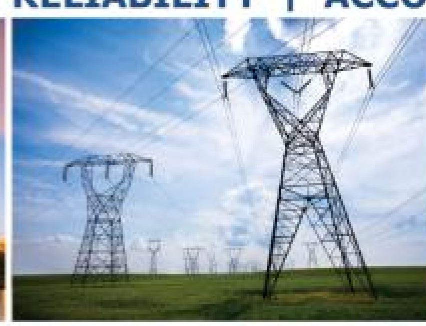
NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2013 Summer Reliability Assessment

May 2013

RELIABILITY | ACCOUNTABILITY



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NERC prepared this assessment in its capacity as the Electric Reliability Organization.[1] The assessment provides an independent view of the 2013 summer reliability outlook for the North American bulk power system (BPS)[2] while identifying trends, reliability issues, and potential risks. Additional insight includes 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.

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About This Report

The *2013 Summer Reliability Assessment* provides an independent assessment of the reliability of the bulk electricity supply and demand in North America for the period June 2013 through September 2013. The report specifically provides a high-level reliability assessment of 2013 summer 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 to 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 the eight NERC Regional Entities and other stakeholder participants submitted by April 30, 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 summer 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 conclusions provided by the Regional Entities.

ERRATA

Version	Release Date	Section	Page	Correction/Update
1.0	**5/15/2013**	**N/A**	N/A	Original Release
2.0	**6/1/2013**	**NPCC-New York**	19	Corrected data in summary table.
		NPCC-New York	19	Modified text on projected demand response availability.
		WECC	2, 7, 41	Corrected data in text, summary tables, and chart.

[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.

Preface

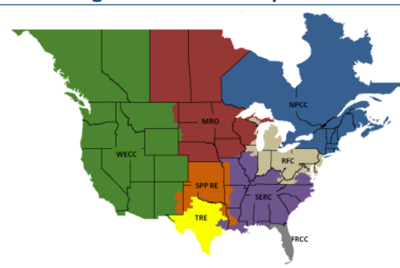
NERC is an international regulatory authority established to evaluate and improve the reliability of the BPS in North America. NERC develops and enforces reliability standards; annually assesses seasonal and long-term (10-year) reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC is the Electric Reliability Organization 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 the industry using a balanced, open, fair, and inclusive process accredited by the American National Standards Institute (ANSI). While NERC does not have authority to set reliability standards for resource adequacy (e.g., reserve margin criteria) or to order the construction of resources or transmission, NERC can independently assess where reliability issues may arise and identify emerging risks. This information, along with NERC recommendations, is then available to policy makers and federal, state, and provincial regulators to support decision making within the electricity 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 26 assessment areas for the long-term assessment and 21 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 and to aid 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.

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2013 Summer Season Key Findings

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

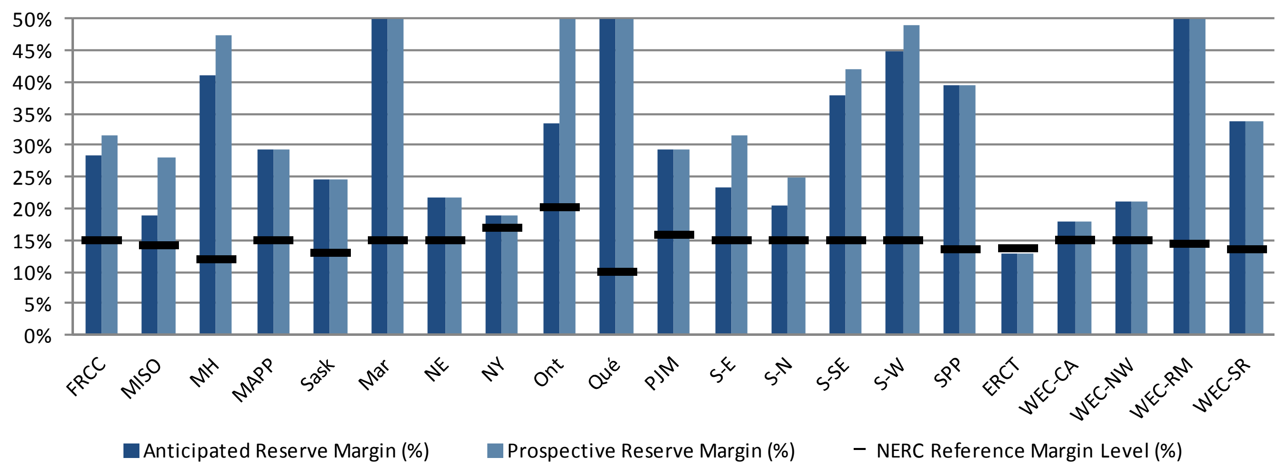
- ERCOT's summer planning reserve margin is projected to be below the NERC Reference Margin Level.
- In southern California, tight supply resources may lead to operational challenges.
- Across North America, increased wind and solar capacity since last summer adds more on-peak supply uncertainty.
- Persisting drought conditions west of the Mississippi River will require close plant and system monitoring.

Additional observations include:

- Retirements and retrofits to meet future environmental regulations are not anticipated to cause reliability concerns this summer.
- Above-average growth in peak demand is projected in ERCOT and WECC.

For the 2013 summer operating period, a majority of the assessment areas are projecting sufficient resources to meet summer peak demands. However, planning reserve margins for ERCOT are below the NERC Reference Margin Level.[7] The planning reserve margins for the peak demand month—which varies for each assessment area—are shown in Figure 1 and in more detail in the next section.[8] Further details on each assessment area are also included in later sections of this report.

Figure 1: 2013 Summer Peak Planning Reserve Margins by Assessment Area



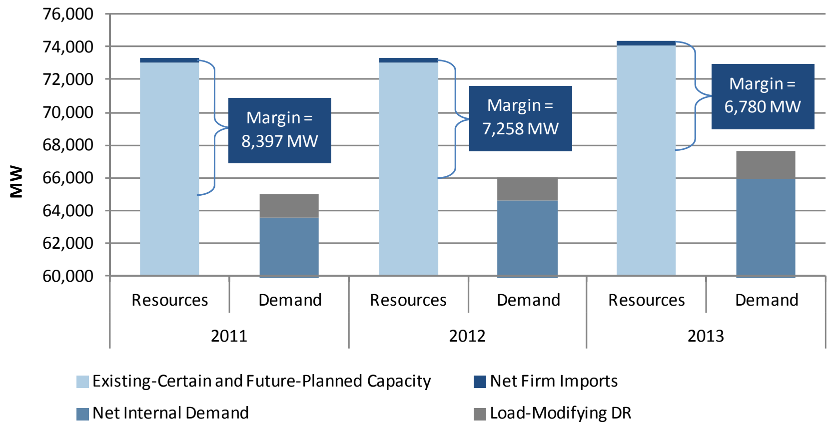
ERCOT Summer Planning Reserve Margin Projected Below NERC Reference Margin Level

The Anticipated Reserve Margin for ERCOT is 12.88 percent for summer 2013. This is below the 13.75 percent target for ERCOT. Sustained extreme weather could be a threat to supply adequacy this summer. ERCOT may need to declare Energy Emergency Alerts (EEA) if there are higher-than-normal forced generation outages or if record-breaking weather conditions similar to the summer of 2011 lead to higher-than-expected peak demands. Insufficient reserves during peak hours could lead to increased risk of entering emergency operating conditions, including the possibility of curtailment of interruptible load and even rotating outages of firm load.

[7] The NERC Reference Margin Levels identified throughout the assessment are planning reserve margins. 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 or subregion may have its 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 NERC Reference Margin Levels for predominately thermal and hydro systems, respectively.

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

Figure 2: 2011–2013 ERCOT Demand and Resource Projections[9]



Generation capacity in ERCOT has not kept pace with load growth and has resulted in diminishing planning reserve margins Figure 2). Delays in generation development are a result of low market prices (due to low natural gas prices and significant wind generation development); reduced availability of capital for financing; and uncertainty associated with changing environmental regulations. The Public Utility Commission of Texas (PUCT) is currently developing solutions to address generation insufficiency for this summer as well as for the long term.

In advance of the summer operating period, ERCOT and generation capacity owners in Texas have taken a number of actions to enhance resource adequacy. ERCOT is working with the PUCT and market participants to ensure that all potential resources, including possible recall of mothballed units and increased demand response programs, are made available during the summer.[10] ERCOT's most recent enhancements include a pilot demand response program aimed at procuring distributed generation and smaller loads, such as residential.[11]

Stressed Conditions in Southern California May Lead to Operational Challenges

In California (WECC-CAMX Assessment Area), the planning reserve margin of 17.88 percent is above the NERC Reference Margin Level (15 percent) for the 2013 summer. However, reliability in southern California, under extreme weather and adverse supply conditions, remains a concern.

Though capacity resources were increased and system reinforcements completed in the southern California area, planning reserve margins still remain tight. As in prior years, significant amounts of imported power are used to fortify reserve margins and preserve reliability, resulting in heavily loaded transmission lines into this area during peak conditions—particularly on the extra high-voltage transmission lines from the east (Sunrise and Southwest Powerlink). As a result, unplanned transmission or generation outages, or extreme temperatures/demand may lead to resource constraints.

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, which have been shut down for repairs since late 2011. In addition to the power generated at the nuclear plant, voltage support for moving that power is an important factor for reliability and avoiding transmission problems in southern Orange County. With this plant unavailable, a prolonged or extreme heat wave, or unexpected resource outages, could result in localized controlled load shedding to maintain system integrity.

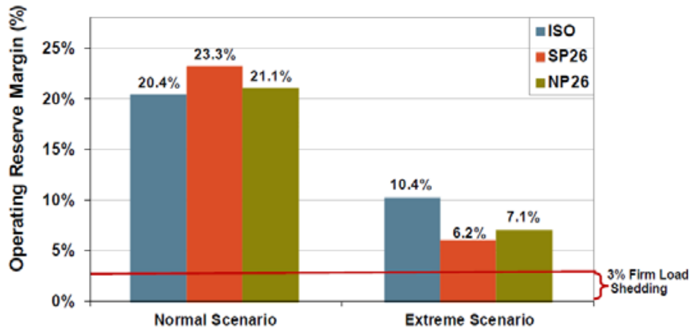
[9] For the *2011 Summer Reliability Assessment*, demand response was counted as a supply-side resource. For the purpose of this comparison, it is counted as a load-modifying resource.

[10] At the time of the summer assessment, ERCOT surveyed the existing mothballed units and established a weighting based on their response as to the probability of their availability for this summer. The survey responses resulted in including 621 MW out of 2293 MW of mothballed generation resources as available this summer. Details can be found in the *Report on the Capacity, Demand, and Reserves in the ERCOT Region*, which has updated data for the 2013 summer: http://www.ercot.com/content/news/presentations/2013/CapacityDemandandReservesReport-Winter_2012_Final.xls. Without these resources in the plan, the resulting Anticipated Reserve Margin for ERCOT would be 11.9 percent.

[11] Pilot Project: Emergency Response Service for Weather-Sensitive Loads (Weather-Sensitive ERS): http://www.ercot.com/content/meetings/board/keydocs/2013/0319/8_Pilot_Project_-_ERS_for_Weather-Sensitive_Loads.pdf

From an operations perspective, the California Independent System Operator (CAISO) has expressed concerns of emerging hydro generation challenges, which are discussed in the following section. Seasonal preparations and nongeneration alternatives to mitigate load shed risk for multiple-contingency events are being considered.[12] Operating reserve margins in the southern portion of CAISO (SP26) appear sufficient to maintain reliability, albeit tight for an extreme demand case. Therefore, from a capacity perspective, sufficient resources are expected to be available to meet summer peak demand.

Figure 3: CAISO (SP26-South and NP26-North)[13] Operating Reserve Margin (%) for Summer 2013[14]



To mitigate potential reliability concerns, several system enhancements have been completed or are planned to be in-service by the summer peak. These enhancements include converting Huntington Beach units 3 and 4 into synchronous condensers,[15] installing capacitors (80 Mvar each at Santiago and Johanna; 160 Mvar at Viejo),[16] the splitting of the Barre-Ellis 220 kV circuits (from two to four lines),[17] the addition of new capacity resources (approximately 1,900 MW),[18] and significant refinements to load curtailment and demand response programs. These improvements should relieve some operational issues and help support system flexibility during periods of stress; however, long-term solutions will likely be needed if SONGS remains out of service.

Figure 4: Supply into Southern Orange County and San Diego with SONGS Off-line

Significant Increases in Wind and Solar Capacity

NERC-wide variable resources are projected to increase since last year's outlook. Solar and wind expected on-peak capacity projections for this year are 2,928 MW and 11,753 MW, respectively. An increase of 2,588 MW and 2,555 MW of expected

[12] *2013 Summer Loads & Resources Assessment*, CAISO (released May 6, 2013): http://www.caiso.com/Documents/2013SummerLoads_ResourcesAssessment.pdf.

[13] CAISO is divided into two zones: Northern California (North of Path 26 or NP26) and Southern California (South of Path 26 or SP26).

[14] This figure shows operating reserve margin, which is different from planning reserve margin. Operating reserve margin includes generation and transmission outages and all demand response and interruptible is used. To maintain criteria, 3 percent operating reserve margin must be maintained. The Normal Scenario is based on a 50/50, normal forecast; the Extreme Scenario is based on a 90/10 forecast (1 in 10 weather).

[15] FERC approved reliability must-run agreement on January 4. The project is on a viable schedule for June operation, though contractual issues remain despite recent FERC rulings.

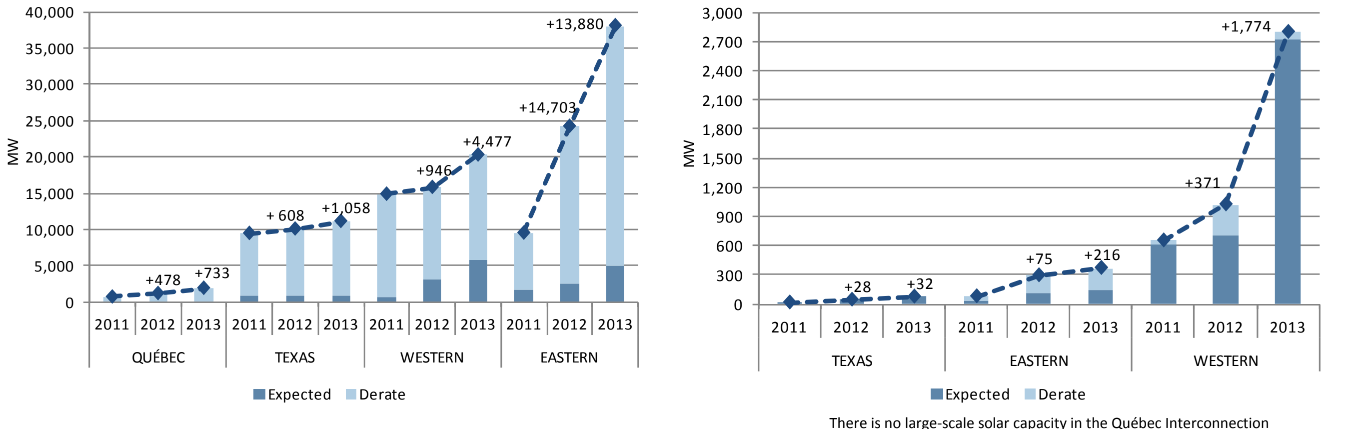
[16] Project approved after September 2012 Board of Governors meeting and is on track for July 1, 2013 completion.

[17] Project is expected to be completed by mid-July 2013.

[18] South of Lugo Walnut Creek Energy Center (500 MW) and El Segundo Power Redevelopment (560 MW) to be in-service by July 2013. Additionally, Sentinel Energy Project (850 MW) is scheduled to be in commercial operation by August 2013.

on-peak wind capacity is projected to supply the Eastern and Western Interconnection, respectively. Over 1,700 MW of new solar capacity has been added in WECC—nearly three times the amount included in the previous summer.

Figure 5: 2011–2013 Wind (Left) and Solar (Right) Capacity Growth by Interconnection



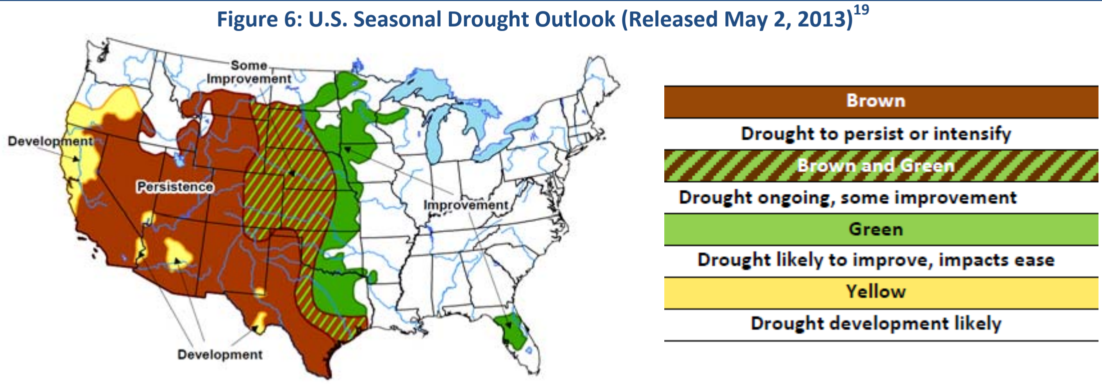
Operationally, an increase in wind and solar resources continues to challenge operators with the inherent swings, or ramps, in power output. In certain areas where large concentrations of wind resources have been added, system planners accommodate added variability by increasing the amount of available regulating reserves and potentially carrying additional operating reserves. Because weather plays a key factor in determining wind and solar output, enhancing regional wind and solar forecasting systems can provide more accurate generation projections. Other methods include curtailment and limitation procedures used when generation exceeds the available regulating resources. In this respect, operating criteria, forecasting, commitment, scheduling, dispatch and balancing practices, procedures, and tools must be enhanced to assist operators in maintaining BPS reliability.

