NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

December 2, 2011

VIA ELECTRONIC FILING

Re: North American Electric Reliability Corporation, *2011 Summer Reliability Assessment*, Docket No. RC11-_-000

The North American Electric reliability Corporation (NERC) submits solely as an informational filing the *2011 Summer Reliability* Assessment; a report prepared by NERC, released on June 30, 2011.

Please contact the undersigned if you have any questions.

Respectfully submitted,

/s/ Holly A. Hawkins

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2011 Summer Reliability Assessment

to ensure the reliability of the bulk power system

May 2011

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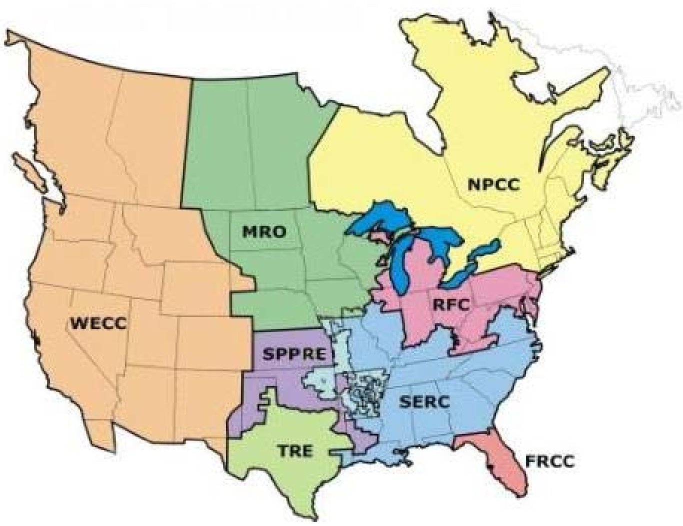
NERC's Mission

The North American Electric Reliability Corporation (NERC) is an international regulatory authority established to evaluate reliability of the bulk power system in North America. NERC develops and enforces Reliability Standards; assesses adequacy annually via ten-year forecasts and winter and summer forecasts; monitors the bulk power system; 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.[1]

NERC assesses and reports on the reliability and adequacy of the North American bulk power system, which is divided into eight Regional Areas as shown on the map below and listed in Table A. The users, owners, and operators of the bulk power system within these Areas account for virtually all the electricity supplied in the U.S., Canada, and a portion of Baja California Norte, México.



Note: *The highlighted Area between SPP RE and SERC denotes overlapping Regional Area boundaries. For example, some load serving entities participate in one Region and their associated transmission owner/operators in another.*

TABLE A: NERC REGIONAL ENTITIES

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

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[1] As of June 18, 2007, the U.S. Federal Energy Regulatory Commission (FERC) granted NERC the legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the Bulk Power System, and made compliance with those standards mandatory and enforceable. In Canada, NERC presently has memorandums of understanding in place with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, and Saskatchewan, and with the Canadian National Energy Board. NERC standards are mandatory and enforceable in Ontario and New Brunswick as a matter of provincial law. NERC has an agreement with Manitoba Hydro making reliability standards mandatory for that entity, and Manitoba has recently 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. Nova Scotia and British Columbia also have frameworks in place for reliability standards to become mandatory and enforceable. NERC is working with the other governmental authorities in Canada to achieve equivalent recognition.

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About This Reliability Assessment

The *2011 Summer Reliability Assessment* provides an independent assessment of the reliability of the bulk electricity supply and demand in North America for the period June 2011 through September 2011 (Table B). The report specifically provides a high-level reliability assessment of 2011 summer resource adequacy and operating reliability, an overview of projected electricity demand and supply changes, and Regionally focused self-assessments.

The primary objective in providing this assessment is to identify areas of concern regarding the reliability of the North American bulk power system and to make recommendations for remedial actions as needed. The assessment process enables bulk power system users, owners, and operators to systematically document their operational preparations for the coming season and exchange vital system reliability information. In addition, NERC does not make any projections or draw any conclusions regarding projected electricity prices or the efficiency of electricity markets.

Table B: NERC's Annual Assessments

Assessment	Outlook	Published
Summer Assessment	Upcoming season	May
Post-Summer Assessment	Previous season	November
Winter Assessment	Upcoming season	November
Post-Winter Assessment	Previous season	May
Long-Term Assessment	Ten-year	November

Report Preparation

This assessment is coordinated by NERC in its capacity as the Electric Reliability Organization.[2] The Reliability Assessment Subcommittee (RAS) of the NERC Planning Committee (PC) prepared this report based on data submitted by the eight NERC Regional Entities and other stakeholder participants as of April 30, 2011. 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 2011 summer season. NERC also uses an active peer review process in developing reliability assessments. The peer review process takes full advantage of industry subject matter expertise from many sectors of the industry. This process also provides essential checks and balances for ensuring the validity of the assessment and conclusions provided by the Regional Entities.

[2] 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."

Areas Assessed

Based on recommendations from industry representatives as well as approval from the NERC Planning Committee, assessment boundaries were reconstructed beginning in 2011 to represent existing operating boundaries used in the planning process.[3] Prior to 2011, Regional Entity boundaries were used for NERC assessments; however, these borders do necessarily signify that planning and operations occur within a single Regional Entity. Therefore, assessment boundaries were enhanced using existing operational and planning boundaries versus traditional NERC Regional Entity boundaries (Figure A). Additional insights will be gained as planning and operations are aligned within each assessment area. Assessment boundary changes from 2010 to 2011 are outlined in Table C.

FIGURE A: 2011 ASSESSMENT AREAS

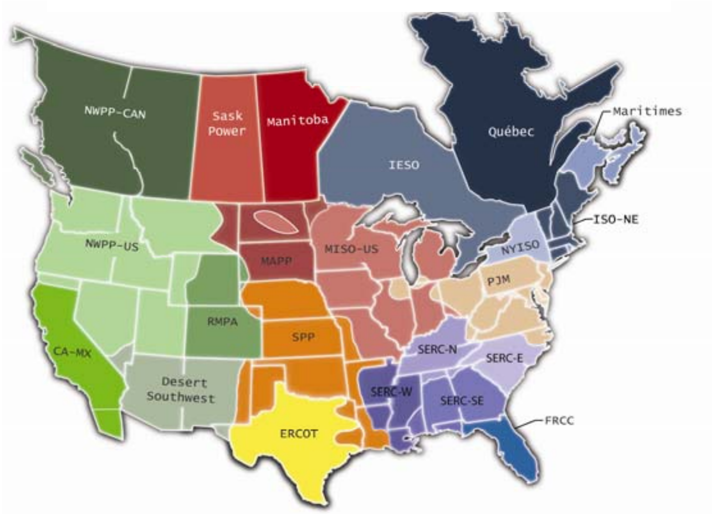


TABLE C: 2010 AND 2011 ASSESSMENT BOUNDARY DIFFERENCES

2010 assessment areas	2011 assessment areas	NERC Regional Entity	Description of Change
TRE	ERCOT	TRE	Area name changed to reflect the operator
FRCC	FRCC	FRCC	No change
New England	ISO-NE	NPCC	Area name changed to reflect the operator
New York	NYISO	NPCC	Area name changed to reflect the operator
Maritimes	Maritimes	NPCC	No change
Ontario	IESO	NPCC	Area name changed to reflect the operator
Québec	Québec	NPCC	No change
MRO CAN	SaskPower, Manitoba	MRO	SaskPower and Manitoba now separate assessment areas
MRO US	MAPP	MRO	MAPP Planning Authority, removed MISO
—	MISO	MRO, RFC, SERC	MISO RTO
—	PJM	RFC, SERC	PJM RTO
Central	SERC-N	SERC	Removed PJM RTO members
Delta	SERC-W	SERC	Removed SPP RTO members
Gateway	—	—	Removed, part of the MISO RTO
Southeastern	SERC-SE	SERC	No change to boundary
VACAR	SERC-E	SERC	Removed PJM RTO members
SPP	SPP	SPP RE	SPP RTO and residual SPP RE members
CA-MX	CA-MX	WECC	No change
Desert SW	Desert SW	WECC	No change
RMPA	RMPA	WECC	No change
NWPP	NWPP	WECC	No change, Data is presented for both the US and Canada portions of NWPP

[3] Reliability Assessment Procedure: Subregional Restructuring to support ISO/RTO Boundaries, December 2010. http://www.nerc.com/docs/pc/ras/Reliability%20Assessments%20-%20Subregional%20Restructuring.pdf

Enhancement to Reserve Margin Calculation

A significant change initiated in 2011 establishes a more consistent method to account for Demand Response in the Reserve Margin (RM) calculation. In previous reliability assessments, some Controllable Capacity Demand Response (CCDR) programs were used to reduce Total Internal Demand (Net Internal Demand), and some programs were included as a supply-side capacity resource. In prior years, the Reserve Margin calculation was based on Net Internal Demand and capacity resources, which included some CCDR on either side of the equation. The method now used calculates Reserve Margin based on Total Internal Demand and includes (CCDR) only as a supply-side resource.[4] This enhancement allows demand to be analyzed irrespective of CCDR penetration, and consistent treatment of CCDR across all assessment areas.

A comparison of the two methods is shown in Table D below:[5]

Table D: Differences in Calculation of Reserve Margins in 2011	
Pre-2011 Reserve Margin Calculation (Majority)	**2011 Reserve Margin Calculation**
$RM = \frac{[\text{Capacity} - (\text{Total Internal Demand} - \text{CCDR})]}{(\text{Total Internal Demand} - \text{CCDR})}$	$RM = \frac{[(\text{Capacity} + \text{CCDR}) - (\text{Total Internal Demand})]}{(\text{Total Internal Demand})}$

Assumptions and Considerations

In the *2011 Summer Reliability Assessment*, the baseline information on future electricity supply and demand is based on several assumptions:[6]

- Supply and demand projections are based on industry forecasts submitted in April 2011. Any subsequent demand forecast or resource plan changes may not be fully represented.
- Peak Demand and Reserve Margins are based on average weather conditions and assumed forecast economic activity at the time of submittal. Weather variability is discussed in each Region's self-assessment.
- Generating and transmission equipment will perform at historical availability levels.
- Future generation and transmission facilities are commissioned and in service as planned; planned outages take place as scheduled.
- Demand reductions projected from Demand Response programs will yield the forecast results if they are activated.
- Non-controllable and non-dispatchable Demand-Side Management programs are reflected in the forecasts of Total Internal Demand.

[4] This change was recommended by the NERC Resource Issues Subcommittee under the direction of the NERC Planning Committee. The recommendation was approved by the NERC Planning Committee in 2010 and is detailed in the report titled *Recommendations for the Treatment of Controllable Capacity Demand Response Programs in Reserve Margin Calculation,* June 2010 http://www.nerc.com/docs/pc/ris/RIS_Report_on_Reserve_Margin_Treatment_of_CCDR_%2006.01.10.pdf

[5] For more information on this change, please see the *Reliability Concepts Used in This Report* section.

[6] Many forecasts report probabilities with a range of possible outcomes. For example, each Regional demand projection is assumed to represent the projected midpoint of possible future outcomes. This means that a future year's actual demand may deviate from the projection due to the inherent variability of the key factors that drive electrical use, such as weather. In the case of the NERC Regional projections, there is a 50-percent probability that actual demand will be higher than the forecast midpoint and a 50-percent probability that it will be lower.

Summary Reliability Assessment of North America

2011 Summer Key Highlights

Demand Increases, Reserve Margins Sufficient

Generating and transmitting resources are forecast to be adequate to meet projected demand for electricity in North America this summer. Total Internal Demand is projected to increase by approximately 10,000 MW this summer to 851,879 MW, but Reserve Margins remain sufficient in both the United States (25.1 percent) and Canada (35.8 percent). However, unanticipated equipment problems and prolonged hot weather could combine to produce localized situations in which demands temporarily exceed available generation and transmission capacity. Localized areas of concern, noted in this report, may require system operators to implement controlled demand reductions (interruptible demands, voltage reductions, and public appeals) to maintain the constant balance between supply and demand needed to ensure overall bulk power system reliability.

Drought Conditions Remain in Portions of North America

The 2011 National Oceanic and Atmospheric Administration (NOAA) Drought forecast released on May 19, 2011, shows large sections of the southwestern United States experiencing drought conditions through August 2011. Drought conditions do not have direct correlation to bulk power system reliability, but areas that experience drought conditions require additional monitoring for potential reliability affects. Extreme weather conditions or scarcity of water for cooling of steam units can add additional stresses on bulk power systems during peaking periods. Based on persistent drought and precipitation predictions, ERCOT appears to be most vulnerable to unexpected generator deratings caused by low water levels on bodies of water supplying cooling water. However, late spring storms have eased drought conditions somewhat across the southeast and Texas.

Incremental Growth in Demand Response

Several NERC Regions are projecting continued increases in Demand Response activities, especially regarding growth in load as a capacity resource. The PJM Interconnection has 2,419 MW of additional Demand Response activities compared to 2010, with almost one-third of this growth attributed to the addition of load used as a capacity resource. Additionally, the ERCOT Region, which had no contractually interruptible (curtailable) Demand Response in 2010, projects a total of 370 MW for 2011. Finally, WECC projects 1,879 MW of Direct Control Load Management Demand Response for 2011, compared to 740 MW in 2010.

Operational Flexibility Required for Unforeseen Events

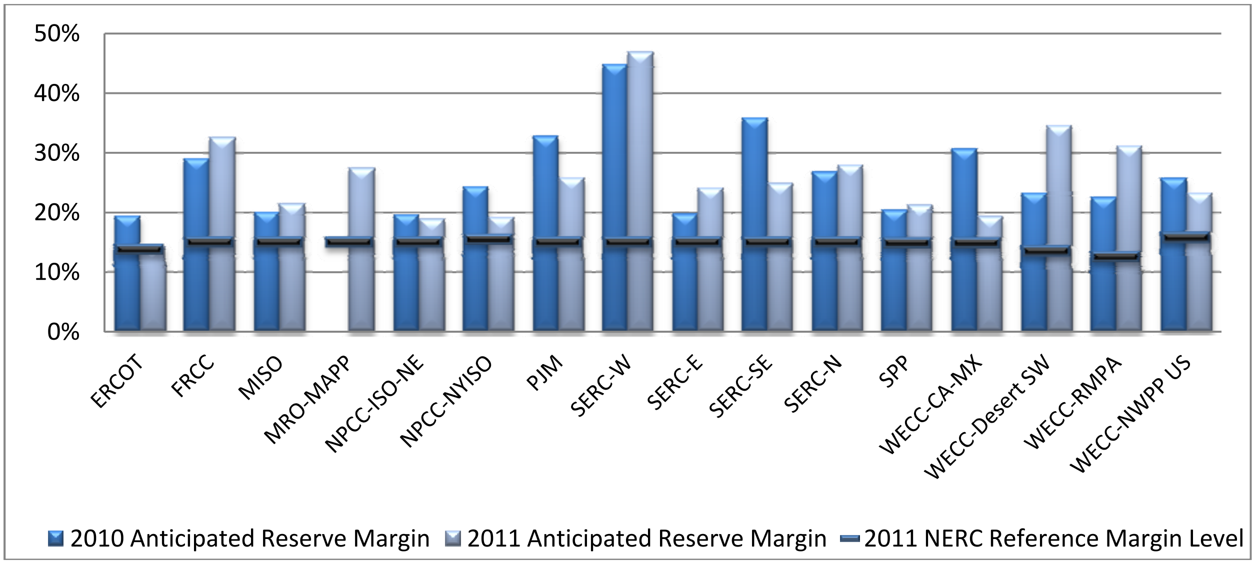
Overall operational conditions, including variable resource operations (such as wind), appear adequate to address forecast conditions during the 2011 summer. All areas have operational strategies and procedures in place to manage potential reliability impacts that may arise. Low probability events such as persistent high temperatures, large precipitation events over short durations, and severe storm outbreaks across wide areas will require operational flexibility to mitigate the impacts from any outages.

Resource Adequacy Assessment

All assessment areas are projected to have sufficient Reserve Margins[7] to ensure reliability throughout the 2011 summer months. Adequate Reserve Margins are essential for maintaining bulk power system reliability by providing system operators with the flexibility needed to withstand unexpected generation or transmission outages and deviations from the demand forecast.

The summer peak Anticipated Planning Reserve Margin across North America is 26.0, which is 2.1 percentage points lower than the 2010 forecast.[8,9,10] Peak demand increases in the U.S. are the predominant source of the overall decrease in Reserve Margins.

FIGURE 1: U.S. PEAK RESERVE MARGIN PROJECTIONS[11]



Areas that peak in the summer are more susceptible to capacity deficiencies caused by extreme and prolonged hot weather. In the U.S., where the majority of the assessment areas are summer-peaking, all areas including Regions, subregions, and ISO/RTO control areas have projected summer on-peak Reserve Margins above the NERC Reference Margin Level[12] (Figure 1). From a national perspective, the Anticipated Reserve Margin for the U.S. is projected to be 25.1 percent.

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[7] In this report, "Reserve Margin" represents "Planning Reserve Margin." Reserve Margins for the 2011 summer are calculated by using projected on-peak capacity resources (generation, demand resources, and net transfers) and a 50/50 demand forecast, which represents a forecast value for an actual value having equal chance of either falling above or below the forecast value.

[8] The North American bulk power system does not have the capability to transmit power across its entire expanse; therefore, a North American Reserve Margin is only a general indicator. It is not representative of resource adequacy within all areas of North America.

[9] The 2010 Reserve Margin was calculated using the same method used in 2011. Approximation was used in developing the 2010 Reserve Margin—error +/-0.2 percentage point.

[10] Peak Reserve Margins for North America, the U.S., and Canada, are calculated by summing the individual assessment area's non-coincident peak demand and resources. Peak summer demand, resources, and Reserve Margins can be found in Table 1.

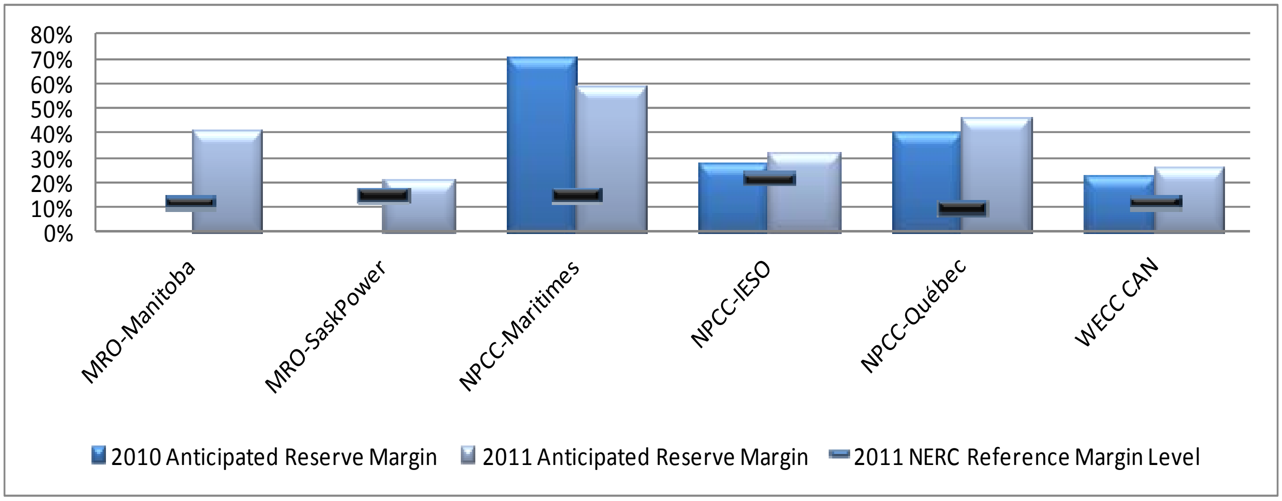
[11] Data for MAPP and SERC assessment areas are not available for 2010 due to the subregional reconstruction [with the exception of SERC-SE)]. For this figure, 2010 Reserve Margins for the SERC-W SERC-E and SERC-S assessment areas are based on the "old" SERC subregions SERC-Delta, SERC-VACAR, and SERC-Central, respectively.

[12] See the *Reliability Concepts Used in this Report* section for the NERC Reference Reserve Margin Level definition.

While areas such as ERCOT and NYISO have projected Reserve Margins close to the NERC Reference Margin Level, they continue to meet their reliability-based requirements and appear to have sufficient resources to meet projected summer peak demands. These areas would be most affected by significant changes to available generation or demand forecasts. However, based on the current forecast, reliability is expected to be maintained.

Most of Canada and the NWPP in the U.S. are winter-peaking areas and are generally less vulnerable to capacity deficits during the summer months. However, these areas provide generation that is vital to resource adequacy of summer-peaking areas to the south. For the 2011 summer, given assumed power transfers and generation out of service for maintenance, these areas show sufficient resources to maintain reliability (Figure 2). From a national perspective, the Anticipated Reserve Margin for the Canada is projected to be 35.8 percent.

FIGURE 2: CANADA PEAK RESERVE MARGIN PROJECTIONS[13]



IESO, the only Canadian subregion that peaks during the summer months, is projecting an increase of 4.2 percentage points in the Anticipated Reserve Margin from 2010 (27.6 percent) to 2011 (31.8 percent). NPCC-Québec and WECC-CAN also show increases, while NPCC-Maritimes is the only winter-peaking area to show a decrease from the 2010 Anticipated Reserve Margin.

Demand Assessment

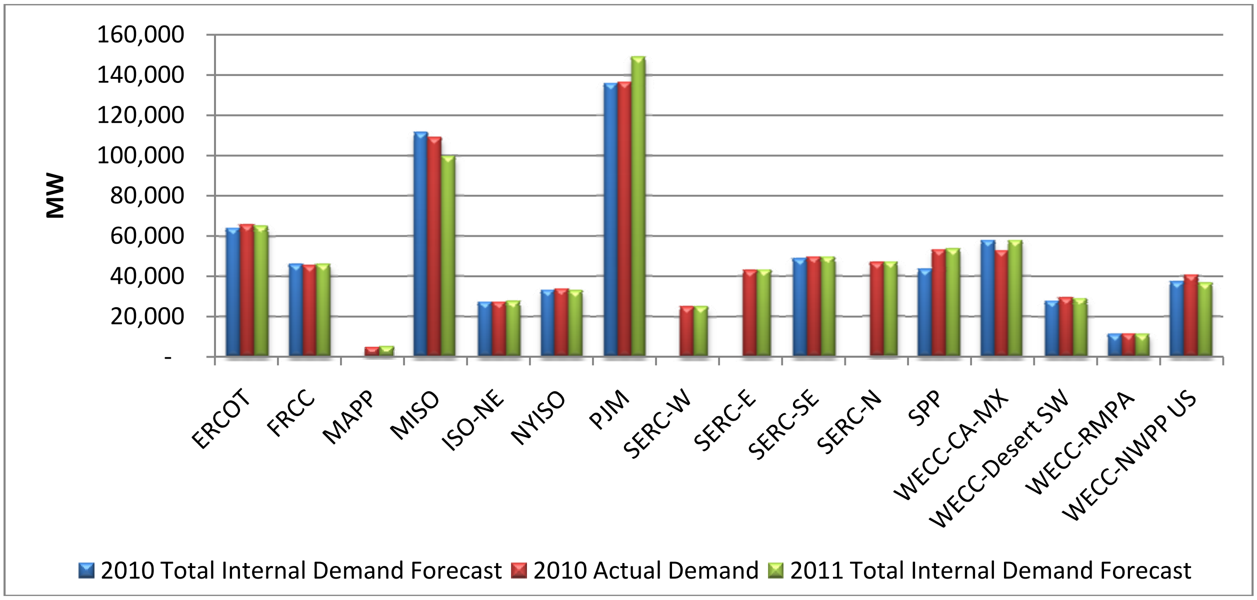
Summer forecast peak demands[14] across NERC appear manageable, with a majority of the areas experiencing little to no demand growth compared to last year (Figure 3). For the system as a whole, the non-coincident summer peak Total Internal Demand is projected to reach 851,879 MW, which is an overall increase of approximately 10,000 MW (1.2 percent) when compared to the 2010 Total Internal Demand forecast (842,029 MW).

[13] Data for SaskPower and Manitoba subareas are not available for 2010 due to the subregional reconstruction.

[14] A 50/50 demand forecast is defined as a demand forecast adjusted to reflect normal weather that is projected on a 50-percent probability basis, *i.e.,* a peak demand forecast level which has a 50 percent probability of being under or over achieved by the actual peak demand.

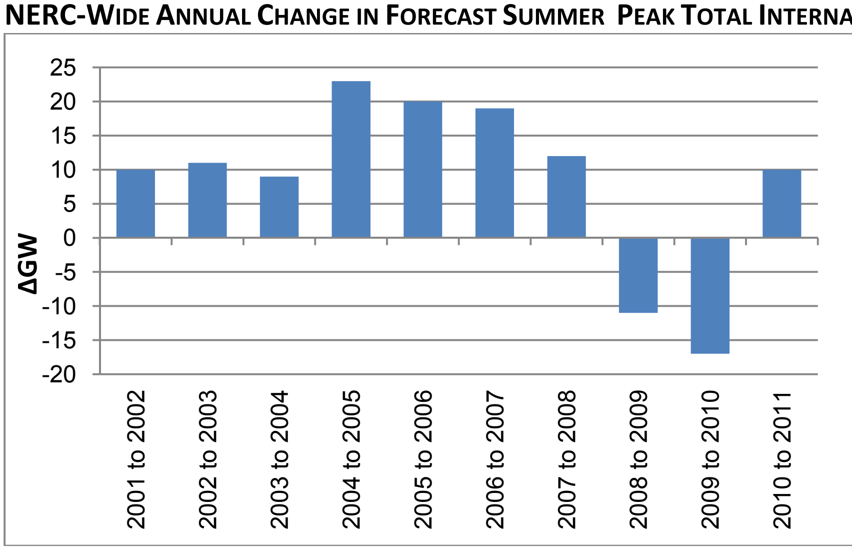
Less predictable economic conditions result in a greater degree of uncertainty in the 2011 demand forecast that is not typically seen in period of more stable economic activity. The overall increase in projected peak demand for 2011 represents the first annual peak demand increase since 2008 (Figure 4). While significantly less than annual increases observed between 2004 and 2007, the growth in demand since last year is in-line with historically average growth.

FIGURE 3: U.S. ASSESSMENT AREAS TOTAL INTERNAL PEAK DEMANDS



In the U.S., the non-coincident summer peak Total Internal Demand is forecast to reach 777,046 MW, representing a increase of approximately 1,700 MW over 2010 actual unadjusted demand (775,388 MW). As noted in the *2010 Post-Summer Reliability Assessment*, extreme and prolonged hot weather contributed to a majority of areas, primarily in the east, experiencing actual demands greater than forecasted. However, when compared to last year's Total Internal Demand forecast, an increase of approximately 9,000 MW (or 1.2 percent) is projected.

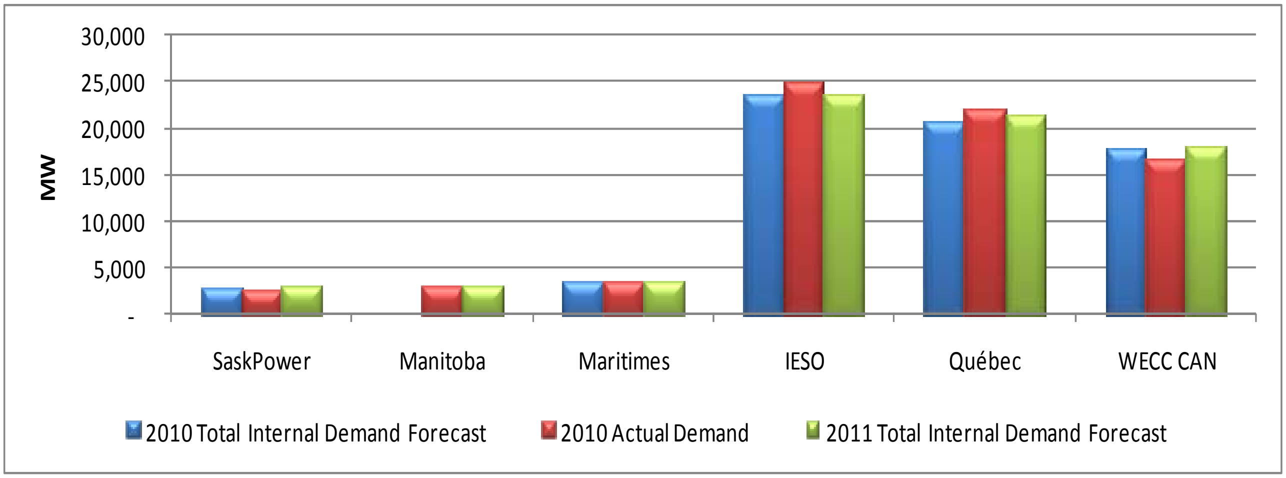
FIGURE 4: NERC-WIDE ANNUAL CHANGE IN FORECAST SUMMER PEAK TOTAL INTERNAL DEMAND



While the realignment of assessment area boundaries does not allow year-to-year comparison in some areas, a majority of the U.S. assessment areas are forecasting slight demand increases when compared to last year. For example, this year, a switch in membership from MISO to PJM significantly increases the PJM demand forecast. However, this increase is completely offset by reductions in MISO. Taking into account these membership changes, growth represented in these two areas shows a net increase of approximately 2,000 MW since 2010.

In Canada, the non-coincident summer peak Total Internal Demand is projected to reach 72,120 MW in July 2011, representing a decrease of 715 MW (1.6 percent) over 2010 actual demand (73,358 MW). When compared to last year's July 2010 forecast, an increase of approximately 640 MW (0.9 percent) is projected. Individual area increases are minimal and overall relatively flat (Figure 5).

FIGURE 5: CANADA AREAS TOTAL INTERNAL PEAK DEMANDS

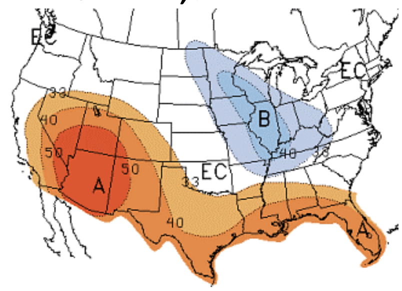


Temperature and Precipitation Forecast

Temperatures are forecast to be below normal in a number of large demand pockets in the Midwestern United States during the 2011 summer season (Figure 6). Additionally, below-normal temperatures are predicted for large areas of Canada during the 2011 summer season (Figure 7). Temperatures are forecast to be above normal in drought-afflicted areas, which could have operational impacts if current conditions persist or intensify.[15]

[15] A more detailed assessment on impacts of drought conditions can be found in the *Operations Assessment and Potential Issues* section of this report.

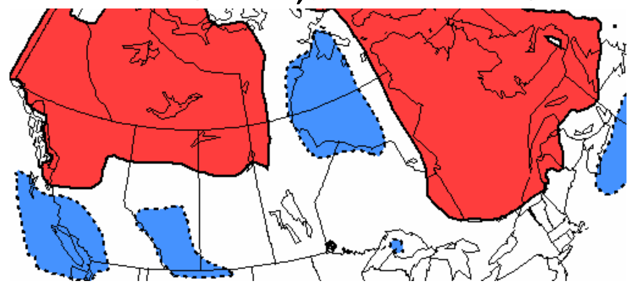
FIGURE 6: U.S. SUMMER MEAN TEMPERATURE PROBABILITY OUTLOOK, JUNE TO AUGUST 2011[16]



Source: NOAA Climate Prediction Center

A (Orange)	Above-Normal Temperatures Forecast
EC (White)	Equal Chance of Above- or Below-Normal Temperatures
B (Blue)	Below-Normal Temperatures Forecast

FIGURE 7: CANADA SUMMER MEAN TEMPERATURE PROBABILITY OUTLOOK, JUNE TO AUGUST 2011[17]

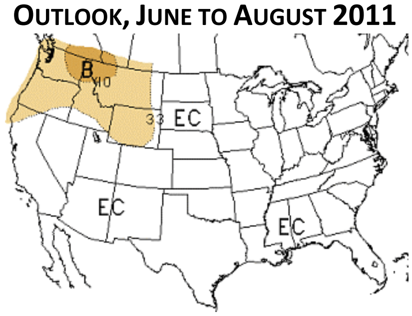


Source: Environment Canada

Red	Above-Normal Temperatures Forecast
White	Equal Chance of Above- or Below-Normal Temperatures
Blue	Below-Normal Temperatures Forecast

Precipitation is projected to be below normal in the Pacfic Northwest in the United States, and above normal in a number of hydro-dense areas in the Canadian provinces, such as Manitoba and Québec (Figure 8 and Figure 9). The precipitation forecast is favorable in the hydro-rich areas this summer. Coupled with above-average river flows and reservoir levels, above-average precipitation provides system operators with more flexibility in managing water resources.

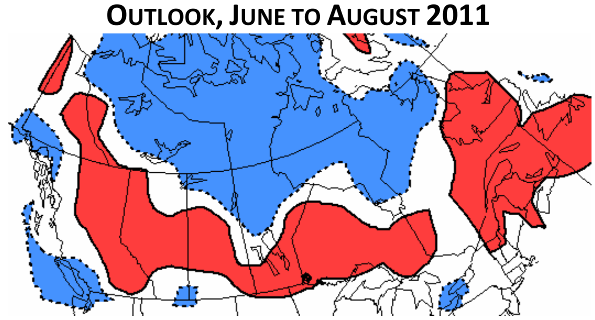
FIGURE 8: U.S. SUMMER MEAN PRECIPITATION OUTLOOK, JUNE TO AUGUST 2011



Source: NOAA Climate Prediction Center

A (Green)	Above-normal Precipitation Forecast
EC (White)	Equal Chance of Above- or Below-Normal Precipitation
B (Brown)	Below-Normal Precipitation Forecast

FIGURE 9: CANADA MEAN SUMMER PRECIPITATION OUTLOOK, JUNE TO AUGUST 2011



Source: Environment Canada

Red	Above-normal Precipitation Forecast
White	Equal Chance of Above- or Below-Normal Precipitation
Blue	Below-normal Precipitation Forecast

[16] http://www.cpc.ncep.noaa.gov/index.php
[17] http://www.weatheroffice.gc.ca/saisons/index_e.html

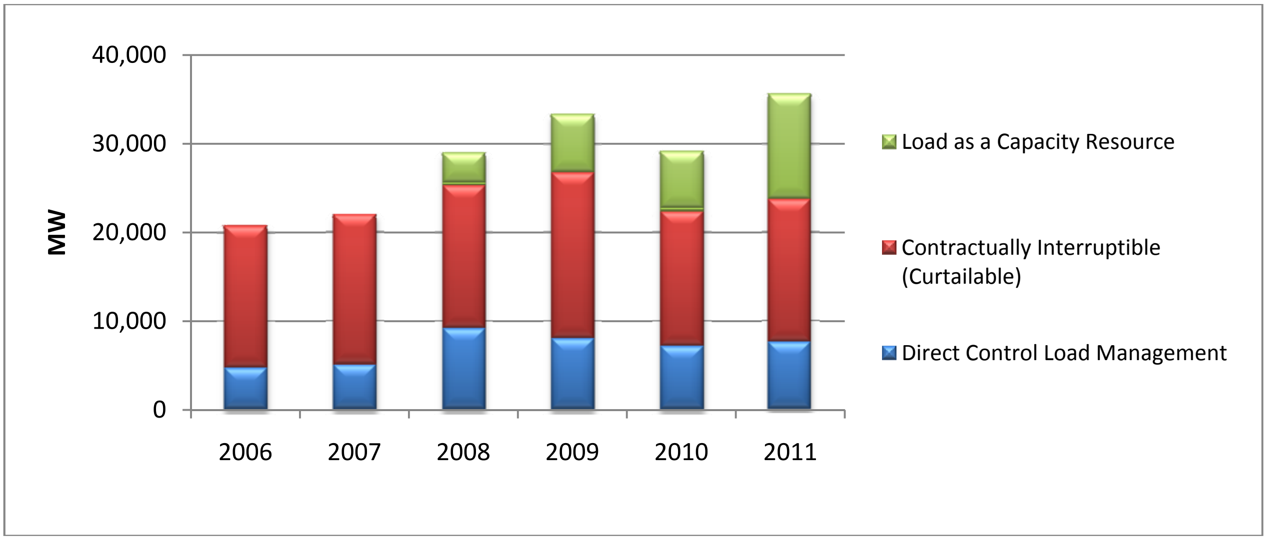
Demand Response Assessment

Another variable affecting demand forecasts is the amount of Demand Response contributing to peak demand reduction. Economic factors and regional, state, or provincial Demand Response initiatives can increase or decrease the amount of responsive demand-side resources available for system operators to manage peak demand.

Demand Response programs for this summer total approximately 35,600 MW for all of NERC.[18] With slightly increasing peak demand forecasts and adequate Reserve Margins, available Demand Response is forecast to contribute more to meet peak demands this summer, with an increase of about 5,300 MW when compared to last year (Figure 10). In all Regions, flat or slightly increased Demand Response participation is forecast for this summer when compared to last summer. PJM and MISO administer approximately 12,000 MW and 8,000 MW of Demand Response, respectively. These relatively large Demand Response participation values represent just under eight percent of the Total Internal Demand for each of the areas, which is the largest amount of all system operators (Figure 11). MISO and PJM continue to expand the types of Demand Response offered in the market, including Demand Response providing ancillary services to accommodate wind forecast errors and other system contingencies.

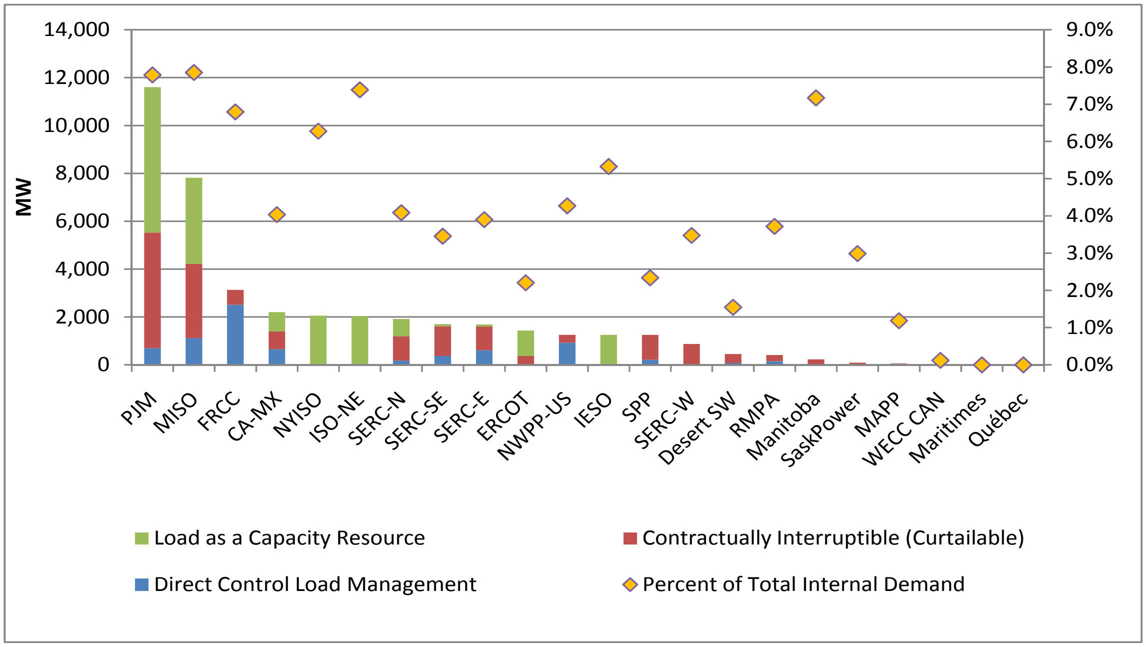
With relatively high Reserve Margins projected for the upcoming summer, Demand Response is not likely to be called on to meet peak demand. However, additional flexibility is provided to operators facilitating the use of these resources to support local reliability issues and other system constraints as needed. For example, Demand Response is being used more to provide ancillary services. Significant technological improvements in both activation methods as well as measurement and verification, enable operators to be confident about the resource's performance in providing fast-acting response.

FIGURE 10: NERC-WIDE DEMAND RESPONSE PROJECTED ON PEAK



[18] Demand Response is not a shareable resource, but is largely used for local-area reliability within a single operating entity. The total NERC value is only a general indicator or reference for growth in Demand Response resources.

FIGURE 11: AREA-LEVEL DEMAND RESPONSE FORECAST ON PEAK



Wind Generation

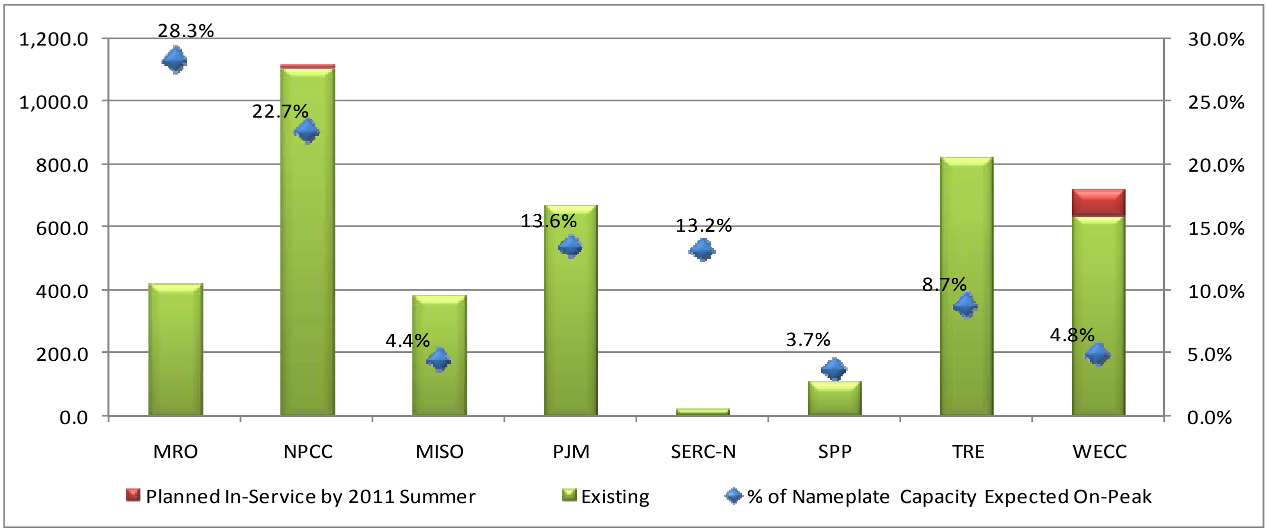
In 2011, expected on-peak wind capacity is forecast to range from approximately 20 MW in SERC-N to a maximum of 1,100 MW in NPCC (Figure 12). WECC is expecting additions of wind capacity this summer with approximately 80 MW of expected on-peak capacity to be added during the summer months. MRO (less MISO) has the largest percentage of nameplate wind capacity expected on peak, at 28.3 percent. Values for expected wind capacity on peak are more conservative this summer with values as low as 4.4 percent in MISO. Lower expected on-peak capacity values are the result of significant changes in the methods to calculate the portion of total nameplate wind capacity incorporated into resource adequacy planning and additionally due to better operational experience with managing wind capacity.

Availability of capacity during times of peak demand (expected on-peak capacity) is an important issue facing wind power when discussing reliability. Because both the availability of variable generation resources sources and demand for electricity are often weather dependent, there can be consistent correlations between system demand levels and variable generation output. For example, in some cases, due to diurnal heating and cooling patterns, wind generation output tends to peak during daily off-peak periods of electricity use. Also, many areas have experienced wind generation output falling off significantly during summer or winter high-pressure weather patterns that can correspond to system peak demand. Therefore, the methods for determining available wind capacity during peak hours becomes increasingly important as more wind resources are interconnected to the bulk power system.[19],[20] On average, the expected on-peak capacity for wind generation in North America is approximately 14.1 percent of nameplate capacity.

[19] Regional differences exist for calculating the expected on-peak capacity contributions of wind resources. http://www.nerc.com/docs/pc/ivgtf/IVGTF_Report_041609.pdf

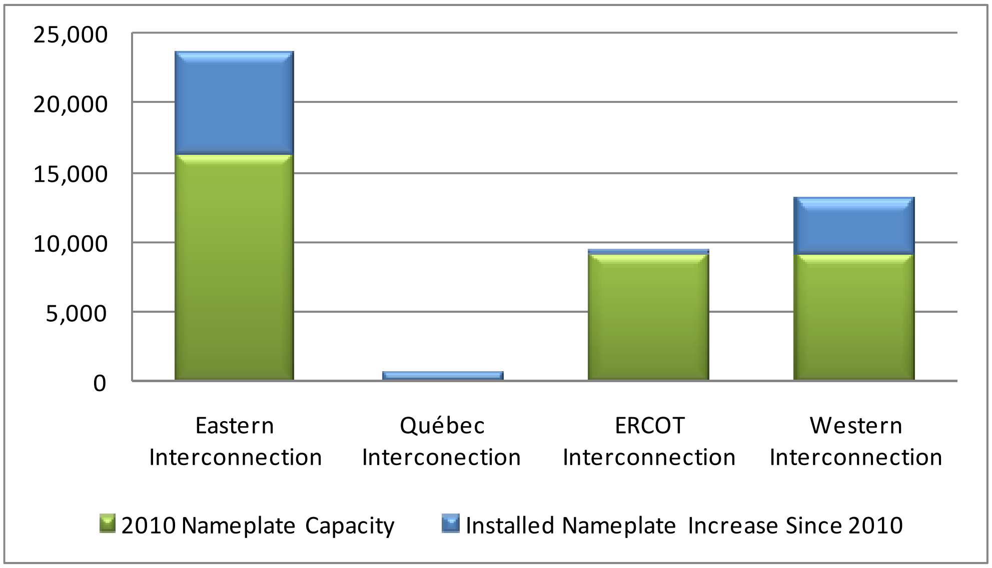
[20] IVGTF Report: *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning*: http://www.nerc.com/files/IVGTF1-2.pdf

FIGURE 12: 2011 WIND EXISTING-CERTAIN AND PLANNED AGAINST CAPACITY ON PEAK



While assessing the expected on-peak capacity of wind resources is important for resource adequacy planning, identifying the amount of nameplate wind capacity is critical to understand the impact to the bulk power system during off-peak periods (Figure 13).[21] Since 2010, the Eastern Interconnection has seen the largest increase in nameplate wind resources, with an addition of approximately 5,800 MW. The largest increases are attributable to growth in both NPCC (increase of approximately 1,900 MW) and PJM (increase of approximately 1,400 MW). As a percentage of total capacity, ERCOT accommodates the largest portfolio of wind resources, representing approximately 10 percent of all capacity resources.

FIGURE 13: INSTALLED WIND NAMEPLATE INCREASES IN 2011[22]



[21] Taking values of the bars in Figure 12 and multiplying them by the percentage values will result in the installed nameplate values in Figure 13.

[22] 2010 Nameplate Capacity was not available for the SERC-N subregion; the 2010 SERC Region total was used instead.

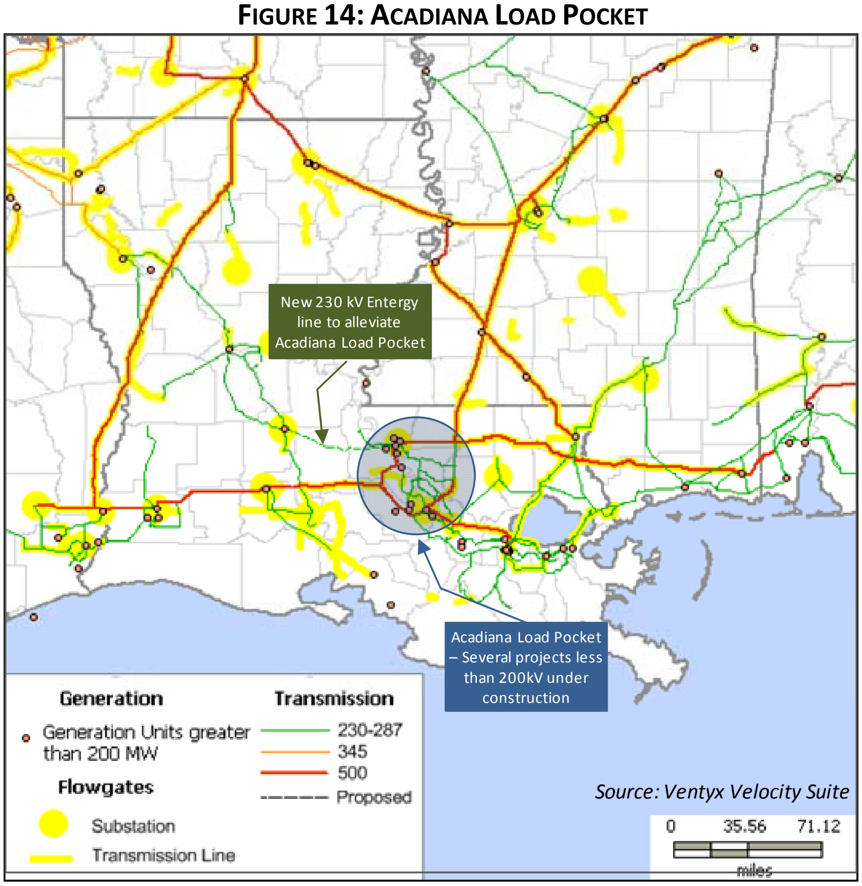
Operations Assessment and Potential Issues

No operational conditions were reported that would have significant adverse impact on bulk system reliability this summer. All operating entities have procedures and strategies to mitigate operational reliability issues that may arise during the summer season. Overall, the assessment areas do not project any major scheduled generating unit outages, transmission facility outages, or unusual operating conditions that would adversely affect reliable operations. The Balancing and Planning Authorities have coordinated the planning of long-range scheduled maintenance outages, assuring there is sufficient generation available during scheduled transmission outages and sufficient transmission capacity available during scheduled generation outages to access needed resources.

Acadiana Load Pocket

The Acadiana Load Pocket (ALP) is an area in south central Louisiana that spans both the SPP RE and SERC reliability areas. The area had a 2010 summer peak demand of 1,723 MWs. The area has experienced regular transmission constraints and numerous Energy Emergency Alert filings by the SPP Reliability Controller (SPP RC) (Figure 14). Transmission within ALP is owned by Entergy, Lafayette Utilities System (LUS), and Cleco Power LLC (Cleco). The transmission constraints and reliability congestion issues within the ALP are primarily caused by the local area load, the lack of efficient generation located in close proximity to the load area, and transmission capacity that limits the amount of import capability.

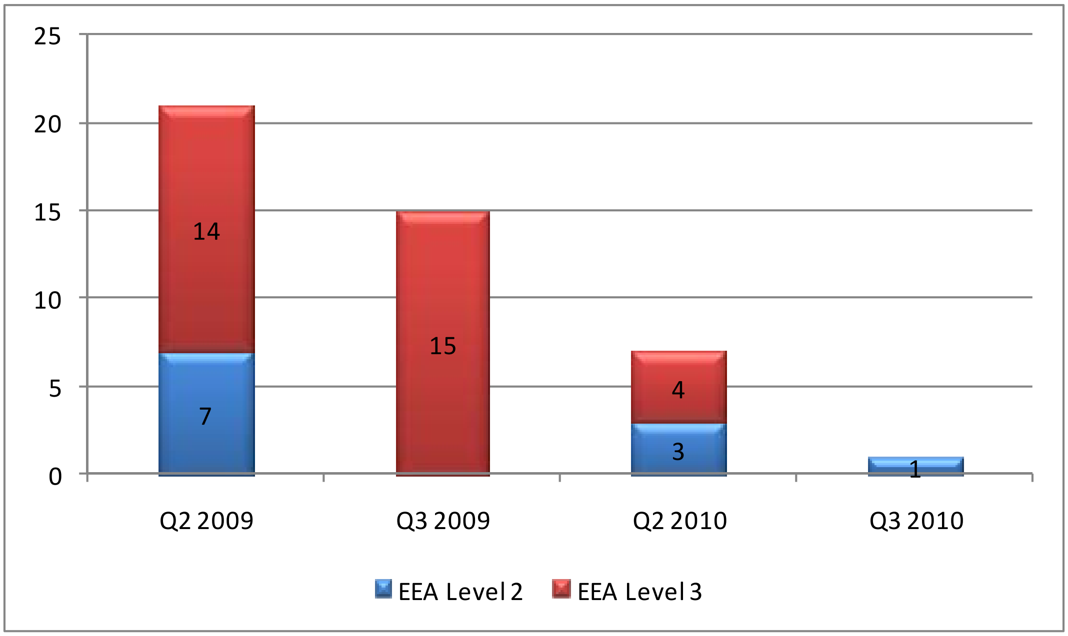
FIGURE 14: ACADIANA LOAD POCKET



The system characteristics listed above continue to be aggressively addressed by the SPP Reliability Coordinator through coordination within the ALP with all of the effected entities. These actions include operating guides developed by the Reliability Coordinator and the operational Planning Engineering staffs of each entity, and the sharing of generation cost of legacy generation required to dispatch during system events. This coordinated effort on the part of all parties in the ALP has limited the load at risk in the area. There has been an increase in the load in the ALP over the last few years due to catastrophic weather events on the Louisiana gulf coast redistributing the population from the larger load centers near the coast to the Acadiana area of Louisiana. Transmission System events in the ALP region of the SPP reliability footprint do not pose a significant threat to the Eastern Interconnection as these events are restricted to the boundaries of the ALP.

Cleco Power, Entergy and LUS are currently constructing an estimated $230 million transmission infrastructure improvement project to mitigate transmission constraints into ALP. The two-phase construction project is scheduled to be complete in 2012. The first phase, a 230 kV line from Roark to Sellers Rd., was energized on May 3, 2011. This line has already alleviated some of the most limiting elements in the Acadiana Load Pocket by as much as 10 percent. Energy Emergency Alerts filed by the SPP Regional Entity continue to decline (Figure 15). That said, if extreme weather persists, and equipment outages occur, this area may experience increased EEA levels.

FIGURE 15: EMERGENCY ENERGY ALERTS FOR 2009 SUMMER SEASON AND 2010 SUMMER SEASON IN SPP RE



Additionally, the constraints within SPP are limiting the amount of additional wind that can be added to the area without curtailment during low load periods. The recently completed AMEC study focused on operations and reliability of planned wind development within and surrounding the Southwestern Public Service (SPS) Area Balancing Authority. SPS serves a 52,000 square mile area in southeastern New Mexico, the Texas Panhandle, portions of Oklahoma, and a small part of Kansas. The study leveraged the National Renewable Energy Lab's wind data for 2004-2006 to simulate future scenarios for 2010.[23] Without considering proactive wind curtailments as an option, the study concluded that operating margins[24] during low load periods within SPS would be jeopardized as wind farm development approached 1,100 to 1,200 MW–only slightly above existing wind capacity levels. SPS is working with SPP RTO to finalize operating procedures for curtailment of generation resources based on transmission priority and communicate them to generation developers as a near-term solution. SPS does have a posted policy for curtailment of resources if necessary.[25] Consolidating the SPP RTO's Balancing Authorities will help facilitate wind integration in the Region, but additional changes to the SPP Open Access Transmission Tariff (OATT), interconnection agreements, operating procedures, and market design may be required to maintain adequate operating margins within portions of SPP as wind development continues.[26]

SPP RTO continues to coordinate operating plans with the operating entities in these areas. Mitigation plans and local in-place operating guides are forecast to provide sufficient flexibility should issues arise. NERC, along with SPP and SERC, will continue to monitor this area for reliability impacts and coordinate any actions with the SPP Reliability Coordinator and SPP Regional Entity.

Drought Conditions

Sufficient water resources are vital to maintain generation availability on bulk power systems. Steam generation is dependent on water from rivers and lakes to cool generating units. The need for water for generator cooling is especially true in areas that are highly dependent on fossil and nuclear generation. Water is also needed to generate and store hydroelectric power. While the southern U.S. is generally more vulnerable to generator outages and environmental derates due to low water levels, the northwest and some Canadian operators are more concerned with managing reservoir levels for power generation with competing uses of water (*i.e.,* human use, agricultural demands, and environmental restrictions).

In both cases, extreme summer weather can cause significant concerns for system operators. During peak conditions, areas affected by drought conditions may have generation limited due to environmental restrictions or low water levels, as well as potential increases in electrical demand due to extreme and prolonged hot weather. This compounding effect can pose reliability issues with few options for mitigation of potential capacity deficiencies. Figure 16 demonstrates the below-average stream flow conditions as detected by United States Geological Survey flow gauges based on historical average flows as of March 2011.[27]

[23] NREL Wind Data: http://www.nrel.gov/wind/integrationdatasets/eastern/methodology.html

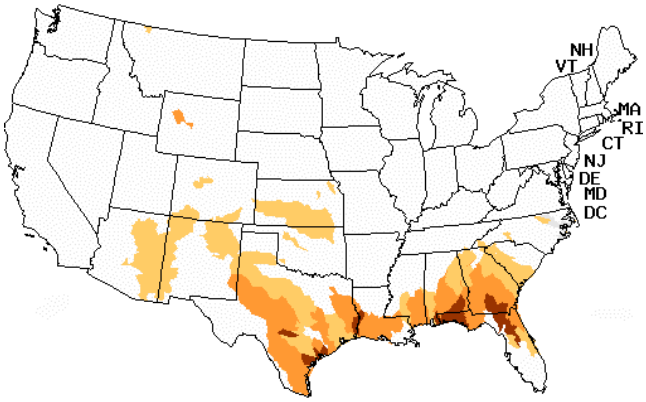
[24] Operating margins refers to the amount of backup generation that is available to handle load as the wind generation falls off.

[25] SPS Curtailment Policy: http://www.oatioasis.com/SPS/SPSdocs/XEL-PRO-Transmission_Procedure_manual_schedules.pdf

[26] Consolidation of balancing authorities was a recommended action in the NERC Report *Accommodating High-Levels of Variable Generation, 2009*: http://www.nerc.com/files/IVGTF_Report_041609.pdf
A follow-on report titled *Ancillary Service and Balancing Authority Area Solutions to Integrate Variable Generation, 2011*, was also published: *http://www.nerc.com/files/IVGTF2-3.pdf*

[27] USGS Water Resources Outlook: http://wateroutlook.nwrfc.noaa.gov/home

FIGURE 16: MAP OF BELOW-NORMAL MONTHLY AVERAGE STREAM FLOW COMPARED TO HISTORICAL STREAM FLOW FOR APRIL 2011 (UNITED STATES)



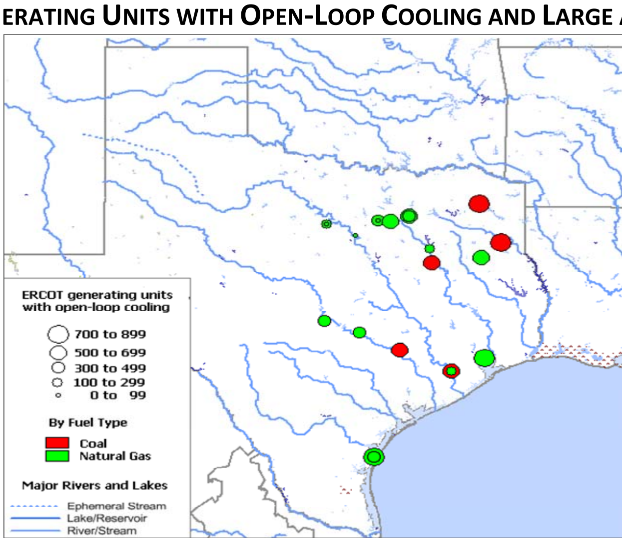
Source: United States Geological Service

Red	Brown	Orange	Tan
Extreme Hydrologic Drought	Severe Hydrologic Drought	Moderate Hydrologic drought	Below Normal

Currently, most of Texas is experiencing drought conditions, though conditions are expected to improve into the summer months.[28] Despite forecasted improvements in both precipitation and drought conditions, ERCOT should closely monitor drought conditions and reservoir levels that could restrict generator performance levels or cause temporary generator shutdowns.

In ERCOT, approximately 20,000 MW of summer-rated capacity (approximately 25 percent of on-peak summer capacity) requires open-loop cooling from nearby bodies of water (Figure 17).[29] Although almost all of the open-loop cooling is from reservoirs dedicated to the power plants, they do need make-up water from rivers or streams to compensate for evaporation. This capacity spans the eastern portion of the ERCOT area—the same area where drought conditions are categorized as "D4-Drought Exceptional" by the NOAA Drought Monitor.

FIGURE 17: ERCOT GENERATING UNITS WITH OPEN-LOOP COOLING AND LARGE AVERAGE WITHDRAWALS

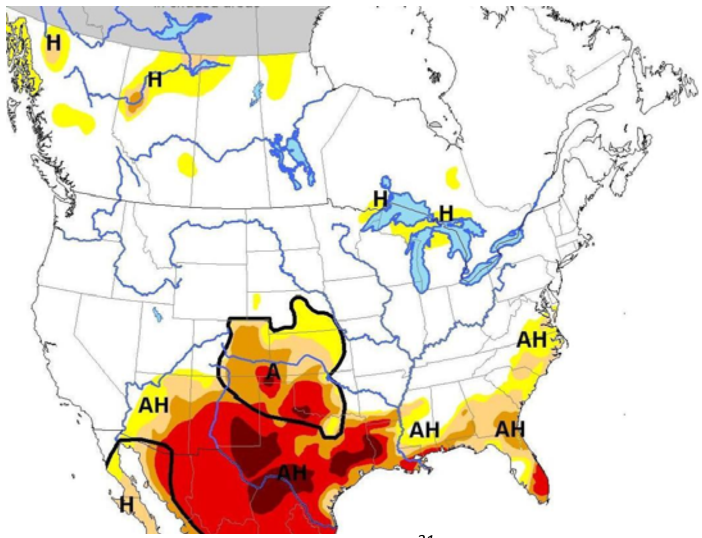


[28] North American Drought Monitor, NOAA: http://www.ncdc.noaa.gov/temp-and-precip/drought/nadm/nadm-maps.php

[29] Annual average cooling water withdrawals of more than 100 cubic feet/second. Based on an independent analysis of data collected by the Energy Information Agency, Forms EIA-860 and EIA-923.

Because drought conditions can lead to a common-mode failure on many units sharing the same bodies of water, close monitoring is needed, as well as flexibility. For the summer peak, ERCOT has approximately 9,000 MW in reserve capacity available to manage unexpected generator forced outages and demand forecasting deviations. While a complete temporary shutdown of vulnerable units is highly unlikely, if half of the vulnerable capacity is derated, the Reserve Margin would be near zero.[30] With Planning Reserve Margins for ERCOT approaching the Regional requirement (within one percentage point), resources may need to be tightly managed in order to maintain sufficient capacity and adequate performance levels should drought conditions persist.

Figure 18: North American Drought Monitor for April 2011



Source: NOAA[31]

Drought Intensities				
D0 (Yellow)	D1 (Light Brown)	D2 (Orange)	D3 (Red)	D4 (Burgundy)
Abnormally Dry	Drought – Moderate	Drought – Severe	Drought – Extreme	Drought – Exceptional

Drought Impact Types Delineates Dominate Impacts / A=Agricultural / H = Hydrological

Similar drought conditions are also being experienced in the southern part of WECC. Parts of WECC is currently experiencing moderate to severe drought conditions, leading to concerns about generation plant operability (Figure 18). The Lower Colorado River Basin is experiencing an unprecedented tenth year of drought conditions. Due to low reservoir levels, the Hoover power plant capacity projection for this summer is forecast to provide an average capacity of 1,692 MW, compared to a maximum plant output of 2,074 MW.

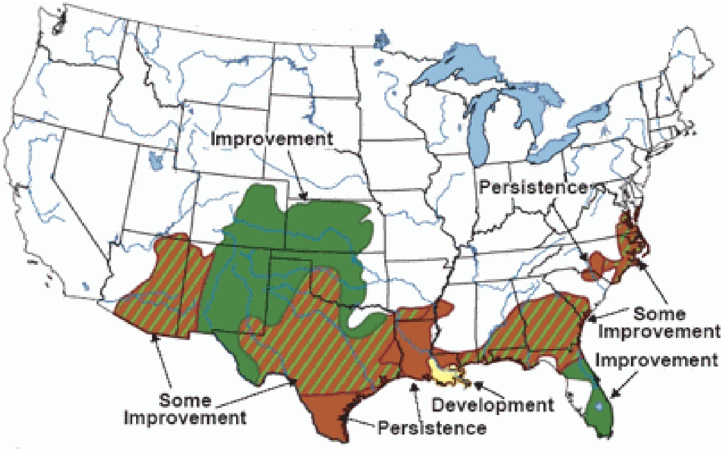
Increased imports and operating procedures may be required if drought conditions worsen. The U.S. Seasonal Drought Outlook forecasts drought conditions to persist or even intensify through the summer months (Figure 19). While no significant reliability concerns have been identified, drought conditions will be closely monitored should conditions intensify and become more widespread.

[30] This is only a sensitivity-based assessment of potential scenarios; no rigorous analysis has been performed involving potentially vulnerable capacity in the ERCOT Region.

[31] http://www.ncdc.noaa.gov/nadm.html

FIGURE 19: U.S. SEASONAL DROUGHT OUTLOOK

VALID: MAY 19, 2011 THROUGH AUGUST 31, 2011

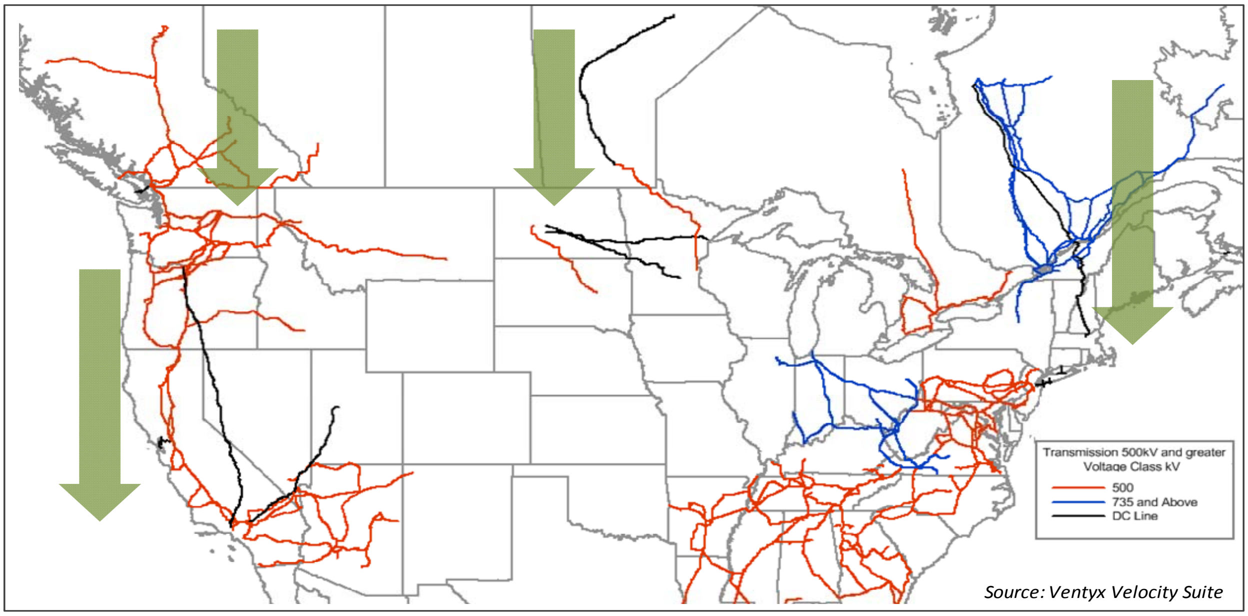


Source: NOAA Climate Prediction Center

Brown	Brown and Green	Green	Yellow
Drought to Persist or Intensify	Drought Ongoing, Some Improvement	Drought Likely to improve, impacts ease	Drought Development Likely

In SERC, reservoir levels are mostly at or near normal levels as the previous drought conditions have greatly subsided throughout the Region. In Canada, drought conditions are not forecast to have any significant impact on reliability during the summer months, though some drought conditions have been observed in northwest Canada.[32] Areas in the north, particularly Canada and the Pacific Northwest, provide generation to the south that is vital to resource adequacy of summer-peaking areas (Figure 20).

FIGURE 20: HIGH CAPACITY TRANSMISSION LINES FROM NORTH TO SOUTH



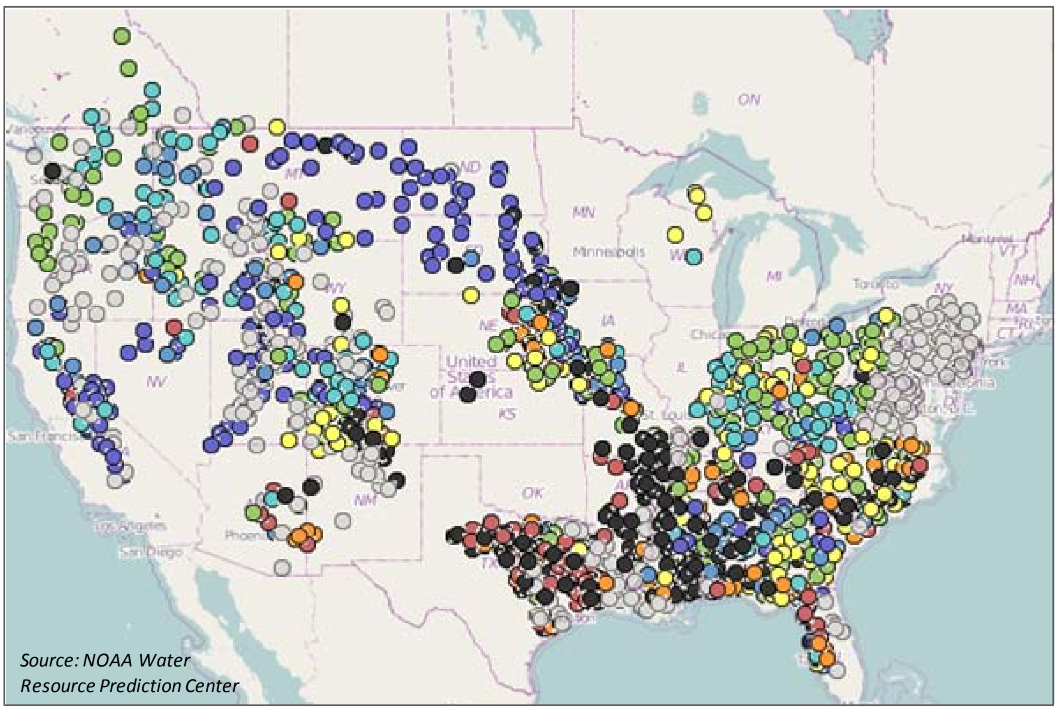
Source: Ventyx Velocity Suite

[32] Agriculture and Agri-Food Canada: *Drought Watch*: http://www.agr.gc.ca/pfra/drought/nlplmr_e.htm

For the Pacific Northwest (operating area NWPP), a La Niña weather pattern resulted in deeper snow pack during November along with late winter storms. As spring progresses and snow begins to melt, several inland Northwest rivers are likely to approach flood stage. The water equivalent in snow pack across the area is running at 101 percent of normal on the Spokane River, 114 percent of normal on the upper and lower Clark Fork, 115 percent of normal on the Kootenai River, 93 percent of normal on the Salmon River, and 103 percent on the lower Snake River drainage.

