV circuit combines. To facilitate connection to the existing transmission system a new 345 kV station, to be called Fitz (formerly Saratoga), is included in the plan at a site due south of the existing Greenwood station and just north of where the existing three ended Pontiac to Greenwood to Belle River 345 kV circuit combines. The Fitz station will then tap the existing Pontiac to Belle River to Greenwood 345 kV circuit and the existing Belle River to Blackfoot 345 kV circuit. Transformation from the 345 kV facilities to the 120 kV facilities will be necessary to maintain continuity to the existing system in and around the Sandusky area. The existing 120 kV facilities between the site that will facilitate the new 345 kV to 120 kV transformation can be utilized to facilitate a connection between the new 345 kV to 120 kV transformation and the existing 120 kV facilities in the Sandusky area.
MISO	Proposed MVP Portfolio 1 - Michigan Thumb Wind Zone	345	120	12-2015	The proposed transmission line will connect into a new station to the south and west of the Thumb area that will tap three existing 345 kV circuits; one between the Manning and Thetford 345 kV stations, one between the Hampton and Pontiac 345 kV stations and one between the Hampton and Thetford 345 kV stations. Two new 345 kV circuits will extend from this new station, to be called Baker (formerly Reese), up to a new station, to be called Rapson (formerly Wyatt or Wyatt East) that will be located to the north and east of the existing 120 kV Wyatt station. In order to support the existing 120 kV system in the northern tip of the Thumb, the two existing 120 kV circuits between the Wyatt and Harbor Beach stations, one that connects directly between Wyatt and Harbor Beach and that connects Wyatt to Harbor Beach through the Seaside station, will be cut into the new Rapson station. From the Rapson station station, two 345 kV circuits will extend down the east side of the Thum to the existing Greenwood 345 kV station and then continue south to the point where the existing three ended Pontiac to Greenwood to Belle River 345 kV circuit combines. To facilitate connection to the existing transmission system a new 345 kV station, to be called Fitz (formerly Saratoga), is included in the plan at a site due south of the existing Greenwood station and just north of where the existing three ended Pontiac to Greenwood to Belle River 345 kV circuit combines. The Fitz station will then tap the existing Pontiac to Belle River to Greenwood 345 kV circuit and the existing Belle River to Blackfoot 345 kV circuit. Transformation from the 345 kV facilities to the 120 kV facilities will be necessary to maintain continuity to the existing system in and around the Sandusky area. The existing 120 kV facilities between the site that will facilitate the new 345 kV to 120 kV transformation can be utilized to facilitate a connection between the new 345 kV to 120 kV transformation and the existing 120 kV facilities in the Sandusky area.
MISO	Proposed MVP Portfolio 1 - Pawnee to Pana - 345 kV Line	345	138	11-2018	Pawnee to Pana 345 kV line including additional transformer at Pana
Assessment	Transformer Project	High-Side	Low-Side	In-Service	Description

Area	Name	Voltage(kV)	Voltage(kV)	(Month-Year)	
MISO	Proposed MVP Portfolio 1: Lakefield Jct. - Winnebago - Winco - Kossuth County & Obrien Coutny - Kossuth County - Webster 345 kV line	345	161	12-2015	New 345 kV line from Lakefield Junction to Kossuth County via Winnebago and Winco and a new 345 kV line from Obrien County to Webster via Kossuth County. Includes 161 kV rebuild as underbuild along portions of the route.
MISO	Proposed MVP Portfolio 1: Lakefield Jct. - Winnebago - Winco - Kossuth County & Obrien Coutny - Kossuth County - Webster 345 kV line	345	161	12-2015	New 345 kV line from Lakefield Junction to Kossuth County via Winnebago and Winco and a new 345 kV line from Obrien County to Webster via Kossuth County. Includes 161 kV rebuild as underbuild along portions of the route.
MISO	Proposed MVP Portfolio 1 - Winco to Hazleton 345 kV	345	161	12-2015	Winco to Lime Creek to Killdeer to Blackhawk to Hazleton 345 kV line and Lime Creek, Killdeer and Black Hawk transformers
MISO	Proposed MVP Portfolio 1 - Winco to Hazleton 345 kV line	345	161	12-2015	Winco to Lime Creek to Killdeer to Blackhawk to Hazleton 345 kV line and Lime Creek, Killdeer and Black Hawk transformers
MISO	Proposed MVP Portfolio 1 - Winco to Hazleton 345 kV line	345	161	12-2015	Winco to Lime Creek to Killdeer to Blackhawk to Hazleton 345 kV line and Lime Creek, Killdeer and Black Hawk transformers
MISO	Proposed MVP Portfolio 1 - Winco to Hazleton 345 kV line	345	161	12-2015	Winco to Lime Creek to Killdeer to Blackhawk to Hazleton 345 kV line and Lime Creek, Killdeer and Black Hawk transformers
MISO	Proposed MVP Portfolio 1 - Winco to Hazleton 345 kV line	345	161	12-2015	Winco to Lime Creek to Killdeer to Blackhawk to Hazleton 345 kV line and Lime Creek, Killdeer and Black Hawk transformers
MISO	Proposed MVP Portfolio 1 - Winco to Hazleton 345 kV line	345	161	12-2015	Winco to Lime Creek to Killdeer to Blackhawk to Hazleton 345 kV line and Lime Creek, Killdeer and Black Hawk transformers
MISO	Chisago County 2nd 345/115 kV transformer	345	115	06-2014	This project is to install a 2nd 345/115 kV transformer at Chisago County
MISO	Noblesville Sta. 138kV Brkrs and 345kV Ckt Sws	345	138	12-2012	Noblesville Gen. Sta. - Replace 138KV OB OCB: 138TR, 13869-9, 138230-7, 13886 and Circuit Switchers: 345230-11, 34519.
MISO	Prairie 3rd transformer	230	115	06-2014	This project is to install a 3rd 230/115 kV transformer at Prairie substation
MISO	Buffalo - Casselton 115 kV Line	345	115	11-2014	Construct 16 mile 115 kV line from Buffalo - Casselton (ND); Replace Buffalo 345/115 kV Transformer; Rebuild portion of Sheyenne - Mapleton 115 kV Line
Manitoba Hydro	Brandon Cornwallis	230	115	Jun-2013	120/160/176 MVA
Manitoba Hydro	Rockwood	230	115	Sep-2015	150/200/250 MVA
Manitoba Hydro	Riel	500	230	Nov-2015	720/960/1200 MVA; Associated with Bipole 3 / Conawapa project
Manitoba Hydro	Riel	500	230	Oct-2019	720/960/1200 MVA; Associated with 5th Manitoba - US tie project
Manitoba Hydro	Brandon Cornwallis	230	115	Jun-2013	120/160/176 MVA
Manitoba Hydro	Rockwood	230	115	Sep-2015	150/200/250 MVA
Manitoba Hydro	Riel	500	230	Nov-2015	720/960/1200 MVA; Associated with Bipole 3 / Conawapa project
Manitoba Hydro	Riel	500	230	Oct-2019	720/960/1200 MVA; Associated with 5th Manitoba - US tie project
Manitoba Hydro	Transcona	230	66	Dec-2012	
Manitoba Hydro	Transcona	230	66	Dec-2012	
Manitoba Hydro	Stanley	230	66	Oct-2012	
Manitoba Hydro	Neepawa	230	66	Dec-2012	
MAPP	Lelands Olds 345/230 replacement	345	230	Oct-2012	Replace 250MVA unit with 600MVA unit.
MAPP	Charlie Creek 345/230 #1	345	230	Jun-2012	Terminal for WAPA CCR-Williston 230 line.

Appendix III: Projected Transformer Projects

Assessment Area	Transformer Project Name	High-Side Voltage(kV)	Low-Side Voltage(kV)	In-Service (Month-Year)	Description
MAPP	Charlie Creek 345/230 #2	345	230	Dec-2014	Add 2nd unit .
MAPP	Blaisdell 230/115	230	115	Jun-2012	Load serving substation.
MAPP	Wheelock 230/115	230	115	Jun-2013	Load serving substation.
MAPP	Williston 345/230	345	230	Jan-2016	Part of AVS-Neset 345 project.
MAPP	Neset 345/230	345	230	Jan-2016	Part of AVS-Neset 345 project.
MAPP	Center 345/230 kV Transformer 2	345	230	Oct-2012	360/480/600/672 MVA ONAN/ONAF/ODAF RATINGS
MAPP	Prairie 345/230 kV Transformer 1	345	230	Oct-2011	360/480/600/672 MVA ONAN/ONAF/ODAF RATINGS
MAPP	Prairie 345/230 kV Transformer 2	345	230	Oct-2012	180 MVA RATING - MOVED FROM CENTER
MAPP	Appledorn	230	69	Nov-2012	
MAPP	Watford City	230	69	Jun-2012	removed 115/69 xfmr
MAPP	Elliot	115	69	Apr-2012	
MAPP	New Underwood	230	115	Jun-2013	
MAPP	Belfield	345	230	Nov-2012	replacing with relocated xfmr
MAPP	Oahe	230	115	Nov-2013	Date not firm, replacement
MAPP	Bismarck kV8A	230	115	Jun-2012	Date not firm, replacement
MAPP	Bismarck kV3A	230	115	May-2013	Date not firm, replacement
MAPP	Creston	161	69	Jun-2013	replacement
MAPP	Sioux Falls (2)	230	115	Apr-2014	replacement
SaskPower	Tantallon Area Reinforcement	230	138	Dec-2012	Planned addition of 2x300 MVA auto-transformer.
SaskPower	Fleet Street Area Reinforcment	230	138	Dec-2012	Planned addition of 2x300 MVA auto-transformer.
SaskPower	Boundary Dam Area Reinforcement	230	138	Dec-2013	Planned addition of 2x350 MVA auto-transformer.
SaskPower	Condie Area Reinforcement	230	138	Dec-2016	Conceptual addition of a 225 MVA auto-transformer.
SaskPower	Regina Area Reinforcement	230	138	Dec-2016	Conceptual addition of a 200 MVA auto-transformer.
SaskPower	Pasqua Area Reinforcement	230	138	Dec-2016	Conceptual addition of a 350 MVA auto-transformer.
SaskPower	Brada Area Reinforcement	230	138	Dec-2016	Conceptual addition of a 150 MVA auto-transformer.
SaskPower	Wolverine Area Reinforcement	230	138	Dec-2016	Conceptual addition of a 200 MVA auto-transformer.
SaskPower	Lloydminster Area Reinforcement	230	138	Dec-2016	Conceptual addition of a 150 MVA auto-transformer.
Maritimes	NO PROJECTS TO REPORT	-	-	-	-
New England	2nd Deerfield Autotransformer	345	115	Dec-2012	Under Construction
New England	NEEWS - GSRP Project - Agawam	345	115	Dec-2013	Under Construction
New England	NEEWS - GSRP Project - Agawam	345	115	Dec-2013	Under Construction
New England	NEEWS - GSRP Project - North Bloomfield	345	115	Dec-2013	Under Construction
New England	NEEWS - CCRP Project - Frost Bridge	345	115	Dec-2017	Planned
New England	MPRP - Albion Rd - Larabee Rd	345	115	Jan-2013	Planned
New England	MPRP - Maguire Rd	345	115	Nov-2013	Planned
New England	Lower South East Massachusetts Upgrades	345	115	Dec-2012	Planned
New England	Greater Boston - North, South, Central - Woburn	345	115	Dec-2015	Concept
New England	Greater Boston - North, South, Central - Sudbury	230	115	Unknown	Concept
New England	Central/Western MA Upgrades Bear Swamp	230	115	Dec-2015	Planned

Assessment Area	Transformer Project Name	High-Side Voltage(kV)	Low-Side Voltage(kV)	In-Service (Month-Year)	Description
New England	Auburn Area Transmission Upgrades - Auburn	345	115	Jun-2013	Planned
New England	Keene Rd	345	115	Dec-2011	Under Construction
New England	Pittsfield/Greenfield Project - Northfield	345	115	Dec-2014	Planned
New England	Greater Boston - North, South, Central - Sudbury	230	115	Dec-2014	Concept
New England	Greater Boston - North, South, Central - Mystic	345	115	Dec-2015	Concept
New England	Northern NH Solution - Littleton	230	115	Dec-2016	Planned
New England	Northern NH Solution - Eagle	345	115	Dec-2016	Planned
New York	Linden VFT	345	345	Unknown	Uprate
New York	Astoria Annex	345	138	Jun-2012	
New York	Wood Street	345	115	Jun-2016	
New York	Coopers Corners	345	115	Jun-2016	
New York	Fraser	345	115	Jun-2016	
New York	Gardenville	345	115	Jun-2017	
Ontario	Oshawa Area TS	500	230	Dec-2016	Conceptual
Ontario	Milton TS	500	230	Dec-2016	Conceptual
Ontario	Bout-de-l'Ile T11	735	315	Dec-2013	
Ontario	Bout-de-l'Ile T12	735	315	Dec-2013	
Québec	Bout-de-l'Ile T11	735	315	Dec-2013	
Québec	Bout-de-l'Ile T12	735	315	Dec-2013	
Québec	Pierre-Le Gardeur T1	315	120	Dec-2014	
Québec	Pierre-Le Gardeur T2	315	120	Dec-2014	
Québec	Saguenay 735/161kV T4	735	161	Dec-2014	
Québec	Arnaud 315/161 kV	315	161	Dec-2014	Saguenay 735/161kV T4
Québec	Figuery 315/120 kV	315	120	Dec-2014	Figuery 315/120 kV T4
Québec	Romaine-1 switching	315	161	Dec-2016	Romaine-1 switching station
Québec	Arnaud-2 T1	735	315	Dec-2018	
Québec	Arnaud-2 T2	735	315	Dec-2018	
Québec	Duchemin T1	735	315	Dec-2018	
Québec	Duchemin T2	735	315	Dec-2018	
Québec	Poularies T1	315	120	Dec-2018	
Québec	Poularies T2	315	120	Dec-2018	
PJM	North Fork	345	138	06-2014	Construct new 345/138 kV station in Marquis - Bixby 345 kV
PJM	Canton Central	345	138	06-2014	Install new 345/138 kV T-3,b1034.3
PJM	Sullivan	765	345	06-2015	Add a 3rd 2250 MVA 765/345 kV transformer at Sullivan station, b1465.1
PJM	Baker	765	345	06-2015	Add an additional 765/345 kV transformer at Baker Station, b1495
PJM	Sorenson	765	345	06-2015	Build a Sorenson 765/345 kV transformer,b1659
PJM	Cloverdale	765	500	03-2015	Install a 765/500 kV transformer at Cloverdale, b1660
PJM	Jackson's Ferry	765	138	06-2015	Install a new 765/138 transformer, 6 new 138 kV breakers at Jackson's Ferry, b1663
PJM	Allen	345	138	06-2016	Expand the Allen station by installing a second 345/138 kV transformer, b1818
PJM	Kanawha River	345	138	09-2016	Add second 345/138 kV transformer at Kanawha River Station, s0358
PJM	Waugh Chapel	230	115	06-2012	Install 4th 230/115 Transformer b0474
PJM	New Substation next to Waukegan Generating Station	345	138	06-2014	Sta 16 Waukegan - Install one of two new 345/138kV transformers at the new 345kV next to present Waukegan generating station
PJM	New Substation next to Waukegan Generating Station	345	138	06-2014	Sta 16 Waukegan - Install two of two new 345/138kV transformers at the new 345kV next to present Waukegan generating station
PJM	Lisle	345	138	06-2014	Install 4th 345/138kV autotransformer
PJM	Plano	345	138	06-2014	Install 1st 345/138kV autotransformer,b0661
PJM	New auto installed at TSS 86 Davis Creek	345	138	06-2015	Install third auto transformer at TSS 86 Davis Creek substation
PJM	New auto installed at TSS 120 Lombard	345	138	06-2016	Install third auto transformer at TSS 120 Lombard substation
PJM	Bath	345	138	06-2015	Install 2nd 345/138kV transformer
PJM	West Milton	345	138	06-2015	Install 2nd 345/138kV transformer
PJM	Shelby	345	138	06-2014	Install 2nd 345/138kV transformer
PJM	Qualitech	345	138	06-2013	New Substation

