NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2007/2008 Winter Reliability Assessment

to ensure the reliability of the bulk power system

November 2007

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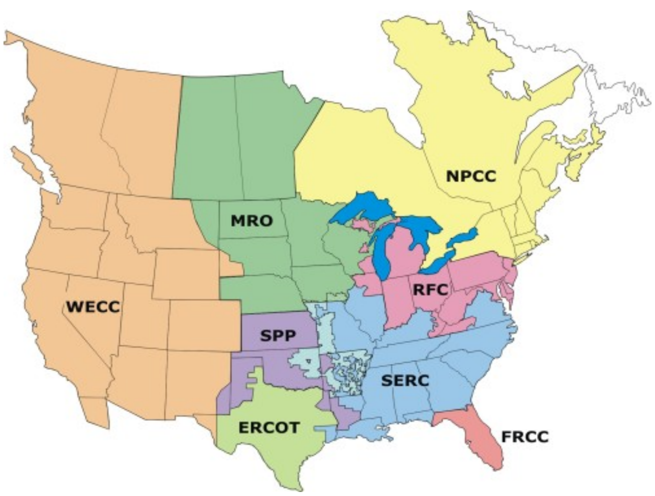
Table of Contents

NERC's Mission

The North American Electric Reliability Corporation's (NERC) mission is to ensure the bulk power system in North America is reliable. To achieve this objective, NERC develops and enforces reliability standards; monitors the bulk power system; assesses and reports on future adequacy; evaluates owners, operators, and users for reliability preparedness; and offers education and certification programs to industry personnel. NERC is a non-profit, self-regulatory organization that relies on the diverse and collective expertise of industry participants that comprise its various committees and sub-groups. It is subject to oversight by governmental authorities in Canada and the United States (U.S.).

NERC assesses and reports on the reliability and adequacy of the North American bulk power system divided into the eight regional areas as shown on the map below. 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, Mexico.



ERCOT Electric Reliability Council of Texas, Inc.	**RFC** Reliability*First* Corporation
FRCC Florida Reliability Coordinating Council	**SERC** SERC Reliability Corporation
MRO Midwest Reliability Organization	**SPP** Southwest Power Pool, Incorporated
NPCC Northeast Power Coordinating Council	**WECC** Western Electricity Coordinating Council

Note: *The highlighted area between SPP 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.*

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. Reliability standards are also mandatory and enforceable in Ontario and New Brunswick, and NERC is seeking to achieve comparable results in the other Canadian provinces. NERC will seek recognition in Mexico once the necessary legislation is adopted.

While the onset of mandatory and enforceable standards does not impact the preparation of this assessment, the significant efforts being made by users, owners, and operators of the bulk power system to comply with these standards are expected to significantly improve reliability.

Introduction

The *2007/2008 Winter Reliability Assessment* report represents NERC's independent judgment of the reliability and adequacy of the bulk power system in North America for the 2007/2008 winter season.

NERC's primary role 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 their remedy. 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. This assessment is prepared by NERC in its capacity as the U.S. Electric Reliability Organization.[1] NERC cannot order construction of generation or transmission or adopt enforceable standards having that effect, as that authority is explicitly withheld by Section 215 of the U.S. Energy Policy Act of 2005[2]. In addition, NERC does not make any projections or draw any conclusions regarding expected electricity prices or the efficiency of electricity markets.

The *2007/2008 Winter Reliability Assessment* provides a high-level assessment of 2007/2008 winter resource adequacy, an overview of projected electricity demand growth, regional highlights, and regional self-assessments.

NERC's Annual Assessments		
Assessment	**Outlook**	**Published**
Summer Assessment	Upcoming season	May
Long-Term Assessment	10 year	October
Winter Assessment	Upcoming season	November

Report Preparation

NERC prepared the *2007/2008 Winter Reliability Assessment* with support from the Reliability Assessment Subcommittee (RAS) under the direction of the NERC Planning Committee (PC). The report is based on data and information submitted by each of the eight regional entities in September 2007 and updated, as required, throughout the process. Any other data sources consulted by NERC staff in the preparation of this document are identified in the report.

NERC uses an active peer review process in preparing its reliability assessments, which takes full advantage of industry subject matter expertise from all sectors of the industry. This process provides an essential check and balance for ensuring the validity of the data and information provided by the regional entities. Each regional self-assessment is individually assigned to two or three subcommittee members from other regions for an in-depth and comprehensive review.

[1] Section 39.11(b) of the U.S. FERC's regulations provide that: "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

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

Reviewer comments are discussed with the regional entity representative and refinements/adjustments are made as necessary. Each regional self-assessment is then subjected to scrutiny and review by the entire subcommittee as a group through several sessions. This review ensures that each member of the subcommittee is fully convinced that each regional self-assessment is accurate, thorough, and complete. The entire document, including the regional self-assessments, is reviewed by the PC and the Member Representatives Committee (MRC). At the conclusion of this process, NERC management reviews the assessment results in detail before the report is submitted to the NERC Board of Trustees for final approval.

To further improve the results and process underlying the preparation of the assessment, in late August NERC held a phone conference designed to review the enhanced self-assessment and data requests and solicit improvements for the reliability assessment process from those preparing and submitting the requested information. Key suggestions from this phone conference were reflected in the final report and/or are expected to be incorporated into the process.

In this report, the baseline calculations of electricity supply[3] and internal demand projections[4] are based on several assumptions, outlined below.

- NERC's projections are based on the regional forecasts submitted in September 2007. Any subsequent resource plan changes may not be fully represented.
- Average weather is assumed at the time of the peak in demand forecasts.
- Economic activity will occur as assumed in the demand forecasts.
- Generating and transmission equipment will perform at historical availability levels.
- Planned outages and additions/upgrades of generation and transmission will be completed as scheduled.
- Demand reductions expected from direct control load management and interruptible demand contracts will be effective, if and when they are needed.
- Other peak demand-side management programs are included in net internal demand forecasts.
- Electricity transfers between regions are contractually arranged and occur as projected.

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[3] See *Reliability Concepts Used in this Report*, for more information about Supply definitions. Capacity provided is not based on unit nameplate. Rather, the capacity is rated for the Winter season and does not include: mothballed units, energy–only, de-rates for water and wind resources, and plants unavailable due to extended, scheduled maintenance.

[4] Forecasts cannot precisely predict the future. Instead, many forecasts report probabilities with a range of possible outcomes. Each regional demand projection, for example, is assumed to represent the expected midpoint of possible future outcomes. This means that a future year's actual demand may deviate from the midpoint projections due to the inherent variability of the key factors that drive electrical use. In the case of the NERC regional projections, on average 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.

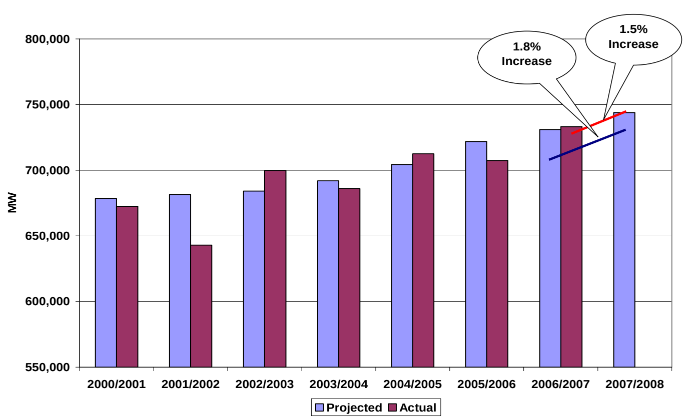
Key Findings

Projected Peak Demand Grows; Capacity Margins & Fuel Inventories Appear Adequate

Projected peak internal demand is forecast to be 1.8 percent higher than last year's (2006/2007) winter forecasts and 1.5 percent higher than last year's recorded peak demand.[5] MRO (3.1 percent), ERCOT (2.8 percent), FRCC (2.5 percent) and WECC (2.4 percent) expect over 2 percent growth from last year's projected winter peak.

Warmer weather in FRCC resulted in a 12 percent drop in recorded peak from winter of 2005/2006 to last winter. FRCC's 2007/2008 winter forecast is thus much higher (26 percent) than last year's recorded winter peak, though growth when compared with last year's forecasted peak is only 2.5 percent. In ERCOT and SPP, however, the forecast peak demand is lower than 2006/2007 winter actual peaks, as both of these regions experienced extreme cold weather conditions last year.

NERC's 2006/2007 and 2007/2008 Winter Projected Total and Actual Demand



Committed and Uncommitted Capacity

Committed Capacity Resources

Generating capacity resources that exist, are under construction, or planned that are considered available, deliverable, and committed to serve demand, plus the net of capacity purchases and sales.

Uncommitted Capacity Resources

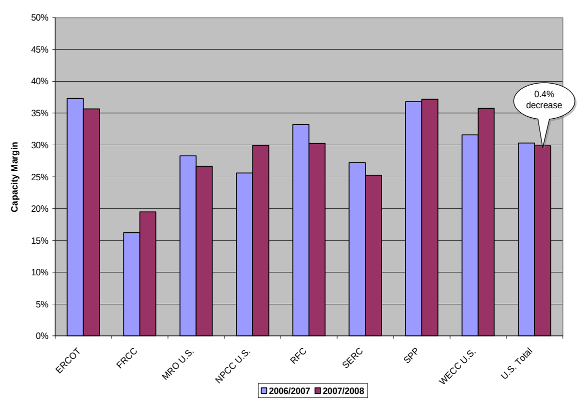
Capacity resources that include one or more of the following:

- Generating resources that have not been contracted nor have legal or regulatory obligation to deliver at time of peak.
- Generating resources that do not have or do not plan to have firm transmission service reserved (or its equivalent) or capacity injection rights to deliver the expected output to load within the region.
- Generating resources that have not had a transmission study conducted to determine the level of deliverability.
- Generating resources that are designated as energy-only resources or have elected to be classified as energy-only resources.
- Transmission-constrained generating resources that have known physical deliverability limitations to load within the region.

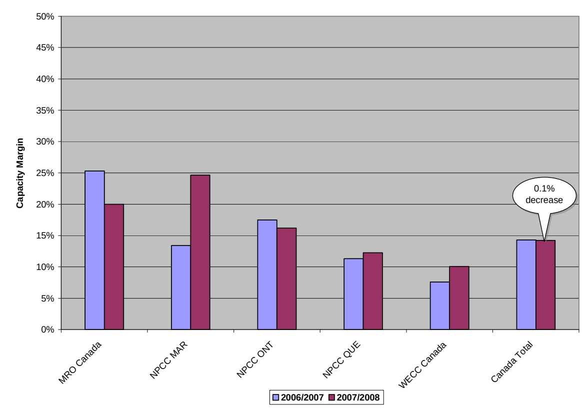
[5] This difference is due to unexpected weather patterns experienced in some regions last winter.

Projected capacity margins reflecting committed generation, are holding steady overall, though projected capacity margins are slightly decreased in the U.S. (0.4 percent) when compared to projected 2006/2007 winter capacity margins. Decreases in projected capacity margins can be seen in ERCOT, MRO-U.S., RFC, and SERC, with increases in FRCC, NPCC-U.S., and WECC-U.S. Most decreases in capacity margin result from generating units transitioning from committed status to uncommitted. All regions expect to meet capacity margin targets.

U.S. Projected 2006/2007 and 2007/2008 Regional Winter Peak Capacity Margins

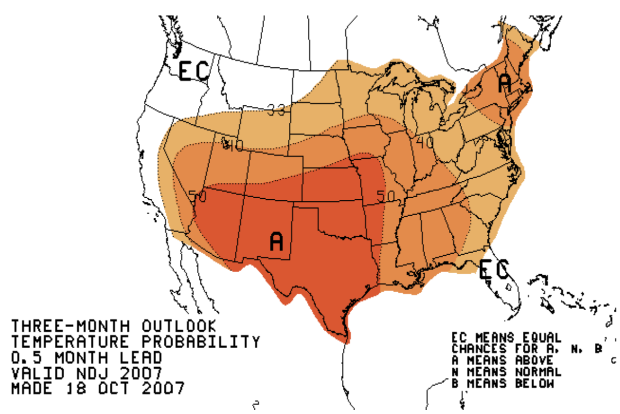


Canadian Projected 2006/2007 and 2007/2008 Regional Winter Peak Capacity Margins



In Canada, projected capacity margins from committed generation are also steady (decreasing 0.1 percent), with decreases in capacity margins seen in MRO-Canada and NPCC-Ontario and increases from committed generation in NPCC-Maritimes and WECC-Canada. NPCC-Quebec and WECC-Canada both have capacity margins near 10 percent.[6] MRO-Canada's reduced capacity margin is due, in part, to demand growth along with increased outgoing firm transactions, wind derates, and energy-only capacity.

Based on the most recent projection of heating degree-days by the National Oceanic and Atmospheric Administration's National Weather Service[7], winter in the lower 48 states is forecast to be four percent colder compared to last winter, but two percent warmer than the 30-year average (1971–2000). Temperatures are expected to be above average in ERCOT and portions of WECC, SPP and NPCC-NE.



[6] Although the reserve margins for WECC-Canada appear relatively lower than other regions, the more reliable nature of hydro resources permit lower reserve margins. In the Quebec *Interim Review of Resource Adequacy 2004*, the required reserve for Québec was 9.7 percent. With Québec reserves in the range of 10.1–16.6 percent, Québec has adequate reserves for the 2007/2008 winter period to meet its reliability criterion.

[7] http://www.cpc.ncep.noaa.gov/

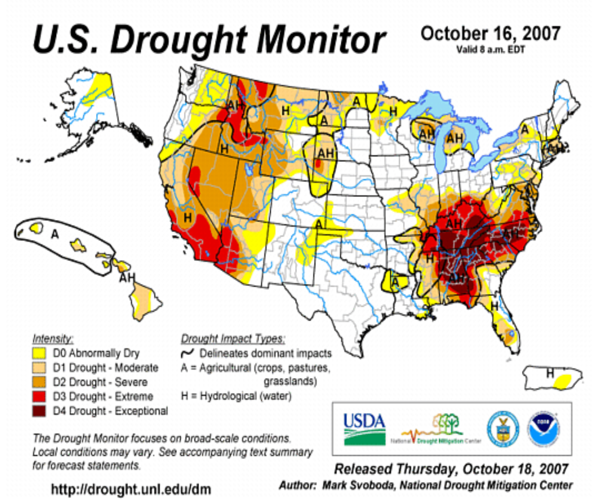
Most regions have taken steps to plan for and manage the risks from extreme weather. For example:

- ISO-NE has developed detailed operating models, testing worst case scenarios if extreme cold winter weather is experienced, and managing risks associated with natural gas, competition for heating operating reserve margins, and tie-line limitations.
- The Northwest Power Pool has developed a plan to manage their capacity resources during potential sudden increases in demand resulting from an "arctic express" cold weather pattern.

Plant inventories for coal at electric generators are ahead of historically normal level with inventories totaling 45 days versus 40 days in July 2006[8]. Natural gas storage has ended injection season only slightly below the all-time high for natural gas storage inventories recorded at the end of November 1990.[9]

[8] https://commerce.us.reuters.com/purchase/showReportDetail.do?sid=1&ticker=MEE.N&id=40503039
[9] http://www.eia.doe.gov/emeu/steo/pub/contents.html

Continuing Drought in the Southeast U.S. Not Expected to Threaten Reliability

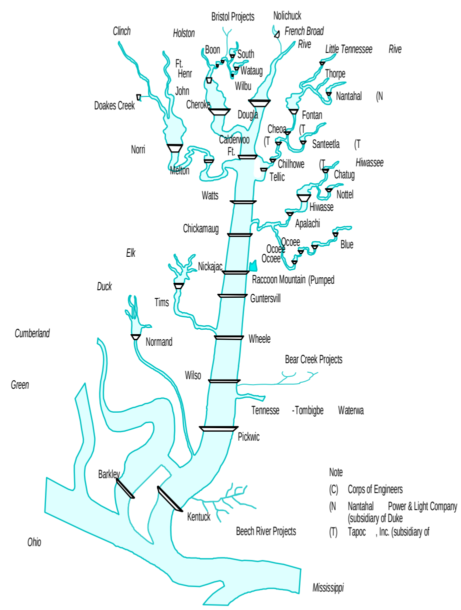


Drought conditions in the Southeastern U.S.[10] have the potential to impact the availability of hydro facilities and generation plants that use rivers and streams for cooling water, but these conditions are not expected to threaten reliability during the 2007/2008 winter season. When rivers become low or water intake temperatures become too warm, these plants may de-rate or shut down in order to meet specific regulations for maintaining water temperature limits or due to inadequate water levels. A unit at the Brown's Ferry nuclear plant was shut down[11] due to similar circumstances during the summer of 2007. Rivers flowing through more than one state or province, providing water use for multiple purposes, may impact multiple plants stationed along their banks. The figure below shows the TVA river system, operated in conservation mode since February 2007. While the mainstem reservoir elevations and storage on the Tennessee River from Knoxville to the Ohio River are in the normal range, and the commercial navigation channel is being maintained at normal depth, tributary reservoirs have about 76% of normal storage.

Despite these concerns, generation levels are expected to be sufficient to meet forecasted peak and daily energy demands for the upcoming winter season. The drought conditions mainly impact the SERC region and are being monitored by a variety of groups within SERC, and government officials. SERC members have developed plans to manage low water conditions.

Recently, the governor of Georgia called for a state of emergency for the northern third of Georgia and asked President Bush to declare it a major disaster area.[12] The concern in this case is that Lake Lanier, a 38,000-acre reservoir supplying more than three million residents with water, including Atlanta, which is less than three months from depletion. Other smaller reservoirs are dropping lower. A minimum flow of water is needed to sustain water levels required for a 100 MW coal-fired power plant in Florida vital to reliability in the area and to meet federal mandates to protect two mussel species.

NERC and SERC are actively monitoring the impacts of the drought on reliability, supporting the SERC region's plans to reduce capacity vulnerability, and 2008 summer preparations.



TVA River System and Hydro Plants

10 http://www.cpc.ncep.noaa.gov/
11 http://www.bloomberg.com/apps/news?pid=newsarchive&sid=a7I2bUOsC4mk
12 http://ap.google.com/article/ALeqM5iYOMIAzXREFVjcYtNagkheasCXwAD8SDBERO0

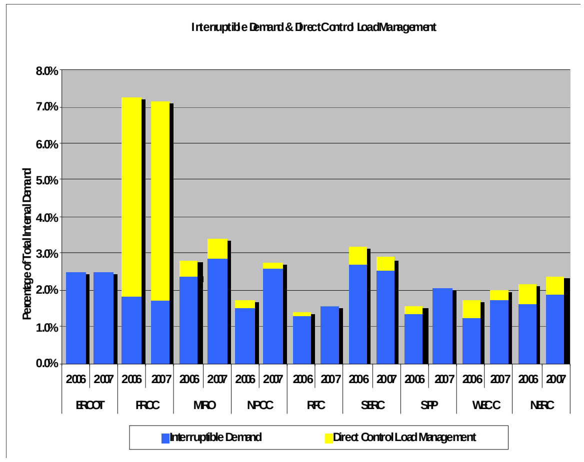
Demand Response Forecasted to Increase in NPCC, SPP, MRO and WECC

Compared to the 2006/2007 Winter Assessment, direct control load management and interruptible demand increased NERC-wide by 12 percent, or about 2,100 MW, and represents over two percent of 2007/2008 Winter Net Internal Demand.

NERC's staff requested additional information from the NPCC region/subregions to determine the cause of significant increases in demand response:

- Curtailment Service Providers and end-users are registering anticipating participation in ISO-NE's upcoming Forward Capacity Market; and
- Demand response is being encouraged in the Maritimes Provinces in preparation for the upcoming18-month refurbishment outage of the Pt. Lepreau nuclear plant.

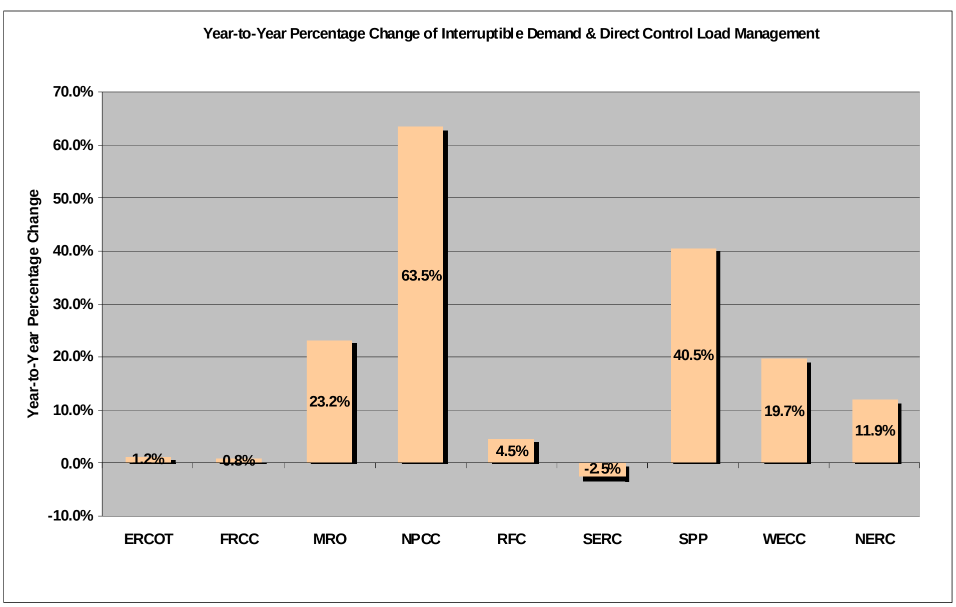
Comparison of Interruptible Demand and Direct Control Load Management as a Ratio of Peak Net Internal



Other significant increases in interruptible demand: SPP (220 MW), MRO (250 MW) and WECC (650 MW). Each region has a smaller offset in direct control load management resulting in a net gain in collected data on demand response.

SERC reflected a 170 MW (2.5 percent reduction) in direct control load management resulting from multiple reported small reductions.

2007/2008 Growth from the 2006/2007 Winter Total of Interruptible Demand and Direct Control Load Management



Transmission System is Adequate for 2007/2008 Winter

Recent additions and up-grading of existing transmission facilities deployed prior to the 2007 Summer, also support the 2007/2008 winter peak internal demand. For example, the commissioning of the Neptune Project between NPCC and Reliability*First* improved reliability for the 2007 summer season and will also improve conditions for the 2007/2008 winter season.

In addition, new facilities and up-rates will provide the same benefits. These include:

- Addition of 345 kV switching stations at Hillje, Oasis, and Elm Creek in ERCOT;
- A 345 kV transmission line from Pt. Lepreau, Province of New Brunswick to Orrington, Maine in NPCC, the second New England tie from New Brunswick to Maine;
- Hines-West Lake Wales 230 kV line in FRCC;
- Arrowhead-Stone Lake 345 kV and the Loop-Forest, Junction-Arcadian 345 kV lines in MRO;
- 450 miles of lines in voltages ranging from 500 kV–138 kV to be built in SERC; and
- A host of facility upgrades in WECC.

A number of bulk transmission outages are scheduled maintenance in northern MRO-U.S. Operating guidelines are being developed to deal with any system conditions.

Adequacy Assessment

Table 1a: Estimated December 2007 Resources and Demands (MW) with Margins (%)

December 2007	Net Internal Demand (MW)	Net Capacity Resources (MW)	Uncommitted Resources (MW)	W/O Uncommitted Available Capacity Margin (%)	With Uncommitted Potential Capacity Margin (%)
United States					
ERCOT	39,672	71,678	915	44.7	45.4
FRCC	37,795	50,367	1,227	25.0	26.7
MRO	33,616	46,061	0	27.0	27.0
NPCC	46,443	70,220	0	33.9	33.9
New England	21,101	31,948	0	34.0	34.0
New York	25,342	38,272	0	33.8	33.8
RFC	144,400	207,546	13,085	30.4	34.6
SERC	160,888	232,338	35,443	30.8	39.9
Central	37,396	49,046	3,514	23.8	28.9
Delta	21,116	34,673	13,666	39.1	56.3
Gateway	14,021	19,776	8,964	29.1	51.2
Southeastern	36,906	54,540	6,540	32.3	39.6
VACAR	51,449	74,303	2,759	30.8	33.2
SPP	29,545	47,049	10,223	37.2	48.4
WECC	107,979	168,065	72	35.8	35.8
AZ-NM-SNV	19,069	35,119	0	45.7	45.7
CA-MX US	40,396	61,668	0	34.5	34.5
NWPP	38,827	57,984	72	33.0	33.1
RMPA	9,687	13,294	0	27.1	27.1
Total-United States	**600,338**	**893,324**	**60,965**	**32.8**	**37.1**
Canada					
MRO	6,887	8,771	100	21.5	22.4
NPCC	60,869	73,042	103	16.7	16.8
Maritimes	4,683	6,484	0	27.8	27.8
Ontario	23,686	26,598	103	10.9	11.3
Quebec	32,500	39,960	0	18.7	18.7
WECC	21,200	23,572	0	10.1	10.1
Total-Canada	**88,956**	**105,385**	**203**	**15.6**	**15.8**
Mexico					
WECC CA-MX Mex	1,538	1,968	0	21.8	21.8
Total-NERC	**690,832**	**1,000,677**	**61,168**	**31.0**	**34.9**

Table 1b: Estimated January 2008 Resources and Demands (MW) and Margins (%)

January 2008	Net Internal Demand (MW)	Net Capacity Resources (MW)	Uncommitted Resources (MW)	W/O Uncommitted Available Capacity Margin (%)	With Uncommitted Potential Capacity Margin (%)
United States					
ERCOT	44,358	72,727	915	39.0	39.8
FRCC	45,993	57,123	1,227	19.5	21.2
MRO	33,770	46,049	0	26.7	26.7
NPCC	47,285	67,500	0	29.9	29.9
New England	21,943	29,058	0	24.5	24.5
New York	25,342	38,442	0	34.1	34.1
RFC	146,400	209,841	13,250	30.2	34.4
SERC	174,146	232,963	35,443	25.2	35.1
Central	40,755	48,946	3,514	16.7	22.3
Delta	23,313	35,081	13,666	33.5	52.2
Gateway	14,355	20,131	8,964	28.7	50.7
Southeastern	40,238	54,463	6,540	26.1	34.0
VACAR	55,485	74,342	2,759	25.4	28.0
SPP	29,566	47,049	10,223	37.2	48.4
WECC	106,704	165,885	78	35.7	35.7
AZ-NM-SNV	18,538	34,238	0	45.9	45.9
CA-MX US	38,972	59,652	6	34.7	34.7
NWPP	39,779	58,711	72	32.2	32.3
RMPA	9,415	13,284	0	29.1	29.1
Total-United States	**628,222**	**899,137**	**61,136**	**30.1**	**34.6**
Canada					
MRO	7,004	8,754	100	20.0	20.9
NPCC	64,167	75,362	274	14.9	15.2
Maritimes	5,019	6,655	0	24.6	24.6
Ontario	24,087	28,740	274	16.2	17.0
Quebec	35,061	39,967	0	12.3	12.3
WECC	20,884	23,337	0	10.5	10.5
Total-Canada	**92,055**	**107,453**	**374**	**14.3**	**14.6**
Mexico					
WECC CA-MX Mex	1,506	1,622	0	7.2	7.2
Total-NERC	**721,783**	**1,008,212**	**61,510**	**28.4**	**32.5**

Table 1c: Estimated February 2008 Resources and Demands (MW) and Margins (%)

February 2008	Net Internal Demand (MW)	Net Capacity Resources (MW)	Uncommitted Resources (MW)	W/O Uncommitted Available Capacity Margin (%)	With Uncommitted Potential Capacity Margin (%)
United States					
ERCOT	44,862	69,730	915	35.7	36.5
FRCC	37,727	54,994	1,227	31.4	32.9
MRO	32,819	45,657	0	28.1	28.1
NPCC	46,747	66,382	0	29.6	29.6
New England	21,405	28,968	0	26.1	26.1
New York	25,342	37,414	0	32.3	32.3
RFC	140,600	209,331	13,250	32.8	36.8
SERC	161,869	232,809	35,443	30.5	39.7
Central	37,330	48,953	3,514	23.7	28.9
Delta	20,134	35,099	13,666	42.6	58.7
Gateway	13,934	20,140	8,964	30.8	52.1
Southeastern	37,773	54,331	6,540	30.5	37.9
VACAR	52,698	74,286	2,759	29.1	31.6
SPP	28,619	47,049	10,223	39.2	50.0
WECC	103,024	162,865	82	36.7	36.8
AZ-NM-SNV	17,786	33,579	0	47.0	47.0
CA-MX US	37,874	57,927	7	34.6	34.6
NWPP	38,175	58,105	75	34.3	34.4
RMPA	9,189	13,255	0	30.7	30.7
Total-United States	**596,267**	**888,817**	**61,140**	**32.9**	**37.2**
Canada					
MRO	6,736	8,453	100	20.3	21.2
NPCC	61,365	74,663	106	17.8	17.9
Maritimes	5,006	6,643	0	24.6	24.6
Ontario	23,250	28,056	106	17.1	17.4
Quebec	33,109	39,964	0	17.2	17.2
WECC	19,776	23,215	0	14.8	14.8
Total-Canada	**87,877**	**106,331**	**206**	**17.4**	**17.5**
Mexico					
WECC CA-MX Mex	1,485	1,622	0	8.4	8.4
Total-NERC	**685,629**	**996,770**	**61,346**	**31.2**	**35.2**

Notes for Table 1a through 1c

Note 1: Uncommitted generation may not be deliverable, though potential capacity margins assume the generation is deliverable.