Monitoring Needed to Manage Persisting Drought Conditions

All Regions have indicated that no substantial operating impacts due to the drought are projected; however, increasing drought conditions could give rise to localized challenges. When water levels fall significantly, water intake structures may be exposed above the water surface, causing the plant to become nonoperational.

Additionally, generators are less efficient as the temperature of cooling water increases and results in a reduction of the power capability of the plant. Along some bodies of water, regulatory limits are placed on the temperature of the cooling water system discharges, and power plants are not allowed to raise water temperatures above levels deemed safe for species of fish and other aquatic life. Again, no major system impacts are expected; however, in certain extreme cases, waivers may be needed to keep critical generation online.

Figure 6: U.S. Seasonal Drought Outlook (Released May 2, 2013)[19]



[19] http://www.cpc.ncep.noaa.gov/products/expert_assessment/seasonal_drought.html.

The National Oceanic and Atmospheric Administration predicts moderate to exceptional drought in 51 percent of the continental United States—primarily in the Central, Midwest, and Western regions (Figure 6). As the summer peak approaches, NERC will closely monitor persisting and developing drought conditions—and impacts to hydro generation and cooling water for thermal generation—in California, the Southwest, the southern Rockies, and Texas.

ERCOT does not expect any implications (such as reservoir levels dropping below power plant physical intake limits) during this summer, but ERCOT continues to monitor the drought conditions. While water planning is not a function of ERCOT, significant steps have been taken by ERCOT and other industry stakeholders to minimize the risk of generator outages and derates such as implementing water conservations programs, optimization of water reuse and recycling, minimizing water consumption, and using gray or lower quality water for cooling. In more extreme cases, intake structures could be modified to increase the relative water head levels from the pump intakes. In 2012, ERCOT held a Drought Best Practices Workshop,[20] which brought regional stakeholders together to discuss mitigation measures that can be applied to minimize drought impacts.

The 2011 drought conditions in ERCOT resulted in an increase of flashover events due to insulator contamination as the initiating cause.[21] As a result of NERC's event analysis and lessons learned process, several West Coast entities heeded the warning and increased the periodic maintenance schedule for insulator cleaning during the 2012 drought conditions. As drought conditions lessened in 2012, events due to insulator contamination decreased. If drought conditions in ERCOT worsen in 2013, it could lead to an increase in contamination-related flashover events similar to 2011.

In parts of MRO-MAPP and MISO, long-term droughts may result in significantly reduced hydroelectric production and cause regional resource inadequacy. For the upcoming summer season, the Missouri River main-stem water levels are being monitored closely, as impacts to this water source may affect significant hydro generation. The U.S. Army Corps of Engineers predicts that 2013 will be a drought year, and electric energy produced from the Missouri River will be approximately 80 percent of the historical average.

Mild drought conditions are expected in SPP, but operational planning indicates that these conditions are not expected to cause any major concerns.

In SERC, some thermal units have been derated due to higher-than-expected river temperatures or lower water flows. Barge pumps have been deployed to help mitigate water flow and cooling problems.

The WECC Region does not perform any special operating studies concerning drought conditions for the seasonal assessments. However, adverse hydro conditions are assumed in WECC's resource adequacy projections. Therefore, limited hydro availability has already been incorporated into the seasonal assessment. Drought studies are performed by the individual Load-Serving Entities (LSEs) and Balancing Authorities (BAs) within WECC, and none have reported any significant drought-related issues. CAISO is currently monitoring below average snow–water content, which may have some impacts on hydro generation.[22]

Generator Retirements and Retrofits to Meet Future Environmental Regulations Not Anticipated to Cause Reliability Concerns this Summer

Assessment areas across the United States report that federal environmental regulations have minimum to no impact on operations and planning for this assessment period. The impacts of recent retirements of fossil-fired generation are reflected in this assessment, and environmental control retrofits are not expected to impact generator outages for the summer peak. The planned outages associated with plant retrofitting are more likely to cause some constraints during the shoulder months (usually during the spring and fall) when generators typically perform preventative maintenance.

[20] http://www.ercot.com/calendar/2012/02/20120227-OTHER.

[21] NERC Lessons Learned document as a result of several events reported to NERC related to insulator coating and flashovers: http://www.nerc.com/files/LL_47_Insulator_Coating.pdf.

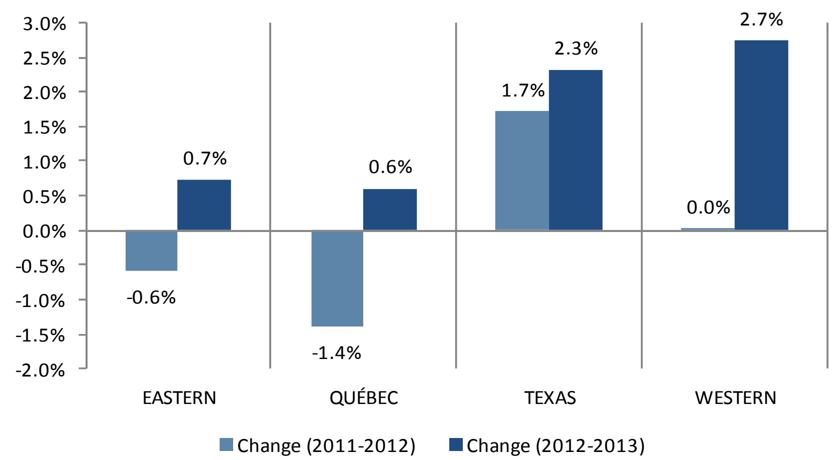
[22] *Briefing on Summer 2013 Outlook & Update on SONGS Mitigation Planning, CAISO:* http://www.caiso.com/Documents/BriefingSummer2013-Presentation-Mar2013.pdf.

Some areas have routine internal communication practices that will alert operational planners at the onset to any potential regulatory impact to plant operations. NERC will continue to monitor the status of the new and current regulations and report whether these regulations create any reliability concerns in the *Long-Term Reliability Assessment*.

Growth in Peak Demand

The NERC-wide non-coincident peak demand projections are 10,157 MW higher than the 2012 summer forecast. Figure 7 shows the annual peak demand changes since the 2011 summer. In the Eastern Interconnection, peak demand is projected to show slight growth after several years of decline following the 2008 economic recession. The Western Interconnection peak demand is projected to increase by 2.7 percent.[23] The increasing peak demand projected in Texas also raises concerns due to ongoing resource concerns. As highlighted in the *2012 Long-Term Reliability Assessment*, the peak demand growth rate in Texas is projected to be the highest in the United States.

Figure 7: 2011–2013 Summer Peak Demand Annual Changes



Active Hurricane Season and Increasing Dependence on Natural Gas

As highlighted in NERC's 2013 special reliability assessment on gas and electric interdependencies,[24] impacts to natural gas production facilities around the Gulf of Mexico are vulnerable to hurricanes. Fuel deliverability concerns can arise for limited periods of time and as increases in gas-fired generation continues these disruptions can have a significant impact to the bulk power system. When hurricanes pass into the Gulf of Mexico, they often disrupt oil and gas production from offshore platforms and in coastal areas. Disruption can be caused by production shut-ins due to the evacuation of personnel from the production area or by damages to production facilities or transmission pipelines that require replacement or repair. Increasing shale gas production in unaffected areas provides the electric industry with resilience to these threats, effectively diffusing much of the risk.

For the upcoming summer, experts have predicted another active hurricane season for the Atlantic coastal areas, which could periodically curtail production of natural gas in the Gulf of Mexico.[25] While the electric industry cannot predict weather or the magnitude to which weather extremes (e.g., tropical disturbances) may affect the fuel supply infrastructure or cause fuel delivery problems, they prepare sensitivity and mitigation strategies in advance. These strategies help the electricity industry have a better understanding of storm impacts as well as the mitigation and restoration efforts.[26]

[23] The forecasted increase in demand is primarily due to new hourly demand curves being used for modeling, but the increase is also due to slight improvements in the economy a slight forecasted economic recovery.
[24] 2013 Special Reliability Assessment: *Accommodating an Increased Dependence on Natural Gas for Electric Power, Phase II* (available: 5/22/13) (Phase I: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Gas_Electric_Interdependencies_Phase_I.pdf, pg 109-110)
[25] http://tropical.atmos.colostate.edu/forecasts/2013/apr2013/apr2013.pdf
[26] NERC, Severe Impact Resilience: Considerations and Recommendations: http://www.nerc.com/comm/OC/SIRTF%20Related%20Files%20DL/SIRTF_Final_May_9_2012-Board_Accepted.pdf

Projected Demand, Resources, and Reserve Margins

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	45,764.0	42,628.0	54,749.2	56,073.7	28.43%	31.54%	15.00%
MISO†	96,193.0	91,532.0	108,742.0	117,267.0	18.80%	28.12%	14.20%
MRO-Manitoba Hydro	3,277.0	3,055.0	4,309.0	4,499.5	41.05%	47.28%	12.00%
MRO-MAPP†	5,111.7	5,025.7	6,498.0	6,498.0	29.30%	29.30%	15.00%
MRO-SaskPower	3,121.8	3,030.8	3,778.2	3,778.2	24.66%	24.66%	13.00%
NPCC-Maritimes	3,150.0	3,150.0	7,689.0	7,689.0	144.10%	144.10%	15.00%
NPCC-New England	27,840.0	26,690.0	32,458.0	32,458.0	21.61%	21.61%	15.00%
NPCC-New York	33,279.0	33,279.0	39,592.2	39,592.2	18.97%	18.97%	17.00%
NPCC-Ontario	23,274.8	23,274.8	31,038.3	37,054.8	33.36%	59.21%	20.20%
NPCC-Québec	21,114.6	21,114.6	31,719.1	31,719.1	50.22%	50.22%	10.00%
RFC-PJM	155,553.0	145,029.0	187,531.1	187,531.1	29.31%	29.31%	15.90%
SERC-E	43,094.0	41,283.0	50,960.5	54,335.5	23.44%	31.62%	15.00%
SERC-N	44,505.0	42,991.0	51,802.6	53,738.6	20.50%	25.00%	15.00%
SERC-SE	48,056.0	46,035.0	63,477.3	65,353.2	37.89%	41.96%	15.00%
SERC-W	25,763.0	25,229.0	36,502.6	37,588.6	44.69%	48.99%	15.00%
SPP	54,168.0	53,177.0	74,130.9	74,213.4	39.40%	39.56%	13.60%
TRE-ERCOT	67,606.0	65,901.0	74,386.4	74,386.4	12.88%	12.88%	13.75%
WECC-CAMX†	56,548.0	54,120.0	63,797.6	63,797.6	17.88%	17.88%	15.01%
WECC-NWPP†	59,003.7	58,079.7	70,390.9	70,390.9	21.20%	21.20%	15.02%
WECC-RMRG	11,610.0	11,137.0	17,075.8	17,075.8	53.32%	53.32%	14.45%
WECC-SRSG	28,956.5	28,477.5	38,122.4	38,122.4	33.87%	33.87%	13.56%
EASTERN INTERCONNECTION	612,150.3	585,409.3	753,258.8	777,670.7	28.67%	32.84%	-
QUÉBEC INTERCONNECTION	21,114.6	21,114.6	31,719.1	31,719.1	50.22%	50.22%	10.00%
TEXAS INTERCONNECTION	67,606.0	65,901.0	74,386.4	74,386.4	12.88%	12.88%	13.75%
WESTERN INTERCONNECTION‡	153,248.5	149,003.5	182,414.6	182,414.6	22.42%	22.42%	14.71%
TOTAL-NERC	**854,119.4**	**821,428.4**	**1,041,779.0**	**1,066,190.9**	**26.83%**	**29.80%**	**-**

†Denotes a boundary change

‡WECC coincident peak

FRCC

Demand Projections

	Megawatts (MW)
Total Internal Demand	**45,764**
Load-Modifying DCLM	2,570
Load-Modifying Contractually Interruptible	566
Net Internal Demand	**42,628**

Resource Projections

	Megawatts (MW)
Net Firm Capacity Transfers	2,033
Existing-Certain & Future-Planned Capacity	52,716
Anticipated Resources	**54,749**
Existing-Other, Future-Other Capacity	1,325
Prospective Resources	**56,074**

Planning Reserve Margins

	Percent (%)
Anticipated Reserve Margin	**28.43**
Prospective Reserve Margin	**31.54**
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 has a geographic coverage of about 50,000 square miles over peninsular Florida.

The Florida Public Service Commission for the FRCC Region requires a 15 percent reserve margin criteria for non-investor owned utilities (IOUs) (applied as the NERC Reference Margin Level) and a 20 percent reserve margin criteria for IOUs. Based on the expected load and generation capacity, the projected reserve margin for 2013 summer is 28.4 percent.

FRCC is projecting a small decrease in the 2013 projected summer peak demand as compared to the previous year's projection for 2013. This is attributed to lower-than-expected consumption and decreased economic activity in the Region. Demand response from interruptible and load management programs within FRCC—totaling 3,136 MW—is treated as a load modifier.

More than 1,200 MW of new generation will be in-service prior to summer 2013, with an additional 150 MW from uprates to existing units. Generation totaling 812 MW returned to service following a planned maintenance upgrades that began in late 2012. A total of 826 MW of generation will be taken out of service for maintenance and will be unavailable throughout 2013 summer. Several units, totaling 1,962 MW, are also scheduled to retire prior to summer 2013. A majority of this capacity is from one generating unit that was retired early in 2013 following a prolonged forced outage.

There are 1,340 MW of generation under firm contract available to be imported from SERC-SE for 2013 summer and 836 MW of member-owned generation, which is dispatched by SERC-SE. These purchases have firm transmission service to ensure deliverability into FRCC. The area has 143 MW of generation under firm contract to be exported during the summer into the SERC-SE Assessment Area. These sales have firm transmission service to ensure deliverability.

Two BES additions and one transmission upgrade project—primarily related to expansion efforts—will be energized over the summer to reliably serve projected demand growth. Currently, FRCC expects that up to 10 high voltage transmission facilities will be out of service for maintenance throughout the summer, with all facilities returning to service by the fall. These outages will be staggered, and all were examined in the FRCC Operational Seasonal Study to verify that they would not adversely impact the reliability of the BPS. There is no change since summer 2012 to the approximately 1,020 MW of Undervoltage Load Shedding (UVLS) programs within FRCC.

FRCC performed a Summer Transmission Assessment and Operational Seasonal Study to assess the adequacy of the BPS under expected peak load and anticipated system conditions during the 2013 summer (taking into account generation and transmission maintenance activities). The results of the study indicate 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. FRCC's transmission system is expected to perform reliably for the projected 2013 summer peak season system operating conditions.

FRCC does not anticipate any issues with the availability of demand response during the 2013 summer season. Based on past experience, demand reduction is used on a limited basis and is expected to be fully available when called upon.

MISO

Demand Projections

	Megawatts (MW)
Total Internal Demand	**96,193**
Load-Modifying DCLM	1,013
Load-Modifying Contractually Interruptible	3,543
Load-Modifying Load as a Capacity Resource	105
Net Internal Demand	**91,532**

Resource Projections

	MW
Supply-Side Load as a Capacity Resource	3,434
Net Firm Capacity Transfers	3,103
Net Expected Capacity Transfers	3,016
Existing-Certain & Future-Planned Capacity	99,189
Anticipated Resources	**108,742**
Existing-Other, Future-Other Capacity	8,525
Prospective Resources	**117,267**

Planning Reserve Margins

	Percent (%)
Anticipated Reserve Margin	**18.80**
Prospective Reserve Margin	**28.12**
NERC Reference Margin Level	**14.20**

The Midcontinent Independent System Operator Inc., or MISO, is an essential link in the safe, 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 consumers with unbiased regional grid management and open access to the transmission facilities under MISO's functional supervision.

***MISO Boundary Changes**: On January 1, 2012, Duke Energy Ohio/Kentucky (DEOK) was consolidated into the PJM RTO, removing approximately 5,700 MW of load and generation from MISO's boundary. Entergy and its six utility operating companies will be integrated into MISO in December 2013. This addition will bring 15,500 miles of transmission, 30,000 MW of generation capacity, and 35,000 MW of load into the MISO boundary.*

The MISO planning reserve margin requirement (applied as the NERC Reference Margin Level for this assessment) is 14.2 percent for the 2013–2014 planning year, which runs from June 1, 2013, through May 31, 2014. The MISO planning reserve margin requirement is 2.5 percent lower this year primarily due to the success of a new external model. The Prospective Reserve Margin of 28.1 percent is well above MISO's planning reserve margin requirement. While it is always possible for a combination of higher loads, higher forced outage rates, fuel limitations, and other factors to lead to the curtailment of firm load, this is a low-probability event for the 2013 summer season.

MISO's peak demand forecast remains static compared to the 2012 summer forecast. Unlike 2012, the 2013 forecast includes transmission losses of 2,392 MW, which aligns with NERC reliability assessment guidelines. Including transmission losses provides a more accurate representation of peak system demand relative to generation requirements.

MISO now allows energy efficiency and demand-side management (DSM) programs to be included in the Planning Resource Auction. The amount of energy efficiency and DSM programs that are expected to be available on-peak this summer are 105 MW and 4,556 MW, respectively.

