NERC

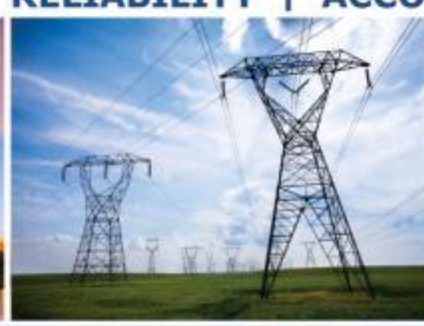
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2013–2014 Winter Reliability Assessment

November 2013

RELIABILITY | ACCOUNTABILITY






North American Electric Reliability Corporation

Atlanta	Washington, D.C.
3353 Peachtree Road NE	1325 G Street NW
Suite 600 – North Tower	Suite 600
Atlanta, GA 30326	Washington, D.C. 20005
404-446-2560	202-400-3000

The North American Electric Reliability Corporation (NERC) prepared this assessment in its capacity as the electric reliability organization (ERO).[1] The assessment provides an independent view of the 2013–2014 winter reliability outlook for the North American bulk power system (BPS)[2] while identifying trends, reliability issues, and potential risks. Additional insights include resource adequacy and operating reliability, as well as an overview of projected seasonal electricity demand for individual assessment areas.

Additional inquiries regarding the information in this assessment may be directed to the NERC reliability assessment staff.

NERC Reliability Assessment Staff

Name	Position	Email	Phone
Thomas Burgess	Vice President and Director	thomas.burgess@nerc.net	404-446-2563
John N. Moura	Director of Reliability Assessment	john.moura@nerc.net	404-446-9731
Noha Abdel-Karim	Senior Engineer	noha.karim@nerc.net	404-446-4699
Elliott J. Nethercutt	Senior Technical Analyst	elliott.nethercutt@nerc.net	202-644-8089
Trinh Ly	Engineer	trinh.ly@nerc.net	404-446-9737
Michelle Marx	Administrative Assistant	michelle.marx@nerc.net	404-446-9727

[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 about 80 percent of all electricity supply interruptions to end-use customers.

Table of Contents

Preface

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 ERO for North America, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.[3] NERC 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 industry using a balanced, open, fair, and inclusive process accredited by the American National Standards Institute (ANSI). While NERC does not have authority to set Reliability Standards for resource adequacy (e.g., reserve margin criteria) or to order the construction of resources or transmission, NERC can independently assess where reliability issues may arise and identify emerging risks. This information, along with NERC's recommendations, is then available to policy makers and federal, state, and provincial regulators to support decision making within the electric sector.

NERC prepared the following assessment in accordance with the Energy Policy Act of 2005, in which the U.S. Congress directed NERC to conduct periodic assessments of the reliability and adequacy of North America's BPS.[4,5] NERC operates under similar obligations in many Canadian provinces, as well as a portion of Baja California Norte, Mexico.

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 Seasonal 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 25 assessment areas for the long-term assessment and 20 areas for the seasonal assessments, both within and across the eight Regional Entity boundaries (as shown by the corresponding table and maps above).[6] To prepare these assessments, NERC collects and consolidates data from all areas, 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 collected in a consistent manner and 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 on important technical challenges and aiding NERC in achieving its mission—to ensure the reliability of the North American BPS.

[3] As of June 18, 2007, the FERC granted NERC the legal authority to enforce reliability standards with all U.S. users, owners, and operators of the BPS, and made compliance with those standards mandatory and enforceable. 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.

[4] H.R. 6 as approved by the 109th 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 details the objectives, scope, data, and information requirements, and Reliability Assessment Process requiring seasonal and long-term reliability assessments on an annual basis.

[6] These maps were generated using Ventyx-Velocity Suites software, modified by NERC. This content may not be reproduced in whole or any part without the prior express written permission of NERC.

About This Report

The *2013–2014 Winter Reliability Assessment* provides an independent assessment of the reliability of the bulk electricity supply and demand in North America from December 2013 through February 2014. The report specifically provides a high-level reliability assessment of 2013 winter resource adequacy and operating reliability, an overview of projected electricity demand and supply changes, and focused area assessments.

The primary objective in providing this assessment is to identify areas of concern regarding the reliability of the North American BPS and make recommendations for remedial actions as needed. The assessment process enables BPS users, owners, and operators to systematically document their operational preparations for the coming season and exchange vital system reliability information.

The Reliability Assessment Subcommittee (RAS) of the NERC Planning Committee (PC) prepared this report based on data that the eight NERC Regional Entities and other stakeholder participants submitted by October 7, 2013. Any other data sources used by NERC staff in the preparation of this document are identified in the report. NERC, in concert with industry stakeholders, performed detailed data checking on the reference information received by the Regions, as well as a review of all self-assessments, to form its independent view and assessment of the reliability projected for the 2013–2014 winter season. NERC also uses an active peer review process to develop reliability assessments. The peer review process takes advantage of industry subject matter expertise from many sectors. This process also provides essential checks and balances for ensuring the validity of the assessment and the conclusions provided by the Regional Entities.

2013–2014 Winter Season Key Findings

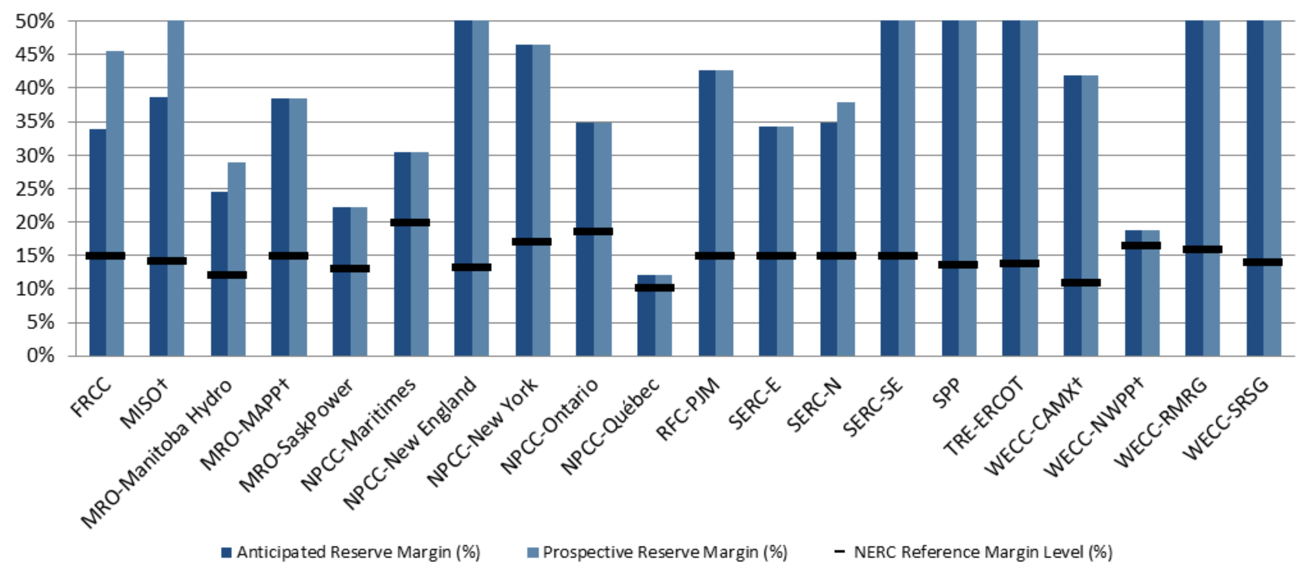
The following key findings in this assessment point to common themes across North America or Region-specific challenges:

- Resources are adequate to meet 2013–2014 winter peak demand.
- Prolonged cold weather events in the Northeast may limit natural gas availability.
- Preparation initiatives are in place for extreme weather and other abnormal operating conditions.

Resource Adequacy

For the 2013–2014 winter operating period, all assessment areas project sufficient resources to meet peak demands. The planning reserve margins for the forecast winter peak are shown in Figure 1 and in more detail in each individual assessment area's section.

Figure 1: 2013–2014 Winter Peak Planning Reserve Margins by Assessment Area[7]



ƚ indicates winter-peaking assessment area

Natural Gas

A continuing trend noted in several NERC *Long-Term Reliability Assessments* and the topic of a recently published NERC special assessment is the increase of gas-fired generation coupled with the reduction in fuel diversity across the overall resource portfolio. The extent of this trend varies from region to region; however, the concerns are high priority in areas where (1) power generators rely on interruptible[8] gas pipeline transportation, (2) natural gas interstate pipelines are constrained to meet demand beyond what has been contracted and committed, and (3) gas use for power generation is growing the fastest. NERC's assessment concluded that as natural gas-fired generation increases, more attention from electric system planners and operators is needed to better understand the interface and interaction between the electric and gas systems. Furthermore, the reliability ramifications of a substantial reliance on just-in-time fuel delivery and the potential for single points of failure across natural gas infrastructure must be taken into account when considering long-term solutions.

---

[7] The y-axis is limited to 50 percent planning reserve margins. In some areas, margins are above 50 percent.

[8] Including both interruptible services and firm capacity released or resold by the primary capacity holder.

Since the 2012–2013 winter season, an additional 6,608 MW of gas-fired generation came on-line. In the same time period, coal-fired generation decreased by almost the same amount. Gas is the largest contributing fuel type, making up 40.6 percent of the Total NERC-wide Resource Mix (Figure 2). The U.S. capacity from gas-fired generation increased last year; however, only 252 miles of new pipeline (4.5 Bcf) were added in 2012—the lowest pipeline addition since 1997 (see Figure 3).[9] More than half of new pipeline projects that entered commercial service in 2012 and 2013 were in the Northeast, but most of that capacity was added outside of New England's constrained areas where there is an increasing reliance on gas-fired generation. Annoucements for new pipeline capacity in 2014 through 2016 show promise to the Northeast, but many of these projects do not alleviate the constraints across the New England interface. Therefore, from a natural gas availability perspective, similar conditions to last year can be expected. For New England, this includes the potential for natural gas interuption to gas-fired generators and a reliance on back-up fuel (generally oil) to meet peak demand.

Figure 2: 2013–2014 Total NERC-wide Resource Mix

	2013-14 On-Peak Winter Capacity (MW)	
Fuel Type	2013-14	Share
Coal	315,748	29.6%
Petroleum	50,626	4.7%
Gas	432,882	40.6%
Nuclear	116,187	10.9%
Hydro	105,974	9.9%
Renewables (non-hydro)	23,940	2.2%
Pumped Storage	21,470	2.0%
TOTAL	**1,066,827**	**100%**

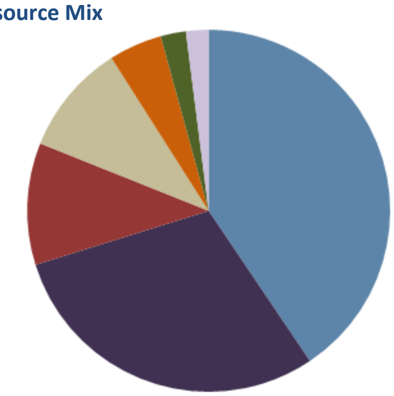
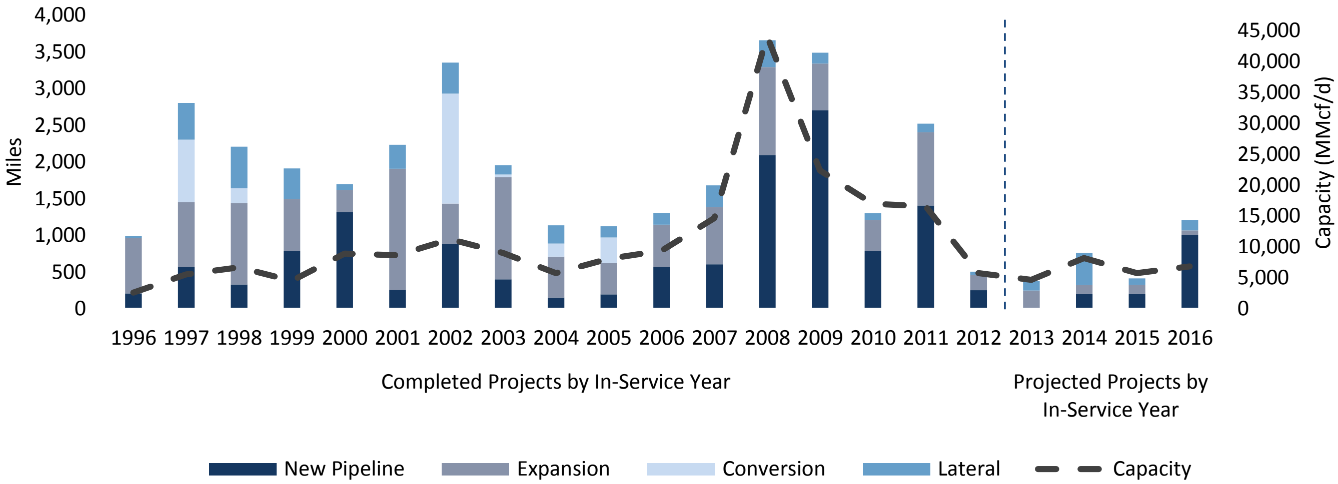


Figure 3: Natural Gas Pipeline Expansions in the United States (including cross-border projects with Canada)



As a result of NERC's assessment and forecasted—and in some cases already observed—emerging reliability impacts, a number of initiatives have been put in place to address both short- and long-term reliability challenges. While longer-term initiatives, such as interconnection-wide planning analyses and major electricity market changes, are covered in NERC's *Long-Term Reliability Assessment*, short-term solutions and challenges for the upcoming winter, by Region, are highlighted below.

[9] http://www.eia.gov/todayinenergy/detail.cfm?id=10511

NPCC-NEW ENGLAND

The New England generation fleet continues to be reliant on natural gas as a primary fuel source. Approximately 45 percent of the Region's generation is gas-fired, with 22 percent of this claiming dual-fuel capability. This generation provides up to 54 percent of New England's electric energy on any given operating day. Generators in New England are heavily dependent on pipeline capacity released by the firm capacity rights holders, with less than 10 percent holding firm contracts. During the 2012–2013 winter, ISO-NE observed lower generator oil inventories than in previous years. Reduced demand for oil has resulted in a reduction in refinery and transportation capability and an increase in the lead time required for replenishment. This, coupled with the need to operate oil-fired generators more frequently because of constrained gas supplies during peak winter conditions, has created concerns about power system reliability during the winter period.

ISO-NE has taken a number of steps to prepare for and mitigate fuel supply risks. ISO-NE operations staff monitors gas pipeline bulletin boards daily to determine expected demand on regional pipelines, pipeline outages, and capacity constraints or Operational Flow Orders. Staff communicates directly with the pipeline operators, as needed, to follow up on any concerns and obtain greater detail on expected conditions. Control room staff also communicates daily with all available dual-fuel and gas-fired generators to determine what generator operators expect to use as their primary fuel source and whether they will be able to meet expected output schedules. This information, along with short-term weather data, is used to develop daily and forward-looking operating plans.

System Operation conducts monthly fuel surveys of all oil- and coal-fired generators. These surveys provide detailed information on fuel-storage capacity, actual inventory, expected replenishment, hours of operation with current fuel supply, staffing, and dual-fuel capability. Survey data is incorporated by System Operations into weekly and seasonal planning, quantifying onsite fuel supplies for "at risk" units and dual-fuel capabilities to improve awareness on operating conditions and unit commitment availability.

The 2012–2013 winter period demonstrated that New England's natural gas dependency risk continues to escalate and existing fuel arrangements of many generators will lead to continued challenging and complex operating conditions when the power system and fuel supply deliveries are stressed. ISO-NE introduced a Winter Reliability Program for winter 2013–2014. The program provides key fuel availability enhancements and serves as an intermediate step to the market-based solutions that will be introduced in 2014. The program provides for increased oil inventories for participating oil-fired generators, with the majority of that oil required to be on-site at generating stations by December 1, 2013. The program requires participating dual-fuel generators to (1) provide ISO-NE with a test plan for switching from gas to oil and (2) demonstrate that capability within the winter period. The program includes a winter demand response program for the winter assessment period. Finally, the program introduces a mechanism for dual-fuel generators switching to oil in real-time to be able to reflect the cost of operating on their secondary fuel.

Monitoring the unique challenges in New England and evaluating the solutions could provide a means for NERC to offer additional insights and recommendations, potentially addressing any residual gaps and other considerations. In many ways, concerns and solutions being formulated in ISO-NE represent a test bed in which effective ways to plan and operate a transforming electric grid with a large penetration of natural gas can be effectively measured. Consequently, NERC assessments can provide insights about addressing challenges and necessary enhancements so that other Regions may apply them to meet their own future needs.

NPCC-NYISO

While New York and New England are geographically similar, the two areas are very different from a natural gas infrastructure topology perspective. New York has a number of interstate natural gas pipelines and storage facilities. Gas supply from the Marcellus and Appalachian Basins offers significant fuel reliability benefits. Additionally, new pipeline capacity in the New York City area is expected to enhance fuel reliability for that area. As such, New York's risk of experiencing natural gas interruptions or curtailments is less than its northeastern neighbor.

In an effort to proactively prepare for the upcoming winter, NYISO evaluated the dual-fuel capabilities of generators. New risk profiles of the natural gas generation fleet are now shared with system operations and include the amount of fuel reserves on-site, the time needed to switch, and the time needed to replenish fuel supplies once used. New control room procedures, including an extreme cold weather event procedure, will be in place this winter to respond to gas system disruptions. The extreme cold weather procedure includes a mechanism for soliciting information related to gas and alternate fuel supplies throughout the operating day. This is a key enhancement in overall gas and electric system coordination.

MISO

While there is an abundance of gas supply in MISO, infrastructure expansion is needed to move gas into the Region and alleviate local constraints. MISO performed a scenario study for the 2013–2014 winter availability of its natural gas generating units.[10]

In October, MISO kicked off a six-month coordination field trial with ANR Pipeline Company to further coordinate between industries, enhance situational awareness, and improve reliability. In addition to the coordination field trial, MISO completed a paper on the misalignment of the gas and electric dispatch days. Additional initiatives include a report on resource adequacy needs, loss-of-load expectation study, a review of coordinated operations, and development of a database of natural gas generators and associated natural gas infrastructure in MISO.

WECC

Natural gas deliveries are often scheduled on a short-term (daily) basis in WECC. This acquisition process, coupled with generally limited storage and potential gas pipeline pressure limitations, may lead to supply interruptions should extreme temperatures occur. The primary mitigation for fuel-related risks in WECC includes geographically diverse supply basins feeding multiple natural gas pipelines, as well as the diverse generation portfolio of nuclear, coal, natural gas, and renewable resources in the Western Interconnection.

According to CAISO, approximately 60 percent of the installed capacity uses natural gas as fuel. On June 7, 2013, Southern California Edison Company (SCE) announced that it would permanently close the San Onofre Nuclear Generating Station (SONGS) in southern California. Without SONGS, CAISO is more dependent on gas as a fuel. If larger generation units—primarily coal and nuclear—continue to retire, this trend will continue. CAISO is taking the initiative to address the onset of gas dependency. Electric Transmission Operators and gas utilities in California can exchange non-public operations information to enhance the coordination interface.

