2006 SUMMER ASSESSMENT

Reliability of the Bulk Power System in North America

North American Electric Reliability Council

May 2006

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Ensuring Electric System Reliability

NERC's mission is to ensure that the bulk power system in North America is reliable, adequate, and secure. Since its formation in 1968, NERC has operated successfully as a self-regulatory organization, relying on reciprocity and the mutual self-interest of all those involved in the generation, transmission, and delivery of electricity in North America. NERC's members are the eight regional reliability councils, whose members account for virtually all electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico.

Peer Review Conducted in Preparation of This Report

The Reliability Assessment Subcommittee (RAS) of the NERC Planning Committee prepared the *2006 Summer Assessment* by conducting a peer review[1] of the data submitted by the eight NERC regional reliability councils (illustrated in Figure 1 on the next page) based on their member systems' projections as of March 24, 2006. Where possible, updates to the data have been incorporated through April 24, 2006. The report provides an assessment of the reliability and adequacy of the bulk power system in North America for the period of June 2006 through September 2006. NERC does not make projections or draw conclusions in this report regarding expected electricity prices for the summer.

In preparing its evaluation, NERC, through the subcommittee, also conducted a peer review of the individual regional self-assessments[2]. The RAS did not independently verify all of the information contained in the individual regional assessments. However, where conflicting or confusing information did arise, RAS independently verified the data. Summaries of the supporting data are contained in Tables 1a–1d and in Figures 2a–c, 3, 4a–c, 5, 6, and 7. Additional supporting documentation is available through the regional offices.

This assessment contains electricity supply and demand projections for June 2006 through September 2006 and is based on several assumptions:

- Weather will be normal.
- Economic activity will occur as assumed in the demand forecasts.
- Generating and transmission equipment will perform at average availability levels.
- Generating units that are undergoing planned outages will return to service as scheduled.
- Generating unit and transmission additions and upgrades will be in service as scheduled.
- Demand reductions expected from direct control load management and interruptible demand contracts will be effective, if and when they are needed.
- Electricity transfers will occur as projected.

While RAS prepares the overall seasonal assessment, it is the task of the individual regions to ensure that their members comply with NERC reliability and have procedures in place to deal with conditions that might be outside the bounds of the assumptions underlying this report.

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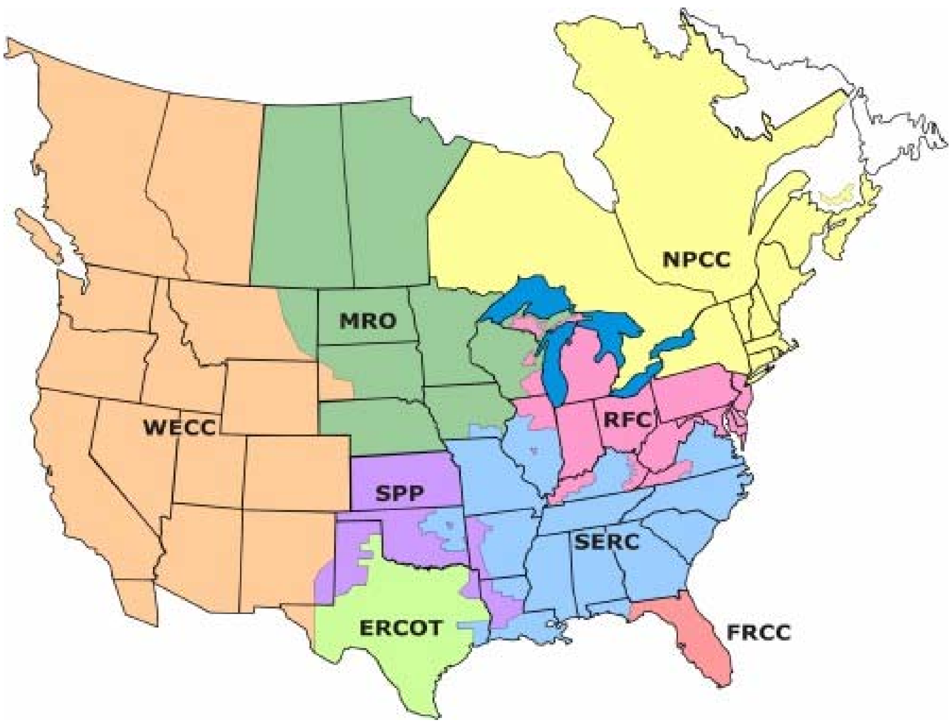
[1] See page 69 for a description of the peer review process used by the RAS in the preparation of the reliability assessments.
[2] Beginning on page 17.

Figure 1: NERC Regional Reliability Councils



ERCOT
Electric Reliability Council of Texas

FRCC
Florida Reliability Coordinating Council

MRO
Midwest Reliability Organization

NPCC
Northeast Power Coordinating Council

RFC
Reliability*First* Corporation

SERC
Southeastern Electric Reliability Council

SPP
Southwest Power Pool

WECC
Western Electricity Coordinating Council

Note: ECAR, MAAC, and portions of MAIN completed their consolidation into a single regional reliability council, Reliability*First* Corporation, which began operations on January 1, 2006. The planning and operational policies and procedures of the new council, as they are developed, will supersede the individual policies and procedures of the previous three regions.

Assessment Summary

Limitations in Southern California and Southwestern Connecticut

Southern California — Southern California will have smaller capacity margins than most other areas in North America this summer. This area relies on significant amounts of imported power, which will keep transmission lines into southern California heavily loaded much of the time. Although transmission capability into the area has been increased by 400 MW since last summer, some constraints remain.

Extreme weather conditions, which can significantly increase demand, or the sudden unplanned loss of large amounts of resources, would require the California Independent System Operator (CAISO) to implement demand response procedures and curtail interruptible loads to maintain required operating reserves. If extreme weather and loss of resources occur simultaneously, the CAISO may also need to shed firm load to balance resources and demand.

Southwestern Connecticut — While electricity supplies are forecast to be adequate overall for New England, transmission constraints may hinder electricity delivery into and within southwestern Connecticut, and have the potential to create reliability problems. New England utilities expect to complete several transmission projects during 2006–2009 that will alleviate some of these constraints. In the meantime, utilities will rely on a combination of new generating units, demand response resources, and conservation and load management projects totaling approximately 250 MW to provide emergency support during the summer of 2006.

Capacity Margins Lower Than Last Summer in Most Regions; Extreme Weather Presents Risk

Although North American electricity resources will increase 1.4% over last summer, capacity margins (the amount of installed generating capacity above peak demand) are decreasing in most regions, except for SERC and NPCC (see Figures 2a–2c on pages 4 and 5). While generating resources and transmission capability will be adequate to serve the demand for electricity for this summer under normal weather conditions, extreme weather continues to present a significant reliability risk in those areas with lower margins.

For the peak month of July 2006, the Northwest Power Pool and Arizona-New Mexico-southern Nevada subregions of WECC, and the Entergy and Gateway subregions of SERC are projected to have the highest overall capacity margins, while lowest capacity margins are projected in the Ontario and New England subregions of NPCC, the MRO region, and the TVA subregion of SERC (see Table 1b). The overall U.S. and Canada capacity margins for July 2006 are projected to be 17% and 23.3%, respectively.

Natural gas-fired units comprise more than 8,000 MW of the approximately 11,800 MW of generation being added this summer. Other large amounts of new generation include more than 1,800 MW of wind, 500 MW of coal-fired, and 300 MW of oil-fired generation. WECC is projected to add nearly 4,000 MW of natural gas-fired units, while NPCC, RFC, and SERC will each add more than 1,000 MW of natural gas-fired units. The majority of the new wind generation, 1,100 MW, is scheduled to be added in WECC.

Nearly 1,200 miles of new or upgraded transmission lines will be added to North America, with more than 400 miles in SERC, and more than 100 miles in each of MRO, NPCC, RFC, and WECC.

Figure 2a: Change in U.S. Subregional Projected Capacity Margins From 2005 to 2006

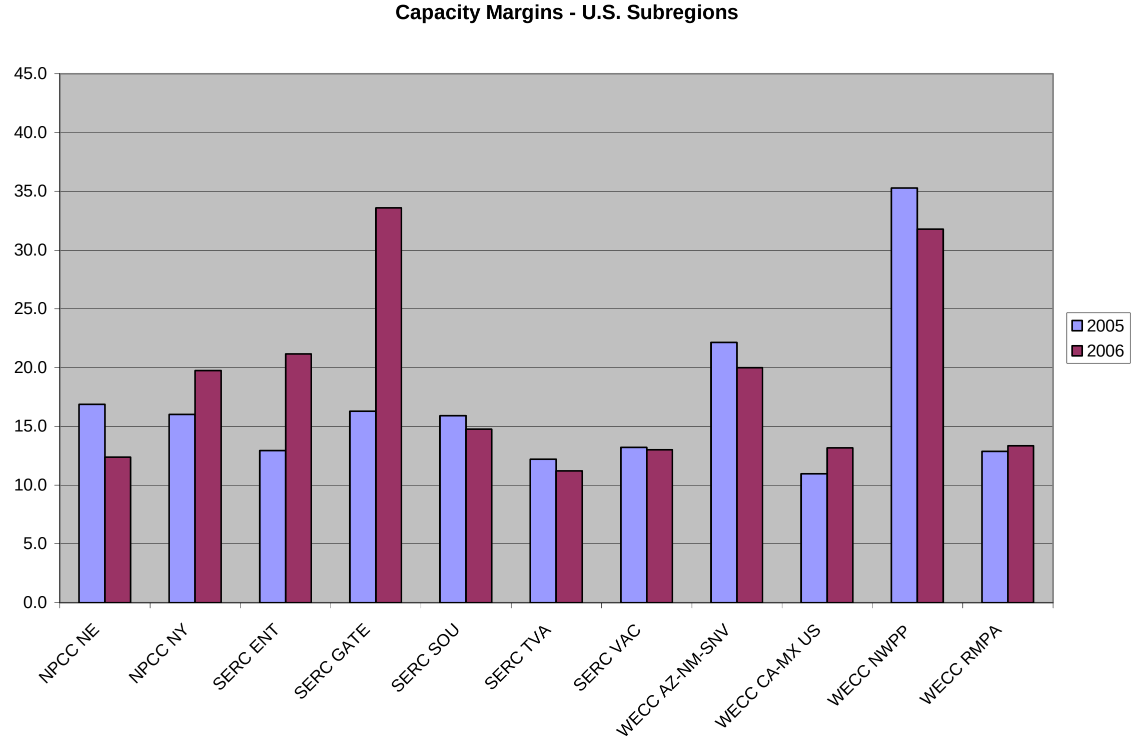
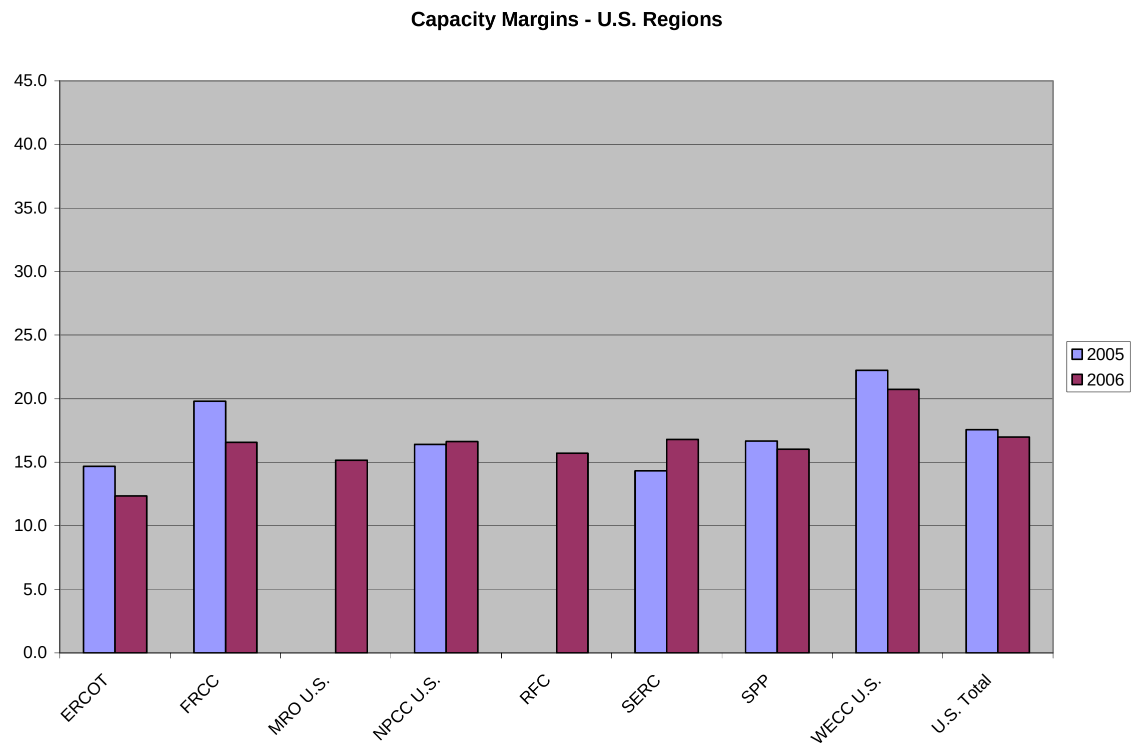
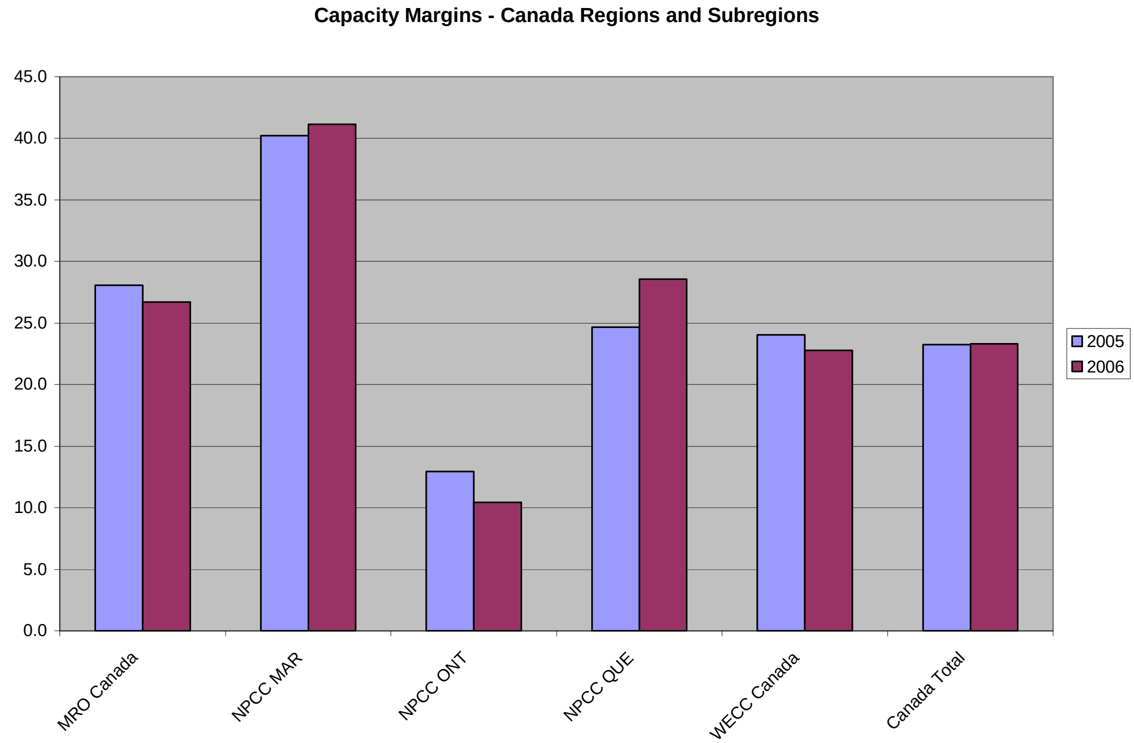


Figure 2b: Change in U.S. Regional Projected Capacity Margins From 2005 to 2006



Note: Due to the unavailability of data, RFC will not have a capacity margin change. Similarly, MRO's data was unavailable due to movement of members related to the formation of RFC. NERC plans to have these data and totals for all regions next year.

Figure 2c: Change in Canadian Projected Capacity Margins From 2005 to 2006



Reliability Improved in Boston and Ontario

***Boston* —** Two new projects will increase transfer capability into the Boston, Massachusetts area. Completion of the NSTAR 345-kV Transmission Reliability Project, planned for this summer, will provide the ability to transfer approximately 24% more power into the Boston load pocket and help to alleviate some of the past reliability concerns.

***Ontario* —** Ontario forecasts that there will be periods this summer when generating resources within Ontario will not be sufficient to meet projected demand, and the province will need to rely on electricity imports from other areas to maintain reliability. The Independent Electricity System Operator (IESO) is in the process of implementing a day-ahead commitment process to address this issue. Ontario also added 632 MW of generating capacity. Transmission capability into the greater Toronto area has been improved with the addition of a second autotransformer and shunt capacitor and an increase in the ratings on other autotransformers. The situation has also improved since last summer because the IESO implemented a number of emergency control actions. In addition, demand management of Ontario resources will be increased.

Coal Delivery Limits Continue

***Powder River Basin (PRB)* —** Last year, railroad track damage due to flooding and derailments limited delivery of coal from the PRB (north-central Wyoming and southeast Montana area) to a number of generating plants. The railroads have taken part of the line out of service as they undercut and replace the ballast; this project is expected to be completed by the end of 2006.

PRB deliveries are increasing, but not enough to restore coal inventories to pre-curtailment levels. Coal delivery limitations do not appear to present a reliability problem for this summer. However, some utilities will need to purchase electricity or use alternate fuels to conserve their coal supplies to ensure that the coal generating units will be available at peak. If coal delivery problems worsen, the ability of some entities to continue to meet electricity demand might be reduced.

NERC has placed the PRB issue on its "Watch List" and will continue to closely monitor developments, both for the coming summer and for the longer term.

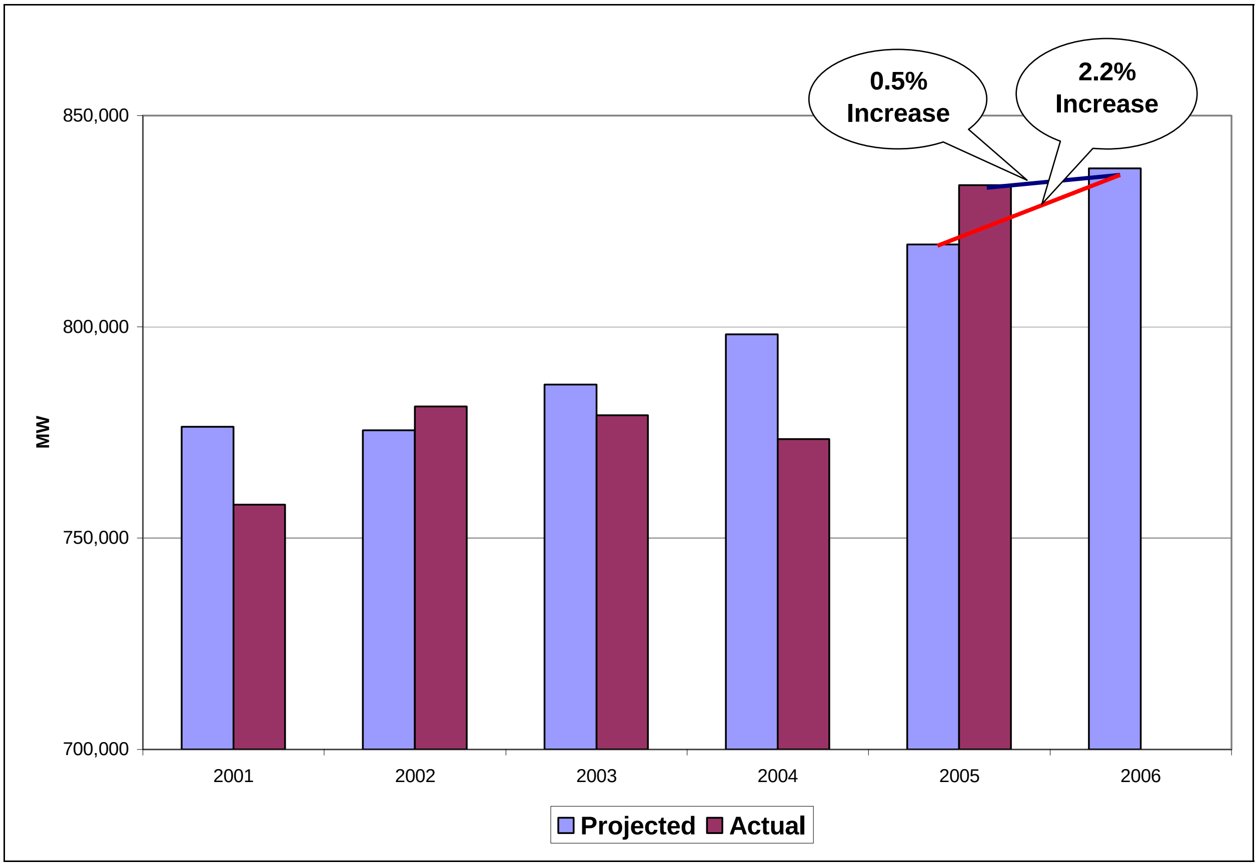
Potential Fuel Impacts From Summer Hurricanes

Experts have predicted another active hurricane season, which could periodically curtail Gulf of Mexico production of natural gas and oil. Although fuel deliverability problems are possible for limited periods of time due to hurricanes in some areas, the immediate impact will likely be economic as some production is shifted to generating units using alternative fuel(s). Secondary impacts could involve changes in emission levels and increased deliveries from alternate fuel suppliers. Regions cannot predict whether and to what extent weather extremes such as tropical disturbances may affect the fuel supply infrastructure or cause fuel delivery problems, but will take steps to mitigate the impact of those types of events.

Peak Demand Continues to Grow

***North America* —** This summer's projected peak demand is 0.5% higher than last summer's actual demand. Last summer's actual demand, which occurred during above-average temperatures in most regions, exceeded projections by about 1.7% (see graph below). Demand projections are based upon historical average weather data, while actual demand reflects actual weather conditions. The demand projections are created by aggregating regions' member demand forecasts, which use different load forecasting methodologies.

Figure 3: Year-to-Year Comparison of Summer Projected and Actual Demand Growth



Other Regional Highlights

Although the situations below bear watching, NERC does not expect them to pose serious problems for or threaten overall reliability. More details are contained in the regional sections of this report.