This year's Existing (Certain, Other, and Inoperable) capacity of 109,550 MW is 10.2 percent lower than MISO's projected Existing capacity of 122,000 MW for the 2012 summer season; however, this is mostly due to a resource accounting discrepancy rather than actual capacity reductions. Last year MISO included capacity derates in the calculation of Existing-Other resources. Removing those derates yields a revised 2012 summer season Existing capacity of 112,500 MW.

Since 2012, 368 MW of coal-fired capacity and 255 MW of gas-fired capacity has been retired; 153 MW of coal-fired capacity, 8 MW of oil-fired capacity, and 52 MW of hydro capacity has been reclassified as behind-the-meter generation; 50 MW of gas-fired generation has been registered with MISO; and 1,600 MW of installed wind capacity has been built (approximately 208 MW Existing summer-rated capacity). MISO's wind resources receive a wind capacity credit based on the effective load-carrying capability of wind generation. The average wind capacity credit for MISO is 13.3 percent. All other intermittent resources receive their unforced capacity rating based on historical summer performance. The remaining 2,372 MW of capacity derates are due to transmission limitations, which were not reported last year. MISO's capacity transactions amount to a net import of 6,119 MW. Regarding nuclear capacity, Dominion Resources Inc. recently announced the planned closure of the 556-MW Kewaunee nuclear plant on May 7, 2013.[27]

To support reliable and efficient transmission service, approximately 465 miles of new transmission lines will be added, and 730 miles of transmission lines will be upgraded or rebuilt; these lines are anticipated to be in-service for the 2013 summer season. Included in these additions and upgrades are six 345-kV lines, one 230-kV line, and nine additional transmission lines (>100 kV); they are located in Minnesota, Wisconsin, Iowa, Illinois, and Michigan. Also, six new transformers and ten transformer upgrades are expected to be in-service to support these new transmission lines.

Similar to previous years, MISO is conducting a Summer Readiness workshop in which they collaborate with stakeholders to maximize preparedness for the summer period. This workshop includes an assessment of MISO's resources and the expected planning reserve margin given a forecasted peak load, an assessment of the transmission system under stressed conditions, and a review of key emergency operating procedures to ensure familiarity with steps and expectations.

During times of peak conditions, or when MISO otherwise forecasts the potential for maximum generation conditions, MISO surveys local BAs to obtain the amount of demand response resources that would be available under a given notification time (e.g., two hours). If MISO reaches the point of needing to call on these resources, then MISO will deploy only the amount needed with the expectation that all will perform. The use of these resources is part of the progression through the Capacity Emergency procedure. If demand response resources don't perform, subsequent steps of the procedure are implemented as necessary.

MISO does not foresee significant impacts to reliability during the 2013 summer season due to environmental or regulatory restrictions. MISO does anticipate that recently finalized and developing EPA regulations will impact MISO in the future, but the main impacts are anticipated beyond the 2013 summer season. MISO conducts ongoing studies to determine the amount of generation maintenance that could be scheduled in a given season, assuming a reduced capacity level as a result of environmental regulations.

Low water levels and high water temperatures can always result from unusually hot and dry weather, and these situations are resolved through existing procedures, depending on the circumstances.

MISO works extensively with neighboring Reliability Coordinators (RCs) for the seasonal assessment and outage coordination processes and via scheduled, daily conference calls and ad-hoc communications as need arises in real-time operations.

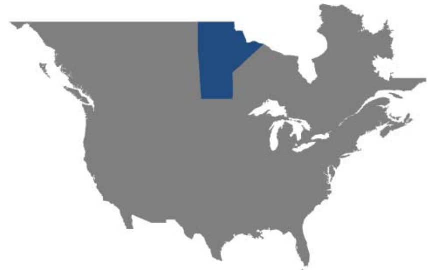
[27] Additional information: http://www.nrc.gov/reading-rm/doc-collections/news/2013/13-027.pdf; http://www.reuters.com/article/2013/04/15/utilities-dominion-kewauneeidUSL2N0D21Q820130415?type=companyNews&feedType=RSS&feedName=companyNews&rpc=43.

MRO-Manitoba Hydro

Demand Projections	
Projected Peak: July	Megawatts (MW)
Total Internal Demand	**3,277**
Load-Modifying Contractually Interruptible	222
Net Internal Demand	**3,055**

Resource Projections	
Projected Peak: July	Megawatts (MW)
Net Firm Capacity Transfers	-1,100
Existing-Certain & Future-Planned Capacity	5,409
Anticipated Resources	**4,309**
Existing-Other, Future-Other Capacity	191
Prospective Resources	**4,500**

Planning Reserve Margins	
Projected Peak: July	Percent (%)
Anticipated Reserve Margin	**41.05**
Prospective Reserve Margin	**47.28**
NERC Reference Margin Level	**12.00**



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

As a predominately hydro region, Manitoba Hydro has both energy and capacity criteria. Manitoba Hydro's capacity criteria is based on system of historical adequacy performance analysis and internal probabilistic resource adequacy studies using the index of loss of load expectation (LOLE) and loss of energy expectation (LOEE). The capacity criterion, which is considered the Reference Margin Level, requires a minimum 12 percent reserve above the forecast peak demand. Annual peak demand occurs during the winter season. The summer peak is approximately 30 percent less than the winter peak.

Manitoba Hydro's demand response is not intended to reduce the peak demand but rather to meet reliability obligations. An industrial customer has agreed to provide 50 MW of curtailable customer load applied as a supply-side resource for ancillary services (non-spinning reserve). Manitoba Hydro's current energy efficiency and conservation portfolio[28] includes customer service, cost recovery, incentive-based and rate-based initiatives, and programs customized to meet the specific energy needs of the residential, commercial, and industrial markets.

Demand response used for ancillary services satisfies a portion of the MISO-Manitoba Hydro Contingency Reserve Sharing Group (CRSG) reserve requirements and are only deployed in the case of large generation-related contingencies on the system. Manitoba Hydro performs an operational study at least once a year. This study determines storage reserve requirements necessary to meet a high load forecast under the lowest historic flow on record. Industrial customers with demand response agreements are required to maintain the availability of the resources more than 95 percent of the time and are restricted to a maximum of 25 curtailments per year; however, only 30 curtailments were conducted from 2010 to 2012. There has never been an instance when Manitoba Hydro has called on an industrial customer to curtail load via an existing demand response agreement and the customer did not have the resources available to curtail. As such, no performance concerns are expected.

There are no recent generation additions or retirements. However, an uprate (rerunning) of the final unit at the Kelsey Generating Station will add 11 MW, scheduled to be in-service prior to the summer peak. In accordance with the MRO Generator Testing Guidelines,[29] on-peak hydro capacity is determined using testing and data processing procedures.[30]

Manitoba Hydro projects 1,100 MW of available capacity exports and no imports. Emergency energy imports are characterized under the MISO-MB Hydro CRSG agreement.[31]

Manitoba Hydro plans to take out a number of lines for regular maintenance during summer 2013. 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.

[28] http://www.hydro.mb.ca/savings_rebates_loans.shtml.
[29] Approved on March 29, 2007.
[30] www.midwestreliability.org/03_reliability/06_gtrtf/Documents/MRO_Generator_Testing_Guidelines.pdf.
[31] https://www.misoenergy.org/Library/Repository/Tariff/Rate%20Schedules/Rate%20Schedule%2002%20-%20Midwest%20ISO-MH%20Coordination%20Agreement.pdf.

MRO-MAPP

Demand Projections	Megawatts (MW)
Total Internal Demand	**5,112**
Load-Modifying DCLM	86
Net Internal Demand	**5,026**

Resource Projections	Megawatts (MW)
Supply-Side DCLM	6
Supply-Side Contractually Interruptible)	10
Net Firm Capacity Transfers	-805
Existing-Certain & Future-Planned Capacity	7,288
Anticipated Resources	**6,498**
Prospective Resources	**6,498**

Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**29.30**
Prospective Reserve Margin	**29.30**
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 Load-Serving Entities (LSEs). The MAPP PA covers an area of approximately 200,000 square miles and serves a population of about 3.5 million. MAPP typically experiences its annual peak demand in summer. There have not been any changes to the MAPP Assessment Area boundary in the last two years, and no changes are expected.

MAPP's planning reserve margins for the 2013 summer season exceed the Reference Margin Level (target) of 15 percent due to a strong generation portfolio and available (DSM) programs. The 2012 MAPP actual summer peak nonsimultaneous demand was 5,062 MW; based on the data submitted to the MRO, the demand forecast was 4,799 MW. This summer's peak demand forecast is 5,129 MW. Non-coincident internal peak demands were used to aggregate individual LSE loads in the MAPP forecast. Resource evaluations are based on non-coincident peak demand conditions.

The total amount of demand response and energy efficiency and conservation expected to be available for the 2013 summer peak is 215 MW. Interruptible Demand and DSM programs amount to about 2 percent of the projected Total Internal Demand. 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 summer season.

Long-term droughts that result in significantly reduced hydroelectric production can cause a regional resource inadequacy. Missouri River main-stem water levels may affect hydro generation for the upcoming summer season. The U.S. Army Corps of Engineers predicts that 2013 will be a drought year, and generation from the Missouri River will be approximately 80 percent of the historical average. Operating flexibility is available to increase generation if required by system conditions.

There are 80 MW of resources projected to come on-line this summer. Northwestern Energy (NWE) is in the process of installing an internal peaking unit of 60 MW in Aberdeen, South Dakota. The simple-cycle, gas-fired unit is expected to be available to serve the summer peak. Regarding wind generation, 242 MW is expected on-peak, with a nameplate rating of 1,098 MW. Additionally, there are 2,135 MW of hydro and 3 MW of existing biomass capacity.

MAPP is projecting 397 MW of firm imports and 1,203 MW of firm exports during the peak. Regarding transmission, the Center – Heskett 230-kV line will be out of service for the 2013 spring and fall seasons for phase raising and reconductoring to increase thermal capacity. This may necessitate reductions of Square Butte Center area generation.

NWE scheduled reconductor work in May 2013 (to be completed in November) on the second phase of 115-kV line between the Seibrecht substation and the Western Area Power Administration's (WAPA) Huron substation. This is the second year of the three-year project. A UVLS was installed at the Williston 57-kV bus in December 2012 due to unexpected localized load growth. The Williston UVLS was put in place as a temporary measure (i.e., short-term fix) until facilities could be constructed. Approximately 70 MW of peak load can be tripped by UVLS.

WAPA and Basin Electric have performed extensive studies on the unexpected load growth in northwestern North Dakota. A third-party expert studied the instability issues at the Langdon Wind Farm that were caused by low short-circuit strength. The Langdon Wind Operating Guide has been updated to require wind farm generator reductions during local line switching; however, instability may still be seen during unexpected line switching, such as that from faults. Inadvertent load tripping can result from this instability. While similar issues exist at the Ashtabula Wind Farm, there are no risks of load tripping.

MRO-SaskPower

Demand Projections

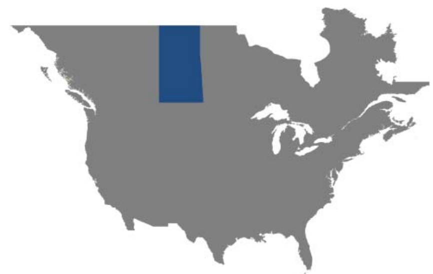
	Megawatts (MW)
Total Internal Demand	**3,122**
Load-Modifying Contractually Interruptible	91
Net Internal Demand	**3,031**

Resource Projections

	Megawatts (MW)
Existing-Certain & Future-Planned Capacity	3,778
Anticipated Resources	**3,778**
Prospective Resources	**3,778**

Planning Reserve Margins

	Percent (%)
Anticipated Reserve Margin	**24.66**
Prospective Reserve Margin	**24.66**
NERC Reference Margin Level	**13.00**



The Saskatchewan Power Corporation is the PA and RC for the province of Saskatchewan and is the principal supplier of electricity in the province. It is a Provincial Crown Corporation and under provincial legislation is responsible for the reliability oversight of the Saskatchewan BPS and its interconnections.

SaskPower (Saskatchewan) projects Anticipated and Prospective Reserve Margins to be over 24 percent for the 2013 summer. Saskatchewan's criteria for adding new generation resources is based on Expected Unserved Energy (EUE). The probabilistic EUE value equates to a 13 percent reserve margin. Total Internal Demand is forecasted to be 3,122 MW for this summer, compared to 3,134 MW for the 2012 summer.

Energy efficiency and conservation and demand response are considered load-modifying resources. Economic incentives, such as the difference in cost of providing DSM programs and serving the load, are the primary reason for DSM programs in Saskatchewan. Increases in projected DSM for the 2013 summer will come from growth of existing programs.

Regarding capacity, a combined-cycle natural gas unit (240 MW summer rating) is expected to be in-service for summer peak. Saskatchewan assumes the availability of 10 percent of nameplate wind capacity to meet peak demand. On-peak expected values for hydro assume nameplate net generation less expected seasonal derates due to water conditions. Saskatchewan plans for all nameplate biomass capacity to meet the peak, based on a base-load contract.

At this time, Saskatchewan has no firm imports or exports that are backed by contracts for the 2013 summer season, nor does it anticipate a need to rely on emergency imports.

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

A UVLS scheme has been installed in the southeastern portion of Saskatchewan. Until planned transmission reinforcements are put into place in 2015, this scheme is required to mitigate potential low voltages under certain generation dispatch scenarios caused by N-1 and N-2 outages. The UVLS scheme targets approximately 70 MVA of load to be shed. This equates to approximately 2 percent of the projected 2013 summer peak.

The UVLS scheme is not projected to directly impact reliability, as it is being implemented to mitigate potential local area post-contingency voltage concerns. A new 230-kV transmission line is planned for the area of concern to reinforce area voltage. This new line has a projected in-service date of mid-2015. The UVLS scheme will remain in place to mitigate potential low voltages for N-1-1 and N-2 outages under certain generation dispatch scenarios.

Manitoba Hydro and Basin Electric are working on the annual 2013 summer season joint study to address mutual impacts on regional operation. As part of the study, a joint report is prepared and applicable guidelines are issued to respective control rooms.

NPCC-Maritimes

Demand Projections	
	Megawatts (MW)
Total Internal Demand	**3,150**
Net Internal Demand	**3,150**

Resource Projections	
	Megawatts (MW)
Supply-Side Contractually Interruptible	175
Existing-Certain & Future-Planned Capacity	7,514
Anticipated Resources	**7,689**
Prospective Resources	**7,689**

Planning Reserve Margins	
	Percent (%)
Anticipated Reserve Margin	**144.10**
Prospective Reserve Margin	**144.10**
NERC Reference Margin Level	**15.00**

The Maritimes Area is a winter peaking area that includes the New Brunswick System Operator (NBSO), Nova Scotia Power Inc. (NSPI), Maritime Electric Company Ltd. (MECL), and the Northern Maine Independent System Administrator, Inc (NMISA). MECL supplies the province of Prince Edward Island. The footprint encompasses approximately two million customers over 55,000 square miles.

The projected Total Internal Demand for the 2013 summer peak period is 3,150 MW, which is slightly lower than the 2012 summer actual peak of 3,169 MW. The assessment area is projecting adequate planning reserve margins during this summer.

The Maritimes Assessment Area has a diverse fuel supply made up of nuclear, natural gas, coal, oil (both light and residual), pet-coke, hydro, tidal, municipal waste, wind, and wood. The 660 MW-net Point Lepreau Nuclear Generating Station returned to service in November 2012 after being out service since April 2008 for refurbishment. Additionally, a 61-MW biomass generator was scheduled to go in-service April 2013. No new capacity transactions have been scheduled for the 2013 summer.

The Maritimes Area does employ UVLS, but there are no existing conditions that would drive the expected use of it during the upcoming summer. A smart grid initiative has recently been announced, but it is two to three years away from implementation.

NPCC-New England

Demand Projections

	Megawatts (MW)
Total Internal Demand	**27,840**
Load-Modifying Load as a Capacity Resource	1,150
Net Internal Demand	**26,690**

Resource Projections

	Megawatts (MW)
Supply-Side Load as a Capacity Resource	701
Net Firm Capacity Transfers	1,103
Existing-Certain & Future-Planned Capacity	30,654
Anticipated Resources	**32,458**
Prospective Resources	**32,458**

Planning Reserve Margins

	Percent (%)
Anticipated Reserve Margin	**21.61**
Prospective Reserve Margin	**21.61**
NERC Reference Margin Level	**15.00**

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 serving 6.5 million households and business; a population comprised of 14 million residents across more than 66,500 square miles. New England has 13 transmission ties neighboring power systems that allow electricity trade with New York, New Brunswick and Hydro-Québec.

ISO-NE has adequate capacity to meet the forecasted peak demand of 26,690 MW[32] for the 2013 summer. During the peak demand month of July, the capacity consists of Existing-Certain generation of 30,654 MW (based on Seasonal Claimed Capabilities (SCC)[33] of 31,759 MW reduced by 1,105 MW of planned outages); active demand resources of 701 MW; and net imports of 1,103 MW. The resulting Anticipated Capacity Reserve Margin is 5,768 MW (21.6 percent).[34] The amount of capacity that is needed to meet the 1-in-10-year disconnection of firm load resource planning reliability criterion is purchased through annual auctions three years in advance of the year of interest. After this primary auction, there are annual reconfiguration auctions prior to the commencement year in order to readjust installed capacity purchases and ensure that adequate capacity will be purchased to meet system needs. The capacity needs can vary from year to year depending on system conditions; for the purposes of this report, the NERC Reference Margin Level is considered to be 15 percent.