These high-water conditions are favorable for NWPP. The latest data from NOAA's Water Resource Prediction Center shows improving projected river flows in the NWPP area (Figure 21). However, a severe summer weather event (heat wave) for the entire NWPP would add approximately 4,000 MW of demand, while at the same time loss-of-head water restrictions could reduce the area's capability by 7,000 MW—a significant compounding effect.[33]

FIGURE 21: NOAA WATER RESOURCES MAP FOR MAY 2011



Source: NOAA Water Resource Prediction Center

Map Legend

>150% of median flow	90% - 110% of median flow	<50% of median flow
130% - 150% of median flow	70% - 90% of median flow	No median
110% - 130% of median flow	50% - 70% of median flow	No Forecast

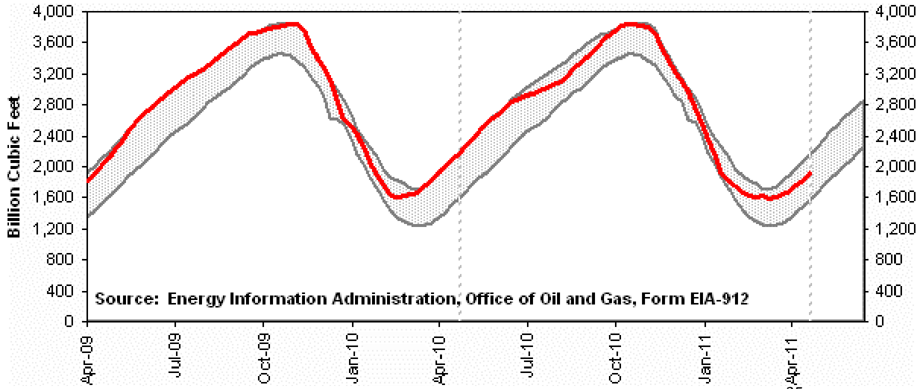
[33] Loss-of-head water restrictions refer to the temporary loss of hydroelectric capacity due to high-water conditions on Regional streams, rivers, lakes, or reservoirs. The term loss-of-head refers to the loss of the distance between the falling water (top and bottom) and resultant losses from backpressure due to high water conditions on the output (tail race) of the power plant.

Operational Challenges - Fuel

Most areas have indicated that they expect no fuel deliverability issues for the upcoming summer at this time. However, the increased reliance on natural gas (NG) as one of the leading fuels used for both intermediate and peaking capacity has prompted NERC to monitor reliability considerations associated with not only supply, but delivery as well. The issue of natural gas deliverability is Region-specific and NERC has undertaken a separate study to better understand the reliability implications. An interim report on this issue is forecast to be issued in Fall 2011.[34]

As of April 15, 2011, natural gas stocks (underground storage) are 165 billion cubic feet (Bcf) less than this time last year, but 23 Bcf above the five-year average (Figure 22).

FIGURE 22: WORKING NATURAL GAS IN UNDERGROUND STORAGE AS OF MAY 20, 2011



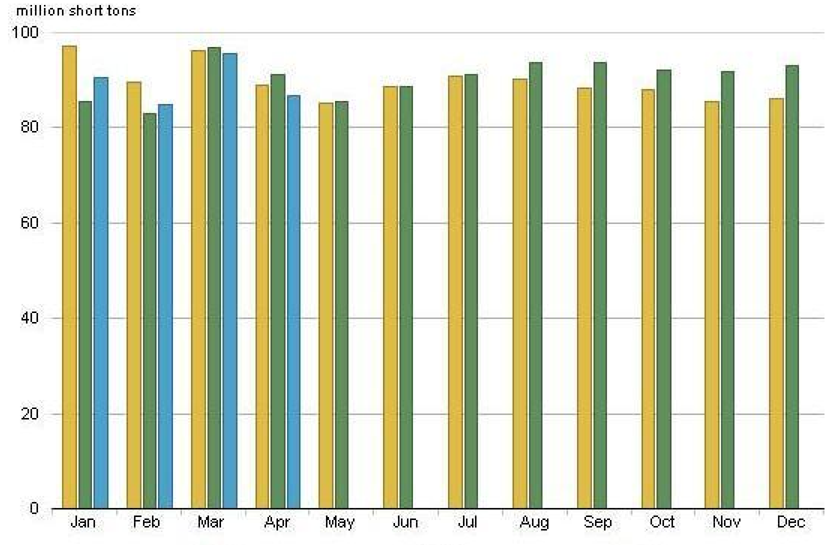
Source: U.S. Energy Information Administration, Form EIA-912[35]

Weather affects a significant portion of demand for natural gas by generators. Persistent high temperatures in large swaths of the United States could further enhance demand and affect storage quantities of natural gas. Given the high amount of domestic production and the adequate amount of natural gas in storage, gas supply issues are not expected.

Coal production in the United States was above 2010 levels in January [91 million short tons (MST) in 2011, compared to 86 MST in January 2010] and February (85 MST in February 2011; 83 MST in February 2010) of this year (Figure 23). This is slightly below production levels in March 2010 (96 MST in March 2011; 97 MST in March 2010). No areas have identified issues with coal stocks or deliveries.

[34] http://www.nerc.com/docs/pc/ras/Draft2011GasStudyScope.pdf
[35] http://ir.eia.gov/ngs/ngs.html

FIGURE 23: U.S. MONTHLY COAL PRODUCTION THROUGH APRIL 2011



Source: Energy Information Administration[36]

Blue	Green	Tan
Year 2011	Year 2010	Year 2009

Oil Supply Review[37]

A Reserve Margin analysis was performed to identify disruption impacts of the oil supply used for electric generation. This analysis, which used generation and demand data from the 2010 Long Term Reliability Assessment, determined that there would be a limited impact on Reserve Margins if an oil disruption occurred (Figure 24).[38] Oil is primarily used for a backup or secondary fuel for electric generation, and is rarely used by generator operators. However, for this analysis, only capacity that uses oil as its primary generation fuel was included. By removing 100 percent of this capacity, no significant impacts to system reliability were observed. This scenario is unlikely, but serves as a stress test to gauge the impacts of a low probability event. In practice, oil is generally stored on-site, therefore system operators are able to determine fuel inventories at any given time, unlike the just-in-time delivery of natural gas. If oil-supply levels are falling drastically and there is a direct impact on generator availability, Reliability Coordinators are notified immediately.[39]

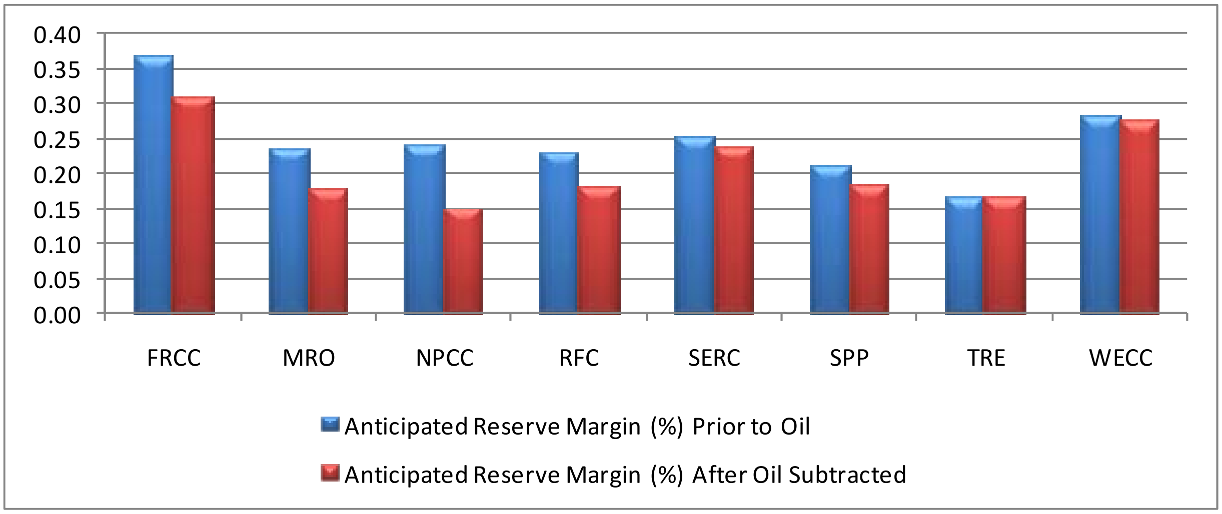
[36] http://www.eia.doe.gov/cneaf/coal/page/coalnews/images/monthly_prod/monthly_prod.jpg

[37] ERCOT, FRCC, NPCC, and WECC use the 2011 peak summer supply and demand forecast from 2011 Summer Reliability Assessment. MRO, SPP, SERC, and RFC use the 2011 peak summer supply and demand forecast from the 2010 Long-Term Reliability Assessment. 2011 peak summer oil capacity forecast from the 2010 Long-Term Reliability Assessment is used for all Regions.

[38] This analysis reviewed the complete loss of oil used as a primary fuel for generation, and did not account for loss of oil in other Areas essential for reliable operation of generator or transmission equipment.

[39] NERC Reliability Standard EOP-004-1: http://www.nerc.com/files/EOP-004-1.pdf

FIGURE 24: RESERVE MARGIN SENSITIVITY ANALYSIS WITH OIL DISRUPTION



Facility Ratings

On October 7, 2010, a NERC Alert that recommended the consideration of actual field conditions in determination of facility ratings was distributed to the industry.[40] The Alert stated:

> *NERC and the Regional Entities have become aware of discrepancies between the design and actual field conditions of transmission facilities, including transmission conductors. These discrepancies may be both significant and widespread, with the potential to result in discrepancies in line ratings.*

In that Alert, NERC recommended that entities verify their rating methods based on actual field conditions rather than solely on design documents and take corrective action if necessary. The Alert required entities to develop a plan to identify and implement any necessary actions to correct their ratings, and report that plan to NERC and Regional entities by January 18, 2011.

The Alert requires applicable Transmission and Generation Owners to perform an assessment of its facilities to verify that the actual conditions conform to the Owner's design tolerances in accordance with its Facility Ratings Methodology.[41] If an Owner identifies a condition or conditions it believes is a discrepancy, NERC recommends that the Owner report the discrepancy to its Reliability Coordinator (RC), Transmission Operator (TOP), and the Planning Authority (PA) at the time of the discrepancy. This coordination may include establishing interim mitigation plans to address the assessment findings and any actions required to maintain bulk power system stability and reliability.

Although such plans may include derating of facilities consistent with actual field conditions, consideration should be given to optimizing the overall robustness and reliability of the bulk power system during the remediation period. A change in facility ratings—deratings in particular—

[40] NERC Alert—*Recommendation to Industry, Consideration of Actual Field Conditions in Determination of Facility Ratings*: http://www.nerc.com/fileUploads/File/Events%20Analysis/Ratings%20Recommendation%20to%20Industry%20FINAL-REVISED.pdf

[41] NERC Reliability Standard FAC-008-1: http://www.nerc.com/files/FAC-008-1.pdf

affect the way in which systems are planned and operated. Facility derates essentially limit the amount of power than can be transmitted from one area to another. In cases where facility deratings affect the deliverability of resources across designated transmission lines, net seasonal generation capacity may also be constrained.

While some entities have already addressed the Alert's recommendations and have subsequently updated facility ratings, some entities have or will submit plans to remediate any identified discrepancies. Any changes that have already occurred have been incorporated into the reliability assessment process, which includes identifying potential generation constraints or reductions to transfer capabilities that can affect overall available capacity for a given area. For the upcoming summer, the Regions have not identified any concerns related to the remedial action taken by the industry to address the recommendations of the Alert. Based on data submitted to NERC as of April 2011, no significant derating has been reported and stressed operating conditions are not forecast.

While assessments of the highest priority facilities are projected to be completed by the end of 2011, assessments of lowest priority facilities are requested by the end of 2013. Remedial action is forecast to be performed within one year from the time a discrepancy is determined. NERC, as well as the Regional Entities, will continue to monitor for significant changes in facility ratings due to remedial actions or interim solutions that can impact reliability.

Nuclear Generation

The recent events at Tokyo Electric's *Fukushima-Daiichi* nuclear power plant in Japan following the March 11 earthquake and resulting tsunami have caused heightened public concern about vulnerabilities of nuclear power facilities in the United States and Canada. The Nuclear Regulatory Commission (NRC), the federal agency responsible for ensuring nuclear plant safety in the United States, is undertaking a systematic and methodical review of the safety of domestic facilities.[42] The objective of this long-term review is to identify any permanent NRC regulation changes determined to be necessary based on experiences and lessons learned from the events in Japan. According to the NRC, its report with recommended actions is not forecast until after the 2011 summer. Therefore, no impacts to the nuclear generation fleet in the United States are projected this summer.

Severe Spring Storms

The weeks of April 18, 2011 and April 25, 2011 saw a significant outbreak of severe weather in the southeastern portion of the United States. Entities located in the SERC Region suffered severe damage to bulk power system assets during this period. This outbreak of strong storms caused extensive damage to not only the Region's distribution systems, but also to the bulk power system. Monumental recovery efforts continue as this assessment is being published. It is expected that currently unknown amounts of both generation and load will be lost due to the historic levels of flooding, and utilities in the affected areas will continue to monitor the situation and operate the system reliably under these difficult conditions.

[42] Testimony by Gregory B. Jaczko, Chairman of United States Nuclear Regulatory Commission to the Environment and Public Works Committee and the Clear Air and Nuclear Safety Subcommittee, United States Senate, April 12, 2011. http://pbadupws.nrc.gov/docs/ML1110/ML111020070.pdf

Preliminary reports indicate there are no expected generation or transmission-related operational issues impacting the summer operating season. One of the most significant impact of these storms resulted in the 3,300 MW Browns Ferry Nuclear Generation Station to come offline due to significant substation damage, as well as the toppling of two 500 kV lines. A preliminary resource adequacy analysis was performed by NERC, which excluded the capacity of the Browns Ferry Nuclear Generation Station in the SERC-N area. Should the nuclear plant be out of service through the summer, sufficient Reserve Margins remain and no Regional issues are expected to impact reliability.

Mid-May tornado activity in the Midwest also affected multiple bulk power system facilities. While these facilities will remain out-of-service until utility crews can repair the damages, no extended impacts have been identified. The extent of the damages remained relatively local, keeping the bulk power system intact and preventing any widespread issues.

As organizations in the SERC and MRO Regions complete their immediate restoration works, additional focus will be spent on planning, contingency analysis, and mitigating any newly discovered vulnerabilities. SERC and MRO will continue to monitor and assist in the coordination of rebuilding efforts through daily situational awareness reports, events analysis, conference calls, and other methods as required.

Geo-Magnetic Disturbances

Designing for robust and resilient performance of the bulk power system in the face of familiar and well-understood threats has been an important emphasis of the electric sector since its inception. As a result, the system is highly reliable and resilient to the more familiar design threats such as equipment failure, human error, severe wind, lightning, and ice loading exposures.

The potential impacts of geo-magnetic disturbance (GMD) events has gained renewed attention as recent studies[43] have suggested the severity of solar storms may be higher and reach lower geographic latitudes than formerly forecast. NERC and the U.S. Department of Energy identified this as a High Impact, Low Frequency event risk to bulk power system reliability in a joint report issued in April 2010.[44] GMD can impact bulk power system reliability in many ways. The two most extensive impacts are the potential damage to transformers, which can result in long-term impacts if replacement transformers cannot be installed rapidly, and short-term disruptions to communication and control. The most well known recent experience in North America was the March 13–14, 1989, geo-magnetic disturbance that led to the collapse of the Hydro Québec system in the early morning hours of March 13, 1989, lasting approximately nine hours.[45]

The solar storm cycle is typically 11 years. The last cycle peaked in 2001 and earlier predictions from the National Oceanic and Atmospheric Administration's (NOAA) Space Weather Prediction Center (SWPC) forecast the maximum peak of sunspots [which is correlated with coronal-mass

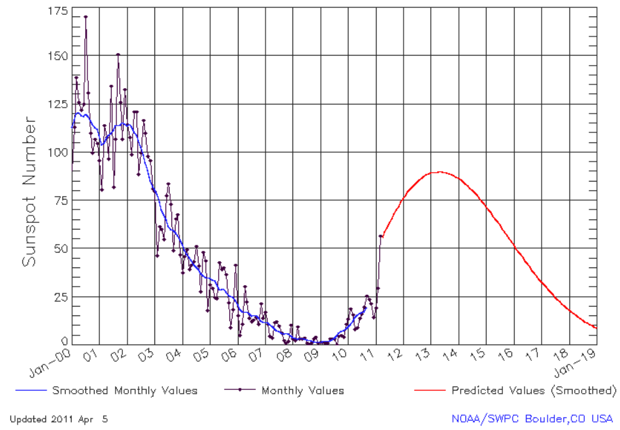
[43] The U.S. Federal Energy Regulation Commission and Oak Ridge National Labs issued a number of reports on Geo-magnetic Storms and their impact on the bulk power system in November 2010: http://www.ornl.gov/sci/ees/etsd/pes/ferc_emp_gic.shtml

[44] The High-Impact, Low-Frequency Report can be found here: http://www.nerc.com/files/hilf.pdf

[45] NERC Report on 1989 GMD Event: http://www.nerc.com/files/1989-Quebec-Disturbance.pdf

ejections (CMEs) also known as solar flares] during 2011 through 2012. Updated forecasts reveal a 2012 through 2013 peak period (Figure 25).[46]

FIGURE 25: NOAA SOLAR CYCLE SUNSPOT NUMBER PROGRESSION



Geo-magnetic storms are unlike terrestrial weather threats to the power grid. These storms can not only develop rapidly but also have continental footprints that can result in widespread simultaneous impact to many points on the system. The system is not designed to operate through the simultaneous loss of many key assets and such an impact could quickly bring the system outside the protection provided by traditional planning and operating reliability criteria, resulting in potential system instability and, in some cases, widespread disturbances and outages. In view of the new awareness of the possible extremes of the geo-magnetic storm environment, a focused review and perspective on the role of the design and operation of the bulk power system with respect to these threats is underway through the NERC sponsored GMD Task Force.[47]

To provide advanced insights for preparation enhancements that could alleviate the potential issues on bulk power system reliability, on May 10, 2011, NERC distributed a NERC Alert to applicable users, owners, and operators. The *Preparing for Geo-Magnetic Disturbances* NERC Alert[48] states,

> *NERC and Regional Entities are monitoring the threat to bulk power system reliability from Geo-Magnetic Disturbances caused by solar activity. This Advisory provides industry with a set of operational and planning actions to prepare for the effects of severe Geo-Magnetic Disturbances on the bulk power system.*

The electric industry has already taken some meaningful steps to mitigate this risk as outlined in the January 2009 Report by the National Academy of Sciences: "Severe Space Weather Events—Understanding Societal and Economic Impacts Workshop Report."[49] While no significant GMD events are predicted for the upcoming summer, progress is being made to prepare and harden systems to withstand or minimize bulk power system impacts during such events.

[46] GMD Background Document: http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2011-05-10-01_GMD_Background_FINAL.pdf
[47] *High-Impact, Low-Frequency Event Risk to the North American Bulk Power System,* June 2010: http://www.nerc.com/files/HILF.pdf
[48] NERC Alert on Geomagnetic Disturbances: http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2011-05-10-01_GMD_FINAL.pdf
[49] http://lasp.colorado.edu/education/journalists/solar_dynamics_ws/papers/lowres%20Severe%20Space%20Weather%20FINAL.pdf

Projected Demand, Resources, and Reserve Margins

To improve consistency and increase granularity and transparency, the NERC Planning Committee approved the following categories[50] for capacity resources and transactions:

1. **Existing:**
   a. **Existing-Certain** — Existing generation resources available to operate and deliver power within or into the Region during the period of assessment.
   b. **Existing-Other** — Existing generation resources that may be available to operate and deliver power within or into the Region during the period of assessment, but may be curtailed or interrupted at any time for various reasons.
   c. **Existing, but Inoperable** — Existing portion of generation resources that are out of service and cannot be brought back into service to serve load during the period assessment.

2. **Future:**
   a. **Future-Planned** — Generation resources anticipated to be available to operate and deliver power within or into the Region during the period of assessment.
   b. **Future-Other** — Future generating resources that do not qualify in Future-Planned and are not included in the Conceptual category.

The monthly estimates of peak-demand, resources and Reserve Margins for each Region during the 2011 summer season are shown in Tables 1 through 5.[51]

Demand, Capacity, and Margins

Total Internal Demand (MW) — 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. Total Internal Demand includes adjustments for indirect Demand-Side Management programs such as conservation programs, improvements in efficiency of electric energy use, and all non-dispatchable Demand Response programs

Net Internal Demand (MW) — Total Internal Demand less Dispatchable, Controllable Capacity Demand Response used to reduce load.

Existing-Certain and Net Firm Transactions (MW) — Existing-Certain capacity resources plus Firm Imports, minus Firm Exports.

Anticipated Capacity Resources (MW) — Existing-Certain and Net Firm Transactions plus Future-Planned capacity resources plus Projected Imports, minus Projected Exports

Prospective Capacity Resources (MW) — Anticipated Capacity Resources plus Existing-Other capacity resources, minus all Existing-Other deratings (includes derates from variable resources, energy-only resources, scheduled outages for maintenance, and transmission-limited resources), plus Future-Other capacity resources, minus all Future-Other deratings.

Existing-Certain and Net Firm Transactions (%) — Existing-Certain, and Net Firm Transactions minus Total Internal Demand shown as a percentage of Total Internal Demand.

Anticipated Reserve Margin (%) — Anticipated Capacity Resources minus Total Internal Demand shown as a percentage of Total Internal Demand.

Prospective Reserve Margin (%) — Prospective Capacity Resources minus Total Internal Demand shown as a percentage of Total Internal Demand.

NERC Reference Reserve Margin Level (%) – Either the Target Capacity Margin provided by the Region/subregion or an NERC-assigned value based on capacity mix (*i.e.,* thermal versus hydro).

[50] See the section entitled *Reliability Concepts Used in this Report* for definitions that are more detailed.
[51] For the ERCOT and WECC (U.S. and Canada) Regions, and the subregions of NPCC and RFC, coincident peaks are provided.

Projected Demand, Resources, and Reserve Margins

Table 1: Estimated Demand, Resources, and Reserve Margins – Summer Peak 2011

	Total Internal Demand (MW)	Net Internal Demand (MW)	Existing-Certain and Net Firm Transactions (MW)	Anticipated Capacity Resources (MW)	Prospective Capacity Resources (MW)	Existing-Certain and Net Firm Transactions (%)	Anticipated Reserve Margin (%)	Prospective Reserve Margin (%)	NERC Reference Reserve Margin Level (%)
United States									
ERCOT	64,964	63,531	73,969	74,229	74,229	13.9%	14.3%	14.3%	13.75%
FRCC	46,091	42,960	61,116	61,116	61,116	32.6%	32.6%	32.6%	15.0%
MISO	99,572	91,753	120,882	120,882	134,098	21.4%	21.4%	34.7%	15.0%
MRO-MAPP	5,087	5,027	6,398	6,484	6,484	25.8%	27.5%	27.5%	15.0%
NPCC-ISO-NE	27,550	25,515	32,761	32,761	32,771	18.9%	18.9%	19.0%	15.0%
NPCC-NYISO	32,712	30,659	38,975	38,975	38,975	19.1%	19.1%	19.1%	15.5%
PJM	148,941	137,341	193,266	193,266	193,266	29.8%	29.8%	29.8%	15.0%
SERC-W	25,101	24,228	36,896	36,896	39,184	47.0%	47.0%	56.1%	15.0%
SERC-E	43,249	41,562	53,048	53,683	53,683	22.7%	24.1%	24.1%	15.0%
SERC-SE	49,314	47,610	61,598	61,598	64,899	24.9%	24.9%	31.6%	15.0%
SERC-N	46,846	44,931	59,961	59,961	59,961	28.0%	28.0%	28.0%	15.0%
SPP	53,512	52,261	64,588	64,851	66,932	20.7%	21.2%	25.1%	14.9%
WECC-CA-MX	57,646	55,442	68,136	68,800	68,800	18.2%	19.3%	19.3%	14.9%
WECC-Desert SW	29,049	28,600	37,816	39,100	39,100	30.2%	34.6%	34.6%	13.5%
WECC-RMPA	10,973	10,565	14,263	14,401	14,401	30.0%	31.2%	31.2%	12.5%
WECC-NWPP US	36,438	35,182	43,889	44,911	44,911	20.4%	23.3%	23.3%	15.8%
Total-U.S.	777,046	737,167	967,562	971,914	992,811	24.5%	25.1%	27.8%	15.0%
Canada									
MRO-Manitoba	3,166	2,939	4,470	4,481	4,481	41.2%	41.5%	41.5%	12.0%
MRO-SaskPower	3,045	2,954	3,673	3,673	3,673	20.6%	20.6%	20.6%	15.0%
NPCC-Maritimes	3,553	3,553	5,646	5,646	5,646	58.9%	58.9%	58.9%	15.0%
NPCC-IESO	23,561	23,561	31,042	31,054	32,366	31.7%	31.8%	37.4%	21.3%
NPCC-Québec	21,283	21,283	31,043	31,084	31,194	45.9%	46.1%	46.6%	10.0%
WECC CAN	18,035	18,013	22,093	22,698	22,698	22.5%	25.9%	25.9%	12.3%
Total-Canada	72,643	72,303	97,967	98,636	100,058	34.9%	35.8%	37.7%	15.0%
México									
WECC CA-MX Mex	2,190	2,190	3,020	3,126	3,126	37.9%	42.7%	42.7%	11.9%
Total-NERC	851,879	811,660	1,068,549	1,073,676	1,095,995	25.4%	26.0%	28.7%	15.0%

TABLE 2: ESTIMATED DEMAND, RESOURCES, AND RESERVE MARGINS - JUNE 2011

	Total Internal Demand (MW)	Net Internal Demand (MW)	Existing-Certain and Net Firm Transactions (MW)	Anticipated Capacity Resources (MW)	Prospective Capacity Resources (MW)	Existing-Certain and Net Firm Transactions (%)	Anticipated Reserve Margin (%)	Prospective Reserve Margin (%)	NERC Reference Reserve Margin Level (%)
United States									
ERCOT	56,997	55,564	73,959	74,219	74,219	29.8%	30.2%	30.2%	13.75%
FRCC	43,900	40,799	61,085	61,085	61,085	39.1%	39.1%	39.1%	15.0%
MISO	93,244	85,425	120,042	120,042	133,280	28.7%	28.7%	42.9%	15.0%
MRO-MAPP	4,635	4,611	6,268	6,354	6,354	35.2%	37.1%	37.1%	15.0%
NPCC-ISO-NE	24,531	22,496	32,453	32,453	32,453	32.3%	32.3%	32.3%	15.0%
NPCC-NYISO	32,712	30,659	38,962	38,962	38,962	19.1%	19.1%	19.1%	15.5%
PJM	139,967	128,367	193,266	193,266	193,266	38.1%	38.1%	38.1%	15.0%
SERC-W	22,681	21,851	36,896	36,896	39,184	62.7%	62.7%	72.8%	15.0%
SERC-E	40,548	38,865	51,908	52,543	52,543	28.0%	29.6%	29.6%	15.0%
SERC-SE	46,545	44,840	61,598	61,598	64,899	32.3%	32.3%	39.4%	15.0%
SERC-N	43,892	42,245	59,622	59,622	59,622	35.8%	35.8%	35.8%	15.0%
SPP	50,294	49,059	64,229	64,323	66,405	27.7%	27.9%	32.0%	13.6%
WECC-CA-MX	50,863	48,833	62,283	62,929	62,929	22.5%	23.7%	23.7%	14.9%
WECC-Desert SW	26,466	25,899	37,057	38,167	38,167	40.0%	44.2%	44.2%	13.5%
WECC-RMPA	10,065	9,659	13,844	14,370	14,370	37.5%	42.8%	42.8%	12.5%
WECC-NWPP US	34,910	33,730	43,023	43,321	43,321	23.2%	24.1%	24.1%	15.8%
Total-U.S.	722,251	682,903	956,495	960,150	981,059	32.4%	32.9%	35.8%	15.0%
Canada									
MRO-Manitoba	3,124	2,897	3,821	3,832	3,832	22.3%	22.7%	22.7%	12.0%
MRO-SaskPower	2,978	2,887	3,616	3,616	3,616	21.5%	21.5%	21.5%	15.0%
NPCC-Maritimes	3,529	3,529	5,527	5,527	5,527	56.6%	56.6%	56.6%	15.0%
NPCC-IESO	22,236	22,236	30,811	30,823	32,134	38.6%	38.6%	44.5%	21.3%
NPCC-Québec	20,740	20,740	29,108	28,893	28,987	40.3%	39.3%	39.8%	10.0%
WECC CAN	17,604	17,510	20,660	21,331	21,331	17.4%	21.2%	21.2%	12.3%
Total-Canada	70,211	69,799	93,543	94,022	95,427	33.2%	33.9%	35.9%	15.0%
México									
WECC CA-MX Mex	1,961	1,961	3,020	3,020	3,020	54.0%	54.0%	54.0%	11.9%
Total-NERC	794,422	754,662	1,053,058	1,057,192	1,079,506	32.6%	33.1%	35.9%	15.0%

TABLE 3: ESTIMATED DEMAND, RESOURCES, AND RESERVE MARGINS - JULY 2011

	Total Internal Demand (MW)	Net Internal Demand (MW)	Existing-Certain and Net Firm Transactions (MW)	Anticipated Capacity Resources (MW)	Prospective Capacity Resources (MW)	Existing-Certain and Net Firm Transactions (%)	Anticipated Reserve Margin (%)	Prospective Reserve Margin (%)	NERC Reference Reserve Margin Level (%)
United States									
ERCOT	60,624	59,191	73,969	74,229	74,229	22.0%	22.4%	22.4%	13.75%
FRCC	45,144	42,012	61,116	61,116	61,116	35.4%	35.4%	35.4%	15.0%
MISO	99,572	91,753	120,104	120,104	133,413	20.6%	20.6%	34.0%	15.0%
MRO-MAPP	5,087	5,027	6,253	6,339	6,339	22.9%	24.6%	24.6%	15.0%
NPCC-ISO-NE	27,550	25,515	32,752	32,752	32,752	18.9%	18.9%	18.9%	15.0%
NPCC-NYISO	32,712	30,659	38,975	38,975	38,975	19.1%	19.1%	19.1%	15.5%
PJM	148,941	137,341	193,266	193,266	193,266	29.8%	29.8%	29.8%	15.0%
SERC-W	23,545	22,661	36,769	36,769	39,057	56.2%	56.2%	65.9%	15.0%
SERC-E	43,249	41,562	53,041	53,676	53,676	22.6%	24.1%	24.1%	15.0%
SERC-SE	48,623	46,918	61,586	61,586	64,887	26.7%	26.7%	33.4%	15.0%
SERC-N	46,846	44,931	59,952	59,952	59,952	28.0%	28.0%	28.0%	15.0%
SPP	53,389	52,152	64,588	64,851	66,932	21.0%	21.5%	25.4%	13.6%
WECC-CA-MX	56,031	53,768	66,880	67,559	67,559	19.4%	20.6%	20.6%	14.9%
WECC-Desert SW	28,751	28,291	36,712	37,776	37,776	27.7%	31.4%	31.4%	13.5%
WECC-RMPA	10,973	10,565	14,263	14,401	14,401	30.0%	31.2%	31.2%	12.5%
WECC-NWPP US	36,438	35,182	43,889	44,911	44,911	20.4%	23.3%	23.3%	15.8%
Total-U.S.	767,475	727,528	964,115	968,262	989,242	25.6%	26.2%	28.9%	15.0%
Canada									
MRO-Manitoba	3,136	2,909	4,419	4,430	4,430	40.9%	41.3%	41.3%	12.0%
MRO-SaskPower	3,045	2,954	3,585	3,585	3,585	17.7%	17.7%	17.7%	15.0%
NPCC-Maritimes	3,532	3,532	5,488	5,488	5,488	55.4%	55.4%	55.4%	15.0%
NPCC-IESO	23,561	23,561	31,042	31,054	32,366	31.7%	31.8%	37.4%	21.3%
NPCC-Québec	20,876	20,876	31,043	31,084	31,194	48.7%	48.9%	49.4%	10.0%
WECC CAN	17,970	17,917	22,093	22,698	22,698	22.9%	26.3%	26.3%	12.3%
Total-Canada	72,120	71,749	97,670	98,339	99,761	35.4%	36.4%	38.3%	15.0%
México									
WECC CA-MX Mex	2,076	2,076	2,895	2,895	2,895	39.5%	39.5%	39.5%	11.9%
Total-NERC	841,671	801,354	1,064,680	1,069,496	1,091,898	26.5%	27.1%	29.7%	15.0%

TABLE 4: ESTIMATED DEMAND, RESOURCES, AND RESERVE MARGINS - AUGUST 2011

	Total Internal Demand (MW)	Net Internal Demand (MW)	Existing-Certain and Net Firm Transactions (MW)	Anticipated Capacity Resources (MW)	Prospective Capacity Resources (MW)	Existing-Certain and Net Firm Transactions (%)	Anticipated Reserve Margin (%)	Prospective Reserve Margin (%)	NERC Reference Reserve Margin Level (%)
United States									
ERCOT	64,964	63,531	73,969	74,229	74,229	13.9%	14.3%	14.3%	13.75%
FRCC	46,091	42,960	61,115	61,115	61,115	32.6%	32.6%	32.6%	15.0%
MISO	98,360	90,541	120,104	120,104	133,433	22.1%	22.1%	35.7%	15.0%
MRO-MAPP	4,868	4,761	6,334	6,420	6,420	30.1%	31.9%	31.9%	15.0%
NPCC-ISO-NE	27,550	25,515	32,761	32,761	32,771	18.9%	18.9%	19.0%	15.0%
NPCC-NYISO	32,712	30,659	38,650	38,650	38,650	18.2%	18.2%	18.2%	15.5%
PJM	143,584	131,984	193,266	193,266	193,266	34.6%	34.6%	34.6%	15.0%
SERC-W	25,101	24,228	36,696	36,696	38,984	46.2%	46.2%	55.3%	15.0%
SERC-E	42,519	40,825	53,048	53,683	53,683	24.8%	26.3%	26.3%	15.0%
SERC-SE	49,314	47,610	61,597	61,597	64,898	24.9%	24.9%	31.6%	15.0%
SERC-N	46,777	44,875	59,961	59,961	59,961	28.2%	28.2%	28.2%	15.0%
SPP	53,512	52,261	64,545	64,808	66,889	20.6%	21.1%	25.0%	13.6%
WECC-CA-MX	57,646	55,442	68,136	68,800	68,800	18.2%	19.3%	19.3%	14.9%
WECC-Desert SW	29,049	28,600	37,816	39,100	39,100	30.2%	34.6%	34.6%	13.5%
WECC-RMPA	10,606	10,196	13,354	14,074	14,074	25.9%	32.7%	32.7%	12.5%
WECC-NWPP US	35,145	33,956	41,923	42,104	42,104	19.3%	19.8%	19.8%	15.8%
Total-U.S.	767,798	727,944	963,275	967,367	988,377	25.5%	26.0%	28.7%	15.0%
Canada									
MRO-Manitoba	3,166	2,939	4,470	4,481	4,481	41.2%	41.5%	41.5%	12.0%
MRO-SaskPower	3,025	2,934	3,673	3,673	3,673	21.5%	21.5%	21.5%	15.0%
NPCC-Maritimes	3,512	3,512	5,490	5,490	5,505	56.3%	56.3%	56.7%	15.0%
NPCC-IESO	22,893	22,893	30,946	30,958	32,258	35.2%	35.2%	40.9%	21.3%
NPCC-Québec	21,283	21,283	29,985	30,282	30,393	40.9%	42.3%	42.8%	10.0%
WECC CAN	18,035	18,013	20,785	21,229	21,229	15.2%	17.7%	17.7%	12.3%
Total-Canada	71,914	71,574	95,349	96,113	97,539	32.6%	33.7%	35.6%	15.0%
México									
WECC CA-MX Mex	2,190	2,190	2,877	2,877	2,877	31.4%	31.4%	31.4%	11.9%
Total-NERC	841,902	801,708	1,061,501	1,066,357	1,088,794	26.1%	26.7%	29.3%	15.0%

TABLE 5: ESTIMATED DEMAND, RESOURCES, AND RESERVE MARGINS - SEPTEMBER 2011

	Total Internal Demand (MW)	Net Internal Demand (MW)	Existing-Certain and Net Firm Transactions (MW)	Anticipated Capacity Resources (MW)	Prospective Capacity Resources (MW)	Existing-Certain and Net Firm Transactions (%)	Anticipated Reserve Margin (%)	Prospective Reserve Margin (%)	NERC Reference Reserve Margin Level (%)
United States									
ERCOT	49,754	48,321	68,938	69,763	69,763	38.6%	40.2%	40.2%	13.75%
FRCC	43,717	40,620	61,081	61,081	61,081	39.7%	39.7%	39.7%	15.0%
MISO	88,928	81,109	120,882	120,882	134,098	35.9%	35.9%	50.8%	15.0%
MRO-MAPP	4,422	4,398	6,398	6,484	6,484	44.7%	46.6%	46.6%	15.0%
NPCC-ISO-NE	23,966	21,931	31,998	31,998	32,008	33.5%	33.5%	33.6%	15.0%
NPCC-NYISO	32,712	30,659	36,942	36,942	36,942	12.9%	12.9%	12.9%	15.5%
PJM	126,463	114,863	193,266	193,266	193,266	52.8%	52.8%	52.8%	15.0%
SERC-W	22,392	21,578	36,843	36,843	39,130	64.5%	64.5%	74.8%	15.0%
SERC-E	38,591	36,893	50,928	51,563	51,563	32.0%	33.6%	33.6%	15.0%
SERC-SE	43,720	42,016	61,597	61,597	64,898	40.9%	40.9%	48.4%	15.0%
SERC-N	42,727	41,441	59,229	59,229	59,229	38.6%	38.6%	38.6%	15.0%
SPP	47,898	46,663	64,136	64,399	66,480	33.9%	34.4%	38.8%	13.6%
WECC-CA-MX	56,468	54,253	67,020	67,792	67,792	18.7%	20.1%	20.1%	14.9%
WECC-Desert SW	26,190	25,617	36,027	36,959	36,959	37.6%	41.1%	41.1%	13.5%
WECC-RMPA	9,210	8,954	11,294	12,172	12,172	22.6%	32.2%	32.2%	12.5%
WECC-NWPP US	29,706	29,251	35,040	35,478	35,478	18.0%	19.4%	19.4%	15.8%
Total-U.S.	686,863	648,566	941,619	946,448	967,344	37.1%	37.8%	40.8%	15.0%
Canada									
MRO-Manitoba	2,954	2,727	3,936	3,947	3,947	33.2%	33.6%	33.6%	12.0%
MRO-SaskPower	2,914	2,823	3,492	3,492	3,492	19.8%	19.8%	19.8%	15.0%
NPCC-Maritimes	3,553	3,553	5,646	5,646	5,646	58.9%	58.9%	58.9%	15.0%
NPCC-IESO	20,426	20,426	28,576	28,591	29,748	39.9%	40.0%	45.6%	21.3%
NPCC-Québec	21,085	21,085	28,884	29,181	29,245	37.0%	38.4%	38.7%	10.0%
WECC CAN	17,430	17,416	20,659	21,141	21,141	18.5%	21.3%	21.3%	12.3%
Total-Canada	68,363	68,031	91,194	91,998	93,219	33.4%	34.6%	36.4%	15.0%
México									
WECC CA-MX Mex	2,121	2,121	2,974	3,126	3,126	40.2%	47.4%	47.4%	11.9%
Total-NERC	757,347	718,718	1,035,787	1,041,572	1,063,689	36.8%	37.5%	40.4%	15.0%

Notes for Tables 1 through 5

Note 1: Existing-Certain resources and Net Firm Transactions are deliverable.

Note 2: The WECC-US peak demands or resources do not necessarily equal the sums of the non-coincident WECC-US subregional peak demands or resources because of subregional monthly peak demand diversity. Similarly, the Western Interconnection peak demands or resources do not necessarily equal the sums of the non-coincident WECC-U.S., Canada, and México peak demands or resources. In addition, the subregional resource numbers include use of seasonal demand diversity between the winter-peaking northwest and the summer-peaking portions of the Western Interconnection.

Note 3: The Demand-Side Management resources are not necessarily sharable between the WECC subregions and are not necessarily sharable within subregions.

Note 4: WECC CA-MX represents only the northern portion of the Baja California Norte, México, electric system interconnected with the United States.

Note 5: These demand and supply forecasts were reported on April 14, 2011.

Note 6: Each Region/subregion may have its own specific Reserve Margin level based on load, generation, and transmission characteristics as well as regulatory requirements. If provided in the data submittal, the Regional/subregional Target Reserve Margin level is adopted as the NERC Reference Reserve Margin Level. If not, NERC assigned a 15-percent Reserve Margin for predominately thermal systems and a ten-percent Reserve Margin for predominately hydro systems.

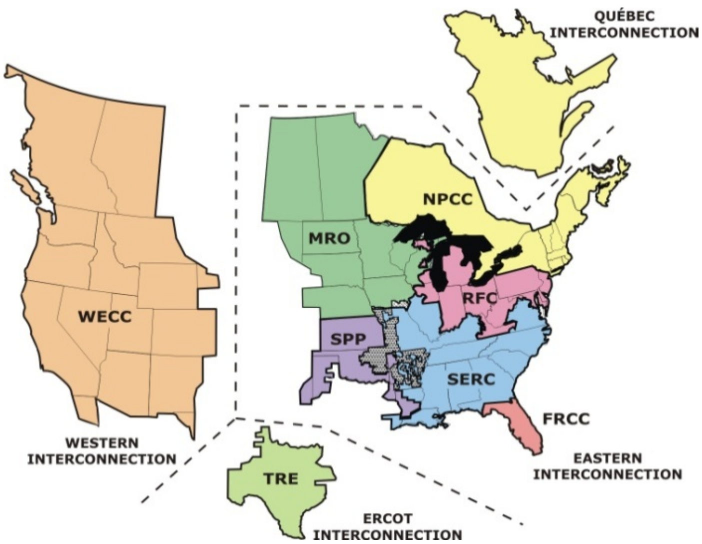
Note 7: Generally, the Anticipated Reserve Margin will be higher than the Existing-Certain & Net Firm Transactions Reserve Margin because Anticipated Reserve Margins include Future-Planned net capacity values (capacity that will be in service between the time the assessment data was compiled and the summer peak). However, Anticipated Reserve Margins also include Expected Transfers (which are less certain than Firm Transfers). In some cases, the Expected Transfer may be an export that outweighs any Future-Planned capacity, thereby resulting in a lesser amount of capacity resources that are available in a given assessment area. In this case, the Anticipated Reserve Margin may be lower than the Existing-Certain & Net Form Transactions Reserve Margin.

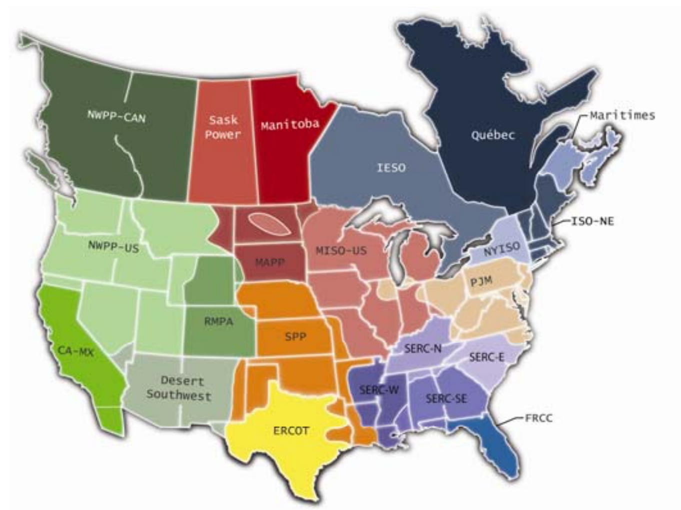
Note 8: Table 1, *ESTIMATED PEAK 2011 SUMMER DEMAND, RESOURCES, AND RESERVE MARGINS,* is compiled using the peak month data from each assessment area. In order to develop the NERC-wide, U.S., and Canada non-coincident aggregated peak Reserve Margins, the peak data from each assessment area is used. Table 1 includes peak data that may be forecast for different months.

Regional Reliability Self-Assessments

Regional Resource and Demand Projections

The figures in the Regional self-assessment pages show the Regional historical demand, projected demand growth, Reserve Margin projections, and generation expansion projections reported by the Regions.





NERC Interconnections **NERC Assessment Areas**

Capacity Fuel Mix

The Regional capacity fuel mix charts shown in each Region's self-assessment presents the relative reliance on specific fuels[52] for its reported generating capacity. The charts for each Region in the Regional self-assessments are based on the most recent data available in NERC's Electricity Supply and Demand (ES&D) database.

[52] Note: The category "Other" may include capacity for which the total capacity of a specific fuel type is less than one percent of the total capacity or the fuel type has yet to be determined.

ERCOT

Introduction

The ERCOT Region is a separate electric interconnection located entirely in the state of Texas and operated as a single Balancing Authority and Reliability Coordinator Area. The generation capacity data are reported to ERCOT by the generation owners. The demand forecast is developed by ERCOT based on economic and weather indicators and historical Regional loads. This report assesses the forecast reliability of the ERCOT Region during 2011 summer.

Demand

The 2010 summer actual peak demand set a new record for the ERCOT Region at 65,776 MW. This peak demand was set with above-normal temperatures in August. The 2011 summer peak demand projected to occur in August is 64,964 MW. This forecast is less than the actual 2010 summer peak demand due to slow economic growth and the fact that the forecast is based on normal weather conditions. The 2011 forecast is slightly higher than the forecast for 2010, which was 64,056 MW.

TABLE 6: FORECAST AND ACTUAL PEAK DEMAND

2010 Total Internal Demand (MW)	2010 Actual Demand (MW)	Difference in Actual versus Forecast (MW)	Difference in Actual versus Forecast (%)	2011 Total Internal Demand (MW)	Difference in 2011 and 2010 Forecast Demand (MW)	Difference in 2010 Actual versus 2011 Forecast (%)	All-Time Summer Peak Demand (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)
64,056	65,776	1,720	2.7%	64,964	908	1.4%	65,776	(812)	-1.2%

The average weather profile (50/50) is used for the ERCOT load forecast. The economic factors that drive the load forecast include per capita income, population, gross domestic product (GDP), and various employment measures that include non-farm employment and total employment. The actual demands used for forecasting purposes are coincident hourly values across the ERCOT Region. The data used in the forecast are differentiated by weather zones.

The forecast peak demands are produced by the ERCOT ISO for the entire ERCOT Region, which is a single Balancing Authority Area, based on the Region-wide actual demands. While the forecast peak demands produced using the average weather profile are used for resource assessments, alternative weather scenarios are used to develop extreme weather load forecasts to assess the impact of weather variability on the peak demand for ERCOT. One scenario is the one-in-ten-year occurrence of a weather event. This scenario is calculated using the 90th percentile of the temperatures in the database spanning the last fifteen years. These extreme temperatures are input into the load-shape and energy models to obtain the forecasts. The extreme temperature assumptions consistently produce demand forecasts that are approximately 5.0 percent higher than the forecasts based on the average weather profile (50/50) for the summer season. Together, the forecasts from these temperature scenarios are usually referred to as 90/10 scenario forecasts.

A 2007 Texas state law[53] mandated that at least 20 percent of an investor-owned utility's (IOU's) annual growth in electricity demand for residential and commercial customers shall, by December 31, 2009, be met through energy efficiency programs each year. The IOUs are required to administer energy savings incentive programs, which are implemented by retail electric and energy efficiency service providers. Some of these programs, offered by the utilities, are designed to produce system peak demand reductions and energy use savings. They include the following: commercial and industrial, residential and small commercial, hard-to-reach, load management, energy efficiency improvement programs, low income weatherization, Energy Star (new homes), air conditioning, air conditioning distributor, air conditioning installer training, retro-commissioning, multifamily water and space heating, Texas SCORE/City Smart, Trees for Efficiency, and third party contracts.

In general, utility savings, as measured and verified by an independent contractor, have exceeded the goals set by the utilities.[54] In the latest assessment, utility programs implemented after electric utility industry restructuring in Texas had produced 1,125 MW of peak demand reduction and 3,014 GWh of electricity savings for the years 1999 through 2008. This demand reduction is accounted for within the load forecast and only the projected incremental portion for the coming year is included as a demand adjustment for the summer season.

Load Resources (LRs)[55] providing Responsive Reserve Service[56] provide an average of approximately 1063 MW of dispatchable, contractually-committed Supply-Side Load as a Capacity Resource during summer peak hours based on the most recently available data. ERCOT's Emergency Interruptible Load Service (EILS), is designed to be deployed in the late stages of a grid emergency prior to shedding involuntary "Firm" load, and also represents Supply-Side Contractually Interruptible Demand. Based on average EILS commitments during 2010, approximately 370 MW of EILS Load can be counted upon during summer peak. Together these two programs would reduce summer peak demand by a little over two percent if activated at that time. Measurement and verification procedures for these programs are defined in the Performance Monitoring section of the ERCOT Protocols.[57]

Generation

ERCOT has 72,255 MW of Existing-Certain generation, of which 106 MW is biomass and 15 MW is solar. ERCOT has approximately 9,185 MW of Existing-Other generation. Approximately 260 MW of Future-Planned capacity is forecast to be in service by June 2011 with a total of 825 MW before the end of the summer season.

[53] http://www.capitol.state.tx.us/tlodocs/80R/billtext/html/HB03693F.htm
[54] http://www.texasefficiency.com/report.html
[55] Previously referred to as Load Acting as Resources (LaaRs)
[56] http://www.ercot.com/content/mktrules/nprotocols/current/02-020111_Nodal.doc
[57] http://www.ercot.com/content/mktrules/nprotocols/current/08-020111_Nodal.doc

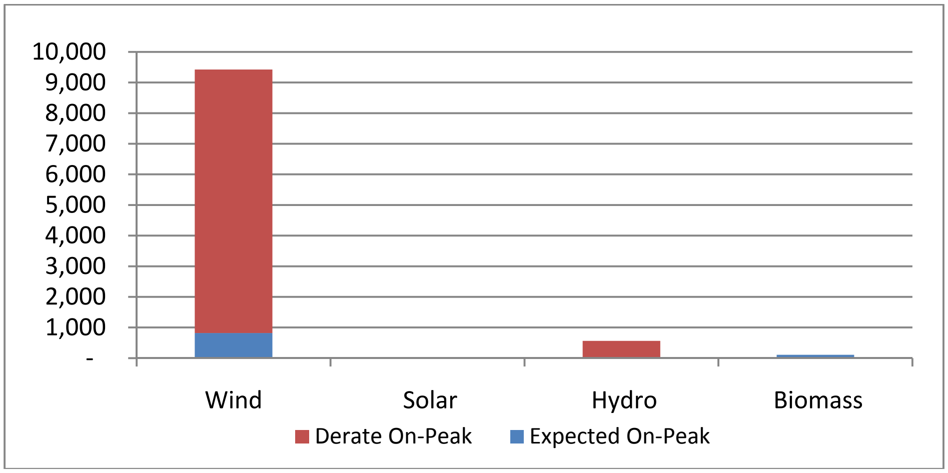
ERCOT has existing wind generation nameplate capacity totaling 9,427 MW; however, only 8.7 percent,[58] or 820 MW, is included in the Existing-Certain amount used for margin calculations. The remaining existing wind capacity amount is included in the Existing-Other category.

TABLE 7: ERCOT EXISTING AND PLANNED PEAK CAPACITY

Existing-Certain (MW)	72,255
Existing-Other (MW)	9,185
Future-Planned (MW)	260

Less than one percent of the ERCOT generation capacity is hydro. These facilities are typically operated as run-of-river or planned release due to downstream needs, and not operated specifically to produce electricity. As a result, hydro conditions should not have a reliability impact on the ERCOT Region this summer. Natural gas supply and transportation issues are typically of more concern in the winter period, due to the competition with home heating for pipeline/distribution capacity. Coal transportation issues are not predicted to have a reliability impact on the ERCOT Region this summer. As a result, fuel conditions are not forecast to impact summer resource availability.

FIGURE 26: ERCOT EXISTING AND PLANNED RENEWABLE GENERATION



There are 2,912 MW of Existing capacity that is mothballed and considered inoperable. This capacity is not counted toward reserves during the 2011 summer. About 5,000 MW is currently scheduled to begin maintenance outages during September, after the typical summer high load period. At the request of the Public Utilities Commission of Texas,[59] ERCOT is reviewing the likely impact of various EPA rule changes on generating capacity in the Region, with a report released on May 11, 2011.[60] Generation owners must submit a Notice of Suspension of Operations to ERCOT 90 days in advance of any retirement, or suspension of operations for more than six months.

[58] The 8.7 percent of wind-installed capacity is based on a 2007 study of the effective load-carrying capability (ELCC) of wind generation. The 2010 LOLEv Study updated the ELCC calculation, but ERCOT did not adopt the revised ELCC for use in Reserve Margin calculations. The 2010 LOLEv Study is available at: http://www.ercot.com/content/meetings/board/keydocs/2010/1116/Item_07_-_2010_Loss_of_Load_Events_(LOLEV),_Target_Reserve_M.zip

[59] http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/37830_15_687162.PDF

[60] ERCOT EPA Report: http://www.ercot.com/news/presentations/2011/ERCOT_Review_EPA_Planning_Final.pdf

ERCOT has not yet received any notices of this type that are directly attributable to new EPA regulations.

TABLE 8: ERCOT EXISTING AND PLANNED RENEWABLE GENERATION

Wind Expected On-Peak	820
Wind Derate On-Peak	8,607
Wind Nameplate/Installed Capacity	9,427
Solar Expected On-Peak	15
Solar Derate On-Peak	-
Solar Nameplate/Installed Capacity	15
Hydro Expected On-Peak	-
Hydro Derate On-Peak	563
Hydro Nameplate/Installed Capacity	563
Biomass Expected On-Peak	106
Biomass Derate On-Peak	-
Biomass Nameplate/Installed	106

Capacity Transactions on Peak

The ERCOT Region is a separate interconnection with only asynchronous ties to Southwest Power Pool (SPP) and México's *Comisión Federal de Electricidad* (CFE) and does not share reserves with other Regions. There are two asynchronous ties between ERCOT and SPP with 820 MW of transfer capability and three asynchronous ties between ERCOT and México with 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 over the asynchronous ties or by transferring block loads. For 2011 summer, ERCOT has 458 MW of imports from SPP and 140 MW from CFE. Of the imports from SPP, 48 MW is tied to a long-term contract for a purchase of Firm power from specific generation. The remaining imports of 410 MW from SPP and 140 MW from CFE represent one-half of the asynchronous tie transfer capability, included to reflect emergency support arrangements. Several SPP members together own 317 MW of a power plant located in the ERCOT Region, resulting in a Firm export of that amount from ERCOT to SPP. There are no known Non-Firm contracts signed or pending, or any other contracts that are known to be under negotiation or study.

TABLE 9: ERCOT IMPORTS AND EXPORTS ON-PEAK

Imports (MW)	598
Firm (MW)	598
Expected (MW)	-
Exports (MW)	317
Firm (MW)	317
Expected (MW)	-
Net Imports (MW)	**281**

ERCOT

Transmission

Several significant transmission improvements, enumerated in Table 10, have been[61] or are projected to be completed throughout the ERCOT Region to meet reliability needs or reduce market congestion[62] prior to or during the summer season.

One of the most significant improvements is the recent completion of the 165 circuit-mile 345 kV double circuit from Zorn/Clear Springs to Hutto Switch. This line, together with the 74 circuit-mile 345 kV double circuit from Salado to Hutto Switch completed last year, creates a new 345 kV path from Zorn/Clear Springs to Salado. A new nine-mile 138 kV line is forecast to be completed prior to the 2011 summer season from Palo Duro to Dilley SS in south Texas. This circuit and a 22-mile upgrade to the Pearsall to Dilley 69 kV line will eliminate several constraints in this Area.

A 12 mile 138 kV line upgrade to the Frisco to Kruegerville in the North Central Texas Area eliminates some load serving constraints between the Collin and Denton load Areas. The conversion of a 28-mile 69 kV line from Hockley to Peters to 138 kV eliminates constraints to the northwest of the Houston Area.

As part of the Zorn/Clear Springs project described above, a new 672 MVA autotransformer will be added at Gilleland SS to provide import into the growing load center from North Austin to Round Rock. Another significant transformer addition is at Hearne, where a new 100 MVA autotransformer will replace an existing 60 MVA unit.

TABLE 10: ERCOT TRANSMISSION ADDITIONS/REBUILDS

Voltage	New Miles	Upgraded Miles
345kV	330	34
138kV	112	279

An additional 300 MVar SVC was added to Renner substation in the Dallas Area to provide dynamic reactive support to loads in that Area. Shunt reactance totaling 500 MVar will be added to various 345 kV stations that are part the Competitive Renewable Energy Zone Transmission Optimization Study prior to the summer season. An additional 903 MVar of reactive support will be added at various locations around the ERCOT System prior to the summer season.

No delays are currently forecast in meeting in-service dates of transmission projects needed for reliability. Some transmission outages may be scheduled during the summer season. ERCOT performs outage coordination to maintain reliability for any planned transmission outages. As transmission constraints are identified, remedial action plans or mitigation plans are developed to provide for preemptive or planned responses to maintain reliability. No transmission constraints are forecast to significantly impact reliability during the summer season.

[61] As of March 2011

[62] Additional details on transmission projects can be found in the *Constraints and Needs Report 2010* located at: http://www.ercot.com/content/news/presentations/2011/2010%20Constraints%20and%20Needs%20Report.pdf

Operational Issues

For the 2011 summer season, no significant special operating studies for 2011 have been performed for the ERCOT Region and no unusual operating conditions that could affect reliability for the upcoming summer are anticipated. ERCOT will use established operational procedures related to variable resources during the summer season. ERCOT has implemented a wind power forecasting system to allow ERCOT ISO system operators to identify and take appropriate action when wind resource schedules may not track projected changes in wind production. ERCOT has also implemented a wind ramp-forecasting tool that provides a probabilistic assessment of the magnitude and likelihood of significant changes in aggregate wind output over upcoming operating periods. Meanwhile, wind output by different Regions is aggregated as a real-time monitoring group to improve operator situational awareness. In addition, ERCOT evaluates the impact of increased installed wind generation on ancillary services requirements on an ongoing basis.[63]

There are no anticipated reliability concerns for the summer season resulting from over-generation during low demand at current levels of wind generation and resource mix. ERCOT limits the participation of Supply-Side Load as a Capacity Resource, or Load Resources, to providing 50 percent of the Responsive Reserve Ancillary Service[64] (currently a 1,150 MW limit), which is deployed in response to large frequency excursions (below 59.7 Hz) or during system emergencies, such as Energy Emergency Alerts (EEA). ERCOT procures Demand Response (DR) products around the clock to address system conditions at all times, not just during peaks. ERCOT's monitoring and testing programs provide confidence that the DR resources will perform when called. The status of Load Resources providing Ancillary Services is monitored in real time via two-second telemetry. Supply-Side Contractually Interruptible Demand, known as Emergency Interruptible Load Service (EILS) load(s), is monitored using after-the-fact metering and are subject to payment reductions and suspension from the program for failing to meet availability requirements. Both DR products are subject to annual unannounced load-shed testing, to be followed by an additional test if the first is unsuccessful. A second consecutive unsuccessful test subjects the resource to suspension.

Table 11: ERCOT Demand Response and Energy Efficiency On-Peak

Non-Dispatchable DSM (MW)	242
Energy Efficiency	242
Non-Controllable Demand-Side Demand Response	-
Total Internal Demand	64,964
Controllable, Dispatchable Demand Response	1,433
Net Internal Demand	63,531

There are no restrictions on the number of deployments in a day for Load Resources procured in the day-ahead Ancillary Services market. EILS Loads are procured for four-month contract periods and are limited to two deployments or a maximum of eight hours over those months—with the proviso that the loads may not return to service until released by ERCOT operations.

[63] http://www.ercot.com/content/mktinfo/dam/kd/ERCOT%20Methodologies%20for%20Determining%20Ancillary%20Service%20Requir.doc

[64] http://www.ercot.com/content/mktrules/nprotocols/current/02-020111_Nodal.doc

EILS was deployed for a total of 28 hours during the EEA event on February 2–3, 2011. While the detailed load-level performance evaluation is still underway, data indicate that the EILS loads met their obligations at the fleet-wide level over the first critical hours of the event. All performance reviews are forecast by the summer season and any deployment issues resolved accordingly.

Currently, there are no low-water level concerns in the ERCOT Region for the assessment period,[65] however, there may be generators with restricted output due to environmental regulations, such as emissions or high water temperatures. Any such generator restrictions that are currently known would be reflected in the Seasonal Net Dependable Capability values reported to ERCOT and used for this assessment. The effects of any limitations that arise are mitigated through procurement of ancillary services and Reliability Unit Commitment (RUC)[66] deployments. These issues do not constitute a significant reliability concern for the Region at this time.

Reliability Assessment

The assessment is generally based on data collected from market participants pursuant to the ERCOT Protocols[67] and forecasts/studies produced by ERCOT. The anticipated Reserve Margin for the 2011 summer assessment period is projected to be 14.3 percent, which is above the minimum Reserve Margin level for ERCOT of 13.75 percent. The Reserve Margin based on Existing-Certain capacity is 13.9 percent, which is also above this minimum Reserve Margin. The ERCOT minimum Reserve Margin target is based on Loss-of-Load Events (LOLEv) analysis of no more than 0.1 events per year based on an updated probabilistic study completed in 2010.[68]

The projected Anticipated Capacity Resources Reserve Margin for 2011 is lower than the 17.0-percent Reserve Margin that was projected for last year's summer assessment due to a higher demand forecast, some reduction in available resources, and changes in accounting for demand programs. A 90th percentile peak demand, roughly five percent higher than the forecast normal peak demand, would result in reserves of approximately 8.8 percent.

TABLE 12: ERCOT ON-PEAK CAPACITY RESOURCES AND RESERVE MARGINS

	2011 Summer Forecast (MW)	2011 Summer Forecast (%)	Change from prior year (MW)	Change from prior year (percentage point)
Existing-Certain and Net Firm Transactions (with Demand Response)	73,969	13.9%	(1,199)	(5.4)
Anticipated Capacity Resources	74,229	14.3%	(989)	(5.1)
Prospective Capacity Resources	74,229	14.3%	(989)	(5.1)
NERC Reference Margin Level	**8,933**	**13.8%**	**926**	1.3

In the ERCOT Region, independent generator owners and operators are responsible for their own fuel supply and transportation arrangements.

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65 http://wiid.twdb.state.tx.us/ims/resinfo/BushButton/lakeStatus.asp. This site is updated regularly and may not currently reflect conditions at the time this assessment was performed

66 http://www.ercot.com/content/mktrules/nprotocols/current/02-020111_Nodal.doc

67 http://www.ercot.com/mktrules/nprotocols/current

68 http://www.ercot.com/content/meetings/board/keydocs/2010/1116/Item_07_2010_Loss_of_Load_Events_(LOLEV),_Target_Reserve_M.zip

In addition, ERCOT is a member of the Texas Energy Reliability Council; this group coordinates between the gas and electric industries and, if necessary, allocates deliveries of natural gas during periods of high demand. In the event of forecasted extreme weather and possible fuel curtailments, ERCOT may request fuel capability information from qualified scheduling entities that represent generation to prepare operationally for potential curtailments. Gas curtailments do not typically occur in the summer season.

An extremely hot summer that results in load levels significantly above forecast, higher than normal unit forced outage rates, or financial difficulties of some generation owners that may make it difficult for them to obtain fuel from suppliers are all risk factors that alone or in combination could result in inadequate supply. In the event that occurs, ERCOT will implement actions described in Section 5.6 of the ERCOT Protocols[69] and Section 4 of the ERCOT Operating Guides,[70] which describe Energy Emergency Alerts (EEA) and procedures for use of interruptible load, voltage reductions, procuring emergency energy over the asynchronous ties, and ISO-instructed Demand Response. A Voltage Stability Screening Analysis to assess reactive power needs on the ERCOT system for the upcoming summer will be completed before the start of the summer season. Response of the network to NERC Category A, B, and selected C contingency tests will be documented

Region Description

The ERCOT Region is a separate electric interconnection located entirely in the state of Texas and operated as a single Balancing Authority. ERCOT is a summer-peaking Region responsible for about 85 percent of the electric load in Texas with an all-time peak demand of 65,776 MW set in August, 2010. The Texas Reliability Entity (Texas RE) is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for the ERCOT Region.

[69] http://www.ercot.com/mktrules/protocols/current.html
[70] http://www.ercot.com/mktrules/guides/operating/current

FRCC

Introduction

The FRCC Region is typically summer-peaking and is divided into ten Balancing Authorities. The FRCC has registered 74 entities (both members and non-members) performing the functions identified in the NERC Reliability Functional Model and defined in the NERC Reliability Standards glossary. The Region has a population of more than 16 million, and has a geographic coverage of about 50,000 square miles over peninsular Florida.

The purpose of this report is to assess the reliability of the FRCC Region for the upcoming 2011 summer season. The FRCC assessment process is performed in accordance with the Florida Public Service Commission (FPSC) requirement that all Florida utilities file an annual Ten-Year Site Plan that details how each utility will manage growth for the next decade. The data from the individual entity plans are aggregated and used in the assessment process to evaluate resource and transmission adequacy.

Demand

Each individual Load Serving Entity (LSE) forecast takes into account historical temperatures to determine the normal projected temperature at the time of peak demand. The demand forecast for this summer also takes into consideration the overall economy in Florida with emphasis on the price of fuel and electricity.

The FRCC is forecast to reach its 2011 summer non-coincident peak total internal demand of 46,091 MW in August, which represents a projected demand increase of 1.2 percent over the actual 2010 summer net demand of 45,225 MW. This projection for the 2011 summer is consistent with historical weather-normalized FRCC demand growth and is 0.1 percent higher than last year's summer forecast of 46,034 MW. The small increase in the 2011 projected summer peak demand is attributed to a sluggish economy primarily driven by a slow housing market and high energy prices.

TABLE 13: FRCC FORECAST AND ACTUAL PEAK DEMAND

2010 Total Internal Demand (MW)	2010 Actual Demand (MW)	Difference in Actual versus Forecast (MW)	Difference in Actual versus Forecast (%)	2011 Total Internal Demand (MW)	Difference in 2011 and 2010 Forecast Demand (MW)	Difference in 2010 Actual versus 2011 Forecast (%)	All-Time Summer Peak Demand (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)
46,034	45,225	(809)	-1.8%	46,091	57	0.1%	46,739	(648)	-1.4%

Each individual LSE within the FRCC Region develops a forecast that accounts for the actual peak demand. The individual peak demand forecasts are then aggregated by summing these forecasts to develop the FRCC Region forecast. These individual peak demand forecasts are coincident for each LSE resulting in some diversity at the Region level.

The 2011 net internal FRCC peak demand forecast includes the effects of 3,131 MW (7.3 percent of Net Internal Demand) of potential demand reductions from the use of direct control load management and interruptible load management programs composed of residential, commercial, and industrial demand. There currently is no critical peak pricing with control incorporated into the FRCC projection. Each LSE within the FRCC treats every Demand-Side Management load control program as “demand reduction” and not as a “capacity resource.”

TABLE 14: FRCC DEMAND RESPONSE AND ENERGY EFFICIENCY ON-PEAK

Non-Dispatchable DSM (MW)	-
Energy Efficiency	-
Non-Controllable Demand-Side Demand Response	-
Total Internal Demand	46,091
Controllable, Dispatchable Demand Response	3,131
Net Internal Demand	42,960

Entities within the FRCC use different methods to test and verify Direct Load programs such as requiring actual load response to periodic testing, and use of a time and temperature matrix along with the amount of customers participating. Projections also incorporate capacity impacts of new energy efficiency programs, which effectively reduces peak demand.

There are a variety of energy efficiency programs implemented by entities throughout the FRCC Region. These programs can include commercial and residential audits (surveys) with incentives for duct testing and repair, high efficiency appliances (air conditioning, water heater, heat pumps, refrigeration, etc.) rebates and high efficiency lighting rebates.

FRCC may assess the peak demand uncertainty and variability by developing Regional bandwidths or 80-percent confidence intervals on the projected or most likely load (50/50). The 80-percent confidence intervals on peak demand can be interpreted to mean that there is a ten-percent probability that in any year of the forecast horizon an actual observed load will exceed the high band. Likewise, there is a ten-percent probability that actual observed load in any year could be less than the low band in the confidence interval. The purpose of developing bandwidths on peak demand loads is to quantify uncertainties of demand at the Regional level. This would include weather and non-weather load variables such as demographics, economics, and price of fuel and electricity. The main factor driving the growth outlook for this summer’s forecast is a weak Florida economy.

The FRCC Region reviews extreme summer conditions from a resource adequacy perspective as part of a Loss of Load Probability (LOLP) study by performing a load sensitivity analysis.

Generation

FRCC supply-side resources considered for the summer assessment are categorized as Existing-Certain, Existing-Other, and Existing, Inoperable.

The total Existing-Certain generation in the FRCC Region for this summer is 55,775 MW, and an additional 2,449 MW of Existing-Other. The FRCC Region also has 2,000 MW of Inoperable generation with a negligible amount of variable generation.

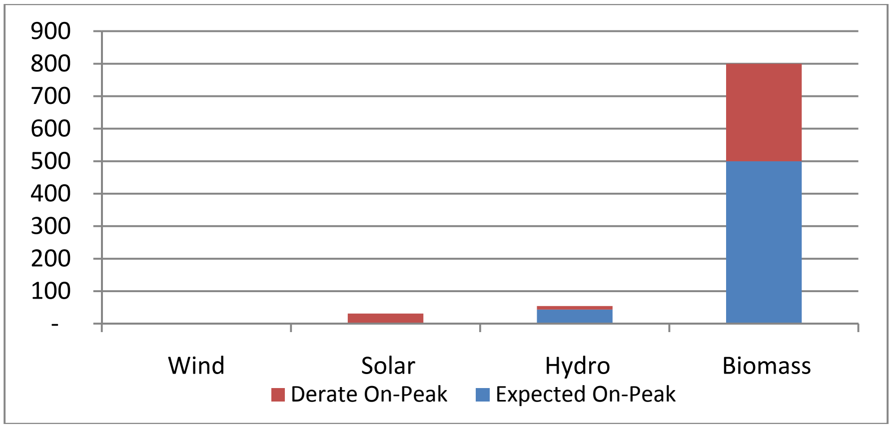
TABLE 15: FRCC EXISTING AND PLANNED PEAK CAPACITY

Existing-Certain (MW)	55,775
Existing-Other (MW)	2,449
Future-Planned (MW)	-

The FRCC Region does not rely on hydro generation, therefore hydro conditions and reservoir levels will not impact the ability to meet the peak demand or the daily energy demand.

For the 2011 summer period, no load serving concerns are anticipated due to fuel supply vulnerabilities. For extreme weather conditions such as hurricanes affecting natural gas supply points, extreme temperatures, or impacts to pipeline infrastructure, alternate short-term fuel supply availability continues to be adequate for the Region. There are no additional fuel availability or supply issues identified at this time, and existing mitigation strategies continue to be refined. Based on recent studies, current fuel diversity, alternate fuel capability, and fuel study results, the FRCC does not anticipate any fuel transportation issues affecting resource capability during peak periods and/or extreme weather conditions this summer.

FIGURE 27: FRCC EXISTING AND PLANNED RENEWABLE GENERATION



The FRCC Region has identified two unit retirements for a total of 565 MW and an additional 856 MW of nuclear generation are expected to be unavailable. There is no significant impact on reliability expected due to the unavailability of these generation resources during the summer season.

Capacity Transactions

Currently, there are 2,209 MW of generation under Firm contract that are available to be imported into the Region from the SERC-SE Area. No portions of these contracts are from Liquidated Damages or “make whole” contracts. These purchases have Firm transmission service to ensure deliverability into the FRCC Region. No Non-Firm or Projected transactions are included in the assessment.

TABLE 16: FRCC IMPORTS AND EXPORTS ON-PEAK

Imports (MW)	2,209
Firm (MW)	2,209
Expected (MW)	-
Exports (MW)	-
Firm (MW)	-
Expected (MW)	-
Net Imports (MW)	**2,209**

Presently, the FRCC Region has 143 MW of generation under Firm contract to be exported into the SERC-SE Area. These sales have Firm transmission service to ensure deliverability into the SERC Region. No portions of these contracts are from Liquidated Damages or "make whole" contracts. The FRCC does not consider Non-Firm or forecast sales to other Regions as capacity resource reductions.

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

Transmission

Major additions to the FRCC bulk power system are mostly related to expansion in order to serve the growing demand and therefore maintain the reliability of the transmission system. No other significant substation equipment additions are projected during the summer of 2011.

Presently no significant transmission lines are forecast to be out of service for maintenance during the summer period and there are no identified concerns in meeting target in-service dates for new transmission additions.