Note 2: It is not always possible to obtain SERC region totals by simply summing the subregions. Due to the diversity caused by geographic size and other factors, peaks do not occur simultaneously. This accounts for non-coincident demands and differences in reported resources, especially purchases and sales, across the subregions and the region.

Note 3: The sum of WECC-U.S. systems, Canada, and Mexico peak hour demands or planned capacity resources do not necessarily equal the coincident Western Interconnection total because of subregional and country peak demand diversity. Also, the WECC-U.S. area subregional net capacity resources numbers include utilization of seasonal demand diversity between the winter peaking northwest and the summer peaking southwest.

Note 4: The WECC-U.S. systems uncommitted resources are not necessarily the sum of the U.S. subregion numbers. Subregion committed and uncommitted resources are for the month of maximum seasonal peak demand, which may differ from the month of maximum seasonal peak demand for the WECC-U.S. area. For the winter peak period, the NWPP-U.S. and AZ-NM-SNV subregions peak in January, while the WECC-U.S. area and the remaining U.S. subregions peak in December. For the summer peak period, the CA-MX-U.S. subregion peaks in August, while the WECC-U.S. area and the remaining U.S. subregions peak in July. Hence, committed and uncommitted additions reported with August and January in-service dates might be reported for some subregions for a given year but not in the WECC-U.S. area until the following year.

Note 5: WECC CA-MEX represents only the northern portion of the Baja California Norte, Mexico electric system interconnected with the U.S.

Note 6: See *Reliability Concepts Used in this Report* section for definitions for demand and capacity mentioned in these tables.

Note 7: Projected resources and margins shown in Tables 1a–c below do not reflect potential fuel supply vulnerabilities or extreme hydro limitations.

Regional Reliability Assessment Highlights

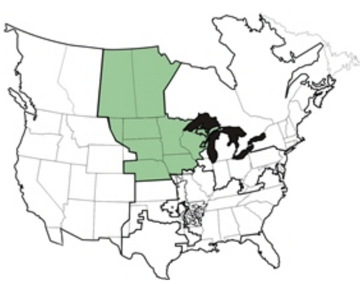
ERCOT

ERCOT expects sufficient resources to meet projected demands during the 2007/2008 winter season and expects fuel supplies to be adequate under normal conditions. However, there is always the possibility of widespread interruption of natural gas supply for electricity generation during unexpected or extended periods of very cold weather when heating use of natural gas is high. Increasing levels of wind generation may present operational challenges for the upcoming winter.

FRCC

FRCC expects to have adequate generating capacity reserves with transmission system deliverability for the 2007/2008 winter peak demand. In addition, uncommitted merchant plant capability of 1,227 MW is available as potential future resources of FRCC members and others.

The transmission capability within the FRCC region is expected to be adequate to supply firm customer demand and to provide planned firm transmission service. Operational issues in the Central Florida area can develop due to unplanned outages of generating units serving this area. However, it is anticipated that existing operational procedures, pre-planning, and training will adequately manage and mitigate the impacts to the bulk transmission system.



MRO

The MRO's projected 2007/2008 winter reserve margin is 34.4 percent without uncommitted resources. This is a slight increase when compared to the projected 2006/2007 winter reserve margin of 33.8 percent.

While reservoir water levels continue to remain low throughout the northern portion of the MRO U.S. region (Montana, North Dakota, and South Dakota), they are sufficient to meet projected peak demand and energy requirements for the 2007/2008 winter season, as indicated in the various regional reserve margin calculations. The Saskatchewan water levels are projected to be above normal levels, and Manitoba water levels are projected to be at normal levels for the upcoming 2007/2008 winter season.[13]

[13] These highlights were summarized from the regional self assessment by NERC Staff, as there wasn't sufficient time for MRO to obtain the required incremental approval for a summary drafted by MRO staff

NPCC

All five of the NPCC areas (the Maritimes area, New England, New York, Ontario, and Québec) project sufficient margins to meet their forecast peak demand and operating reserve obligations. Of the five areas, the Maritimes area and Québec are typically winter peaking systems. Since the winter of 2006/2007, the transmission systems within NPCC have been strengthened. When compared to the winter of 2006/2007, significant enhancements to the bulk power system have been made, or are being completed. These include the following:

- In December of 2007, a second 345 kV interconnection between the state of Maine and the province of New Brunswick will be energized, connecting the Pt. Lepreau and Orrington substations. The new tie will improve regional reliability and increase the New Brunswick to New England capability by 300 MW.

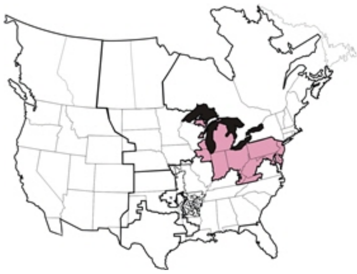
- The second of two new 345 kV underground cables from Stoughton, Massachusetts, into the Boston area has been energized. The first of the two cables was placed in service in October of 2006, and together the two 345 kV cables increase the Boston area import transfer capability by approximately 1,000 MW.

- The Lévis substation in Québec will add a 735 kV and 315 kV de-icing device, part of which will serve as a Static Var Compensator (SVC) to be used during normal system operations. When utilized to de-ice transmission, the device will generate direct current in selected 735 kV and 315 kV transmission lines at the Lévis substation near Québec City. Commissioning began in October, and the SVC will be available for the winter operating period.

- The Neptune HVdc submarine cable was energized during the summer of 2007. Connecting PJM and Long Island, it has a 660 MW rated capacity.

- The new 345 kV Mott Haven substation in New York City, serving load in the borough of the Bronx, was energized in late spring of 2007.

- In Ontario, Hydro One has identified the need for transmission reinforcements and local voltage support. For the winter period, reactive compensation at eight transformer stations located around the province will have been installed (667.2 MVAR).



RFC

The Reliability*First* region expects capacity resources and the transmission system to be adequate for the expected operating conditions during the winter of 2007/2008. The comparable capacity margin for 2007/2008 is 34.4 percent, slightly less than last year.

The output of one power plant within Reliability*First* will be restricted due to environmental issues. However, the restriction may be lifted for the duration of emergency operating conditions. Reliability*First* does not expect local environmental restrictions on any generating units to significantly impact availability during peak load conditions.

SERC

Three subregions of the SERC region are experiencing severe drought conditions that extended from the summer season. Although limited relief is expected from the current conditions over the upcoming season, the region expects capacity resources and the transmission system to be sufficient to meet forecast peak demands and daily energy demands for the upcoming winter period even though the reliance on hydro will be reduced. Drought impacts on other generation types are being monitored though no significant impact is expected.

SPP

SPP operations personnel anticipate normal winter operations. All fuel supplies throughout the winter are expected to be adequate, and there are no known unusual operating conditions expected to adversely affect reliability for the upcoming winter.

WECC

WECC anticipates that hydro and thermal generation will be sufficient to meet both seasonal peak demand and the daily demands throughout the region. Fuel supplies, including river flows and water storage, are expected to be adequate under normal conditions. Very severe winter storms, however, may adversely affect transmission, generating plant availability, and fuel supplies in areas impacted by the storms.

Regional Reliability Self-Assessments

INTRODUCTION

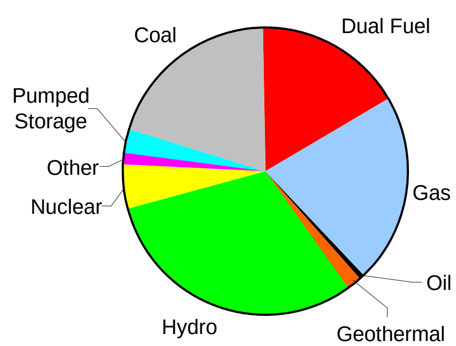
Regional Resource and Demand Projections

The figures in the regional self-assessment pages show the regional historical demand, projected demand growth, capacity margin projections, and generation expansion projections reported by the regions.

Capacity Fuel Mix

The regional capacity fuel mix charts show each region's relative reliance on specific fuels[14] 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 database.

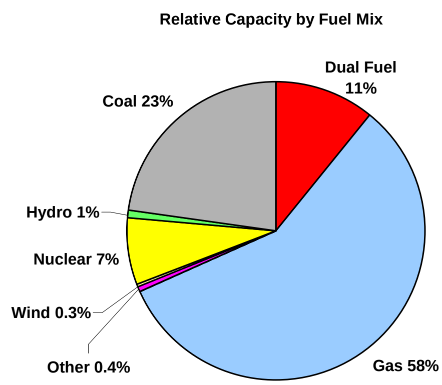
Sample — Relative Capacity by Fuel Mix



[14] Note: The category "Other" may include capacity for which a fuel type has yet to be determined.

ERCOT

Projected Total Internal Demand	45,987	MW
Interruptible Demand & DCLM	1,125	MW
Projected Net Internal Demand	44,862	MW
Last Winter's Peak Demand	50,408	MW
Change	(8.8)	%
All-Time Winter's Peak Demand	50,408	MW
Deliverable Internal Capacity	69,757	MW
Projected Purchases and Incoming Adjustments	191	MW
Projected Sales and Outgoing Adjustments	218	MW
Net Capacity Resources	69,730	MW
Capacity Margin	35.7	%
Reserve Margin	55.4	%
With Uncommitted Resources		
Total Potential Resources	70,645	MW
Capacity Margin	36.5	%
Reserve Margin	57.5	%



Demand

The 2007/2008 winter peak demand forecast of 45,987 MW for the ERCOT region was based on a region-wide econometric forecast model that uses the historical trend adjusted for economic and weather variables, primarily heating and cooling degree-days. The forecast is a decrease of 9 percent from the 2006/2007 actual peak demand of 50,409 MW, which was also ERCOT's all-time winter peak demand and was the result of abnormally cold temperatures. The 2007/2008 winter peak demand forecast is an increase of 2.8 percent over last year's forecast of 44,715 MW for the 2006/2007 winter peak.

In addition to the base forecast, ERCOT also produces forecasts using temperatures at the 90th percentile of all temperatures in the last 12 years to account for the variability and uncertainty in the forecast.

Transfers of up to 218 MW to the Southwest Power Pool (SPP) are due to SPP member's ownership of that amount of capacity of a power plant located in ERCOT.

Interruptible loads typically make 1,125 MW available through ERCOT's ancillary services market. The amount of interruptible load was derived through a statistical approach based on having a 95 percent confidence in the end result. The mean and standard deviation were calculated from the total number of hourly observations and the result was reported. The ERCOT retail market may contain additional amounts of load management that are not quantified. The Public Utility Commission of Texas requires transmission utilities to invest in energy efficiency programs sufficient to reduce residential and commercial demand growth by 10 percent, based on the past five years' growth; this reduction is embedded in the load forecast.

Generation

During the 2007/2008 winter period, ERCOT projects 77,972 MW of operable committed resources. Approximately 1,970 MW of this is new generation capacity that has commenced or will commence commercial operation between March 1, 2007 and November 30, 2007. ERCOT projects 915 MW of operable uncommitted resources.

Less than one percent of the ERCOT generation capability is fueled by hydro. Reservoir levels are normal to slightly above normal.

Purchases and Sales

ERCOT does not rely on outside assistance or external resources under normal operating conditions to meet demand. For the 2007/2008 winter period there will be a total of 820 MW of DC tie transfer capability between ERCOT and SPP and 286 MW of capability between ERCOT and Mexico's Comision Federal de Electricidad (CFE). However, only 191 MW from the SPP region are shown as firm purchases. These purchases are not necessary for ERCOT to meet the winter peak. As stated above, entities in SPP can call on up to 218 MW of capacity in ERCOT, which is classified as a capacity sale from ERCOT.

Fuel

ERCOT has 10.7 percent of capacity with dual fuel capability. Natural gas fuel supply interruptions are a potential concern during the winter in ERCOT due to heating demands. The Energy Information Administration (EIA) reports an abundance of natural gas for the 2007 / 2008 winter period, even over the ample supply in the previous winter. No significant disruptions in gas supply were experienced in ERCOT during the 2006/2007 winter period, and ERCOT does not anticipate curtailments in the 2007/2008 winter period. In the event of forecasted extreme weather and possible fuel curtailments, ERCOT may request fuel capability information from qualified scheduling entities (QSE) that represent generation to better prepare operationally for potential curtailments (See Section 5.6.5 of the ERCOT Protocols[15]). Specific information that may be requested can be found in the ERCOT Operating Guides.[16]

Transmission

Currently, ERCOT has three units under Reliability Must-Run (RMR) contract in the Laredo area of south Texas representing a total capacity of 169 MW. The Laredo area has experienced high load growth over the years. The existing transmission system cannot support the necessary energy imports to satisfy the area and maintain ERCOT's N-1 security requirements without the dispatch of generation located in the Laredo area. In addition a 100-MW variable frequency transformer DC tie with Mexico has been installed. This device does not eliminate the need for the RMR units but will help ensure that adequate capacity is available to restrict the Laredo energy imports to acceptable levels that satisfy the Laredo area security criteria.

The 345-kV Elm Creek switching station was built to the east of San Antonio to help reduce congestion in the San Antonio area. In addition, the 345-kV Hillje and Oasis switching stations

[15] http://www.ercot.com/mktrules/protocols/current.html
[16] http://www.ercot.com/mktrules/guides/operating/index.html

went in service in the Houston area to help increase energy imports into Houston. An additional 22 miles of 138-kV transmission is anticipated to be in service for the winter assessment period. No unusual transmission flow patterns are expected for the 2007/2008 winter.

ERCOT has interconnections through DC ties with the Eastern Interconnect (SPP) and with Mexico's Comision Federal de Electricidad (CFE). The maximum imports/exports over theses ties will be 1,106 MW total (820 MW DC interconnections with SPP and 286 MW DC interconnections with CFE). These ties can be operated at maximum import and export provided there are no area transmission elements out of service. In the event of a transmission outage in the area of these ties, studies will be run during the outage coordination period to see if any import/export limits are needed during the outages. Otherwise, no special studies are done to determine capacity assistance from resources outside of ERCOT.

Operational Issues

ERCOT does not expect any unusual operating conditions during the winter or any environmental or regulatory restrictions that could cause operational problems. Some resources in or near load centers have scheduled planned annual maintenance during this winter. These outages have been studied and are not expected to impact reliable operations. If environmental or regulatory restriction changes occur, they will be addressed in a way to ensure reliability standards are met and maintained. ERCOT also has an Emergency Electric Curtailment Plan (EECP) to address potential reliability issues that may arise. The EECP includes procedures for use of interruptible load, voltage reductions, procuring emergency energy over the DC ties and load shedding to avoid uncontrolled loss of load (See Section 5.6.6.1 of the ERCOT Protocols[17]).

Unusually high winds or a rapid decrease in wind speed can affect wind generation operating capability. The different technologies of wind turbines respond to very high wind speeds in different ways. Some are able to stay on line, while others have the capability to curtail output and some trip. On February 24, 2007, ERCOT experienced winds in excess of 65 mph in some areas of West Texas, which caused about 1,550 MW of wind generation to trip over a two hour period. After the tripping and automatic curtailing of wind generation, ERCOT implemented Step One of EECP because the level of the responsive reserves on the ERCOT system dropped below the EECP trigger of 2,300 MW, as reserves were used to replace the reduced wind generation. The effect of high speed wind or a rapid decrease in wind speed on wind generation is difficult to predict. With over 4,100 MW of wind generation on the ERCOT grid, this could present operational challenges for the upcoming winter.

Reliability Assessment Analysis

The projected capacity margin for winter 2007/2008 of 35.7 percent is well above the minimum planning margins that ERCOT has established and is slightly lower than the 37.3 percent capacity margin that was projected for winter 2006/2007. ERCOT's reserve margin target is 12.5 percent, which equates to a capacity margin of 11 percent. This was based on a loss-of-load probability (LOLP) study, which concluded that the margin should provide about a one-day-in-ten-years loss-of-load expectation. This reserve margin should be sufficient to cover, among other uncertainties, the potentially higher peak demand associated with 10th percentile temperatures.

[17] http://www.ercot.com/mktrules/protocols/current.html

Resources that are counted in determining ERCOT's margins are:

- Existing in-service capacity based on demonstrated summer net dependable capacity (except for wind generation and capacity that has the capability to switch between ERCOT and other interconnections)
- Future planned generation with signed interconnection agreements and air permits for fossil-fueled plants
- Switchable capacity to the extent its owners have indicated they intend to be in the ERCOT market
- Based on a recent LOLP study which includes a determination of the effective load-carrying capability of wind, 8.7 percent of existing wind capacity and future wind capacity with signed interconnection agreements (*ERCOT Target Reserve Margin Analysis*[18]).

The ERCOT planning authority performs a security-constrained unit commitment and economic dispatch analysis for the upcoming year. This analysis is performed on an hourly basis for a variety of conditions to ensure deliverability of sufficient resources to meet a load level that is approximately 10 percent higher than the expected coincident system peak demand plus operating reserves. Load data is based on the non-coincident demands projected by the transmission owners.

Operationally, transmission operating limits are adhered to through market-based generation re-dispatch directed by ERCOT as the balancing authority and reliability coordinator. Operational resource adequacy is also maintained by ERCOT through market-based procurement processes (See Sections six and seven of the ERCOT Protocols[19]).

The ERCOT planning authority and the transmission planners in the ERCOT region perform a variety of analyses, including steady-state powerflow, security-constrained unit commitment and economic dispatch, voltage and transient stability analyses to plan the system and ensure performance within NERC and ERCOT transmission planning standards. Transmission planning is increasingly using voltage and transient stability analysis to establish transfer limits and recommend transmission improvements. Voltage stability has become a more pressing concern with increasing power transfers in ERCOT and lessons learned from the 2003 Northeast blackout. ERCOT operators are able to perform real-time voltage stability analysis.

Other than running studies during the outage coordination period to assess import/export limits in the event of a transmission outage in the area of the DC ties, no special studies are done to determine capacity assistance from resources outside of ERCOT.

ERCOT has hired an outside consultant to conduct a study of the impact of additional wind generation capacity on system ancillary service requirements. This study will include a detailed analysis of the current variability of load in ERCOT and the expected changes in this variability as additional wind resources are added to the system. The study will also analyze the capability of the current generating fleet in ERCOT to provide the levels of ancillary services required due

[18] http://www.ercot.com/calendar/2007/01/20070112-GATF.html
[19] http://www.ercot.com/mktrules/protocols/current.html

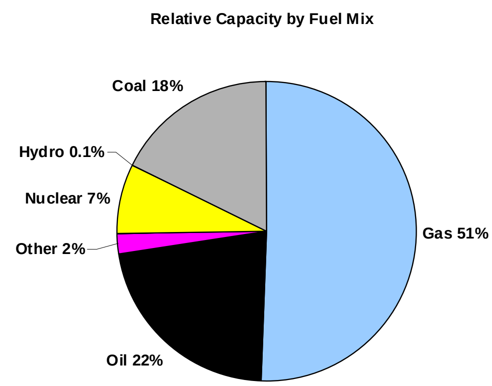
to the expected variability of net load and the likelihood and potential impacts of extreme weather events. This study will be complete by the end of 2007.

Regional Description

ERCOT is a separate electric interconnection located entirely in the state of Texas and operated as a single balancing authority. ERCOT has 135 members that represent independent retail electric providers; generators, and power marketers; investor-owned, municipal, and cooperative utilities; and retail consumers. It is a summer-peaking region responsible for about 85 percent of the electric load in Texas with a 2006 peak demand of 62,339 megawatts. ERCOT serves a population of more than 20 million in a geographic area of about 200,000 square miles. Additional information is available on the ERCOT Web site (www.ercot.com).

FRCC

Projected Total Internal Demand	49,526	MW
Interruptible Demand & DCLM	3,533	MW
Projected Net Internal Demand	45,993	MW
Last Winter's Peak Demand	39,291	MW
Change	26.0	%
All-Time Winter's Peak Demand	44,472	MW
Deliverable Internal Capacity	54,630	MW
Projected Purchases and Incoming Adjustments	2,493	MW
Projected Sales and Outgoing Adjustments	0	MW
Net Capacity Resources	57,123	MW
Capacity Margin	19.5	%
Reserve Margin	24.2	%
With Uncommitted Resources		
Total Potential Resources	58,350	MW
Capacity Margin	21.2	%
Reserve Margin	26.9	%



Demand

The Florida Reliability Coordinating Council (FRCC) is forecast to reach its 2007/2008 winter peak demand of 49,526 MW in January, which represents a projected demand increase of 26 percent over the actual 2006/2007 winter demand of 39,291 MW primarily due to the lack of prolonged cold (less than 40°F) temperatures throughout South Florida in the prior winter. This weather-normalized projection is consistent with historical FRCC demand growth, and is almost 2.5 percent higher than last year's forecast of 48,296 MW for the 2006/2007 winter peak demand. The peak demand forecast includes the potential 2,699 MW of demand reductions from the use of direct control load management and a potential 834 MW of demand reductions from the use of interruptible load management programs. The winter peak demand forecast accounts for ongoing energy efficiency programs related to appliance replacement, improved insulation, etc.

The FRCC winter peak demand forecast is an aggregation of the load forecast of each of its member utilities. The FRCC internal winter demand forecast, based on previous actual peak demands compared to previous peak demand forecasts, has a tendency to over-forecast due to the number of projected peaks higher than observed actual peaks. Florida has not experienced a cold winter since 2003. Weather and temperature variations typically differ from the "normalized" weather assumptions particularly for the winter months in Florida. Therefore, weather volatility is the single most significant factor that will impact this year's winter peak demand. Other factors that influenced an increase to the forecast include population growth and the Florida economy with the projected price of fuels dampening the growth outlook.

FRCC assesses the peak demand uncertainty and variability by developing regional bandwidths or 80 percent confidence intervals on the projected or most likely load (90/10). The 80 percent confidence intervals on peak demand can be interpreted to mean that there is a 10 percent probability that in any year of the forecast horizon that actual observed load could exceed the high band. Likewise, there is a 10 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 variability such as demographics, economics, and price of fuel and electricity.

Generation

The total committed generation in the FRCC for this winter is 54,630 MW with an additional 1,227 MW of uncommitted generation. The net capacity of resources available within the region to meet the projected winter peak yields a 24.2 percent reserve margin, exclusive of uncommitted resources, adequately satisfying the 15 percent reserve margin requirement. This year's forecasted reserve margin is 2.3 percent higher than last year's forecast reserve margin of 21.9 percent. 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 and the daily energy demand.

Since the beginning of the year, a net capacity of 2,058 MW will have been placed online prior to the upcoming winter season, with all of the generation resulting from newly commissioned gas-fired generation, and the remainder from the uprate of existing facilities. No uncommitted generation has been reported for commercial operation prior to the upcoming winter season.

Only existing capacity under firm contract or committed to serve firm load has been included in FRCC's capacity resources. FRCC has 4,464 MW of existing merchant plant capacity, of which 3,237 MW are under firm contract and have been included in committed capacity resources. The committed resources are included in the various system operation conditions that are studied.

Purchases and Sales

Currently, there are 1,627 MW of generation under firm contract available to be imported into the region on a firm basis with another 866 MW of FRCC utility owned generation dispatched out of the southeastern subregion of SERC. These combined imports account for five percent of the reserve margin, and have firm transmission service to ensure deliverability into the FRCC region. The FRCC region has no firm long-term sales to other regions.

Fuel

The FRCC regional Load and Resource Plan is an assessment tool developed to aggregate regional capacity resource data from utilities within the FRCC, in order to assess regional long-term resource adequacy along with overall fuel diversity. Included in the plan are requirements for identification of primary and secondary fuel sources used for existing and planned generating facilities. Currently, the expected percentage of generation with dual-fuel capability in the FRCC region is 53 percent with fuel diversity varying based on the prevailing economics of fuel availability. Typically, during winter peak load conditions, operators can increase fuel diversity by dispatching dual fuel units to maximize fuel availability of the existing fuel supply infrastructure and prepare for the impact of extreme weather.

Based on past operating experience with hurricane impacts to the fuel supply infrastructure within the region, the FRCC revised its Generating Capacity Shortage Plan in 2007. This plan distinguishes between generating capacity shortages, caused by abnormally high system loads and unavailable generating facilities, from those caused by short-term, generating fuel or availability constraints. Since a significant portion of electric generation within Florida uses remotely supplied natural gas, the plan specifically distinguishes generating capacity shortages by primary causes (i.e., hurricanes and abnormally high loads) in order to provide a more effective regional coordination.

