2003/2004 WINTER ASSESSMENT

Reliability of the Bulk Electricity Supply in North America

North American Electric Reliability Council

November 2003

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Introduction

The North American Electric Reliability Council (NERC) Reliability Assessment Subcommittee (RAS) prepared this independent assessment of the reliability of the bulk electricity supply and demand in North America for December 2003 through February 2004, the *2003/2004 Winter Assessment*. This report assesses the expected peak demand and available resources to meet that demand this winter based upon data submitted by the Regions as of October 3, 2003. Where possible, updates to the data have been incorporated through October 27, 2003. This report also addresses transmission reliability issues. NERC does not make projections or draw conclusions in this report regarding expected electricity prices for the winter.

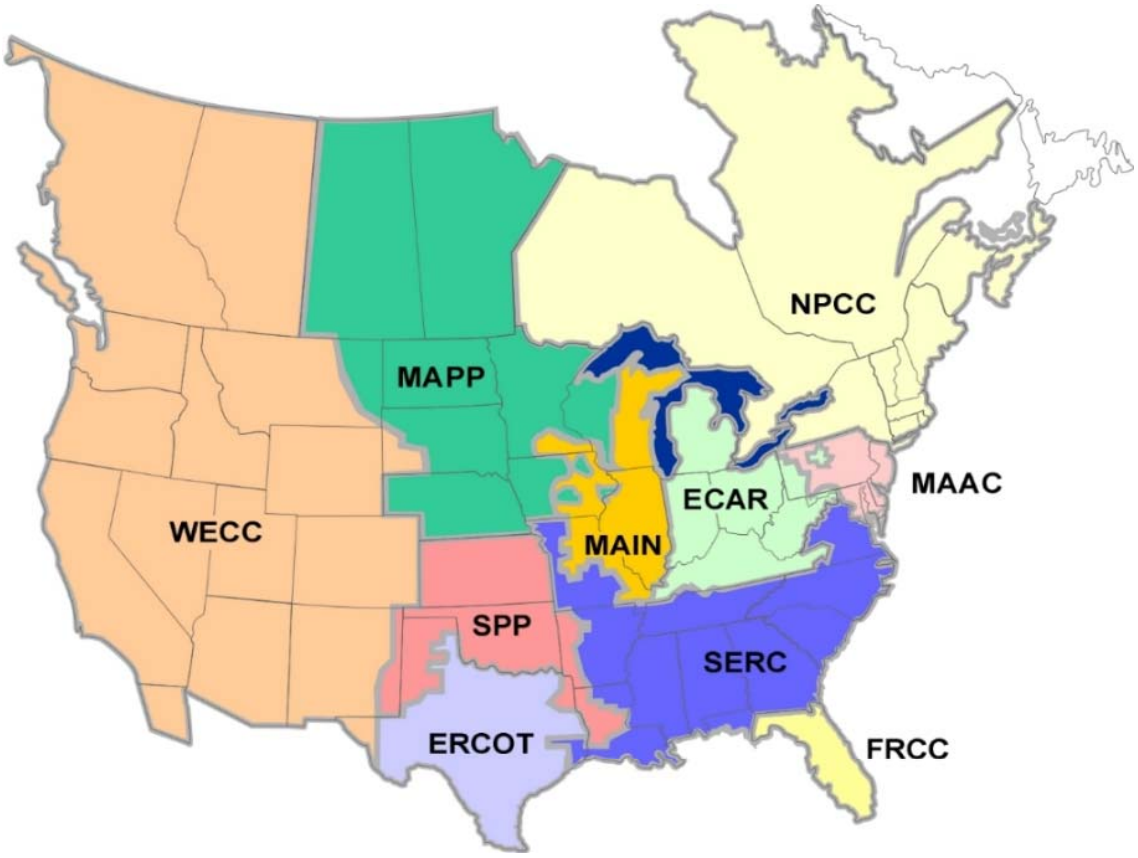
About NERC

The mission of the North American Electric Reliability Council (NERC) is to ensure that the bulk electric system in North America is reliable, adequate, and secure. Since its formation in 1968, NERC has operated successfully as a voluntary organization, relying on reciprocity, peer pressure, and the mutual self-interest of all those involved. Through this voluntary approach, NERC has helped to make the North American bulk electric system the most reliable in the world.

NERC is a not-for-profit corporation whose members are ten regional reliability councils.[1] The members of these councils come from all segments of the electric industry: investor-owned utilities; federal power agencies; rural electric cooperatives; state, municipal, and provincial utilities; independent power producers; power marketers; and end-use customers. These entities account for virtually all the electricity supplied and used in the United States, Canada, and a portion of Baja California Norte, Mexico.

1 See Figure 1— NERC Region map on the following page.

FIGURE 1 – NERC RELIABILITY REGIONS



ECAR
East Central Area Reliability Coordination Agreement

ERCOT
Electric Reliability Council of Texas

FRCC
Florida Reliability Coordinating Council

MAAC
Mid-Atlantic Area Council

MAIN
Mid-America Interconnected Network, Inc.

MAPP
Mid-Continent Area Power Pool

NPCC
Northeast Power Coordinating Council

SERC
Southeastern Electric Reliability Council

SPP
Southwest Power Pool

WECC
Western Electricity Coordinating Council

Northeast Blackout

On August 14, 2003, the northeast portion of the Eastern Interconnection experienced a widespread, cascading blackout affecting up to 50 million people. NERC is participating in the ongoing investigation being conducted by the U.S./Canada Power System Outage Task Force. A report describing the sequence of events and other related information as of September 11, 2003 can be found on the NERC website at: Blackout Investigation (www.nerc.com). The task force expects to issue its "interim report" on November 18, 2003.

On October 15, 2003, NERC requested that each entity in North America that operates a control area and each NERC reliability coordinator review a list of reliability practices to ensure that organizations are within NERC and regional reliability council standards and established good utility practices. The list covered the following items:

1. **Voltage and Reactive Management**: Ensure sufficient voltage support for reliable operations.

2. **Reliability Communications**: Review, and as necessary strengthen, communication protocols between control area operators, reliability coordinators, and ISOs.

3. **Failures of System Monitoring and Control Functions**: Review and establish, as necessary, a formal means to immediately notify control room personnel when SCADA or EMS functions, that are critical to reliability, have failed and when they are restored.

4. **Emergency Action Plans**: Ensure that emergency action plans and procedures are in place to safeguard the system under emergency conditions by defining actions operators may take to arrest disturbances and prevent cascading.

5. **Training for Emergencies**: Ensure that all operating staff are trained and certified, if required, and practice emergency drills that include criteria for declaring an emergency, prioritized action plans, staffing and responsibilities, and communications.

6. **Vegetation Management**: Ensure high voltage transmission line rights-of-way are free of vegetation and other obstructions that could contact an energized conductor within the normal and emergency ratings of each line.

Details of the request can be found on the NERC website at: Quick Action Request. NERC and the industry will continue to review and analyze the facts surrounding the August 14 blackout, and make recommendations and take appropriate actions to preserve reliability in the future.

Assessment Summary

Supply Adequacy

Generating resources will be adequate to meet the demand for electricity throughout North America this winter. New generating resources have been added in several NERC Regions since last winter, and generating capacity margins are greater than those projected for last winter in most Regions.

In spite of this favorable outlook, there is always the chance that unanticipated equipment problems and high demand caused by extreme weather could combine to create supply problems.

Transmission Adequacy

Transmission systems are expected to perform reliably this winter. However, operating experience shows that market conditions can, at times, cause large and widely varying flows. If these conditions occur this winter, local operating procedures, congestion management procedures, as well as the NERC Transmission Loading Relief (TLR) procedure will need to be invoked in order to maintain transmission system security. Reliability coordinators, transmission planners, and system operators need to regularly communicate and coordinate their actions to preserve the reliability of the bulk electric transmission system. Adequate system reliability will be maintained if identified transmission limitations are adhered to and operating procedures are implemented as required.

Coincident failures of critical equipment, while highly improbable, may result in the degradation of bulk electric system reliability. However, emergency action plans and procedures to safeguard the system under emergency conditions should minimize this possibility by defining actions system operators should take to arrest disturbances and prevent cascading events.

Peak Demands

Peak demand in North America is projected to be 1.1% higher than that projected for last winter, but 1.1% lower than last year's actual. Demand projections are based upon weather-normalized data, while actual demand figures include weather impacts. Details are addressed in the individual regional assessments.

Fuel Supply

Fuel supplies, inventories, and deliveries are expected to be adequate this winter. Recent fluctuations in wholesale gas prices may result in variations in generation dispatch patterns that will change transmission-loading patterns. The potential for curtailment of natural gas supplies during periods of cold weather could present problems in some regions, particularly in ERCOT and ISO-New England. The potential impacts of these curtailments are discussed in the individual regional assessments.

Areas of Interest

ECAR/MAIN/SERC
A number of transfer capabilities between the ECAR, MAIN and SERC Regions are expected to be limited by the Bull Run-Volunteer-Phipps Bend 500 kV Corridor in east Tennessee, because this corridor is used for both north-south and east-west transfers. Transfer capabilities from SERC to MAIN, SERC to ECAR, MAIN to ECAR, and between some MAIN and SERC subregions are expected to be lower than historical levels for this winter due to this limit.