ERCOT Relieves Transmission Constraints — Approximately 67 miles of 345-kV transmission lines along with seven new 345-kV autotransformers are scheduled for completion prior to the summer of 2006. Transmission owners in ERCOT plan to invest almost $1 billion in transmission upgrades throughout this year. One significant transmission addition expected to be in place prior to the summer, the Nelson Sharpe 345-kV substation and 345/138-kV autotransformer, will relieve constraints in the Corpus Christi area and enable ERCOT to terminate a reliability must run (RMR) contract for generation in the area. Although projected available resources this summer will meet ERCOT's adequacy criteria, they are expected to be close to the minimums required by the criteria. Events such as an extremely hot summer that result in demand levels significantly above forecast, higher than normal unit forced outage rates, or financial difficulties of some generation owners that may make it difficult for them to obtain fuel from suppliers, are all risk factors mitigated by ERCOT's adequacy criteria when considered alone. However, an unanticipated combination of these risk factors could result in inadequate supply.

FRCC Increases Reliance on Natural Gas — Due to the growing interdependence of generating capacity and natural gas, FRCC has undertaken initiatives to increase coordination among natural gas suppliers and generators within the region. 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.

MRO Deals With Seams — The MRO region encompasses numerous operational seams, including market-to-market (Midwest ISO to PJM), market-to-nonmarket (Midwest ISO to MAPP Regional Transmission Group), and U.S. market-to-Canadian province (Midwest ISO to Manitoba Hydro) seams. System operation and reliability coordination on each side of a seam is often conducted differently, requiring close coordination and communication. The establishment of joint operating agreements and seams operating agreements for the purpose of real-time and projected data transfer has facilitated coordination and communication. However, transmission loading relief (TLR) avoidance and improvements in next-hour projections will be a top priority for the summer of 2006 to maintain operating reliability.

NPCC Cautions About Extreme Weather Conditions — A widespread and prolonged heat wave with high humidity and near record temperatures may require the implementation of established operating procedures and programs to keep electricity supply and demand in balance. Portions of New England and New York could experience a very limited number of times when the implementation of interruptible power contracts, voltage reductions, and/or reductions in reserve requirements may be required.

Should other severe conditions materialize, such as reductions in planned resources, delays of expected transmission projects, and/or additional transmission limitations into NPCC coincident with higher than expected demand, the use of these operating procedures would more likely be required in Boston, Massachusetts, southwestern Connecticut, and, to a lesser extent, in New York City and Long Island, New York.

RFC Adds a Major Transmission Line — American Electric Power's Wyoming-Jacksons Ferry 765-kV line, which is scheduled for completion during June 2006, will reduce the risks of potential widespread interruptions that in the past could result from extra-high voltage line outages overloading the stability-limited Kanawha-Matt Funk 345-kV circuit. Complex operating procedures were previously used to mitigate this contingency.

SERC Adjusts to Katrina Impacts — The demand and energy data for the SERC region, specifically the Entergy and Southern subregions, reflect the reduction and redistribution of loads due to Hurricane Katrina. Entergy estimates that the area surrounding the Hurricane Katrina impact zone will experience loading above the level measured in 2005 due to the influx of people seeking short-term accommodations while awaiting the redevelopment of the impacted zones. Entergy expects that the demand increases in these areas will not impact regional reliability for the coming season. Several substations continue to operate in a functionally and capacity limited state in the impacted zone. In addition, four substations and four transmission lines remain out of service within the same area. Entergy expects that these out-of-service facilities will not impact regional reliability for the coming season.

SPP Addresses a Load Pocket — Central Louisiana Electric Company (CLECO) and Entergy have completed installation of a 500/230-kV transformer at Wells that now provides better reliability for the Acadiana load pocket. Additional studies are being performed jointly with CLECO, Lafayette Utilities System, and Entergy to provide additional resources into this load pocket.

Capacity Fuel Mix

The regional capacity fuel mix charts, shown as a comparative percentage of regional generating capacity, illustrate each region's relative dependence on various fuels for its reported generating capacity. The charts below for the United States, Canada, and total NERC, and for each region beginning on page 17, are based on the most recent data available in NERC's *Electricity Supply and Demand* database.

Figure 4a: U.S. Capacity Fuel Mix

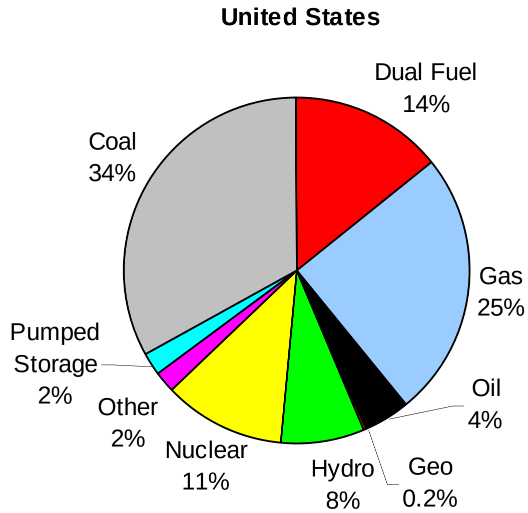


Figure 4b: Canadian Capacity Fuel Mix

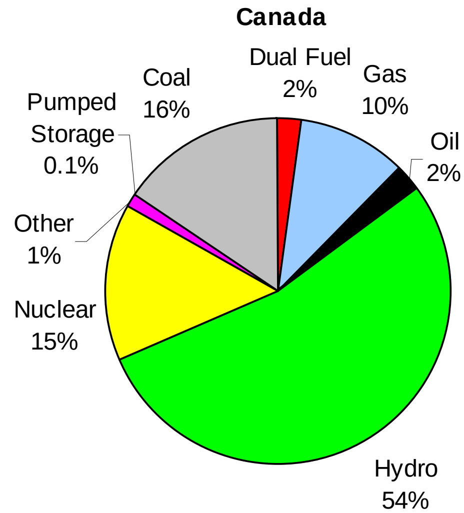
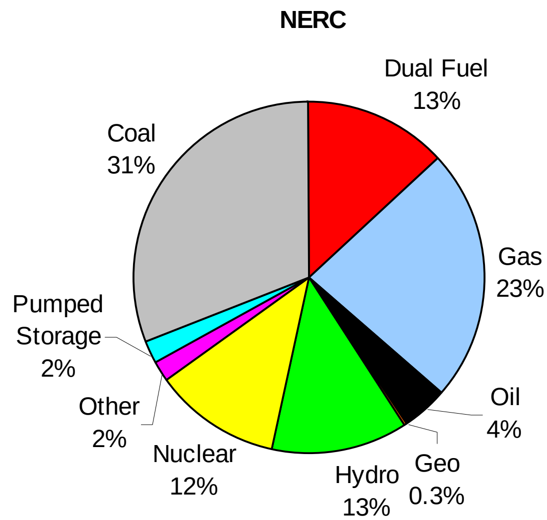


Figure 4c: NERC Capacity Fuel Mix



Summer 2006 Resources[3]

A compilation of demand and resources for the 2006 summer as well as estimated capacity margins are contained in Tables 1a–d on the following pages. The margins shown in Tables 1a–d do not reflect potential fuel supply problems or hydro limitations.

[3] See notes to tables 1a, 1b, 1c, and 1d on page 14.

Table 1a: Estimated June 2006 Summer Resources, Demands, and Margins

June 2006	Net Internal Demand (MW)	Net Capacity Resources (MW)	Uncommitted Resources (MW)	Available Capacity Margin W/O Uncommitted (%)	Potential Capacity Margin With Uncommitted (%)
United States					
ERCOT	54,757	68,209	0	19.7	19.7
FRCC	41,254	51,193	1,150	19.4	21.2
MRO	37,369	44,933	45	16.8	16.9
NPCC	57,101	71,983	0	20.7	20.7
New England	23,806	30,499	0	21.9	21.9
New York	33,295	41,484	0	19.7	19.7
RFC	176,300	220,373	7,300	20.0	22.6
SERC	169,215	222,049	32,457	23.8	33.5
Entergy	24,397	34,953	16,602	30.2	52.7
Gateway	15,571	26,074	2,341	40.3	45.2
Southern	43,590	55,958	5,547	22.1	29.1
TVA	30,268	36,807	3,315	17.8	24.6
VACAR	55,389	68,257	4,652	18.9	24.0
SPP	37,622	48,379	7,652	22.2	32.9
WECC	119,630	158,827	0	24.7	24.7
AZ-NM-SNV	25,985	34,649	0	25.0	25.0
CA-MX US	50,549	60,772	0	16.8	16.8
NWPP	33,030	51,121	0	35.4	35.4
RMPA	10,066	12,285	0	18.1	18.1
Total-U.S.	**693,248**	**885,946**	**48,604**	**21.8**	**25.8**
Canada					
MRO	5,415	7,584	0	28.6	28.6
NPCC	47,982	61,986	0	22.6	22.6
Maritimes	3,153	5,207	0	39.4	39.4
Ontario	24,292	27,930	0	13.0	13.0
Quebec	20,537	28,849	0	28.8	28.8
WECC	16,548	20,685	0	20.0	20.0
Total-Canada	**69,945**	**90,255**	**0**	**22.5**	**22.5**
Mexico					
WECC CA-Mex	1,818	2,356	0	22.8	22.8
Total-NERC	**765,011**	**978,557**	**48,604**	**21.8**	**25.5**

Reserve margin calculations can be found in the summary table at the beginning of each regional self-assessment section.

Table 1b: Estimated July 2006 Summer Resources, Demands, and Margins

July 2006	Net Internal Demand (MW)	Net Capacity Resources (MW)	Uncommitted Resources (MW)	Available Capacity Margin W/O Uncommitted (%)	Potential Capacity Margin With Uncommitted (%)
United States					
ERCOT	58,052	68,889	0	15.7	15.7
FRCC	42,288	51,243	1,150	17.5	19.3
MRO	39,870	45,955	45	13.2	13.3
NPCC	60,006	71,972	0	16.6	16.6
New England	26,711	30,488	0	12.4	12.4
New York	33,295	41,484	0	19.7	19.7
RFC	187,500	222,395	7,300	15.7	18.4
SERC	183,464	221,564	32,465	17.2	27.8
Entergy	26,354	34,440	16,602	23.5	48.4
Gateway	17,286	26,022	2,341	33.6	39.1
Southern	47,700	55,958	5,555	14.8	22.5
TVA	32,677	36,807	3,315	11.2	18.6
VACAR	59,447	68,337	4,652	13.0	18.6
SPP	40,288	48,379	7,652	16.7	28.1
WECC	128,629	162,224	0	20.7	20.7
AZ-NM-SNV	28,350	35,440	0	20.0	20.0
CA-MX US	54,240	62,747	0	13.6	13.6
NWPP	34,932	51,220	0	31.8	31.8
RMPA	11,107	12,817	0	13.3	13.3
Total-U.S.	**740,097**	**892,621**	**48,612**	**17.1**	**21.4**
Canada					
MRO	5,416	7,578	0	28.5	28.5
NPCC	49,096	63,665	0	22.9	22.9
Maritimes	3,051	5,436	0	43.9	43.9
Ontario	25,139	28,072	0	10.4	10.4
Quebec	20,906	30,157	0	30.7	30.7
WECC	16,966	21,975	0	22.8	22.8
Total-Canada	**71,478**	**93,218**	**0**	**23.3**	**23.3**
Mexico					
WECC CA-Mex	1,913	2,355	0	18.8	18.8
Total-NERC	**813,488**	**988,194**	**48,612**	**17.7**	**21.5**

Reserve margin calculations can be found in the summary table at the beginning of each regional self-assessment section.

Table 1c: Estimated August 2006 Summer Resources, Demands, and Margins

August 2006	Net Internal Demand (MW)	Net Capacity Resources (MW)	Uncommitted Resources (MW)	Available Capacity Margin W/O Uncommitted (%)	Potential Capacity Margin With Uncommitted (%)
United States					
ERCOT	60,506	69,030	0	12.3	12.3
FRCC	42,761	51,247	1,150	16.6	18.4
MRO	38,980	45,952	45	15.2	15.3
NPCC	60,006	71,883	0	16.5	16.5
New England	26,711	30,399	0	12.1	12.1
New York	33,295	41,484	0	19.7	19.7
RFC	184,400	222,392	7,300	17.1	19.7
SERC	181,632	221,551	32,473	18.0	28.5
Entergy	27,123	34,408	16,602	21.2	46.8
Gateway	16,704	26,034	2,341	35.8	41.1
Southern	47,257	55,958	5,563	15.5	23.2
TVA	31,870	36,807	3,315	13.4	20.6
VACAR	58,678	68,344	4,652	14.1	19.6
SPP	40,631	48,379	7,652	16.0	27.5
WECC	127,940	162,023	0	21.0	21.0
AZ-NM-SNV	27,782	35,618	0	22.0	22.0
CA-MX US	55,010	63,358	0	13.2	13.2
NWPP	34,493	50,410	0	31.6	31.6
RMPA	10,655	12,637	0	15.7	15.7
Total-U.S.	**736,856**	**892,457**	**48,620**	**17.4**	**21.7**
Canada					
MRO	5,585	7,622	0	26.7	26.7
NPCC	48,598	63,118	0	23.0	23.0
Maritimes	3,038	5,641	0	46.1	46.1
Ontario	24,502	28,000	0	12.5	12.5
Quebec	21,058	29,477	0	28.6	28.6
WECC	16,876	22,234	0	24.1	24.1
Total-Canada	**71,059**	**92,974**	**0**	**23.6**	**23.6**
Mexico					
WECC CA-Mex	1,965	2,355	0	16.6	16.6
Total-NERC	**809,880**	**987,786**	**48,620**	**18.0**	**21.9**

Reserve margin calculations can be found in the summary table at the beginning of each regional self-assessment section.

Table 1d: Estimated September 2006 Summer Resources, Demands, and Margins

September 2006	Net Internal Demand (MW)	Net Capacity Resources (MW)	Uncommitted Resources (MW)	Available Capacity Margin W/O Uncommitted (%)	Potential Capacity Margin With Uncommitted (%)
United States					
ERCOT	48,348	66,387	0	27.2	27.2
FRCC	41,323	51,143	1,150	19.2	21.0
MRO	35,888	46,134	45	22.2	22.3
NPCC	52,399	70,324	0	25.5	25.5
New England	21,846	29,398	0	25.7	25.7
New York	30,553	40,926	0	25.3	25.3
RFC	160,700	220,479	7,300	27.1	29.4
SERC	165,776	221,334	32,481	25.1	34.7
Entergy	24,138	34,383	16,602	29.8	52.7
Gateway	15,144	26,094	2,341	42.0	46.7
Southern	43,119	55,958	5,571	22.9	29.9
TVA	30,536	36,807	3,315	17.0	23.9
VACAR	52,839	68,092	4,652	22.4	27.4
SPP	37,259	48,379	7,652	23.0	33.5
WECC	117,811	158,003	0	25.4	25.4
AZ-NM-SNV	25,731	35,172	0	26.8	26.8
CA-MX US	51,022	60,518	0	15.7	15.7
NWPP	31,465	50,143	0	37.2	37.2
RMPA	9,593	12,170	0	21.2	21.2
Total-U.S.	**659,504**	**882,183**	**48,628**	**25.2**	**29.1**
Canada					
MRO	5,306	7,650	0	30.6	30.6
NPCC	47,504	60,978	0	22.1	22.1
Maritimes	3,192	5,422	0	41.1	41.1
Ontario	23,262	26,235	0	11.3	11.3
Quebec	21,050	29,321	0	28.2	28.2
WECC	16,591	21,718	0	23.6	23.6
Total-Canada	**69,401**	**90,346**	**0**	**23.2**	**23.2**
Mexico					
WECC CA-Mex	1,931	2,355	0	18.0	18.0
Total-NERC	**730,836**	**974,884**	**48,628**	**25.0**	**28.6**

Reserve margin calculations can be found in the summary table at the beginning of each regional self-assessment section.

Notes to Tables 1a, 1b, 1c, and 1d

***Net Internal Demand* —** Projected peak hour demand for the given month, including standby demand, less the sum of direct control load management and interruptible demands. The regions are not expected to reach their peak demands simultaneously. Demand served under liquidated damages contracts is included.

***Net Capacity Resources* —** Existing available generating capacity committed to serving demand, plus new units scheduled for service by the given month, plus the net of firm capacity purchases and sales, does not reflect potential fuel supply problems or hydro limitations.

***Uncommitted Resources* —** Generating resources that are built or expected to be in operation, but are not counted towards capacity margin and reserve margin calculations.

Uncommitted resources may 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

***Available Capacity Margin* —** The difference between net capacity resources (available committed resources) and net internal demand, expressed as a percentage of net capacity resources. Variations from capacity margins in regional tables may exist due to differences in reporting methods for purchases and sales.

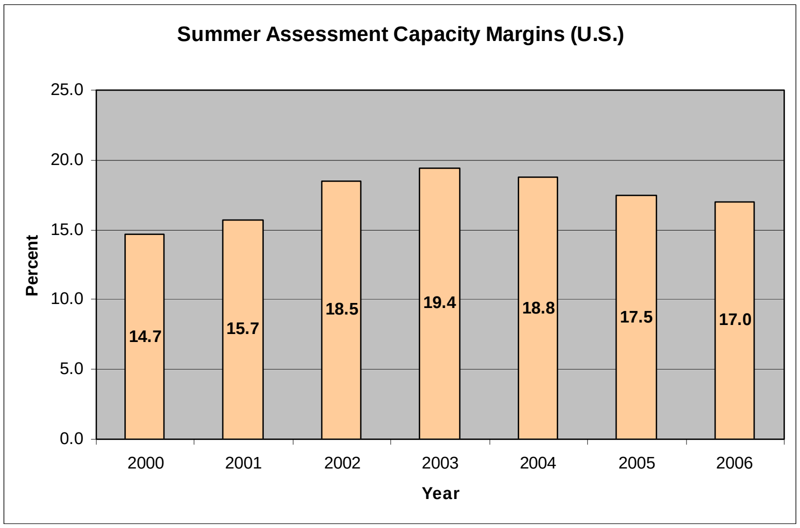
***Potential Capacity Margin* —** The difference between total potential resources and net internal demand, expressed as a percentage of total potential resources. This is the capacity that could be available to cover random factors such as forced outages of generating equipment, demand forecast errors, weather extremes, and capacity service schedule slippage. Variations from capacity margins in regional tables may exist due to differences in reporting methods for purchases and sales.

***WECC CA-MEX* —** Represents only the northern portion of the Baja California Norte, Mexico, electric system that is interconnected with the United States.

Selected Reliability Trends

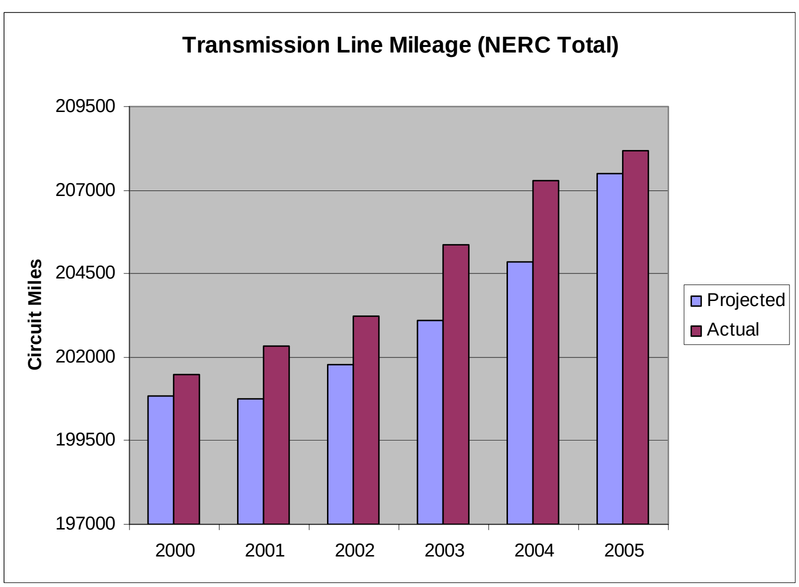
The Reliability Assessment Program will be instituting a process to highlight various indicators of reliability performance trends. Below are three indicators based on data extracted from NERC reliability assessment reports.

Figure 5: 2000 to 2006 U.S. Capacity Margins



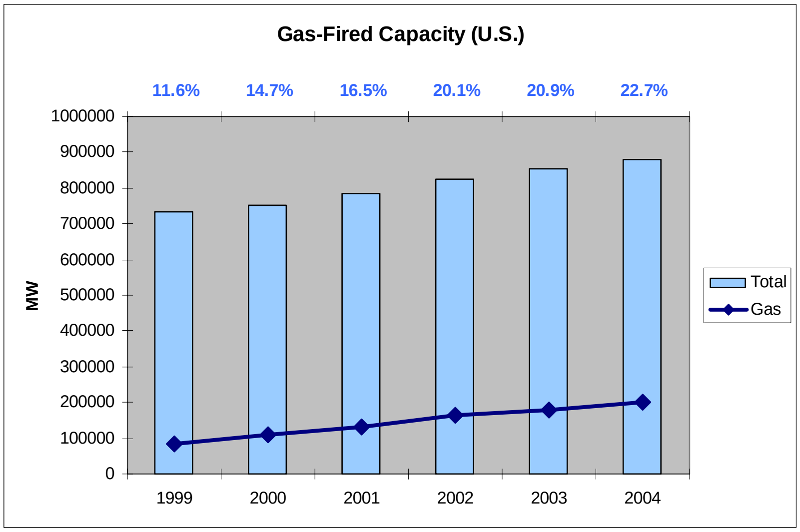
NERC's Summer Assessment report includes the projected capacity margins by region for the summer months. Projected summer margins in the United States rose from a low in the summer of 2000 to a high in the summer of 2003, then declined through the summer of 2006. While regional margins vary from the U.S. average, the downward trend in U.S. margins over the last four years indicate a general slowing of capacity additions relative to projected demand growth. NERC will monitor this trend closely and identify in its seasonal assessment reports any areas that are projected to have less than adequate margins.

Figure 6: Increase in Transmission Line Mileage



NERC includes in its *Electricity Supply & Demand* report the total circuit miles of existing transmission lines 230 kV and above, plus projections of transmission line additions for the following five years. Over the last six years, the actual transmission line mileage has exceeded what had been projected five years earlier. While this is a positive trend, NERC is still concerned that the average annual growth rate of transmission line circuit mileage is only 0.66%, which is well below the growth in electricity demand and capacity.