Potential Operational Challenges

Demand and Weather Uncertainty

According to the National Oceanic Atmospheric Administration's (NOAA) Winter Outlook (November to February), the 2013–2014 winter climate in the United States is expected to be mild. The ERCOT, SPP, and WECC are expected to experience above-normal winter temperatures. According to Environment Canada, the majority of Canada is expected to have normal winter weather; however, the southwestern region of Canada, WECC-BC, may experience a colder winter.

Extreme Weather and Preparation Initiatives

In early February 2011, customers in the southwestern region of the United States experienced unusually cold and windy weather. For five consecutive mornings, low temperatures reached into the teens, and there were many sustained hours of below-freezing temperatures throughout Texas and New Mexico.

Electric entities located within the TRE, WECC, and SPP Regions were affected by the extreme weather, as were gas entities in Texas, New Mexico, and Arizona. More details regarding the cold-snap outages can be found in a joint FERC/NERC report.[11] Subsequent to the issuance of the August 2011 joint report, NERC issued eight lessons learned reports.[12]

[10] The results can be found in the MISO section.
[11] More details regarding the cold-snap outages are available in a joint FERC/NERC report: *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
[12] Lessons Learned – Southwest Cold Weather Event, http://www.nerc.com/page.php?cid=5|393

Operating limit testing, potential fuel-need determination, and fuel-switching capability tests are routine power plant functions. However, performing such activities during extreme cold weather conditions is not routine. Due to the cold snap in early February 2011 and in anticipation of extreme cold weather, some Regions implemented modifications, enhancements, or new procedures for 2013–2014 winter season planning and preparation processes. Many of the southern Regions that don't typically experience cold weather reported that they are well prepared for extreme conditions.

Preparation and precaution measures include:

- Weatherizing units;
- Testing for units that claim dual-fuel capability;
- Inspecting heaters and heat-tracing equipment;
- Testing blackstart units in cold weather; and
- Assessments for the need to establish protected circuits for electric service to natural gas compression stations.

Power plants subject to subfreezing weather conditions are generally equipped with various plant freeze-up prevention elements. Such facilities routinely inspect those elements and make necessary repairs and improvements. In ERCOT, a new rule requires separate submission of weatherization plans for each generation resource. Previously, the bulk of emergency operations plans submitted did not pertain to weatherization. The plans also required ERCOT to sort through lengthy plans to identify parts that may or may not be intended to apply to weatherization procedures and imposed a substantial administrative burden. In WECC, some Balancing Authorities—particularly those in areas most heavily impacted by the February 2011 cold weather event—are implementing more rigorous plant winterization programs. Changes implemented because of the 2011 event (e.g., heat-tracing) are focused on plant freeze-up prevention.

Regions that weren't affected by the 2011 cold snap, such as FRCC and SERC, also incorporated the lessons learned and made modifications to their policies and procedures. Although many of the recommendations helped to reinforce plans and procedures already in place, some entities took additional steps to improve their plans.

Scheduled Maintenance Outages

Because cold weather fronts can move in rapidly under extreme conditions, risk-based and conservative approaches for outage coordination should be considered.

As the date for compliance with federal, environmental regulations approaches (i.e., 2015 for the Mercury and Air Toxics Standards), an increasing amount of scheduled outages to retrofit, repower, or otherwise reconfigure fossil-fired generators is expected. As noted in NERC's prior special assessments, approximately 600 to 700 unit retrofits will be needed to meet environmental requirements over the long term—many of these occurring between 2013 and 2016. Given the relatively short time line 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 could impact operations and reduce operational flexibility.

For summer-peaking areas—mostly in the United States—the winter season provides an opportunity to perform scheduled maintenance on generation and transmission systems. A lower demand means less transmission and resources are needed concurrently. While scheduled outages are typically coordinated in a manner that minimizes risk of a reliability issue (i.e., use of a zonal maintenance margin in MISO), unexpected cold snaps in certain parts of the country can quickly trigger a reliability challenge if transmission or generation outages make it difficult to get supply to specific areas.

PJM

In September 2013, unusually hot weather across the PJM footprint triggered controlled interruptions of electricity in Michigan, Ohio, Indiana, and Pennsylvania. While PJM has an extensive outage analysis coordination process designed to avoid conflicting outages, load forecasts play a significant part in determining the amount of outages that PJM will allow—a common approach across all Transmission Operators. However, load forecasts are inherently uncertain—particularly in the winter for summer-peaking areas. PJM plans to continue to monitor any new generator deactivation notices received and adequacy projections to include generation retirements, planned outages, and expected queued generation.

FRCC

Currently, FRCC expects to have up to 15 staggered BES transmission facilities out of service throughout the 2013–2014 winter period. Many of these BES facilities are not planned to be out of service for the entire duration of the winter season. These outages were studied as part of the FRCC Operational Seasonal Study process. SERC and FRCC hold weekly conference calls to coordinate outages and discuss any potential operational issues in FRCC.

MRO

Manitoba Hydro plans to take out a number of lines for regular maintenance during the 2013–2014 winter. Because these outages will limit the power transfer capability, Manitoba is developing temporary operating procedures to ensure reliable system operations during the outages.

The MAPP Assessment Area has seasonal studies for upcoming operating seasons. These studies include extended planned outages that will occur during the upcoming season and sensitivities looking at known areas of concern. For example, WAPA, in conjunction with Basin Electric, performed extensive studies in the northwestern North Dakota region due to unexpected load growth in the area.

SaskPower plans for reliable transmission operation on a short-term basis by performing daily day-ahead and week-ahead studies, weekly month-ahead studies, and semiannual joint seasonal studies with Manitoba and input from Basin Electric. For planned and emergency outages, further detailed study work is performed and temporary operating guides are issued as required.

SERC

A line outage in the Duke Energy territory has the potential to cause transactions curtailment and redispatch of available generation. In addition, a 161-kV line, in the TVA territory, is tentatively scheduled to be out of service for the winter in order to increase the line's capacity. An existing operating guide for this area will be used to address any N-1 contingency constraints during this outage.

ERCOT

ERCOT has an outage scheduling system and process that coordinates all transmission line outages. The initial energize date of new transmission lines are managed through additional operational procedures. Any of these outages or new line initial energize date delays may result in constraints in real time for the ERCOT Interconnection.

WECC

In WECC, transfer coordination between neighboring assessment areas is handled with varying methods. In the southwestern subregion, the coordination is handled by a WECC transmission engineer who communicates with neighboring utilities while performing seasonal studies. Another communication method is the Utilities Outage Coordination Forum in the Rocky Mountain subregion. This group discusses and coordinates all generation and transmission outages scheduled for the next year. This group includes all neighboring Transmission Operators, Balancing Authorities, and the Reliability Coordinator (RC). Finally, the Balancing Authorities in WECC participate and communicate in their Reserve Sharing Groups to coordinate imports and exports during peak demand periods.

Projected Demand, Resources, and Reserve Margins

The following table contains data collected by NERC to assess the reserve margins for each assessment area. The methods and assumptions for the data collection process can be found on the NERC website. More detailed assessment area data can be requested from NERC.

Summary Table A: Projected Demand, Resources, & Planning Reserve Margins

Assessment Area	Total Internal Demand (MW)	Net Internal Demand (MW)	Anticipated Resources (MW)	Prospective Resources (MW)	Anticipated Reserve Margin (%)	Prospective Reserve Margin (%)	NERC Reference Margin Level (%)
FRCC	46,456.0	43,384.0	58,065.3	63,128.6	33.84%	45.51%	15.00%
MISO†	103,445.7	99,569.2	138,133.8	150,981.0	38.73%	51.63%	14.20%
MRO-Manitoba Hydro	4,543.0	4,317.0	5,377.0	5,567.5	24.55%	28.97%	12.00%
MRO-MAPP†	5,799.2	5,424.2	7,506.2	7,506.2	38.38%	38.38%	15.00%
MRO-SaskPower	3,471.0	3,385.0	4,135.7	4,135.7	22.18%	22.18%	13.00%
NPCC-Maritimes	5,376.0	5,145.4	6,715.4	6,715.4	30.51%	30.51%	20.00%
NPCC-New England	21,299.0	21,299.0	36,445.0	36,445.0	71.11%	71.11%	13.30%
NPCC-New York	24,709.0	24,709.0	36,189.7	36,189.7	46.46%	46.46%	17.00%
NPCC-Ontario	22,282.0	22,282.0	30,051.2	30,051.2	34.87%	34.87%	18.60%
NPCC-Québec	37,232.8	37,232.8	41,700.9	41,700.9	12.00%	12.00%	10.10%
RFC-PJM	132,229.0	132,229.0	188,683.9	188,683.9	42.69%	42.69%	15.00%
SERC-E	42,359.0	40,882.0	54,861.1	54,903.1	34.19%	34.30%	15.00%
SERC-N	41,397.0	39,858.0	53,741.9	54,925.9	34.83%	37.80%	15.00%
SERC-SE	45,956.0	43,938.0	66,715.1	68,688.1	51.84%	56.33%	15.00%
SPP	34,415.0	33,672.5	65,828.9	65,828.9	95.50%	95.50%	13.60%
TRE-ERCOT	47,632.0	45,925.0	73,619.0	73,619.0	60.30%	60.30%	13.75%
WECC-CAMX†	38,936.0	38,088.0	54,019.4	54,019.4	41.83%	41.83%	10.96%
WECC-NWPP†	65,954.3	65,617.3	77,953.0	77,953.0	18.80%	18.80%	16.52%
WECC-RMRG	9,780.0	9,504.0	14,837.0	14,837.0	56.11%	56.11%	15.87%
WECC-SRSG	18,009.4	17,725.4	38,724.3	38,724.3	118.47%	118.47%	13.97%
EASTERNINTERCONNECTION	533,736.9	520,094.3	752,450.4	773,750.4	44.68%	48.77%	-
QUÉBECINTERCONNECTION	37,232.8	37,232.8	41,700.9	41,700.9	12.00%	12.00%	10.10%
TEXASINTERCONNECTION	47,632.0	45,925.0	73,619.0	73,619.0	60.30%	60.30%	13.75%
WESTERNINTERCONNECTION‡	131,980.4	130,263.4	180,603.7	180,603.7	38.65%	38.65%	14.71%
TOTAL-NERC	**750,582.1**	**733,515.5**	**1,048,374.0**	**1,069,674.0**	**42.92%**	**45.83%**	**-**

†Denotes a boundary change

‡WECC coincident peak

FRCC

Demand Projections

	Megawatts (MW)
Total Internal Demand	**46,456**
Load-Modifying DCLM	2,521
Load-Modifying Contractually Interruptible	551
Net Internal Demand	**43,384**

Resource Projections

	Megawatts (MW)
Net Firm Capacity Transfers	2,185
Existing-Certain & Future-Planned Capacity	55,880
Anticipated Resources	**58,065**
Existing-Other, Future-Other Capacity	5,063
Prospective Resources	**63,129**

Planning Reserve Margins

	Percent (%)
Anticipated Reserve Margin	**33.84%**
Prospective Reserve Margin	**45.51%**
NERC Reference Margin Level	**15.00%**

FRCC's membership includes 30 Regional Entity Division members and 24 Member Services Division members composed of investor owned utilities, cooperative systems, municipal utilities, power marketers, and independent power producers. FRCC is divided into 10 Balancing Authorities with 72 registered entities (both members and nonmembers) performing the functions identified in the NERC Reliability Functional Model and defined in the NERC Reliability Standards. The Region contains a population of more than 16 million people and covers roughly 50,000 square miles in peninsular Florida.

The Florida Public Service Commission approved a 15 percent Reserve Margin criteria for noninvestor owned utilities and a 20 percent Reserve Margin criteria for investor owned utilities, which is applied as 15 percent for the NERC Reference Margin Level. Based on the expected load and generation capacity, the projected Reserve Margin is above 30 percent for the season during the assessment period (i.e., 2013–2014 winter season). A rebound in the economy could potentially increase the demand, energy, and load projections that could realign the Reserve Margin with previous projections from past assessments.

FRCC is forecasted to reach its 2013–2014 winter non-coincident peak total internal demand of 46,456 MW in January, which represents a projected demand increase of 28 percent above the actual 2012–2013 winter demand of 36,409 MW. This projection is consistent with historical weather-normalized FRCC demand growth and is 0.2 percent higher than 2012–2013 winter forecast of 46,367 MW. During winter 2012–2013, FRCC experienced very mild temperatures, resulting in lower internal demand.

In 2010, the Florida Public Service Commission approved more aggressive Demand-Side Management (DSM) goals for the state's participating entities. Financial incentives have also been made available to various utilities with DSM achievements that exceed FERC-approved goals. It is projected that over the coming decade, Demand Response will increase at an average annual growth rate of about 1.2 percent.

FRCC is not expecting any issues that could lead to large-scale impact to generator availability during the winter season. For the upcoming winter season, 146 MW of natural gas generation is set to retire. This retirement is not expected to have an impact on generation scheduled to serve load. More than 282 MW of new generation will be brought on-line early during the winter season, with an additional 20 MW of capacity from the uprate of existing units.

Only the contractual firm capacity available from variable resources (e.g., solar, hydro, biomass) has been included as firm generation. Any variability in firm unit output has been removed.

There are 1,340 MW of generation under firm contract, available to be imported into the Region from the SERC-SE Assessment Area throughout the winter season, and another 845 MW of member-owned generation, which is dynamically dispatched out of the SERC-SE Assessment Area.

The FRCC Region does not rely on external resources for emergency imports. However, there are emergency power contracts in place between SERC members and FRCC entities. All firm on-peak capacity imports into FRCC have firm transmission service agreements in place to ensure deliverability. Such capacity resources are included in the calculation of FRCC's Planning Reserve Margins.

FRCC has not identified any specific large-scale projects needed to maintain or enhance reliability during the 2013–2014 winter season. The FRCC Region expects all scheduled BES additions and transmission upgrade projects to become energized before the winter peak. These projects are primarily related to expansion to serve localized load growth and maintain the reliability of the BES in the longer-term planning horizon. In addition, no concerns were identified for meeting the target in-service dates of new projects that may impact system reliability during the winter season.

Currently, FRCC expects to have up to 15 staggered BES transmission facilities out of service throughout the 2013–2014 winter season, but many of these facilities are not planned to be out of service for the entire duration of the season. These outages were studied as part of the FRCC Operational Seasonal Study process and are not anticipated to affect reliability within the Region.

At this time, there are no plans for additional undervoltage load shedding (UVLS) within the FRCC Region. Currently, about 1,020 MW of UVLS are armed within the FRCC Region. The majority of the UVLS relays are designed to respond to local low-voltage conditions that could be caused by multiple-contingency events.

FRCC expects the BES to perform adequately over various system operating conditions with the ability to deliver the resources to meet the load requirements at the time of the winter peak demand. FRCC performed a *Winter Transmission Assessment and Operational Seasonal Study* to assess the adequacy and robustness of the BES within the FRCC Region under expected 2013–2014 winter peak load and anticipated system conditions, taking into account generation and transmission maintenance activities. The regional assessment and operational study analyzed the performance of the transmission system under normal conditions, single-contingency events, and select multiple-contingency events, which were determined to be relevant by past studies. The results were coordinated and peer-reviewed by FRCC's Operations Planning Working Group (OPWG) to ensure the BES performs adequately throughout the winter time frame. The results of study demonstrated that potential thermal and voltage conditions exceeding the applicable screening criteria can be successfully mitigated under normal conditions, single-contingency events, and select multiple-contingency events. The BES within the FRCC Region is expected to perform reliably for the anticipated 2013–2014 winter peak season system operating conditions.

DSM load control programs within FRCC are treated as "demand reduction," not as a capacity resource. Based on past experience, demand reduction is used on a limited basis and is expected to be fully available when called on. FRCC does not anticipate any issues with the availability of demand reduction during the 2013–2014 winter season.

FRCC does not anticipate any reliability impacts as result of environmental or regulatory restrictions for the 2013–2014 winter. Additionally, FRCC does not anticipate any significant issues impacting the FRCC Region as a result of neighboring areas. The OPWG, under the direction of the FRCC Operations Planning Coordinator, holds weekly conference calls to coordinate outages and discuss any potential operational issues. Transmission Operators from FRCC and adjacent Transmission Operators from SERC participate on the weekly call.

MISO

Demand Projections

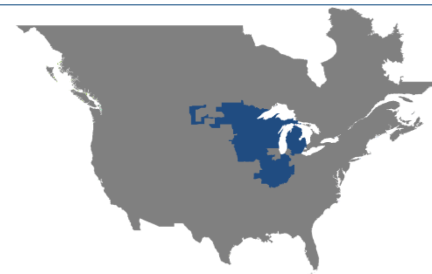
	Megawatts (MW)
Total Internal Demand	**103,446**
Load-Modifying DCLM	280
Load-Modifying Contractually Interruptible	3,597
Load-Modifying Load as a Capacity Resource	0
Net Internal Demand	**99,569**

Resource Projections

	MW
Supply-Side Load as a Capacity Resource	3,394
Net Firm Capacity Transfers	1,535
Existing-Certain & Future-Planned Capacity	133,204
Anticipated Resources	**138,134**
Existing-Other, Future-Other Capacity	12,847
Prospective Resources	**150,981**

Planning Reserve Margins

	Percent (%)
Anticipated Reserve Margin	**38.70%**
Prospective Reserve Margin	**51.60%**
NERC Reference Margin Level	**14.20%**



The Midcontinent Independent System Operator, Inc. (MISO) is a not-for-profit, member-based organization that coordinates the cost-effective delivery of electric power across all or parts of 15 U.S. states and the Canadian province of Manitoba. As a regional transmission organization (RTO), MISO provides regional grid management and open access to the transmission facilities under MISO's functional supervision. MISO currently manages energy and operating reserves markets, which consist of 12 Balancing Authorities—including MISO Balancing Authority —28 Local Balancing Authorities, and 362 Market Participants, who serve approximately 48 million people.[13]

***MISO Boundary Changes**: Beginning December 19, 2013, MISO will coordinate all RTO activities in the newly combined footprint that consists of all or parts of 11 states in MISO's Midwest Region and all or parts of four states in MISO's South Region. The full integration of the six Entergy operating companies, CLECO, and South Mississippi Electric Power Association (SME) increases MISO's energy and operating reserves markets to include an additional 28 Market Participants, who together serve approximately four million people. This section assesses the reliability of MISO's Market Area, effective December 19, for the upcoming 2013–2014 winter season. Joining companies are also covered in this analysis.*

The MISO Planning Reserve Margin is the reserve margin target level in percent form, and it represents the reserve percentage the MISO system must hold above its applicable system peak demand (summer peaking) to meet a reliability criterion of one-day-in-10 years loss-of-load expectation (LOLE). MISO's Planning Reserve Margin is 14.2 percent for the 2013–2014 Planning Year (i.e., June 2013 to May 2014). MISO does not calculate a seasonal requirement. For the purposes of this assessment, the 14.2 percent Planning Reserve Margin is applied as the NERC Reference Margin Level for the 2013–2014 winter.

MISO's Anticipated Capacity Resources Reserve Margin for the upcoming winter peak is 38.7 percent, which is 24.5 percentage points higher than the requirement. The table below provides a breakdown of the Anticipated Capacity Resources Reserve Margin and its demand and capacity components by the Midwest Region, the South Region, and the entire MISO footprint for the 2013–2014 winter season. MISO does not anticipate its reserve margin to fall below 14.2 percent during the 2013–2014 winter.