NPCC

Ontario — If generation additions occur as scheduled, available resources are forecast to be adequate throughout Ontario this winter. If this is not the case, some planned generator outages may be deferred, and additional imports will likely be required to meet peak demands. A combination of high demand levels under extreme weather conditions and lower than forecast levels of available generation could lead to significant reliance on imports.

Québec — For the month of January, the capacity margin is expected to be 550 MW below the planning reserve requirement. If the return of the 660 MW Gentilly 2 nuclear plant is delayed beyond late December 2003, that shortage could be further increased. The shortage would be dealt with through various possible actions, including purchases from neighboring systems, implementation of a new load management program for large industrial customers, or advancing the commissioning date for the second generating unit at Sainte-Marguerite 3 hydro plant to January 2004.

TABLE 1: REGIONAL RESOURCE PROJECTIONS FOR WINTER 2003/2004 AND 2002/2003

	Projected Available Resources			Net Generating Capacity Additions Expected
	Winter* 2003/2004	Winter 2002/2003	Change	October 2003– February 2004
Region	(MW)	(MW)	(%)	(MW)
ECAR	133,320	121,749	9.5	1,150
ERCOT	82,875	74,588	11.1	2,085
FRCC	51,116	49,166	4.0	1,958
MAAC	66,723	66,345	0.6	780
MAIN	69,473	68,405	1.6	0
MAPP	41,934	40,659	3.1	243
NPCC	137,789	131,182	5.0	2,134
SERC	182,086	168,307	8.2	552
SPP	44,178	46,935	(5.9)	0
WECC	176,653	155,220	13.8	2,317

Note: It is not possible to obtain the projected available resources for 2003/2004 winter by simply adding the available resources for 2002/2003 winter to the new generating additions listed in Table 1. Available resources include the varying impacts of purchases and sales, planned unit outages, unit uprate/derates, etc. The net generating capacity additions listed are only those planned to be added since September 2003, as reported by the Regions in Appendix 1. Other new generation has been added since last winter, prior to October 2003.

***** Refers to all generating units for January except for WECC, which is for December.

TABLE 2: REGIONAL PEAK DEMAND COMPARISONS FOR WINTER 2003/2004 AND 2002/2003

	Winter 2003/2004	% Change from Winter 2002/2003	
Region [1]	Projection [2]	Actual	Projection
ECAR	86,087	(1.4)	(1.1)
ERCOT	42,308	(6.8)	(3.5)
FRCC	44,266	(1.1)	2.5
MAAC	44,748	(3.2)	(0.1)
MAIN	41,611	3.2	0.2
MAPP	30,604	4.9	1.8
NPCC	110,086	(0.3)	1.6
SERC	142,283	(7.2)	3.4
SPP	29,556	5.2	0.0
WECC	120,385	4.8	2.0

Note: Demand projections are weather-normalized; actuals are not. Some interruptible demand or direct control load management may have been activated at the time of the actual winter peak demand.

[1] Regions are not expected to reach their peak demand simultaneously.
[2] Value listed is the projected internal demand.

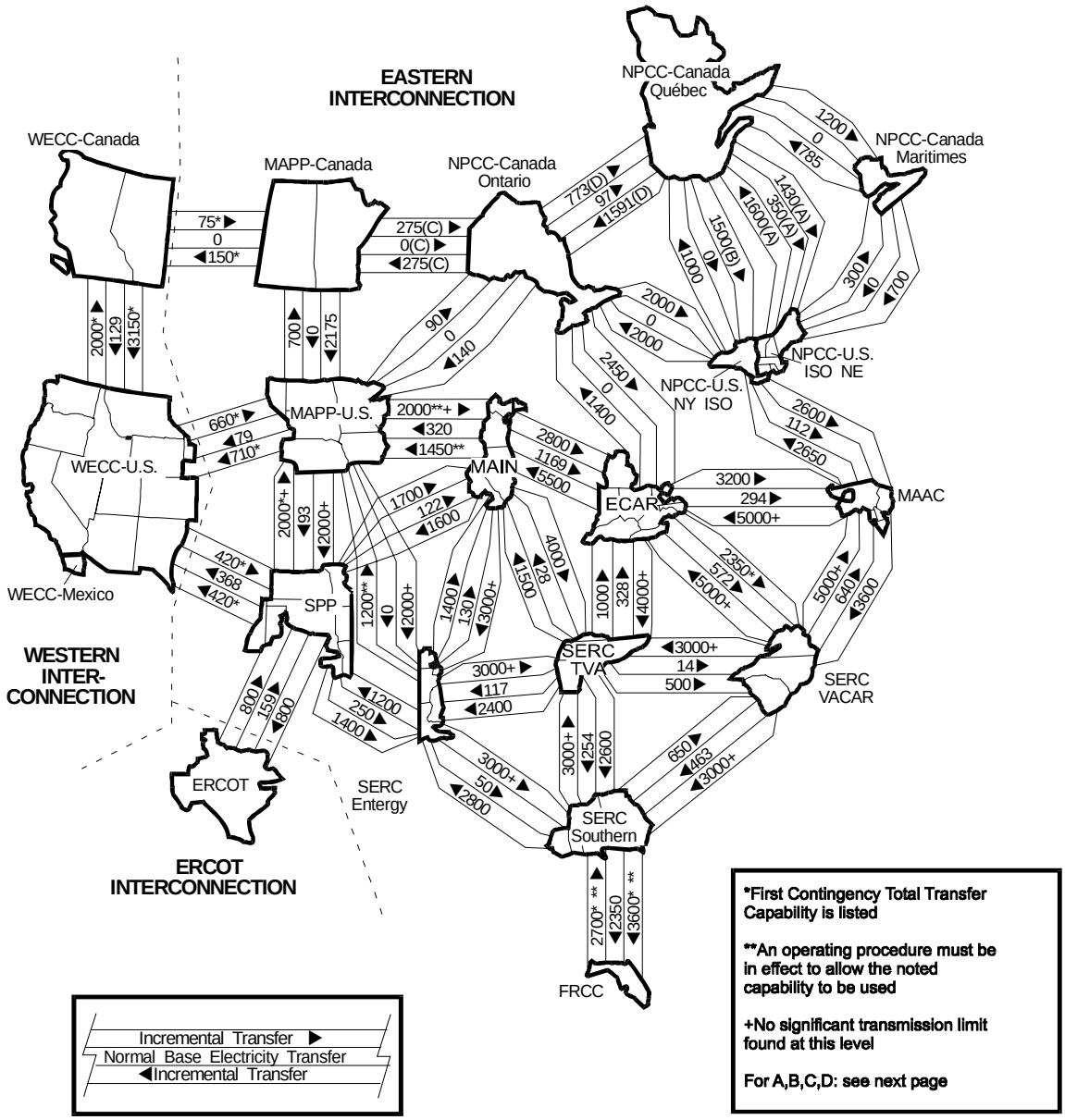
TABLE 3: ESTIMATED 2003/2004 WINTER RESOURCES AND DEMANDS (MW) AND MARGINS (%)