For capacity constraints due to inadequate fuel supply, the FRCC State Capacity Emergency Coordinator (SCEC) along with the Reliability Coordinator (RC) have been provided with an enhanced ability to assess regional fuel supply status by initiating fuel data status reporting by regional utilities. This process relies on utilities to report their actual and projected fuel availability along with alternate fuel capabilities, to serve their projected system loads. This is typically provided by type of fuel and expressed in terms relative to forecast loads or generic terms of unit output, depending on the event initiating the reporting process. Data is aggregated at the FRCC and is provided, from a regional perspective, to the RC, SCEC and governing agencies as requested. Fuel data status reporting is typically performed when threats to regional fuel availability have been identified and is quickly integrated into an enhanced regional daily capacity assessment process along with various other coordination protocols to ensure accurate reliability assessments of the region and also ensure optimal coordination to minimize impacts of regional fuel supply issues and/or disruptions.

Transmission

Transmission constraints in the Central Florida area may require remedial actions depending on system conditions creating increased west-to-east flow levels into the Central Florida metropolitan load areas. Permanent solutions have been identified and implementation of these solutions is underway. A new 230kV transmission line within the Central Florida area from Hines to West Lake Wales is expected to be complete by December of 2007 thus improving reliability in this area. Transmission configuration changes have been implemented to mitigate transmission constraints in the Central Florida area. This winter, remedial operating strategies have been developed and will continue to be evaluated to ensure system reliability.

Major additions or changes to the FRCC transmission system are mostly related to expansion in order to serve the growing demand and, therefore, maintain the reliability of the transmission system. For the winter of 2007/2008, no additional transmission constraints have been identified since typical transmission system flow patterns have not changed significantly since the winter of 2006/2007.

Operational Issues

No scheduled generating unit or transmission facility maintenance outages of any significance are planned for the winter period. Scheduled transmission outages are typically performed during seasonal off peak periods to minimize any impact on the bulk electric system. In addition, there are no foreseen environmental and/or regulatory restrictions or unusual operating conditions that can potentially impact reliability in the FRCC region during the 2007/2008 winter period.

FRCC has a RC agent that monitors real-time system conditions and evaluates near-term operating conditions of the bulk electric grid. The RC uses a region-wide state estimator and contingency analysis program to evaluate current system conditions. These programs are provided with new input data from operating members every ten seconds. These tools enable the FRCC RC to implement operational procedures such as generation redispatch, sectionalizing, planned load shedding, reactive device control, and transformer tap adjustments to successfully mitigate the line loading and voltage concerns that occur in real time and those identified in the FRCC transmission studies.

Reliability Assessment Analysis

The FRCC region is required by the State of Florida to maintain a 15 percent Reserve Margin. Presently, there are no requirements in the FRCC region to plan for or maintain a specific capacity margin. However, based on the expected load and generation capacity, the calculated capacity margin for the winter of 2007/2008 is 19.5 percent. This year's calculated capacity margin is 1.5 percent higher than last year's calculation for the winter of 2006/2007.

The expected reserve margin for this winter includes a total of 2,493 MW import from the southeastern subregion of SERC to the FRCC. These imports account for 5.0 percent of the total reserve margin, and have firm transmission service to ensure deliverability into the FRCC region. During last year's winter a total of 2,394 MW (firm transmission service) of external resources were included in the reserve margin calculation for the region. The increase in import over last year's winter assessment is primarily due to a firm purchase of 75MW from the southeastern subregion of SERC.

The 15 percent Reserve Margin was established based on an LOLP analysis that incorporated system generating unit information to determine the probability that existing and planned resource additions will not be sufficient to serve forecasted 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 and non-firm imports into the region; and the non-availability of load control programs), the peninsular Florida electric system maintains an LOLP well below the criterion.

Companies within FRCC use bandwidth analysis and/or Monte Carlo simulation to assess peak demand uncertainty and variability. For the bandwidth analysis, the company develops a bandwidth on the projected or most likely demand. The purpose of developing bandwidths on peak demand is to quantify all uncertainties of demand, which would include weather and non-weather demand variability such as demographics, economics, and the price of fuel and electricity. For the Monte Carlo method, simulations are performed on peak demands to arrive at a probabilistic distribution as to range and likelihood of this range of outcomes. Factors that determine the level of demand for electricity are assessed in terms of their own variability and this variability is incorporated in the simulations. If the installed and planned generation is sufficient to cover a significant portion of the demand variability, then the system is deemed to be reliable.

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 winter peak demand. The results of the 2007/2008 Winter Transmission Assessment, which evaluated the steady-state winter peak load conditions under different operating scenarios, indicates that any concerns about 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.

Availability and deliverability of external resources are ensured by firm transmission contracts and purchase power contracts. These external resources were included in the 2007/2008 Winter Transmission Assessment demonstrating the deliverability of these external resources. Since external resources account for only 5 percent of the total 24.2 percent reserve margin in the FRCC for the 2007/2008 winter, the unavailability of these external resources is above the reserve margin criteria for the region.

An interregional transfer study is performed annually to evaluate the transfer capability between FRCC and the southeastern subregion of SERC. Joint studies of the Florida/Southeastern transmission interface indicate a winter seasonal import capability of 3,700 MW into the region, and an export capability of 2,000 MW. Any transfer-related contingencies resulting in transmission overloads or voltage violations can be resolved by operator procedures.

Transient stability studies are performed by the FRCC and no issues have been identified that would impact the winter 2007/2008 season. Small signal analysis is performed when damping issues are identified during transient stability studies. Voltage stability studies performed in the region identify the worst case conditions such as the unavailability of multiple units. These studies are normally load flow based using an algorithm that can identify voltage limitations.

The FRCC recently completed the *2007/2008 Winter Transmission Assessment* and other studies to ensure the requirements contained in NERC Reliability Standards TPL-001, TPL-002, TPL-003, and TPL-004-0 are being met.

The FRCC has emergency procedures in place to address unexpected events such as the loss of a major gas pipeline or the impact of a hurricane. In addition, the FRCC maintains an underfrequency load shedding program and other SPS systems that can minimize the impact to the bulk power system following an extreme event such as the loss of all lines on a 500kV corridor or all generators at a plant by providing coordinated operation of controlled separation systems.

The FRCC regional Load and Resource Plan is developed on an annual basis and includes specification of primary and secondary fuel sources for generating facilities. Based on the interdependence of generating capacity and natural gas, the FRCC continues to increase coordination among natural gas suppliers and generators within the region. This coordination continues to provide the data necessary to perform short-term natural gas availability assessments in order to provide operators with near-term assessments of the gas delivery system on a regionally coordinated basis for appropriate operational recommendations. The FRCC continues to assess and coordinate responses to regional fuel supply impacts and issues, including fuel inventory and alternate supply availability, as they are identified.

The FRCC has developed a high-level, transient gas flow model to study and analyze the gas pipeline system and its impact on reliability in peninsular Florida. Study results, based on detail natural gas pipeline models, indicate that potential gas transportation issues can be adequately mitigated with operating reserves including the use of dual fuel units on liquid fuels.

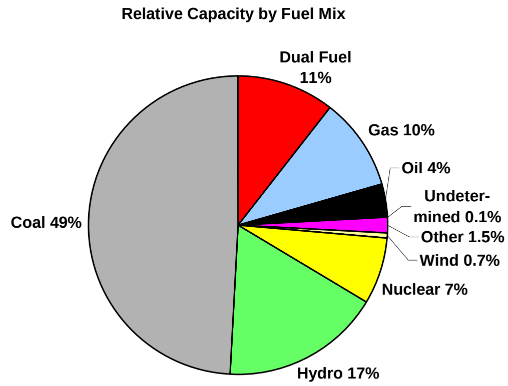
For the 2007/2008 winter period, fuel supplies continue to be adequate for the region and these supplies are not expected to be impacted by extreme weather during winter peak load conditions. There is no identified fuel availability or supply issues at this time, and no additional mitigation strategies have been developed. Based on current fuel diversity, alternate fuel capability, and study results, the FRCC does not anticipate any fuel transportation issues affecting capability during peak periods and/or extreme weather conditions.

Regional Description

FRCC's membership includes 27 members, which is composed of investor-owned utilities, cooperative systems, municipal utilities, power marketers, and independent power producers. Historically, the region has been divided into 11 Balancing Authorities. As part of the transition to the RRO, FRCC has registered 109 entities (both members and non-members) performing the functions identified in the NERC Reliability Functional Model defined in the NERC Reliability Standards glossary. The region contains a population of more than 16 million people, and has a geographic coverage of about 50,000 square miles over peninsular Florida. Additional details are available on the FRCC website (http://www.frcc.com).

MRO

Projected Total Internal Demand	42,204	MW
Interruptible Demand & DCLM	1,430	MW
Projected Net Internal Demand	40,774	MW
Last Winter's Peak Demand	41,323	MW
Change	2.1	%
All-Time Winter's Peak Demand	41,323	MW
Deliverable Internal Capacity	51,432	MW
Projected Purchases and Incoming Adjustments	3,741	MW
Projected Sales and Outgoing Adjustments	370	MW
Net Capacity Resources	54,803	MW
Capacity Margin	25.6	%
Reserve Margin	34.4	%
With Uncommitted Resources		
Total Potential Resources	54,903	MW
Capacity Margin	25.7	%
Reserve Margin	34.7	%



Demand

The Midwest Reliability Organization's (MRO) expected 2007/2008 winter non-coincident peak total internal demand in the combined MRO U.S. and MRO Canada is 42,204 MW assuming normal weather conditions. This forecast is 3.2 percent above last winter's peak total demand forecast of 40,877 MW and 2.1 percent above last winter's actual peak demand of 41,323 MW. The 41,323 MW actual peak value is not adjusted to exclude any additional interruptible demand and DSM that may not have been implemented or to include any interruptible demand and DSM that were implemented. The actual 2006/2007 winter peak demand of 41,323 MW was 1.1 percent above the forecast, assuming no interruptible demand and DSM at the time of the winter peak.

Interruptible demand (1,210 MW, 3.0 percent) and DSM (220 MW, 0.5 percent) programs, amounting to 3.5 percent of the MRO's Projected Net Internal Peak Demand (40,774 MW), are used by a number of MRO 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 winter season.

Each MRO 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. The regional peak demand forecast is the aggregate of the member individual forecasts. From a regional perspective, there were no significant changes in this year's forecast assumptions in comparison to last year.

Peak demand uncertainty and variability due to extreme weather and/or other conditions are accounted for within the determination of adequate generation reserve margin levels. Both the MAPP Generation Reserve Sharing Pool (GRSP) members and the former MAIN members within MRO[20] utilize a Load Forecast Uncertainty (LFU) factor within the calculation for the 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.

High and low demand forecasts for the Saskatchewan system were simulated using a Monte Carlo method to reflect economic and weather uncertainties. This model considers each uncertainty independently from other variables and assumes a probability distribution around the expected demand forecast. Results are based on an 80 percent confidence interval, meaning there is an 80 percent probability of the demand falling within the bounds created by the high and low forecasts.

Generation

1,173 MW of committed capacity and 100 MW of uncommitted capacity have been placed in service (new units or up-rates of existing units) within the MRO between March1 and November 30, 2007 for the 2007/2008 winter season.

While reservoir water levels continue to remain low throughout the northern portion of the MRO U.S. region (Montana, North Dakota, and South Dakota), they are sufficient to meet projected peak demand and energy requirements for the 2007/2008 winter season, as indicated in the various regional reserve margin calculations. The Saskatchewan water levels are projected to be above normal levels, and Manitoba water levels are projected to be at normal levels for the upcoming 2007/2008 winter season.

Purchases and Sales

For the 2007/2008 winter season, the MRO is projecting total firm purchases of 3,741 MW. This capacity includes imports into the MRO region from other surrounding regions and purchases from Independent Power Producers (IPPs) within the MRO region. Purchases of 2,661 MW are from municipals or other utilities with resources internal to the MRO. The remaining purchases of 1,080 MW consist of external transactions. The MRO will be exporting approximately 370 MW of projected sales out of the MRO Region. This net firm purchase of 3,371 MW equates to 8 percent of the projected total internal demand.

Throughout the MRO region, firm transmission service is required for all generation resources that are utilized to provide firm capacity; therefore, these firm generation resources are fully deliverable to the load. The MRO is forecast to meet the various reserve margin targets without needing to include energy-only, uncommitted, or transmission-limited resources.

Different transmission providers within the MRO region treat Liquidated Damage Contracts (LDC) according to their tariff policies. Most MRO members are within non-retail access jurisdictions (except for Upper Michigan) and; therefore, liquidated damages products are not typically used.

[20] The former MAIN members are Alliant Energy, Wisconsin Public Service Corp., Upper Peninsula Power Co., Wisconsin Public Power Inc., and Madison Gas and Electric.

Fuel

The MRO has 5,611 MW of generation that has dual fuel capability consisting primarily of gas/oil. This is 10.9 percent of the MRO winter 2007/2008 internal capacity.

For accreditation of a dual fuel capable unit within the MAPP group, annual generation capability tests must be provided using each fuel source. As a general rule, regardless of fuel, generation should have appropriate permitting to allow for 500 hours per year, except for internal combustion engines, which should allow for 300 hours per year. The former MAIN members now in the MRO did not have any specific policies regarding generators with dual-fuel capability.

MAPP member generation owners must have fuel available in sufficient quantity to operate the unit for four hours for five consecutive days. The former MAIN members now in the MRO did not have any specific policies regarding generators with dual-fuel capability.

The MRO members consider known and anticipated fuel supply or delivery issues in its assessment. Because the MRO has a large diversity in fuel supply, inventory management, and delivery methods throughout the region, it does not have a specific region-wide mitigation procedure in place should fuel delivery problems occur. The MRO and its members closely monitor the delivery of Powder River Basin coal to ensure adequate supply. The MRO does not foresee any significant fuel supply and/or fuel delivery issues for the upcoming 2007/2008 winter season. Therefore, there should be no apparent impact to the reliability of meeting peak electrical demand for the 2007/2008 winter season.

100 percent of gas fired generation in the MRO is under firm contract for 2007/2008 winter.

Policies or practices for on-site coal vary within the MRO region. Specific practices are determined by the individual member companies and a region-wide policy of on-site coal inventory does not exist. However, inherent within the obligation to serve load is that adequate on-site coal inventory exists.

Transmission

Assessments for the individual transmission areas are provided below.

Iowa

Reliable operation of the system, without any significant operating problems, is expected in the state of Iowa[21] during the winter 2007/2008 period. Two new flowgates were added to the transmission service and congestion management processes in 2007 to monitor potentially heavy east to west and south to north power transfers across Iowa.

The 790 MW Walter Scott Energy Center Unit-4, which became fully operational in June 2007, will help eliminate the majority of operational issues associated with the east to west system bias across Iowa. However, strong south to north system bias, typical for the winter season, across the transmission system in Iowa is expected to continue and will be managed with standing congestion procedures.

[21] MEC Operational Studies conducted by System Operations Department, August 2007.

Control centers that operate the transmission system in Iowa will work closely with the MISO-St. Paul RC on monitoring all Iowa critical facilities. Congestion management procedures and NERC TLR will be used, in accordance with approved operating guides, to operate the system within system operating limits.

Since Iowa is a summer peaking area, maintenance on transmission and generation facilities is scheduled to take place during the winter season. Detailed operational studies associated with these outages will be performed to make sure that these outages do not cause any operational problems. Temporary operating guides will be provided in cases where studies detect a potential violation of system operating limits.

Nebraska

No significant operational concerns are expected in Nebraska[22] during winter 2007/2008. Where large transfers might occur, operating guides and operating procedures have been put into place to maintain the reliable operation of the Nebraska regional transmission system.

Operational studies have been performed and will be updated as necessary for scheduled transmission and generation outages during the winter peak and off-peak time periods. Temporary operating guides will be issued for those outages which require actions or limitations to protect system operating limits.

Five constrained interfaces are used in transmission service and congestion management processes which are impacted by north-to-south and west-to-east transfers across the MRO system. Transfer limits on these constrained interfaces are not typical during the winter season in Nebraska. In the past, the Nebraska/Iowa regional transmission system has experienced heavy south-to-north transfers due to drought conditions and winter peak load conditions in northern MRO. These south-to-north transfers across the MRO system have a more profound impact on the eastern Nebraska system than on the western Nebraska system. A flowgate in eastern Nebraska is used to manage potential post-contingent overloads during heavy south-to-north transfers. All of these interfaces have approved operating guides that have proven to be effective in dealing with system conditions throughout the year.

Winter season load distributions are considered worst case for stability in the western Nebraska area. Operating guides have been developed which adequately protect the western Nebraska region for winter season load levels and maximum transfer conditions.

Northern MRO

The northern MRO[23] region consists of the Dakotas, Minnesota, part of Montana, and the Canadian provinces of Manitoba and Saskatchewan. No significant operational issues are expected this winter for the Northern MRO region. Existing operating guides, and temporary operating guides that are developed as needed, are expected to maintain reliable system conditions throughout the upcoming winter season.

[22] Winter Peak and Off-Peak Operational Studies performed by NPPD Transmission Planning Department, 2007. 2007/2008 Winter Power Flow Study performed by LES System Protection Department, 2007.

[23] NMORWG Winter Peak sensitivity reviews and voltage stability analysis, pre-winter 2007/2008.

Reservoir water levels continue to remain low throughout the northern MRO-U.S. area (Montana, North Dakota, and South Dakota), and these will likely continue to reduce the magnitude and duration of exports out of northern MRO and also cause the recent significant imports of power into the MRO region to continue. Water conditions in Manitoba are normal, and normal Manitoba-U.S. exports are likely. No internal or external transmission constraints are expected that will significantly impact reliability in Saskatchewan.

A number of bulk transmission outages are scheduled in the northern MRO-U.S. area for maintenance; however, no operating problems are expected. Temporary operating guides will be developed as necessary. Several large wind generation additions to the northern MRO-U.S. area are expected this winter. A number of other small generators have recently been installed.

The Arrowhead-Stone Lake 345 kV line, which will complete the Arrowhead-Stone Lake-Gardner Park (Weston) 345 kV line, is expected to be completed by February/March 2008. This will complete the installation of a significant new 345 kV interconnection from Minnesota into Wisconsin and will significantly improve the operational flexibility of the northern MRO system. Studies are underway to redefine and develop updated transfer limits, and proposed flowgate redefinitions for the Minnesota-Wisconsin interface. No other major transmission additions are expected in northern MRO during the upcoming winter season.

The 345kV transmission line from Nobles County to Lakefield Junction along with the series compensator at Fieldon is scheduled to be completed this winter. This will increase the wind generation outlet capability in southwest Minnesota (Buffalo Ridge area) from 425 MW — 825 MW.

Overall, the northern MRO system is expected to operate reliably under forecasted load and firm exchange levels.

Wisconsin — Upper Michigan System

The WUMS electric transmission system encompasses the service territories of five BAs — Alliant Energy-Wisconsin Power & Light, We Energies, Wisconsin Public Service Corporation, Madison Gas & Electric Company, and Upper Peninsula Power Company. The WUMS system consists of 345, 230, 161, 138, 115, and 69 kV transmission facilities and is owned by American Transmission Company, LLC (ATCLLC). The operation of WUMS is coordinated between ATCLLC and the Midwest Independent System Operator (Midwest ISO).

Reliable operation of the WUMS transmission system is expected during the winter 2007/2008 season.[24]

Major transmission projects expected to be in-service by the end of February 2008 are listed below. These additions and upgrades strengthen the reliability of the WUMS system for the upcoming winter season and beyond.

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[24] 2007 — ATCLLC 10-Year Transmission System Assessment, http://www.atc10yearplan.com. Midwest ISO Winter 2007/2008 Assessment Studies, http://extranet.midwestiso.org/operations/seasonal.php (on-going) Reliability First Corporation (RFC) Winter 2007/2008 Transmission Assessment Studies (on-going) Eastern Interconnection Reliability Assessment Group (ERAG) Winter 2007/2008 Inter-regional Transmission Assessment, MRO-RFC-SERC West-SPP (MRSWS) sub-group study (on-going)

- Increase ratings of Sunset Point — Ellinwood and Ellinwood — Fitzgerald 138 kV lines.
- Rebuild Morgan — White Clay 138 kV line.
- Increase ratings of North Appleton — Lawn Road — White Clay 138 kV lines.
- Install Plymouth #4 substation.
- Loop Holland — Howard's Grove into Plymouth #4.
- Increase rating of Paris — St Martin 138 kV line.
- Install Cypress 345 kV substation.
- Loop Forest Junction — Arcadian 345 kV line into Cypress 345 kV substation.
- Build Rubicon — Hustisford 138 kV line.
- Increase rating of St Lawrence — Glacier 138 kV line.

For winter 2007/2008, WUMS western and southern interfaces continue to require close monitoring to ensure operation within limits when WUMS is a net importer.

Western interface
The WUMS system is susceptible to voltage instability during heavy imports from the west. The Midwest ISO conducts daily P-V analysis and establishes lower transfer limits when necessary to help prevent voltage instability. Completion of the Arrowhead to Stone Lake 345 kV line, which will complete the Arrowhead — Stone Lake — Gardner Park (Weston) 345 kV line, in February/March 2008 will alleviate the western interface issues.

Southern interface
With high imports into the WUMS system from the south and loss of the Wempletown — Rockdale 345 kV line, the Paddock 345/138 kV transformer could be overloaded. This constraint can be managed by increasing the generation at Townline Road, University and a few other alternative sites. Also with high imports or exports through southeast Wisconsin, the Lakeview — Zion — Waukegan 138 kV line could be overloaded for loss of the Pleasant Prairie — Zion 345 kV line. This constraint is closely monitored and managed following an operating guide. The ATCLLC has filed an application with the Public Service Commission of Wisconsin to add a new 345 kV transmission line between the Rockdale and Paddock 345 kV substations that will help to alleviate southern interface constraints.

Other discussions
The eastern portion of the Upper Peninsula of Michigan (UP) can experience flows in both directions from east to west and west to east. Heavy flows in either direction can cause potential thermal violations in the eastern UP. This constraint is currently managed by opening the 69 kV lines between the eastern UP and the rest of the WUMS system.

The need to import power into UP from northeast Wisconsin continues. The 138 kV corridor consisting of the three 138 kV lines south of the Morgan and Stiles substations continues to be a potential constraint that could lead to thermal and voltage violations under contingencies during periods of high flows towards UP. This constraint is closely monitored and managed following an operating guide.

Operating studies have been or will be performed for all scheduled transmission or generation outages during the 2007/2008 winter season. Temporary operating guides are or will be in place if necessary for managing the scheduled outages to ensure reliability.

Operational Issues

There are no known major generating unit or transmission facility outages that could impact reliability during the winter 2007/2008 season. Operating guides are developed by the transmission operators on an ongoing basis to deal with facility outages.

There are no known unusual operating conditions that could impact reliability during the winter 2007/2008 season.

There are no known environmental or regulatory restrictions that could impact reliability during the winter 2007/2008 season.

Reliability Assessment Analysis

Reserve margins are typically used as criteria for a target level. The MRO's projected 2007/2008 winter reserve margin is 34.4 percent without uncommitted resources. This is a slight increase when compared to the projected 2006/2007 winter reserve margin of 33.8 percent.

For the MAPP GRSP, which includes all MRO members except the former MAIN members and Saskatchewan, resource adequacy is measured through the accreditation rules and procedures. The MAPP GRSP requires a 15 percent reserve margin,[25] based on periodically conducted LOLE studies.

The former MAIN members now within MRO do not belong to the MAPP GRSP. Generation resource adequacy for the former MAIN members is assessed based on LOLE studies previously conducted by the MAIN region. Although conducted on a yearly basis, MAIN's LOLE studies consistently recommended a minimum short-term planning reserve margin of 14 percent.

Saskatchewan's reliability criterion is based on annual expected unserved energy (EUE) analysis and equates to an approximate 15 percent reserve margin requirement.

The MRO members within each of the above three groups are expected to meet their minimum reserve assessment targets for the 2007/2008 winter. The projected MRO reserve margin of 34.4 percent is in excess of the minimum targets established for resource adequacy.

Because the net purchases of 3,371 MW only comprises 8 percent of the total internal demand, none of these resources are required to meet the reserve margins on a regional basis (34.4 percent regional reserve margin exists).

Generation deliverability is performed by transmission providers within the MRO region. Links to deliverability criteria within the MRO region are:

http://www.midwestiso.org/page/Generator+Interconnection

[25] The MAPP GRSP Handbook, http://www.mappcor.org/assets/pdf/GRSP_Handbook_20070116.pdf

http://www.mappcor.org/content/policies.shtml
https://www.oatioasis.com/spc/

No specific analysis is performed to ensure external resources are available and deliverable. However, to be counted as firm capacity the MAPP GRSP, former MAIN utilities and Saskatchewan require external purchases to have a firm contract and firm transmission service.

Inter-Regional Assessment
The following discussion is based on the MRO/RFC/SPP/SERC-W 2007/2008 Winter Inter-regional Assessment.[26]

Non-simultaneous Import Capabilities into MRO from RFC-W, SERC-W, and SPP regions:

Transfer Direction	TIC (MW)
RFC_W-MRO	2400
SPP-MRO	2750
SERCW-MRO	1900

The Total Import Capability (TIC) is equal to the net import into MRO in the base case plus the First Contingency Incremental Transfer Capability (FCITC) obtained in the transfer analysis.

Transient, voltage, and small signal stability studies are performed as part of the near-term/long-term transmission assessments.[27] Voltage stability is also evaluated in the Midwest ISO's seasonal assessments.[28] The results are not available prior to the due date of this regional assessment. No transient, voltage, or small signal stability issues are expected that impact reliability during the winter 2007/2008 season.

Planning coordinators and transmission planners are the applicable entity, and ultimately are accountable, for TPL-001–004. MRO transmission owners analyze their transmission system to make sure they meet standards TPL 001-004 either thru individual company analysis or through participation in sub-regional or RTO planning groups.[29]

The transmission operators and RCs within the MRO region manage congestion during emergency conditions. RCs, transmission operators, and BAs are required to have emergency plans in place per NERC EOP Standards. The MRO itself is not directly involved with managing congestion in real-time operations.

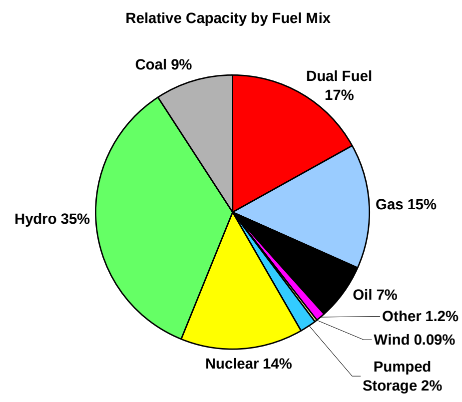
[26] Eastern Interconnection Reliability Assessment Group (ERAG) Winter 2007/2008 Inter-regional Transmission Assessment, MRO-RFC-SERC West-SPP (MRSWS) sub-group study (on-going.)
[27] 2007 — ATCLLC 10-Year Transmission System Assessment, http://www.atc10yearplan.com, 2007 MAPP System Performance Assessment. MAPP Small Signal Stability Analysis Project Report, June 2007. Midwest ISO 2007 Expansion Planning, http://www.midwestiso.org/page/Expansion%20Planning (on-going.)
[28] Midwest ISO Winter 2007/2008 Assessment Studies, http://extranet.midwestiso.org/operations/seasonal.php (on-going.)
[29] 2007 — ATCLLC 10-Year Transmission System Assessment, http://www.atc10yearplan.com, 2007 MAPP System Performance Assessment. MAPP Small Signal Stability Analysis Project Report, June 2007. Midwest ISO 2007 Expansion Planning, http://www.midwestiso.org/page/Expansion%20Planning (on-going.)