The 2013 reference summer peak demand forecast of 26,690 MW is 228 MW (about 0.9 percent) higher than the 2012 summer peak demand forecast of 26,462 MW and may be characterized as having a 50 percent chance of being exceeded. The forecasted demand values in this report take into account reductions due to passive demand resources (energy efficiency) with capacity supply obligations in ISO-NE's Forward Capacity Market (FCM).[35] Last year's reference summer peak demand forecast was 26,462 MW. This was 582 MW (2.2 percent) higher than ISO-NE's 2012 summer peak demand of 25,880 MW, which occurred on July 17, 2012.

For the 2013 summer, ISO-NE has 701 MW of active demand resources that are expected to be available on-peak. The active demand resources consist of real-time demand response and Real-Time Emergency Generation (RTGE), which can be activated with the implementation of ISO-NE Operating Procedure No. 4 – Action during a Capacity Deficiency (OP 4).[36] These active Demand Response (DR) resources can be used to help mitigate an actual or Anticipated Capacity deficiency. OP 4 Action 2 is the dispatch of real-time demand resources and is implemented in order to manage operating reserve requirements. Action 6, which is the dispatch of RTGE resources, may be implemented to maintain 10-minute reserve.

In addition to active demand resources, there are 1,150 MW of passive demand resources (i.e., energy efficiency and conservation), which are treated as demand reducers in this report. These include installed measures (e.g., products, equipment, systems, services, practices, or strategies) on end-use customer facilities that result in additional and verifiable

[32] This includes passive demand credit of 1,150 MW.

[33] Seasonal Claimed Capability is the summer or winter claimed capability of a generating unit or approved combination of units and represents the maximum dependable load-carrying ability of such unit or units, excluding capacity required for station use.

[34] ISO-NE ensures that it has enough capacity to meet system needs through its FCM. When generating capacity is based on FCM Capacity Supply Obligations (CSOs) of 29,578 MW instead of SCCs of 31,759 MW, the operating reserve margin based on Existing-Certain Capacity, which includes a reduction of 1,105 MW for planned maintenance, together with active demand response and imports, is 3,687 MW, or 13.8 percent.

[35] http://www.iso-ne.com/markets/othrmkts_data/fcm/index.html.

[36] http://www.iso-ne.com/rules_proceds/operating/isone/op4/index.html.

reductions in the total amount of electrical energy used during on-peak hours. The amount of energy efficiency is based on capacity supply obligations in the FCM.

ISO-NE has an established long-term forecast methodology for energy efficiency that takes into account the potential impacts of growing energy efficiency and conservation initiatives in the Region. However, in the near term (i.e., up to three years in the future), the amount of energy efficiency is based on capacity supply obligations in the FCM. Select assets that participate in the real-time demand response programs are under direct load control by the load response providers (LRPs). The LRP implements direct load control of these assets upon dispatch instructions from ISO-NE.

Reserve margins for the ISO-NE Assessment Area are based on Anticipated or Prospective resources. The Anticipated Reserve Margin will remain above the Reference Margin Level during the 2013 summer season.

Natural gas-fired generation represents the largest component of ISO-NE's total installed capacity at 13,598 MW (42.8 percent), followed by oil-fired generation at 7,083 MW (22.3 percent), nuclear generation at 4,624 MW (14.6 percent), and coal at 2,289 MW (7.2 percent). Hydroelectric capacity (1,374 MW) and pumped-storage capacity (1,720 MW) make up 4.3 percent and 5.4 percent of the total, respectively. The remaining 3.4 percent of capacity consists of renewable capacity such as that provided by wind or biomass facilities.

A total of 179 MW of new generation based on nameplate ratings has been installed since last summer. Most of that capacity (42 MW summer capability, or 155 MW nameplate rating) consists of wind facilities. With these additions, the total 2013 expected summer on-peak wind capacity is 97 MW. A gas-fired combustion turbine accounts for the remaining 24 MW.

ISO-NE has not approved any long-term generator outages that would impact reliable operations during the 2013 summer period. However, 986 MW of oil-fired generation has been forced off-line and, although the required equipment repairs have been scheduled, the units are not expected to return to service for the summer capacity period. Additionally, ISO-NE does not have any information about behind-the-meter generation, other than RTEG. RTEG is a form of distributed generation that is classified as an active demand resource in the FCM and is dispatched by ISO-NE during implementation of OP 4. A total of 234 MW of RTEG has an obligation to provide capacity in summer 2013.

Within the Existing-Certain category, approximately 97 MW of capacity is wind generation that is expected to be available at the time of peak demand. This reflects a 684 MW derate on peak from the total nameplate capability of 781 MW. Solar generation makes up 32 MW of on-peak capacity, derated from its nameplate capacity of 53.5 MW. Existing-Certain capacity also includes 1,374 MW of hydroelectric resources. This reflects a 641 MW derate on peak from the total nameplate capability of 2,015 MW. Biomass capacity in the Existing-Certain category totals 942 MW. The derating methodology used is based on the average of the median net output during the summer or winter reliability hours[37] of the previous year.

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

The forecast for summer 2013 includes on-peak firm capacity imports of 1,203 MW.[38] These firm capacity imports, which include transfers from Hydro-Québec, New York, and New Brunswick, have been contracted for delivery within the 2013 FCM Capability Period.[39] Additionally, 100 MW of firm exports to New York are projected for the 2013 summer.

In conjunction with their Local Control Centers (LCC), ISO-NE determines all System Operating Limits (SOLs) and which subset of SOLs will be classified as Interconnection Reliability Operating Limits (IROLs) as captured in the *Master/Local Control Center Procedure No. 15 – System Operating Limits Methodology* (MLCC 15).[40] These limits are determined by utilizing network study models in both the real-time EMS and off-line network study models. These models include PSS/E, with regard to thermal, voltage, and stability requirements necessary to protect against instability, uncontrolled separation, or cascading outages from single-element contingencies and specified multiple-element contingencies. These models include all key generators and transmission above 230 kV, as well as an equivalence model for the 115 kV and 138 kV lines in both the neighboring reliability control areas of New Brunswick and New York. The Québec transmission system is asynchronously interconnected to New England via HVdc and is therefore modeled as a generation or load. These interface

[37] The summer reliability hours are the hours ending 2:00 pm (EDT) through 6:00 pm (EDT) each day of the summer period (June through September) and all summer period hours in which the ISO has declared a shortage event.
[38] http://www.iso-ne.com/trans/celt/report/2013/2013_celt_report.pdf.
[39] Data in this report is based on the most current Annual Reliability Auction (ARA) for the 2013–2014 capacity period.
[40] http://www.iso-ne.com/rules_proceds/operating/mast_satllte/mlcc15.pdf.

limit calculations utilize facility ratings and generator technical characteristics and are reviewed for elements' in-service and out-of-service conditions to ensure that the proper precontingency requirements can be met during planned or unplanned outage conditions.

ISO-NE meets with NY-ISO on a yearly basis to evaluate changes to the transmission system that would have an impact on import and export capabilities. The findings are then shared with the adjacent RC for a review in determining a safe and reliable transfer limit. If changes are required, efforts are coordinated for a smooth implementation. These meetings also occur with NBSO on an as-needed basis, but do not occur with Québec because it is asynchronously interconnected.

The existing New England transmission system is anticipated to be sufficient for the 2013 summer assessment period. An ongoing enhancement to the 345-kV transmission system is in progress. In November 2012, a 345-kV line was installed in western Massachusetts, which is the first step in the 345-kV improvements for the Greater Springfield Reliability Project (GSRP).[41] In March 2013, the installation and reconfiguration of two 345-kV transmission lines was completed. A 345-kV line from western Massachusetts into Connecticut and the reconfiguration of the 3-terminal line section from central Connecticut will strengthen a previous 115-kV corridor, enhance transfer capabilities, and improve low-voltage issues under high transfers as part of the GSRP.

By June 2013, a new 345-kV transmission line in Rhode Island will be in-service. It will be available to address transfer capability and high-voltage issues that may occur during light load levels in the 2013 summer period, and it will ultimately strengthen the import area.

Lastly, two 345-kV lines will be completed and in-service for Maine and southeastern Massachusetts by June 2013. The first 345-kV line will strengthen northern Maine's electric system, which is an integrated part of the Maine Power Reliability Program (MPRP),[42] and it will ultimately support additional transfers. The remaining line is a 345-kV transmission line that will strengthen transfers to the lower southeast Massachusetts area.

All significant transmission lines and transformers are expected to be in-service through the 2013 summer 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.

ISO-NE has not employed any new technologies to enhance reliability since the 2012 summer assessment. However, ISO-NE is developing synchrophasor technology as part of a smart grid investment grant from the U.S. Department of Energy. The implementation phase of the project will conclude in June 2013, and its performance will be monitored through 2015 to determine how the technology might be used to enhance reliability in the near future.

ISO-NE continues to integrate new power supply sources—including new variable resources—into the network. All new resources are studied in detail by ISO-NE Operations Engineering prior to commercial operation. These are all integrated through the use of operating guides and interface limits and through the EMS. To facilitate system operation with potentially large amounts of wind power, ISO-NE follows Operating Procedure No. 14 Appendix F – Wind Plant Operators Guide (OP 14F).[43] OP 14F is chiefly concerned with requirements for real-time and static-type data that will facilitate accurate wind power forecasting over the intra-day, day-ahead, and week-ahead timescales, as well as data for use in situational awareness functions for ISO-NE operators.

The implementation of the FCM has enhanced the integration of demand resources into system operations. ISO-NE has two real-time demand resource programs that can be used to manage load and reserves as part of implementation of OP 4. The first program is focused on load response and is used early in OP 4. The second is Real Time Emergency Generator Asset (RTEG), which is accessed in a later OP 4 action. All of these resources are audited in both the summer and winter period each year for their ability to perform. Based on demand response audits in summer 2012 and the response of active demand response during the July 22, 2011 OP 4 event, ISO-NE expects that approximately 90 to 95 percent of demand response capacity will perform. In addition, each resource submits the hourly status of its capability to the ISO, and the system operators are able to view that capability in real time. Finally, the operators are provided with telemetry from each resource to monitor the real-time performance of the resources in relation to their capacity supply obligations.

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[41] The proposed improvements are designed to address the greater Springfield and north-central Connecticut area electric systems that can become overloaded even during normal operating conditions and to meet more stringent federal and regional reliability standards.

[42] The proposed improvements are designed to keep the system operating reliably over the coming decades and to provide the infrastructure for the state's emerging wind, hydro, biomass, and tidal energy industries.

[43] The ISO Operating Procedure OP 14, Appendix F is located here at: http://www.iso-ne.com/rules_proceds/operating/isone/op14/op14f_rto_final.pdf.

There are no environmental or regulatory restrictions currently being discussed or forecast for the Region that may significantly impact system reliability during the summer reliability assessment period. In the past, environmental restrictions on coastal or river-based generating units due to cooling water discharge temperatures during extremely hot summer days or low hydrological conditions have resulted in temporary capacity reductions ranging from 50 MW to 500 MW. It is expected that such temporary reductions will be significantly reduced in the future due to the installation of closed-loop cooling systems.

The regional gas pipelines and local gas distribution companies communicate with ISO-NE to identify any planned maintenance that may impact fuel deliveries to the power sector. ISO-NE was informed well in advance of a two-week planned outage of a regional gas pipeline scheduled for early June. Though the New England generation fleet is predominantly reliant on gas (nearly 50 percent is gas-fired fuel supply), delivery options have historically been readily available to generators within New England during the summer months. For the summer of 2013, ISO-NE does not foresee system-wide fuel supply or delivery constraints.

ISO-NE continues to exchange information pertaining to the impact of planned and unplanned generation and transmission outages with neighboring power systems within the planning and real-time horizons in a timely manner. Agreements and requirements are in place to maintain communication and coordination efforts that will preserve situational awareness throughout the summer capacity period. ISO-NE does not anticipate any significant issues that would impede receiving or providing support in maintaining system reliability to neighboring reliability control areas and BAs in a timely fashion.

NPCC-New York

Demand Projections	
	Megawatts (MW)
Total Internal Demand	**33,279**
Net Internal Demand	**33,279**

Resource Projections	
	Megawatts (MW)
Supply-Side Load as a Capacity Resource	1,558
Net Firm Capacity Transfers	1,969
Existing-Certain & Future-Planned Capacity	36,065
Anticipated Resources	**39,592**
Prospective Resources	**39,592**

Planning Reserve Margins	
	Percent (%)
Anticipated Reserve Margin	**18.79**
Prospective Reserve Margin	**18.79**
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 Installed Reserve Margin (IRM), also applied in this report as the NERC Reference Margin Level for 2013, is 17 percent. This compares with the IRM for 2012 of 16 percent. An NYCA IRM study is conducted annually by the New York State Reliability Council (NYSRC) Installed Capacity Subcommittee to provide parameters for establishing NYCA IRM requirements for the following capability year. The principle drivers that increased the required IRM are: (1) a special case resource (SCR) model change; (2) an updated load forecast uncertainty model; and (3) an updated external control area (outside world) model. NYISO is projecting an adequate IRM during the 2013 summer. Unplanned outages could reduce available capacity. However, even accounting for such outages, there are no foreseen reliability issues.

The weather-normalized 2012 peak was 33,106 MW, which was 189 MW (0.6 percent) lower than the forecast of 33,295 MW. The current 2013 peak forecast, which was updated December 2012, is 33,279 MW. It is lower than the April 2012 forecast of 33,696 MW by 417 MW (1.2 percent). This is attributed to the impacts of lower economic growth in the region.

An updated economic forecast was obtained in August 2012 from Moody's Analytics. Individual transmission districts are seeing lower growth in New York City and Long Island than in previous forecasts. A slight decrease in peak demand in Long Island is attributed to impacts of Hurricane Sandy. There were no changes in load forecasting methodology since the 2012 summer assessment.

The total available for this summer is approximately 1,558 MW – over 600 MW less than what was available for the summer of 2012. Recent capacity additions or enhancements now available use natural gas as the primary fuel. Interruptions in natural gas supplies could impact generator availability.

Since the 2012–2013 winter reliability assessment was produced, three generation facilities are projected to retire development of the. The Danskammer Generation Units 1–6 (537.4 MW nameplate), Dunkirk 2 (100 MW nameplate) and Montauk Diesels 2–4 (6 MW nameplate) will retire before the summer 2013 season. No new generation resources will be added prior to or during the 2013 summer season.

No high-priority transmission projects are needed for reliability purposes during the summer peak. However, the Hudson Transmission Partners (HTP) project—an HVdc interconnection between PJM and New York City (New York Zone J)—is anticipated to be energized before the summer 2013 peak period. While the project will be in-service, necessary network reinforcements will not be available this summer, which limits the amount of firm transmission rights to 13 MW. The interconnection facility will have a rating of 660 MW. When network reinforcements are complete, 320 MW are designated for firm transmission rights with the remaining capability classified as nonfirm transmission rights.

The Moses – Massena MMS2 230-kV line will be out of service for summer 2013 due to a breaker failure at the Massena switchyard. The Ramapo PAR 4500, one of two 345-kV phase angle regulators that control power flow on the Branchburg – Ramapo 5018 500-kV line from PJM to New York, will be out of service for the summer. This will limit flow on the 5018 line to approximately 500 MW. There are no foreseen reliability issues due to these outages.

Several new capacitors will be installed before the summer 2013 season in western New York: 300 Mvar at the Gardenville, Dunkirk, Huntley, and Homer Hill 115-kV substations. There are no conditions expected to require the use of UVLS, and there have been no new technological additions.

High-capacity factors on certain New York City peaking units could result in possible violations of their daily NO_x emission limits if they were to fully respond to the NYISO dispatch signals. Significant run time on peaking units, indicating the potential for a violation, could be the result of long-duration hot weather events or loss of significant generation or transmission assets in New York City. In 2001, the New York State Department of Environmental Conservation (DEC) extended the agreement it previously had with the New York Power Pool to address the potential violation of NO_x and opacity regulations if NYISO were required to keep these peaking units operating to avoid the loss of load. Pursuant to the terms of this agreement (DEC, Declaratory Order # 19–12), if NYISO were to issue an instruction to a generator to go to maximum capability in order to avoid loss of load, any violations of NO_x RACT emission limits or opacity requirements imposed under DEC regulations would be subject to the affirmative defense for emergency conditions. This determination is limited to circumstances in which the maximum capability requested by NYISO would involve the generation of the highest level of electrical power achievable by the subject generators with the continued use of properly maintained and operating pollution control equipment required by all applicable air pollution control requirements.

NPCC-Ontario

Demand Projections	
	Megawatts (MW)
Total Internal Demand	**23,275**
Net Internal Demand	**23,275**

Resource Projections	
	Megawatts (MW)
Supply-Side Contractually Interruptible (Curtailable)	694
Existing-Certain & Future-Planned Capacity	30,344
Anticipated Resources	**31,038**
Existing-Other, Future-Other Capacity	6,017
Prospective Resources	**37,055**

Planning Reserve Margins	
	Percent (%)
Anticipated Reserve Margin	**33.36**
Prospective Reserve Margin	**59.21**
NERC Reference Margin Level	**20.20**

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

Ontario's 2013 reserve margin target as determined in accordance with the NPCC resource adequacy design criterion is 20.2 percent. For 2012, the target reserve margin was 20.4 percent. The reserve margin requirements are calculated annually for the next five years and published on the Independent Electricity System Operator (IESO) website.[44] From June through September 2013, the available reserve margin is expected to be within the range of 33.4 percent and 48.4 percent for normal weather. The Anticipated Reserve Margins are not expected to fall below Ontario's target reserve margin (20.2 percent) during the summer season.