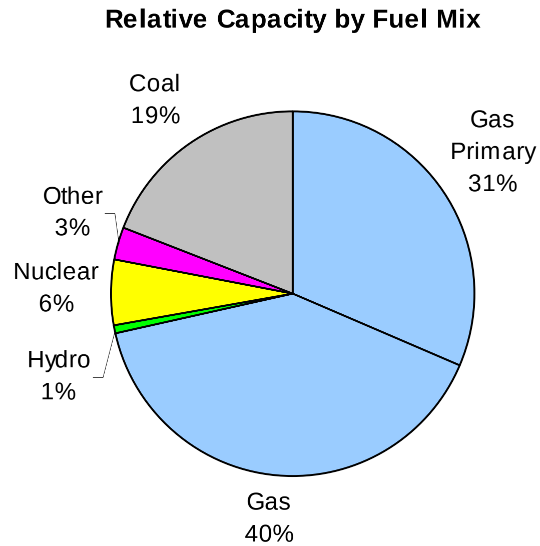
Figure 7: Increase in U.S. Gas-fired Capacity



NERC has continued to highlight in its reliability assessment reports the increased dependence on natural gas for electricity generation. Over the last six years, the fraction of U.S. generating capacity that uses natural gas as its primary fuel source has nearly doubled, reaching almost 23% of total installed capacity. Regional dependence on natural gas varies widely. NERC will continue to follow this trend and evaluate the risk of electricity supply disruptions due to gas supply and delivery disruptions.

Regional Self-Assessments
ERCOT

Projected Total Internal Demand	61,656	MW
Interruptible Demand & DSM	1,150	MW
Projected Net Internal Demand	60,506	MW
Last Summer's Peak Demand	60,210	MW
Change	2.4	%
All-Time Summer Peak Demand	60,210	MW
Deliverable Internal Capacity	69,152	MW
Projected Purchases	40	MW
Projected Sales	162	MW
Net Capacity Resources	69,030	MW
Capacity Margin	12.3	%
Reserve Margin	14.1	%
With Uncommitted Resources		
Total Potential Resources	69,030	MW
Capacity Margin	12.3	%
Reserve Margin	14.1	%



Demand

The Electric Reliability Council of Texas's (ERCOT) 2006 summer peak demand forecast of 61,656 MW is based on a set of econometric models that project demands for each weather zone in ERCOT as a function of economic factors and weather variables. This forecast is an increase of 2.4% from the 2005 actual peak demand of 60,210 MW, which is also ERCOT's all-time peak demand, and an increase of 3.3% from the 2005 forecast of 59,702 MW. This increase is due to a change in forecast method and the strong performance of the Texas economy. The forecast reflects the expectation of continuing economic and population growth in Texas and normal summer temperatures. The projected sale of 162 MW reflects a transfer of this capacity to SPP, due to SPP members' ownership of that amount of capacity of a power plant located in ERCOT. Interruptible loads typically result in 1,150 MW available through ERCOT's ancillary services market; whereas, the ERCOT retail market may also contain additional amounts of load management that cannot be quantified.

Demand Sensitivity Analysis

ERCOT's peak demand forecasts are based on statistical normal temperatures. Unseasonably hotter or cooler weather can result in actual demands above or below the forecast value. The ERCOT reserve margin requirement of 12.5% (equivalent to an 11% capacity margin) was established to accommodate this demand variation along with the potential of unexpected limited generating unit forced outages.

The analysis of variability in demand and weather volatility was performed with a system forecasting model that runs a Monte Carlo simulation of a median weather profile and a 90th percentile profile forecast using extreme weather and calendar variables. This analysis resulted in a high forecast of 65,443 MW.

Energy

For 2006, ERCOT is projecting an energy forecast of 305,505 GWh. This represents a forecast which is 2.1% higher than the 2005 actual of 299,223 GWh and 3.3% above the 2005 forecast of 295,653 GWh. This increase is due to a change in forecast method and the performance of the Texas economy. The 2006 forecast was developed by weather zones and aggregated by summing across all zones; whereas, the forecast in 2005 was based on ERCOT total system demand data. The recent performance of the economy for Texas shows that it is in a recovery period and has improved since the beginning of 2005, with the long-term economic outlook for Texas showing an expanding economy for the next ten years.

Resources

The projected capacity margin at peak, according to the NERC-requested calculation method, for this assessment is 12.3%. However, the capacity margin calculated according to the ERCOT regional prescribed calculation is 14.5%, which is above the corresponding regional minimum capacity margin requirement of 11% (corresponding to a 12.5% reserve margin). The main differences between the calculations are the inclusion in the ERCOT calculation of capacity that can be switched between ERCOT and SPP (unless those units' owners have indicated they will not be available to ERCOT) and including half of the dc tie capability in the regional calculation. The actual capacity margin during the peak hour for 2005 was 10% according to the NERC calculation method. The increase in capacity margin forecast for 2006 is due to a 3,500 MW increase in net capacity resources since 2005 due to new generation capacity added during the year and some capacity being returned from mothball status.

ERCOT has dc interconnections with both SPP and Mexico's Comision Federal de Electricidad (CFE). These tie capabilities total 820 MW with SPP and 36 MW with CFE. Entities within ERCOT have contracts to purchase 40 MW from SPP via the dc ties; whereas, entities within SPP can call on 162 MW of capacity in ERCOT (it is classified as a capacity sale from ERCOT as previously mentioned). In addition, 1,260 MW of generation capacity located in SPP and not counted in ERCOT's capacity resources for this assessment has the physical capability of switching to ERCOT. This generation has historically been connected into the ERCOT grid.

Approximately 500 MW of new generation capacity, including 380 MW of wind generation (of which 2.9% of nameplate capacity is counted in reserve calculations), is expected to commence commercial operation before the summer peak in 2006. This added capacity, along with additions last winter, and units being taken in and out of mothball status, result in a net increase in capacity of about 400 MW from last summer. Almost 7,000 MW of existing generation in ERCOT is in mothball status. For the summer of 2006, ERCOT will have RMR contracts for several critical generating units needed to maintain transmission reliability requirements in Laredo and Bryan-College Station. These units would have otherwise been mothballed or retired.

ERCOT is a separate electric interconnection with a single planning authority, balancing authority, and reliability coordinator. To determine the deliverability of generation to load, the ERCOT planning authority verifies that a feasible dispatch of all available generation in ERCOT would exist to meet energy and operating reserve requirements without violating transmission system limits under numerous contingencies according to NERC standards. Operationally, transmission operating limits are adhered to through market-based generation redispatch directed by ERCOT as the balancing authority and reliability coordinator. Operational resource adequacy is also maintained by ERCOT through market-based procurement processes as outlined in the ERCOT Protocols.

Although projected available resources this summer will meet ERCOT's adequacy criteria, they are expected to be close to the minimums required by the criteria. Events such as an extremely hot summer that results in demand levels significantly above forecast, higher than normal unit forced outage rates or financial difficulties of some generation owners that may make it difficult for them to obtain fuel from suppliers, are all risk factors mitigated by ERCOT's minimum reserve margin criteria when considered alone. However, an unanticipated combination of these risk factors could result in inadequate supply. In the event that occurs, ERCOT will implement its Emergency Electric Curtailment Plan (EECP) as defined in the ERCOT Protocols. The EECP includes procedures for use of interruptible load, voltage reductions, procuring emergency energy over the dc ties, and involuntary load shedding to avoid system collapse.

Fuel

No comprehensive fuel supply interruption analysis was considered necessary in preparation for the 2006 summer. Natural gas fuel supply interruptions, a potential concern during the winter in ERCOT due to higher heating demands, typically have not occurred during the summer months. It should be noted that no significant disruptions in gas supply were experienced in ERCOT last summer, even with the significant damage to gas production and processing facilities due to Hurricanes Rita and Katrina. It is also anticipated that no significant problems with coal supply deliveries impacting reliability in ERCOT are expected this summer. Approximately 50% of the coal generating plants in ERCOT (10% of total ERCOT capacity) use Powder River Basin coal.

Transmission

No unusual transmission flow patterns are expected for the summer. Typical transmission flows where constraints are normally encountered are:

- South Texas to north Texas
- West Texas to north Texas
- South Texas to Houston
- Out of the McCamey area (wind generation)
- Dallas-Fort Worth area import
- Bryan-College Station area flows
- Lower Rio Grande Valley cross-valley flows
- Laredo area import
- Morgan Creek Plant to the east

Approximately 67 miles of 345-kV transmission lines along with seven new 345-kV autotransformers are scheduled for completion prior to the summer of 2006. Transmission owners in ERCOT plan to invest almost $1 billion in transmission upgrades throughout this year. One significant transmission addition expected prior to the summer, the Nelson Sharpe 345-kV substation and 345/138-kV autotransformer, will relieve constraints in the Corpus Christi area and enable ERCOT to terminate an RMR contract for generation in the area.

Operational Issues

All planned outages on transmission elements that significantly reduce intra-ERCOT transfers are scheduled to be completed by May 15. Three major generation resources have scheduled maintenance through May and will return to service by late May or early June. All of these resources are located in an area of more than adequate capacity and are not deemed critical to maintaining system security. No unusual operating conditions that would impact system reliability are expected this summer.

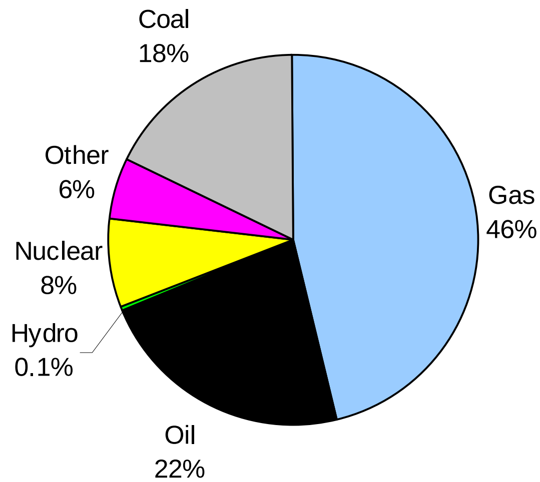
Several resources in the Bryan-College Station area have limited hours of run time due to emissions limitations. A combination of these units will be required during high demand conditions to maintain the local transmission system within operating limits. ERCOT expects to have sufficient availability of these resources to maintain system reliability through the summer season. A selection of these resources has been procured by ERCOT through RMR contracts to ensure availability over the summer months.

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% of the electric demand in the state of Texas. ERCOT serves a population of more than 15 million in a geographic area of about 200,000-square miles.

FRCC

Projected Total Internal Demand	45,520	MW
Interruptible Demand & DSM	2,759	MW
Projected Net Internal Demand	42,761	MW
Last Summer's Peak Demand	46,396	MW
Change	(1.9)	%
All-Time Summer Peak Demand	46,396	MW
Deliverable Internal Capacity	48,858	MW
Projected Purchases	2,389	MW
Projected Sales	0	MW
Net Capacity Resources	51,247	MW
Capacity Margin	16.6	%
Reserve Margin	19.8	%
With Uncommitted Resources		
Total Potential Resources	52,397	MW
Capacity Margin	18.4	%
Reserve Margin	22.5	%

Relative Capacity by Fuel Mix



Demand

The Florida Reliability Coordinating Council (FRCC) is forecast to reach its 2006 summer peak demand of 45,520 MW in August, which represents a projected demand decrease of 1.9% over the actual 2005 summer demand of 46,396 MW. This projection is consistent with historical weather-normalized FRCC demand growth and is 4.6% higher than last year's summer forecast of 43,495 MW. The higher 2005 summer peak demand has been attributed to a few days of extremely high temperatures and low humidity. The 2006 peak demand forecast includes 2,759 MW of potential demand reductions from the use of load management and interruptible load management programs.

Demand Sensitivity Analysis

Individual companies within FRCC employ two different techniques to assess the peak demand uncertainty and variability. First, the company develops a bandwidth on the projected or most likely demand (50% probability). The purpose of developing bandwidths on peak demand is to quantify all uncertainties of demand. This would include weather and nonweather demand variability such as demographics, economics, and price of fuel and electricity.

Monte Carlo simulations on peak demands are performed to arrive at a probabilistic distribution as to range and likelihood of this range of outcomes of peak demand. Factors that determine the level of demand for electricity are assessed in terms of their own variability and this variability 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 at a given level of probability.

A FRCC methodology for developing bandwidths for the region forecast has not been developed; however, FRCC is assessing possible methodologies to develop region forecast bandwidths.

Energy

The projected energy consumption for the 2006 summer season is forecasted to reach 234,341 GWh. This represents almost a 2.0% increase over the actual net energy for load for the previous 2005 summer period of 228,090 GWh.

Even though the projected peak demand is expected to be slightly lower than the 2005 actual demand, the projected energy forecast is expected to be higher due to demand growth.

Resources

The net capacity of resources available within the region to meet the projected summer peak yields a 19.8% reserve margin, exclusive of uncommitted resources, adequately satisfying the 15% regional reserve margin requirement. This margin is lower than last year's forecast 24% reserve margin, and includes 1,552 MW of external long-term firm nonrecallable purchases and 837 MW of externally-owned capacity from outside the region. An additional 240 MW of firm net generation is scheduled to be online prior to the upcoming summer season, mostly attributable to uprates of existing generation.

Only existing capacity that is under firm contract or committed to serve load has been included in FRCC's capacity resources. FRCC has 4,913 MW of existing merchant plant capacity, of which 3,763 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.

Fuel

For the 2006 summer period, FRCC does not anticipate any fuel transportation issues affecting capability during peak periods and fuel supplies are expected to continue to be adequate for the region.

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. Due to the growing interdependence of generating capacity and natural gas, FRCC has undertaken initiatives to increase coordination among natural gas suppliers and generators within the region. This coordination has provided the data necessary to perform short-term natural gas availability assessments in order to provide operators with near-term status of the gas delivery system along with the basis for other operational recommendations, up to and including regional appeals for conservation. 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.

For the 2006 summer period, FRCC has not developed any additional fuel delivery coordination strategies. The fuel delivery situation continues to improve with the continued restoration of Gulf of Mexico natural gas production that was shut in during the 2005 hurricane season. In addition, the PRB coal delivery issue is expected to be of minimal impact to regional capacity.

During peak demand periods, operators within FRCC will use the fuel supply infrastructure to its maximum capability as most fuel delivery infrastructure is designed around projected loading. The type of infrastructure and preferred generation dispatch used would be based on economic conditions surrounding the types of fuels, along with availability of external purchased power. Typically, during peak summer conditions, some alternate fuel unit dispatch may be used depending on system economics.

In addition to the short-term fuel assessment, FRCC continues its work on a more detailed natural gas pipeline and electric interdependency study process. Although somewhat delayed by the 2005 hurricane season and work in support of NERC's transition to the Electric Reliability Organization (ERO), FRCC has developed a high-level, transient gas flow model to study and finitely analyze the gas pipeline system and its impact on reliability in peninsular Florida. Additional data related to natural gas use within the region has been collected and input into the gas flow model and scenarios are being developed to perform reliability analysis. This effort will be ongoing through 2006.

Transmission

FRCC expects the bulk transmission system to perform adequately over various system operating conditions. The results of the 2006 Summer Transmission Study, which evaluated the steady-state summer peak demand conditions under different operating scenarios, indicate that any concerns about thermal overloads or voltage conditions can be managed successfully by operator intervention. Such interventions would include generation redispatch, system reconfiguration, reactive device control, and transformer tap adjustments.

An interregional transfer study is performed annually to evaluate the transfer capability between FRCC and the southern subregion of SERC for the upcoming summer and winter seasons. Any transfer-related contingencies resulting in transmission overloads or voltage violations would be resolved by operational procedures. Joint studies of the Florida/Southern transmission interface indicate an import capability of 3,600 MW into FRCC, and export capability of 1,300 MW.

Operational Issues

The FRCC region experienced significantly higher demand levels than were forecast during the summer of 2005. Coupled with additional generation in the southwest portion of central Florida, those levels created increased west-to-east flow levels across the central Florida metropolitan load areas. Specific operational strategies were developed to coordinate and mitigate these impacts to the bulk power system reliability.

Several transmission modifications have been accelerated and are being implemented this spring to increase the operational margins and transmission configuration options for the area. If the region experiences comparable demand levels to the summer of 2005, the same sensitivities to area dispatches and transmission configuration would be expected as operational issues for the summer of 2006. Should these operational issues arise, operational procedures (with pre-planning and training) will manage the impacts to the bulk power system in the area to ensure reliable operations.

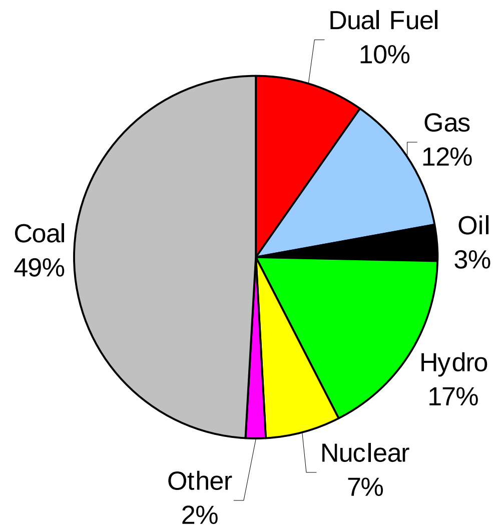
No scheduled maintenance outages of any significance are planned for the summer period. Even with the increased reliance on operational procedures to resolve potential transmission loading concerns, FRCC does not foresee any reliability issues for the 2006 summer period.

FRCC's membership includes 28 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 control areas. As part of the transition to the ERO, FRCC has registered 109 entities (both members and nonmembers) performing the functions identified in the NERC Reliability Functional Model and 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 Web site http://www.frcc.com.

MRO

Projected Total Internal Demand	47,181	MW
Interruptible Demand & DSM	1,895	MW
Projected Net Internal Demand	45,286	MW
Last Summer's Peak Demand	45,442	MW
Change	3.8	%
All-Time Summer Peak Demand	45,442	MW
Deliverable Internal Capacity	51,790	MW
Projected Purchases	3,085	MW
Projected Sales	446	MW
Net Capacity Resources	54,429	MW
Capacity Margin	16.8	%
Reserve Margin	20.2	%
With Uncommitted Resources		
Total Potential Resources	54,474	MW
Capacity Margin	16.9	%
Reserve Margin	20.3	%

Relative Capacity by Fuel Mix



Demand

The Midwest Reliability Organization's (MRO) expected summer noncoincident peak net internal demand in combined MRO U.S. and MRO Canada is 45,286 MW. This forecast is 4.0% above last summer's actual peak demand of 43,549 MW, which includes the 2005 actual data for the new MRO members (Alliant, Wisconsin Public Service, Upper Peninsula Power Company, Wisconsin Public Power, and Madison Gas and Electric). The demand forecast assumes average weather conditions.

The total internal demand for the 2006 summer is forecast to be 47,181 MW. This projection is based on average historical summer weather. The forecast 2006 summer peak (excluding new members) is 36,780 MW, which is 1,079 MW (3.0%) higher than the forecast 2005 summer peak of 35,701 MW. The forecast 2006 total summer peak (including new members) is 47,181 MW (3.8%) higher than the actual 2005 summer peak (including new members) of 45,442 MW. This all-time actual summer peak occurred in August 2005.

Demand Sensitivity Analysis

Both the MAPP Generation Reserve Sharing Pool (GRSP), and the former MAIN/MRO members, utilize a load forecast uncertainty factor (LFU) within the determination of adequate generation reserve margin levels. The LFU considers both uncertainty attributable to weather conditions and economic conditions and is factored into the loss of load expectation study used to determine adequate reserve margin levels.

The reserve margin requirements established by the MAPP GRSP are based on probabilistic analyses that utilize a demand forecast uncertainty of 3.0%; the former MAIN members recommended minimum reserve margin is based on a probabilistic analysis that utilizes a weather-only LFU of 3.3% and an all-factors LFU sensitivity of 5.0–6.3%.

Energy

The 2006 summer forecast energy consumption for MRO-Total (132,780 GWh) is 0.9% above the 2005 summer actual energy (131,632 GWh), which includes the 2005 actual data for the new MRO members.

The 2006 summer forecast energy consumption for MRO-U.S. (113,203 GWh) is 1.2% above the 2005 summer actual energy (111,811 GWh), which includes the 2005 actual data for the new MRO members. The 2006 summer energy consumption for MRO-Canada (19,577 GWh) is 1.2% below the 2005 summer actual energy (19,821 GWh).

Resources

The projected MRO reserve margin is 20.2%. This compares to the 2005 summer reserve margin of 21.3%. Both values are applicable for the current MRO footprint. No significant capacity additions are anticipated for the summer of 2006. For 2006, and until the MRO develops its own recommended reserve margin, the MRO is applying the MAPP GRSP reserve margin to those members of the pool and the former MAIN reserve margins to those members formerly in MAIN.

In the MAPP GRSP, which includes all MRO members except Alliant, Wisconsin Public Service, Upper Peninsula Power Company, Wisconsin Public Power, and Madison Gas and Electric, resource adequacy is measured through the accreditation rules and procedures. The MAPP GRSP has a 15% reserve margin requirement and has determined that the GRSP members will have a 19.7% reserve margin for the upcoming summer.

The remaining MRO members, which are not part of the MAPP GRSP pool, will continue to meet their previous MAIN recommended reserve margin of 14% for the upcoming summer.

Uncommitted resources within the MRO region for the upcoming summer total 45 MW.

MRO projects a net capacity import into the MRO from other regions. About 3,085 MW of purchases are planned from out of the MRO region, and 446 MW of sales are planned out of the MRO region.

Fuel

The MRO has surveyed the Powder River Basin coal delivery situation in the region and the results show that no direct impacts to the reliability of meeting peak electrical demand. However, if coal delivery problems worsen, some entities within the MRO have responded that their ability to continue to meet electrical demand would be reduced.

Transmission

Northern MRO

No significant operational issues are expected for the northern MRO region. Exports out of the Dakotas region are expected to be below transmission stability export limits. Exports from Manitoba to the United States are expected to be normal within the established stability limitations.

Iowa

During the summer of 2006, east-to-west power transfers across Iowa are expected to be the most influential factor regarding reliability of the system. However, this predominant flow pattern is not expected to cause any significant operational issues. A south-to-north system bias may also cause curtailments of schedules and activation of congestion management tools.

Overall, the Iowa system is expected to operate in a reliable manner during the summer of 2006 by meeting NERC standards and regional reliability criteria.

Nebraska

No significant operational issues are expected in Nebraska during the summer of 2006. However, during the summer peak and off-peak loading periods, two export interfaces will require close monitoring (Cooper South Interface-COOPER_S and the Western Nebraska to Western Kansas Interface-WNE_WKS). These two interfaces have experienced extreme volatility in flows and significant increases in TLRs following the start-up of the MISO Day 2 Market.