Regional Description

The Midwest Reliability Organization (MRO) membership now totals 42 members which include Cooperative, Canadian Utility, Federal Power Marketing Agency, Generator and/or Power Marketer, Small Investor Owned Utility, Large Investor Owned Utility, Municipal Utility, Regulatory Participant, and Transmission System Operator. The MRO region covers all or portions of Iowa, Illinois, Minnesota, Nebraska, North and South Dakota, Michigan, Montana, Wisconsin, and the provinces of Manitoba and Saskatchewan. The total geographic area is approximately 1,000,000 square miles with an approximate population of 20 million (http://www.midwestreliability.org/).

NPCC

Projected Total Internal Demand	114,615	MW
Interruptible Demand & DCLM	3,163	MW
Projected Net Internal Demand	111,452	MW
Last Winter's Peak Demand	112,349	MW
Change	2.0	%
All-Time Winter's Peak Demand	115,099	MW
Deliverable Internal Capacity	143,159	MW
Projected Purchases and Incoming Adjustments	1,006	MW
Projected Sales and Outgoing Adjustments	1,303	MW
Net Capacity Resources	142,862	MW
Capacity Margin	22.0	%
Reserve Margin	28.2	%
With Uncommitted Resources		
Total Potential Resources	143,136	MW
Capacity Margin	22.1	%
Reserve Margin	28.4	%



Coordinated NPCC Assessment Process

The NPCC Reliability Assessment Program (RAP) brings together the efforts of the Council and its members in the coordinated assessment of the reliability of the bulk power system of NPCC. The Reliability Coordinating Committee (RCC), as the primary technical arm of the Council, directs the RAP and monitors the compliance with all aspects of the program. The RCC is served by five NPCC task forces, which address the major technical disciplines of planning, operations, system protection, energy management systems, and cyber security.

The assessment of transmission reliability and resource adequacy is directed to the five NPCC areas: the 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 (the New York ISO), Ontario (the Independent Electricity System Operator) and Québec (Hydro-Québec TransÉnergie.)

Subregions

Maritimes

Demand

Based on the Maritimes area 2007/2008 demand forecast, a peak of 5,527 MW is predicted to occur for the winter period, December through February. The actual peak for winter 2006/2007 was 5,493 MW on January 31, 2006, which was 71 MW (1.29 percent) lower than last year's forecast of 5,564 MW. This peak was also the all-time Maritimes' peak demand. The reduction in demand was due to higher than forecasted temperatures, resulting in a lower electric heating load. The Maritimes area load is the mathematical sum of the forecasted weekly peak loads of the sub-areas (New Brunswick, Nova Scotia, Prince Edward Island, and the area served by the Northern Maine Independent System Operator). As such, it does not take the effect of load coincidence within the week into account. If the total Maritimes area load included a coincidence factor, the forecast load would be approximately 1–3 percent lower.

For the New Brunswick System Operator, the load forecast is based on an End-use Model (sum of forecasted loads by use i.e., water heating, space heating, lighting, etc.) for residential loads and an Econometric Model for general service and industrial loads, correlating forecasted economic growth and historical loads. Each of these models is weather adjusted using a 30-year historical average. For Nova Scotia, the load forecast is based on a 30-year historical climate normal for the major load center, along with analyses of sales history, economic indicators, customer surveys, technological and 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 forecasted annual peak. The remaining months are prorated on the previous year. The Northern Maine Independent System Administrator performs a trend analysis on historic data in order to develop an estimate of future loads.

The Maritimes area does not have any load management in place for this winter. In the Maritimes area there are between 500 and 540 MW of interruptible demand available during the 2007/2008 winter assessment period; there is 521 MW forecasted to be available at the time of the seasonal peak. No demand response is netted with internal demand.

Generation

There was an addition of 18 MW of new committed capacity placed in service in the Maritimes area from March 1, 2007 to November 30, 2007. The Maritimes area is forecasting normal hydro conditions for the winter 2007/2008 assessment period. The Maritimes area hydro resources in both New Brunswick and Nova Scotia are run of the river systems with limited headpond storage capacity located at each of the facilities. Therefore, these facilities are primarily used as peak shaving units or they provide operating reserves. These facilities are primarily utilized as peaking units or for providing operating reserve.

The Maritimes area is not reliant on outside assistance during the assessment period. There is a 200 MW firm export with a New Brunswick point-of-receipt and a Québec

(TransÉnergie) point-of-delivery. There are no firm purchases from other regions currently designated/scheduled by any loads in the Maritimes area during the assessment period.

Fuel

In the Maritimes area there are two generation facilities with dual-fuel capability — Tuft's Cove, NS (natural gas or oil) and Dalhousie, NB (Orimulsion or oil). These two facilities account for about 10 percent of the Maritimes generating capacity. For these generators the responsibility for fuel switching plans lies with the generation owner. All applicable units have the required procedures. Each facility maintains an adequate supply of its primary fuel. Fuel procurement practices incorporate target fuels inventories for each plant and unit in the fuel supply plan. Base load and intermediate loaded units maintain a 30 day fuel supply on-site and peaking units maintain 5-7 days of fuel inventory. For this winter, fuel supplies are expected to be adequate during the projected peak winter demand and extreme weather conditions should have no impact on the fuel supply. The fuel supply in the Maritimes area is very diverse and includes nuclear, natural gas, coal, oil (both light and residual), Orimulsion, hydro, tidal, municipal waste, and wood. All gas-fired generation facilities in the Maritimes have 100 percent of gas supply and delivery under firm contract. In addition, the coal-fired generation facilities have sufficient on-site coal supply and inventory for this winter. Because of the diverse mix of generation sources and good fuel supply levels the Maritimes area does not consider potential fuel-supply interruptions in this regional assessment.

Transmission

For this winter period there are no anticipated transmission constraints on the Maritime system. A new transmission addition, Line 3016, a 345 kV circuit, from Pt. Lepreau, NB to Orrington, Me, is anticipated to be in service December 2007. This provides a second 345 kV tie with New England and increases the normal New Brunswick to New England power export capability from 700 MW to 1,000 MW and the New England to New Brunswick import capability from 300 MW to 550 MW (250 MW is contingent firm). The transmission flow pattern in the Maritimes area, overall, is not anticipated to change. In terms of operating characteristics, load sharing between the new line 3016 and the existing line 3001 will be approximately a 60/40 split at a 1000 MW export from NB and a 80/20 split during low exports.

Operational Issues

The Maritimes area has an adequate projected capacity margin and there are no major generating unit or transmission facility outages anticipated for the winter that will impact reliability in the Maritimes area. Furthermore, there are no unusual operating conditions or environmental or regulatory restrictions anticipated for the winter that will impact reliability in the Maritimes area.

Reliability Assessment Analysis

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 winter

2007/2008 assessment period. These surplus margins range from 10 percent–26 percent based on weekly projections over the period from December 2007 through March 2008. These surplus margins are higher than the 10 percent–20 percent levels projected for the December 2006 through March 2007 period. The Maritimes area assesses its seasonal resource adequacy in accordance with the NPCC C-13 Operational Planning Coordination Procedure. 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. No external resources are used to by the Maritimes area to meet its capacity margins in either the 2006/2007 or 2007/2008 periods.

New England

Demand

ISO-New England's (ISO-NE's) balancing authority reference peak load forecast for the winter of 2007/2008 is 23,070 MW. This is considered to be total demand in that it does not include reductions resulting from demand response programs. This winter's forecast is 520 MW (2.3 percent) higher than the 2006/2007 winter projected peak of 22,550, and 210 MW (1.0 percent) higher than the weather normalized 2006/2007 winter peak load of 22,860 MW. The forecast is 1,430 MW higher than the actual non-normalized 21,640 MW 2006/2007 winter peak demand. The key factor leading to the higher forecast in 2007/2008 is underlying demographic and economic growth.

The reference case forecast is the 50/50 forecast (50 percent chance of being exceeded), corresponding to a New England weighted dry-bulb temperature of 6.8° F. The 6.8° F dry-bulb temperature corresponds to the 50^{th} percentile of the extreme weather distribution and is consistent with the average temperature at the hour of the NEPOOL winter peak load for the previous 20 years. The forecast is for the New England coincident peak demand.

Since only central air conditioning systems are under ISO-NE's direct control load management, no load management is included in total net demand during the winter. A total of 1,127 MW of demand response resources that could be interrupted during times of capacity shortages is included in the net demand. Reductions from existing demand-side management programs are accounted for in the historical data that are used in ISO-NE's load forecasting model. In the winter of 2006/2007, the monthly amount obtained from energy efficiency programs was estimated to be approximately 105 MW. Demand response is treated as a resource, and is therefore not included in the demand forecast. ISO-New England addresses peak demand uncertainty in two ways:

- Weather — peak load distribution forecasts are made based on 37 years of historical weather which includes the reference forecast (50 percent chance of being exceeded), and extreme forecast (10 percent chance of being exceeded);
- Economics — alternative forecasts are made using high and low economic scenarios.

The 2007/2008 winter load forecasts for the various weather and economic scenarios are:

Economic Assumptions	Weather Assumptions	
	50/50	90/10
Reference Economic Forecast	23,070 MW	24,045 MW
Alternative High Economic Forecast	23,300 MW	24,270 MW
Alternative Low Economic Forecast	22,850 MW	23,825 MW

ISO New England plans for the demand level associated with the extreme 90/10 peak demand under the reference economic forecast.

Generation

For this winter reliability assessment, ISO-NE projects an installed capacity margin of over 7,100 MW (24 percent) under the reference economic forecast at the 50/50 peak load level forecast, and over 5,000 MW (18 percent) under the reference economic forecast at the 90/10 peak load level during the peak load period (January 2008). These capacity margins, along with the margins for the alternative economic forecasts, are shown in the table below. The net margin is based on known outages, anticipated generation additions and retirements, projected firm purchases and sales, and the impact of expected Demand Response Programs. It also takes into consideration generation that may be unavailable due to inadequate natural gas supply during the peak load weeks in January and February. This amounts to 3,900 MW under the 50/50 load forecast and 5,000 MW under the 90/10 forecast. The margin does not include allowances for any other unplanned outages or for operating reserve.

Load Forecast	50/50 Peak		90/10 Peak	
	Load Forecast (MW)	Margin (MW)	Load Forecast (MW)	Margin (MW)
Reference Economic Forecast	23,070	7,115	24,045	5,043
Alternative High Economic Forecast	23,300	6,885	24,270	4,815
Alternative Low Economic Forecast	22,850	7,335	23,825	5,260

The projected margins are sufficient to cover the New England operating reserve requirement, which is approximately 1,800 MW; however, higher than expected unit outages and/or higher than anticipated load could adversely affect the forecasted margin. During the 2006/2007 winter peak load period, the projected capacity margin under the 50/50 peak load forecast was about 5,600 MW, and the capacity margin under the 90/10 forecast was about 4,400 MW. These margins are about 1,500 MW and 640 MW lower, respectively, than the 50/50 and 90/10 margins forecasted for the 2007/2008 winter.

Since March 1, 2007, a total of about 8 MW in new generation has been added to the system. An additional 95 MW is expected to become commercial prior to the winter period. Hydro conditions are anticipated to be sufficient to meet the expected demand this winter. Hydro generation contributes approximately 5 percent of the total New England generating capacity, and reservoir levels are expected to be normal for the upcoming winter.

The forecast of winter firm external capacity purchases is 401 MW. This includes 310 MW from Hydro-Québec and 91 MW from New York. Only firm, Installed Capacity (ICAP) purchases that are known in advance are included as capacity. For the winter period, there is a firm sale to New York (Long Island) of up to 345 MW via the Cross Sound Cable. While the entire 401 MW of ICAP purchases are backed by firm contracts for generation, there is no requirement for those purchases to have firm transmission service. However, it is specified that deliverability of ICAP purchases must meet the New England 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 ICAP, but the market participant bears the associated risk of ICAP market penalties if it chooses to use non-firm transmission. The 310 MW purchase from Hydro-Québec is a Liquidated Damage Contract (LDC), and the 91 MW purchase from New York is not.

Fuel

New England has approximately 8,600 MW (winter ratings) of fully functional dual-fuel capacity. Of the approximately 13,200 MW of plants in New England that have natural gas as the primary fuel, approximately 4,900 MW, or 37 percent, have dual-fuel capability. New England also has approximately 600 MW of light oil primary-fueled capacity and 3,100 MW of heavy oil primary capacity with natural gas-burning capability. For the units/stations with fully functional dual-fuel capability, the time necessary for performing fuel switching operations varies significantly. Some stations require 24-hours notice or more, while other stations can perform fuel switching while they are online, or “on-the-fly.” ISO-NE encourages the expansion of single-fuel, gas-only units to dual-fuel capability in addition to promoting the procurement of firm gas supply and transportation contracts. In preparation for winter operations, ISO-NE routinely assesses the dual-fuel capability of the generation fleet as well as performs an assessment of regional gas-fired generation transportation contracts to identify the prioritization of their entitlements. In general, for the primary-fueled natural gas-fired facilities, those that have dual-fuel capability usually have only a 1-2 day (under full-load operation) supply of liquids on site. Re-supplying liquids to most of these facilities (via trucking) could be problematic during extreme winter weather conditions.

The New England region relies heavily on natural gas to generate electricity. Since New England’s gas-fired electricity generators continue to compete with the ever-growing core natural gas market (i.e., for space heating) for supply and finite transportation infrastructure, fuel delivery issues could occur. New market incentives, such as those provided by the Forward Capacity Market, are designed to promote the availability of resources when needed most. These incentives have increased and should continue to increase the number of generators with dual-fuel generating capability or firm-fuel supplies. Approximately 1,125 MW of gas-fired generation has already been converted to dual-fuel capability since the 2006/2007 winter season. Furthermore, ISO-NE is continually working to enhance the coordination between electric power system and natural gas system operations to improve reliability. The Electric/Gas Operations Committee (EGOC) routinely meets to discuss seasonal preparedness. During extreme cold winter weather, when the demand for natural gas and electricity peak coincidently, ISO-NE has developed a “cold weather” operating procedure that can be implemented to help synchronize electric system commitments to natural gas procurement and nomination deadlines. Currently, only 3,200 MW of the 8,300 MW of single-fuel, gas-only capacity in New England has firm natural gas transportation contracts, which can be characterized as "firm" mainline contracts back to regional trading hubs.

The fuel procurement and storage strategies for New England's coal-fired stations are a function of those merchant facilities' market strategies and are confidential in nature.

Transmission

For the winter of 2007/2008, ISO-NE does not anticipate transmission constraints that will affect New England regional reliability. During the 2007/2008 winter season, the Northeast Reliability Interconnect Project (NRI) is expected to go into service. It consists of installing an 84-mile 345 kV line emanating from the Orrington Substation in Maine to the United States/New Brunswick border. The circuit will continue for 60 miles to the Pt. Lepreau Substation in New Brunswick. The project also includes 115 kV capacitor bank additions, 345 kV circuit breaker additions, series compensation on an adjacent 345 kV circuit, and Special Protection System modifications within the New England Control area. This project will improve regional reliability and increase the New Brunswick to New England transfer capability by 300 MW.

Operational Issues

No major generating unit outages are scheduled for the upcoming winter period.

Significant transmission facility outages planned for this winter include the following:

- The 383 line from Millstone to Card will be out of service several times between 11/27/07 and 1/9/08. This line can cause Millstone generation to be reduced upon any loss of another single element from Millstone station.
- The 394 line from Ward Hill to Seabrook will be out of service 2/11/08 to 2/14/08. This line can have an impact on the North — South, New England — Boston, Northern New England Scobie + 394, Seabrook — South, Sandy Pond — South + Northern New England 345 kV — Scobie + 394 interface limits.
- The 342 line from Canal — Jordan Road — Pilgrim and Auburn Street substations, 335 Auburn Street and Holbrook substations line, and the Auburn Street 210 345/115 kV transformer (450 MVA), are to be removed from service at various times between 1/28/08 and 2/4/08. Work will affect the Lower Southeast Massachusetts interface as well as restrict the Canal units, depending on which element is out of service.

No unusual operating conditions are expected. No environmental and/or regulatory restrictions are anticipated to impact reliability during the 2007/2008 winter period.

Reliability Assessment Analysis

On a monthly basis, ISO-NE uses a weekly operable capacity analysis to assess the reliability and adequacy of the region[30]. The analysis takes into consideration the forecasted capability of all generators, net firm purchases and sales, the forecasted peak load exposure (both 50/50 and 90/10 forecasts), the operating reserve requirement, and planned and unplanned outages. The operating reserve requirement is 1,800 MW, and the total unplanned outages are assumed to be 6,700 MW under the 50/50 load forecast and 7,800 MW under the 90/10 forecast during the January peak load weeks. Included in those unplanned outage totals are variables representing generation at risk due to natural gas supply (3,900 MW under the 50/50 forecast and 5,000 MW under the 90/10 forecast) during the weeks of highest forecast winter demand. While ISO-NE does not expect those levels of gas-fired generation unavailability, the assumption is made to identify its worst operable capacity situation. The results are used by the ISO to identify the means to mitigate the problem if it occurs. The weekly operable capacity analysis does not take into account demand response resources or tie-line benefits. The resulting capacity margin for the 50/50 load forecast during the winter peak load period (in January) is 1,140 MW, or 4.9 percent. For the 90/10 load forecast, the margin is forecasted to be -940 MW, or -3.9 percent.

ISO New England expects to be able to manage the negative operable capacity margin as a result of the extreme (90/10) winter peak load conditions assumed because these margins do not include the short-term capacity and energy purchases from neighboring systems that are anticipated to help serve the electrical demands on the system. In the case of extreme cold winter weather, ISO-NE's cold weather operating procedure would go into effect, helping to increase the availability of natural gas-fired generators. During periods when the capacity margins are negative, ISO-NE will have to implement Operating Procedure No. 4 — *Action During a Capacity Deficiency*[31] (OP 4). OP 4 is designed to provide additional generation and load relief needed to balance electric demand and supply while striving to maintain appropriate operating reserves. Capacity available under OP 4 includes over 1,100 MW of demand response resources, as well as emergency assistance from neighboring balancing authorities. For the purposes of ISO-NE's operable capacity studies, 800 MW of emergency assistance, also referred to as tie-line benefits, is assumed to be available. In addition, there are 1,800 MW of operating reserve that can be used to meet load.

ISO New England does not base its capacity requirements on a set capacity margin criterion. Rather, it uses a probabilistic loss-of-load-expectation analysis to calculate the total amount of installed capacity needed to meet the NPCC once-in-10-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 2007/2008 capability year. The annual ICR translates to approximately 33,000 MW in terms of winter ratings, which results in reserves ranging from 43 percent–50 percent. The model used for conducting the 2007/2008 system-wide ICR calculations for New England accounts for all known external

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

[31] Operating Procedure No. 4 may be found on ISO-NE's website at http://www.iso-ne.com/rules_proceds/operating/isone/index.html.

firm purchases and sales, which in 2007/2008 amount to a net value of 58 MW. Tie-line benefits potentially available from neighboring systems during the winter months were not included in the ICR modeling.

To identify the impact of transmission constraints on the deliverability of generating capacity, ISO-NE models expected internal transmission constraints by subdividing the New England Control area into 13 sub-areas and assuming static transmission-interface limits. Using the GE Multi-Area Reliability Simulation (MARS) model, the loss-of-load-expectation (LOLE) of the New England control area and each of its sub-areas is calculated at a range of load conditions. The results of these calculations show a greater need for generating capacity when compared to the results of a single-bus LOLE model. This is because the transmission constraints prevent excess capacity from reaching areas where it is most needed. During the winter of 2007/2008, no transmission constraints that would affect the deliverability of generation are anticipated. ISO New England has determined that the Connecticut (CT) sub-area of New England may have transmission import restrictions at high load conditions during the summer peak. However, during the winter peak loads, transmission transfer capabilities to meet the CT sub-area generation needs are more than adequate. ISO-NE conducted a tie-reliability benefits study to identify the amount of emergency assistance that would be available from neighboring BAs. Based on that analysis, it was determined that 800 MW of tie-reliability benefits will be available during the winter months. As assumed in the *ISO New England Installed Capacity Requirements for 2008/09 through 2016/17 Capability Years Report*[32], the import capabilities to New England are as follows:

Interface	**Transfer Capability (MW)**	**Basis for Interface Limit**
New Brunswick — New England	1,000	Second New Brunswick Tie Study
Hydro-Quebec — New England		
Phase II	1,400[33]	PJM and NYISO Loss of Source Studies
Highgate	200	Various Transmission Studies
New York — New England	1,600	NYISO Operating Study, Winter 2005-06
Cross Sound Cable	330	Cross Sound Cable System Impact Study

The most recent system wide transient stability study was conducted as part of the *2004 Comprehensive Area Transmission Review of the New England Bulk Power System (Study Year — 2009)*, September 9, 2005. The results of this analysis are applicable to all seasons and load levels, including the 2007/2008 winter season. Additionally, for generator interconnections or changes to transmission system topology, the impact on transient performance of the system is considered. In instances where there may be an adverse impact to the transient performance of the system, the change in topology must be tested to assess its impact on system performance. In no case will an adverse impact on transient system performance be accepted. In the event that such an adverse impact is discovered, the project must be revised in some manner to eliminate the concern. Therefore, each and every change

[32] The ICR Report is posted at http://www.iso-ne.com/genrtion_resrcs/reports/nepool_oc_review/2007/report_cover%20_icr1011.pdf.
[33] The transfer capability for energy over Phase II could be as high as 2,000 MW. That amount could be limited down due to voltage constraints in NY and PJM.

to the transmission system is either implicitly or explicitly evaluated from a transient perspective. There is nothing in particular about the winter 2007/2008 season that would introduce any new transient concerns. Virtually all transient analyses performed on the New England transmission system have utilized time domain analysis to assess both transient stability and damping.

The *2004 Comprehensive Area Transmission Review of the New England Bulk Power System (Study Year — 2009),* September 9, 2005, ensures compliance with NERC Standards TPL-001 through TPL-004 for the 2007/2008 winter. This study assessed a peak load level of 29,090 MW, while reflecting summer equipment ratings. Using the *2007/2016 Forecast Report of Capacity, Energy, Loads, and Transmission*, the 90/10 extreme weather forecast for the 2007/2008 winter is 24,045 MW. Not only is the extreme load forecast 5,000 MW lower than that studied in the *2004 Comprehensive Area Transmission Review*, but the cooler temperatures associated with winter peak load translate to equipment ratings that are the same or, in most instances, significantly higher than that used in the *2004 Comprehensive Area Transmission Review*.

ISO-NE has addressed concerns regarding resource unavailability due to the regional lack of natural gas, which may result from the simultaneous need for natural gas by both electric generators and the core, space-heating market during the coldest winter days. To account for the possibility that many natural gas-only units may not be available at those times, the ISO-NE includes an additional variable in its weekly operable capacity assessments during the highest winter load weeks of January and February: “generation at risk due to natural gas supply.” That number is calculated based on the gas-only capacity that is forecast to be unavailable due to temperature effects on prioritization of gas pipeline transportation contracts. Solutions to mitigate the potential for reduced availability of natural gas-fired units include: revised market rules and procedures (*Appendix H of Market Rule 1 — Operations During Cold Weather Events*) that coordinate electric and gas market timelines; continuation of the enhanced coordination between electric power system and natural gas system operations that was begun following the January 2004 Cold Snap; and implementation of additional conservation, energy-efficiency, and demand-response measures to reduce the system-wide dependency on gas-fired generating capacity.

In addition, the ISO-NE’s Operating Procedure No. 21, *Actions during an Energy Emergency*, was developed to mitigate impacts resulting from all types of fuel supply shortages or other abnormal system conditions, during any time of the year.

During real-time operation, upon a significant loss of resources simultaneously, the ISO would call upon both synchronized and non-synchronized operating reserves under Operating Procedure No. 4 — *Action During a Capacity Deficiency*, to deliver energy to replenish the loss of capacity on the system. ISO-NE’s weekly operable capacity analyses assess the reliability (resource adequacy) implications from various fuel-supply disruption scenarios. Fuel supplies in New England are expected to be adequate during the 2007/2008 winter peak demand. However, extreme winter weather would likely result in the reduction of natural gas supply and transportation available to New England’s electric generation sector. At particular risk are the 5,100 MW of gas-only generators without firm gas transportation contracts.

New York

Demand

The forecast peak for the NYISO is 25,324 MW, which is 294 MW higher than last year's forecast and 267 MW higher than last year's actual 2006/2007 NYISO peak load, which occurred on February 5, 2006. The forecast load is 0.86 percent lower than the all-time winter peak load of 25,541 MW that occurred on December 20, 2004. The NYISO uses a weather index that relates dry bulb air temperature and wind speed to the load response in the determination of the forecast. At the forecast load levels, a one-degree decrease in this index will result in approximately 100 MW of additional load.

The NYISO Emergency Demand Response Program (EDRP) and Special Case Resources (SCR) load relief programs are also available, if needed.

The NYISO conducted a load forecast uncertainty analysis based on the combined effects of both weather and the economy. This analysis was conducted for annual energy, summer peak demand, and winter peak demand. The results of this analysis were used to make projections of upper and lower bounds of each of these forecasts. The upper bounds were at the 90th percentile and the lower bounds were at the 10^{th} percentile.

Generation

The NPCC and New York State Reliability Council (NYSRC) have reliability standards. The amount of resources necessary to meet the reliability standards is calculated through the NYSRC Installed Reserve Margin (IRM) analysis. And the procurement of those resources is accomplished through the NYISO Installed Capacity (ICAP) auction process. The ICAP requirement for the winter period is 38,965 MW, which includes a 16.5 percent installed reserve margin. The minimum net capacity resources for the winter total 37,084 MW. The IRM has been reduced slightly (from the previous 18 percent requirement) based on the NYSRC 2007 IRM study. The overall New York resource supply would not be significantly impacted by fuel interruptions because of the diversity of sources and because of the dual-fuel capability present at many locations. The minimum net capacity resource for the winter period 2006/2007 was 37,117 MW, a difference of 33 MW compared to this winter period 2007/2008 of 37,084 MW.