Assessment Area	Transformer Project Name	High-Side Voltage(kV)	Low-Side Voltage(kV)	In-Service (Month-Year)	Description
PJM	New Reynolds	765	345	08-2018	New Transformer
PJM	Crescent	345	138	06-2014	Add 3rd 345/138 kV Autotransformer, s0168
PJM	Logans Ferry	345	138	12-2012	New Logans Ferry 345kV substation with 345/138kV autotransformer, toi334.3
PJM	Collier	345	138	06-2013	Install a No. 3 345/138 kV autotransformer at the Collier substation
PJM	Steele	230	138	06-2013	3rd Transformer, b0725
PJM	Harmony	230	138	06-2013	2nd Transformer, b0733
PJM	Loretto	230	138	06-2017	2nd Transformer, b0753
PJM	Welton Spring	765	500	06-2014	new substation - Suspended
PJM	Kemptown	765	500	06-2014	new substation - Suspended
PJM	502 Junction	500	138	12-2013	First Transformer
PJM	Cranberry	500	138	06-2012	New Sub - 333/448/560 MVA transformer #1
PJM	Cranberry	500	138	06-2012	New Sub - 333/448/560 MVA transformer #2
PJM	Fulton	345	138	06-2013	New Sub - 180/240/336 MVA Transformer
PJM	Hayes	345	138	06-2014	New Sub - 269/358/448 MVA transformer
PJM	Chamberlin	345	138	06-2016	Add 2nd transformer - 240/320/400 MVA
PJM	Raritan River	230	115	06-2013	Second Transformer
PJM	Petersburg	345	138	12-2012	Replace existing 150 MVA transformer with 300MVA unit
PJM	Rapson 1	345	120	12-2013	Thumb Project
PJM	Rapson 2	345	120	12-2013	Thumb Project
PJM	Banner	345	120	12-2015	Thumb Project
PJM	Bunce Creek	220	220	04-2012	Replace PAR with 800MVA (Summer Normal) 2 PARS in Series at Bunce Creek.
PJM	Keystone	345	230	06-2015	0
PJM	Pere Marquette	345	230	06-2015	0
PJM	Weeds Lake	345	138	06-2013	0
PJM	Chichester	230	138	04-2012	Add 2nd transformer tied directly in parallel to existing transformer. Ratings are for the transformer facility with both transformers in parallel.
PJM	Waneeta	230	138	06-2016	Install 2nd Waneeta Transformer
PJM	Brighton	500	230	06-2012	Replace Existing Transformer
PJM	Burches Hill	500	230	06-2013	3rd Transformer
PJM	Benning	230	115	06-2012	New 115kV Station at Benning - there are 2 trs at this sub - TR 13 ratings shown
PJM	Benning	230	115	06-2012	New 115kV Station at Benning - there are 2 trs at this sub - TR 14 ratings shown
PJM	Lackawanna	500	230	06-2015	In-service date changed; 750 MVA nameplate. #3
PJM	Lackawanna	500	230	06-2015	In-service date changed; 750 MVA nameplate. #4
PJM	Lackawanna	230	138	12-2017	(New 230-138 kV Substation - Add transformer #5) (336 MVA Nameplate)
PJM	Lackawanna	230	138	12-2017	(New 230-138 kV Substation - Add transformer #6) (336 MVA Nameplate)
PJM	Elroy	500	138	06-2012	Install a second Elroy 500/138 kV transformer,b0614.1
PJM	Jenkins	230	138	12-2017	(New 230-138 kV Substation - Add transformer #5) (336 MVA Nameplate)
PJM	Jenkins	230	138	12-2017	(New 230-138 kV Substation - Add transformer #6) (336 MVA Nameplate)
PJM	Breinigsville	500	138	06-2015	New 500-138 kV Sub - Add Transformer #1 (336 MVA)
PJM	Monroe	230	138	12-2014	Add 2nd 230/138 kV Transformer (336 MVA)
PJM	North Lancaster	500	230	06-2017	750 MVA nameplate.(New 500-230 kV Substation - Add transformer #1)
PJM	Roseland	500	230	06-2012	First Transformer, b0489.4
PJM	Roseland	500	230	06-2012	Second Transformer, b0489.4
PJM	Bergen	230	138	06-2014	Install 230/138 kV transformer at Bergen substation
SERC-E	Horse Gap to Watauga Relocation	230	99	Dec-2020	Planned/Move three single phase transformers from Horse Gap Substation to new Watauga 230 kV Substation.
SERC-E	West end 230 kV Transformers	230	115	Jun-2012	Under Construction/Replace existing 200 MVA transformers with new 300 MVA transformers
SERC-E	Folkstone 230 kV Substation	230	115	Jun-2013	Under Construction/Install 1-200 MVA 230/115 kV transformer
SERC-E	Selma 230/115 kV Transformer	230	115	Jun-2013	Conceptual/Replace exsiting 200 MVA with a 300 MVA transformer
SERC-E	Mt. Olive 230 kV substation	230	115	Dec-2011	Complete/Install 1-200MVA 230/115 kV Transformer
SERC-E	Fayetteville 230/115 kV Transformer	230	115	Jun-2014	Conceptual/Replace both 200 MVA transformer with 300 MVA banks.
SERC-E	Falls 230/115 kV Transformer	230	115	Jun-2016	Planned/Add 2nd 230/115 kV 300MVA transformer
SERC-E	Orangeburg	230	115	Dec-2012	Under Construction/New station under construction
SERC-E	Pomaria	230	99	Jun-2013	Planned/approval is pending
SERC-E	Purrysburg	230	115	Dec-2014	Conceptual/future substation
SERC-E	Bucksville	230	115	Jun-2014	Conceptual/future substation
SERC-E	Wassamassaw	230	115	Jun-2017	Conceptual/future substation
SERC-E	Winnsboro	230	99	Sep-2013	Planned/associated with nuclear integration
SERC-E	Richburg	230	99	Jun-2014	Planned/associated with nuclear integration
SERC-E	Sandy Run	230	115	Jun-2015	Conceptual/associated with nuclear integration
SERC-E	St. George	230	115	Apr-2018	Conceptual/associated with nuclear integration

Assessment Area	Transformer Project Name	High-Side Voltage(kV)	Low-Side Voltage(kV)	In-Service (Month-Year)	Description
SERC-E	Varnville	230	115	May-2019	Conceptual/associated with nuclear integration
SERC-E	Lake Murray 230/115kV #2	230	115	May-2013	Planned/Add 2nd 336 MVA transformer
SERC-E	Lake Murray 230/115kV #3	230	115	Dec-2015	Cancelled/Add 3rd 336MVA transformer
SERC-E	CIP 230/115kV #2	230	115	May-2020	Planned/Add 2nd 336MVA transformer
SERC-E	Denny Terrace 230/115kV #3	230	115	Dec-2015	Cancelled/Add 3rd 336MVA transformer
SERC-E	Ritter 230/115kV	230	115	Feb-2011	Complete/Construction 336MVA Substation
SERC-E	Graniteville 230/115kV #3	230	115	May-2012	Under Construction/Add 3rd 336MVA transformer
SERC-E	Carolina Forest	230	115	Jun-2012	Under Construction
SERC-E	Saluda River 230/115 kV	230	115	May-2015	Planned/Construct 230/115 kV 336 MVA Autotransformer
SERC-E	Cainhoy 230/115kV	230	115	May-2014	Planned/Construct 230/115 kV 336 MVA Autotransformer
SERC-E	Raeford 230/115 kv transformers, replace existing	230	115	Jun-2018	Planned/Replace two existing 200 MVA with 300 MVA transformers
SERC-N	4th Middletown 345/138	345	138	Dec-2013	Planned/Install 4th 345/138kV transformer at Middletown
SERC-N	Battlefield (NES)	161	99	Jun-2013	Planned/Add 161:69kV 200 MVA transformer to Battlefield substation
SERC-N	Clay, MS	500	161	Jun-2012	Under Construction/Install four single phase 500-161 kV transformers
SERC-N	Montgomery, TN	500	161	Jun-2013	Under Construction/Install three, single phase 500-161 kV transformers
SERC-N	Houston Levee sub 73 - Add 3rd Bank (MLGW)	161	99	Unknown	Under Construction/Add 3rd bank to existing substation
SERC-N	Lakeland Sub 85-Add 3rd bank (MLGW)	161	99	Dec-2012	Planned/Add 3rd bank to existing substation
SERC-N	34645 replacement (MLGW)	161	115	Unknown	Under Construction/replacement due to in-service failure (replacement has higher rating)
SERC-N	2nd Brown North 345/138kV	345	138	May-2015	Conceptual/Add a 2nd Brown North 345/138kV Transformer
SERC-N	Matanzas 161/138kV #1	161	138	Mar-2013	Planned/New Matanzas #1 161/138kV Transformer
SERC-N	Matanzas 161/138kV #2	161	138	Mar-2013	Planned/Add Matanzas #2 161/138kV Transformer
SERC-N	Jasper	345	161	Jun-2012	Planned/Planned
SERC-N	Barnett	345	161	Jun-2016	Planned/Planned
SERC-N	Wheaton	345	161	Jun-2015	Planned/Planned
SERC-N	Enon	345	161	Jun-2016	Planned/Planned
SERC-N	Thomas Hill #2	345	161	Jun-2013	Planned/Planned
SERC-SE	Bonaire	500	230	Dec-2012	Under Construction/Spare Single Phase Unit
SERC-SE	Hopewell	230	115	Jun-2015	Cancelled
SERC-SE	Sharon Springs	230	115	Jun-2018	Planned/New Substation
SERC-SE	East Social Circle	230	115	Jun-2014	Cancelled/Second transformer
SERC-SE	East Walton	500	230	Jun-2017	Planned/New substation
SERC-SE	Dresden	500	230	May-2014	Under Construction/New Substation
SERC-SE	Turf Club	230	115	May-2022	Indefinitely Postponed/Add transformation at Turf Club
SERC-SE	South Bessemer AUTO #2	230	115	May-2022	Indefinitely Postponed/Install second auto at South Bessemer; No longer needed within planning horizon
SERC-SE	Holt TS - Tuscaloosa TS AutoBank	230	115	May-2011	Complete/Install 230/115kV AutoBank at Tuscaloosa TS
SERC-SE	Greene County AutoBank	230	115	May-2013	Planned/Add 400MVA 230/115kV Autobank#2 at Plant Greene County
SERC-SE	South Duncanville AutoBank	230	115	May-2015	Cancelled/Add 400MVA 230/115kV Autobank at South Duncanville
SERC-SE	Farley 500/230kV #1 & #2 Autos	500	230	May-2019	Planned/Replace lowside equipment to achieve higher rating; No longer needed until 2019
SERC-SE	North Opelika Bank #2	230	115	May-2022	Indefinitely Postponed/Install second auto at North Opelika; No longer needed in planning horizon
SERC-SE	Autaugaville 500/230kV Auto	500	230	Jun-2012	Planned/Install new auto at Autaugaville 500 kV sub
SERC-SE	County Line Rd Bank #2	230	115	May-2014	Planned/Install second auto at County Line Road
SERC-SE	Silverhill	230	115	Jun-2021	Planned/Install a third autobank (400MVA unit)
SERC-SE	Middle Fork 500/230 kV Project	500	230	Unknown	Indefinitely Postponed/New 2016 MVA auto addition; Postponed
SERC-SE	Gainesville #2 230/115 kV Bank B	230	115	Jun-2015	Cancelled/Bundle LS jumpers and main bus, and raise the relay settings on the LSBUOC to allow for the Bank bonus rating of 339 MVA.