	December				January				February			
	Available[1] Resources (MW)	Net Internal Demand[2] (MW)	Available Capacity Margin[3] (%)	Available Reserve Margin[4] (%)	Available[1] Resources (MW)	Net Internal Demand[2] (MW)	Available Capacity Margin[3] (%)	Available Reserve Margin[4] (%)	Available[1] Resources (MW)	Net Internal Demand[2] (MW)	Available Capacity Margin[3] (%)	Available Reserve Margin[4] (%)
United States												
ECAR[5]	133,312	79,934	40.0	66.8	133,320	83,629	37.3	59.4	133,086	79,903	40.0	66.6
ERCOT	82,815	40,097	51.6	106.5	82,875	41,182	50.3	101.2	83,595	36,817	56.0	127.1
FRCC	51,116	33,833	33.8	51.1	51,116	40,766	20.2	25.4	51,116	34,647	32.2	47.5
MAAC	66,723	42,835	35.8	55.8	66,723	44,380	33.5	50.3	66,723	43,099	35.4	54.8
MAIN	70,253	37,559	46.5	87.0	69,473	38,779	44.2	79.2	68,886	36,948	46.4	86.4
MAPP	33,447	23,011	31.2	45.4	33,607	23,307	30.6	44.2	33,524	22,454	33.0	49.3
NPCC	65,671	45,318	31.0	44.9	65,917	46,112	30.0	42.9	65,821	45,011	31.6	46.2
New York	31,902	24,130	24.4	32.2	32,152	24,130	25.0	33.2	32,152	24,130	25.0	33.2
NEPOOL	33,769	21,188	37.3	59.4	33,765	21,982	34.9	53.6	33,669	20,881	38.0	61.2
SERC[6 & 7]	182,078	124,112	31.8	46.7	182,086	137,511	24.5	32.4	181,629	128,722	29.1	41.1
Entergy	28,672	19,184	33.1	49.5	28,672	21,523	24.9	33.2	28,672	19,017	33.7	50.8
Southern	54,076	34,157	36.8	58.3	54,719	38,841	29.0	40.9	54,287	36,436	32.9	49.0
TVA	31,896	24,647	22.7	29.4	31,915	26,657	16.5	19.7	31,890	24,810	22.2	28.5
VACAR	68,132	46,124	32.3	47.7	67,481	50,490	25.2	33.7	67,481	48,459	28.2	39.3
SPP	44,178	27,749	37.2	59.2	44,178	28,519	35.4	54.9	44,178	26,958	39.0	63.9
WECC[6]	151,206	98,365	34.9	53.7	150,420	98,660	34.4	52.5	147,407	94,756	35.7	55.6
NWPP	54,941	34,864	36.5	57.6	55,172	35,560	35.5	55.2	55,125	33,910	38.5	62.6
Rocky Mountain	11,865	9,135	23.0	29.9	11,808	8,617	27.0	37.0	11,749	8,529	27.4	37.8
Arizona-New Mexico-Southern Nevada	30,368	16,757	44.8	81.2	29,863	17,097	42.7	74.7	29,605	16,182	45.3	83.0
California	54,032	37,609	30.4	43.7	53,577	37,386	30.2	43.3	50,928	36,135	29.0	40.9
Total-United States	**880,799**	**552,813**	**37.2**	**59.3**	**879,715**	**582,845**	**33.7**	**50.9**	**875,965**	**549,315**	**37.3**	**59.5**
Canada												
MAPP	8,371	6,393	23.6	30.9	8,327	6,461	22.4	28.9	8,019	6,221	22.4	28.9
NPCC	70,768	59,937	15.3	18.1	71,872	62,649	12.8	14.7	71,145	60,255	15.3	18.1
Maritimes	6,320	4,593	27.3	37.6	6,323	4,860	23.1	30.1	6,177	4,851	21.5	27.3
Ontario	28,235	23,487	16.8	20.2	28,588	23,754	16.9	20.4	28,020	23,233	17.1	20.6
Quebec	36,213	31,857	12.0	13.7	36,961	34,035	7.9	8.6	36,948	32,171	12.9	14.8
WECC	23,036	18,899	18.0	21.9	22,806	18,214	20.1	25.2	22,134	17,607	20.5	25.7
Total-Canada	**102,175**	**85,229**	**16.6**	**19.9**	**103,005**	**87,324**	**15.2**	**18.0**	**101,298**	**84,083**	**17.0**	**20.5**
Mexico												
WECC-Mexico[8]	2,411	1,307	45.8	84.5	2,110	1,260	40.3	67.5	2,296	1,264	44.9	81.6
Total- NERC	**985,385**	**639,349**	**35.1**	**54.1**	**984,830**	**671,429**	**31.8**	**46.7**	**979,559**	**634,662**	**35.2**	**54.3**
Eastern Interconnection	**725,917**	**480,681**	**33.8**	**51.0**	**726,619**	**512,113**	**29.5**	**41.9**	**724,127**	**484,218**	**33.1**	**49.5**
Western Interconnection	**176,653**	**118,571**	**32.9**	**49.0**	**175,336**	**118,134**	**32.6**	**48.4**	**171,837**	**113,627**	**33.9**	**51.2**
ERCOT Interconnection	**82,815**	**40,097**	**51.6**	**106.5**	**82,875**	**41,182**	**50.3**	**101.2**	**83,595**	**36,817**	**56.0**	**127.1**

Notes to Table 3

1. Existing available generating capacity, plus new units scheduled for service by the given month, plus the net of firm capacity purchases and sales.
2. 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.
3. The difference between available resources and net internal demand, expressed as a percentage of available resources. This is the capacity 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.
4. The difference between available resources and net internal demand, expressed as a percentage of net internal demand. This is the capacity available to cover random factors such as forced outages of generating equipment, demand forecast errors, weather extremes, and capacity service schedule slippage. Some Regions use available reserve margin as one of their standards in assessing adequacy. Available capacity margins are shown in this report for comparison purposes.
5. This is the aggregate noncoincident peak demand projection, adjusted for the historical diversity of the ECAR Region.
6. The sum of the area's resources does not equal the regional total because portions of the reported area sales/purchases are internal to the Region.
7. Total connected generating capacity in SERC, including both utility and merchant facilities, is estimated at 198,242 MW, which is about 26,000 MW (15%) higher than the capacity reported and included in the calculation for capacity margin above.
8. Only the northern portion of the Baja California Norté Mexico electric system is interconnected to the United States.

FIGURE 2: NORMAL BASE ELECTRICITY TRANSFERS AND FIRST CONTINGENCY INCREMENTAL TRANSFER CAPABILITIES (NONSIMULTANEOUS), MW



Definitions and Notes to Figure 2

The nonsimultaneous transfer capabilities shown in Figure 2 represent the ability of the transmission network to transfer electricity from one area to another for a single demand and generation pattern. Different patterns of demand and generation cause variations in transfer capabilities on a day-to-day (or hour-to-hour) basis. Therefore, the values on this diagram should be considered as representative, rather than definitive. The values in Figure 2 result from Regional and interregional assessments conducted seasonally. For more information, refer to the interregional studies for this peak demand season.

First Contingency Incremental Transfer Capability (FCITC) is the amount of electricity, incremental above normal base electricity transfers, that can be transferred over the transmission network in a reliable manner, based on the following conditions:

1. With all transmission facilities in service, all facility loadings are within normal ratings and all voltages are within normal limits.
2. The bulk electric system is capable of absorbing the dynamic electric swings and remaining stable following a disturbance resulting in the loss of any single generating unit, transmission circuit, or transformer.
3. After the dynamic swings following a disturbance (resulting in the loss of any single generating unit, transmission circuit, or transformer, but before operator-directed system adjustments are made), all transmission facility loadings are within emergency ratings and all voltages are within emergency limits.

First Contingency Total Transfer Capability (FCTTC) is the total amount of electric power (net of normal base power transfers plus first contingency incremental transfers) that can be transferred between two areas of the interconnected transmission system in a reliable manner based on conditions 1, 2, and 3 in the FCITC definition above.

Specific Diagram Notes to Figure 2

Note A — The base limit for the Phase II tie HVDC facility between ISO NE and TransÉnergie ranges between 1,200 and 1,800 MW, and can be increased when west-to-east transfers in the MAAC Region and the New York Central East interface flows are below their limits.

The expected total transfer capability of 2,085 MW from TransÉnergie to ISO NE is based on 1,800 MW through Phase II, 225 MW through Highgate, and 60 MW through the Stanstead-Derby tie.

The expected total transfer capability of 1,200 MW from ISO NE to TransÉnergie is based on 1,200 MW through Phase II, zero MW through Highgate, and zero MW through the Stanstead-Derby tie.

Note B — The FCTTC from TransÉnergie to NYISO is 1,500 MW over the Chateauguay-Massena 765 kV interconnection #7040, on which the power flow is controlled by the HVDC facilities at Chateauguay and radial generation at Beauharnois. This limit is dependent on internal NYISO conditions, particularly voltage profiles in the central New York 345 kV system. The 1,500 MW FCTTC does not include Hydro-Québec resources that can be radially connected to the Niagara Mohawk system.

Note C — An additional 55 MW will be transferred from Manitoba into The IMO (radial generation over the Seven Sisters-Kenora 115 kV circuit #SK1 interconnection).

Note D – Transactions between Ontario (IMO) and Québec (Hydro-Québec TransÉnergie) are limited to isolated pockets of demand and generation; there are no synchronous AC ties or HVDC interconnections between the two systems. These total transfer capabilities include 200 MW through Brascan system.

Regional Self-Assessments

Summary tables are provided for each Region in the Regional Assessments to provide a quick reference of projected demand and resources for the coming winter. The following definitions are used in the tables:

Projected Internal Demand	Internal Demand plus Standby Demand (monthly coincident)
Interruptible Demand & DSM	Interruptible Demand and Direct-Control Demand-Side Management
Projected Net Internal Demand	Projected Internal Demand less Interruptible Demand and Direct Control Load Management (monthly coincident)
Last Winter's Peak Demand	Last winter's Actual Peak Demand
% Change	Change in Projected Internal Demand compared to last winter's Actual Peak Demand
All-time Winter Peak Demand	All-time Winter Peak Demand
Net Operable Capacity	Installed Capacity less Inoperable Capacity
Projected Purchases	Total Projected Firm Capacity Purchases
Projected Sales	Total Projected Firm Capacity Sales (adjusted for joint-ownership transfers)
Net Capacity Resources	Net Operable Capacity plus Projected Purchases less Projected Sales
% Capacity Margin	Net Capacity Resources less Projected Net Internal Demand divided by Net Capacity Resources, expressed as a percent
% Reserve Margin	Net Capacity Resources less Projected Net Internal Demand divided by Net Internal Demand, expressed as a percent

Monthly noncoincident projections are used in these tables and the selected month has the highest projected net internal demand.

Historical demands may be either seasonal or monthly noncoincident values.

ECAR

Demand

Projected Internal Demand	86,087 MW
Interruptible Demand & DSM	2,458 MW
Projected Net Internal Demand	83,629 MW
Last Winter's Peak Demand	87,300 MW
Change	-1.4%
All-Time Winter Peak Demand	87,300 MW
Net Operable Capacity	131,171 MW
Projected Purchases	2,914 MW
Projected Sales	765 MW
Net Capacity Resources	133,320 MW
Capacity Margin	37.3%
Reserve Margin	59.4%

ECAR's winter total internal demand forecast is 86,087 MW. This is 1,213 MW (1.4%) lower than the 2002/03 winter peak demand of 87,300 MW, which is ECAR's record winter peak. Total connected capacity to serve demand within ECAR is projected to be 131,171 MW (net seasonal capability), which is 7,573 MW higher than in last winter's assessment. Including the projected 3,870 MW of planned unit outages and net scheduled interchange into the region of 2,149 MW, the net capacity resources are 133,320. The capacity margin in the Region based on net internal demand (83,629 MW) is 49,691 MW (37.3%), compared to a projected capacity margin of 30.7% for last winter.