Net resource additions, totaling 55 MW are expected to be available for service during the winter period. The Prattsburgh wind project with a capacity of 55 MW is expected to be available during the winter capability period. The 55 MW is the nameplate rating. For the winter, wind resources are discounted to 30% capacity. The overall capacity in the New York area will be reduced by 236 MW due to the retirement of Russell Station.

There are no extraordinary concerns regarding hydro conditions this winter.

For the winter 2007/2008, the NYISO has purchases of 75 MW (50 MW from ISONE, 25 MW from PJM) and sales of 273 MW (182 MW to PJM, 91 MW to ISONE) are expected this winter. The purchases and sales are not included in the ICAP requirement; also, they are not yet finalized for the winter capability period.

Fuel

Overall, New York has a diverse fuel supply mix including gas, oil, coal, nuclear, and hydro. Traditionally, the New York area generation mix has been dependent on fossil fuels for the largest portion of the installed capacity. Recent capacity additions or enhancements use natural gas as the primary fuel. Extreme weather or other conditions might limit the availability of natural gas are not anticipated to impact system reliability to New York because a number of the steam units in southeastern New York have dual-fuel capability, employing the use of residual or distillate oil as an alternative to natural gas. By capacity, 38 percent of generators in the New York area have dual fuel capability. Adequate supplies of all fuel types are expected to be available.

Transmission

Major transmission facility additions to the New York bulk power system planned for the winter 2007/2008 capability period include 115 kV transmission upgrades in the Rochester area in anticipation of the planned Russell Station retirement. Additionally, taps in the 230 kV Willis-Plattsburgh lines are planned for new wind farms under construction. These additions will primarily affect the Rochester and northern New York local areas and do not have a significant impact on bulk power system capability or power flow patterns. NYISO conducts seasonal assessments of transmission security and participates in the RFC-NPCC seasonal interregional assessments.

Operational Issues

There are no generation outages scheduled or unusual operating conditions that are expected to impact reliability.

Reliability Assessment Analysis

The NYISO uses a multi-area probabilistic model to evaluate the capacity requirements for the New York area, and to assess the adequacy of projected resources to meet those requirements. The multi-area model includes transmission limitations between each of the modeled areas, including limitations both within New York and between New York and the neighboring systems, to ensure the deliverability of capacity resources to the load. The transmission limits included in the model are developed from power flow and stability studies that assess the emergency transfer limits between the areas with respect to NERC, NPCC, and local reliability standards and criteria. Dispatch-sensitive transfer limits are developed and represented in the multi-area model as necessary. Similar assessments are performed at the NPCC level with participation by PJM. The model and methodology used by the NYISO is consistent with that used by NPCC in the regional analysis.

Currently, the NYISO dispatches the system while optimizing loading across the voltage stability limited Central East interface. The Central East voltage limit is analyzed using comprehensive studies, and verified in real time for the actual configuration of the New York system. The NYISO regulates reactive power issues by implementing real-power transfer limits on Central East, and bus voltage limits to protect against post-contingency voltage collapse.

Ontario

Demand

Ontario's forecast winter peak demand is 24,323 MW based on seasonal normal weather and takes into consideration the impacts of planned conservation. The forecast peak for winter 2007/2008 is 388 MW (1.6 percent) higher than the 23,935 MW actual peak demand that occurred on February 13, 2007 and is 656 MW lower than the all-time winter peak demand that occurred in December 2004. The 2007/2008 forecast is 2.5 percent higher than last winter's weather-corrected peak demand of 23,740 MW.

The IESO quantifies the uncertainty in peak demand due to weather variation. Load Forecast Uncertainty (LFU) represents the impact on demand of one standard deviation in the underlying weather parameters. For the upcoming winter peak of 24,323 MW the LFU is 939 MW. The extreme weather peak forecast for the winter is 25,142 MW.

A sizeable number of loads within the province bid their load into the market and are responsive to price and to dispatch instructions. Other loads have been contracted by the Ontario Power Authority to provide demand response under tight supply conditions. The combined amount of these demand measures has been steadily increasing and now amounts to approximately 804 MW. Since the programs vary in terms of contract conditions, they are given different levels of dependability. As such, we assume that 531 MW are available for seasonal capacity planning purposes, but only 236 MW of the 804 MW are under IESO control.

Planned conservation and demand management (CDM) activities will blunt much of the load growth moving forward, both in the near-term and the long-term.

Generation

The Ripley Wind Power Project with an installed capacity of 76 MW is expected to be placed in service in November 2007. Ten percent of the installed wind capacity is assumed to be available at the time of weekday peak.

The 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. 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 utilized. Water resources are managed by generators through market offers to meet the hourly demands of the day. Most hydro storages are energy limited. Hydro operators identify weekly and daily limitations in advance of real-time operations. For 2007/2008 winter, hydroelectric production is forecast to be at median levels to meet peak demand and daily energy demands.

The IESO is not aware of any firm purchase or sale contracts with other areas for the winter season. However, market participants may arrange limited external purchases of capacity to avoid deferral or cancellation of generator outages in the event that operating reserve deficiencies are forecast in the near-term.

Therefore, the IESO plans for Ontario to meet NPCC adequacy criteria without explicit reliance on external resources. External resources are normally procured on an economic basis through the IESO-administered markets.

Fuel

The Ontario fuel-supply infrastructure is judged to be adequate during the winter peak demand period, and there is no fuel delivery problem anticipated for this winter. Gas pipeline capacity has not limited the energy or capacity capability of Ontario generation fueled solely by natural gas and is not expected to be a problem for this winter. In addition, on site coal inventory is expected to be adequate at the Ontario coal-fired plants.

About six percent of Ontario's generation has dual-fuel capability, all of which is provided by one generating station. Sufficient inventory of backup fuel is built up at the station by December 1st each year to last until the end of the following March.

The IESO requires generator market participants in Ontario to provide specific information regarding energy or capacity impacts if fuel-supply limitations are anticipated. No limitation has been reported for the coming winter months.

In anticipation of growing amounts of gas-fired generation in Ontario over the coming years, the Ontario Gas Electric Interface Working Group (OGEIWG) was formed with various stakeholders. The group is establishing communication protocols and a framework for contingency analysis in order to manage operational and reliability issues in both energy sectors. Earlier work by this group provided cross-functional training and pipeline company input on gas-electric day coordination relative to design of an electricity day-ahead market in Ontario.

Transmission

The Ontario transmission system is expected to be adequate to supply the coming winter's demand under the forecast conditions.

A high-voltage shunt capacitor at Richview TS that suffered significant damage at the beginning of 2007 was returned to service and is available at half of its 410 Mvar capacity. Hydro One is examining options to restore the capability of the Richview capacitor bank to its original rating, and will implement a solution once an appropriate plan is identified.

The electricity demand growth experienced in Ontario in the last decade has resulted in a number of area loads reaching or exceeding the continuous capability of the existing transformer stations. To address this problem and provide additional transformer capacity for future load growth, Hydro One and other distributors have initiated plans to build new transformer stations and replace existing transformers where appropriate. Six new transformer stations at Whitby, Everett, Red Lake, Toyota Woodstock, Preston, and London Talbot will be placed in service before the 2007/2008 winter.

In some cases, the local transmission system may be reaching its capability and the need for transmission reinforcements and installation of local voltage support equipment has been identified. In response to these findings, Hydro One initiated the installation of reactive compensation at eight transformer stations located around the province (Whitby DESN 21.6 Mvar, Orangeville TS 245 Mvar, Lakehead TS 60 Mvar, Detweiler TS 245 Mvar, Woodstock TS 20 Mvar, Halton TS 21.6 Mvar, Meadowvale TS 32.4 Mvar, and Belle River TS 21.6 Mvar). The last of these low voltage shunt capacitor installations, at Belle River TS, will be completed before the end of the year.

Phase angle regulators (PARs) are installed on the Michigan — Ontario interconnection but are not available to regulate flows except in emergencies, pending agreement. The inability to regulate flows combined with limiting ratings on the PAR equipment can result in significant limitation of imports from Michigan. The IESO, the Midwest ISO, Hydro One, and International Transmission Company agreed to temporarily bypass the phase angle regulators for normal operation until an agreement is reached that will allow full use of their regulating capability. Bypassing the PARs increases Ontario's MW transfer levels in the winter. Currently the phase angle regulators are always bypassed during normal operation.

Operational Issues

There is no unusual operating condition, environmental, or regulatory restriction that is expected to affect the capacity availability anticipated for this winter. All known planned generator outages and forecast energy limitations have been included in the IESO's adequacy assessment.

Reliability Assessment Analysis

Planning reserves, determined on the basis of the IESO's requirements for Ontario self sufficiency, are above target levels for all weeks but one in this period. Adjustments to planned outages or market-driven economic imports have been evaluated as sufficient to address this potential shortfall in the first week of December. As a consequence, resources available within Ontario together with imports or available operating actions are forecast to be adequate to meet demand and energy requirements during the winter period. On average, the projected capacity margins for the upcoming winter are 2 percent lower than that for the winter of 2006/2007.

NPCC requires Ontario to complete a Comprehensive Review of resource adequacy every three years, looking at the next five years to assess the extent to which Ontario is expected to comply with NPCC resource adequacy criterion. In intervening years, an Interim Review of resource adequacy is normally performed. The most recent published review is the 2006 Comprehensive Review for the period 2007–2011. This review indicated that Ontario is expected to comply with NPCC resource adequacy criterion.

Although energy supplies available within Ontario are expected to be adequate overall, energy deficiencies could arise as a result of higher than forecast forced outage situations, prolonged extreme weather conditions, and other influencing factors. Interconnection capability and available market and operational measures are expected to be sufficient to ensure winter energy demands can be met for a wide variety of conditions.

The IESO uses a measure of forecast uncertainty in a probabilistic analysis to account for variations in demand due to weather volatility. This uncertainty is used in conjunction with the normal weather demand forecast to determine the resource adequacy. Also, the IESO creates a demand forecast based on extreme weather and uses it in further assessing system adequacy.

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*, posted on the IESO Web at http://www.ieso.ca/imoweb/monthsYears/monthsAhead.asp

Prior to phase angle regulator (PAR) control of the Ontario — Michigan interconnection, the interconnections can carry coincident exports from 3,512 MW up to 5,912 MW, and coincident imports from 4,115 MW up to 5,915 MW. The higher values associated with the Ontario coincident import ranges 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 these high import levels would rarely, if ever, materialize. Therefore, at best, due to internal constraints in the Ontario transmission network, Ontario has an expected coincident import capability of approximately 4,000 MW.

Previous studies have shown that when full PAR control is available on all four Ontario — Michigan interconnections, control of unscheduled flows of up to 600 MW could be achieved. When Lake Erie circulation is limiting, the PAR control will act to improve the capability to match interface flows to schedules. As a consequence, having PAR control will increase the probability of meeting or exceeding the 4,000 MW import capability and under favorable conditions would allow improvement to 4,600 MW.

The IESO regularly conducts transmission studies that include results of stability, voltage, thermal, and short-circuit analyses. These studies can be comprehensive, intermediate, or interim and are conducted in accordance with the appropriate NPCC guidelines. An intermediate transmission review was performed by the IESO in 2006 to conform to NPCC criteria. Presently, the IESO is preparing the 2007 comprehensive review that studies the Ontario power system up to 2012. This review will be submitted to NPCC later this year. Since the implementation of mandatory compliance to the NERC TPL standards in June 2007, the IESO's comprehensive 2007 transmission studies are being prepared to comply with these standards, in addition to NPCC criteria.

For winter 2007/2008, the capability of the Ontario grid has been assessed as adequate, with no material issue identified.

The IESO analyzes extreme contingencies and extreme system conditions in compliance with NPCC criteria. A small number of these low probability events can lead to inter-area disturbances or unacceptable impacts on Ontario reliability. Actions to mitigate potential impacts are considered based on the likelihood of the event and the capability to reduce the probability of occurrence or the severity of the outcome. Solutions range from providing redundancy in special protection systems up to and including automatic shedding of load.

Québec

Demand

The 2007/2008 winter projected peak internal demand is 36,361 MW. This forecast is slightly lower than last year's forecast for the 2006/2007 winter (36,391 MW). This result is due to a downward revision of the industrial sector combined with an increase of demand in other sectors. The observed peak demand for winter 2006/2007 was 36,251 MW. Winter 2006/2007 had many relatively cold days without reaching any record cold temperatures. December 2006 and January 2007 were warmer than normal but February 2007 was colder than normal. A particular combination of temperature and wind velocity on February 5, 2007 caused the winter peak to occur later than usual in the season. So, when compared with the observed peak demand for 2006/2007 winter, the peak forecast for the 2007/2008 winter is only 100 MW higher.

Since the global demand uncertainty (weather and demand forecast uncertainty) for the winter peak forecast has a standard deviation of about 1,700 MW for the first year of forecasting, the probability that the actual peak for winter 2007/2008 will be within the range of +/- 1,700 MW around the forecast peak is 68 percent (assuming a normal distribution).

The total interruptible demand in the Québec sub-region is 1,050 MW. When performing reliability analyses, a reserve of 30 percent is applied to the interruptible load to account for operational constraints. Moreover, Hydro-Québec distribution relies on 250 MW of load management in the form of voltage reduction. As established by tests done in 2007, voltage reduction represents a resource as reliable as a firm purchase for Hydro-Québec Distribution. This is why Hydro-Québec Distribution includes this capacity in its assessment power balance. However, when assessing resource adequacy through its modeling tools, voltage reduction is considered an Emergency Operating Procedure. Each year Hydro-Québec distribution presents an update of its Energy Efficiency Plan to the Québec Energy Board for the next and upcoming years. For the 2007/2008 winter peak demand forecast the capacity contribution of the different programs implemented by Hydro-Québec since the last few years is estimated to be about 700 MW. Of this amount, the energy efficiency program contributes about 300 MW.

Hydro-Québec has developed hourly chronological load profiles based on an analysis of historical weather conditions. This methodology is useful to quantify weather uncertainty and its impacts on peak demand. For the winter peak, weather conditions uncertainty is about 1,500 MW, equivalent to one standard deviation. Since last year, the historical period of weather conditions has been changed to include the last six years of observation (years 2001 to 2006). Last year, the historical weather conditions covered the years 1971 to 2000. This change has increased the weather uncertainty by about 300 MW since the last six years of historical conditions were clearly more variable than the previous historical period. The demand forecast uncertainty — under normal weather conditions — takes into account the realisation of high-and low-demand scenarios. These scenarios are driven by economic and demographic parameters. Statistical simulations of these parameters lead to different possible outcomes. The demand forecast uncertainty — measured by a standard deviation analysis — is about 700 MW (or near 2 percent of the base case scenario) for the first year of forecasting. The global demand uncertainty for the winter peak, which is the independent combination of demand forecast uncertainty and weather uncertainty, is about 1,700 MW (equivalent to one standard deviation) for the first year of forecasting.

Generation

Between the period from March 1, 2007 through November 30, 2007, the Mercier hydro generating station in Southwest Québec will have been commissioned Generating capacity of this station is 52 MW. The Québec area's reservoir levels are sufficient to meet both peak demand and the daily energy demand throughout the winter because reservoir levels are higher than the expected mean levels.

The Québec area does not need to rely on any external purchases for the 2007/2008 winter peak period as capacity margins are adequate. On the other hand, there are no firm sales affecting the Québec sub-regional capacity margins. Québec has no Liquidated Damage Contracts[34] in place. The 310 MW sale to New England is a Liquidated Damage Contract (LDC).

Fuel

Neither Hydro-Québec distribution nor Hydro-Québec production has dual-fuel capacity and related dual-fuel capacity contracts in Québec. Quebec's generation is predominately hydro plus Québec has one nuclear generating unit and one gas-fired generating unit. No fuel deliverability problems are anticipated. Hydro-Québec distribution is the sole electricity purchaser from the 547 MW gas-fired cogeneration plant. For the next winter peak period, this generator has a firm natural gas supply contract along with the firm transportation capacity. Québec has no coal-fired generation.

Transmission

There are no long-term internal transfer limitations that will impact reliability on the Québec system. No major outages are expected and no major maintenance is scheduled during the winter. Transmission margins for the peak period are adequate to carry the net internal demand plus the firm capacity sales. Moreover, enough transmission capability remains on the system to carry additional resources that would be called upon if load was greater than forecast.

A phase on each of the two 735/315 kV, 1,650 MVA transformers at Némiscau substation failed during spring and summer 2007. These transformers integrate the Eastmain-1 generation (480 MW) into the TransÉnergie system. When both transformers are out of service, the Eastmain-1 generation is entirely bottled. One transformer has now returned to service but the other failed phase on the second transformer has to be replaced. In the meantime, a temporary reserve bus is being installed to have access to the sound phases of the transformer now on forced outage, if needed. A new transformer is to be installed in 2009.

No bulk power system additions are anticipated for this peak period. TransÉnergie is now in the last phases in the construction of the Lévis 735/315 kV de-icing device. Part of this device will serve as a Static Var Compensator to be used under normal system operation. The other part of the device will be used as a direct current (DC) generator to eventually de-ice a specific number of 735 and 315 kV lines around the Lévis substation near Québec City. Commissioning began in October and the Static Var Compensator will be available for the winter operating period.

Operational Issues

There are no major transmission outages anticipated for the winter. No major maintenance is scheduled during this period. No unusual operating conditions are anticipated for this winter period. No environmental and/or regulatory restrictions that could impact reliability are anticipated in the Québec area.

Reliability Assessment Analysis

In its 2006 Interim Review of Resource Adequacy, Québec determined that it requires 3,711 MW of reserves to meet the NPCC resource adequacy criterion. This represents 10.1 percent of the peak load. For this winter assessment the Québec area has a projected capacity margin of 12.7 percent (percentage of net internal demand). There are many assumptions used to assess the resource adequacy of the Québec area. A complete description of the assumptions is available in the *2005 Québec Area Triennial Review of Resource Adequacy*. Please refer to the following Web site: http://www.npcc.org/adequacy.cfm. Regarding external resources used to meet target margin levels, for the 2006/2007 winter period, Hydro-Québec distribution had bought 200 MW from New York area. For the upcoming 2007/2008 winter Hydro-Québec distribution has not contracted any purchase. Each year, Québec has to produce resource adequacy assessments for the NPCC and the Québec Energy Board. These assessments are done during the fall for the next winter peak period and the following years. Please refer to the following Web sites: http://www.npcc.org/adequacy.cfm and for the last assessment to the Québec Energy Board (December 2006): http://www.regie-energie.qc.ca/audiences/Suivi.html

For 2007/2008 winter the projected capacity margin is 4,906 MW — about 500 MW higher than last winter. The net internal demand is 40 MW lower than last year. The net capacity resources are 401 MW higher than last year because of new hydraulic units having been committed.

The Québec area does not forecast load under extreme weather conditions. Hydro-Québec Distribution’s base load forecast scenario represents normal weather conditions that are the average of the last 36 years of winter conditions, each year having the same probability of occurrence. However, climatic uncertainty is modeled by recreating each hour of the past 36-year period of climatic conditions (1971 through 2006) under the current load forecast conditions. Moreover, each year of historic data is shifted up to ± 3 days to gain information on conditions that occurred during a weekend for example. Such an exercise generates a set of 252 different demand scenarios. The base case scenario is the arithmetical average of those 252 scenarios. The Québec area does produce a high demand scenario. The economic parameters are adjusted higher and the same methodology as for the base case is then reproduced. For the first year of forecasting, the high case scenario is 2 percent–3 percent higher than the base case scenario. Moreover, it is recognized that extreme weather conditions may occur during the winter operating period. A number of studies have shown that under such conditions demand may reach as much as 4,000 MW over the base case scenario. For the 2007/2008 winter the projected capacity margin is sufficient to handle this extreme condition. To make sure that the transmission system will sustain this extreme condition, TransÉnergie has made it into a transmission planning criterion. This has led TransÉnergie to add equipment to the system to guarantee transmission capability under these conditions.

The Québec area fully complies with the NPCC resource adequacy criterion that takes into account the internal transfer capabilities. In assessments to meet adequacy criteria, no deliverability concerns have been identified. During each upcoming fall period Hydro-Québec distribution determines if capacity purchases are needed for the next winter period. This resource adequacy assessment is done using the same model and assumptions as for the NPCC resource adequacy review, except that only the Hydro-Québec distribution part of the demand and the resources are considered for this study. The NPCC is now in the process of completing a tie benefits transmission transfer capability report. In its 2005 Review of Interconnection Assistance Reliability Benefits, results show about 3,400 MW of tie benefit potential for the Québec area with 3,520 MW of total tie capacity during the Québec area peak load.

Transient and voltage stability studies are performed continuously by TransÉnergie to establish the system transfer limits on all possible system configurations. No particular issue has been found to impact the winter 2007/2008 season. For any client requesting to be connected to the system or for any firm point to point transmission service request, TransÉnergie will carry out the proper impact studies using the methodology described in the document: "*Tarifs et conditions du service de transport d'Hydro-Québec TransÉnergie*" (TransÉnergie Transmission Service Tariffs and Conditions). As described in this document, impact studies will determine system additions and/or modifications such that NERC, NPCC, and TransÉnergie requirements, criteria, and standards are met. This would include NERC Standards TPL-001 — TPL-004. Subsequently, if a project moves forward, TransÉnergie will carry out a full planning study. The goal is then to optimize the transmission solution selected during the impact study, again making sure that all requirements, criteria and standards are met. The system undergoes a yearly internal review using load flow and stability studies and particularly every five years a full planning review is undertaken leading to the publication of the Comprehensive Transmission Review as per document NPCC B-4 "Guideline for NPCC area Transmission Reviews."

Generation plants do not share common infrastructures other than the transmission grid. Therefore, no extreme contingencies are foreseeable other than a loss of transmission capacity. During the winter operating period, the day-ahead capacity margin requirement is twice the operating reserve to account for uncertainties on load forecast and on the availability of generating units. TransÉnergie assesses a number of extreme credible contingencies that might occur beyond the largest single contingency. This may be the loss of a transmission corridor (three 735 kV lines) necessitating automatic generation rejection and load shedding schemes in order to preserve transient and long-term stability. It may also be the permanent loss of a major transmission path (for example, three 735 kV lines from Churchill Falls). These conditions, among others, have been assessed using stability and load flow analysis and the appropriate mitigating measures have been documented. In all these cases, the impact on operating reserves depends on the availability of internal and external resources to supplement the loss of generation or import due to the contingency.

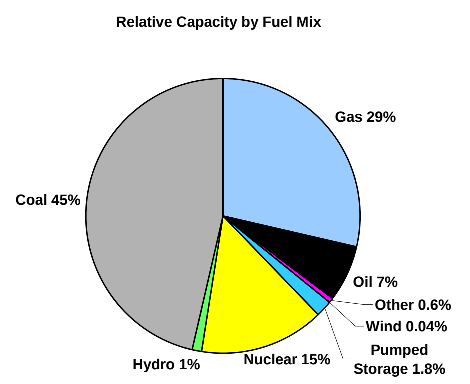
In Québec, non-hydraulic resources account for only a small portion of total resources. Plants using heating oil or jet fuel are refueled by boat or by truck and generally not during the winter season. Natural gas is used at a single cogeneration plant and is delivered under a firm natural gas purchase contract. No fuel delivery problems are anticipated.

Regional Description

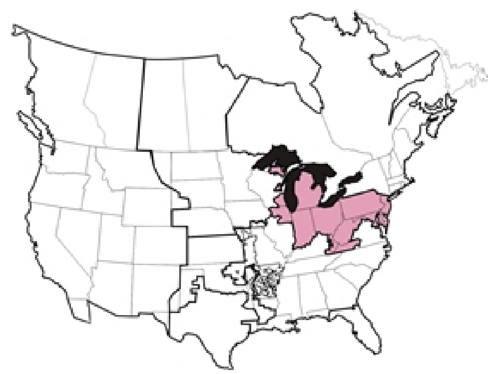
The Northeast Power Coordinating Council, Inc. (NPCC) is the cross-border regional entity and criteria services corporation for Northeastern North America. It is the NPCC mission to promote and enhance the reliable and efficient operation of the international, interconnected bulk power system in Northeastern North America pursuant to its agreement with the Electric Reliability Organization, which designates NPCC as a regional entity and delegates authority from the U.S. Federal Energy Regulatory Commission, and by Memoranda of Understanding with applicable Canadian Provincial regulatory and/or governmental authorities. The geographic area covered includes New York, the six New England states, and Ontario, Québec, and Maritimes provinces in Canada. The total population served is approximately 56 million, and the total geographic area is approximately one million square miles. NPCC was originally formed shortly after the 1965 Northeast Blackout to promote the reliability and efficiency of the interconnected power systems within its geographic area. Additional information can be found on the NPCC Web site (http://www.npcc.org/).

RFC

Projected Total Internal Demand	148,700	MW
Interruptible Demand & DCLM	2,300	MW
Projected Net Internal Demand	146,400	MW
Last Winter's Peak Demand	151,769	MW
Change	(2.0)	%
All-Time Winter's Peak Demand	151,769	MW
Deliverable Internal Capacity	207,714	MW
Projected Purchases and Incoming Adjustments	2,377	MW
Projected Sales and Outgoing Adjustments	250	MW
Net Capacity Resources	209,841	MW
Capacity Margin	30.2	%
Reserve Margin	43.3	%
With Uncommitted Resources		
Total Potential Resources	223,091	MW
Capacity Margin	34.4	%
Reserve Margin	52.4	%



Introduction



Reliability*First* Corporation, which began operation on January 1, 2006, was formed through the combination of portions of the former ECAR, MAAC, and MAIN regional reliability councils. Transition from the previous heritage-region activities to a single set of processes and procedures is still in progress, and is expected to be complete by the end of 2007. At this time, heritage regional requirements still apply to the members of the former regions that are now in RFC.

All RFC members are affiliated with either the Midwest ISO or PJM Interconnection (PJM) as their regional transmission organization (RTO), except Ohio Valley Electric Corporation (OVEC), a generation and transmission utility with facilities in Indiana, Kentucky and Ohio. Although OVEC is not affiliated with either RTO, OVEC's Reliability Coordinator services are performed by PJM.

Effective January 1, 2007, E.ON U.S. and the City of Springfield, Illinois became members of the SERC region and are no longer a part of RFC. This assessment excludes E.ON U.S. and the City of Springfield information and data for the entire assessment period. Also, Duquesne Light Co. has announced its intention to withdraw from PJM effective on or about January 1, 2008 and join Midwest ISO at that time. For this assessment, Duquesne's load of about 2,300 MW is included with PJM.

Demand

Reliability*First's* total internal demand (TID) forecast for winter 2007/2008 is 148,700 MW. This is 400 MW (0.3 percent) higher than last year's TID forecast for the 2006/2007 winter, and 3,069 MW (2.0 percent) lower than last winter's actual peak demand of 151,769 MW experienced in the Reliability*First* region. While the winter 2006/2007 TID forecast of 148,300 MW was exceeded by more than 3,000 MW, the actual peak demand was within the expected range for a weather induced load increase, since demand is forecast on an average expected ("50/50") weather basis, and weather extremes can add 5 percent (7,400 MW) or more to the peak demand.