Table 1: MISO Resource Adequacy – North and South

	NERC Reference Margin Level (%)	Net Internal Demand (MW)	Reference Margin Requirement (MW)	Anticipated Resources (MW)	Anticipated Reserves (MW)	Anticipated Reserve Margin (%)
MISO Midwest	14.20%	73,186	83,580	100,636	27,450	37.50%
MISO South	14.20%	26,383	30,129	37,497	11,114	42.10%
MISO	**14.20%**	**99,569**	**113,709**	**138,133**	**38,565**	**38.70%**

[13] MISO Corporate Fact Sheet

Load Serving Entities (LSEs) submit monthly peak demand forecasts for two years and an additional eight years seasonal non-coincident peak demand forecasts to MISO's peak per Module E of MISO's tariff.[14] Based on these forecasts, MISO anticipates an Unrestricted Non-Coincident Peak Demand of 105,606 MW for the upcoming winter season, which consists of 78,024 MW for its Midwest Region and 27,582 MW for its South Region. For its Midwest Region, MISO anticipates 1.98 percent diversity, or 1,545 MW, based on eight years of historical actual winter peak demands. For its South Region, MISO anticipates 2.23 percent diversity, or 615 MW, based on the MISO's 2005 load shape. MISO calculated diversity for South Region in this manner because eight years of winter peak actuals were not readily available for the Region and MISO's LOLE analysis considers the 2005 load shape to be a normal representation for the Region. Therefore, MISO anticipates a coincident Total Internal Demand of 103,446 MW for the upcoming winter season, which consists of 76,479 MW for its Midwest Region and 26,967 MW for its South Region. For the Midwest Region, this represents a 1.9 percent increase and a 2.8 percent increase from last year's forecast demand and last year's actual demand, respectively.

Interruptible Load (IL), Direct Control Load Management (DCLM), and Energy Efficiency Resource (EER) DSM programs are eligible to participate in MISO's Planning Resource Auction as registered Load Modifying Resources (LMRs) to count toward meeting MISO's Planning Reserve Margin Requirement (one-day-in-10 years LOLE Requirement).[15]

In the 2013 Planning Resource Auction, 4,548 MW of LMR DSM cleared and committed to serving MISO load throughout the 2013–2014 Planning Year for MISO's Midwest Region. However, some of these resources, such as air conditioning programs, are unavailable during the winter months. Therefore, for the upcoming winter season, MISO anticipates 3,877 MW on winter peak—3,292 MW for its Midwest Region and 584 MW for its South Region.

Per MISO's Emergency Operating Procedures, LMR DSM is an emergency resource callable only during a Maximum Generation Emergency Event Step 2b. For this reason, uncertainty exists regarding how much will be available during an emergency situation. MISO is putting procedures in place to track the availability of these resources as the real-time operating horizon approaches. However, for the purposes of this assessment, it is assumed that the full 3,877 MW will be available during winter peak conditions.

MISO anticipates 136,812 MW of Existing-Certain capacity resources to be available during peak conditions for the upcoming winter season, which includes 98,489 MW for its Midwest Region and 38,323 MW for its South Region.[16]

In addition to Existing-Certain capacity resources, 13,575 MW of Existing-Other capacity resources (winter-rated capacity) exist in MISO, which includes 10,892 MW for its Midwest Region and 2,683 MW for its South Region. There are 3,710 MW (1,943 MW Midwest Region) of Existing-Other capacity resources that are classified as Energy-Only with no firm point-to-point transmission service. For the Midwest Region, 8,949 MW of Existing-Other capacity resources are deliverable throughout the system; however, they are not obligated to serve MISO's reserve requirement for the upcoming winter season.

Also, 241 MW of Future-Planned approved retirements will occur in the Midwest Region before this winter season, while no capacity additions are projected in MISO Generation Interconnection Queue (GIQ) for the same time period. In addition to Future-Planned retirements, Future-Planned scheduled maintenance is anticipated to total 2,627 MW and 739 MW on the winter peak hour for the Midwest Region and South Region, respectively.

---

[14] https://www.misoenergy.org/_layouts/MISO/ECM/Download.aspx?ID=19175

[15] See section 4.3 of the Resource Adequacy Business Practice Manual

[16] MISO Midwest Region Market Participants procured internal capacity resources or cleared internal capacity resources in the 2013 Planning Resource Auction to count towards meeting their PRM requirement. Those resources were then converted to a Must Offer Requirement totaling 101,470 MW of summer rated capacity, which have an obligation to offer into the "Day-Ahead Energy and Operating Reserves Market" throughout the 2013–14 Planning Year. In aggregate, this 101,470 MW of summer-rated capacity is equivalent to 98,489 MW of firm deliverable winter-rated capacity. Therefore, for the purposes of this assessment, MISO anticipates 98,489 MW of Existing-Certain capacity resources during winter peak conditions for its Midwest Region. Since MISO South Region Market Participants have not yet procured or cleared internal capacity resources for December 2013 through May 2014, for the purposes of this assessment, MISO assumes that all South Region internal capacity resources, which meet the eligibility requirements outlined in Section 4.2 of MISO's Resource Adequacy Business Practice Manual, are available to count towards meeting their PRM requirements. Therefore, MISO anticipates 38,323 MW of Existing-Certain capacity resources during winter peak conditions for its South Region.

The MISO Midwest Region's existing capacity wind resources receive a wind capacity credit, based on the Effective Load Carrying Capability of wind generation at each wind Commercial Pricing Node. The average wind capacity credit percentage is 13.3 percent.[17] Total existing wind nameplate capacity in MISO is equal to 11,606 MW, all of which is located in the Midwest Region, while the total wind capacity credit MW is equal to 1,757 MW (approximately 15 percent of nameplate). Out of the 1,757 MW of wind capacity credit, only 755 MW of Existing-Certain wind capacity is obligated to serve MISO's reserve requirement during the winter season (approximately 7 percent of nameplate). All other intermittent Existing Capacity resources receive their unforced capacity rating based on historical performance, per Section 4.2.2 of MISO's Resource Adequacy Business Practice Manual.

External resources are eligible to participate in the Planning Resource Auction as registered Capacity Resources.[18] For its Midwest Region, MISO assumes the 3,103 MW that cleared in the 2013 Planning Resource Auction to be available throughout the winter season. The amount of imports to MISO South is 567 MW. This makes 3,670 MW overall system imports for MISO.

Based on information received from PJM, MISO projects 1,481 MW of firm exports into PJM. The amount of exports from MISO South is 654 MW. This makes the overall system exports for MISO to be 2,135 MW.

Annually, MISO develops its MISO Transmission Expansion Plan (MTEP) to identify, assess, and address reliability issues within its electric transmission system member footprint. Table 2 details transmission projects (> 200 kV) that have been evaluated, have a proposed in-service date on or before February 2014, and are set for approval as part of the MTEP13 reliability assessment, which is scheduled to go before the MISO Board of Directors in December 2013.

Table 2: MISO Transmission Projects

Geographic Location by TO Member System	Project Name	Project Description	State	Expected In-Service Date	Max kV
AmerenIL	Mt. Vernon, West Breaker Replacements	Replace 345-kV Breakers 4526, 4530, and 4534 with 3000 A, 41-kA interrupting capability breakers due to age and condition. Install new 345-kV, 3000 A, 41-kA interrupting capability breaker to complete 345-kV ring bus and separate the 345-kV transformer position from the Mt. Vernon, West-Prairie State 345-kV line position. Replace 138-kV, Bus-Tie Breaker 1402 due to age and fault duty near capability. Replace disconnect switches, CTs, and wave trap in the Mt. Vernon, West–West Frankfort, East 345-kV line position to match or exceed line conductor ratings (2546 A summer emergency/2978 A winter emergency).	IL	June 2013	345
MEC	Webster 345/161-kV Transformer Replacement	Replace failed Webster 345/161-kV, 500-MVA transformer AB with a 560-MVA unit	IA	April 2013	345
ATC LLC	Uprate Morgan-Plains 345 kV	Rerate line 35321 Morgan–Plains 345 kV	WI	May 2013	345
SMP	Byron T9 345/161kV Transformer Replacement	Replacement of the failed Byron T9 345/161 transformer - without LTC	MN	December 2013	345
DEI	Thorntown 230/69-kV Bk1 Replace	Thorntown 230/69-kV Bk1 Replace with a 150-MVA nameplate transformer	IN	December 2013	230

[17] 2013 Wind Capacity Report
[18] See section 4.2.4 of the Resource Adequacy Business Practice Manual

IPL	Petersburg - Frances Creek - Hanna 345-kV line rating upgrade	Increase line rating from 956 to 1195 MVA	IN	December 2013	345

MISO's planning process evaluates all delayed projects to ensure reliability is maintained. There are no potential reliability impacts due to schedule delays of transmission identified. Additionally, during the upcoming winter season, MISO does not have any existing transmission lines or transformer outages scheduled that are expected to significantly impact reliability, and there are no lines identified that are necessary to maintain or enhance reliability during the winter peak within the Assessment Area. Renewable energy resources, whose capabilities are limited by fuel-dependent forecasts, create challenges for grid operators who dispatch generation to balance the moment-to-moment electricity demand as efficiently and reliably as possible. Due to the current and projected increase in wind generation in the footprint, MISO began working with stakeholders in January 2010 to design and implement a market mechanism to take advantage of advances in wind technology that make the concept of nondispatchability less applicable. The introduction of Dispatchable Intermittent Resources will allow such resources to fully participate in the energy markets and result in more economic and reliable grid operations.[19]

Through the use of industry-leading, wide-area visualization tools, system operators gain a clearer look at system conditions. One of these tools, Synchrophasors, provides more precise grid measurements by using data collected from Phasor Measurement Units (PMUs). PMU measurements are taken at very high speeds (typically 30 observations per second, compared to once every four seconds using current technology). Each measurement is time-stamped to synchronize data from widely dispersed locations in the power system network, providing a more comprehensive view of the entire interconnection. Synchrophasors can give better indications of grid stress, which allows operators to be more proactive when corrective actions are necessary.[20, 21]

MISO has some vulnerability analyses in progress, including:

- Load Levels – normal distribution plot plus narrative (MISO level)
- Planning Reserves Prior to EOP – Reserves anticipated under normal operating conditions taking into account forced outages (narrative plus graphic)
  - Shown at three load levels (50/50, 1 sigma, 2 sigma, and 3 sigma from 50/50 forecast)
  - Mid- and High-Forced Levels
  - MISO, Midwest, and South
- Off-peak and on-peak hours reserve levels through the month of January 2014 (expected peak month)
  - Considering scheduled maintenance
  - Average forced outages
  - Three load levels
  - Also consider various levels of non-firm gas derates

MISO also studied the amount of fuel availability during 2013–2014 winter for its natural gas generating units. In this study, the amount of available non-firm gas was reduced in increments and the effect of this reduction on Existing-Certain capacity was calculated. The table below summarizes this effect for the Midwest Region.

[19] Wind Integration
[20] Smart Grid Initiatives
[21] MISO's MTEP12 Report Section 7.7 covers the Synchrophasor project and other smart grid initiatives.

Table 3: MISO's Gas Study Results

Non-Firm Gas Reduced by	Unavailable EC
0%	-
10%	3,157
20%	6,314
30%	9,470
40%	12,627
50%	15,784
60%	18,941
70%	22,098
80%	25,255
90%	28,411
100%	31,568

MISO also reviewed possible risks that might occur during off-peak hours of the winter due to high amount of scheduled outages. As a result of this study, MISO does not anticipate any reliability issue during any of those off-peak hours.

MRO-Manitoba Hydro

Demand Projections

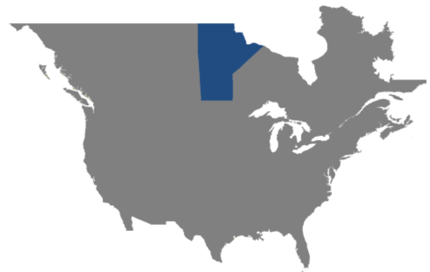
	Megawatts (MW)
Total Internal Demand	**4,543**
Load-Modifying Contractually Interruptible	226
Net Internal Demand	**4,317**

Resource Projections

	Megawatts (MW)
Net Firm Capacity Transfers	-100
Existing-Certain & Future-Planned Capacity	5,477
Anticipated Resources	**5,377**
Existing-Other, Future-Other Capacity	191
Prospective Resources	**5,568**

Planning Reserve Margins

	Percent (%)
Anticipated Reserve Margin	**24.55%**
Prospective Reserve Margin	**28.97%**
NERC Reference Margin Level	**12.00**



Manitoba Hydro is a Provincial Crown Corporation that provides electricity to 542,000 customers throughout Manitoba and natural gas service to 267,000 customers in various communities throughout southern Manitoba. Manitoba Hydro also has formal electricity export sale agreements with more than 35 electric utilities and marketers in the midwestern U.S., Ontario, and Saskatchewan. Manitoba Hydro is its own Planning Authority and Balancing Authority (BA). Manitoba Hydro is a coordinating member of the MISO. MISO is the Reliability Coordinator for Manitoba Hydro.

Manitoba Hydro performs a probabilistic assessment to determine the NERC Reference Margin Level. The 12 percent reserve margin has not changed since the release of the prior winter assessment.

The demand forecasting method changed from the method used for the *2012–2013 Winter Reliability Assessment*. Demand forecast is now calculated using the system load factors and applied to the forecast monthly and annual energy. Load factors are the ratio of the average hourly energy over a time period (usually a month or year) divided by the energy used within one specific hour (the peak demand value). A 10-year historical average load factor was calculated using the historical peak values on the historical weather adjusted energy.

Manitoba Hydro's current Energy Efficiency and Conservation portfolio includes customer service, cost-recovery, incentive- 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.

Demand response in the form of curtailable load at Manitoba Hydro is not used to meet peak demands. Manitoba Hydro has restrictions for the number times demand response can be deployed. Quarterly reports are sent to Manitoba Hydro's System Control to apprise them of the number of curtailments that have occurred and remain to date.

Manitoba Hydro plans to take out a number of lines for regular maintenance during the winter of 2013–2014. These outages will limit the power transfer capability to and from neighboring utilities. Temporary operating procedures will be developed to ensure reliable system operations during these line maintenance outages.

The capacity transactions during the winter peak in the assessment period do not significantly contribute to the reserve margin in the Assessment Area. Export transactions are 50 MW higher than the prior winter assessment period.

Manitoba Hydro's emergency energy imports are characterized under the MISO-MBHydro Contingency Reserve Sharing Group (CRSG) agreement. Manitoba Hydro system operators have the ability to request emergency energy imports from MISO, under the CRSG, only upon significant contingencies of generation or transmission facilities. Manitoba Hydro is its own BA, meaning all emergency energy imports would be from external BAs in MISO. The total reserve carried in the Reserve Sharing Group is 2000 MW (i.e., 150 MW for Manitoba Hydro and 1850 MW for MISO).

Manitoba Hydro is expected to have sufficient internal generating resources to cover winter peak demand. Imports are not required for normal operations during winter peak demand.

Manitoba Hydro does not foresee a need for any high-priority transmission projects to maintain or enhance reliability during the winter of 2013–2014. Manitoba Hydro does not have any significant substations that have been installed since last winter to report.

At least once a year, Manitoba Hydro performs an operational study to determine the storage reserve requirements necessary to meet demand under the lowest historic flow on record and a high load forecast. No unique operational problems have been observed.

Since January 1, 2010, Manitoba's Climate Change and Emissions Reductions Act [22]has precluded the use of coal to generate power, except to support emergency operations. As such, this does not preclude operation to support reliability.

It is not anticipated that there will be any additional issues or circumstances that will change the assessment projections during the assessment period. There are no known significant issues or concerns that could lead to large-scale impact to generator availability during the winter season.

There are no expected fuel-related challenges for this winter season. Manitoba Hydro's system is predominantly hydro-based and does not rely on natural gas as a primary fuel source. Reservoir levels are sufficient to meet both peak demand and daily energy demand for this winter season.

[22] http://web2.gov.mb.ca/laws/statutes/ccsm/c135e.php

MRO-MAPP

Demand Projections

Projected Peak: July	Megawatts (MW)
Total Internal Demand	**5,799**
Load-Modifying DCLM	370
Load-Modifying Contractually Interruptible	5
Net Internal Demand	**5,424**

Resource Projections

Projected Peak: July	Megawatts (MW)
Net Firm Capacity Transactions (Transfers)	-295
Existing-Certain & Future-Planned Capacity	7,801
Anticipated Resources	**7,506**
Prospective Resources	**7,506**

Planning Reserve Margins

Projected Peak: July	Percent (%)
Anticipated Reserve Margin	**38.38%**
Prospective Reserve Margin	**38.38%**
NERC Reference Margin Level	**15.00%**

The Mid-Continent Area Power Pool (MAPP) is an association of electric utilities and other electric industry participants operating in all or parts of Iowa, Minnesota, Montana, North Dakota, and South Dakota. Currently, the MAPP PA includes entities in two BA areas and 13 LSEs. The MAPP PA covers an area of approximately 200,000 square miles and serves a population of about 3.5 million. MAPP is a summer-peaking Region.

Due to MAPP's strong generation portfolio and DSM programs for the 2013–2014 winter season, Reserve Margins (Anticipated, Prospective, and Adjusted Potential Planning) exceed the Target Reference Margin of 15 percent for thermal systems and 10 percent for hydro systems.

MAPP assumes a 50/50 weather forecast and normal economic conditions. The 2012–2013 MAPP actual winter peak non-coincident demand was 5,387 MW. The 2012–2013 winter's demand forecast was 5,561 MW, based on the data submitted to the Midwest Reliability Organization (MRO). The 2013–2014 winter peak demand forecast is 5,424 MW. Non-coincident internal peak demands were used to aggregate individual Load-Serving Entity (LSE) loads in the MAPP forecast. Resource evaluations are based on non-coincident peak demand conditions.

Each MAPP LSE uses its own forecasting methodology. In general, the peak demand forecast includes factors involving recent economic trends (e.g., industrial, commercial, agricultural, residential) and 50/50 forecast weather patterns. Ames Municipal Electric System's demand is now projected based on the local historical peak plus an estimate of the economically driven growth. Their demand was previously based on averages obtained from the previous five years.

The total amount of Demand Response and Energy Efficiency and Conservation that is expected to be available on-peak for the 2013–2014 winter season is 375 MW. Interruptible Demand and DSM programs amount to about 6 percent of the MAPP Projected Total Internal Peak Demand of 5,777 MW.

A wide variety of programs, including direct load control (e.g., electric appliance cycling) and interruptible load, may be used to reduce peak demand during the winter season. MAPP LSEs estimate peak demand reductions for the winter season based upon analytical methodologies or after-the-fact determinations. Minnkota Power Cooperative's (MPC) demand response—the bulk of the MAPP demand response—is treated as load-modifying.

For the upcoming winter season, Missouri River main-stem water levels may affect hydro generation. The U.S. Army Corps of Engineers remains in conservation mode with total runoff for the year estimated to be 90 percent of normal weather condition. Operating flexibility is available to increase generation if required by system conditions.