Some of these TLR events resulted in system operating limits (SOLs) and interconnection reliability operating limits (IROLs) being exceeded on these flowgates due to limitations of the NERC Interchange Distribution Calculator (IDC), coordination of the MISO market flow impacts on external flowgates and other external market activities which do not respect MAPP flowgate limits. During these events, Nebraska Public Power District (NPPD) was required to perform emergency redispatch of local generation to restore the flowgates to their reliability limits. During peak loading periods with heavy exports to the south, NERC TLR and MISO market binding procedures are expected to be implemented to limit the flows on the COOPER_S and WNE_WKS Interface.

With increased demand in the western Nebraska region during the summer months, stability limitations associated with the Gerald Gentleman Station Stability Interface are less severe.

Wisconsin/Upper Michigan (WUMS)

The WUMS transmission system, encompassing the facilities of the American Transmission Company, is susceptible to voltage instability during heavy imports into the region from the west (MRO to WUMS). The default interface limit is defined as an IROL and is closely monitored and managed by MISO to no more than 790 MW. In addition, the MISO conducts a daily P-V analysis and establishes lower transfer limits when necessary to help prevent voltage instability.

Construction outages are scheduled at the Upper Peninsula of Michigan and Wisconsin interface that will continue throughout the summer. However, the interface limit during construction outages is expected to be adequate.

Operational Issues

As a region, the MRO encompasses numerous operational seams including market-to-market (Midwest ISO to PJM), market-to-nonmarket (Midwest ISO to MAPP Regional Transmission Group), and a market-to-Canadian province (Midwest ISO to Manitoba Hydro) seams. System operation and reliability coordination on each side of a seam is often conducted differently, requiring close coordination and communication. The establishment of joint operating agreements and seams operating agreements for the purpose of real-time and projected data transfer has facilitated coordination and communication.

Even though multiple operational seams agreements are in effect in the MRO footprint, following the start-up of the MISO Day 2 Market, the MRO reliability region experienced an increase in TLR events. In addition to the increased frequency of TLR events, a marked increase in the duration per event and the magnitude of relief required per call was experienced. During some of these events, SOL and IROL limits were exceeded to the point where emergency redispatch was required. The rapid succession of change orders to the IDC tool to accommodate market flows, combined with RTO market entities uploading their own market flow and marginal zone impacts to the IDC, seems to have reduced the IDC's capability to effectively manage and predict system flows.

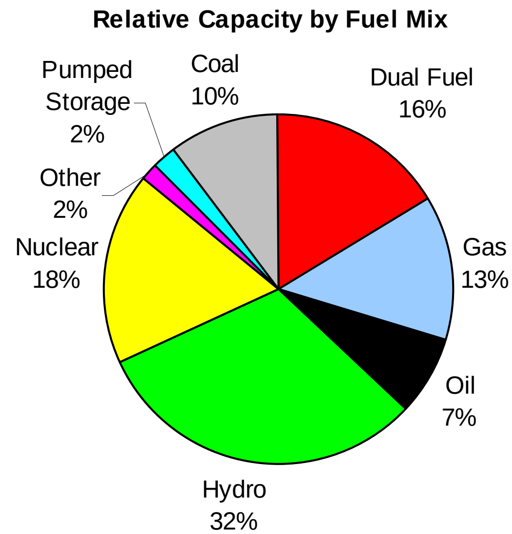
TLR events in the MRO region are evaluated by a MAPP/Midwest ISO Seams Implementation Working Group to assess accuracy, comparability, and to initiate improvements to the congestion management processes. For example, a TLR avoidance procedure whereby the Midwest ISO will bind (and internally redispatch for) a constrained Midwest ISO element prior to calling TLR, when it is appropriate, was implemented in fall of 2005.

TLR avoidance and improvements in next-hour projections will be a top priority for the summer of 2006 to maintain operating reliability.

The MRO region includes more than 40 members supplying approximately 280,000,000 megawatt-hours to more than twenty million people. The MRO membership is comprised of municipal utilities, cooperatives, investor-owned utilities, a federal power marketing agency, Canadian Crown Corporations, and independent power producers. The MRO region spans eight states and two Canadian provinces covering roughly one million square miles. Membership solicitation is ongoing.

NPCC

Projected Total Internal Demand	111,063	MW
Interruptible Demand & DSM	1,961	MW
Projected Net Internal Demand	109,102	MW
Last Summer's Peak Demand	109,833	MW
Change	1.1	%
All-Time Summer Peak Demand	110,262	MW
Deliverable Internal Capacity	134,740	MW
Projected Purchases	3,333	MW
Projected Sales	2,436	MW
Net Capacity Resources	135,637	MW
Capacity Margin	19.6	%
Reserve Margin	24.3	%
With Uncommitted Resources		
Total Potential Resources	135,637	MW
Capacity Margin	19.6	%
Reserve Margin	24.3	%



Demand

The Northeast Power Coordinating Council's (NPCC) aggregate 2006 summer projected net internal demand is 109,102 MW (U.S. systems 60,006 MW, Canadian systems 49,096 MW). The total internal demand forecast is based on average weather conditions and is 1.1% above last summer's actual peak demand, which was established under generally above normal temperatures in the region. The 2006 projected net internal demand is 3.2% higher than last summer's projected net internal demand. The peak demand forecast includes an expectation that 1,961 MW of controllable load management and interruptible demand will be served.

Resources

For the summer of 2006, NPCC has determined through its annual assessment process that each NPCC area is in compliance with the resource adequacy criterion for a loss of load expectation (LOLE) of no more than 0.1 day per year, on average. For July of 2006, the reserve margin for NPCC is 26,535 MW (24.3%), an increase of 6.3% when compared with the July 2005 reserve margin of 24,964 MW (23.6%).

ISO-New England (ISO-NE), the New York Independent System Operator (NYISO) and the IESO expect sufficient resources to be available to meet projected demands during the summer of 2006. Québec and the Maritimes are predominately winter-peaking control areas and therefore adequate resources, including the supply for firm external sales, are expected to be available.

The 640 MW increase in new capacity in Ontario, including the return to service of a deactivated 515-MW nuclear unit, has made some improvement in the Ontario resource supply situation. However, under heavy demand conditions Ontario may still rely on power imports.

The ISO-NE is projecting that the area may fall short of the needed electricity supplies to meet electricity use and maintain required operating reserves. During these conditions, the ISO-NE would initiate Operating Procedure No. 4, *Action During a Capacity Deficiency*, which is designed to help maintain a reliable power system under these conditions. The OP-4 includes the implementation of demand response programs as well as calling on assistance from surrounding control areas.

In southeastern New York, and within New York City, a total of 1,000 MW of new resources have been added at the Astoria complex since the summer of 2005. The Poletti expansion project, completed in

December of 2005, increased the capacity of the New York Power Authority (NYPA) Poletti plant at the Astoria complex by 500 MW. The SCS Astoria plant, scheduled for service by the end of May, is a new 500-MW gas-fired generator, also located in the Astoria complex.

Transmission

The NPCC Task Force on System Studies has determined through these reviews that the bulk power system for each of the NPCC areas for the summer of 2006 is in compliance with NPCC Document A-02, *Basic Criteria for Design and Operation of Interconnected Power Systems.*

As in past years, the Connecticut area may face reliability problems due to transmission constraints into and within that area. Under certain conditions, the electric demand in these areas could exceed the combined ability of the electric generating resources in the area and the available transmission capacity to import electric energy into the region. Approximately 250 MW of quick-start capacity through the combination of generation resources, demand response resources, or peak demand reducing conservation and load management projects has been made available for use to improve the supply situation during the summer of 2006.

Elsewhere in the New England subregion, two new projects will increase regional reliability prior to the 2006 summer peak by increasing transfer capability into the Boston, Massachusetts load pocket. The first consists of building the Stoughton 345-kV switching station and looping the West Walpole-to-Holbrook line through it. The second consists of the addition of two new 345-kV cables that will emanate from Stoughton—one to the Hyde Park substation and one to the K Street substation. Also, the Ward Hill 345-kV substation will be expanded to include an additional three autotransformers and the 115-kV lines supplied by those autotransformers will be reconductored.

In Ontario transmission capability into the GTA has been enhanced with the addition of the second 500/230-kV, 750-MVA autotransformer at the Parkway Substation in the fall of 2005, a 240-Mvar shunt capacitor at the Essa Substation and the planned removal of deratings on 500/230-kV, 750-MVA autotransformers at the Cherrywood and Trafalgar Substations. Also, the three Phase Angle Regulators (PARs) are in-service on the Michigan-Ontario interconnections. These PARs were operated at neutral tap position throughout the summer of 2005 because an agreement on operation of the phase shifters to control flow had not been reached. Until the necessary agreements are in place, the PARs will only be operated off neutral tap to prevent a 5% voltage reduction in Ontario or Michigan, to prevent shedding firm load, and for testing. Without agreement to control flow, the Lake Erie loop flow congestion experienced in 2005 can be expected to reoccur in 2006. The interface capability can be temporarily increased if the PARs are bypassed, and this option is being considered by the IESO for the summer of 2006.

Operational Issues

NPCC used probabilistic analysis to estimate the annual LOLE together with the projected use of area operating procedures designed to mitigate resource shortages for the summer of 2006 (May through September). These measures include reducing 30-minute operating reserve, voltage reduction, reducing 10-minute operating reserve, and public appeals.

Reliance on these operating procedures is not expected for the NPCC areas during the 2006 summer period under normal demand assumptions, with the expected usage of these operating procedures significantly less than one occurrence due to recently added capacity in the NPCC areas, additional demand response programs and transmission projects.

If reductions in anticipated resources, delay of expected transmission projects, and/or additional transmission limitations into NPCC materialize coincident with higher than expected loads, New England

and New York may experience conditions during the summer of 2006 that require the use of their operating procedures designed to mitigate resource shortages. The potential use of these operating procedures is more likely to be required in the Boston, southwestern Connecticut, New York City, and Long Island areas, under severe case conditions.

NPCC participates in the MAAC-ECAR-NPCC (MEN) Interregional Transmission System Reliability Assessment which determines, for both the summer and winter operation seasons, wide-area first contingency total transfer capabilities consistent with the market structures within the regions.

A detailed summary of the expectations of each of the NPCC areas follows:

Subregions

Maritimes

Demand — Based on the Maritimes area 2006 demand forecast, a peak of 3,738 MW is predicted to occur for the summer period, June through August, during the week beginning June 4, 2006. This is a 5.86% increase over the summer of 2005 actual peak of 3,519 MW, which occurred on July 20, 2005. Since the Maritimes area is a winter-peaking area, forecasted peaks for the shoulder months of May and September are normally higher than the summer period. For the week beginning April 30, 2006, the predicted peak is 4,061 MW.

Resources — When allowances for unplanned outages (based on a discrete MW value representing a typical forced outage) are considered, the Maritimes area is projecting more than adequate capacity margins for the summer of 2006 assessment period. Net margins ranging from 29 to 57% are projected over the period May through September 2006. The Maritimes area has no new generation resources scheduled for commercial operation during the summer period May through September 2006.

The fuel supply in the Maritimes area is very diverse and includes nuclear, natural gas, coal, oil (both light and residual), Orimulsion™, petroleum coke, hydro, tidal, municipal waste, and wood. The Maritimes area does not anticipate any restrictions in capacity due to fuel supply. Units that have been converted to the Orimulsion™ fuel retain their full capability on oil. Moreover, the area anticipates normal hydro conditions and the reservoirs are expected to be full.

Transmission — No major additions have been made to the Maritimes bulk transmission system since last summer. Interconnection capability remains unchanged and is capable of delivering up to 700 MW to New England and is capable of delivering up to 640 MW to Québec.

Operational Issues — Since the Maritimes are predominately winter-peaking control areas and therefore adequate resources, including the supply for firm external sales, are expected to be available.

New England

Demand — ISO-NE's control area reference peak demand forecast for the summer of 2006 is 27,025 MW. This is 480 MW (1.8%) higher than the weather-normalized 2005 summer peak demand of 26,545 MW. The reference case forecast is the 50/50 forecast (50% chance of being exceeded), corresponding to a New England 3-day Weighted Temperature-Humidity Index (WTHI) of 80.1, which is equivalent to a dry bulb temperature of 90 degrees Fahrenheit and a new dew point temperature of 70 degrees Fahrenheit. The 80.1 WTHI is the 95th percentile of a weekly weather distribution and is consistent with the average of the WTHI value at the time of the summer peak over the last 30 years.

Demand Sensitivity — ISO NE produces a distribution of forecasted seasonal peak demand based on the weekly weather distribution. The 90/10 peak demand forecast (10% chance of being exceeded) for the summer of 2006 is 28,785 MW and is considered to be the extreme summer peak demand forecast. The 90/10 forecast corresponds to a New England WTHI of 82 degrees. At the upper end of the summer peak demand forecast distribution, a one-degree increase in WTHI results in approximately 700 MW of additional demand forecasted.

Resources — New England is projected to have total capacity resources of 30,803 MW (August) within New England. This capacity represents all capacity available to serve demand and located in New England and includes 25 MW of additional generation that is anticipated to be operational by June 1, 2006. The net of firm external capacity purchases and sales with areas outside of New England is a net export of 136 MW. Total interruptible demand resources assumed available for the summer of 2006 is 314 MW. This includes demand that is interrupted during times of capacity shortages. Not included in this assessment is voluntary load that will interrupt based on the price of energy. As of March 31, 2006, there are approximately 112 MW enrolled in this program. Including capacity purchases and sales, interruptible demand, and known reductions due to maintenance, New England is forecasted to have an installed capacity margin of 3,724 MW (13.8%) for the month of August under the reference demand forecast (50/50). Including capacity purchases and sales, interruptible demand, and known reductions due to maintenance, New England is forecasted to have an installed capacity margin of 1,964 MW (6.8%) for the month of August under the extreme demand forecast (90/10).

As it has been in past years, the Connecticut region may face reliability problems due to transmission constraints into and within that region. In order to address this reliability concern, ISO-NE issued a Request For Proposal (RFP) in December 2003 for up to 300 MW of quick-start capacity through the combination of generation resources, demand response resources, or peak-demand reducing conservation and load management projects. Approximately 250 MW of capacity, nearly all of which are demand-side resources, will be available for the summer of 2006. These resources are included within the total interruptible demand.

Fuel supply interruptions are not considered in the calculation of the available capacity margin for the 2006 summer. Historically, traditional fuel supply and delivery options have been readily available to generators within New England during the summer months. For the summer of 2006, ISO NE does not foresee any fuel supply or delivery problems.

Transmission — The 2005 New England Regional System Plan outlines a number of the ongoing transmission planning studies and projects that are taking place. The report continues to describe the various areas of the region where transmission projects are needed for reliability.

- The first stage of the NSTAR 345-kV Transmission Reliability Project consists of building the Stoughton 345-kV switching station and looping the West Walpole-to-Holbrook line through it. Two new 345-kV cables will emanate from Stoughton—one to the Hyde Park substation and one to the K Street substation. Also, the Ward Hill 345-kV substation will be expanded to include an additional three autotransformers and the 115-kV lines supplied by those autotransformers will be reconductored. Both of these projects will increase regional reliability by increasing transfer capability into the Boston load pocket.
- An additional 345-kV, 160-Mvar reactor will be installed at the Lexington substation to help control Boston area high voltage during light demand periods.
- The new East Cambridge substation will improve reliability to Cambridge, Massachusetts, and decrease reliance on local generation.
- The Middletown Reliability Project, which includes the installation of a 345-115-kV autotransformer at Haddam coupled with some 115-kV line work, will improve reliability to the Middletown area of Connecticut and decrease reliance on local generation.

- Upgrading the 345-kV substation terminals at the Southington and Haddam Neck substations will help ease cross-state transfers, from eastern Connecticut to the southwest Connecticut load pocket, by increasing the thermal capability of the 345-kV line from Haddam Neck to Southington.
- Transmission improvements are also under way in southern Vermont as part of the requirements necessary for an increase in power at the Vermont Yankee Nuclear station. This includes new shunt capacitors that are being installed at the Vermont Yankee 115-kV substation. These capacitors will improve reliability in the southeastern Vermont and southeastern New Hampshire areas by providing voltage support.

For the summer of 2006, ISO-NE does not anticipate transmission constraints will affect reliability beyond those in the southwestern Connecticut subarea and within the state of Connecticut. As identified in the *ISO New England Regional System Plan 2005,* the subareas of greater Connecticut (state of Connecticut) and southwest Connecticut are considered critical areas in terms of service reliability, and shorter-term system improvements have been implemented in these areas. Coupled with reactive improvements to the distribution system, several completed reliability projects in Connecticut have enhanced both system reliability and market efficiency. Highlights of these projects are as follows:

- Elimination of a Long Mountain stuck-breaker contingency that led to the loss of three 345-kV lines
- Installation of the Glenbrook static compensator (STATCOM) to improve voltage performance in southwest Connecticut
- Installation of two dynamic voltage ampere reactive systems to improve voltage performance in southwest Connecticut
- Installation of capacitor banks at strategic locations in Connecticut to further support steady-state voltage conditions
- Replacement of circuit breakers across Connecticut to increase short-circuit interrupt duty

Operational Issues — When scheduling major resource outages, ISO-NE ensures that the reliability of the control area will not be adversely affected. For the summer of 2006, ISO-NE projects that there may be instances when the New England control area may not have sufficient operable capacity to meet its peak demand and operating reserve requirements, especially in Connecticut due to its transmission import limits. Consequently, ISO-NE expects to invoke operating procedures to mitigate any short-term operable capacity deficiency. ISO-NE has in place Operating Procedure No. 4 (OP-4) *Action During a Capacity Deficiency*, that includes purchasing emergency energy from the interconnected grid, interrupting interruptible load customers, and implementing voltage reductions in the event of a capacity shortage. OP-4 is used by system operators as part of "normal" operations to mitigate capacity shortages.

Although New England projects there may be instances when the New England control area may not have sufficient operable capacity within the control area to meet its peak demand and operating reserve requirements, the area is forecasted to meet its resource planning reliability criterion (RPRC) of once-in-10-years disconnection on noninterruptible customers. Load relief from operating procedures is also considered as resources for meeting the New England RPRC of once-in-10-years disconnection of noninterruptible customers. The total estimated load relief obtainable from OP-4 has not been reflected in the available resources reported above.

ISO-NE does not expect to implement Operating Procedure No. 7 (OP-7), *Action in an Emergency*, which are procedures to be followed in the event of an operating emergency involving unusually low frequency, equipment overload, or unacceptable voltage levels in an isolated or widespread area of New England.

NPCC and ISO-NE Resource Planning Reliability Criteria state that:

> Resources will be planned and installed in such a manner that, after due allowance for the factors enumerated below, the probability of disconnecting noninterruptible customers due to resource deficiency, on the average, will be no more than once in ten years. Compliance with this criteria shall be evaluated probabilistically, such that the LOLE of disconnecting noninterruptible customers due to resource deficiencies shall be, on average, no more than 0.1 day per year.
>
> - The possibility that demand forecasts may be exceeded as a result of weather variations.
> - Immature and mature equivalent forced outage rates appropriate for generating units of various sizes and types, recognizing partial and full outages.
> - Due allowance for scheduled outages and deratings.
> - Seasonal adjustment of resource capability.
> - Proper maintenance requirements.
> - Available operating procedures.
> - The reliability benefits of interconnections with systems that are not Governance Participants.
> - Such other factors as may from time-to-time be appropriate.

Load relief through the ISO-NE Operating Procedure 4 is used to meet this criterion as stated under *f. Available Operating Procedures.* When determining New England's capability to meet this criterion, a spectrum of peak loads are modeled probabilistically to capture the possible impact that weather variations have on the demand forecast.

New York

***Demand* —** The forecast peak for the NYISO is 33,295 MW, which is 1,333 MW higher than last year's forecast, and 1,220 MW higher than last year's actual 2005 NYISO peak demand, which occurred on July 26. The forecast demand is 3.8 % higher than the all-time peak demand of 32,075 MW that occurred on July 26, 2005.

***Demand Sensitivity* —** The forecast is developed by the NYISO using a THI value of 84.2 degrees, which is representative of weather conditions during peak demand conditions. At forecast demand levels, a one-degree increase in the THI will result in approximately 610 MW of additional demand. Under extreme 90/10 weather, the peak demand could reach 34,900 MW.

***Resources* —** The NYISO conducts semi-annual and monthly installed capability (ICAP) auctions. Based on the forecast demand for 2006, the ICAP requirement is 39,288 MW after including the 18% installed reserve margin requirement. External suppliers can fulfill a portion of NYISO's ICAP requirement. An external ICAP supplier must declare that the amount of generation that is accepted as ICAP in New York will not be sold elsewhere. The external entity in which the resource is located has to agree that the reserve will not be recalled or curtailed to support its own loads in that other control area; or will treat the supplier using the same pro rata curtailment priority for resources under its control. The energy that has been accepted as ICAP in New York must be demonstrated to be deliverable to the NYISO border.

The NYISO sets a limit on the amount of ICAP that can be provided by suppliers external to the New York control area.

When allowances are taken for unplanned outages and derates (based on historical performance of 8.77% unavailable capacity), the net available resources will be 35,842 MW, which will be sufficient to meet the NYISO demand and operating reserve requirements during the peak demand hours, with a reserve margin of approximately 8.189 MW (24.5%).

The NYISO uses a multi-area probabilistic model to evaluate the capacity requirements for the 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 are consistent with that used by NPCC in the regional analysis.

NYISO expects approximately 600 MW of demand relief from emergency operating procedures that include internal load curtailment by the transmission owners, public appeals, and 5% system-wide voltage reductions. Participation in the Emergency Demand Response Program and Special Case Resources programs represents an additional 1,100 MW available through the market.

Resource additions, totaling 500 MW are expected to be available for service prior to the summer peak. The new SCS Astoria plant is a 500-MW natural gas-fired combined-cycle plant. This facility is expected to be in service by May. A total of 1,000 MW has been added at the Astoria complex (which is in-city) since the summer of 2005. The Poletti expansion project increased capacity of the NYPA Poletti plant at the Astoria complex by 500 MW; this was completed during the winter. The SCS Astoria plant is a new 500-MW plant, also at the Astoria complex.

Transmission — Major transmission facilities will not be added to the New York bulk power system prior to the summer of 2006 period.

Currently, the NYISO dispatches the system while optimizing loading across the voltage stability limited Central East interface within New York State. The Central East voltage limit is analyzed using comprehensive studies, and verified in real time for the actual configuration of the NYCA 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.