The regional demand forecast is derived by aggregating the demand forecasts of the reporting entities. The Reliability*First* member forecasts are based on expected average winter weather conditions and expected economic conditions during the winter of 2007/2008 based on late 2006 economic forecasts. Extreme weather can be expected to add up to 7,400 MW to the peak. Demand-side management programs and interruptible demand contracts that could be utilized, if necessary, are expected to total 2,300 MW at the time of the winter peak.

This regional assessment does not specifically address peak demand uncertainty and variability, or the variability in demand due to weather. Planning for such uncertainties is the responsibility of each individual load serving entity. As a sensitivity analysis, a calculation based on a weather induced 5 percent load increase (7,400 MW) is performed. Even with such a load increase, the reserve margin would be adequate to meet the demand.

Generation

Total internal capacity is expected to be 225,409 MW at the time of the projected 2007/2008 winter peak. The PJM and Midwest ISO markets have commitments for 211,709 MW. After accounting for 3,995 MW of scheduled maintenance, the deliverable internal capacity used in this resource assessment is projected to be 207,714 MW. The 13,700 MW difference between the total internal capacity and net deliverable internal capacity is 13,250 MW not committed to either market and 450 MW of inoperable capacity.

Purchases and Sales

At this time, members have made arrangements to purchase 1,011 MW from outside the Reliability*First* region. An additional 1,366 MW of member-owned capacity is located outside of the region, for an expected import of 2,377 MW. There is also a 250 MW transaction to another region that constitutes the net export. The net interchange added to the deliverable internal capacity is the 209,841 MW of net capacity resources in this assessment. PJM and Midwest ISO report that these are all firm power transactions with firm transmission service and none are contracts with liquidated damages provisions. The external purchases are not necessary for the Reliability*First* region to satisfy its benchmark reserve margin.

Fuel

The Reliability*First* region has a diversified fuel supply. About 46 percent of the capacity uses coal for its fuel, with another 15 percent of the capacity being nuclear fueled. Oil and natural gas fuels 6 percent and 29 percent of the capacity respectively, and 3 percent of the capacity is hydroelectric. The remaining 1 percent of capacity uses a variety of renewable and other energy supplies.

Reliability*First* does not perform an explicit fuel supply interruption study, but reviews the potential for major supply problems based on past disruptions reoccurring. Adequate pipeline capacity is expected to be available during the winter, when needed to operate the gas units. Additionally, the Energy Information Administration reports that natural gas in storage in September is at the high end of the five year range for gas in storage. (See Web site[35]). Reliability*First* does not expect any problem with gas availability this winter.

At this time there are no known conditions affecting coal deliveries by rail that are expected to cause coal delivery problems for Reliability*First* members this winter. Since only 3 percent of the regional capacity is hydroelectric, and more than half of the hydro capacity in Reliability*First* is pumped storage, there is no expectation that hydro conditions will be a regional concern.

Reliability*First* expects each member to be ready to mitigate any fuel supply disruption that may occur. Although Reliability*First* has not compiled a list of mitigation actions that could be taken, some members may implement fuel switching for those units with dual-fuel capability, if it becomes necessary to maintain reliable fuel supplies. Data available to Reliability*First* indicates that at least 25 percent of the regional capacity has dual-fuel capability. Reliability*First* has not verified with individual members the ease or difficulty involved with switching to alternate fuels.

The most likely impacts of extreme winter weather on fuel supplies are frozen coal and low gas availability due to high residential gas use. Coal is routinely treated to prevent freezing during winter when weather conditions indicate the need. Anticipated reserve margins should be sufficient to minimize the need for gas-fired electric generation. Extreme weather conditions during peak load conditions should not materially affect the ability to adequately supply generation across the region.

Transmission

Historically, Reliability*First* and the heritage regions have experienced widely varying power flows due to transactions and prevailing weather conditions across the region. As a result, the transmission system could become constrained during peak periods because of unit unavailability and unplanned transmission outages concurrent with large power transactions. Generation redispatch has the potential to mitigate some of these potential constraints. Notwithstanding the benefits of this redispatch, should transmission constraint conditions occur, local operating procedures, as well as the NERC transmission loading relief (TLR) procedure may be required to maintain adequate transmission system reliability.

Certain critical flowgates that have experienced TLRs in previous winters continue to be identified as heavily loaded in various reliability assessments and may require operator intervention to ensure adequate reliability levels are maintained.

[35] http://www.eia.doe.gov/oil_gas/natural_gas/info_glance/natural_gas.html

The additions of new transformers at Wylie Ridge, the commissioning of the Neptune HVDC transmission line and a new wind farm have changed the flow patterns in each of those areas. However, these system changes do not adversely impact reliability.

Operational Issues

During normal operations and for typical operation planning scenarios, there are some transmission constraints within both the PJM and Midwest ISO areas of Reliability*First*. All of these identified constraints can be alleviated with generation redispatch or other operating plans/procedures with minimal impact on reliability. Reliability*First* does not anticipate any significant impact on reliability from scheduled generating unit or transmission facility outages.

In addition to the above, NERC TLR procedures (level 5 and above) and other operating procedures are available to maintain reliable system operations. An example is the multi-regional agreement involving balancing authorities around Lake Erie to use generation and phase angle regulator redispatch to mitigate emergency TLR procedures and curtailments in situations where the affected system(s) is about to curtail firm demand.

The output of one power plant within Reliability*First* is restricted due to environmental issues. However, the restriction may be lifted for the duration of emergency operating conditions. Reliability*First* does not expect local environmental restrictions on any generating units to significantly impact availability during peak load conditions.

Reliability Assessment Analysis

A generation resource assessment and a transmission assessment of the Reliability*First* systems on a region-wide basis have been performed for the upcoming winter peak demand season. Reliability*First* assessment procedures were applied to all generation and transmission facilities within the Reliability*First* footprint that might significantly impact bulk electric system reliability. These assessments consider Reliability*First* as a single integrated system. Regional reliability assessments are performed to determine the adequacy of the existing and future bulk power system to serve projected load, given the proposed changes or additions to generation capacity and transmission facilities. If transmission deficiencies are discovered during this process, the member system with the deficiency will determine the actions to be taken.

Reliability*First* actively participated in three of the Eastern Interconnection Reliability Assessment Group (ERAG) interregional seasonal transmission assessment efforts and also conducts its own transfer capability analyses and assessment. Transfer capability results are included in each of the regional and interregional seasonal reports. Simultaneous import capabilities are projected to be adequate for the winter.

Within Reliability*First*, each individual company along with its RTO performs planning analyses for facility additions. The PJM and Midwest ISO RTOs are planned and operated employing one security-constrained economic dispatch protocol using the applicable local criteria, the PJM deliverability requirements, and PJM market rules. External units that are considered capacity in PJM must sign an agreement specifying that if a capacity emergency is called, the capacity of the units must be available to PJM. Transmission availability is secured before an external unit can be considered PJM capacity. The Midwest ISO energy market tariff requires load serving entities to comply with their applicable resource adequacy standards. Load and capability information is reported to Midwest ISO annually to monitor compliance.

PJM performs voltage stability analysis (voltage drop) as part of all planning studies and also a periodic analysis (every five minutes) is performed by the PJM EMS. Results are translated into thermal interface limits for the operators to monitor. Transient stability studies are performed as needed and are an integral part of the regional Transmission Expansion Plan (RTEP) analysis and are presented to the PJM Transmission Expansion Advisory Committee (TEAC). Small signal analysis is performed as part of long term studies and not in the pre-seasonal time frame.

Reliability*First* has developed a planning reserve requirement criterion, which will become effective for the 2008 summer peak season. In the interim, Reliability*First* is using a 15 percent reserve margin target as a benchmark to assess the region. Reliability*First* does not require individual members to plan for resource unavailability due to extreme credible contingencies that might occur. Therefore, Reliability*First* has not surveyed its members to determine how the individual members plan for resource unavailability beyond the largest single contingency. Both PJM and Midwest ISO conduct comprehensive analyses to determine the deliverability of generation within their RTOs. All committed generation in this assessment is considered deliverable.

Reliability*First* forecasts its capacity margin to be 30.2 percent. The forecast capacity margin in the region last winter was 33.5 percent. However, the 2006/2007 margin included all deliverable resources while the 2007/2008 margin includes just the committed resources. A more meaningful comparison of year to year capacity margins is based on the potential capacity resources. The 2006/2007 capacity margin with the potential resources was 35.7 percent. The comparable capacity margin for 2007/2008 is 34.4 percent, slightly less than last year.

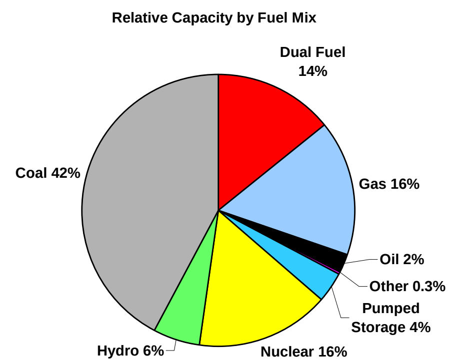
Reliability*First* assesses the region using reserve margin instead of capacity margin. The reserve margin for this winter of 43.3 percent is greater than the interim benchmark of 15 percent being used in this assessment. Based on the projected reserve levels, the committed capacity resources in the Reliability*First* region are expected to be adequate this winter.

Region Description

*Reliability*First *currently consists of 43 regular members, 20 associate members, and 3 adjunct members operating within 10 NERC balancing authorities, which includes over 360 owners, users, and operators of the bulk electric system. They serve the electrical requirements of more than 72 million people in an area covering all of the states of Delaware, Indiana, Maryland, Ohio, Pennsylvania, New Jersey, and West Virginia, plus the District of Columbia; and portions of Illinois, Kentucky, Michigan, Tennessee, Virginia, and Wisconsin. Additional details are available on the Reliability*First *website (http://www.rfirst.org).*

SERC

Projected Total Internal Demand	179,300	MW
Interruptible Demand & DCLM	5,155	MW
Projected Net Internal Demand	174,146	MW
Last Winter's Peak Demand	175,164	MW
Change	2.4	%
All-Time Winter's Peak Demand	177,197	MW
Deliverable Internal Capacity	230,143	MW
Projected Purchases and Incoming Adjustments	6,908	MW
Projected Sales and Outgoing Adjustments	4,088	MW
Net Capacity Resources	232,963	MW
Capacity Margin	25.2	%
Reserve Margin	33.8	%
With Uncommitted Resources		
Total Potential Resources	268,406	MW
Capacity Margin	35.1	%
Reserve Margin	54.1	%



Demand

The SERC total internal demand for the 2007/2008 winter is forecast to be 179,300 MW, which is 4,136 MW (2.4 percent) higher than the actual 2006/2007 winter peak of 175,164 MW that occurred in February 2007. This projection is based on average historical winter weather. The forecast 2007/2008 winter peak is 172,883 MW (excluding new SERC members), which is 6,540 MW (4 percent) higher than the forecast 2006/2007 winter peak of 166,343 MW (excluding new SERC members). These increases are due to typical load growth as well as colder temperatures during the 2006/2007 winter season. The all-time actual winter peak was 175,164 MW, which occurred in February 2007.

The level of forecast demand uncertainty varies within the region. Demand forecasts are normally assessed under normal historical weather and load conditions. The studied forecast variations are used in modeling processes to determine median expected normal winter peak data. The SERC total internal demand is an aggregate of SERC member systems.

The SERC region has significant demand response programs. These programs allow demand to be reduced or curtailed when needed to maintain reliability. Interruptible demand and load management capabilities for 2007/2008 winter are 4,570 MW and 585 MW respectively for a total of 5,155 MW, compared with the 5,286 MW reported last winter. Various types of programs (water heater load control, interruptible load programs, etc) are used through diverse customer segments within the region to help with peak demand reduction when needed.

A combination of load-forecasting tools and other fundamental analyses help to derive seasonal forecasts. These tools are used to form scenarios and predict peak demand under extreme weather or other conditions based on historical temperature probabilities.

Temperatures that are higher or lower than normal and the degree to which interruptible demand and load management are utilized can result in actual peak demands that vary considerably from the reported forecast peak demand. Although SERC does not perform extreme weather or load sensitivity analyses at the region level to account for this, SERC members address these issues in a number of ways, considering all NERC, SERC, regulatory, and other requirements. These member methodologies must be documented and are subject to audit by SERC.

While member methodologies vary to account for differences in system characteristics, many commonalities exist. Common considerations include:

- Use of econometric linear regression models
- Relationship of historical annual peak demands to key variables such as weather, economics, and demographics
- Variance of forecasts due to such things as high and low economic scenarios and mild and severe weather
- Development of, and studies using, a suite of forecasts to account for the variables mentioned above

In addition, many SERC members use sophisticated, industry accepted software packages to evaluate load sensitivities in the development of load forecasts.

Generation

SERC members report a total of 230,143 MW of committed resources for 2007/2008 winter. This includes an expected 2,898 MW of new committed capacity, to be placed in service from March 1, 2007 through November 30, 2007. Also, approximately 2,404 MW of new uncommitted capacity is expected in this period. The projected 2007/2008 winter capacity margin, which includes only committed capacity resources, for SERC is 25.2 percent, indicating capacity resources in SERC are expected to be adequate to supply the projected firm winter demand.

To understand the extent of generation development in the region, it is instructive to examine the amount of committed and uncommitted generation connected to the transmission systems within SERC for the upcoming winter season. Over 268,000 MW of generating capability is expected to be connected in the region. Although the SERC region does not implement a regional reserve requirement, members adhere to their respective state commissions' regulations and internal business practices regarding maintaining adequate resources. SERC members use various methodologies to ensure adequate resources are available and deliverable to the load.

Sales from SERC members that cross the SERC boundary total 2,506 MW[36] and purchases to SERC members that cross the SERC boundary total 1,713 MW. These firm purchases and sales that have been accounted for in the capacity margin calculations for the region and the subregions. Overall, the region is not considered to be dependent on outside purchases or transfers to meet the load.

SERC members recognize that planning for variability in resource availability is necessary. Many SERC members manage this variability through reserve margins, demand-side management programs, fuel inventories, diversified fuel mix and sources, and transfer capabilities. Some SERC members participate in Reserve Sharing Groups (RSG). In addition, emergency energy contracts are used within the region and with neighboring systems to recover from unplanned outages. Although such measures as emergency sales and purchases, and activation of shared reserves have been used in the region during the past year, their use has not been on a frequency different than in previous years.

Impact of Drought Conditions

Generation from hydro for the upcoming 2007/2008 winter season is expected to be below normal. Hydro reservoirs are currently below normal levels in the Southeastern, Central, and VACAR subregions due to severe drought conditions that extended the summer season. Limited relief is expected from the current conditions over the upcoming season. Some subregions have taken steps to monitor conditions through various committee efforts such as the VACAR Operating Task Force (OTF). Other subregions have reported that reduced energy from hydro has primarily been recovered from other controlled resources. Although these conditions are expected for various subregions within SERC, generation levels are expected to be sufficient to meet forecast peak demands and daily energy demands for the upcoming winter period. Drought impacts on other generation types are being monitored even though no significant impact is expected.

Fuel

Sufficient inventories (including access to salt-dome natural gas storage), fuel-switching capabilities, alternate fuel delivery routes and suppliers, and emergency fuel delivery contracts are some of the important measures used by SERC members to reduce reliability risks due to fuel supply issues. SERC entities with large amounts of gas-fired generation connected to their systems have conducted electric-gas interdependency studies.

In-depth studies have simulated pipeline outages for near and long-term study periods as well as both summer and winter forecasted peak conditions. Also included, for each of the major pipelines serving the service territory, is an analysis of the expected sequence of events for the pipeline contingency, replacing the lost generation capacity, and assessment of electrical transmission system adequacy under the resulting conditions. Dual fuel units are tested to ensure their availability and that back-up fuel supplies are adequately maintained and positioned for immediate availability. Some generating units have made provisions to switch

[36] Note that these Sales are exclusively Inter-Regional. The data in the SERC Summary Table includes both Inter-regional and Intra-subregional sales.

between two different natural gas pipeline systems, reducing the dependence on any single interstate pipeline system. Moreover, the diversity of generating resources serving SERC member loads further reduces the region's risk.

Current projections indicate that the fuel supply infrastructure and fuel inventories for the winter period are adequate even considering possible impacts due to weather extremes. Additionally, new international gas supplies are continuing to emerge for the U.S. market.

Although fuel deliverability problems are possible for limited periods of time due to weather extremes such as flooding, assessments indicate that this should not have a negative impact on reliability. The immediate impact will likely be economic as some production is shifted to other fuels. Secondary impacts could involve changes in emission levels and increased deliveries from alternate fuel suppliers.

Transmission

Deliverability is an important consideration in the analyses to ensure adequate resources are available at the time of peak. The transmission systems within SERC have been planned, designed, and operated such that the region's generating resources with firm contracts to serve load are not constrained. Network customers may elect to receive energy from external resources by utilizing available transmission capacity. To the extent that firm capacity is obtained, the system is planned and operated in accordance with NERC reliability standards to meet projected customer demands and provide contracted transmission services. Therefore, SERC anticipates no constraints that would reduce the availability of committed capacity resources.

The SERC region has extensive transmission interconnections between its subregions and to the FRCC, MRO, RFC, and SPP regions of NERC. These interconnections permit the exchange of firm and non-firm power and allow systems to assist one another in the event of an emergency. Approximately 449 miles of 138 kV, 161 kV, 230 kV, 345 kV, and 500 kV transmission lines are scheduled for completion by winter 2007/2008.

Coordinated transmission reliability and transfer capability studies for the 2007/2008 winter season are being conducted among all the SERC subregions and, through ERAG activities, with the neighboring regions. Preliminary results of these studies indicate the bulk transmission systems within SERC have no significant issues that will significantly impact reliability.

Reliability Assessment Process

Although SERC members plan for facility (transmission and generation) additions on an individual basis, SERC performs many assessment and study functions at the regional level in order to provide coordination and promote reliability. In 2006, SERC consolidated a number of regional study activities under the direction of the SERC Engineering Committee. These regional study groups are responsible for the development of models and associated studies to ensure that planning activities in SERC are coordinated. An extensive data collection effort is also required as part of the reliability assessment effort performed by SERC. Data collection is accomplished through a staff-facilitated Data Collection Task

Force consisting of representatives from each reporting entity in SERC. SERC's relational database (Portal) is utilized extensively as the mechanism, via surveys and compliance and data forms, for gathering and compiling data. The collection of data for the EIA-411 has historically been a part of these reliability assessment activities as well.

SERC utilizes its staff-facilitated Reliability Review Subcommittee (RRS) to perform assessments of future reliability and adequacy of the region and to prepare reports. Using information from the region's data collection efforts, the RRS makes an independent assessment of the ability of the region and subregions to meet member obligations given the demand growth projections, the amount of committed or contracted capacity, etc. The RRS determines if the resource information submitted represents a reasonable and attainable plan. Also, the RRS annually performs a transmission assessment based on regional, interregional, and subregional reliability studies. The studies are reviewed and analyzed. The RRS will request the appropriate regional study groups to perform any additional studies as required. The RRS's assessment provides a judgment on the ability of the transmission systems within SERC to operate securely under the expected range of operating conditions over the assessment period as required by the NERC reliability standards. The SERC Supplement on Reliability Assessments outlines SERC's interpretation and clarifies SERC's expectations of members with regard to the NERC standards on regional and interregional self-assessment reliability reports, TPL-005 and TPL-006[37].

Subregions

SERC serves as a regional entity with delegated authority from NERC for the purpose of proposing and enforcing reliability standards within the SERC region. SERC is divided geographically into five subregions that are identified as Central (formerly TVA), Delta (formerly Entergy), Gateway, Southeastern (formerly Southern), and VACAR. SERC and its five subregions are all summer peaking.

Delta

Demand

The total internal demand for the 2007/2008 winter season is forecast to be 23,715 MW based on normal weather conditions. This is 887 MW (4 percent) higher than the forecast 2006/2007 winter peak demand of 22,828 MW and is 357 MW (2 percent) higher than the actual 2006/2007 winter peak demand of 23,358 MW. The level of certainty is subject to variance primarily due to actual weather conditions and other factors, such as economic/load growth, differing from those assumed in the forecast. Demand forecasts are normally assessed under median weather conditions, but are correlated with actual weather data within the subregion. This data is used for modeling processes to determine a median expected normal winter peak data.

Within this subregion, interruptible demand and load management capabilities for 2007/2008 winter is approximately 402 MW, which is about 8 percent of the total SERC region demand management programs. These programs (Water Heater Load control, Interruptible Load

[37] http://serc1.org/documents/serc%20supplements/planning/active%20supplements%20(wholly%20or%20partially%20reference%20current%20nerc%20reliability%20standards)/reliability%20assessments%20serc%20supplement%20(11-3-06).pdf

Programs, etc.) are used through a variety of customer segments within the subregion to help with peak demand reduction. A combination of load-forecasting tools and other fundamental analysis help to derive seasonal forecasts. These tools are used to form scenarios and predict peak demand under extreme weather condition or other conditions based on historical temperature probabilities.

Generation

Delta subregional members report a total of 31,783 MW of committed resources for 2007/2008 winter. The projected capacity margin in the subregion, including only committed capacity, is 34 percent as compared to 40 percent for the last winter season. This decrease is primarily due to changes relating designated network resource (e.g., retirement of Ruston generating facility and changes with reserve sharing groups) and load growth within the area. This high capacity margin in this summer-peaking subregion should be adequate to meet forecast demand for the upcoming winter season. Although the subregion is adequate in supplying its load, it has access to reserve sharing programs, fuel diversification, and other resource contracts and power agreements to ensure deliverability and operations in times of catastrophic events. Several analyses (Loss-of-Load Expectation, etc.), coordinated with neighboring regions and other SERC subregions, indicate that transmission transfer capability will be adequate on all interfaces this winter to support reliable operations. Sales to entities outside the subregion total 235 MW. Purchases from entities outside the subregion total 3,932 MW. These firm purchases and sales have been accounted for in the capacity margin calculations for the subregion. Overall, the subregion is not dependent on outside purchases or transfers to meet the demands of its load.

Fuel

To ensure reliability of capacity, units within the subregion are also tested annually/semi-annually on alternative fuels (up to 95 hours). Approximately 20 percent of generating capacity has dual fuel capabilities with sufficient inventory levels. Hydro conditions are expected to be normal based upon current reservoir levels and normal anticipated weather conditions. Within the subregion, plant coal inventory levels of range from 40 days to 60 days. Approximately 15 percent-20 percent of the member gas-fired generation is under firm delivery supply contract or can be supplied from the member's gas storage facilities.

Transmission

Several transmission improvements, being constructed to increase system reliability, are scheduled for service during winter 2007 in the Delta subregion. For example, a new 230/115 kV autotransformer will be installed at the Amite 230/115 kV Substation, along with 18 miles of transmission line conversion to 230 kV operation. These improvements will mitigate several potential single-contingency overloads in the area. Although the subregion does not foresee any transmission constraints that would significantly impact system reliability and deliverability of firm resources for the upcoming winter peak season, other local area improvements are underway to ensure reliable delivery of power to users of the transmission grid.

The subregion is not projecting severe winter storms in its service territory that could significantly affect reliability due to transmission facility outages caused by the weather events. However, several storm response plans have been put in place to coordinate the restoration of transmission facilities and maintain system reliability should severe winter storms occur. Continual "next-event" analysis is performed to address any unforeseen catastrophic events as well as studies that satisfy extreme contingency conditions (TPL-003 and TPL-004). From this analysis, mitigation plans are developed to maintain reliability of the system.

The subregion is heavily involved with SERC study groups (e.g., Near Term Study Group, Long Term Study Group) to coordinate its transmission transfer capability studies and to ensure that import transfer capabilities and external resources for import are adequate for projected winter peaks. Other reliability analyses (i.e., those relating to steady-state load flow, short circuit, transient, voltage, and small signal stability) are also performed on a near-term and longer-term basis, as required by NERC reliability standards TPL-001-0 through TPL-004-0. These reliability studies have been performed and documented to ensure the continuance of reliable service to users of the transmission systems within the subregions.

Operational Issues

The Delta subregion does not expect any major generating unit outages or transmission facility outages that would impact system reliability for the 2007/2008 winter season.

Gateway

In 2007, the City of Springfield, Illinois (CWLP) joined SERC and the Gateway subregion.

Demand

The total internal demand for the 2007/2008 winter season is forecasted to be 14,472 MW based on normal weather conditions. The total internal demand (excluding new members in 2007) is forecast to be 14,160 MW, which is 169 MW (1 percent) lower than the forecast 2006/2007 winter peak demand of 14,329 MW and is 664 MW (5 percent) lower than the actual 2006/2007 winter peak demand of 14,824 MW. These decreases are due to stagnant or decreases in growth and variation of mild weather compared to last year. A combination of load-forecasting tools and other fundamental analysis help to derive the seasonal forecast. These tools are used to form scenarios and predict peak demand under extreme weather or other conditions based on historical temperature probabilities. The level of certainty varies within the subregion, but a 50/50 forecast is typically used to develop demand forecasts for modeling purposes, considering extensive historical load data and weather patterns to determine median expected normal winter peak data. Within this subregion, interruptible demand and load management capabilities for 2007/2008 winter are approximately 118 MW, which are about 2 percent of the SERC region demand management programs. These programs are not commonly used within the subregion, but the entities that have them normally use a variety of load shedding, interruptible load, and load management switch programs.

Generation

Gateway subregional members report a total of 18,435 MW of committed resources for 2007/2008 winter. The projected capacity margin in the subregion, including only committed capacity, is 29 percent as compared to 46 percent projected for last year. This decrease is primarily due to internal capacity additions offset by the expiration of designated network resource contracts and returning approximately 5300 MW of generation to uncommitted status. Capacity in the subregion should be adequate to supply the winter peak forecast demand. There are no predicted reliability concerns due to resource adequacy or deliverability. The subregion is generally adequate in supplying its load requirements and minimally relies on resources from outside of the subregion. Some of the subregion members have access to fuel diversification and other resource contracts and power agreements to ensure deliverability and operations in times of catastrophic events. Several analyses are being coordinated with RTOs, neighboring regions, and the other SERC subregions. Preliminary results indicate that transmission transfer capability will be adequate on all subregion interfaces this winter to support reliable operations. Sales to entities outside the subregion total 855 MW. Purchases from entities outside the subregion total 292 MW. These firm purchases and sales have been accounted for in the capacity margin calculations for the subregion. Overall, the subregion is not dependent on outside purchases or transfers to meet the demands of its load.

But, as stated above, the subregion is not considered to be dependent on outside purchases or transfers to meet the demands of its load.

Fuel

To ensure reliability of capacity, units within the subregion are also tested annually/semi-annually on alternative fuels (up to 95 hours). Up to 38 percent of member's gas-fired plants have dual fuel capabilities with sufficient inventory levels. Hydro resources are not significant in this area. Within the subregion, plant coal inventory levels range from 15 days up to 60 days. Up to 45 percent of member's gas-fired generation is under firm delivery supply contract or can be supplied from the member's gas storage facilities.