There are 90 MW of Future-Planned resources projected to come on-line throughout the assessment period. Northwestern Energy installed a simple-cycle, gas-fired internal peaking unit of 60 MW in Aberdeen, South Dakota, which began commercial operation on April 30, 2013. Basin Electric Power Cooperative also added two 45 MW units—one at the Pioneer Generation Station and one at the Lonesome Creek Generation Station—and plans to add two more 45 MW units at the Pioneer Generation Station, which are scheduled to be operational in January 2014. These units are being added to support load growth in North Dakota's northwestern oil fields.

Since the *2012–2013 Winter Reliability Assessment*, there have been 14 MW of capacity retirements, all belonging to MPC. In addition to the retired capacity, Ames Municipal's generator 1 was taken out of commission due to a catastrophic failure in July 2013.

Of the Existing capacity resources, 383 MW of wind generation is expected on-peak, with a nameplate rating of 1,131 MW. Additionally, there are 2,336 MW of hydro and 3 MW of biomass existing capacity resources.

MAPP projects total firm imports to be 701 MW and total firm exports to be 996 MW. Import and export contracts are firm for energy and transmission service for at least one year. Capacity transactions projected beyond the length of firm contracts may be based on expected extensions of those contracts.

Center–Heskett 230-kV line will be out of service this fall for phase raising and reconductoring to increase thermal capacity. This may necessitate reductions of Square Butte Center area generation. Additionally, Northwestern Energy (NWE) began to reconductor the second phase of 115 KV between NWE's Seibrecht substation and Western Area Power Administration's (WAPA) Huron substation in May 2013. This is scheduled to be completed by November 2013. This is the second year of a three-year project. To enhance reliability, a 200-MW line is being constructed between Ames and Ankeny in Iowa. MPC's new 345-kV line from Center to Grand Forks is scheduled to be in-service in January 2014, and this line will be used to enhance reliability and provide an outlet for existing generation.

In December 2012, UVLS was installed at the Williston 57-kV bus due to unexpected load growth in the area. The UVLS prevents low post-contingent voltages in the local area. Approximately 70 MW of peak load can be tripped by UVLS. A system upgrade is scheduled to be in-service in March 2014.

Using the contingencies developed for the MAPP Transmission Reliability Assessment, WAPA performs seasonal studies for the entire WAPA footprint. These files contain contingencies within the WAPA footprint and neighboring systems in the Dakotas, Canada, Iowa, Minnesota, and Nebraska that are selected to produce the most severe system results and impacts. These seasonal studies are performed for the upcoming operating season and include extended planned outages that will occur during the upcoming season. These seasonal studies include sensitivities looking at known areas of concern. As a part of these seasonal studies, WAPA and Basin Electric have performed extensive studies in northwestern North Dakota because of unexpected load growth in the area.

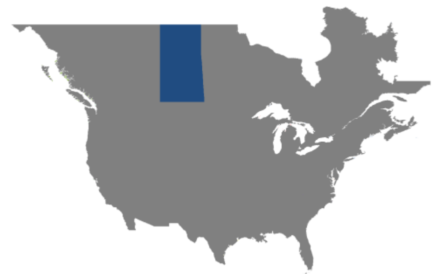
MAPP performs studies that consider known and anticipated fuel supply or delivery issues. Because the MAPP Planning Authority area has a large diversity in fuel supply, inventory management, and delivery methods, MAPP does not have a specific mitigation procedure in place should fuel delivery problems occur. Resource providers do not foresee any significant fuel supply or delivery issues for the upcoming 2013–2014 winter assessment period. Any fuel supply issues that may develop will be handled on a case-by-case basis. Adequate water supply is anticipated for normal generation during the winter assessment period. Coal stockpiles are near full, and there do not appear to be any supply or transportation issues at this time.

MRO-SaskPower

Demand Projections	
Projected Peak: July	Megawatts (MW)
Total Internal Demand	**3,471**
Load-Modifying Contractually Interruptible	86
Net Internal Demand	**3,385**

Resource Projections	
Projected Peak: July	Megawatts (MW)
Existing-Certain & Future-Planned Capacity	4,136
Anticipated Resources	**4,136**
Prospective Resources	**4,136**

Planning Reserve Margins	
Projected Peak: July	Percent (%)
Anticipated Reserve Margin	**22.18%**
Prospective Reserve Margin	**22.18%**
NERC Reference Margin Level	**13.00%**



Saskatchewan, a Canadian province, comprises a geographic area of 651,900 km^2 and serves approximately one million people. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the sole Planning Authority, Reliability Coordinator, Balancing Authority, and the principal supplier of electricity for Saskatchewan. It is a Provincial Crown Corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan BES and its interconnections.

SaskPower's criterion for adding new generation resources is based on Expected Unserved Energy (EUE). A probabilistic analysis is performed to determine the requirement for adding new generation resources. The probabilistic EUE value equates to an approximate 13-percent NERC Reference Margin Level, which is within the range stated in the prior winter assessment. An adequate Planning Reserve Margin is projected for SaskPower during the 2013–2014 winter assessment period. The anticipated Reserve Margin does not fall below the NERC Reference Margin level for the assessment period.

SaskPower's forecasted peak Total Internal Demand (TID) was 3,512 MW for the 2012–2013 winter assessment period and is 3,471 MW for the 2013–2014 winter assessment period. This year's forecast uses a 50/50 forecast and cannot be directly compared to last year's forecast (i.e., 90/10), which was also a mostly likely forecast but with a higher probability. The economic outlook remains consistent with the previous winter assessment period forecast.

The primary driver for DSM programs is economic incentive (i.e., difference in cost between providing the DSM program and the cost of serving the load). Increases in DSM for the 2013–2014 winter assessment period will come from growth of existing programs. DSM programs currently account for 59 MW of load reduction. No new Demand Response programs are being incorporated for the 2013–2014 winter assessment period. SaskPower uses Demand Response for peak shaving and has energy-limited contracts in place with a number of customers to provide this service. Demand Response currently accounts for 86 MW of reduction in TID. Contracted terms with Demand Response customers for the capacity, available hours, and number of interruptions are expected to be sufficient to be utilized for all months.

Since the previous winter assessment (2012–2013), a Combined-Cycle, natural-gas generation plant (net capability of 271 MW) has been added and one conventional coal-fired thermal plant (net capability of 62 MW) has been retired.

For the 2013–2014 winter assessment period, there are no significant planned transmission projects that involve upgrades to existing lines, and there are no project delays or service outages for any transmission facilities have been identified that would impact reliability for the assessment period. SaskPower plans for reliable transmission operation on a short-term basis by performing daily day-ahead and week-ahead studies, weekly month-ahead studies, and semiannual joint seasonal studies with Manitoba and input from Basin Electric (North Dakota). For planned and emergency outages, further detailed study work is performed and temporary operating guides are issued, as required.

For the 2013–2014 winter assessment period, 20 percent of wind nameplate capacity available to meet peak demand is used. The wind available to meet peak requirements is based on the historical (since installation) actual wind generation over a four-hour period during the peak for each day for the entire year. Currently, SaskPower does not have any solar resources.

On-peak expected values for hydro assume nameplate net generation less expected seasonal derates due to water conditions. All of biomass nameplate capacity is assumed to be available to meet demand based on a base-load contract.

There are no capacity transactions in SaskPower during the assessment period, meaning coordination is not required for imports. SaskPower does not plan to rely on imports during the 2013–2014 winter.

The following are the top transmission projects for reliability. These projects are heavily dependent on load growth, and they facilitate load deliverability. Project scopes have been defined, funds have been secured, and engineering and construction resources are currently being allocated. Delays are assessed when indicated, and interim measures (if required) are implemented to ensure system reliability is not impacted. At this time, there are no confirmed delays for targeted in-service dates for these planned projects or any major concerns with temporary service outages for any existing line or transformer facilities.

- By late 2013, two new 300-MVA, 230/138-kV auto-transformers will be installed in eastern Saskatchewan.
- By late 2013, two new 300-MVA, 230/138-kV auto-transformers will be installed in southeastern Saskatchewan.
- By late 2013 or 2014, two new 350-MVA, 230/138-kV auto-transformers will be installed in southeastern Saskatchewan.

There is no significant substation equipment that is newly available for the 2013–2014 winter assessment period.

No unique operational problems have been observed, no special operating studies have been performed, and no environmental or regulatory restrictions are anticipated to impact reliability for the 2013–2014 winter assessment period.

No significant issues that have the potential to impact operations within SaskPower during the assessment period have been identified in any neighboring areas. SaskPower also participates in the other regional study groups as a means to maintain communication and coordination with neighboring entities. For planned and emergency outages, further detailed study work is performed and temporary operating guides are issued as required. Coordination and communication efforts between SaskPower and neighboring areas are ongoing between system operators and—formally—as part of joint operational seasonal studies and other operational and planning studies as required.

Other than variances with load projections for the assessment period, there are no other potential issues or circumstances that have been identified in SaskPower that could result in substantial changes from the assessment projections for the 2013–2014 winter assessment period.

No notable issues have been identified in SaskPower that could lead to large-scale impact to generator availability during the 2013–2014 winter assessment period. All natural gas resources have firm on-peak transportation contracts with large natural gas storage facilities located within the province to back the contracts. Therefore, there are no anticipated problems, vulnerabilities, or disruptions to gas resources. Quarterly meetings are held with the natural gas provider and discussions have occurred to enhance coordination activities specifically on electric–gas interdependencies. Coal resources have firm contracts and are mine-to-mouth. Stockpiles are maintained at each facility in the event that mine operations are unable to meet the required demand of the generating facility.

NPCC-Maritimes

Demand Projections	Megawatts (MW)
Total Internal Demand	**5,376**
Load-Modifying Contractually Interruptible	231
Net Internal Demand	**5,145**

Resource Projections	Megawatts (MW)
Supply-Side Contractually Interruptible	14
Existing-Certain & Future-Planned Capacity	6,701
Anticipated Resources	**6,715**
Prospective Resources	**6,715**

Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**30.51%**
Prospective Reserve Margin	**30.51%**
NERC Reference Margin Level	**20.00%**

The Maritimes Area serves a population of approximately 1,910,000. It includes New Brunswick, Nova Scotia, Prince Edward Island, and the area served by the Northern Maine Independent System Operator (parts of northern and eastern Maine). New Brunswick and Nova Scotia are the two Balancing Authorities. The New Brunswick Power - System Operator is the RC for the Maritimes Area, which covers approximately 57,800 square miles.

The operating reserve margins for the Maritimes Area are based in accordance with NPCC Directory #1 Appendix F: Procedure for Operational Planning Coordination.[23] The assessment considers the regional Operating Reserve criteria, which is 100 percent of the largest single contingency and 50 percent of the second largest contingency. The Maritime Area is projecting adequate surplus capacity margins above its operating reserve requirements for the 2013–2014 winter period.

There are no significant changes in the demand forecast since the *2012–2013 Winter Reliability Assessment*. Forecasted peak demand was 5,246 MW for the 2012–2013 winter period and is 5,376 MW for the 2013–2014 winter, a slight increase of 130 MW or 2.4 percent.

The Maritimes Area is broken up into subareas, and each subarea has its own Energy Efficiency programs.[24] These programs are primarily aimed at helping residential consumers reduce their heating costs. The program is also usually geared toward heat, as the Maritimes Area is a winter-peaking system.

The only demand response considered in resource adequacy assessment for the Maritimes Area is interruptible load. The Maritimes Area uses a 20-percent reserve criterion for planning purposes, equal to 20 percent times the difference of the Forecast Peak Load MW minus Interruptible Load MW.

In November 2012, the 660-MW (Net) Point Lepreau nuclear power station returned to service after being out of service for refurbishment since April 2008. There are no plans for any significant resources to retire.

Coincidence of high winter wind generation with the peak winter loads results in the Maritimes Area receiving a higher capacity benefit from wind projects versus a summer-peaking area. The effective wind capacity calculation also assumes a good geographic dispersion of the wind projects to mitigate the occurrences of having zero wind production. The capacity benefit during this winter assessment period as compared to 2013 summer's assessment period is an increase of approximately 3 percent.

No known capacity transactions are scheduled at this time.

[23] https://www.npcc.org/Standards/Directories/Directory%201%20-%20Design%20and%20Operation%20of%20the%20Bulk%20Power%20System%20%20Clean%20April%2020%202012%20GJD.pdf
[24] For further information on the Energy Efficiency programs please review the links: www.maritimeelectric.com,www.nppower.com,www.mainepublicservice.com,www.emec.com, www.nspower.ca/energy_efficiency/programs/,www.nspower.ca/en/home/energysavings/default.aspx

The Maritimes Area, through existing agreements with neighboring Balancing Authority areas, namely, ISO-NE and TransÉnergie, has established procedures for the acquisition of emergency energy. However, the Maritimes Area does not rely on this assistance when doing its winter assessment.

There are no environmental or regulatory restrictions that could impact reliability in the Maritimes Area during the assessment period.

The Maine Power Reliability Program (MPRP) project in New England has the ability to impact the amount of energy transfers between New Brunswick and New England. The respective Operation groups of New Brunswick Power and ISO-New England coordinate this project, which involves setting any transfer limits up to and including real time. This should not cause any reliability issues because the Maritime Area is not reliant on energy transfers to meet its requirements.

It is the responsibility of the Generator Owners to ensure that fuel supplies are adequate. The Maritime Area does not consider potential fuel supply interruptions in the regional assessment. The fuel supply in the Maritimes Area is diverse and includes nuclear, natural gas, heavy fuel oil/natural gas, coal/pet coke, light oil, diesel, bunker, hydro/tidal, biomass, biogas, and wind.

NPCC-New England

Demand Projections

	Megawatts (MW)
Total Internal Demand	**21,299**
Net Internal Demand	**21,299**

Resource Projections

	Megawatts (MW)
Supply-Side Load as a Capacity Resource	566
Net Firm Capacity Transfers	1,083
Existing-Certain & Future-Planned Capacity	26,625
Anticipated Resources	**28,274**
Prospective Resources	**33,849**

Planning Reserve Margins

	Percent (%)
Anticipated Reserve Margin	**32.75%**
Prospective Reserve Margin	**58.92%**
NERC Reference Margin Level	**13.30%**

The New England electric grid is an 8,000-mile, high-voltage transmission system that connects electric utilities, publicly owned electric companies, over 350 power generators, suppliers, alternative resources and serves 6.5 million households and businesses—a population comprised of 14 million residents across more than 66,500 square miles. New England has 13 transmission ties with neighboring power systems that allow electricity trade with New York, New Brunswick, and Québec.

The New England (ISO-NE) Reference Margin Level is based on the capacity needed to meet the NPCC one-in-10-years LOLE resource planning reliability criterion. The amount of capacity (MW) needed, referred to as the Installed Capacity Requirement (ICR), varies from year to year depending on expected system conditions. The ICR is calculated three years in advance for the Forward Capacity Auction and is updated annually. For this assessment, the resulting Reference Margin Level is 13.3 percent during the 2013–2014 commitment period.[25] In previous years, ISO-NE did not have a fixed capacity or reserve margin requirement, meaning an ICR-based target was not used in those assessments. Instead, ISO-NE assumed a 15-percent Reference Margin Level assigned by NERC for predominantly thermal systems. ISO-NE does not anticipate Planning Reserve Margins to fall below the reference margin for the winter period. ISO-NE is a summer-peaking system. Because the ICR is based on the summer peak levels, ISO-NE should have adequate capacity during the lower-peaking winter period.

For winter 2013–2014, ISO-NE's Anticipated Resources, after accounting for planned maintenance, gas at risk, and unplanned outages, is 28,274 MW. This results in an Anticipated Reserve Margin of 32.7 percent of the reference demand forecast of 21,299 MW. The 2012–2013 winter peak demand forecast was 21,392 MW. This was 505 MW (2.4 percent) higher than ISO-NE's 2012–2013 winter metered peak demand of 20,887 MW. The 2013–2014 winter peak demand forecast of 21,299 MW is 93 MW (0.4 percent) lower than the 2012–2013 winter peak demand forecast of 21,392 MW. The reason for the lower demand forecast this winter is the lower economic growth forecast.

ISO-NE does anticipate the potential for various amounts of single-fuel, gas-only power plants to be temporarily unavailable during cold or extreme winter weather conditions or during force majeure conditions on the regional gas grid. New England projects approximately 3,998 MW of natural gas-fueled capacity will most likely be at risk for this winter period and is accounted for in unplanned outages. During more extreme cold weather conditions, New England does anticipate the potential for further reduced liquid natural gas (LNG) supplies into the Northeast, resulting in 1,147 MW of additional reductions. This risk is evaluated and accounted for in long- and short-term outage coordination efforts, and plans to mitigate these scenarios are balanced with real-time supplemental commitment and use of emergency procedures, as needed.

During the 2013–2014 winter period, a total of 1,712 MW of demand resources are expected to be on peak. This includes 1,146 MW of Energy Efficiency and Conservation and 566 MW of active demand resources. Both categories of demand resources are treated as capacity in ISO-NE's Forward Capacity Market (FCM).

The 1,146 MW of Energy Efficiency and Conservation includes installed measures (e.g., products, equipment, systems, services, practices or 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.

[25] The ICR is an annual requirement that is based on the summer peak load period.

The 566 MW of active demand resources consist of Real-Time Demand Response (RTDR) and Real-Time Emergency Generation (RTEG), which can be activated with the implementation of ISO-NE Operating Procedure No. 4 – Action during a Capacity Deficiency (OP-4). These active demand resources can be used to help mitigate an actual or anticipated capacity deficiency. OP-4 Action 2 is used to dispatch RTDR, which is implemented in order to manage operating reserve requirements. Action 6, which is the dispatch of RTEG, may be implemented to maintain 10-minute reserve.

Since 2011, active demand resources have been triggered three times under OP-4 to reduce the peak demand. Two of those events occurred during the winter. On January 28, 2013, the full 373 MW of RTDR with Capacity Supply Obligations (CSO) was activated, and nearly 100 percent responded. On the morning of December 19, 2011, RTDR reduced the load by 380 MW, which was 75.4 percent of the 504 MW activated. The lower response on that day was due to the event occurring early in the morning, when the loads were low and less demand resource was available to respond. Unannounced audits for active demand resources are conducted twice a year during the summer and winter periods. The 2012–2013 winter demand resources audit results showed an average performance of 110 percent of Capacity Supply Obligations for RTDR and RTEG. Based on these audit results, as well as the historical response of RTDR when activated, demand resources are expected to perform as needed to meet peak demand.

In addition, demand resources submit an hourly status of their capability to ISO-NE, and system operators are able to view that capability in real time. Finally, system operators can monitor the real-time performance of the resources in relation to their capacity supply obligations using telemetry from each resource.

There have been no significant generator additions or retirements from the previous winter. Two wood-burning power plants, rated at 38 MW and 68 MW, and one fuel cell rated at 16 MW are expected to be in-service before the 2013–2014 winter. Within the Existing-Certain category, the following types of generating capacity are expected to be available at the time of peak demand: approximately 164 MW of wind; 1,596 MW of hydroelectric resources; and 943 MW of biomass.

The winter capability of variable generation is equal to the median of net output during the winter reliability hours, which are the hours ending 6:00 p.m. through 7:00 p.m. during the months of October through May, as well as any winter hour with a shortage event.