NYISO operates in accordance with principles detailed in the NPCC Document B-3: *Guideline for Inter-Area Voltage Control*. Existing agreements with neighboring control areas ensure that the NYISO will be responsible for the reactive power needs within its system. Generating units that participate in the NYISO Voltage Support Service program are required to perform reactive power capability tests on an annual basis during the peak capability period.

Operational Issues — The NYISO has implemented wide-area view display capability for use by the control room system operators. These displays present interarea, real-time data and present a geographical overview of EHV transmission conditions of the Lake Erie transmission path and critical interarea interconnections.

Ontario

Demand — Ontario's forecast summer peak demand is 25,502 MW based on monthly normalized weather. Previously Ontario reported peak demands based on weekly normalized weather. The forecast peak using monthly normalization is higher than the forecast peak using weekly normalization.

The forecast peak for the summer of 2006 is 2.5% lower than the 26,160-MW actual peak demand, which occurred on July 13, 2005.

The IESO quantifies the uncertainty in peak demand due to weather variation. LFU represents the impact on demand of one standard deviation in the underlying weather. For the upcoming summer peak of 25,502 MW, the LFU is 1,068 MW.

A sizeable number of loads within the province bid their load into the market and are responsive to price and to dispatch instructions. The amount of this "dispatchable load" has been steadily increasing and now amounts to approximately 700 MW, of which 360 MW is included for capacity planning purposes.

Resources — Resources available within Ontario together with imports are forecast to be adequate to meet demand and energy requirements during the summer period. Planning reserves determined on the basis of Ontario self-sufficiency are below target levels for seven of the 13 weeks. Rescheduling of generator outages and reliance on imports are expected to be sufficient to ensure summer demands and operating reserve requirements can be met for a wide variety of conditions. No firm sales are projected for the 2006 summer period.

The expected Ontario hydroelectric capacity included in this adequacy assessment is based on a revised process using historical data. This approach results in lower hydroelectric capability expectations throughout the year.

More than 640 MW of new capacity was made available in the latter part of 2005 and early this year. The restart of Pickering A nuclear unit in the fall of 2005 contributed 515 MW and the commissioning of the Greater Toronto Airport Authority's new combined-cycle generating plant at Pearson International Airport this year yielded 128 MW. More than 200 MW of installed wind capacity from three wind farms is expected to come on-line before the summer of 2006. Ten percent of the installed capacity is assumed to be available at the time of peak.

Energy supplies available within Ontario are expected to be adequate overall, but energy deficiencies could arise as a result of higher than forecast forced outage situations, prolonged extreme demands, and other influencing factors. Available imports are expected to be sufficient to ensure summer energy demands can be met for a wide variety of conditions.

As a result of the market enhancements being implemented, additional installed resources and transmission infrastructure enhancements described in this report, Ontario is in a better position to withstand demanding circumstances similar to the summer of 2005 when demands were high and hydroelectric resources were much lower than normal.

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

The ability to supply load in the GTA was challenging during the summer of 2005. Transmission capability into the GTA has been enhanced with the addition of the second 500/230-kV, 750-MVA autotransformer at Parkway TS in the fall of 2005, a 240-Mvar shunt capacitor at Essa TS, and the planned removal of deratings on 500/230-kV, 750-MVA autotransformers at Cherrywood TS and Trafalgar TS.

Imports from New York were limited at times by transmission constraints internal to Ontario in the summer of 2005. These limitations are being addressed by augmenting the five existing 230-kV circuits between Niagara Falls and Hamilton that form the Queenston Flow West interface with a new 230-kV double-circuit line between Allanburg TS and Middleport TS. This expansion project, together with improved 230-kV circuit ratings in the Burlington area, will remove these internal restrictions. New York imports are expected to be limited by the ties to New York, with a net increase in import capability of about 350 MW. In addition, an existing Special Protection System at St. Lawrence is planned to be enhanced and be available under peak demand conditions to maximize simultaneous import capability from Hydro-Québec and New York. These changes, targeted for the summer of 2006, will increase Ontario's ability to import from New York.

The PARs are in service on the Michigan-Ontario interconnections but were operated at neutral tap position throughout the summer of 2005 because an agreement to operate the phase shifters to control flow has not been reached. High loop flows continue to be present through the Ontario system. Phase shifters have been installed by Hydro One in Ontario to mitigate the problems caused by the loop flows affecting Ontario's most heavily used interfaces. This equipment cannot be used as intended until IESO and MISO complete their operating agreement. The inability to regulate flows combined with lower than expected ratings on the equipment resulted in significant congestion of imports from the Michigan direction in 2005. Until the necessary agreements are in place, the PARs will only be operated off neutral tap to prevent a 5% voltage reduction in Ontario or Michigan, to prevent shedding firm load, and for testing. Without agreement to control flow, the congestion experienced in 2005 can be expected to reoccur in 2006. The interface capability can be temporarily increased if the PARs are bypassed, and this option is being considered by the IESO for the summer of 2006.

The maximum transfer capability over the Michigan-Ontario interface is achieved with four regulated tie lines in service, and it is IESO's goal to achieve that maximum level. Due to forced outages, however, the 230-kV circuit B3N (Scott Transformer Station x Bunce Creek, Michigan) and its in-line PAR are unavailable. Currently, the circuit and PAR do not have a firm return-to-service date. The outage of the B3N circuit alone, combined with reduced ratings on the ties at Lambton and inability to regulate the PARs, results in no change to the Michigan-to-Ontario transfer capability in the summer and the winter, and an incremental decrease to the Ontario-to-Michigan transfer capability of about 400 MW in both summer and winter. Interregional transmission transfer capability studies have been conducted to determine levels of external assistance that can be imported during the forecast 2006 summer peak demand.

Operational Issues — A number of operational issues were experienced during the summer of 2005. One of the most serious reliability concerns was the failure of significant amounts of import transactions in real time. One of the root causes of these failures was determined to be the lack of a day-ahead commitment process in Ontario to facilitate scheduling. The IESO is in the process of implementing a day-ahead commitment process to address this issue. This process is expected to reduce the failure of imports in real time, increase commitment certainty for generators, and better anticipate next day energy or capacity shortfalls so that mitigating action can be taken. Implementation is scheduled for June 1, 2006.

In addition, demand management of Ontario resources will be increased. The existing Transitional Demand Reduction Program and Emergency Demand Reduction Program will be supplemented through implementation of an Emergency Load Reduction Program, expected to provide about 200 MW of demand response under the IESO's direction. This program is modeled on similar programs implemented by other ISOs.

No unusual operating conditions, environmental, or regulatory restrictions are expected to affect the capacity availability anticipated for this summer. All known planned generator outages and forecast energy limitations have been included in the IESO's adequacy assessment.

Ontario is expected to continue to rely on imports over peak periods this summer.

External resources are normally procured on an economic basis through the IESO-administered markets. Alternatively, market participants may arrange 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.

The extent of use of emergency actions in Ontario during the summer of 2005 is considered unacceptable by the IESO. As a result of the market enhancements being implemented, additional installed resources and transmission infrastructure enhancements described in this report, forecast use of emergency procedures for severe operating situations is expected to be less than in the summer of 2005. Resource adequacy remains within regional criteria.

The Ontario fuel supply infrastructure is judged to be adequate during the summer peak demand, and no fuel delivery problems are anticipated for this summer.

IESO requires generator market participants in Ontario to provide specific information regarding energy or capacity impacts if fuel supply limitations are anticipated. In general, fuel delivery infrastructure redundancy for nonrenewable resources such as coal, uranium, oil, and gas is sufficient that more explicit analysis is considered only on an ad hoc basis.

In anticipation of growing amounts of gas-fired generation in Ontario over the coming years, the IESO has joined with Union Gas, Enbridge, TransCanada Pipelines, and the Ontario Energy Board to form the Ontario Gas Electric Interface Working Group. This group will establish communication protocols, cross-functional training, contingency analysis, and gas-electric day coordination in order to manage operational and reliability issues in both energy sectors.

***Reserve Adequacy Assessment and Reserve Above Requirements* —** 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 site at: http://www.ieso.ca/imoweb/monthsYears/monthsAhead.asp.

Québec

***Demand* —** The Hydro-Québec system is a winter-peaking system. The forecast peak demand for the period from June to September is expected to be 21,778 MW in August. The actual peak demand for the 2005 summer operating period, which was also the all-time peak demand from June to September, was 21,614 MW, occurring on June 28, 2005.

The Québec seasonal peak demand forecasts for 2006 are about 200 MW lower than the 2005 forecasts due to the unseasonably warm summer experienced during the 2005 summer operating period. A normal weather assumption has been used to construct these forecasts.

Québec's firm sales to other areas of NPCC are expected to be 1,370 MW (losses included) from June to September.

***Resources* —** Net capacity resources are expected to be more than sufficient to meet expected internal demand, contractual obligations, and reserve requirements during the summer of 2006. The available capacity margin is expected to exceed 8,000 MW throughout the summer, and in the month of July it is expected to exceed 9,000 MW. This will represent a capacity margin that will range between 28.6% and over 30%.

In September, TransCanada Energy will commission a 507-MW cogeneration plant (natural gas) in the Bécancour industrial park, east of Montréal. Moreover, Hydro-Québec has secured a firm purchase of 200 MW from New Brunswick.

Transmission — The transmission additions to be done by TransÉnergie during the summer operating period concern mainly the integration of new generation at Eastmain 1 Generating Station, which will be put in service by Hydro-Québec production after the summer operating period.

To integrate Eastmain 1 (160 MW in fall 2006 and eventually 480 MW), TransÉnergie will put in service a 37 mile double-circuit 315-kV line between Eastmain 1 and Némiscau substation. Two 1650-MVA, 735/315-kV transformers in Némiscau and one 166-MVA, 13.8/315-kV transformer in Eastmain 1 will also be commissioned this summer.

The TransCanada Energy G.S. will gradually be integrated to the 230-kV system near Bécancour, for full operation in September 2006. These lines are already in service.

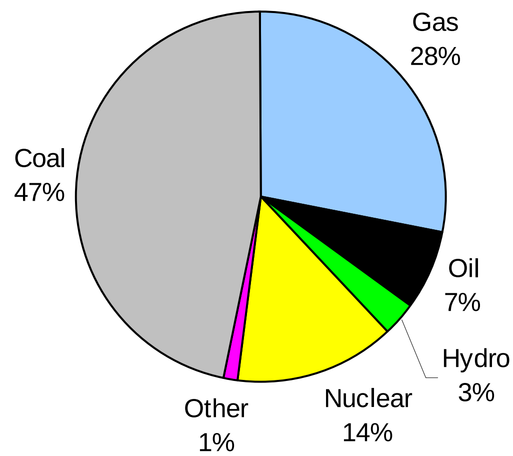
Operational Issues — Transmission outage plans are assessed to meet demand, firm sales, expected additional sales and additional uncertainty margins. A certain number of outages will affect inter-area transfer capabilities in the shoulder months but transfer capabilities to New England and New York will be optimized for the summer.

NPCC is a voluntary nonprofit organization. Its 37 current members represent transmission providers and transmission customers serving the northeastern United States and central and eastern Canada. Also included are five nonvoting public interest memberships extended to regulatory agencies with jurisdiction over participants in the electricity market in northeastern North America as well as public-interest organizations expressing interest in the reliability of electric service in the region. The geographic area covered by NPCC, approximately one million square miles, includes the state of New York, the six New England states, and the provinces of Ontario, Québec, New Brunswick, and Nova Scotia.
http://www.npcc.org/

RFC

Projected Total Internal Demand	191,600	MW
Interruptible Demand & DSM	4,100	MW
Projected Net Internal Demand	187,500	MW
Last Summer's Peak Demand	190,200	MW
Change	0.7	%
All-Time Summer Peak Demand	190,200	MW
Deliverable Internal Capacity	221,220	MW
Projected Purchases	2,767	MW
Projected Sales	1,592	MW
Net Capacity Resources	222,395	MW
Capacity Margin	15.7	%
Reserve Margin	18.6	%
With Uncommitted Resources		
Total Potential Resources	229,695	MW
Capacity Margin	18.4	%
Reserve Margin	22.5	%

Relative Capacity by Fuel Mix



The former ECAR, MAAC, and MAIN regional reliability councils have combined to form Reliability*First* Corporation (RFC), which began operation on January 1, 2006 as one of the now eight regional reliability councils under NERC. All of the former members of MAAC, most of the former ECAR members, and some of the former MAIN members are now members of RFC. Two former ECAR members have joined the SERC region, and the remaining former MAIN members have joined either the MRO or SERC regions. The RFC region, except for a small portion of the footprint in Ohio, is covered by either MISO or PJM.

All RFC members are affiliated with either MISO or PJM for operations and reliability coordination with the exception of Ohio Valley Electric Corporation (OVEC), a generation and transmission utility located in Kentucky and Ohio. OVEC is not affiliated with either RTO, but OVEC reliability coordinator services are performed by PJM. In addition, Federal Energy Regulatory Commission (FERC) has conditionally approved the withdrawal of E.ON.US (a.k.a. LG&E Energy) from MISO. Effective this summer, TVA will become the reliability coordinator for E.ON.US, which will be included in the Tennessee Valley Authority (TVA) reliability plan. TVA is now included in the former ECAR regional reliability plan.

Transition to a single set of processes is still in progress for all three of the previous heritage regional activities, including assessment work. The assessment below reflects the combined efforts of three separate assessment activities for the summer of 2006. RFC, through the three heritage regional (ECAR, MAAC, and MAIN) processes along with the associated interregional groups, conducted the 2006 summer transmission assessments as in the past. The assessment below reflects a combination of the separate assessments. Heritage regional requirements still apply to the former members now with RFC.

Demand

RFC's total internal demand forecast for the summer of 2006 is 191,600 MW. This demand forecast is derived from the aggregate demand forecasts of the RFC member companies, based on expected summer weather. This is 1,400 MW (0.7%) higher than the actual peak demand experienced during the summer of 2005 for these companies. A comparison of the 2006 forecast to the 2005 forecast may be available later this year when RFC collects the 2005 demand forecasts from its members.

Demand-side management programs and interruptible demand contracts that could be curtailed, if necessary, are expected to total 4,100 MW at the time of the summer peak. At the present time, members have arranged for a net of 1,592 MW of power sales to entities outside the RFC region.

Demand Sensitivity Analysis

At this time in the transition of ECAR, MAAC, and MAIN to RFC, the regional assessment has not specifically addressed peak demand uncertainty and variability, or the variability in demand due to weather. As a sensitivity analysis, a calculation based on a weather induced 5% demand increase would result in a 12.8% reserve margin with only the committed resources and a 16.5% reserve margin including the uncommitted resources. Planning for such uncertainties is the responsibility of each individual load serving entity.

Energy

RFC does not currently compare or evaluate seasonal energy forecasts.

Resources

RFC projects net capacity resources to serve demand in the region to be 222,395-MW (net seasonal capability), which is about 400 MW more capacity resources than were in the RFC regional area for the summer of 2005. RFC projects its capacity margin to be 15.7%. The forecast capacity margin in the ECAR, MAAC, and MAIN regions last summer were 19.5%, 15.8%, and 15.2%, respectively. The reserve margin of 18.6% for this summer exceeds the MAAC reserve requirement of 15%, the MAIN recommended reserve of 14%, and the state of Wisconsin requirement of 18%. ECAR did not have a specified reserve requirement. RFC is developing a reserve requirement criterion, although that effort is not scheduled to be completed until 2007. However, based on the data listed above, capacity resources in the RFC region are expected to be adequate this summer, with the capacity margins slightly less than last year, while the reserve margins remain above the requirements of the former MAAC and MAIN regions.

At this time, members have made arrangements to purchase 1,732 MW. An additional 1,035 MW of member-owned capacity is located outside of the region, for a minimum expected import of 2,767 MW.

Since only 3% of the regional capacity is hydroelectric, and more than half of the hydro capacity in RFC is pumped storage, hydro conditions are not expected to be a regional concern.

Approximately 1,529 MW of new capacity in the RFC region is expected to be available to meet the 2006 summer peak.

Since the formation of RFC from the ECAR, MAAC, and MAIN regions occurred only recently, a comprehensive study of resource deliverability has not yet been conducted. However, the PJM RTO conducts analyses to determine that the aggregate PJM capacity can be delivered to the aggregate PJM load. PJM has approximately 5,300 MW of behind-the-meter and energy-only resources, which includes approximately 800 MW of uncommitted capacity and approximately 4,500 MW of energy-only capacity that is not considered committed capacity for this assessment. An analysis conducted in ECAR had determined that about 2,000 MW of capacity might not be deliverable. That analysis determined the levels of export restriction from one area of the ECAR region to other areas in the region under first contingency conditions. Based on those heritage regional analyses, this assessment considered 7,300 MW of capacity as nondeliverable or uncommitted. MISO has developed a deliverability test consistent with its tariff, which may or may not result in additional committed capacity within RFC and which has not been included in this assessment.

Fuel

The Reliability*First* region is broadly diversified with regard to the fuel supply. About 47% of the capacity uses coal for its fuel, with another 14% of the capacity being nuclear fueled. This 61% of the capacity is primarily base and intermediate duty generation. Oil and natural gas fuels are 7% and 28% of the capacity, respectively, and 3% of the capacity is hydroelectric. The remaining 1% of capacity uses a variety of renewable and other energy supplies. During the summer, the oil and gas-fired capacity will experience the most significant day-to-day usage swings, as these are most often the units operating on the margin during the peak.

A review of the gas transmission system has concluded that gas transmission contingencies during the summer would not be expected to have a significant effect on generating unit operations across the region, although local problems could exist. Deliveries of PRB coal are no longer limited due to last May's derailment and subsequent track maintenance. Significant coal delivery problems are not expected for RFC members this summer. Extreme summer weather during peak demand conditions should not materially affect the ability to adequately supply generation across the region.

Transmission

Historically, 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 TLR procedure, may be required to maintain adequate transmission system reliability.

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

American Electric Power's Wyoming-Jacksons Ferry 765-kV line, which is scheduled for completion during June 2006, will reduce the risks of potential widespread interruptions that in the past could result from extra-high voltage line outages overloading the stability-limited Kanawha-Matt Funk 345-kV circuit. Complex operating procedures were previously used to mitigate this contingency.

Operators are monitoring new flow patterns that are approaching limits around the southeast side of Lake Michigan NIPS-AEP-METC systems. These increased flows appear to be more of an issue when the Ludington pumped storage facility is operating in the pumping mode, typically during early morning hours when system demand is beginning to rise.

RFC actively participated in the existing interregional seasonal transmission assessment efforts. Transfer capability results are included in each of the interregional seasonal reports. Simultaneous import capabilities are projected to be adequate for the summer. New interregional agreements are being negotiated between RFC and its neighboring regions.

Peer reviews of former ECAR member transmission assessments will be conducted again for this summer to ensure that the former ECAR transmission owners have conducted sufficient analyses and to complement the regional and interregional efforts. The seasonal assessments include both thermal and voltage analyses for base case and stressed case conditions with single, double, and if warranted, extreme contingencies. The results of these assessments will be communicated to transmission operators and reliability coordinators. In addition to the required level of capacity reserves, PJM requires that the capacity resources be able to be delivered to the load.

There have been 338 MW of additional generation retirements since last summer across PJM but no additional retirements in the east. With the installation of the third 500/230-kV transformer bank at Branchburg and additional facilities as defined in the PJM Regional Transmission Expansion Plan, and RMR contracts that have been negotiated, the overall PJM generation and transmission combined LOLE probability continues to exceed the adequacy requirement of one occurrence in ten years. The bulk transmission system in PJM is expected to perform adequately over a wide range of system conditions.

Operational Issues

The PJM portion of RFC has no significant reliance on any one fuel source, does not depend on outside resources to any great extent (1%) and its membership's compliance with applicable criteria prevents any undeliverable load pockets. PJM is large enough that geographic diversity of weather helps balance its load and the load diversity is further enhanced by markets that are mature and well tested. External units that are considered capacity in PJM must sign an agreement specifying that if a capacity emergency is called, that unit’s capacity must be provided to PJM. Transmission availability is secured before an external unit can be considered PJM capacity. The MISO portion of RFC also has no significant reliance on any one fuel source.

RFC does not anticipate any generating unit or transmission facility outages that could impact reliability during the 2006 summer. During peak summer conditions in 2005, low voltages were experienced in the Baltimore, Washington, D.C., and northern Virginia area due to high west-to-east transfers and higher than forecast demand in the area. Since then, system reinforcements have been added to provide additional reactive support that is expected to mitigate the low voltage issues.

In addition to the NERC TLR procedure, other operating procedures are available to maintain reliable system operations, such as a multiregional 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.

RFC does not expect local environmental restrictions on certain generating units to significantly impact availability during peak demand conditions.

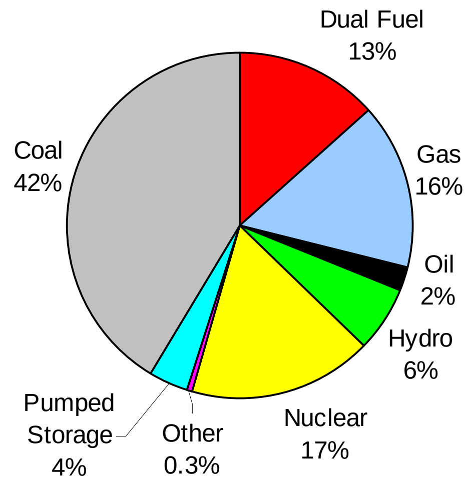
*RFC membership currently consists of 43 regular members and 19 associate members serving more than 72 million people in an area covering all of the states of Delaware, Indiana, Maryland, Ohio, Pennsylvania, New Jersey, and West Virginia, plus the District of Columbia; and portions of Illinois, Kentucky, Michigan, Tennessee, Virginia, and Wisconsin. Additional details are available on the Reliability*First *Web site http://www.reliabilityfirst.com.*

SERC

Projected Total Internal Demand	188,508	MW
Interruptible Demand & DSM	5,044	MW
Projected Net Internal Demand	183,464	MW
Last Summer's Peak Demand	190,704	MW
Change	(1.2)	%
All-Time Summer Peak Demand	190,704	MW
Deliverable Internal Capacity	222,055	MW
Projected Purchases	2,091	MW
Projected Sales	2,582	MW
Net Capacity Resources	221,564	MW
Capacity Margin	17.2	%
Reserve Margin	20.8	%
With Uncommitted Resources		
Total Potential Resources	254,029	MW
Capacity Margin	27.8	%
Reserve Margin	38.5	%

Capacity, Sales, Purchases[4]

Relative Capacity by Fuel Mix



Demand

The Southeastern Electric Reliability Council's (SERC) total internal demand for the 2006 summer is forecast to be 188,508 MW. This projection is based on average historical summer weather. The forecast 2006 summer peak (excluding new SERC members) is 167,871 MW which is 2,726 MW (1.7%) higher than the forecast 2005 summer total internal demand of 165,145 MW. The forecast 2006 total summer peak (including new SERC members) is 2,196 MW (1.2%) lower than the actual 2005 summer peak (including new SERC members) of 190,704 MW. This reduction is due to the impacts of Hurricanes Katrina and Rita, as well as above-average temperatures in 2005. The all-time actual summer peak occurred in July 2005.