Based on the projections of connected demand, generation, and interchange power contracts, there is a low probability of exceeding the margin available for contingencies (capacity resources minus the sum of peak demand, planned unit outages, and operating reserve requirements) this winter. ECAR projects that there is less than 1% likelihood that it will rely on supplemental capacity resources at the time of the winter peak demand or for average daily conditions. Supplemental capacity resources include curtailment of contractually interruptible loads, curtailment of demand-side management (DSM) loads, and additional purchased power. Under unanticipated extreme conditions, the capability of the transmission system to import electricity may not be sufficient, even if there is available electricity to import from other Regions. Such extreme conditions would be a combination of factors related to adverse weather, to random generator outages, and to limitations on fuel supplies for electric generation.

More detailed ECAR assessment information is available from ECAR. See report 03-GRP-33A for the demand and capacity assessment, available at www.ecar.org.

Transmission

There is a continuing need for the reliability coordinators, transmission planners, and operators to communicate and coordinate their actions to preserve the continued reliability of the ECAR system. It is anticipated that the ECAR transmission system could become constrained as a result of unit unavailability and/or economic transactions that have historically resulted in widely varying flows within and through ECAR. If these conditions occur this winter, local operating procedures, as well as the NERC Transmission Loading Relief (TLR) procedure will need to be invoked in order to maintain transmission system security. As long as transmission limitations are identified and available operating procedures are implemented when required, no cascading events are anticipated.

Very few transmission facility changes are expected for this winter as compared to last winter. Facilities that have experienced TLRs in the past continue to show up as constraints in this assessment. Depending upon real-time conditions, it is likely that many of these facilities will experience TLRs again this winter.

The ECAR and MAIN import FCTTC from TVA and the MAIN-to-ECAR FCTTC for the upcoming winter are expected to be lower than historical levels. Additionally, these import levels are limited by the same TVA facility, the Bull Run-Volunteer 500 kV line. These lower levels of import capabilities into MAIN and ECAR from TVA and their limitation by a common facility is a concern for the MAIN-ECAR-TVA interface for the projected winter conditions. Further concern is that this facility is a constraint for transfers in other directions as

well. For further discussion of the impact of TVA area facility limitations, refer to the SERC section in this report.

Operations

As a result of regional transmission organization (RTO) activity, ECAR has coordinated the transition process that has realigned the control areas and the reliability coordinators responsible for monitoring system operations in the ECAR Region. All ECAR control areas have made the transition to the reliability coordinators associated with the Midwest ISO, PJM, or TVA. These are the reliability coordinators that will monitor power flows and control critical transmission interface loadings throughout ECAR.

In addition to the NERC TLR procedure, other operating procedures are available to maintain reliable system operations. These include:

- A multiregional agreement involving control areas around Lake Erie to use generation redispatch to mitigate emergency TLR procedures and curtailments in situations where the affected system(s) is about to curtail firm demand.
- Operating procedures will be used by the reliability coordinators to reduce the risks of potential widespread interruptions that may result from EHV outages overloading the paralleling stability-limited Kanawha-Matt Funk 345 kV circuit until AEP's Wyoming-Jacksons Ferry 765 kV line is completed by June 2006.

Additional details on the demand and capacity assessment, ECAR report 03-GRP-33A, is available on the ECAR website (www.ecar.org). Detailed information on the transmission assessment, ECAR report 03-TSPP-3A, is available by contacting the ECAR office.

ERCOT

Projected Internal Demand	42,333 MW
Interruptible Demand & DSM	1,151 MW
Projected Net Internal Demand	41,182 MW
Last Winter's Peak Demand	45,414 MW
Change	(6.8)%
All-Time Winter Peak Demand	45,414 MW
Net Operable Capacity	82,956 MW
Projected Purchases	110 MW
Projected Sales	191 MW
Net Capacity Resources	82,875 MW
Capacity Margin	50.3 %
Reserve Margin	101.2 %

Demand

The ERCOT forecast peak demand for this winter is 42,333 MW, compared to the actual winter 2002/2003 peak demand of 45,414 MW, which is the all-time winter peak. The 2003/2004 forecast is lower due to the assumption of normal weather. The last two winter seasons in ERCOT have been slightly colder than normal. Demand forecasts are made using weather-normalized historic growth rates.

Resources

Generating entities in ERCOT plan to mothball 2,252 MW of gas-fueled capacity during the 2003/2004 winter season. ERCOT has Reliability Must Run (RMR) contracts with 1,243 MW of capacity that would have otherwise been mothballed in order to manage local transmission congestion. Even with the unavailable mothballed capacity, the capacity margin in ERCOT is expected to be greater than 50% throughout the winter and no overall resource adequacy problems are expected. Projected net capacity additions for the winter total 2,085 MW. Entities in ERCOT have contracts that enable them to purchase 110 MW from SPP; however, these purchases are not necessary to meet ERCOT demand requirements.

A major concern is whether there will be a recurrence of natural gas fuel supply problems experienced in late February 2003 when there were widespread fuel curtailments during an extended period of cold weather. Over 60% of ERCOT installed generating capacity is fueled solely by natural gas. On February 25, 2003, ERCOT implemented the first step of the Emergency Electric Curtailment Plan (EECP) to address a shortage of electricity due to the natural gas curtailments. Fortunately, the market was able to increase generation to avoid further steps of the EECP and no interruptible or firm load shedding was necessary.

Transmission

The current major ERCOT transmission constraints center around the transfer of generation to serve the load centers of Houston and the Dallas-Fort Worth area and local congestion in the Corpus Christi and Rio Grande Valley areas. Typically these constraints are not as severe in the lower load winter months as in the summer peak season. However, with over 997 MW of wind generation capacity operational in West Texas and only 440 MW of transmission transfer capacity available, it is expected that regular curtailments of wind generation will continue to occur. Overall, it is expected that ERCOT's transmission congestion management procedures will be sufficient to operate within transmission limits during the winter.

No significant additional transmission additions are planned to be in service for the 2003/2004 winter season.

Operations

In addition to the possibility of implementing emergency procedures if widespread natural gas supply curtailments to generation occur, the outages of two autotransformers in August 2003 will present additional operational challenges this winter.

The Zorn 138/345 kV 478 MVA AT2 was forced out of service on August 1, 2003. A temporary transformer is to be installed by December 2003 until a compatible transformer is specified, purchased, and installed for this site. The permanent replacement is scheduled for installation in December of 2004. During this outage, it is necessary for ERCOT to dispatch generation and perform switching actions to mitigate loading on the remaining Zorn 138/345 kV transformer 478 MVA AT1 and other transmission elements in the immediate area. ERCOT has been successful in managing the flow on the elements in this area over summer peak conditions and expects to be able to operate in a reliable state during winter conditions based on expected planned outages and load forecasts.

The West Denton 138/345 kV 448 MVA transformer was forced out of service August 20 due to internal damage. It is not expected that this transformer will be replaced prior to summer 2004. The West Denton transformer is the only 345 kV source for the Denton area and, without the transformer, the nearby 138 kV system approaches system limits under peak conditions. Specific generation in the Denton area must be dispatched during peak conditions to maintain the system within limits.

FRCC

Projected Internal Demand	44,266 MW
Interruptible Demand & DSM	3,500 MW
Projected Net Internal Demand	40,766 MW
Last Winter's Peak Demand	44,744 MW
Change	(1.1 %)
All-Time Winter Peak Demand	45,635 MW
Net Operable Capacity	49,566 MW
Projected Purchases	1,550 MW
Projected Sales	–0
Net Capacity Resources	51,116 MW
Capacity Margin	20.2 %
Reserve Margin[1]	25.4 %

[1] FRCC uses Reserve Margin, not Capacity Margin, as its standard to assess adequacy.

Demand

The Florida Reliability Coordinating Council (FRCC) is forecast to reach its 2003/2004 winter firm peak demand of 40,766 MW in January. This projection is consistent with historical, weather-normalized FRCC demand growth. This estimate includes demand reductions due to the use of load management and interruptible demand capabilities. The demand reduction capabilities are estimated to be 3,500 MW.

Resources

The net capacity resources within FRCC, which include 1,550 MW of external long-term firm non-recallable purchases, are expected to adequately meet the forecasted firm peak demand with a 25% reserve margin. This is slightly higher than the forecasted 2002/2003 winter reserve margin of 24%.
The FRCC regional reserve margin requirement is 15%.

Existing merchant capacity that is under firm contract has been included in FRCC's capacity resources. Additional merchant capacity is scheduled to be in service in April 2004.

Loads in Florida are typically at a low level through the winter period, with occasional peak periods lasting from one to a few days. No scheduled generation outages of any significance are planned for the winter period. Since January 1, 2003, an additional 2,284 MW of net generation will have been added prior to the 2003/2004 winter peak. The majority of this increase in net generation is due to the re-powering of existing units.