The forecast for 2013–2014 winter period includes on-peak firm capacity imports of 1,183 MW. These firm capacity imports, which include transfers from Québec, New York, and New Brunswick, have been contracted for delivery within the 2013–2014 FCM capacity commitment period. Additionally, 100 MW of firm exports to New York are projected for the 2013–2014 winter. Emergency imports are not relied on for meeting the Reserve Margin Level for ISO-NE.

All significant transmission lines and transformers are expected to be in-service through the 2013–2014 winter season. In the event of a major unplanned outage of a significant generator or transmission facility, operating procedures are in place to maintain system reliability. There are no high-priority transmission projects expected to be energized in New England to enhance or maintain reliability during the winter assessment period.

Because of established outage coordination processes, ISO-NE and its neighboring power systems exchange information on planned and unplanned generation and transmission outages. Agreements and procedures are in place to ensure the availability of these imports during the winter peak period.

ISO-NE has not been notified nor does it anticipate any significant issues in the neighboring areas that would impact New England's system reliability. In addition, ISO-NE expects to provide and receive support from neighboring Reliability Control Areas and Balancing Authorities to maintain system reliability.

ISO-NE has not identified any significant environmental or regulatory restrictions that would adversely impact system reliability or require special operating studies for the 2013–2014 winter period.

ISO-NE does not expect any challenges regarding environmental impact, demand increase, or potential influence from delays in construction of transmission or generation facilities. However, ISO-NE does plan for the potential for various amounts of single-fuel, gas-only power plants being unavailable during extreme winter weather conditions or force majeure on regional gas grid and plans accordingly.

ISO-NE has several procedures for dealing with loss of system capacity including: Operating Procedure #4 – Action During a Capacity Deficiency (which details use of demand response, emergency energy purchases, voltage reductions, reduction of system reserve requirements, requests for non-obligated capacity, and public appeals); Operating Procedure #7 – Action in an Emergency (which covers shedding of firm system load); and Operating Procedure #21 – Action During an Energy Emergency (which details actions to be taken for forecasted energy and fuel shortages).

NPCC-New York

Demand Projections

	Megawatts (MW)
Total Internal Demand	**24,709**
Net Internal Demand	**24,709**

Resource Projections

	Megawatts (MW)
Supply-Side Load as a Capacity Resource	917
Net Firm Capacity Transfers	1,063
Existing-Certain & Future-Planned Capacity	34,211
Anticipated Resources	**36,190**
Prospective Resources	**36,190**

Planning Reserve Margins

	Percent (%)
Anticipated Reserve Margin	**46.46%**
Prospective Reserve Margin	**46.46%**
NERC Reference Margin Level	**17.00%**

NYISO is the only BA in the New York Control Area (NYCA). The NYCA is over 48,000 square miles. It serves a total population of about 19.5 million people and peaks annually in the summer. There have been no changes to the NYCA boundary nor are there any expected changes. This report addresses the reliability assessment for the NYCA for May 2013 through October 2013.

The New York State Reliability Council (NYSRC) determined that an Installed Reserve Margin (IRM), applied as the NERC Reference Margin Level, of 17 percent in excess of the New York Control Area (NYCA) seasonal peak demand forecasts for the Capability Year 2013–2014 is required to meet the Northeast Power Coordinating Council (NPCC) and NYSRC resource adequacy criterion. The 2013–2014 Capability Year IRM is 1 percent higher than the IRM set for the 2012–2013 Capability Year (i.e., 16 percent). The New York Balancing Authority projects adequate reserves for the 2013–2014 winter season.

The IRM is established annually by the NYSRC and is subject to state and federal regulatory approval. A NYCA IRM study is conducted annually by the NYSRC Installed Capacity Subcommittee to provide parameters for establishing NYCA IRM requirements for the following capability year. The three principle drivers responsible for the increased IRM are:

- A Special Case Resource (SCR) model change;
- An updated load forecast uncertainty model; and
- An updated external Control Area (Outside World) model.

The 2013–2014 winter season peak load forecast is 24,709 MW, which is 0.5 percent less than the forecast peak of 24,832 MW for the 2012–2013 winter and 51 MW more than the actual winter peak of 24,658 MW in 2012–2013. This forecast load is 3.95 percent lower than the all-time high winter peak load of 25,541 MW, which occurred on December 20, 2004.

For the 2013–2014 winter period, NYISO projects that 916 MW of SCRs will be available. NYISO also forecasts adequate capacity and it is unlikely these resources will be required. There are no restrictions on the number of times demand response resources can be deployed.

Since the 2012–2013 winter period, there have been or will be generator nameplate additions of 158 MW and retirements or mothballing of 823 MW. Significant additions include the Orangeville Wind Farm (94 MW), which is planned to be in-service by December 2013. The most significant reduction in capacity came from the retirement of Danskammer (537.4 MW), which was damaged beyond repair during Superstorm Sandy. Other significant reductions include the mothballing of Dunkirk 1 (100 MW) and Niagara Biogen (56 MW) and the retirements of Syracuse Energy (101.6 MW), Chateaugay Power (19.7 MW), Montauk Diesels units 2–4 (6 MW), and Freeport 9 (2.1 MW). Sufficient generation should be available for the winter season, and there are no anticipated capacity issues.

The Ramapo 4500 PAR has been on forced outage since it failed in February 2013. While the parallel 3500 PAR remains in service, this condition reduces the import capability from PJM on the 500-kV Branchburg–Ramapo 5018 line. Repairs are expected to be complete by the end of December 2013. In addition, the 5018 line is scheduled to be out of service from October 28 to December 6.

For the purposes of determining installed capacity to meet the required IRM, wind and solar are counted at their nameplate ratings while hydro and biomass are counted at their Dependable Maximum Net Capability, which is determined through peak output testing to determine the sustainable net output of a generator to the system.

In May 2013, a new tie-line to PJM came on-line. The Hudson Transmission Partners project (HTP) consists of a back-to-back dc converter in Bergen, New Jersey, connected to West 49th Street 345-kV substation in New York City via a 345-kV cable. HTP is expected to be capable of providing 660 MW to New York.

The NYISO maintains Joint Operating Agreements, which include provisions for the procurement, or supply, of emergency energy, and provisions for wheeling emergency energy from remote areas if required, with each of its adjacent Reliability Coordinators. Prior to the operating month, NYISO informs the neighboring control areas of the capacity-backed transactions that are expected to be imported to and exported from NYCA in the upcoming month. Discrepancies identified by neighboring control areas are resolved.

About 52 percent of statewide capacity is gas-fired; although, 44 percent of statewide capacity is dual-fuel capable. Nearly 80 percent of NYCA's gas-fired generators (including dual-fuel capable units) are located behind the city gate. That is, many gas-fired generators are located within a local gas distribution company territory and are not directly connected to the interstate pipeline. While some of these generators rely on firm transportation contracts alone, many rely on some combination of firm transportation contracts and interruptible transportation contracts.

Differences in market timing between the gas day purchase and nomination cycles and the electric day scheduling process may lead to concerns about the sufficiency of gas purchased and scheduled day-ahead and, more specifically, the ability of gas-fired generators to respond to changing system conditions in real-time this winter.

The NPCC Area Transmission Review (ATR) requires each area to conduct a Comprehensive Area Transmission Review (CATR) at least every five years and either an Interim or an Intermediate ATR in each of the years between CATRs, as appropriate. As part of the NYSRC rules, gas system contingencies are evaluated in the ATR.

NYSRC rules also require that the New York BPS be operated such that the loss of a single gas facility does not result in the loss of electric load within the New York City or Long Island zones. Gas-system contingencies are considered when assessing the reliable delivery of electricity in the New York City and Long Island zones. Specific loss of generator gas supply studies, which evaluate critical line breaks near generation facilities, are performed by Consolidated Edison (Con Ed) and the Long Island Power Authority (LIPA) and are reviewed by NYISO. The planned system is expected to be compatible with local rules regarding loss of generator gas supply. In addition, NYISO had an external consultant assess the gas system to determine any vulnerabilities to fuel interruptions. New pipeline expansions in New York City indicate there should be sufficient gas to meet power demand this winter.

Attachment BB of the NYISO OATT contains the New York State Gas–Electric Coordination Protocol,[26] which was implemented in response to FERC Order 698. The protocol establishes a procedure for communication among electric and gas industry participants in the event that either NYISO (for the BPS) or a Transmission Owner (for the local power system) determines that the loss of a generator due to a gas system event would likely lead to the loss of firm electric load. In addition, participants from the gas and electric industries meet regularly through NYISO's Gas and Electric Coordination Working Group.

NYISO submitted surveys to its dual-fuel capable generators to determine the amount of fuel reserves on-site, time needed to switch, and the time needed to replenish fuel supplies once used. New control room procedures, including an extreme cold weather event procedure, will be in place this winter to respond to potential gas system disruptions. The extreme cold weather procedure includes a mechanism for soliciting information related to gas and alternate fuel supplies throughout the operating day.

[26] http://www.nyiso.com/public/webdocs/markets_operations/documents/Tariffs/OATT/Attachments/att_b.pdf

NPCC-Ontario

Demand Projections

	Megawatts (MW)
Total Internal Demand	**22,282**
Net Internal Demand	**22,282**

Resource Projections

	Megawatts (MW)
Supply-Side Contractually Interruptible (Curtailable)	512
Existing-Certain & Future-Planned Capacity	29,539
Anticipated Resources	**30,051**
Prospective Resources	**30,051**

Planning Reserve Margins

	Percent (%)
Anticipated Reserve Margin	***34.87%***
Prospective Reserve Margin	***34.87%***
NERC Reference Margin Level	***18.60%***

Ontario's electrical power system covers an area of 415,000 square miles and serves the power needs of more than 13.5 million people. Ontario is interconnected electrically with Québec, Manitoba, Minnesota, Michigan, and New York. No footprint changes occurred during the past two years, and no changes are anticipated.

Ontario's reserve margin target, which was determined in accordance with the NPCC resource adequacy design criterion, is 18.6 percent for calendar year 2014. For calendar year 2013, the target reserve margin was 20.2 percent. A combination of higher weekly peak demands (outside of the week of the annual peak demand) and updates in generator maintenance outage schedule submitted by market participants resulted in the need for a higher reserve requirement to meet the LOLE criterion in the 2013 assessment, as compared to the 2014 assessment. The reserve margin requirements are calculated annually for the next five years and published on the IESO's website.[27] During winter 2013–2014, the available reserve margin is expected to be within the range of 27.0 percent and 52.6 percent for normal weather. Therefore, the Anticipated Reserve Margin is not expected to fall below the Ontario's target reserve margin (18.6 percent) over the winter season.

Under normal weather, the forecasted peak demand is 22,282 MW for winter 2013–2014. This forecast is fairly similar to the 22,087 MW forecast for the previous winter (2012–2013). There has not been a substantial change in the forecast process nor in the forecast drivers. Modest economic and population growth underpins the rise in the projected winter peak. Embedded generation (i.e., distributed generation) is generation connected to the distribution system that is not metered as a market participant. Embedded generation does not affect winter peak demands, because the vast majority of the embedded generation is solar-powered and the winter demand tends to peak after the sun has set. Likewise, most of the conservation measures have a greater impact on summer-cooling loads, as those loads are predominantly electric.

Since the *2012–2013 Winter Reliability Assessment*, there has not been a significant change to the DSM programs. There is 1,275 MW of total DSM capacity for this upcoming winter. Of that total, just over 512 MW is deemed reliably available at the time of the winter system peak. IESO breaks DSM into two components: conservation and demand measures.

Conservation includes the impacts from Energy Efficiency, time of use rates, and fuel switching. Demand measures include the Ontario Power Authority's (OPA) Demand Response 3 Program, dispatchable loads, and the Peaksaver Program. All these programs act to temporarily reduce load and are triggered according to market prices, the supply cushion, or by contract. OPA, responsible for verifying program savings and overseeing conservation targets, provides the projected impacts of conservation. The demand forecast is decremented for the impacts of conservation. There has not been a significant change in the conservation program mix.

Demand measures are not decremented from demand, but are instead treated as a resource to be dispatched as necessary. The programs have not changed since the *2012–2013 Winter Reliability Assessment*. To determine the amount of effective capacity, IESO uses historical data to determine the amount of demand measures that could be expected to be made available during peak demands. Although the programs have not changed, the calculation of effective capacity is updated to reflect

[27] IESO

the most recent behavior of the demand measures participants. The Peaksaver Program is not available during the winter as it is an air conditioner cycling program. For the 2012–2013 winter period, OPA's Demand Response programs were never activated, and dispatched loads accounted for just over 1,000 MWh during the winter daily peaks. As mentioned, the Peaksaver Program is not available during the winter period, meaning the overall effective capacity of the demand measures in the winter is lower than during the summer period. There are limits to the number of times and duration that IESO can call upon the OPA's Demand Response 3 program. However, these limits have never been reached in any prior year. Each time the program has been called upon to make a reduction, it has been successful. As such, it is expected that OPA's Demand Response 3 program will continue to be available in the unlikely event that it would be needed over the course of winter 2013–2014.

Under the Global Adjustment Allocation, large electricity consumers can reduce the overall price they pay for electricity by reducing demand during the five highest peak demand days. This has had the unintended impact of reducing the dispatchable loads capacity offered into the market during periods of high demand. Therefore, should IESO experience a significantly higher than expected peak demand during the winter of 2013–2014, it is possible that the quantity of available capacity of dispatchable demand would be significantly reduced. However, the offset would be that those large consumers would reduce their demand by an amount equal to or greater than the loss in dispatchable capacity.

Overall, there is little concern regarding the availability or reliability of demand measures during the winter peak periods.

In January 2013, Ontario's provincial government announced a one-year advance in the phase-out of the 3,000 MW of coal-fired generation in southern Ontario. The two affected facilities will be removed from service on or before December 31, 2013. The existing generation resources in addition to the new generation resources are sufficient to ensure continued reliability upon the retirement of these coal-fired generation plants. No concerns are anticipated as a result of the phase-out of the coal-fired generation in southern Ontario.

Since the end of last winter, the installed wind generation capacity has been increased by 166 MW, while a further 452 MW are planned to be added prior to winter 2013–2014. In other words, the total incremental wind additions from winter 2012–2013 to winter 2013–2014 is 618 MW. This will bring the total grid-connected wind generation to 2,177 MW.

At this time, deviations from the median hydroelectric production are not anticipated for the upcoming winter. In the operating time frame, water resources are managed by market participants through market offers to meet the hourly demands of the day. Since most hydro storage facilities are energy-limited, hydroelectric operators identify weekly and daily limitations for near-term planning in advance of real-time operations.

There are no firm imports or exports identified for the winter period.

For use during daily operation, operating agreements between IESO and neighboring jurisdictions in NPCC, RFC, and MRO include contractual provisions for emergency imports directly by IESO. No reliance on emergency energy is needed to meet Ontario's Planning Reserve Margin Reference Level for the next winter. IESO also participates in a simultaneous activation of reserve procedures, which includes IESO, ISO-NE, New Brunswick System Operator, NYISO, and PJM. This participation enhances recovery from generation losses when they occur.

Transmission transfer capability in all zones is expected to be sufficient to supply load in these areas with a margin to allow for planned outages. The completion date for non-critical transmission reinforcements from the Niagara region into the Hamilton–Burlington area continues to be delayed. Completion of this project will increase the transfer capability from the Niagara region to the rest of the Ontario system. However, even without this project, transmission transfer capability in Niagara and its vicinity is expected to be sufficient to supply load in the area with a margin to allow for planned outages.

Since last winter, the following substations have been installed:

- Hydro One built a new 230/28-kV DESN (Tremaine TS) in the Southwest Zone. This DESN is comprised of two 75/100/125-MVA three winding transformers.
- Hydro One built a new switching station (Sandusk SS) to facilitate the connection of the new Port Dover and Nanticoke Wind Project in the Southwest Zone.

- Hydro One installed a new switching station connecting Summerhaven Wind Energy Centre to N37S and S39M.
- Hydro One extended transmission circuits into Little Long GS, Harmon GS, and Smokey Falls GS as part of the Lower Mattagami generation expansion.

Surplus Baseload Generation (SBG) conditions observed over the summer are expected to be moderate over the winter as off-peak demands rise and wind generation dispatch adds additional capability to manage surpluses.

As part of IESO's analysis, an extreme weather scenario is used to assess the system under stress conditions. The extreme weather scenario is generated by taking the most severe weather over the last 40 years on a week-by-week basis. This gives an outer envelope of the conditions that the system may face through the upcoming season.

The coordination work necessary to identify potential seasonal issues is performed through NPCC working group CO-12, which is tasked to do the seasonal assessments for the NPCC Region. Each day, IESO coordinates and communicates its *Next Day Operations Report* with the neighbors (NYISO, Québec, and MISO) via emails. The plan covers the forecast demand and resource adequacy; forecast weather; critical transmission outages occurring the next day; and generator outages greater than 200 MW occurring the next day. Also, once the outage plans are approved, affected neighbors are notified via telephone or email two to three business days before they commence. The date of outage commencement, duration, and transfer limits are conveyed at this time.

Seasonal planning assessments of Ontario's resource and transmission system that cover a planning horizon of 18 months are produced quarterly. These assessments are shared with Ontario's neighboring BAs and TOPs. IESO also participates in planning meetings and conducts coordinated seasonal transmission studies and assessments with its neighboring entities such as MISO and NYISO on either an annual or biannual basis, as well as with the Eastern Interconnection Reliability Assessments Group (ERAG).

Ontario has diverse generation resources consisting of nuclear, hydroelectric, gas and oil, and renewables (i.e., wind and solar). Following the coal phase-out, about 30 percent of the fleet will be gas-fired and dual-fuel (gas and oil). One 2,100-MW, gas-fired generating facility has dual-fuel capability—the back-up fuel being residual oil. The Generator Owner maintains a minimum fuel inventory over the winter period based on their historical dispatch, energy requirements, and fuel deliverability. Due to the diversity of generation resources in Ontario, there is no need for IESO to conduct planning studies to review if critical system loads are dependent on a single fuel source.

There are long-standing communication protocols in place between IESO and gas pipeline and distribution system operators to manage and share information under tight supply conditions in either sector (gas or electric). The communication protocol allows for IESO to communicate directly with the gas distributor in situations in which a contingency has occurred on the gas transmission system affecting either day-ahead or real-time operations. To prepare for the peak seasons, IESO meets with gas pipeline operators every six months (in April and October) to discuss the storage situation and planned maintenance.

NPCC-Québec

Demand Projections	
Projected Peak:	Megawatts (MW)
Total Internal Demand	**37,233**
Net Internal Demand	**37,233**

Resource Projections	
Projected Peak:	Megawatts (MW)
Net Firm Capacity Transactions (Transfers)	-398
Existing-Certain & Future-Planned Capacity	39,819
Anticipated Resources	**41,701**
Supply-Side Direct Control Load Management	250
Supply-Side Contractually Interruptible	1,660
Prospective Resources	**41,701**

Planning Reserve Margins	
Projected Peak:	Percent (%)
Anticipated Reserve Margin	**12.00%**
Prospective Reserve Margin	**12.00%**
NERC Reference Margin Level	**10.10%**

The Québec Assessment Area (Québec Area) is a NERC subregion in the northeastern part of the NPCC Region, covering 643,803 square miles with a population of 8 million (province of Québec). The Area is one of the four NERC Interconnections in North America with ties to Ontario, New York, New England, and the Maritimes, consisting either of HVdc ties or radial generation or load to and from neighboring systems. Transmission voltages are 735, 315, 230, 161, 120 and 69 kV with a ± 450-kV HVdc multi-terminal line. Transmission line length totals 33,639 km (20,902 miles) as of December 31, 2012. The Area is winter-peaking.