Transmission constraints within the FRCC Region may require remedial actions depending on system conditions. Permanent solutions such as the addition of new transmission lines and the rebuild of existing 230kV transmission lines have been identified and implementation of solutions is underway. In the interim, remedial operating strategies and specific remedies have been developed to mitigate thermal loadings and will continue to be evaluated to ensure system reliability.

An interregional transfer study is performed annually to evaluate the total transfer capability between the FRCC and SERC-SE Areas. Joint studies of the Florida/SERC-SE transmission interface indicate a summer seasonal import capability of 3,700 MW into the Region and an export capability of 900 MW. These joint studies account for constraints within the FRCC and/or the SERC-SE.

Operational Issues

The FRCC expects the bulk transmission system to perform adequately over various system operating conditions with the ability to deliver the resources to meet the load requirements at the time of the summer peak demand. The results of the 2011 Summer Transmission Assessment, which evaluated the steady-state summer peak load conditions under different operating scenarios, indicates that any concerns with thermal overloads or voltage conditions can be managed successfully by operator intervention. Such interventions may include generation redispatch, system sectionalizing, reactive device control, and transformer tap adjustments. The operating scenarios analyses included the unavailability of major generating units within the FRCC. Therefore, various dispatch scenarios were evaluated to ensure generating resources within the FRCC are deliverable by meeting NERC Reliability Standards under these operating scenarios.

No operational changes are needed to accommodate variable resources for 2011 summer. Minimum demand and over-generation scenarios typically do not occur under normal conditions due to limited variable resources within the FRCC Region. Based on past experience, Demand Response resources have operated as projected and to be available and perform as forcast during the summer season.

There are no foreseen environmental and/or regulatory restrictions or unusual operating conditions that can potentially impact reliability in the FRCC Region during the 2011 summer period.

No unusual operating conditions are projected that could impact reliability for the upcoming 2011 summer. The FRCC has a Reliability Coordinator agent that monitors real-time system conditions and evaluates near-term operating conditions of the bulk electric grid. The Reliability Coordinator uses a Region-wide state estimator and contingency analysis program to evaluate current system conditions. These programs are provided with real-time operating data from operating entities within the Reliability Coordinator footprint. These tools enable the FRCC Reliability Coordinator to implement operational strategies and procedures such as generation redispatch, sectionalizing, planned load shedding, reactive device control, and remotely controlled transformer tap adjustments to successfully mitigate potential or actual line loading and voltage concerns that may occur in real-time.

Reliability Assessment

Individual entities within the FRCC Region are required by the State of Florida to maintain a 15-percent Reserve Margin (20 percent for individual Investor Owned Utilities). Based on the forecast load and generation capacity, the calculated Reserve Margin for the 2011 summer is 32.6 percent overall. When Load Management and Interruptible loads are treated as a resource under Controllable Capacity Demand Response (CCDR), the Reserve Margin is 22.6 percent. For Regional purposes of Reserve Margin calculations, the FRCC uses Load Management and Interruptible loads as a demand reduction under CCDR, thus providing an equivalent Reserve Margin of 24.2 percent for the same MW of reserve. The entities within the FRCC Region plan their individual systems to meet the Reserve Margin criteria under both summer and winter peak demand conditions.

FRCC

TABLE 17: FRCC ON-PEAK CAPACITY RESOURCES AND RESERVE MARGINS

	2011 Summer Forecast (MW)	2011 Summer Forecast (%)	Change from prior year (MW)	Change from prior year (percentage point)
Existing-Certain and Net Firm Transactions (with Demand Response)	61,115	32.6%	6,101	4.1
Anticipated Capacity Resources	61,115	32.6%	5,845	3.5
Prospective Capacity Resources	61,115	32.6%	5,845	3.5
NERC Reference Margin Level	**6,914**	**15.0%**	**9**	-

The 15-percent Reserve Margin was established based on a Loss of Load Probability (LOLP) analysis that incorporated system generating unit information to determine the probability that existing and planned resource additions will not be sufficient to serve forecast loads. The objective of this study is to establish resource levels such that the specific resource adequacy criterion of a maximum LOLP of 0.1/day in a given year is not exceeded.

The results of the most recent LOLP analysis indicated that for the "most likely" and extreme scenarios (*e.g.,* extreme seasonal demands, no availability of Firm or Non-Firm imports into the Region, or the non-availability of load control programs), the peninsular Florida electric system maintains a LOLP well below the criterion. This year's calculated Reserve Margin is 4.9 percent[71] lower than last year's calculation for the summer of 2011 primarily related to an increase in planned unit maintenance and the retirement of two units.

Although the FRCC has reviewed various types of fuel supply issues in the past, the increased reliance of generating capacity on natural gas has caused the FRCC to address this fuel type specifically. The FRCC continues coordination efforts among natural gas transportation service providers (pipeline operators) and generators within the Region. The FRCC Generating Capacity Shortage Plan includes specific actions to address potential or actual capacity constraints due to natural gas availability concerns and includes close coordination with the pipeline operators serving the Region. FRCC pipeline operators are included in various emergency contacts lists and are included in Regional communications as appropriate. The FRCC Operating Committee has also developed the FRCC Communications Protocols—Reliability Coordinator, Generator Operators and Natural Gas Transportation Service Providers procedure—to enhance the existing coordination between the FRCC Reliability Coordinator, Regional power plant operators and the natural gas pipeline operators operating within the FRCC Region (reference FERC Order 698). In addition, the Region continues to review and enhance fuel industry coordination through the work of the FRCC Fuel Reliability Working Group (FRWG), which serves as a Regional fuel reliability forum that studies the interdependencies of fuel and electric reliability while supporting coordinated Regional responses to fuel issues and emergencies.

No specific reactive power studies have been performed for the upcoming summer. However, the steady-state summer assessment incorporates an algorithm that can identify potential voltage limitations related to the outage of generation resources.

[71] Value is based on the FRCC method of calculating Reserve Margin (treating CCDR as a demand reduction).

Other Area-Specific Issues

The FRCC is not anticipating any other reliability concerns for the 2011 summer conditions. Non-projected potential reliability real-time issues identified by the Reliability Coordinator can be resolved with existing operational strategies and procedures.

Area Description

FRCC's membership includes 29 Regional Entity Division members and 24 Member Services Division members, both of which are composed of investor-owned utilities, cooperative systems, municipal utilities, power marketers, and independent power producers. The FRCC Region is typically summer peaking and divided into ten Balancing Authorities. FRCC has registered 74 entities (both members and non-members) performing the functions identified in the NERC Reliability Functional Model and defined in the NERC Reliability Standards glossary. The Region has a population of more than 16 million, and has a geographic coverage of about 50,000 square miles over peninsular Florida. Additional details are available on the FRCC website (https://www.frcc.com/default.aspx).

MISO

MISO

Introduction

MISO's Planning Authority Region covers 750,000 square miles and includes 13 states. MISO's Midwest Energy and Operating Reserves market includes 347 market participants that serve over 40 million people. MISO experiences its annual peak during the summer season.

MISO market participants use the Module E Capacity Tracking (MECT) tool to submit its forecast Demand and Resources at each Load Commercial Pricing Node for the upcoming planning year. These forecasts are then aggregated to determine the MISO assessment area demand, generation, and Reserve Margin forecasts for the upcoming summer season. The latest MISO Commercial Model is used for calculation of Existing-Other capacity resources.

Coordination amongst several MISO departments occurs to provide accurate forecast information for each section of the report. Load and resource forecasts are provided in the Demand and Generation sections, and transmission and operational concerns are identified in the Transmission and Operational Issues sections.

Demand

The demands as reported by Network Customers are weather normalized, or 50/50, forecasts. A 50/50 forecast is the mean value in a normal probability distribution, meaning there is a 50-percent chance the actual load will be higher and a 50-percent chance the actual load will be lower than the forecast. Historically, reported load forecasts have been accurate as each member has expert knowledge of their individual loads with respect to weather and economic assumptions. During last year's summer season, MISO experienced an instantaneous peak of 108,907 MW and settled peak of 107,188 MW on August 10 ending 16:00 EST. The instantaneous load is the highest value metered during the peak hour, while the settled load is the integrated average value of metered data over the peak hour. For consistency with other reporting entities, the settled load of 107,188 MW is being used for the purpose of this analysis.

TABLE 18: MISO FORECAST AND ACTUAL PEAK DEMAND[72]

2010 Total Internal Demand (MW)	2010 Actual Demand (MW)	Difference in Actual versus Forecast (MW)	Difference in Actual versus Forecast (%)	2011 Total Internal Demand (MW)	Difference in 2011 and 2010 Forecast Demand (MW)	Difference in 2010 Actual versus 2011 Forecast (%)	All-Time Summer Peak Demand (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)
111,414	108,907	(2,507)	-2.3%	99,572	(11,842)	-10.6%	116,030	(16,458)	-14.2%

Last year's unrestricted non-coincident demand forecast of 112,701 MW was 8.9 percent higher than this year's unrestricted non-coincident demand forecast of 102,651 MW. This difference is

72 The 2011 Demand Numbers reflect the migration of First*Energy* (ATSI) into PJM from MISO

mostly due to First*Energy*'s exit from MISO effective June 2011, which accounts for approximately an 11.7 percent reduction from last year's demand forecast.[73] The Big Rivers Integration contributed a 1.6 percent increase, while the existing membership experienced load growth of 1.3 percent, thus bringing the net load reduction to 8.9 percent.

An unrestricted non-coincident peak demand is created on a Regional basis by summing the coincident monthly forecasts for the individual Load Serving Entities (LSE). Using historic market data, a load diversity factor was calculated by observing the individual peaks of each Local Balancing Authority and comparing them against the system peak. This produced an estimated diversity of 3,080 MW; therefore, the MISO is able to estimate a total internal coincident demand of 99,572 MW. This total internal coincident demand is used when comparing to the target Reserve Margin in the Reliability Assessment section.

MISO bases its resource evaluation on the actual market peak. MISO currently separates Demand Resources into two separate categories: Interruptible Load and Direct Controlled Load Management (DCLM). Interruptible load of 3,093 MW (3.1 percent of Total Internal Demand) for this assessment is the magnitude of customer demand (usually industrial) that, in accordance with contractual arrangements, can be interrupted at the time of peak by direct control of the system operator (remote tripping) or by action of the customer at the direct request of the system operator. DCLM of 1,118 MW (one percent of Total Internal Demand) for this assessment is the magnitude of customer service (usually residential) that can be interrupted at the time of peak by direct control of the applicable system operator. DCLM is typically used for "peak shaving." The Resource Adequacy processes as set forth in Module E of MISO's tariff acts as the measurement and verification tool for Demand Response.[74]

The MISO does not currently track Energy Efficiency programs; however, they may be reflected in individual LSE load forecasts. To account for uncertainties in load forecasts, MISO applies a probability distribution, Load Forecast Uncertainty (LFU), to consider a larger range of forecast demand levels. LFU is derived from variance analyses to determine how likely forecasts will deviate from actual load. There have not been any changes made due to the economic recession in either of both of the load forecast methods/assumptions and the impact to the actual forecast. MISO addresses extreme summer conditions during the Post Summer Assessment.

Generation

Last year's Existing-Certain and Existing-Other capacity totaling 141,993 MW is 7.1 percent higher than MISO's projected Existing-Certain and Existing-Other capacity of 131,842 MW for the 2011 summer season. This difference is mostly due to First Energy and Cleveland Public Power's exit from MISO effective June 2011, which accounts for approximately a 9.5-percent MW reduction from last year's forecast. MISO also plans to have 1,850 MW of Existing-Inoperable capacity during the 2011 summer season, compared to 0 MW during the 2010 summer season. The Big Rivers Integration contributed a 1.4-percent MW increase. The remaining MW changes were from new generation,[75] retirements and suspensions,[76] and reclassified units,[77] which brought the

[73] The corresponds with a 10.6 percent reduction in Total Internal Demand from 2010 to 2011.
[74] DCLM and IL represent last summer's peak MW values per the MECT tool.
[75] New Generation does not necessarily refer to newly built generation. It is simply new from the March 2010 Commercial Model to the March 2011 Commercial Model.
[76] Retirement and suspension information gathered per the Attachment Y process.

net MW reduction to 5.8 percent. Table 19 and Table 20 display retirements and suspensions by NERC Region and fuel type.

TABLE 19: UNIT RETIREMENTS, MW IN MISO

Fuel Type	MRO	RFC	SERC	Total
Coal	37	689	-	726
Gas	31	232	-	263
Oil	-	65	-	65
Grand Total	68	986	-	1,054

TABLE 20: SUSPENSIONS, MW IN MISO

Fuel Type	MRO	RFC	SERC	Total
Coal	-	581	314	895
Gas	-	342	138	480
Oil	27	-	448	475
Grand Total	27	923	900	1,850

TABLE 21: MISO EXISTING AND PLANNED PEAK CAPACITY

Existing-Certain (MW)	107,391
Existing-Other (MW)	24,451
Future-Planned (MW)	-

MISO projects zero MW for Future (-Planned and -Other) over the assessment timeframe. Of the Existing and Future capacity, it is difficult to predict the wind capacity available on peak due to the intermittent nature of wind. However, the MISO determined maximum wind capacity credits using an Equivalent Load Carrying Capacity (ELCC), a metric commonly used by the National Renewable Energy Laboratory (NREL). The MISO used the ELCC for wind generation and Loss of Load Expectation analyses for the summer seasonal assessment.[78] Wind shows an Existing-Certain capacity of 382 MW on peak over the assessment timeframe using a 12.9-percent capacity credit for those resources committed as a Planning Resource capacity to the MISO within the Module E Capacity Tracking (MECT) tool. The wind capacity credit increased by 4.9 percent (eight percent was used for 2010 summer) due to a method change in the ELCC metric and because of better wind performance in 2010 due to increased diversity (a new Iowa member was integrated in 2010, which provided an additional 1,407 MW of nameplate wind capacity). Not all Existing wind capacity was committed in the MECT tool. The Existing-Other capacity for wind is 8,290 MW on-peak over the assessment timeframe. Hydro shows an Existing-Certain capacity of 3,144 MW on-peak over the assessment timeframe. The Existing-Other capacity for hydro is 524 MW on-peak over the assessment timeframe. Of the Existing and Future capacities, biomass shows 147 MW on peak throughout the assessment timeframe. MISO anticipates 3,608 MW of Behind-the-Meter Generation (BTMG) and 49 MW of Demand Response Resources (DRR) to be available for the 2011 summer season. Hydro conditions for the summer appear normal and there are no reports of reservoir levels showing insufficiencies to meet peak demand or daily energy demand throughout the summer. MISO has no reports experiencing or expecting conditions (*i.e.,* weather, fuel supply,

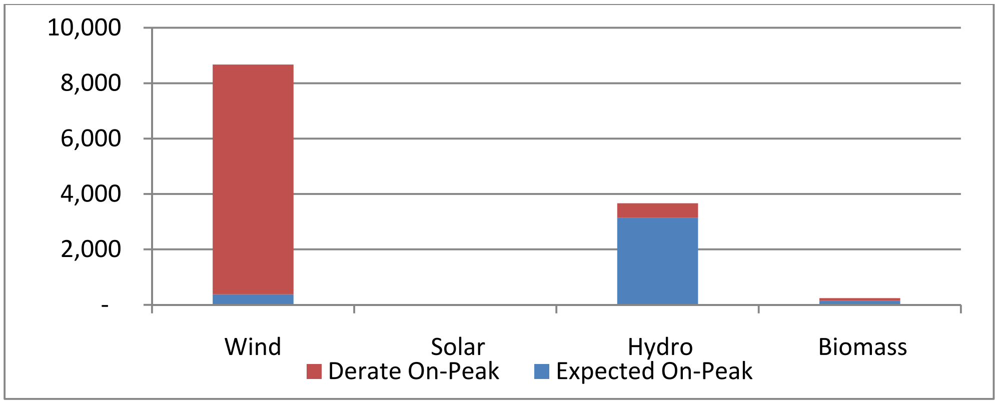
[77] MW Change from last year Commercial Model, Unit either designated to BTMG or Psuedo Tied Out of MISO
[78] http://www.midwestiso.org/Library/Repository/Study/LOLE/2010%20LOLE%20Study%20Report.pdf

fuel transportation) that would reduce capacity. MISO does not anticipate any existing significant generating units being out of service or retired during the summer season.

TABLE 22: MISO EXISTING AND PLANNED RENEWABLE GENERATION

Wind Expected On-Peak	382
Wind Derate On-Peak	8,290
Wind Nameplate/Installed Capacity	8,672
Solar Expected On-Peak	-
Solar Derate On-Peak	-
Solar Nameplate/Installed Capacity	-
Hydro Expected On-Peak	3,144
Hydro Derate On-Peak	524
Hydro Nameplate/Installed	3,668
Biomass Expected On-Peak	148
Biomass Derate On-Peak	96
Biomass Nameplate/Installed	244

FIGURE 28: MISO EXISTING AND PLANNED RENEWABLE GENERATION



Capacity Transactions on-Peak

The MISO only reports power imports (not exports) to the MISO market or reported interchange transactions into the MISO market. The forecast reflects 4,894 MW of power imports from year to year.[79]

Table 23 below gives a percentage breakdown of the 4,894 MW of power imports by neighboring systems. All these imports are Firm and fully backed by Firm transmission and Firm generation. No import assumptions are based on partial path reservations. There are no transactions with Liquidated Damages Contract (LDC) clauses or "make-whole" contracts that are included as Firm capacity. The MISO does not intend to rely on outside assistance or external resources for emergency imports for this summer season.

[79] 2010 summer peak power imports obtained from the MECT.

TABLE 23: PERCENT IMPORTS BY NEIGHBORING SYSTEMS IN MISO

Local Balancing Authority	Percent Imports
CE	1.74%
CWLD	3.03%
EEI	23.79%
LGEE	1.33%
MHEB	26.89%
OPPD	0.05%
OVEC	4.80%
PJM	26.17%
WAPA	12.20%

TABLE 24: MISO IMPORTS AND EXPORTS ON-PEAK

Imports (MW)	4,894
Firm (MW)	4,894
Expected (MW)	-
Exports (MW)	-
Firm (MW)	-
Expected (MW)	-
Net Imports (MW)	**4,894**

Transmission

The following projects were put in service since last summer season to enable reliable and efficient transmission service for the MISO assessment area: 55 miles of new 161 kV line in ITCM, SMP, and XEL; 168 miles of new 138 kV line in ATC LLC, and 47 miles of new 115 kV line in GRE, MP, and OTP have been put into service. In addition, 37 miles of 345 kV line in Ameren Illinois connecting Prairie State Power Plant to the existing Baldwin Stallings 345 kV line were put in service in December 2010. Eight new bulk power transformers are also forecast to be in service before the 2011 summer season. These will be in Areas of American Transmission Co., Ameren Missouri, Great River Energy, ITC Midwest, and Vectren.

The following projects are anticipated to come into service during the 2011 summer season to enable reliable and efficient transmission service for the MISO assessment area. 121 miles of line upgrades or re-builds are anticipated to be in service for the upcoming summer season. Included in this are: One 230 kV line in DEM, one 161kV line in Ameren Missouri, eight 138 kV lines in Ameren Illinois, ATCLLC, IPL, METC, and Vectren, and two 115 kV lines in XEL. Also projected to be in service are three new bulk power transformers in Areas of METC, NIPS, and XEL.

Major upgrades to MISO's transmission system with anticipated in-service dates and descriptions are shown in Table 25. There are no concerns in meeting target in-service dates of transmission identified. MISO does not anticipate any existing, significant transmission lines or transformers being out of service through the summer season. MISO does not have any transmission constraints that could significantly impact reliability.

TABLE 25: MISO MAJOR TRANSMISSION UPGRADES FORECAST TO BE IN SERVICE FOR 2011 SUMMER SEASON

NERC Region	Geo by TO	Project Name	Length (Miles)	HS kV	LS kV	Projected ISD	Project Description
RFC	METC	Argenta-Palisades 345kV ckt. 1 & 2		345		40,330	Remove the SAG limit on Argenta-Palisades 345kV ckt 1 and 2. Upgrade terminal equipment at both substations.
MRO	GRE	G362 — Pleasant Valley second 500 MVA 345/161 kV transformer		345	161	40,360	G362 — Pleasant Valley 345/161 kV transformer
MRO	ITCM	Replace Salem 345/161 kV transformer with 448 MVA unit		345	161	40,360	Replace Salem 345/161 kV transformer with 450 MVA unit
SERC	AmerenMO	Gray Summit — Second 560 MVA 345/138 kV Transformer		345	138	40,483	Install a 345 kV six-position ring bus making Labadie Tyson 1 and 2 345 kV lines and add a second 560 MVA 345/138 kV transformer.
RFC	Vectren (SIGE)	New 345/138kV Substation at AB Brown		345	138	40,483	New 448MVA 345/138kV transformer in addition to the Gibson-AB Brown-Reid 345kV line.
SERC	AmerenIL	Coffeen Plant-Coffeen, North — 2nd. Bus tie		345		40,483	Coffeen Plant and Coffeen North Substation — Add a second 345 kV bus-tie between Coffeen Plant and Coffeen, North, with 3000 A summer emergency capability. Replace a 1600 A wavetrap at Coffeen, North and a 1600 A disconnect switch at the tap to Ramsey, E
SERC	AmerenIL	Prairie State Power Plant transmission outlet	37	345		40,513	Establish a new Prairie State 345 kV switchyard including a six-position breaker and ½ bus arrangement to accommodate two generating units and four 345 kV outlet lines with nine - 345 kV circuit breakers. Tap the existing Baldwin-Stallings 345 kV line 4531 "in and o
MRO	ITCM	G164-Lakefield Jct 345 kV Breaker & Half		345		40,575	Convert the Lakefield 345kV ring bus to breaker and a half.
RFC	ITC	B3N Interconnection		220		4th Quarter 2011	Returns the Bunce Creek to Scott 220 kV circuit to service, and replaces the Phase Angle Regulator with two new phase angle regulating transformers in series
MRO	ITCM	Replace Hazleton 345/161 kV transformer #1 with 448 MVA unit		345	161	40,634	Replace Hazleton 345/161 kV transformer #1 with 448 MVA unit
MRO	ATC LLC	2nd Kewaunee 345-138 kV Transformer		345	138	40,664	Reconfigure Kewaunee 345/138 kV switchyard and install a second Kewaunee 345-138 kV transformer of 500 MVA.
MRO	XEL	North Mankato 115 kV project	6	345	115	40,695	1) New 345/115 kV Transformer at the proposed Helena 345 kV switching station. 2) New 115 kV line from Helena - St. Thomas.
RFC	METC	Murphy Second 345/138kV Transformer		345	138	40,695	Install a second 345/138kV transformer at Murphy substation
RFC	NIPS	Green Acres Sub.-- 345-138kV Transformer		345	138	40,695	Install a 560 MVA 345/138 kV transformer, one 345 kV and one 138 kV circuit breaker and associated equipment at Green Acres Substation.

Below are the Total Import Capability values (TIC) for the 2011 summer peak. Historically, these values have been determined by the Eastern Interconnection Reliability Assessment Group (ERAG). Import values into the MRO have been provided as in the past. In future assessments, these values shall be reported on a assessment area-to-assessment area basis. In the below values, the TIC value includes of a base case flow of 1810 MW as a net import into the MRO Region.

TABLE 26: MISO TRANSPORT IMPORT CAPABILITIES

RFC_W TO MRO	SERC_W TO MRO	SPP TO MRO
2,360 MW	2,460 MW	3,010 MW

Operational Issues

MISO is not anticipating any unusual operating conditions during the 2011 summer season and has not undertaken any studies to determine the impacts of potentially adverse conditions.

FERC has recently accepted a MISO proposal to create a new resource type by which intermittent resources can register, called Dispatchable Intermittent Resources (DIR). The increase in the amount of Intermittent Resources, and the limitations that currently exist with respect to modeling, dispatching, and pricing have corresponding impacts on MISO system operations and market performance. The proposed new DIR resource type and the related Tariff changes are intended to address market and operational issues relating to the curtailment of Intermittent Resources, and to increase the participation of wind generators and other similar Intermittent Resource types in the Energy and Operating Reserves Market.

The new resource designation, which took effect on March 1, will allow newly registered DIRs to begin participating in MISO's markets on June 1. MISO is currently evaluating the need for modifications to existing procedures and/or the development of new procedures related to Dispatchable Intermittent Resources.

MISO does not anticipate experiencing any reliability concerns as a result of minimum demand or over-generation during the summer period. However, if those conditions do occur, MISO has a Minimum Generation Event Procedure[80] that clearly identifies actions to be taken to effectively manage these conditions.

MISO has no concerns regarding the response of any Demand Response Resources (DRR) that are deployed during the summer period. Given the currently limited use of such resources in the MISO markets, the impact from any performance issues would be relatively minor. In the event that such resources are part of a plan being used to mitigate a capacity shortage situation, the MISO's Capacity Emergency Procedure identifies the actions to be taken to effectively manage such conditions, including emergency energy purchases and use of operating reserves.

TABLE 27: MISO DEMAND RESPONSE AND ENERGY EFFICIENCY ON-PEAK

Non-Dispatchable DSM (MW)	49
Energy Efficiency	49
Non-Controllable Demand-Side Demand Response	-
Total Internal Demand	99,572
Controllable, Dispatchable Demand Response	7,819
Net Internal Demand	91,753

80 http://www.midwestiso.org/Library/Repository/Procedure/RTO-EOP-003%20Supply%20Surplus%20Procedure.pdf

The number of times that a Demand Response Resource could be deployed during any period would be restricted by the type of resource and its offer parameters. For a DRR Type II, the combination of its Minimum Run Time and Minimum Down Time once deployed would restrict the resource's availability for deployment during the remainder of the period. Similarly, for a DRR Type I, the combination of its Minimum Interruption, Minimum Duration, and Minimum Non-Interruption Interval would do the same.

MISO does not foresee any impact to reliability during the upcoming summer period from environmental and/or regulatory restrictions. MISO is considering, however, the possible impacts from various future scenarios to understand the longer-term effects that these types of restrictions could have on the resources that we manage.

MISO does not anticipate any other unusual operating conditions for the 2011 summer season.

Reliability Assessment

The goal of a Loss of Load Expectation (LOLE) study is to determine a level of reserves that ensures that the probabilities for loss of load within the MISO system over each integrated peak hour for the planning period sum to one day in ten years or 0.1 days/year.[81] Refer to Table 3-5 of the 2010 LOLE Study Report for a comparison of Planning Year 2011's PRM to 2010's PRM.

Table 28: MISO On-Peak Capacity and Reserve Margins

	2011 Summer Forecast (MW)	2011 Summer Forecast (%)	Change from prior year (MW)	Change from prior year (percentage point)
Existing-Certain and Net Firm Transactions (with Demand Response)	120,104	20.6%	(9,676)	0.5
Anticipated Capacity Resources	120,104	20.6%	(9,676)	0.5
Prospective Capacity Resources	133,413	34.0%	(3,729)	7.1
NERC Reference Margin Level	**14,936**	**15.0%**	**(1,776)**	-

According to the 2011 LOLE study, the Reserve Margin requirement calculated for the MISO is 17.4 percent of MISO Net Internal Demand[82] of its market Area for the 2011 summer season. In addition to the 107,391 MW of Exist-Certain capacity resources, MISO expects 4,894 MW of external resources that are available to serve load.[83] Behind-the-meter generation is considered a capacity resource when calculating the MISO Reserve Margin, thus making it Reserve Margin neutral. This additional capacity arrives at a total designated capacity of 115,942 MW and brings the projected Reserve Margin for MISO to 20,581 MW, which is 20.6 percent of MISO Net Internal Demand. In this case, there are three Reserve Margins: Existing, Anticipated, and Prospective. Since no Future capacity is anticipated for this upcoming summer season, Existing and Anticipated are the same. In addition to the 107,391 MW of Existing-Certain capacity resources and 4,894 MW of external resources, MISO expects 1,118 MW of Direct Control Load Management, 3,093 MW of Interruptible Load, and 3,608 MW of Behind-the-meter generation. These three supply-side Demand Response mechanisms—DCLM, IL, and BTMG—are considered capacity resources, thus making them Reserve Margin neutral. This additional capacity arrives at Existing-Certain and Net

81 http://www.midwestiso.org/Library/Repository/Study/LOLE/2011%20LOLE%20Study%20Report.pdf

82 MISO Net Internal Demand is Total Internal Demand less DCLM and IL (95,361 MW)

83 External, BTMG, and DRR values are based on actual 2010 summer peak values from the MECT.

Firm Transaction capacity of 120,104 MW and brings the projected Existing and Anticipated Reserve Margin to 20,532 MW, which is 20.6 percent of total internal demand. Adding Existing-Other capacity of 24,451 MW brings the projected Prospective Reserve Margin to 34 percent. The 2011 summer projected Reserve Margin of 21.6 percent is higher than the 17.4 percent MISO system planning Reserve Margin for 2011 and is slightly lower than the 25 percent Reserve Margin forecast in 2010.[84] With this in mind, Firm load curtailment is a very low probability event for the 2011 summer period.

For inclusion in seasonal assessments, the MISO uses Energy Information Administration fuel forecasts to identify any system-wide fuel shortages and there are none projected for the 2011 summer period. In addition to the seasonal assessments, the MISO's Independent Market Monitor submits a monthly report to the MISO's Board of Directors that covers fuel availability and security issues. During the operating horizon, the MISO relies on market participants to anticipate reliability concerns related to the fuel supply or fuel delivery. Since there are no requirements to verify the operability of backup fuel systems or inventories, supply adequacy and potential problems must be communicated appropriately by the market participants to enable adequate response time. MISO has not performed any dynamic or static reactive power studies for the upcoming summer season.

RTO Description

MISO as a Planning Authority operates as a single Balancing Authority and experiences its annual peak during the summer season. MISO's scope of operations covers 750,000 square miles, which includes 13 states. MISO's Midwest Energy and Operating Reserves market includes 347 market participants who serve over 40 million people.

[84] All forecast demand, resource, and Reserve Margin values are subject to change before the 2011 summer season because MISO members have until the month prior to a given plan month to finalize forecasts in the MECT tool.

MRO

Executive Summary

MISO's membership has changed since the 2010 summer season forecast. Big Rivers Electric Corporation joined MISO on December 1, 2010.[85] Also, First Energy and Cleveland Public Power plan to consolidate into the PJM RTO on June 1, 2011.[86]

Last year's unrestricted non-coincident demand forecast of 112,701 MW for MISO is 8.9 percent higher than this year's unrestricted non-coincident demand forecast of 102,651 MW. This difference is mostly due to First Energy's exit from MISO effective June 2011, which accounts for approximately a 11.7 percent reduction from last year's demand forecast. The Big Rivers Integration contributed a 1.6-percent increase, while the existing membership experienced load growth of 1.3 percent, thus bringing the net load reduction to 8.9 percent.

MISO forecasts Existing-Certain capacity to be 107,391 MW for the 2011 summer season, an 11.7-percent decrease compared to the prior summer season. The majority of this resource reduction is due to First Energy's forecast departure from the MISO effective June 1, 2011. Currently, no future resources are anticipated to be in service in the MISO footprint for the upcoming summer. The 2011 summer projected Reserve Margin of 21.6 percent is higher than the 17.4-percent MISO system planning Reserve Margin for 2011. For more detail on how the 17.4- and 21.6-percent Reserve Margins are calculated, please see the Reliability Assessment section of this report. With this in mind, Firm load curtailment is a very low probability event for the 2011 summer period.

The 2010 MAPP actual non-simultaneous peak demand was 4,798 MW. This year's summer peak demand forecast is 5,087 MW. The Existing MAPP capacity resources for the 2011 summer season are 7,659 MW. The projected Reserve Margins in MAPP (23 percent Existing, 25 percent Anticipated, and 25 percent Prospective) for the 2011 summer season are in excess of the MAPP target Reserve Margin of 15 percent for predominately thermal systems, and ten percent for predominately hydro systems.

Within Manitoba Hydro, total internal demand projections range between 2,954 and 3,166 MW during the summer assessment timeframe. Projections were lowered due to modeling enhancements and the economic recession. There are no significant drivers for significant changes to report. Existing capacity resources range between 5,828 and 5,935 MW during the assessment timeframe. Existing-Certain capacity resources range between 4,704 and 5,353 MW during the assessment timeframe. Approximately eight MW of additional Existing-Certain capacity resources were added since the prior reporting year. It is projected to have an additional 11 MW of future capacity resources placed in service through the end of the assessment timeframe. Reserve Margins are projected to range between 22.3 percent and 41.5 percent during the assessment timeframe. Manitoba Hydro has a capacity Reserve Margin criteria requiring a minimum of a 12-percent reserve above forecast peak demand. The Existing-Certain and Net Firm Transaction Reserve Margin ranges between 22.3 percent and 41.2 percent during the assessment timeframe.

[85] http://www.midwestiso.org/AboutUs/MediaCenter/PressReleases/Pages/BigRiversElectricCorporationIntegratesintoMidwestMarkets.aspx
[86] http://www.firstenergycorp.com/content/dam/newsroom/files/news-releases/2009-07-31%20RTO.pdf

The projected Reserve Margins are well above Manitoba Hydro's minimum Reserve Margin requirement of 12 percent.

SaskPower's 2010 summer peak demand forecast was 2,951 MW. This year's 2011 summer peak demand forecast is 3,045 MW. An average of 3,926 MW of Existing capacity resources is forecast to be in service through the 2011 summer assessment timeframe. SaskPower's summer projected Reserve Margin is forecast to be between 18 percent and 22 percent, well above their target Reserve Margin of approximately 13 percent.

Transmission Summary

Thirty-seven miles of new 345 kV transmission lines are projected to be in service within the MISO before the 2011 summer season. Several lower voltage transmission lines totaling 269 miles are also forecast to be in service across the MISO Planning Authority footprint. Eight new bulk power transformers are also projected to be in service before the 2011 summer season. Along with new transmission projects that have come on line since the 2010 summer season, several transmission lines below 345 kV totaling 121 miles are forecast to come into service during the 2011 summer season. Three new bulk power transformers are also projected to come into service during the upcoming summer season. For now, no transmission reliability concerns are identified in the coordinated seasonal assessment, which is currently in progress.

Within the MAPP Planning Authority footprint, 14 miles of 115 KV line are being built.

This summer, Manitoba Hydro will be installing transmission facilities required to deliver the Wuskwatim Generating Station (generation service date is spring 2012). These include:

- A new Thompson Birchtree 230 kV Station and 45 km of 230 kV line from Thompson Birchtree-Wuskwatim.
- Two 137 km, 230 kV lines between Wuskwatim and Herblet Lake, and
- One 160 km, 230 kV line from Herblet Lake to The Pas Ralls Island.
- A 150 MVar Static Var Compensator (SVC) will be installed at the Thompson Birchtree 230 kV Station to provide transient voltage support.

Within SaskPower, there will be no new significant BES transmission lines, transformers, or substation equipment installed since last summer.

Operations Summary

With respect to Operations, there are no foreseeable challenges facing the operation of the Bulk Power Systems within the MISO, the MAPP, the Manitoba Hydro, or the SaskPower footprints. Within Manitoba Hydro, commissioning of the new Wuskwatim Transmission facilities will be the most important activity this summer outside of normal operations.

Nameplate wind generation reported by the four Planning Authorities totals 10,147 MW. Each Planning Authority assumes different availability at peak demand, however the aggregate of the four assessment areas indicates that 800 MW, or roughly eight percent of nameplate, will be available at peak demand. The MISO, as the Reliability Coordinator for its Planning Coordinator footprint as well as MAPP's footprint manages the majority of this wind generation. Additional detail on wind generation management is included within the MISO section of this report.

MRO Introduction

The NERC Reliability Assessments for 2011 will include newly defined assessment areas (previously called subregions) for several Regional Entities, including the MRO. In previous years' assessments, the MRO had two subregions, defined as MRO-US and MRO-Canada. MRO previously collected data from the individual utilities, companies, and Registered Entities within the MRO footprint and summed the data to reflect a total for the two subregions and the MRO Region as a whole. However, the MRO-US and MRO-Canada subregions were not congruent or compatible with Planning Authority and/or ISO/RTO footprints. This was less than desirable when comparing Reserve Margins and other planning and operating information. Data reported for this reliability assessment and future assessments will be "assessment area" concentric, meaning the assessment areas will be based on ISO, RTO, and/or Planning Authority (or in some instances a group of Planning Authorities) footprints, and the data will be kept whole to improve the accuracy of the report. In 2011, the MRO has collected narrative and data from four Planning Authorities that are now designated as assessment areas in the NERC assessments:

- MISO
- MAPP
- Saskatchewan Power
- Manitoba Hydro

The information collected from these four Planning Authorities is kept whole and reported as a NERC assessment area in this report to maintain the integrity and accuracy of the data. Since the MISO footprint is geographically contained and registered within three Regional Entities (MRO, SERC, and RFC), each of these three Regional Entities review the MISO section of this report.

Because the sum of the four Planning Authority footprints is not congruent with the MRO footprint, an MRO total for demand and generation is not reported in this year's report as it has been in past years. The reliability assessments for 2011 will establish new benchmarks for comparing this year's newly defined assessment areas with future year assessments.

MRO-MAPP

MAPP

Introduction

The Mid-Continent Area Power Pool (MAPP) is an association of electric utilities and other electric industry participants operating in all or parts of the following states and provinces: Iowa, Minnesota, Montana, North Dakota, and South Dakota.[87]

MAPP sends each LSE in its Planning Authority a seasonal assessment data request to submit its forecast Demand and Resources for the upcoming season. These forecasts are then aggregated to determine the MAPP assessment area Demand, Generation, and Reserve Margin forecasts for the upcoming summer season.

MAPP also assigns portions of the Seasonal Assessment write-up to its Transmission Operations Subcommittee, including the Transmission, Operations Issues, and Reliability Assessment sections.

Demand

MAPP makes normal weather and normal economic assumptions. The 2010 MAPP actual peak non-simultaneous demand was 4,798 MW. Last summer's demand forecast was 5,810 MW based on the data submitted to MRO. This year's summer peak demand forecast is 5,087 MW. The decrease in demand forecast is due in part to decreasing load forecasts and in part to 350 MW of load reporting shifted to the MISO Planning Authority. Non-coincident internal peak demands were used to aggregate individual member loads for use in the MAPP forecast. Resource evaluations are based on non-coincident peak demand conditions.

TABLE 29: MRO-MAPP FORECAST AND ACTUAL PEAK DEMAND

2010 Total Internal Demand (MW)	2010 Actual Demand (MW)	Difference in Actual versus Forecast (MW)	Difference in Actual versus Forecast (%)	2011 Total Internal Demand (MW)	Difference in 2011 and 2010 Forecast Demand (MW)	Difference in 2010 Actual versus 2011 Forecast (%)	All-Time Summer Peak Demand (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)
5,810	4,798	(1,012)	-17.4%	5,087	(723)	-12.4%	6,249	(1,162)	-18.6%

Interruptible Demand (60 MW) and Demand-Side Management (DSM) (11 MW) programs are used by a number of MAPP members. A wide variety of programs, including direct load control (such as electric appliance cycling) and interruptible load, may be used to reduce peak demand during the summer season. Interruptible Demand (60 MW, 1.2 percent) and Demand-Side Management (11 MW, 0.2 percent) programs, amount to 1.4 percent of the MAPP Projected Total Internal Peak Demand of 5,087 MW.

[87] 2010 MAPP System Performance Assessment.
MAPP Members Reliability Criteria and Study Procedures Manual, November, 2009.
MAPP Small Signal Stability Analysis Project Report, June 2007.
MAPP Loss of Load Expectation Study 2010–2019, December 2009.

MAPP Members use various measurement and verification programs for Demand Response, such as those based on International Performance Measurement and Verification Protocols (IPMVP). Reductions in demand due to energy efficiency total 12 MW, or 0.2 percent of the MAPP Projected Total Internal Peak Demand of 4,997 MW.

Each MAPP member uses its own forecasting method. In general, the peak demand forecast includes factors involving recent economic trends (industrial, commercial, agricultural, residential) and normal weather patterns. There were no changes in this year's forecast assumptions in comparison to last year. The continued recession and nation-wide economic downturn continue to negatively impact the load forecast.

Peak demand uncertainty and variability due to extreme weather or other conditions are accounted for within the determination of adequate generation Reserve Margin levels. MAPP Members use a Load Forecast Uncertainty (LFU) factor within the calculation for the Loss of Load Expectation (LOLE) and/or the percentage Reserve Margin necessary to obtain a LOLE of 0.1 day per year, or one day in ten years. The load forecast uncertainty considers uncertainties attributable to weather and economic conditions.

Generation

The Existing-Certain and Existing-Other capacity resources for the 2011 summer season are 7,599 MW with an additional 80 MW of Future capacity. These values do not include Firm or Non-Firm purchases and sales. The month of July was used as the peak summer month in all cases to be consistent. Of the 7,599 MW of Existing-Certain capacity resources, 398 MW of variable capacity is forecast on peak, with a nameplate rating of 1,177 MW. Of the 1,177 MW of Existing capacity resources, three MW of biomass capacity is projected on peak. With respect to existing wind forecast on peak, MAPP uses a method that is based on a median of actual wind output: the four peak hours per day for each and every day of the four summer months. This dataset uses ten years or the life of the wind plant. This is a different method when compared to the effective load carrying capability (ELCC) study performed by the MISO and other RTOs. The MISO ELCC study looks at the MISO's top eight annual summer peaks for the last five years (40 peak values total) to determine how much wind is actually generated during summer peak conditions and compares the amount of wind generated to the MISO's load.

TABLE 30: MRO-MAPP EXISTING AND PLANNED PEAK CAPACITY

Existing-Certain (MW)	6,823
Existing-Other (MW)	776
Future-Planned (MW)	80

High winter water levels coupled with forecast spring runoff are projected to cause high water conditions for all of 2011 summer. No abnormal operating conditions or restrictions are forecast to impact reliability during 2011 summer. MAPP is not experiencing or expecting conditions that would reduce capacity for the 2011 summer season. MAPP does not anticipate any significant generating units to be out of service or retired during the 2011 summer season.

FIGURE 29: MRO-MAPP EXISTING AND PLANNED RENEWABLE GENERATION

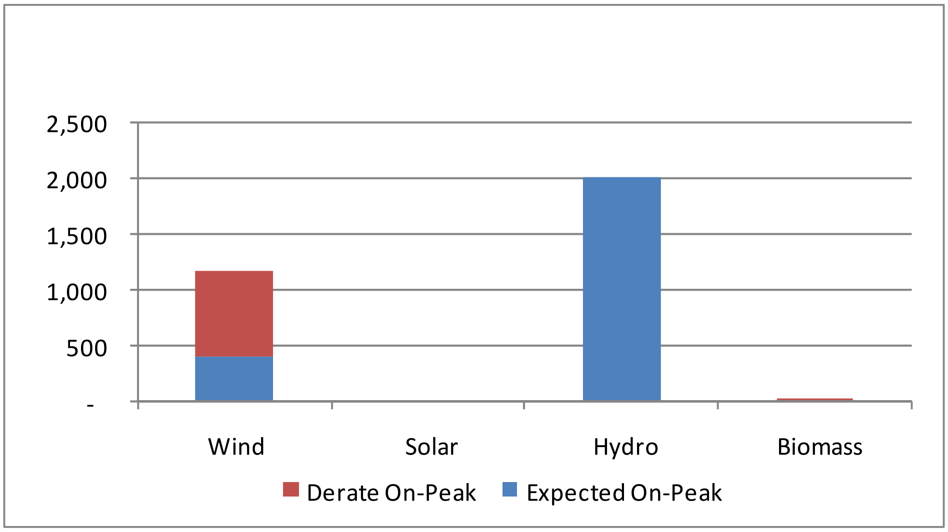


TABLE 31: MRO-MAPP EXISTING AND PLANNED RENEWABLE GENERATION

Wind Expected On-Peak	398
Wind Derate On-Peak	776
Wind Nameplate/Installed Capacity	1,173
Solar Expected On-Peak	-
Solar Derate On-Peak	-
Solar Nameplate/Installed Capacity	-
Hydro Expected On-Peak	2,007
Hydro Derate On-Peak	-
Hydro Nameplate/Installed	2,007
Biomass Expected On-Peak	3
Biomass Derate On-Peak	0
Biomass Nameplate/Installed	3

Capacity Transactions

For the 2011 summer season, MAPP is projecting total imports of 375 MW. These imports are from sources external to MAPP. Of the 375 MW of imports into MAPP, 369 MW are considered Firm, none are considered Non-Firm, and six MW are considered Projected.

For the 2011 summer season, MAPP is projecting total exports of 1,301 MW. These exports are from sources internal to MAPP. Of the 1,301 MW of exports out of MAPP, 999 MW are considered Firm, 302 MW are considered Non-Firm and none are considered as Forecast.

TABLE 32: MRO-MAPP IMPORTS AND EXPORTS ON-PEAK

Imports (MW)	375
Firm (MW)	369
Expected (MW)	6
Exports (MW)	999
Firm (MW)	999
Expected (MW)	-
Net Exports (MW)	**624**

For both imports and exports, Firm contracts exist for both the generation and the transmission service. Transmission providers within MAPP treat Liquidated Damage Contracts (LDC) according to their tariff policies. Most MAPP members are within non-retail access jurisdictions and therefore liquidated damages products are not typically used. MAPP is forecast to meet the various Reserve Margin targets without needing to include Energy-Only, uncertain, or transmission-limited resources. No emergency MW are required to meet the Reserve Margin target in MAPP.

Transmission

NorthWestern Energy is in the process of building 14 miles of 115 kV line between Western Area Power Administration's (Western) Letcher Junction Substation and Mitchell Transmission Substation. The estimated completion of the substation upgrade and line is late 2011 summer. This project will provide additional support to the Mitchell Area. MAPP does not have any current concerns in meeting target in-service dates for new transmission additions.

Multiple outages are scheduled for sections of the Center 345 kV, Square Butte 230 kV, and Prairie 230 kV substations throughout the spring, summer, and fall of 2011 in order to perform preparatory work for the Center-Grand Forks 345 kV line. No operating problems are projected. Temporary operating guides will be developed as necessary. MAPP does not anticipate any transmission constraints that will significantly impact reliability this summer.

Operational Issues

No significant operational issues are forecast this summer for MAPP. The existing operating guides and temporary operating guides that are developed as needed have maintained reliable system conditions throughout the year. Reservoir water levels have improved significantly since last year.

TABLE 33: MRO-MAPP DEMAND RESPONSE AND ENERGY EFFICIENCY ON-PEAK

Non-Dispatchable DSM (MW)	23
Energy Efficiency	12
Non-Controllable Demand-Side Demand Response	11
Total Internal Demand	5,087
Controllable, Dispatchable Demand Response	60
Net Internal Demand	5,027

The Basin Electric Power Cooperative(BEPC)/Western/Heartland Consumers Power District (Heartland) Integrated System has energized several new interconnections since the 2010 summer season. A 100 MW simple-cycle gas turbine was placed in service in Culbertson, Montana.

The SD Prairiewinds 183 MW wind plant that interconnects at Wessington Springs substation in South Dakota is anticipated to be in service by early 2011. An additional 100 MW wind plant was added to the Hilken substation in North Dakota. A new 230 kV line from Williston to Tioga in North Dakota was placed in service in January 2011. The new line will be used to support load growth in the Area and imports/exports with Saskatchewan. Western will begin rebuilding the 115 kV line from Charlie Creek to Watford City for 230 kV construction. Temporary operating guides will be developed as necessary.

In the Minnkota Power Cooperative Area, wind generation development near Fargo, North Dakota, may result in constraints on the 230 kV network lines in the Fargo Area, for which upgrades are still pending. These constraints are addressed by a Special Protection System and operating guides, which specify conditions requiring generation curtailment. Multiple outages are scheduled for sections of the Center 345 kV, Square Butte 230 kV, and Prairie 230 kV substations throughout the spring, summer, and fall of 2011 in order to perform preparatory work for the Center-Grand Forks 345 kV line. No operating problems are projected. Temporary operating guides will be developed as necessary.

Overall, the MAPP system is forecast to operate under all load and Firm exchange levels while meeting the Area's reliability criteria. MAPP anticipates normal levels of demand during 2011 summer in the MAPP assessment area.

Reliability Assessment

Some members of MAPP self impose a planning Reserve Margin as identified in the LOLE completed by MAPP on December 31, 2009. The MAPP LOLE study requires a 15-percent Reserve Margin for predominantly thermal systems, and ten-percent Reserve Margin for predominantly hydro systems.

TABLE 34: MRO-MAPP ON-PEAK CAPACITY RESOURCES AND RESERVE MARGINS[88]

	2011 Summer Forecast (MW)	2011 Summer Forecast (%)
Existing-Certain and Net Firm Transactions (with Demand Response)	6,253	22.9%
Anticipated Capacity Resources	6,339	24.6%
Prospective Capacity Resources	6,339	24.6%
NERC Reference Margin Level	**763**	**15.0%**

The projected Reserve Margins in MAPP (23 percent Existing, 25 percent Anticipated, and 25 percent Prospective) for the 2011 summer season are in excess of the MAPP target Reserve Margin of 15 percent for predominately thermal systems and ten percent for predominately hydro systems. This summer's projected Reserve Margin is 22.9 percent. This compares to last summer's projected Reserve Margin of 29.7 percent. The decrease in Reserve Margin this summer is primarily due to an increase in exports.

[88] Change from prior year values are not included for the MRO-MAPP Area.

No specific analysis is performed to ensure external resources are available and deliverable. However, to be counted as Firm capacity, the various transmission providers require external purchases to have a Firm contract and Firm transmission service.

MAPP considers known and anticipated fuel supply or delivery issues in its assessment. Because the Area has a large diversity in fuel supply, inventory management, and delivery methods, MAPP does not have a specific mitigation procedure in place should fuel delivery problems occur. The MAPP members do not foresee any significant fuel supply and/or fuel delivery issues for the upcoming 2011 summer season. However, if problems occur, they will be addressed on a case-by-case basis.

No supply transportation/delivery issues are anticipated or mitigated for the 2011 summer season. However, if problems occur, they will be addressed on a case-by-case basis.

Transient, voltage, and small signal stability studies are performed as part of the near- and long-term transmission assessments. Reactive power resources are considered in on-going operational planning studies. No transient, voltage, or small signal stability issues are projected that impact reliability during the 2011 summer season.

Area Description

The Mid-Continent Area Power Pool (MAPP) Planning Authority Area covers electric utilities operating in all or parts of the following states: Iowa, Minnesota, Montana, North Dakota, and South Dakota. Currently, the MAPP Planning Authority covers one Balancing Authority and 18 Load Serving Entities. The MAPP footprint 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.

MRO-Manitoba Hydro

Manitoba Hydro

Introduction

Manitoba Hydro is a Provincial Crown Corporation providing electricity to 521,600 customers throughout Manitoba and natural gas service to 261,150 customers in various communities in southern Manitoba. Manitoba Hydro also has formal electricity export sale agreements with more than 35 electric utilities and marketers in Midwestern U.S., Ontario, and Saskatchewan.

Manitoba Hydro is its own Planning Authority and Balancing Authority. Manitoba Hydro is a coordinating member of the Midwest Reliability Organization. The MISO is the Reliability Coordinator for Manitoba Hydro.

Manitoba Hydro collects data from various sources including historical operating data, data from neighboring utilities, physical equipment data, forecast data generated from internal and external computer models that integrate various data sources, and internal and external reports. Analysis methods include industry-accepted practices using computer models.

Demand

The forecast adjusts historical load to remove the weather effect for the purpose of forecasting future load. Normal weather for the forecast prepared in August 2010 was based on 25 years of Winnipeg temperatures—from April 1985 to March 2010. Economic forecast assumptions are derived from the 2010 Economic Outlook and the 2010 Energy Price Outlook. These documents contain Manitoba Hydro's forecasts of economic variables including prices of electricity, natural gas and oil, Gross Domestic Product (GDP), Manitoba population, and housing.

Table 35: MRO-Manitoba Forecast and Actual Peak Demand

2010 Total Internal Demand (MW)	2010 Actual Demand (MW)	Difference in Actual versus Forecast (MW)	Difference in Actual versus Forecast (%)	2011 Total Internal Demand (MW)	Difference in 2011 and 2010 Forecast Demand (MW)	Difference in 2010 Actual versus 2011 Forecast (%)	All-Time Summer Peak Demand (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)
N/A	3,164	-	-	3,166	-	-	3,422	(256)	-7.5%

The actual peak for summer 2010 was 3,164 MW.

Last year's total internal demand forecast for July was 3,287 MW. This year's total internal demand forecast for July is 3,166 MW. A more detailed hourly analysis was performed for the 2011 forecast that broke down the hourly load-by-load research sectors and re-evaluated the monthly peaks. This analysis and current economic conditions contributed to the lower summer peaks in the 2011 forecast. Manitoba Hydro's peak load is used in the resource evaluations for Manitoba Hydro.

Manitoba Hydro’s Curtailable Rate Program is not intended to reduce the summer peak demand but rather to meet reliability obligations. Manitoba Hydro will curtail customers in response to system emergencies and to maintain planning and operating reserves. As a percentage of Total Internal Demand, Demand Response can reduce peak demand ranges from 7.2 percent to 7.7 percent during the assessment period.

Upon a system contingency/emergency, the System Control Centre may curtail the customer by the terms of the contracts agreed upon in the Curtailable Rates Program. The Control Centre measures the amount of curtailment through the EMS/SCADA system and monitors it throughout the curtailment period. The curtailment is logged and a memo is issued after the fact outlining its extent, the amount curtailed, and the reason for curtailment.

Manitoba Hydro’s current Power Smart portfolio includes customer service, cost-recovery, incentive- and rate-based initiatives, and programs customized to meet the specific energy needs of the residential, commercial, and industrial markets. This portfolio, consisting of energy-efficiency, conservation, load management, and customer self-generation programs, is designed to help customers conserve energy, reduce energy bills, and protect the environment.

The measurement and verification activities conducted by Manitoba Hydro are tailored to the specific requirements of each energy efficiency program and sector. The intensity of measurement and verification is based on variability of use and the benefit of measurement in relation to the cost.

- The residential market is characterized by a large number of customers with typically homogeneous energy use patterns. Due to the size and homogeneity of the sector, measurement and verification is minimal. Energy savings are based on a deemed savings per technology in conjunction with surveyed use patterns.
- The commercial market is characterized by fewer numbers and customers with typically homogeneous use patterns. Measurement and verification is limited due to cost/benefit implications and the ability to use deemed savings and standardized use patterns based upon technology.
- The industrial market includes programs that will establish an appropriate measurement and verification plan for each customer. The plan will follow the principles outlined in the International Performance Measurement and Verification Protocol – Volume 1 (March 2002).

The Evaluations department within Manitoba Hydro models evaluations according to the International Performance Measurement and Verification Protocols (IPMVP) from the Efficiency Valuation Organization and DSM best practices.

The standard deviation of the one-year June-to-September peak forecasts is estimated to be six percent. Therefore, it is forecast that the peak in any of those four months will be within plus or minus 12 percent of the predicted peak 95 percent of the time (19 times out of 20) This covers all sources of variability, including weather, the economy, and other factors.

Economic assumptions are updated every year and this year's modifications took into account the economic recession. In addition, known load reductions were factored in. This was part of the reason for the lower forecast 2011 summer peaks.

The summer peaks represent a 25-year average hottest weekday each month. They do not represent the extreme single year hottest weekday. However, the standard deviation estimate of six percent for the peak indicates that an extreme summer condition (one year in 40) would be about 12 percent higher than the average peak.

Generation

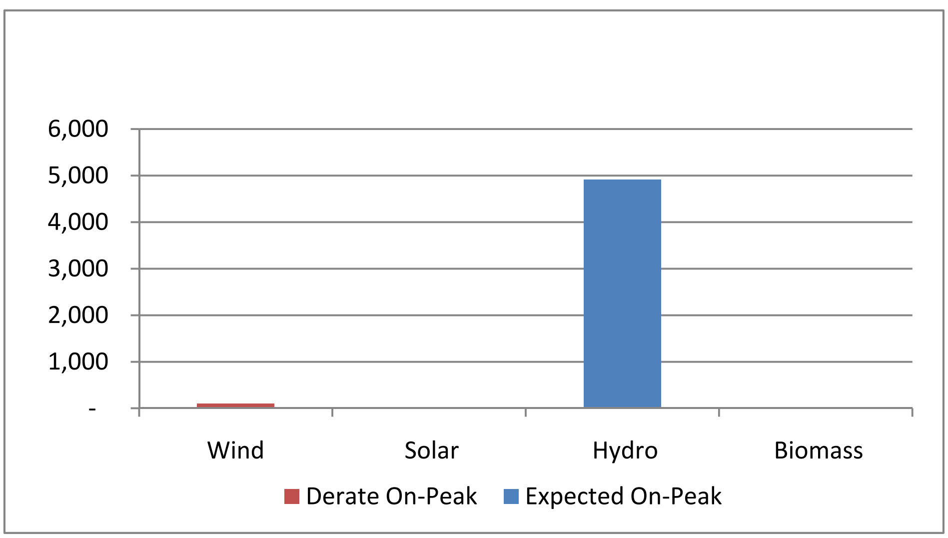
Existing-Certain capacity ranges from 4,704 to 5,353 MW during the assessment timeframe. Existing-Other capacity ranges from 300 to 926 MW during the assessment timeframe. Future capacity additions are 11 MW during the assessment timeframe.

TABLE 36: MRO-MANITOBA EXISTING AND PLANNED PEAK CAPACITY

Existing-Certain (MW)	5,353
Existing-Other (MW)	300
Future-Planned (MW)	11

Included in the Existing-Certain capacity above is the Jenpeg Generation Station (GS), with associated nameplate of 131 MW. The projected on-peak amounts for Jenpeg GS range from 91 MW to 130 MW during the assessment period. This hydro station is considered variable generation because it is run-of-the-river and considered an energy resource, and because its output can only be modified for a 24-hour period. These on-peak capacity values are calculated based on the MRO Generator Testing Guidelines.[89]

FIGURE 30: MRO-MANITOBA EXISTING AND PLANNED RENEWABLE GENERATION



[89] http://www.midwestreliability.org/REL_asr.html

Manitoba Hydro has two other existing variable capacity resources: St. Leon wind plant, which has about 104 MW of nameplate capacity and St. Joseph wind plant, with a nameplate capacity of 138 MW. These MWs are included in Existing-Other resources because Manitoba Hydro does not count wind generation resources for reliability/capacity purposes. St. Joseph wind plant is also presently transmission-limited. Manitoba Hydro has no biomass-sourced capacity.

TABLE 37: MRO-MANITOBA EXISTING AND PLANNED RENEWABLE GENERATION

Wind Expected On-Peak	-
Wind Derate On-Peak	104
Wind Nameplate/Installed Capacity	104
Solar Expected On-Peak	-
Solar Derate On-Peak	-
Solar Nameplate/Installed Capacity	-
Hydro Expected On-Peak	4,912
Hydro Derate On-Peak	-
Hydro Nameplate/Installed Capacity	4,912
Biomass Expected On-Peak	-
Biomass Derate On-Peak	-
Biomass Nameplate/Installed	-

Reservoir levels are sufficient to meet both peak demand and daily energy demand. Manitoba Hydro has no known concerns or forecast conditions that would reduce capacity. Manitoba Hydro expects no significant generating units to be out of service or retired during the summer season.

Capacity Transactions

Manitoba Hydro does not have any capacity imports in summer, but has 1,110 MW of Firm on-peak capacity exports during the assessment period. Manitoba Hydro does not have any Non-Firm on-peak capacity exports during the assessment period, and does not expect to negotiate any more capacity on peak export contracts during the assessment period than what has been reported above. All of Manitoba Hydro's exports are backed by Firm contracts for both generation and transmission.

TABLE 38: MRO-MANITOBA IMPORTS AND EXPORTS ON-PEAK

Imports (MW)	-
Firm (MW)	-
Expected (MW)	-
Exports (MW)	1,110
Firm (MW)	1,110
Expected (MW)	-
Net Imports (MW)	**1,110**

All of Manitoba Hydro's 1,110 MW Firm on-peak capacity export contracts contain liquidated damage clauses and are "make-whole" as defined by FERC Order No. 890.

Manitoba Hydro participates in the MISO's contingency reserve sharing pool, which is made up of 2,000 MW of reserves. Manitoba Hydro is required to carry 150 MW of these reserves.

Transmission

New transmission facilities were required to accommodate the new Wuskwatim Generating Station (First unit Dec 2011). These facilities include the following:

- A new Thompson Birchtree 230 kV Station (2007) and 28-mile Thompson Birchtree-Wuskwatim 230 kV line was commissioned in April 2007, initially to supply construction power to build Wuskwatim.
- Once Wuskwatim is in service, the Thompson Birchtree-Wuskwatim line will serve as one of the generation outlet lines: two 85-mile 230 kV lines between Wuskwatim and Herblet Lake, and one 99-mile 230 kV line from Herblet Lake to the Pas Ralls Island.

These transmission facilities are projected to be energized in August 2011.

No new transformers, other than those required for the generation interconnection described above, are planned for 2011 summer. For Wuskwatim, a 150 MVar Static Var Compensator (SVC) will be installed at the Thompson Birchtree 230 kV Station to provide transient voltage support.

Manitoba Hydro expects to meet the in-service dates for the Wuskwatim transmission facilities. Manitoba Hydro does not anticipate any significant transmission lines or transformers being out of service through the summer season. Manitoba Hydro does not foresee any transmission constraints that could significantly impact reliability.

All Manitoba Hydro transfer capabilities with our neighboring utilities are determined in accordance with NERC, Regional, and Manitoba Hydro reliability standards and criteria such that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency and specified multiple contingencies. These studies, which consider simultaneous transfers and transmission and generation constraints, include the following:

- Manitoba Hydro – United States (MH-USA): interconnecting tie line transfer limits are developed through joint studies with the Interconnected Study Working Group (ISG) subject to review by the Northern MAPP Operating Review Working Group (NMORWG).
- Manitoba Hydro – Ontario (MH-Hydro One): interface transfer capability is determined from separate analyses conducted by Manitoba Hydro's System Performance department and by Ontario Independent Electricity System Operator (IESO), and is also coordinated with the latest analysis and guides from the Manitoba-Ontario-Minnesota (MOM) interconnection working group.
- Manitoba Hydro – SaskPower (MH-SP): interconnecting tie line transfer limits are developed through joint studies by the two utilities on a semi-annual (winter and summer) basis. Analyses are conducted to determine interface transfer capabilities for the most probable operating configurations and also to examine sensitivities of the transfer capabilities to variances in major network parameters on both sides of the interface.

Seasonal transfer capabilities are posted prior to the start of the season at: https://oasis.midwestiso.org/documents/mheb/ops_guide.html

Operational Issues

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

The St. Joseph Wind Plant has begun commercial operation. It is a 138 MW facility that has secondary service. Network Integration Transmission Service will be available in fall of 2011, subject to upgrade of transmission facilities. Wind resources in the Manitoba Hydro footprint are not used for capacity calculations for Manitoba Hydro.

TABLE 39: MRO-MANITOBA DEMAND RESPONSE AND ENERGY EFFICIENCY ON-PEAK

Non-Dispatchable DSM (MW)	41
Energy Efficiency	41
Non-Controllable Demand-Side Demand Response	-
Total Internal Demand	3,166
Controllable, Dispatchable Demand Response	227
Net Internal Demand	2,939

No reliability concerns are forecast at low demand periods due to over-generation.

Curtailable load is not used to meet peak demands. Manitoba Hydro does have restrictions as to how many times Demand Response can be deployed. Quarterly reports are sent to Manitoba Hydro's System Control to inform it of the number of allowable curtailments that have occurred to date and how many are remaining.

There are no environmental or regulatory restrictions that would impact reliability. Manitoba Hydro does not anticipate unusual operating conditions that could significantly impact reliability for the upcoming summer.

Reliability Assessment

Existing Reserve Margins are projected to range from 22.3 percent to 41.2 percent during the assessment timeframe. Anticipated and prospective Reserve Margins are projected to range between 22.7 percent and 41.5 percent during the assessment timeframe. These Reserve Margins are well above the required minimum Reserve Margin of 12 percent.

TABLE 40: MRO-MANITOBA ON-PEAK CAPACITY RESOURCES AND RESERVE MARGINS

	2011 Summer Forecast (MW)	2011 Summer Forecast (%)
Existing-Certain and Net Firm Transactions (with Demand Response)	4,470	41.2%
Anticipated Capacity Resources	4,481	41.5%
Prospective Capacity Resources	4,481	41.5%
NERC Reference Margin Level	**380**	**12.0%**

As a predominantly hydro area, Manitoba has both an energy criterion and a capacity Reserve Margin criterion. These criteria are set forth based on system historical adequacy performance analysis with reference to probabilistic resource adequacy studies. The energy criteria requires adequate energy resources to supply the Firm energy demand in the event that the lowest recorded coincident river flow conditions on the 96-year hydraulic flow record are repeated. The capacity Reserve Margin criterion requires a minimum 12-percent reserve above the forecast peak demand. Manitoba Hydro performs its own Loss-of-Load Expectation studies and in previous years also participated in MAPP Regional Loss-of-Load Expectation studies. The MAPP Loss-of-Load Expectation (LOLE) Study for the Ten-Year Planning Horizon 2010–2019 dated December 30, 2009, included Manitoba in the study Region. Manitoba Hydro is preparing a 2011 Loss-of-Load Expectation Study and anticipates completion of this study in the spring of 2011.

Reserve Margins decreased in June and September this year compared to last year, which is primarily due to more scheduled outages than last year. Reserve Margins have increased in July and August this year compared to last, primarily due to a predicted decrease in peak demand.

Manitoba Hydro does not anticipate any supply issues for the 2011 summer. Alberta gas supply to Manitoba is plentiful. Gas supply is available either from Alberta or from the east via backhaul arrangements. Manitoba Hydro does not have any Firm arrangements in place for supply at this time.

Manitoba Hydro does not anticipate any transportation issues for 2011 summer. Alberta's options for gas transportation to Manitoba are plentiful. TransCanada Pipelines has been experiencing significant de-contracting of Firm transport by its customers resulting in more than enough available transport capability should Manitoba Hydro have to run its gas-fired generation during the summer season. Manitoba Hydro does not have any Firm arrangements in place for transport at this time.

Manitoba Hydro has conducted reactive power studies in accordance with NERC VAR-001 standards and identified the required reactive reserves for the province. Reactive power studies have not been refreshed for 2011 summer, as the standing guide is still valid.

Area Description

Manitoba Hydro is a provincial Crown Corporation and the sole provider of electricity to 521,600 customers throughout the Canadian Province of Manitoba. Manitoba Hydro is its own Balancing Authority. The electricity is transmitted over nearly 62,140 miles of transmission and distribution lines. The lengths of transmission lines connected to Manitoba Hydro's transmission network include the following:

- *1,240 miles of 500 kV transmission (AC and HVDC)*
- *3,110 miles of 230 kV transmission (AC)*
- *870 miles of 138 kV transmission (AC)*
- *1,800 miles of 115 kV transmission (AC)*

Manitoba is one of ten Canadian provinces and has an area of 250,950 sq mi. Manitoba Hydro is a winter-peaking utility.

Saskatchewan Power

Introduction

Saskatchewan is a province of Canada that comprises a geographic area of 251,700 square miles and a population of approximately one million people. Peak demand is typically experienced during the winter. The Saskatchewan Power Corporation is the Planning Authority/Reliability Coordinator 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 bulk power system and its interconnections.

SaskPower owns and operates 7,555 miles of transmission lines and 52 high-voltage switching stations. SaskPower operates networked transmission facilities at the 230 kV and 138 kV levels. This extensive network is designed to serve Saskatchewan's large geographic Area and widely dispersed population. The Saskatchewan transmission system is characterized by relatively long 230 kV and 138 kV transmission lines connecting dispersed generating stations to sparsely distributed load supply points. Saskatchewan has transmission interconnections with the provinces of Alberta and Manitoba, and with the U.S. state of North Dakota.

Demand

Saskatchewan develops energy and peak demand forecasts based on a provincial econometric model and forecast industrial load data. Forecasts take into consideration the Saskatchewan economic forecast, historical energy sales, customer forecasts, normalized weather and historical data, and system losses. Methods, assumptions, and a summary of results are included in Saskatchewan's annual Load Forecast Report.

Weather has a significant impact on the amount of electricity consumed by non-industrial customers. Due to this weather sensitivity, averages of daily weather conditions for the last 30 years are used to develop the energy forecast. Peak load is forecast on a heating-season basis and represents the highest level of demand placed on the supply system.

The 2010 summer peak demand was 2,702 MW with a total internal demand of 3,109 MW. The 2009/2010 actual winter peak demand was slightly higher at 3,156 MW.

TABLE 41: SASKPOWER FORECAST AND ACTUAL PEAK DEMAND

2010 Total Internal Demand (MW)	2010 Actual Demand (MW)	Difference in Actual versus Forecast (MW)	Difference in Actual versus Forecast (%)	2011 Total Internal Demand (MW)	Difference in 2011 and 2010 Forecast Demand (MW)	Difference in 2010 Actual versus 2011 Forecast (%)	All-Time Summer Peak Demand (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)
3,109	2,702	(407)	-13.1%	3,045	(64)	-2.1%	2,825	220	7.8%

Last year's summer peak demand forecast was 2,951 MW. This year's summer peak demand forecast is 3,045 MW. This year's summer peak demand is forecast to be slightly higher than last year's forecast demand due mainly to economic growth.

Coincident hourly peak data are used in resource evaluations in Saskatchewan. Saskatchewan has Direct Control interruptible demand contracts with customers. Contractually interruptible demand is approximately three percent of Total Internal Demand. Saskatchewan has established evaluation measures based on standard industry protocols for Demand Response verification.

Saskatchewan has programs designed to help customers save power, save money, and help the environment. These include energy efficiency, conservation, education, and load management programs. Residential programs focus on consumer education on energy efficiency and market transformation of lighting, appliances, and furnace motors including retailer/manufacturer partnerships and end-user incentives. Commercial and industrial programs include energy performance contracting, energy audits, and information services along with the market transformation of lighting, geothermal, and heating, ventilating, and air conditioning (HVAC). Measurement and verification programs are based on industry standard protocols.

Saskatchewan develops annual energy and peak demand forecasts based on a provincial econometric model and forecast industrial load data. The economic forecast provides information on population and household growth, and growth rates for commercial, farm, and oilfield categories. The forecast for the industrial class is based on individual meetings with each customer to record their future load requirements. The provincial econometric model is coordinated with the provincial government to ensure consistency. Summary details are provided in Saskatchewan's annual Load Forecast Report.

High and low forecasts are developed for Saskatchewan to cover possible ranges in economic variations and other uncertainties, such as weather, using a Monte Carlo simulation model to reflect those uncertainties. This model considers each variable independent of the other variables and assumes the distribution curve of a probability of occurrence of a given result to be normal. The probability of the load falling within the bounds created by the high and low forecasts is projected to be 90 percent (confidence interval).

Load forecast method has not changed notwithstanding the economic recession. Load forecast assumptions are routinely adjusted based in part on economic conditions and forecasts. In cases where economic performance is forecast to decline, the impact would be to lower the actual load forecast due to projected decline in industrial load.

Saskatchewan addresses weather uncertainty using a Monte Carlo simulation model that considers a range of weather conditions based on historical observations.

Generation

An average of 3,926 MW of Existing capacity resources is forecast to be in service through the assessment timeframe. No Future capacity resources are projected to be in service during the assessment timeframe. 197 MW (nameplate capacity) is variable (wind).

Of this amount, ten percent, or 20 MW, is forecast on-peak. For reliability purposes, Saskatchewan considers ten percent of wind nameplate capacity to be available to meet summer peak. No portion is biomass.

TABLE 42: SASKPOWER EXISTING AND PLANNED PEAK CAPACITY

Existing-Certain (MW)	3,544
Existing-Other (MW)	272
Future-Planned (MW)	-

Saskatchewan reservoirs are at normal conditions and regular operating regimes are projected. Reservoir levels are sufficient to meet both peak demand and the daily energy demand throughout the upcoming system. Reservoirs are sufficiently large to meet daily requirements, and current hydrological conditions are forecast to be normal during the upcoming season. There are no concerns about fuel supply or fuel transportation. Saskatchewan does not anticipate any significant generating units to be out of service or retired during the summer season.