Entergy and Southern subregions demand data reflect the reduction and reallocation of load due to Hurricane Katrina. As reported in the *2005/2006 Winter Assessment*, a portion of the Entergy Texas load was temporarily served by ERCOT due to the impact of Hurricane Rita. Within weeks, Entergy was able to restore its system to a state that allowed it to transfer the load back and serve it reliably.

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 demand-side management capabilities for 2006 summer are 5,044 MW (including 494 MW from new SERC members) as compared with the 5,047 MW reported last summer.

Demand Sensitivity Analysis

Temperatures that are higher or lower than normal and the degree to which interruptible demand and demand-side management is utilized can result in actual peak demands that vary considerably from the reported forecast peak demand. Although SERC does not perform load sensitivity analyses at the region

[4] In response to NERC's *2006 Summer Assessment* request, SERC's reporting methodology for including sales and purchases from nonmembers in the Demands & Capacity tables has changed in order to more closely match the formulas contemplated by the tables and instructions. Prior to the *2005/2006 Winter Assessment*, SERC included all nonmember sales and purchases in the rows marked "Sales" and "Purchases." Now, only sales and purchases that cross a subregional or regional boundary are included in the "Sales" and "Purchases" lines of the Demands & Capacity tables. Nonmember sales or purchases that do not cross a boundary are included in the "Deliverable Internal Capacity" line of the table. As a result of this change in reporting methodology, comparisons from one season to another of capacity, sales, or purchases will yield distorted results. The change in reporting methodology does not impact the "Net Capacity Resources" values.

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.

Energy

The projected seasonal electric energy usage in the SERC region (including new SERC members) for the 2006 summer is 361,310 GWh. This is 0.4% less than the actual 362,941-GWh electric energy usage during the 2005 summer season (including new SERC members).

The projected seasonal electric energy usage in the SERC region (excluding new SERC members) for the 2006 summer is 333,360 GWh. This is 2.9% more than the forecast of 324,062 GWh for the 2005 summer season (excluding new SERC members). This increase in energy usage is due to normal growth and within the expected range.

Resources

Capacity resources in SERC are expected to be adequate to supply the projected firm summer demand. The projected 2006 summer capacity margin for SERC is 17.2 %, which is higher than last year’s projected capacity margin of 14.3%.

No major generator outages are planned for the summer that could impact reliability. Hydro reservoir levels are expected to be sufficient to meet forecast peak demands and daily energy demands for the summer period.

Planned firm transactions across the SERC electrical borders include 2,091 MW of purchases coming into the region and 2,582 MW of sales out of the region. These transactions have been included in the capacity margin for the region and are not significantly different from last summer’s transactions.

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.

Deliverability is an important consideration in the analyses to ensure adequate resources are available at the time of peak. The transmission system has 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.

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, activation of shared reserves, and voltage reductions have been used in the region during the past year, their use has not been on a frequency different than in previous seasons.

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. 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 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 for the summer period is adequate even considering possible impacts due to weather extremes. Mild winter temperatures experienced should result in a strong gas storage position heading into summer, which would reduce demand for storage injections. Additionally, new international gas supplies are expected to be available to the U.S. market during the 2006 summer.

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

The majority of SERC members do not rely on PRB coal. SERC members that do receive PRB coal have experienced some reduced deliveries, but are presently receiving sufficient PRB coal. In addition, these members have alternate coal supply contracts and other mitigation procedures in place.

Merchant Generation

SERC has had significant merchant generation development over the past several years. Much of this merchant generation has not been contracted to serve load within SERC and its deliverability is not assured. For these reasons, only merchant generation contracted to serve SERC load is included in the firm capacity margins reported for SERC.

However, a significant amount of the uncommitted merchant capacity within the region has been participating in the short-term markets, indicating that a portion of the uncommitted resources is currently deliverable. To understand the extent of generation development in the region, it is instructive to examine the amount of generation connected to the transmission system for the upcoming summer season. Over 254,000 MW of generating capability is expected to be connected in the region. This generation exceeds the forecast summer total peak demand by over 67,000 MW.

Transmission

The SERC region has extensive transmission interconnections between its subregions. SERC also has extensive interconnections to the FRCC, MRO, RFC, and SPP regions of NERC. These interconnections permit the exchange of large amounts of firm and nonfirm power and allow systems to assist one another in the event of an emergency.

Approximately 140 miles of 161-kV, 230-kV, 345-kV, and 500-kV transmission lines are scheduled for completion prior to or during the summer of 2006. SERC members invested approximately $1.26 billion in new transmission lines and system upgrades (includes transmission lines 100 kV and above and transmission substations with a low-side voltage of 100 kV and above) in 2005 and plan to invest approximately $1.38 billion in 2006.

Coordinated interregional transmission reliability and transfer capability studies for the 2006 summer season were conducted among all the SERC subregions and with the neighboring regions. These studies indicate that the bulk transmission systems within SERC and between adjoining regions can be expected to provide adequate and reliable service over a range of system operating conditions. No significant reliability concerns or limits to transfers were identified.

Subregions

Entergy

Demand — The projected total internal demand for the 2006 summer season is 27,637 MW based on normal weather conditions. This is 381 MW (1.4%) lower than the forecast 2005 summer peak demand of 28,018 MW and is 134 MW (0.5%) higher than the actual 2005 summer peak demand of 27,503 MW.

Resources — The projected capacity margin in the subregion is 21.2% as compared to 12.9% last year. This increase is primarily due to the acquisition of new network resources (Perryville and Attala) and loss of load due to Hurricanes Katrina and Rita. The Perryville and Attala plants were added as network resources for the Entergy operating companies with a plant capacity of 718 MW and 463 MW, respectively. Capacity in the subregion should be adequate to supply forecast demand.

Operational Issues — Entergy continues to monitor demand growth in the cities surrounding the areas affected by Hurricanes Katrina and Rita. No reliability concerns are anticipated for the upcoming peak season as a result of the load redistribution. Demand in the greater New Orleans area has decreased due to the effects of Hurricane Katrina. Entergy anticipates that as much as 85% of total load, which includes 100% of the area's industrial load, will return to service in the impacted area by the 2006 summer season. Entergy estimates that other areas surrounding the Hurricane Katrina impact zone may experience loading above the level measured in 2005 due to the influx of people seeking short-term accommodations while awaiting the redevelopment of the impacted zones.

Generation facilities in the greater New Orleans area that were adversely affected by Hurricane Katrina are not currently in service. Two critical generating facilities that were adversely affected by Hurricane Katrina are expected to be returned to service by the 2006 summer peak. Several substations continue to operate in a functionally and capacity limited state in the impacted zone. In addition, four substations and four transmission lines remain out of service within the same area.

Entergy assessments indicate that these out-of-service facilities will not impact regional or local reliability for the coming season. These system elements will be restored as local system requirements dictate. All transmission substations and lines damaged by Hurricane Rita in east Texas and southwest Louisiana have been restored. No major generating unit outages or transmission facility outages, which would impact system reliability, are planned for the 2006 summer season.

The domestic natural gas and oil industries are still in a recovery and assessment mode in the aftermath of Hurricanes Katrina and Rita. Most major production, processing, and transportation facilities are expected to return to service prior to the summer season, but may still operate at less-than-normal capability for the 2006 summer peak season due to limited production facilities in the Gulf of Mexico. Entergy cannot predict whether and to what extent weather extremes such as tropical disturbances may affect fuel supply infrastructure or cause fuel delivery problems, but will take steps to mitigate the impact of those types of events. As a result, Entergy does not expect that fuel supply infrastructure problems or fuel delivery problems that may occur will affect reliability during summer peak demand conditions.

Associated Electric Cooperative Incorporated's (AECI) Thomas Hill and Holden generating plants' output may need to be restricted during contingency conditions due to transmission outlet constraints. Sufficient internal generation reserves are available for replacement power.

Several transmission projects to increase system reliability are scheduled for completion prior to the summer of 2006 in the Entergy subregion. Entergy is adding series compensation on the China-Porter 230-kV line, as well as a 300-Mvar static var compensator at the Porter 138-kV station. Due to the impacts of Hurricane Katrina and uncertainty of load return, Entergy is deferring the remaining Downstream of Gypsy transmission upgrades and part of the Amite South Import Improvement projects.

The need and timing of these projects are currently being reevaluated. AECI is converting approximately 32 miles of lines between the Cuba, Steelville, and Salem stations from 69 kV to 161 kV to relieve loading in south central Missouri.

Gateway

Effective January 1, 2006, SERC membership expanded to include several members in the central part of the country, resulting in the creation of a fifth SERC subregion (Gateway subregion). The Gateway subregion is comprised of the following SERC members: Ameren Services Company, City of Columbia, Missouri, Electric Energy, Inc., Illinois Municipal Electric Agency, and Southern Illinois Power Cooperative.

***Demand* —** The projected total internal demand for the 2006 summer season is 17,619 MW based on normal weather conditions. This is 838 MW (4.5%) lower than the forecast 2005 summer peak demand of 18,457 MW and 781 MW (4.2%) lower than the actual 2005 summer peak demand of 18,400 MW.

***Resources* —** The projected capacity margin in the Gateway subregion is 33.6% compared to 15.3% last year. In 2005, a number of independent power producer (IPP) generators were connected in the Gateway subregion but were not designated to serve load.

For the summer of 2006, Gateway members purchased some of this previously unclaimed IPP generation. Subregion-wide, available generation levels have not changed significantly from 2005 to 2006, but previously undesignated generation is now committed to serving load in the subregion. This is reflected in the reported capacity margin increase for the subregion.

***Operational Issues* —** No reliability problems are anticipated on the transmission systems of the Gateway subregion members this summer.

The startup of the Midwest ISO market on April 1, 2005 created a marked change in dispatch across the Midwest ISO footprint. The security-constrained economic dispatch allows the market to prevent some TLRs prior to escalation of flows. The seams agreements that have recently been initiated with PJM and SPP should further reduce the need to call for TLR because of increased coordination.

However, a few transmission lines in the subregion can experience heavy loading during certain periods, particularly for heavy north-to-south flows during shoulder or off-peak conditions. For example, Ameren's Bland-Franks 345-kV line and Southern Illinois Power Cooperative's 161-kV tie line with Big Rivers Electric Cooperative have experienced heavy loading in the past and this condition may reoccur during the 2006 summer season. In the short term, constraints will be addressed through local operating procedures, generation redispatch, and the TLR process to maintain reliability.

A number of transmission addition and upgrade projects are under way or planned for completion over roughly the next two and one-half years which will increase ratings on limiting facilities, relieve constrained transmission paths, or provide additional transmission support to local areas. Major subregion projects scheduled for completion prior to the 2006 summer season include:

- The addition of the Moreau-Mariosa Delta-Apache Flats 161-kV line to improve reliability to the Jefferson City, Missouri, area,
- The addition of the Grindstone-Boone and Grindstone-Rebel 161-kV lines to improve reliability to the Columbia, Missouri, area, and
- The replacement of terminal equipment at the Newton plant switchyard in the Newton-Casey 345-kV line.

Southern

Demand — The projected total internal demand for the 2006 summer season is 47,867 MW based on normal weather conditions. This is 907 MW (1.9%) higher than the forecast 2005 summer peak demand of 46,960 MW and 874 MW (1.9%) higher than the actual 2005 summer peak demand of 46,993 MW. Data for 2006 summer includes the impacts from Hurricane Katrina.

Resources — The projected capacity margin in the Southern subregion is 14.8% compared to 15.9% last year. In addition to the resources included in the capacity margin calculation, demand side options are available during peak periods along with large amounts of merchant generation in the subregion. Several hydro facilities in the subregion are undergoing major rehabilitation such as rewinding of generators, turbine replacements, and switchyard work. However, the outages will be coordinated in such a way that reliability and contractual commitments will not be impacted.

Capacity in the subregion should be adequate to supply forecast demand. Additionally, the preliminary results of the VASTE (VACAR (Virginia/Carolinas), AEP, Southern, TVA, Entergy) Summer Reliability Study indicate assistance can be imported into the Southern control area (SCA) during the upcoming summer peak. Analysis for the most recent SCA OASIS postings indicates simultaneous SCA import capability to be over 5,900 MW for the most restrictive summer month. No local deliverability problems are anticipated within Southern Company.

Operational Issues — No reliability problems are anticipated on the transmission systems of the Southern subregion members this summer. The Southern control area routinely experiences significant loop flows due to transactions external to the control area itself. The availability of large amounts of excess generation within the southeast results in fairly volatile day-to-day scheduling patterns. The transmission flows are often more dependent on the weather patterns, fuel costs or market conditions outside the Southern control area rather than by loading within the control area.

Significant changes in gas pricing dramatically impact dispatch patterns. Adjustments to total transfer capability will be made if needed based on actual flows. Local procedures will be utilized as needed, but no delivery problems are anticipated within Southern Company. Utilizing the TLR process is not anticipated, but available if necessary.

All remaining major outages due to Hurricane Katrina are scheduled to return to service by June 1, prior to the 2006 summer season. Substantial reduction of load is anticipated in Mississippi during a multi-year rebuilding cycle due to the widespread destruction of homes and businesses.

A second 230/115-kV transformer at McIntosh has been added to prevent contingency overloads. Moselle unit 5, a 75-MW combustion turbine, is expected to come on-line June 1, 2006.

TVA

Two of the new SERC members, East Kentucky Power Cooperative (EKPC) and Big Rivers Electric Cooperative (BREC), have joined the TVA subregion.

Demand — The projected total internal demand for the 2006 summer season including the new members is 34,953 MW based on normal weather conditions. The projected internal demand (excluding the new members) of 31,935 MW is 816 MW (2.6%) higher than the forecast 2005 summer peak demand of 31,119 MW. The projected total internal demand for 2006 is 231 MW (0.7%) higher than the actual 2005 summer peak (including new SERC members) of 34,722 MW.

Resources — The projected capacity margin in the subregion is 11.2% compared to 11.1% last summer. Capacity in the subregion should be adequate to supply forecast demand. Several hydro facilities in the subregion are undergoing major rehabilitation such as rewinding of generators, turbine replacements, and switchyard work. However, the outages will be coordinated in such a way that reliability and contractual commitments will not be impacted.

The actual 2005 summer peak was higher than planning forecasts. Comparison with actual system loading snapshots from the state estimator proved highly beneficial to analysis of this peak. Several line uprating projects have been accelerated. Forecast values for more extreme conditions will be considered in future planning.

The system has been operating without the Roane transformer bank (1,350 MVA) following failure of one phase in January 2005. The bank was returned to service in April 2006. New transformers being shipped to the 500-kV Madison substation were on barges in New Orleans during Hurricane Katrina and were subsequently found to have experienced high impact forces. However, TVA's standardization of transformer design allowed substitution of the transformers that were intended for the new Bradley 500-kV substation. The Madison 2nd bank installation will be completed in March 2007, thus avoiding any concern for delay of the Browns Ferry Nuclear Unit 1 restart.

The thermal ratings of all equipment in the transmission system database used for planning and operations have been checked over the past year, providing a high confidence in system model accuracy.

Operational Issues — No reliability problems are anticipated on the transmission systems of the TVA subregion members this summer. The TVA transmission system has experienced large and volatile flows in recent years and these flows may occur again this summer. 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. Operating guides have been developed to address these constraints.

Big Rivers facilities have the potential to reach normal or emergency ratings during times of heavy north-to-south flows. The New Hardinsburg 138/161-kV transformer (BREC), the New Hardinsburg (BREC) to Paradise (TVA) 161-kV interconnection, and the Henderson County 138/161-kV transformer (BREC) may experience high loadings.

EKPC's Avon 345/138-kV autotransformer is expected to be a constraint for the 2006 summer. This transformer was overloaded on several occasions in 2005 during periods of significant north-south transfers. Another constraint anticipated for the 2006 summer is loading of LG&E Energy's Goddard-Rodburn 138-kV line. EKPC is in the process of implementing a Dynamic Thermal Circuit Rating (DTCR) program to maximize the power flow through the 345/138-kV autotransformer at the Avon substation. The DTCR program will be implemented as an interim measure to more accurately identify the transformer limit using actual conditions. EKPC has identified transmission system additions to be made by 2007 summer that will greatly reduce the power flows on the Avon transformer.

EKPC is currently seeking approval from the Kentucky Public Service Commission to construct a new 138-kV line from the Cranston substation to the Rowan County substation. This line will provide a parallel path to LG&E Energy's Goddard-Rodburn 138-kV line.

A rebuild of the Avon-Boonesboro North 138-kV line was completed in October 2005, and an operating guide titled BREC-Wilson Unit Outage was approved.

Coordinated studies with RFC members and the other SERC subregions indicate that transmission transfer capability will be adequate on all interfaces this summer to support reliable operations.

VACAR

Demand — The projected total internal demand for the 2006 summer season is 61,217 MW based on normal weather conditions. This is 1,094 MW (1.8%) higher than the forecast 2005 summer peak demand of 60,123 MW and 1,869 MW (3.0%) lower than the actual 2005 summer peak demand of 63,086 MW, due to the hotter than normal weather last year.

Resources — Several hydro facilities in the subregion are undergoing major rehabilitation such as rewinding of generators, turbine replacements, and switchyard work. These outages will be coordinated in such a way that reliability and contractual commitments will not be impacted. Reservoir levels are adequate to meet demand and energy for the upcoming summer peak season. Normal rainfall is expected within the region for the summer peak season for operating hydro facilities. Line loading on the Progress-Yadkin (Tillery) tie could cause a reduction in schedules; however, firm demands will not be impacted.

Six 2-MW distributed generators (DGs) came on-line since the summer of 2005. Nine additional planned DGs are scheduled to be operational by June 2006. A project to upgrade Bath County unit 3 will result in 37 MW of additional capacity for the summer of 2006 operations.

The projected capacity margin in the subregion is 13.0% compared to 13.2% last summer. Capacity in the subregion should be adequate to supply forecast demand.

Operational Issues — No reliability problems are anticipated on the transmission systems of the VACAR subregion members this summer. Coordinated studies for the summer season were performed with RFC members and the other SERC subregions. These studies indicate that transmission transfer capability will be adequate on all interfaces this summer to support reliable operations.

The Duke-to-TVA tie could experience heavy loading this summer, similar to previous years since this 161-kV tie is responsive to many transaction paths. An operating procedure is in place to maintain reliability should this heavy loading occur.

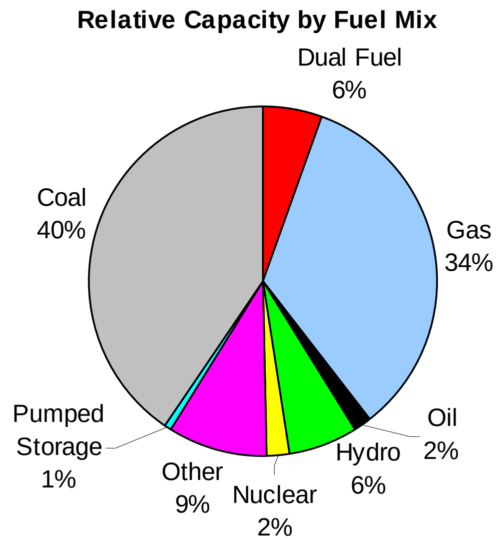
Heavy loading internal to the VACAR subregion could be experienced on several facilities. Studies have shown that generation internal to VACAR can be redispatched to relieve the loading on these internal lines, if necessary.

Also, several improvements to VACAR facilities have been completed or are planned. The new Darlington County-Florence 230-kV transmission line and the Lake Murray 230-kV loop-in and 230/115-kV substation will be completed by the summer of 2006. The Camden-Dalzell 230-kV line is expected to be energized in June 2006, and the Kingstree-Cross 230-kV #2 line is expected to be energized in September 2006. These transmission lines are intended to reinforce delivery of power from the Cross Generating Station. The Riverview-Ripp Switching Station 230-kV circuits 1 and 2 are being bundled prior to the summer season and should relieve generation deliverability constraints. The Lynnhaven-Virginia Beach transmission line was converted to 230-kV operation to relieve contingency overloading and the construction of the Oak Green substation has enabled stronger networking of the 115-kV system in Dominion Virginia Power's northwest area.

The SERC region includes portions of 16 states in the southeastern and central United States, and covers an area of approximately 560,000 square miles. SERC is divided geographically into five diverse sub-regions that are identified as Entergy, Gateway, Southern, Tennessee Valley Authority, and the Virginia-Carolinas Area (VACAR). Currently totaling in excess of 50, SERC membership is comprised of investor-owned, municipal, cooperative, state and federal systems, RTOs/ISOs, independent power producers, and power marketers.

SPP

Projected Total Internal Demand	41,424	MW
Interruptible Demand & DSM	793	MW
Projected Net Internal Demand	40,631	MW
Last Summer's Peak Demand	41,306	MW
Change	0.3	%
All-Time Summer Peak Demand	42,471	MW
Deliverable Internal Capacity	47,898	MW
Projected Purchases	2,030	MW
Projected Sales	1,549	MW
Net Capacity Resources	48,379	MW
Capacity Margin	16.0	%
Reserve Margin	19.1	%
With Uncommitted Resources		
Total Potential Resources	56,031	MW
Capacity Margin	27.5	%
Reserve Margin	37.9	%



Demand

The Southwest Power Pool's (SPP) noncoincident total internal demand forecast for the upcoming summer peak month of August is 41,424 MW, which is 0.3% higher than the adjusted 2005 actual summer peak monthly total internal noncoincident demand of 41,306 MW. Actual peak demand for the 2005 summer was very close to what was projected. Although actual demand is very dependent upon weather conditions and typically includes interruptible loads, forecasted net internal demands are based on normal weather conditions and do not include interruptible loads.

These demand projections include the effects of interruptible demand and load management capabilities. The forecasted values are 742 MW of interruptible demand and 51 MW of load management. SPP is a summer-peaking system and the winter peaks are normally substantially less than those experienced in the summer.

SPP has a total of 1,549 MW of firm sales to other regions for the summer season; they break down into 43 MW to ERCOT, 103 MW to RFC, 1,003 MW to SERC, 0 MW to MRO, and 400 MW to WECC. These firm sales are reflected in the load flow models and may not necessarily match with the projected sales number in the summary table for SPP. The number in the summary table includes additional nonfirm sales from merchant generation, municipalities, and other neighboring markets.