Transmission

The FRCC bulk transmission system is expected to perform adequately over various system operating conditions. The results of the "2003/04 Winter Transmission Study," which evaluated different operating scenarios, indicate that any thermal overloads or voltage violations can be managed successfully by operator intervention. Such interventions include generation re-dispatch, system sectionalizing, reactive device control, and transformer tap adjustments.

Operations

FRCC has approved a new Central East-Central West Flowgate for central Florida. The new flowgate will be used to alleviate heavy east-to-west flows that occur under certain operating conditions. It will be placed in the NERC Book of Flowgates.

FRCC has examined the fuel supply, and found that it continues to be adequate for the Region.

FRCC does not foresee any reliability issues for the 2003/2004 winter.

MAAC

Projected Internal Demand	44,748 MW
Interruptible Demand & DSM	368 MW
Projected Net Internal Demand	44,380 MW
Last Winter's Peak Demand	46,239 MW
Change	(3.2 %)
All-Time Winter Peak Demand	46,239 MW
Net Operable Capacity	66,235 MW
Projected Purchases	488 MW
Projected Sales	–0
Net Capacity Resources	66,723 MW
Capacity Margin	33.5 %
Reserve Margin	50.3 %

Demand

The MAAC 2003/2004 winter forecast net peak demand is 44,380 MW. This forecast includes the effects of interruptible demand and load management capabilities, which are estimated to be 368 MW. The forecast peak assumes normal winter weather conditions. MAAC is a summer-peaking region. This forecast is 1,859 MW lower than the actual MAAC all-time winter peak of 46,239 MW that occurred on January 23, 2003.

Resources

From 2002 to 2003, MAAC's winter generating capacity is expected to increase by a net of 3,090 MW to 66,235 MW. Of the expected increase, 2,512 MW is already in service. All nuclear units should be in service and at full capacity (13,174 MW) at the time of the peak. MAAC also has 488 MW of external capacity resources under contract through the winter peak period. With the planned new generation, existing internal generation, and external capacity resources included, the MAAC capacity margin is forecasted to be 33.5% at the time of the forecasted peak.

MAAC expects to have sufficient generating capacity to serve the 2003/2004 forecast winter peak demand. When MAAC served its all-time winter peak on January 23, 2003, no emergency procedures were implemented.

MAAC has a net of 1,020 MW of long-term firm transmission service in place for energy sales out of MAAC through the winter peak period. Presently, these transactions are not capacity backed and therefore can be curtailed in the event of a PJM Capacity Emergency. Historically, approximately 500 MW of external capacity has been transferred into MAAC on peak winter days and could therefore increase the capacity margin by 0.5%.

Transmission

The bulk transmission system is anticipated to perform reliably under the forecast conditions, and based on identified system enhancements, is expected to meet MAAC criteria requirements.

Operations

PJM, the RTO in the MAAC Region, is well prepared for operating emergencies should they occur. Regular drills have been conducted to exercise procedures in preparation should there be an extremely cold winter.

MAIN

Demand

MAIN's total projected noncoincident peak demand forecast for winter 2003/2004 is 41,611 MW, assuming normal weather conditions. This is 3.2% above last winter's actual non-coincident peak demand. Approximately 3,000 MW of demand in MAIN is being served from resources that do not meet MAIN's recommendations for firm purchases or capacity purchases, because of source system recallability, non-firm transmission reservations, or various other contractual provisions, including "financial firm" liquidated damages resources. MAIN defines these resources as uncommitted, and excludes them from calculated reserve and capacity margins.

Net firm purchases from outside of the region total 682 MW.

Projected Internal Demand	41,611 MW
Interruptible Demand & DSM	2,832 MW
Projected Net Internal Demand	38,779 MW
Last Winter's Peak Demand	40,311 MW
Change	3.2%
All-Time Winter Peak Demand	42,180 MW
Net Operable Capacity	54,640 MW
Projected Purchases	1,729 MW
Projected Sales	1,047 MW
Net Capacity Resources[1]	55,322 MW
Capacity Margin	29.9%
Reserve Margin	42.7%

[1] Total connected generating capacity in MAIN, including both utility and merchant facilities, is estimated at 68,791 MW, which is about 14,151 MW (25.9%) higher than the capacity reported and included in the calculation for capacity margin above.

Resources

The 54,640 MW of net operable capacity resources excludes 14,151 MW from being counted toward reserves because it does not meet MAIN's recommendations for firm capacity. MAIN's forecasted reserve margin based on capacity committed to serve load in MAIN is 42.7%. MAIN expects no energy limitations this winter.

On September 17, 2003, Energy Information Administration reported a cautious optimism on the short-term outlook for natural gas supplies, thus normal levels of fuel availability are expected. Extreme weather can cause disruptions of natural gas within the region, which would primarily impact generation without the capability to switch to alternative fuel sources. There are adequate resources utilizing other fuels to serve the expected peak load within MAIN during a severe natural gas curtailment. Approximately 7,200 MW or 13% of MAIN's committed resources are gas-fired without fuel switching capability.

Limitations of hydro resources are not expected. Hydro resources account for less than 2% of MAIN's installed capacity.

Transmission

In general, the transmission system is expected to perform reliably under a wide range of conditions. On the whole, import capabilities into MAIN from surrounding regions are considered adequate.

However, there is a concern that MAIN and ECAR import capabilities from TVA for 2003/2004 winter are expected to be lower than historical levels. The import capability from TVA to MAIN dropped from 2,100 to 1,600 MW. These imports are limited by the same TVA facility, Bull Run-Volunteer 500 kV line. This TVA facility also limits SERC West to MAIN, MAIN to ECAR, and some MAIN subregional transfers. For further discussion of the impact of the TVA facility limitations, refer to the SERC section of this report.

Operations

Except for normal scheduled nuclear unit refueling and other scheduled generation outages, MAIN does not anticipate any major unit outages for the winter period.

Local environmental restrictions on certain generation units are not expected to significantly impact availability during peak load conditions.

The MET utilities will maintain close operations surveillance and control during winter operating conditions and particularly during periods of heavy interregional transfers to ensure the continued reliability of the bulk power system.

Historically constrained interfaces such as MAPP-to-MAIN continue to require special operating attention and procedures to maintain reliable operation. Several lines in southern MAIN have also experienced heavy loadings requiring TLR in past years. While some system reinforcements have been made, similar power transfer conditions will require close monitoring of system facilities and close coordination among all parties on a continued basis.

MAPP

Projected Internal Demand	30,604 MW
Interruptible Demand & DSM	836 MW
Projected Net Internal Demand	29,768 MW
Last Winter's Peak Demand	30,098 MW
% Change	1.7 %
All-Time Winter Peak Demand	31,255 MW
Net Operable Capacity & IPP's	41,758 MW
Projected Purchases	4,500 MW
Projected Sales	4,330 MW
Net Capacity Resources	41,934 MW
Capacity Margin	29.0 %
Reserve Margin	40.9 %

Demand

The expected winter noncoincident peak demand in combined MAPP-U.S. and MAPP-Canada is 30,908 MW. That is 2.7% above last winter's peak forecast of 30,098 MW and 2.1% above last winter's actual peak demand. The load forecast assumes average weather conditions.

Resources

The projected MAPP capacity margin is 29.0%. The MAPP Reserve Capacity Obligation requirement is 15%, which is equivalent to a 13.04% capacity margin requirement. This also compares to the 2002/2003 winter capacity margin of 27.3%. Capacity additions for winter 2003/2004 are 83 MW, consisting of gas turbines and internal combustion turbines.

There is a projected net capacity import into the MAPP Region. There are 2,916 MW of firm purchases planned between MAPP members and from entities outside of the MAPP Region. There are 1,345 MW of firm sales planned from MAPP members and to entities out of the MAPP Region.

There are no fuel limitations anticipated in the region that would impact resource adequacy for winter 2003/04.

Transmission

MAPP reliability coordinators continue to monitor the 18 transmission constraints within the region that can limit MAPP imports and exports.

The reliability of the MAPP transmission system is currently measured by determining the thermal, voltage, and dynamic stability limitations, and by studying transmission system historical performance. MAPP members regularly conduct studies that provide an indication of transmission system strength, and the necessary data to facilitate expansion analyses of the MAPP network. MAPP continues to place emphasis on voltage security and stability analysis due to export considerations from the North Dakota area.

These studies indicate that the MAPP transmission system is adequate to meet firm obligations of the member systems for this coming winter season.

Operations

No operational issues are expected for the transmission system within the region during the winter season. There are no anticipated environmental or regulatory restrictions that will curtail availability of transmission system during the winter season.

Subregions

Iowa

No major operational issues are expected in Iowa for the winter season. In the event that heavy power transfers cause operational problems, existing standing operating guides for the Iowa constrained interfaces will be implemented. These standing guides have proven to be effective dealing with this operating condition in the past.

In addition, two generators at the Greater Des Moines Energy Center, which became operational during summer 2003, should provide better operational control of heavy east-to-west power transfers across Iowa.

During periods with heavy transfers from south-to-north, specific thermal flowgates will be monitored closely and are likely to be periodically in TLR in order to eliminate post-contingency overloading. Heavy flows are again expected this winter on the Raun-Sioux City 345 kV line and on the Raun-Lakefield Jction 345 kV line, which may cause TLR implementation to protect the Raun-Morningside 161 kV line and the Morningside-Plymouth 161 kV line. Special operating guides will be in place to deal with these operational conditions. Special operating guides will be prepared for two extended outages of 345 kV lines associated with the line relaying replacement projects (the Council Bluffs-Sub 3456 345 kV line and the Raun-Sioux City 345 kV line).