Transmission

Several transmission line improvements and additions have been constructed in the Gateway subregion to enhance system reliability and were scheduled for completion prior to winter 2007. Even though there are no improvements scheduled for the upcoming winter, reconductoring and up-rating over 200 miles of transmission lines in the subregion have been reported for the year. These improvements will mitigate several potential single-contingency and multi-contingency overloads in the area. Although the majority of the subregion has not experienced any significant constraints on its transmission system, some areas have reported potential contingency overloads that have been relieved by security constrained dispatch coordination or transmission loading relief to avoid negative impacts on the system. Some entities have reported that they are considering building additional facilities to alleviate the constraints. Even though the subregion has experienced some constraints, the constraints are not expected to significantly impact reliability or deliverability of generation. Continual contingency analysis is performed by RTOs and operations planners to address any unforeseen catastrophic events. RTOs and transmission planners within the subregion have also performed studies to ensure that the performance of the transmission system in the Gateway subregion meets NERC Standards TPL-001–TPL-004. From these analyses, mitigation plans are formed to maintain reliability to the area. Black start and system restoration plans are available to enhance system recovery in the event of a catastrophic failure.

Other study analyses (transient, voltage, small signal, etc) are performed on a near-term and long-term basis as required to meet the NERC Reliability Standards and local planning criteria. To increase transmission system reliability that is impacted by levels of load uncertainty, generation dispatch, and net scheduled interchange, transmission system contingency analysis and transfer capability studies are performed on a near-term and long-term basis as well. Representatives from the Gateway subregion participate with the SERC Near-Term and Long-Term Study Groups to coordinate seasonal and longer term transmission transfer capabilities to ensure that transmission margins are sufficient, as measured by incremental transfer (import) capabilities from external resources, for the study period. Coordinated studies with neighboring regions and the other SERC subregions indicate that transmission transfer (import) capabilities will be adequate on all interfaces this winter to support reliable operations. Long term studies that have been performed do not show any significant shortcomings in the Gateway subregion.

Operational Issues

No reliability issues are expected on the transmission systems in the Gateway subregion for this winter period. The Gateway subregion is also not projecting any significant transmission facility outages, additions or other operating measures that could affect reliability within the service area. There are also no projected reliability impacts from environmental, regulatory or unusual operating conditions that would affect system operation in the subregion.

Southeastern

Demand

The total internal demand for the 2007/2008 winter season is forecast to be 41,538 MW based on normal weather conditions. This is 998 MW (2 percent) higher than the forecast 2006/2007 winter peak demand of 40,540 MW and is 525 MW (1 percent) higher than the actual 2006/2007 winter peak demand of 41,013 MW. The data shows that weather conditions are closely comparable to last year, along with the load growth in the area. The level of certainty varies within the subregion. Demand forecasts are normally assessed under normal historical weather and load conditions. This data is used for modeling processes to determine a median expected normal winter peak data. Within this subregion, interruptible demand and load management capabilities for 2007/2008 winter is approximately 1,300 MW, which is approximately 25 percent of the SERC region demand management programs. This subregion is summer peaking and does not expect to utilize load management and interruptible demand programs for the mild weathered winter season. A combination of load-forecasting tools and other fundamental analysis help to derive seasonal mild and extreme weather forecast. These tools are used to form scenarios and predict peak demand under extreme weather condition or other conditions based on historical temperature probabilities. In other areas of the subregion, 15 percent reserves are planned to accommodate for uncertainties.

Generation

Southeastern subregional members report a total of 52,952 MW of committed resources for 2007/2008 winter. Considering only committed capacity, the projected capacity margin in the subregion, including only committed capacity, is 26.0 percent, which is slightly greater than the 25.8 percent reported last year. Capacity in the subregion should be adequate to supply forecast demand. In addition, majority of the subregion has reported a 15 percent+ reserve margin target. Deliverability to load within the subregion relies on the majority of its internal resources. There are no predicted reliability concerns due to resource adequacy and deliverability. The subregion is adequate in supplying its load and does not rely on outside sources. Several analyses (Loss-of-Load, etc.) are coordinated with neighboring regions and the other SERC subregions and indicate transmission transfer capability will be adequate to support reliable operations on all interfaces this winter. Sales to entities outside the subregion total 2345 MW. Purchases from entities outside the subregion total 865 MW. These firm purchases and sales have been accounted for in the capacity margin calculations for the subregion.

Fuel

To ensure reliability of capacity, dual fuel capable units within the subregion are tested annually/semi-annually on alternative fuels (up to 60 hours). Up to 35 percent of member's gas-fired plants have dual fuel capabilities and sufficient fuel inventory levels. Hydro resources are projected to be below normal levels due to weather conditions, but this is not expected to be a reliability concern. Within the subregion, plant coal inventory levels range from 25 days minimum up to 60 days. Members within the subregion reported up to 60 percent of gas-fired generation is under firm delivery supply contract or can be supplied from the member's gas storage facilities.

Transmission

Several transmission line improvements and additions are scheduled for completion during the Winter Assessment period in the Southeastern subregion. For example, this subregion has reported over 48 miles of re-rating and transmission lines conversions in the Assessment period. In addition, approximately 80 miles of new transmission are planned to enter service within the area for the winter period, along with new facilities (Gordon and Cumming 230/115 kV Substations). These improvements will mitigate several potential single- and double-contingency overloads in the area. Overall the subregion is not experiencing constraints on its transmission system and is not expecting any for the upcoming winter season. It is also not expected to experience any deliverability problems, minimal flow patterns, or any other concerns that would affect system reliability. Contingency analyses (Disaster Recovery Plans, UVLS, system reconfiguration, re-dispatch, curtailments, etc) are performed on a regular basis in order to address unforeseen catastrophic events as well as satisfy extreme conditions (TPL-001 through TPL-004). From this analysis, mitigation plans are formed to maintain reliability to the area. Other study analyses (transient, voltage, small signal, etc) are performed on both a near-term and long-term basis. Generation capability analysis, transmission system analysis and transfer studies are conducted on a near-term and long-term basis to decrease potential impact of load uncertainty. Studies have been documented to ensure proper planning has been performed to ensure the reliability of the subregion.

The subregion is heavily involved with SERC Study Groups (example SERC Near Term Study Group) to coordinate its transmission transfer capabilities to ensure that import transfer capabilities for import are adequate for projected winter peaks. Coordinated studies with neighboring regions and the other SERC subregions indicate that transmission transfer capability will be adequate on all interfaces to support reliable operations for the Winter Assessment period.

Operational Issues

No reliability problems are anticipated on the transmission systems of the Southeastern subregion members this winter. There are also no projected reliability impacts from environmental, regulatory or unusual operating conditions. Fossil generating units in the area have numerous operating limits related to air and/or water quality. These regulations are typical and tend to come from federal and state legislation. They are managed on a daily basis to meet reliability criteria. This subregion also routinely experiences significant loop flows due to transactions external to the area. The large amounts of uncommitted generation in the region can result in fairly volatile day-to-day scheduling patterns. The flows are frequently dependent on weather patterns, fuel costs or market conditions outside of the area rather than from within the area.

Central

E.ON U.S. Services Inc. for LG&E & KU Companies and Owensboro, KY Municipal Utilities joined SERC and the Central subregion in 2007.

Demand

The total internal demand for the 2007/2008 winter season is forecast to be 42,373 MW based on normal weather conditions. The total internal demand (excluding new members in 2007) is forecast to be 36,297 MW, which is 1,207 MW (3 percent) higher than the forecast 2006/2007 winter peak demand of 35,090 MW and is 1,786 MW (5 percent) higher than the actual 2006/2007 winter peak demand of 34,511 MW. Within this subregion, interruptible demand and load management capability for 2007/2008 winter is approximately 1618 MW, which is about 31 percent of the total region demand management programs. Because the subregion is summer peaking, load management and interruptible demand programs (curtailment tariffs, interruptible load programs, etc) are not expected to be used for a normal winter season. A combination of load-forecasting tools, demand calculations, and other fundamental analyses are used to derive seasonal normal and extreme load forecasts based on historical temperature probabilities. Load forecast uncertainty generally narrows as the operations planning horizon is entered. Load forecasts improve in the short term horizon as weather patterns can be more accurately predicted. Operational planning studies are therefore utilized to assess load "spikes" caused by extreme winter conditions. Real time power flow snapshots are used by planning to compare the planned vs. actual conditions, possibly leading to the identification or re-prioritization of capital projects.

Generation

Central subregional members report a total of 47,219 MW of committed resources for 2007/2008 winter. The projected capacity margin in the subregion, including only committed capacity, is 17 percent as compared to 15.7 percent last year. The subregion plans for a minimum of 15 percent capacity reserve margin. This margin is established to meet LOLE requirements. Sales to entities outside the subregion total 93 MW. Purchases from entities outside the subregion total 274 MW. These firm purchases and sales have been accounted for in the capacity margin calculations for the subregion. The subregion performs annual studies to ensure the deliverability of the current resource plan. Transmission projects are identified and initiated as required. Although resource plans do not include external resources, studies include evaluation of transfer capabilities. While the lower and constant reservoir elevations continue at Wolf Creek and Center Hill dams on the Cumberland River as a result of ongoing dam safety issues, together with residual drought conditions, this has not affected the subregion's ability to maintain adequate planning and operational reserves.

Fuel

Approximately 9.2 percent of plants within the Central subregion have dual fuel capability. All units are adequate with remote start and fuel oil operation capabilities. Gas fuel inventories for winter are 90-120 hours depending on gas transportation issues for each individual facility. At dual fuel facilities the oil is maintained for backup supply if gas is not available. The subregion's normal practice for gas-fired generation is to have firm contracts for fuel delivery. Coal Inventory targets are set by a supply chain interruption model combined with consideration for supply chain fluctuation capability. Current plans are to hedge winter interruption risks with inventories ranging from 17 days to 37 days supply depending upon individual supply chain variability.

Transmission

Several transmission line improvements and additions being constructed to increase system reliability are scheduled for completion prior to or during winter 2007 including over 323 miles of re-rating and transmission line conversions. In addition, over 266 miles of new transmission are planned to go in-service within the area, along with new facilities (ex., Madison 500/161-kV Transformer). These improvements will mitigate several potential single-contingency overloads in the area. The Central subregion does not have transmission constraints that could significantly impact reliability and is not expecting any constraints for the upcoming winter season.

The subregion is currently participating in intra- and inter-regional studies to assess transfer capabilities for projected 2007/2008 winter peak conditions. These studies will be released in mid-November. Contingency analyses (Disaster Recovery Plans, UVLS, system reconfiguration, re-dispatch, curtailments, etc) is performed on a regular basis in order to address any unforeseen catastrophic events as well as studies that satisfy extreme conditions (TPL-001 through TPL-004).

The subregion is heavily involved with SERC Study Groups (Near Term Study Group, etc.) to coordinate its transmission transfer capabilities and ensure that import transfer capabilities are adequate for projected winter peaks. Other study analyses (transient, voltage, small signal, etc) are performed annually to meet TPL standards requirements. Coordinated studies with neighboring regions and the other SERC subregions indicate that transmission transfer capability will be adequate on all interfaces this winter to support reliable operations.

Operational Issues

No reliability problems are anticipated on the transmission systems of the Central subregion members this winter. The TVA transmission system has experienced large and volatile flows in recent years and these flows may occur again this winter. The 500-kV corridor in upper east Tennessee continues to experience congestion due to west to east and south to north transfer patterns. Additionally, the 500-kV corridor from western Kentucky to middle Tennessee can experience congestion during high west to east and north to south transfers.

EKPC completed a new 345 kV line this spring (North Clark-JK Smith) and installed a 345/138 kV autotransformer at JK Smith, which has eliminated the Avon transformer constraint reported last year. For BREC, during certain generator and transmission outage scenarios, internal and external facility loadings may limit the ability to import power into the BREC balancing area. Coordinated operating guides have been developed to address these potential transmission constraints. No other potential operating issues or constraints have been identified. For E-ON, high north to south transfers across the system in conjunction with an N-1 contingency and various generation patterns can cause SOL violations. Operating procedures which include TLR, re-configuration and re-dispatch are in place to address these issues. Other than the detailed impacts above, there are no projected reliability impacts from environmental, regulatory or unusual operating conditions that would affect system operation in the subregion.

VACAR

Demand

The total internal demand for the 2007/2008 winter season is forecast to be 57,200 MW based on normal weather conditions. This is 1,470 MW (3 percent) higher than the forecast 2006/2007 winter peak demand of 55,730 MW and is 96 MW (.2 percent) lower than the actual 2006/2007 winter peak demand of 57,296 MW. These comparisons show that economic growth is steady across the subregion. The level of certainty varies within the subregion, but a 50/50 forecast is widely used. Demand forecast are normally accessed under extensive historical load data and weather patterns. This data is used for modeling processes to determine a median expected normal winter peak data.

Within the VACAR subregion, interruptible demand and load management capabilities for the 2007/2008 winter is approximately 1716 MW, which is approximately 33 percent of the SERC region demand management programs. This subregion is summer peaking and does not expect to utilize load management interruptible demand programs for mild winter seasons. These programs are in variations of load shedding, interruptible rate structures and load control curtailment programs, etc. A combination of load-forecasting tools and other fundamental analysis help to derive seasonal forecast. These tools are used to form scenarios and predict peak demand under extreme weather condition or other conditions based on historical temperature probabilities.

Generation

VACAR subregional members report a total of 69,589 MW of committed resources for 2007/2008 winter. The projected capacity margin in the subregion, including only committed capacity is 25 percent and is unchanged compared to last winter's capacity margin. Capacity in the subregion should be adequate to supply forecast demand. In addition, a majority of the subregion has planning targets to maintain 15 percent reserve margin to account for any uncertainties in resource adequacy. Even though parts of the subregion are experiencing constraints, it is predicted that deliverability to load within the subregion will remain adequate and reliability will be maintained. The overall subregion is adequate in supplying its load and does not rely solely on outside sources but on a short-term basis only. Undeliverable resources from internal sources in the subregion have caused some of the VACAR entities to look for other resource contracts to meet peak demand. Sales to entities outside the subregion total 560 MW. Purchases from entities outside the subregion total 1545 MW. These firm purchases and sales have been accounted for in the capacity margin calculations for the subregion.

Fuel Supply and Delivery

VACAR members report 46 percent of gas-fired plants have dual fuel capabilities with sufficient inventory levels. The current drought has caused substantial constraints on hydro operation. However, projected hydro generation and reservoir levels should be adequate to meet both normal and emergency energy demands for the 2007/2008 Winter. Within the VACAR subregion, plant coal inventory levels range from 30 days up to 60 days. Thirty-six percent of VACAR member's gas-fired generation is under firm delivery supply contract or can be supplied from the member's gas storage facilities.

Transmission

Several transmission line improvements and additions are scheduled for completion during the Winter Assessment period in the VACAR subregion. For example, this subregion has reported over 11 miles of re-rating and transmission lines conversions. In addition, over 100 miles of new transmission are planned to enter service within the area, along with new substation facilities (ex., Hopkins and Lake Murray 230/115 kV). These improvements will mitigate several potential single-contingency overloads in the area. Overall the subregion is not predicted to experience any constraints on its transmission system and is not expecting any constraints for the upcoming winter season.

Minimal affects to reliability during the upcoming winter season will occur from transmission facility outages, transmission additions or temporary operating conditions. The subregion is not predicting to experience any deliverability and reliability problems, flow patterns, or any other concerns that would affect reliability on the system. Continual contingency analyses are performed on a regular basis in order to address any unforeseen catastrophic events as well as studies that satisfy extreme conditions (TPL-001 and TPL-004). From this analysis, mitigation plans are formed to maintain reliability to the area. Other study analyses (transient, voltage, small signal, etc) performed on a near-term and long-term basis, as required by NERC Reliability Standards. To increase reliability that is impacted by levels of load uncertainty, capacity simulations, transmission system analysis and transfer studies are on a near-term and long-term basis as well. Long term studies that were performed do not reflect any harmful impact to the bulk electric system. Studies have been documented to ensure planning proper planning as been done to increase the reliability of the region.

The subregion is heavily involved with SERC Study Groups (SERC Near Term Study Group) to coordinate its transmission transfer capabilities to ensure that import transfer capabilities and external resources for import are adequate for projected winter peaks. Coordinated studies with neighboring regions and the other SERC subregions indicate that transmission transfer capability will be adequate on all interfaces this winter to support reliable operations.

Operational Issues

No reliability problems are anticipated on the transmission systems of the VACAR subregion members this winter. There are also no projected unusual environmental, regulations or unusual operating condition that would affect the system of the subregion as well.

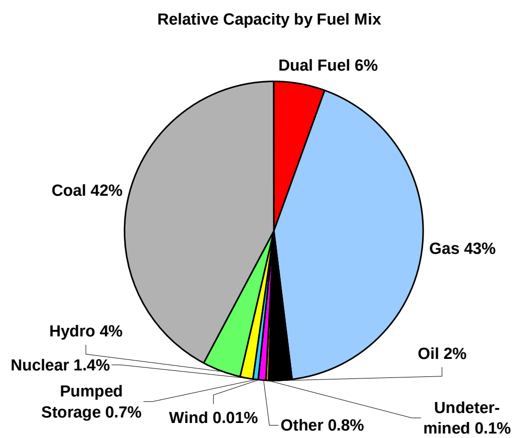
Region Description

The SERC Reliability Corporation (SERC) is a nonprofit corporation responsible for promoting and improving the reliability, adequacy, and critical infrastructure of the bulk power supply systems in all or portions of 16 central and southeastern states (all of Alabama, Georgia, Mississippi, North Carolina and South Carolina, and portions of Arkansas, Florida, Illinois, Iowa, Kentucky, Louisiana, Missouri, Oklahoma, Tennessee, Texas and Virginia). SERC's 63 members comprised of investor-owned utilities, municipal, cooperative, state and federal systems, RTOs/ISOs, merchant electricity generators, and power marketers, cover an area of approximately 560,000 square miles and serve approximately 40 million customers.

SERC serves as a Regional Entity with delegated authority from NERC for the purpose of proposing and enforcing reliability standards within the SERC region. SERC is divided geographically into five sub-regions that are identified as Delta, Gateway, Southeastern, Central, and VACAR. SERC and its five subregions are all summer peaking. Additional information can be found on the SERC Web site (www.serc1.org).

SPP

Projected Total Internal Demand	30,183	MW
Interruptible Demand & DCLM	617	MW
Projected Net Internal Demand	29,566	MW
Last Winter's Peak Demand	30,331	MW
Change	(0.5)	%
All-Time Winter's Peak Demand	30,686	MW
Deliverable Internal Capacity	46,677	MW
Projected Purchases and Incoming Adjustments	1,991	MW
Projected Sales and Outgoing Adjustments	1,619	MW
Net Capacity Resources	47,049	MW
Capacity Margin	37.2	%
Reserve Margin	59.1	%
With Uncommitted Resources		
Total Potential Resources	57,272	MW
Capacity Margin	48.4	%
Reserve Margin	93.7	%



Demand

The winter non-coincident total internal demand is projected to be 31,087 MW[38], which is comparable to the previous winter forecasted peak demand of 29,788 MW. Actual peak demand for the 2006/2007 winter load season within SPP was 30,885 MW. Last year, SPP experienced a significant increase in demand due to abnormally low temperatures throughout the peak winter months. SPP members, however, are not anticipating similar load demand this year. To quantify peak demand uncertainty and variability due to extreme weather, economic conditions, and other variables an analysis of our region has been completed by the Bandwidth Working Group. The outcome of this report supports the current predicted growth rates and allows for up to a 1.2 percent variation in current and future predictions through the year 2012.[39]

These projections include the effects of interruptible demand and load management capabilities. The forecasted values are 617 MW of interruptible demand and 0 MW of load management. SPP is a summer peaking system and the winter peaks are always less than those experienced in the summer.

[38] Note that the internal demand reported in the SPP Summary Table is the coincident peak, while this is the non-coincident peak. Therefore it is different then the summary table.
[39] URL http://www.spp.org/publications/BWG_Report_2003.pdf

Generation

The total committed generation in the SPP for the 2007/2008 winter is 46,677 MW with an additional 10,223 MW of uncommitted capacity. The SPP capacity margin based on committed resources is expected to be 37.2 percent[40] for the 2007/2008 winter, which is comparable to the calculated capacity margin from last year. The actual capacity margin may be slightly different due to the fact that SPP members may experience coincident peak demand during different months of winter and include short-term firm purchases towards their committed resources. However, both numbers (actual and reported capacity margin) are significantly above the 12 percent minimum criteria for the region.[41]

Normal hydro capacity is expected for the winter conditions. The energy output from hydro is not expected to have regional impact since only 3.9 percent of SPP capacity is hydro.

Purchases and Sales

SPP has a total of 1,619 MW of firm sales to other regions for the winter season and a total of 1,991 MW of projected purchases from the other regions. Also, there are additional short-term firm purchases as reported in EIA-411 for meeting capacity margin as well as all short-term firm transactions from merchant generation, municipalities and other neighboring markets. Currently there are no Liquidated Damage Contracts (LDCs) within the SPP region.

Fuel

All fuel supplies throughout the winter are expected to be adequate. SPP monitors potential fuel supply limitations for hydro and gas resources by consulting with its generation owning/controlling members at the beginning of each year. Managing and predicting the energy output from intermittent resources like run-of-river hydro and wind farms are more challenging. Wind resources are not expected to provide a significant portion of the region’s capacity during peak load conditions in the near-term horizon. Although dispatched to help cover high peak periods, hydro capacity represents a small fraction of the total resources in SPP. Regarding adequacy, the coal supply of the Powder River Basin (PRB) is not considered to be a high-risk issue by SPP members at this time. Natural gas sources are abundant in the SPP region and are not considered to be at high risk regarding supply adequacy or security.

A small portion of the SPP capacity is considered to be dual fuel. SPP has 2,451 MW of generation capacity that is considered to be dual-fuel capable. The dual-fuel capacity represents about 5.5 percent of the total SPP capacity.

SPP Criteria 2.4.2 requires the availability of an adequate and reliable fuel supply by all SPP members who own or operate generating facilities. Where contractual or physical arrangements permit curtailment or interruption of the normal fuel supply, sufficient quantities of standby fuel should be provided.

[40] Calculated based on the non-coincident peaks and short-term firm transactions

[41] SPP Capacity Margin requirement was based on the LOLE study performed by SPP staff in 1997.

Transmission

The transmission system within SPP is expected to perform reliably over the 2007/2008 winter season. No new constraints have been identified to affect reliability. SPP continues to observe the limits on the 115-161 kV transmission lines along the Oklahoma and Arkansas border for n-1 contingencies and, while monitoring these closely, is working with other regions to assess and solve these localized problems.

American Electric Power West (AEPW) has completed construction of a new 6-mile 138kV transmission line that loops into Sapulpa station from the Jenks to 52nd and Delaware line. In addition, AEPW plans the completion of the new 25-mile 138kV transmission line from Winnsboro to North Minneola and will have it energized by the end of winter 2007/2008. These projects are part of the enhancements that AEPW is doing to address load expansion around Tulsa, OK and East Texas, respectively, and are expected to be completed by the end of winter 2007/2008.

Oklahoma Gas and Electric (OG&E) is working on the completion of a new 5-mile 138kV transmission line from Piedmont to Richards around Oklahoma City area. OG&E plans on having a new 10-mile 161kV transmission line between Razorback and Igo in NW Arkansas to be completed by the end of winter 2007. In addition to the projects above, OG&E is also expecting to complete the 6-mile Oklahoma Municipal Power Authority (OMPA) — Garber to (OG&E) — Chitwood 138kV tie by the end of winter 2007. This project is to be completed under the OG&E OMPA Transmission Service Agreement. These projects will help with the load expansion in the Oklahoma City and Northwest Arkansas areas.

These ongoing transmission projects will address reliability predominantly during summer peak condition and their completion in the next few months will not have impact reliability during the upcoming winter season.

Operational Issues

SPP operations personnel anticipate normal winter operations. All fuel supplies throughout the winter are expected to be adequate. There are no known unusual operating conditions expected to impact reliability for the upcoming winter. There are no scheduled maintenance outages of operational concern.

Reliability Assessment Analysis

The load forecast data is collected by SPP from individual members as non-coincident data and then the data is summed up to produce the total forecast for SPP. SPP members use actual loads with normalized weather data for projecting the load forecast for each area.

SPP has historically determined import capabilities and limits on a regional basis through the MMS agreement (MAIN, MAPP/MRO, and SPP). These responsibilities have transferred to ERAG (Eastern Interconnection Reliability Assessment Group) which creates models and performs studies of regional import and export capability. SPP supports the MRSWS (MRO-RFC-SERC WEST-SPP) study that has been finalized by the study group for the 2007 winter peak load operating conditions. The preliminary results of this study show exports out of SPP to have no significant constraints for this upcoming winter peak condition. Imports into SPP from the East and North are limited due to a 161 kV line in western Arkansas. SPP will work through ERAG to come-up with a long-range mitigation plan for this constrained area. Currently, a local operating guide is used to mitigate this constraint.

SPP recently completed additional studies to ensure the requirements contained in NERC Reliability Standards TPL-001, TPL-002, TPL-003, and TPL-004. The contingency analysis, which was recently completed, looked at the system performance under normal conditions and following the loss of a single transmission element. Mitigations were documented for all overloaded branches and voltage violations. A load flow study was performed to look at the system performance following the loss of selected two or more transmission elements as well as selected extreme transmission events. Mitigations were discussed between SPP and the Transmission Owners to alleviate the overloaded branches and voltage violations from this study.

Transient and voltage stability screenings were done as part of the SPP Transmission Expansion Plan (STEP). No significant issues were found in these screenings analyses.

Deliverability of generation as designated Resources is in accordance with the SPP Tariff sections 19 and 32 and Attachment C, D and Z.[42]

SPP has an Under Frequency Load Shedding (UFLS) program to cover the catastrophic events like loss of up to 30 percent of generation. This program effectively shed loads in three steps of 10 percent to arrest the declining frequency and avoid any cascading impact.

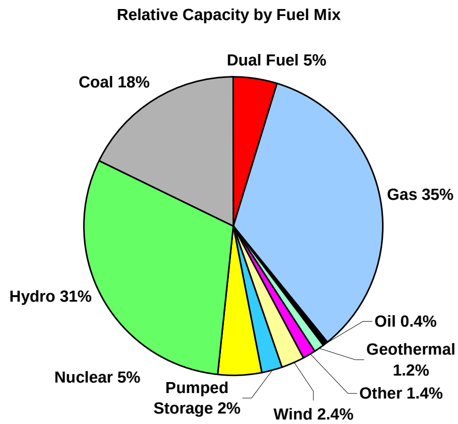
Regional Description

The Southwest Power Pool (SPP) region covers a geographic area of 255,000 square miles and has members in eight states: Arkansas, Kansas, Louisiana, Mississippi, Missouri, New Mexico, Oklahoma, and Texas. SPP manages transmission in seven of those states. SPP's footprint includes 17 balancing authorities and 52,301 miles of transmission lines. SPP has 50 members that serve over 4.5 million customers. SPP's membership consists of 12 investor-owned utilities, 8 municipal systems, 11 generation and transmission cooperatives, 2 state authorities, 3 independent power producers, 11 power marketers, and 2 independent transmission companies. Additional information can be found on the SPP Web site (www.spp.org).