The Québec Area demand forecast for the 2013–2014 winter peak (i.e., 37,233 MW) is 310 MW lower than the 2012–2013 winter peak demand forecast presented in last year's winter assessment. This drop in the demand forecast is mainly attributed to the industrial sector.

Total Energy Efficiency and Conservation is included in the forecasted demand. For the 2013–2014 winter peak period, Energy Efficiency and Conservation accounts for a 1,980 MW reduction in the forecast. This is 200 MW more than the estimated impact of Energy Efficiency and Conservation on the expected 2012–2013 winter peak demand in the last winter assessment.

In the Québec subregion, demand response (DR) programs are specifically designed for peak-load reduction during winter operating periods. Demand response consists of interruptible demand programs (for large industrial customers), totalling 1,660 MW for the 2013–2014 winter period, 80 MW more than last winter. Demand response 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. Interruptible load program specifications differ among programs and participating customers. They usually allow for one or two calls per day and between 40 to 100 hours interruption per winter period. Interruptible load programs are planned with participating industrial customers with whom contracts are signed. All customers are regularly contacted before the peak period (generally during fall), so that their commitment to provide their capacity when called during peak periods is ascertained. These programs have been in operation for years and, according to the records, customer response is highly reliable.

The Reference Margin Level is drawn from the Québec Area's *2012 Interim Review of Resource Adequacy*,[28] approved by NPCC's Reliability Coordinating Committee on November 27, 2012, and is approximately 10 percent for the 2013–2014 winter period, as it was in the *2012–2013 Winter Reliability Assessment*. The anticipated reserve margin level is not expected to fall below the NERC Reference Margin Level for the 2013–2014 Winter Operating Period. For this winter assessment, reserve margin level evaluations were done for peak conditions only.

For the 2013–2014 Winter, Total Internal Capacity will be 43,534 MW. Compared to the previous winter assessment, an additional 600 MW of wind power is expected to be commissioned for the 2013–2014 winter peak period. There are no planned resource retirements that would significantly impact the available on-peak capacity for the next winter.

Hydro conditions for this upcoming winter peak period are such that reservoir levels are sufficient to meet both peak demand and the daily energy demand throughout the winter.

[28] https://www.npcc.org/Library/Resource%20Adequacy/2012%20Quebec%20Interim.pdf

Biomass and wind resources are owned by Independent Power Producers (IPPs). These IPPs have signed contractual agreements with Hydro-Québec. Therefore, for biomass resources, expected on-peak capacity and maximum capacity are equal to contractual capacity, representing almost 100 percent of nameplate capacity. For wind resources, capacity contribution at peak is estimated at 30 percent of contractual capacity, representing 700 MW for the 2013–2014 winter period. Maximum wind capacity is set equal to contractual capacity, which generally equals nameplate capacity.

During the 2013–2014 Winter Operating Period, firm capacity exports of 898 MW are planned. On the other hand, the Québec Area should purchase about 870 MW on short-term markets for the 2013–2014 winter peak period, of which 500 MW is firm. This purchase is included in the Anticipated Reserve Margin. Expected capacity purchases are planned by Hydro-Québec Distribution as needed for the Québec internal demand. 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. However, the Québec Area does not rely on any emergency capacity imports to meet its Reserve Margin Reference Level.

No transmission equipment is scheduled for maintenance outages in Québec during the winter. No existing transmission lines will be taken out of service for this winter season. Moreover, no major transmission lines are coming into service.

Hydro-Québec TransÉnergie (HQT) is adding a new 735-kV section at Bout-de-l'Île (east end of Montréal Island) substation, originally a 315/120-kV station. The Boucherville–Duvernay line (Line 7009), which passes near Bout-de-l'Île, will be looped into the new station. In November 2013, a new -300/+300-Mvar Static Var Compensator (SVC) will be integrated into the 735-kV section. 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 regional subsystem. Many of the present 120-kV distribution stations will eventually be rebuilt into 315-kV stations, and the Montréal regional network will be converted to 315 kV. The addition of a second -300/+300-Mvar SVC at Bout-de-l'Île in 2014 is also projected.

As a member of the Western Climate Initiative, the province of Québec put in place a cap-and-trade system to help curb greenhouse gas emissions. Given that there are only two fossil fuel power plants in the Québec Area (one fuel-fired power plant that is only used a few hours a year for peaking purposes and one natural gas cogeneration power plant, which is presently mothballed), this cap-and-trade system is not expected to have an impact on resource adequacy in the Québec Area. Therefore, fuel supply and transportation is not an issue in Québec.

During the 2013–2014 Winter Operating Period, no significant issues concerning neighboring areas that could impact operations in the Québec Area have been identified. However, during very cold weather periods, NPCC subregions discuss and coordinate planned interchange schedules. NPCC conference calls are held as needed in this context.

There are no potential issues that could substantially change the assessment projections.

Finally, following the failure of a current transformer in 2011, the *2012–2013 Winter Reliability Assessment* discussed the ongoing HQT 735-kV current transformer replacement program. This program has continued into 2013. As of October 2013, 17 out of the original 281 current transformers have yet to be replaced, but should be completed in time for the 2013–2014 winter peak period.

PJM

Demand Projections

	Megawatts (MW)
Total Internal Demand	**132,229**
Net Internal Demand	**132,229**

Resource Projections

	Megawatts (MW)
Net Firm Capacity Transactions (Transfers)	3,353
Existing-Certain & Future-Planned Capacity	185,331
Anticipated Resources	**188,684**
Prospective Resources	**188,684**

Planning Reserve Margins

	Percent (%)
Anticipated Reserve Margin	**42.69%**
Prospective Reserve Margin	**42.69%**
NERC Reference Margin Level	**15.00%**

PJM Interconnection is an RTO that coordinates the movement of wholesale electricity in all or parts of 13 states and Washington, D.C. Acting as a neutral, independent party, PJM operates a competitive wholesale electricity market and manages the high-voltage electricity grid to ensure reliability of an area that spans 214,000 square miles and serves more than 60 million people. PJM is a PC, RC, and BA for the entire PJM region.

***PJM Boundary Changes**: This year's report includes the load and generation of East Kentucky Power Cooperative, which was integrated into PJM on June 1, 2013.*

The PJM RTO Reserve Requirement is 15.9 percent for the 2013–2014 planning period, which runs from June 1, 2013, through May 31, 2014. This is a 0.5 percent increase from the previously reported value. This is the result of a flatter monthly load shape in the summer,[29] which increases the amount of time spent near the peak and therefore the share of loss of load risk in comparison with last year's study.[30] Though the more recent model has slightly better-performing units, which would tend to decrease the PJM Reserve Requirement, the flatter forecast monthly load shape more than offsets this decrease, resulting in an overall increase of 0.5 percentage points. PJM is expected to meet its Reserve margin Requirement through the entire 2013–2014 winter peak season. The PJM Reserve Margin is expected to be 42.7 percent.

The load of East Kentucky Power Cooperative will add approximately 2,340 MW to the PJM winter peak forecast. A downward revision to the economic outlook—especially in 2013 and 2014—has resulted in lower peak and energy forecasts in this year's report, compared to the same year in last year's report.

The total amount of Energy Efficiency for the PJM Area expected to be available on peak for this winter is assumed to be 0 MW. Demand-side resources available during the 2013–2014 winter peak period are forecasted to be 0 MW.

Total increase of generation across all of PJM is approximately 520 MW. As part of the above total, units 2 and 3 at Peach Bottom nuclear power plant in PECO were each increased 70 MW. PJM continues to closely monitor any new generator deactivation notices received and closely monitor adequacy projections to include generation retirements, planned outages (retrofit and maintenance) as well as expected queued generation. The following units retired since last winter:

Table 5: Retired Units since 2012-2013 Winter

Unit	MW	PJM Transmission Owner Area
Niles 1	109	FirstEnergy (ATSI)
Elrama 4	171	Duquesne
Potomac River 1-5	482	PHI (Pepco)
Conesville 3	165	AEP
Schuylkill 1	166	PECO
Hutchings 4	62	Dayton
Titus 1-3	243	FirstEnergy (MetEd)
Walter C Beckjord 2-3	222	Duke Energy (Ohio Kentucky)

[29] PJM Reserve Requirement study is only performed for summer since PJM is summer peaking.
[30] http://www.pjm.com/~/media/planning/res-adeq/2012-pjm-reserve-requirement-study.ashx.

Variable resources are only counted partially for PJM Reserve Margin 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 (June 1 through September 30) 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. Biomass and hydro is counted at 100 percent of reported Existing Certain because, typically, these resources are only fully utilized over the daily peak.

Capacity transactions amount to a net import of 3,352.4 MW in 2013. This import is composed of specific transactions for each generator. These transactions include the firm reservation rights for the generation and firm transmission rights to transfer the power across the PJM border. All import and export contracts that are counted towards the PJM Reserve Margin are firm for both capacity and transmission service. PJM has no reliance on outside assistance for emergency imports. Capacity Benefit Margin is reserved on transmission across the PJM border, but there is no reservation of capacity with its neighbors. The original transaction agreements include the firm reservation rights for the generation and firm transmission rights to transfer the power across the PJM border.

The Hudson Transmission Partners (HTP) project is a back-to-back HVdc interconnection between PJM and New York City (New York Zone J). While the interconnection facility is rated at 660 MW, only 320 MW are designated for firm transmission service with the remaining 340 MW designated for non-firm transmission service at this time. Only a small portion of the firm transmission rights (13 MW) will be available this winter because the required network transmission upgrades needed to make the full 320 MW deliverable in the PJM system will not be in-service. The remaining capability will be available for non-firm service.

Last winter was mild in PJM. No special studies are performed for the winter peak season besides the normal winter operating study (not yet complete) and interregional analysis, which has shown no significant problems. There are currently no environmental or regulatory restrictions that could impact reliability this winter in PJM.

The gas supply for 80 to 90 percent of PJM’s gas-fired generation is non-firm. PJM has established the Gas Electric Senior Task Force to explore, identify, and address, as needed, gas–electric issues. This task force includes participation of the natural gas industry. Additionally, PJM is participating in the Eastern Interconnection Planning Collaborative's Gas–Electric System Interface Study, which—among other things—seeks to identify any constraints or contingencies on the natural gas system that could impact the electric system.

SERC

Demand Projections

	SERC-E Megawatts (MW)	SERC-N Megawatts (MW)	SERC-SE Megawatts (MW)
Total Internal Demand	**42,359**	**41,397**	**45,956**
Load-Modifying DCLM	430	0	590
Load-Modifying Contractually Interruptible	1,028	890	1,352
Load-Modifying Load as a Capacity Resource	19	0	76
Net Internal Demand	**40,882**	**39,858**	**43,938**

Resource Projections

	Megawatts (MW)	Megawatts (MW)	Megawatts (MW)
Net Firm Capacity Transfers	1,186	-1,157	17
Existing-Certain & Future-Planned Capacity	53,675	54,899	66,698
Anticipated Resources	**54,861**	**53,742**	**66,715**
Existing-Other, Future-Other Capacity	42	1,184	1,973
Prospective Resources	**54,903**	**54,926**	**68,688**

Planning Reserve Margins

	Percent (%)	Percent (%)	Percent (%)
Anticipated Reserve Margin	**34.19%**	**34.83%**	**51.84%**
Prospective Reserve Margin	**34.30%**	**37.80%**	**56.33%**
NERC Reference Margin Level	**15.00%**	**15.00%**	**15.00%**

SERC-E

SERC-N

SERC-SE

SERC is a summer-peaking area that covers all or portions of Alabama, Florida, Georgia, Iowa, Kentucky, Mississippi, Missouri, North Carolina, Oklahoma, South Carolina, Tennessee, and Virginia. The SERC Assessment Area excludes entities that are members of PJM or MISO. There are thirteen BAs in the SERC Assessment Area: SERC-E: Alcoa Power Generating, Inc. – Yadkin Division (Yadkin), Duke Energy Carolinas and Duke Energy Progress (Duke), South Carolina Electric & Gas Company (SCE&G), and South Carolina Public Service Authority (Santee Cooper, SCPSA). SERC-N: Associated Electric Cooperative, Inc. (AECI), Constellation Energy Control and Dispatch, LLC (CECD), Electric Energy, Inc. (EEI), LG&E and KU Services Company (as agent for Louisville Gas and Electric (LG&E) and Kentucky Utilities (KU), and Tennessee Valley Authority (TVA). SERC-SE: PowerSouth Energy Cooperative (PowerSouth), South Mississippi Electric Power Association (SMEPA), and Southern Company Services, Inc. (Southern).

Assessment Area Boundary Changes*: East Kentucky Power Cooperative (EKPC) joined PJM on June 1, 2013, and is no longer reported in the SERC-W Assessment Area, which has been removed. The Entergy BA is being consolidated into the MISO BA effective December 19, 2013. With winter loads on the Eastern Interconnection, this consolidation may result in heavy energy flows from South to North. To ensure that the transition is accomplished with minimal impact to reliability, AECI, Southern Company, and TVA are working with MISO and other impacted utilities through an Operations Reliability Coordination Agreement. This integration coordination will limit the impact of any increased flow impacts as a result of the integration during winter 2013–2014. Additionally, some concerns exist related to generator outages in the Big Rivers footprint, resulting in heavy flows. TVA and SPP have jointly identified short-term ratings to address this issue.*

The SERC Assessment Area demand forecast for winter 2013–2014 is lower than that of winter 2012–2013. This is primarily due to EKPC joining PJM. Other contributors to this change are a tempered economy and a more accurate forecasting method for aligning monthly energy and peak demand.

Utilities in the SERC Assessment Area have a variety of Energy Efficiency and Demand Response (DR) programs that are offered to residential and commercial customers to help them manage electrical usage and reduce cost. These programs have minimal direct impact on reserve margins during the winter months. Deployment of Energy Efficiency and Conservation continues to exceed annual goals, and new program designs are being studied and piloted.

Some of the demand response programs have both economic and reliability options. The economic options have some restrictions, while the reliability options have few or no restrictions. If called upon, these programs are forecasted to perform as expected during the winter, as they have in the past.

Since winter 2012–2013, the following generating units have been, or are planned to be, retired:

- Canadys units 1, 2, and 3, Eaton units 1-3, and John Sevier units 1 and 2 (December 2012; 522 MW)
- Jefferies units 3 and 4, Grainger units 1 and 2 (January 2013; 477 MW)
- Tyrone unit 3 (February 2013; 71 MW)
- Buck units 5 and 6, Bowen unit 6, and Riverbend (April 2013; 766 MW)
- Boulevard units 2 and 3 (July 2013; 37 MW)
- Branch 2 (October 2013; 325 MW)
- Sutton units 1–3 (December 2013; 602 MW)
- Buffalo Dunes (January 2014; 202 MW)

The following generating units have been added since winter 2012–2013 or are planned for addition during winter 2013–2014:

- Buck combined cycle (CC), Cleveland County, Cliffside unit 6, Dan River CC, and Wayne County CC (3,237 MW)
- Lee CC (1,049 MW)

A certain line outage in the Duke Energy Progress territory has the potential to cause curtailing transactions and redispatch of available generation. In addition, the Marshall–C33 161-kV line, in the TVA territory, is tentatively scheduled to be out of service for the winter in order to increase the line's capacity. An existing operating guide for this area will be used to address any N-1 contingency constraints during this outage.

There are few distributed and variable resources in SERC. Wind and solar resources are analyzed based on historical patterns and are not included in the on-peak capacity or in the reserve margin. For hydro resources, capacity and energy production are based on comprehensive modeling of the competing water management requirements. Considering the relative capacity and the operational nature of these resources, expected on-peak capacity values are predictable and consistent.

Firm capacity transactions contribute to the reserve margin calculations similar to system generation. Non-firm capacity transactions do not contribute to the reserve margin calculations and are expected to be used for economical purpose rather than for meeting reserve margin requirements.

Operational reliance on emergency imports in the SERC Assessment Area is based on agreements within the VACAR Reserve Sharing Arrangement, supported by Transmission Reliability Margin (TRM), which target 1.5 times the largest resource (1,135 MW) within the group for operating reserves. In addition, the TEE Contingency Reserve Sharing Group (TCRSG), consisting of two BAs internal to the SERC Assessment Area, provides immediate contingency response, thereby enabling the group to comply with the Distributed Control System (DCS) standard and prevent the curtailment of native load. Request and confirmation for reserve activation is through an electronic portal or backup process via voice communication. PowerSouth maintains an emergency energy agreement with Southern for 250 MW. Upon the loss of specific PowerSouth generators, PowerSouth can request the emergency energy from Southern. Operational reliance on using emergency imports external to the BA includes AECI's Reserve Sharing Agreements with SPP, a BA-to-BA agreement with MISO that provides for emergency energy, and SMEPA's participation in the SPP Reserve Sharing Group.

In December 2013, TVA will place the Montgomery 500/161-kV #2 transformer bank into service. This will enhance reliability around Clarksville, Tennessee, and make up for the loss of the Montgomery 500/161-kV #1 transformer bank. This project provides stronger voltage support and reduces line loadings in the area.

Since winter 2012–2013, a Jacksonville SVC was installed in the Duke system to provide dynamic Mvar response for voltage support. TVA also installed multiple PMUs across the Tennessee Valley. Examples of these PMUs include Browns Ferry Nuclear Plant, Raccoon Mountain Pumped Storage, and Sequoyah Nuclear Plant.

In the SERC Region, EPA's Mercury and Air Toxics Standards (MATS), National Ambient Air Quality Standards, anticipated greenhouse gas new source performance standards, effluent guidelines, coal combustion residual regulations, and operation limits related to air and water quality will have minimal impact on winter 2013–2014 reliability. In the future, these regulations are expected to somewhat impact the ability to produce electricity. However, the utilities in the SERC Region continue to adapt their operations and pursue improvements and retrofits without sacrificing system reliability in compliance with the new requirements.

Utilities in the SERC Assessment Area did not identify any challenges to meet demand related to fuel availability. Firm fuel contracts, long-term resource planning, and diversity of fuels are taken into consideration well in advance to prevent any large-scale impact to generation availability during winter 2013–2014.

SPP

Demand Projections

	Megawatts (MW)
Total Internal Demand	**34,415**
Load-Modifying DCLM	0
Load-Modifying Contractually Interruptible	743
Net Internal Demand	**33,673**

Resource Projections

	Megawatts (MW)
Supply-Side DCLM	38
Supply-Side Contractually Interruptible	347
Net Firm Capacity Transfers	515
Existing-Certain & Future-Planned Capacity	64,948
Anticipated Resources	**65,848**
Existing-Other, Future-Other Capacity	0
Prospective Resources	**65,829**

Planning Reserve Margins

	Percent (%)
Anticipated Reserve Margin	**95.50%**
Prospective Reserve Margin	**95.50%**
NERC Reference Margin Level	**13.60%**

Southwest Power Pool (SPP) is a NERC Regional Entity (RE) that encompasses all or part of Arkansas, Kansas, Louisiana, Mississippi, Missouri, New Mexico, Oklahoma, and Texas and covers 370,000 square miles. For this NERC report, the SPP Assessment Area also includes the entire state of Nebraska. The SPP RE reporting footprint includes the Midwest Reliability Organization Regional Entity members that are part of the SPP Planning Coordinator, which consists of the Nebraska entities. SPP's footprint consists of 17 Balancing Authority Areas, including 48,368 miles of transmission line, 915 generating plants, and 2,378 substations.