Assessment Area	Transformer Project Name	High-Side Voltage(kV)	Low-Side Voltage(kV)	In-Service (Month-Year)	Description
SERC-SE	Gainesville #2 230/115kV Bank C	230	115	Jun-2018	Indefinitely Postponed/Replace the existing autobank with a 400 MVA autobank.
SERC-SE	Gainesville #2 230/115 kV Bank B	230	115	Jun-2018	Indefinitely Postponed/Replace the existing autobank with a 400 MVA autobank.
SERC-SE	O'Hara 500/230 - kV Tfm#2 Addition	500	230	Unknown	Indefinitely Postponed/Add a second 2000 MVA, 500/230-kV tfm. at O'Hara
SERC-SE	South Metro Atlanta Project Phase-3	230	115	Jun-2018	Planned/Install 1- 400 MVA Tfm. at McDonough Primary substation
SERC-SE	Corn Crib 230/115 kV Project	230	115	Jun-2018	Planned/New 230/115-kV substation with a 300MVA bank
SERC-SE	Offerman Third 230/115 kV Transformer	230	115	Jun-2019	Cancelled/140 MVA
SERC-SE	S. Macon 230/115kV TFM Replacement	230	115	Unknown	Indefinitely Postponed/Replace existing autobanks w/ 400MVA autobanks
SERC-SE	Snellville 230/115 kV Transformer	230	115	May-2016	Indefinitely Postponed/Replace 1600A low-side breaker with 2000A breaker
SERC-SE	Roswell 230/115 kV Transformer Project	230	115	May-2018	Indefinitely Postponed/Install a 230/115kV transformer in the Roswell substation
SERC-SE	Scottdale 230/115kV Transformer	230	115	Unknown	Indefinitely Postponed/Add a 2nd 230/115kV transformer at Scottdale
SERC-SE	Plant McDon. Network Impvmts-P'tree Tfm. Removal	230	115	May-2013	Planned/Plant McDon. Network Impvmts-P'tree Tfm. Removal
SERC-SE	East Carrollton 230/115kV transformer	230	115	Unknown	Indefinitely Postponed/New 230/115-kV substation with a 300MVA bank
SERC-SE	Factory Shoals 230/115kV transformer	230	115	May-2011	Complete/New 230/115-kV substation with a 300MVA bank
SERC-SE	Meldrim	230	115	Feb-2012	Planned/new 300 MVA, 230/230-kV xfr
SERC-SE	Boulevard	230	115	Jun-2015	Planned/^new 300 MVA, 230/230-kV xfr
SERC-SE	Dorchester	230	115	Jun-2017	Planned/2nd 400 MVA, 230/230-kV xfr
SERC-SE	McIntosh	230	115	Jun-2016	Planned/replace 280 MVA, 230/230-kV xfr W/ 400 MVA xfr
SERC-SE	Waynesboro	230	115	Jun-2019	Planned/replace 280 MVA, 230/230-kV xfr W/ 400 MVA xfr
SERC-SE	Laguna Beach	230	115	Dec-2012	Planned/400 MVA Bank#2
SERC-SE	Santa Rosa BK1	230	115	Jun-2015	Planned/400 MVA Bank#1
SERC-SE	Santa Rosa BK2	230	115	Jun-2015	Planned/400 MVA Bank#2
SERC-SE	Shoal River	230	115	Jun-2022	Planned/400 MVA Bank#2
SERC-SE	Carriere SW	230	115	Jul-2011	Complete/New Substation / Under Construction
SERC-SE	Vimville	230	115	Mar-2013	Planned/New Substation
SERC-SE	Orange Grove	230	115	Jun-2022	Planned/New Substation
SERC-SE	Highland City	230	115	Jun-2013	Planned/400 MVA Bank #1
SERC-SE	Meridian NE Bank 1	230	115	Jun-2013	Planned/Replace Transformer / On Order
SERC-SE	Meridian NE Bank #2	230	115	Jun-2013	Planned/Replace Transformer / On Order
SERC-SE	Ocean Springs Bank #2	230	115	Dec-2014	Planned/Installing a parallel 230/115 kV transformer in an existing station
SERC-SE	Newnan Primary	115	99	Apr-2011	Complete/Replace aged 115/46kV transformer
SERC-SE	silver Creek Interconnection	161	115	Aug-2011	Complete/Silver Creek Interconnection
SERC-SE	Waynesboro Transformer Replacemtn	230	161	Apr-2011	Under Construction/Waynesboro 230/161kV Substation
SERC-SE	Silver Creek Interconnection	161	99	Jun-2011	Planned/Prentiss 161/69kV Substation
SERC-SE	South Hoy 161kV Transmission Project	161	99	Jun-2013	Planned/South Hoy 161/69 kV Substation
SERC-SE	East Waynesboro Substation	161	99	Jun-2013	Planned/East Waynesboro 230/69/ kV Substation
SERC-SE	North Selma Bank #1	230	115	May-2014	Planned/Replace equipment to achieve higher rating
SERC-SE	South Enterprise Bank #1	230	115	May-2015	Planned/New auto at South Enterprise
SERC-SE	Union City	500	230	Jun-2013	Planned/Spare Single Phase Unit
SERC-SE	Highway 54	230	115	Jun-2019	Planned/New transformer
SERC-SE	Moundville AutoBank	230	115	May-2015	Planned/Add 400MVA 230/115kV Autobank at Moundville
SERC-SE	Gadsden 115kV/44kV Replacements	115	99	Dec-2012	Planned/Repalce 2 existing transformers with 2 60MVA Banks

Assessment Area	Transformer Project Name	High-Side Voltage(kV)	Low-Side Voltage(kV)	In-Service (Month-Year)	Description
SERC-SE	North Tifton 500/230kV Auto Replacement	500	230	Jun-2015	Planned/Replace existing 1350-MVA 500/230 kV auto with a new 2016 MVA 500/230 kV auto.
SERC-SE	Northwest 230/115kV Transformer Bank A	230	115	Jun-2014	Planned/Re-rate the existing 280 MVA 230/115 kV auto
SERC-SE	Northwest 230/115 kV Transformer Bank B	230	115	Jun-2014	Planned/Re-rate the existing 280 MVA 230/115 kV auto
SERC-SE	Offerman 230/115kV Autobank Replacements	500	230	Jun-2016	Planned/Replace existing 140 MVA 230/115 kV auto transformers with two 280-300 MVA 230/115 kV auto transformers.
SERC-SE	Scottdale 230/115kV Transformer	230	115	Jun-2020	Planned/Replace 1590 AAC low side jumpers with 2500 AAC jumpers
SERC-SE	South Hall 500/230kV Project	500	230	Jun-2018	Planned/Add a second 2016 MVA, 500/230-kV tfm. at South Hall
SERC-SE	Thomson Primary 230/115kV Project	230	115	Jun-2021	Planned/Install a 2nd 300 MVA, 230/115 kV transformer
SERC-SE	Bassett Creek 230/115kV	230	115	Jun-2015	Planned/Bassett Creek 230/115kV XFMR
SERC-W	Holland Bottoms 500-115	500	115	Dec-2011	Under Construction/Add a new 500-115 kV Substation in Little Rock
SERC-W	Holland Bottoms 500-161	500	161	Jun-2012	Planned/Add a new 500-161 kV Substation in Little Rock
SERC-W	Acadiana Area Improvement Project Phase 1	230	138	May-2011	Complete/Add 500 MVA, 230-138 kV auto at Meaux
SERC-W	Sarepta	345	115	Jun-2011	Under Construction/Construct a new 345-115 kV substation consisting of a 500 MVA auto. Cut station into EL Dorado to Longwood 345 kV line.
SERC-W	Ouachita Transmission Service	500	115	Jun-2012	Planned/Split Sterlington 115 kV bus and replace 500-115 auto #2 with 750 MVA
SERC-W	McAdams	500	230	Jun-2011	Complete/Add 2nd 500/230kV Auto
SERC-W	S.Grenada	230	115	Jun-2012	Planned/Add 230/115kV Auto
SERC-W	Baxter Wilson	500	115	Jun-2012	Under Construction/Add 2nd 500/115kV Auto
SERC-W	Senatobia Industrial	230	115	Jun-2016	Planned/Add 230/115kV Auto
SERC-W	Grimes	345	138	Jun-2018	Conceptual/Add 3rd auto at Grimes; rated 525 MVA
SERC-W	Cypress	500	138	Jun-2018	Conceptual/Add 2nd auto at Cypress; rated 750 MVA
SERC-W	Hartburg	500	230	Jun-2017	Conceptual/Add 2nd auto at Hartburg; rated 800 MVA
SERC-W	PineBluff Voltage Support	500	230	Jun-2015	Planned/Add new 500-230 kV auto at White Bluff
SERC-W	Mabelvale - Replace Autos	500	115	Jun-2016	Planned/Replace existing (2) autos with 800MVA units
SERC-W	SELA Improvement Plan Phase 3	230	115	Jun-2012	Planned/230-115 kV auto at Alliance
SERC-W	Sorrento Upgrade Auto	138	115	Jun-2014	Planned/Sorrento Upgrade 138/115 kV Auto
SPP	Turk	345	138	Sep-2012	
SPP	Canadian River	345	138	Jun-2013	
SPP	Diana	345	138	Jun-2013	
SPP	Shipe Road	345	161	Jun-2014	
SPP	Osage Creek	345	161	Jun-2014	
SPP	Tonnece Substation	345	161	Jul-2012	Transformer installed but not yet energized
SPP	EASTOWN SUB ADDITION	345	161	Dec-2012	
SPP	NASHUA	345	161	Jan-2015	
SPP	ALP	230	138	May-2012	230/138kV 300 MVA transformer at Bonin
SPP	Ogallala T-1 Replacement	230	115	Jun-2014	Replaces existing 187 MVA T-1 with 336 MVA
SPP	Stegall T-2 Addition	345	230	Jun-2015	Addition of second 400 MVA transformer at Stegall
SPP	Ft Smith	500	161	Jun-2017	
SPP	Greenwood	138	69	Jun-2014	
SPP	Woodward EHV	345	138	Jun-2014	
SPP	Northwest	345	138	Jun-2017	
SPP	Pleasant Hill	230	115	Jun-2014	
SPP	Cherry St. Intg.	230	115	Jun-2013	
SPP	Randall County	230	115	Apr-2013	2nd autotransformer
SPP	TUCO	345	230	Jun-2012	2nd autotransformer
SPP	Hitchland-Woodward Project	345	230	Jun-2012	2nd autotransformer

Appendix III: Projected Transformer Projects

Assessment Area	Transformer Project Name	High-Side Voltage(kV)	Low-Side Voltage(kV)	In-Service (Month-Year)	Description
SPP	Potter	230	115	Jun-2012	
SPP	Swisher	230	115	Jun-2017	transformer upgrade to 250 MVA
SPP	XIT	230	115	Dec-2015	new 250 MVA; part of 115 to 230kV conversion
SPP	Eddy County	230	115	Apr-2013	2nd autotransformer
SPP	Table Rock 1	161	69	Dec-2012	Replacement
SPP	Paragould 3	161	69	Dec-2013	Replacement
SPP	Poplar Bluff 2	161	69	Dec-2014	Replacement
SPP	Nixa 1	161	69	Dec-2015	Replacement
SPP	Paragould 2	161	69	Dec-2016	Replacement
SPP	Table Rock 2	161	69	Dec-2017	Replacement
SPP	Table Rock 1	161	69	Dec-2012	Replacement
SPP	Rose Hill	345	138	Jun-2013	
SPP	87th Street	345	115	Dec-2012	
SPP	Auburn	230	115	Jun-2014	
SPP	Summit	345	115	Dec-2014	
SPP	Baldwin Creek	230	115	Jun-2015	
SPP	N Manhattan	230	115	Jun-2012	
SPP	Viola	345	138	Dec-2015	Conceptual
SPP	Cocodrie Auto #2	230	138	Jul-2012	Second Autotransformer at Cocodrie Substation
SPP	Wells Auto #2	500	230	Jun-2012	Second Autotransformer at Wells Substation
SPP	Rork Auto #2	230	138	Jul-2012	Second Autotransformer at Rork, From Acadia Power Plant
WECC-US	North Gila	500	230	Jun-2014	Planned
WECC-US	Sun Valley	500	230	Jun-2014	Planned
WECC-US	Meridian T2	500	230	Oct-2013	Coquitlam, near Vancouver
WECC-US	Kelowna Bulk Transformer Capacity Addition	230	138	Dec-2015	Third transformer will be added at the LEE Terminal to provide adequate transformation capacity to supply Kelowna area load during single contingency conditions.
WECC-US	Kitimat Modenization Project	287	25	Feb-2014	Five 287/100/28 kV 219 MVA regulating transformers will be installed (Low-side is 100/25)
WECC-US	Hooper Springs	138	115	Dec-2014	Construct a 200 MVA Hooper Springs Substation adjacent to Three Mile Knoll (PAC) substation. Re-assessing plan of service that has least environmental impacts.
WECC-US	Ponderosa Transformer Addition	500	230	Oct-2013	Central Oregon Reinforcement project, 700 MVA 500/230 transformer at Ponderosa substation. Under construction.
WECC-US	Rocky Reach Auto Transformer #1	230	115	Dec-2016	Transformer Replacement Conceptual
WECC-US	Alberhill System Project	500	115	Jun-2014	This project includes installation of: (a) one 500/115kV substation; (b) two new 500kV line segments; (c) two new 560 MVA 500/115kV transformers; (d) a new 115kV subtransmission line; and (e) modifications to existing 115kV lines
WECC-US	Bayfront Substation Project	230	69	Dec-2012	This project includes installation of: (a) one 230/69kV substation to replace the existing 138/69kV South Bay substation; (b) two 224 MVA 230/69kV transformers; (c) loop in Miguel - Silvergate 230kV line into new substation; (d) transfer all existing 69kV lines from existing South Bay substation to the new substation; (e) re-configure existing 138kV lines to eliminate the need for South Bay 138kV bus
WECC-US	Sunrise Powerlink Project	500	230	Jun-2012	This project includes the following major installation of: (a) one new 500/230kV Suncrest Substation; (b) two new 1120 MVA 500/230kV transformers at Suncrest Substation; (c) one new 500kV line from Imperial Valley to Suncrest substation; (d) two new 230kV overhead/underground lines/cables from Suncrest to Sycamore Canyon substation
WECC-US	Rapids Transformer	230	115	Dec-2013	Transformer at Rapids Switchyard connecting 230-kV bus to 115-kV bus
WECC-US	PICANTE	345	115	Aug-2011	Completed
WECC-US	AFTON	345	115	May-2015	Conceptual
WECC-US	Midpoint S/S	345	230	Jun-2012	Replace existing 500 MVA with new 700 MVA (expected schedule)
WECC-US	Justice S/S	230	138	Dec-2012	New Tie Bank (expected schedule) (Location change - King to Justice)
WECC-US	Borah S/S	500	345	Jun-2019	New Tie Bank (expected schedule)
WECC-US	Bowmont	500	345	Jun-2016	Tie Bank #2
WECC-US	Langley	230	138	Jun-2012	New Tie Bank
WECC-US	Harry Allen 500 /230 kV TX #3	525	230	Dec-2014	Conceptual
WECC-US	Harry Allen 345 /230 kV TX #3	345	230	Jun-2011	In Service
WECC-US	Colstrip 230	230	100	Oct-2011	In Service
WECC-US	Great Falls 230 Switchyard	230	100	Jun-2012	On Site
WECC-US	South Butte	230	161	Dec-2012	In 2012 Budget
WECC-US	Horizon to Sunset	230	115	Jun-2012	Install a 230/115 kV, 320 MVA auto transformer at Horizon Substation
WECC-US	Bethel	500	230	Jan-2017	Installation of a new 500/230 kV transformer bank at PGE's Bethel Substation located in Salem, Oregon
WECC-US	Bethel	230	115	Jan-2017	Replacement of a existing 230/115 kV transformer bank at PGE's Bethel Substation located in Salem, Oregon
WECC-US	Rio Puerco	345	115	May-2011	Fully constructed