A number of generation projects are expected to be on-line before the summer 2013 season. Though some delays are possible, Ontario still meets the reserve margin target with the existing generation capacity. The IESO addresses summer extreme weather conditions by conducting planning studies that use the most severe weather experienced over the last 31 years. Adequacy assessments show that Ontario will have sufficient reserves over the entire summer period.

The 2012 summer peak demand forecast was 23,409 MW under normal weather and 25,842 MW under extreme weather. The actual (non-weather-corrected) peak demand was 24,636 MW. Actual demand was significantly higher than the normal weather forecast with actual conditions meeting those of the extreme weather scenario. The weather-corrected peak demand was 23,501 MW; that is, 0.4 percent higher than the normal weather forecasted demand. For summer 2013, the peak demand forecast is expected to be 23,275 MW under normal weather and 25,430 MW under extreme weather.

Ontario continues to experience growth in embedded generation capacity and participation in conservation initiatives. Conservation reduces end-use consumption while embedded generation simply offsets it, and both lead to a reduction in the wholesale demand measured by the IESO. These two factors combined will more than offset any demand increases from population growth and economic expansion, and will lead to an overall decline in electricity consumption, as measured at the wholesale level.

Energy demand is forecast to decrease by 0.6 percent in 2013 after the 0.4 percent increase seen in 2012. The growth in embedded solar capacity over the forecast horizon will have a significant impact on summer peak demands by effectively reducing demand for grid-supplied energy during sunny days. Time-of-use rates and the global adjustment allocation will add to this downward pressure on the summer peaks. Conservation will continue to grow throughout the forecast. The demand forecast is decremented for the impacts of conservation and embedded generation. Other demand measures, such as dispatchable loads, demand response programs, and contracted loads, are not decremented from the demand forecast but instead are treated as resources in the assessment. Therefore, the effects of demand measures are added back into the demand history, and the forecast is produced prior to these impacts. That total demand measure capacity is discounted—based on historical and contract data—to reflect the reliably available capacity. The impact of time-of-use rates and the global adjustment allocation are factored into the demand forecasts. The global adjustment allocation has an impact on summer peaks.

[44] http://www.ieso.ca/imoweb/monthsYears/monthsAhead.asp.

The majority of Ontario's demand response programs are dispatchable and market-driven. The two main initiatives are dispatchable loads and demand response 3 (DR3). The dispatchable loads bid into the market and are dispatched off like any resource. This program has a total capacity of roughly 900 MW. The DR3 program contracts loads that are dispatched off the system based on the supply cushion—the difference between demand and supply. This program has a capacity of 400 MW. One other program (Peaksaver) provides an additional 160 MW of capacity. Although the demand response total capacity is roughly 1,460 MW, the effective capacity is just under 700 MW due to program restrictions and market participant actions. None of the IESO's demand response programs are used for ancillary services.

There are no notable issues that could lead to large-scale impacts to generator availability during the summer season. Also, no resource additions or retirements occurred since the 2012–2013 Winter Reliability Assessment.

The addition of 30 MW of hydroelectric generation is planned before summer 2013. One biomass generator (40 MW) and four wind farms (468 MW) will be added before or during summer 2013. Atitokan coal unit G1 (211 MW) will remain shut down beyond the 2013 summer season for biomass fuel conversion. Two refurbished nuclear units with a capacity of more than 1,500 MW have returned to service since summer 2012.

In its determination of resource adequacy, the IESO plans for Ontario to meet NPCC regional criteria without reliance on external resources. There are no firm imports or exports identified for the summer period.

For use during daily operation, operating agreements between the IESO and neighboring jurisdictions in NPCC, RFC, and MRO include contractual provisions for emergency imports directly by the IESO. No emergency generation is needed to meet Ontario's planning reserve margin reference level for the next summer. IESO also participates in the NPCC simultaneous activation of reserve, which includes the following participants: IESO, ISO-NE, NBSO, NYISO, and PJM.

The completion date for 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. Until the project is in-service, the supply needs in southern Ontario will continue to be met through the existing system.

A few local transmission circuits, in northwest, northeast, and Ottawa zones in Ontario, will be taken out of service during the summer season. The interfaces will be operated at reduced limits in account of these line outages. One tie-line (PA-301) will be taken out of service, reducing import from and export to New York limits.

As stated earlier, the IESO plans for Ontario to meet NPCC regional criteria without reliance on external resources. For this reason, the impact of reductions in imports and exports mentioned above will not cause any potential reliability concerns.

There are no significant transmission line upgrades this summer. There is no significant substation equipment that is newly available for the 2013 summer peak. Also, there are no wide-area UVLS programs in Ontario or plans to install any.

On November 1, 2012, regular day-ahead and pre-dispatch scheduling processes incorporated the hourly centralized forecast of variable generators participating in the IESO-administered markets. The addition of the hourly centralized forecast is expected to help manage the system efficiency and reliability.

A centralized forecast has been developed for all transmission-connected wind resources, with a full implementation set to be complete by the end of 2013.

The IESO has just over 1,450 MW of demand response capacity, of which roughly 694 MW is deemed to be reliably available at the time of the system peak.

There are no new environmental or regulatory restrictions that could impact reliability. Additionally, no significant issues have been identified for the upcoming summer season with the neighboring NPCC areas. The coordination and communication of issues that may be a concern is performed through NPCC working group CO-12, which is tasked with the seasonal assessments for the NPCC Region.

NPCC-Québec

Demand Projections	
Projected Peak: July	Megawatts (MW)
Total Internal Demand	**21,115**
Net Internal Demand	**21,115**

Resource Projections	
Projected Peak: July	Megawatts (MW)
Net Firm Capacity Transfers	-1,352
Net Expected Capacity Transfers	-396
Existing-Certain & Future-Planned Capacity	33,467
Anticipated Resources	**31,719**
Prospective Resources	**31,719**

Planning Reserve Margins	
Projected Peak: July	Percent (%)
Anticipated Reserve Margin	**50.22**
Prospective Reserve Margin	**50.22**
NERC Reference Margin Level	**10.00**

The Québec Assessment Area is located in the northeastern part of the NPCC Region. 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. The Québec system is winter-peaking because a large amount of space heating. The system is almost 93 percent hydro. Transmission system line length totals 33,639 km (20,902 miles). Population served is about 8 million and the Province of Québec has an area of approximately 1,667,000 km^2 (643,600 sq. mi.).

The NERC reference margin level (target) for summer and winter seasons is 10 percent. Assumptions used to establish reserve margin criteria, target margin levels, and resource adequacy levels, and results thereof, are discussed in the *2012 Québec Area Interim Review of Resource Adequacy* (approved by the NPCC Reliability Coordinating Committee on November 27, 2012). The assessment can be found on NPCC's website.[45]

The assessment area is projecting planning reserve margins well above the target during the 2013 summer operating period. No potential issues or circumstances that could result in substantial changes from current projections are expected.

The Québec Assessment Area's Total Internal Demand forecast for the 2013 summer peak period is 21,115 MW. This forecast is similar to the 2012 summer forecast of 20,988 MW. Energy efficiency programs and energy saving trends are accounted for directly in the assessment area's demand forecasts. Energy efficiency and conservation programs are implemented throughout the year by Hydro-Québec Distribution (HQD) and the provincial government's Ministry of Natural Resources. The total amount of conservation associated with existing and projected programs is estimated to be equivalent to 1,480 MW for the 2013 summer peak. Demand response programs are neither required nor available during summer operating periods.

In the Québec Assessment Area, system maintenance (generator and transmission) is completed during summer periods (including late spring to late fall). Thus, in general, generator unavailability is due to scheduled maintenance. There are no other particular issues that could affect generator availability during the 2013 summer operating period.

However, one major retirement occurred since the development of the 2012–2013 Winter Reliability Assessment. The Gentilly-2 nuclear GS (675 MW) was permanently retired on December 28, 2012.

Finally, a total of 172 MW of wind and hydro capacity are expected to come in-service for summer 2013. In this assessment, wind power generation (156 MW) is completely derated, while 16 MW of hydro power capacity is expected to be added on peak.

The Québec Assessment Area's resource portfolio includes (in order of importance) hydro, wind, and biomass. There are no solar resources. For hydro resources, maximum capacity is set equal to the power that each plant can generate at its maximum rating during two full hours, and expected on-peak capacity is set equal to maximum capacity minus scheduled maintenance outages and restrictions.

Biomass and wind resources are owned by independent power producers (IPPs). These IPPs have signed contractual agreements with Hydro-Québec. Therefore, for biomass, maximum capacity and expected on-peak capacity are equal to contractual values. In the case of wind resources, Hydro-Québec Distribution has evaluated expected capacity during winter operating seasons only since the area is winter peaking. Summer wind capacity expected on peak is set to zero, as wind resources are derated by 100 percent for summer operating periods.

[45] https://www.npcc.org/Library/Resource%20Adequacy/Forms/Public%20List.aspx.

The Québec Area projects a total of 1,748 MW of capacity exports to neighboring areas for the 2013 summer period. Firm capacity exports include more than 700 MW to New England, 500 MW to New York, and 145 MW to Ontario. The remaining capacity exports (about 400 MW) are expected capacity exports to New York. There is no reliance on capacity imports during this assessment period.

No specific projects are needed to maintain or enhance reliability during the 2013 summer season. In the NERC reliability assessment for winter 2012–2013, a number of transmission projects were mentioned for the winter peak period, such as wind plant integration projects, a 230-kV subsystem reinforcement, and three satellite substations, as well as a new Special Protection System (SPS). These projects have been commissioned and are now in-service.

As mentioned above, in the Québec Assessment Area most transmission line, transformer, and generating unit maintenance occurs during the summer period. Summer peak load is typically about 56 percent of winter peak load, and resource availability is not a problem at all during summer operating periods, even though exports to summer peaking subregions of NPCC are sustained during peak hours.

Usually, system additions or enhancements are commissioned in preparation for winter operating periods. Therefore, no significant substation equipment such as SVCs, synchronous condensers, HVdc stations, or series compensation are newly available for the 2013 summer operating season.

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

TransÉnergie's significant operating studies are performed for the winter season, when weather conditions will translate into higher demand levels. Readers may refer to previous NERC winter reliability assessments[46] for details. A 735-kV current transformer replacement program was, however, initiated during summer 2012. This challenging program forced a complete re-planning of summer maintenance schedules, which affected transmission capability and occasionally export capability to neighboring summer-peaking control areas. Phase 1 of this program, which involved 60 percent of the concerned CTs, was successfully completed in 2012. Phase 2 will be completed in 2013. Otherwise, abnormally hot weather also contributed to transmission constraints that had to be managed in real time. The 735-kV grid is normally limited by transient and voltage stability considerations, but rarely by thermal capacity constraints.

The only variable resources presently integrated in the Québec Area are wind resources. Nameplate capacity is now 1,714 MW. A total of approximately 3,350 MW are planned to be in-service in 2015.

No environmental or regulatory restrictions are expected to impact system reliability during summer periods.

[46] http://www.nerc.com/page.php?cid=4|61

PJM

Demand Projections

	Megawatts (MW)
Total Internal Demand	**155,553**
Load-Modifying DCLM	1,052
Load-Modifying Contractually Interruptible	9,472
Net Internal Demand	**145,029**

Resource Projections

	Megawatts (MW)
Existing-Certain & Future-Planned Capacity	185,331
Anticipated Resources	**187,531**
Prospective Resources	**187,531**

Planning Reserve Margins

	Percent (%)
Anticipated Reserve Margin	**29.31**
Prospective Reserve Margin	**29.31**
NERC Reference Margin Level	**15.90**

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 Boundary Changes*: This year's report includes the load and generation of Duke Energy Ohio/Kentucky (DEOK), which was integrated into the PJM RTO on January 1, 2012, and the generation and load of East Kentucky Power Cooperative (EKPC), which will be 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. The PJM RTO Reserve Requirement is slightly (0.3 percent) higher this year due to higher historical generator forced outage rates, which has a direct influence on the reserve requirement. For more information see the 2012 PJM Reserve Requirement Study.[47] The Anticipated Reserve Margin of 29.3 percent is well above the PJM RTO reserve requirement of 15.9 percent.

With the exception of the addition of EKPC demand on June 1, 2013, the demand forecast has increased at a typical rate of 1.3 percent. DEOK was integrated into the PJM RTO on January 1, 2012, which added approximately 5,400 MW to the PJM forecast at the time. The load of EKPC, which will be integrated into PJM on June 1, 2013, will add approximately 1,910 MW of load to the PJM RTO 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 the 2012 report. No change in the seasonal weather outlook has been incorporated into the 2013 summer PJM RTO load forecast. No other seasonal issues are expected to impact the demand forecast.

DSM is accepted in PJM through bidding into the PJM RPM market. The bidder can decide if they want to act as a resource (i.e., they would receive additional payment for energy) or as a load reduction when called for by the PJM system operators. The total amount of energy efficiency for the PJM Area that is expected to be available on peak for summer 2012 is 651 MW. Demand-side resources available during the summer peak period will total 10,524 MW. DSM used for reserves is limited by RFC criteria BAL-002-02[48] to 25 percent of the PJM operating reserve requirement. This type of DSM is typically fully subscribed and can range up to approximately 2,500 MW during a peak summer day.

There are no notable issues that could lead to large-scale impact to PJM generator availability during the summer season. Net change from summer 2012 is a loss of 2,748 MW of Existing-Certain capacity. Significant changes are listed below:

[47] http://www.pjm.com/~/media/planning/res-adeq/2012-pjm-reserve-requirement-study.ashx.
[48] https://rfirst.org/standards/BAL002RFC02/Pages/BAL-002-RFC-02.aspx.

Unit name (Company)	Change (MW)	Unit name (Company)	Change MW)	Unit name (Company)	Change (MW)	Unit name (Company)	Change (MW)
Rockgen CT 2 (Atlantic Electric)	156	Willow Island 2 (FE- Allegheny Power)	-138	Fisk Coal 19 (COMED)	-326	Potomac River 1 (PEPCO)	-88
Sporn 5 (AEP)	-440	Burger 4 (FE-ATSI)	-120	DEMEC 2 (Delmarva)	51	Potomac River 2 (PEPCO)	-88
Albright 1 (FE-Allegheny Power)	-73	Burger 5 (FE-ATSI)	-120	Elrama 1 (Duquesne)	-93	Potomac River 3 (PEPCO)	-102
Albright 2 (FE-Allegheny Power)	-73	Niles 1 (FE-ATSI)	-109	Elrama 2 (Duquesne)	-93	Potomac River 4 (PEPCO)	-102
Albright 3 (FE-Allegheny Power)	-137	Niles 2 (FE-ATSI)	-108	Elrama 3 (Duquesne)	-103	Potomac River 5 (PEPCO)	-102
Rivesville 6 (FE-Allegheny Power)	-86	Crawford Coal 8 (COMED)	-319	Elrama 4 (Duquesne)	-171	Hall Branch (Dominion)	52
Willow Island 1 (FE- Allegheny Power)	-51	Crawford Coal 7 (COMED)	-213	Schuylkill 1 (PECO)	-166		

Variable resources are only counted partially for PJM resource adequacy studies. Both wind and solar initially use class average capacity factors, which are 13 percent for wind and 38 percent for solar. Performance over the peak period is tracked, and the class average capacity factor is supplanted with historic information. After three years of operation, only historic performance over the peak period is used to determine the individual unit's capacity factor. Biomass and hydro are counted at 100 percent of reported Existing-Certain because these resources are typically only fully utilized over the peak period of the day.

Capacity transactions amount to a net import of 2,220 MW. This import is composed of specific transactions for each participating generator. These transactions include the firm reservation rights for the generation and firm transmission rights to transfer the power across the PJM border. PJM has no reliance on outside assistance for emergency imports. No further coordination is necessary.

There are no high-priority transmission projects (not yet energized) that are needed to enhance or maintain reliability during the summer peak. There will be no transmission lines that will be taken out of service during the summer season that may create constraints in the assessment area. There are no significant transmission projects that involve upgrades to existing lines that have gone into service since summer 2012. There are no project delays or service outages for any transmission facilities (lines or transformers) that will impact reliability during the assessment period.

UVLS is utilized at two 138-kV buses in PJM. The relays trip approximately 25 MW of load and work in conjunction with other non-BES UVLS installations. The relays are installed to prevent voltage collapse or instability for one possible Type C (loss of two 345-kV lines) contingency and three Type D (two loss of right-of-way and one loss of substation—two voltage levels) contingencies. UVLS is not required for TPL[49] compliance, but is installed as a safety net to prevent voltage collapse or instability.

[49] http://www.nerc.com/page.php?cid=2|20.

SERC-E

Demand Projections

	Megawatts (MW)
Total Internal Demand	**37,289**
Load-Modifying DCLM	845
Load-Modifying Contractually Interruptible	1,032
Load-Modifying CPP with Control	14
Net Internal Demand	**35,398**

Resource Projections

	Megawatts (MW)
Net Firm Capacity Transfers	11
Existing-Certain & Future-Planned Capacity	49,911
Anticipated Resources	**49,922**
Existing-Other, Future-Other Capacity	2,840
Prospective Resources	**52,762**

Planning Reserve Margins

	Percent (%)
Anticipated Reserve Margin	**41.03**
Prospective Reserve Margin	**49.05**
NERC Reference Margin Level	**15.00**

SERC-E (which excludes utilities that are within the PJM) is a summer-peaking assessment area covering portions of North and South Carolina. The five BAs in this area are Alcoa Power Generating, Inc – Yadkin Division; Duke Energy Carolinas; Progress Energy Carolinas; South Carolina Electric & Gas Company; and South Carolina Public Service Authority. The SERC-E Assessment Area serves an estimated 4.4 million customers over an approximate area of 32,000 square miles. There have been no changes to the boundary over the past two years.