[42] http://www.spp.org/publications/SPP_Tariff.pdf

WECC

Projected Total Internal Demand	133,351	MW
Interruptible Demand & DCLM	2,634	MW
Projected Net Internal Demand	130,717	MW
Last Winter's Peak Demand	132,477	MW
Change	0.7	%
All-Time Winter's Peak Demand	132,477	MW
Deliverable Internal Capacity	193,115	MW
Projected Purchases and Incoming Adjustments	677	MW
Projected Sales and Outgoing Adjustments	187	MW
Net Capacity Resources	193,605	MW
Capacity Margin	32.5	%
Reserve Margin	48.1	%
With Uncommitted Resources		
Total Potential Resources	193,677	MW
Capacity Margin	32.5	%
Reserve Margin	48.2	%



Demand

The aggregate WECC 2007/2008 winter total internal demand is forecast to be 133,351 MW (U.S. systems 110,314 MW, Canadian systems 21,499 MW, and Mexican system 1,538 MW). The forecast is based on normal weather conditions and is 0.7 percent above last winter's actual peak demand, which was established under generally above normal to somewhat above normal temperatures in the region. The 2007/2008 winter total internal demand forecast is 2.4 percent greater than last winter's forecast peak demand of 130,255 MW for the 2006/2007 winter period. Firm capacity commitments to external areas total 220 MW.

The internal demand forecast includes 343 MW of direct control demand-side management capability and 2,291 MW of interruptible demand capability. The 2007/2008 winter period direct control direct control load management and interruptible demand capability has increased by about 300 MW compared to last year[43]. The direct control demand-side management capability is located mostly in Alberta, Canada. The interruptible demand capability includes industrial interruptible demand and water pumping demand.

Weather sensitivity analyses indicate that the 133,351 MW average weather winter peak demands may increase by as much as 3,998 MW, assuming a one-in-ten-year cold snap. Such a cold snap would reduce the region's capacity margin to about 30.3 percent and the reserve margin to about 43.4 percent[44].

[43] Note this increase compares projected 2007/2008 Winter to actual direct control load management and interruptible demand experienced in 2006/2007 Winter. Comparing this 2007/2008 projection to the 2006/2007 Winter seasonal assessment projection would yield an increase of over 450 MW.

[44] Percentages are calculated assuming a 3,998 MW increase in firm peak demand (i.e., a projected Net Internal Demand of 134,715 MW) to reflect a 1-in-10 cold snap. This is more conservative than the data shown in the summary table reflecting the NERC requested 50/50 demand forecast.

Resource Assessment

For the peak winter month of December, WECC expects a capacity margin of 32.5 percent, which corresponds to a 48.1 percent reserve margin. WECC's capacity margin last winter was 32.5 percent. The forecast margin of approximately 63,000 MW significantly exceeds this year's supply adequacy model[45] planning margin of about 13,664 MW. Net committed capacity for this winter is expected to be 193,605 MW compared to 184,463 MW for winter 2006/2007. The net committed capacity resources of 193,605 MW include 677 MW of firm capacity purchases from external areas.

WECC has not established an interconnection-wide process to address the issue of planning for variability in resource availability due to fuel and other conditions. The 62,400 MW gross hydroelectric resource capability used for this assessment has been reduced by roughly 5,000 MW to reflect river flow limitations and other factors. Installed wind capability of about 7,000 MW has been reduced by about 6,400 MW to reflect expected available capability during the winter period. Transmission limitations that restrict generator access to the power grid are largely associated with wind farm interconnections. These limitations, however, do not exceed the wind derates referenced above. Transmission limitations for other generation sources are reported at 52 MW. Gross uncommitted resource additions total about 500 MW of nameplate wind additions. The derated uncommitted wind additions total about 70 MW. WECC's assessment analysis considers all existing resources as committed

Fuel

WECC has not implemented a formal fuel supply interruption analysis methodology. Historically, coal-fired plants have been built at or near their fuel source and generally have long-term fuel contracts with the mine operators, or actually own the mines. Gas-fired plants were historically located near major load centers and relied on relatively abundant western gas supplies. Many of the older gas-fired generators in the region have backup fuel capability and normally carry an inventory of backup fuel, but WECC does not require verification of the operability of the backup fuel systems and does not track onsite backup fuel inventories. Most of the newer generators are strictly gas-fired plants, increasing the region's exposure to interruptions to that fuel source.

A survey of major power plant operators indicates that their natural gas supplies largely come from the San Juan and Permian Basins in Western Texas, from gas fields in the Rocky Mountains, and from the Sedimentary Basin of Western Canada.

It is not expected that extremes of winter weather during peak load conditions would have any impact on the fuel supply infrastructure. Dual-fuel capability is not a significant issue within the Western Interconnection. Only a nominal amount of generation outside of the Southwest has dual fuel capability and almost all of the Southwest dual-fueled plants are subject to severe air emission limitations that make alternate fuel use prohibitive for anything other than very short term emergency conditions.

[45] http://www.wecc.biz/documents/meetings/PCC/2007/October/PSA_Final_Report_09-17-07.pdf

Transmission

WECC and Regional Entities have several processes in place that relate to generation deliverability. For example, extensive operating studies are prepared that model the transmission system under a number of load and resource scenarios and operating procedures are developed to maintain safe and reliable operations.[46] WECC prepares an annual power supply assessment that is designed to identify major load zones within the region that may experience load curtailments due to physically-constrained paths and internal resource limitations. Major power grid operators have internal processes for identifying and addressing local area resource limitations, and independent grid operators have formal procedures for obtaining reliability must run capability, including voltage support capability, for resource-constrained areas. The resources reported in this assessment have been reduced to reflect deliverability constraints identified by transfer capability studies, interconnection agreement studies, etc.

The Southern California area imports significant amounts of power and it is expected that the transmission into that area of the Western Interconnection will be utilized much of the time. The transmission system is considered adequate for all projected firm transactions and significant amounts of economy energy transfers. Reactive reserve margins are expected to be adequate for all expected peak load conditions in all areas. Close attention to maintaining appropriate voltage levels is expected to prevent voltage problems.

While WECC has eight back-to-back direct current ties to the Eastern Interconnection with a combined transfer capability of almost 1,500 MW, only about 490 MW of net capacity imports are planned for the 2007/2008 winter period. The net non-simultaneous capacity imports for the 2006/2007 winter period were about 400 MW. It has been reported that the capacity imports have firm resource and associated firm transmission commitments.

Individual entities within the Western Interconnection 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 generation and transmission projects that may impact the interconnected system. These processes identify potential deliverability issues that may result in actions such as the implementation of system protection schemes designed to ensure deliverability and to mitigate possible adverse power system conditions.

Transmission projects for all of WECC's subregions that have been installed during the time from March 2007 – September 2007 or that are projected to come on line during the time period of October 2007 – February 2008 are indicated in the tables at the back of WECC's section[47].

Operational Issues

WECC does not expect major generating unit outages, transmission facility outages, or unusual operating conditions that would adversely impact reliable operations this winter. No environmental or regulatory restrictions have been reported that are expected to adversely impact reliability.

[46] http://www.wecc.biz/documents/library/OTC/2007-8_Winter_OTCPC_Approved%20Limits.pdf

[47] The region is currently reviewing the impacts of the recent fires in Southern California on the transmission system.

Other Items

The Northwest Power Pool has a publicly available document on its website[48] that addresses 2007/2008 winter conditions.

Subregions

Northwest Power Pool (NWPP) Area

The Northwest Power Pool 2006/2007 coincidental winter peak of 59,905 MW occurred on November 28, 2006. During the time of the November 2006 peak, the Power Pool weighted average temperature was 4° Fahrenheit below normal, which results in about 1,500 MW higher peak demand. Therefore, the Power Pool weather adjusted coincidental winter peak was 58,405 MW or 100 percent of the original forecast. The non-coincident capacity margin was 22.8 percent.

The 2007/2008 coincidental winter peak demand forecast for the Power Pool area of 60,000 MW is based on normal weather, reflects the prevailing economic climate, and has a 50 percent probability of not being exceeded. The Power Pool peak demand forecast includes approximately 525 MW of interruptible demand capability and load management. The aggregated sum of the individual balancing authorities' forecasts produces a higher forecast demand because of the inability to account for the diversity of loads among the various balancing authority areas.

The 2007/2008 Power Pool area generating capability is projected to be 83,000 MW, prior to adjusting for maintenance. In determining planning margin, one must further adjust both load and capability for a severe weather event. A severe weather event for the entire Power Pool area will add approximately 6,000 MW of load while at the same time reducing the capability by 7,000 MW. The estimated operating reserve requirement is approximately 5,000 MW. Accounting for the severe weather event and the operating reserve yields a planning margin of approximately 9.2 percent.

Under normal weather conditions, the Power Pool area does not anticipate dependence on imports from external areas during winter peak demand periods.

Resources — Over 60 percent of the Power Pool resource capability is from hydro generation. In addition, generation is produced from conventional thermal plants and miscellaneous resources, such as nonutility-owned gas-fired cogeneration or wind.

Hydro Capability — Northwest power planning is done by sub-area. Idaho, Nevada, Wyoming, Utah, British Columbia and Alberta individually optimize their resources to their demand. The Coordinated System (Oregon, Washington and Western Montana) coordinates 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 years). Critical water in the Coordinated System equates to approximately 11,000 average megawatts 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 megawatts.

[48] http://www.nwpp.org/publications.html

The Coordinated System hydro reservoirs refilled to approximately 94.1percent of the Energy Content Curve by July 31, 2007. 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 (winter) electric power generation, flood control, biological opinion requirements resulting from the Endangered Species Act, as well as special river operations for recreation, irrigation, navigation, and the refilling of the reservoirs each year. Anytime precipitation levels are below normal, balancing these interests becomes even more difficult. With the competition for the water, power operations for the 2007/2008 Winter must be effective and efficient. The goal is to manage all the competing requirements while refilling the reservoirs to the highest extent possible.

***Sustainable Hydro 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 capacity 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 expected sustainable capacity must be determined before establishing a representative capacity 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 upon the availability of water for hydro-electric generation.

The Power Pool has developed the expected 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 at least 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 most relative to the Northwest in the winter.

Thermal Generation — 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 winter peak period.

***Transmission* —** Constrained paths within the Power Pool area are known and operating studies modeling these constraints have been performed and operating procedures have been developed to assure safe and reliable operations.

The Northwest Operational Planning Study Group (NOPSG) coordinates seasonal inter-area and intra-area transmission transfer capability studies. Daily studies to determine transfer capabilities during planned outage conditions are coordinated by the operators of the individual operating paths.

***Transmission Facilities* —** No major transmission facility outages are scheduled for winter 2007/2008.

Operations — Balancing Authorities within the Power Pool use a fully automated system of sharing resources, when requested, to meet the NERC Disturbance Control Standard for loss of generation in the Pool area. The system has the ability to automatically move generation over a 2-Province, 8-State area while taking into consideration transmission constraints within the area. This system assures adequate resources are available over a broad area; an adequate response is delivered within the prescribed time; and the impact of the disturbance to internal as well as neighboring systems is mitigated.

The Northwest 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.

In the fall of 2000, the area developed an Emergency (ER) Response Process to address immediate power emergencies. The ER Team (ERT) remains in place and would be utilized 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 or imports of additional power from other areas outside of the Power Pool.

In view of the present overall power conditions, including the forecasted water condition, the area represented by the Power Pool is estimating that it will be able to meet firm loads including the required reserve. Should any resources be lost to the area beyond the required forced outage reserve margin and or loads are greater than expected as a result of extreme weather, the Power Pool area may have to look to alternatives which may include emergency measures to meet obligations.

California–Mexico Power Area

This is a summer-peaking area. The 2007/2008 winter peak demand forecast of 43,630 MW is 1.5 percent greater than last winter's actual peak demand of 43,006 MW and is 2.5 percent greater than last winter's forecast peak demand of 42,566 MW. The areas' 2006/2007 winter peak demand occurred during a period of generally normal to warmer than normal temperatures. The forecast peak demand includes 1,696 MW of interruptible demand and load management. The projected capacity margin for the peak month is 34.1 percent.

Although several major constrained transmission paths have been upgraded in recent years, path constraints still exist. Operating procedures are in place to manage any high loading conditions that may occur during the winter. Entities within the area report having no concerns with maintaining adequate reactive reserve margins.

All power plants in California are required to operate in accordance with strict air quality environmental 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 expected that environmental issues will have additional adverse impacts on resource adequacy within the area.

Rocky Mountain Power Area

The Rocky Mountain Power Area's (RMPA) peak demand may occur in either summer or winter. The 2007/2008 winter peak demand forecast of 9,807 MW is 4.9 percent greater than last winter's actual peak demand of 9,347 MW and is 2.1 percent greater than last winter's forecast peak demand of 9,604 MW. Last winter's peak demand was lower than expected due to warmer temperatures. The forecast peak demand includes 120 MW of interruptible demand and load management capability. The projected capacity margin for the peak month is 27.1 percent.

Hydro conditions for the 2007/2008 winter period are expected to be near normal and reservoir releases will be similar to last year. The Glen Canyon power plant is operating under environmental impact restrictions that limit water releases. The release limitations reduce peaking capability by about 450 MW, but under normal hydro conditions the plant is able to respond to short-term emergency conditions.

The transmission system is expected 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. Consequently, the WECC Unscheduled Flow Mitigation Procedure may be invoked on occasion this winter to provide line loading relief for these paths.

Arizona-New Mexico-Southern Nevada Power Area

This is a summer-peaking area. The 2007/2008 winter peak demand forecast of 19,351 MW is 1.2 percent above last winter's actual peak demand of 19,120 MW and is 6.6 percent greater than last winter's forecast peak demand of 18,146 MW. Last winter's peak demand was higher than expected due to cooler temperatures. The forecast for the area includes 282 MW of load management and interruptible demand capability. The projected capacity margin for the peak month is 45.6 percent, excluding 52 MW of transmission limited resources.

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 expected to be adequate throughout the area.

Fuel supplies are expected to be adequate to meet winter peak demand conditions. The physical gas commodity and pipelines that supply this area have proven very reliable. In addition, firm coal supply and transportation contracts are in place, and sufficient coal inventories are anticipated for the winter season.

WECC Scheduled Transmission Facility Additions, Retirements, & Re-ratings (230 kV and above) (March through September 2007)

Control Area or Company	Facility	Length (Miles)	Capacity (MVA)	Voltage (kV)	Type of Change (Action)	Expected Operating Date	Actual Operating Date
AZ-NM-SNV							
SRP	Anderson-Orme 230 kV Line		875 MVA	230 kV AC		5/2007	5/2007
SRP	Libert-Orme 230 kV Looping into Rudd		875 MVA	230 kV AC		5/2007	5/2007
SRP	Rudd 500/230 kV Transformer #4		598 MVA	500 kV AC		5/2007	5/2007
APS	Palm Valley 230 kV substation	14	1200 MVA	230 kV AC		6/2007	6/27/2007
CA-MX							
CFE	Xochimilco – Wisteria	2	388 MVA	230 kV AC		4/2007	6/18/2007
CFE	Xochimilco - Mexicali	2	388 MVA	230 kV AC		4/2007	6/22/2007
CISO (PG&E)	Henrietta-Gregg 230 kV Reconductoring (T-260A)	40	754 MVA	230 kV AC		5/2007	2/16/2007
CISO (PG&E)	Colgate 230/60 kV Transformer Capacity Increase (T314)		134 MVA	230/60 kV AC		3/2007	3/15/2007
CISO (SCE)	Valley Sub Serrano 500 kV Line from pos 6X to 7X			500 kV AC	Upgrade		3/24/2007
CISO (PG&E)	Bottle Rock Interconnection			230 kV AC	Upgrade		3/27/2007
CISO (SDGE)	Otay Mesa PPA Project (Miguel-Sycamore) – BP03191A	28	912 MVA	230 kV AC		5/2007	5/1/2007
CISO (SDGE)	Otay Mesa PPA Project(Miguel-Southbay-Oldtown) – BP03191B	20	912 MVA	230 kV AC		6/2007	5/11/2007
CISO (SDGE)	TL23011 Loop-in Palomar Energy Substation		797 MVA	230 kV AC	New		5/29/2007
CISO (PG&E)	Contra Costa 230/115 kV TB No.3		180 MVA	230 kV AC	Upgrade		5/31/2007
CISO (SDGE)	New Miguel 230kV Capacitors		2 x 63 MVAR	230 kV AC	New		6/01/2007
CISO (SCE)	Etiwanda – San Bernardino 230 kV Disc Upgrade			230 kV AC	Upgrade		6/01/2007
CISO (SCE)	Inland Empire Energy Project			500 kV AC	New		6/18/2007
CISO (SCE)	Valley Substation – Shunt Capacitor 1		165 MVAR	500 kV AC		6/2007	6/22/2007
CISO (SCE)	Valley Substation - Shunt Capacitor 2		165 MVAR	500 kV AC		6/2007	6/22/2007
CISO (PG&E)	Hicks-Metcalf 230kV Line Re-conductor			230 kV AC	Re-conductor		7/01/2007
CISO (SCE)	Rector SVC		200 MVAR	230 kV AC	New		7/11/2007
NWPP							
IPC	Midpoint Substation (Capacitor Bank - Shunt)		175 MVAr	345 kV AC		5/2007	3/2007
PAC(E)	Camp Williams – Mona #4	46	1163 MVA	345 kV AC		5/2007	4/2007
PAC(W)	Meridian – Lone Pine #1	5	424 MVA	230 kV AC	Re-conductor	5/2007	5/2007
NWMT	Three Rivers Substation		200 MVA	230 kV AC		5/2007	6/2007
IPC	Borah Substation (Capacitor Bank - Shunt)		175 MVAr	345 kV AC		5/2007	6/2007

Control Area or Company	Facility	Length (Miles)	Capacity (MVA)	Voltage (kV)	Type of Change (Action)	Expected Operating Date	Actual Operating Date
NWPP *(continued from previous page)*							
AESO	Benalto – AB – Shunt Capacitor Bank		110 A	240 kV DC		8/2007	6/2007
AESO	Jasper Terminal, Edmonton – AB – Shunt Capacitor Bank		110 A	240 kV DC		9/2007	
IPC	Borah – Hunt	70	550 MVA	230 kV AC		5/2007	7/2007
IPC	Copperfield - Series Reactor (20 ohm)		1200 A	230 kV AC		6/2007	7/2007
RMPA							
PSC	Peetz Logan-Pawnee 230kV Line	70	800 MVA	230 kV AC		9/2007	8/2007

Transmission Facilities Scheduled for Initial Service, Retirement, Re-ratings (230 kV and above) (October 2007 through February 2008)

Control Area or Company	Facility	Miles	Capacity (MVA)	Voltage (kV)	Type of Change	Projected Operating Date
AZ/NM/SNV						
-	-	-	-	-	-	-
CA/MX						
CISO (SCE)	Lewis – Vermont 230 kV Trans. Line – City of Anaheim	1.5	3.23	230	New	10/2007
CISO (PG&E)	Newark 230 kV bus Tie Upgrade			230	Upgrade	11/2007
CISO (PG&E)	Ravenswood Reactive Support		300	230	New	12/2007
CISO (SDGE)	San Luis Rey 230 kV rearrangement			230		12/2007
CISO (PG&E)	Eastshore – Replace Transformer Bank 1		420	230	Upgrade	12/2007
CISO (PG&E)	Metcalf-Monta Vista #1 and #2 230 kV Reconductoring (T-647A)	27	1714	230 / 60	Reconductoring	12/2007
CISO (SCE)	Barre 3A Transformer Replacement		280	230	Upgrade	12/2007
TID	Tracy-Westley #2, 230 kV Upgrade Westley 230 kV ring bus to a breaker and a half bus.	0.2	Summer 651 Winter 791	230	Re-terminate Add Breakers to Tracy & Westley	1/2008
TID	Westley 230/115 kV Two Transformers		167 + 167	230 / 115	New	1/2008
CISO (PG&E)	McCall Convert 115kV Bus to BAAH			230	Upgrade	2/2008
NWPP						
AVA	Benewah ID to Shawnee WA	60	797	230	New	12/2007
RMPA						
PSCO	Denver Terminal – Arapahoe 230kV Line	7	495	230	New	11/2007
PSCO	Cedar Creek-Keenesburg 230kV Line	72	414	230	New	12/2007
PRPA	Timberline – Harmony 230-kV line uprate	3	733	230	Re-conductor	12/2007
PSCO	Spruce – Smoky Hill 230-kV line uprate	10	800	230	Re-conductor	12/2007
PSCO	Pawnee-Smoky Hill – Daniels Park 230-kV line uprate	114	637	230	Tower raise / new switches	12/2007

Regional Description

WECC's 189 members represent the entire spectrum of organizations with an interest in the bulk power system. Serving an area of nearly 1.8 million square miles and 71 million people, it is the largest and most diverse of the eight NERC regional reliability organizations. The WECC region is spread over a wide geographic area with significant distances between load and generation areas. In addition, the northern portion of the region is winter peaking while the southern portion of the region is summer peaking. Consequently, transmission constraints are a significant factor affecting economic grid operation in the region. However, reliability in WECC is best examined at a subregional level. Additional information can be found on the WECC Web site (www.wecc.biz).

Abbreviations Used in This Report

AZ-NM-SNV	Arizona-New Mexico-Southern Nevada (Subregion of WECC)
CA-MX-US	California-Mexico (Subregion of WECC)
dc	Direct Current
DOE	U.S. Department of Energy
ECAR	East Central Area Reliability Coordination Agreement
EECP	Emergency Electric Curtailment Plan
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
FERC	U.S. Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
GHG	Greenhouse Gas
GRSP	Generation Reserve Sharing Pool
GTA	Greater Toronto Area
GWh	Gigawatthours
ICAP	Installed Capacity
IESO	Independent Electric System Operator (in Ontario)
IPSI	Integrated Power System Plan
IROL	Interconnection Reliability Operating Limit
ISO	Independent System Operator
ISO-NE	New England Independent System Operator
kV	Kilovolts (one thousand volts)
LFU	Load Forecast Uncertainty
LNG	Liquefied Natural Gas
LOLE	Loss of Load Expectation
LSE	Load-serving Entities
LTRA	Long-Term Reliability Assessment
MAAC	Mid-Atlantic Area Council
MAIN	Mid-America Interconnected Network, Inc.
MAPP	Mid-Continent Area Power Pool
MISO	Midwest Independent Transmission System Operator
MRO	Midwest Reliability Organization
MVA	Megavoltamperes
Mvar	Megavars
MW	Megawatts (millions of watts)
NERC	North American Electric Reliability Corporation
NIETC	National Interest Electric Transmission Corridor
NPCC	Northeast Power Coordinating Council
NWPP	Northwest Power Pool Area (subregion of WECC)
NYISO	New York Independent System Operator
OVEC	Ohio Valley Electric Corporation
PAR	Phase Angle Regulators

PC	NERC Planning Committee
PJM	PJM Interconnection
PRB	Powder River Basin
PRSG	Planned Reserve Sharing Group
RAS	Reliability Assessment Subcommittee of NERC Planning Committee
RCC	Reliability Coordinating Committee
RFC	ReliabilityFirst Corporation
RFP	Request For Proposal
RMPA	Rocky Mountain Power Area (subregion of WECC)
RMR	Reliability Must Run
RRS	Reliability Review Subcommittee
RTO	Regional Transmission Organization
SCR	Special Case Resources
SERC	Southeastern Electric Reliability Council
SOL	System Operating Limit
SPP	Southwest Power Pool
SPS	Special Protection System
THI	Temperature Humidity Index
TLR	Transmission Loading Relief
TVA	Tennessee Valley Authority
VACAR	Virginia and Carolinas (subregion of SERC)
WECC	Western Electricity Coordinating Council

Reliability Concepts Used in This Report

Available Capacity Margin — The difference between ***committed*** capacity resources and peak demand, expressed as a percentage of capacity resources.

Capacity Margin — Capacity that could be available to cover random factors such as forced outages of generating equipment, demand forecast errors, weather extremes, and capacity service schedule slippage.

Committed Capacity Resources — Generating capacity resources that exist, under construction, or planned that are considered available, deliverable, and committed to serve demand, plus the net of capacity purchases and sales.

Potential Capacity Margin — The difference between ***committed*** plus ***uncommitted*** capacity resources and peak demand, expressed as a percentage of capacity resources. This is the capacity that could be available to cover random factors such as forced outages of generating equipment, demand forecast errors, weather extremes, and capacity service schedule slippage.

Net Internal Demand — Projected total internal demand less interruptible demand and direct control demand-side management. The regions are not expected to reach their peak demand simultaneously. Demand served under liquidated damages contracts is included.

Net Capacity Resources **—** Net generating capacity resources (existing, under construction, or planned) considered available (net operable), deliverable, and committed to serve demand, plus the net of capacity purchases and sales.

Uncommitted Capacity Resources — Capacity resources that include one or more of the following:

- Generating resources that have not been contracted nor have legal or regulatory obligation to deliver at time of peak.
- Generating resources that do not have or do not plan to have firm transmission service reserved (or its equivalent) or capacity injection rights to deliver the expected output to load within the region.
- Generating resources that have not had a transmission study conducted to determine the level of deliverability.
- Generating resources that are designated as energy-only resources or have elected to be classified as energy-only resources.
- Transmission-constrained generating resources that have known physical deliverability limitations to load within the region.

How NERC Defines Bulk Power System Reliability

NERC defines the reliability[49] of the interconnected bulk power system in terms of two basic and functional aspects:

- **Adequacy** — The ability of the bulk power system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
- **Security** — The ability of the bulk power system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements from creditable contingencies.

Regarding Adequacy, system operators can and should take "controlled" actions or procedures to maintain a continual balance between supply and demand within a balancing area (formerly control area). These actions include:

- Public appeals.
- Interruptible demand — customer demand that, in accordance with contractual arrangements, can be interrupted by direct control of the system operator or by action of the customer at the direct request of the system operator.
- Voltage reductions (sometimes referred to as "brownouts" because incandescent lights will dim as voltage is lowered, sometimes as much as 5 percent).
- Rotating blackouts — the term "rotating" is used because each set of distribution feeders is interrupted for a limited time, typically 20–30 minutes, and then those feeders are put back in service and another set is interrupted, and so on, rotating the outages among individual feeders.

Under the heading of Security, 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. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.

What occurred in 1965 and again in 2003 in the northeast were uncontrolled cascading blackouts. What happened in the summer of 2000 in California, when supply was insufficient to meet all the demand, was a "rotating blackout" or controlled interruption of customer demand to maintain a balance with available supplies while maintaining the overall reliability of the interconnected system.

[49] NERC is reviewing the definition of reliability http://www.nerc.com/~members/OC_PC/ALR/

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