Assessment Area	Transformer Project Name	High-Side Voltage(kV)	Low-Side Voltage(kV)	In-Service (Month-Year)	Description
WECC-US	Yatahey Transformer	345	115	Dec-2015	
WECC-US	Ojo Transformer	345	115	Dec-2014	
WECC-US	Nyberg 115 kV Substation	115	13.8	Unknown	In service during 2011
WECC-US	Overton 115 kV Substation	115	13.8	12-2013	
WECC-US	Reader Tranformer Replacements	115	13.8	12-2013	Replace the two exiting 41 MVAs with two 80 MVAs
WECC-US	Rattlesnake Butte Substation	115	13.8	12-2012	
WECC-US	Boone 230:115 kV Transformer #2	230	115	12-2013	
WECC-US	Fordham T1	230	115	Dec-2011	In service
WECC-US	Fordham T2	230	115	Dec-2011	In service
WECC-US	Horseshoe T1	230	115	May-2012	under construction
WECC-US	Horseshoe T2	230	115	May-2012	under construction
WECC-US	Timberline T2	230	115	May-2013	Planned
WECC-US	Boyd T2	230	115	May-2015	Planned
WECC-US	Missile Site	345	230	Jun-2013	
WECC-US	Alderton Substation Transformer	230	115	Oct-2014	New 230/115-kV transformer at Alderton to feed load growth in Pierce County.
WECC-US	Sedro Woolley Substation Transformer #2	230	115	Oct-2012	New 230/115-kV transformer at Sedro Woolley to feed load growth in Skagit County.
WECC-US	St. Clair Substation Transformer	230	115	Oct-2013	New 230/115-kV transformer at St. Clair to feed load growth in Thurston County.
WECC-US	Lakeside Substation Transformer	230	115	Oct-2017	New 230/115-kV transformer at Lakeside to feed load growth in King County.
WECC-US	Foss Corner Transformer	230	115	Oct-2018	New 230/115-kV transformer at Foss Corner to feed load growth in Kitsap County. This project is conceptual.
WECC-US	Heyborne Substation	60	12.5	Jun-2009	24/32/40 MVA (120kV Initially connected at 60 kV)
WECC-US	Thorne	120	60	Jun-2011	75 MVA (Low-side is 60/12.5)
WECC-US	3rd Kyrene 500/230kV Transformer	500	230	May-2012	Transformer
WECC-US	Pinal Central #1 500/230kV Transformer	500	230	May-2014	Transformer
WECC-US	Pinal Central #2 500/230kV Transformer	500	230	May-2014	Transformer
WECC-US	Vail T3	345	138	May-2012	Substation mdifications are in progress to install transformer upon arrival. Project is on schedule.
WECC-US	Almond GSU #1	115	13.8	May-2012	
WECC-US	Almond GSU #2	115	14	May-2012	
WECC-US	Almond GSU #3	115	14	May-2012	
WECC-US	Grayson	115	69	Mar-2012	
WECC-US	Minnekahta 230/69 kV Substation	230	69	12-2011	70 MVA. Went into service on 12-2011
WECC-US	St. Onge 230/69 kV Substation	230	69	12-2014	150 MVA
WECC-US	East Business Park 115 kV Substation	115	13.8	12-2012	Cheyenne, WY Service Area
WECC-US	North Range 115 kV Substation	115	13.8	12-2012	Cheyenne, WY Service Area
WECC-US	Swan Ranch 115 kV Substation	115	13.8	12-2012	Cheyenne, WY Service Area
WECC-US	Ault 230/115kV XFMR Addition	230	115	12-2012	Phase 2 of the Ault-Cheyenne Project
WECC-US	Laramie River Station 345/230 kV Transformer #2	345	230	Sep-2013	Install a second 345/230 kV - 600 MVA Transformer at the Laramie River Station (LRS).
WECC-US	Liberty Substation Replacement	345	230	Jan-2013	Replace existing 600 MVA unit with like
WECC-US	Mead Substation Replacement	345	230	Jan-2016	Replace existing 600 MVA unit with 1200 MVA
WECC-US	Coolidge Transformer Addition	230	69	Jan-2014	Install new 150 MVA unit

Appendix III: Projected Transformer Projects

Assessment Area	Transformer Project Name	High-Side Voltage(kV)	Low-Side Voltage(kV)	In-Service (Month-Year)	Description
WECC-US	Great Falls	230	161	Jun-2012	100 MVA unit. Replaces existing 161/100 kV Rainbow unit. Includes relocation of interconnect with NWE from Rainbow 100 kV to Great Falls 230 kV.
WECC-US	Bowdoin	230	115	Jun-2013	33 MVA unit to serve new substation tap located between existing Richardson Coulee and Malta 161 kV substations for the purpose of new oil load development. (Considered either 161 kV or 230 kv)
WECC-CAN	Livock Phase Shifter	240	240	Jun-2012	
WECC-CAN	Heartland	500	240	Oct-2012	
WECC-CAN	Wolf Creek	240	138	Mar-2013	
WECC-CAN	Hazelwood	240	138	Mar-2013	
WECC-CAN	Johnson	240	138	Mar-2013	
WECC-CAN	Nilrem	240	138	Apr-2012	
WECC-CAN	Pemukan	240	138	May-2013	
WECC-CAN	Lanfine	240	138	Mar-2013	
WECC-CAN	CoyoteLake	240	138	Apr-2013	
WECC-CAN	SS-65	240	138	Jul-2013	
WECC-CAN	Foothills	240	138	Jan-2015	
WECC-CAN	Chapel Rock	500	240	Apr-2016	
WECC-CAN	Fidler	240	138	Aug-2015	
WECC-CAN	Journault	240	138	Jul-2015	
WECC-CAN	Whitla	240	138	Mar-2014	
WECC-CAN	Bowmanton	240	138	Mar-2014	
WECC-MX	Metropoli	230	115	Jan-2016	Planned
WECC-MX	Tijuana	230	115	Jan-2016	Planned
WECC-MX	Cucapah	400	230	Apr-2014	Planned
WECC-MX	Santa Isabel	230	161	Jun-2014	Planned

Appendix IV: About This Assessment

About This Report

The *2012 Long-Term Reliability Assessment* provides an independent view of the 10-year reliability outlook for the North American BPS,[297] while identifying trends, emerging issues, and potential risks. Additional insight will be offered regarding resource adequacy and operating reliability, as well as an overview of projected electricity demand growth for individual assessment areas. The 10-year period observed in this assessment is from 2013-2022, with the 2013 summer as the initial season. Information and data for the 2012 summer and 2012/2013 winter seasons are provided in NERC's seasonal reliability assessments.[298] This new approach eliminates overlap between seasonal and long-term assessments.

2012 Assessment Structure

New for 2012, NERC's seasonal and long-term reliability assessments have been restructured. Prior NERC assessments included Regional or Assessment Area sections with resource adequacy projections combined with additional information describing the methods and assumptions used to arrive at these projections.[299] The resource adequacy outlook for each assessment area is constantly changing, based on the most recent demand forecast, or announcements of new capacity or capacity retirements. However, the methods and assumptions used by each assessment area are more consistent. Therefore, this information (including the most current load forecasting models, resource adequacy studies, and other information used in the development of the seasonal and long-term projections) has been removed from the assessment area sections of the *2012 Long-Term Reliability Assessment* and instead been posted separately on the NERC website.

NERC Assessment Areas

Prior to 2011, NERC seasonal and long-term reliability assessments collected and presented data and information based on Regional Entity boundaries. These boundaries were established through consideration of the respective membership of each Regional Entity, comprising both Planning Coordinators and Load Serving Entities (LSEs). There are approximately 80 NERC Planning Coordinators, 10 of which are Independent System Operators (ISOs) or Regional Transmission Organizations (RTOs), and which encompass a large portion of North America. Four of these Planning Coordinators operate in the Regional Entities listed below:

- American Transmission Co., LLC: MRO, RFC
- Midwest Independent Transmission System Operator, Inc: MRO, RFC, SERC
- PJM Interconnection, LLC: RFC, SERC
- Southwest Power Pool: MRO, SPP

Historically, these four Planning Coordinators have provided capacity and load data to multiple Regional Entities. Consequently, this data was divided based on political boundaries that failed to accurately reflect the planning and operational properties of the BPS. This approach has reduced the accuracy of the resource and demand balance in these four Planning Coordinators that span over multiple Regional Entity boundaries. Taking these considerations into account, NERC instituted the following assessment areas in the 2011:

[297] 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 account for 80 percent of all electricity supply interruptions to end-use customers.
[298] NERC *2012 Summer Reliability Assessment* and *2012/2013 Winter Reliability Assessment*: http://www.nerc.com/page.php?cid=4|61.
[299] 2012 LTRA methods and assumptions: http://www.nerc.com/files/2012LTRA_PartII.pdf.

Figure A: 2012 LTRA Assessment Areas[300]

It is important to note that ISO/RTO boundaries are subject to change over time, due to consolidation of LSEs and alterations in resource planning and acquisition arrangements. NERC's Assessment Areas will adjust accordingly, and any potential changes will be identified in future reliability assessments.

The term "Assessment Area" has been applied consistently throughout this reliability assessment. However, the terms "Region" or "subregion" may also be used when the Assessment Area boundaries are synonymous to the Regional Entity or subregional boundaries.[301]

Demand, Resources, and Reserve Margin Concepts

Demand

NERC uses the following terms to categorize on-peak electricity demand:

- **Total Internal Demand**: The sum of the metered (net) output of all generators within the system and the metered line flows into the system, less the metered line flows out of the system (forecast). Total Internal Demand includes adjustments for indirect Demand-Side Management programs such as Conservation programs, improvements in efficiency of electricity use, and all load-modifying non-dispatchable Demand Response programs.

[300] For NERC's seasonal reliability assessments, WECC is divided into four subregions: Northwest Power Pool (NWPP), Rocky Mountain Reserve Group (RMRG), Southwest Reserve Sharing Group (SRSG), and California/Mexico (CAMX). These seasonal subregions are structured around WECC's Reserve Sharing Groups that experience similar demand patterns and employ similar operating practices. Additionally, the Western Reliability Coordination Offices collect actual demand data from the Reserve Sharing Groups, and leveraging the same footprints allows for consistent comparisons between demand forecasts and actual demands. NERC further divides the CAMX and NWPP subregions to provide additional data granularity for Canada and Mexico. For additional information, refer to the WECC section.

[301] For example, the ERCOT Assessment Area is synonymous to the ERCOT ISO and TRE Regional Entity; however, there is a PJM Assessment Area, but no PJM region within this assessment.

- **Net Internal Demand**: Total Internal Demand less Dispatchable, Controllable Capacity Demand Response used to reduce peak load and not counted as a resource. This value is used in the Planning Reserve Margin calculation.

Capacity Resources

NERC uses the following terms to categorize Capacity Resources and transactions in seasonal assessments:

Existing Capacity Resources

- **Existing-Certain**: Existing generation resources available to operate and deliver power within or into the Assessment Area during the period of assessment.
- **Existing-Other**: Existing generation resources that may be available to operate and deliver power within or into the Assessment Area during the period of assessment, but that may be curtailed or interrupted at any time for various reasons.
- **Existing-Inoperable**: Existing portion of generation resources that are out of service and cannot be brought back into service to serve load during the period assessment.
- Future-Planned: Generation resources anticipated to be available to operate and deliver power within or into the Assessment Area during the period of assessment.
- **Future-Other**: Future generating resources that do not qualify in Future-Planned and are not included in the Conceptual Category.

Capacity Transactions

- **Net Firm and Expected Transactions**: Firm and Expected Imports, minus Firm and expected exports, including all Firm contracts with a reasonable expectation to be implemented.

Reserve Margins

Reserve Margins are capacity-based metrics and do not provide a comprehensive assessment of performance in energy-limited systems (e.g., hydro capacity with limited water resources or systems with significant variable generation). Each Capacity Resource Category is also used to calculate each different Planning Reserve Margin.

Planning Reserve Margins for each Assessment Area are compared to the NERC Reference Margin Level, which is assigned for each NERC Assessment Area as defined and imposed by the corresponding Regional Entity, State Public Utility Commission, Provincial authority, or other delegating body. In the absence of a defined Reference Margin, NERC has applied 10 or 15 percent Reference Margin Levels for predominately hydro or thermal systems, respectively.

The NERC Reference Margin Level serves as a basis for determining whether more resources (e.g., generation, Demand-Side Management, capacity transfers) may be needed within that Assessment Area.

Demand and Supply forecasts were reported between February and August, 2011 depending on the Assessment Area.

Values for both Total Internal Demand and Net Internal Demand for each Assessment Area represent on-peak projections.

The WECC-United States peak demands or resources do not necessarily equal the sums of the non-coincident WECC-United States subregional peak demands or resources because of subregional monthly peak demand diversity. Similarly, the Western Interconnection peak demands or resources do not necessarily equal the sums of the non-coincident WECC-United States, Canada, and Mexico peak demands or resources. In addition, the subregional resource numbers include use of seasonal demand diversity between the winter-peaking northwest and the summer-peaking portions of the Western Interconnection.

- **2012 Updated Reserve Margin Calculations**

The continued saturation of Demand Response highlights the need for NERC's reliability assessments to accurately reflect how these resources are treated in each Assessment Area. Demand Response programs offer different functionality that ultimately depends on how each program is used by the respective Balancing Authority. While some Demand Response programs are considered supply-side resources, others are considered as Demand-Side resources, or load modifiers. In 2010, the NERC Resource Issues Subcommittee (RIS) released several recommendations[302] to address the treatment of Controllable Capacity Demand Response (CCDR) in future NERC reliability assessments. Most importantly, all CCDR were to be considered supply-side resources.