FIGURE 31: SASKPOWER EXISTING AND PLANNED RENEWABLE GENERATION

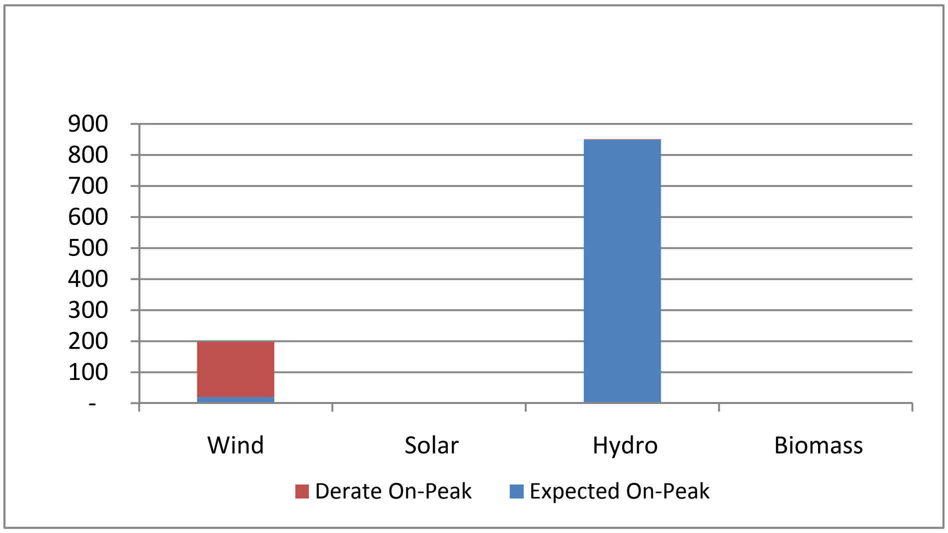


TABLE 43: SASKPOWER EXISTING AND PLANNED RENEWABLE GENERATION

Wind Expected On-Peak	20
Wind Derate On-Peak	178
Wind Nameplate/Installed Capacity	198
Solar Expected On-Peak	-
Solar Derate On-Peak	-
Solar Nameplate/Installed Capacity	-
Hydro Expected On-Peak	850
Hydro Derate On-Peak	2
Hydro Nameplate/Installed Capacity	852
Biomass Expected On-Peak	-
Biomass Derate On-Peak	-
Biomass Nameplate/Installed	-

Capacity Transactions

Saskatchewan has no on-peak imports scheduled this season from other assessment areas that will affect Saskatchewan's capacity margin. Saskatchewan has a Firm export of 50 MW scheduled for the summer reporting period. No partial path reservations or LDCs are involved. One-hundred percent of the energy contract is Firm and has Firm transmission reserved.

Saskatchewan does not rely on emergency imports.

Transmission

There have been no new significant BES transmission lines, transformers, or substation equipment installed since last summer. No internal or external transmission constraints are projected that will impact reliability.

Saskatchewan performs joint seasonal operating studies with Manitoba for the MRO-Canada assessment area to define transfer capability for Saskatchewan. Import capabilities may be referenced on the SaskPower OASIS. The studies consider simultaneous transfers and transmission and generation constraints. MRO interregional transmission transfer capability is addressed by the ERAG study.

Operational Issues

There were no special operating studies or procedures required for 2011 summer. No reliability concerns are anticipated during minimum demand or for over-generation.

Table 44: SaskPower Demand Response and Energy Efficiency On-Peak

Non-Dispatchable DSM (MW)	-
Energy Efficiency	-
Non-Controllable Demand-Side Demand Response	-
Total Internal Demand	3,045
Controllable, Dispatchable Demand Response	91
Net Internal Demand	2,954

No environmental or regulatory restrictions have been identified at this time that could potentially impact reliability in Saskatchewan. No unusual operating conditions that could significantly impact reliability are anticipated.

Reliability Assessment

Assessment is performed by SaskPower planning and operating Areas. Reference documents are footnoted below.[90]

[90] SaskPower 2010 Supply Development Plan:
http://www.saskpower.com/news_publications/assets/annual_reports/2010_skpower_annual_report.pdf
SaskPower 2010 Load Forecast Report: http://generationprocurement.saskpower.com/current.shtml
Manitoba Hydro -Saskatchewan Power Seasonal Operating Guideline on Manitoba-Saskatchewan Transfer Capability

TABLE 45: SASKPOWER ON-PEAK CAPACITY RESOURCES AND RESERVE MARGINS

	2011 Summer Forecast (MW)	2011 Summer Forecast (%)	Change from prior year (MW)	Change from prior year (percentage point)
Existing-Certain and Net Firm Transactions (with Demand Response)	3,585	17.7%	(253)	(10.7)
Anticipated Capacity Resources	3,585	17.7%	(203)	(9.0)
Prospective Capacity Resources	3,585	17.7%	(202)	(9.0)
NERC Reference Margin Level	**457**	**15.0%**	**(10)**	-

Saskatchewan uses a probabilistic method of establishing planning reserve (Forecast Unserved Energy). Saskatchewan performs an annual Projected Unserved Energy analysis to determine the requirement for adding new generation resources. Saskatchewan's EUE studies result in a target planning Reserve Margin of approximately 13 percent. This summer's projected Reserve Margin is between 18 percent and 22 percent. Last summer's projected Reserve Margin was between 19 percent and 20 percent.

Fuel-supply coordination or interruption in Saskatchewan is generally not considered to be an issue due to system design and operating practices.

Coal resources have Firm contracts and are mine-mouth, and stockpiles are maintained at each facility in the event that mine operations are unable to meet the required demand of the generating facility. Typically, there are 20 days of on-site stockpile for each of the coal facilities, which in total represent approximately 47 percent of total provincial installed capacity. Strip coal reserves are also available and only need to be loaded and hauled from the mine. These reserves range from 30 to 65 days depending on the plant.

Natural gas resources have Firm on-peak transportation contracts with large natural gas storage facilities located within the province to back the contracts. Typically, Saskatchewan does not rely on external generation resources. All hydro facilities and reservoirs are fully controlled by SaskPower. Finally, Saskatchewan does not anticipate any supply transportation or delivery issues. Dynamic and reactive power resources are considered in on-going operational planning studies.

Other Region-Specific Issues

Saskatchewan does not anticipate any other reliability concerns for the 2011 summer.

Region Description

SaskPower is the Balancing Authority for the province of Saskatchewan. Saskatchewan is a province of Canada and has a geographic area of 251,700 square miles and a population of approximately one million people. Peak demand is experienced in the winter.

NPCC

Executive Summary

The five Northeast Power Coordinating Council, Inc. (NPCC) Reliability Coordinator areas, or subregions, are defined by the following footprints:

- Maritimes Area (the New Brunswick System Operator, Nova Scotia Power Inc., the Maritime Electric Company Ltd. and the Northern Maine Independent System Administrator, Inc);
- New England (the ISO New England Inc.);
- New York (New York ISO);
- Ontario (Independent Electricity System Operator); and
- Québec (Hydro-Québec TransÉnergie).

Demand, Capacity & Reserve Margins

When compared with projections for 2010 summer, the New York and Ontario subregions are projecting higher Reserve Margins, while the New England subregion is projecting a similar but slightly lower Reserve Margin. The Québec and Maritimes subregions are winter-peaking and have very high summer Reserve Margins forecast for 2011 summer (Table 46).

TABLE 46: NPCC DEMAND AND RESERVE MARGINS

NPCC Balancing Authority area	2011 Summer Forecasted Peak (MW)	2011 Summer Forecasted Reserve Margin (%)	2010 Summer Forecasted Reserve Margin (%)	2010 Summer Forecasted Peak (MW)	2010 Summer Actual Peak (MW)
Maritimes	3,553	58.9	55.0	3,610	3,497
New England	27,550	18.8	19.6	27,190	27,102
New York	32,699	19.2	15.1	33,025	33,452
Ontario	23,561	36.3	26.4	23,556	25,075
Québec	21,283	40.9	44.6	20,677	22,092

The Northeast Power Coordinating Council, Inc. has in place a comprehensive resource assessment program directed through Appendix D, *Guidelines for Area Review of Resource Adequacy,* of NPCC Regional Reliability Reference Directory 1, *Design and Operation of the Bulk Power System* (http://www.npcc.org/documents/regStandards/Directories.aspx). This document charges the NPCC Task Force on Coordination of Planning (TFCP) to assess periodic reviews of resource adequacy for the five subregions. In assessing each review, the TFCP will ensure that the proposed resources of each subregion will comply with Section 5.2 of Directory 1, which is quoted below:

> *"Each Area's probability (or risk) of disconnecting any Firm load due to resource deficiencies shall be, on average, not more than once in ten years. Compliance with this criterion shall be evaluated probabilistically, such that the loss of load expectation [LOLE] of disconnecting Firm load due to resource deficiencies shall be, on average, no more than 0.1 day per year.*

> *This evaluation shall make due allowance for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Areas and Regions, transmission transfer capabilities, and capacity and/or load relief from available operating procedures."*

These resource assessments are complemented by the efforts of the Working Group on the Review of Resource and Transmission Adequacy (Working Group CP-08), which assesses the interconnection benefits assumed by each NPCC Area in demonstrating compliance with NPCC resource adequacy requirements.

The NPCC real time operating reserve requirements are indicated in NPCC Directory #5, "Reserve."[91]

Table 47 below indicates the anticipated internal capacity resources within the NPCC subregions for the 2011 summer months.

TABLE 47: NPCC 2011 SUMMER ANTICIPATED INTERNAL CAPACITY (MW)

NPCC Balancing Authority Area	June	July	August	September
Maritimes	5,734	5,695	5,697	5,853
New England	31,317	31,616	31,625	30,862
New York	36,687	36,700	40,717	40,717
Ontario	30,823	31,054	30,958	28,591
Québec	30,775	32,966	32,164	31,063

Capacity additions and retirements include the following:

- In Québec, Eastmain-1-A's three 256 MW units will be placed in service (one each in June, July, and August) in the James Bay Area of the Quebec system.
- No large capacity additions are anticipated during this summer in the Maritimes, New England, New York, or Ontario subregions.
- However, in Ontario two more coal units with a capacity of about 1,000 MW will be shut down after 2011 summer. Four coal units with a total capacity of about 2,000 MW were shut down in October last year.

Transmission

Table 48 below indicates the major anticipated 2011 summer system transmission additions.

[91] http://www.npcc.org/documents/regStandards/Criteria.aspx

TABLE 48: NPCC TRANSMISSION ADDITIONS FOR 2011 SUMMER

NPCC Area	Transmission Project	Voltage (kV)	In-service
Maritimes	None for this summer	—	—
New England	Rumford – Rumford Industrial Park	115	Summer
New England	King Street – West Amesbury	115	Summer
New York	M29 project: 1) circuit from Sprain Brook 345 kV substation to a new substation, Academy 345 kV, 2) two three-winding 345/138/13.8 transformers 3) two 138 kV PAR controlled transformers into Sherman Creek 138 kV	345	Summer
New York	Stony Ridge Project: 1) Stony Ridge 230 kV substation, between the Canandaigua – Hillside 230 kV line, and 2) a step-down 230/115 kV transformer into a new Sullivan Park 115 kV substation.	230	Summer
Ontario	Kirkland Lake 115 kV SVC , Nanticoke 500kV SVC, Detweiler 230 kV SVC	115-500	Summer
Québec	315 kV transmission project to integrate the Eastmain-1-A (1 km) and La Sarcelle (102 km) hydro projects into the grid.	315	Summer

Significant recent transmission additions are noted and described below:

- In northern Maine, the Keene Road Substation with one 345/115 kV went into service. The installation of the Keene Road autotransformer provides a second supply source to the Area.
- In January 2011, the expansion of the Kent County 345/115 kV substation was completed in Rhode Island. The expansion included installing a second 345/115 kV autotransformer as part of the Greater Rhode Island Transmission Reinforcements that provide additional transformation in the Area to address various thermal and voltage issues.
- In December 2010, the Vermont Southern Loop Project was completed. The project consisted of installing a 51-mile, 345 kV line between the Vermont Yankee plant and Coolidge, Vermont, along with two 345/115 kV autotransformers at Newfane and Vernon, Vermont. The project addresses thermal and voltage problems for key contingencies under heavy import conditions into Vermont.
- In late 2010, Ontario Hydro One installed series compensation on the 500 kV north-south lines at Nobel Switching Station and additional static VAR compensation facilities at Porcupine TS to increase the transfer capability.
- Hydro One also added a 200 MVar shunt capacitor bank at Buchanan TS in the southwest zone.
- Also in Ontario, a new 230 kV transformer station (TS) named Kitchener-Wilmot MTS#9 with two 230/28 kV transformers was added and a new load supply facility called Ellwood MTS comprising two 230/13.2 kV transformers was added.

Significant anticipated additions are noted and described below:

- The Consolidated Edison M29 project will be in service for the 2011 summer operating period. The M29 project consists of a circuit from Sprain Brook 345 kV substation to a new substation, Academy 345 kV, then to two three-winding 345/138/13.8 transformers and two 138 kV PAR controlled transformers into Sherman Creek 138 kV.
- The NYSEG/RG&E Stony Ridge Project includes a new Stony Ridge 230 kV substation, which is located between the Canandaigua-Hillside 230 kV line, and a step-down 230/115 kV transformer into a new Sullivan Park 115 kV substation.
- A new 115 kV line will be installed between the Rumford and Rumford Industrial Park substations in Maine. This is a component of the Rumford-Woodstock-Kimball Road Project and addresses thermal and voltage issues within the Rumford Area.
- In Summer 2011, Hydro One will have in service static VAR compensation (SVC) facilities at Kirkland Lake (115 kV, 40 Mvar), Nanticoke (500kV, 350 Mvar) and Detweiler (230 kV, 350 Mvar)

Operations

The following are highlights that should be noted with regard to operations within NPCC during the 2011 summer period:

- The Beck-Packard BP76 tieline between New York and Ontario is forecast to be out of service throughout the summer operating period.
- In New Brunswick, the Point Lepreau generating station (CANDU nuclear-635 MW) will be out of service throughout the summer operating period.
- Phase angle regulators (PARs) are installed on all four of the Michigan-Ontario interconnections. One PAR on the Keith-Waterman 230 kV circuit J5D has been in-service and regulating since 1975. The other three available PARs on the Lambton-St. Clair 230 kV circuit L51D and 345 kV circuit L4D and the Scott-Bunce Creek 230 kV circuit B3N remain idle. Although the operating agreements are now ready, the completion of the filing process with FERC and the Department of Energy, may delay the in-service date for the remaining PARs until after the summer period.
- In New York, the South Mahwah-Waldwick J3410 line and the Watercure 345/230 kV transformer will be in service for the summer operating period.
- The Norwalk Harbor-Northport 138kV 1385 NNC 601 cable between New England and Long Island, New York is scheduled to return to service on June 30, 2011.

Maritimes

Introduction

The New Brunswick System Operator (NBSO) is the Reliability Coordinator for the Maritimes Area, which consists of four subregions. The Maritimes Area is a winter-peaking system and as such does not expect to experience any reliability issues. The weekly net margins for 2011 summer cited in the NPCC CO-12 Reliability Assessment Report range from 39 to 47 percent. These net margins take into account known maintenance outages and deratings, and apply an unplanned outage estimate.

Demand

The Maritimes Area load is the mathematical sum of the forecast weekly peak loads of the subareas (New Brunswick, Nova Scotia, Prince Edward Island, and the Area served by the Northern Maine Independent System Operator). The Maritimes Area is a winter-peaking system. For the NBSO, the load forecast is based on an End-use Model (sum of forecast loads by use (*e.g.,* water heating, space heating, lighting, etc.) for residential loads and an Econometric Model for general service and industrial loads, correlating forecast economic growth and historical loads. Each of these models is weather adjusted using a 30-year historical average as follows:

- For Nova Scotia, the load forecast is based on a ten-year average measured at the major load center, along with analyses of sales history, economic indicators, customer surveys, technology, demographic changes in the market, and the price and availability of other energy sources.
- For Prince Edward Island, the load forecast uses average long-term weather for the peak period (typically December) and a time-based regression model to determine the forecast annual peak. The remaining months are prorated on the previous year.
- The Northern Maine Independent System Administrator performs a trend assessment on historic data in order to develop an estimate of future loads.

The NBSO as the Reliability Coordinator for the Maritimes Area uses the non-coincident peak when doing its resource evaluations.

Based on the Maritimes Area 2011 demand forecast, a peak of 3,553 MW is predicted to occur for the summer period, June through September. The actual peak for 2010 summer was 3,497 MW on September 1, 2010, which was 113 MW (3.1 percent) lower than last year's forecast of 3,610 MW.

TABLE 49: NPCC-MARITIMES FORECAST AND ACTUAL PEAK DEMAND

2010 Total Internal Demand (MW)	2010 Actual Demand (MW)	Difference in Actual versus Forecast (MW)	Difference in Actual versus Forecast (%)	2011 Total Internal Demand (MW)	Difference in 2011 and 2010 Forecast Demand (MW)	Difference in 2010 Actual versus 2011 Forecast (%)	All-Time Summer Peak Demand (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)
3,610	3,497	(113)	-3.1%	3,553	(57)	-1.6%	3,576	(23)	-0.6%

In the Maritimes Area there is between 378 MW and 412 MW of interruptible demand available during the assessment period; there is 379 MW forecast to be available at the time of the Maritimes Area seasonal peak. This is approximately ten percent of the Total Internal Demand. The interruptible load demand that may be used is from industrial loads that are metered and therefore can be monitored to determine what level of load would be available to curtail under emergency operating conditions.

The Maritimes Area is broken up into subareas, and each subarea has its own energy efficiency programs. These programs are primarily aimed at the residential consumer to help reduce their heating costs, as the Maritimes Area is a winter-peaking system.[92]

The Maritimes Area does not address quantitative analyses to assess the variability in projected demand due to weather, the economy, or other factors.

In addition, the Maritimes does not develop an extreme (*e.g.,* 90/10) summer forecast in its seasonal assessment.

The Maritimes Area resources will be 7,550 MW of Existing capacity (-Certain and -Other). The Maritimes Area does not consider conceptual, future, or inoperable resources when doing its seasonal assessment.

TABLE 50: NPCC-MARITIMES EXISTING AND PLANNED PEAK CAPACITY

Existing-Certain (MW)	5,853
Existing-Other (MW)	1,697
Future-Planned (MW)	-

Generation

During this period, there was 119 MW of existing wind with a nameplate rating of 774 MW.

Wind project capacity is derated to its demonstrated or projected average output for each summer or winter capability period. The derated wind capacity in the Maritimes Area is based on results from the Sept. 21, 2005, NBSO report *Maritimes Wind Integration Study*.[93]

[92] The stakeholders that comprise the Maritimes Areas are: www.maritimeelectric.com, www.nppower.com, www.mainepublicservice.com, www.emec.com, www.nspower.ca/energy_efficiency/programs/

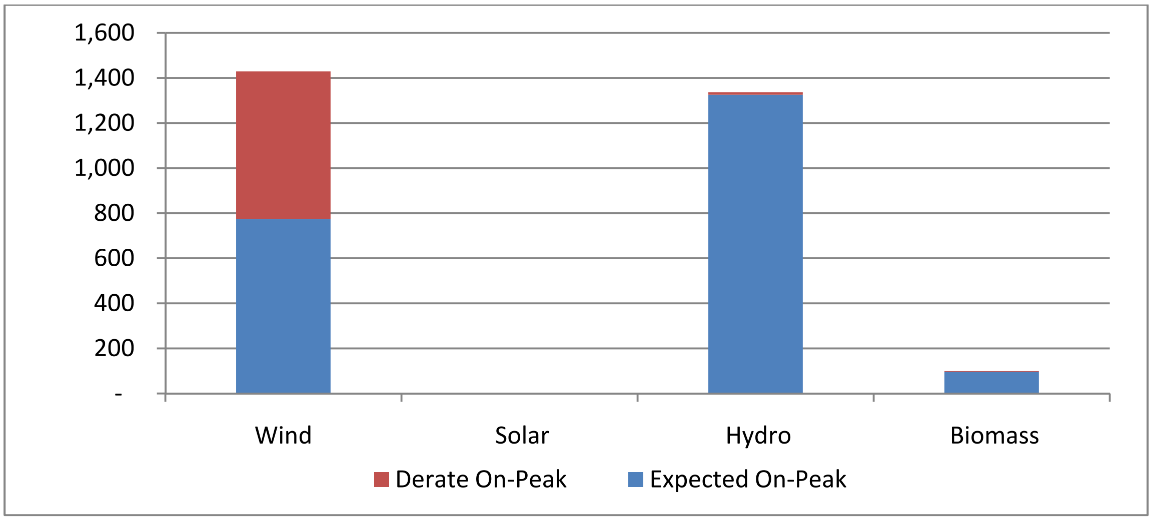
[93] http://www.nbso.ca/Public/_private/2005%20Maritime%20Wind%20Integration%20Study%20_Final_.pdf

This wind study showed that the effective capacity from wind projects, and their contribution to LOLE, was equal to or better than their seasonal capacity factors. Coincidence of high winter wind generation with the peak winter loads results in the Maritimes Area receiving a higher capacity benefit from wind projects than a summer-peaking Area. The effective wind capacity calculation also assumes a good geographic dispersion of the wind projects in order to mitigate the occurrences of having zero wind production. Wind is the only variable resource currently considered in the Maritimes Area resource adequacy assessment.

During this period, there will be 96 MW of existing Biomass with a nameplate rating of 99 MW.

The Maritimes Area is forecasting normal hydro conditions for the 2011 summer assessment period. The Maritimes Area hydro resources are run-of-the-river facilities with limited reservoir storage facilities. These facilities are primarily used as peaking units or for providing operating reserve.

FIGURE 32: NPCC-MARITIMES EXISTING AND PLANNED RENEWABLE GENERATION



The Maritimes Area does not expect to experience any conditions that would cause any capacity reductions.

TABLE 51: NPCC-MARITIMES EXISTING AND PLANNED RENEWABLE GENERATION

Wind Expected On-Peak	774
Wind Derate On-Peak	655
Wind Nameplate/Installed Capacity	1,429
Solar Expected On-Peak	-
Solar Derate On-Peak	-
Solar Nameplate/Installed Capacity	-
Hydro Expected On-Peak	1,325
Hydro Derate On-Peak	12
Hydro Nameplate/Installed Capacity	1,337
Biomass Expected On-Peak	96
Biomass Derate On-Peak	3
Biomass Nameplate/Installed	99

The Point Lepreau generation station will be out of service during the entire summer Assessment period. Since the 2010/2011 Winter assessment, a 96 MW coal fired facility was scheduled to retire May 31, 2011. These outages and retirements are not anticipated to cause any reliability issues as the Maritimes are a winter-peaking Area.

Capacity Transactions

No imports are scheduled for the Maritimes subregion at this time. There is a Firm sale of 207 MW to Hydro-Québec, which is tied to specific generators within New Brunswick. The sale is not based on a Liquidated Damage Contract.

TABLE 52: NPCC-MARITIMES IMPORTS AND EXPORTS ON-PEAK

Imports (MW)	-
Firm (MW)	-
Expected (MW)	-
Exports (MW)	207
Firm (MW)	207
Expected (MW)	-
Net Exports (MW)	**207**

The Maritimes Area does have agreements in place for the purchase of emergency energy from other NPCC Areas. In addition, there is a reserve sharing agreement between Balancing Authorities within the Maritimes Reliability Coordinator Area and there is an agreement for simultaneous activation of reserve within NPCC. Nevertheless, the Maritimes Area does not rely on this assistance when doing its summer assessment.

Transmission

There has been no significant new bulk power transmission addition since the last reporting summer period and no new transmission facilities are scheduled to go into service during the coming summer period.

There are no major transmission facilities scheduled to be out of service for extended periods during the 2011 summer with all existing significant transmission lines forecast to be in service during the summer reporting period. There are no transmission constraints that could impact reliability.

Projected 2011 summer transfer capabilities include:

- NB to Maine Electric Power Company (MEPCO): 1000 MW
- MEPCO to NB: 550 MW (ISO-NE may limit the interface due to the possibility of overloading a transformer in New England under certain system conditions and as warmer summer temperatures arrive).
- HQ to NB: HVdc + Radial Load = Between 888 MW and 917 MW. (The reason for the range is due to the varying radial load in the Madawaska and Eel River Area during the summer reporting period). The HVdc stations give a total 741 MW (Madawaska: 391 MW + Eel River: 350 MW).
- NB to HQ: 735 MW

The latest studies that compile Maritimes transfer capabilities are the IPL/NRI studies on the NB/ISO-NE interface. An Area's import capabilities are based on real time values based on transmission and generation being in or out of service. NBSO has rules based on study results for simultaneous transfer capability with our interconnections. Transmission or generation constraints are recognized that are external to the Maritimes Area.

Operational Issues

The Maritimes Area assesses its seasonal resource adequacy in accordance with NPCC Directory #1, Appendix F *Procedure for Operational Planning Coordination.* As such, the assessment considers the Regional Operating Reserve criteria: 100 percent of the largest single contingency and 50 percent of the second largest contingency. When allowances for unplanned outages (based on a discreet MW value representing an historical assessment of the total forced outages in MW typically realized at the time of peak for the given operating season) are considered, the Maritimes Area is projecting adequate surplus capacity margins above its operating reserve requirements for the 2011 summer assessment period.

TABLE 53: NPCC-MARITIMES DEMAND RESPONSE AND ENERGY EFFICIENCY ON-PEAK

Non-Dispatchable DSM (MW)	-
Energy Efficiency	-
Non-Controllable Demand-Side Demand Response	-
Total Internal Demand	3,553
Controllable, Dispatchable Demand Response	-
Net Internal Demand	3,553

The amount of wind presently operating does not require any special operational changes.

The Maritimes Area does not anticipate any reliability concerns due to minimum demand and over-generation. There are adequate generation facilities within the Maritimes that can easily be removed from service to prevent that from happening.

The only Demand Response considered in resource adequacy assessment for the Maritimes Area is interruptible load. The Maritimes Area uses a 20-percent reserve criterion for planning purposes, equal to 20 percent x (Forecast Peak Load MW - Interruptible Load MW). This is not an area for concern for summer operating conditions.

There are no environmental or regulatory restrictions that could impact reliability in the Maritimes Area during the assessment period, and no unusual operating conditions are anticipated for the summer that will impact reliability in the Maritimes Area.

Reliability Assessment

When allowances for unplanned outages (based on a discreet MW value representing an historical assessment of the total forced outages in MW typically realized at the time of peak for the given operating season) are considered, the Maritimes Area is projecting more than adequate surplus capacity margins above its operating reserve requirements for the 2011 summer assessment period.

TABLE 54: NPCC-MARITIMES ON-PEAK CAPACITY RESOURCES AND RESERVE MARGINS

	2011 Summer Forecast (MW)	2011 Summer Forecast (%)	Change from prior year (MW)	Change from prior year (percentage point)
Existing-Certain and Net Firm Transactions (with Demand Response)	5,646	58.9%	637	3.9
Anticipated Capacity Resources	5,646	58.9%	607	3.0
Prospective Capacity Resources	5,646	58.9%	607	3.0
NERC Reference Margin Level	**533**	**15.0%**	**(9)**	-

The projected Existing-Certain, anticipated, and prospective Reserve Margins for the 2011 summer period range from 55 to 59 percent as compared to the projected Reserve Margins for the 2010 summer of 55 to 73 percent. The NPCC target level margin requires that the probability (or risk) of disconnecting any Firm load due to resource deficiencies shall be, on average, not more than once in ten years.

The Maritimes Area does not consider potential fuel supply interruptions in the summer assessment. The fuel supply in the Maritimes Area is very diverse and includes nuclear (presently out of service), natural gas, coal, oil (both light and residual), pet-coke, hydro, tidal, municipal waste, wind, and wood.

The NB transmission system is robust, comprised of a 345 kV transmission ring with additional supporting 230 kV transmission. For those Areas that may suffer low voltage post contingency, there are specific “must run” procedures that require generation on line to meet necessary reactive reserves for contingencies. This requirement is applied for generation assessments as well as the day-ahead review to ensure that there are sufficient reactive reserves. No special dynamic or reactive assessment studies were required.

Other Specific Issues

The Maritimes Area is not anticipating any reliability concerns during 2011 summer. Therefore, no actions are necessary.

Area Description

The Maritimes Area is a winter-peaking system. This Area covers approximately 57,800 square miles and serves a population of approximately 1,910,000. It includes New Brunswick, Nova Scotia, Prince Edward Island, and the Area served by the Northern Maine Independent System Operator (parts of northern and eastern Maine). In the Maritimes Area, New Brunswick and Nova Scotia are Balancing Authorities. The New Brunswick System Operator is the Reliability Coordinator for the Maritimes Area.

New England

Executive Summary

ISO New England Inc. (ISO-NE) reports that due to the ongoing effects of the recession, this year's forecast for summer peak demand has decreased slightly from last year's forecast for the same period. On June 1, 2010, implementation of a new Forward Capacity Market (FCM) brought a large influx of both Energy Efficiency (EE) and Demand Resources (DR) into the supply mix. These demand-side resources account for approximately 6.2 percent of ISO-NE capacity contracted to serve the 2011 summer demands. In addition, 10 MW of new supply-side capacity resources are projected to commercialize during August 2011 and there are no projections for capacity attrition during the period. Although ISO-NE has no specific or fixed Reserve Margin requirements, the Reserve Margin entitled Existing-Certain capacity and net Firm transactions reflects a Reserve Margin of 5,211 MW (18.9 percent) for the reference case demand forecast and a Reserve Margin of 3,066 MW (10.3 percent) for the extreme case demand forecast.[94] These Reserve Margins are slightly down from those forecast for the 2010 summer peak demand and energy. This set of circumstances produces a very positive forecast for ISO-NE to reliably serve the 2011 summer peak and energy demands.

During 2011 summer, there are no projections of any significant transmission lines being out of service and no transmission constraints are anticipated that would significantly impact Regional reliability. There are two new transmission lines scheduled to be placed in service prior to the 2011 summer period: a new 115 kV line is scheduled to be installed between the Rumford and Rumford Industrial Park substations in Maine and another new 115 kV line is scheduled to be installed between the King Street and West Amesbury substations in Massachusetts. Two new transformer projects have recently been placed into service. The installation of a 345/115 kV autotransformer at the Keene Road Substation in Maine was completed in late 2010, and in early 2011 the expansion of the Kent County 345/115 kV substation was completed in Rhode Island.

As noted earlier, the New England assessment area is projecting positive Reserve Margins for the 2011 summer period. There are no fuel supply concerns, environmental restrictions, transmission constraints, or other operational issues projected for this summer. Therefore, no special studies or assessments are being performed by ISO-NE.

Introduction

ISO New England Inc. (ISO-NE) is the Regional Transmission Organization (RTO) for the six-state New England Region. ISO-NE is responsible for the reliable operation of the Bulk Power System, administration of the Region's wholesale electricity markets, and management of the comprehensive planning process. ISO-NE has performed a deterministic assessment of New England's projected power system operations for the 2011 summer period. ISO-NE has compiled the information requested by NERC for demand, energy, resources (both supply and demand-side), imports/exports, and transmission.

[94] This is due to the fact that New England's resource adequacy criterion is based on the one day-in-ten-years Loss of Load Expectation (LOLE) and it is not based on a fixed Reserve Margin. NERC has assigned New England a target Reserve Margin of 15 percent, which is the designation for a thermal-based power system.

From that data collection process, the projected 2011 summer Reserve Margins are determined. These results are then discussed with ISO-NE System Operations to identify any potential operational issues that could not be identified through the deterministic capacity assessment. The results of both of these analyses are reflected within this narrative.

Demand

The forecast reference case is the 50/50 forecast (50 percent chance of being exceeded), corresponding to a New England three-day weighted, temperature-humidity index (WTHI) of 79.9, which is equivalent to a dry bulb temperature of 90 degrees Fahrenheit and a dew point temperature of 70 degrees. The 79.9 WTHI is the 95th percentile of a weekly weather distribution and is consistent with the average of the WTHI value at the time of the summer peak over the last 40 years. The reference demand forecast is based on the reference economic forecast, which reflects the Regional economic conditions that would "most likely" occur.

TABLE 55: NPCC-NEW ENGLAND FORECAST AND ACTUAL PEAK DEMAND

2010 Total Internal Demand (MW)	2010 Actual Demand (MW)	Difference in Actual versus Forecast (MW)	Difference in Actual versus Forecast (%)	2011 Total Internal Demand (MW)	Difference in 2011 and 2010 Forecast Demand (MW)	Difference in 2010 Actual versus 2011 Forecast (%)	All-Time Summer Peak Demand (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)
27,190	27,102	(88)	-0.3%	27,550	360	1.3%	28,130	(580)	-2.1%

ISO-NE's actual 2010 summer peak demand of 27,102 MW occurred on July 6, 2010. This actual 2010 peak demand was 8.0 percent higher than the actual 2009 summer peak demand of 25,100 MW, which occurred on August 18, 2009. The reference peak demand forecast for the 2010 summer was 27,190 MW.

The reference 2011 summer peak demand forecast is 27,550 MW, which is 360 MW (1.3 percent) higher than the reference 2010 summer peak demand forecast of 27,190 MW.[95] The key factor leading to this change in the forecast is the gradually improving economic recession.

The extreme 2011 summer peak demand forecast is 29,695 MW, which is 385 MW (1.3 percent) higher than the extreme 2010 summer peak demand forecast of 29,310 MW. However, the extreme 2011 summer peak demand forecast is still 140 MW lower than the value forecast last year (29,835 MW) for the same time period.

ISO-NE develops an independent load forecast for the Balancing Authority Area. ISO-NE uses historical hourly demand data from individual member utilities, which are based on revenue quality metering (RQM). These data are then used to develop historical demand data upon which the peak demand and energy forecasts are based.

[95] This value, 27,550 MW, is the same for the unrestricted non-coincident peak demand (line 1) and the total internal demand (line 2), from the corresponding NERC 2011 Summer Assessment spreadsheet, July and August 2011 values.

From this, ISO-NE develops a forecast of both state and monthly peak and energy demands. The peak demand forecast for ISO-NE and the states can be considered a coincident peak demand forecast.

Demand resources are treated as capacity in ISO-NE's FCM. For 2011 summer, there are 2,035 MW of demand resources (7.4 percent of forecast peak demand). Within this total are 1,261 MW of active demand resources and 774 MW of passive demand resources (*e.g.,* energy efficiency). The active demand resources (1,261 MW) are real-time Demand Response and real-time emergency generation, which can be activated with the implementation of ISO-NE Operating Procedure No. 4 – *Action during a Capacity Deficiency* (OP-4).[96] Some assets in the real-time Demand Response programs are under direct load control by the load response providers (LRP). The LRP implements direct load control of these assets upon dispatch instructions from ISO-NE, for example, interruption of central air conditioning systems in residential and commercial facilities.

Under the FCM, energy efficiency can be included in the category of on-peak and seasonal peak demand resources.[97] This includes installed measures (*e.g.,* products, equipment, systems, services, practices, and strategies) on end-use customer facilities that result in additional and verifiable reductions in the total amount of electrical energy used during on-peak hours.

An approved FCM measurement and verification (M&V) plan will be used for the purpose of evaluating the performance of both active and passive demand resources. Commercial operation and seasonal audits will be conducted, consistent with ISO-NE operating manuals, to ensure that all FCM demand resources are capable of providing their contractual demand reductions.

Not included in this assessment is voluntary demand that may interrupt based on the price of wholesale energy. As of March 1, 2011, there were approximately 61 MW enrolled in the ISO-NE's price response program. The actual value of the demand that responds is captured in collected Demand Response data; at the time of the peak in 2010, this amount was about 24 MW.

ISO-NE addresses peak demand uncertainty in two ways:

- **Weather** – Peak demand distribution forecasts are made based on 40 years of historical weather, which includes the reference forecast (50-percent chance of being exceeded), and extreme forecast (ten-percent chance of being exceeded); and
- **Economics** – Alternative forecasts are made using high and low economic scenarios.

The economic assumptions resulting from the recession have reduced the demand forecast. However, no changes have been made to the method for forecasting demand notwithstanding the recession.

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

[97] The rules addressing the treatment of demand resources in the FCM may be found in Section III.13.1.4 of ISO New England's Market Rule 1, Standard Market Design, located at: www.iso-ne.com/regulatory/tariff/sect_3/2-16-09_mr1_sect_13-14.pdf

ISO-NE also reviews the projected 2011 summer conditions using the extreme 90/10 peak demand forecast based on the reference economic forecast. For 2011 summer, that value is 29,695 MW.

Generation

ISO-NE's Existing-Certain generating capacity amounts to 29,590 MW based on summer ratings. An additional 3,251 MW of capacity is identified within the Existing-Other category, and that value consists of two subcategories of additional capacity. The first subcategory of capacity, approximately 3,005 MW, is the amount of ISO-NE's capacity that exceeds the FCM capacity supply obligation (CSO).[98] The second subcategory of capacity, totaling 26 MW, is the total capacity of generators that did not participate in the FCM. There is zero MW of Existing, Inoperable capacity.

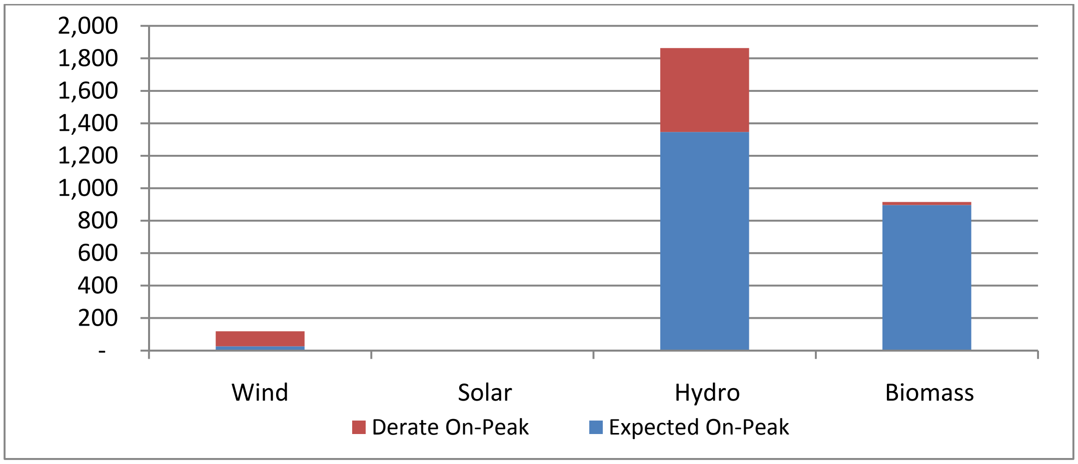
TABLE 56: NPCC-NEW ENGLAND EXISTING AND PLANNED PEAK CAPACITY

Existing-Certain (MW)	29,590
Existing-Other (MW)	3,251
Future-Planned (MW)	-

A total of ten MW of future capacity addition is projected for commercialization within the August peak-demand period. This includes zero MW of Future-Planned capacity and ten MW of Future-Other wind capacity.

Approximately 26 MW of the Existing-Certain capacity is wind generation that is projected to be available at the time of peak demand. This reflects a 93 MW on-peak derate from the total nameplate capability of 119 MW. Wind capability under ISO-NE's FCM is rated seasonally. FCM wind capability during the summer and winter seasons is equal to the average of a median calculation performed for each year over the previous five years. For the summer season, the median calculation is the median net output during the hours ending 1400 through 1800, each day of June through September, and any summer hour with a "shortage event."[99]

FIGURE 33: NPCC-NEW ENGLAND EXISTING AND PLANNED RENEWABLE GENERATION



[98] The CSO is the FCM contracted capacity, which will receive payments for reliably serving the 2011 summer peak and energy demands.

[99] These are events under which ISO-NE operations is currently experiencing either an operating reserve or capacity deficiency.

The method for rating non-FCM wind assets, which generally tend to be the smaller facilities, is the same as for FCM resources except that the capacities are based on only the preceding year (not up to five years) of summer or winter output data.

Approximately zero MW of Existing-Certain capacity is solar generation that is forecast to be available at the time of peak demand.

Biomass capacity within the Existing-Certain category totals 897 MW. This reflects an 18 MW derate on peak, from the total capability of 915 MW.

The Existing-Certain capacity also includes 1,346 MW of hydroelectric resources. This reflects a 517 MW derate on peak from the total nameplate capability of 1,863 MW. Monthly ratings for hydroelectric resources with little or no storage capability are calculated based on the maximum capacity of the unit(s), adjusted for historical hydrological conditions and upstream storage. Those hydroelectric resources with pondage and storage of at least ten times their seasonal claimed capability rating must annually demonstrate their summer and winter capability. Hydrological conditions for New England during the 2011 summer are projected to be normal.

The ten MW of wind capacity that is included within the ten MW of future capacity additions is projected to go into service during 2011 summer. This reflects a 50 MW derate on peak, from the total nameplate capability of 60 MW.

Table 57: NPCC-New England Existing and Planned Renewable Generation

Wind Expected On-Peak	26
Wind Derate On-Peak	93
Wind Nameplate/Installed Capacity	119
Solar Expected On-Peak	-
Solar Derate On-Peak	-
Solar Nameplate/Installed Capacity	-
Hydro Expected On-Peak	1,346
Hydro Derate On-Peak	517
Hydro Nameplate/Installed Capacity	1,863
Biomass Expected On-Peak	897
Biomass Derate On-Peak	18
Biomass Nameplate/Installed Capacity	915

ISO-NE is not projecting any disruptions to Regional fuel supply chains serving the electric power sector.

ISO-NE is not projecting any significant generating facilities to be out of service during the 2011 summer peak demand period. There are no retirements scheduled within the 2011 summer period that relate to compliance with environmental regulations.

Capacity Transactions

The forecast for 2011 summer on-peak Firm capacity imports is 1,236 MW. These Firm capacity imports include 688 MW from Hydro-Québec, 284 MW from New Brunswick, and 264 MW from

New York. These Firm capacity imports have been contracted for delivery within the 2011/2012 FCM Capability Period.[100]

TABLE 58: NPCC-NEW ENGLAND IMPORTS AND EXPORTS ON-PEAK

Imports (MW)	1,236
Firm (MW)	1,236
Expected (MW)	-
Exports (MW)	100
Firm (MW)	100
Expected (MW)	-
Net Imports (MW)	**1,136**

While the entire 1,236 MW of Firm capacity imports are backed by Firm FCM contracts for generation, there is no requirement for those purchases to have Firm transmission service. However, it is specified that deliverability of external capacity imports must meet the FCM delivery requirement and should be consistent with the deliverability requirements of internal generators. The market participant is free to choose the type of transmission service it wishes to use for the delivery of energy associated with the FCM Firm capacity import, but that market participant bears the associated risk of FCM penalties if it chooses to use Non-Firm transmission.

There are no capacity import contracts that can be characterized as "liquidated damage contracts" or "make-whole" contracts as defined by FERC Order 890.

The forecast for 2011 summer on-peak Firm capacity exports is 100 MW. This Firm capacity export is a 100 MW sale to New York (Long Island) via the Cross-Sound Cable. This Firm capacity export has been contracted for delivery within the 2011/2012 FCM Capability Period.

Although the Firm capacity export is backed by a Firm generation contract, FCM rules will dictate whether the capacity and associated energy can be considered recallable by ISO-NE.

There are no capacity export contracts that can be characterized as "liquidated damage contracts" or "make-whole" contracts as defined by FERC Order 890.

The Firm capacity import contracts have a capacity supply obligation (CSO) under FCM and can be characterized as resources that ISO-NE can count on as part of fulfilling its Installed Capacity Requirement (ICR). A reasonable amount of emergency assistance that is obtainable from external NPCC Areas can also be used by ISO-NE as "tie benefits." During the 2011 summer, a total of 1,800 MW of tie benefits is assumed obtainable from the three NPCC Areas that New England has direct interconnections with: Québec, New Brunswick, and New York.

Transmission

There are two new transmission lines that are anticipated to be placed into service prior to 2011 summer.

[100] The 2011/2012 FCM Capability Period is from June 1, 2011, to May 31, 2012.

- A 115 kV line will be installed between the Rumford and Rumford Industrial Park substations in Maine. This is a component of the Rumford-Woodstock-Kimball Road Project and addresses thermal and voltage issues within the Rumford Area.
- A 115 kV line will be installed between the King Street and West Amesbury substations in Massachusetts. This is part of the Merrimack Valley-North Shore Project that addresses various thermal and voltage issues in the northeast Massachusetts Area.

There are three new transformer projects that were recently placed in service.

- In December 2010, the installation of a 345/115 kV autotransformer at the Keene Road Substation in Maine was completed. The installation of the Keene Road autotransformer provides a second supply source to the Area.
- In January 2011, the expansion of the Kent County 345/115 kV substation was completed in Rhode Island. The expansion included installing a second 345/115 kV autotransformer as part of the Greater Rhode Island Transmission Reinforcements that provides additional transformation in the Area to address various thermal and voltage issues.
- In December 2010, the Vermont Southern Loop Project was completed. The project consisted of installing a 51-mile, 345 kV line between the Vermont Yankee plant and Coolidge, Vermont, along with two 345/115 kV autotransformers at Newfane and Vernon, Vermont. The project addresses thermal and voltage problems for key contingencies under heavy import conditions into Vermont.

No other significant substation equipment, such as SVCs, FACTS devices, or HVdc, has recently been added.

There are no reliability concerns in meeting the projected in-service dates for these new transmission additions. Mitigation plans have been developed to address identified future needs.

All significant transmission lines and transformers are forecast to be in service through the 2011 summer season. Upon a major outage of a significant transmission facility, operating procedures are in place to maintain system reliability.

During 2011 summer, there are no anticipated transmission constraints that would significantly impact reliability. However, there are localized system requirements dependent upon the operation of local Area generation under certain operating conditions. Operating procedures and guides are in place to address outages of this type of generation.

The import capabilities into New England and the transmission studies on which they are based are listed in Table 59. These transmission studies are reviewed and updated on a regular basis. All of the transmission studies account for both transmission and generation constraints within power systems external to New England.

TABLE 59: NEW ENGLAND'S EXTERNAL TRANSMISSION INTERFACE CAPABILITIES (MW)

Interface	Transfer Capability (MW)	Interface Capability
New Brunswick-New England	700	The transfer capability from New Brunswick to New England is 1,000 MW. However, in this assessment it was assumed to be 700 MW, reflecting limitations imposed by internal New England constraints that are currently under review by ISO New England
Hydro-Québec-New England Phase II	1,200–1,400[101]	PJM and NYISO Loss of Source Studies
Hydro-Québec-Highgate	200	Various Transmission Studies
New York-New England	1,400	NYISO Operating Studies
Cross-Sound Cable	346[102]	Cross-Sound Cable System Impact Study

Operational Issues

There are no significant anticipated unit outages, environmental restrictions, variable resources, transmission constraints, or temporary operating measures that would adversely impact system reliability during the 2011 summer period. Because of this projection, there are no special operating studies that have been performed for the 2011 summer period.

To date, there are no special operating procedures that are a result of the recent integration of variable or intermittent resources such as wind, solar, etc. Since ISO-NE has less than one MW of solar capacity within its system, there is no need to forecast the output of solar resources.

Conditions where day-ahead cleared resources exceed forecast or real-time system demand can occur anytime, but are most prevalent during low demand conditions. It is anticipated that these conditions will be mitigated by implementing some or all of the actions of ISO-NE System Operating Procedure entitled SOP-RTMKTS.0120.0015 – *Implement Minimum Generation Emergency Remedial Action*. Those actions include de-committing generators, dispatching pumping load at pumped storage facilities, reducing on-line generators, and temporarily curtailing real-time external purchases.

The implementation of the FCM has enhanced the integration of demand resources into system operations. Operating Procedures to dispatch the demand resources have been developed and tuned. Demand response availability assumptions are based on their performance during ISO-NE OP-4 events or the results of annual response audits. The performance of demand-side resources can be monitored by System Operators in real-time and the actual performance of these resources affects their forward-going FCM compensation. If ISO-NE does not activate all the Demand

[101] The Hydro-Québec Phase II interconnection is a HVDC tie with equipment ratings of 2,000 MW. Due to the need to protect the loss of this line at full import level in the PJM and NY Control Areas' systems, ISO-NE has assumed its transfer capability for capacity and reliability calculation purposes to be 1,200 MW to 1,400 MW. This assumption is based on the results of loss of source analyses conducted by PJM and NY.

[102] The capability of the Cross-Sound Cable is 346 MW. However, losses reduce the amount of MWs that are actually delivered across the cable. When 346 MW is injected into the cable, 330 MW is received at the point of withdrawal. Recent study work has shown that the actual transfer capability from New York (Long Island) to New England (Connecticut) is very dependent on the specific generation dispatch at New Haven and reduces to zero with the plant(s) in full operation.

Response programs within all load zones by August 15 of each calendar year, then ISO-NE will initiate pre-defined audits of those programs within the necessary load zones.

TABLE 60: NPCC-NEW ENGLAND DEMAND RESPONSE AND ENERGY EFFICIENCY ON-PEAK

Non-Dispatchable DSM (MW)	-
Energy Efficiency	-
Non-Controllable Demand-Side Demand Response	-
Total Internal Demand	27,550
Controllable, Dispatchable Demand Response	2,035
Net Internal Demand	25,515

There are no environmental or regulatory restrictions currently being discussed or forecast for the Area that would impact system reliability. However, during extremely hot summer days and/or low hydrological conditions, there may be environmental restrictions on coastal or river-based generating units due to cooling water discharge temperatures. Such conditions have occurred several times in the past, resulting in temporary reductions in capacity ranging in aggregate anywhere from 50 MW to 500 MW. These environmental restrictions translate into capacity reductions and are reflected within ISO-NE's forced outage assumptions. ISO-NE monitors these situations and anticipates that additional resources should be available to cover these temporary reductions in generating capacity.

On a monthly basis, ISO-NE uses a weekly operable capacity analysis to assess the reliability and adequacy of the Region.[103] This analysis takes into consideration the FCM resources, the net of Firm capacity imports and exports, the forecast peak demand, operating reserve requirements, all known or planned outages, and the potential for the temporary unplanned outages of generation or transmission facilities. The resultant operable capacity margins are either surplus or deficient. In order to be prepared for peak demand during the summer, ISO-NE takes the approach of applying the forecast for the summer peak demand to the months of July and August. Operating procedures can be used in real-time to mitigate any negative operable capacity margins that materialize.

There are no unusual operating issues or concerns that are projected to impact transmission system operations within New England for the 2011 summer period.

Reliability Assessment Analysis (RAA)

ISO-NE bases its capacity requirements on a probabilistic loss-of-load expectation analysis that calculates the total amount of installed capacity needed to meet the Northeast Power Coordinating Council's (NPCC) once-in-ten-year requirement for preventing the disconnection of Firm load due to a capacity deficiency. This value, known as the Installed Capacity Requirement (ICR), was calculated for the 2011/2012 Capability Period to be 32,463 MW.[104] After taking into

[103] The operable capacity analyses, which are included with ISO-NE's Annual Maintenance Schedule (AMS), are posted at: http://www.iso-ne.com/genrtion_resrcs/ann_mnt_sched/index.html

[104] The 32,463 MW ICR value does not reflect a reduction in capacity requirements relating to HQICCs that are allocated to the Interconnection Rights Holders, as required by Market Rule 1. After deducting the HQICC value of 911 MW per month, the net ICR for use in the 2011/2012 third annual reconfiguration auction is 31,552 MW.

account emergency purchases from the interconnections, the net amount of capacity needed to meet the resource adequacy criterion is 31,552 MW.

TABLE 61: NEW ENGLAND ON-PEAK CAPACITY RESOURCES AND RESERVE MARGINS

	2011 Summer Forecast (MW)	2011 Summer Forecast (%)	Change from prior year (MW)	Change from prior year (percentage point)
Existing-Certain and Net Firm Transactions (with Demand Response)	32,761	18.9%	244	(0.7)
Anticipated Capacity Resources	32,761	18.9%	244	(0.7)
Prospective Capacity Resources	32,771	19.0%	(937)	(5.0)
NERC Reference Margin Level	**4,133**	**15.0%**	**54**	-

The model used for conducting New England's 2011/2012 ICR calculation accounts for all Firm capacity imports and exports, which amounts to a net value of 1,111 MW. In addition, ISO-NE assumes that it will be able to obtain 1,800 MW of emergency assistance, also referred to as tie benefits, from other neighboring NPCC Areas during possible capacity shortage conditions within New England. That amount is based on the results of a 2010 probabilistic tie benefits study.

In addition to the tie benefits study, ISO-NE has analyzed projected 2011/2012 system conditions of the neighboring Balancing Authority Areas, as reflected in the most recent NPCC Resource Adequacy Assessment (RAA), and determined that the 1,800 MW tie benefits are reasonable and achievable. The Areas assumed to be providing the tie benefits are Québec, New Brunswick, and New York. The tie benefit value of 1,800 MW amounts to about 50 percent of New England's total import capability.

NERC has assigned New England a target Reserve Margin of 15 percent, which is the designation for a thermal-based power system. ISO-NE's projected 2010 and 2011 summer Reserve Margins are summarized in Table 61. The 2011 reference case (50/50) summer total internal demand is 27,550 MW. The Existing-Certain capacity and Net Firm transactions value is 32,761 MW. The resultant reference case 2011 summer Existing-Certain capacity and Net Firm transactions Reserve Margin is 5,211 MW, which equates to 18.9 percent.

The 2011 extreme case (90/10) summer total internal demand is 29,695 MW. The amount of summer capacity to serve that demand (Existing-Certain capacity and Net Firm transactions) is 32,761 MW. The resultant extreme case 2011 summer Reserve Margin is 3,066 MW, which equates to 10.3 percent.

Both 2011 summer margins, reference and extreme case, are sufficient to cover New England's operating reserve requirement, which is approximately 2,000 MW; however, higher-than-forecast unit outages and/or higher-than-anticipated demand could adversely affect the forecast Reserve Margins.

For the previous year, the 2010 summer peak demand period, the projected Reserve Margin under the 50/50 peak demand forecast was approximately 5,327 MW (19.6 percent), and the projected Reserve Margin under the 90/10 peak demand forecast was approximately 3,207 MW (10.9 percent). The 50/50 and 90/10 Reserve Margins forecasts for the 2011 summer are about 116 MW and 141 MW lower, respectively, than the 50/50 and 90/10 Reserve Margins forecast for the 2010 summer.

Table 62: New England 2010 and 2011 Summer Reserve Margins (MW)

Weather Forecast	2010 Summer (MW & Percent)	2011 Summer (MW & Percent)
Reference Case (50/50)	5,327 (19.6%)	5,211 (18.9%)
Extreme Case (90/10)	3,207 (10.9%)	3,066 (10.3%)

The prospective capacity resources to serve 2011 summer demand amount to 32,771 MW. Since the 2011 reference case (50/50) summer total internal demand is 27,550 MW, the resultant 2011 summer prospective capacity resource Reserve Margin is 5,221 MW, which equates to 19.0 percent.

ISO-NE routinely gauges the impacts that fuel supply disruptions could have upon system or subregional reliability.

Because natural gas is the predominant fuel used to produce electricity in New England, ISO-NE continuously monitors natural gas pipeline systems in New England, via their electronic bulletin board postings, to ensure that emerging gas supply or delivery issues can be incorporated into the daily or next-day operating plans. Should natural gas issues arise that may impact fuel deliveries to power generators, ISO-NE has predefined communication protocols in place with the Gas Control Centers of both Regional pipelines and local gas distribution companies (LDCs), in order to quickly understand the emerging situation and then implement mitigation measures. ISO-NE's Operating Procedure No. 21 – *Action during an Energy Emergency (OP21)* is designed to help mitigate the impacts on bulk power system reliability resulting from Regional fuel supply deficiencies.[105] OP21 is used to facilitate communication with market participants in an attempt to bring more fuel supply to the system.

There are no fuel supply or deliverability concerns for the 2011 summer period. Historically, many fuel supply and delivery options have been readily available to generators within New England during the summer months. If fuel-related issues were to arise that would jeopardize the balance between supply and demand, ISO-NE has a predefined series of actions and steps as well as a network of communications plans in place to disseminate the information necessary to inform both the regulatory community and the public.

Transmission planning studies have demonstrated that adequate reactive resources are provided throughout New England. In instances where dynamic reactive power supplies are needed, devices such as STATCOMs, SVCs, synchronous condensers, and DVARs have been employed to meet the required need. If additional reactive power support is necessary in real time, generation will be committed to meet the requirement. Operational studies are performed in the near term to develop and update operating guides supporting adequate voltage/reactive performance.

[105] Operating Procedure No. 21 is located on ISO-NE's web site located at: http://www.iso-ne.com/rules_proceds/operating/isone/op21/index.html.

Area Description

ISO New England Inc. is a Regional Transmission Organization (RTO) serving Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. It is responsible for the reliable operation of New England's bulk power generation and transmission system, administering the Region's wholesale electricity markets, and managing the comprehensive planning of the Regional bulk power system. The New England Regional electric power system serves 14 million people living in a 68,000 square-mile area. New England is a summer-peaking electrical system, which recorded its all-time peak demand of 28,130 MW on August 2, 2006.

New York

Executive Summary

The New York Balancing Authority area 2011 summer peak load forecast is 32,712 MW, which is 313 MW lower than the forecast of 33,025 MW peak for the 2010 summer and 740 MW lower than the actual summer peak in 2010 of 33,452 MW. This forecast load is 3.6 percent lower than the all-time summer peak load of 33,939 MW that occurred on August 2, 2006. The 2010 forecast was lower due to the impact of the current economic recession on electric energy consumption. The existing Certain Capacity in the New York Control Area (NYCA) for the upcoming summer operating period is 36,687 MW. 1,328 MW of Certain Capacity has been added since summer 2010. With the existing certain capacity of 36,687 MW and the expected peak of 32,712 MW, there is a summertime reserve margin of 19%.

The Consolidated Edison M29 project and the NYSEG/RG&E Stony Ridge project will be in service for the 2011 summer operating period. The M29 project consists of a circuit from Sprain Brook 345 kV substation to a new substation, Academy 345 kV, then to two three-winding 345/138/13.8 transformers and two 138 kV PAR controlled transformers into Sherman Creek 138 kV. The NYSEG/RG&E Stony Ridge Project includes a new Stony Ridge 230 kV substation, which is located between the Canandaigua-Hillside 230 kV line, and a step-down 230/115 kV transformer into a new Sullivan Park 115 kV substation.

The NYISO expects no outstanding challenges.

Introduction

NYISO is the only Balancing Authority in the New York Control Area (NYCA). The NYCA is over 48,000 square miles serving a total population of about 19.4 million people and peaking annually in the summer. This report addresses the reliability assessment for the NYCA for May 2011 through October 2011.

Demand

The weather assumptions for most Regions of the state are set at the 50th percentile of the historic series of prevailing weather conditions at the time of the system coincident peak. For Orange & Rockland and for Consolidated Edison, the weather assumptions are set at the 67th percentile of the historic series of prevailing weather conditions at the time of the system coincident peak.

The economic assumptions are based on projections for 2011 provided to the NYISO and the state's transmission owners by Moody's Analytics.

The 2010 summer coincident peak demand forecast was 33,025 MW; the 2011 forecast is 32,712 MW. The decrease in the forecast is due primarily to a drop in weather-adjusted peak demand from 33,063 MW in 2009 to 32,453 MW in 2010. This decrease is attributed primarily to the impacts of the economic recession.

The peak demand for the New York Control Area is a coincident peak demand for the New York Transmission Owner systems.

TABLE 63: NPCC-NEW YORK FORECAST AND ACTUAL PEAK DEMAND

2010 Total Internal Demand (MW)	2010 Actual Demand (MW)	Difference in Actual versus Forecast (MW)	Difference in Actual versus Forecast (%)	2011 Total Internal Demand (MW)	Difference in 2011 and 2010 Forecast Demand (MW)	Difference in 2010 Actual versus 2011 Forecast (%)	All-Time Summer Peak Demand (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)
33,025	33,452	427	1.3%	32,712	(313)	-0.9%	33,939	(1,227)	-3.6%

The NYISO projected in its 2011 Installed Reserve Margin Study that there will be 2,053 MW of Special Case Resources and 166 MW of Emergency Demand Response, for a total of 2,219 MW available for active demand response or load management. The forecasted total of 2,219 MW of demand response in reliability programs represents 6.8 percent of the 2011 summer peak demand forecast of 32,712 MW in Total Internal Demand.

Special Case Resources' performance is determined by comparing the actual hourly interval metered energy to the Average Peak Monthly Demand (APMD). Emergency Demand Response Resources' performance is determined by comparing the actual hourly interval metered energy to the Customer Baseline Load (CBL). For more details on the APMD and the CBL methodologies, refer to the NYISO ICAP Manual, Section 4.12.2; Appendix J, Section 3.3, UCAP based on Load/Demand Reduction applicable to Special Case Resources; and the NYISO EDRP Manual, Section 5.2, Calculation of Customer Baseline Load (CBL).[106]

The NYISO is currently evaluating possible changes to the measurement and verification of Special Case Resources through the stakeholder process.

Programs are currently offered throughout the state by a number of utilities and state agencies for a cross-section of market segments and energy efficiency measures. Individual utilities include the peak demand impact of these programs in their forecasts. Each utility and agency maintains a database of installed measures from which estimates of impacts can be determined. The impact evaluation methodologies and measurement and verification standards are specified by the state's Evaluation Advisory Group, a part of the New York Department of Public Staff reporting to the NY Public Service Commission.

The NYISO and the state's electric utilities jointly meet to establish the 2010 weather-adjusted peak, the annual growth rate, and the variability of three criteria of peak demand growth:

- The historic variation in the weather-adjusted peak demand;
- The historic variation in the ratio of peak demand to economic growth, and
- The historic variation in summer energy growth.

[106] http://www.nyiso.com/public/index.jsp

The method for developing the summer coincident peak forecast has not changed since 2010. The starting point for the 2011 forecast is -1.8 percent lower than that of the 2010 forecast, but the growth rate is somewhat higher: +0.8 percent in 2011 versus -0.1 percent in 2010.

Extreme summer conditions are explicitly addressed at the Regional and subregional levels as part of the 2011 Installed Reserve Margin Study that the NYISO performs for the New York State Reliability Council.[107]

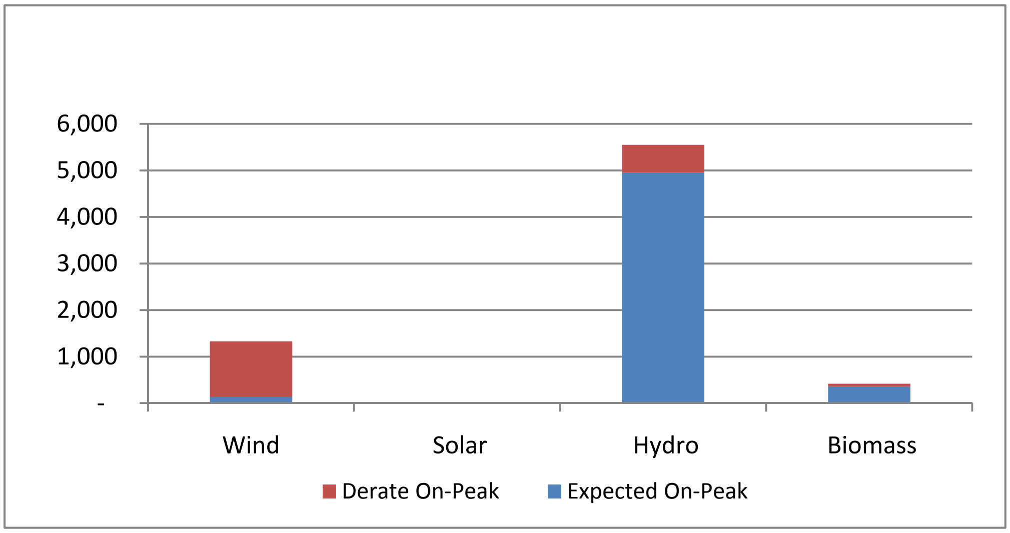
Generation

For 2011, the New York Balancing Authority Area expects 40,717 MW of existing capacity, with 34,667 MW of that classified as Existing-Certain. Of the Existing-Certain capacity, 133 MW is from wind generation and 358 MW is biomass generation. Existing-Other is 2,289 MW and consists mainly of wind, hydro, and biomass derated capacity. Based on historical performance, a 7.6-percent derate factor is applied for the majority of generators, including biomass. Wind generation is derated to ten percent of rated capacity, a 90-percent derate factor, in the summer operating period.

TABLE 64: NPCC-NEW YORK EXISTING AND PLANNED PEAK CAPACITY

Existing-Certain (MW)	34,667
Existing-Other (MW)	2,289
Future-Planned (MW)	-

FIGURE 34: NPCC-NEW YORK EXISTING AND PLANNED RENEWABLE GENERATION



Hydro conditions are anticipated to be sufficient to meet the forecast demand this summer. The New York Control Area is not experiencing continued effects of a drought or any conditions that would create capacity reductions. Reservoir levels are projected to be normal for the upcoming summer. NYISO is not experiencing or expecting conditions that would reduce capacity.

[107] http://www.nyiso.com/public/webdocs/services/planning/resource_adequacy/LCR_report_2_28_08.pdf

TABLE 65: NPCC-NEW YORK EXISTING AND PLANNED RENEWABLE GENERATION

Wind Expected On-Peak	133
Wind Derate On-Peak	1,196
Wind Nameplate/Installed Capacity	1,329
Solar Expected On-Peak	-
Solar Derate On-Peak	-
Solar Nameplate/Installed Capacity	-
Hydro Expected On-Peak	4,951
Hydro Derate On-Peak	603
Hydro Nameplate/Installed Capacity	5,554
Biomass Expected On-Peak	358
Biomass Derate On-Peak	63
Biomass Nameplate/Installed	421

No significant generating units will be out of service or retired between May and October 2011.

Capacity Transactions

The NYISO projects net Firm imports into the New York Balancing Authority Area of 222 MW during 2011 summer. Due to NYISO market rules the specific projected sales and purchases are considered confidential non-public information and cannot be explicitly indicated in this report.

Capacity purchases in New York are not required to have accompanying Firm transmission reservations, but adequate transmission rights must be available to assure delivery to New York when scheduled. External capacity is also subject to external availability rights. Availability on the import interface is offered on a first-come first-serve basis. The total capacity purchased for this summer operating period may increase since there remains both time and external rights availability.

Due to NYISO market rules, information on specific import and export transactions is considered confidential. Information on the aggregated or net forecast capacity imports and exports during peak summer conditions is not yet known. Capacity is traded in the NYISO market as a monthly product, and total imports and exports are not finalized until shortly before the month begins. NYISO does not rely on external resources for emergency assistance.

Transmission

The Consolidated Edison M29 project and the NYSEG/RG&E Stony Ridge project will be in service for the 2011 summer operating period. The M29 project consists of a circuit from Sprain Brook 345 kV substation to a new substation, Academy 345 kV, then to two three-winding 345/138/13.8 transformers and two 138 kV PAR controlled transformers into Sherman Creek 138 kV.

The NYSEG/RG&E Stony Ridge Project includes a new Stony Ridge 230 kV substation, which is located between the Canandaigua-Hillside 230 kV line, and a step-down 230/115 kV transformer into a new Sullivan Park 115 kV substation.

No delays of circuit additions are projected to impact reliability.

The South Mahwah-Waldwick J3410 line and the Watercure 345/230 kV transformer will be in service for the summer operating period. The Norwalk Harbor-Northport 138kV 1385 NNC 601 cable is scheduled to return to service on June 30, 2011. The Beck-Packard BP76 is forecast to be out of service through the summer operating period.

The NYISO does not have any transmission constraints that could significantly impact reliability. New York Balancing Authority Area import capability is summarized in Table 66. These values are derived by joint studies with adjoining Areas and recognize transmission and generation constraints.

TABLE 66: NYISO TRANSFER CAPABILITIES

Import Area	Transfer Capability
PJM	2,500 MW
Linden VFT	300 MW
Neptune Cable	660 MW
Québec	1,500 MW
Cedars-Dennison	200 MW
New England	2,100 MW
Cross Sound Cable	340 MW
1385 Cable	100 MW
Ontario	1,900 MW

Operational Issues

NYISO conducts seasonal capability assessment studies. There were no unique operational problems observed from these studies

NYISO has incorporated variable resources into the dispatch software, along with Limited Energy Storage Resources, (*e.g.,* flywheel and batteries). These resources are integrated such that no unique operational procedures are required.

NYISO does not anticipate any reliability issues from minimum demand or over-generation conditions.

TABLE 67: NPCC-NEW YORK DEMAND RESPONSE AND ENERGY EFFICIENCY ON-PEAK

Non-Dispatchable DSM (MW)	-
Energy Efficiency	-
Non-Controllable Demand-Side Demand Response	-
Total Internal Demand	32,712
Controllable, Dispatchable Demand Response	2,053
Net Internal Demand	30,659

The use of Demand resources are fully integrated into the policies and procedures of the NYISO. The program design promotes participation and the ISO expectation is for full participation. Further control actions are outlined in ISO policies and procedures. There is no limitation as to the number of times a resource can be called upon to provide response.

There are no environmental or regulatory restrictions currently being discussed or forecast for the Area that may impact system reliability. At this time, NYISO does not anticipate any unusual conditions that will impact reliability.

Reliability Assessment Analysis (RAA)

With the existing capacity of 40,717 MW and the expected peak of 32,712 MW, there is a summertime reserve margin of 24.5 percent. This exceeds the 15.5 percent annual reserve margin set by the New York State Reliability Council ("NYSRC").

NYISO complies with NPCC and NYSRC resource adequacy criteria of no more than one occurrence of loss of load per ten years due to a resource deficiency, as measured by 0.1 days/year LOLE. The assumptions take into account demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring control Areas, NYS Transmission System emergency transfer capability, and capacity and/or load relief from available operating procedures.

TABLE 68: NPCC-NEW YORK ON-PEAK CAPACITY RESOURCES AND RESERVE MARGINS

	2011 Summer Forecast (MW)	2011 Summer Forecast (%)	Change from prior year (MW)	Change from prior year (percentage point)
Existing-Certain and Net Firm Transactions (with Demand Response)	38,650	18.2%	2,597	1.0
Anticipated Capacity Resources	38,650	18.2%	1,017	(4.1)
Prospective Capacity Resources	38,650	18.2%	1,017	(4.1)
NERC Reference Margin Level	**5,070**	**15.5%**	**117**	0.5

When capacity deratings and estimated maintenance outages are considered and estimated non-firm power imports are not considered, the existing, anticipated and prospective reserve margins are 19.1 percent, 19.1 percent, 18.2 percent and 12.9 percent for the months of June, July, August and September, respectively. The September margins are low because of the conservative assumption that the summer peak demand would apply throughout the summer period (June- September) and because of increased scheduled maintenance. During September if tight margin conditions are anticipated scheduled maintenance outages can be deferred.

The NYSRC establishes the Installed Reserve Margin (IRM)[108] based on a technical study conducted by the NYISO and the Installed Capacity Subcommittee (of the NYSRC). The 2010–2011 IRM Study found that the New York Control Area has the required amount of installed capacity needed to meet the 0.1 days/year LOLE criterion. Following this study, the NYISO conducts the Locational Installed Capacity Requirements (LCR) study.[109] This study determines the amount of Unforced Capacity (UCAP) that load-serving entities must procure to reliably meet demand in New York's high load Areas.

[2] NYSRC Report titled, *New York Control Area Installed Capacity Requirements for the Period May 2010 Through April 2011* (December 5, 2009).

[3] NYISO Report titled *Locational Minimum Installed Capacity Requirements Study Covering The New York Control Area For the 2010–2011 Capability*, January 7, 2010.

A description of the method and requirements for the NPCC Region are provided in the NPCC Regional Discussion in the Demand, Capacity, and Reserve Margins section. The NPCC requirement applies to all five NPCC Reliability Coordinator Areas.

NYISO has adopted the New York State Gas-Electric Coordination Protocol as Appendix BB[110] to its Open Access Transmission Tariff (OATT). This Coordination Protocol applies to circumstances in which the NYISO has determined (for the bulk power system) or a Transmission Owner has determined (for the local power system) that the loss of a Generator due to a Gas System Event would likely lead to the loss of Firm electric load. This Coordination Protocol also applies to communications following the declaration of an Operational Flow Order or an Emergency Energy Alert.