SERC-E reviewed and revised resource plans as needed, and the results indicate that the utilities are planning for reserves in the range of 12–15 percent for the 2013 summer season. These reserves will provide adequate and reliable power supply during the 2013 summer and do not fall below the NERC Reference Margin Level (i.e., assigned as 15 percent). As SERC-E is a predominantly fossil-fired area, utilities do not adhere to a regional target or reserve margin criteria. Utilities include renewables in their portfolios to meet the requirements of the Renewable Energy and Energy Efficiency Portfolio Standard (REPS) of North Carolina.[50]

A few entities are still assessing the effects of newly approved energy efficiency programs installed on the system in previous years. However, a variety of existing programs that support energy efficiency and demand response is offered to customers in this reporting area. Commitment to these programs is part of a long-term, balanced energy strategy for meeting future energy needs. Load response is modeled and measured by trending real-time load data from telemetry and statistical models that identify the difference between the actual and projected consumption absent the curtailment event.

Demand response and energy efficiency programs are treated as load-modifying, used to reduce the effects of summer peaks, and are considered part of the utilities' resource planning.

Companies within the SERC-E Assessment Area do not expect any notable issues that could lead to large-scale impacts to generator availability during the summer season. SERC-E projects that 50,893 MW of Existing-Certain capacity will be available to help meet peak summer demand. Entities have reported 2,531 MW of retirements prior to the 2013 summer, with no unit retirements expected during the summer. Approximately 3,099 MW of resources have been added since the prior season, and 57 MW are projected to be added during this summer.

There are 9 MW of new generator uprates in-service, and the same 64 MW of inoperable generation from 2012 remains out of service. Additionally, extended scheduled outages of 295 MW are expected during this summer.

Utilities took steps to coordinate and complete scheduled generator outages ahead of the peak demand period. Emergent generation unavailability will be coordinated with Transmission Operators (TOPs) using NERC's System Data Exchange (SDX) tools. Ongoing studies are underway to identify any generation and transmission limitations in the area.

Imports and exports within SERC-E Assessment Area are accounted for in the reserve margin. Most of the contracts in the area are for a 10-year period for the winter- and summer-peaking seasons. These transactions are external and internal to the Region and the assessment area. All purchases are backed by firm contracts for both generation and transmission and are not considered to be based on partial path reservations. Very few imports and exports are associated with Liquidated Damages Contracts in which the contracts are considered 100 percent "make-whole."

[50] http://www.ncuc.commerce.state.nc.us/reps/reps.htm.

To meet reserve margins during the 2013 summer, entities within the SERC-E Assessment Area do not rely on resources outside the Region for emergency imports, reserve sharing, assistance, or resources. Most entities within this area participate in Reserve Sharing Agreements (RSAs) with other Virginia–Carolinas (VACAR) utilities. Collectively, members of the VACAR RSA hold 1.5 times the largest single contingency (1,135 MW) in the VACAR RSA area to meet reserve margin targets necessary to respond to generation losses. The Reserve Sharing Group is expected to have adequate reserves throughout the 2013 summer operating period.

To ensure expected imports will be available during the time of peak demand, SERC-E communicates daily with neighboring entities, evaluating each member's load forecasts and expected system conditions. This coordination with neighboring assessment areas adheres to standard operating procedures.

SERC-E transmission projects are focused on the completion of facility construction ahead of the seasonal peaks. If unexpected delays occur that would result in reliability concerns, mitigating actions would be developed accordingly. Mitigating measures include redispatch of generation, operating procedures, SPSs, and other nonroutine operating arrangements. Companies within the SERC-E Assessment Area review and confirm completion dates and monitor the construction status of all projects on an ongoing basis. Transmission projects that address potential SOL or IROL issues commonly receive the highest priority for resources. Close coordination between construction management and operations planning ensures schedule requirements and completion requirements are well understood. Other TOPs in the SERC-E Assessment Area are also subject to the NERC recommendation and have not reported any negative transmission reliability or adequacy concerns.

A few construction projects that will increase transfer capabilities and enhance reliability in the SERC-E Assessment Area are planned and will be implemented in phases around seasonal peak load periods. In response to NERC recommendation to utilities entitled "Consideration of Actual Field Conditions in Determination of Facility Ratings" and to address the need to maintain and enhance reliability, the Progress Energy Corporation (PEC) is currently implementing a special transmission project. The entity is using Light Detection and Ranging (LiDAR) technology to analyze these conditions. The project is scheduled to be completed by the end of 2014. Any concerns that result from the project analyses will be addressed through an immediate remediation strategy.

The PEC is in the process of installing a new SVC to enhance voltage stability. Utilities indicated that they expect to deploy Phasor Measurement Units (PMUs) to be used in events analysis, in addition to plans to modernize the bulk communication infrastructure to enhance the overall electric system reliability.

Reserve margins are planned such that the loss of multiple units can be accommodated without threatening reliability. The VACAR RSA is in place to support recovery from such extreme events. Generation maintenance schedules are carefully studied and reviewed to ensure reliability concerns are addressed and to accommodate as much maintenance as possible prior to seasonal peak periods.

Utilities report that there are no environmental or regulatory restrictions projected within SERC-E that could impact reliability of the system. Lake levels are carefully managed—to the extent weather conditions and inflows permit—in order to mitigate hydro capacity limitations during seasonal peak load periods. There are no other unusual operating conditions anticipated that could impact reliability for summer 2013.

Entities within this subregion participate in SERC study groups that assess the subregion on a seasonal basis. The 2013 SERC Near-Term Study Group (NTSG) Summer Reliability Report is currently in progress. Entities also study potential issues, report results, and coordinate solutions through their bilateral reliability agreements. The effect of lower gas prices on generation dispatch and the resulting changes in transmission power flow continues to be of importance; planning and operating studies are ongoing to analyze these changes. The transmission system continues to be capable of handling changes in power flows.

SERC-N

Demand Projections

	Megawatts (MW)
Total Internal Demand	**44,505**
Load-Modifying DCLM	198
Load-Modifying Contractually Interruptible	1,007
Load-Modifying Load as a Capacity Resource	309
Net Internal Demand	**42,991**

Resource Projections

	Megawatts (MW)
Net Firm Capacity Transfers	-1,352
Existing-Certain & Future-Planned Capacity	53,155
Anticipated Resources	**51,803**
Existing-Other, Future-Other Capacity	1,936
Prospective Resources	**53,739**

Planning Reserve Margins

	Percent (%)
Anticipated Reserve Margin	**20.50**
Prospective Reserve Margin	**25.00**
NERC Reference Margin Level	**15.00**

SERC-N (which excludes utilities that are within the PJM) is a summer-peaking area covering most of Tennessee and Kentucky, northern Alabama, northeastern Mississippi, and small portions of Georgia, Iowa, Missouri, North Carolina, Oklahoma, and Virginia. There are five BAs in SERC-N: Associated Electric Cooperative, Inc. (AECI), Constellation Energy Control and Dispatch, LLC (CECD), Electric Energy, Inc. (EEI), LG&E and KU Services Company (as agent for Louisville Gas and Electric Company and Kentucky Utilities Company) (LG&E KU), and Tennessee Valley Authority (TVA). The SERC-N area serves an estimated 10.1 million customers over approximately 88,400 square miles.

***SERC-N Boundary Changes**: East Kentucky Power Cooperative (EKPC), which was reported in the 2012 summer assessment in SERC-N, has joined PJM effective June 1, 2013, and is no longer reported in this area. On December 19, 2013, Entergy will join MISO. This has the potential to significantly change flows between these Regions, as well as loop flows through adjoining Regions. Discussions between parties are continuing and studies are being undertaken.*

The SERC-N Assessment Area is projecting adequate planning reserve margins for the 2013 summer. Utilities in SERC-N do not adhere to a regional target or reserve margin criteria, and because this is a predominantly fossil-fueled region, NERC assigns a 15 percent reserve margin target for the assessment. Entity planning considers reserves in the range of 12–15 percent to be adequate for the upcoming summer. Actual reserves for 2013 are anticipated to be significantly higher, assuming typical weather and operating conditions. This is due to past system development and the weakening of customer growth and energy usage in the area. No potential issues or circumstances that could result in substantial changes from the assessment projections have been identified.

Apart from modest decreases in load growth and demand in the assessment area, utilities in SERC-N report that there have not been any significant changes in the demand forecast since summer 2012. Small changes reported in demand are mostly related to incentives for customers in controlling their load levels, lower than expected load growth, and EKPC's move to PJM. Seasonal weather changes and economic outlooks are incorporated in the load level forecasts, and no significant changes have been reported that would affect the demand forecasts.

Energy efficiency and conservation is accounted for in the load forecast in SERC-N. While LG&E KU LSE's Demand Conservation program is considered load-modifying, TVA considers these programs as a resource. LG&E KU LSE incorporates energy and demand savings related to energy efficiency and conservation into the load forecast. A direct load control program and interruptible load contracts may be used to reduce peak demand. The direct load control program targets residential and commercial customers and is designed for summer operation. The Demand Conservation program is layered into the hourly demand forecast for peak hours in a manner that is consistent with the way the company dispatches these programs in practice.

TVA's deployment of energy efficiency and conservation continues to exceed annual goals; new program designs are being studied and placed into the pilot stage. Dispatchable demand response is proceeding at a slower pace than projected due to issues with contractual design and local power company funding constraints. Third-party delivered demand response and participation in dispatchable pricing products continues to grow, as does the deployment of dispatchable voltage regulation. A pilot design for demand response for ancillary services is currently in development and will be deployed in the summer of 2013.

The LG&E KU LSE currently has nine residential and three commercial energy efficiency programs that provide demand and energy savings. Programs available to residential customers are summer load control, lighting, heating, ventilation, and air conditioning (HVAC) tune-ups, new home construction, home energy analysis, low-income weatherization, appliance incentives, refrigerator removal, and behavioral marketing. Programs available to commercial customers are summer load control, HVAC tune-ups, and building energy analysis and incentives. These programs, plans, and goals recognize that improving peak demand reduction can help slow demand growth in a cost-effective manner while addressing air pollution and global climate change.

Utilities in SERC-N do not anticipate any issues that could lead to a significant impact to generator availability during the summer season. Since the prior season, 71 MW have been retired, while 4 MW of uprates have been added. The planned idling and retirement of generating plants—in particular coal plants under agreement with the EPA and other plants—will require transmission system improvements to be completed within appropriate schedules. Transmission plans include consideration for system upgrades that will be required with changes to NERC planning standards.

Variable resources are limited within this area; therefore, no changes in planning procedures are needed. No changes are expected in the river flow and reserve levels for hydro generation. Generator Owners (GOs), Generator Operators (GOPs), and BAs directly report on-peak capacity values. Typically, wind capacity at peak is estimated as a derated percentage of nameplate, which is 12 percent for TVA.

Any scheduled outage for generation units in the area is coordinated with the TOPs through procedures in Seams agreements with neighboring RTOs and RCs, and the TOs are notified immediately when outages are scheduled.

Imports within SERC-N utilities are backed by firm contracts for both generation and transmission and do not include make-whole provisions. Imports and exports have been accounted for in the reserve margin calculations for the reporting area. Most of the contracts in the area are agreements for a 10-year period for the winter- and summer-peaking seasons. Although not reported, import assumptions are not based on partial path reservations.

Contingency reserves and emergency imports are obtained from a variety of resources, such as MISO (under Attachment RR of the MISO ancillary services market tariff), PJM, and the TEE Contingency Reserve Sharing Group (TCRSG). The TCRSG consists of three internal BAs and is intended to provide immediate contingency response. This enables the group to comply with the Disturbance Control Standard (DCS) and assist in preventing curtailment of native load. Listed below are major projects in the TVA area that are planned to be in-service to meet the 2013 summer peak demands:

- West Ringgold #2 230/115-kV transformer: Replaced a failed 200-MVA transformer. This project restored the system back to normal.
- Montgomery #2 500/161-kV 1300-MVA transformer: This prevents contingency loss of the Montgomery #1 transformer that would cause line overloads and voltage violation in the Montgomery area.
- Clay 500/161-kV substation 1300-MVA 500/161-kV bank: This will support central Mississippi and prevent overloading of the West Point and Lowndes 500/161-kV transformer banks for the contingency loss of either.
- Catalpa Creek 161-kV second feed: This project will consist of constructing a new switching station and constructing new lines or rerouting existing lines into it. This will provide additional area capacity and avoid contingency low voltage. Catalpa Creek, Modified Fluff, and Golden Triangle all have low voltage for N-1 scenarios.
- Gallatin – Angeltown 161-kV transmission line: This 20-mile line and new switching station will prevent Gallatin FP – Lafayette line overloads and low voltage at the East Gallatin 161-kV stations for contingency loss of the Gallatin Primary – Portland line.
- Goodlettsville 161-kV substation: This project will install new structures and conductors to connect the Goodlettsville loop into the Springfield – North Nashville 161-kV transmission line to prevent undervoltage contingencies at Goodlettsville, Bethel Road, and White House.

Other transmission projects in the SERC-N Assessment Area that would increase transfer capability, and thereby increase the reliability of the system, include:

- LG&E KU is planning an interconnection project, which is a new 161/138-kV substation between the KU system and Big Rivers Electrical Cooperative in southwestern Kentucky. This is scheduled for June 2013.
- AECI is constructing a new West New Madrid 500/345-kV substation. This new station is located on the New Madrid – Dell 500-kV transmission line approximately a quarter mile from New Madrid.

System conditions may necessitate the use of local area generation redispatch or the reconfiguration of transmission elements to alleviate anticipated next contingency overloads. Entities also have the option to invoke NERC Transmission Loading Relief (TLR) procedures in scenarios that are not easily remedied by local area solutions.

The majority of utilities in SERC-N reported that there are no existing conditions in the system that require UVLS protection devices. The few UVLS schemes that exist in the system (covering approximately 380 MW) are not anticipated to be needed. Their major role is to protect the system in case of a wide-area undervoltage event.

Many entities within the area perform routine operating studies (bi-annual load forecast study; monthly, weekly, and daily operational planning efforts; annual assessment of summer peak and temperature, etc.) to assess their systems. These studies take weather, demand, and unit availability into consideration to help to address any risks. Based on the results of these studies, entities do not anticipate operational problems.

Due to the small amount of variable resources in the area, no changes in operating procedures are needed. Operation guidelines are in place to mitigate any impact of the few variable resources in SERC-N. Variable resources can be curtailed for reasons of system reliability (i.e., line loading relief and minimum generation limits).

Due to limited demand response in the area, reliability concerns associated with demand response resources are not of concern during the summer for the majority of utilities in the SERC-N. A primary concern in deployment of demand response resources is the restrictions that exist regarding how many days in succession these resources can be called.

Utilities are aware of potential environmental and regulatory restrictions for the upcoming summer. In response, some units have been derated due to higher-than-expected river temperatures and lower water flows. Barge pumps have been deployed to help mitigate water flow and cooling problems.

Capacity reserves are expected to be well above 15 percent, meaning thermal derates should not impact system reliability. There are no unusual operating conditions anticipated that could impact reliability for the summer.

Entities within this subregion participate in SERC study groups that assess the subregion on a seasonal basis. The 2013 SERC NTSG Summer Reliability Report is currently in progress. In addition, entities study potential issues, report results, and coordinate solutions to potential issues through their bilateral reliability agreements. The effect of lower gas prices on generation dispatch and the resulting changes in transmission power flow continue to be noted. Planning and operating studies are ongoing to analyze these changes. The transmission system continues to be capable of dealing with these changes in power flows.

SERC-SE

Demand Projections

	Megawatts (MW)
Total Internal Demand	**48,056**
Load-Modifying DCLM	584
Load-Modifying Contractually Interruptible	1,361
Load-Modifying Load as a Capacity Resource	76
Net Internal Demand	**46,035**

Resource Projections

	Megawatts (MW)
Net Firm Capacity Transfers	-1,161
Existing-Certain & Future-Planned Capacity	64,638
Anticipated Resources	**63,477**
Existing-Other, Future-Other Capacity	1,876
Prospective Resources	**65,353**

Planning Reserve Margins

	Percent (%)
Anticipated Reserve Margin	**37.89**
Prospective Reserve Margin	**41.96**
NERC Reference Margin Level	**15.00**

SERC-SE is a summer-peaking area covering all or portions of Alabama, Georgia, Mississippi, and Florida. The four BAs in this area are PowerSouth Energy Cooperative (PowerSouth), South Mississippi Electric Power Association (SMEPA), Southeastern Power Administration (SEPA) and Southern Company Services, Inc. (Southern). SERC-SE serves an estimated 14.2 million customers over an approximate area of 120,000 square miles. There have been no changes to the boundary over the past two years.

The SERC-SE Assessment Area is projecting adequate planning reserve margins for the 2013 summer. Utilities do not adhere to any regional or reporting area targets or reserve margin criteria. However, Georgia requires that SERC-SE maintain at least 13.5 percent near-term (less than 3 years) and 15 percent long-term (3 years or more) reserve margin levels for IOUs. Most entities use the NERC Reference Margin Level of 15 percent to ensure reliability and indicate that projected reserve margins remain above this target, and NERC assigned this level to the SERC-SE Assessment Area for this report. The addition of resources and the expiration and acquisition of firm purchase contracts are contributing factors to adequate margins. Assuming typical weather and operating conditions, 2013 reserves are anticipated to be adequate due to reductions in load forecast resulting from the recent recession and economic downturn.