Attempts to impellent a uniform approach presented unforeseen complications in NERC's 2011 reliability assessments. While certain Assessment Areas internally modeled CCDR as a load modifier in their Loss of Load Expectation (LOLE) studies, NERC was collecting and presenting CCDR exclusively as a supply-side resource. The most critical impact was reflected in a misrepresentation of the Assessment Area's Reserve Margins.

The Reliability Assessment Subcommittee (RAS) revisited this issue in early 2012 and provided new recommendations for the treatment of Demand Response. Assessment Areas were asked to report Demand Response based on how it is modeled within their respective LOLE studies. Ultimately, Demand Response should be considered as a Demand-Side resource only if the Assessment Area does not carry reserves for this curtailable demand during the peak.

The modifications to the collection and presentation of CCDR have required additional modifications to the Planning Reserve Margin calculations.

Table A: NERC Reserve Margin Updates

Period	Complete		Simplified
Pre-2011	$RM = \dfrac{[\text{Capacity} + \text{CCDR}_{\text{TOTAL}}] - [\text{Total Internal Demand} - \text{CCDR}_{\text{TOTAL}}]}{[\text{Total Internal Demand} - \text{CCDR}_{\text{TOTAL}}]}$	$\Rightarrow$	$\dfrac{[\text{Capacity} + \text{CCDR}_{\text{TOTAL}}] - \text{Net Internal Demand}}{\text{Net Internal Demand}}$
2011	$RM = \dfrac{[\text{Capacity} + \text{CCDR}_{\text{SUPPLY}}] - \text{Total Internal Demand}}{\text{Total Internal Demand}}$	$\Rightarrow$	$\dfrac{[\text{Capacity} + \text{CCDR}_{\text{SUPPLY}}] - \text{Total Internal Demand}}{\text{Total Internal Demand}}$
2012	$RM = \dfrac{[\text{Capacity} + \text{CCDR}_{\text{SUPPLY}}] - [\text{Total Internal Demand} - \text{CCDR}_{\text{DEMAND}}]}{[\text{Total Internal Demand} - \text{CCDR}_{\text{DEMAND}}]}$	$\Rightarrow$	$\dfrac{[\text{Capacity} + \text{CCDR}_{\text{SUPPLY}}] - \text{Net Internal Demand}}{\text{Net Internal Demand}}$

- **Total Internal Demand** — The sum of the metered (net) output of all generators within the system and the metered line flows into the system, less the metered line flows out of the system (forecast). Total Internal Demand includes adjustments for the indirect Demand-Side Management programs such as Conservation programs, improvements in efficiency of electricity use, and all non-dispatchable Demand Response Programs. This value is used in the Planning Reserve Margin calculation.
- **Net Internal Demand** — Total Internal Demand less Dispatchable, Controllable Capacity Demand Response used to reduce peak load.

[302] Recommendations for the Treatment of Controllable Capacity Demand Response Programs in Reserve Margin Calculations: http://www.nerc.com/docs/pc/ris/RIS_Report_on_Reserve_Margin_Treatment_of_CCDR__Percent2006.01.10.pdf.

Appendix V: Reliability Concepts Used in this Assessment

How NERC Defines BPS Reliability

NERC defines the reliability of the interconnected BPS in terms of two basic and functional aspects:[303]

- **Adequacy** — The ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components.
- **Operating Reliability** — The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components.

Regarding adequacy, system operators should take "controlled" actions or procedures to maintain a continual balance between supply and demand within a balancing area (formerly control area). These actions include:

- Public appeals.
- Interruptible demand—demand that the end-use customer makes available to its LSE via contract or agreement for curtailment.[304]
- Voltage reductions (sometimes referred to as "brownouts" because incandescent lights will dim as voltage is lowered, sometimes as much as 5 percent).
- Rotating blackouts—the term "rotating" is used because each set of distribution feeders is interrupted for a limited time, typically 20–30 minutes, and then those feeders are put back in service and another set is interrupted, and so on, rotating the outages among individual feeders.

Under the heading of Operating Reliability are all other system disturbances that result in the unplanned or uncontrolled interruption of customer demand, regardless of cause. When these interruptions are contained within a localized area, they are considered unplanned interruptions or disturbances. When they spread over a wide area of the grid, they are referred to as "cascading blackouts"—the uncontrolled successive loss of system elements triggered by an incident at any location.

Planning Reserve Margin

The Planning Reserve Margin is a key metric that measures the flexibility of meeting customer demands and handling the loss of one or more system elements, as well as unforeseen, higher-than-expected demands. Specifically, the Planning Reserve Margin is the difference between the total resource capacity (which includes all generation physically available to provide deliverable power to load, transfers from neighboring area, and Demand Response resources designated as a supply-side resource) and system peak demand. It is the fraction of capacity available to provide for scheduled maintenance, emergency outages, system operating requirements, and unforeseen, higher-than-expected demands.

Planning Reserve Margins are needed because a dependable supply of electricity is essential to the health, safety, and economic well-being of customers. Because electricity cannot be stored in large scale quantities and must be produced at the instant it is used, there must always be some margin to allow for the repair and maintenance of equipment and the unavailability of resources.

Planning Reserve Margins differ from Operating Reserve Margins in that Operating Reserve Margins are based on day-ahead and real-time system needs. Operating Reserve Margins, much like shock absorbers, are needed so that the electric system can respond and rebalance when sudden failures of equipment or sudden increases in customer demand occur. This type of margin must be instantly available so the electric system can remain in dynamic balance. Operating reserves include such products as contingency reserves, spinning and non-spinning reserves, and regulation. Operating Reserve Margins also

[303] Additional information regarding the Adequate Level of Reliability (ALR): http://www.nerc.com/docs/pc/Definition-of-ALR-approved-at-Dec-07-OC-PC-mtgs.pdf.
[304] Interruptible Demand (or Interruptible Load) is a term used in NERC Reliability Standards. See *Glossary of Terms Used in Reliability Standards*, February 12, 2008, at http://www.nerc.com/files/Glossary_12Feb08.pdf.

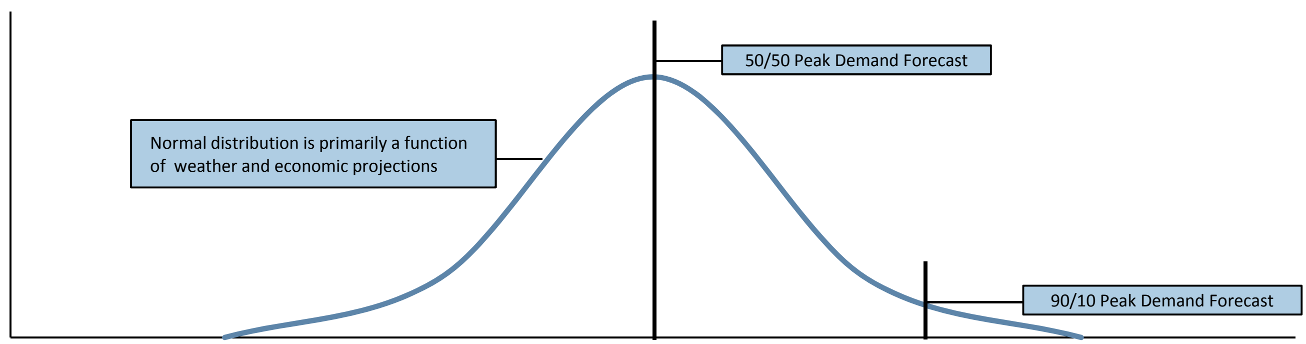
provide flexibility in operations, which allows the system operator to use the most economical plants to serve customer demand, thus reducing fuel and operating costs.

How Margins are Assessed

Proper planning, construction, and operation of the system according to well-established standards and guidelines assure adequate Planning and Operating Reserve Margins. Adequate Planning Reserve Margins depend on future electricity demands, completion of new generation and transmission facilities, retirement of generation, and performance of existing facilities. Assuring sufficient Planning Reserve Margins starts with a forecast of the future electricity requirements of residential, commercial, industrial, and governmental customers for up to 10 years or more in the future. Demand forecasts are continually reviewed and updated as economic conditions and other factors change.

For NERC reliability assessments, aggregated load forecasts are a single number or point; that is, the peak load or energy requirements for a given year are reported as a single specific value. In actuality, any forecast in itself is not a point or single value, but a probability distribution. The specific value represented in the assessment represents the probabilistic midpoint of the distribution such that the likelihood of exceeding it is equal to the likelihood of its not being reached (i.e., a 50/50 forecast). While this has been understood within the industry, increasing interest in and attention to load forecasts by non-industry groups has led to frequent misunderstanding of the forecasts.

Figure B: Example Load Forecast Distribution



Furthermore, point or single value forecasts imply a greater degree of precision and certainty than is appropriate. The load or load growth actually experienced is a function of many factors over which the electric power industry has little or no control—including the performance of local and national economies, the price of electricity, domestic versus foreign production of goods and services, industrial and other policies, changing technologies, federal and state legislation, and weather. These and many other factors greatly influence the actual peak loads and energy requirements and make deviation from forecast values a common occurrence. In addition, comparing actual loads to point forecasts may be misleading since it does not appropriately express the wide variation of causative factors involved.

Both demand and supply forecasts are subject to uncertainties and risks. Changes in future economic growth can affect demand forecasts, and supply forecasts can change if new facilities are delayed, postponed, or cancelled. Generation retirement uncertainties also exist in the supply forecast.

Uncertainty and risks are significant and must be factored into the planning process. Planning Reserve Margins provide the flexibility to mitigate and lower potential risks and uncertainties. The best way to deal with the risks and uncertainties is to increase flexibility by shortening lead times to site, license, and construct facilities, and keeping open all supply and demand options for the future.

Upon calculating Planning Reserve Margins, a comparison to the NERC Reference Margin Level is made. Planning Reserve Margins for each Assessment Area are compared to the NERC Reference Margin Level, which is assigned for each NERC Assessment Area as defined and imposed by the corresponding Regional Entity, State Public Utility Commission, Provincial authority, or other delegating body. In the absence of a defined Reference Margin Level, NERC has applied either a 10 or a 15 percent Reference Margin Level for predominately hydro or thermal systems, respectively. There are no NERC Reliability Standards that mandate maintaining a certain level of Planning Reserves. There is also no one appropriate margin for each utility, power pool, ISO/RTO, or Region. Operating conditions tend to be quite different because of changing weather conditions, characteristics of generation and transmission facilities, varying economic conditions, custom demand patterns, etc. Additionally, Planning Reserve Margins are not comparable across the difference Assessment Areas.

Developing Planning Reserve Margin Targets

As BPS planning has become increasingly complex, analytical techniques developed to assess resource adequacy have also become increasingly complex. Common to most methods is a sophisticated application of probability theory. Most techniques require assumptions that also derive from probability theory. For example, an estimate must be made of the probability that generating units modeled will be available when called upon to serve. Historical forced outages rates are used to forecast future rates, but such an assumption is uncertain, and the likelihood of higher or lower rates is inherent in the estimate.

Perhaps the most widely recognized index of reliability is Loss of Load Expectation (LOLE), also known as Loss of Load Probability (LOLP), which is ordinarily measured in days per year. These probabilistic values can then be used to determine what level of Planning Reserve Margin is needed in order to meet a loss of load of 0.1 day per year. Like generation and demand distributions, the LOLE is also a distribution. The ability to serve load without Firm load interruption for every peak hour (except for one) for 10 years is an industry-accepted, non-binding planning guideline. The resulting Planning Reserve Margin target is one that is probabilistically associated with the 0.1 day per year Loss of Load expectation (LOLE = 0.1).

For some Assessment Areas, the methods are not as complex. For example, the FRCC Planning Reserve Margin target (NERC Reference Margin Level) is based on a state-mandated flat percentage. For others, a target is applied based on a generally accepted level using historical performance and engineering judgment.

Demand Response Concepts and Categorization

As the industry's use of Demand-Side Management evolves, NERC's data collection and reliability assessments need to change, highlighting programs and Demand-Side service offerings that have an impact on bulk system reliability.

NERC's seasonal and long-term reliability assessments assume projected Energy Efficiency programs are included in the Total Internal Demand forecasts. This including adjustments for utility indirect Demand Response programs such as Conservation programs, improvements in efficiency of electric energy use and rate incentives, and rebates. DSM involves all activities or programs undertaken to influence the amount and timing of electricity use.

The table below explains Demand Response categories, also defined in Terms Used in this Assessment section.

Table B: NERC Data Collection and Categorization for Demand-Side Management

Demand Response (DR)				
Dispatchable				Non-Dispatchable
Controllable			Economic	
Capacity	Ancillary	Energy-Voluntary	Economic	Time-Sensitive Pricing
Direct Load Control	Spinning Reserves	Emergency	Energy-Price	Time-of-Use
Interruptible Demand	Non-Spinning Reserves		Demand Bidding and Buyback	Critical Peak and Real Time Pricing
Critical Peak Pricing with Control	Regulation			System Peak Response Transmission Tariff
Load as a Capacity Resource				

2012 Emerging Issues and NERC-Supported Studies

The Reliability Assessment Subcommittee keeps the most up-to-date information on emerging reliability issues on the NERC website including published reports and RAS materials. The table below provides a link for additional information on Emerging Reliability Issues discussed in this report (Table C).