Demand Sensitivity Analysis

SPP does not perform a demand sensitivity analysis at the regional level. Instead each SPP member annually provides to SPP a 10-year forecast of peak demand and net energy requirements. This information conforms to requirements set by SPP in conjunction with applicable NERC and government agencies. The forecasts are developed in accordance with generally recognized methodologies and also in accordance with the following principles:

- Each member selects its own demand forecasting methodology and establishes its own forecast.
- Each member forecasts demand based on expected weather conditions.
- Methods used, factors considered, and assumptions made are submitted along with the annual forecast to SPP.
- The resultant SPP forecast is the total of the member forecasts.

- High- and low-growth rates and extreme weather scenario bands are then produced for the SPP regional and subregional demand and energy forecasts.
- Economic, technological, sociological, demographic, and any other significant factors are considered when producing the forecast.

To insure against negative impacts due to forecast error, SPP requires a 12% capacity margin.

Energy

The projected seasonal electric energy usage in the SPP region (including changes to the SPP membership) for the 2006 summer is 78,247 GWh. This is 2.1% less than the actual 79,865-GWh electric energy usage during the 2005 summer season (including changes to the SPP membership) and is 3.5% more than the forecast of 75,497 GWh for the 2005 summer season. This increase in energy usage is due to normal growth and within the expected range.

Resources

The SPP capacity margin based on committed resources is expected to be 16.0% for 2006 summer, which is comparable to the calculated capacity margin from last year. This is above the 12% minimum capacity margin criteria for the region.

SPP has a total of 2,030 MW of firm purchases from other regions for the summer season, composed of 218 MW from ERCOT, 246 from RFC, 1,211 MW from SERC, 250 MW from MRO, and 105 MW from WECC. These firm purchases are reflected in the load flow models and may not necessarily match with the projected purchases number in the summary table for SPP. The number in the summary table includes additional nonfirm purchases as reported in EIA-411 for meeting capacity margin as well as all nonfirm transactions from merchant generation, municipalities, and other neighboring markets.

Lafayette Utilities will be adding two new combustion turbine units this summer at Hargis for a total of 96 MW of new generation capacity.

The SPP Regional State Committee will be responsible for development of supply adequacy mechanisms to be used by SPP as an RTO. Currently, SPP criteria requires that members maintain a minimum capacity margin of 12% unless their system is primarily hydro-based and then the capacity margin can be reduced to 9%. SPP is developing additional market operations processes to compliment SPP’s current method of addressing generation deliverability concerns, e.g., the SPP Automatic Reserve Share Program.

Fuel

All fuel supplies throughout the summer 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. Hydro capacity represents a small fraction of the total resources in SPP. The water levels are extremely low at this moment but they are on the rise and with the normal expected inflow, the levels will be back to maximum capacity by the end of the summer. The coal supply issue due to the PRB railroad issue is not considered to be a high-risk issue by SPP members regarding supply adequacy. Natural gas sources are abundant in the SPP region and are not considered to be at high risk regarding supply adequacy or security. Managing and predicting the energy output from intermittent resources like run-of-river hydro and wind farms are more challenging. However, these resources are not expected to provide a significant portion of the region’s capacity during peak demand conditions.

Transmission

Aquila added a new 345/161-kV transformer near Peculiar, Missouri. In addition, Southwestern Public Service (SPS) in February added a new 25 mile 230-kV line from Seven Rivers-Eddy County with a

230/115-kV step down transformer at Seven Rivers in Eddy County, New Mexico. KCPL recently reconductored the 41 mile LaCygne-W. Gardner 345-kV line. The Arcadia 345-kV bus (OKGE) is undergoing terminal upgrades that are sponsored by Redbud Energy as a requested upgrade under the SPP Open Access Transmission Tariff (OATT). The transmission system within SPP is expected to perform reliably over the 2006 summer demand season.

Regional imports into SPP from TVA and Entergy are limited by the Danville-Magazine 161-kV line at a 200-MW level which is marginally adequate. Imports into SPP north from Ameren are also limited by the Montgomery-Guthrie 161-kV line at a 150 MW level which is also marginally adequate. SPP will continue to work with Entergy and Ameren to address these constraints. On an annual basis, SPP uses the Model Development Working Group to gather information and coordinate data to be used in the development of new load flow model sets. The models constructed by SPP contain grandfathered transactions as well as SPP OATT transactions and the projected renewal rights for all such transactions. These models are used to determine necessary transmission upgrades and generation dispatches to provide reliable transmission service from designated resources to support firm off-system sales as well as the native load requirements within the SPP footprint.

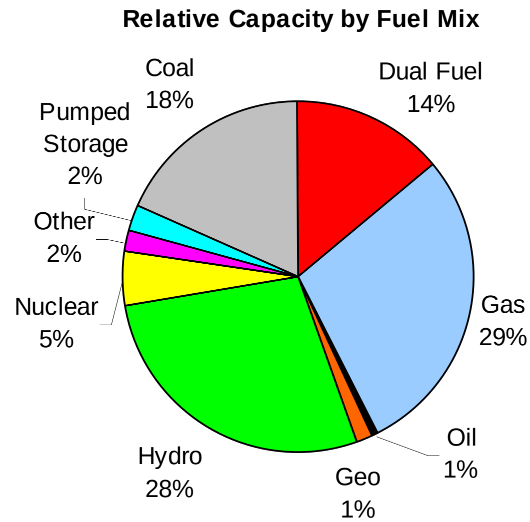
Operational Issues

SPP operations personnel anticipate normal summer operations. No known unusual operating conditions are expected to impact reliability for the upcoming summer, nor are any scheduled maintenance outages expected to be of operational concern.

SPP's 50 members serve more than four million customers and cover a geographic area of 400,000 square miles containing a population of more than 18 million people. SPP's current membership consists of 14 investor-owned utilities, six municipal systems, eight generation and transmission cooperatives, three state authorities, one federal government agency, two independent power producers, and 16 power marketers.

WECC

Projected Total Internal Demand	150,581	MW
Interruptible Demand & DSM	3,073	MW
Projected Net Internal Demand	147,508	MW
Last Summer's Peak Demand	149,409	MW
Change	0.8	%
All-Time Summer Peak Demand	149,409	MW
Deliverable Internal Capacity	186,277	MW
Projected Purchases	501	MW
Projected Sales	224	MW
Net Capacity Resources	186,554	MW
Capacity Margin	20.9	%
Reserve Margin	26.5	%
With Uncommitted Resources		
Total Potential Resources	186,554	MW
Capacity Margin	20.9	%
Reserve Margin	26.5	%



Demand

The Western Electricity Coordinating Council's (WECC) aggregate 2006 summer total internal demand is forecast to be 150,581 MW (U.S. systems 131,403 MW, Canadian systems 17,265 MW, and Mexican system 1,913 MW). The forecast is based on normal weather conditions and is 0.8% above last summer's actual peak demand, which was established under generally normal to below normal temperatures in the region. The 2006 summer total internal demand forecast is 3.0% greater than the 2005 summer total internal demand forecast of 146,246 MW. Firm capacity commitments to external areas total 224 MW. The internal demand forecast includes 759 MW of direct control demand-side management capability and 2,314 MW of interruptible demand capability.

Demand Sensitivity Analysis

WECC has not established an interconnection-wide process for addressing the issue of planning for peak demand uncertainty and variability in demand due to weather and other conditions. Individual entities within the interconnection, however, have addressed multiple uncertainties and variability issues as a part of either their integrated resources plan procedures or other similar processes. Those various independent processes generally report that reserve margins in the mid-teens provide sufficient cushion relative to multiple uncertainties, in all areas except for the southern California area. The Northwest Power Pool, California Energy Commission, and CAISO have publicly available documents on their respective Web sites that address 2006 summer conditions. Those documents are available at:
http://www.nwpp.org/publications.html, (2006 summer has not been posted as of April 17, 2006)
http://energy.ca.gov/2005publications/CEC-700-2005-026/CEC-700-2005-026-SD.PDF,
http://www.caiso.com/14e2/14e2c7ad4ea10.pdf (the CAISO document is its preliminary report. The final report has not been posted as of April 17, 2006).

Energy

The WECC 2006 summer energy is forecast to be 300,193 GWh, which is 4.9% above last summer's energy of 286,144 GWh and is 0.6% greater than the 2005 forecast energy of 298,280 GWh. The 2005 summer temperatures were near normal to below normal for much of the region.

Resources

For the peak summer month of July, WECC expects a capacity margin of 20.9%, which corresponds to a 26.5% reserve margin. WECC's reserve margin last summer was 22.0%. Net capacity for this summer is expected to be 186,554 MW compared to 179,180 MW for the summer of 2005. The net capacity resources of 186,554 MW include 501 MW of firm capacity purchases from external areas.

Net generation capacity has increased by about 3,250 MW from last October through May 2006. The net generation capacity increase is net of the shutdown of the 1,580-MW Mohave coal-fired plant and about 960 MW of wind capability derates. Net generation capacity additions during the 2006 summer period are expected to total about 70 MW, including about 452 MW of nameplate wind capability, derated by 400 to 52 MW. The capacity resource margin in the northern California area may be slightly reduced from the reported values due to the potential economic shutdown announced by two plants in the San Francisco area totaling a little more than 1,000 MW. The CAISO is currently in commercial discussions with the plant owner regarding payments or other alternatives for plant operations, if needed, during the summer peak.

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 hydroelectric resource capability has been reduced by about 5,600 MW in the NWPP subregion due to the impact that upstream or downstream operations might have on hydro facilities in the middle of the reference area, scheduled maintenance, and other factors. In addition, hydro resource capability has been reduced by 670 MW in the Rocky Mountain Power Area and Arizona-New Mexico-Southern Nevada Power area subregions, and 1,850 MW in the California-Mexico subregion to reflect historical hydro capacity experience with runoff conditions and water user requirements. Near-term precipitation has been near normal in major river basins in the Western Interconnection so hydroelectric energy generation is expected to be near normal for most of the interconnection. However, Colorado River generation may still be reduced somewhat as Glen Canyon and Hoover Dam reservoirs start a refill recovery from the drought of the early 2000s.

WECC has not established a formal regional resource adequacy criterion. However, WECC has a "Minimum Reserve Requirements" planning methodology developed specifically for assessing adequacy of power supply on a subregional basis. The forecast capacity margin of 20.9% exceeds the 12.3% capacity margin established by the methodology.

Fuel

WECC has not implemented a formal fuel supply interruption analysis methodology and does not consider such conditions in any formal assessment process. 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. While many of the older gas-fired generators in the region have backup fuel capability and normally carry an inventory of backup fuel, 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 Permian Basin in west Texas, from gas fields in the Rocky Mountains, and from western Canada. A fuel supply survey taken last fall indicated that only a handful of coal-fired plants have been directly affected by last year's coal delivery interruptions from the Power River Basin coal fields. The operators of those plants reported experiencing supply interruptions during the summer and had reported that winter deliveries had returned to normal.

It is not expected that extremes of summer weather during peak demand 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.

As noted above, plants relying on PRB coal that have experienced fuel deliverability problems may experience minimum on-site storage conditions. WECC does not have a process for monitoring fuel inventory conditions and does not monitor fuel acquisitions by entities within the Western Interconnection.

Transmission

WECC and subregional 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 demand and resource scenarios and operating procedures are developed to maintain safe and reliable operations. 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 the operating studies.

Many operating entities within the region have reported that they did not experience significant new flow patterns last summer, but flow patterns are expected to change this summer due to an increase in series compensation on the transmission ties between Arizona and California. The upgrades to the Palo Verde-Devers 500-kV line and the 500-kV Southwest Power link will increase southern California import capability by 400 MW into that region, from 9,700 to 10,100 MW. The southern California area relies on significant amounts of imported power and it is expected that the transmission into that area of the Western Interconnection will be heavily loaded much of the time.

The transmission system is considered adequate for all projected firm transactions but is expected to have a limited ability to support unusually large amounts of economy energy transfers. Consequently, schedule curtailments on constrained paths may increase compared with last summer. Reactive reserve margins are expected to be adequate for all expected peak demand conditions. 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 500 MW of net capacity imports are planned for the 2006 summer period. The net nonsimultaneous capacity imports for the 2005 summer were about 700 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.

Operational Issues

WECC does not expect major generating unit outages, transmission facility outages, or unusual operating conditions that would adversely impact reliable operations this summer. However, a 1,243-MW unit at the Palo Verde nuclear station has been experiencing mechanical problems and has been operated at a significantly reduced output for several months. The unit is scheduled to undergo a June shutdown for approximately five weeks to correct a long-standing vibration problem but the shutdown is not expected to result in a capacity inadequacy condition, and the capacity is not being counted on for this summer.

No environmental or regulatory restrictions have been reported that are expected to adversely impact reliability.

As mentioned above, the southern California area is highly reliant on imports from other areas to meet its load responsibility. Under normal operating conditions the transfer capability is sufficient to serve the import requirements. However, the CAISO's 2006 Summer Operations Assessment states that its control area high demand forecast is 2,660 MW above the forecast used for this assessment and that it may need to call upon demand response and interruptible loads in response to high demand and major change in its control area-wide resources in the range of 3,000 MW.

Subregions

California–Mexico Power Area

This is a summer-peaking area. The 2006 summer peak demand forecast of 59,037 MW is 2.9% above last summer's actual peak demand of 57,389 MW. The forecast peak demand includes 2,062 MW of interruptible demand and load management. The projected capacity margin for the peak month is 13.3%.

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 summer. 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. However, 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.

Arizona-New Mexico-Southern Nevada Power Area

This is a summer peaking area. The 2006 summer peak demand forecast of 28,685 MW is 1.6% above last summer's actual peak demand of 28,236 MW. Last summer's peak demand was higher than expected due to relatively hot temperatures. The forecast for the area includes 335 MW of load management and interruptible demand capability. The projected capacity margin for the peak month is 20.0%. An extended outage of the Palo Verde plant would reduce the July AZ-NM-SNV capacity margin from 20.0% to about 18%. The CA-MX margin would be unchanged as planned purchases from NWPP would be increased to offset the approximately 350-MW Palo Verde capacity reduction.

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 summer peak demand conditions. Prior to last year, the area experienced drought conditions and reduced water flows on the Colorado River and many other tributaries. However, due to improved water flows and improved current reservoir storage levels, it is expected that hydroelectric generation reductions will not be an issue for the 2006 summer period.

Rocky Mountain Power Area

The Rocky Mountain Power area's peak demand may occur in either summer or winter. The 2006 summer peak demand forecast of 11,323 MW is 2.1% higher than last summer's actual peak demand of 11,086 MW. Last summer's peak demand was higher than expected due to relatively hot temperatures. The forecast peak demand includes 216 MW of interruptible demand and load management capability. The projected capacity margin for the peak month is 13.3%.

For the first part of the decade, water inflows into the hydro system were below average, resulting in below average reservoir storage conditions. While inflows this past year or two have been much closer to normal, reservoir releases will be similar to last year and some purchases of energy may be required to supplement actual daily hydroelectric generation. 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 summer to provide line loading relief for these paths.

Northwest Power Pool (NWPP) Area

The Northwest Power Pool 2005 coincidental summer peak of 50,812 MW occurred on July 18, 2005. The 2005 coincidental summer peak was 98.7% of the forecast. The 2006 summer peak forecast for the power pool area, as one single entity, of 51,500 MW is based on normal weather, reflects the prevailing economic climate, and has a 50% probability of not being exceeded. The power pool peak area demand forecast includes approximately 200 MW of interruptible demand capability and load management.

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

***Resources* —** Over 60% of the NWPP 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* —** NWPP power planning is done by subarea. 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 MW of firm energy load carrying capability, when reservoirs start full. Under average water-year conditions, the additional nonfirm energy available is approximately 3,000 average MW.

The 2006 mid-February forecast for the January through July Volume Runoff (Columbia River flows) at The Dalles, Oregon, is 106 million acre-feet, or 99% of the 30-year average.

Last year, the Coordinated System hydro reservoirs refilled to approximately 93.8% of the Energy Content Curve by July 31, 2005.

April Through July — This period is the refill season when reservoirs store spring runoff. The water fueling associated with hydro powered resources can be difficult to manage because of 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. Any time precipitation levels are below normal, balancing these interests becomes even more difficult.

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 maximize the hydrology throughout the year while ensuring all the competing purposes are evaluated. Since hydro can be limited due to several 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 more relative to the northwest in the winter; however, under summer extreme low water conditions, it impacts summer conditions.

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 summer peak.

Transmission — Constrained paths within the NWPP 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 coordinates seasonal inter-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 projects are scheduled for the summer of 2006. The recent completion of the Bonneville Power Administration’s Schultz-Wautoma 500-kV project and Puget Sound Energy’s reconductoring of the Bothell-Sammamish 230-kV line should benefit the North of John Day and Northern Intertie paths, respectively.

The Pacific DC Intertie (PDCI) will have a 3,100 MW north-to-south (export) limit. The PDCI south-to-north (import) limit will be 2,200 MW due to lack of direct service industry (DSI) load tripping remedial action.

It is anticipated that the West of Hatwai path will have a 4,065-MW operating transfer limit for the summer period.

Operations — Control areas 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, 7-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.

During late 2000 and 2001, electricity demand decreased due to concerns surrounding the electricity crisis, large increase in electricity rates (retail and wholesale), and an economic slowdown. The northwest DSI, which are mostly aluminum smelters, electricity consumption dropped from just above 2,500 average MW in 2000 to less than 500 average MW in 2002. It is anticipated that the electricity consumption for the DSIs will remain relatively flat at 500 MW for the summer of 2006 season.

The NWPP has developed an adequacy response process whereby a team addresses the area's ability to avoid a power emergency by promoting regional coordination and communications. Essential pieces of that effort include timely analyses of the power situation and communication of that information to all parties including, but not limited to, utility officials, elected officials, and the general public.

In the fall of 2000, the area developed an Emergency Response (ER) 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.

WECC's 174 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 councils. WECC's service territory extends from Canada to Mexico, including the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 western states between. Transmission lines span long distances connecting the verdant Pacific Northwest with its abundant hydroelectric resources to the arid Southwest with its large coal-fired and nuclear resources.

Table 2: Generating Units Scheduled for Initial Service, Retirement, or Rerating March 2006 through September 2006

Region	Facility	Adds	Deducts	Unit Type	Fuel Type	Change To Unit	Projected Operating Date
ERCOT	Big Spring Electricity Generating Facility	16.5	-	Steam Turbine	Unknown	New	April
	Horse Hollow 2 East	112.5	-	Wind	Wind	New	June
	Horse Hollow 2 West	186.3	-	-	-	-	-
	Limestone Upgrade	110.0	-	Steam Turbine	Lignite	New	May
	Red Canyon 1	84.0	-	Wind	Wind	New	June
FRCC	Brandy Branch 4	13.0	-	Combined Cycle	Natural Gas	Uprate	April
	Cape Canaveral 1	3.8	-	Combustion Turbine	Natural Gas	Uprate	June
	Cape Canaveral 2	-	5.0	Steam Turbine	Residual Fuel Oil	Derate	June
	Central Energy Plant 1	17.0	-	Combined Cycle	Natural Gas	Uprate	February
	Cutler 5	8.0	-	Steam Turbine	Residual Fuel Oil	Uprate	June
	Cutler 6	3.0	-	Steam Turbine	Natural Gas	Uprate	June
	Ft. Myers 1	33.0	-	Steam Turbine	Natural Gas	Uprate	June
	J. D. Kennedy Gt7	22.0	-	Other	Bituminous Coal	Uprate	June
	Manatee 2	3.8	-	Combustion Turbine	Natural Gas	Uprate	June
	Martin 1	-	6.0	Steam Turbine	Residual Fuel Oil	Derate	June
	Martin 3	-	7.0	Steam Turbine	Residual Fuel Oil	Derate	June
	Martin 4	6.0	-	Steam Turbine	Residual Fuel Oil	Uprate	June
	Northside 1	13.0	-	Steam Turbine	Residual Fuel Oil	Uprate	June
	Port Everglades St1	22.0	-	Combined Cycle	Natural Gas	Uprate	June
	Port Everglades St3	22.0	-	Combined Cycle	Natural Gas	Uprate	June
	Port Everglades St4	8.9	-	Steam Turbine	Petroleum Coke	Uprate	June
	Putnam 1St	-	7.0	Steam Turbine	Residual Fuel Oil	Derate	June
	Riviera 3	8.0	-	Steam Turbine	Residual Fuel Oil	Uprate	June
	Sanford 4	12.0	-	Steam Turbine	Residual Fuel Oil	Uprate	June
	Sanford 5	4.0	-	Combined Cycle	Natural Gas	Uprate	June
	St. Johns River 2	14.0	-	Steam Turbine	Residual Fuel Oil	Uprate	June
	Stock Island Ct4	42.0	-	Combustion Turbine	Distillate Fuel Oil	New	July

Table 2 (cont.): Generating Units Scheduled for Initial Service, Retirement, or Rerating March 2006 through September 2006

Region	Facility	Adds	Deducts	Unit Type	Fuel Type	Change To Unit	Projected Operating Date
FRCC	University Of Florida P1	10.0	-	Combustion Turbine	Natural Gas	Uprate	March
MRO Canada	Poplar River 2	10.0	-	Steam Turbine	Lignite	Uprate	July
MRO U.S.	Arcadia Electric 10	2.0	-	Internal Combustion	Distillate Fuel Oil	New	June
	Belleville, KS 4	0.5	-	Internal Combustion	Natural Gas	Uprate	May
	Belleville, KS 6	3.1	-	Internal Combustion	Natural Gas	Uprate	May
	Canaday 1	25.0	-	Steam Turbine	Natural Gas	Uprate	May
	Columbus 3	4.0	-	Hydro	Water	Uprate	March
	Elk City Station 5	0.8	-	Internal Combustion	Landfill Gas	New	June
	Elk City Station 6	0.8	-	Internal Combustion	Landfill Gas	New	June
	Fort Calhoun 1	5.0	-	Steam Turbine	Nuclear	Uprate	May
	Glencoe 14	4.8	-	Internal Combustion	Distillate Fuel Oil	New	June
	Groton 1	95.0	-	Combustion Turbine	Natural Gas	New	June
	Lakefront 9	58.4	-	Steam Turbine	Petroleum Coke	New	April
	Ottumwa 1	22.4	-	Steam Turbine	Subbituminous Coal	Uprate	June
	Timberline Trail Landfill	3.2	-	Internal Combustion	Landfill Gas	New	March
	Wessington Springs Power Plant	3.6	-	Internal Combustion	Distillate Fuel Oil	New	September
NPCC ISO-NE	Uconn Cogen	24.9	-	Combined Cycle	Gas/Oil	New	June
NPCC Maritimes	None	-	-	-	-	-	-
NPCC NYISO	Scs Astoria	500.0	-	Combined Cycle	Natural Gas	New	May
NPCC Ontario	Erie Shores Wind Farm	99.0	-	Wind	Wind	-	May
	Hamilton Community Digester Energy	2.0	-	Steam	Sewage	-	July
	Nuclear Uprate	17.0	-	Steam	Uranium	-	July
	Prince Wind Farm	99.0	-	Wind	Wind	-	September
NPCC Quebec	Beauharnois G.S.	3.0	-	Hydro	-	Uprate	August
	Robert Bourrassa G.S. (Lg2)	6.0	-	Hydro	-	Uprate	August
	Transcanada Energy (Bécancour)	507.0	-	Cogeneration	Natural Gas	New	September
RFC	Arnold	10.0	-	Wind	Wind	New	March
	Bear Creek	34.0	-	Wind	Wind	New	March
	Bustleton	7.1	-	Combustion Turbine	Natural Gas	New	March