Nebraska

No significant operational issues are expected in Nebraska during winter 2003/2004. There are five constrained export interfaces posted on the MAPP OASIS, however exports do not typically reach limits during the winter season in Nebraska. All of these interfaces have approved operating guides that have proven effective in dealing with system conditions throughout the year.

During the 2002/2003 winter season, the Nebraska/Iowa regional transmission system experienced heavy south-to-north transfers across the system. These south-to-north transfers were primarily attributed to low WAPA hydro generation and high winter peak loads in the Dakotas. Omaha Public Power District (OPPD) developed an operating guide to address potential post-contingent overloads during heavy south-to-north transfers through their system. This operating guide outlines the potential for overloads of the OPPD Sub 1226-to-Tekamah 161 kV line. Upgrades of the Sub 1226-Tekamah 161 kV line are scheduled to be completed prior to the end of 2003, which should reduce the potential for implementing NERC TLR procedures to protect the Sub 1226-Tekamah 161 kV line during the expected reoccurrence of south-to-north flows across the system this winter.

During the winter season, low local-area load levels, high base-load generation, and a lack of synchronous ties to the west are considered to be the worst case for western Nebraska area stability. These characteristics set up high power transfers out of this region with a predominant west-to-east system bias across Nebraska's bulk transmission system.

Transmission contingencies involving the 345 kV and 230 kV transmission systems in western and central Nebraska can impact the stability of western Nebraska resources. In the past several years, there has been a large increase in the number of days the DC ties have been transferring power from east-to-west, which reduces the west-to-east flows that are normally seen across Nebraska. It is anticipated that this pattern of the DC ties flowing in the east-to-west direction will continue this winter.

Northern MAPP

No significant operational issues are expected this winter for the northern MAPP Region. The existing standing guides have proven to effectively deal with the system conditions throughout the year.

The Manitoba-U.S. interface limit has been increased by 200 MW based upon recent operating studies. However, water levels continue to remain low throughout the northern MAPP Region, and will likely continue to reduce the magnitude and duration of exports out of northern MAPP, and also continue to contribute to the recent significant imports of power into the northern MAPP Region.

Winter peak load conditions (especially in eastern North Dakota and northwestern Minnesota) with transfers from the United States into Manitoba remain a stressed condition for the northern MAPP Region, and the northern MAPP Operating Review Working Group continues to monitor that condition closely and will implement temporary operating guides if necessary to address unplanned facility outages. A 47 MVA combustion turbine generator with synchronous condensing capability has come on line in northwestern Minnesota at Solway and provides much needed voltage support to that area.

A number of bulk transmission outages are scheduled in the northern MAPP Region for maintenance into the late fall and early winter; however, no operating problems are expected. Temporary operating guides will be developed as necessary. Several additional small 20–40 MW sized wind farms are scheduled to come on line just prior to or during this winter season in northern MAPP.

NPCC

Demand

NPCC is expected to have net capacity resources that are sufficient to meet expected demand and reserve requirements during the 2003/2004 winter operating period. The IMO projections are predicated on the return to service of 2,000 MW of nuclear generation before the winter peak. If these units return to service as planned, resources are forecast to be adequate for the upcoming winter period. Current information indicates that activity milestones are being met, providing some confidence that this is achievable. If the return to service of this capacity is delayed, imports will likely be required to meet peak demands. In that case, sufficient generation resources and associated transfer capabilities are expected to be available throughout the winter. A detailed summary of the expectations of each of the NPCC subregions follows:

Net Internal Demand	110,086 MW
Interruptible Demand & DSM	1,325 MW
Projected Net Internal Demand	108,761 MW
Last Winter's Peak Demand	110,392 MW
Change	(0.3 %)
All-Time Winter Peak Demand	110,392 MW
Net Operable Capacity	130,979 MW
Projected Purchases	7.484 MW
Projected Sales	672 MW
Net Capacity Resources	137,789 MW
Capacity Margin	21.1 %
Reserve Margin	26.7 %

Subregions

Maritimes

The Maritimes area forecasts a noncoincident winter peak demand of 5,342 MW, which is predicted to occur during the period from December through March. This compares with the actual noncoincident peak demand for the winter of 2002/2003 of 5,479 MW that was experienced in February of that season.

The Maritimes area is forecasting normal hydro conditions for the winter 2003/2004 assessment period. The fuel supply in the Maritimes area is diverse and includes nuclear, natural gas, coal, oil (both light and residual), orimulsion, hydro, tidal, municipal waste, and wood. The area does not anticipate any fuel supply problems. Units that have been converted to the orimulsion fuel retain their full capability to burn oil as an alternative fuel.

There have been no major additions to the Maritimes bulk transmission system. There are no planned capacity additions for the winter period. Interconnection capability with the neighboring areas remains unchanged, and the Maritimes Area is capable of delivering up to 700 MW to New England and up to 785 MW to Québec.

The Maritimes Area closely monitors air emissions and other environmental discharges to ensure compliance with standards and limits set forth by Canadian federal and provincial environmental regulations. For the 2003/2004 winter period, there may be occasions when some units are required to be derated in order to meet these regulations. However, these are expected to be infrequent and of short duration.

ISO New England (ISO-NE)

ISO New England's forecast for the 2003/2004 winter peak demand (net internal demand) is 22,010 MW. This projected peak is 250 MW higher than last year's projected peak of 21,760 MW, and 475 MW higher than last year's actual winter peak of 21,535 MW, which occurred on January 22, 2003. The peak of January 22, 2003, is also the all-time winter peak.

For the winter peak load period, the ISO-NE projects a net operable capacity margin of approximately 11,800 MW (35%).

The forecast of average monthly winter external capacity purchases is 507 MW, which includes 280 MW from Hydro-Québec, 100 MW from New Brunswick, and 127 MW from New York.

ISO-NE projects that there will be sufficient operable capacity within NEPOOL to meet the region's anticipated peak demands and operating reserve requirements during the winter period. However, there is a concern that generators in New England may experience temporary problems with procuring natural gas deliveries during cold snaps. ISO-NE observed that as much as 2,200 MW of gas-fired capacity was unavailable during peak periods last winter because of fuel related issues.

There are no critical transmission circuits scheduled to be out of service. Both generator and transmission maintenance schedules are continually reviewed and coordinated to ensure that the necessary facilities will be available during the peak winter months.

New York ISO (NYISO)

The 2003/2004 winter forecast peak for the New York ISO is 24,130 MW, which is 420 MW lower than the 2002/2003 winter forecast of 24,550 MW.

The NYISO total capacity for the coming winter is 37,756 MW. When allowances are taken for unplanned outages, the net available resources will be 32,152 MW, which will be sufficient to meet the NYISO load and operating reserve requirement during the peak load hours.

Since last winter, resources totaling 1,182 MW were placed in service. Of this, 1,080 MW represents a new natural gas-fired combined-cycle generating station located near Athens, New York. The remaining resource additions are two combustion turbine installations in the Long Island load zone.

Ontario

Ontario's forecast winter peak demand of 24,054 MW is based on normal weather; it is approximately 3% higher than the 2002/2003 normalized winter peak demand of 23,318 MW. The all-time record winter peak demand of 24,158 MW occurred on January 22, 2003. There are no firm sales projected for winter 2003.

Two Bruce A and one Pickering A nuclear units are scheduled to return to service before the winter. If these units return to service as planned, resources are forecast to be adequate during the upcoming winter. Current information indicates that activity milestones are being met, providing some confidence that this is achievable.

If the scheduled generation additions do not occur, available resources are forecast to be below planning requirements for most weeks throughout the winter. In this case, a small number of planned generator outages could be deferred or cancelled, and imports will likely be required to meet peak demands. A combination of high demand levels under extreme weather conditions and lower than forecast levels of available generation could lead to significant reliance on imports.

Energy supplies within Ontario are expected to be adequate overall, but shorter-term energy deficiencies could arise as a result of higher than forecast forced outage situations, extreme demands, or other influencing factors.

The Ontario fuel supply and delivery infrastructures are anticipated to be adequate during this winter.

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

Even though the estimated in-service date for the installation of a new phase angle regulator (PAR) on the Ontario-Michigan tie line Lambton-St. Clair 345 kV circuit L4D has been delayed until spring 2004, it is not expected to impact reliability during the winter period.

Transfer capability from Michigan to Ontario is expected to be reduced on occasion by about 150 MW until the end of February 2004 due to the forced outage of the B3N interconnection as the result of a tower failure. Transfers from Ontario to Michigan are not expected to be affected.

Interregional transmission transfer capability studies have been conducted to determine levels of external assistance that can be imported during the forecast 2003/2004 winter peak demand period. The study results are reflected in the FCITCs reported in Figure 2.

There are no unusual operating conditions, environmental constraints, or regulatory restrictions that are expected to affect the capacity availability anticipated for this winter. All known planned generator outages have been included in the adequacy assessment of the Independent Electricity Market Operator (IMO).