Table C: NERC 2012 Emerging Issues

2012 Emerging Reliability Issue	Reference Documents	NERC Actions
Generator Retirements and Environmental Control Retrofits	• Potential Impacts of Future Environmental Regulations[305]	Monitoring of Facility Retirements
Transmission Siting and Planning	• Transmission Siting and Permitting, February 2009, Lawrence Berkeley National Laboratory[306]	Monitoring of Developments
Geomagnetic Disturbance Impacts to System Operations and Communications	• Effects of Geomagnetic Disturbances on the Bulk Power System, Feb. 2012,[307] • Severe Impact Resilience Task Force report[308]	NERC GMDTF Phase 2 Work plan[309]
Global Supply Chains and Fuel Reliability	• National Strategy for Global Supply Chain Security, US Department of Homeland Security, January 2012[310]	Monitoring of Developments
Coordinated Cyber or Physical Attacks on Electricity Infrastructure	• High Impact, Low Frequency Event Risk to the North American BPS, June 2010, NERC and US DOE[311] • Cyber Attack Task Force Report[312], May 2012, SIRTF	Critical Infrastructure Protection Committee Initiatives[313]
Accommodating Variable Resources in System Operations	• Accommodating High Levels of Variable Generation, April 2009[314] • Integration of Variable Generation Task Force reports[315]	Phase 2 Work of the Integrating Variable Generation Task Force
Gas-Electric Interdependency	• A Primer of the Natural Gas and Electric Power Interdependency in the United States, December 2011[316]	Gas-Electric Interdependency Phase II Assessment
Potential Operational Risks Associated with Interaction of SPS / Remedial Action Scheme	• Arizona – Southern California Outages on September 8, 2011: Causes and Recommendations, May 2012 • US Federal Energy Regulatory Commission and NERC[317]	On-going FERC, NERC, and WECC to initiatives to track and mitigate future impacts
Fault-Induced Delayed Voltage Recovery (FIDVR)	• Fault-Induced Delayed Voltage Recovery, December 2008,[318]	PC subcommittees to develop guidelines for addressing protection and control considerations for FIDVR studies
Electric Industry Workforce	• Workforce Trends in the Electric Utility Industry: 2006, US Dept. of Energy[319] • Aging and Retiring Work Force: New Challenges for Public Power[320]	N/A
Aging Infrastructure	• Failure to Act: The Economic Impact of Current Investment Trends in Electricity Infrastructure, 2011, American Society of Civil Engineers[321]	N/A

305 http://www.nerc.com/files/EPA%20Section.pdf
306 http://certs.lbl.gov/ntgs/issue-5.pdf
307 http://www.nerc.com/files/2012GMD.pdf
308 http://www.nerc.com/filez/sirtf.html
309 http://www.nerc.com/docs/pc/gmdtf/GMD_Phase_2_Project_Plan_APPROVED.pdf
310 http://www.whitehouse.gov/sites/default/files/national_strategy_for_global_supply_chain_security.pdf
311 http://www.nerc.com/files/hilf.pdf
312 http://www.nerc.com/docs/cip/catf/12-CATF_Final_Report_BOT_clean_Mar_26_2012-Board%20Accepted%200521.pdf
313 http://www.nerc.com/page.php?cid=1|9|117|139
314 http://www.nerc.com/files/Special%20Report%20-%20Accommodating%20High%20Levels%20of%20Variable%20Generation.pdf
315 http://www.nerc.com/page.php?cid=4|61
316 http://www.nerc.com/files/Gas_Electric_Interdependencies_Phase_I.pdf
317 http://www.ferc.gov/legal/staff-reports/04-27-2012-ferc-nerc-report.pdf
318 http://www.nerc.com/docs/pc/tis/FIDV_R_Tech_Ref_V1-1_PC_Approved.pdf
319 http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/Workforce_Trends_Report_090706_FINAL.pdf
320 http://www.publicpower.org/files/pdfs/workforce.pdf
321 http://www.asce.org/uploadedFiles/Infrastructure/Failure_to_Act/energy_report_FINAL2.pdf

Appendix VI: List of Acronyms

Abbreviation	Term	Abbreviation	Term
A/C	Air Conditioning	ICR	Installed Capacity Requirement
AEP	American Electric Power	IESO	Independent Electric System Operator (in Ontario)
AESO	Alberta Electric System Operator (WECC subregion)	IOU	Investor Owned Utility
AFC	Available Flowgate Capability	IPSI	Integrated Power System Plan
ASM	Ancillary Services Market	IRM	Installed Reserve Margin
ATCLLC	American Transmission Company, LLC	IROL	Interconnection Reliability Operating Limit
ATR	AREA Transmission Review (of NYISO)	IRP	Integrated Resource Plan
AWEA	American Wind Energy Association	ISO	Independent System Operator
BA	Balancing Authorities	ISO-NE	ISO New England, Inc.
BASN	Basin (WECC subregion)	kV	Kilovolts (one thousand volts)
BC	British Columbia (WECC subregion)	LaaRs	Loads acting as a Resource
BCF	Billion cubic feet	LCR	Locational Installed Capacity Requirements
BCFD	Billion cubic feet per day	LDC	Liquidated Damage Contract
CAGR	Compound Annual Growth Rate	LFU	Load Forecast Uncertainty
CALN	California-North (WECC subregion)	LNG	Liquefied Natural Gas
CALS	California-South (WECC subregion)	LOLE	Loss of Load Expectation
CANW	WECC-Canada (WECC subregion, includes AESO and BC)	LOLP	Loss of Load Probability
CFL	Compact Fluorescent Light	LOOP	Loss of off-site power
CMPA	California-Mexico Power Area	LRP	Long Range Plan
COI	California-Oregon Intertie	LSE	Load-serving Entities
COS	Coordinated Outage [transmission] System	LTRA	Long-Term Reliability Assessment
CPUC	California Public Utilities Commission	LTSG	Long-term Study Group
CRO	Contingency Reserve Obligation	MAAC	Mid-Atlantic Area Council
CRPP	Comprehensive Reliability Planning Process (of NYISO)	Maf	Million acre-feet
DADRP	Day-Ahead Demand Response Program	MAIN	Mid-America Interconnected Network, Inc.
DC	Direct Current	MAPP	Mid-Continent Area Power Pool
DCLM	Direct Controlled Load Management	MCRSG	Midwest Contingency Reserve Sharing Group
DFW	Dallas/Fort Worth	MEXW	WECC-Mexico (WECC Subregion)
DLC	Direct Load Control	MISO	Midwest Independent Transmission System Operator
DOE	U.S. Department of Energy	MPRP	Maine Power Reliability Program
DSG	Dynamics Study Group	MRO	Midwest Reliability Organization
DSI	Direct-served Industry	MVA	MegaVolt Ampere
DSM	Demand-Side Management	MVAr	MegaVolt Ampere reactive
DSW	Desert Southwest (WECC subregion)	MW	Megawatts (millions of watts)
DVAR	D-VAR® reactive power compensation system	MWEX	Minnesota Wisconsin Export
EDRP	Emergency Demand Response Program	NB	New Brunswick
EE	Energy Efficiency	NBSO	New Brunswick System Operator
EEA	Energy Emergency Alert	NDEX	North Dakota Export Stability Interface
EECP	Emergency Electric Curtailment Plan	NEEWS	New England East West Solution
EIA	Energy Information Agency (U.S. Department of Energy)	NERC	North American Electric Reliability Corporation
EILS	Emergency Interruptible Load Service (of ERCOT)	NIETC	National Interest Electric Transmission Corridor
EISA	Energy Independence and Security Act of 2007 (USA)	NOPSG	Northwest Operation and Planning Study Group
ELCC	Effective Load-carrying Capability	NORW	Northwest (WECC subregion)
EMTP	Electromagnetic Transient Program	NPCC	Northeast Power Coordinating Council, Inc.
ENS	Energy Not Served	NPDES	National Pollutant Discharge Elimination System
EOP	Emergency Operating Procedure	NPPD	Nebraska Public Power District
ERAG	Eastern Interconnection Reliability Assessment Group	NSPI	Nova Scotia Power Inc.
ERCOT	Electric Reliability Council of Texas	NTSG	Near-term Study Group
ERO	Electric Reliability Organization	NWPP	Northwest Power Pool Area (WECC subregion)
FCITC	First Contingency Incremental Transfer Capability	NYISO	New York Independent System Operator
FCM	Forward Capacity Market	NYPA	New York Planning Authority
FERC	U.S. Federal Energy Regulatory Commission	NYRSC	New York State Reliability Council, LLC
FP	*Future-Planned*	OASIS	Open Access Same Time Information Service
FO	*Future-Other*	OATT	Open Access Transmission Tariff
FRCC	Florida Reliability Coordinating Council	OP	Operating Procedure
GADS	Generating Availability Data System	OPA	Ontario Power Authority
GDP	Gross Domestic Product	OPPD	Omaha Public Power District
GGGS	Gerald Gentleman Station Stability	ORWG	Operating Reliability Working Group
GHG	Greenhouse Gas	OTC	Operating Transfer Capability
GRSP	Generation Reserve Sharing Pool (of MAPP)	OVEC	Ohio Valley Electric Corporation
GTA	Greater Toronto Area	PA	Planning Authority
GWh	Gigawatt hours	PACE	PacifiCorp East
HDD	Heating Degree Days	PAR	Phase Angle Regulators
HVac	Heating, Ventilating, and Air Conditioning	PC	NERC Planning Committee
IA	Interchange Authority	PCAP	Pre-Contingency Action Plans
ICAP	Installed Capacity	PCC	Planning Coordination Committee (of WECC)

Abbreviation	Term	Abbreviation	Term
PJM	PJM Interconnection	SCR	Special Case Resources
PRB	Powder River Basin	SEMA	Southeastern Massachusetts
PRC	Public Regulation Commission	SEPA	State Environmental Protection Administration
PRSG	Planned Reserve Sharing Group	SERC	SERC Reliability Corporation
PSA	Power Supply Assessment	SMUD	Sacramento Municipal Utility District
PUCN	Public Utilities Commission of Nevada	SOL	System Operating Limits
QSE	Qualified Scheduling Entities	SPP	Southwest Power Pool
RA	Resource Adequacy	SPS	Special Protection System
RAP	Remedial Action Plan (of ERCOT)	SPS	Special Protection Schemes
RAR	Resource Adequacy Requirement	SRIS	System Reliability Impact Studies
RAS	Reliability Assessment Subcommittee	SRWG	System Review Working Group
RC	Reliability Coordinator	STATCOM	Static Synchronous Compensator
RCC	Reliability Coordinating Committee	STEP	SPP Transmission Expansion Plan
RFC	ReliabilityFirst Corporation	SVC	Static VAr Compensation
RFP	Request For Proposal	TCF	Trillion Cubic Feet
RGGI	Regional Greenhouse Gas Initiative	TFCP	Task Force on Coordination of Planning
RIS	Resource Issues Subcommittee	THI	Temperature Humidity Index
RMR	Reliability Must Run	TIC	Total Import Capability
RMRG	Rocky Mountain Reserve Group	TID	Total Internal Demand
ROCK	Rockies (WECC subregion)	TLR	Transmission Loading Relief
RP	Reliability Planner	TOP	Transmission Operator
RPM	Reliability Pricing Mode	TPL	Transmission Planning
RRS	Reliability Review Subcommittee	TRE	Texas Regional Entity
RSG	Reserve Sharing Group	TRM	Transmission Reliability Margins
RTEP	Regional Transmission Expansion Plan (for PJM)	TS	Transformer Station
RTO	Regional Transmission Organization	TSP	Transmission Service Provider
RTP	Real-time Pricing	TSS	Technical Studies Subcommittee
RTWG	Renewable Technologies Working Group	TVA	Tennessee Valley Authority
SA	Security Analysis	UFLS	Under Frequency Load Shedding Schemes
SasKPower	Saskatchewan Power Corporation	UVLS	Under Voltage Load-Shedding
SCADA	Supervisory Control and Data Acquisition	VAr	Voltampere reactive
SCC	Seasonal Claimed Capability	VACAR	Virginia and Carolinas (subregion of SERC)
SCD	Security Constrained Dispatch	VSAT	Voltage Stability Assessment Tool
SCDWG	Short Circuit Database Working Group	WALC	Western Area Lower Colorado
SCEC	State Capacity Emergency Coordinator (of FRCC)	WECC	Western Electricity Coordinating Council
		WTHI	Weighted Temperature-Humidity Index
		WUMS	Wisconsin-Upper Michigan Systems

Appendix VII: Terms Used in This Assessment

Ancillary (Controllable Demand Response) — Demand-Side resource displaces generation deployed as operating reserves and/or regulation; penalties are assessed for non-performance.

Anticipated Capacity Resources — Existing-Certain and Net Firm Transactions plus Future-Planned Capacity Resources plus Resource-Side Demand Response plus Expected Imports, minus Expected Exports.

Anticipated Reserve Margin (Percent) — Anticipated Capacity Resources minus Net Internal Demand, shown as a percent of Net Internal Demand.

Capacity Categories — See **Existing Generation Resources, Future Generation Resources,** and **Conceptual Generation Resources**.

Capacity Margin (Percent) — See **Deliverable Capacity Margin (Percent)** and **Prospective Capacity Margin (Percent)**. Roughly, Capacity minus Demand, divided by Capacity or (Capacity-Demand)/Capacity. Replaced in 2009 with Reserve Margin(s) (Percent) for NERC Assessments.

Conceptual Generation Resources — This category includes generation resources that are not included in Existing Generation Resources or Future Generation Resources but have been identified or announced on a resource planning basis through one or more of the following sources:

- Corporate announcement
- Entered into or is in the early stages of an approval process
- Is in a generator interconnection (or other) queue for study
- "Place-holder" generation for use in modeling, such as generator modeling needed to support NERC Standard TPL analysis, as well as integrated resource planning resource studies.

Resources included in this category may be adjusted using a confidence factor (percent) to reflect uncertainties associated with siting, project development or queue position.

Conservation — See **Energy Conservation.**

Contractually Interruptible (Curtailable) (Controllable Capacity Demand Response) — Dispatchable, Controllable, Demand-Side Management achieved by a customer reducing load upon notification from a control center. The interruption must be mandatory at times of system emergency. Curtailment options integrated into retail tariffs that provide a rate discount or bill credit for agreeing to reduce load during system contingencies. It is the magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted at the time of the Regional Entity's seasonal peak. In some instances, the demand reduction may be affected by action of the System Operator (remote tripping) after notice to the customer in accordance with contractual provisions.

Controllable (Demand Response) — Dispatchable Demand Response, Demand-Side resources used to supplement generation resources resolving system and/or local capacity constraints.

Critical Peak Pricing (CPP) (Non-dispatchable Time-Sensitive Pricing Demand Response) — Rate and/or price structure designed to encourage reduced consumption during periods of high wholesale market prices or system contingencies by imposing a pre-specified high rate for a limited number of days or hours.

Critical Peak Pricing (CPP) with Control (Controllable Capacity Demand Response) — Dispatchable, Controllable, Demand-Side Management that combines direct remote control with a pre-specified high price for use during designated critical peak periods, triggered by system contingencies or high wholesale market prices.

Curtailable — See **Contractually Interruptible.**

Demand — See **Net Internal Demand**, **Total Internal Demand.**

Demand Response — Changes in electric use by Demand-Side resources from normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices, or when system reliability is jeopardized. Demand Response can be counted in resource adequacy studies either as a load-modifier, or as a resource.