There are no anticipated fuel delivery problems for this summer operating period.

The NYISO performs dynamic and static reactive power studies based on anticipation of issues. No reactive power issues are anticipated for this summer.

Other Area-Specific Issues

There are no anticipated reliability concerns.

Area Description

NYISO is the only Balancing Authority in the New York Control Area. The NYCA covers over 48,000 square miles, serves a total population of about 19.4 million people, and peaks annually in the summer.

[4] New York State Gas-Electric Coordination Protocol, Attachment BB to the NYISO Open Access Tariff (OATT), June 30, 2010.

Ontario

Introduction

The Independent Electricity System Operator (IESO) is the Reliability Coordinator and Balancing Authority for the province of Ontario. The IESO manages the wholesale electricity market and oversees the reliable operation of the provincial electricity grid.

Ontario's resource portfolio and transmission system are adequate to meet the forecast demands over the 2011 summer. This self-assessment narrative is based on the results from the 18-Month Outlook published quarterly on the IESO website at www.ieso.ca/18-month.outlook. The IESO gathers information relating to generation and transmission resources from Market Participants.

Demand

The IESO is forecasting a summer peak demand of 23,561 MW (July 2011) for Ontario. This forecast is based on Monthly Normal weather and incorporates the impacts of planned conservation, growth in embedded generation, time-of-use rates, and slow economic recovery. The forecast peak for 2011 summer is 6.0 percent lower than last summer's actual peak of 25,075 MW, which occurred on July 8, 2010, under warmer-than-normal conditions. The 2011 summer peak forecast is 1.5 percent lower than last summer's weather-corrected peak demand of 23,916 MW. The current forecast's decrease is the result of several factors, including: conservation initiatives, growth in embedded generation, and price incentives to modify use patterns during peak periods.

TABLE 69: NPCC-IESO FORECAST AND ACTUAL PEAK DEMAND

2010 Total Internal Demand (MW)	2010 Actual Demand (MW)	Difference in Actual versus Forecast (MW)	Difference in Actual versus Forecast (%)	2011 Total Internal Demand (MW)	Difference in 2011 and 2010 Forecast Demand (MW)	Difference in 2010 Actual versus 2011 Forecast (%)	All-Time Summer Peak Demand (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)
23,556	25,075	1,519	6.4%	23,561	5	0.0%	27,005	(3,444)	-12.8%

Since the forecast is at the system level, it represents the coincident peak of the zones that make up the IESO-controlled grid. The peak conditions are generated using Monthly Normal weather. This provides a typical monthly peak for each of the summer months based on 31 years of weather data history.

A number of loads within the province participate in Demand Response programs with a total capacity of 1,800 MW or 7.6 percent of forecast peak demand. Of this total capacity about 1,200 MW is included for seasonal capacity planning purposes and 775 MW is deemed to be interruptible. The IESO dispatches and settles the majority of the Demand Response capacity and the measurement and verification is done within the settlement process. The remaining capacity is verified and measured by the Ontario Power Authority (OPA), which has responsibility for those remaining programs.

The OPA, Ontario Energy Board, and distributors are responsible for promoting, developing, and delivering conservation programs within Ontario. These programs include a number of different types of conservation measures with the distributors having a great deal of latitude in how they meet their conservation targets. Validation and verification of these savings are the purview of the OPA and distributors.

The IESO quantifies the uncertainty in peak demand due to weather variation through the use of Load Forecast Uncertainty (LFU), which represents the impact on demand of one standard deviation in the underlying weather parameters. For the upcoming summer peak of 23,561 MW, the LFU is 1,433 MW. Economic factors do not have a significant impact on near-term seasonal assessments.

As part of the IESO's analysis, it uses an extreme weather scenario to analyze the system under duress. The extreme weather scenario is generated by taking the most severe weather since 1970 on a week-by-week basis. This gives an "outer envelope" of the conditions that the system may face through the upcoming season.

Generation

The total capacity of existing installed generation resources (34,830 MW) and loads as a capacity resource (1,235 MW) connected to the IESO-controlled grid is 36,065 MW, of which the amount of Certain capacity is 29,576 MW for June 2011. The Other capacity is 5,227 MW for June 2011, which includes the on-peak resource deratings, planned outages, and transmission-limited resources. Inoperable capacity of 28 MW is identified for the study period.

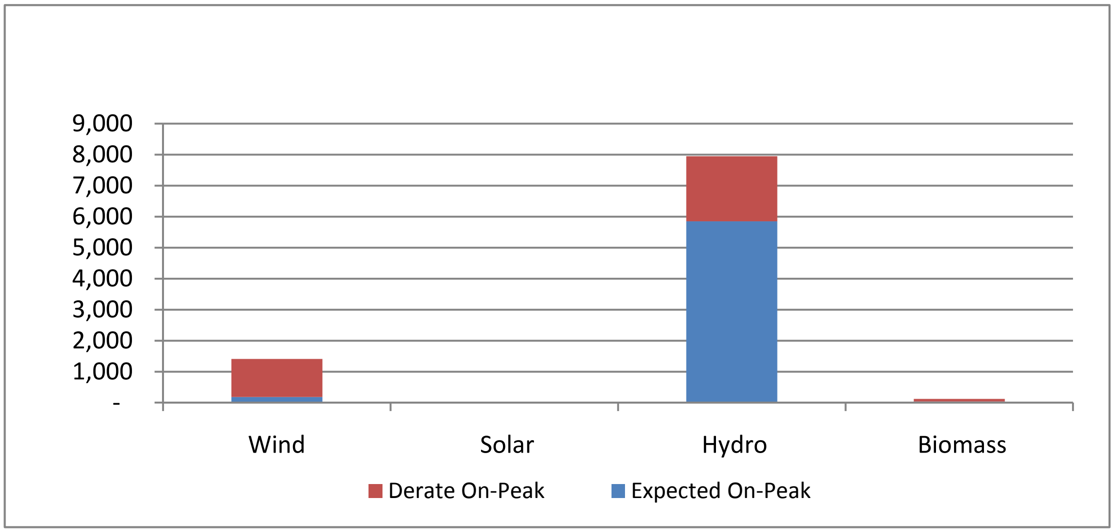
The certain capacities for July, August, and September are 29,807 MW, 29,711 MW, and 27,342 MW respectively.

TABLE 70: NPCC-IESO EXISTING AND PLANNED PEAK CAPACITY

Existing-Certain (MW)	29,807
Existing-Other (MW)	4,996
Future-Planned (MW)	12

The Future Capacity Additions for the summer months are 80 MW. This is made up of a wind project, Raleigh Wind Energy Centre (78 MW), and the two MW Leamington Pollution Control Plants. Both projects are scheduled to come into service before summer. The Future-Planned resources for June to August are 12 MW and for September are 14 MW, and Future-Other resources for the same months are 68 MW and 66 MW.

FIGURE 35: NPCC-IESO EXISTING AND PLANNED RENEWABLE GENERATION



To model wind resources in the seasonal assessments, the IESO uses an estimated wind capacity contribution during peak demand hours. This model captures wind output during the top five contiguous daily peak demand hours for the winter and summer seasons, as well as monthly shoulder periods. Two sets of wind data are considered: simulated wind data over a fixed ten-year history, and actual wind plant output data collected since March 2006. A conservative approach is employed, which selects the lesser value of the two data sets (simulated vs. actual) for each winter/summer season and shoulder period month. For the seasonal assessments, wind capacity contribution is represented deterministically by selecting median values observed during the winter and summer seasons and shoulder period months.

The wind capacity contribution for the summer season, June to August, is estimated at 13 percent of the installed capacity. The factor used for the shoulder month, September, is 16 percent. The 'Certain' capacity for wind is 184 MW and 'Other' capacity is 1,228 MW for summer months. For September, the 'Certain' capacity is 225 MW and 'Other' capacity is 1,186 MW. No other variable resources (solar etc.) are connected to the IESO-controlled grid or are expected to be connected in the study period.

TABLE 71: NPCC-IESO EXISTING AND PLANNED RENEWABLE GENERATION

Wind Expected On-Peak	184
Wind Derate On-Peak	1,228
Wind Nameplate/Installed Capacity	1,412
Solar Expected On-Peak	-
Solar Derate On-Peak	-
Solar Nameplate/Installed Capacity	-
Hydro Expected On-Peak	5,852
Hydro Derate On-Peak	2,095
Hydro Nameplate/Installed Capacity	7,947
Biomass Expected On-Peak	37
Biomass Derate On-Peak	85
Biomass Nameplate/Installed Capacity	122

NPCC-IESO

For biomass, the Certain capacity is 37 MW and Other capacity is 85 MW.

IESO resource adequacy assessments include hydroelectric generation capacity contributions based on median historical values of hydroelectric production plus operating reserve provided during weekday peak demand hours. The capacity assumptions are updated annually, in the second quarter of each year. Energy capability is provided by market participants' forecasts. The amount of available hydroelectric generation is greatly influenced both by water-flow conditions on the respective river systems and by the way in which water is used by the generation owner. Due to lower-than-normal precipitation in the spring/summer seasons, the hydroelectric capability for 2010 summer months was 16 percent to 22 percent lower than the historical values. As a result, the IESO revised its planning assumptions for the fall months. However, with hydroelectric output returning to normal values, material deviations from median conditions are not anticipated at this time for the upcoming summer. In the operating timeframe, water resources are managed by market participants through market offers to meet the hourly demands of the day. Since most hydro storage facilities are energy limited, hydroelectric operators identify weekly and daily limitations for near-term planning in advance of real-time operations.

The IESO does not anticipate any weather or fuel-related constraints for the province that would reduce generating capacity.

Two more coal units with a total capacity of about 1,000 MW will be shut down after 2011 summer. Four coal units with a total capacity of about 2,000 MW were shut down last year in October. These shut-downs are key elements of the Province of Ontario's climate change initiative to phase out coal-fired electricity by 2014. Gradual capacity additions have been taking place over several years in anticipation of the coming coal generation retirements.

Capacity Transactions

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

TABLE 72: NPCC-IESO IMPORTS AND EXPORTS ON-PEAK

Imports (MW)	-
Firm (MW)	-
Expected (MW)	-
Exports (MW)	-
Firm (MW)	-
Expected (MW)	-
Net Exports (MW)	**0**

For use during daily operation, the IESO has agreements in place with neighboring jurisdictions in NPCC, RFC, and MRO Regions for emergency imports and reserve sharing. Day to day, external resources are normally procured on an economic basis through the IESO-administered markets.

Transmission

Since last summer, Kitchener-Wilmot Hydro has built a new 230 kV transformer station (TS) named Kitchener-Wilmot MTS#9, with two 230/28 kV transformers. Hydro Ottawa has built a new load facility called Ellwood MTS comprising two 230/13.2 kV transformers.

In late 2010, Hydro One installed series compensation on the 500 kV north-south lines at Nobel Switching Station and additional static VAR compensation facilities at Porcupine TS to increase the transfer capability. Hydro One also added a 200 MVar shunt capacitor bank at Buchanan TS in the southwest zone.

New static VAR compensation facilities at Kirkland Lake TS, Nanticoke TS and Detweiler TS will be in service in Summer 2011 to provide additional transfer capability.

The completion date for transmission reinforcements from the Niagara Region into the Hamilton-Burlington Area continues to be delayed. This delay impacts the use of the available imports and Ontario generation in the Niagara Area, particularly during hot weather and high demand periods or during outage conditions. Under the conditions forecast for this summer, studies show that the system is adequate to meet projected demands without this reinforcement.

The failed R76 voltage regulator and the BP76 circuit on the Niagara intertie will not be available for summer. The bypass, which was built to facilitate the Niagara interties' (PA301 and PA302) planned outages last fall, will remain available for use in case of outages on either or both the interties until the R76 voltage regulator returns.

Phase angle regulators (PARs) are installed on all four of the Michigan-Ontario interconnections. One PAR on the Keith-Waterman 230 kV circuit J5D has been in-service and regulating since 1975. The other three available PARs on the Lambton-St. Clair 230 kV circuit L51D and 345 kV circuit L4D and the Scott-Bunce Creek 230 kV circuit B3N remain idle. Although the operating agreements are now ready, the completion of the filing process with FERC and the Department of Energy, may delay the in-service date for the remaining PARs until after the summer period.

Regardless of these outages, Ontario meets all reliability criteria without dependence on any external resources.

Ontario has many operating limits and instructions that could limit transfers under specific conditions, but for the forecast conditions, including design-criteria contingencies, sufficient resources and bulk system transfer capability is projected to be available to manage potential congestion and supply forecast demand.

In the summer, Ontario's theoretical maximum capability for exports could be up to 5,500 MW and coincident imports up to 5,900 MW. These values represent theoretical levels that could be achieved only with a substantial reduction in generation dispatch in the West and Niagara transmission zones. In practice, the generation dispatch required for high import levels would rarely, if ever, materialize.

Therefore, at best, due to internal constraints in the Ontario transmission network in conjunction with external scheduling limitations, Ontario has a forecast coincident import capability of approximately 4,800 MW.

Operational Issues

The IESO addresses summer extreme weather conditions by doing planning studies using the most severe weather experienced since 1970. Studies show that Ontario will have sufficient reserves over the entire summer period. Available operational and market measures and interconnection capability are evaluated to be sufficient to meet summer energy demands.

The IESO is planning a centralized wind and solar forecasting service to improve the accuracy of variable generation forecasts. The forecasting service will assist with the dispatch of wind and solar generation in real-time. This service will not be in place for the upcoming summer season.

Ontario is expecting to experience surplus baseload generation (SBG) under minimum demand conditions. Such SBG conditions are projected to occur over the summer months of 2011. Current operating procedures (*i.e.,* curtailment of intermittent variable generators and imports, spilling of water from must-run hydroelectric generating stations, and dispatching down nuclear generators) are adequate to deal with the SBG conditions.

TABLE 73: NPCC-IESO DEMAND RESPONSE AND ENERGY EFFICIENCY ON-PEAK

Non-Dispatchable DSM (MW)	130
Energy Efficiency	130
Non-Controllable Demand-Side Demand Response	-
Total Internal Demand	23,561
Controllable, Dispatchable Demand Response	1,235
Net Internal Demand	22,326

Demand measures currently comprise about 5.2 percent of total resources. At these levels, any failure to respond does not pose any significant concern to reliability. Demand measures are grouped into two categories: price sensitive and voluntary. The IESO considers only price sensitive demand for adequacy assessment purposes. The majority of the IESO's Demand Response programs have significant financial penalties for non-compliance and as such the Demand Response programs are deemed reliable.

There are limits on the number of hours that Demand Response can be called upon, however they are numerous enough that it is not seen as an impediment to reliability.

There are no known unusual operating conditions, or environmental or regulatory restrictions, that are forecast to impact reliability for this summer.

Reliability Assessment Analysis

The IESO uses a multi-Area resource adequacy model, in conjunction with power flow analyses, to determine the deliverability of resources to load. This process is described in the document *Methodology to Perform Long-Term Assessments*.[111]

The Reserve Margin target for Ontario (Certain resources) is 21.3 percent based on the NPCC criteria. Planning reserves, determined on the basis of the IESO's requirements for Ontario self-sufficiency, are above target levels over this period for normal weather conditions. On average, the projected Reserve Margins for the upcoming summer are 6.6 percent higher than the projected margin for the 2010 summer. These temporary levels are projected as Ontario positions itself for coal shutdowns in later years. The IESO requires demonstrated reliable performance from replacement resources prior to approving the removal of the coal facilities.

TABLE 74: NPCC-IESO ON-PEAK CAPACITY RESOURCES AND RESERVE MARGINS

	2011 Summer Forecast (MW)	2011 Summer Forecast (%)	Change from prior year (MW)	Change from prior year (percentage point)
Existing-Certain and Net Firm Transactions (with Demand Response)	31,042	31.7%	1,272	5.4
Anticipated Capacity Resources	31,054	31.8%	988	4.2
Prospective Capacity Resources	32,366	37.4%	1,436	6.1
NERC Reference Margin Level	**5,019**	**21.3%**	**731**	3.1

Reserve requirements are established in conformance with the NPCC Regional criteria. The NPCC target level margin requires that the probability (or risk) of disconnecting any Firm load due to resource deficiencies shall be, on average, not more than once in ten years. The latest study results are published in the NYISO 18-Month Outlook.[112]

The IESO works with the Ontario gas transportation industry to identify and address issues. There are communication protocols in effect between the IESO and the gas pipeline operators to manage and share information under tight supply conditions in either sector (gas or electricity).

Generator owners/operators are required to keep sufficient supplies (*e.g.,* coal, nuclear) of fuel. Coal inventories at the coal-fired stations are being carefully managed leading to the end of 2014, when all coal generation has been legislated to cease.

The IESO regularly conducts transmission studies that include results of stability, voltage, and thermal and short-circuit analyses in conformance with NPCC criteria. The IESO's transmission studies are conducted to comply with the NERC TPL standards, in addition to NPCC criteria.

The IESO has market rules and connection requirements that establish minimum dynamic reactive requirements, and the requirement to operate in voltage control mode for all resources connected to the IESO-controlled grid. In addition, the IESO's transmission assessment criteria includes requirements for absolute voltage ranges, and permissible voltage changes, transient voltage-dip

[111] http://www.ieso.ca/imoweb/pubs/marketReports/Methodology_RTAA_2010dec.pdf

[112] http://www.ieso.ca/imoweb/pubs/marketReports/18MonthOutlook_2011feb.pdf

criteria, steady-state voltage stability, and requirements for adequate margin demonstrated via pre- and post-contingency P-V curve analysis. These requirements are applied in facility planning studies. Seasonal operating limit studies review and confirm the limiting phenomenon identified in planning studies.

Area Description

The province of Ontario covers an area of 1,000,000 square kilometers (415,000 square miles) with a population of 13 million. The Independent Electricity System Operator (IESO), as the Reliability Coordinator and Balancing Authority for the Province of Ontario, directs the operations of the IESO-controlled grid (ICG) and administers the electricity market. The ICG experiences its peak demand during the summer, although winter peaks remain strong.

Québec Interconnection

Introduction

The Québec Area is an NERC subregion in the northeastern part of the NPCC Region. Hydro-Québec (the main utility in the Area) ensures generation, transmission, and distribution services for its internal load and point-to-point transmission services for wholesale customers through its interconnections with neighboring Areas. There are other systems in the subregion—interconnected with *TransÉnergie's* grid—mostly with their own generation and transmission to feed their industrial loads. *TransÉnergie,* Hydro-Québec's transmission division, acts as Balancing Authority, Reliability Coordinator, and system controller for the Area. The regulatory body in Québec is the *Régie de l'énergie du Québec* (Québec Energy Board).

One important characteristic of the Québec subregion is that it is winter peaking. The all-time internal peak hourly demand was 37,717 MW set on January 24, 2011 (preliminary assessment). A large amount of space heating load is present during winter operating periods. Summer peak demands are of the order of 22,000 MW (about 57 percent of peak winter demand). Summer operating periods are usually characterized by extensive generator and transmission maintenance in preparation for the upcoming winter. Notwithstanding this, both internal demand and capacity sales are met while still being able to assist neighboring summer peaking Areas as needed, up to inter-area transfer capabilities.

Transmission voltages are 735, 315, 230, 161, and 120 kV with a ±450 kV HVdc multi-terminal line. Transmission line length totals 33,453 km (20,774 miles). Installed Capacity will be 43,012 MW in September 2011, of which approximately 40,300 MW (93.7 percent) will be hydroelectric capacity.

The Québec subregion is one of the four NERC Interconnections in North America. There are asynchronous ties with Ontario, New York, New England, and the Maritimes, which consist of HVdc installations, radial generation, or load to and from neighboring systems.

This report will briefly discuss demand forecasts, generation availability, capacity transactions, resource adequacy, transmission adequacy, operational issues, and reliability. No particular issues of any kind are forecast for the upcoming summer operating period.

Demand

The Load Serving Entity in Québec is Hydro-Québec Distribution (HQD). The Entity is regulated by the *Régie de l'énergie du Québec* (Québec Energy Board) and as such, it must file a Procurement Plan and annual updates of this plan with the *Régie*. All assumptions (weather, economic, demographic, and energy-use) on which the demand forecast is based are presented in the 2011–2020 HQD Procurement Plan document that can be found on the Québec Energy Board website.[113]

This document discusses, among other subjects, the following:

[113] http://internet.regie-energie.qc.ca/Depot/Projets/86/Documents/R-3748-2010-B-0019-DEMANDE-PIECEREV- 2011_01_19.pdf

- Demand and energy forecast,
- Energy efficiency programs,
- Resource procurement (demand and energy), and
- Low, base, and high case load forecast scenarios.

Hydro-Québec Distribution conducts its load forecast for the Québec subregion represented as a single entity. There is no demand aggregating, and the Area's peak forecast information is coincident. Resource evaluations are based on coincident winter peak forecasts, with low, base, and high case scenarios.

TABLE 75: NPCC-QUÉBEC FORECAST AND ACTUAL PEAK DEMAND

2010 Total Internal Demand (MW)	2010 Actual Demand (MW)	Difference in Actual versus Forecast (MW)	Difference in Actual versus Forecast (%)	2011 Total Internal Demand (MW)	Difference in 2011 and 2010 Forecast Demand (MW)	Difference in 2010 Actual versus 2011 Forecast (%)	All-Time Summer Peak Demand (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)
20,677	22,092	1,415	6.8%	21,283	606	2.9%	22,092	(809)	-3.7%

The forecast Internal Peak Demand for the 2011 NERC summer period is 21,283 MW, forecast to occur during August. This represents the total Québec load including Hydro-Québec Distribution's load and small isolated systems in Québec's far north.

Table 76 summarizes and compares the subregion's actual and forecast internal demands for 2010 and 2011.

TABLE 76: QUÉBEC 2010 AND 2011 SUMMER INTERNAL DEMAND (MW)

	June	July	August	September
Actual 2010 (A)	20,567	22,092	21,970	21,766
Forecast 2010 (B)	20,427	20,475	20,655	20,677
Difference (A-B)	140	1,617	1,315	1,089
Forecast 2011 (C)	20,740	20,876	21,283	21,085
Difference (C-B)	313	401	628	408

The 2011 summer demand forecast is higher than that of 2010 summer forecast. The load forecast increase is explained mainly by the ongoing general economic recovery after the economic slowdown during the last two years.

This forecast does not take Demand Response Programs into account. In Québec there are two Demand Response Programs consisting of interruptible industrial load. They are not required (nor available) during summer operating periods.

The demand forecast does, however, take energy efficiency programs and energy saving trends into account. Hydro-Québec Distribution promotes the wise use of electricity as a way to reduce demand. These programs are implemented throughout the year. The following list shows programs and tools for promoting energy saving:

a. For residential customers
    i. *Energy Wise* home diagnostic
    ii. *Recyc-Frigo* (old refrigerator recycling)
    iii. Electronic thermostats
    iv. *Energy Star* qualified appliances
    v. Residential Lighting
    vi. Pool-filter timers and Solar pool cover
    vii. *Energy Star* windows and patio doors
    viii. *Rénoclimat* renovating grant
    ix. Geothermal energy
b. For business customers – small and medium power users
    x. Empower program for building optimization
    xi. Empower program for industrial systems
    xii. Efficient products program
    xiii. Traffic light optimization program
    xiv. *Energy Wise* diagnosis
c. For business customers – large power users
    i. Continuous measurement and management of electric power
    j. Industrial analysis and demonstration program
    k. Plant retrofit program

Program characteristics can be found on Hydro-Québec's website.[114]

To assess variability in projected demand due to weather, the economy, or other factors Hydro-Québec Distribution proceeds with a number of quantitative analyses. In these analyses, overall uncertainty is defined as the independent combination of climatic uncertainty and load uncertainty.

Load uncertainty is due to the inherent inability to perfectly forecast economic variable evolution, demographics, energy, and inherent modeling errors. These variables impact the demand forecast.

Climatic uncertainty is modeled by recreating each hour of the last 36-year period of climatic conditions (1971 through 2006) under the current load forecast conditions. Moreover, each year of historical data are shifted up to ±3 days to gain information on conditions that occurred during a weekend, for example.

[114] http://www.hydroquebec.com/energywise/index.html

Moreover, Hydro-Québec has developed hourly chronological load profiles based on a 36-year analysis of historical weather conditions (1971–2006). This method is useful to quantify weather uncertainty and its impacts on peak demand. Since Québec has a winter-peaking load profile, uncertainty—measured by a standard deviation analysis—is lower during the summer than during the winter. As an example, at the summer peak, weather condition uncertainty is about 300 MW, equivalent to one standard deviation. During winter, this uncertainty is approximately 1,500 MW. Extreme weather deviations are quantified at about 800 MW for the summer peak and at about 4,700 MW for the winter peak. Otherwise, extreme summer conditions are not explicitly addressed by the subregion. NERC winter assessments provide information on extreme winter conditions in Québec.

For this assessment, the Québec subregion has not introduced any changes to the load forecast method and assumptions due to the economic recession.

Generation

The following section supplies details on Total Internal Capacity in Québec to present as clear a picture as possible of supply-side resources in the Area.

Table 77: NPCC-Québec Existing and Planned Peak Capacity

Existing-Certain (MW)	31,396
Existing-Other (MW)	9,442
Future-Planned (MW)	768

The amount of Existing (-Certain, -Other, and Inoperable) and Future (-Planned and -Other) capacity resources in service or forecast to be in service from June 1, 2011, through September 30, 2011, is described in Table 78 below.

Table 78: Anticipated Resources for 2011 Summer in Québec (MW)

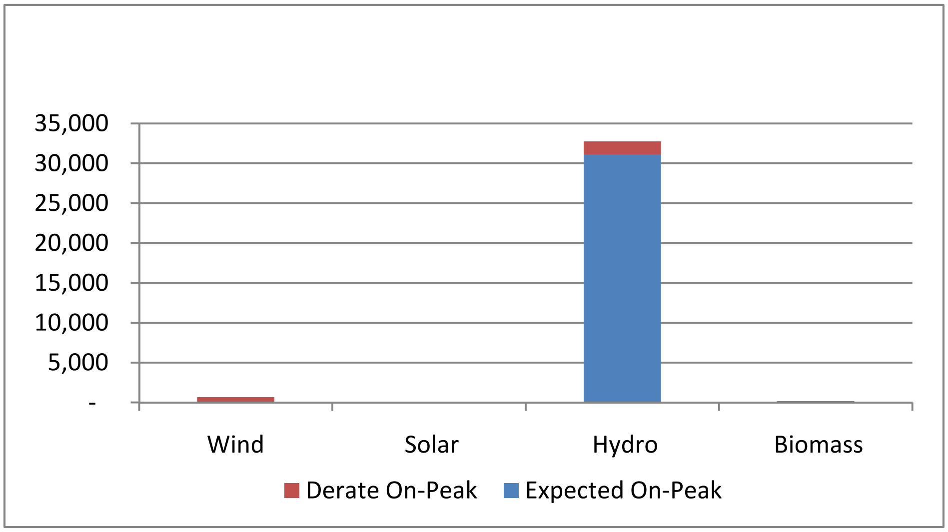
Capacity in 2011	June	July	August	September
Existing-Certain	30,519	32,454	31,396	30,295
Existing-Other	10,325	8,385	9,442	10,552
Existing Inoperable	1,397	1,397	1,397	1,397
Total Existing	42,241	42,236	42,235	42,244
Future-Planned	256	512	768	768
Future-Other	0	0	0	0
Total Internal Capacity	42,497	42,748	43,003	43,012

Relatively high numbers in the Existing-Other line are representative of high maintenance outages in summer in preparation for the upcoming winter season. The Existing Inoperable line represents capacity contracts with other systems within the subregion that are not available during the summer season.

The Future-Planned line shows the gradual (one unit per month in June, July, and August) coming on line of the Eastmain-1-A hydroelectric generating station on the James Bay system. Total Internal Capacity will finally total 43,012 MW in September 2011.

Total Internal Capacity, as shown in Table 78 above, includes variable resources. In Québec these resources are made up uniquely of wind capacity. The present wind capacity installed in Québec is 659 MW. For summer assessments, this is entirely derated when conducting resource adequacy analyses.

FIGURE 36: NPCC-QUÉBEC EXISTING AND PLANNED RENEWABLE GENERATION



Finally, 164 MW of biomass is included in the Total Internal Capacity.

As mentioned in the Introduction Section, hydroelectric generation accounts for about 94 percent of total installed capacity in Québec. Thus, to assess its energy reliability the subregion has developed an energy criterion stating that sufficient resources should be available to go through sequences of two or four consecutive years of low water inflows totaling 64 TWh and 98 TWh, respectively, and having a two-percent probability of occurrence. (System annual internal use for 2010 was about 184 TWh.) These assessments are presented three times a year to the *Régie de l'énergie du Québec* (Québec Energy Board). Normal hydro conditions are projected for 2011 summer and reservoir levels are sufficient to meet both peak demand and daily energy demand throughout the summer.

There is 2,348 MW of thermal generation included in the Total Internal Capacity shown in Table 78. This includes one 675 MW CANDU nuclear generator and one combined cycle 507 MW natural gas unit (TransCanada Energy). The rest of this thermal capacity is made up of gas turbines (716 MW) and oil-fired generation (450 MW), not usually operated in summer. Thus, no fuel issues or any other conditions that would create capacity reductions are forecast for the 2011 summer period.

TABLE 79: NPCC-QUÉBEC EXISTING AND PLANNED RENEWABLE GENERATION

Wind Expected On-Peak	-
Wind Derate On-Peak	659
Wind Nameplate/Installed Capacity	659
Solar Expected On-Peak	-
Solar Derate On-Peak	-
Solar Nameplate/Installed Capacity	-
Hydro Expected On-Peak	31,134
Hydro Derate On-Peak	1,642
Hydro Nameplate/Installed Capacity	32,776
Biomass Expected On-Peak	164
Biomass Derate On-Peak	-
Biomass Nameplate/Installed	164

Finally, as was mentioned above, there is a large amount of generator maintenance during summer operating periods. The scheduling is done to avoid reliability impacts. Maintenance scheduling also accounts for forecast Firm and non-Firm sales to neighboring summer-peaking NPCC subregions. As for 2011 summer particularly, TransCanada Energy's (TCE) natural gas generating station (507 MW) is still under a temporary shutdown agreement with HQD. This temporary shutdown does not affect reliability.

Capacity Transactions

Imports on Peak

The resource adequacy assessment shows that no external purchases are required for the 2011 summer operating period to maintain reliability. This is usually true for any summer season in the Québec subregion. There is, however, a Firm purchase of 200 MW from specific generators in the Maritimes Area for the 2011 summer.

TABLE 80: NPCC-QUÉBEC IMPORTS AND EXPORTS ON-PEAK

Imports (MW)	200
Firm (MW)	200
Expected (MW)	0
Exports (MW)	2,082
Firm (MW)	1,611
Expected (MW)	471
Net Exports (MW)	**1,882**

This purchase is backed by Firm contracts for both generation and transmission, but there is no path reservation. Moreover, all energy purchases (if required) into the Québec subregion are subject to damages for delivery failures.

Under emergency conditions the Québec Area can rely on imports from Ontario, New York, and the Maritimes. Import capabilities are shown in Table 81 below in the Transmission section. Capabilities may vary with system conditions. *TransÉnergie* has agreements with all neighboring subregions that detail conditions and procedures for exchanging emergency energy. A procedure supervises Control Centre actions and communications for this energy exchange. However, it should be noted here that during summer periods, there are no reliability concerns in Québec.

Exports on Peak

The resource adequacy assessment for 2011 summer shows 2,082 MW of export capacity transactions for June through September. The Expected category transactions total 421 MW and the Firm category transactions total 1,661 MW.

Firm transactions are to New England (1,041 MW), Ontario (145 MW), and New York (475 MW). Projected transactions are to New York (421 MW).

The portion of Export Transactions backed by Firm contracts for both generation and transmission is 22 percent of total exports (310 MW to New England and 145 MW to Ontario). There are no transactions defined as Liquidated Damage Contracts (LDCs).

The subregion's Existing-Certain, anticipated, and prospective resource Reserve Margins are all higher than the required reserve to meet its resource adequacy criterion. These sales do reduce Reserve Margins during summer months but they still remain higher than the required target.

Transmission

No significant new bulk power transmission facilities, whether transmission lines, transformers, or substation equipment, are anticipated to be placed in service for this summer. However, a number of wind generation integration projects are presently under construction for in-service dates around the end of 2011. Finally, a 315 kV transmission project to integrate the Eastmain-1-A (one km) and La Sarcelle (102 km) hydro projects into the grid is also ongoing. Eastmain-1-A's three 256 MW units will be placed in service, one each in June, July, and August. Both generating stations are in the James Bay Area of the system. Presently, there are no concerns about not meeting in-service dates or about reliability impacts resulting from possible delays.

Most transmission line, transformer, and generating unit maintenance is done during the summer period. summer peak load is typically about 57 percent of winter peak load. Resource availability is therefore not a problem at all during summer operating periods even though exports to summer-peaking subregions of NPCC are sustained during peak hours. As a matter of fact, available resources for exports may exceed actual interconnection summer transfer capabilities. Internal generating unit and transmission outage plans are assessed to meet internal demand, Firm sales, forecast additional sales, and uncertainty margins. Interconnection maintenance outages are scheduled outside peak periods. Therefore, no impact on internal reliability and inter-area capabilities with neighboring systems is projected.

No internal transmission constraints that could significantly impact reliability are forecast in the Québec subregion for the 2011 summer operating period.

Table 81 indicates interregional transfer capabilities out of and into Québec with its neighboring systems for the 2011 summer operating period.[115]

[115] Limits obtained and updated from the NPCC Reliability Assessment for 2010 summer.

These limits represent Normal Transfer Capability (NTC) values for the summer operating period. Actual Feasible Transfer Capability (FTC) values during peak periods in Québec may be different. They are not simultaneous.

Both NTC and FTC values are posted in Appendix III of the NPCC Seasonal Reliability Assessments.[116]

TABLE 81: 2011 SUMMER INTERCONNECTION NORMAL TRANSFER CAPABILITY (MW)

Interconnection	Capability out of Québec	Capability into Québec
Ontario North (D4Z, H4Z)	85	85
Ontario Ottawa (X2Y, P33C, Q4C)	410	120
Ontario Brookfield (D5A, H9A)	250	110
Ontario Beauharnois (B5D, B31L)	800	470
Ontario Ottawa (Outaouais Interconnection)	1,250	1,250
New York (CD11, CD22)	199	100
New York (7040)	1,500	1,000
New England (Highgate)	225	170
New England (Stanstead-Derby)	40	0
New England (Sandy Pond)	2,000	1,700
Maritimes (Madawaska + Eel River)	865	735

These limits recognize transmission or generation constraints in both Québec and its neighbors for the 2011 summer operating period. They are reviewed periodically with neighboring systems and are posted in the NPCC Seasonal Reliability Assessments. These limits may not exactly correspond to other numbers posted in Hydro-Québec's Annual Reports or on TransÉnergie's website. Such numbers—usually corresponding to winter ratings—are maximum import/export capabilities available at any one time of the year. The present NERC assessment focuses on summer conditions. Moreover, these limits do not correspond to TTC and ATC values posted on the OASIS. They are only intended to offer a global picture of transfer capabilities to the readers of this assessment.

Transient and voltage stability studies are performed continuously by *TransÉnergie* (acting as Transmission Planner) to establish transfer limits on all interfaces. No problems are anticipated for the light load summer operating period. Voltage support in the southern part of the system (load Area) is a concern only during winter operating periods, especially during episodes of heavy load.

Operational Issues

TransÉnergie's significant operating studies are performed for winter operating periods, where weather conditions will translate into higher demand levels. Readers may refer to previous NERC Winter Reliability Assessments for details. They are available at this footnoted website address:[117]

[116] http://www.npcc.org/documents/reports/Seasonal.aspx
[117] http://www.nerc.com/page.php?cid=4|61

The Québec subregion participates in NPCC's seasonal CO-12 (Operations Planning) and CP-8 (Multi-Area Probabilistic Assessment) Working Group assessments of system reliability. These assessments are available at this footnoted website address.[118]

All operational planning studies conducted in the subregion are done in compliance with NPCC and NERC planning standards. These include planning studies for the bulk power system, generation integration studies, impact studies, NPCC reviews, transfer limit studies, etc. The last Comprehensive Review of the Québec transmission system for 2011–2012 was approved by NPCC's Reliability Coordinating Committee in May 2008. The last Interim Review of the Québec transmission system for 2015 was completed in October 2010.

No particular operational problems have been predicted for the oncoming 2011 summer operating period.

Presently, the only variable resources integrated in the subregion are wind resources. The nameplate capacity is 659 MW but the maximum output to this day has been 591 MW. Average hourly output over the year 2010 was 179 MW (27.1 percent global plant capacity factor). A total of 3,000 MW of wind resources are planned to come into service gradually until 2015, resulting from three solicitations, of which about 676 MW is projected to be in service by the end of 2011.

TABLE 82: NPCC-QUÉBEC DEMAND RESPONSE AND ENERGY EFFICIENCY ON-PEAK

Non-Dispatchable DSM (MW)	-
Energy Efficiency	-
Non-Controllable Demand-Side Demand Response	-
Total Internal Demand	21,283
Controllable, Dispatchable Demand Response	-
Net Internal Demand	21,283

As mentioned earlier, the Québec subregion is a separate Interconnection from the Eastern Interconnection into which other NPCC subregions are interconnected. Thus, the Interconnection's frequency does not follow Eastern Interconnection frequency. The system's installed capacity will be 43,012 MW (as of September 2011) but as little as 12,000 MW of capacity may be connected to the grid during summer low load periods and system inertia may be quite low. Frequency regulation is therefore a concern. The normal frequency profile is 59.5 to 60.5 Hz and frequency excursions following a NPCC transmission design contingency may reach 58.5 to 61.5 Hz. Interconnections with other NPCC Areas consist either of HVdc ties or radial generation to and from neighboring systems.

Considering all of this, to this day, wind generation variability has not significantly impacted the system's day-to-day operation and the present level of wind generation does not necessitate particular operating procedures. However, data acquisition for different wind generation variables constitutes valuable information for system management and wind generation forecasting is used in the subregion's system forecasting software.

[118] http://www.npcc.org/documents/reports/Seasonal.aspx

NPCC-Québec

For the longer term, a number of foreseeable impacts on system management may show up and will be addressed:

- Wind generation variability on system load and interconnection ramping
- Frequency and voltage regulation problems
- Increase of start-ups/shutdowns of hydro units due to load following coupled with wind variability. Generally units must be operated within certain limits to maximize turbine efficiency.
- Reduction of low load operation flexibility due to low inertial response of wind generation coupled to must-run hydro generation

Some subregions anticipate reliability concerns resulting from minimum demand and over-generation. This is not the case in the Québec subregion. There is hydroelectric must-run generation on run-of-the-river installations but this is small relative to system size. Moreover, as mentioned before, most generator maintenance is done in summer while reservoirs are allowed to fill up. Moreover, a relatively high level of exports is usually maintained to summer-peaking Areas. Neither are there any reliability concerns resulting from high levels of Demand Response resources in the subregion. Demand response consists uniquely of interruptible load programs that are not used during summer operating periods.

Moreover, there are no known environmental and/or regulatory restrictions that could impact reliability in Québec for the 2011 summer operating period, and no other unusual operating conditions that could significantly impact reliability for the upcoming summer are anticipated.

Reliability Assessment

The assessment process, be it for Resource Adequacy or for Transmission Adequacy used for Québec assessments, is documented in NPCC Regional Reliability Reference Directory #1 – *Design and Operation of the Bulk Power System* (adopted December 1, 2009). The process is summarized in the NPCC Regional Assessment Summary above. When performing these assessments, Hydro-Québec Distribution and Hydro-Québec *TransÉnergie* conform to the NPCC "Guidelines for Area Reviews" and all requirements therein.

TABLE 83: NPCC-QUÉBEC ON-PEAK CAPACITY RESOURCES AND RESERVE MARGINS

	2011 Summer Forecast (MW)	2011 Summer Forecast (%)	Change from prior year (MW)	Change from prior year (percentage point)
Existing-Certain and Net Firm Transactions (with Demand Response)	29,985	40.9%	(1,313)	(10.5)
Anticipated Capacity Resources	30,282	42.3%	(254)	(5.4)
Prospective Capacity Resources	30,393	42.8%	(324)	(5.8)
NERC Reference Margin Level	**2,128**	**10.0%**	**61**	**-**

The last Comprehensive Review (conducted every five years) of the Québec transmission system for 2011–2012 was approved by NPCC's Reliability Coordinating Committee in May 2008. The last Interim Review (conducted annually) of the Québec transmission system for 2015 was completed in October 2010.

The last Québec Area Comprehensive Review of Resource Adequacy, drafted by Hydro-Québec Distribution in 2008, was approved by the Reliability Coordinating Committee on March 11, 2009. The last Interim review of Resource Adequacy was posted December 2010.

Moreover, HQD must file a Procurement Plan and annual updates of this plan with the *Régie de l'énergie.* These plans and updates must be approved by the *Régie* after a hearing. Finally, HQP must assess its energy reliability according to its energy criterion and submit these assessments three times a year to the *Régie de l'énergie du Québec.*

Table 84 shows projected Reserve Margins for the 2011 summer operating period based on Existing-Certain Capacity and Net Firm Transactions. The target Reserve Margin is calculated for winter operating periods when reliability issues may be forecast. This target Reserve Margin is about ten percent.

TABLE 84: QUÉBEC PROJECTED RESERVE MARGINS FOR 2011 SUMMER

Existing	MW	8,318	10,117	8,652	7,749
	Percent	40.1	48.5	40.7	36.7
Anticipated	MW	8,153	10,208	8,999	8,096
	Percent	39.3	48.9	42.9	38.4
Prospective	MW	8,247	10,318	9,110	8,160
	Percent	39.7	49.4	42.8	38.7

Assumptions used to establish Reserve Margin criteria, target margin levels and resource adequacy levels, and results thereof, are discussed in the last 2010 Québec Interim review of Resource Adequacy (filed with NPCC on October 2010 for approval) and can be found at the NPCC's website.[119] The NPCC target level margin requires that the probability (or risk) of disconnecting any Firm load due to resource deficiencies shall be, on average, not more than once in ten years. Resource adequacy studies are not performed for summer operating periods.

The 2011 summer projected existing resources Reserve Margin levels are between 37 and 49 percent, as can be seen in Table 84 above. This is slightly lower than last summer's projected Reserve Margins. The 2011 summer monthly demand forecast is about 300 to 600 MW higher than the corresponding monthly forecast for 2010 summer. At the same time, Firm capacity exports are about 600 MW higher in 2011 compared to 2010. This is coupled to a drop in the Existing-Certain capacity from 2010 to 2011 of about 1,400 to 1,900 MW (higher maintenance rates) in June, July, and September, even though Eastmain-1-A is being commissioned in 2011. These lower Reserve Margin levels do not affect the subregion's reliability for the 2011 summer operating period.

[119] http://www.npcc.org/documents/reviews/Resource.aspx

NPCC-Québec

Moreover, many subregions must coordinate with the fuel industry to ensure that supplies are adequate and that transportation is secured throughout the summer operating period. This does not apply to the Québec subregion since about 93 percent of resources are hydroelectric and the system is winter peaking. Fossil fuel generation is used only for peaking purposes in winter and fuel is stocked on site at the beginning of each winter period.

Other Area-Specific Issues

Finally, the subregion does not anticipate any reliability concerns for the 2011 summer operating period and no Area specific issues, other than those discussed herein, are anticipated.

Area Description

Québec is an NPCC subregion and is winter-peaking. There is one Balancing Authority within the Area. The subregion is a separate Interconnection from the Eastern Interconnection into which other NPCC Areas are interconnected. TransÉnergie *(the Transmission Owner and Operator in Québec) operates interconnections with Ontario, New York, New England, and the Maritimes. Interconnections consist of either HVdc ties or radial generation, or load to and from the neighboring systems.*

Summer-peak load is typically about 57 percent of winter-peak load. The all-time internal hourly peak demand was 37,717 MW, set on January 24, 2011. Installed capacity will be 43,012 MW in September 2011, of which approximately 40,300 MW (93.7 percent) is hydroelectric capacity. Existing wind capacity totals 659 MW. Transmission voltages on the system are 735, 315, 230, 161, and 120 kV with a ±450 kV HVdc multi-terminal line. Transmission line length totals about 33,453 km (20,774 miles).

Population served is around 7 million and the Québec Area covers about 1,668,000 square kilometers (644,300 square miles). Most of the population is grouped along the St-Lawrence River basin. The largest load Area is in the southwest part of the province, mainly around the Greater Montréal Area, extending down to the Québec City Area.

PJM

Executive Summary

The forecast for the 2011 PJM RTO summer peak is 148,941 MW, which includes the integration of First*Energy* (ATSI) and Cleveland Public Power (CPP) into PJM. First*Energy* (ATSI) and CPP load is projected to contribute 12,671 MW to the 2011 PJM peak. Because of the addition of First*Energy* (ATSI) and CPP to this year's peak load forecast, comparison to last year's forecast is difficult to follow but is detailed in the body of this report. The anticipated growth rate from last year to this year is 1.1 percent and is slightly lower than normal still showing effects of the economic downturn. The total PJM capacity resources forecast to be in service during the 2011 summer peak period is approximately 180,406 MW of Existing-Certain generation. 12,770 MW of ATSI and CPP generation is being added to PJM's total on June 1, 2011. Approximately 640 MW were added in the rest of PJM since last summer. No resources are projected to be added through the summer peak period. The PJM projected Reserve Margin for 2011 summer is 29.8 percent. DSM is used as a resource in this calculation. This level is well in excess of the required Reserve Margin of 15.5 percent. The Reserve Margin indicated above includes Firm imports and exports. No additional resources will be added over the summer peak period so the above-mentioned Reserve Margin will apply for the entire 2011 summer-peak season. No subregions exist in PJM. There were no Resource reliability concerns identified in the Regional assessment.

The Harrisonburg-Valley 230 kV line went in service in June 2010. A single 345/138 kV transformer was added at both the Don Marquis and the New Arsenal substations. Two Doubs 500/230 kV transformers were replaced. A single 230/115 kV transformer was added at the Trowbridge, Elmont, and Lanexa substations. The energizing of the TrAIL line and the replacement of the last Doubs transformer will increase transfer capability into the Washington/Baltimore/Northern Virginia area. No additional transmission additions are forecast to be placed in service through the 2011 summer peak period. No transmission reliability concerns were raised during this assessment.

No significant operation challenges are projected this summer.

Introduction

PJM Interconnection is a Regional Transmission Organization (RTO) that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia. Along with being a Regional Transmission Operator, PJM is a Reliability Coordinator, Transmission Operator, Balancing Authority, Planning Coordinator, Transmission Planner, Resource Planner, and Transmission Service Provider for its footprint. PJM is the largest wholesale market in the world with an all-time peak load of over 145,000 MW.

This summer the American Transmission System Inc. (ATSI) portion of First*Energy* and Cleveland Public Power (CPP) are joining PJM and their load and generation are included in this summer's pre-seasonal assessment. First*Energy* is now fully in PJM.

Demand

The PJM demand forecast included non-coincident and RTO coincident models for each PJM zone. The PJM load forecast process produced a weather distribution of peak load forecasts by applying a Monte Carlo simulation using 37 years of historical weather (from 1973 to 2009). The economic variable used in the PJM load forecast is Real Gross Metropolitan Product (GMP) for major metropolitan Areas within the RTO. The current forecast uses the economic forecast release from Moody's Economy.com[120] which was revised in January 2011. The PJM RTO 2010 summer peak was 136,465 MW, which occurred on July 6, 2010, hour ending 1700 EDT. On a weather-normalized basis, the PJM RTO 2010 summer peak forecast was 135,750 MW. The projection for the 2011 PJM RTO summer peak is 148,941 MW with the integration of First Energy (ATSI) and CPP into PJM. The additional First*Energy* (ATSI) and CPP load is forecast to contribute 12,671 MW to the 2011 PJM peak. PJM forecasts the load of the entire RTO and the individual transmission zones on a coincident basis. Since PJM is summer-peaking, the coincident 50/50 summer peaks are used in resource adequacy evaluations.

TABLE 85: PJM FORECAST AND ACTUAL PEAK DEMAND[121]

2010 Total Internal Demand (MW)	2010 Actual Demand (MW)	Difference in Actual versus Forecast (MW)	Difference in Actual versus Forecast (%)	2011 Total Internal Demand (MW)	Difference in 2011 and 2010 Forecast Demand (MW)	Difference in 2010 Actual versus 2011 Forecast (%)	All-Time Summer Peak Demand (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)
135,750	136,465	715	0.5%	148,941	13,191	9.7%	144,644	4,297	3.0%

For the 2010/2011 delivery year PJM has contractually interruptible Demand-Side Management of 11,600 MW. Demand response can reduce PJM's peak demand by 7.8 percent. For Measurement and Verification (M&V) of Demand Response, participants submit load data from the EDC meters used for retail service or from meters meeting PJM's standards (see PJM Manual 11, Section 10.6). Participants will be audited.

Energy Efficiency programs included in the 2011 load forecast are impacts approved for use in the PJM Reliability Pricing Model (RPM). At time of the 2011 load forecast publication, 75 MW of Energy Efficiency programs have been approved as RPM resources in 2011. Measurement and verification of energy efficiency programs are governed by rules specified in PJM Manual 18B. To demonstrate the value of an energy efficiency resource, resource providers must comply with the measurement and verification standards defined in this manual by establishing M&V plans and providing post-installation M&V reports, and may undergo an M&V audit.

Regional analysis was achieved as a result of having Regional models. The PJM load forecast process produced a weather distribution of peak load forecasts by applying a Monte Carlo simulation for each model. The official peak load forecast is the median (50/50) value, but extreme peak forecasts (90/10) are also published and used in reliability analyses.

[120] Moody's Economy.com: http://www.economy.com

[121] The 2011 Demand Numbers reflect the integration of First*Energy* (ATSI) and Cleveland Public Power (CPP) into PJM

A downward revision to the economic outlook from Moody's Economy.com for the PJM Area has resulted in lower peak and energy forecasts in the 2011 load report, compared the 2010 load report.

Generation

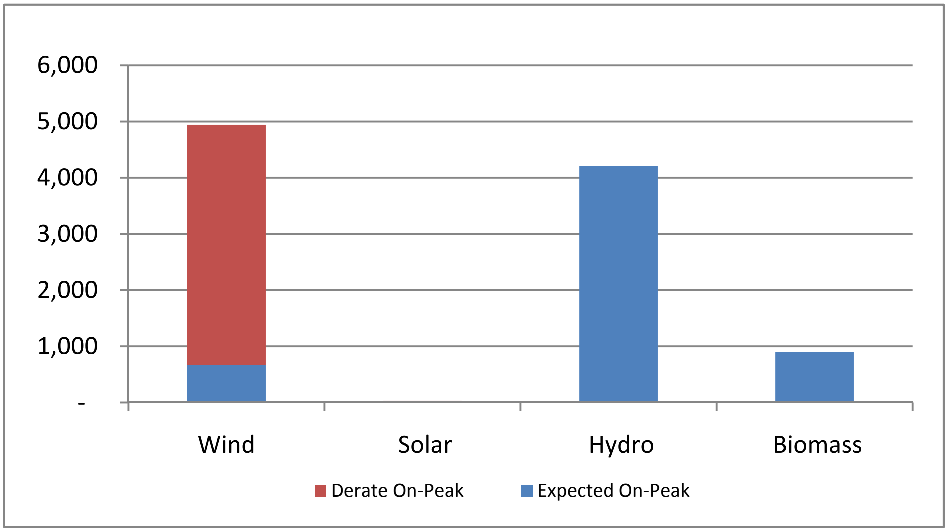
The total PJM capacity resources projected to be in service during the 2011 summer peak period are 180,406 MW of Existing-Certain generation within the PJM RTO. This total includes the addition of First*Energy* (ATSI) and CPP generation. No Existing-Other or Existing, Inoperable capacities are counted towards PJM capacity values.

TABLE 86: PJM EXISTING AND PLANNED PEAK CAPACITY

Existing-Certain (MW)	180,406
Existing-Other (MW)	4,292
Future-Planned (MW)	-

Variable generation amounts to nearly 5,000 MW nameplate and 670 MW forecast on-peak. 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.

FIGURE 37: PJM EXISTING AND PLANNED RENEWABLE GENERATION



PJM has additional renewable resources of 896 MW of Biomass capacity counted fully in the capacity calculations.

PJM has approximately 4,200 MW of conventional and pumped hydro generation and reservoir levels are adequate.

PJM is not experiencing or expecting any conditions that would reduce overall capacity or reduce specific unit types.No significant generation is projected to be out of service over the summer peak period.

TABLE 87: PJM EXISTING AND PLANNED RENEWABLE GENERATION

Wind Expected On-Peak	670
Wind Derate On-Peak	4,272
Wind Nameplate/Installed Capacity	4,942
Solar Expected On-Peak	12
Solar Derate On-Peak	20
Solar Nameplate/Installed Capacity	32
Hydro Expected On-Peak	4,212
Hydro Derate On-Peak	-
Hydro Nameplate/Installed Capacity	4,212
Biomass Expected On-Peak	896
Biomass Derate On-Peak	-
Biomass Nameplate/Installed	896

Capacity Transactions

PJM has Firm capacity imports of 3,858 MW. No Non-Firm imports are planned at this time. No additional Firm capacity imports are planned at this time. All transactions are Firm for both generation and transmission. No imports are based on partial path reservations. No import contracts are Liquidated Damage Contracts.

TABLE 88: PJM IMPORTS AND EXPORTS ON-PEAK

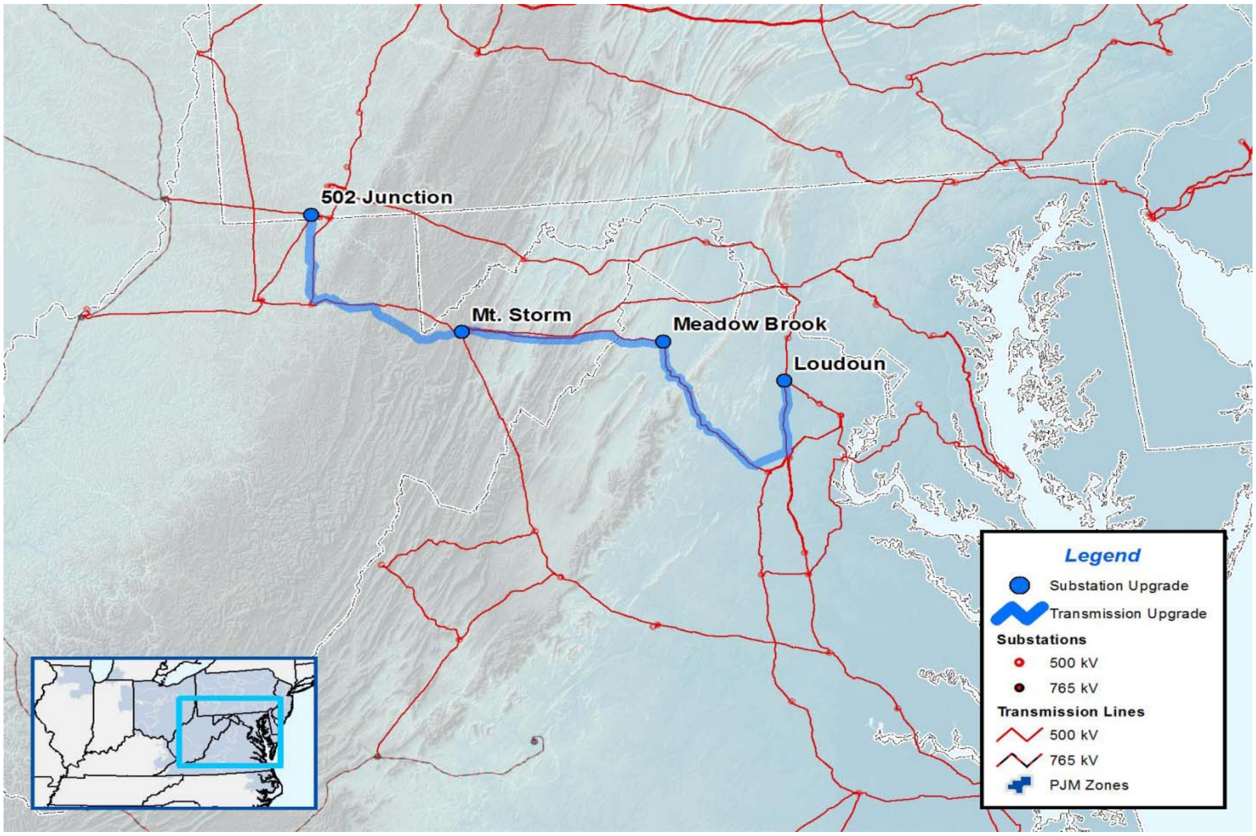
Imports (MW)	3,858
Firm (MW)	3,858
Expected (MW)	-
Exports (MW)	2,598
Firm (MW)	2,598
Expected (MW)	-
Net Imports (MW)	**1,260**

PJM has Firm capacity exports of 2,598 MW. No Non-Firm exports are planned at this time. No additional Firm capacity exports are planned at this time. All transactions are Firm for both generation and transmission. No exports are based on partial path reservations. No export contracts are Liquidated Damage Contracts. PJM has no planned reliance on outside assistance for emergency imports to satisfy reserve requirements.

Transmission

The Harrisonburg-Valley 230 kV line went into service in June 2010. A single 345/138 kV transformer was added at both the Don Marquis and the New Arsenal substations. Two Doubs 500/230 kV transformers were replaced. A single 230/115 kV transformer was added at the Trowbridge, Elmont, and Lanexa substations. No other significant substation equipment has been added since last summer.

The TrAIL 500kV Line in the Allegheny Power/Dominion areas will increase import capability into the Baltimore/Washington/Northern Virginia area by approximately 1,000 MW. The AP South Interface capability is increased by approximately 500 MW. Meadowbrook to Loudoun 500 kV was energized on April 13. Mt. Storm to Meadowbrook 500 kV was energized on May 13 and the 502 Junction to Mt. Storm 500 kV line is to be energized on May 20.



There are no concerns in meeting target in-service dates for new transmission additions. PJM does not anticipate any existing significant transmission lines or transformers being out of service through the summer season. No significant transmission constraints are anticipated. No significant changes are forecast from last year's assessment. RFC and SERC interregional studies are ongoing under the Eastern Interconnection Reliability Assessment Group (ERAG).

Operational Issues

No special operating procedures are required from integration of variable resources. PJM has developed a Wind Power Forecast tool and visualization to assist operations. PJM has integrated wind into its automated dispatch systems.

PJM does not anticipate any reliability concerns resulting from minimum demand and over-generation. Intermittent resources can be required to disconnect. Established procedures ensure reliability concerns resulting from over-generation are addressed.

PJM does have a concern with the growth of typical Demand Response that has been offered in the PJM RPM Market. This type of Demand Response is limited to being called ten times per year and may only be used in the summer peak period even though historically Demand Response has never been called more than four times in a peak season. PJM is considering offering a new type of Demand Response that can be called any number of times and any time during the year.

TABLE 89: PJM DEMAND RESPONSE AND ENERGY EFFICIENCY ON-PEAK

Non-Dispatchable DSM (MW)	-
Energy Efficiency	-
Non-Controllable Demand-Side Demand Response	-
Total Internal Demand	148,941
Controllable, Dispatchable Demand Response	11,600
Net Internal Demand	137,341

PJM requires Generation owners to place resources into the "Maximum Emergency Category" if environmental restrictions limit run hours below pre-determined levels. Maximum Emergency units are the last to be dispatched.

No other unusual operating conditions that could significantly impact reliability for the upcoming summer are anticipated.

Reliability Assessment

Reserve Margin requirements are established for each year at least three years into the future. Details can be found in the 2010 Reserve Requirement Report.[122]

TABLE 90: PJM ON-PEAK CAPACITY RESOURCES AND RESERVE MARGINS

	2011 Summer Forecast (MW)	2011 Summer Forecast (%)	Change from prior year (MW)	Change from prior year (percentage point)
Existing-Certain and Net Firm Transactions (with Demand Response)	193,266	29.8%	26,266	3.1
Anticipated Capacity Resources	193,266	29.8%	26,266	3.1
Prospective Capacity Resources	193,266	29.8%	26,266	3.1
NERC Reference Margin Level	**23,086**	**15.5%**	**23,086**	-

The PJM projected Reserve Margin for 2011 summer is 29.8 percent. DSM is used as a resource in this calculation. This level is well in excess of the required PJM Reserve Margin of 15.5 percent. PJM has adopted a Loss of Load Expectation (LOLE) standard of one occurrence in ten years. PJM performs an annual LOLE study to determine the Reserve Margin required to satisfy this criterion. The study recognizes, among other factors, load forecast uncertainty due to economics and weather, generator unavailability, deliverability of resources to load, and the benefit of interconnection with neighboring systems. The methods and modeling assumptions used in this study are available in PJM Manual 20.[123]

[122] http://www.pjm.com/planning/resource-adequacy-planning/~/media/documents/reports/2010-pjm-reserve-requirement-study.ashx

[123] http://www.pjm.com/~/media/documents/manuals/m20.ashx

The latest Reserve Margin requirement study is available.[124] Reserve Margins have remained relatively similar to the 2010 levels even with the addition of First*Energy* and CPP's loads and generation. 2010 Reserve Margin 28.7 percent; 2011 Reserve Margin 29.8 percent.

PJM has established rules and procedures to ensure fuel is conserved to maintain an adequate level of on-site fuel supplies under forecast peak load conditions. PJM coordinates with neighboring entities and gas pipelines to quickly address fuel issues.

No potential or actual supply transportation/delivery issues are anticipated. No fuel supply issues are anticipated. No fuel transportation issues are anticipated.

PJM has developed Reactive Transfer Interfaces to ensure sufficient dynamic MVAR reserve in load centers that rely on economic imports to serve load. PJM day-ahead and real-time Security Analyses ensure sufficient generation is scheduled and committed to control pre- and post-contingency voltages and voltage drop criteria within acceptable predetermined limits as outlined in M-3, section 3.

Area Description

PJM has 688 members that operate within 183,000 square miles of service territory. 1,295 generators with diverse fuels serve a single summer-peaking Balancing Authority. PJM is in two NERC Regional Entities: RFC and SERC). PJM companies serve 56 million people in 13 states (Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, North Carolina, New Jersey, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia) and Washington, D.C.

[124] http://www.pjm.com/planning/resource-adequacy-planning/~/media/documents/reports/2010-pjm-reserve-requirement-study.ashx

RFC

Executive Summary

All Reliability*First* Corporation (RFC) members are affiliated with either the Midwest ISO (MISO) or the PJM Interconnection (PJM) Regional Transmission Organization (RTO) for market operations and reliability coordination. Ohio Valley Electric Corporation (OVEC), a generation and transmission company located in Indiana, Kentucky and Ohio, is not a member of either RTO and is not affiliated with their markets. OVEC's Reliability Coordinator services have been performed by PJM. On June 1, 2011, OVEC's Reliability Coordinator will change from PJM to Midwest ISO. This change in Reliability Coordinator does not impact the RFC reliability assessment. Also, RFC does not have officially designated subregions. The Midwest ISO and PJM each operate as a single Balancing Authority area. Since all RFC demand is in either Midwest ISO or PJM except for the small load (less than 100 MW) within the OVEC Balancing Authority area, the reliability of the PJM RTO and Midwest ISO are assessed and the results used to indicate the reliability of the RFC Region.

The forecast for the 2011 PJM RTO summer peak is 148,941 MW which includes the integration of FirstEnergy American Transmission Systems Incorporated (ATSI) into PJM. The anticipated growth rate from last year to this year is 1.1 percent and is slightly lower than normal, still showing effects of the economic downturn.

Last year's unrestricted non-coincident demand forecast of 112,701 MW is 8.9 percent higher than this year's unrestricted non-coincident demand forecast of 102,651 MW for the Midwest ISO. This difference is mostly due to FirstEnergy's exit from Midwest ISO effective June 2011, which accounts for approximately an 11.7 percent reduction from last year's demand forecast. The Big Rivers Integration contributed a 1.6 percent increase, while the existing membership experienced load growth of 1.3 percent, thus bringing the net load reduction to 8.9 percent.

The Net Internal Demand peak of the RFC Region forecast for the 2011 summer season is 164,100 MW and is projected to occur during July 2011. This value is based on a Total Internal Demand forecast of 178,600 MW, with the full reduction of 14,500 MW (8.1) percent of Total Internal Demand) from the Demand Response programs within the Region.

Compared to the actual 2010 summer peak demand of 174,300 MW for the RFC Region, the 2011 forecast Net Internal Demand is 10,200 MW (5.8 percent) lower than the actual 2010 summer peak demand. In addition, the 2010 forecast of 2011 summer Net Internal Demand peak demand was 175,400 MW, making this year's summer Net Internal Demand peak demand forecast 11,300 MW (6.4 percent) lower than last year's 2010 summer peak demand forecast.

The total PJM capacity resources expected to be in service during the 2011 summer peak period is 180,406 MW of Existing Certain generation within the PJM RTO. This includes the transfer of 12,770 MW of ATSI generation from the Midwest ISO to PJM on June 1, 2011. Approximately 640 MW of generation were added in the rest of PJM since last summer.

Last year's Existing (Certain, Other, and Inoperable) capacity of 131,284 MW is 22 percent higher than Midwest ISO's projected Existing Certain capacity of 107,391 MW for the 2011 summer season. This difference is mostly due to FirstEnergy's exit from Midwest ISO effective June 2011. The remaining MW changes were from new generation, retirements and suspensions, and reclassified units.

The RFC region has 211,700 MW of capacity for this summer that is identified as Existing, Certain in this assessment.

When the PJM projected reserve margin for summer 2011 is calculated with the Demand-side Management (DSM) programs reducing the demand, the reserve margin is 32.3 percent, the same as 2010. NERC has also requested that all reporting entities calculate their reserve margins with DSM programs used as a resource in the reserve margin calculation. With DSM included as a resource, the reserve margin is 29.8 percent. Both calculated reserve margins are above the required reserve margin of 15.5 percent. The indicated reserve margin includes firm imports and exports.

The Midwest ISO's current calculation of the summer 2011 reserve margin is 21.6 percent, based on DSM reducing the load. With DSM included as a resource, the reserve margin is 20.7 percent. Both calculated reserve margins are higher than the 17.4 percent MISO system planning reserve margin calculated for 2011 and less than the 25 percent reserve margin forecasted in 2010.

Analyses were conducted by the Midwest LOLE Working Group and PJM to satisfy RFC regional reliability standard BAL-502-RFC-02, which requires Planning Coordinators to determine the reserve margin at which the Loss of Load Expectation (LOLE) is one day in ten years (0.1 day/year) on an annual basis for their planning area. These analyses include demand forecast uncertainty, outage schedules, determination of transmission transfer capability, internal deliverability, other external emergency sources, treatment of operating reserves and other relevant factors when determining the probability of firm demand exceeding the available generating capacity. The assessment of PJM resource adequacy was based on reserve requirements determined from the PJM analysis. Similarly, the assessment of MISO resource adequacy was based on reserve requirements determined from the MISO analysis. Since PJM and MISO are projected to have sufficient resources to satisfy their respective reserve margin requirements, the RFC region is projected to have adequate resources for the 2011 summer period.

The original ITC*Transmission* Bunce Creek (B3N) Phase Angle Regulating transformer that failed in March 2003 has been replaced by two (series) Phase Angle Regulating transformers. Installation of the transformers was completed in December 2009. Energizing the transformers was dependent upon completion of protective system work in coordination with Hydro One, which was completed in July 2010. Until ITC*Transmission* and Hydro One are authorized to begin operating the B3N Phase Angle Regulating transformers to control flows, the Phase Angle Regulating transformers on the L4D and L51D interconnections will be placed in the by-pass mode. The PAR on the Ontario - Michigan J5D interconnection near Windsor will be operated to assist in the management of local system congestion and for the optimization of power transfers.

The Phase Angle Regulating transformers on the ITC*Transmission* – Hydro One interconnections will be used to control interconnection flows pending the receipt by ITC*Transmission* of an amended Presidential Permit from the U.S. Department of Energy and completion of various contractual and operational agreements between and among the respective Transmission Owners and Reliability Coordinators. The goal was to place the PAR's in service sometime during summer 2011 but current conditions indicate that the agreements will not be ready in time.

Many new additions to the bulk-power system since last summer are expected to be placed in-service within the Reliability*First* footprint. These include a total of 339 miles of transmission line at 100 kV and above, plus eleven new transformers with a total capacity of 6,650 MVA and four replacement transformers with a total capacity of 3,400 MVA. These system changes are expected to enhance reliability of the bulk-power system within Reliability*First*. Detailed information can be found in the PJM and Midwest ISO sections of this report.

On May 5, 2010, the 500/345 kV transformer #5 at Allegheny Power's Wylie Ridge substation failed, and then on August 15, 2010, the 500/345 kV transformer #8 also failed. Transformer #8 is being replaced in June, and transformer #5 is scheduled to be replaced in September. The Wylie Ridge substation is an interconnection point between the AEP and FE 345 kV systems and the AP 500 kV system. Loss of Wylie Ridge transformation can potentially reduce the transfer capability from west to east through PJM. PJM and Midwest ISO have jointly managed congestion at the Wylie Ridge interface prior to the addition of the third and fourth 500/345 kV transformers in 2007, and since that time during planned maintenance outages of any of the transformers. Transmission congestion may increase during operation with only the three transformers, but is not expected to impact reliability or the ability to meet demand.

There are no concerns in meeting target in-service dates of new transmission identified. PJM and the Midwest ISO do not anticipate any other significant transmission lines or transformers being out-of-service during the 2011 summer. No constraints are anticipated that could significantly impact reliability.

SERC

SERC-W Summary

SERC-W (including SPP RC entities registered in SERC) is a summer-peaking assessment area covering portions of four southeastern states (Arkansas, Louisiana, Mississippi, and Texas). The ten registered Balancing Authorities in this Area are identified as Entergy; City of Benton; City of Conway; City of North Little Rock, Arkansas; City of Osceola; City of Ruston, Louisiana; City of West Memphis; Louisiana Generating, LLC; Plum Point Energy Associates, LLC; and Union Power Partners, L.P.

The 2011 summer projected Total Internal Demand for utilities in SERC-W (including Southwest Power Pool RC entities registered in SERC) is 25,101 MW. Although a comparison of the forecast to prior years is not available due to the restructuring of the assessment assessment areas, SERC-W entities report that their forecasts are relatively unchanged due to consistent economic assumptions in the current forecasts. Companies within SERC-W expect to have the noted Existing-Certain (34,713 MW), Existing-Other (3,419 MW), and Existing Inoperable (1,255 MW) capacity on peak. Since 2010, the amount of Existing-Certain capacity has not increased. No Future resources are projected to be in service through the end of the assessment period. Aggregate 2011 summer Reserve Margins are 46.2 percent, indicating capacity resources in the Area are projected to be adequate to supply the projected Firm demand. The Existing-Certain and Net Firm Transaction, and Anticipated summer peak Reserve Margins for the utilities in the Area are projected to be 46.2 and 55.3 percent, respectively. The entities within this Area do not adhere to any Regional assessment area targets or Reserve Margin criteria. These margins are well above the 15-percent NERC Reference Marginal Level. Current entity processes in assessing demand, capacity, and reserve margin projections are considered to be consistent with the assumptions portrayed in last summer’s reporting period.

SERC-W utilities plan to have an additional five miles of 161 kV and 40 miles of 230 kV transmission lines in service for the upcoming summer season compared to last summer. In addition, these entities plan to install or upgrade three transformers by the end of the assessment period. No transmission reliability concerns are forecast to significantly impact Bulk Power System reliability for the 2011 summer season. The companies within the Area regularly participate in the SERC Near-Term Study Group (NTSG) seasonal reliability studies and develop assessments to ensure reliability on the system.