Hydro-Québec

Assuming typical winter peak conditions, Hydro-Québec's internal peak demand for winter 2003/2004 is expected to reach 34,550 MW. This forecast represents an increase of 5.3% as compared to the 2002/2003 winter forecast of 32,809 MW but is 439 MW less than the Québec all-time winter peak demand of 34, 989 MW, which occurred on January 22, 2003. This all-time peak demand occurred after several consecutive days of extreme cold accompanied by high winds.

Hydro-Québec's energy requirements are largely met by hydro generating stations located on different river systems scattered over a large geographical territory, with the major plants backed by multi-year reservoirs. To cope with inflow variations, Hydro-Québec's system can rely on those multi-year reservoirs together with some other non-hydraulic sources, including fossil generation. Based on the level of current water reserves in Hydro-Québec's reservoirs and the availability of other non-hydraulic sources, Hydro-Québec generation availability will meet the energy reliability criterion throughout this winter operating period.

The new generating capacity to be added to the system for the winter operating season will come from the refurbishment of a unit at Outardes 3 hydro plant, for a 64 MW addition, and from the first unit, to be operated at 280 MW, of the Sainte-Marguerite 3 hydro plant. The second unit of the Sainte-Marguerite 3 hydro plant is expected to be commissioned later in the spring of 2004. Those two Sainte-Marguerite 3 generators were announced in the 2003 Summer Assessment, but their in-service dates have since been delayed.

The planning reserve requirement for the Québec control area for the winter 2003/2004 period is 3,475 MW. For the month of January, the capacity margin is expected to be only 2,926 MW, a shortfall of 550 MW. If the return of the 660 MW Gentilly 2 nuclear plant is delayed beyond late December 2003, that shortage could be further increased. The shortage would be dealt with through various possible actions, including purchases from neighboring systems, implementation of a new load management program for large industrial customers, or advancing the commissioning date for the second generating unit at Sainte-Marguerite 3 hydro plant to January of 2004.

The transmission reinforcement program that was initiated following the January 1998 ice storm is still progressing. The eastern 735 kV loop Des Cantons/Montérégie/Hertel will be in service by the end of December 2003. With this new line, transfer capability and voltage support in the Montréal-Québec area will be enhanced. In addition, the implementation of a new centralized load shedding scheme based on the voltage behavior of the main grid will be implemented on the system, thus improving system reliability for extreme events with a low probability of occurrence.

SERC

Demand

Projected Internal Demand	142,283 MW
Interruptible Demand & DSM	4,772 MW
Projected Net Internal Demand	137,511 MW
Last Winter's Peak Demand	153,242 MW
Change	(7.2%)
All-Time Winter Peak Demand	153,242 MW
Net Operable Capacity	173,687 MW
Projected Purchases	9,405 MW
Projected Sales	796 MW
Net Capacity Resources [1]	182,086 MW
Capacity Margin	24.5 %
Reserve Margin	32.4 %

[1] Total connected generating capacity in SERC, including both utility and merchant facilities, is estimated at 223,224 MW, is which significantly higher than the capacity reported above and included in the calculation for capacity margin.

The total internal demand for the 2003/2004 winter is forecast to be 142,283 MW. This projection is based on average historical winter weather. The forecast 2003/2004 winter peak is 4,664 MW (3.4 %) higher than the forecast 2002/2003 winter peak and is 10,959 MW (7.2 %) lower than the actual 2003 winter peak (the winter of 2003 was significantly colder than normal).

There are significant demand response programs in the SERC Region. These programs allow demand to be reduced or curtailed when needed to maintain reliability. Interruptible demand and demand-side management capabilities decreased to 4,772 MW from the 6,458 MW reported last winter.

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 forecast peak demand.

Resources

Capacity resources in SERC are expected to be adequate to supply the projected firm winter demand. The projected 2003/2004 winter capacity margin for SERC is 24.5 %. This is higher than last year's projected capacity margin of 22.4 %. Planned transactions across the SERC electrical borders include 1,158 MW of purchases coming into the region and 667 MW of sales leaving the region. These transactions, plus a net of 8,118 MW of purchases from non-SERC members located internal to the SERC Region, have been included in the capacity margin for the region.

Merchant Generation

There has been significant merchant generation development in SERC for the past few years. Much of this merchant generation has not been contracted to serve load within the region and its deliverability is not assured. For these reasons, only merchant generation contracted to serve SERC load is included in the capacity margins reported for the SERC Region. Similarly, this generation would only be included in the calculation of capacity margins for other regions if it were to have contracts for firm delivery to those regions.

To understand the extent of generation development in the region, it is instructive to examine how much generation is connected to the transmission system. As of December 31, 2002, total generation connected to the transmission system in SERC, including uncommitted merchant generation, was 200,744 MW. Since the last winter assessment, approximately 22,480 MW of additional generation is expected to connect to the transmission system by December 1, 2003, bringing total connected generation to 223,224 MW. This connected generation exceeds forecast winter peak demand by 80,941 MW or 57%.

Transmission

The SERC Region has extensive transmission interconnections between its subregions. SERC also has extensive interconnections to the ECAR, FRCC, MAAC, MAIN, MAPP, and SPP Regions of NERC. For interconnections of 161 kV and above, the voltage and number of interconnections at that voltage are shown in Figure 3. These interconnections permit the exchange of large amounts of firm and non-firm power and allow systems to assist one another in the event of an emergency.

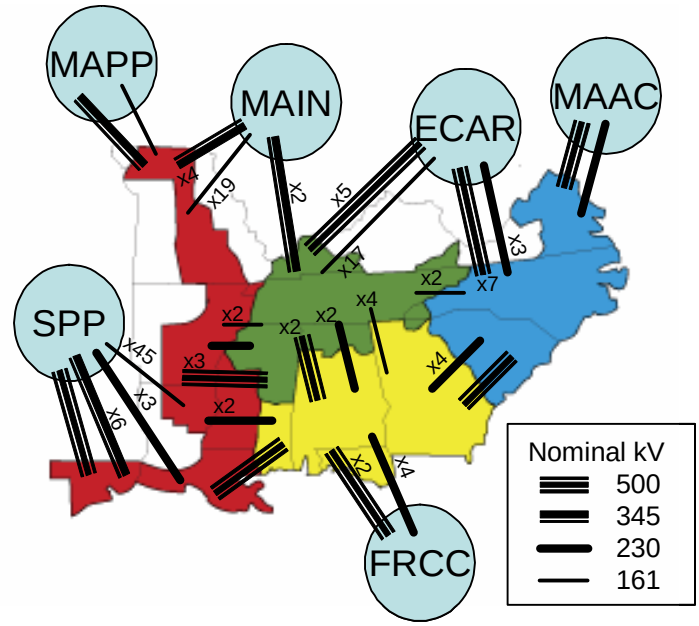


FIGURE 3: NUMBER OF INTERCONNECTIONS BY SERC SUBREGION
(the number after "X" refers to the number of interconnections)

Approximately 304 miles of new 230 kV, 345 kV, and 500 kV transmission lines were built in 2002 with an additional 400 miles planned for completion in 2003 and first quarter 2004. SERC members invested more than $1 billion in new transmission lines and system upgrades in 2002 (100 kV and above) and planned to invest approximately $1.1 billion in 2003.

Coordinated interregional transmission reliability and transfer capability studies for the 2003/04 winter 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.

Operations

The drought conditions that existed in many parts of SERC in 2002 have been relieved by significant rains during 2003. Drought is not expected to be a reliability concern for the 2003/2004 winter. Environmental restrictions are not anticipated to significantly impact operations. Fuel supplies are expected to be adequate and no delivery problems are anticipated. Planned maintenance outages for generators are minimal and should not impact reliability.

Heavy and widely varying electricity flows are anticipated within SERC. These flows are largely driven by excess generation within SERC and external weather conditions. Generator outages within SERC can also play an important role in determining how these flows occur. Heavy loading on the Bull Run-Volunteer-Phipps Bend 500 kV corridor could reduce transfer limits to the north and east of TVA below historical values. Critical facilities will be monitored and appropriate actions taken to maintain reliability in the event of excessive flows. Operating procedures are in place where needed to maintain reliability for outages of key transmission facilities.

Subregions

Entergy
The projected total internal demand for the 2003/2004 winter season is 21,533 MW and is based on normal weather conditions. This is 1,516 MW (7.6 %) higher than the forecast 2002/2003 winter peak and is 1,619 MW

(7.0 %) higher than the actual 2002/2003 winter peak. The projected capacity margin in the subregion is 23.9 %. Capacity in the subregion should be adequate to supply forecast demand.

No reliability problems are anticipated on the Entergy transmission system this winter. Studies for the winter season have shown the Little Gypsy-Fairview 230 kV line to be a limit to exports for certain facility outages, but these limits occur at high transfer levels. The Ray Braswell 500/230 kV autotransformer remains a critical element for exports to the East. Coordinated studies with SPP, MAIN, and the other SERC subregions indicate that there will be adequate transmission transfer capability on all interfaces this winter to support reliable operations. No internal constraints were identified that would present a reliability concern.

Southern

The projected total internal demand for the 2003/2004 winter season is 39,040 MW based on normal weather conditions. This is 2,554 MW (7.0 %) higher than the forecast 2002/2003 winter peak and is 4,438 MW (10.2 %) lower than the actual 2002/2003 winter peak. The projected capacity margin in the subregion is 26.2 %. Capacity in the subregion should be adequate to supply forecast demand.