Derate (Capacity) — The amount of capacity that is expected to be unavailable on seasonal peak.

Direct Control Load Management (DCLM) or Direct Load Control (DLC) (Controllable Capacity Demand Response) — Demand-Side Management that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises. DCLM as defined here does not include Interruptible Demand.[322]

Dispatchable (Demand Response) — Demand-Side resource curtails according to instruction from a control center.

Disturbance Classification Scale — See **NERC's BPS Disturbance Classification Scale.**

Disturbance Event — See **NERC's BPS Disturbance Classification Scale.**

Economic (Controllable Demand Response) — Demand-Side resource that is dispatched based on an economic decision.

Emergency (Controllable Energy-Voluntary Demand Response) — Demand-Side resource curtails during system and/or local capacity constraints.

Energy Conservation — The practice of decreasing the quantity of energy used.

Energy Efficiency — Permanent changes to electricity use by replacement of end-use devices with more efficient end-use devices or more effective operation of existing devices. Generally, it results in reduced consumption across all hours rather than event-driven targeted load reductions.

Energy Emergency Alert Levels — The categories for capacity and emergency events based on Reliability Standard EOP-002-0:

- Level 1 — All available resources in use.
- Balancing Authority, Reserve Sharing Group, or Load Serving Entity foresees or is experiencing conditions in which all available resources are committed to meet Firm load, Firm transactions, and reserve commitments, and is concerned about sustaining its required operating reserves, and non-Firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
- Level 2 — Load management procedures in effect.
- Balancing Authority, Reserve Sharing Group, or Load Serving Entity is no longer able to provide its customers' expected energy requirements, and is designated an Energy Deficient Entity.
- Energy Deficient Entity foresees or has implemented procedures up to, but excluding, interruption of Firm load commitments. When time permits, these procedures may include, but are not limited to: Public appeals to reduce demand, Voltage reduction, Interruption of non-Firm end use loads in accordance with applicable contracts, Demand-Side Management, and Utility load Conservation measures.
- Level 3 — Firm load interruption imminent or in-progress.
- Balancing Authority or Load Serving Entity foresees or has implemented Firm load obligation interruption. The available energy to the Energy Deficient Entity, as determined from Level (Alert) 2, is only accessible with actions taken to increase transmission transfer capabilities.

[322] DCLM is a term defined in NERC Reliability Standards. See *Glossary of Terms Used in Reliability Standards*, Updated April 20, 2009 www.nerc.com/files/Glossary_2009April20.pdf

Energy-Only (Capacity) — Energy-only resources are generally generating resources that are designated as energy-only resources or have elected to be classified as energy-only resources and may include generating capacity that can be delivered within the area but may be recallable to another area.

Energy-Price (Controllable Economic Demand Response) — Demand-Side resource that reduces energy for incentives.

Energy-Voluntary (Controllable Demand Response) — Demand-Side resource curtails voluntarily when offered the opportunity to do so for compensation, but non-performance is not penalized.

Existing-Certain (Existing Generation Resources) — Existing generation resources available to operate and deliver power within or into the Region during the period of analysis in the assessment. 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 the period of analysis in the assessment.
2. Where organized markets exist, designated market resource[323] that is eligible to bid into a market or has been designated as a Firm network resource.
3. Network Resource,[324] as this term is used for FERC pro forma or other regulatory approved tariffs.
4. Energy-only resources[325] confirmed able to serve load during the period of analysis in the assessment and will not be curtailed.[326]
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[327] during the period of analysis in the assessment.

Existing-Certain and Net Firm Transactions — Existing-Certain Capacity Resources plus Firm imports, minus Firm exports. (MW)

Existing-Certain and Net Firm Transactions (Percent) (Margin Category) — Existing-Certain and Net Firm Transactions minus Net Internal Demand, shown as a percent of Net Internal Demand.

Existing Generation Resources — See **Existing-Certain**, **Existing-Other**, **Existing-Inoperable**.

Existing-Inoperable (Existing Generation Resources) — This category contains the existing portion of generation resources that are out of service and cannot be brought back into service to serve load during the period of analysis in the assessment. This category can include inoperable resources that could return to service at some point in the future. This value may vary for future seasons and can be reported as zero. This includes all existing generation not included in categories Existing-Certain or Existing-Other, but is not limited to the following:

1. Mothballed generation (that cannot be returned to service for the period of the assessment).
2. Other-Existing but out of service generation (that cannot be returned to service for the period of the assessment).
3. This category does not include behind-the-meter generation or non-connected emergency generators that normally do not run.
4. This category does not include partially dismantled units that are not forecast to return to service.

[323] Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.
[324] Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.
[325] Energy-only resources are generally generating resources that are designated as energy-only resources or have elected to be classified as energy-only resources and may include generating capacity that can be delivered within the Area but may be recallable to another Area (Source: 2008 EIA 411 document OMB No. 1905-0129)." Note: Other than wind and solar energy, WECC does not have energy-only resources that are counted towards capacity.
[326] Energy-only resources with transmission service constraints are to be considered in category Existing-Other.
[327] *Ibid*.

Existing-Other (Existing Generation Resources) — Existing generation resources that may be available to operate and deliver power within or into the Region during the period of analysis in the assessment, but may be curtailed or interrupted at any time for various reasons. This category also includes portions of intermittent generation not included in Existing-Certain. This category includes but is not limited to the following:

- A resource with non-Firm or other similar transmission arrangements.
- Energy-only resources that have been confirmed able to serve load for any reason during the period of analysis in the assessment, but that may be curtailed for any reason.
- Mothballed generation (that may be returned to service for the period of the assessment).
- Portions of variable generation not counted in the Existing-Certain Category (e.g., wind, solar, etc.) that may not be available or derated during the assessment period.
- Hydro generation not counted as Existing-Certain or derated.
- Generation resources constrained for other reasons.

Expected (Transaction Category) — A category of Purchases/Imports and Sales/Exports contracts:

1. "Expected" implies that a contract has not been executed, but is in negotiation, projected or other. These Purchases or Sales are expected to be Firm.
2. Expected Purchases or Sales should be considered in the reliability assessments.

Firm (Transaction Category) — A category of Purchases/Imports and Sales/Exports contracts:

1. "Firm" implies a contract has been signed and may be recallable.
2. Firm Purchases and Sales should be reported in the reliability assessments. The purchasing entity should count such capacity in margin calculations. Care should be taken by both entities to appropriately report the generating capacity that is subject to such Firm contract.

Future Generation Resources (See also **Future-Planned** and **Future-Other**) — This category includes generation resources for which the reporting entity has a reasonable expectation of coming on-line during the period of the assessment. As such, to qualify in either of the Future categories, the resource must have achieved one or more of these milestones:

1. Construction has started.
2. Any of the following regulatory permits being approved:
    a. Site permit
    b. Construction permit
    c. Environmental permit
3. Regulatory approval has been received to be in the rate base.
4. Approved power purchase agreement.
5. Approved and/or designated as a resource by a market operator.

Future-Other (Future Generation Resources) — This category includes future generating resources that do not qualify in Future-Planned and are not included in the Conceptual Category. This category includes but is not limited to generation resources during the period of analysis with the following characteristics:

1. May be curtailed or interrupted at any time for any reason.
2. Energy-only resources that may not be able to serve load during the period of analysis in the assessment.
3. Variable generation not counted in the Future-Planned Category or may not be available or is derated during the assessment period.
4. Hydro generation not counted in Future-Planned Category or derated.
5. Resources included in this category may be adjusted using a confidence factor to reflect uncertainties associated with siting, project development, or queue position.

Future-Planned (Future Generation Resources) — Generation resources anticipated to be available to operate and deliver power within or into the Region during the period of analysis in the assessment. 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[328] that is eligible to bid into a market or has been designated as a Firm network resource.
3. Network Resource,[329] as this term is used for FERC pro forma or other regulatory approved tariffs.
4. Energy-only resources confirmed able to serve load during the period of analysis in the assessment and will not be curtailed.[330]
5. Where applicable, included in an integrated resource plan under a regulatory environment that mandates resource adequacy requirements and the obligation to serve.

Load as a Capacity Resource (Controllable Capacity Demand Response) — A resource that commits to pre-specified load reductions when system contingencies arise.[331]

NERC's BPS Disturbance Classification Scale[332] — The NERC Event Analysis program breaks events into two general classifications: Operating Security Events and Resource Adequacy Events. Each event is categorized during the triage process to help NERC and Regional Event Analysis staffs determine an appropriate level of analysis or review. Similar to scales used to rank large weather systems and storms, NERC's BPS Event Classification Scale is designed to classify BPS disturbances by severity, size, and impact to the general public.

Operating Security Events — Operating reliability events significantly affect the integrity of interconnected system operations. They are divided into five categories to take into account different ways the system could be impacted.

- **Category 1**: An event results in any one or a combination of the following actions:
    a. The loss of a bulk power transmission component beyond recognized criteria; i.e., single-phase line-to-ground fault with delayed clearing, line tripping due to growing trees, etc.
    b. Frequency below the Low Frequency Trigger Limit (FTL) more than five minutes.
    c. Frequency above the High FTL more than five minutes.
    d. Partial loss of dc converter station (mono-polar operation).
    e. "Clear-Sky" Inter-area oscillations.
    f. Intended and controlled system separation by proper Special Protection Schemes/Remedial Action Schemes (SPS/RAS) action of Alberta from the Western Interconnection, New Brunswick from New England, or Florida from the Eastern Interconnection.
    g. Unintended system separation resulting in an island of a combination of load and generation of 20 MW to 300 MW.
    h. Proper SPS/RAS actuation resulting in load loss of 100 MW to 500 MW.

- **Category 2**: An event results in any one or a combination of the following actions:
    a. Complete loss of dc converter station.
    b. The loss of multiple bulk power transmission components.

[328] Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.
[329] Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.
[330] Energy-only resources with transmission service constraints are to be considered in category Future, Other.
[331] These resources are not limited to being dispatched during system contingencies. They may be subject to economic dispatch from wholesale balancing authorities or through a retail tariff and bilateral arrangements with a third-party curtailments service provider. Additionally, this capacity may be used to meet resource adequacy obligations when determining panning Reserve Margins.
[332] http://www.nerc.com/page.php?cid=5 Percent7C252.

c. The loss of an entire switching station (all lines, 100 kV or above).
d. The loss of an entire generation station of five or more generators (aggregate stations of 75 MW or higher).
e. Loss of off-site power (LOOP) to a nuclear generating station.
f. The loss of load of 300 MW to 500 MW (excluding SPS/RAS, UFLS, or UVLS actuation).
g. Proper SPS/RAS, UFLS, or UVLS actuation that results in loss of load of 500 MW or greater.
h. The loss of generation (between 1,000 and 2,000 MW in the Eastern Interconnection or Western Interconnection and between 500 MW and 1,000 MW in the Texas or Québec Interconnections).
i. The planned automatic rejection of generation through Special Protection Schemes (SPS) or Remedial Action Schemes (RAS) of less than 3,000 MW in the Western Interconnection, or less than 1,500 MW in the Eastern, Texas, and Québec Interconnections.
j. Unintended system separation resulting in an island of a combination of load and generation of 301 MW to 5,000 MW.
k. SPS/RAS misoperation.

- **Category 3**: An event results in any one or a combination of the following actions:
  a. The loss of load from 500 MW to 1,000 MW (excluding SPS/RAS, UFLS, or UVLS actuation).
  b. The unplanned loss of generation (excluding automatic rejection of generation through SPS/RAS) of 2,000 MW or more in the Eastern Interconnection or Western Interconnection, and 1,000 MW or more in the Texas or Québec Interconnections.
  c. Unintended system separation resulting in an island of a combination of load and generation of 5,001 MW to 10,000 MW.

- **Category 4**: An event results in any one or a combination of the following actions:
  a. The loss of load from 1,000 MW to 9,999 MW (excluding SPS/RAS, UFLS, or UVLS actuation).
  b. Unintended system separation resulting in an island of a combination of load and generation of more than 10,000 MW.

- **Category 5**: An event results in any one or a combination of the following actions:
  a. The loss of load of 10,000 MW or more.
  b. The loss of generation of 10,000 MW or more.

Resource Adequacy Events — Adequacy events are divided into three categories based on Standard EOP-002-0 (Capacity and Energy Emergencies).

- **Category A1**: No disturbance events and all available resources in use.
  a. Required operating reserves cannot be sustained.
  b. Non-Firm wholesale energy sales have been curtailed.

- **Category A2**: Load management procedures in effect.
  a. Public appeals to reduce demand
  b. Voltage reduction
  c. Interruption of non-Firm end per contracts
  d. Demand-Side Management
  e. Utility load Conservation measures

- **Category A3**: Firm load interruption imminent or in progress.

(NERC) Reference Margin Level (Percent) — Either the Target Reserve Margin provided by the Region/subregion or NERC assigned based on capacity mix (i.e., thermal/hydro). Each Region/subregion may have its own specific margin level based on load, generation, and transmission characteristics as well as regulatory requirements. If provided in the data submittals, the regional/subregional Target Reserve Margin level is adopted as the NERC Reference Margin Level. If not, NERC assigned 15 percent Reserve Margin for predominately thermal systems and for predominately hydro systems, 10 percent.

Net Internal Demand — Equals the Total Internal Demand reduced by the total Dispatchable, Controllable, Capacity Demand Response equaling the sum of Direct Control Load Management, Contractually Interruptible (Curtailable), Critical Peak Pricing (CPP) with Control, and Load as a Capacity Resource.

Non-Dispatchable (Demand Response) — Demand-Side resource curtails according to tariff structure, not instruction from a control center.

Non-Firm (Transaction Category) — A category of Purchases/Imports and Sales/Exports contracts:

1. "Non-Firm" implies a non-Firm contract has been signed.
2. Non-Firm Purchases and Sales should not be considered in the reliability assessments.

Non-Spin Reserves (Controllable Ancillary Demand Response) — Demand-Side resource not connected to the system but capable of serving demand within a specified time.

On-Peak (Capacity) — The amount of capacity that is expected to be available on seasonal peak.

Operating Reliability Events Categories — See **NERC's BPS Disturbance Classification Scale.**

Prospective Capacity Reserve Margin (Percent) — Prospective Capacity Resources minus Net Internal Demand shown as a percent of Net Internal Demand.

Prospective Capacity Resources (MW) — Anticipated Capacity Resources plus Existing-Other Capacity Resources, plus Future-Other Capacity Resources.