***SPP Footprint Changes**: Earlier in the year, SPP RE began coordinating with Entergy, CLECO, Lafayette Utilities System, Louisiana Energy and Power Authority, and MISO to transition those entities to the MISO Balancing Authority Area and the MISO Market. The transition began in June 2013, and no operational issues were experienced. The transfer will conclude in December 2013 and remove 2,550 MW of load and 4,887 MW of generating capacity from the SPP RE Assessment Area. Additional coordination activities will take place between the SPP and MISO RCs, but no unmanageable activities are forecasted. SPP is coordinating with other RCs via the Operations Reliability Coordination Agreement (ORCA) to agree upon an exchange of data used to develop appropriate modeling and generation dispatch forecasts for use in modeling and reliability processes. This data exchange will allow the entities to more accurately model the flows on each other's systems.*

The SPP Assessment Area target Reserve Margin remains unchanged at 13.6 percent from the 2012–2013 winter assessment. SPP RE is projected to have an adequate Reserve Margin of 94.2 percent—well above SPP Regional Transmission Organization's (RTO) minimum required target Reserve Margin of 13.6 percent during the 2013–2014 winter season.

According to the SPP RE demand forecast, projected Total Internal Demand has increased from 33,704 MW in the 2012–2013 forecast to 34,415 MW for the 2013–2014 winter assessment. This demand forecast comparison is reported on a consistent footprint[31] with the 2013–2014 winter assessment area and equates to an annual growth rate of 2.1 percent. The weather and operational forecast for the SPP RE Region is expected to be near normal for the upcoming winter. SPP RE's annual growth rate is consistent with the 2012–2013 assessment projections.

SPP RE members include their own Demand Response and Energy Efficiency programs as reductions in their load forecasts. The utilization of Demand Response resources is not vital to meeting the energy and capacity obligations of the SPP Region. As SPP RE does not rely on these programs for resource adequacy, there are no short-term concerns about the use and growth of Demand Response programs being unresponsive or unavailable.

SPP RE has added approximately 842 MW[32] of new generation since the 2012–2013 winter assessment. No new up-rates have been reported since the 2012–2013 winter period. A total of 759 MW of capacity additions are projected to be added during the 2013–2014 winter. Approximately 5,520 MW of generation are expected to be out of service for scheduled

[31] For purposes of showing footprint consistency, SPP removed CLECO, LAFA, and LEPA from the 2012 forecast. The 33,704 MW above reflects this change.

[32] This number reflects the increase in SPP's total generation from 2012–2013 to 2013–2014 models.

maintenance during the 2013–2014 winter time frame. The units are not expected to come back into service until after the winter season.

The expected on-peak capacity values for wind, solar, and hydro generation are determined by historical performance guidelines established in the SPP Criteria Section 12.0.[33] The maximum nameplate capacity for these variable resources is 11,108 MW.[34] Due to the amount of internal generation capacity available, On-Peak Capacity Transactions are not considered a significant impact to operational reliability in SPP.

SPP RE members, along with some members of the MRO Region, jointly participate in a Reserve Sharing Group. Group members receive contingency reserve assistance from each other, but the group does not require support from generation resources outside the SPP RE Region.[35] The SPP RTO's Operating Reliability Working Group sets the Reserve Sharing Group's Minimum Annual Contingency Reserve Requirement. The SPP 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. SPP RTO sets aside Transmission Reserve Margin (TRM) to allow for loss of the most impacting generation on each flowgate. This ensures that reserve assistance among members is viable.

SPP does not rely on imports to be available during the time of peak demand. However, SPP does exchange information and coordinate with all neighboring entities in various seasonal planning venues. Some of these include the model sharing conducted via the Eastern Interconnection Reliability Assessment Group (ERAG) process as well as a Coordinated Seasonal Assessment with several neighbors.

As SPP RE has an abundant generation supply and a robust transmission system, significant long-term generator outages or environmental retrofits are not a concern at this time. SPP continues to perform operational studies, twice annually, reviewing the time frame of one week to four years and identifying any reliability concerns that may result from the EPA's recent environmental regulations. Retirements and extended outages are not expected to impact reliability during the period.

As mentioned earlier, SPP RC is coordinating with Entergy and MISO to transition CLECO, LUS, and LEPA into the MISO Market and BA. As a result of this transition, significant changes in flows may result as compared to what has historically been planned, observed, and managed using existing congestion management processes. SPP RTO and MISO are evaluating ways to mitigate reliability concerns from these operational changes by improving how flows are accounted and reviewing congestion management techniques for potential enhancements. These additional coordination activities are expected to continue to ensure the continued reliable operation of the interconnected transmission system.

SPP RTO also has several members transitioning to a consolidated Balancing Authority within the SPP RE footprint on March 1, 2014. Deployment testing and parallel operations will be conducted during the winter assessment period; however, no operational concerns are indicated.

There are no forecasted fuel-related challenges for the 2013–2014 winter season. SPP RTO possesses a significant generation margin and, therefore, does not rely on gas-fired generation without firm natural gas fuel contracts in order to meet its required reserve margin. Only single-plant or unit interruptions are studied as part of the normal seasonal planning process. SPP RC continues to participate in FERC's Gas–Electric Coordination Task Force, which is improving situational awareness and policy development in order to address operational challenges that may limit gas supplies needed for electric generation. Primarily, those generators identified necessary to resolve an indicated local reliability issue or a local capacity requirement are required by SPP Criteria to possess an alternative fuel supply.[36] The capability to perform with the alternative fuel is also required by SPP Criteria in order to receive the capacity accreditation.

[33] The related SPP criteria is available in the following report (not currently available to the public): http://www.spp.org/publications/SPP%20Criteria%20and%20Appendices%20January%202012.pdf.

[34] This number is considered nameplate and SPP would not expect this total capacity to be available (consists of wind, hydro, and solar).

[35] While the RSG does have generation-owning members outside the SPP footprint, that generation is not expected to provide support into SPP except for intra-hour contingency events.

[36] See section 12.1.5: http://www.spp.org/publications/SPP%20Criteria%20and%20Appendices%20July%202013.pdf.

TRE-ERCOT

Demand Projections

	Megawatts (MW)
Total Internal Demand	**47,632**
Load-Modifying Contractually Interruptible	583
Load-Modifying Load as a Capacity Resource	1,124
Net Internal Demand	**45,925**
Energy Efficiency	**119**

Resource Projections

	Megawatts (MW)
Net Firm Capacity Transfers	271
Existing-Certain & Future-Planned Capacity	73,348
Anticipated Resources	**73,619**
Prospective Resources	**73,619**

Planning Reserve Margins

	Percent (%)
Anticipated Reserve Margin	**60.30%**
Prospective Reserve Margin	**60.30%**
NERC Reference Margin Level	**13.75%**

The Electric Reliability Council of Texas (ERCOT) is the Independent System Operator (ISO) for the ERCOT Interconnection, scheduling power on an electric grid that connects 40,530 miles of transmission lines and 550 generation units and serves about 23 million electricity consumers. The ERCOT Region is an electric interconnection that is located entirely in Texas and operates as a single BA. The Texas Reliability Entity (TRE) is responsible for the RE functions described in the Energy Policy Act of 2005 for the ERCOT Region.

The Anticipated Reserve Margin for the ERCOT Region is projected to be 60.3 percent, or 27,694 MW, for the 2013–2014 winter season. This estimate is well above ERCOT's Target Reserve Margin of 13.75 percent, referred to as the minimum Planning Reserve Margin criterion in ERCOT's market protocol documentation. The risk of falling below 13.75 percent (6,477 MW) is low. In ERCOT's winter reliability assessment, a combined extreme weather and forced outage scenario was developed in which loads increase by 13,776 MW above the forecasted 2013–2014 winter peak while forced outages increase by 4,326 MW. Under this scenario, the Anticipated Reserve Margin drops to 16.1 percent (9,592 MW), still above the Target Reserve Margin.

ERCOT's Target Reserve Margin of 13.75 percent is based on the 2010 loss-of-load probability (LOLP) study. ERCOT stakeholders reviewed an updated Target Reserve Margin value, based on the 2012 LOLP study, and a final decision by ERCOT's Board of Directors on whether to approve or modify this proposed updated value is anticipated by the end of 2013.

According to the ERCOT demand forecast, the 2013–2014 winter peak demand is forecasted to be 47,632 MW, which is 10 percent below the 2012–2013 winter peak demand forecasted last year and 6 percent below the actual 2012–2013 winter peak demand. This reduction in the 2013–2014 winter peak demand forecast is due to more mild forecasted weather, resulting from a change in the representative weather year selected for input into ERCOT's load forecasting model. ERCOT used 2010 as the weather year for the 2012–2013 winter peak demand forecast. However, for the 2013–2014 winter peak demand forecast, 2009 was selected as the weather year because ERCOT's meteorologist determined that it was most representative of weather expectations. Temperatures at the time of peak were significantly higher in 2009 than 2010. For the three largest ERCOT load forecast zones, the temperature increase averaged about 8 degrees Fahrenheit.

ERCOT expects an incremental 119 MW of Energy Efficiency improvements across the ERCOT Region for the 2013–2014 winter season. This Energy Efficiency represents 0.25 percent of the forecasted 2013–2014 winter peak demand and is the result of recent Energy Efficiency improvements installed by transmission owners to meet legislative and regulatory requirements. A 2011 Texas state law increased mandates for IOUs to meet a portion of their annual growth in electricity demand for residential and commercial customers through Energy Efficiency measures. Under the new law and the subsequently adopted rule from the Public Utility Commission of Texas, the utilities shall—by 2013—meet 30 percent of their annual demand growth through Energy Efficiency programs, escalating to 40 percent of weather-adjusted summer peaks in subsequent years. The IOUs are required to administer energy savings incentive programs, which are implemented by retail electric and Energy Efficiency service providers. Some of these programs, offered by the utilities, are designed to produce system peak demand reductions and energy consumption savings.[37] While the statutory and regulatory requirements are based on the utilities' summer peak demand, the Energy Efficiency programs—excluding the summer-only Load Management programs—impact the ERCOT winter peak load forecast.

Load Resources providing Responsive Reserve Service (RRS), an Ancillary Service, are anticipated to provide an average of approximately 1,124 MW of dispatchable, contractually committed Load-Modifying Load as a Capacity Resource during the upcoming winter peak hours based on the most recently available data. This set of loads is the only load-modifying resource providing ancillary services to the ERCOT grid.

ERCOT's Emergency Response Service (ERS), which is designed to be deployed in the late stages of a grid emergency yet prior to shedding involuntary firm load, represents Demand-Side Contractually Interruptible (Curtailable) Demand. Based on average ERS commitments during the 2012–2013 winter season and taking into account historic growth in the program, approximately 583 MW of ERS Load is expected to be available during winter peak hours.

Together these two programs (ERS and Load Resources providing RRS), if fully called, would reduce the 2013–2014 winter peak demand by approximately 3.6 percent and increase the Anticipated Reserve Margin by 3.5 percentage points.

In general, utility savings—as measured and verified by an independent contractor—have exceeded the goals set by the utilities. In the latest assessment, utility programs implemented after the electric utility industry restructuring in Texas had produced 5,122 GWh of electricity savings from 1999 through 2012. This demand reduction is accounted for within the load forecast, and only the expected incremental portion, 119 MW, is included as a demand adjustment for the winter season.

ERCOT's demand response (DR) resources are procured around-the-clock for operational needs and therefore are not designed specifically to help meet peak demand. With that understood, ERCOT has no concerns relating to the demand response resources' availability or performance. ERCOT's demand response services undergo rigorous qualification and testing requirements and are monitored for availability. In addition to financial consequences for compliance failures, the resources are subject to regulatory fines by the Public Utility Commission of Texas for any reported violations of the protocols. This combination of factors has led to a high level of performance and availability for ERCOT demand response and provides the ISO with a high confidence level in their ability to perform when needed.

For ERS resources, there is no limit on the number of potential deployment events during any four-month contract term; however, after eight hours of total deployment time, the resources are no longer obligated to perform unless they have renewed their obligation voluntarily. Note that if a deployment event is still in effect when the eighth hour of deployment is reached, the resources are obligated to remain deployed until recalled by ERCOT (i.e., when system reserves have been fully restored).

Load Resources providing Responsive Reserves are procured on a daily basis in ERCOT's Day-Ahead Market for hour-long obligation blocks for the following day. There is no limit on the number or duration of deployment events during any obligated hours.

Existing-Certain generation capacity in ERCOT, as reported by Generation Owners, for the 2013–2014 winter season is expected to be 73,336 MW.

Since the last winter assessment, the amount of resources anticipated has increased by 56 MW. The significant resources that came on-line include the 970-MW Sandy Creek coal plant, W.A. Parish addition gas plant, Blue Summit wind project, Los Vientos wind project, and the Bryan Solar project. Additionally, there was a capacity expansion at the Bobcat Bluff wind farm and other future wind plant additions that will come on-line this winter season. Plant retirements include the Lower Colorado River Authority's 425-MW Ferguson natural gas plant (which is being replaced in the summer of 2014 with a new 540–MW, combined-cycle plant) and two Leon Creek gas units (previously categorized as mothballed). Finally, there is a reduction to winter capacity due to a mothballing of units, mainly driven by that of Martin Lake SES coal plant.

[37] Programs include the following: Commercial and Industrial, Residential and Small Commercial, Hard-to-Reach, Load Management, Energy Efficiency Improvement Programs, Low Income Weatherization, Energy Star (New Homes), Air Conditioning, Air Conditioning Distributor, Air Conditioning Installer Training, Retro-Commissioning, Multifamily Water and Space Heating, Texas SCORE/City Smart, Trees for Efficiency, and Third-Party Contracts.

ERCOT currently uses 8.7 percent as the Effective Load Carrying Capability (ELCC) of wind generation. This capacity contribution was approved by the ERCOT Board of Directors in November 2010. The ELCC of wind generation is determined as part of the evaluation of the Target Reserve Margin for the ERCOT Region. Using a LOLP Monte Carlo model, the reliability impacts of wind generation are compared to average dispatchable gas turbine generation capacity of the ERCOT fleet to determine the ratio of wind reliability benefits to that of a thermal unit. ERCOT currently assumes that 100 percent of solar capacity is available on-peak due to the small installed capacity amount (75 MW) and expects that the variability of these resources would not adversely affect grid reliability. However, in anticipation of greater solar generation prevalence, ERCOT will develop an estimate of the solar ELCC. For hydro, the peak capacity contribution is 88 percent based on a new methodology being considered by stakeholders that uses the average capacity available during the 20 highest peak load hours over each of the preceding three years. Biomass generation is assigned a peak capacity contribution value of 100 percent.

ERCOT has an outage scheduler system and outage scheduling process that coordinates all transmission line outages. The initial energize date of new transmission lines are managed through additional operational procedures. Any of these outages or new line initial energize date delays may result in constraints in real-time in the ERCOT Interconnection. ERCOT utilizes real-time congestion analysis tools, including a State Estimator, Real-Time Contingency Analysis, Voltage Stability Assessment Tool, Transient Stability Assessment Tool, and Security Constrained Economic Dispatch application to manage congestion in real-time. No reliability concerns have been identified at this time.

The ERCOT Region is a separate Interconnection with only asynchronous ties to SPP and Mexico's Comisión Federal de Electricidad (CFE). For this coming winter, ERCOT included 458 MW of imports from SPP and 143 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 143 MW from CFE represent half of the asynchronous tie transfer capability, included to reflect operational procedures in place for requesting emergency assistance across its dc ties. However, ERCOT plans to meet the load requirements for the upcoming winter season without relying on emergency imports or exports. Several SPP members own a power plant located in the ERCOT Region, resulting in a firm export of 330 MW to SPP during the winter season. Net capacity transactions contribute 0.6 percentage points towards the Anticipated Reserve Margin for the 2013–2014 winter season.

Several significant transmission improvements in the ERCOT Region are expected to meet reliability needs or reduce market congestion prior to or during the 2013–2014 winter season. The Competitive Renewable Energy Zone (CREZ) project is expected to be completed by the end of 2013 and will add an additional 3,144 circuit miles of 345-kV line to the ERCOT system. This project is primarily designed to deliver wind generation from West Texas to load centers in the eastern part of the state and mitigate associated transmission constraints. The project also involves adding dynamic reactive devices at four stations in fall 2013 for a total capability of +1400/-945 Mvar.

ERCOT is a separate Interconnection with only dc tie connections with other Regions. While ERCOT does not rely upon the dc ties for imports from a transmission planning perspective, it currently assumes that 50 percent of the dc-tie capacity is available as a capacity resource for resource adequacy assessment purposes.

The 2012–2013 winter season was mild for the ERCOT Interconnection, and no unique operational problems were observed. ERCOT conducts a Winter Fuel Survey to determine which generation plants have dual-fuel capabilities. Currently, no issues have been identified related to fuel for the winter season. ERCOT has continued to follow up with generators and performed site visits regarding weatherization. ERCOT visited several resources this fall, but has not yet identified any weatherization issues for the winter season. ERCOT has a forecasting system for variable generation within the Region that includes a six-hour ahead probabilistic ramp forecasting tool called the ERCOT Large Ramp Alert System (ELRAS) and has not identified reliability issues related to variable generation for the winter season. Regarding the ongoing drought conditions throughout much of Texas, ERCOT has hired a drought-monitoring consultant and a meteorologist to aid in closely monitoring water conditions across the state. To date, the analysis indicates that the drought conditions are not expected to materially affect generation output during the winter. ERCOT is closely monitoring the availability of cooling water at generating resources.

Currently available information indicates that it is unlikely that water availability will limit generation resources during the 2013–2014 winter season. However, if drought conditions in Texas continue to worsen, it is possible that reductions in cooling pond levels could limit the ability for some generators to operate. At this time, ERCOT has not identified any restrictions on the resources in the Region that would impact reliability of the ERCOT Interconnection.

As ERCOT is a single Interconnection with no synchronous ties to other Balancing Authorities or Reliability Coordinators, there are no neighboring areas that would impact operations in the ERCOT Interconnection. ERCOT has held several outage coordination meetings to address coordinating the CREZ transmission expansion within the Region.

ERCOT does not envision any regulatory or market issues that would substantially change the assessment projections for the 2013–2014 winter season.

Generation capacity from natural gas provided 44.6 percent of the total ERCOT load for 2012. Historically, gas generation has less than 50 percent of its fuel supply on firm gas contracts and is a function of the abundant Gulf Coast gas supplies. The role of Texas as a major natural gas supply hub results in a robust and efficient spot gas market.