To minimize reliability concerns for the 2011 summer, SERC-W entities are studying reliability with a critical and conservative approach. Any issues that result from the studies are addressed within the appropriate timeframe. Curtailment Processes and Emergency Response Plans are routinely updated. As necessary, transmission-wide and local Area procedures, redispatch, and operating guidelines will be implemented to maintain reliability for the summer. Because Energy Emergency Alerts (EEA) have been issued in the past for the Acadiana Area, the SPP Independent Coordinator of Transmission-Entergy will continue to monitor this Area closely and implement mitigation plans as necessary as part of its Reliability Coordinator function.

A two-phase joint project to construct a 230 kV overlay in the Acadiana load pocket is currently in the construction phase with targeted in-service dates of 2011 and 2012. Overall, there are no other anticipated reliability concerns for the 2011 summer.

SERC-N Summary

SERC-N is a summer-peaking Area covering five southeastern states (Tennessee, Alabama, Georgia, Kentucky, and Mississippi.). This Area consists of six Balancing Authorities identified as Associated Electric Cooperative, Inc.; Batesville Balancing Authority; East Kentucky Power Cooperative; Electric Energy, Inc.; LG&E and KU Services Company as agent for Louisville Gas and Electric Company and Kentucky Utilities Company; and Tennessee Valley Authority.

The 2011 summer projected Total Internal Demand for utilities in SERC-N is 46,846 MW. Comparisons to previous years' forecasts are not available due to the restructuring of the assessment assessment areas. However, entities identified no significant differences between last year's summer demand forecast versus this year's projections. Companies within the TVA assessment area expect to have the noted Existing-Certain (57,610 MW), Existing-Other (621 MW), and Existing-Inoperable (71 MW) capacity on peak. Since 2010, the amount of Existing-Certain capacity has increased by 785 MW. There are no Future resources projected to be in service through the end of the assessment period. Aggregate 2011 summer Reserve Margins are 28.0 percent, indicating capacity resources in the Area are projected to be adequate to supply the projected Firm summer demand. The Existing-Certain and Net Firm Transaction, and Anticipated summer-peak Reserve Margins (as reported in February 2011) for utilities in the Area are projected to both be 28.0 percent. Entities within this Area do not adhere to any Regional/assessment area targets or Reserve Margin criteria. However, these margins are well above the 15-percent NERC Reference Marginal Level. The economy is a significant concern within this assessment area. Entity processes continue to capture modest growth in customer demand, derates (unusually high river temperatures limiting once-through cooling systems) and other outages into short-term projections to ensure reliability.

Utilities plan to have added 12 miles of 100 kV, nine miles of 115 kV, 7 miles of 138 kV, 195 miles of 161 kV, nine miles of 230 kV, and 45 miles of 345 kV new transmission lines in service for the upcoming summer season since last summer. In addition, six transformers are projected to be installed or upgraded by the end of the assessment period. No transmission reliability concerns are forecast to significantly impact Bulk Power System reliability for the summer season. System conditions may at times dictate local Area generation re-dispatch or reconfiguration of transmission elements to alleviate anticipated next contingency overloads. NERC TLR procedures are commonly invoked in scenarios that are not easily remedied by a local Area solution. Entities regularly evaluate the transmission system to identify any future constraints and mitigate concerns that could significantly impact reliability.

SERC-N utilities continue to minimize operational restrictions around the hydro units and transmission loading issues through ongoing operational planning/longer-term planning processes. Industry events are also monitored for potential lessons learned.

SERC-E Summary

SERC-E (excludes utilities that are within the PJM) is a summer-peaking Area covering portions of two southeastern states (North Carolina and South Carolina). The five Balancing Authorities 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 2011 summer projected Total Internal Demand for utilities in SERC-E is 43,249 MW. Comparisons to previous years' forecast are not available due to the restructuring of the assessment assessment areas. However, entities identified no significant differences between last year's summer demand forecast versus this year's projections. Companies within the SERC-E assessment area expect to have the noted Existing-Certain (49,768 MW), Existing-Other (two MW), and Existing-Inoperable (113 MW) capacity on peak. Since 2010, no new Existing-Certain capacity has become operational. There are 635 MW of Future resources projected to be in service through the end of the assessment period. Aggregate 2011 summer Reserve Margins are 24.1 percent, indicating capacity resources in the Area are projected to be adequate to supply the projected Firm summer demand. The Existing-Certain and Net Firm Transaction, and Anticipated summer-peak Reserve Margins (as reported in February 2011) for utilities in the Area are projected to be 22.6, and 24.1 percent respectively. Entities within this Area do not adhere to any regional assessment area targets or Reserve Margin criteria. However, these margins are well above the 15-percent NERC Reference Marginal Level. Additionally, short-term growth projections have been adjusted to the current economy. Margins for the upcoming season continue to be based on load reductions due to the economy, increased Demand-Side Management, significant increases in generation, and mild weather.

Utilities plan to have added five miles of 100 kV, seven miles of 115 kV, and 158 miles of 230 kV new transmission lines in service for the upcoming summer season since last summer. In addition, three transformers are projected to be installed or upgraded by the end of the assessment period. No transmission reliability concerns are forecast to significantly impact Bulk Power System reliability for the summer season. Coordinated Regional, subregional, and company studies are performed on a routine basis.

Entities in the Area continue to monitor reservoir levels as the seasons and conditions change. Loop and parallel flows imposed by neighboring BAs have the potential to create contingency overloads; however, both procedures and agreements are in place that can effectively manage flows on the system.

SERC-SE Summary

SERC-SE is a summer-peaking assessment area covering portions of four southeastern states (Alabama, Georgia, Mississippi, and Florida). This assessment area consists of four Balancing Authorities identified as PowerSouth Energy Cooperative; South Mississippi Electric Power Association; Southeastern Power Administration; and Southern Company Services, Inc.

The 2011 summer projected Total Internal Demand for the utilities in SERC-SE is 49,314 MW. Due to the restructuring of the assessment assessment areas, a comparison of the forecast to prior years is not available. However, SERC-SE entities report that growth rates for the upcoming summer are projected to decrease in the short term due to the downturn of the economy. Companies within SERC-SEexpect to have the noted Existing-Certain (61,072 MW), Existing-Other (3,301 MW), and Existing Inoperable (zero MW) capacity on peak. Since 2010, the amount of Existing-Certain capacity has increased by 822 MW. Additionally, no Future resources are projected to be in service through the end of the assessment period. Aggregate 2011 summer Reserve Margins are 24.9 percent, indicating capacity resources in the Area are projected to be adequate to supply the projected Firm summer demand. The Existing-Certain and Net Firm Transaction, and Anticipated summer peak Reserve Margins for the utilities in the Area are projected to be 24.9 and 31.6 percent, respectively. Most SERC-SE entities use a reference marginal level of 15 percent to ensure reliability, and indicate that projected Reserve Margins remain well above this target. Entity processes continue to capture weather, economics, and demographics in their projections through models and assessments that take into account historical peaks and various conditions that affect the system. As conditions from the economic downturn continue to show slowed growth, entities account for this trend in their models through the reduction of load.

SERC-SE utilities plan to have an additional 24 miles of 115 kV, eight miles of 161 kV, and 53 miles of 230 kV new transmission lines in service for the upcoming summer season compared to last summer. In addition, eight transformers are forecast to be installed or upgraded by the end of the assessment period. No transmission reliability concerns are projected to significantly impact Bulk Power System reliability for the summer season. To minimize impacts on the system, the utilities within the assessment area annually develop assessments of the transmission system. If constraints occur, mitigation procedures are in place to relieve constraints.

The following are the most common challenging operational issues: loop flows, congestion, potential climate legislations, and real-time transmission loading issues. Entities have found that the availability of large amounts of excess generation within the Areas has resulted in fairly volatile day-to-day scheduling patterns and exacerbation of transmission loading concerns. These operational issues are not reliability concerns but market issues. Transmission constraints identified are studied and can be mitigated as needed to minimize reliability concerns on the Bulk Power System. SERC-SE companies are also monitoring the reliability impacts of potential climate legislation.

SERC-W

Demand

Projected Total Internal Demand for utilities in SERC-W (including SERC-SPP RC entities registered in SERC) for the upcoming summer is 25,101 MW. This forecast is 74 MW (0.3 percent) higher than the actual 2010 summer peak demand of 25,027 MW. Due to the restructuring of entity reporting footprints for this assessment, the comparisons of demand forecast are not available for this Area. The relatively unchanged forecast is due to economic assumptions in the current forecasts. The increase primarily reflects retail load growth and increases in wholesale load. The forecast assumes ten-year typical weather and continues to anticipate a gradual economic recovery.

TABLE 91: SERC-W FORECAST AND ACTUAL PEAK DEMAND

2010 Total Internal Demand (MW)	2010 Actual Demand (MW)	Difference in Actual versus Forecast (MW)	Difference in Actual versus Forecast (%)	2011 Total Internal Demand (MW)	Difference in 2011 and 2010 Forecast Demand (MW)	Difference in 2010 Actual versus 2011 Forecast (%)	All-Time Summer Peak Demand (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)
N/A	25,027	-	-	25,101	-	-	-	25,101	-

The summer forecast is also based on a forecast study that produced new econometrically based forecasts of residential/commercial/industrial load, future economic/demographic conditions, and historical data. Typical weather is defined by calculating an average daily temperature from ten years of historical weather data and determining a month that contains the smallest differential from the ten-year monthly average.

The utilities in SERC-W perform detailed extreme weather and/or load sensitivity analyses in their respective operational and planning studies to address projected demand. While utility methodologies vary, common attributes include:

- Use of econometric linear regression models;
- The relationship of historical annual peak demands to key variables such as weather, economic conditions, and demographics;
- Variance of forecasts due to high and low economic scenarios, and mild and severe weather; and
- Development of a suite of forecasts to account for the variables mentioned above, and associated studies using these forecasts.

In addition, many utilities in the assessment area use sophisticated, industry-accepted methods to evaluate load sensitivities in the development of load forecasts. When appropriate, utilities adhere to their respective state commissions' regulations, any RTO requirements, and internal business practices for determining their forecast and reserve requirements. The internal peak demands of individual entities are aggregated as a non-coincident peak value.

Demand-Side Management (DSM) programs among the utilities in SERC-W include: interruptible load programs for larger customers, direct-control load management programs for agricultural customers, and a range of conservation/load management programs for all customer segments. There are no significant changes in the amount or availability of load management and interruptible demand since last year. Demand Response is projected to be 3.5 percent of Total Internal Demand.

Measurements and verification for interruptible Demand Response programs for larger customers are conducted on a customer-by-customer basis. These include an annual review of customer information and Firm load requirements. Compliance is determined by a review of customer load data as related to the terms and conditions of the electric rate schedule.

Energy-efficiency programs are implemented to distribution cooperatives and the residential sector. A variety of programs including home energy audits, compact fluorescent lights (CFLs), Energy Star-rated washing machines and dishwashers, Energy Star-rated heat pumps and air conditioners, weatherization, and high efficiency water heaters have been added to company portfolios over the years. SERC-W utilities plan to offer these types of programs as long as they are determined to be cost-effective. Annual Measurement and Verification (M&V) programs measure energy savings and costs for each of these energy-efficiency programs. Information from these M&V programs will be used to fine tune energy-efficiency programs and to determine their cost effectiveness. The current forecast includes energy-efficiency programs that have received regulatory approval. As programs advance, they will be incorporated into retail sales and load forecasts.

Load scenarios for outage planning purposes are developed regularly to address variability issues in demand. These load scenarios include load forecasts based on high and low scenarios for energy sales and scenarios for alternative capacity factors. The forecasts are based on normal weather, economic, and demographic conditions. Scenarios are also modified from these forecasts to produce updated forecasts for both optimistic and pessimistic conditions. Most SERC-W entities update forecasts frequently (approximately every two years) with annual updates completed in the interim years. The economic downturn has reduced expectations of economic activity compared to previous forecasts reflected in the relatively unchanged 2011 summer forecast. This has resulted in a reduction of demand and energy forecasts. The current load forecast reflects lower sales through 2014, with the largest decreases in the industrial class due to reduced operations and delayed expansions resulting from the economic downturn.

Some SERC-W entities address extreme weather conditions through the production of load scenarios. Other entities have a thorough planning process that examines summer peak conditions during extreme Bulk Power System events. In the long-term planning timeframe, local loads are adjusted to reflect a 100-degree Area temperature so studies capture the effects of local extreme temperatures. For the operational planning timeframe, in addition to next-day planning, SERC-W entities regularly study import limitations for various load pockets on the system. These analyses cover summer peak conditions, including extreme summer conditions, as necessary. Occasionally special analyses are preformed to examine conditions associated with weather events such as hurricanes, heat waves, cold fronts, or ice storms.

Generation

Companies within SERC-W expect to have the following Existing (-Certain, -Other and Inoperable) and Future (-Planned and -Other) capacity on peak. This capacity is projected to help meet demand during this time period.

TABLE 92: SERC-W SUMMER CAPACITY BREAKDOWN

Capacity Type	Year 2011 (MW)
Existing-Certain	34,713
Nuclear	5,228
Hydro/Pumped Storage	266
Coal	6,300
Oil/Gas/Dual Fuel	22,039
Other/Unknown	880
Solar	0
Biomass	0
Wind	0
Existing-Other	3,419
Existing, Inoperable	1,255
Future capacity	0

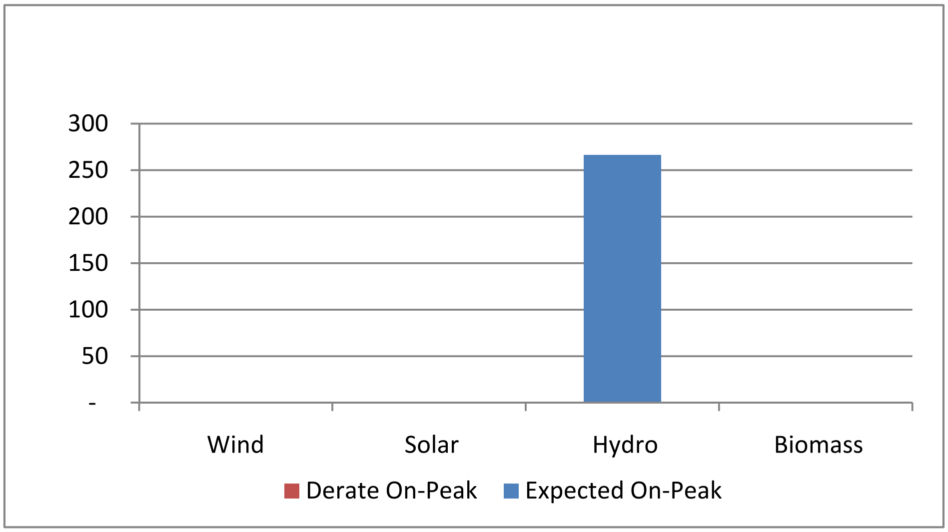
Only Firm capacity is counted toward the peak in calculations. In most cases, SERC-W entities do not count variable resources due to their irregularity during peak demand periods. However, other entities consider wind values based on a time-period method using monthly capacity value measures. The process first examines the highest ten percent of load hours for the respective month, and ranks wind generation in those hours from high to low. The wind generation value that exceeds 85 percent of the time is defined as the capacity value of the wind resource. This method is based on research from various sources discussing estimation of the capacity value of wind resources. For base load resources like biomass and in-stream hydro, the assumption is 100 percent of the rated capacity value.

TABLE 93: SERC-W EXISTING AND PLANNED PEAK CAPACITY

Existing-Certain (MW)	34,713
Existing-Other (MW)	3,419
Future-Planned (MW)	-

Hydro conditions are projected to be normal for the summer assessment period based on current reservoir levels and rainfall. However, some SERC-W entities anticipate limitations on running units located on the Arkansas River due to limited rainfall in the Oklahoma and Kansas Areas. Normally the rainfall in these Areas is low in the summertime, which results in irregular flow.

FIGURE 38: SERC-W EXISTING AND PLANNED RENEWABLE GENERATION



SERC-W entities are not expecting any conditions associated with weather, fuel supply, or fuel transportation that would reduce capacity. Portfolios of Firm-fuel resources ensure adequate fuel supplies to generating facilities during projected summer peak demand. Those resources include nuclear and coal-fired generation that are relatively unaffected by summer weather events, fuel oil inventory located at the dual-fuel generating plants, approximately ten Bcf of natural gas in storage at a natural-gas storage facility owned by a SERC-W company, and short-term purchases of Firm natural gas generally supplied from other gas storage facilities and delivered using Firm-gas transportation contracts. This mix of resources provides diversity of fuel supply and minimizes the likelihood and impact of weather, fuel supply, and fuel transportation conditions that might otherwise reduce capacity.

TABLE 94: SERC-W EXISTING AND PLANNED RENEWABLE GENERATION

Wind Expected On-Peak	-
Wind Derate On-Peak	-
Wind Nameplate/Installed Capacity	-
Solar Expected On-Peak	-
Solar Derate On-Peak	-
Solar Nameplate/Installed Capacity	-
Hydro Expected On-Peak	266
Hydro Derate On-Peak	-
Hydro Nameplate/Installed Capacity	266
Biomass Expected On-Peak	-
Biomass Derate On-Peak	-
Biomass Nameplate/Installed	-

Additionally, entities do not anticipate significant unit retirements or scheduled maintenance outages during the summer.

Capacity Transactions

Utilities within SERC-W expect the imports and exports listed below for 2011 summer. These imports and exports have been accounted for in the Reserve Margin calculations for the assessment area.

All contracts for these imports/exports are backed by Firm transmission and are tied to specific generators. No imports or exports have been reported to be based on partial path reservations. Additionally, none are associated as liquidated damage or "make whole" contracts.

TABLE 95: SERC-W IMPORTS AND EXPORTS ON-PEAK

Imports (MW)	4,363
Firm (MW)	4,213
Expected (MW)	150
Exports (MW)	3,253
Firm (MW)	3,103
Expected (MW)	150
Net Imports (MW)	**1,110**

The reporting entities in the Area are dependent on certain imports, transfers, or contracts to meet the demands of their loads. Most SERC-W entities are members of the Southwest Power Pool (SPP) reserve sharing group. Group participants within SPP generally transfer reserves into the Area to either replace (largest contingency) or supply generation to the Area. These reserves are not counted or relied on in the resource adequacy assessment, or for capacity or Reserve Margins. System operators generally coordinate the scheduling and transmitting of the reserves.

Transmission

Table 96 shows new Bulk Power System transmission facilities (transmission lines, transformers, and significant substation equipment) under construction since 2010 summer that are anticipated to be in service for the upcoming summer.

TABLE 96: SERC-W FORECAST TRANSMISSION

Transmission project name	Transmission type	In-service date	Operating voltage (kV)
Sterlington-North Bastrop 1	Under Construction	06/01/11	115
North Crossett-North Bastrop 1	Under Construction	06/01/11	115
Jacinto-Lewis Creek 1	In-Service	03/02/11	230
Segura-Moril 1	In-Service	05/05/10	230
Osage Creek-Grandview 1	Under Construction	08/01/11	161
Sellers Road-Meaux 1	Under Construction	05/02/11	230

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TABLE 97: SERC-W TRANSFORMER ADDITIONS

Transformer Project Name	High-side Voltage (kV)	Low-side Voltage (kV)	In-service Date	Status/Description
Magee sub	161	115	06/01/11	Under Construction – Upgrade Magee Auto 1 to 336 MVA
Magee sub	161	115	06/01/11	Under Construction – Upgrade Magee auto 2 to 336 MVA
Acadiana Area Improvement Project Phase 1	230	138	05/02/11	Under Construction – Add auto at Meaux
Acadiana Area Improvement Project Phase 1	500	230	05/02/11	Under Construction – Add new auto at Richard
Sarepta Project	345	115	05/01/11	Under Construction – Construct a new 345-115 kV substation consisting of a 500 MVA auto. Cut station into EL Dorado to Longwood 345 kV line
Add auto at Lewis Creek	230	138	03/02/11	In-Service – Add a 230/138 auto at Lewis Creek
McAdams Area Upgrades	500	230	06/01/11	Under Construction – Add second auto at McAdams at 560 MVA
Acadiana Area Improvement Project Phase 1	230	138	05/02/11	Under Construction – Add 500 MVA, 230-138 kV auto at Meaux

The entities within SERC-W do not expect any delays in meeting in-service dates for projects scheduled for the summer assessment period.

There are also no significant transmission facility outages that impact Bulk Power System reliability. Prior to approval of any proposed maintenance outages, studies are completed to identify any impacts on reliability.

No transmission constraints are projected to significantly impact Bulk Power System reliability for the 2011 summer. Companies within SERC-W regularly participate in SERC Near-Term Study Group (NTSG) seasonal reliability studies and in the ERAG MRO-RFC-SERC West-SPP (MRSWS) interregional studies. The preliminary NTSG 2011 Summer Reliability Study results indicate that import capabilities into the Area are projected to increase for all transfer directions studied. Studies from previous years identified lower import capability levels. However, the preliminary study results indicate that recent upgrades and planned additions on schedule for completion by June 2011 will increase the import capability levels for the transfer directions studied.

The current NTSG studies include a review of both subregional-to-subregional and company-to-company transfer capabilities. These studies do not exactly include the new SERC-W defined Area transfer, but SERC-W is very similar to one of the defined company Areas that is included in the NTSG 2011 study. Therefore, it is reasonable to expect that similar increases in the transfer capability levels would occur if a specific comparison to SERC-W could be made. The interregional transmission transfer capabilities are not currently available, in part due to the recent decision to report as a new SERC subarea.

Operational Issues

The companies within the assessment area that are transmission-dependent rely on operating studies that are performed by transmission operators. Resource availability, fuel availability, and hydro conditions are forecast to be normal during the summer. Loss-of-Load studies are performed annually for the regulated utility for the current year based on updated load forecast and unit availability data. The long-term test of resource adequacy is met by achieving a 16.85 percent planning Reserve Margin.

TABLE 98: SERC-W DEMAND RESPONSE AND ENERGY EFFICIENCY ON-PEAK

Non-Dispatchable DSM (MW)	-
Energy Efficiency	-
Non-Controllable Demand-Side Demand Response	-
Total Internal Demand	25,101
Controllable, Dispatchable Demand Response	873
Net Internal Demand	24,228

Due to an insignificant amount of variable generation connected to the distribution system, there are no concerns about integrating these resources onto the system. Wind agreements are used as a tool to allow operators to enhance reliability and can be used in situations such as curtailing for TLR and managing minimum generation problems. An energy forecasting package is used to predict wind plant output given meteorological data collected at the wind plants. Additionally, SERC-W entities are not anticipating reliability concerns resulting from high levels of Demand Response resources, environmental/regulatory constraints, or unusual operating conditions that could potentially impact reliability.

Reliability Assessment

There are generally two methods used for resource adequacy assessment among the utilities in SERC-West (ICTE):

- **Deterministic** — A stated, deterministic minimum-reserve guideline. In some cases, the reserve guideline is derived explicitly from other measures, such as operating-reserve requirements, load-forecast uncertainty, or largest single contingency.
- **Probabilistic** — A stated probabilistic guideline, which is usually translated into an equivalent minimum-reserve guideline for use in long-range planning studies.

SERC-W utilities projected an aggregate 46.2-percent Reserve Margin for the 2011 summer assessment period. These entities have reported no significant changes to the Reserve Margin from 2010 reporting to the current summer. The existing, anticipated, and prospective summer-peak Reserve Margins (as reported in February 2011) for utilities in SERC-W are projected to be 46.2, 46.2, and 55.3 percent respectively. SERC-W entities within this Area do not adhere to any Regional/assessment area targets or Reserve Margin criteria.

TABLE 99: SERC-W ON-PEAK CAPACITY RESOURCES AND RESERVE MARGINS

	2011 Summer Forecast (MW)	2011 Summer Forecast (%)
Existing-Certain and Net Firm Transactions (with Demand Response)	36,696	46.2%
Anticipated Capacity Resources	36,696	46.2%
Prospective Capacity Resources	38,984	55.3%
NERC Reference Margin Level	**3,765**	**15.0%**

Various utility resource planning departments in the Area conduct studies annually (either in-house or through contractors) to assess resource adequacy. Modeling of resources and delivery aspects of the power system are used in all phases of the studies. The overall goal of the studies is to ensure that resources (existing and owned) are available at the time of system peak. One example of an entity's method would be the Entergy System's use of the Entergy Reliability Analysis with Interruptible Loads (ERAILS) model. This model is a proprietary computer simulation model, developed by the Entergy Generation Planning group, to perform the resource requirements analyses. The ERAILS model uses Monte Carlo statistical techniques to estimate each day's "actual" peak load based on the forecast load and the load forecast variance, the total resources available to serve that load based on available resources, forced outages, the characteristics of each resource, and the probability of being able to meet the load, plus off-system sales and operating reserves. The fundamental objective of the process is to identify the amount of incremental resources necessary to serve Firm load at a reliability level of no more than one day/ten years loss-of-load expectation and to serve interruptible retail and limited-Firm wholesale loads with an average of ten or fewer days of interruption during the summer.

Resource adequacy studies in SERC-W take into account potential resource deactivations and anticipated unit outages, existing and owned resources, and limited and long-term purchase contracts. Results help develop one- and ten-year resource plans that meet target Reserve Margins.

Fuel supplies are anticipated to be adequate. Coal stockpiles are maintained at 45 days or more. Natural gas contracts are Firm, with some plants having fuel oil back-up. Extreme weather conditions should not affect deliverability of natural gas. Typically, supplies are limited only when there are hurricanes in the Gulf of Mexico. There is access to local gas storage to offset typical gas curtailments. Many SERC-W utilities maintain portfolios of Firm-fuel resources to ensure adequate fuel supplies to generating facilities during projected peak demand. Those Firm-fuel resources include nuclear and coal-fired generation that are relatively unaffected by weather events.

Various portfolios contain fuel oil inventories located at the dual-fuel generating plants, approximately ten Bcf of natural gas in storage at a natural-gas storage facility owned by a SERC-W company, short-term purchases of Firm natural gas generally supplied from other gas storage facilities, and Firm-gas transportation contracts. This mix of resources provides diversity of fuel supply and minimizes the likelihood and impact of potentially problematic issues on system reliability. Close relationships (contracts) are maintained with coal mines, gas pipelines, gas producers, and railroads that serve its coal power plants. These relationships ensure that adequate fuel supplies are on hand to meet load requirements. Upon the occurrence of fuel interruption or forced outage within some entity facilities, it is common that exporting contracts out of the facility will be curtailed in coordination with the affected balancing authorities until operations can return to normal.

The companies throughout the Area individually perform studies to assess transient dynamics, voltage, and small-signal stability issues for summer conditions in the near-term planning horizons as required by NERC Reliability Standards. These entities also participate in various SERC study groups to annually assess potential issues on the system. For the 2011 summer, a voltage stability study was performed to assess the impact of the proposed generation on voltage stability and rotor angle stability in one of the defined load pockets. The study results indicated that transmission improvements and additional reactive support or FACTS devices are needed in the Area to help maintain the voltage stability.

Other Area-Specific Issues

To minimize reliability concerns for the summer period, SERC-W entities are studying reliability with a critical and conservative approach. Any issues that result from the studies are addressed within the appropriate timeframe. Curtailment Processes and Emergency Response Plans are routinely updated. As necessary, transmission-wide and local Area procedures, redispatch, and operating guidelines will be implemented to maintain reliability for the summer. Because Energy Emergency Alerts (EEA) have been issued in the past for the Acadiana Area, the SPP Independent Coordinator of Transmission-Entergy (SPP-ICTE) will continue to monitor this Area closely and implement mitigation plans as necessary as part of its Reliability Coordinator function. A two-phase joint project to construct a 230 kV overlay in the Acadiana load pocket is currently in the construction phase with targeted in-service dates of 2011 and 2012. Overall, there are no other anticipated reliability concerns for the summer.

SERC-W Description

SERC-W (including SPP RC entities registered in SERC) *is a summer-peaking assessment area covering portions of four southeastern states (Arkansas, Louisiana, Mississippi, and Texas) with a population of approximately 34.1 million.*[125] *Owners, operators, and users of the Bulk Power System in these states cover an area of approximately 133,500 square miles. There are ten registered Balancing Authorities in SERC-West (ICTE): Entergy; City of Benton; City of Conway; City of North Little Rock, Arkansas; City of Osceola; City of Ruston, Louisiana; City of West Memphis; Louisiana Generating, LLC; Plum Point Energy Associates, LLC; and Union Power Partners, L.P.*

SERC-W

[125] http://en.wikipedia.org/wiki/List_of_U.S._states_and_territories_by_population

SERC-N

Demand

Projected Total Internal Demand for utilities in SERC-N for the upcoming summer is 46,846 MW. The projected Total Internal Demand is 145 MW (0.3 percent) higher than the actual 2010 summer peak of 46,701 MW. Due to the restructuring of entity reporting footprints for this assessment, the comparisons of demand forecasts are not available for this Area.[126] However, entities report that there are no significant differences between last year's summer demand forecast versus this year's projections. Direct Load Control (DLC) programs for air conditioners and water heaters are captured to contribute to a lower summer peak. However, projections reflect increases in demand due to the improvements of both the U.S. and Regional economies.

The 2011 summer demand forecast is based on normal weather conditions and projected economic data for the Area's population, forecast demographics, employment, energy exports, and gross regional product increases and decreases. Economic data from the national level are also considered. Secondary forecasts are also developed for extreme and mild weather conditions and for optimistic and pessimistic economic scenarios. Forecasts also consider continued economic recovery for both the Region and U.S. economies.

TABLE 100: SERC-N FORECAST AND ACTUAL PEAK DEMAND

2010 Total Internal Demand (MW)	2010 Actual Demand (MW)	Difference in Actual versus Forecast (MW)	Difference in Actual versus Forecast (%)	2011 Total Internal Demand (MW)	Difference in 2011 and 2010 Forecast Demand (MW)	Difference in 2010 Actual versus 2011 Forecast (%)	All-Time Summer Peak Demand (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)
N/A	46,701	-	-	46,846	-	-	-	46,846	-

Utilities in SERC-N perform detailed load sensitivity analyses in their respective operational and planning studies to address projected demand. While utility methodologies vary, common attributes include:

- Use of econometric linear regression models;
- Relationship of historical annual peak demands to key variables such as weather, economic conditions, and demographics;
- Variance of forecasts due to high and low economic scenarios, and mild and severe weather; and
- Development of a suite of forecasts to account for the variables mentioned above, and associated studies using these forecasts.

[126] Reliability Assessment Procedure, Subregional Restructuring to Support ISO/RTO Boundaries.

When appropriate, utilities adhere to their respective state commissions' regulations, any RTO requirements, and internal business practices for determining their forecast and reserve requirements. The internal peak demands of individual entities are aggregated as a non-coincident peak value.

The primary source of current Demand Response for utilities within SERC-N is the DLC program and the interruptible product portfolio. DLC includes a program with interruptible load contracted to, and verified by, a third party, and has companies that have contractually agreed to reduce their loads within minutes of a request. The estimate used in operational planning takes into account the amount of load available and is not a sum of total load under contract. Other Demand Response products that use control devices are also used by entities within the Area on air conditioning units and/or water heaters in residences. Entities are planning for increased demand reductions from these programs. Demand Response can be tracked and verified by the readings of meters. Other entities test summer load-control programs—residential and commercial—for operational functionality each spring and analysis of load profiles allows for verification of demand reduction. Within this assessment area, Demand Response is projected to be 4.1 percent of Total Internal Demand for the upcoming summer. This percentage is projected to reduce peak demand on entity systems.

Energy-efficiency programs such as customer cost-saving energy surveys and audit evaluations, customer education, responsive pricing, residential/commercial conservation, electric thermal storage incentives, new construction (heat pump and geothermal), energy-manufactured homes, air-source heat-pump programs (replacing resistance heat ten years old or more), low-income weatherization, low-income assistance, HVAC system improvements, industrial compressed-air programs, and various advanced lighting and third-party verification and measurement groups are currently in operation within the Area to residential and commercial customers. Commercial/industrial/direct-served industry consumers have programs targeted to focus on efficiency improvements in HVAC, lighting, motors and controls, and other electrical-intensive equipment. For measurement and verification within these programs, entities have reported they may use third-party evaluators to review the performance of all programs on an ongoing basis to assure the programs continue to achieve the projected levels of energy and demand reductions. Some entities have reported that programs must pass a quantitative and a qualitative screening assessment to focus on customer acceptance, reliability, and cost effectiveness. Additional programs are forecast to surface in 2011 and will increase reductions for the upcoming summer months. In March 2011, TVA published a new Integrated Resource Plan that includes a goal of achieving 3.5 percent of sales in energy efficiency savings by 2015.

Entities use a variety of techniques to assess the variability in projected demand due to a variety of conditions such as weather and the economy. One method used to accomplish this is to annually analyze the relationship between seasonal peak loads and temperature at, and leading up to, the time of the peak. Other utilities may use forecasts assuming normal weather, and then develop models for milder conditions based on historical peaks. They would then use demand models to predict variances. These long- and short-term models reflect optimistic and pessimistic conditions that include scenarios including extreme difference in economic and weather conditions.

For the majority of the load in the Area, peak information is developed as a coincident value for the assessment area-wide model, and non-coincident values for each distribution delivery point.

Generation

Capacity within SERC-N is shown below for the following categories of Existing (-Certain, -Other, and Inoperable) and Future (-Planned and -Other) capacity. This capacity is projected to help meet demand during the assessment period. Variable resources are limited within this Area, although there are some purchases sourced from wind that are included in the transfer amount, and a small amount of solar supply that is part of a customer-owned generation buy-back program. The capacity values of wind contracts are usually based on the applicable contract terms. The assumed contribution at the time of the system peak is computed by applying a 12-percent capacity credit factor to the nameplate ratings of the associated wind generators This 12-percent factor is consistent with the credit applied by RTOs to other wind resources in that same geographical Area. There are approximately 150 MW (nameplate) of wind located inside SERC-Central (TVA). The contributions from the customer-owned solar resources are based on the solar insulation values for the TVA Area at the time of the summer peak. TVA is continuing to evaluate these and other renewable resources as part of its integrated resource planning process.

TABLE 101: SERC-N SUMMER CAPACITY BREAKDOWN

Capacity type	Year 2011 (MW)
Existing-Certain	57,610
Nuclear	6,671
Hydro/Pumped Storage	6,685
Coal	28,588
Oil/Gas/Dual Fuel	15,617
Other/Unknown	13
Solar	0
Biomass	17
Wind	20
Existing-Other	621
Existing, Inoperable	71
Future capacity	0

SERC-N anticipates near-normal precipitation for 2011 summer through 2012 spring. Entities anticipate average hydro conditions and sufficient reservoir levels for the upcoming summer. Estimates for this year are consistent with the latest long-term hydro forecast.

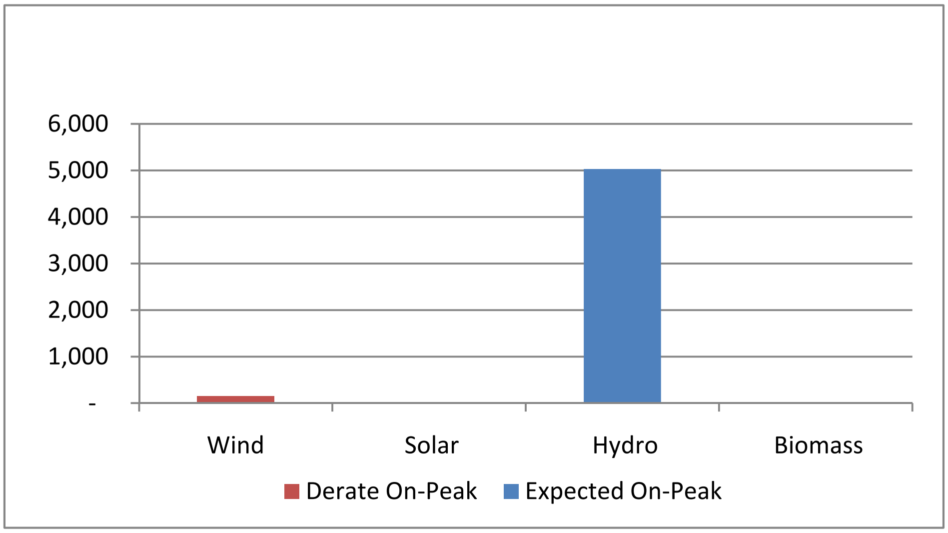
Wolf Creek and Center Hill dams continue to experience operational restrictions. These restrictions have limited the availability of Firm capacity within the Area. However, entities have compensated for this lack of capacity by implementing other purchases in their portfolios for the season. Overall, entities do not anticipate conditions that would reduce capacity.

Although entities do source fuel supply from the Gulf of Mexico, and supply may be impacted during severe weather, the use of storage, (segregated in two storage facilities) shale gas supply, backhauls, and supplier-delivered gas should be sufficient to meet generation needs. Fuel levels for utilities within the assessment area are not a concern for the summer. Emergency procedures are in place to address a variety of issues relating to fuel supply or extreme weather.

TABLE 102: SERC-N EXISTING AND PLANNED PEAK CAPACITY

Existing-Certain (MW)	57,610
Existing-Other (MW)	621
Future-Planned (MW)	-

FIGURE 39: SERC-N EXISTING AND PLANNED RENEWABLE GENERATION



As usual, the majority of the generating units are scheduled to be in service during the 2011 summer with essentially no planned or maintenance outages from mid-June through late September. Any outages are accounted for in capacity planning and generation planning with no impact to overall reliability. Entities have the ability to make purchases from the short-term markets as necessary.

TABLE 103: SERC-N EXISTING AND PLANNED RENEWABLE GENERATION

Wind Expected On-Peak	20
Wind Derate On-Peak	132
Wind Nameplate/Installed Capacity	152
Solar Expected On-Peak	-
Solar Derate On-Peak	-
Solar Nameplate/Installed Capacity	-
Hydro Expected On-Peak	5,032
Hydro Derate On-Peak	-
Hydro Nameplate/Installed Capacity	5,032
Biomass Expected On-Peak	17
Biomass Derate On-Peak	-
Biomass Nameplate/Installed	17

SERC-N

Capacity Transactions

Utilities within SERC-N have reported the following imports and exports for the 2011 summer. The majority of these imports/exports are backed by Firm contracts and Firm transmission contracts, and do not include "make-whole provisions" or are backed by Firm generation contracts. Although not reported, import assumptions are not based on partial path reservations. These imports have been included in the aggregate Reserve Margin for utilities in the Area.

Table 104: SERC-N Imports and Exports On-Peak

Imports (MW)	1,862
Firm (MW)	1,862
Expected (MW)	-
Exports (MW)	1,435
Firm (MW)	1,435
Expected (MW)	-
Net Imports (MW)	**427**

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 TVA-East Kentucky Power Cooperative-E.ON (or TEE) Contingency Reserve Sharing Group (TCRSG). The TCRSG consists of three Balancing Authorities that are internal to the Area and is intended to provide an immediate response to contingencies. This enables the group to comply with DCS standards and assist in preventing the curtailment of native load. Even though some entities rely on internal/external resources for imports, there are some companies within the Area that do not depend on short-term outside purchases or transfers from other Regions or assessment areas to meet demand requirements. Total emergency MWs from these imports were not reported, but are available as needed.

Transmission

Table 105 shows new Bulk Power System transmission facilities (transmission lines, transformers, substation equipment) completed since last summer that are projected to be in service for the upcoming summer. Entities do not anticipate any significant reliability concerns associated with project in-service date adjustments. Additionally, there are no significant facilities anticipated being out of service during the 2011 summer.

TABLE 105: SERC-N PROJECTED TRANSMISSION

Transmission Project Name	Transmission Type	In-service Date	Operating Voltage (kV)
Higby Mill-West Lexington 1	Complete	05/30/10	138
Rutherford-Almaville 1	Complete	06/01/10	161
Camp Clark-Hyder Hill 1	Complete	06/02/10	161
Camp Clark-Lamar 1	Complete	06/02/10	161
Edmonson-Gravois 1	Complete	06/02/10	161
Hyder Hill-Stockton (AEC) 1	Complete	06/02/10	161
Marion Tap-Spalding 1	Complete	06/02/10	161
North Warsaw-Edmonson 1	Complete	06/02/10	161
Stockton-Morgan 1	Complete	06/02/10	161
Mill Creek-Hardin County 1	Complete	06/30/10	345
Rutherford-Christiana 1	Complete	10/19/10	161
Fredericktown-Wedeken Tap Sec. 1 1	Complete	11/02/10	161
Fredricktown-Fredricktown (UE) 1	Complete	11/02/10	161
Resaca N.-Moss Lake 1	Complete	12/01/10	115
Resaca N.-Moss Lake 1	Complete	12/01/10	230
Gallatin-Lascassas 1	Complete	12/16/10	161
Gallatin-Lebanon 1	Complete	12/16/10	161
Lebanon-Lascassas 1	Complete	12/16/10	161
Long Lane-Phillipsburg 1	Complete	12/31/10	100
Middletown-Collins 1	Complete	01/12/11	138
Chouteau Plant-Sportsman Acres 1	Complete	02/02/11	161
GRDA-Sportsman Acres 1	Complete	02/02/11	345
Apache Flats-Scruggs 1	Planned	06/02/11	161
Rolla (South)-Yancy Mills 1	Planned	06/02/11	100
Willow Springs-Summersville East 1	Planned	06/02/11	161

TABLE 106: SERC-N TRANSFORMER ADDITIONS

Transformer project name	High-side voltage (kV)	Low-side voltage (kV)	In-service date	Status/Description
Bull Run	500	161	05/28/10	Complete – Install a single phase 500-161-26.4-13.2 kV to replace failed transformer
Sportsman Acres	345	161	06/01/10	Complete – Transformer #1
Sportsman Acres	345	161	06/01/10	Complete – Transformer #2
Rutherford, Tennessee	500	161	10/19/10	Complete – Install four, single phase 500-161 kV transformers
Moss Lake, Georgia	230	115	11/18/10	Complete – Install a three-phase 230-115-13 kV autotransformer
Guntersville, Alabama	161	115	03/31/11	Under Construction – Retire six, single phase 154-115-11.5 kV transformers
Guntersville, Alabama	161	115	03/31/11	Under Construction – Install four, single phase 161-115-11.5 kV transformers
West Ringgold, Georgia	230	115	06/01/11	Under Construction – Install three phase 230-115-26 kV transformer
Jackson, Tennessee	500	161	06/01/11	Under Construction – Install three, single phase 500-161 kV transformers

Entity responses show no indications of transmission constraints that will lead to reliability concerns for the upcoming summer. System conditions may at times dictate local Area generation re-dispatch or reconfiguration of transmission elements to alleviate anticipated next-contingency overloads. NERC TLR procedures are commonly invoked in scenarios that are not easily remedied by a local Area solution. Entities will continue to evaluate the transmission system to identify any future constraints and mitigate concerns that could significantly impact reliability in the future. Interregional transmission transfer capabilities for the upcoming summer are being developed, but the summer peak simultaneous value is estimated at approximately 1,800 MW.

Operational Issues

Many entities within the Area perform routine operating studies (biannual load forecast studies; monthly, weekly, and daily operational planning efforts; annual assessments of summer peak and temperature; etc.) to assess the system. These studies take into consideration weather, demand, and unit availability. This helps to address any inadequacies and mitigate their risks. Based on the results of these studies, entities do not anticipate operational problems.

TABLE 107: SERC-N DEMAND RESPONSE AND ENERGY EFFICIENCY ON-PEAK

Non-Dispatchable DSM (MW)	122
Energy Efficiency	122
Non-Controllable Demand-Side Demand Response	-
Total Internal Demand	46,846
Controllable, Dispatchable Demand Response	1,915
Net Internal Demand	44,931

The majority of the entities have not included variable resources as Firm capacity on their systems, with the exception of TVA, which has contracted for up to 1,600 MW of wind power Entities are not anticipating operational changes or concerns due to integration of variable resource contracts for the summer assessment period. In addition, there are limited concerns resulting from minimum demand and/or over-generation. However, some entities have reported that if minimum demand occurs in the MISO, entities will be required to take units off-line during minimum generation events. They will continue to look at the minimum conforming load and the minimum generation for the units on line. Net scheduled interchanges, plus the minimum on all the generators, are assessed to see if adjustments can be made to address minimum load conditions. System operators around the Area have the authority to take units off line during real-time conditions to address minimum generation issues as needed.

Due to limited Demand Response within the Area, reliability concerns associated with Demand Response resources are not a concern for this summer. There are no environmental or regulatory restrictions, or other unusual operating conditions anticipated that would impact reliability.

Reliability Assessment

There are generally three methods used for resource adequacy assessment among the utilities in SERC-Central (TVA):

- **Deterministic** — A stated, deterministic minimum-reserve guideline. In some cases, the reserve guideline is derived explicitly from other measures, such as operating-reserve requirements, load-forecast uncertainty, or largest single contingency.
- **Probabilistic** — A stated probabilistic guideline, which is usually translated into an equivalent minimum-reserve guideline for use in long-range planning studies.
- **Economic** — An economically optimized probabilistic guideline, which is translated into an equivalent minimum-reserve guideline.

The existing, anticipated, and prospective summer-peak Reserve Margins (as reported in February 2011) for utilities in SERC-Central (TVA), are projected to be 28.0 percent for all margin categories. Entities within this Area do not adhere to any regional assessment area targets or Reserve Margin criteria. However, some individual entity criteria are established based on the Balancing Authority's criteria, such as most severe single contingency, cost of unserved energy, unit availability, import availability/capability, load forecast, and loss-of-load probability studies (such as one day in ten years). Other utilities report that planning Reserve Margins are established with the objective of minimizing overall cost of reliability to the customer, while not exposing customers to significant risk. To achieve this goal, planning reserves are calculated on a probabilistic assessment of reliability under uncertainty, which includes uncertainty related to weather, economic growth, unit availability, transmission capability, and other drivers, to determine forecast reliability costs at various levels of reliability. Using this analysis as a basis, a target level of planning reserves is selected such that the cost of additional reserves plus the cost of reliability events to the customer is minimized. This target (optimal) Reserve Margin is then adjusted to reduce risks and enhance reliability beyond minimum levels to produce the final levels of planning reserves that are used for study purposes. Entity results show that they are planning for reserves in the range of 12 to 15 percent for the upcoming summer. Entities continue to implement new study capabilities and detailed probabilistic assessments into their annual planning processes.

TABLE 108: SERC-N ON-PEAK CAPACITY RESOURCES AND RESERVE MARGINS

	2011 Summer Forecast (MW)	2011 Summer Forecast (%)
Existing-Certain and Net Firm Transactions (with Demand Response)	59,952	28.0%
Anticipated Capacity Resources	59,952	28.0%
Prospective Capacity Resources	59,952	28.0%
NERC Reference Margin Level	**7,027**	**15.0%**

Projected Reserve Margins cannot be compared to last summer, as this is the first year the new SERC-N data are being reported. However, entities within the new assessment area note that margins remain high due to lower peak demand last year and projections of current customer demand and available resources for the upcoming summer. In 2010 summer, non-projected thermal derates and other outages occasionally caused the actual reserves to fall below the planning target.

SERC-N

These reductions in available capacity on-peak were driven primarily by weather (unusually high river temperatures limiting once-through cooling systems). Entities are taking steps to minimize the potential for these types of derates in the upcoming summer.

In order to ensure fuel delivery, the practice of having a diverse portfolio of suppliers is common within the assessment area. Entity fuel departments typically monitor supply conditions on a daily basis through review of receipts and coal burns, and interact daily with both coal and transportation suppliers to review situations and foreseeable interruptions. Any identifiable interruptions are assessed with regard to current and desired inventory levels. By purchasing from different regions, coal is projected to move upstream or downstream to various plants. Some plants have the ability to re-route deliveries among themselves. Some stations having coal delivered by rail can also use trucks to supplement deliveries. Utilities have reported that they maintain fuel reserve targets greater than 30 days of on-site coal inventory. Fuel supplies are reported to be adequate and readily available for the upcoming summer. Multiple contracts are in place for local coal from Area mines. In the event of a potential supply or transportation disruption, entity processes allow the engagement of stakeholders. Coal and gas service plans are provided to manage the situation. Planned unit maintenance outages or derates may be delayed or cancelled.

Dynamics and static reactive power studies are also upheld by utilities on an individual basis. Some utilities follow the procedure of making sure the steady-state operating point is at least five percent below the voltage collapse point at all times to maintain voltage stability. Studies are performed on peak cases to verify system stability margins. Other utilities follow guidelines to ensure that voltage stability will be maintained via Q-V assessment. P-V analysis for certain Areas of the system is also performed to monitor reliability. These studies have identified some potential localized voltage stability concerns. Entities are in the process of developing a voltage stability limit for the interface of concern. Other entities report that no static reactive power-limited Areas on the Bulk Power System were found. Operating guides are in place that address existing issues found in previous studies.

Other Area-Specific Issues

Entities continue to minimize reliability concerns through ongoing operational planning and longer-term planning processes. Industry events are also monitored for potential lessons learned.

SERC-N Description

SERC-N is a summer-peaking assessment area covering portions of five southeastern states (Tennessee, Alabama, Georgia, Kentucky, and Mississippi.) with a population of approximately 27.6 million.[127] *Owners, operators, and users of the Bulk Power System in these states cover an area of approximately 101,000 square miles. There are six Balancing Authorities in SERC-Central (TVA): Associated Electric Cooperative, Inc.; Batesville Balancing Authority; East Kentucky Power Cooperative; Electric Energy, Inc.; LG&E and KU Services Company as agent for Louisville Gas and Electric Company and Kentucky Utilities Company; and Tennessee Valley Authority.*

[127] http://en.wikipedia.org/wiki/List_of_U.S._states_and_territories_by_population

SERC-E

Demand

The sum of the Total Internal Demands of the utilities in SERC-E (excluding utilities that are within the PJM assessment area) for 2011 summer is forecast to be 43,249 MW and is based on normal weather conditions. This is 437 MW (1.0 percent) higher than the actual 2010 summer peak demand of 42,812 MW. Due to the restructuring of entity reporting footprints for this assessment, the comparisons of demand forecasts with previous years are not available for this Area; however, entities are predicting insignificant differences in their forecasts. Additionally, short-term growth projections have been adjusted to the current economic assumptions throughout the service Area.

TABLE 109: SERC-E FORECAST AND ACTUAL PEAK DEMAND

2010 Total Internal Demand (MW)	2010 Actual Demand (MW)	Difference in Actual versus Forecast (MW)	Difference in Actual versus Forecast (%)	2011 Total Internal Demand (MW)	Difference in 2011 and 2010 Forecast Demand (MW)	Difference in 2010 Actual versus 2011 Forecast (%)	All-Time Summer Peak Demand (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)
N/A	42,812	-	-	43,249	-	-	-	43,249	-

Entities in the Area continue to use a variety of methods to predict load. These may include regressing demographics, specific historical weather and demand assumptions, or the use of a Monte Carlo simulation using multiple years of historical weather. Vendors such as Economy.com and IHS Global Insight were used for economic projections, and weather projections were taken from various sources such as the National Oceanic and Atmospheric Administration or individual company databases. Estimated demand and energy savings from future energy efficiency and Demand Response programs are also accounted for in the forecast, as well as rate increase impacts and potential carbon legislation impacts. Overall, assumptions for this period reflect modest demand declines in the long term relative to historic levels.

Utilities in SERC-E perform detailed extreme weather and load sensitivity analyses in their respective operational and planning studies to address projected demand. While utility methodologies vary, common attributes include:

- Use of econometric linear regression models;
- Relationship of historical annual peak demands to key variables such as weather, economic conditions, and demographics;
- Variance of forecasts due to high and low economic scenarios, and mild and severe weather; and
- Development of a suite of forecasts to account for the variables mentioned above, and associated studies using these forecasts.

In addition, many utilities in the assessment area use sophisticated, industry-accepted methodologies to evaluate load sensitivities in the development of load forecasts. When appropriate, utilities adhere to their respective state commissions' regulations, any RTO requirements, and internal business practices for determining their forecast and reserve requirements. The internal peak demands of individual entities are aggregated as a non-coincident peak value.

A variety of programs that support energy efficiency and Demand Response are offered to customers in this assessment area. Some of the programs are current energy-efficiency and Demand-Side management programs that include interruptible capacity, load control curtailing programs, residential air conditioning direct loads, energy products loan programs, standby generator controls, residential time-of-use, Demand Response programs (interruptible and related rate structures), Power Manager Power Share conservation programs,[128] residential Energy Star rates, Good Cents new home programs, commercial Good Cents programs, thermal storage cooling programs, H_20 Advantage water heater programs, general service and industrial time-of-use, and hourly pricing for incremental load interruptible. These programs are used to reduce the affects of summer peaks and are considered part of the utilities' resource planning. The commitments to these programs are part of a long-term, balanced, energy strategy to meet future energy needs. Load response will be measured by trending real-time load data from telemetry and statistical models that identify the difference between the actual use and the projected use absent the curtailment event.

Demand Response is projected to be 7.1 percent of Total Internal Demand. This percentage is projected to reduce peak demand on entity systems within the Area.

Measurements and verification for interruptible Demand Response programs for larger customers are conducted on a customer-by-customer basis. These include an annual review of customer information and Firm load requirements. Compliance is determined by a review of customer load data as related to the terms and conditions of the electric rate schedule.

To assess demand variability, various assumptions are used to create forecasts. These assumptions are developed using economic models, historical weather (normal/extreme) conditions, energy use, and demographics. Entities continue to evaluate the inputs used in this process and track the actual parameters with forecast predictions. Forecasts are based on an assessment of historical events that occurred over the previous ten years as well as assumptions regarding the future. These assumptions relate to key factors known to influence energy use and peak demand (*i.e.,* economic activity, price of electricity, weather conditions, and local Area demographics). Non-weather sensitive industrial energy forecasts may be developed subjectively based on historical trends and information provided by individual industrial customers. Projections of peak demand are developed for the summer season and are based on equations that incorporate total energy requirements and long-term peak demand. In addition to the peak-demand base-case forecast, high- and low-range scenarios are developed to address uncertainties regarding future and extreme weather conditions.

[128] www.duke-energy.com

Simulations for both energy and peak demand address the uncertainty associated with those factors and are included in econometric models. Results from the simulations are used to produce probabilistic high- and low-range forecasts. Model inputs include probability distributions of total personal income, heating and cooling degree-days, and peak-day average temperatures. No major changes have been made to reflect the economic downturn. Outputs for each year of the forecast period include energy and peak demand distributions including projections from zero- to 100-percent probability levels in increments of five percent. The high- and low-range forecasts are represented by the fifth and 95th percentiles. Results provide peak demand estimates for given temperatures and the probabilities that peak demand will rise or fall to specific levels around the base-case forecast. Daily load forecasts may be prepared by using software such as Neural Electric Load Forecaster (NELF), which takes into account daily temperature forecasts for service Areas. Daily load forecasts are used to perform next-day studies and daily switching studies.

Representations of historical peak demand data within the models are modified to reflect the various scenarios of extreme summer and winter conditions in the future.

Generation

Companies within SERC-E expect to have the aggregate capacity on-peak listed in Table 110. This capacity is projected to meet demand during this time period. Entities within the Area include renewables in their portfolio to meet the requirements of the Renewable Energy and Energy Efficiency Portfolio Standard (REPS) of North Carolina. Under this standard, investor-owned utilities in North Carolina will be required to meet up to 12.5 percent of their energy needs through renewable energy resources or energy-efficiency measures. Rural electric cooperatives and municipal electric suppliers are subject to a ten-percent REPS requirement.[129] Variable resources are assessed for their availability to meet the needs of customers reliably and economically, based on the requirements of the standard and maintaining the flexibility to make long-term resource decisions. No companies in this subarea have reported any wind capacity for the 2011 summer.

Table 110: SERC-E Summer Capacity Breakdown

Capacity Type	Year 2011 (MW)
Existing-Certain	49,768
Nuclear	11,452
Hydro/Pumped Storage	6,160
Coal	19,188
Oil/Gas/Dual Fuel	12,847
Other/Unknown	100
Solar	0
Biomass	21
Wind	0
Existing-Other	2
Existing, Inoperable	113
Future capacity	635

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

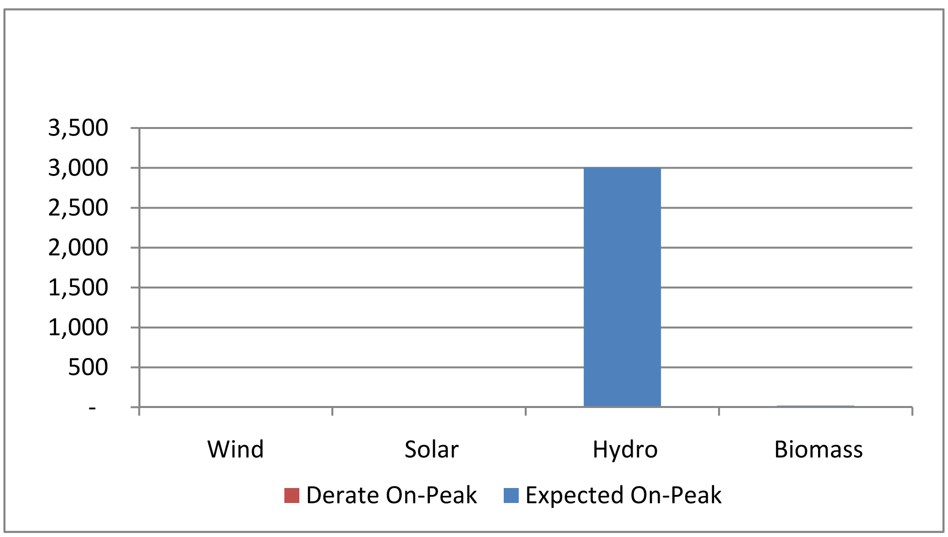
Rainfall conditions within SERC-E have deteriorated throughout the 2010/2011 winter from previous conditions. The seasonal drought outlook for the Southeast U.S., summarized from information provided by the Southeast Regional Climate Center,[130] projects a warning for likely drought development across the coastal region of the Carolinas through 2011 spring. Similarly, drought conditions are forecast to persist or intensify in the Piedmont regions of North and South Carolina. While reservoir levels are currently adequate, reduced inflows from the western watershed may impact hydroelectric operations in the fall and winter. However, entities are anticipating reservoir levels to be sufficient to meet peak demand and daily energy demand throughout the forecast summer season if normal rainfall occurs.

TABLE 111: SERC-E EXISTING AND PLANNED PEAK CAPACITY

Existing-Certain (MW)	49,768
Existing-Other (MW)	2
Future-Planned (MW)	635

There are no known or projected significant conditions or generator outages that would reduce capacity in the Area. Therefore, no peak capacity reductions are projected for the summer season.

FIGURE 40: SERC-E EXISTING AND PLANNED RENEWABLE GENERATION



[130] http://www.sercc.com/

TABLE 112: SERC-E EXISTING AND PLANNED RENEWABLE GENERATION

Wind Expected On-Peak	-
Wind Derate On-Peak	-
Wind Nameplate/Installed Capacity	-
Solar Expected On-Peak	-
Solar Derate On-Peak	-
Solar Nameplate/Installed Capacity	-
Hydro Expected On-Peak	3,006
Hydro Derate On-Peak	-
Hydro Nameplate/Installed Capacity	3,006
Biomass Expected On-Peak	21
Biomass Derate On-Peak	-
Biomass Nameplate/Installed	21

Capacity Transactions

Utilities within SERC-E reported the imports and exports listed below for the upcoming summer season. These transactions include both external and internal transactions 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. Of the imports/exports below, very few are associated with LDC (approximately 311 MW) in which the contracts are considered 100-percent "make-whole."

To meet Reserve Margins during the period, SERC-E entities do not rely on resources outside the Region for emergency imports, reserve sharing, or outside assistance/external resources. Most entities within this Area participate in reserve sharing agreements (RSA) with other 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. The Reserve Sharing Group is projected to have adequate reserves throughout the 2011 summer operating period.

TABLE 113: SERC-E IMPORTS AND EXPORTS ON-PEAK

Imports (MW)	1,586
Firm (MW)	1,586
Expected (MW)	-
Exports (MW)	-
Firm (MW)	-
Expected (MW)	-
Net Imports (MW)	**1,586**

Transmission

Table 114 and Table 115 below show that several improvements to transmission facilities (transmission lines and transformers) have been completed or are planned to be completed by this summer. No significant substation equipment is anticipated to be placed in service prior to the 2011 summer.

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Table 114: SERC-E Forecast Transmission

Transmission project name	Transmission type	In-service date	Operating voltage (kV)
Piercetown-Plainview Ret 1	Complete	07/01/10	100
Asheville-Enka 1	Complete	12/01/10	230
Denny Terrace-Pineland 1	Under Construction	05/01/11	230
Robert Bosch Tap-Robert Bosch 1	Planned	05/30/11	115
Pepperhill-Robert Bosch 1	Under Construction	05/30/11	115
Pleasant Garden (Duke)-Asheboro (Progress) 1	Under Construction	06/01/11	230
Rockingham-West End 2	Under Construction	06/01/11	230
Asheboro-Pleasant Garden 1	Under Construction	06/01/11	230
Richmond-Ft. Bragg Woodruff St 1	Under Construction	06/01/11	230

Table 115: SERC-E Transformer Additions

Transformer project name	High-side voltage (kV)	Low-side voltage (kV)	In-service date	Description/Status
Enka 230 kV substation	230	115	12/01/10	Complete – Install 1-300 MVA 230/115 kV transformer at existing 115 kV substation
Ritter 230/115kV	230	115	05/01/11	Under Construction – Addition of 336MVA Substation
Asheboro 230 kV Transformer	230	115	02/18/11	Complete – Replace two existing 200 MVA Transformers with 300 MVA transformers.

Delays with the above in-service dates have not been identified as a risk. If delays occur that would result in reliability concerns, mitigating actions would be developed accordingly. Mitigating measures can include re-dispatch of generation, operating procedures, and Special Protection Schemes. On an ongoing basis, companies review/confirm completion dates and monitor the construction status of all projects. Transmission projects planned to address a potential SOL or IROL issue commonly receive the highest priority for resources. New construction efforts are focused on completing facilities ahead of seasonal peak periods. Close coordination between construction management and operations planning ensures schedule requirements and completion requirements are well understood. Several large-scale construction projects are planned and will be implemented in phases around seasonal peak load periods to mitigate reliability concerns associated with line clearances and non-routine operating arrangements during higher seasonal load periods. Additionally, no significant transmission facility outages are anticipated to be out of service during the summer months.

No significant summer transmission constraints have been identified for the assessment period. Regional studies are performed on a routine basis internally and externally. Coordinated single transfer capability studies with external utilities are performed quarterly through the SERC NTSG. Projected seasonal import and export capabilities are consistent with those identified in this assessment. Constraints external to the SERC assessment areas are evaluated as part of the SERC East-RFC seasonal study group efforts. There are no anticipated transmission constraints identified that significantly impact reliability. The interregional transmission transfer capabilities are not currently available, in part due to the recent decision to report as a new Area.

Operational Issues

Entities did not specify a need to perform special operating studies for the summer. No operational problems or constraints are anticipated during the assessment period. 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.

TABLE 116: SERC-E DEMAND RESPONSE AND ENERGY EFFICIENCY ON-PEAK

Non-Dispatchable DSM (MW)	247
Energy Efficiency	247
Non-Controllable Demand-Side Demand Response	-
Total Internal Demand	43,249
Controllable, Dispatchable Demand Response	1,687
Net Internal Demand	41,562

Since amounts of both distributed and variable generation are limited in the Area and entities hold a diverse amount of resources, special operating procedures are not needed for the integration of variable resources or minimum demand over-generation. There are no identified concerns with meeting peak demands by calling on Demand Response resources, although entities do have restrictions on the number of times that emergency Demand Response actions can be employed and are readily available as needed.

There are no environmental or regulatory restrictions projected within the assessment area. 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.

Loop and parallel flows imposed by neighboring BAs have the potential to create contingency overloads; however, procedures and agreements are in place to effectively manage flows on the system. Overall, there are no unusual operating conditions anticipated that could affect reliability for the summer.

Reliability Assessment

There are generally three methods used for resource adequacy assessment among the utilities in SERC-East (VACS):

- **Deterministic** — A stated, deterministic minimum-reserve guideline. In some cases, the reserve guideline is derived explicitly from other measures, such as operating-reserve requirements, load-forecast uncertainty, or largest single contingency.
- **Probabilistic** — A stated probabilistic guideline, which is usually translated into an equivalent minimum-reserve guideline for use in long-range planning studies.
- **Economic** — An economically optimized probabilistic guideline, which is translated into an equivalent minimum-reserve guideline.

The projected existing, anticipated, and prospective summer-peak Reserve Margins (as reported in February 2011) for utilities in SERC-E are projected to be 22.6, 24.1, and 24.1 percent respectively. Utilities within this Area do not adhere to any Regional assessment area targets or Reserve Margin criteria.

However, some utilities adhere to North Carolina Utilities Commission regulations. Other utilities established individual target margin levels to benchmark margins that will meet the needs for peak demand. Assumptions used to establish the individual utilities' reserve/target margin criteria or resource adequacy levels are based on prevailing expectations of reasonable lead times for the development of new generation, procurement of purchased capacity, siting of transmission facilities, and other historical experiences that are sufficient to provide reliable power supplies. Other assumptions include levels of potential DSM activations, scheduled maintenance, environmental retrofit equipment, environmental compliance requirements, purchased power availability, and peak-demand transmission capability/availability. Risks that would have negative impacts on reliability are also an important part of the process to establish assumptions. Some of these risks would include the deteriorating age of existing facilities on the system, significant amount of renewables, increases in energy-efficiency/DSM programs, extended base-load capacity lead times (*e.g.,* coal and nuclear), environmental pressures, and derating of units caused by extreme hot weather/drought conditions. In order to address these concerns, companies continue to monitor these risks in the future and make any necessary adjustments to the Reserve Margin target in future plans.

TABLE 117: SERC-E ON-PEAK CAPACITY RESOURCES AND RESERVE MARGINS

	2011 Summer Forecast (MW)	2011 Summer Forecast (%)
Existing-Certain and Net Firm Transactions (with Demand Response)	53,041	22.6%
Anticipated Capacity Resources	53,676	24.1%
Prospective Capacity Resources	53,676	24.1%
NERC Reference Margin Level	**6,487**	**15.0%**

Resource adequacy studies also help to determine entity Reserve Margins. The study recognizes, among other factors such as load forecast, uncertainty due to economics and weather, generator unavailability, deliverability of resources to load, and the benefit of interconnection with neighboring systems. Uncertainties may also be addressed through capacity margin objectives and practices in other resource assessments at the operational level. These studies may be performed annually using inputs provided from generator operators. As conditions warrant, entities may see the need to perform additional assessments to mitigate challenging conditions on the system. Entities report that the latest studies project Reserve Margins to be in the range of 17 to 25 percent based on the current forecast, generation, and Demand-Side resources. Overall, operational problems are not anticipated for the summer.

The projected aggregate Reserve Margin for entities within the Area is 24.1 percent, which cannot be compared to last summer's projections due to the restructuring of SERC-East (VACS).

However, entities in the Area responded that changes are insignificant to last year's reporting. Margins for the upcoming season continue to be based on load reductions due to the economy, increased DSM, significant increases in generation, and mild weather. It is anticipated that capacity in the Area should be adequate to supply forecast demand.

Fuel supply or delivery problems are not anticipated for the period. Utilities maintain enough diesel fuel to run the generation units for an order-cycle of fuel. Firm gas supply and transportation contracts are monitored to align with inventory levels of coal and oil supplies, natural gas storage, and generation capacity margins. Entities have ongoing communication with commodity and transportation suppliers to transmit near- and long-term fuel requirements. These communications take into account market trends, potential resource constraints, and historical and projected demands. Regular discussions are framed to ensure potential interruptions can be mitigated and addressed in a timely manner.

Exchange agreements, alternative fuel, or redundant fuel supplies may also be used to mitigate emergencies in the fuel industry or economic scenarios. On-site fuel oil inventory allows for seven-day operations on some units. This was considered to be ample time to coordinate with the industry to obtain adequate supplies. Contracts are in place for months, and often years, into the future. Vendor performance is closely monitored and potential problems are addressed long before issues become critical. Contracts and market positions are considered to be diverse enough to mitigate any supply or delivery issues as they occur.

Static reactive power and dynamics assessments are performed and produced on an individual company basis within SERC-East (VACS). Most entities participate in the SERC Dynamics Study Group to assess annual dynamic conditions on the system. The majority of the studies for the upcoming season do not show any issues that will impact reliability. However, a study was done on the eastern North Carolina coastal Area (Jacksonville/Havelock/Morehead City) that resulted in a long-term project to install a large static VAR compensator at the Jacksonville 230 kV substation. Similarly, another dynamic study was recently performed in the western Area of North Carolina, which validated the existing procedure to operate a minimum complement of generators at various load/import levels to ensure adequate dynamic reactive resources are available for this Area.

Other Area-Specific Issues

To minimize reliability concerns on the system, entities regularly study and review annual and seasonal assessments. These assessments serve to develop a seasonal strategy for maintaining adequate system operating performance. Entities are also active participants within the SERC NTSG, which performs annual reliability studies for summer and winter peak conditions as well as quarterly OASIS studies for summer, fall, winter, and spring conditions. No unique operational problems were observed for the 2011 summer.

Transmission maintenance schedules are carefully reviewed and evaluated to insure reliability concerns are addressed, and to permit as much prioritized maintenance as can be accommodated prior to seasonal peak periods.

Likewise, new construction efforts are focused on completing facilities ahead of seasonal-peak periods. Annual planning activities continue to address both near- and long-term facility needs.

Area Description

SERC-E is a summer-peaking assessment area covering portions of two southeastern states (North Carolina and South Carolina) with a population of approximately 13.9 million.[131] *Owners, operators, and users of the Bulk Power System in these states cover an area of approximately 58,900 square miles. There are five Balancing Authorities in SERC-East (VACS): Alcoa Power Generating, Inc – Yadkin Division; Duke Energy Carolinas; Progress Energy Carolinas; South Carolina Electric & Gas Company; and South Carolina Public Service Authority.*

131 http://en.wikipedia.org/wiki/List_of_U.S._states_and_territories_by_population

SERC-SE

Demand

Total aggregate internal demand for utilities in SERC-SE for the 2011 summer season is forecast to be 49,314 MW, based on economic and normal weather conditions as determined by historical system-average weather. This is 204 MW (0.4 percent) lower than the actual 2010 summer peak demand of 49,518 MW. Due to the restructuring of entity reporting footprints for this assessment, the comparisons of demand forecast are not available for this Area. However, SERC-SE entities report that growth rates for the upcoming summer are projected to decrease in the short term due to the effects of the economy.

TABLE 118: SERC-SE FORECAST AND ACTUAL PEAK DEMAND

2010 Total Internal Demand (MW)	2010 Actual Demand (MW)	Difference in Actual versus Forecast (MW)	Difference in Actual versus Forecast (%)	2011 Total Internal Demand (MW)	Difference in 2011 and 2010 Forecast Demand (MW)	Difference in 2010 Actual versus 2011 Forecast (%)	All-Time Summer Peak Demand (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)
N/A	49,518	-	-	49,314	-	-	-	49,314	-

The entities in SERC-SE continue to use a variety of methods to predict load. These may include regressing demographics, specific historical weather and demand assumptions, or the use of a Monte Carlo simulation using multiple years' of historical weather. Vendors such as Economy.com and IHS Global Insight were used for economic projections, while weather projections were taken from various sources such as the National Oceanic and Atmospheric Administration or individual company databases. Estimated demand and energy savings from future energy efficiency and Demand Response programs are also accounted for in the forecast, as well as rate increase impacts and potential carbon legislation impacts. Overall, assumptions for this period reflect modest declines in the long term relative to historic levels.

The utilities in SERC-SE perform detailed extreme weather and load sensitivity analyses in their respective operational and planning studies to address projected demand. While utility methodologies vary, common attributes include:

- Use of econometric linear regression models;
- Relationship of historical annual peak demands to key variables such as weather, economic conditions, and demographics;
- Variance of forecasts due to high and low economic scenarios, and mild and severe weather; and
- Development of a suite of forecasts to account for the variables mentioned above, and associated studies using these forecasts.

In addition, many utilities in the assessment area use sophisticated, industry-accepted methodologies to evaluate load sensitivities in the development of load forecasts. When appropriate, utilities adhere to their respective state commissions' regulations, any RTO requirements, and internal business practices for determining their forecast and reserve requirements. The internal peak demands of individual entities are aggregated as a non-coincident peak value.