Table 2 (cont.): Generating Units Scheduled for Initial Service, Retirement, or Rerating March 2006 through September 2006

Region	Facility	Adds	Deducts	Unit Type	Fuel Type	Change To Unit	Projected Operating Date
RFC	Chicago Heights	20.0	-	Steam	Municipal Solid Waste	New	March
	Colora 5	155.0	-	Combustion Turbine	Natural Gas	New	March
	Colora 6	155.0	-	Combustion Turbine	Natural Gas	New	March
	Daleville	1.6	-	Internal Combustion	Landfill Gas	New	March
	Frackville-Hauto	24.0	-	Wind	Wind	New	June
	Geneva	29.0	-	Combustion Turbine	Natural Gas	New	March
	Grangston	6.0	-	Combustion Turbine	Natural Gas	New	March
	Greenland Gap	300.0	-	Wind	Wind	New	September
	Harrisburg	22.0	8.0	Steam	Municipal Solid Waste	Retire old unit, add new	May
	Kelso Gap	99.0	-	Wind	Wind	New	March
	Lakewood CT3	167.0	-	Combustion Turbine	Natural Gas	New	March
	Lasalle (Wind)	150.0	-	Wind	Wind	New	May
	Letort	3.2	-	Internal Combustion	Landfill Gas	New	March
	Linden 1	436.0	-	Combined Cycle	Natural Gas	New	April
	Linden 2	750.0	-	Combined Cycle	Natural Gas	New	April
	Mitchell CT	17.0	-	Combustion Turbine	Natural Gas	Reactivate	April
	Motiva	142.0	-	Steam	Oil	New	March
	Pequest River	4.0	-	Internal Combustion	Landfill Gas	New	June
	Poplar Grove	25.0	-	Wind	Wind	New	September
	Prairie View 2	3.2	-	Internal Combustion	Landfill Gas	-	July
	Rochelle	2.0	-	Internal Combustion	Oil	New	March
	Rochelle	20.0	-	Internal Combustion	Oil	New	March
SERC Entergy	None	-	-	-	-	-	-
SERC Gateway	Audrain 1-8	600.0	-	Combustion Turbine	Natural Gas	New	April
	Goose Creek 1-6	430.0	-	Combustion Turbine	Natural Gas	New	April
	Racoon Creek 1-4	300.0	-	Combustion Turbine	Natural Gas	New	April
SERC Southern	Hatch 1	106.0	-	Nuclear	Nuclear	Uprate	April
	Moselle Moselle Unit #5	75.0	-	Combustion Turbine	Natural Gas	New	June
SERC TVA	Boone 2	6.3	-	Hydro	Water	Uprate	August
	Raccoon Mountain 2	18.3	-	Pumped Storage	Water	Uprate	July

Table 2 (cont.): Generating Units Scheduled for Initial Service, Retirement, or Rerating March 2006 through September 2006

Region	Facility	Adds	Deducts	Unit Type	Fuel Type	Change To Unit	Projected Operating Date
SERC VACAR	Albemarle Hospital 1	1.8	-	Internal Combustion Engine	Distillate Fuel Oil	New	June
	Albemarle Prime Power Park 1	1.8	-	Internal Combustion Engine	Distillate Fuel Oil	New	March
	Albemarle Prime Power Park 2	1.8	-	Internal Combustion Engine	Distillate Fuel Oil	New	March
	Bath County 3	37.0	-	Pumped Storage	Water	Uprate	April
	Cherryville City Hall 1	1.8	-	Internal Combustion Engine	Distillate Fuel Oil	New	June
	Lincolnton High School 1	1.8	-	Internal Combustion Engine	Distillate Fuel Oil	New	June
	Maiden Community Center 1	1.8	-	Internal Combustion Engine	Distillate Fuel Oil	New	June
	Monroe Middle School 1	1.8	-	Internal Combustion Engine	Distillate Fuel Oil	New	June
	Morganton Station 5 1	1.8	-	Internal Combustion Engine	Distillate Fuel Oil	New	June
	Pineville Delivery 1 1	1.8	-	Internal Combustion Engine	Distillate Fuel Oil	New	June
	US DOE Savannah River Site (D-Area) 1	-	35.0	Fossil	Bituminous Coal	Retire	June
SPP	Hargis	98.0	-	Combustion Turbine	Natural Gas	New	June
WECC AZ-NM-SNV	Abiquiu 3	3.0	-	Hydro	Water	New	April
	Allen GT 2	77.0	-	Combustion Turbine	Natural Gas	New	June
	Chuck Lenzie Cc 2	580.0	-	Combined Cycle	Natural Gas	New	April
	Lanl Ta-3 4	21.0	-	Combustion Turbine	Natural Gas	New	June
	Luna	570.0	-	Combined Cycle	Natural Gas	New	May
	Santan	275.0	-	Combined Cycle	Natural Gas	New	May
	Springerville 3	400.0	-	Steam	Coal	New	July
WECC CA-MX-MX	None	-	-	-	-	-	-
WECC CA-MX-US	Castaic 4	13.0	-	Pumped Storage	Water	Uprate	June
	Chula Vista	44.0	-	Combustion Turbine	Natural Gas	New	June
	Cosumnes CC 1	500.0	-	Combined Cycle	Natural Gas	New	March

Table 2 (cont.): Generating Units Scheduled for Initial Service, Retirement, or Rerating March 2006 through September 2006

Region	Facility	Adds	Deducts	Unit Type	Fuel Type	Change To Unit	Projected Operating Date
WECC CA-MX-US	Escondido	44.0	-	Combustion Turbine	Natural Gas	New	June
	Hunters Point Gt 1	-	52.0	Combustion Turbine	Natural Gas	Retire	May
	Hunters Point 4	-	163.0	Steam	Natural Gas	Retire	May
	Palomar CC 1	559.0	-	Combined Cycle	Natural Gas	New	April
	Riverside	96.0	-	Combustion Turbine	Natural Gas	New	April
	Solano	24.0	-	Wind	Wind	New	July
	Walnut CC 1	269.0	-	Combined Cycle	Natural Gas	New	March
WECC Canada	Brilliant Expansion	120.0	-	Hydro	Water	New	August
	Castle Rock	115.0	-	Wind	Wind	New	September
	Chin Chute	30.0	-	Wind	Wind	New	July
	China Creek	3.0	-	Hydro	Water	New	April
	Kettles Hill 1-5	9.0	-	Wind	Wind	New	March
	Kettles Hill 6-30	54.0	-	Wind	Wind	New	July
	Long Lake	228.0	-	Combustion Turbine	Natural Gas	New	March
	Soderglen	11.0	-	Wind	Wind	New	May
	Syncrude UE1	27.0	-	Combined Cycle	Natural Gas	New	March
WECC NWPP	Big Horn	200.0	-	Wind	Wind	New	May
	Cep Arlington	200.0	-	Wind	Wind	New	May
	Current Creek Cc	516.0	-	Combined Cycle	Natural Gas	Conversion to CC	May
	Current Creek Gt	-	280.0	Combustion Turbine	Natural Gas	Conversion to CC	May
	Desert Peak 2	15.0	-	Geothermal	Geothermal Steam	New	June
	Hidden Hollow	3.0	-	Internal Combustion	Landfill Gas	New	April
	Leaning Juniper	200.0	-	Wind	Wind	New	May
	Oregon Trails	11.0	-	Wind	Wind	New	May
	Pilgrim Stage	11.0	-	Wind	Wind	New	May
	Rocky Mtn Hardin	109.0	-	Steam	Coal	New	March
	Thousand Springs	11.0	-	Wind	Wind	New	May
	Tuna Gulch	11.0	-	Wind	Wind	New	May
	Wild Horse	229.0	-	Wind	Wind	New	September
WECC RMPA	Gross	-	-	Hydro	Water	New	June

Table 3: Transmission System Additions and Upgrades (230 kV and above)
March 2006 through September 2006

Region	Facility	Adds	Deducts	Capacity MVA	Voltage kV	Type Of Change	Projected Operating Date
ERCOT	Watermill-West Levee Second Circuit	9.0	-	-	345	New	April
	Venus-Johnson Line	10.2	-	-	345	New	May
	Jewett-Tomball Line	16.0	-	-	345	Upgrade	May
	Jewett-T H Wharton Line	32.0	-	-	345	Upgrade	May
	Adicks Autotransformer	-	-	600	345/138	New	July
	Bellaire Autotransformer (A2)	-	-	800	345/138	New	June
	Clear Springs Autotransformer	-	-	478	345/138	New	June
	Greens Bayou Autotransformer	-	-	800	345/138	Upgrade	June
	Nelson Sharpe Autotransformer	-	-	675	345/138	New	May
	Rio Hondo Autotransformer	-	-	675	345/138	New	May
	Tomball Two Autotransformers	-	-	800	345/138	New	June
	Valley 345/138 Autotransformer	-	-	600	345/138	New	May
FRCC	None	-	-	-	-	-	-
MRO Canada	None	-	-	-	-	-	-
MRO U.S.	Wilmarth - Mankato Energy Center	0.8	-	-	345	New	March
	Columbia - North Madison	17.0	-	1361	345	New	June
	Birchtree - Wuswatim	28.0	-	564.5	230	New	March
	Gardner Park - Stone Lake	140.0	-	1200	345	New	June
NPCC ISO-NE	Stoughton - Hyde Park	11.2	-	520	345	New	June
	Stoughton - K Street	15.4	-	520	345	New	June
	Southington - Haddam Neck	-	-	1470	345	Re-rating	September
NPCC Maritimes	None	-	-	-	-	-	-
NPCC NYISO	None	-	-	-	-	-	-
NPCC Ontario	Queenston Flow West	95.0	-	591	230	New	September
	Essa Shunt Capacitor	-	-	240	230	New	June
NPCC Quebec	Eastmain 1 - Nemiscau (Double Circuit Line)	36.9	-	3270	315	New	August
	Eastmain 1 Transformer	-	-	166	13.8/315	New	August
	Nemiscau Transformer	-	-	1650	735/315	New	August
	Nemiscau Transformer	-	-	1650	735/315	New	August

Table 3 (cont.): Transmission System Additions and Upgrades (230 kV and above)
March 2006 through September 2006

Region	Facility	Adds	Deducts	Capacity MVA	Voltage kV	Type Of Change	Projected Operating Date
RFC	Red Lion - Milford	43.0	-	750	230	New	June
	Milford - Indian River	47.0	-	750	230	New	June
	Wyoming - Jacksons Ferry	90.0	-	3975	765	New	June
	Roberts T-1	-	-	831 / 934	345/138	Transformer replacement with higher capacity bank	June
	Miami Fort Tb 10	-	-	422 / 474	345/138	Transformer replacement with higher capacity bank	April
	Lenox	-	-	624 / 681	345/120	Transformer replacement with higher capacity bank	April
	Clifty Creek T-100a	-	-	513/576	345/138	Transformer replacement with higher capacity bank	April
SERC Entergy	Steelville-Cuba	11.3	-	203	161	Conversion	April
	Salem-Steelville	20.9	-	203	161	Conversion	April
SERC Gateway	Grindstone To Boone	2.5	-	223	161	New	June
	Grindstone To Rebel	2.5	-	223	161	New	June
	Jeff City-Guthrie	4.0	-	335	161	New	June
	Jeff City-Apache Flats	12.0	-	335	161	New	June
	Newton-Casey	26.5	-	1319	345	Re-rating	June
SERC Southern	Villa Rica - Boat Rock	5.0	-	602	230	New	June
	Cedar Hill-Portland (Line Segment)	11.0	-	602	230	New	May
	Mcgrau Ford-Blankets Creek	17.0	-	602	230	New	April
	Dresden - South Coweta	23.5	-	602	230	New	May
	South Bessemer-Duncanville	27.0	-	502	230	Re-rating	March
	Blankets Creek Substation	-	-	400	230	New	May
	Dresden Switching Station	-	-	0	230	New	May
	Norcross Capacitor Bank	-	-	180 Mvar	230	New	May
	Portland Substation	-	-	400	230	New	June
	South Coweta	-	-	400	230	New	May
	Villa Rica Primary Substation	-	-	400	230	New	April
SERC TVA	Guntersville Hydro-Georgia Mtn. Tap	10.6	-	391	161	Re-rating	June
	Gallatin-Portland	18.7	-	371	161	Re-rating	May
	Volunteer-Cherokee	19.1	-	371	161	Re-rating	June

Table 3 (cont.): Transmission System Additions and Upgrades (230 kV and above)
March 2006 through September 2006

Region	Facility	Adds	Deducts	Capacity MVA	Voltage kV	Type Of Change	Projected Operating Date
SERC TVA	Roane Reactors	-	-	120	500	New	April
	Roane Transformer Replacement	-	-	1344	500/161	New	April
SERC VACAR	Hopkins - Hopkins Tap	1.0	-	475	230	New	April
	Hopkins - Hopkins Tap	1.0	-	475	230	New	April
	Beaumeade - Greenway	6.0	-	796	345	New	May
	Chesapeake - Greenwich	11.0	-	705	230	Re-rating	May
	Camden-Dalzell	20.0	-	956	345	New	June
	Riverview - Ripp Sw Sta	29.1	-	956	230	Re-rating	May
	Riverview - Ripp Sw Sta	29.1	-	956	230	Re-rating	May
	Doubs - Mt Storm	99.0	-	2600	500	Re-rating	May
SPP	None	-	-	-	-	-	-
WECC AZ-NM-SNV	Las Vegas - Las Vegas	1.0	-	2787	525	New	March
	Fc – Cholla Cap Bank #1	-	-	117	345	New	March
	Fc – Cholla Cap Bank #2	-	-	117	345	New	March
	Fc – Moenkopi Cap Bank	-	-	100	500	New	June
	Hass – N.Gila Cap Bank	-	-	490	500	New	June
	Magnolia Sub Transformer	-	-	300	230/69	New	June
	Reach Sub Transformer	-	-	188	230/69	New	June
WECC CA-MX-MX	Nothing To Report	-	-	-	-	-	-
WECC CA-MX-US	Lugo - Serrano	-	50.0		500	Retirement	June
	Dublin - Livermore	8.0	-	400	230	New	May
	Mira Loma Serrano	22.0	-	2598	500	New	June
	Jefferson - Martin	27.0	-	420	230	New	June
	San Diego - San Diego	28.0	-	912	230	New	June
	Lugo - Mira Loma	31.0	-	2598	500	New	June
	Miguel - Mission	35.0	-	607	230	New	June
	Colgate Sub Transformer	-	-	75	230/60	Re-rating	June
	Midway Sub Transformer	-	-	420	230/115	Re-rating	July
	Path 15 Cap Bank Shunt 1	-	-	2310	230	New	April

Table 3 (cont.): Transmission System Additions and Upgrades (230 kV and above)
March 2006 through September 2006

WECC CA-MX-US	Path 15 Cap Bank Shunt 2	-	-	2310	230	New	April
	Path 49 Series Capacitor	-	-	1646	500	New	June
	Path 49 SVC	-	-	400	500	New	June
	Path 49 Transformer	-	-	1120	500/230	New	June
	Table Mt Sub Transformer	-	-	420	230/60	Re-rating	June
	Valley Sub Svc #1	-	-	100	500	New	February
	Valley Sub Svc #2	-	-	100	500	New	February
WECC Canada	90th South Loop-In	2.0	-	1396	345	New	June
	Nothing To Report	-	-	-	-	-	-
WECC NWPP	Terminal Sub Loop-In	2.0	-	1396	345	New	June
	Sherwood-Murrayhill #2	5.0	-	418	230	New	June
	Allston Transformer	-	-	300	230/115	New	June
	Boulder Transformer #2	-	-	250	230/115	New	June
	Camp Williams Cap Bank	-	-	160	345	New	June
	Copco Transformer	-	-	250	230/115	New	June
	Dillon Capacitor Bank	-	-	400	230	New	February
	Dry Creek Transformer	-	-	250	230/115	New	June
WECC RMPA	Nixon - Kelker	14.0	-	319	230	New	June

Definitions, Peer Review Process, and Abbreviations

How NERC Defines Bulk Power System Reliability

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

- Resource 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.
- Operating Reliability — The ability of the bulk power system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

Peer Review Process

The Reliability Assessment Subcommittee uses a three-phase approach in its peer reviews process during the preparation of reliability assessments. First, prior to the subcommittee meeting(s), each regional self assessment is individually assigned to a subcommittee member (from another region) for an in depth, comprehensive review of the self assessment. The results of that analysis are reviewed with the writer(s) of the respective self assessment, and refinements/adjustments are made as necessary prior to the subcommittee meeting. Second, during the subcommittee meeting(s), each regional self assessment is subjected to a group scrutiny and review by the entire subcommittee. Finally, at each meeting a region is selected on a rotating basis to present a review of the assessment process used in their region following a broad set of questions aimed towards providing the subcommittee with a thorough understanding of that region's assessment procedures and practices.

Abbreviations Used In This Report

AZ-NM-SNV	Arizona-New Mexico-Southern Nevada (Subregion of WECC)
CA-MX	California-Mexico (Subregion of WECC)
CAISO	California Independent System Operator
CFE	Comision Federal de Electricidad
dc	Direct Current
ECAR	East Central Area Reliability Coordination Agreement
EECP	Emergency Electric Curtailment Plan
ERCOT	Electric Reliability Council of Texas
FRCC	Florida Reliability Coordinating Council
GRSP	Generation Reserve Sharing Pool
GTA	Greater Toronto Area
GWh	Gigawatthours
ICAP	Installed Capability
IESO	Independent Electric System Operator (in Ontario)
IROLS	Interconnection Reliability Operating Limits
ISO	Independent System Operator
ISO-NE	New England Independent System Operator
kV	kilovolts (thousands of volts)
LFU	Load Forecast Uncertainty

LOLE	Loss of Load Expectation
MAAC	Mid-Atlantic Area Council
MAIN	Mid-America Interconnected Network, Inc.
MAPP	Mid-Continent Area Power Pool
MEN	MAAC-ECAR-NPCC
MISO	Midwest Independent System Operator
MRO	Midwest Reliability Organization
MVA	Megavoltamperes
Mvar	Megavars
MW	Megawatts (millions of watts)
NERC	North American Electric Reliability Council
NPCC	Northeast Power Coordinating Council
NPPD	Nebraska Public Power District
NWPP	Northwest Power Pool Area (subregion of WECC)
NYISO	New York Independent System Operator
NYPP	New York Power Pool
OP-4	NEPOOL Operating Procedure 4 (Action During a Capacity Deficiency)
PAR	Phase Angle Regulators
PDCI	Pacific Direct Current Intertie
PJM	Pennsylvania-New Jersey-Maryland
PRB	Powder River Basin
RAS	Reliability Assessment Subcommittee
RFC	Reliability*First* Corporation
RFP	Request For Proposal
RMPA	Rocky Mountain Power Area (subregion of WECC)
RMR	Reliability Must Run
RTO	Regional Transmission Organization
SERC	Southeastern Electric Reliability Council
SOL	System Operating Limits
SPP	Southwest Power Pool
THI	Temperature Humidity Index
TLR	Transmission Loading Relief
TVA	Tennessee Valley Authority
VACAR	Virginia and Carolinas (subregion of SERC)
WECC	Western Electricity Coordinating Council
WTHI	Weighted Temperature-Humidity Index
WUMS	Wisconsin-Upper Michigan

Reliability Assessment Subcommittee

Kevin J. Dasso
Chairman
Sr. Director – Engineering & Planning
Pacific Gas & Electric Company

Kent Saathoff
ERCOT Representative
Director of System Operations
Electric Reliability Council of Texas

John E. Odom, Jr.
FRCC Representative
Manager of System Planning
Florida Reliability Coordinating Council

Hoa Nguyen
MRO Representative
Power Supply Coordinator
Montana–Dakota Utilities Company

John G. Mosier, Jr.
NPCC Representative
Director, Operations
Northeast Power Coordinating Council

Mark J. Kuras
RFC Representative
Senior Engineer, Interregional
Coordination and Compliance
PJM Interconnection, L.L.C.

Bernard M. Pasternack, P.E.
RFC Representative
Managing Director, Transmission
Asset Management
American Electric Power

H. Clay Young
SERC Representative
Manager, Transmission Planning
South Carolina Electric & Gas Company

Keith Tynes
SPP Representative
Manager, Planning
Southwest Power Pool

James Leigh-Kendall
WECC Representative
Supervisor, Power System Assessments
Sacramento Municipal Utility District

Masheed H. Saidi
Vice Chairman
Senior Vice President, U.S. Transmission
National Grid USA

K.R. (Chuck) Chakravarthi
IOU Representative
Manager, Interconnection and Special Studies
Southern Company Services, Inc.

John Lawhorn
ISO/RTO Representative
Manager, Economic Studies
Midwest ISO, Inc.

Robert Snow
FERC
Senior Electrical Engineer
Federal Energy Regulatory Commission

Scott Beecher
Alternate FRCC
Staff Engineer
Florida Reliability Coordinating Council

Christopher Plante
Alternate MRO
Director of Transmission Analysis
WPS Resources Corporation

Glenn P. Catenacci, PE
Alternate RFC
Staff Engineer
Public Service Electric and Gas Company

Jeffrey L. Mitchell
Alternate RFC
Director, Engineering
Reliability*First* Corporation

Poonum Agrawal
DOE Liaison
Program Manager/Engineer
U.S. Department of Energy

William W. Lohrman
NERC Manager of Reliability Assessments
North American Electric Reliability Council

Shaun E. Streeter
NERC Staff Analyst
North American Electric Reliability Council