Provisional (Transaction Category) — A category of Purchases/Imports and Sales/Exports with contracts. Provisional implies that the transactions are under study but negotiations have not begun. These Purchases and Sales are expected to be provisionally Firm.

Purchases/Imports — See **Transaction Categories.**

Real-Time Pricing (RTP) (Non-dispatchable Time-Sensitive Pricing Demand Response) — Rate and price structure in which the price for electricity typically fluctuates to reflect changes in the wholesale price of electricity on either a day-ahead or hour-ahead basis.

Reference Margin Level — See **NERC Reference Margin Level.**

Regulation (Controllable Ancillary Demand Response) — Demand-Side resources responsive to Automatic Generation Control (AGC) to provide normal regulating margin.

Renewable Energy — The United States Department of Energy, Energy Efficiency and Renewable Energy glossary defines "Renewable Energy" as "energy derived from resources that are regenerative or for all practical purposes cannot be depleted. Types of renewable energy resources include moving water (hydro, tidal and wave power), thermal gradients in ocean water, biomass, geothermal energy, solar energy, and wind energy. Municipal solid waste (MSW) is also considered to be a renewable energy resource."[333] The government of Canada has a similar definition.[334] Variable generation is a subset of Renewable Energy — See **Variable Generation**.

Renewables — See **Renewable Energy.**

[333] http://www1.eere.energy.gov/site_administration/glossary.html#R.
[334] http://www.cleanenergy.gc.ca/index.cfm?action=faq.summary.

Reserve Margin (Percent) — See **Deliverable Capacity Reserve Margin (Percent)** and **Prospective Capacity Reserve Margin (Percent)**. Roughly, Capacity minus Demand, divided by Demand or (Capacity-Demand)/Demand. Replaced Capacity Margin(s) (Percent) for NERC Assessments in 2009.

Resource Adequacy Events — See **NERC's BPS Disturbance Classification Scale.**

Sales/Exports Contracts — See Transaction Categories.

Spinning/Responsive Reserves (Controllable Ancillary Demand Response) — Demand-Side resources that are synchronized and ready to provide solutions for energy supply and demand imbalance within the first few minutes of an electric grid event.

System Peak Response Transmission Tariff (Non-dispatchable Time-Sensitive Pricing Demand Response) — The rate and/or price structure in which interval metered customers reduce load during coincident peaks as a way of reducing transmission charges.

Target Reserve Margin (Percent) — Established target for reserve margin by the Region or subregion. Not all Regions report a Target Reserve Margin. The NERC Reference Margin Level is used if a Target Reserve Margin is not provided.

Total Internal Demand — The sum of the metered (net) output of all generators within the system and the metered line flows into the system, less the metered line flows out of the system. The demands for station service or auxiliary needs (such as fan motors, pump motors, and other equipment essential to the operation of the generating units) are not included. Internal Demand includes adjustments for indirect Demand-Side Management programs such as Conservation programs, improvements in efficiency of electric energy use, all non-dispatchable Demand Response programs (such as Time-of-Use, Critical Peak Pricing, Real-time Pricing and System Peak Response Transmission Tariffs) and some dispatchable Demand Response (such as Demand Bidding and Buy-Back). Adjustments for controllable Demand Response should not be incorporated in this value.

Time-of-Use (TOU) (Non-dispatchable Time-Sensitive Pricing Demand Response) — Rate and/or price structures with different unit prices for use during different blocks of time.

Time-Sensitive Pricing (Non-dispatchable Demand Response) — Retail rates and/or price structures designed to reflect time-varying differences in wholesale electricity costs, and thus provide consumers with an incentive to modify consumption behavior during high-cost or peak periods.

Transaction Categories (See also **Firm, Expected and Provisional**) — Contracts for Capacity are defined as an agreement between two or more parties for the Purchase and Sale of generating capacity. Purchase contracts refer to imported capacity that is transmitted from an outside Region or subregion to the reporting Region or subregion. Sales contracts refer to exported capacity that is transmitted from the reporting Region or subregion to an outside Region or subregion. For example, if a resource subject to a contract is located in one Region and sold to another Region, the Region in which the resource is located reports the capacity of the resource and reports the sale of such capacity that is being sold to the outside Region. The purchasing Region reports such capacity as a purchase but does not report the capacity of such resource. Transmission must be available for all reported Purchases and Sales.

Transmission-Limited Resources — The amount of transmission-limited generation resources that have known physical deliverability limitations to serve load within the Region. If capacity is limited by both studied transmission limitations and generator derates, the generator derates take precedence. For example, a 100 MW wind farm with a wind capacity variation reduction of 50 MW and a transmission limitation of 60 MW would take the 50 MW wind variation reduction first and list 10 MW in the transmission limitation.

Transmission Loading Relief (TLR) Levels — Various levels of the TLR Procedure from Reliability Standard IRO-006-4 — Reliability Coordination — Transmission Loading Relief:

- TLR Level 1 — Notify Reliability Coordinators of potential SOL or IROL Violations
- TLR Level 2 — Hold transfers at present level to prevent SOL or IROL Violations
- TLR Level 3a — Reallocation of Transmission Service by curtailing Interchange Transactions using Non-Firm Point-to-Point Transmission Service to allow Interchange Transactions using higher priority Transmission Service
- TLR Level 3b — Curtail Interchange Transactions using Non-Firm Transmission Service Arrangements to mitigate an SOL or IROL Violation
- TLR Level 4 — Reconfigure Transmission
- TLR Level 5a — Reallocation of Transmission Service by curtailing Interchange Transactions using Firm Point-to-Point Transmission Service on a pro-rata basis to allow additional Interchange Transactions using Firm Point-to-Point Transmission Service
- TLR Level 5b — Curtail Interchange Transactions using Firm Point-to-Point Transmission Service to mitigate an SOL or IROL violation
- TLR Level 6 — Emergency Procedures
- TLR Level 0 — TLR concluded

Transmission Status Categories — Transmission additions were categorized using the following criteria:

- Under Construction: Construction of the line has begun
- Planned (any of the following):
- Permits have been approved to proceed
- Design is complete
- Needed in order to meet a regulatory requirement
- Conceptual (any of the following)
- A line projected in the transmission plan
- A line that is required to meet a NERC TPL Standard or included in a powerflow model and cannot be categorized as "Under Construction" or "Planned"
- Projected transmission lines that are not "Under Construction" or "Planned"

Variable Generation — Variable generation technologies generally refer to generating technologies whose primary energy source varies over time and cannot reasonably be stored to address such variation.[335] Variable generation sources that include wind, solar, ocean and some hydro generation resources are all renewable-based. Variable generation in this report refers only to wind and solar resources. There are two major attributes of a variable generator that distinguish it from conventional forms of generation and may impact the BPS planning and operations: variability and uncertainty.

- **Variability** — The output of variable generation changes according to the availability of the primary fuel (wind, sunlight and moving water) resulting in fluctuations in the plant output on all time scales.
- **Uncertainty** — The magnitude and timing of variable generation output is less predictable than for conventional generation.

[335] http://www.nerc.com/files/IVGTF_Report_041609.pdf.

Appendix VIII: Probabilistic Assessments

Beginning in 2012, the NERC Reliability Assessment Subcommittee has enhanced its reliability assessment process by supplementing its resource adequacy metric (mainly Planning Reserve Margin) with probabilistic metrics.

NERC's Generation and Transmission Reliability Planning Models Task Force (GTRPMTF) recommended the creation of an annual report summarizing a probabilistic assessment of the resource adequacy by area across NERC.[336] The GTRPMTF was subsequently disbanded and the Planning Committee has assigned RAS to coordinate the assembly of this report.

In 2011, the RAS piloted this effort to produce enhanced resource adequacy metrics for the *2010 Long-Term Reliability Assessment*.[337] The NERC Planning Committee (PC) approved the recommendations from this report which initiates a mandatory probabilistic assessment study to be performed biennially.

The *Probabilistic Assessment* report is designed to complement the *Long-Term Reliability Assessment* by providing additional probabilistic statistics of Loss of Load Hours (LOLH) and Expected Unserved Energy (EUE). Included in this request, RAS plans to report on the third and fifth year of the *2012 Long-Term Reliability Assessment*—2014 and 2016 results.

Because of the complexity and time requirements of configuring and running models to produce probabilistic results, the analysis schedule does not align with the timeline of the *Long-Term Reliability Assessment.* Therefore, the probabilistic assessment will be published biennially in the following spring after the *Long-Term Reliability Assessment* is published. The schedule for completion is as follows:

August 21, 2012	Introduction webinar - field participant questions
September 6, 2012	Issue letter requesting participation in 2012 assessment
September-October 2012	Confirm final *2012LTRA R*eference case data
December 10, 2012	RAS-ProbA Team conference call: pre-submission inquires
October 21, 2012	First draft due to NERC
January 17, 2013	RAS-ProbA Team conference call: peer review
February 1, 2013	Final drafts due to NERC
February 4-8, 2013	NERC staff consolidation of reports
February 8, 2013	Draft report submitted to RAS-ProbA Team
February 15, 2013	RAS-ProbA Team conference call: review of initial draft
February 25, 2013	Draft report submitted to RAS
March 2013	Draft report submitted to PC (possible approval in March)
June 2013	PC approval of final report

More information can be found on the NERC Reliability Assessment Subcommittee website.[338]

[336] http://www.nerc.com/docs/pc/gtrpmtf/GTRPMTF_Meth_&_Metrics_Report_final_w._PC_approvals,_revisions_12.08.10.pdf
[337] *2010 Long-Term Reliability Assessment: Pilot Probabilistic Assessment,* June 2012: http://www.nerc.com/files/2012_ProbA.pdf
[338] http://www.nerc.com/filez/ras.html

Appendix IX: Assessment Preparation

This assessment was prepared by NERC in its capacity as the Electric Reliability Organization.[339] NERC cannot order construction of generation or transmission or adopt enforceable standards having that effect, as that authority is explicitly withheld by Section 215 of the U.S. Federal Power Act and similar restrictions in Canada.[340] In addition, NERC does not make any projections or draw any conclusions regarding expected electricity prices or the efficiency of electricity markets.

The Assessment Area sections were developed by the Reliability Assessment Subcommittee (RAS), which is under the direction of the NERC Planning Committee (PC). The data and information presented in this assessment was submitted by each of the eight Regional Entities on an Assessment Area basis. Additional data was incorporated by NERC staff with sources provided when applicable.

Reliability Assessment Subcommittee Members

Name	Position	Represents	Job Title	Organization
Vince Ordax	Chair	FRCC*	Manager of Planning	FRCC
Curtis Crews	Vice Chair	TRE*	Lead Reliability Assessment Engineer	TRE
Justin Michlig	Member	MRO	Transmission Planning Specialty Engineer	Xcel
William B. Kunkel	Member	MRO*	Senior Engineer	MRO
John Lawhorn	Member	MRO	Senior Director, Regulatory and Economic Studies	Midwest ISO, Inc.
Madhuri Kandukuri	Member	MRO	Senior Engineer , Regulatory and Economic Studies	Midwest ISO, Inc.
Josh Collins	Member	MRO	Engineer I	Midwest ISO, Inc.
Bagen Bagen	Member	MRO	Principal Planning Engineer	Manitoba Hydro
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John G Mosier Jr.	Member	NPCC*	Assistant Vice President of System Operations	NPCC
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James Useldinger	Member	SPP RE	Manager, T&D System Operations	KCP&L
Warren Lasher	Member	TRE	Manager, System Assessment	ERCOT
Layne Brown	Member	WECC*	Manager, Reliability Assessments	WECC
Tina G. Ko	Member	WECC	Manager, Resources & Loads Analysis	BPA
James Leigh-Kendall	Member	WECC	Manager, Reliability Compliance and Coordination	SMUD
Jerry D. Rust	Observer	N/A	President	NPPC
Sedina Eric	Observer	GOV	Electrical Engineer	FERC
David J. Burnham	Observer	GOV	Electrical Engineer	FERC
Patricia Hoffman	Observer	GOV	Assistant Secretary	DOE
Maria A. Hanley	Observer	GOV	Energy Analyst	DOE-NETL
Erik Paul Shuster	Observer	GOV	Engineer	DOE
Peter Balash	Observer	GOV	Senior Economist	DOE
C. Richard Bozek	Observer	Trades	Director, Environmental Policy	EEI
Daniel Brooks	Observer	Trades	Manager, Power Delivery System Studies	EPRI

*Regional Entity Representative

[339] Section 39.11(b) of the U.S. FERC's regulations provide that: "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."

[340] http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=109_cong_bills&docid=f:h6enr.txt.pdf.

Assessment areas are subject to thorough review by the RAS. This review allows all members multiple opportunities to examine information and data provided by each assessment area. Data sharing also allows members to validate capacity transfers between neighboring assessment areas.

The NERC PC endorses this report prior to its being sent to the NERC Board of Trustees (BOT) for approval. The draft includes comments received from representatives on the NERC Operating Committee (OC) and the Member Representatives Committee (MRC). Drafts of the document are considered confidential and embargoed until approval is received from the NERC BOT.

2012 Long-Term Reliability Assessment Data and Information Request (Distributed by NERC in January, 2012)

- Letter to Regional Entities: http://www.nerc.com/docs/pc/ras/2012%20LTRA%20Request%20Letter.doc.
- Data Form: http://www.nerc.com/docs/pc/ras/ERO2012_LTRA_v4.xls.
- Data Form Instructions: http://www.nerc.com/docs/pc/ras/ERO2012_LTRA_v3_Instructions.pdf .
- Schedule: http://www.nerc.com/docs/pc/ras/2012LTRA_Schedule_Updated.pdf .

2012 Long-Term Reliability Assessment Supplemental Data and Information Request

In July 2012, NERC requested additional information and data to support changes in reference cases and more granular data on projected generator retirements. The supplemental data request also required the assessment areas to submit estimates of on-peak gas-fired generation capacity (MW) with firm supply and transportation of natural gas.

- Letter to Regional Entities: http://www.nerc.com/docs/pc/ras/2012LTRA_Supplemental__Letter.pdf.
- Supplemental Data Form http://www.nerc.com/docs/pc/ras/ERO2012_LTRA_Supplemental_v3.xls.
- Supplemental Data Form Instructions: http://www.nerc.com/docs/pc/ras/2012LTRA_Supplemental_Request-Instructions_v2.pdf.

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