Demand Response programs within the Area consist of programs ranging from customer stand-by generation, real-time and critical-peak pricing (reducing energy use based on price signaling), and interruptible demand programs (requesting customers to reduce energy use) to direct load control programs (energy provider curtailing customer energy use). These programs allow entities within the assessment area to have better ability to control various amounts of load when needed for reliability purposes.

One example of a Demand Response program is the H_2O Plus program, which uses the storage capacity of electric water heaters. This program allows SERC-SE entities to install load control devices that can be activated during peak periods, which results in the following benefits:

- Helps reduce the need to build or purchase capacity.
- Responds to volatile wholesale energy markets.
- Improves the efficiency (load factor) as well as the use of generation, transmission, and distribution systems.
- Provides low-cost energy to member cooperatives.
- Increases off-peak kWh sales.

A total of 6,520 load control devices are projected to be installed by the end of June 2011 with a total of 7,519 projected on being installed by December 2011. Each water heater has a peak reduction capability of 1.2 kW in the winter and 0.5 kW in the summer.Demand Response is projected to be 4.0 percent of Total Internal Demand.

Various utilities in SERC-SE have residential energy-efficiency programs[132] that may include educational presentations, home energy audits, home inspector programs, compact fluorescent light bulbs, electric water heater incentives, heat pump incentives, energy-efficient new-home programs, Energy Star-rated appliance promotions, appliance recycling programs, loans or financing options/incentives, weatherization, programmable thermostats, and ceiling insulation. Commercial programs include energy audits, lighting programs, and plan review services.

Other programs such as business assistance/audits, weatherization assistance for low-income customers, residential energy audits, and comfort advantage energy-efficient home programs promote reduced energy use, supply information, and develop energy-efficiency presentations for various customers and organizations. SERC-SE utilities are also beginning to work with states' energy divisions on energy-efficiency planning efforts.

[132] http://www.southerncompany.com/corporateresponsibility/electricity/championing.aspx

Training seminars addressing energy efficiency, HVAC sizing, and energy-related end-use technologies are also offered to educate customers.

To address measurement and verification of energy-efficiency and DSM programs, SERC-SE entities may use third parties to conduct impact/process evaluations for commercial programs, or they may use load response statistical models to identify the difference between the actual use and the projected use absent the curtailment event. Response may also be tracked and verified by the readings of meters, as well as testing residential and commercial summer load-control programs for verification of demand reduction through generation dispatch personnel. Evaluations may be conducted annually with a comprehensive report due at the end of a program cycle. Reports are projected to determine annual energy savings and portfolio cost-effectiveness.

To assess variability, some SERC-SE utilities develop forecasts using econometric assessment based on approximately 40-year (normal, extreme, and mild) weather, economics, and demographics. Other SERC-SE entities use the assessment of historical peaks, Reserve Margins, and demand models to predict variance (optimistic and pessimistic scenarios). The economic downturn is captured within this process mainly through the reduction of load. Mild and extreme weather predictions are also captured through the collection of extreme historical weather data factored into demand models.

Generation

Utilities within SERC-SE expect to have the aggregate capacity listed below on peak to help meet demand during this time period. Below are the Existing (-Certain, -Other, and Inoperable) and Future (-Planned and -Other) resources in the Area. Variable resources (*i.e.,* wind and solar) are limited within this assessment area and are evaluated by analyzing their historical or projected output profiles. The result is a determination of the comparative capacity value to that of a typical combustion turbine on the system. Within SERC-SE, biomass (*i.e.,* wood, wood waste, municipal solid waste, landfill gas, ethanol, and other) is the most viable renewable resource. Future planned biomass generation is included in the Integrated Resource Plans at less than the nameplate capacity for converted boilers, and at nameplate capacity for units receiving new boilers. Landfill gas facilities are included at their nameplate ratings. Contracts with external parties for these resources usually require proof of capacity and allow for capacity payment penalties for excessive unavailability and derating events.

TABLE 119: SERC-SE SUMMER CAPACITY BREAKDOWN

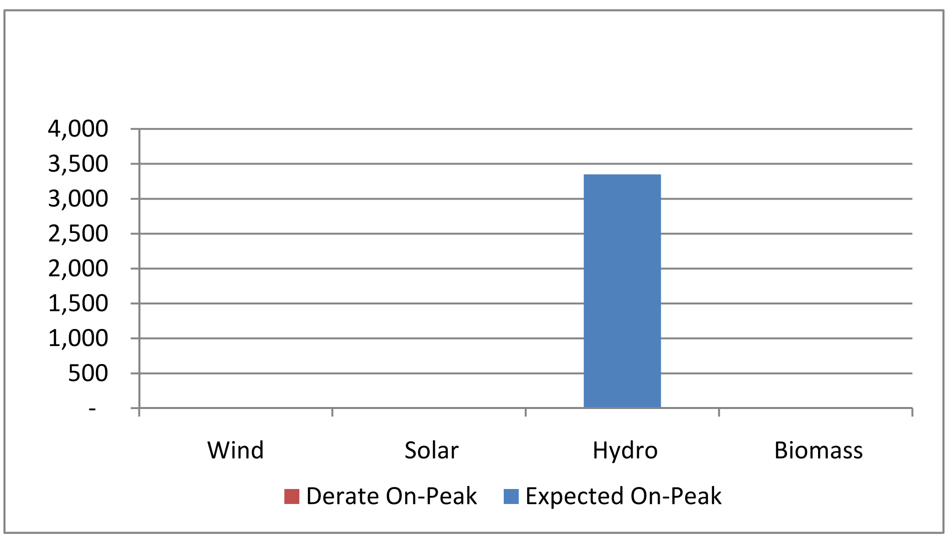
Capacity Type	Year 2011 (MW)
Existing-Certain	61,072
Nuclear	5,795
Hydro/Pumped Storage	4,983
Coal	25,349
Oil/Gas/Dual-Fuel	24,799
Other/Unknown	127
Solar	2
Biomass	17
Wind	0
Existing-Other	3,301
Existing-Inoperable	0
Future capacity	0

Some SERC-SE entities anticipate below-normal rainfall for early spring, but expect levels to return to normal in the summer. This sequence of events may result in below-normal output for hydro-peaking generation this summer since lower stream flows in the spring will likely not have recovered even if rainfall returns to normal in the summer. To address this concern, these entities are expecting that daily system load demands will be met by combining available hydro generation with other resources.

TABLE 120: SERC-SE EXISTING AND PLANNED PEAK CAPACITY

Existing-Certain (MW)	61,072
Existing-Other (MW)	3,301
Future-Planned (MW)	-

FIGURE 41: SERC-SE EXISTING AND PLANNED RENEWABLE GENERATION



Overall, the Area is not experiencing, and does not anticipate, any conditions that would significantly reduce capacity for the summer or cause reliability concerns. SERC-SE entities also do not anticipate any existing significant generating units being out of service or retired during the summer season.

TABLE 121: SERC-SE EXISTING AND PLANNED RENEWABLE GENERATION

Wind Expected On-Peak	-
Wind Derate On-Peak	-
Wind Nameplate/Installed Capacity	-
Solar Expected On-Peak	2
Solar Derate On-Peak	-
Solar Nameplate/Installed Capacity	2
Hydro Expected On-Peak	3,350
Hydro Derate On-Peak	-
Hydro Nameplate/Installed Capacity	3,350
Biomass Expected On-Peak	17
Biomass Derate On-Peak	-
Biomass Nameplate/Installed	17

Capacity Transactions

SERC-SE utilities reported the following imports and exports for the upcoming 2011 summer season.

TABLE 122: SERC-SE IMPORTS AND EXPORTS ON-PEAK

Imports (MW)	2,309
Firm (MW)	2,309
Expected (MW)	-
Exports (MW)	3,488
Firm (MW)	3,488
Expected (MW)	-
Net Exports (MW)	**1,179**

All imports/exports were reported to be backed by Firm contracts for both generation and transmission, but none are associated with LDCs or considered "make whole." These Firm imports and exports have been included in the Reserve Margin calculations for the assessment area. SERC-SE 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. Overall, SERC-SE entities are not dependent on outside imports or transfers to meet the demands of their loads.

Transmission

Table 123 and Table 124 show bulk power system transmission facilities (*e.g.,* transmission lines, transformers, significant substation equipment) that have been placed in service since 2010 summer or are projected to be in service for the 2011 summer season.

SERC-SE

Table 123: SERC-SE Forecast Transmission

Transmission project name	Transmission type	In-service date	Operating voltage (kV)
Dum Jon-Thomson 1	Complete	06/01/10	230
East Lake Road-Jackson Creek 1	Complete	06/01/10	230
East Lake Road-Ola 1	Complete	06/01/10	230
Jim Moore Road-Sharon Church 1	Complete	06/01/10	230
Sokol Park DS-Carolls Creek Tp 1	Complete	06/01/10	115
Pagamore-Huntsville 1	Complete	06/01/10	230
Murphy Mill Jct-Murphy Mill 1	Complete	06/01/10	115
White Oak SS-Polkville 1	Complete	06/01/10	161
Bethabara-Clarksboro 1	Complete	07/01/10	230
Florida Gas Tap-Florida Gas 1	Complete	08/01/10	115
Pegamore-Huntsville 1	Complete	08/05/10	230
Coffee Springs Jct-Coffee Springs 1	Complete	09/01/10	115
Gaston-Bessemer 1	Complete	10/01/10	230
Brentwood-Fairfield 2	Complete	12/08/10	115
Providence-West Grelot 1	Complete	01/25/11	115
Hammock Bay Jct-Hammock Bay 1	Under Construction	03/30/11	115
Holt-Tuscaloosa 1	Under Construction	05/01/11	230
Wright-Freedom Way 1	Under Construction	05/01/11	115
Kiln-Carriere SW 1	Under Construction	06/01/11	230
Plant McDonough CC-Plant McDonough (black) 2	Under Construction	06/01/11	230
Plant McDonough CC-Plant McDonough (white) 1	Under Construction	06/01/11	230
Kiln-Carriere SW 1	Under Construction	06/01/11	230
Silver Creek-Prentiss 1	Under Construction	06/01/11	161
Kingston Jct-Kingston 1	Under Construction	08/26/11	115
Pt Washington Jct-Pt Washington 1	Under Construction	08/31/11	115

Table 124: SERC-SE Transformer Additions

Transformer project name	High-side voltage (kV)	Low-side voltage (kV)	In-service date	Description/Status
Evans Primary	230	115	06/01/10	Complete – Replace 125 MVA, 230/115-kV transformer with a 300 MVA transformer
Ola	230	115	06/01/10	Complete – New Substation
Purvis Bulk Transformer Replacement	230	161	06/01/10	Under Construction – Upgrading tie transformer at Purvis bulk
Thomson	500	230	06/01/10	Complete – New 1344 MVA, 500/230-kV transformer
Thomson	230	115	06/01/10	Complete – Replace 140 MVA, 230/115-kV transformer with a 300 MVA transformer
Logtown West	230	115	10/01/10	Complete – Replace transformer
Brentwood	230	115	12/16/10	Complete-400 MVA Bank #2
Waynesboro Transformer Replacement	230	161	04/01/11	Under Construction – Waynesboro 230/161kV Substation
Carriere SW	230	115	05/01/11	Under Construction – New substation
Factory Shoals 230/115kV transformer	230	115	05/01/11	Planned – New 230/115-kV substation with a 300MVA bank
Holt TS-Tuscaloosa TS Autobank	230	115	05/01/11	Planned – Install 230/115kV Autobank at Tuscaloosa TS
Meldrim	230	115	06/01/11	Planned – New 300 MVA, 230/115-kV transformer
Silver Creek Interconnection	161	115	06/01/11	Under Construction – Silver Creek Interconnection

Currently, there are no major concerns with meeting in-service dates for transmission improvements. The economic environment is resulting in reduced load forecasts, which in turn tends to delay the need for some project improvements.

SERC-SE entities do not currently have any significant transmission outages scheduled for the summer operating season. Transmission operators may schedule transmission outages during the summer operating season as system conditions allow. Every planned transmission outage is thoroughly and repeatedly analyzed for any reliability impacts prior to approval and execution. Additionally, SERC-SE entities did not report transmission constraints that could significantly impact reliability for the 2011 summer season. If constraints develop, mitigation procedures are in place to relieve them. The interregional transmission transfer capabilities are not currently available, due in part to the recent decision to report as a new SERC subarea.

Operational Issues

SERC-SE entities perform studies of operating conditions for 12 to 13 months into the future. These studies include the most up-to-date information regarding load forecasts, transmission and generation status, and Firm transmission commitments for the time period studied and are often updated on a monthly basis. Additionally, reliability studies are conducted on two-day-out and next-day conditions. Studies are updated as changing system conditions warrant. The current operational planning studies do not identify any unique operational problems for the summer season. While the analysis has not been conducted for 2011 at this time, SERC-SE entities may annually conduct the analysis assuming the upcoming summer peak loads are approximately 105 percent of the forecast peaks. This analysis is done to support operations for the upcoming summer.

Table 125: SERC-SE Demand Response and Energy Efficiency On-Peak

Non-Dispatchable DSM (MW)	90
Energy Efficiency	90
Non-Controllable Demand-Side Demand Response	-
Total Internal Demand	49,314
Controllable, Dispatchable Demand Response	1,704
Net Internal Demand	47,610

Currently there are no significant amounts of distributed resources installed within SERC-South (SOCO); therefore, there are no anticipated operational changes, concerns, or special operating procedures related to distributed resource integration. Demand Response programs currently in place do not negatively impact reliability. Limitations on the deployment of Demand Response resources are identified and addressed in the individual contracts with those resources. All programs are well coordinated with transmission and generation operations.

Fossil generating units in the Southern Balancing Authority have operating limits related to air and/or water quality. These are derived from both federal and state regulations. A number of these units have unique limits on operations and/or emissions; some are annual limits while others are seasonal. These restrictions are continually managed in the daily operation of the system while maintaining reliability.

Similarly, hydroelectric units in the Area are run in cooperation with the U.S. Army Corps of Engineers to maintain water levels and river flow as well as system reliability. Overall, no existing conditions are projected to impact the reliability of the Bulk Power System because of environmental restrictions.

The Southern Control Area routinely experiences significant loop flows due to transactions external to the Control Area itself. The availability of large amounts of excess generation within the Southeast U.S. results in fairly volatile day-to-day scheduling patterns. The transmission flows are often more dependent on the weather patterns, fuel costs, or market conditions outside the Southern Control Area rather than on loading within the Control Area. Significant changes in natural gas pricing dramatically impacts dispatch patterns. All transmission constraints identified in current operational planning studies for the summer assessment period can be mitigated through generation adjustments, system reconfiguration, or system purchases. Overall, there are no unusual operating conditions anticipated that could impact reliability for the summer.

Reliability Assessment

The projected existing, anticipated, and prospective summer-peak Reserve Margins (as reported in February 2011) for utilities in SERC-SE are projected to be 24.9, 24.9, and 31.6 percent respectively. SERC-SE utilities do not adhere to any Regional/assessment area targets or Reserve Margin criteria. However, the State of Georgia requires maintaining at least 13.5 percent near-term (less than three years) and 15 percent long-term (three years or more) Reserve Margin levels for investor-owned utilities. Most SERC-SE entities use a target of 15 percent to ensure reliability and indicate that projected Reserve Margins remain well above this target. Recent analyses of load forecasts indicate that projected Reserve Margins remain well above 15 percent for the next several years for most utilities in the subregion. Analyses account for planned generation additions, retirements, deratings due to environmental control additions, load deviations, weather uncertainties, forced outages, and other factors. Resource adequacy is determined by extensive analysis of costs associated with forecast unserved energy, market purchases, and new capacity. These costs are balanced to identify a minimum cost point that is the optimum Reserve Margin level.

Table 126: SERC-SE On-Peak Capacity Resources and Reserve Margins

	2011 Summer Forecast (MW)	2011 Summer Forecast (%)
Existing-Certain and Net Firm Transactions (with Demand Response)	61,597	24.9%
Anticipated Capacity Resources	61,597	24.9%
Prospective Capacity Resources	64,898	31.6%
NERC Reference Margin Level	**7,397**	**15.0%**

The projected Reserve Margin for SERC-SE for the 2011 summer season is 24.9 percent. Due to the restructuring of the entity reporting footprints for this assessment, the comparisons of projected Reserve Margins are not available for this assessment area.

The fuel supply infrastructure, fuel delivery system, and fuel reserves are all adequate to meet peak gas demand. Various companies within SERC-SE have Firm transportation diversity, diverse fuel mixes, gas/coal storage, Firm pipeline capacity, and on-site fuel supplies to meet the peak demand. When situations limit supply, established communications allow for ordering additional supplies. These lines of communications include daily emails, phone calls, internet accessibility, SCADA and instant messaging so that SERC-SE entities are well aware of fuels moving to various generating stations or to storage. Some utilities have implemented fuel storage, coal conservation programs, and various other fuel policies to address concerns. Policies are also in place to ensure that storages are filled well in advance of hurricane season (June 1 of each year). These tactics help to ensure balance and create flexibility to serve anticipated generation needs. Relationships with coal mines and coal suppliers, daily communication with railroads for transportation updates, and ongoing communication with the coal plants and energy suppliers ensures that supplies are adequate and potential problems are transmitted well in advance to enable adequate response time.

SERC-SE utilities individually perform studies and maintain individual criteria to address any dynamic and static reactive issues. Studies are created each year for the upcoming summer and generally for a future-year case. The studies did not indicate any issues that would impact reliability in the 2011 summer season. For example, several companies have performed fault-induced delayed voltage recovery (FIDVR) studies. To address dynamic reactive criterion, some utilities follow the practice of having a sufficient amount of generation on line to ensure that no bus voltage is projected to be subjected to a delayed voltage recovery following the transmission system being subjected to a worst-case, normally cleared fault. Studies of this involve modeling half of the Area load as small motor load in the dynamics model. Prior to each summer, an operating study is performed to quantify the impact of generating units in preventing voltage collapse following a worst-case, normally cleared fault. The generators are assigned points, and the system must be operated with a certain number of points on line depending on current system conditions including the amount of load on line and the current transmission system configuration. The study is performed over a range of loads from 105 percent of peak summer load down to around 82 percent of peak summer load conditions.

SERC-SE Description

SERC-SE is a summer-peaking assessment area covering portions of four southeastern states (Alabama, Georgia, Mississippi, and Florida) with a population of approximately 35.1 million.[133] *Owners, operators, and users of the Bulk Power System in these states cover an area of approximately 119,800 square miles. There are four Balancing Authorities within SERC-South (SOCO): PowerSouth Energy Cooperative; South Mississippi Electric Power Association; Southeastern Power Administration; and Southern Company Services, Inc.*

[133] http://en.wikipedia.org/wiki/List_of_U.S._states_and_territories_by_population

SPP

Introduction

Southwest Power Pool, Inc. (SPP) operates and oversees the electric grid in the southwestern quadrant of the Eastern Interconnection. In addition to serving as an NERC Regional Entity, SPP is an FERC-recognized Regional Transmission Organization (RTO). The SPP RTO footprint includes all or part of nine states: Arkansas, Kansas, Louisiana, Mississippi, Missouri, Nebraska, New Mexico, Oklahoma, and Texas.[134] The Nebraska members belong to the Midwest Reliability Organization Regional Entity, but this year's assessment is being performed on the RTO footprint so the Nebraska members will be included in the SPP RTO report.

This report provides a high-level overview of the 2011 summer reliability assessment for the SPP RTO Region—specifically, demand growth, capacity adequacy, and operational reliability. The summer assessment is used to identify any Areas of concern regarding reliability for the SPP RTO.

This report is created with data and information submitted by SPP Reporting Entities, which are validated and cross-checked to verify consistency. Once this process has been completed, SPP RE staff aggregate the information into one dataset for the entire SPP RTO Area. SPP RE staff use a peer review process to validate the data and develop the reliability assessments.

The summer assessment evaluates the forecast demand, capacity resources, and future capacity additions for the upcoming summer timeframe. New bulk transmission (greater than 100 kV) that has been installed since the last summer assessment through the end of the current summer assessment is reported. Projected operational and reliability concerns are also addressed for the upcoming summer timeframe.

Demand

Although actual demand is very dependent on weather conditions and typically includes the effects of interruptible loads, forecast net internal demands are based on ten-to-30-year average summer weather, or 50/50 weather.[135] Some SPP RTO members base their peak load forecast on a 50-percent confidence level as approved by their respective state commission(s). This means that the actual weather on the peak summer day is forecast to have a 50-percent likelihood of being hotter and a 50-percent likelihood of being cooler than the weather assumed in deriving the load forecast. The SPP RTO was not significantly impacted by the economic turndown. Milder summer conditions have had a more drastic impact on the forecast swings. The SPP RTO bandwidth working group performed a study that included the 2011 summer timeframe and determined that the 13.6-percent Reserve Margin is adequate to cover any extreme load forecast for the SPP RTO footprint.

[134] To read more about the differences between the SPP RE and SPP RTO footprints, open the Footprints document on the SPP.org Fast Facts page.

[135] SPP RTO members use different historical yearly averages with the least amount being ten years and the greatest being 30 years.

TABLE 127: SPP FORECAST AND ACTUAL PEAK DEMAND

2010 Total Internal Demand (MW)	2010 Actual Demand (MW)	Difference in Actual versus Forecast (MW)	Difference in Actual versus Forecast (%)	2011 Total Internal Demand (MW)	Difference in 2011 and 2010 Forecast Demand (MW)	Difference in 2010 Actual versus 2011 Forecast (%)	All-Time Summer Peak Demand (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)
43,426	53,145	9,719	22.4%	53,512	10,087	23.2%	49,312	4,200	8.5%

The projected non-coincident total internal demand forecast for the 2011 summer peak is 53,512 MW, and the actual 2010 summer peak demand was 53,145 MW, which is based on the SPP RTO footprint. Comparison to the previous forecast is unavailable due to the change in reporting footprints. Forecast data are collected from individual reporting members as monthly non-coincident values and then summed up to produce the total forecast for SPP RTO. The summer peak is the peak condition upon which the SPP RTO Region bases its resource evaluations.

Each SPP RTO member also provides their Demand Response programs and then subtracts those values from their load forecasts to report the net load forecast. Based on the SPP RTO members' inputs, currently 213 MW of interruptible demand and 1038 MW of load management are reported. SPP RTO does not have the means to measure or verify the Demand Response programs in place due to the minimal amount of megawatts contained in the programs. The part of the Demand Response programs that can reduce peak demand against the Total Internal Demand is 2.3 percent.

SPP RTO members are reporting 145 MW of energy efficiency programs. In March 2010, SPP RTO member Oklahoma Gas and Electric (OG&E) installed approximately 42,000 smart meters on customer homes in Norman, Oklahoma, along with the information delivery infrastructure to carry the information to and from the customers and OG&E. An estimated 3,000 Norman customers were or will be asked to participate in a study during the summers of 2010 and 2011 using the in-home devices and/or internet portals as a means to get electricity pricing and use information.[136]

The SPP RTO bandwidth working group study, which included the 2011 summer timeframe, determined the 13.6-percent Reserve Margin is adequate to cover any extreme summer conditions.

Generation

SPP RTO expects to have 69,599 MW of total internal capacity for the upcoming summer season. This consists of Existing-Certain capacity of 61,395 MW; Existing-Other capacity of 7,508 MW; Existing, Inoperable capacity of 467 MW; and Future-Planned capacity of 203 MW.

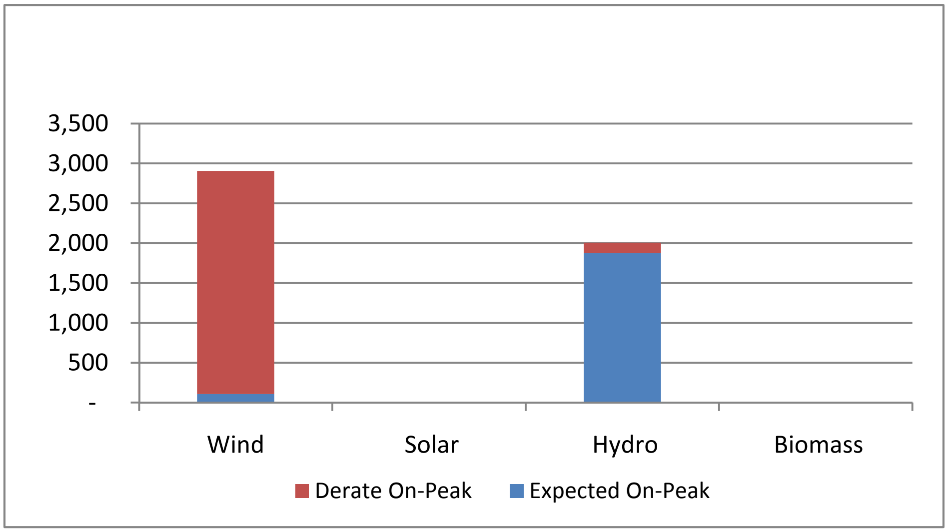
TABLE 128: SPP EXISTING AND PLANNED PEAK CAPACITY

Existing-Certain (MW)	61,395
Existing-Other (MW)	7,508
Future-Planned (MW)	203

[136] Program results will not be available until the end of the two-year study period.

Of the 3,817 MWs of variable generation (mostly wind) connected to the SPP RTO transmission system, the projected on-peak capacity is 106 MW.[137] The forecast on-peak biomass portion (landfill gas) is 11 MW. The hydro capacity within the SPP RTO Area represents only a small fraction of the total resources (approximately one percent). SPP RTO monitors potential fuel supply limitations for hydro and gas resources by consulting with its generation owning/controlling members at the beginning of each year.

FIGURE 42: SPP EXISTING AND PLANNED RENEWABLE GENERATION



Since hydro capacity is only a small fraction of SPP RTO resources reservoir levels do not materially impact the SPP RTO Reserve Margins. Additionally, there are no anticipated issues concerning the reservoir levels that would impact meeting the peak and daily energy demands during the summer season. The SPP RTO Area is not projected to experience drought conditions during the summer season that would prevent the Area from meeting its capacity needs. There are no known conditions that the SPP RTO is experiencing that would reduce capacity within the Area. There are no significant generating units planned to be out of service or retired during or prior to the summer season.

[137] Wind resources were not to be counted toward on-peak capacity unless four years of historical operational data was available for reference. The SPP Criteria for wind resource reporting has changed and will have an impact on the on-peak wind numbers go forward, starting with the 2011 LTRA.

TABLE 129: SPP EXISTING AND PLANNING PLANNED RENEWABLE GENERATION

Wind Expected On-Peak	107
Wind Derate On-Peak	2,800
Wind Nameplate/Installed Capacity	2,907
Solar Expected On-Peak	-
Solar Derate On-Peak	-
Solar Nameplate/Installed Capacity	-
Hydro Expected On-Peak	1,876
Hydro Derate On-Peak	130
Hydro Nameplate/Installed Capacity	2,006
Biomass Expected On-Peak	11
Biomass Derate On-Peak	-
Biomass Nameplate/Installed	11

Capacity Transactions on Peak

SPP RTO members have reported the following imports and exports for 2011 summer. None of the sales contracts are a Liquidated Damages Contract. All Firm power contracts are backed by transmission and generation.

TABLE 130: SPP IMPORTS AND EXPORTS ON-PEAK

Imports (MW)	3,052
Firm (MW)	2,992
Expected (MW)	60
Exports (MW)	1,094
Firm (MW)	1,094
Expected (MW)	-
Net Imports (MW)	**1,959**

SPP RTO members along with some members of the SERC Region have formed a Reserve Sharing Group. The members of this group receive contingency reserve assistance from other SPP RTO Reserve Sharing Group members, but it does not require support from generation resources outside the SPP RTO Region. The SPP RTO's Operating Reliability Working Group (ORWG) sets the Minimum Daily Contingency Reserve Requirement for the SPP RTO Reserve Sharing Group. The SPP RTO Reserve Sharing Group maintains a minimum first Contingency Reserve equal to the generating capacity of the largest unit scheduled to be on line.

Transmission

SPP RTO currently has several projects under construction that are scheduled to be in service before the current assessment timeframe, June to September 2011, expires. There are also several new transformer and substation projects. Project details are shown in the
Table 131 and Table 132 below.

TABLE 131: SPP FORECAST TRANSMISSION UPGRADES

Transmission Project Name	Transmission Status	In-service Date	Operating Voltage (kV)
Sumner County-Timber Junction	Completed	09/15/10	138
Steele City-Knob Hill	Completed	10/01/10	115
Turk - Sugar Hill	Completed	12/16/10	138
Stranger Creek-Thornton Street	Completed	02/24/11	115
Sherman Tap-Hitchland*	Planned	05/20/11	115
Sherman-Dallam*	Planned	05/20/11	115
Texas Co.-Hitchland*	Planned	05/20/11	115
Sheldon-Folsom*	Planned	05/31/11	115
Johnson County-Caney Creek	Planned	06/01/11	138
Etoile-Chireno	Planned	06/01/11	138
Atoka - WFEC Tupelo	Planned	06/01/11	138
WFEC Snyder-AEP Snyder	Planned	06/30/11	138
Phillipsburg-Rhoades	Planned	07/01/11	115
Doss - Legacy	Planned	07/31/11	115
Gaines Co.-Legacy	Planned	07/31/11	115
Navajo #5-Navajo #4	Planned	07/31/11	115
Navajo #5-Navajo #3	Planned	07/31/11	115
Eagle Creek-Seven Rivers	Planned	07/31/11	115
Sub 1341-Sub 1251	Planned	08/01/11	161
Sub 1341-Sub 1305	Planned	08/01/11	161
Exxon-Mobil Hawkins-Perdue 138	Planned	08/01/11	138
Exxon-Mobil Hawkins-Lake Hawkins	Planned	08/01/11	138
Ben Wheeler-Barton's Chapel (Rayburn)	Planned	08/30/11	138

TABLE 132: SPP TRANSFORMER ADDITIONS

Transformer Project Name	High-side Voltage (kV)	Low-side Voltage (kV)	In-service Date	Description/Status
Sportsman Acres	345	161	02/01/11	Install a new transformer
Hitchland*	230	115	05/20/11	Install a new transformer
Hitchland*	345	230	05/20/11	Install a new transformer
Johnson County	345	138	06/01/11	Install a new transformer

** Units are projected to be in service before the published target date*

There are no known concerns about meeting target in-service dates or placing these projects in service during peak load periods for reliability projects that have been approved by the SPP RTO Board of Directors. Assuming these projects come on line as scheduled, there are no known transmission constraints that could impact the reliability of the SPP transmission grid. The SPP RTO relies heavily on its Project Tracking process to monitor projects and ensure they meet their issued timelines.[138] If a project's timeline is extended due to construction delays or unforeseen issues placing the project in service, the SPP RTO will conduct a study to address any reliability issues associated with the extension.

[138] The Engineering and Planning section of SPP.org has a page on Project Tracking

There are no known significant transmission lines scheduled to be out of service during the upcoming summer months.

The SPP RTO is monitoring transmission constraints in the SPS Area and in the Acadiana Load Pocket. The SPP RTO worked with AMEC Earth and Environmental and Southwestern Public Service (SPS)/Xcel Energy staff to investigate the operational impacts of increased wind penetration to secure reliable operations within the SPS Area. SPS serves a 52,000 square mile area in southeastern New Mexico, the Texas Panhandle, portions of Oklahoma, and a small part of Kansas. Due to significant existing, approved, and requested wind plant development, constraints must be resolved in the near-term before major transmission capability can be installed to improve internal and interface capabilities. The recently completed AMEC study for spring 2010 conditions focused on operations and reliability, and did not investigate the economics associated with planned or potential wind development within and surrounding the SPS Balancing Authority. The study leveraged the National Renewable Energy Lab's wind data for 2004–2006 to simulate future scenarios for 2010. Without considering proactive wind curtailments as an option, the study concluded that operating margins during low load periods within SPS would be jeopardized as wind farm development approached 1,100 to 1,200 MW–only slightly above existing wind capacity levels, without curtailments.[139] SPS is working with SPP RTO to finalize operating procedures for curtailment of generation resources based on transmission priority and communicate them to generation developers as a near-term solution. SPS does have a posted curtailment policy for curtailment of resources if necessary. Consolidating the SPP RTO's Balancing Authorities will help facilitate wind integration in the Area, but additional changes to the SPP OATT, interconnection agreements, operating procedures, and market design may be required to maintain adequate operating margins within SPS and other portions of SPP as wind development continues.

The Acadiana Load Pocket located in southern Louisiana, with a 2010 summer peak demand of 1,723 MWs, spans both the SPP RE and SERC reliability areas and continues to be constrained as the transmission improvements for this area are being constructed. The reliability congestion issues in the ALP area are due to the lack of generation and transmission capacity that limit the amount of import capability. The City of Lafayette, CLECO, and Entergy are in the process of constructing these reliability additions and upgrades, which will be completed during the summer of 2012. The first phase of the project, a 230 kV line from Roark to Sellers Rd., was energized on May 3, 2011. This line has already alleviated some of the most limiting elements in the Acadiana Load Pocket by as much as 10 percent. Completion of the project should further alleviate some of the transmission congestion in this area.

The system characteristics listed above continue to be aggressively addressed by the SPP Reliability Coordinator through coordination within the ALP with all of the effected entities. These actions include operating guides developed by the Reliability Coordinator and the operational Planning Engineering staffs of each entity, and the sharing of generation cost of legacy generation required to dispatch during system events. This coordinated effort on the part of all parties in the ALP has limited the load at risk in the area. There has been an increase in the load in the ALP over the last few years due to catastrophic weather events on the Louisiana gulf coast redistributing the population from the larger load centers near the coast to the Acadiana area of Louisiana.

[139] Operating margins refers to the amount of backup generation that is available to handle load as the wind generation falls off.

Transmission System events in the ALP region of the SPP reliability footprint do not pose a significant threat to the Eastern Interconnect as these events are restricted to the boundaries of the ALP.

For the rest of the system, SPP RTO is not aware of any transmission constraints that could significantly impact reliability for the upcoming summer that has not already been addressed by mitigation plans or with local operating guides.

SPP RTO staff participates in the Eastern Interconnection Reliability Assessment Group's inter-Regional study effort. This study is conducted to examine the potential constraints on the SPP RTO Region as a result of simulated import and export with neighboring Regions. The preliminary results of the study indicate that the SPP imports are limited due to the 161 kV facilities across the Arkansas-Oklahoma border. This has been a known issue for the last several years, and the SPP RTO is working with SERC members on mitigating this in the near future. In the meantime, the SPP RTO does not expect any reliability issues for the 2011 summer as it does not rely on the incremental transfer capability from neighboring Regions to meet the projected demand.

Operational Issues

For the upcoming summer, SPP RTO projects less than four percent of the total wind capacity to be available on peak. SPP RTO grid operators will continue to monitor any operating challenges for this assessment period. Additionally, improved wind forecasting tools are needed. To that end, a project is currently underway to obtain and implement a Region-wide wind-forecasting tool.

TABLE 133: SPP DEMAND RESPONSE AND ENERGY EFFICIENCY ON-PEAK

Non-Dispatchable DSM (MW)	157
Energy Efficiency	145
Non-Controllable Demand-Side Demand Response	12
Total Internal Demand	53,512
Controllable, Dispatchable Demand Response	1,252
Net Internal Demand	52,261

SPP RTO does not foresee any unmanageable reliability concerns due to minimum demand and over-generation. Reliability Coordinator directives may be used to force some generation offline in the case of over-generation. In some local cases, generation that may need to be directed offline must be back on line for load pickup in less than the minimum allowed down time. Widespread balancing issues are not forecast due to generation fleet flexibility. Local congestion in Areas with excess generation may require cycling of units or re-evaluation of short term System Operating Limit (SOL) values.

There are no concerns with the use of Demand Response resources to meet peak demands due to the small amount of Demand Response on the SPP RTO system.

SPP RTO operations staff does not anticipate any environmental and/or regulatory restrictions that could potentially impact reliability.

As a result of Flowgate assessment analysis, there are no unusual operating conditions projected for the upcoming summer months. There are no known reliability concerns resulting from high levels of Demand Response resources as Demand Response resources in the SPP RTO Region are minimal at this time.

There are no anticipated unit outages or need for the use of temporary operating measures that are foreseen for this summer. There are no new Smart Grid programs that have been fully implemented within the past year that will have any influence on reliability of the Region. There are no known unusual operating conditions that have not already been discussed that could impact the reliability of the Region for the upcoming assessment timeframe.

Reliability Assessment

Currently, SPP RTO criterion requires that its members maintain a minimum capacity margin of 12 percent (13.6 percent Reserve Margin). SPP RTO members, by meeting this requirement, adequately cover a 90/10 weather scenario. The SPP Reserve Margin based on Existing resources is forecast to be 20.6 percent for 2011 summer. The 2010 summer Reserve Margin was projected to be 19.2, but was based on the SPP RE footprint, and the 2011 projected summer Reserve Margin is based on the SPP RTO footprint.[140] On an anticipated resources basis, SPP has sustained around a 21.1-percent Reserve Margin. The Reserve Margin with prospective capacity resources is 25.0 percent.

TABLE 134: SPP ON-PEAK CAPACITY RESOURCES AND RESERVE MARGINS

	2011 Summer Forecast (MW)	2011 Summer Forecast (%)	Change from prior year (MW)	Change from prior year (percentage point)
Existing-Certain and Net Firm Transactions (with Demand Response)	64,545	20.6%	13,543	1.5
Anticipated Capacity Resources	64,808	21.1%	13,289	0.7
Prospective Capacity Resources	66,889	25.0%	10,624	(6.5)
NERC Reference Margin Level	**7,278**	**13.6%**	**1,372**	-

Based on the LOLE study performed by SPP RTO staff last year for the 2011 study period, the capacity or Reserve Margin requirement for SPP RTO remained unchanged. Additionally, the 12-percent capacity margin or 13.6 Reserve Margin requirement is also checked annually in the EIA-411 reporting as well as through supply adequacy audits of Regional members conducted every five years by the SPP RTO. The last supply adequacy audit was conducted in 2007.

Due to the diverse generation portfolio in SPP RTO, there is no concern of the fuel supply being affected by the extremes of summer weather during peak conditions. If there is to be a fuel shortage, SPP RTO members are to communicate that to SPP RTO operations staff, in advance, so that they can take the appropriate measures that SPP RTO would enact if capacity or reserves become insufficient due to unavailable generation.

[140] NERC made a decision this past in fall that SPP would no longer do the NERC Assessments based on the RE footprint as done in years past, but would report the NERC Assessments based on the RTO footprint.

In that case, SPP RTO would declare either an EEA (Energy Emergency Alert) or OEC (Other Extreme Contingency) and post as needed on the RCIS (Reliability Coordinator Information System). SPP does not expect any immediate impact on the reliability of the Region due to the current economic conditions.

The SPP RTO conducted a 2009 SPP Stability Study for the 2014 summer peak case. This assessment discusses potential events that could lead to instability within the SPP RTO footprint for NERC-defined categories (A, B, C, and D) of events submitted by SPP RTO members. Events in one category B event, two category C events, and three category D events were required to have mitigation plans before they were found to be stable. The SPP RTO also conducted a transient stability screening of the SPP RTO footprint on the previously mentioned case using generic clearing times (conservative values) based on the kV level of the transmission line segment. The unstable events were a non issue once actual clearing times were applied based on feedback from SPP members.

SPP RTO also conducted a transient stability screening of the SPP RTO footprint on the previously mentioned cases. The unstable events were mitigated by applying either the proper clearing time or system generation re-dispatch in order to maintain system stability.

In addition, SPP RTO has conducted a Power-Voltage (P-V) analysis study for the nine potential load pockets within the SPP RTO footprint based on a 2014 summer peak load condition. Although one issue found was that the Midland, Texas, Area within SPS may face voltage issues in the 2014 summer peak, the owner of the load area that is served in that region is pursuing moving the load area back to ERCOT, thus eliminating voltage issues on the SPP system. SPP RTO is monitoring the resolution of this situation. SPP RTO staff will coordinate any potential reactive reserve issues and the mitigation plans associated with it during their annual reliability assessment effort.

Other Area-Specific Issues

SPP RTO continues to perform real-time, current day, next day, and seasonal Reliability assessments for the SPP RC footprint. The results of these studies are shared with SPP RTO members and coordination occurs using these studies to prepare to operate the system reliably.

Region Description

The Southwest Power Pool, Inc. Regional Transmission Organization (SPP RTO) covers a geographic area of 370,000 square miles and has members in nine[141] *states: Arkansas, Kansas, Louisiana, Missouri, Mississippi, Nebraska, New Mexico, Oklahoma, and Texas. SPP's Reliability Coordinator footprint includes 29 balancing authorities and the RTO has over 50,000 miles of transmission lines. SPP typically experiences peak demand in the summer months.*

SPP has 60 members that serve over 6.2 million households. SPP's membership consists of 14 investor–owned utilities, 12 generation and transmission cooperatives, ten power marketers, nine municipal systems, seven independent power producers, four state authorities, and four independent transmission companies. SPP was a founding member of the North American Electric Reliability Corporation in 1968, and was designated by the Federal Energy Regulatory Commission as an RTO in 2004 and a Regional Entity (RE) in 2007. As an RTO, SPP ensures reliable supplies of power, adequate transmission infrastructure, and competitive wholesale prices of electricity. The SPP RE oversees compliance enforcement and reliability standards development. Additional information can be found on www.SPP.org.

WECC

WECC

Executive Summary

WECC does not expect any major scheduled generating unit outages, transmission facility outages, or unusual operating conditions that would adversely affect reliable operations of the power grid this summer. The integration of wind generation will continue to require modifications to the way system operators plan for and dispatch generation in order to provide sufficient operating flexibility, including providing incremental and decremental reserves. However, WECC does not anticipate any new reliability issues related to the integration of wind generation during the timeframe of the summer assessment.

Introduction

WECC is one of eight electric reliability councils in North America, and is responsible for coordinating and promoting bulk power system reliability in the Western Interconnection. WECC is geographically the largest and most diverse of the eight Regional Entities that have Delegation Agreements with the North American Electric Reliability Corporation (NERC). WECC's service territory extends from Canada to México. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in México, and all or portions of 14 Western states in between.

For resource adequacy assessments WECC staff uses a production cost model to calculate coincidental peak demand and available variable resources for the entire WECC Region. The model creates annual demand curves for each month of the study period using an algorithm of the annual peak, the annual energy, and Balancing Authority (BA) specific historic hourly-demand curves. These curves are aggregated to product coincidental peaks for WECC and each of the subregions. For variable generation, wind curves were created using three-years of one-hour interval wind speed data, and solar production curves were created using two years of synthetic data. Hydro generation is dispatched economically, limited by projected annual energy. The coincidental peak demands and forecast peak hour outputs for the variable generation resources created during this simulation are reported in this assessment.

For the summer assessment the WECC Region is divided into four subregions; Northwest Power Pool (NWPP), Rocky Mountain Reserve Group (RMRG), Southwest Reserve Sharing Group (SRSG), and California/México (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 have similar operating practices. Second, the Western Reliability Coordination Offices collect actual demand data from the Reserve Sharing groups. Creating the seasonal assessments using the same footprint allows for after-the-fact comparison between demand forecasts and actual demand.

WECC requested information from its BAs concerning studies they have performed for the summer assessment period. WECC also requests that BAs update any applicable data (actual loads, forecasts, outages, future and existing resource status changes) that have been previously submitted to WECC. The submitted information and data are then reviewed and compiled into the resulting resource assessment for the Western Region and subregions.

The purpose of the summer assessment is to highlight any reliability concerns associated with resources, including generation and transmission, or system operations under normal weather conditions. WECC expects to have adequate generation capacity, reserves, and transmission for the forecast peak demands and energy loads. However, abnormal weather conditions would result in different Reserve Margins and severe adverse weather conditions or non-projected equipment failure may result in localized power supply or delivery limitations.

Demand

WECC instructs its BAs to submit forecasts with a 50-percent probability of occurrence. These forecasts consider various factors such as population growth, economic conditions, and normalized weather so that there is a 50-percent probability of actual demand exceeding, or falling below, the forecast. The peak demand forecasts presented here are coincident sums of shaped hourly demands adjusted by the 50/50 demand forecasts.

TABLE 135: WECC FORECAST AND ACTUAL PEAK DEMAND

2010 Total Internal Demand (MW)	2010 Actual Demand (MW)	Difference in Actual versus Forecast (MW)	Difference in Actual versus Forecast (%)	2011 Total Internal Demand (MW)	Difference in 2011 and 2010 Forecast Demand (MW)	Difference in 2010 Actual versus 2011 Forecast (%)	All-Time Summer Peak Demand (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)
148,365	147,305	(1,060)	-0.7%	149,148	783	0.5%	161,131	(11,983)	-7.4%

Due largely to a partial economic recovery that is forecast in the Region, the aggregate WECC 2011 summer total coincident peak demand is forecast to be 149,148 MW and is projected to occur in August. The forecast is 3.9 percent above last summer's actual coincident peak demand of 147,305 MW, which was established under generally normal to slightly warmer than normal temperatures but with poor economic conditions in the Region. The 2011 summer coincident peak demand forecast is less than one percent above the 2010 summer forecast's coincident peak demand of 148,365 MW.

Demand-side Management (DSM) programs offered by Load-Serving Entities (LSE) vary widely. The 2011 demand forecast includes 1,771 MW of direct control load management, 1,693 MW of contractually interruptible demand, three MW of critical-peak-pricing with control, and 807 MW of load as a capacity resource. As a percent of Total Internal Demand, total Demand Response could reduce peak demand by almost three percent. Direct control load management programs largely focus on air conditioner cycling programs while interruptible demand programs focus primarily on large water pumping operations and large industrial operations such as mining. Each LSE is responsible for verifying the accuracy of its DSM and energy efficiency programs. Methods for verification include direct end-use metering, sample end-use metering, and baseline comparisons of metered demand and usage.

Energy efficiency programs vary by location and are generally offered by the LSE. Programs include Energy Star builder incentive programs, business lighting rebate programs, retail compact fluorescent light bulb programs, home efficiency assistance programs, and programs to identify and develop ways to streamline energy use in agriculture, manufacturing, water systems, etc. For purposes of verification, some LSEs retain independent third parties to evaluate their programs.

WECC staff did not perform any quantitative analyses on a Regional or subregional basis to assess the variability in demand associated with variations in weather or the economic recession. All margin results used demands associated with normal weather conditions, and no attempts were made to address extreme temperature changes.

Generation

WECC modeled the Western Interconnection using Existing capacity for the peak month of August as follows:

- Total Capacity — 220,066 MW
  - Wind: 13,198 MW (640 MW projected on-peak)
  - Solar: 652 MW (611 MW forecast on-peak)
  - Biomass: 1,427 MW (1,081 MW projected on-peak)
- Total Internal Capacity — 223,936 MW
  - Wind: 14,826 MW (721 MW forecast on-peak)
  - Solar: 789 MW (719 MW projected on-peak)
  - Biomass: 1,462 MW (1,107 MW forecast on-peak)

The projected hydro levels for the 2011 summer season are projected to be near to above normal, and hydro generation is forecast to be sufficient to meet the summer peak demands and energy loads.

TABLE 136: WECC EXISTING AND PLANNED PEAK CAPACITY

Existing-Certain (MW)	169,817
Existing-Other (MW)	34,813
Future-Planned (MW)	3,870

The WECC Region is not currently experiencing any weather or fuel-related issues that would reduce capacity and, due to past experience, WECC does not expect to see any. Additionally, WECC does not expect any significant generating units to be taken out of service or retired during the summer period.

FIGURE 43: WECC EXISTING AND PLANNED RENEWABLE GENERATION

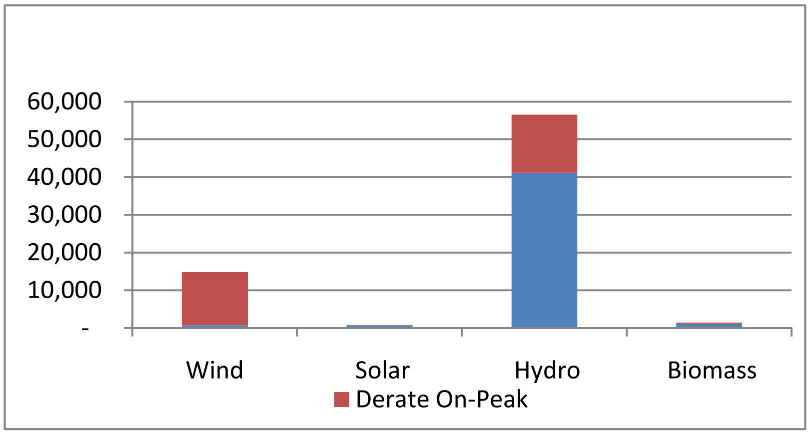


TABLE 137: EXISTING AND PLANNED RENEWABLE GENERATION

Wind Expected On-Peak	721
Wind Derate On-Peak	14,105
Wind Nameplate/Installed Capacity	14,826
Solar Expected On-Peak	719
Solar Derate On-Peak	70
Solar Nameplate/Installed Capacity	789
Hydro Expected On-Peak	41,157
Hydro Derate On-Peak	15,377
Hydro Nameplate/Installed Capacity	56,534
Biomass Expected On-Peak	1,107
Biomass Derate On-Peak	346
Biomass Nameplate/Installed	1,453

Capacity Transactions

The WECC Region does not rely on imports from outside the Region when calculating peak demand reliability margins. Neither does the Region model exports to Areas outside of WECC that could adversely affect reliability margins. The WECC Region does not rely on outside assistance or external resources for emergency imports for system reliability. WECC does not track subregional purchase/sale contracts or their associated transmission. Only transfers from remotely-owned large thermal and hydroelectric units (resources located outside the owner's subregion) are allocated to that subregion. All transfers assumed in the Reserve Margin calculations are theoretical transfers that could happen, but are not actual contracts. This treatment ensures that resources are counted once and only once.

TABLE 138: WECC IMPORTS AND EXPORTS ON-PEAK

Imports (MW)	-
Firm (MW)	-
Expected (MW)	-
Exports (MW)	-
Firm (MW)	-
Expected (MW)	-
Net Exports (MW)	**0**

WECC

Some WECC entities rely heavily on short-term power markets, generally using the Western System Power Pool (WSPP) contracts. The WSPP Agreement is a set of FERC-approved standardized power sales contracts used by jurisdictional and non-jurisdictional entities. The most commonly used WSPP contract is the Firm Capacity/Energy Sale or Exchange (Schedule C), which contains liquidated damage provisions and is heavily relied on as the template for such transactions. These contracts do not reference specific generating units or a system of units, and liquidated damages are the only remedy for non-delivery.

Transmission

Individual entities within WECC have established generator interconnection requirements that include power flow and stability studies to identify adverse impacts from proposed projects. In addition, WECC has established a review procedure that is applied to larger transmission projects that could impact the interconnected system. The details of this review procedure can be viewed on the WECC website.[142] These processes identify potential deliverability issues that may result in actions such as the implementation of Special Protection Systems designed to enhance deliverability and to mitigate possible adverse power system conditions.

Other measures that have been implemented to reduce the likelihood of widespread system disturbances include:

- An islanding scheme for loss of the AC Pacific Intertie that separates WECC into two islands and drops load in the generation-deficit southern island,
- A coordinated off-nominal frequency load shedding and restoration plan,
- measures to maintain voltage stability,
- A comprehensive generator testing program,
- Enhancements to the processes for conducting system studies, and
- A reliability management system.

Seasonal operating studies are reviewed to ensure that System Operating Limits (SOL) of critical transmission paths are identified and managed through nomograms and operating procedures. Four subregional Study Groups prepare seasonal studies for major paths in a coordinated subregional approach for review and approval by WECC's Operational Transfer Capability Policy Committee (OTCPC). Based on these ongoing activities, transmission system reliability within the Western Interconnection is projected to meet NERC and WECC standards.

WECC does not anticipate any impact to reliability due to out-of-service transmission lines or transmission constraints.

Operational Issues

WECC staff does not perform any special operating studies concerning extreme weather or drought conditions for the summer assessment.

[142] Overview of Policies and Procedures for Project Coordination Review, Project Rating Review, and Progress Reports.

However, these studies are performed by the individual LSEs and BAs within WECC. No new operating procedures have been implemented during the past year to integrate variable resources into the bulk power grid.

TABLE 139: WECC DEMAND RESPONSE AND ENERGY EFFICIENCY ON-PEAK

Non-Dispatchable DSM (MW)	740
Energy Efficiency	740
Non-Controllable Demand-Side Demand Response	-
Total Internal Demand	149,148
Controllable, Dispatchable Demand Response	4,274
Net Internal Demand	144,874

WECC does not anticipate any reliability concerns due to minimum demand and possible over-generation, or concerns due to Demand Response resources. No new environmental or regulatory restrictions have been reported that are forecast to adversely affect reliability during the summer period. WECC does not anticipate any other unusual operating conditions that could significantly affect reliability for the upcoming summer.

Reliability Assessment

Projected Reserve Margins for the peak month of August are 16.7 percent based on existing resources, 19.3 percent based on existing plus anticipated resources, and 19.3 percent based on existing resources plus anticipated resources plus prospective resources. The actual operating margin at the time of peak last summer was 14.7 percent. The WECC target margin is 14.2 percent. For the summer assessment, WECC requested information from its BAs about any studies they have performed for the summer assessment period. WECC also requests Balancing Authorities to update any applicable data (actual loads, forecasts, outages, and future and existing resource status changes) that have been previously submitted to WECC. The submitted information and data are then reviewed and compiled into the resulting resource assessment for the WECC Region and subregions.

TABLE 140: WECC ON-PEAK CAPACITY RESOURCES AND RESERVE MARGINS

	2011 Summer Forecast (MW)	2011 Summer Forecast (%)	Change from prior year (MW)	Change from prior year (percentage point)
Existing-Certain and Net Firm Transactions (with Demand Response)	174,091	16.7%	(9,081)	(10.3)
Anticipated Capacity Resources	177,961	19.3%	(6,743)	(8.8)
Prospective Capacity Resources	177,961	19.3%	(6,743)	(8.8)
NERC Reference Margin Level	**21,179**	**14.2%**	**(37)**	(0.1)

The loads and resources are compared against the target Reserve Margins that were developed for WECC's Power Supply Assessment (PSA) and NERC's *Long-Term Reliability Assessment* (LTRA).[143,144]

[143] WECC's Power Supply Assessment : http://www.wecc.biz/committees/StandingCommittees/PCC/LRS/Lists/SiteNews/Attachments/2/Draft%20PSA%2018Aug09%20posted.doc

[144] NERC's *2010 Long Term Reliability Assessment*: http://www.nerc.com/files/2010_LTRA_v2-.pdf

The target Reserve Margins were created using a building block approach for developing Planning Reserve Margins. The building block approach has four elements: contingency reserves, regulating reserves, reserves for additional forced outages, and reserves for one-in-ten weather events. The building block values were developed for each BA and then aggregated by subregions and the entire WECC Region for the PSA, the LTRA, and the seasonal assessment analyses. The aggregated summer season Planning Reserve Margin target for WECC of 14.2 percent may be lower or higher than some of the state, provincial, or LSE requirements within WECC, but was developed specifically for use in the above-mentioned assessments.

WECC staff does not analyze possible fuel supply adequacy or fuel supply interruption scenarios. However, fuel supply studies are performed by the individual LSEs and BAs within the Region, and no fuel supply issues have been reported to WECC. Historically, multiple fuel supply and delivery options have been available to generators within WECC. Coal-fired plants have been built at or near their fuel sources and generally have long-term fuel contracts with the mine operators, or actually own the mines. The current coal supply for these plants is considered adequate. Gas-fired plants are historically located near major load centers and rely on relatively abundant western gas supplies from the San Juan basin in the Four Corners Area, the Permian Basin in western Texas, the gas field in the Rocky Mountains, and the Sedimentary Basin in western Canada. Access to multiple supply regions reduces the concerns of fuel supply interruption. It is not projected that natural gas supply or transportation issues will occur this summer.

Other Region-Specific Issues

WECC does not anticipate any reliability concerns for the upcoming summer season.

California/México Area (CA-MX)

Demand

The California/México Area is a summer-peaking Area. The 2011 summer coincident peak demand of 57,646 MW, which is projected to occur in August, is lower than the 2010 summer forecast coincident peak demand of 57,609 MW. The 2011 summer forecast is 8.6 percent greater than 2010's actual coincident peak demand of 52,717 MW. The Area's 2010 summer peak demand occurred during a period of generally normal temperatures in northern California and warmer than normal temperatures in southern California. For the 2011 summer period, direct control load management demand, contractually interruptible demand, critical peak-pricing with control demand and load as a capacity resource demand total 2,204 MW, or 3.8 percent, of Total Internal Demand. While Area entities expect to serve all Firm demand, it should be noted that a significant portion of California operates under a market system that includes load as a capacity resource that may be bid into the market. Hence, served Non-Firm demand may be less than the 2,204 MW forecast by the amount of the capacity bids in effect during the peak hour.

TABLE 141: WECC-CA-MX FORECAST AND ACTUAL PEAK DEMAND

2010 Total Internal Demand (MW)	2010 Actual Demand (MW)	Difference in Actual versus Forecast (MW)	Difference in Actual versus Forecast (%)	2011 Total Internal Demand (MW)	Difference in 2011 and 2010 Forecast Demand (MW)	Difference in 2010 Actual versus 2011 Forecast (%)	All-Time Summer Peak Demand (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)
57,609	52,717	(4,892)	-8.5%	57,646	37	0.1%	-	57,646	-

Generation

WECC modeled the California/México Area using Existing capacity for the peak month of August as follows:

- Total Capacity — 64,414 MW
    - Wind: 2,718 MW (51 MW forecast on-peak)
    - Solar: 479 MW (461 MW projected on-peak)
    - Biomass: 444 MW (443 MW forecast on-peak)
- Total Internal Capacity — 65,078 MW
    - Wind: 2,779 MW (51 MW projected on-peak)
    - Solar: 519 MW (499 MW forecast on-peak)
    - Biomass: 471 MW (469 MW projected on-peak)

TABLE 142: WECC-CA-MX EXISTING AND PLANNED PEAK CAPACITY

Existing-Certain (MW)	50,241
Existing-Other (MW)	7,955
Future-Planned (MW)	664

WECC-CA-MX

FIGURE 44: WECC-CA-MX EXISTING AND PLANNED RENEWABLE GENERATION

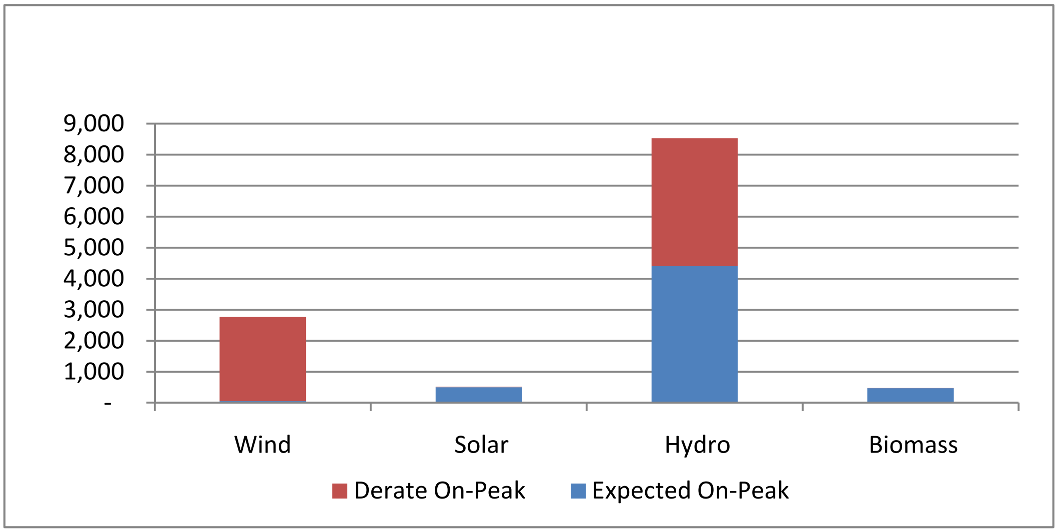


TABLE 143: WECC-CA-MX EXISTING AND PLANNED RENEWABLE GENERATION

Wind Expected On-Peak	51
Wind Derate On-Peak	2,718
Wind Nameplate/Installed Capacity	2,769
Solar Expected On-Peak	499
Solar Derate On-Peak	20
Solar Nameplate/Installed Capacity	519
Hydro Expected On-Peak	4,415
Hydro Derate On-Peak	4,119
Hydro Nameplate/Installed Capacity	8,534
Biomass Expected On-Peak	469
Biomass Derate On-Peak	1
Biomass Nameplate/Installed	470

California hydro generation is forecast to be near to above normal as statewide snow water content as of March 1 was 125 percent of average. Snowpack is the best indicator of conditions for a large portion of the hydroelectric generation as the plants are largely fed from snowmelt rather than reservoir storage.

Transmission

Although several major constrained transmission paths have been upgraded in recent years, path constraints can still exist. Operating procedures are in place to manage any high loading conditions that may occur during the summer.

Many Areas of California are prone to seasonal brush and forest fires that may impact the transmission system. While the fire-related transmission outages may temporarily affect local Areas, widespread and significant interruptions to electric power delivery are not projected to be an issue during the summer peak period.

Operational Issues

The San Francisco Bay Area, San Diego Area, and Los Angeles Basin have been identified as reactive power-limited Areas. The California ISO has developed reactive power reserve monitoring tools and nomograms for each of those Areas to ensure that adequate reactive power is available to protect against the next credible contingency.

Table 144: WECC-CA-MX Imports and Exports On-Peak

Imports (MW)	15,936
Firm (MW)	15,936
Expected (MW)	-
Exports (MW)	245
Firm (MW)	245
Expected (MW)	-
Net Imports (MW)	**15,691**

Entities in California have developed several ongoing annual processes to prepare for summer peak conditions. The processes used by the California ISO include:

- Assessing utility procurement plans to meet resource adequacy requirements;
- Working with investor-owned utilities to further refine execution of Demand Response programs;
- Working directly with the power plant owners on:
  - maintenance procedures, and
  - testing units prior to summer peak load period;
- Working with transmission owners on maintenance programs;
- Holding operator training workshops to bring together grid operators from all over the West;
- Working with California fire authorities to:
  - review current conditions,
  - review real-time notification procedures, and
  - participate in operator training workshops;
- Coordinating with BAs in the West to:
  - share information and prepare for contingencies, and
  - foster ongoing relationships to rely on each other during critical periods; and
- Coordinate with state energy agencies, Flex Your Power, and investor-owned utilities to promote conservation.

Table 145: WECC-CA-MX Demand Response and Energy Efficiency On-Peak

Non-Dispatchable DSM (MW)	408
Energy Efficiency	408
Non-Controllable Demand-Side Demand Response	-
Total Internal Demand	57,646
Controllable, Dispatchable Demand Response	2,204
Net Internal Demand	55,442

Reliability Assessment Analysis

The projected Reserve Margins for the peak month of August are 18.2 percent (29.0 percent in 2010) based on existing resources, 19.3 percent based on existing plus anticipated resources, and 19.3 percent based on existing resources plus anticipated resources plus prospective resources. The California/México target margin is 14.9 percent. The 2011 margins are lower because fewer imports were modeled than in prior years. Generation and transmission facilities are forecast to be sufficient to provide reliable electric service throughout the Area. An assessment for the California Independent System Operator portion of the subregion is scheduled to be available by mid-May at: http://www.caiso.com/docs/2003/04/25/200304251132276595.html.

Table 146: WECC-CA-MX On-Peak Capacity Resources and Reserve Margins

	2011 Summer Forecast (MW)	2011 Summer Forecast (%)	Change from prior year (MW)	Change from prior year (percentage point)
Existing-Certain and Net Firm Transactions (with Demand Response)	68,136	18.2%	(3,098)	(11.3)
Anticipated Capacity Resources	68,800	19.3%	(3,112)	(11.4)
Prospective Capacity Resources	68,800	19.3%	(3,112)	(11.4)
NERC Reference Margin Level	**8,589**	**14.9%**	**63**	0.1

Other Area Issues

All power plants in California are required to operate in accordance with strict air quality regulations. Some plant owners have upgraded emission control equipment to remain in compliance with increasing emission limitations while other owners have chosen to discontinue operating some plants. The effects of owners' responses to environmental regulations have been accounted for in the Area's resource data and it is not projected that environmental issues will have additional adverse impacts on resource adequacy within the Area during the upcoming summer season.

The California Public Utilities Commission's year-ahead and month-ahead resource adequacy program requires jurisdictional LSEs to demonstrate a 15-percent Planning Reserve Margin. The California ISO requires the non-jurisdictional LSEs to demonstrate a planning Reserve Margin that meets each load-serving entity's local regulatory authority's planning criteria. The year-ahead requirement is 90 percent of the full 115 percent of total resource adequacy obligation. That full 115 percent of total resource adequacy obligation needs to be demonstrated 30 days prior to the beginning of each month.

California is very aggressively pursuing a variety of smart grid and smart metering programs. These efforts include improvements to the collection voltage and phase angle information to provide a more robust model and a more reliable smart grid. Smart metering programs for both active and passive demand control are either already implemented or are under active development, but it is not forecast that such programs will significantly affect system operations during the upcoming summer period.

Desert Southwest Area

Demand

The Desert Southwest is a summer-peaking Area. The 2011 summer coincident peak demand of 29,049 MW, which is projected to occur in August, is 1.1 percent above the 2010 actual coincident peak demand of 29,306 MW. The 2011 peak forecast is 4.4 percent more than 2010's forecast coincident peak demand of 27,816 MW. The Area's 2010 summer peak demand occurred during a period of generally normal to warmer than normal temperatures. For the 2011 summer period, direct control load management demand, contractually interruptible demand, critical peak-pricing with control demand and load as a capacity resource demand a total 449 MW, or 1.5 percent of Total Internal Demand.

TABLE 147: WECC-DESERT SW FORECAST AND ACTUAL PEAK DEMAND

2010 Total Internal Demand (MW)	2010 Actual Demand (MW)	Difference in Actual versus Forecast (MW)	Difference in Actual versus Forecast (%)	2011 Total Internal Demand (MW)	Difference in 2011 and 2010 Forecast Demand (MW)	Difference in 2010 Actual versus 2011 Forecast (%)	All-Time Summer Peak Demand (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)
27,816	29,306	1,490	5.4%	29,049	1,233	4.4%	30,642	(1,593)	-5.2%

Generation

WECC modeled the Desert Southwest Area using Existing capacity for the peak month of August as follows:

- Total Capacity — 43,046 MW
  - Wind: 584 MW (25 MW projected on-peak)
  - Solar: 65 MW (117 MW forecast on-peak)
  - Biomass: 112 MW (62 MW projected on-peak)
- Total Internal Capacity — 44,330 MW
  - Wind: 584 MW (25 MW forecast on-peak)
  - Solar: 245 MW (175 MW projected on-peak)
  - Biomass: 112 MW (62 MW forecast on-peak)

TABLE 148: WECC-DESERT SW EXISTING AND PLANNED PEAK CAPACITY

Existing-Certain (MW)	40,962
Existing-Other (MW)	1,616
Future-Planned (MW)	1,284

Above-average hydro conditions are anticipated for this summer. However, the Lower Colorado River Basin has experienced a ten-year drought that has led to low reservoir levels at the Hoover power plant. Current Hoover power plant capacity projections for this summer indicate an projected average capacity of 1,692 MW compared to a maximum plant output of 2,074 MW.

The latest 24-month study projections developed by the U.S. Bureau of Reclamation indicate that reservoir elevations are sufficient to meet peak demand and daily energy demand throughout the 2011 summer period.

FIGURE 45: WECC-DESERT SW EXISTING AND PLANNED RENEWABLE GENERATION

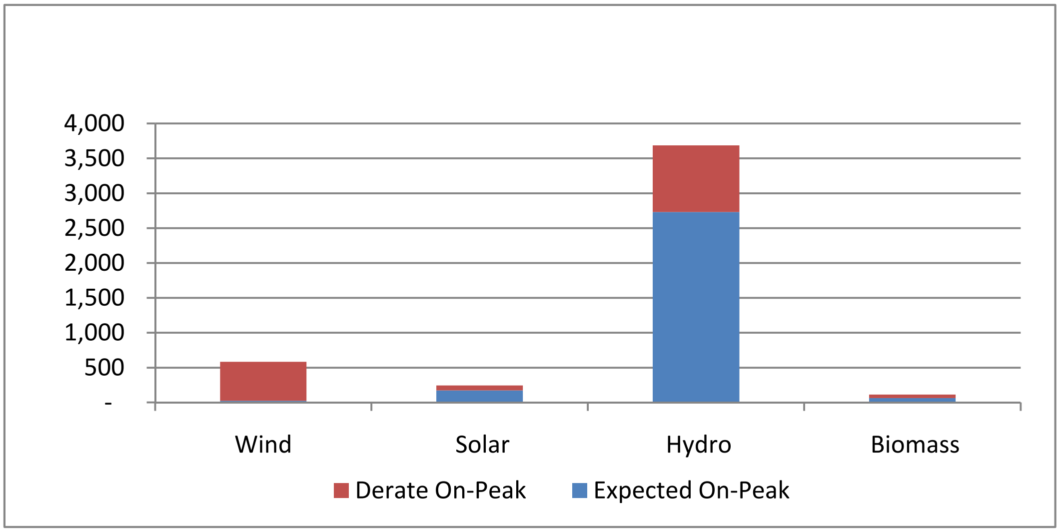


TABLE 149: WECC-DESERT SW EXISTING AND PLANNED RENEWABLE GENERATION

Wind Expected On-Peak	25
Wind Derate On-Peak	559
Wind Nameplate/Installed Capacity	584
Solar Expected On-Peak	175
Solar Derate On-Peak	70
Solar Nameplate/Installed Capacity	245
Hydro Expected On-Peak	2,730
Hydro Derate On-Peak	957
Hydro Nameplate/Installed Capacity	3,687
Biomass Expected On-Peak	62
Biomass Derate On-Peak	50
Biomass Nameplate/Installed	112

Transmission

Based on inter- and intra-area studies, the transmission system is considered adequate for projected Firm transactions and a significant amount of economy electricity transfers. When necessary, phase-shifting transformers in the southern Utah/Colorado/Nevada transmission system will be used to help control unscheduled flows. Reactive Reserve Margins have been studied and are forecast to be adequate throughout the Area.

Biennial studies are performed to determine the system import limit for the Phoenix and Yuma metropolitan Areas with all local generation out of service, and to determine the maximum load-serving capability with local generation modeled as being in service.[145]

[145] APS Reliability Must-Run Analysis

Operational Issues

Fuel supplies are projected to be adequate to meet summer peak demand and energy load conditions. In addition, Firm coal supply and transportation contracts are in place, and sufficient coal inventories are anticipated for the summer season.

TABLE 150: WECC-DESERT SW IMPORTS AND EXPORTS ON-PEAK

Imports (MW)	2,797
Firm (MW)	2,797
Expected (MW)	-
Exports (MW)	6,392
Firm (MW)	6,392
Expected (MW)	-
Net Exports (MW)	**3,595**

TABLE 151: WECC-DESERT SW DEMAND RESPONSE AND ENERGY EFFICIENCY ON-PEAK

Non-Dispatchable DSM (MW)	144
Energy Efficiency	144
Non-Controllable Demand-Side Demand Response	-
Total Internal Demand	29,049
Controllable, Dispatchable Demand Response	449
Net Internal Demand	28,600

Reliability Assessment Analysis

The projected Reserve Margins for the peak month of August are 30.2 percent (28.0 percent in 2010) based on existing resources, 34.6 percent based on existing plus anticipated resources, and 34.6 percent based on existing resources plus anticipated resources plus prospective resources. The Desert Southwest target margin is 13.5 percent. Generation and transmission facilities are forecast to be sufficient to provide reliable electric service throughout the Area.