No fuel delivery problems or vulnerabilities are expected for the winter season. Fuel delivery problems are not studied as part of the seasonal studies unless restrictions are identified by the generation resource as a seasonal limitation. ERCOT does consider known fuel limitations once restrictions are imminent, as these are captured in studies via the Current Operating Plans (COPs) that identify the generation resource's capability and availability for the subsequent seven days. In the past, coal-fired resources have had coal delivery issues. These issues were addressed by resources adjusting their COPs so that the resource burned coal at lower rates during off-peak periods and then raising its output during peak periods. Additionally, deratings are required to be supplied via the outage scheduling process. Any fuel restrictions that derate the generator are included up to 45 days ahead. Lastly, ERCOT issues alternative fuel surveys prior to the coldest-predicted months and will request updates to the fuel survey if severe weather threatens a large area within ERCOT.

ERCOT does not coordinate with gas supply companies for normal operations. ERCOT has worked with gas companies in cases where gas supply would be limited due to pipeline maintenance. ERCOT does coordinate with gas companies and transmission companies to help restore key gas facilities after system emergencies to maintain supply to generation resources and is currently working to coordinate with gas providers for blackstart restoration efforts. This does not impact real-time operation.

Switching to fuel oil as a mitigation strategy for gas supply disruptions is available for ERCOT. However, the amount of oil-fired generation and on-site reserves are determined by the resource owners. ERCOT's role is limited to monitoring and alerting generators of the risks of fuel disruptions and issuing notifications when extreme weather conditions are forecasted.

Under ERCOT market protocols, generators are required to submit emergency operation and weatherization plans, as well as declarations that weatherization preparations for critical equipment have or will be completed for the summer and winter seasons. Risk of wide-scale generator unavailability due to fuel considerations has not been an operational concern within ERCOT.

WECC

Demand Projections

	WECC-CAMX Megawatts (MW)	WECC-NWPP Megawatts (MW)	WECC-RMRG Megawatts (MW)	WECC-SRSG Megawatts (MW)
Total Internal Demand	**38,936**	**65,954**	**9,780**	**18,009**
Load-Modifying DCLM	54	48	0	0
Load-Modifying Contractually Interruptible	533	289	276	284
Load-Modifying Load as a Capacity Resource	261	0	0	0
Net Internal Demand	**38,088**	**65,617**	**9,504**	**17,725**
Energy Efficiency	**215**	**355**	**49**	**156**

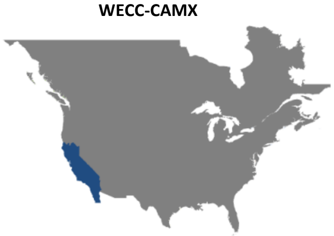
Resource Projections

	Megawatts (MW)	Megawatts (MW)	Megawatts (MW)	Megawatts (MW)
Net Firm Capacity Transfers	2,556	0	-1,000	-1,942
Existing-Certain & Future-Planned Capacity	51,463	77,953	15,837	40,666
Anticipated Resources	**54,019**	**77,953**	**14,837**	**38,724**
Prospective Resources	**54,019**	**77,953**	**14,837**	**38,724**

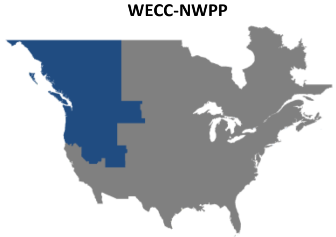
Planning Reserve Margins

	Percent (%)	Percent (%)	Percent (%)	Percent (%)
Anticipated Reserve Margin	**41.83%**	**18.80%**	**56.11%**	**118.47%**
Prospective Reserve Margin	**41.83%**	**18.80%**	**56.11%**	**118.47%**
NERC Reference Margin Level	**10.96%**	**16.52%**	**15.87%**	**13.97%**

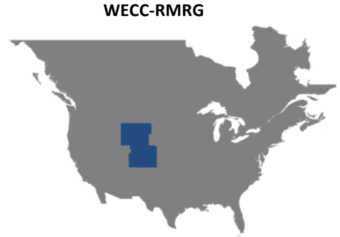
WECC-CAMX



WECC-NWPP



WECC-RMRG



WECC-SRSG

The Western Electricity Coordinating Council (WECC) is one of eight electric reliability councils in North America and is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members, including 39 Balancing Authorities (BAs), represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and approximately 81 million people, it is geographically the largest and most diverse of the NERC Regional Reliability Organizations. WECC's service territory extends from Canada to Mexico. It includes the Canadian provinces of Alberta and British Columbia, the northern portion of Baja California in Mexico, and all or portions of the 14 western states in between. For seasonal planning, the WECC Region is divided into four subregions: Northwest Power Pool (NWPP), Rocky Mountain Reserve Group (RMRG), Southwest Reserve Sharing Group (SRSG), and California/Mexico (CA/MX). These subregions are used for two reasons. First, the subregions are structured around Reserve Sharing Groups. These groups have similar demand patterns and operating practices. Second, the WECC Reliability Coordinator collects actual demand data from the BAs within the Reserve Sharing Groups. Creating the seasonal assessments using the same boundary allows for after-the-fact comparison between demand forecasts and actual demand.

WECC Internal Boundary Changes*: In 2013, there was a small change in the footprints of two of the subregions. Valley Electric Association, Inc. moved from Nevada Power within the SRSG to the CAISO in the CA/MX subregion. In addition, several subregions have different boundaries in the Seasonal Assessment than in the Long-Term Reliability Assessment. The Balancing Authorities of northern California and the Turlock Irrigation District, although physically located in California, are members of the NWPP and their demand and resources are reported in that subregion. Likewise, California's Imperial Irrigation District is a member of the SRSG and its demand and resources are reported in that subregion.*

The Existing and Anticipated Reserve Margins for WECC's four subregions are expected to exceed their respective NERC Reference Reserve Margins.[38] The Reference Reserve Margins are calculated using a Building Block methodology created by

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

WECC's Loads and Resources Subcommittee.[39] The elements of the Building Block methodology are consistent from year to year, but the calculations can and do have slight annual variances by subregions. Abnormal weather conditions would result in different reserve margins and severe adverse weather conditions or unexpected equipment failure may result in localized power supply or delivery limitations.

The aggregate WECC 2013–2014 winter total coincident peak demand is forecast to be 131,980 MW and is projected to occur in December. The 2013–2014 winter coincident peak demand forecast is 0.7 percent above last winter's forecast coincident peak demand of 131,070 MW. The increase in the current year winter peak demand forecasts largely reflects an expectation of normal weather conditions and slight but steady economic growth.

There have been no significant changes from prior years to the DSM programs in the Western Interconnection for the 2013–2014 winter assessment period. The active programs offered by LSEs vary widely. The 2013–2014 winter demand forecast includes 102 MW of Direct Control Load Management (DCLM), 1,354 MW of contractually interruptible demand, 0 MW of Critical Peak Pricing with control, and 261 MW of load as a capacity resource.

As a percent of Total Internal Demand, total demand response could reduce peak demand by 1.3 percent. Interruptible demand programs for the winter period focus primarily on large water-pumping operations and large industrial operations, such as mining. In some situations, these programs may be activated by LSEs during high power-cost periods but, in general, the programs are only activated during periods when local power supply issues arise. Each LSE is responsible for verifying the accuracy of its DSM and energy efficiency programs. Methods for verification include direct end-use metering, sample end-use metering, and baseline comparisons of metered demand and usage. State and other regulatory drivers have led to nominal increases in DSM program penetration within the WECC subregions. Within some established market structures, DSM has been established as an ancillary service.[40]

Energy efficiency programs vary by location and are offered by the LSE. Programs include Energy Star builder incentives, business lighting rebates, retail compact fluorescent light bulbs, home efficiency assistances, and programs to identify and develop ways to streamline energy use in agriculture, manufacturing, water systems, etc.

As mentioned in the *2013 Summer Reliability Assessment*, the 2,250-MW San Onofre Nuclear Generating Station (SONGS) in southern California has experienced premature wear in the steam tubes for both of the plant's units, and they were shut down for repairs.[41] The decision has been made to permanently retire the units. However, the retirement of SONGS has been offset by the addition of several new generating units in the California area that result in a net increase of 205 MW for the winter 2013–2014 assessment period.

The Comisión Federal de Electricidad is scheduled to add three gas turbine units in Mexico that will contribute 134 MW of capacity for the winter period. Additionally, the 250 MW (48 MW winter capacity) Solana Gila Bend Solar project located in Arizona is anticipated to be on-line for this assessment period.

Several transmission maintenance projects have been reported, and the appropriate impact studies have been conducted to ensure that these projects do not pose an adverse impact to reliability during the 2013–2014 winter season. In addition, no specific projects have been reported that are needed to maintain reliability.

WECC's modeling for the winter assessment peak period gives a total renewables expected capacity of 37,318 MW from an installed capacity of 90,223 MW. Detailed information on how the expected on-peak capacity values are calculated for variable generation (wind, solar, hydro and biomass) can be found in the Methods and Assumptions guide.[42]

The WECC Region does not rely on imports from outside the Region when calculating peak demand reliability margins or outside assistance or external resources for emergency imports and does not model exports to areas outside of WECC. WECC

[39] Elements of the Building Block Target are detailed in NERC's Attachment II: Seasonal Assessment – Methods and Assumptions: http://www.nerc.com/pa/RAPA/ra/Pages/default.aspx

[40] http://www.aeso.ca/downloads/AESO_LTO_Update_Final.pdf

[41] Southern California Edison Announces Plans to Retire San Onofre Nuclear Generating Station: http://www.songscommunity.com/news2013/news060713.asp.

[42] NERC's Seasonal Assessment – Methods and Assumptions can be found here: http://www.nerc.com/pa/RAPA/ra/Pages/default.aspx

does not track subregional purchase and sale contracts or their associated transmission. Only transfers from remotely owned, large thermal and hydroelectric units (resources located outside the owner's subregion) are allocated to the owner's subregion. All other transfers are modeled as theoretical transfers, but are not actual contracts. This modeling treatment ensures that resources are only counted once.

No transmission facility project delays or temporary service outages that will adversely impact reliability during the 2013–2014 winter period have been reported. One transmission project of note is the One Nevada Transmission Line (ON Line), which is a 500-kV transmission line that will provide greater system reliability by linking the northern and southern systems of Nevada Energy. Originally scheduled to be in-service December 2012, it has been delayed until the end of 2013. Due to the delay of its implementation, no reliability issues were experienced in 2012 and none are anticipated for the 2013–2014 winter period.

Transfer coordination between neighboring assessment areas is handled with varying methods. In the Southwest subregion, the coordination is handled by transmission engineers communicating with neighboring utilities while performing seasonal studies. Another communication method is the Utilities Outage Coordination Forum in the Rocky Mountain subregion. The group discusses and coordinates all generation and transmission outages scheduled for the next year. This group includes all neighboring Transmission Operators, BAs, and the RC. Finally, the BAs in WECC participate and communicate in their Reserve Sharing Groups to coordinate imports and exports during peak demand periods.

Many system enhancements, such as transformer and capacitor bank additions, have been completed and are available for the winter period. Although these additions will increase local reliability and overall system operations, none of the additions are considered significant for reliability purposes.

Efforts are underway throughout the Western Interconnection to address the lessons learned from the February 2011 Southwest Cold Weather Event.[43] No additional unique operational issues have been identified for the 2013–2014 winter assessment period.

Power plants operate under numerous environmental and other regulatory restrictions, including emission, water level, and water-temperature limitations. The cumulative magnitude of the restrictions, although not quantified, is incorporated into the expected on-peak capacities used for this assessment. These restrictions, which are known and planned for by the individual Generator Operators, are not expected to adversely affect reliability during the winter period.

Normal operational activities require communication and coordination between BAs. The coordination is being accomplished using the practices of collaboration on seasonal assessments, long-term outage coordination forums, and communication with the WECC RC and neighboring BAs. For example, in the Southwest subregion, operations engineers participate in bi-weekly coordination conference calls with representatives from neighboring BAs to discuss outages and related operations plans.

While no significant issues are identified that could impact fuel sources for generating units, entities routinely coordinate their fuel supply needs with fuel and transportation suppliers. For example, significant portions of the coal supply are acquired under long-term contracts with mines and transportation providers, and the power plants generally have significant on-site coal storage facilities. These long-term arrangements are largely unaffected by short-term conditions, so seasonal planning coordination beyond pre-established parameters is minimal. On the other hand, natural gas deliveries are often scheduled on a short-term (often daily) basis. This short-term acquisition process, coupled with generally limited storage and potential gas pipeline pressure limitations, may lead to supply interruptions should other conditions, such as an unexpected cold snap or colder-than-expected temperatures, occur. The primary mitigation for fuel-related risks in WECC includes geographically diverse supply basins feeding multiple natural-gas pipelines, as well as the diverse generation portfolio of nuclear, coal, natural gas, and renewable resources in the Western Interconnection.

[43] February 2011 Southwest Cold Weather Event: http://www.nerc.com/pa/rrm/ea/Pages/February-2011-Southwest-Cold-Weather-Event.aspx

Appendix I: Assessment Preparation

This assessment was prepared by NERC in its role as the electric reliability organization (ERO).[44] 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.[45] 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.

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 for approval. The draft includes comments received from representatives on the NERC Operating Committee (OC) and the Member Representatives Committee (MRC).

The following concepts and definitions are used in NERC's reliability assessments to determine resource adequacy and calculate Planning Reserve Margins.

Demand Concepts

	Definition
Total Internal Demand	The sum of the metered (net) outputs of all generators within the system and the metered line flows into the system, less the metered line flows out of the system (forecast). Total Internal Demand includes adjustments for the indirect Demand-side management programs such as Conservation programs, improvements in efficiency of electricity use, and all nondispatchable demand response programs.
Load-Modifying Demand Response	Changes in electric use by load-modifying resources from the 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. This value is used in the planning reserve margin calculation.
Net Internal Demand	Total Internal Demand, less Load-Modifying Demand Response used to reduce peak load.

Resource Concepts

	Definition
Existing-Certain Capacity	Existing generation resources available to operate and deliver power within or into the assessment area (or Region) during the period of assessment.
Net Firm Capacity Transfers	Firm and Expected Imports, minus Firm and Expected Exports; including all Firm contracts with a reasonable expectation to be implemented.
Existing-Certain & Net Firm Capacity Transactions	Existing-Certain Capacity, plus Net Firm Capacity Transactions
Future-Planned Capacity	Generation resources anticipated to be available to operate and deliver power within or into the Region during the period of assessment.
Supply-Side Demand Response	Demand response counted as a resource and backed by firm reserves.
Anticipated Resources	Existing-Certain and Net Firm Capacity Transactions, plus and Future-Planned Capacity, plus Supply-Side Demand Response
Existing-Other, Future-Other Capacity	Existing or planned generation resources that may be available to operate and deliver power within or into the assessment area (or Region) during the period of assessment, but may be curtailed or interrupted at any time for various reasons.
Prospective Resources	Anticipated Resource, plus Existing-Other and Future-Other Capacity

[44] 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."

[45] http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=109_cong_bills&docid=f:h6enr.txt.pdf.

Planning Reserve Margins Concepts

	Definition
Existing-Certain & Net Firm Capacity Transactions Reserve Margin	Existing-Certain and Net Firm Capacity Transactions, minus Net Internal Demand, Divided by Net Internal Demand
Anticipated Reserve Margin	Anticipated Resources, minus Net Internal Demand, Divided by Net Internal Demand
Prospective Reserve Margin	Prospective Resources, minus Net Internal Demand, Divided by Net Internal Demand
NERC Reference Margin Level	The NERC Reference Margin Levels identified throughout the assessment are planning reserve margins and firm load would not be disrupted to maintain these margins. Rather, the margins are reference points that indicate areas that have lower reserves and tighter margins. The tighter margins are not forecasts of resource shortages. However, areas with tighter margins have a higher possibility, although not likelihood, of resource shortages associated with extreme events such as record-setting temperature deviations. Each Region/subregion may have their own specific margin level (or method) based on load, generation, and transmission characteristics as well as regulatory requirements. If provided in the data submittals, the assessment area's target reserve margin level is adopted as the NERC Reference Margin Level. If not, NERC assigned 15 percent and 10 percent for predominately thermal and hydro systems, respectively.

Reliability Assessment Subcommittee Members

Name	Position	Represents	Job Title	Organization
Vince Ordax	Chair	FRCC*	Director of Planning	FRCC
Layne Brown	Vice Chair	WECC*	Manager, Reliability Assessments	WECC
Richard Becker	Member	FRCC*	Transmission Planning Engineer	FRCC
Justin Michlig	Member	MRO	Transmission Planning Specialty Engineer	Xcel Energy Inc.
William B. Kunkel	Member	MRO*	Senior Engineer	MRO
John Lawhorn	Member	MRO	Senior Director, Regulatory and Economic Studies	Midcontinent ISO, Inc.
Josh Collins	Member	MRO	Political & Economist Studies Engineer	Midcontinent ISO, Inc.
Salva R. Andiappan	Member	MRO	Manager- Modeling and Reliability Assessments	MRO
Digaunto Chatterjee	Member	MRO	Manager, Resource Forecasting	Midwest ISO, Inc.
Philip A. Fedora	Member	NPCC*	Assistant Vice President, Reliability Services	NPCC
John G Mosier Jr.	Member	NPCC*	Assistant Vice President of System Operations	NPCC
Peter Wong	Member	NPCC	Manager, Resource Adequacy	ISO-NE
Kevan L. Jefferies	Member	NPCC	Manager - Market Forecasts and Modeling	Ontario Power Generation Inc.
Paul D. Kure	Member	RFC*	Senior Consultant, Resources	RFC
Tim Fryfogle	Member	RFC*	Associate Engineer	RFC
Mark J. Kuras	Member	RFC	Senior Lead Engineer	PJM
Glenn P Catenacci	Member	RFC	Principal Staff Engineer	PSE&G
Esam A.F. Khadr	Member	RFC	Managing Director Electric Delivery Planning	PSE&G
Mohammed Ahmed	Member	RFC	Manager, East Training Planning	AEP
Barbara A. Doland	Member	SERC*	Data Analyst	SERC
Amir Najafzadeh	Member	SERC*	Reliability Engineer	SERC
Maria Haney	Member	SERC*	Reliability Assessment Engineer	SERC
Hubert C. Young	Member	SERC	Senior Manager, Capacity Planning	TVA
K. R. Chakravarthi	Member	SERC	Manager, Interconnection and Special Studies	Southern Company Services, Inc.
Ben Crisp	Member	SERC	Director of Assessments	SERC
Alan C. Wahlstrom	Member	SPP RE*	Lead Engineer, Compliance	SPP RE
David Kelley	Member	SPP RE*	Manager, Interregional Coordination	SPP Inc.
Debbie K. Currie	Member	SPP RE*	Lead Engineer	SPP RE
Lewis De La Rosa	Member	TRE	Senior Reliability Engineer	TRE
Peter Warnken	Member	TRE	Manager, Resource Adequacy	ERCOT
Warren Lasher	Member	TRE	Director, System Planning	ERCOT
James Leigh-Kendall	Member	WECC	Manager, Reliability Compliance and Coordination	SMUD

*Regional Entity Representative

For more information about this report please visit the following links:

- About NERC Reliability Assessments
- Reliability Concepts Used in this Assessment
- Reliability Assessment Glossary
- Reliability Assessment Acronyms