Key factors leading to a slightly decreasing demand forecast are mostly related to economic uncertainties due to the recession and slow recovery. Low short-term growth scenarios were used as the basis for developing the demand and energy forecasts. Additionally, modifications were made to the demand forecast based on wholesale customer changes and mild winter weather. There were no changes or enhancements reported for load forecasting methods used by the assessment area since the 2012 summer assessment.

Energy efficiency and conservation is reflected in the load forecast using historic data. Currently the majority of utilities in SERC-SE consider demand response as a load-modifying component. Southern considers nondispatchable (passive) demand response as a load-modifying component and dispatchable (active) DSM programs as a capacity resource (supply-side).

Since the prior assessment, PowerSouth has enhanced and expanded their H_2O plus program to reduce demand during high energy use. In conjunction with adding a new energy efficiency program in July 2012 that provides rebates as incentives for consumers to purchase higher efficiency heating, cooling, and lighting devices, PowerSouth is developing a program that would enable consumers to finance residential energy efficiency improvements.

Since the prior season, 50 MW of resources have been added and 2 MW have been retired within the SERC-SE area. No resources will be added during the 2013 summer season, and no maintenance outages are scheduled. SMEPA has purchased and now owns the existing Batesville Generation Facility.

Utilities within SERC-SE report firm imports and exports, which are accounted for in the reserve margin calculations for the reporting area. The majority of the contracts in the area are firm agreements that typically last five or more years. All imports and exports were reported to be backed by firm contracts for both generation and transmission.

Reporting entities maintain emergency reserve sharing agreements with organizations such as the SPP Reserve Sharing Group and entities internal to the area (approximately 250 MW). Other contract agreements with neighboring utilities provide capacity for outages of specific generation. Total emergency MW from these imports were not reported but are available as needed. Overall, entities are not dependent on outside imports or transfers to meet load demands.

Apart from PowerSouth, which installed a new 115-kV capacitor bank at Gulf Shores' substation, no other utilities in SERC-SE have reported additions of any significant substation equipment for the 2013 summer.

Southern is the only utility in SERC-SE that uses UVLS schemes but does not rely on them for maintaining reliability during the summer. Southern has almost completed the installation of smart meters throughout its service territory; full distribution will be complete by the end of 2013. Smart meters allow for more accurate real-time data, which enables enhanced demand management and helps isolate grid problems for faster restoration. PowerSouth has reported they are replacing some existing electromechanical devices, such as protective relays. The replacement of electromechanical devices often provides enhanced information and real-time monitoring of the devices' health.

Although most utilities are not affected by any environmental and regulatory restrictions, numerous operating limits related to air and water quality are in place due to federal and state regulations. These restrictions are continually managed in the daily operation of the system. Southern runs hydroelectric units, in cooperation with the Army Corps of Engineers, to maintain water levels and river flow as well as system reliability. The organization is actively pursuing improvements and retrofits necessitated by new environmental regulations. Extensive coordination efforts are underway to ensure that all the necessary improvements can be completed without sacrificing the reliability of the system in the interim.

Southern coordinates any planned work with potential interface impacts with its first-tier neighbors on a weekly and quarterly basis. Significant outages in neighboring areas are reviewed along with internal outages to ensure reliability can be maintained. For the 2013 summer, Southern does not anticipate any issues in neighboring areas that would significantly impact SERC-SE operations.

SERC-W

Demand Projections	
	Megawatts (MW)
Total Internal Demand	**25,763**
Load-Modifying Contractually Interruptible	534
Net Internal Demand	**25,229**

Resource Projections	
	Megawatts (MW)
Net Firm Capacity Transfers	-1,096
Existing-Certain & Future-Planned Capacity	37,599
Anticipated Resources	**36,503**
Existing-Other, Future-Other Capacity	1,086
Prospective Resources	**37,589**

Planning Reserve Margins	
	Percent (%)
Anticipated Reserve Margin	**44.69**
Prospective Reserve Margin	**48.99**
NERC Reference Margin Level	**15.00**

SERC-W (including SPP RC entities registered in SERC) is a summer-peaking assessment area covering portions Arkansas, Louisiana, Mississippi, and Texas. The 11 registered BAs encompass approximately 91,000 square miles and a population of 5.3 million people. Significant footprint changes will be completed by December 2013. In 2014, Entergy will be reported by MISO and it is anticipated that several of the remaining entities within SERC-W will also join MISO.

Reserves are not projected to fall below the NERC Reference Margin Level of 15 percent during the 2013 summer season. Utilities do not adhere to a regional or reporting area target or reserve margin criteria. The presence of existing and owned resources and limited and long-term purchase contracts are contributing factors to adequate margins. Potential unit deactivations and anticipated unit outages are taken into account to meet the target reserve margin when developing plans for the season.

The key factor leading to demand forecast changes is related to the slow economic recovery. Typical weather conditions are used to forecast the load shapes for the residential, commercial, and governmental classes. Since the 2012 summer assessment, enhancements were made to the use of hourly load profiles in the forecast.

For the utilities with demand response, this resource primarily consists of commercial and industrial load on interruptible rates, and it is considered as a load-modifying resource that differentiates total and firm load requirements.

No resources have been retired since the winter assessment was performed. A 10-MW biomass facility is scheduled to come into service during the summer period, and 293 MW of uprates will be in place prior to the summer period. A 93-MW unit will be retired and converted to a synchronous condenser. For the summer period, 965 MW have been reported as inoperable. No other resources will be added during the 2013 summer season. Currently entities in SERC-W are studying potential approaches for incorporating variable resources into their planning processes. An energy forecasting package is used to predict wind farm output given meteorological data collected at the wind farms.

There are interchange agreements with neighboring control areas to ensure needed imports under critical peak demand events are available. Under these agreements, real-time and day-ahead personnel are in place to coordinate imports if necessary. From a transmission perspective, Entergy coordinates with neighboring areas to ensure that adequate transfer capabilities will be available for the upcoming season's expected imports. This is accomplished via participation in intra-regional (SERC NTSG) and inter-regional Eastern Interconnection Reliability Assessment Group (ERAG) and Midwest Reliability Organization-ReliabilityFirst-SERC WestSouthwest Power Pool (MRSwS) working groups and coordination studies. The preliminary results of the *NTSG 2013 Summer Reliability Study* indicate that additional import capability is available on all paths studied.

A three-phase project is currently underway to construct a 230-kV transmission line and install a 230–115-kV autotransformer in lower Plaquemines Parish of southeast Louisiana. The project will provide an additional transmission source into the area to help support the underlying area load during a single contingency event. Loss of a single 115-kV transmission element will result in a long radial configuration causing low voltages and elements to exceed their thermal capability. Without this improvement, and due to the radial configuration during the contingency, local nonconsequential load loss in the extreme southeast Louisiana area will be required in order to eliminate any thermal and voltage violations. Phases 1 and 2 of this project have been successfully completed; however, routing issues and landowner opposition are expected to delay the final phase. The project was targeted for completion prior to the summer of 2013; right-of-way issues are expected to delay the completion of the project into the second quarter of 2014 or beyond.

Entergy is currently constructing an interconnection with a new generator in the Amite South region of southern Louisiana. There are no other significant transmission projects that involve upgrades to the existing transmission lines scheduled to be placed in service prior to the upcoming 2013 summer season.

Entergy plans to modify its existing UVLS scheme in the western area of Texas to replace its existing SCADA-based scheme with a microprocessor relay-based scheme.

Entergy has adopted an automated critical clearing time methodology by using POM-TS software to automatically generate the critical clearing times for generating units, helping to analyze stability limits on the system under planning and operational conditions and determine the stability margin on the system. Entergy is using optimal power flow (OPF) for reactive power planning and management, helping in the assessment of reactive power needs of the system. Also, Entergy is planning to deploy a total of 41 PMUs to monitor abnormal system conditions and disturbances. The data obtained from PMUs is used in model validation and investigating corrective actions. Louisiana Generating, LLC is systematically upgrading communications with relay devices. This will assist in quickly evaluating events and system restoration.

SPP

Demand Projections

	Megawatts (MW)
Total Internal Demand	**54,168**
Load-Modifying DCLM	49
Load-Modifying Contractually Interruptible	942
Net Internal Demand	**53,177**

Resource Projections

	Megawatts (MW)
Supply-Side DCLM	88
Supply-Side Contractually Interruptible	319
Net Firm Capacity Transfers	2,374
Existing-Certain & Future-Planned Capacity	71,350
Anticipated Resources	**74,131**
Existing-Other, Future-Other Capacity	83
Prospective Resources	**74,213**

Planning Reserve Margins

	Percent (%)
Anticipated Reserve Margin	**39.4**
Prospective Reserve Margin	**39.6**
NERC Reference Margin Level	**13.60**

SPP is a NERC RE that covers 370,000 square miles and encompasses all or part of Arkansas, Kansas, Louisiana, Mississippi, Missouri, New Mexico, Oklahoma, and Texas. The SPP RE reporting boundary includes the Midwest Reliability Organization (MRO) Regional Entity members that are part of the SPP Planning Coordinator, which consists of the Nebraska entities. SPP's boundary consists of 20 BA Areas including 48,368 miles of transmission line, 915 generating plants, and 6,408 transmission-class substations.

***SPP Footprint Changes**: The SPP RC is coordinating with Entergy, CLECO, Lafayette Utilities System, Louisiana Energy and Power Authority, and MISO for the transition of those entities to the MISO Reliability Coordination footprint and eventually into the MISO BA Area and the MISO Market. The transition to the MISO RC footprint is scheduled to take place June 1, 2013, and is not expected to impact the 2013 SPP RE summer assessment. The transition of these entities to the MISO BA and Market is expected to occur in December 2013. This transition into the MISO Market and BA is expected to result in significant changes in flows as compared to what has historically been observed and managed using existing congestion management processes. SPP and MISO are evaluating ways to mitigate reliability concerns from these operational changes by improving how flows are accounted and reviewing congestion management techniques for potential enhancements. These additional coordination activities are expected to continue beyond the summer season to ensure the continued reliable operation of the interconnected transmission system. The map above represents the current SPP boundary for this assessment.*

SPP's Reference Margin Level is 13.6 percent. SPP is projected to have an adequate reserve margin of 38.8 percent for the 2013 summer season, well above SPP's minimally required reserve margin of 13.6 percent.

A total of 342 MW of capacity additions will be added over the summer. According to the SPP demand forecast, projected Total Internal Demand has increased from 54,051 MW to 54,168 MW since summer 2012—an annual growth rate of 0.2 percent. [51] There are no identified potential issues or circumstances that could result in substantial changes from these projections.

The 2012 summer actual peak demand was higher than the forecasted peak demand due to extremely hot weather across the SPP boundary. The weather and operational forecast for SPP is expected to be near normal for the 2013 summer. SPP's annual growth rate is consistent with the 2012 assessment numbers.

SPP 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 SPP.

Several new generation units have been added to the SPP fleet since the 2012 summer assessment, including 308 MW of wind, 552 MW of gas, and 168 MW of coal. SPP projects 338 MW of Future-Planned resources will be added by September 2013.

[51] Beginning with the 2012/2013 winter assessment, SPP reported a coincident Total Internal Demand forecast based on modeling data submitted by individual entities. Previously, SPP reported a non-coincident Total Internal Demand forecast based on aggregated member data. .

No new uprates have been reported since the 2012 summer. Approximately 2,263 MW of generation are expected to be out of service for scheduled maintenance during the 2013 summer timeframe; the units are not expected to come back into service until after the summer season. [52]

On-Peak Capacity Transactions are not considered a significant impact to operational reliability in SPP due to the volume of internal generation capacity available. SPP RE members, along with some members of the SERC Region, jointly participate in a Reserve Sharing Group.

Since SPP RE has an abundant generation supply and a robust transmission system, significant long-term generator outages are not a potential concern at this time. There are no short-term concerns about the use and growth of demand response programs being unresponsive or unavailable, as SPP RE does not rely on these programs for resource adequacy. Generator outages due to environmental retrofits are not expected to cause any reliability concerns due to the abundance of supply. SPP continues to perform operational studies, twice annually, looking ahead weekly through the upcoming four years to identify 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 summer period.

SPP RE has one SPS that was implemented in fall of 2012 for reliability purposes and is expected to be in-service for three years. Upon loss of either the Woodward EHV – Tatonga 345-kV line or the Tatonga – Northwest 345-kV line, the SPS will trip the Centennial Wind Farm if a 138-kV line from Woodward to Wind Farm Switching Station becomes overloaded. This protection system is expected to be in place until construction is complete on the expansion of the Woodward EHV substation connecting a second 345/138-kV transformer as well as new 345-kV lines to Hitchland, Tuco, and Thistle. These additional upgrades are expected to be complete sometime in 2015.

[52] Beginning with the 2012/2013 winter assessment, SPP reported a higher Existing-Certain forecast, compared to previous assessments due to a methodology change. Instead of aggregating individual entity-reported data, SPP RTO is now using the SPP Model Development Working Group (MDWG) model as a base case for all current year capacity resources, and will then subtract out all the reported outages. The use of the MDWG data set provides a consistent source of data for load, generation, and transmission topology for use in the NERC reliability assessments and SPP's transmission planning studies.

TRE-ERCOT

Demand Projections	
	Megawatts (MW)
Total Internal Demand	**67,606**
Load-Modifying Contractually Interruptible	483
Load-Modifying Load as a Capacity Resource	1,222
Net Internal Demand	**65,901**

Resource Projections	
	Megawatts (MW)
Net Firm Capacity Transfers	281
Existing-Certain & Future-Planned Capacity	74,105
Anticipated Resources	**74,386**
Prospective Resources	**74,386**

Planning Reserve Margins	
	Percent (%)
Anticipated Reserve Margin	**12.88**
Prospective Reserve Margin	**12.88**
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 serving about 23 million electricity consumers. The ERCOT Region is an electric interconnection that is located entirely in the state of 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 summer season peak of 66,548 MW that occurred on June 26, 2012, was 1,757 MW below the 2011 summer season peak. The forecasted Total Peak Demand for 2013 summer season is 67,998 MW. The growth rate from summer 2012's forecasted peak load (66,195 MW) to summer 2013's forecasted peak load based on the 50/50 average weather conditions is 2.72 percent.

The target reserve margin level (referred to in this assessment as the NERC Reference Margin Level) for ERCOT is 13.75 percent—the same value in the 2012 Summer Assessment. The ERCOT minimum target reserve margin is based on loss of load events (LOLEV) analysis of no more than 0.1 events per year. ERCOT stakeholders are currently reviewing a recently completed loss of load study that supports the target reserve margin determination; a final decision by the ERCOT Board is expected later this summer.

The Anticipated Reserve Margin is expected to fall below the ERCOT target reserve margin level during August. This is due to the insufficient addition of generation capacity, which has not kept pace with load growth, a condition primarily driven by depressed wholesale electricity prices. ERCOT has an energy-only market design, requiring developers of new generation to base revenue expectations primarily on long-term locational market prices. Delays in thermal generation development can potentially result from low market prices (due to low natural gas prices and significant wind generation development); reduced availability of capital for financing; and uncertainty associated with changing environmental regulations. PUCT has increased the system-wide offer cap to encourage investments in new capacity. Additionally, ERCOT revised its protocols so that additional capacity can be procured from existing resources if needed. ERCOT is working with the PUCT and market participants to ensure that all potential resources, including possible recall of mothballed units and increased demand response programs, are made available during the summer. PUCT has several proceedings related to resource adequacy and has taken comments from ERCOT, its stakeholders, and the public into consideration.[53] ERCOT is also working through its stakeholder committee process to study and facilitate revisions to ERCOT market protocols and pricing rules intended to bolster reserve margins. Several proposed initiatives focus on demand response resources, such as revising market rules to stimulate greater participation of weather-sensitive loads in the Emergency Response Service (ERS) program.

The planning reserve margin based on Existing-Certain capacity is projected to be 11.31 percent and the Anticipated Reserve Margin and the Prospective Reserve Margin is 12.88 percent for this summer. These are below the minimum 13.75

[53] PUCT Docket 40000 can be found at: http://interchange.puc.state.tx.us/WebApp/Interchange/application/dbapps/filings/pgControl.asp?TXT_CNTRL_NO=40000&TXT_STYLE=&TXT_UTILITY_TYPE=A&TXT_D_FROM_STYLE=40000&TXT_D_TO_STYLE=40000.
PUCT Docket 41060 can be found at: http://interchange.puc.state.tx.us/WebApp/Interchange/application/dbapps/filings/pgControl.asp?TXT_UTILITY_TYPE=A&TXT_CNTRL_NO=41060&TXT_ITEM_MATCH=1&TXT_ITEM_NO=&TXT_N_UTILITY=&TXT_N_FILE_PARTY=&TXT_DOC_TYPE=ALL&TXT_D_FROM=&TXT_D_TO=&TXT_NEW=true.
PUCT Docket 41061 can be found at: http://interchange.puc.state.tx.us/WebApp/Interchange/application/dbapps/filings/pgControl.asp?TXT_UTILITY_TYPE=A&TXT_CNTRL_NO=41061&TXT_ITEM_MATCH=1&TXT_ITEM_NO=&TXT_N_UTILITY=&TXT_N_FILE_PARTY=&TXT_DOC_TYPE=ALL&TXT_D_FROM=&TXT_D_TO=&TXT_NEW=true.

percent target reserve margin level for ERCOT. ERCOT may need to declare EEAs during this summer, if there are higher-than-normal forced generation outages or if record-breaking weather conditions similar to the summer of 2011 lead to higher-than-expected peak demands. Insufficient reserves during peak hours could lead to increased risk of entering emergency operating conditions, including the possibility of curtailment of interruptible loads and even rotating outages of firm loads.