TABLE 152: WECC-DESERT SW ON-PEAK CAPACITY RESOURCES AND RESERVE MARGINS

	2011 Summer Forecast (MW)	2011 Summer Forecast (%)	Change from prior year (MW)	Change from prior year (percentage point)
Existing-Certain and Net Firm Transactions (with Demand Response)	37,816	30.2%	4,197	7.0
Anticipated Capacity Resources	39,100	34.6%	5,467	11.4
Prospective Capacity Resources	39,100	34.6%	5,467	11.4
NERC Reference Margin Level	**3,922**	**13.5%**	**139**	(0.1)

WECC-RMPA

Rocky Mountain Power Area (RMPA)

Demand

The 2011 summer coincident peak demand of 10,973 MW is projected to occur in July and is 2.6 percent less than the 2010 actual coincident peak demand of 11,208 MW. The 2011 summer coincident peak forecast is slightly less than the 2010 summer projected coincident forecast peak demand of 10,979 MW. The Area's 2010 summer peak demand occurred during a period of generally warmer than normal temperatures. For the 2011 summer period, direct control load management demand, contractually interruptible demand, critical peak-pricing with control demand, and load as a capacity resource demand total 408 MW, or 3.7 percent of Total Internal Demand.

TABLE 153: WECC-RMPA FORECAST AND ACTUAL PEAK DEMAND

2010 Total Internal Demand (MW)	2010 Actual Demand (MW)	Difference in Actual versus Forecast (MW)	Difference in Actual versus Forecast (%)	2011 Total Internal Demand (MW)	Difference in 2011 and 2010 Forecast Demand (MW)	Difference in 2010 Actual versus 2011 Forecast (%)	All-Time Summer Peak Demand (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)
10,979	11,208	229	2.1%	10,973	(6)	-0.1%	-	10,973	-

Generation

WECC modeled the Rocky Mountain Area using Existing Capacity for the peak month of July as follows:

- Total Capacity — 16,722 MW
  - Wind: 1,420 MW (60 MW projected on-peak)
  - Solar: 8 MW (4 MW forecast on-peak)
  - Biomass: 9 MW (9 MW projected on-peak)
- Total Internal Capacity — 17,493 MW
  - Wind: 2,020 MW (66 MW forecast on-peak)
  - Solar: 25 MW (4 MW projected on-peak)
  - Biomass: 9 MW (9 MW forecast on-peak)

Hydro conditions for the 2011 summer period are projected to be above normal and reservoir releases should be more than sufficient to meet contractual requirements. Under normal conditions, the Glen Canyon hydro plant is subject to water release restrictions. However, in a declared emergency condition, where power system reliability and stability are judged to be at risk, the restrictions may be waived.

Table 154: WECC-RMPA Existing and Planned Peak Capacity

Existing-Certain (MW)	14,075
Existing-Other (MW)	2,169
Future-Planned (MW)	771

Figure 46: WECC-RMPA Existing and Planned Renewable Generation

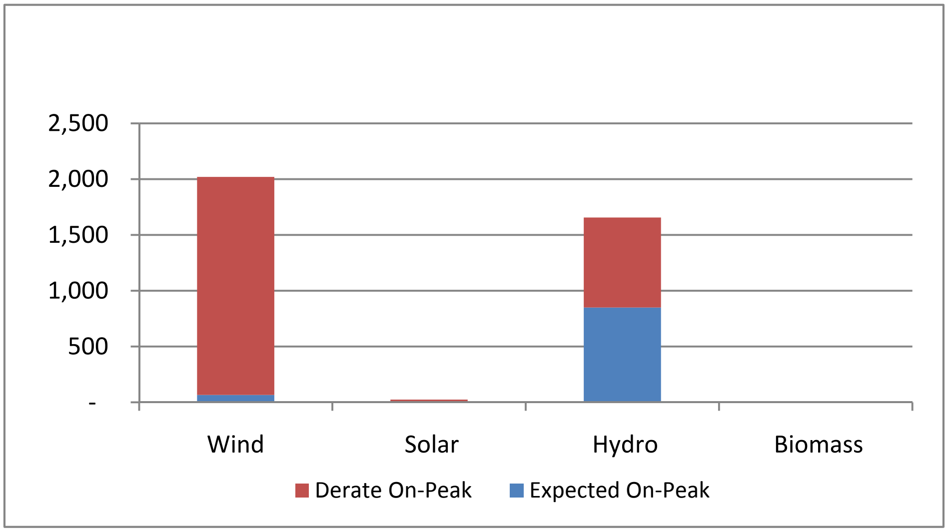


Table 155: WECC-RMPA Existing and Planned Renewable Generation

Wind Expected On-Peak	66
Wind Derate On-Peak	1,954
Wind Nameplate/Installed Capacity	2,020
Solar Expected On-Peak	4
Solar Derate On-Peak	21
Solar Nameplate/Installed Capacity	25
Hydro Expected On-Peak	851
Hydro Derate On-Peak	805
Hydro Nameplate/Installed Capacity	1,656
Biomass Expected On-Peak	9
Biomass Derate On-Peak	-
Biomass Nameplate/Installed	9

Transmission

The transmission system is forecast to be adequate for all Firm transfers and most economy energy transfers. However, the transmission path between southeastern Wyoming and Colorado often becomes heavily loaded, as do the transmission interconnections to Utah and New Mexico. WECC's Unscheduled Flow Mitigation Plan[146] may be invoked to provide line-loading relief for these paths, if needed. The RMPA, like several other Areas in WECC, has Bulk Power System transmission lines that are potentially exposed to fire hazards that may adversely impact intra-region power transfers.

[146] WECC Unscheduled Flow Mitigation Plan

Colorado entities have participated in the 2010 Colorado Coordinated Planning Group Study, WECC operating transfer studies, and the Common Use System (CUS) studies as required by FERC Order 890 (through the CUS Transmission Coordination & Planning Committee).[147]

Operational Issues

Fuel supplies are projected to be adequate to meet summer peak demand and energy load conditions. In addition, Firm coal supply and transportation contracts are in place, and sufficient coal inventories are anticipated for the summer season.

Table 156: WECC-RMPA Imports and Exports On-Peak

Imports (MW)	396
Firm (MW)	379
Expected (MW)	17
Exports (MW)	1,249
Firm (MW)	599
Expected (MW)	650
Net Exports (MW)	**853**

Table 157: WECC-RMPA Demand Response and Energy Efficiency On-Peak

Non-Dispatchable DSM (MW)	49
Energy Efficiency	49
Non-Controllable Demand-Side Demand Response	-
Total Internal Demand	10,973
Controllable, Dispatchable Demand Response	408
Net Internal Demand	10,565

Reliability Assessment Analysis

The projected Reserve Margins for the peak month of July are 30.0 percent (31.0 percent in 2010) based on existing resources, 31.2 percent based on existing plus anticipated resources, and 31.2 percent based on existing resources plus anticipated resources plus prospective resources. The Desert Southwest target margin is 12.5 percent. Generation and transmission facilities are forecast to be adequate to provide reliable electric service throughout the Area.

Table 158: WECC-RMPA On-Peak Capacity Resources and Reserve Margins

	2011 Summer Forecast (MW)	2011 Summer Forecast (%)	Change from prior year (MW)	Change from prior year (percentage point)
Existing-Certain and Net Firm Transactions (with Demand Response)	14,263	30.0%	364	(1.1)
Anticipated Capacity Resources	14,401	31.2%	536	0.5
Prospective Capacity Resources	14,401	31.2%	536	0.5
NERC Reference Margin Level	**1,372**	**12.5%**	**21**	0.2

[147] Transmission Coordination & Planning Committee

Northwest Power Pool (NWPP)

Summary

The Northwest Power Pool (NWPP) is comprised of all or major portions of the states of Washington, Oregon, Idaho, Wyoming, Montana, Nevada, and Utah; a portion of northern California; and the Canadian provinces of British Columbia and Alberta. This vast area covers 1.2 million square miles of the WECC's 1.8 million square miles. The NWPP, in collaboration with its members (20 Balancing Authorities), has conducted a reliability assessment to evaluate the ability of the NWPP to meet the load requirements during the 2011 summer. Since the NWPP covers a large and diverse Area of the Western Interconnection, its members face unique issues in the day-to-day coordinated operations of the system. The NWPP Area in aggregate is a winter-peaking Area with a large amount of hydro resources.

Analyses indicate the NWPP will have adequate generation capacity and energy, required operating reserves (regulating reserve and contingency reserve), and available transmission to meet the forecast Firm loads for the 2011 summer operations, assuming normal ambient temperature and normal weather conditions.

This assessment is valid for the NWPP Area as a whole. However, these overall results do not necessarily apply to all subareas (individual members, BAs, states, or provinces) when assessed separately.

The NWPP has a publicly available document on its website that addresses 2011 summer conditions. That document is available at: http://www.nwpp.org/publications.html.

Historic Demand

The NWPP 2010 coincident summer peak demand of the United States and Canada was 53,989 MW and occurred on August 17, 2010. The 2010 coincident summer peak demand was 90 percent of the forecast; however, the coincident peak demand occurred during below-normal temperature conditions. Normalizing for temperature variance (50 percent probability), the 2010 coincident peak demand would have been 57,000 MW or 95 percent of the forecast. Traditionally, the NWPP summer peak occurs in late July. With the cooler-than-normal temperatures and the economic recession, the 2010 peak demand occurred later in the season.

Table 159: WECC-NWPP (U.S.) Forecast and Actual Peak Demand

2010 Total Internal Demand (MW)	2010 Actual Demand (MW)	Difference in Actual versus Forecast (MW)	Difference in Actual versus Forecast (%)	2011 Total Internal Demand (MW)	Difference in 2011 and 2010 Forecast Demand (MW)	Difference in 2010 Actual versus 2011 Forecast (%)	All-Time Summer Peak Demand (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)
37,062	40,555	3,493	9.4%	36,438	(624)	-1.7%	-	36,438	-

TABLE 160: WECC-NWPP (CAN) FORECAST AND ACTUAL PEAK DEMAND

2010 Total Internal Demand (MW)	2010 Actual Demand (MW)	Difference in Actual versus Forecast (MW)	Difference in Actual versus Forecast (%)	2011 Total Internal Demand (MW)	Difference in 2011 and 2010 Forecast Demand (MW)	Difference in 2010 Actual versus 2011 Forecast (%)	All-Time Summer Peak Demand (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)	Difference in 2011 Forecast Demand versus All-Time (MW)
17,703	16,603	(1,100)	-6.2%	18,035	332	1.9%	17,338	697	4.0%

Forecast Demand

The economic recession that began in 2007 has had an impact on the NWPP (United States and Canada) power use and future forecasts. There has been no noticeable recovery to date. The 2011 summer coincident peak demand forecast for the NWPP of 58,000 MW is based on normal weather, reflects the prevailing economic climate (stagnant), and has a 50-percent probability of not being exceeded.

TABLE 161: WECC-NWPP (U.S.) EXISTING AND PLANNED PEAK CAPACITY

Existing-Certain (MW)	47,586
Existing-Other (MW)	16,469
Future-Planned (MW)	296

TABLE 162: WECC-NWPP (CAN) EXISTING AND PLANNED PEAK CAPACITY

Existing-Certain (MW)	22,663
Existing-Other (MW)	5,078
Future-Planned (MW)	689

The NWPP has approximately 575 MW of interruptible demand capability and load management. In addition, the load forecast incorporates any benefit (load reduction) associated with demand-side resources not controlled by the individual utilities. Some of the entities within the NWPP have specific programs to manage peak issues during extreme conditions. Normally these programs are used to meet the entities' operating reserve requirements and have no discernable impacts on the projected NWPP peak demand.

Under normal weather conditions, the NWPP does not anticipate dependence on imports from external Areas during summer peak demand periods. However, if much-lower-than-normal precipitation occurs, it may be extremely advantageous to use transfer capabilities from outside the NWPP to reduce reservoir drafts.

Resource Assessment

Approximately 60 percent of the NWPP resource capability is from hydro generation. The remaining generation resources are conventional thermal plants and miscellaneous resources such as nonutility-owned, gas-fired cogeneration or wind.

Hydroelectric Capability – NWPP power planning is done by subarea. Idaho, Nevada, Wyoming, Utah, northern California, British Columbia, and Alberta individually optimize their resources to their demand. The Coordinated System (Oregon, Washington, northern Idaho and western Montana) oversees the operation of its hydro resources to serve its demand. The Coordinated System hydro operation is based on critical water planning assumptions (currently the 1936–1937 water year). Critical water in the Coordinated System equates to approximately 11,000 average MW of Firm energy load carrying capability, when reservoirs start full. Under average water year conditions, the additional Non-Firm energy available is approximately 3,000 average MW.

April through July – This period is the refill season when reservoirs store spring runoff. The May 2011 final forecast for the January through July runoff (Columbia River flows at The Dalles, Oregon) is 128.0 million acre-feet, which is 119 percent of the 30-year average. The water "fueling" associated with hydro-powered resources can be difficult to manage because there are several competing purposes including, but not limited to: current electric power generation; future (summer) electric power generation; flood control; biological opinion requirements resulting from the Endangered Species Act; and special river operations for recreation, irrigation, navigation, and the refilling of the reservoirs each year. Any time precipitation levels are below normal, balancing these interests becomes even more difficult. With the competition for the water, power operations for the summer must be effective and efficient. The goal is to manage all the competing requirements while refilling the reservoirs to the highest extent possible.

Sustainable Hydroelectric Capability – Operators of the hydro facilities optimize the use of available water throughout the year while assuring all the competing purposes are evaluated. Although available Reserve Margin at time of peak can be calculated to be greater than 20 percent, this can be misleading. Since hydro can be limited due to conditions (either lack of water or imposed restrictions), the projected sustainable capacity must be determined before establishing a representative Reserve Margin. In other words, the Firm energy load carrying capability (FELCC) is the amount of energy that the system may be called on to produce on a Firm or guaranteed basis during actual operations. The FELCC is highly dependent on the availability of water for hydroelectric generation.

The NWPP has developed the forecast sustainable capacity based on the aggregated information and estimates that the members have made with respect to their own hydro generation. Sustainable capacity is for periods greater than two hours during daily peak periods assuming various conditions. This aggregated information yielded a reduction for sustained capability of approximately 7,000 MW. This reduction is more relevant to the Northwest in the winter; however, under summer extreme-low-water conditions, it also impacts summer conditions.

Thermal Generation Capacity – No thermal plant or fuel problems are anticipated. To the extent that existing thermal resources are not scheduled for maintenance, thermal and other resources should be available as needed during the summer peak period.

Thermal Generation and Hydro Generation Integration – The diversity of the NWPP provides operational efficiencies. The northwest portion of the NWPP peaks in the winter whereas the Rocky-Mountain portion peaks in the summer. Also, the eastern portion of the NWPP has the majority of the thermal generation whereas the western portion has the majority of the hydro generation. This allows the maximum integration of the resources to meet the coincident peak for both the winter and the summer. In addition, this diversity allows the BAs to maximize the use of the transmission while meeting Firm customer load. The thermal generation in the east, integrated with the hydro generation in the west, improves the total available Firm energy and increases the NWPP's system reliability.

Having the flexibility to use hydro generation to meet peak and base load thermal generation to meet the Firm energy requirements is predicated on availability of transmission (see Transmission Operating Issues, below).

Wind Generation – Several states have enacted renewable portfolio standards that will require some NWPP members to satisfy at least 20 percent of their load with energy generated from renewable energy resources. This may result in a significant increase in variable generation within the NWPP, creating new operational challenges that will have to be addressed in the future. Some of the safety-net programs such as contingency reserve and under-frequency load shedding will be reevaluated for effectiveness.

FIGURE 47: WECC-NWPP (U.S.) EXISTING AND PLANNED RENEWABLE GENERATION

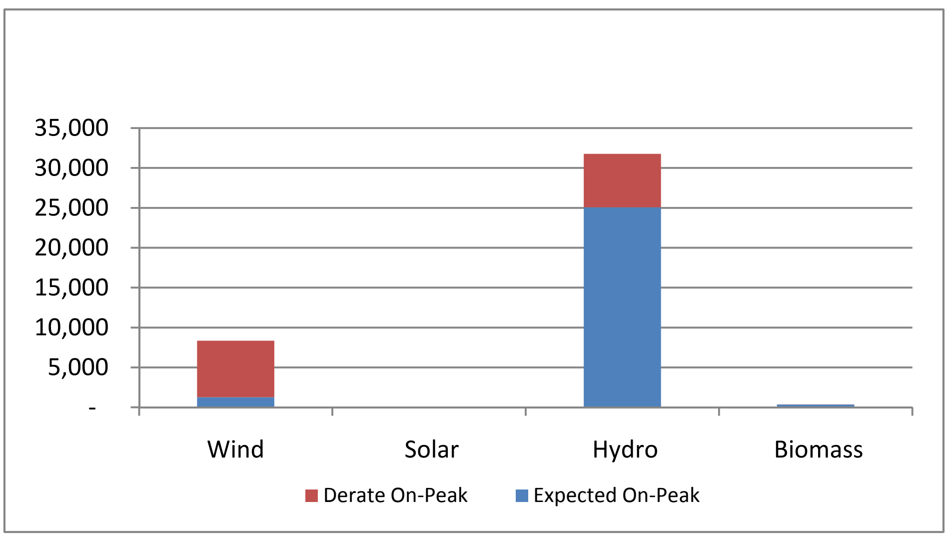


TABLE 163: WECC-NWPP (U.S.) EXISTING AND PLANNED RENEWABLE GENERATION

Wind Expected On-Peak	1,263
Wind Derate On-Peak	7,093
Wind Nameplate/Installed Capacity	8,356
Solar Expected On-Peak	-
Solar Derate On-Peak	-
Solar Nameplate/Installed Capacity	-
Hydro Expected On-Peak	25,084
Hydro Derate On-Peak	6,685
Hydro Nameplate/Installed Capacity	31,769
Biomass Expected On-Peak	342
Biomass Derate On-Peak	23
Biomass Nameplate/Installed	365

The NWPP estimats the installed wind generation capacity for the 2011 summer season will be approximately 8,600 MW, but the on-peak contribution is projected to be closer to 1,500 MW. With the increasing variable generation, conventional operation of existing hydro and thermal resources is being impacted.

FIGURE 48: WECC-NWPP (CAN) EXISTING AND PLANNED RENEWABLE GENERATION

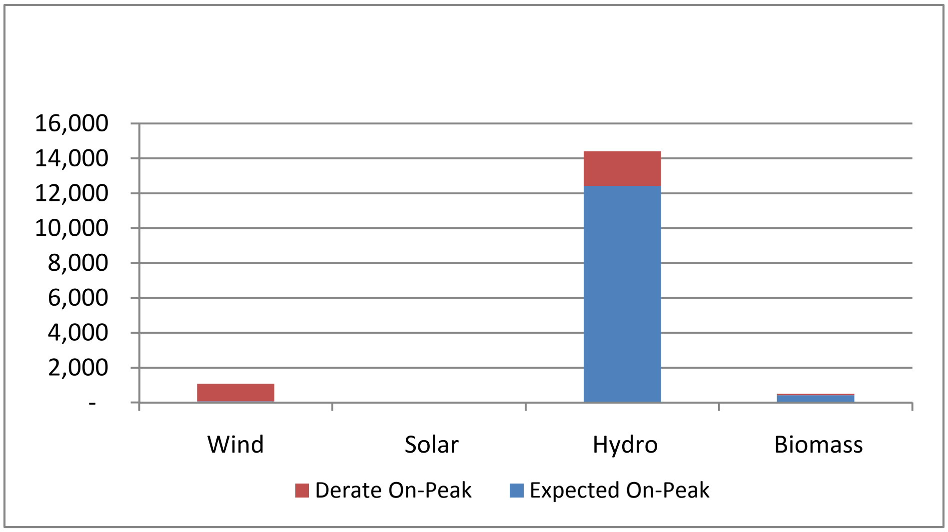


TABLE 164: WECC-NWPP (CAN) EXISTING AND PLANNED RENEWABLE GENERATION

Wind Expected On-Peak	67
Wind Derate On-Peak	1,020
Wind Nameplate/Installed Capacity	1,087
Solar Expected On-Peak	-
Solar Derate On-Peak	-
Solar Nameplate/Installed Capacity	-
Hydro Expected On-Peak	12,432
Hydro Derate On-Peak	1,973
Hydro Nameplate/Installed Capacity	14,405
Biomass Expected On-Peak	418
Biomass Derate On-Peak	79
Biomass Nameplate/Installed	497

The wind generation manufacturers' standard operating temperature for wind turbines range from -10° C to +40° C (14° F to 104° F). During the summer peaking period, the temperature in the Areas where the majority of the wind turbines are located can exceed 104° F, leaving no capability from the wind generation during those periods. In addition, there is a risk of over-generation in the spring and fall. When both the wind and hydro generation are in high generation mode, and given the environmental constraints on dissolved gases in the river, there are times when desired generation may exceed forecast load plus the ability to export.

Operating procedures have been introduced to address this situation.

Biomass Generation – The installed capacity of biomass generation within the NWPP is 670 MW with projected on-peak amounts of 668 MW.

Other Generation – Within the NWPP there is an underground natural gas storage facility. This storage is located near many of the gas plants located in the NWPP Area, minimizing any effect that a regional gas problem may cause. In addition, one entity in the NWPP Area has over 700 MW of generation that can be fired on diesel fuel.

External Resources – No reliance on resources outside of the NWPP is projected for the 2011 summer season.

TABLE 165: WECC-NWPP (U.S.) IMPORTS AND EXPORTS ON-PEAK

Imports (MW)	4,900
Firm (MW)	4,174
Expected (MW)	726
Exports (MW)	9,127
Firm (MW)	9,127
Expected (MW)	-
Net Exports (MW)	**4,227**

TABLE 166: WECC-NWPP (CAN) IMPORTS AND EXPORTS ON-PEAK

Imports (MW)	-
Firm (MW)	-
Expected (MW)	-
Exports (MW)	2,145
Firm (MW)	1,900
Expected (MW)	245
Net Exports (MW)	**2,145**

Transmission Assessment

Several BAs are constructing new transmission within the NWPP Area to address load service issues. The new transmission has low impact on the overall transfer of power from one zone to another. No significant transmission lines are scheduled to be out of service during the summer season.

However, replacement of the Midpoint, Idaho, 500 MVA transformer with a 700 MVA transformer is scheduled for the first week of June. Should the in-service date be delayed, depending on the amount of generation armed for tripping, the Borah West path (WECC Path 17) may be derated by 500 to 1,000 MW.

Constrained paths within the NWPP Area are known and operating studies modeling these constraints have been performed. As a result of these studies, operating procedures have been developed to assure safe and reliable operations.

Transmission Operating Issues

The BAs constantly monitor critical paths to assure availability of capacity on the transmission system for flow of contingency reserve from one zone to another. Seven critical paths allow the NWPP to enjoy maximum efficiency and reliability. These critical paths are: Path 1 – Alberta to British Columbia; Path 3 – British Columbia to Oregon-Washington-Montana; Path 66 – Oregon-Washington-Montana to Northern California; Path 14 and Path 55 – Oregon-Washington-Montana to Idaho; and Path 16 and Path 20 – Idaho to Nevada-Wyoming-Utah. If any of these Paths become constrained, the ability to maximize efficiency and reliability is significantly reduced within the NWPP.

Depending upon the constraint, the above zones may become isolated and therefore dependent upon the resource within the zone to meet the reliability requirements. Operational constraints are seldom a limiting factor. However, when they are limiting, the operating programs are designed to assure reliability is met all the time, even under transmission constraints.

Outage Coordination – The NWPP coordinated outage (transmission) system was designed to assure that outages could be coordinated among all stakeholders (operators, maintenance personnel, transmission users, and operations planners) in an open process. This process had to assure that proper operating studies were accomplished and transmission impacts and limits known, to fulfill a requirement from the 1996 West Coast disturbances that the system be operated only under studied conditions. The WECC Reliability Coordinator is involved in the outage coordination process and has direct access to the outage database.

Monthly Coordination – The outage coordination process requires NWPP members to designate significant facilities that, if out of service by themselves or in conjunction with another outage, will impact system capabilities. The significant facilities are defined and updated annually by the NWPP members. The scheduled outage of these critical facilities is posted on a common database. All utilities post proposed significant outages on WECC's Coordinated Outages System (COS). Outages are to be submitted to the COS at least 45 days ahead of the month they are proposed to occur so they can be viewed by interested entities. The involved entities then facilitate the NWPP coordination of all these outages. Entities can comment on the preliminary impacts, and schedules may be adjusted to maximize reliability and minimize market impacts. If coincidental outages cause too severe an impact, the requesting utilities work together to adjust schedules accordingly.

A final outage plan is posted with estimated path capabilities 30 days prior to the month in which the outages will occur. Detailed operational transfer capability studies are then performed and the limits for each affected path are posted at least 15 days prior to the outage.

Emergency outages can be requested outside of these schedule guidelines. Emergency outages are coordinated among adjacent utilities to minimize system exposure. Utilities can use the COS system to assure the system topology is correct for the next-day operating studies. As transmission operators increase the number of short-term outages in addition to the significant outages, the WECC Reliability Coordinator will be able to access the WECC COS database and use the final outage schedule in its real-time system analysis. This coordinated outage process has been very effective. The outage information is used by NWPP member utilities to perform system studies to maximize system reliability.

Semi-annual Planning – Long-Range Significant Outage Planning (LRSOP) – The NWPP staff facilitates outage meetings every six months with each utility's outage coordinator to discuss proposed longer-term outages. Utilities discuss anticipated outages needed for time-critical construction and periods where transmission capacity may need to be maximized. The outages are posted on the WECC COS and on the individual companies' OASIS sites.

Specific responsibilities of LRSOP include:

- sharing outage information with all parties affected by outages of significant equipment (*i.e.,* equipment that affects the transfer capability of rated paths). Information is shared two times each year for a minimum of a six-month period. The first meeting each year coordinates outages for July through December. The second meeting coordinates outages for January through June;
- reviewing the outage schedules to assure that needed outages can be reliably accomplished with minimal impact on critical transmission use; and
- having outage coordinators post the outages on the Coordinated Outages System within the applicable timeframes.

Next-Day Operating Studies – Additional path curtailments may be required depending upon current system conditions and outages. These curtailment studies are performed by the individual path operators based on the outage schedule developed through the COS process. According to the COS process, these studies are performed at least 15 days prior to the outage.

Individual path operators and transmission owners may also perform updated next-day studies to capture emergency outage requests and current system conditions such as generation dispatch to determine if the SOL studies and limits are still accurate. Based on these studies, additional SOL curtailments may be made by the path operators. The modified SOLs are posted on the individual transmission owner's OASIS and the Reliability Coordinator is notified.

The WECC Reliability Coordinator also performs system studies to ensure interconnected system reliability. The WECC Reliability Coordinator performs real-time system thermal studies to evaluate current operating conditions across the entire Interconnection.

The WECC Reliability Coordinator is in the process of incorporating real-time voltage tools to complement the thermal analysis currently being performed. Transient stability analysis capability is planned in the future. When the WECC Reliability Coordinator observes real-time reliability problems it contacts the path operator to discuss the issue and work on a solution. The WECC Reliability Coordinator will issue a directive for action if there is an imminent reliability threat and the Balancing Authority does not eliminate the reliability problem within an appropriate timeframe.

Voltage Stability – The WECC-1-CR System Performance Criteria, requirement WRS3, is used to plan adequate voltage stability margin in the NWPP Area as appropriate. Simulations are used to assure system performance is adequate and meets the required criteria.

Operating Issues

The NWPP Area does not anticipate any operating issues for the 2011 summer season.

Reliability Assessment Analysis

The NWPP does not have one explicit method for determining an adequacy margin. Bonneville Power Administration (BPA) and the Northwest Power and Conservation Council co-chair a regional forum that establishes targets for regional resource adequacy in the Pacific Northwest (PNW) region. The forum does not provide standards for regional utilities including BPA. The current standard, adopted in 2008, requires the LOLP probability to be less than 5% for both winter and summer energy and capacity. The latest assessment for 2015 indicates that the PNW region meets this standard for both energy and capacity. Others will use a Reserve Margin approach.

Table 167: WECC-NWPP (U.S.) Demand Response and Energy Efficiency On-Peak

Non-Dispatchable DSM (MW)	135
Energy Efficiency	135
Non-Controllable Demand-Side Demand Response	-
Total Internal Demand	36,438
Controllable, Dispatchable Demand Response	1,256
Net Internal Demand	35,182

Table 168: WECC-NWPP (CAN) Demand Response and Energy Efficiency On-Peak

Non-Dispatchable DSM (MW)	-
Energy Efficiency	-
Non-Controllable Demand-Side Demand Response	-
Total Internal Demand	18,035
Controllable, Dispatchable Demand Response	22
Net Internal Demand	18,013

Since no one method exists for the entire NWPP, the NWPP has elected to use a Reserve Margin analysis for the summer assessment. The 2011 NWPP generating capability is projected to be 87,000 MW, prior to adjusting for maintenance.

Based on the prior operating season, the NWPP has assumed a 1,500 MW contribution from wind resources during peak conditions. In determining planning margin for the current summer season one must further adjust for operating reserve requirement, which is approximately 3,500 MW. At this point, based on a load of 50-percent probability of not being exceeded, the planning margin is approximately 32 percent.

A severe weather event for the entire NWPP would add approximately 4,000 MW of load while at the same time under extreme water restrictions the sustained hydroelectric generation would reduce the capability by 7,000 MW. In addition, under the severe weather conditions wind generation is forecast to be minimal. However, accounting for the severe weather event and the available generation, the NWPP will meet the peak load requirements with no additional margin.

Contingency Reserve Sharing Procedure

As permitted by NERC and WECC criteria and standards, the NWPP has instituted a Reserve Sharing Program for contingency reserve. Those who participate in a reserve-sharing group are better positioned to meet the NERC disturbance control standard because they have access to a deeper and more diverse pool of shared reserve resources. Also, an increase in efficiency is obtained since the shared reserve obligation for the group as a whole is less than the sum of each participant's reserve obligation computed separately.

By sharing contingency reserve, the participants are entitled to use not only their own "internal" reserve resources, but to call on other participants for assistance if internal reserve does not fully cover a contingency. The reserve sharing process is automated but a manual backup process will be activated should communication links fail or the computer system malfunctions.

The NWPP is designated as a reserve sharing group (RSG) as provided under WECC Operating Reliability Criteria. Each member of the RSG submits its contingency reserve obligation (CRO) and most severe single contingency (MSSC) to a central computer. The combined member CRO must be larger than the RSG MSSC. If not, then each member's CRO is proportionally increased until this requirement is met. When any RSG member loses generation they have the right to call upon reserves from the other RSG members as long as they have first committed their own CRO. A request for contingency reserve must be sent within four minutes after the generation loss, and the received contingency reserve can only be held for 60 minutes. A request is sent via the member's energy management system to the central computer. The central computer then distributes the request proportionally among members within the RSG. Each member may be called to provide reserve up to its CRO. Critical transmission paths are monitored in this process to ensure SOL limits are not exceeded. If a transmission path SOL is exceeded the automated program redistributes the request among RSG members that are delivering reserve along non-congested paths. The WECC Reliability Coordinator continuously monitors the adequacy of the RSG reserve obligation, MSSC, and the deployment of reserve. If a reserve request fails due to various reasons, backup procedures are in place to fully address the requirements.

Reliability Coordinator

The Reliability Coordinator is responsible for monitoring, advising, and directing action when necessary in order to preserve the reliability of transmission service between and within the interconnected systems of Balancing Authorities within the Western Interconnection.

TABLE 169: WECC-NWPP (U.S.) ON-PEAK CAPACITY RESOURCES AND RESERVE MARGINS

	2011 Summer Forecast (MW)	2011 Summer Forecast (%)	Change from prior year (MW)	Change from prior year (percentage point)
Existing-Certain and Net Firm Transactions (with Demand Response)	43,889	20.4%	(400)	(2.4)
Anticipated Capacity Resources	44,911	23.3%	359	(0.4)
Prospective Capacity Resources	44,911	23.3%	358	(0.4)
NERC Reference Margin Level	**5,757**	**15.8%**	**(1,210)**	(3.0)

TABLE 170: WECC-NWPP (CAN) ON-PEAK CAPACITY RESOURCES AND RESERVE MARGINS

	2011 Summer Forecast (MW)	2011 Summer Forecast (%)	Change from prior year (MW)	Change from prior year (percentage point)
Existing-Certain and Net Firm Transactions (with Demand Response)	20,785	15.2%	(274)	(3.8)
Anticipated Capacity Resources	21,229	17.7%	(391)	(4.5)
Prospective Capacity Resources	21,229	17.7%	(391)	(4.5)
NERC Reference Margin Level	**2,218**	**12.3%**	**182**	0.8

Strategic Undertakings

Adequacy Response Team – The NWPP has developed an Adequacy Response Process whereby a team addresses the Area's ability to avoid a power emergency by promoting Regional coordination and communications. Essential pieces of that effort include timely analyses of the power situation and communication of that information to all parties including but not limited to utility officials, elected officials, and the general public.

Emergency Response Team (ERT) – In the fall of 2000, the Area developed an Emergency Response Process to address immediate power emergencies. The ERT remains in place and would be used in the event of an immediate emergency. The ERT would work with all parties in pursuing options to resolve the emergency including but not limited to load curtailment and imports of additional power from Areas outside the NWPP.

Largest Risk

The largest risk facing BAs within the NWPP is a significant weather event that would last over a five-day period and have temperatures at 10^{o} F above normal. This type of an event would increase the overall peak demand by 3,000 MW. Any additional contingency during such a weather event could cause loss of local load.

Conclusions

In view of the present overall power conditions, including the forecast water conditions, the Area represented by the NWPP is estimating that it will be able to meet Firm loads, including the required operating reserve. Should any resources be lost to the Area beyond the contingency reserve requirement and/or loads are greater than projected as a result of extreme weather, the

NWPP may have to look to alternatives, which may include emergency measures to meet obligations.

Regional Description

The WECC Region is a summer-peaking Region comprised of 37 Balancing Authorities. The WECC Region is nearly 1.8 million square miles, including the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in México, and all or portions of 14 Western states in between. It is the largest and most diverse of the eight NERC Regional reliability organizations. Additional information regarding WECC can be found at www.wecc.biz.

Reliability Concepts Used in This Report

How NERC Defines Bulk Power System Reliability

NERC defines the reliability of the interconnected BPS in terms of two basic and functional aspects:[148]

> **Adequacy** — the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably forecast unscheduled outages of system components.
>
> **Operating Reliability** — the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components.

Regarding adequacy, system operators can and should take "controlled" actions or initiate procedures to maintain a continual balance between supply and demand within a balancing Area (formerly control Area). These actions include:

- public appeals;
- interruptible demand — demand that the end-use customer makes available to its LSE via contract or agreement for curtailment;[149]
- voltage reductions (sometimes referred to as "brownouts" because incandescent lights will dim as voltage is lowered, sometimes as much as five percent); and
- rotating blackouts — the term "rotating" is used because each set of distribution feeders is interrupted for a limited time, typically 20–30 minutes, and then those feeders are put back in service and another set is interrupted, and so on, rotating the outages among individual feeders.

Under the heading of Operating Reliability, are all other system disturbances that result in the unplanned and/or uncontrolled interruption of customer demand, regardless of cause. When these interruptions are contained within a localized Area, they are considered unplanned interruptions or disturbances. When they spread over a wide area of the grid, they are referred to as "cascading blackouts"—the uncontrolled successive loss of system elements triggered by an incident at any location.

Demand Response Concepts and Categorization

As the industry's use of Demand-Side Management (DSM) evolves, NERC's data collection and reliability assessments need to change highlighting programs and demand-side service offerings that have an impact on bulk system reliability.

NERC's seasonal and long-term reliability assessments currently assume projected energy efficiency (EE) programs are included in the Total Internal Demand forecasts, including adjustments for utility indirect Demand Response programs such as conservation programs, improvements in efficiency of electric energy use, rate incentives, and rebates. DSM involves all activities or programs undertaken to influence the amount and timing of electricity use (Figure 49).

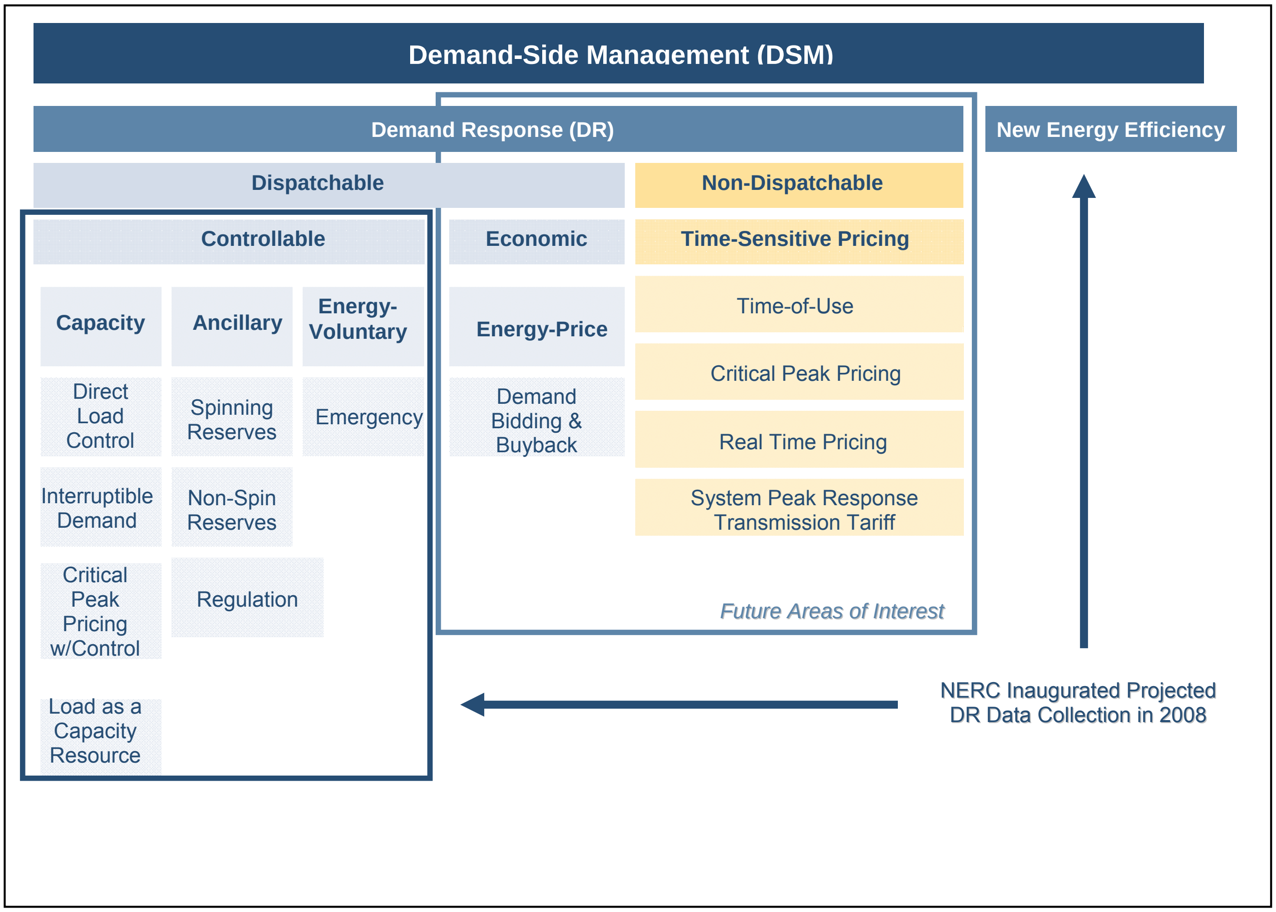
[148] See http://www.nerc.com/docs/pc/Definition-of-ALR-approved-at-Dec-07-OC-PC-mtgs.pdf for more information about the Adequate Level of Reliability (ALR).

[149] Interruptible Demand (or Interruptible Load) is a term used in NERC Reliability Standards. See *Glossary of Terms Used in Reliability Standards*, February 12, 2008, at http://www.nerc.com/files/Glossary_12Feb08.pdf.

Reliability Concepts Used in This Report

Note that the context of these activities and programs is DSM, rather than Bulk Power Systems and, therefore, they are not meant to mirror those used in the system context. The Demand Response categories defined in *Terms Used in this Report* support Figure 49.

FIGURE 49: DEMAND-SIDE MANAGEMENT AND NERC'S DATA COLLECTION



A significant change initiated in 2011 establishes a more consistent method to account for Demand Response in the Reserve Margin (RM) calculation. In previous reliability assessments, some Controllable Capacity Demand Response (CCDR) programs were used to reduce Total Internal Demand (Net Internal Demand), and some programs were included as a supply-side capacity resource. In prior years, the Reserve Margin calculation was based on Net Internal Demand and capacity resources, which included some CCDR on either side of the equation. The method currently implemented now calculates Reserve Margin based on Total Internal Demand and includes (CCDR) only as a supply-side resource.[150]

A comparison of the two methods is shown in Figure 50:

Figure 50: Differences in Calculation of Reserve Margins in 2011	
Pre-2011 Reserve Margin Calculation (Majority)	**2011 Reserve Margin Calculation**
$RM = \dfrac{[\text{Capacity} - (\text{Total Internal Demand} - \text{CCDR})]}{(\text{Total Internal Demand} - \text{CCDR})}$	$RM = \dfrac{[(\text{Capacity} + \text{CCDR}) - (\text{Total Internal Demand})]}{(\text{Total Internal Demand})}$

Whether CCDR is treated as a supply-side resource or a demand reduction, the quantity (MW value) of the Reserve Margin does not change. More importantly, the quantity of the Reserve Margin does not need to change based on individual Reserve Margin requirements, since the same uncertainties that a Reserve Margin addresses (*e.g.,* unit outages, demand forecast uncertainty, etc.) are present irrespective of how the percentage value of Reserve Margins is calculated.

This important concept can be explained and justified using the example scenarios in Table 171. For each example, two methods are used to calculate Reserve Margins: the "Pre-2011" method, which accounts for CCDR by reducing Total Internal Demand, and the "2011" method, which accounts for CCDR as a supply-side resource. For all examples, the "Reserve Margin - MW" value for both methods are equal.

- In Example 1, a hypothetical system's Reserve Margin is calculated. For the 2011 method, the calculated Reserve Margin is two percentage points less than the Pre-2011 method due to a smaller amount of reserve capacity available as a percentage of demand.
- In Example 2, half of the hypothetical system's entire demand is participating in a CCDR program. In this scenario, an Area is planning to serve 1,000 MW of peak demand with 1,000 MW of generation. In order to meet reserve requirements, 500 MW of the 1,000 MW of demand are enrolled in the CCDR program. The Pre-2011 method assumes the plan to serve only 500 MW; therefore, given 500 MW of reserve capacity, the calculated Reserve Margin is 100 percent. This is not a traditional planning strategy. Instead, the 2011 method is used to calculate a 50-percent Reserve Margin, which is representative in assuming 1,000 MW of demand are planned to be served, with 500 MW of reserve capacity beyond the 1,000 MW of generation.

[150] This change was recommended by the NERC Resource Issues Subcommittee under the direction of the NERC Planning Committee. The recommendation was approved by the NERC Planning Committee in 2010 and is detailed in the report titled *Recommendations for the Treatment of Controllable Capacity Demand Response Programs in Reserve Margin Calculation,* June 2010 http://www.nerc.com/docs/pc/ris/RIS_Report_on_Reserve_Margin_Treatment_of_CCDR_%2006.01.10.pdf

TABLE 171: EXAMPLE RESERVE MARGIN CALCULATIONS USING DIFFERENT METHODS

Method Used	Example 1		Example 2	
Year	Pre-2011	2011	Pre-2011	2011
Net Internal Demand	9,000	10,000	500	1,000
Total Internal Demand	10,000	10,000	1,000	1,000
CCDR	1,000	1,000	500	500
Supply-Side Resources	11,000	12,000	1,000	1,500
Reserve Margin – MW	2,000	2,000	500	500
Reserve Margin – %	22.2%	20.0%	100.0%	50.0%

Because the system operator can dispatch CCDR (based on economics or reliability) similar to traditional generation resources, these resources should be counted on the supply-side. In this way, the Reserve Margin calculation is based on, and related to, total demand.

Terms Used in This Report

Ancillary (Controllable Demand Response) — Demand-side resource displaces generation deployed as operating reserves and/or regulation; penalties are assessed for nonperformance.

Ancillary Services — Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Service Provider's transmission system in accordance with good utility practice. (From FERC order 888-A.)

Anticipated Capacity Resources — Existing-Certain and Net Firm Transactions plus Future-Planned capacity resources plus Projected Imports, minus Forecast Exports. (MW)

Anticipated Reserve Margin (%) — Anticipated Capacity Resources minus Total Internal Demand shown as a percent of Total Internal Demand

Capacity (generator) **—** The output power, commonly expressed in megawatts (MW), that generating equipment can supply to system load.

Capacity (Controllable Demand Response**) —** Demand-side resource displaces or augments generation for planning and/or operating resource adequacy; penalties are assessed for nonperformance.

Capacity Categories — *See* ***Existing Generation Resources, Future Generation Resources,*** *and* ***Conceptual Generation Resources***.

Conceptual Generation Resources — This category includes generation resources that are not included in *Existing Generation Resources* or *Future Generation Resources*, but have been identified and/or announced on a resource planning basis through one or more of the following sources:

1. Corporate announcement
2. Entered into or are in the early stages of an approval process
3. Is in a generator interconnection (or other) queue for study
4. "Place-holder" generation for use in modeling, such as generator modeling needed to support NERC Standard TPL assessment, as well as integrated resource planning resource studies.

Resources included in this category may be adjusted using a confidence factor (%) to reflect uncertainties associated with siting, project development or queue position.

Conservation — *see* ***Energy Conservation***

Contractually Interruptible (Curtailable) (Controllable Capacity Demand Response) — Dispatchable, Controllable, Demand-side management achieved by a customer reducing its load upon notification from a control center. The interruption must be mandatory at times of system emergency. Curtailment options integrated into retail tariffs that provide a rate discount or bill credit for agreeing to reduce load during system contingencies. It is the magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted at the time of the Regional Entity's seasonal peak. In some instances, the demand reduction may be effected by action of the System Operator (remote tripping) after notice to the customer in accordance with contractual provisions.

Controllable (Demand Response**)** — Dispatchable Demand Response, demand-side resources used to supplement generation resources resolving system and/or local capacity constraints.

Critical Peak Pricing (CPP) (Non-dispatchable Time-Sensitive Pricing Demand Response**) —** Rate and/or price structure designed to encourage reduced use during periods of high wholesale market prices or system contingencies by imposing a pre-specified high rate for a limited number of days or hours.

Critical Peak Pricing (CPP) with Control (Controllable Capacity Demand Response) — Dispatchable, Controllable, Demand-side management that combines direct remote control with a pre-specified high price for use during designated critical peak periods, triggered by system contingencies or high wholesale market prices.

Curtailable — *See* ***Contractually Interruptible***

Demand — *See* ***Net Internal Demand, Total Internal Demand***

Demand Bidding and Buyback (Controllable Energy-Price Demand Response**) —** Demand-side resource that enables large consumers to offer specific bid or posted prices for specified load reductions. Customers stay at fixed rates, but receive higher payments for load reductions when the wholesale prices are high.

Demand Response — Changes in electric use by demand-side resources from their normal use 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.

Derate (Capacity) — The amount of capacity that is projected to be unavailable on seasonal peak.

Direct Control Load Management (DCLM) or Direct Load Control (DLC) (Controllable Capacity Demand Response) — Demand-Side Management that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises. DCLM as defined here does not include Interruptible Demand.[151]

Dispatchable (Demand Response**)** — Demand-side resource curtails according to instruction from a control center.

Economic (Controllable Demand Response**) —** Demand-side resource that is dispatched based on an economic decision.

Emergency (Controllable Energy-Voluntary Demand Response) **—** Demand-side resource curtails during system and/or local capacity constraints.

Energy Conservation — The practice of decreasing the quantity of energy used.

Energy Efficiency — Permanent changes to electricity use through replacement with more efficient end-use devices or more effective operation of existing devices. Generally, it results in reduced consumption across all hours rather than event-driven targeted load reductions.

Energy Emergency Alert Levels — The categories for capacity and emergency events based on Reliability Standard EOP—002-0:

- **Level 1 — All available resources in use.**

[151] DCLM is a term defined in NERC Reliability Standards. See *Glossary of Terms Used in Reliability Standards*, Updated April 20, 2009 at: www.nerc.com/files/Glossary_2009April20.pdf

- Balancing Authority, Reserve Sharing Group, or Load Serving Entity foresees or is experiencing conditions where all available resources are committed to meet firm load, firm transactions, and reserve commitments, and is concerned about sustaining its required Operating Reserves, and Non-Firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

- **Level 2 — Load management procedures in effect**.
  - Balancing Authority, Reserve Sharing Group, or Load Serving Entity is no longer able to provide its customers' forecast energy requirements, and is designated an Energy Deficient Entity.
  - Energy Deficient Entity foresees or has implemented procedures up to, but excluding, interruption of Firm load commitments. When time permits, these procedures may include, but are not limited to: public appeals to reduce demand, voltage reduction, interruption of Non-Firm end use loads in accordance with applicable contracts, Demand-side management, and utility load conservation measures.
- **Level 3 — Firm load interruption imminent or in progress**.
  - Balancing Authority or Load Serving Entity foresees or has implemented Firm load obligation interruption. The available energy to the Energy Deficient Entity, as determined from Level (Alert) 2, is only accessible with actions taken to increase transmission transfer capabilities.

Energy Only (Capacity) — Energy Only Resources are generally generating resources that are designated as Energy-Only resources or have elected to be classified as Energy-Only resources and may include generating capacity that can be delivered within the Area but may be recallable to another Area.

Energy-Price (Controllable Economic Demand Response**) —** Demand-side resource that reduces energy for incentives.

Energy-Voluntary (Controllable Demand Response) — Demand-side resource curtails voluntarily when offered the opportunity to do so for compensation, but nonperformance is not penalized.

Existing-Certain (Existing Generation Resources) — Existing generation resources available to operate and deliver power within or into the Region during the period of analysis in the assessment. Resources included in this category may be reported as a portion of the full capability of the resource, plant, or unit. This category includes, but is not limited to the following:

1. Contracted (or Firm) or other similar resource confirmed able to serve load during the period of analysis in the assessment.
2. Where organized markets exist, designated market resource[152] that is eligible to bid into a market or has been designated as a Firm network resource.
3. Network Resource,[153] as that term is used for FERC *pro forma* or other regulatory approved tariffs.

[152] Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.

[153] Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.

4. Energy-Only resources[154] confirmed able to serve load during the period of analysis in the assessment and will not be curtailed.[155]
5. Capacity resources that cannot be sold elsewhere.
6. Other resources not included in the above categories that have been confirmed able to serve load and not to be curtailed[156] during the period of analysis in the assessment.

Existing-Certain and Net Firm Transactions — Existing-Certain capacity resources plus Firm Imports, minus Firm Exports. (MW)

Existing-Certain and Net Firm Transactions (%) (Margin Category) — Existing-Certain and Net Firm Transactions minus Total Internal Demand shown as a percentage of Total Internal Demand.

Existing Generation Resources — *See* ***Existing-Certain, Existing-Other, Existing, but Inoperable.***

Existing, Inoperable (Existing Generation Resources) — This category contains the existing portion of generation resources that are out of service and cannot be brought back into service to serve load during the period of analysis in the assessment. However, this category can include inoperable resources that could return to service at some point in the future. This value may vary for future seasons and can be reported as zero. This includes all existing generation not included in categories Existing-Certain or Existing-Other, but is not limited to, the following:

1. Mothballed generation (that cannot be returned to service for the period of the assessment).
2. Other existing but out-of-service generation (that cannot be returned to service for the period of the assessment).

Note: This category does not include behind-the-meter generation or non-connected emergency generators that normally do not run.

Note: This category does not include partially dismantled units that are not forecast to return to service.

Existing-Other (Existing Generation Resources) — Existing generation resources that may be available to operate and deliver power within or into the Region during the period of analysis in the assessment, but may be curtailed or interrupted at any time for various reasons. This category also includes portions of intermittent generation not included in Existing-Certain. This category includes, but is not limited to the following:

1. A resource with Non-Firm or other similar transmission arrangements.
2. Energy-Only resources that have been confirmed able to serve load for any reason during the period of analysis in the assessment, but may be curtailed for any reason.
3. Mothballed generation (that may be returned to service for the period of the assessment).
4. Portions of variable generation not counted in the Existing-Certain category (*e.g.,* wind, solar, etc. that may not be available or derated during the assessment period).
5. Hydro generation not counted as Existing-Certain or derated.
6. Generation resources constrained for other reasons.

[154] Energy Only Resources are generally generating resources that are designated as Energy-Only resources or have elected to be classified as Energy-Only resources and may include generating capacity that can be delivered within the Area but may be recallable to another Area (Source: 2008 EIA 411 document OMB No. 1905-0129). Note: Other than wind and solar energy, WECC does not have Energy-Only resources that are counted towards capacity.

[155] Energy only resources with transmission service constraints are to be considered in category Existing-Other.

[156] Energy only resources with transmission service constraints are to be considered in category Existing-Other.

Projected (Transaction Category) — A category of Purchases/Imports and Sales/Exports contract. The following notes apply:

1. Forecast implies that a contract has not been executed, but is in negotiation, projected, or other. These purchases or sales are projected to be Firm.
2. Forecast purchases and sales should be considered in the reliability assessments.

Firm (Transaction Category) — A category of Purchases/Imports and Sales/Exports contract. The following notes apply:

1. Firm implies a contract has been signed and may be recallable.
2. Firm purchases and sales should be reported in the reliability assessments. The purchasing entity should count such capacity in margin calculations. Care should be taken by both entities to appropriately report the generating capacity that is subject to such Firm contract.

Future Generation Resources (*See also* ***Future-Planned*** *and* ***Future-Other***) — This category includes generation resources the reporting entity has a reasonable expectation of coming on line during the period of the assessment. As such, to qualify in either of the Future categories, the resource must have achieved one or more of these milestones:

1. Construction has started.
2. Regulatory permits being approved are any one of the following:
   a. Site permit
   b. Construction permit
   c. Environmental permit
3. Regulatory approval has been received to be in the rate base.
4. Approved power purchase agreement.
5. Approved and/or designated as a resource by a market operator.

Future-Other (Future Generation Resources) — This category includes future generating resources that do not qualify in *Future-Planned* and are not included in the Conceptual category. This category includes, but is not limited to, generation resources during the period of analysis in the assessment that:

1. may be curtailed or interrupted at any time for any reason;
2. may not be able to serve load during the period of analysis in the assessment; and
3. is variable generation not counted in the *Future-Planned* category or may not be available or is derated during the assessment period.
   Note: Hydro generation not counted in category *Future-Planned* or derated.
   Note: Resources included in this category may be adjusted using a confidence factor to reflect uncertainties associated with siting, project development, or queue position.

Future-Planned (Future Generation Resources) — Generation resources anticipated to be available to operate and deliver power within or into the Region during the period of analysis in the assessment. This category includes, but is not limited to, the following:

1. Contracted (or Firm) or other similar resource
2. Where organized markets exist, designated market resource[157] that is eligible to bid into a market or has been designated as a Firm network resource

[157] Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.

3. Network Resource[158] as that term is used for FERC pro forma or other regulatory approved tariffs
4. Energy-Only resources confirmed able to serve load during the period of analysis in the assessment and will not be curtailed[159]
5. Where applicable, included in an integrated resource plan under a regulatory environment that mandates resource adequacy requirements and the obligation to serve

Load as a Capacity Resource (Controllable Capacity Demand Response) — The magnitude of customer demand that, in accordance with contractual arrangements, is committed to pre-specified load reductions when called upon by a Balancing Authority. These resources are not limited to being dispatched during system contingencies and may be subject to economic dispatch from wholesale balancing authorities. Additionally, this capacity may be used to meet resource adequacy obligations when determining Planning Reserve Margins.

NERC Reference Reserve Margin Level (%) — Either the Target Reserve Margin provided by the Region/subregion or NERC assigned based on capacity mix (*i.e.,* thermal/hydro). Each Region/subregion may have its own specific margin level based on load, generation, and transmission characteristics as well as regulatory requirements. If provided in the data submittals, the Regional/subregional Target Reserve Margin level is adopted as the NERC Reference Reserve Margin Level. If not, NERC assigned a 15-percent Reserve Margin for predominately thermal systems and ten percent for predominately hydro systems.

Net Internal Demand: — Equals the Total Internal Demand reduced by the total Dispatchable, Controllable, Capacity Demand Response equaling the sum of Direct Control Load Management, Contractually Interruptible (Curtailable), Critical Peak Pricing (CPP) with Control, and Load as a Capacity Resource.

Non-dispatchable (Demand Response**) —** Demand-side resource curtails according to tariff structure, not instruction from a control center.

Non-Firm (Transaction Category) — A category of Purchases/Imports and Sales/Exports contract.

Note: Non-Firm implies a Non-Firm contract has been signed.

Note: Non-Firm purchases and sales should not be considered in the reliability assessments.

Non-Spin Reserves (Controllable Ancillary Demand Response) — Demand-side resource not connected to the system but capable of serving demand within a specified time.

On-Peak (Capacity**) —** The amount of capacity that is projected to be available on seasonal peak.

Prospective Capacity Reserve Margin (%) – Prospective Capacity Resources minus Total Internal Demand shown as a percentage of Total Internal Demand.

Prospective Capacity Resources — Anticipated Capacity Resources plus Existing-Other capacity resources, minus all Existing-Other deratings (includes derates from variable resources, energy-only resources, scheduled outages for maintenance, and transmission-limited resources), plus Future-Other capacity resources, minus all Future-Other deratings (MW).

[158] Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.
[159] Energy only resources with transmission service constraints are to be considered in category Future-Other.

Provisional (Transaction Category) — A category of Purchases/Imports and Sales/Exports contract.

Note: Provisional implies that the transactions are under study, but negotiations have not begun. These purchases and sales are forecast to be provisionally Firm.

Note: Provisional purchases and sales should be considered in the reliability assessments.

Purchases/Imports Contracts — *See* ***Transaction Categories***

Real Time Pricing (RTP) (Non-dispatchable Time-Sensitive Pricing Demand Response**) —** Rate and price structure in which the price for electricity typically fluctuates to reflect changes in the wholesale price of electricity on either a day-ahead or hour-ahead basis.

Reference Reserve Margin Level — *See* ***NERC Reference Reserve Margin Level***

Regulation (Controllable Ancillary Demand Response) — Demand-side resources responsive to Automatic Generation Control (AGC) to provide normal regulating margin.

Renewable Energy — The United States Department of Energy, Energy Efficiency & Renewable Energy glossary defines Renewable Energy as "energy derived from resources that are regenerative or for all practical purposes cannot be depleted. Types of renewable energy resources include moving water (hydro, tidal, and wave power), thermal gradients in ocean water, biomass, geothermal energy, solar energy, and wind energy. Municipal solid waste (MSW) is also considered to be a renewable energy resource."[160] The government of Canada has a similar definition.[161] Variable generation is a subset of Renewable Energy — See ***Variable Generation***.

Renewables — *See* ***Renewable Energy***

Reserve Margin (%) — *See also* ***Anticipated Capacity Reserve Margin (%)*** *and* ***Prospective Capacity Reserve Margin (%).*** Roughly, Capacity minus Demand, divided by Demand or (Capacity-Demand)/Demand. Replaced Capacity Margin(s) (%) for NERC Assessments in 2009.

Sales/Exports Contracts — *See* ***Transaction Categories***

Spinning/Responsive Reserves (Controllable Ancillary Demand Response) — Demand-side resources that are synchronized and ready to provide solutions for energy supply and demand imbalance within the first few minutes of an electric grid event.

System Peak Response Transmission Tariff (Non-dispatchable Time-Sensitive Pricing Demand Response**) —** Rate and/or price structure in which interval metered customers reduce load during coincident peaks as a way of reducing transmission charges.

Target Reserve Margin (%) — Established target for Reserve Margin by the Region or subregion. Not all Regions report a Target Reserve Margin. The NERC Reference Reserve Margin Level is used in those cases where a Target Reserve Margin is not provided.

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. The demands for station service or auxiliary needs (such as fan motors, pump motors, and other equipment essential to the operation of the generating units) are not included. Internal Demand includes adjustments for indirect Demand-Side Management programs such as conservation programs, improvements in efficiency of electric energy use, all non-dispatchable Demand Response programs (such as Time-of-Use, Critical Peak Pricing, Real Time Pricing, and System Peak

[160] http://www1.eere.energy.gov/site_administration/ glossary.html#R
[161] http://www.cleanenergy.gc.ca/faq/ index_e.asp#whatiscleanenergy

Response Transmission Tariffs) and some dispatchable Demand Response (such as Demand Bidding and Buy-Back). Adjustments for controllable Demand Response are not be incorporated in this value.

Time-of-Use (TOU) (Non-dispatchable Time-Sensitive Pricing Demand Response**)** — Rate and/or price structures with different unit prices for use during different blocks of time.

Time-Sensitive Pricing (Non-dispatchable Demand Response**)** — Retail rates and/or price structures designed to reflect time-varying differences in wholesale electricity costs, and thus provide consumers with an incentive to modify use behavior during high-cost and/or peak periods.

Transaction Categories (*See also* ***Firm, Non-Firm, Projected*** *and* ***Provisional)*** **—** Contracts for Capacity are defined as an agreement between two or more parties for the Purchase and Sale of generating capacity. Purchase contracts refer to imported capacity that is transmitted from an outside Region or subregion to the reporting Region or subregion. Sales contracts refer to exported capacity that is transmitted from the reporting Region or subregion to an outside Region or subregion. For example, if a resource subject to a contract is located in one Region and sold to another Region, the Region in which the resource is located reports the capacity of the resource and reports the sale of such capacity that is being sold to the outside Region. The purchasing Region reports such capacity as a purchase, but does not report the capacity of such resource. Transmission must be available for all reported Purchases and Sales.

Transmission-Limited Resources — The amount of transmission-limited generation resources that have known physical deliverability limitations to serve load within the Region.

> Example: If capacity is limited by both studied transmission limitations and generator derates, the generator derates take precedence. For example, a 100 MW wind plant with a wind capacity variation reduction of 50 MW and a transmission limitation of 60 MW would take the 50 MW wind variation reduction first and list 10 MW in the transmission limitation.

Transmission Status Categories — Transmission additions were categorized using the following criteria:

- **Under Construction**
  - Construction of the line has begun
- **Planned** (any of the following)
  - Permits have been approved to proceed
  - Design is complete
  - Needed in order to meet a regulatory requirement
- **Conceptual** (any of the following)
  - A line projected in the transmission plan
  - A line that is required to meet a NERC TPL Standard or is included in a powerflow model and cannot be categorized as “Under Construction” or “Planned”
  - Projected transmission lines that are not “Under Construction” or “Planned”

Variable Generation — Variable generation technologies generally refer to generating technologies whose primary energy source varies over time and cannot reasonably be stored to address such variation.[162] Variable generation sources, which include wind, solar, ocean, and some hydro generation resources, are all renewable based. Variable generation in this report refers only

[162] http://www.nerc.com/files/IVGTF_Report_041609.pdf

to wind and solar resources. There are two major attributes of a variable generator that distinguish it from conventional forms of generation and may impact the Bulk Power System planning and operations: variability and uncertainty.

- **Variability** — The output of variable generation changes according to the availability of the primary fuel (wind, sunlight, and moving water) resulting in fluctuations in the plant output on all time scales.
- **Uncertainty** — The magnitude and timing of variable generation output is less predictable than for conventional generation.

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Abbreviations Used in This Report

AEP	American Electric Power
AFC	Available Flowgate Capability
ASM	Ancillary Services Market
ATCLLC	American Transmission Company
ATR	AREA Transmission Review (of NYISO)
AWEA	American Wind Energy Association
AZ-NM-SNV	Arizona-New Mexico-Southern Nevada (Subregion of WECC)
BA	Balancing Authorities
BCF	Billion cubic feet
BCFD	Billion cubic feet per day
CA-MX-US	California/México (subregion of WECC)
CFE	*Commission Federal de Electricidad*
CFL	Compact Fluorescent Light
CMPA	California/México Power Area
COI	California-Oregon Intertie
COS	Coordinated Outage (transmission) System
CPUC	California Public Utilities Commission
CRO	Contingency Reserve Obligation
CRPP	Comprehensive Reliability Planning Process (of NYISO)
DADRP	Day-Ahead Demand Response Program
dc	Direct Current
DCLM	Direct Controlled Load Management
DLC	Direct Load Control
DOE	U.S. Department of Energy
DSG	Dynamics Study Group
DSI	Direct-served Industry
DSM	Demand-Side Management
DVAR	D-VAR® reactive power compensation system
EDRP	Emergency Demand Response Program
EE	Energy Efficiency
EEA	Energy Emergency Alert
EECP	Emergency Electric Curtailment Plan
EIA	Energy Information Agency (of DOE)
EILS	Emergency Interruptible Load Service (of ERCOT)
EISA	Energy Independence and Security Act of 2007 (USA)
ELCC	Effective Load-carrying Capability
EMTP	Electromagnetic Transient Program
ENS	Energy Not Served
EOP	Emergency Operating Procedure
ERAG	Eastern Interconnection Reliability Assessment Group
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
FCITC	First Contingency Incremental Transfer Capability
FCM	Forward Capacity Market
FERC	U.S. Federal Energy Regulatory Commission
FP	Future-Planned
FO	Future-Other
FRCC	Florida Reliability Coordinating Council

GADS	Generating Availability Data System
GDP	Gross Domestic Product
GGGS	Gerald Gentleman Station Stability
GHG	Greenhouse Gas
GRSP	Generation Reserve Sharing Pool (of MAPP)
GTA	Greater Toronto Area
GWh	Gigawatt hours
HDD	Heating Degree Days
HVac	Heating, Ventilating, and Air Conditioning
IA	Interchange Authority
ICAP	Installed Capacity
ICR	Installed Capacity Requirement
IESO	Independent Electric System Operator (in Ontario)
IOU	Investor Owned Utility
IPL/NRI	International Power Line/Northeast Reliability Interconnect Project
IPSI	Integrated Power System Plan
IRM	Installed Reserve Margin
IROL	Interconnection Reliability Operating Limit
IRP	Integrated Resource Plan
ISO	Independent System Operator
ISO-NE	New England Independent System Operator
kV	Kilovolts (one thousand volts)
LaaRs	Loads acting as a Resource
LCR	Locational Installed Capacity Requirements
LDC	Load Duration Curve
LFU	Load Forecast Uncertainty
LNG	Liquefied Natural Gas
LOLE	Loss of Load Expectation
LOLP	Loss Of Load Probability
LOOP	Loss of off-site power
LRP	Long Range Plan
LSE	Load-serving Entities
LTRA	Long-Term Reliability Assessment
LTSG	Long-term Study Group
MAAC	Mid-Atlantic Area Council
Maf	Million acre-feet
MAIN	Mid-America Interconnected Network, Inc.
MAPP	Mid-Continent Area Power Pool
MCRSG	Midwest Contingency Reserve Sharing Group
MISO	Midwest Independent Transmission System Operator
MPRP	Maine Power Reliability Program
MRO	Midwest Reliability Organization
MVA	Megavolt amperes
MVar	Mega-vars
MW	Megawatts (millions of watts)
MWEX	Minnesota Wisconsin Export
NB	New Brunswick
NBSO	New Brunswick System Operator
NDEX	North Dakota Export Stability Interface
NEEWS	New England East West Solution

NERC	North American Electric Reliability Corporation
NIETC	National Interest Electric Transmission Corridor
NOPSG	Northwest Operation and Planning Study Group
NPCC	Northeast Power Coordinating Council
NPDES	National Pollutant Discharge Elimination System
NPPD	Nebraska Public Power District
NSPI	Nova Scotia Power Inc.
NTSG	Near-term Study Group
NWPP	Northwest Power Pool Area (subregion of WECC)
NYISO	New York Independent System Operator
NYPA	New York Planning Authority
NYRSC	New York State Reliability Council, LLC
NYSERDA	New York State Energy and Research Development Agency
OASIS	Open Access Same Time Information Service
OATT	Open Access Transmission Tariff
OP	Operating Procedure
OPA	Ontario Power Authority
OPPD	Omaha Public Power District
ORWG	Operating Reliability Working Group
OTC	Operating Transfer Capability
OVEC	Ohio Valley Electric Corporation
PA	Planning Authority
PACE	PacifiCorp East
PAR	Phase Angle Regulators
PC	NERC Planning Committee
PCAP	Pre-Contingency Action Plans
PCC	Planning Coordination Committee (of WECC)
PJM	PJM Interconnection
PRB	Powder River Basin
PRC	Public Regulation Commission
PRSG	Planned Reserve Sharing Group
PSA	Power Supply Assessment
PUCN	Public Utilities Commission of Nevada
QSE	Qualified Scheduling Entities
RA	Resource Adequacy
RAP	Remedial Action Plan
RAR	Resource Adequacy Requirement
RAS	Reliability Assessment Subcommittee of NERC Planning Committee
RC	Reliability Coordinator
RCC	Reliability Coordinating Committee
RFC	ReliabilityFirst Corporation
RFP	Request For Proposal
RIS	Resource Issues Subcommittee of NERC Planning Committee
RMPA	Rocky Mountain Power Area (subregion of WECC)
RMR	Reliability Must Run
RMRG	Rocky Mountain Reserve Group
RPM	Reliability Pricing Mode
RRS	Reliability Review Subcommittee
RSG	Reserve Sharing Group
RTEP	Regional Transmission Expansion Plan (for PJM)
RTO	Regional Transmission Organization

RTP	Real Time Pricing
RTWG	Renewable Technologies Working Group
SA	Security Analysis
SaskPower	Saskatchewan Power Corp.
SCADA	Supervisory Control and Data Acquisition
SCC	Seasonal Claimed Capability
SCD	Security Constrained Dispatch
SCDWG	Short Circuit Database Working Group
SCEC	State Capacity Emergency Coordinator (of FRCC)
SCR	Special Case Resources
SEMA	Southeastern Massachusetts
SEPA	State Environmental Protection Administration
SERC	SERC Reliability Corporation
SMUD	Sacramento Municipal Utility District
SOL	System Operating Limits
SPP	Southwest Power Pool
SPS	Special Protection System
SPS/RAS	Special Protection Schemes / Remedial Action Schemes
SRIS	System Reliability Impact Studies
SRWG	System Review Working Group
STATCOM	Static Synchronous Compensator
STEP	SPP Transmission Expansion Plan
SVC	Static Var Compensation
TCF	Trillion Cubic Feet
THI	Temperature Humidity Index
TIC	Total Import Capability
TID	Total Internal Demand
TLR	Transmission Loading Relief
TOP	Transmission Operator
TPL	Transmission Planning
TRE	Texas Regional Entity
TRM	Transmission Reliability Margins
TS	Transformer Station
TSP	Transmission Service Provider
TSS	Technical Studies Subcommittee
TVA	Tennessee Valley Authority
USBRLC	United States Bureau of Reclamation Lower Colorado Region
UFLS	Under Frequency Load Shedding Schemes
UVLS	Under Voltage Load-Shedding
var	Voltampre reactive
VACAR	Virginia and Carolinas (subregion of SERC)
VSAT	Voltage Stability Assessment Tool
WALC	Western Area Lower Colorado
WECC	Western Electricity Coordinating Council
WTHI	Weighted Temperature-Humidity Index

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ERRATA

Page 61, Table 29: This table originally listed the 2010 Total Internal Demand for the MRO-MAPP Area to be 42, 579 MW. This value was based on the MRO-US subregional boundary (prior to 2011) and has been corrected to reflect the actual 2010 Total Internal Demand of 5,810 MW for the MAPP Area.

Page 65, Table 34: This table originally included two columns indicating changes from the prior year. These columns have been removed.

Page 135, last paragraph: The last line in the paragraph indicates 1,630 MW of generation added for PJM last summer. The actual value should be 640 MW.

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The following NERC industry groups have collaborated in efforts to produce NERC's *2011 Summer Reliability Assessment*:

NERC Group	Relationship	Contribution
Board of Trustees	NERC's Independent Board	• Review Assessment Approve for publication
Planning Committee (PC)	Reports to NERC's Board of Trustees	• Review Assessment and Endorse
Operating Committee (OC)	Reports to NERC's Board of Trustees	• Review Assessment and provide comments to PC
Reliability Assessments Subcommittee (RAS)	Reports to the PC	• Provide Regional Self-Assessments • Peer Reviews • Review Report
Data Coordination Working Group (DCWG)	Reports to the RAS	• Develop data and Regional reliability narrative requests

to ensure
the reliability of the
bulk power system