Sharyland Utilities purchased Cap Rock Electric Cooperative and has begun to move load from SPP into ERCOT. There are no boundary changes associated with this load and transmission assets transfer. This load is included in the summer forecast.

The long-term load forecast is now based on a daily energy model. The forecasted daily energy is allocated to all hours of the day via a neural network model. The previous forecast was based on a monthly energy model with forecasted monthly energy allocated to all hours of the month via a neural network model.[54]

Energy efficiency projections are based on the targets outlined in Texas Senate Bill 1125[55] and in Utilities Code Section 39.905 (b-4). Utility savings—as measured and verified by an independent contractor—have exceeded utility goals, proving that meeting these targets is a reasonable planning assumption. The demand projections also assume that 50 percent of the targets are already included in the load forecasting model. The targets are applied to the entire ERCOT service territory.

Demand response programs are counted as load-modifying resources in ERCOT. ERCOT also has 1,222 MW of Load Resources (LRs) providing ancillary services that are contractually committed to ERCOT during summer peak hours and are categorized as a capacity resource. ERCOT also has ERS, a 10-minute demand response and distributed generation service, designed to be deployed in the late stages of a grid emergency, prior to shedding involuntary Firm load. The ERS represents Load-Modifying Contractually Interruptible (Curtailable) Demand. Since July 2012, ERCOT has been piloting a demand response program that allows participants a 30-minute ramp period, resulting in some growth in the service. Additionally, ERCOT is seeking approval from its Board to allow the pilot project for weather-sensitive loads to participate in ERS. Measurement and verification procedures for these programs are defined in the Performance Monitoring section of the ERCOT Protocols.[56]

In addition to these demand response programs, several Transmission Service Providers (TSPs) have individual contractual programs with loads that can respond to instructions to reduce total energy usage. These programs are expected to attract approximately 250 MW of additional demand response capacity this summer and are subject to concurrent deployment with existing ERCOT demand response programs, pursuant to agreements between ISO and the TSPs. Additionally, based on market participant projections, ERCOT will likely to see an increase in ERS participation by distributed generation resources.

At this time, there are no impending drought concerns for the upcoming summer that would reduce ERCOT generating capability.[57] ERCOT continues to monitor the ongoing drought conditions. Reservoir levels are not expected to drop below power plant physical intake limits during summer 2013.[58]

One large thermal generation unit that was out of service for maintenance beginning in January 2013 returned to service near the end of April 2013. New generation capacity of 1,032 MW that consists of 60 MW of wind generation (with nameplate capacity of 690 MW), 898 MW of coal generation, and 74 MW of gas generation is expected to assume commercial operation by this summer.

ERCOT currently uses 8.7 percent as the Effective Load Carrying Capacity (ELCC) contribution of wind generation. This capacity contribution was approved by the ERCOT Board in November 2010. The ELCC of wind generation is determined as part of the evaluation of the target reserve margin for the ERCOT Region. 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. In anticipation of greater solar generation prevalence, ERCOT is developing an estimate of the solar ELCC. For hydro, the peak capacity contribution is 88 percent based on a new methodology being considered by stakeholders that uses the average capacity available during the 20 highest peak load hours over each of the preceding three years. No on-peak capacity value is calculated for biomass generation.

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[54] Methodology of ERCOT Load Forecast is located at: http://www.ercot.com/content/gridinfo/load/2013_Long-Term_Hourly_Peak_Demand_and_Energy_Forecast.pdf.

[55] Texas Senate Bill 1125 language can be found at: http://legiscan.com/TX/text/SB1125/2011.

[56] http://www.ercot.com/content/mktrules/nprotocols/current/08-120112_Nodal.doc.

[57] http://www.ercot.com/content/meetings/board/keydocs/2013/0319/5_Spring_and_Summer_Weather_Outlook.pdf.

[58] ERCOT held a workshop discussing drought concerns: http://www.ercot.com/calendar/2012/02/20120227-OTHER. Additional ongoing research is being done of the drought issue: http://www.ercot.com/content/meetings/board/keydocs/2013/0319/5_Spring_and_Summer_Weather_Outlook.pdf.

The ERCOT Region is a separate Interconnection with only asynchronous ties to SPP and Mexico's Comision Federal de Electricidad (CFE). As such, ERCOT does not share reserves with other Regions. There are two asynchronous ties between ERCOT and SPP with a total of 820 MW of transfer capability and three asynchronous ties between ERCOT and Mexico with a total of 280 MW of transfer capability. The ERCOT Region does not rely on external resources to meet demand under normal operating conditions; however, under emergency support agreements, it may request external resources for emergency services over the asynchronous ties or block transfer of discrete loads.

For summer 2013, ERCOT included 458 MW of imports from SPP and 140 MW from CFE. Of the imports from SPP, 48 MW are tied to a long-term contract for a purchase of firm power from specific generation. The remaining imports of 410 MW from SPP and 140 MW from CFE represent half of the asynchronous tie transfer capability, included to reflect emergency support arrangements. SPP members own 317 MW located in the ERCOT Region, resulting in a firm export of that amount to SPP.

Energizing parts of the Competitive Renewable Energy Zone (CREZ) system (Brown – Killeen double circuit 345 kV and West Shackelford – Sam Switch/Navarro double circuit 345 kV) significantly increases the ERCOT West – North transfer limits. Five new 345/138-kV autotransformers, with a total of 2,550-MVA capacity, are also scheduled to be energized by this summer.

The most significant congestion on the ERCOT system in 2012 was experienced in the Odessa North area (west Texas) due to the unprecedented growth in load from oil and natural gas exploration. Multiple transmission upgrades scheduled to be completed prior to this summer are expected to reduce the congestion and improve the reliability in the west Texas area.

A stability assessment indicated that an N-1-1 contingency (loss of two 345-kV circuits) in southern Texas can potentially depress the voltage below 0.8 per unit if it occurred during peak load conditions. An existing UVLS scheme with less than 300 MW of load in the area can improve the voltage recovery to prevent a cascading event. The Lobo – North Edinburg 345-kV line project is planned to be in-service by 2016 to resolve this issue.

The ERCOT Board approved a pilot project to test Fast-Responding Regulation Service (FRRS), which is a form of ancillary regulation service that requires resources to respond within 60 cycles of an instruction or triggering event. One purpose of the FRRS pilot project is to determine if FRRS can improve ERCOT's ability to arrest frequency decay during unit trips and reduce the need for Regulation Service. The FRRS pilot project began on February 25, 2013.[59] Duke Energy Renewable's 36-MW battery storage project at the Notrees Wind Farm, which became operational in December 2012, currently participates in the FRRS pilot program.

A Voltage Stability Screening Analysis, conducted by ERCOT, to assess reactive power needs on the ERCOT system for the upcoming summer will be completed before the start of the summer season. The network's response to NERC Category A, B, and selected C contingencies test will be documented. ERCOT uses established operational procedures related to variable resources during the 2013 summer season. ERCOT is performing its seasonal Voltage Profile study and reviewing the Congestion Mitigation Plans for summer 2013.

At the beginning of March 2013, ERCOT implemented the Large Ramp Alert System (ELRAS)—a wind power forecasting system—to allow ERCOT ISO system operators to identify and take appropriate action when wind resource schedules do not track expected changes in wind production. ERCOT also implemented operational procedures that use a wind ramp forecasting tool to provide a probabilistic assessment of the magnitude and likelihood of a significant change in aggregate wind output over upcoming operating periods. In addition, ERCOT evaluates the impact of increased installed wind generation on ancillary services requirements on an ongoing basis.[60]

ERCOT procures Load Resources across all hours to address system conditions at all times, not just during peaks. ERCOT's monitoring and testing programs ensure that these Load Resources will perform when called on.[61] The status of Load Resources providing ancillary services is monitored in real time via two-second telemetry. ERCOT also procures ERS loads. These resources are monitored using after-the-fact metering and are subject to payment reductions and suspension from the program for failing to meet availability requirements.

ERCOT is reviewing congestion mitigation plans and working with the TOs within the ERCOT Interconnection to ensure all foreseeable congestion mitigation plans are reviewed and updated prior to summer.

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[59] http://www.ercot.com/content/mktrules/pilots/frrs/FRRS_Governing_Document_(Board_Approved).doc.

[60] The methodology can be found at: http://www.ercot.com/content/mktinfo/dam/kd/ERCOT%20Methodologies%20for%20Determining%20Ancillary%20Service%20Requir.doc.

[61] http://www.ercot.com/content/mktrules/nprotocols/current/08-120112_Nodal.doc.

WECC

Demand Projections

	WECC-CAMX Megawatts (MW)	WECC-NWPP Megawatts (MW)	WECC-RMRG Megawatts (MW)	WECC-SRSG Megawatts (MW)
Total Internal Demand	**56,548**	**59,004**	**11,610**	**28,957**
Load-Modifying DCLM	677	673	0	60
Load-Modifying Contractually Interruptible	670	251	473	419
Load-Modifying Load as a Capacity Resource	1,081	0	0	0
Net Internal Demand	**54,120**	**58,080**	**11,137**	**28,478**

Resource Projections

	WECC-CAMX Megawatts (MW)	WECC-NWPP Megawatts (MW)	WECC-RMRG Megawatts (MW)	WECC-SRSG Megawatts (MW)
Net Firm Capacity Transfers	7,301	620	446	-5,368
Existing-Certain & Future-Planned Capacity	56,497	69,771	16,630	43,490
Anticipated Resources	**63,798**	**70,391**	**17,076**	**38,122**
Prospective Resources	**63,798**	**70,391**	**17,076**	**38,122**

Planning Reserve Margins

	WECC-CAMX Percent (%)	WECC-NWPP Percent (%)	WECC-RMRG Percent (%)	WECC-SRSG Percent (%)
Anticipated Reserve Margin	**17.88**	**21.20**	**53.32**	**33.87**
Prospective Reserve Margin	**17.88**	**21.20**	**53.32**	**33.87**
NERC Reference Margin Level	**15.01**	**15.02**	**14.45**	**13.56**




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 38 BAs, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and approximately 81 million people, it is 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 RC 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 BA 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 their 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 Margin Levels,[62] which are calculated using a building block methodology[63] created by WECC's Loads and Resources Subcommittee. The elements of the building block methodology are consistent from year to year but the

[62] 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.
[63] Elements of the Building Block Target are detailed in NERC's Attachment II: Seasonal Assessment – Methods and Assumptions. http://www.nerc.com/page.php?cid=4|61|409.

calculations can, and do, have slight annual variances by subregion. The reserve margin adequacy is largely due to the construction of power plants in anticipation of a load growth that was interrupted by the economic recession. 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 summer total coincident peak demand is forecast to be 153,248 MW and is projected to occur in August. The forecast is 0.2 percent above summer 2012's actual peak demand of 152,901 MW, which was established under improving economic conditions and warmer-than-normal temperatures with near to record high temperatures in portions of the Region. The 2013 summer coincident peak demand forecast is 2.7 percent above last summer's forecast coincident peak demand of 149,173 MW. The forecasted increase in demand is primarily due to new hourly demand curves being used for modeling, but the increase is also due to a slight forecasted economic recovery. All margin results used demands associated with normal weather conditions, and no attempts were made to address extreme temperature changes.

Demand response programs offered by LSEs vary widely. The 2013 Total Internal Demand forecast includes 1,348 MW of direct control load management, 1,816 MW of contractually interruptible demand, and 1,081 MW of load as a capacity resource. These various DSM programs are treated as load-modifiers that reduce Total Internal Demand when calculating planning margins. In some situations, these programs may be activated by LSEs during high-power cost periods but, in general, are only activated during periods when local power supply issues arise. It is assumed that demand response may be shared among LSEs, BAs, and subregions. However, DSM sharing is not a contractual arrangement. Consequently, reserve margins may be overstated as they do not reflect demand response potentially not being available to respond to external energy emergencies.

Energy efficiency and conservation programs vary by location and are generally offered by the LSEs. The reduction in demand associated with these programs is reflected in the seasonal load forecasts supplied by the BAs. 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.

WECC's modeling data[64] report for the Western Interconnection included the following:

- Existing-Certain capacity at 180,430 MW
- Existing-Other capacity at 0 MW
- Existing-Inoperable capacity at 14,455 MW

Net Future-Planned resources totaling 2,960 MW are expected to be added from the beginning of January 2013 through the end of September 2013.

The 2,250-MW San Onofre Nuclear Generating Station (SONGS) in southern California experienced premature wear in the steam tubes for both of the plant's units, and was shut down for repairs.[65] The planning reserve margins for California are projected to be quite tight for the summer season. With this plant unavailable, a heat wave could result in localized controlled load shedding to maintain the integrity of the system.

Although not needed to maintain reliability, the Montana – Alberta Tie Line (MATL) is expected to enter service in June 2013. This is a 300-MW, 230-kV transmission line that will connect northern Montana and southern Alberta.

Many system enhancements such as transformer and capacitor bank additions have been completed and are available for the summer peak. Although these additions will increase local reliability and overall system operations, they are not significant for reliability purposes.

Most, if not all, BAs reported that they have UVLS schemes (at least 1,445 MW) in place, and none reported that they expect these schemes to operate during the summer season. The only time these schemes would operate is under extreme supply shortage conditions due to events such as the loss of multiple major transmission lines or generating units.

Several BAs reported that they have added new PMUs to provide data to the WECC RC and for their own efforts to increase reliable operations of the system.

One entity indicated it had replaced over 90 percent of its analog retail meters with digital smart meters. However, the entity notes that it does not consider this particular initiative to be directly related to a near-term increase in the reliability of the BPS.

[64] The modeling data for all resources reflect capacities as of the forecasted summer 2013 peak.
[65] Information on the status of SONGS: http://www.songscommunity.com/.

The introduction of formalized operating procedures by BAs directly addressed the issue of over-generation during minimum demand periods; therefore, it is not currently an operational concern within the Western Interconnection. Although over-generation may be addressed through various resource curtailment approaches, none are without associated costs to either or both the generation owners and the consumers.

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

On September 8, 2011, customers in Baja California, Mexico, southern California's Imperial, Orange, and San Diego counties, and a small portion of southwestern Arizona experienced a major power outage. Several entities within WECC have taken, or are in the process of taking, actions to prevent similar disturbances in the future. These actions include the implementation of additional real-time data exchange and coordination with additional entities in the Southwest. These processes will help facilitate a more detailed monitoring capability of neighboring systems in their energy management systems and real-time contingency analysis applications. In addition, the WECC RC has coordinated the development of an interim monitoring procedure for the San Diego and Imperial Valley areas with specific actions that will be taken for overload conditions.

In response to the June 5, 2012 letter sent to Regional Entity executives,[66] WECC established an update page on its website that reports on the status of "Key Categories of Findings and Recommendations." This page is updated monthly with the latest information concerning activities related to these recommendations. These updates are found on the September 8, 2011 Outage Event Response page on the WECC website.[67]

[66] http://www.nerc.com/files/REMG-Ltr_wth_attachement1-06-05-12.pdf.
[67] http://www.wecc.biz/About/sept8/Pages/default.aspx.

Appendix I: Assessment Preparation

This assessment was prepared by NERC in its capacity as the Electric Reliability Organization.[68] 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.[69] In addition, NERC does not make any projections or draw any conclusions regarding expected electricity prices or the efficiency of electricity markets.

The assessment area sections were developed by the Reliability Assessment Subcommittee (RAS), which is under the direction of the NERC Planning Committee (PC). The data and information presented in this assessment was submitted by each of the eight Regional Entities on an assessment area basis. Additional data was incorporated by NERC staff with sources provided when applicable.

Reliability Assessment Subcommittee Members

Name	Position	Represents	Job Title	Organization
Vince Ordax	Chair	FRCC*	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.
Madhuri Kandukuri	Member	MRO	Senior Engineer , Regulatory and Economic Studies	Midcontinent ISO, Inc.
Josh Collins	Member	MRO	Political & Economist Studies Engineer	Midcontinent ISO, Inc.
Bagen Bagen	Member	MRO	Principal Planning Engineer	Manitoba Hydro
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
Bob Mariotti	Member	RFC	Supervisor - Short Term Forecasting	DTE Energy
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
Gary S. Brinkworth	Member	SERC	Senior Manager, Capacity Planning	TVA
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
Shirley Mathew	Member	TRE	Senior Reliability Engineer	TRE
Kevin Hanson	Member	TRE	Senior Reliability Engineer	ERCOT
Warren Lasher	Member	TRE	Director, System Planning	ERCOT
Tina G. Ko	Member	WECC	Manager, Resources & Loads Analysis	BPA
James Leigh-Kendall	Member	WECC	Manager, Reliability Compliance and Coordination	SMUD

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[68] 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."

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

Assessment areas are subject to thorough review by the RAS. This review allows all members multiple opportunities to examine information and data provided by each assessment area. Data sharing also allows members to validate capacity transfers between neighboring assessment areas.

The NERC PC endorses this report prior to its being sent to the NERC Board of Trustees for approval. The draft includes comments received from representatives on the NERC Operating Committee (OC) and the Member Representatives Committee (MRC).

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 & 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

Planning Reserve Margins Concepts

	Definition
Existing-Certain & Net Firm Capacity Transactions Reserve Margin	Existing-Certain & 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.

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

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