No reliability problems are anticipated on the Southern transmission system this winter. However, heavy and widely varying flows have been experienced on the Southern system and on the TVA,VACAR, and FRCC interfaces. These flows seem to be driven by the large amount of excess generation within the subregions and by weather conditions.

Transmission constraints may occur on the 230 kV system around Atlanta depending upon the specific flow patterns that are experienced. Operating procedures will be used to manage the situation should it occur and these constraints are not expected to threaten reliability. Coordinated transmission studies with the other SERC subregions and with FRCC have not identified any constraints restricting full operation of committed generation to serve area demand.

TVA

The projected total internal demand for the 2003/2004 winter season is 29,267 MW based on normal weather conditions. This is 230 MW (0.8%) lower than the forecast 2002/2003 winter peak and is 730 MW (2.4%) lower than the actual 2002/2003 winter peak. The projected capacity margin in the subregion is 15.2 %. Capacity in the subregion should be adequate to supply forecast demand.

No reliability problems are anticipated on the TVA transmission system this winter. The TVA transmission system experienced large and widely varying flows in recent years and these flows may occur again this winter. These flows are driven by the large amounts of generation to the south of TVA and weather-related demand to the north of TVA. The Bull Run-Volunteer-Phipps Bend 500 kV corridor in east Tennessee could experience heavy loading as a result of these flows. Studies are being conducted to identify ways to relieve the loading on these facilities. Coordinated studies with ECAR, MAIN, and the other SERC subregions indicate that there will be adequate transmission transfer capability on all interfaces this winter to support reliable operations. No internal constraints were identified that would present a reliability concern to TVA; however, heavy loading on the Bull Run-Volunteer-Phipps Bend 500 kV corridor could reduce transfer limits to the north and east of TVA below historical values.

VACAR

The projected total internal demand for the 2003/2004 winter season is 52,443 MW based on normal weather conditions. This is 256 MW (0.5%) lower than the forecast 2002/2003 winter peak and is 4,172 MW (7.4 %) lower than the actual 2002/2003 winter peak. The projected capacity margin in the subregion is 19.3%. Several large generating units have planned outages during the winter but these outages do not present a reliability concern. Capacity in the subregion should be adequate to supply forecast demand.

No reliability problems are anticipated on the VACAR transmission systems this winter. Coordinated studies for the 2003/2004 winter season were performed with ECAR, MAAC, and the other SERC subregions. These studies indicate that there will be adequate transmission transfer capability on all interfaces this winter to support reliable operations. The Santeetlah-Robinsville 161 kV Duke-to-TVA tie could experience heavy loading this winter. An operating procedure is in place to maintain reliability should this heavy loading occur. Transfer capability into VACAR from the other SERC subregions is less than in prior years due to increased loading on the TVA Bull Run-Volunteer and Watts Bar-Volunteer 500 kV lines. No internal constraints were identified that would present a reliability concern.

SPP

Demand

This winter's noncoincident net internal demand is projected to be 28,519 MW, which is comparable to last winter's forecasted peak demand of 28,611 MW. These projections are based on normal weather conditions and are consistent with historical experience. These demand projections include the effects of interruptible demand and load management capabilities. SPP is a summer peaking system and the winter peaks are normally substantially less than those experienced in the summer.

Projected Internal Demand	29,556 MW
Interruptible Demand & DSM	1,037 MW
Projected Net Internal Demand	28,519 MW
Last Winter's Peak Demand	28,105 MW
Change	5.2%
All-Time Winter Peak Demand	29,178 MW
Net Operable Capacity	44,659 MW
Projected Purchases	895 MW
Projected Sales	1,376 MW
Net Capacity Resources	44,178 MW
Capacity Margin	35.4%
Reserve Margin	54.9%

Resources

Since the last winter assessment, members have added 383 MW of new committed generating capacity to the SPP Region. The SPP capacity margin is expected to be 35.4% for the 2003/2004 winter, which is comparable to the calculated capacity margin from last year. This is significantly above the 12% minimum criteria for the region. Reservoir levels in SPP have recovered to normal levels since last winter. Hydro capacity is currently expected to be available during peak periods in the winter. Fuel supply throughout the winter is also expected to be adequate.

Transmission

The LaCygne-Stilwell 345 kV line is a critical outlet for large base-load generating units owned by Westar Energy and KCP&L. It is also heavily impacted by merchant activity in the SPP Region, as well as in the SERC and the MAPP Regions. This line was identified as one of the key constraints in the Eastern Interconnection in the FERC 2001: *Electric Transmission Constraint Study* by the Division of Market Development. It was the only SPP facility limitation recognized in the study.

SPP transmission owners, through the regional planning process, reached agreement on cost assignment and benefit to upgrade this key limitation. An innovative transmission upgrade approach using energized conductor replacement enabled construction to be completed ahead of schedule, providing for increased SPP reliability and transmission system capacity in 2003.

No significant transmission additions will be made in SPP during the upcoming winter. Transmission studies indicate SPP has adequate import capability for the 2003/2004 winter. Compared to last winter, import capability from the Entergy subregion of SERC has increased considerably.

SPP, through its Transmission Working Group, is developing a regional planning process that will be implemented in 2004.

Currently, minor transmission upgrades continue to be negotiated to accommodate transmission service requests. However, most upgrades negotiated to accommodate transmission service requests and still maintain reliability are not comprehensive. They generally provide incremental upgrades necessary to meet the minimum needs of each service request.

Operations

SPP operations personnel anticipate smooth winter operations. Historically, the SPP system has seen low loading periods and transfer levels in the winter resulting in fewer TLR conditions than in the summer. There are no scheduled maintenance outages of operational concern.

WECC

Demand

The aggregate 2003/04 WECC winter total internal demand is forecast to be 120,385 MW (U.S. systems 100,179 MW, Canadian systems 18,899 MW, and Mexican system 1,307 MW). The forecast is based on average weather conditions, and is 4.8% above last winter's actual peak demand, which was established under generally normal to above normal temperatures in the region.

Projected Internal Demand	120,385 MW
Interruptible Demand & DSM	1,814 MW
Projected Net Internal Demand	118,571 MW
Last Winter's Peak Demand	114,918 MW
Change	4.8 %
All-Time Winter Peak Demand	120,122 MW
Net Operable Capacity	176,206 MW
Projected Purchases	567 MW
Projected Sales	120 MW
Adj. To Sales & Purchases	—
Net Capacity Resources	176,653 MW
Capacity Margin	32.9 %
Reserve Margin	49.0 %

Resources

For the peak winter month of December, WECC's capacity margin is expected to be 32.9%. However, WECC is a large geographical region. If multiple areas peak simultaneously, portions of the region may need to take action to reduce electricity consumption and ensure that adequate operating reserves are maintained.

Fuel supplies are expected to be adequate in all areas of the region under normal winter weather conditions. The hydroelectric resource capability has been reduced by about 2,160 MW in the Northwest Power Pool subregion due largely to biological opinion requirements resulting from the Endangered Species Act. In the California-Mexico subregion, the hydroelectric resource capability has been reduced by 3,000 MW based on hydro capacity experience with runoff conditions and irrigation requirements. Hydroelectric capability for the other WECC subregions is about the same as the generating capability under median hydro conditions.

Transmission

WECC conducts extensive operating studies that model the transmission system under a number of load and resource scenarios and develops operating procedures to maintain safe and reliable operations. The transmission system is considered adequate for all projected firm transactions and most economy energy transfers.

Subregions

Northwest Power Pool (NWPP) Area
NWPP is a winter peaking area. The 2003/2004 winter peak demand forecast of 54,000 MW for the combined Northwest United States and Canadian areas is 6.6% above last winter's actual peak demand of 50,644 MW. The winter peak demand forecast includes 237 MW of load management and interruptible demand. The projected capacity margin for one hour for the peak month is 31.1%. Analyses indicate the Northwest region will be able to meet firm loads and operating reserve requirements for the 2003/2004 winter operations, assuming normal weather conditions.

Past analyses of temperature and load relationships indicate that the peak demand of NWPP will increase by approximately 300 MW per degree below normal. Experience indicates that a "cold snap," when daily temperatures average 19 to 22 degrees below normal, can increase the peak demand by approximately 6,000 MW.

New transmission facilities that will be available for the winter include the Kangley-Echo Lake 500 kV line, a nine-mile extension of the Schultz-Raver #2 500 kV line built to serve growth in the Seattle area. Two new series capacitors are being installed at the Schultz substation to prevent voltage instability in the Puget Sound area, and additional 230/500 kV transformers are being installed at the Pearl and Snoking substations.

Constrained transmission paths within the NWPP area have been identified, operating studies modeling these constraints have been performed, and operating procedures have been developed to ensure safe and reliable operations.

California–Mexico Power Area

This is a summer peaking area. The 2003/04 winter peak demand forecast of 40,220 MW is 2.6% above last winter's actual peak demand of 39,192 MW. The forecast peak demand includes 1,304 MW of interruptible demand and load management. The projected capacity margin for the peak month is 31.1%.

California ISO Control Area (CISO)

Demand Forecast — The CISO winter peak demand forecast for normal weather conditions is 32,995 MW, which is 2.1% greater than the 2002/03 winter peak demand of 32,307 MW.

A portion of the peak demand forecast represents customer demand that is subject to voluntary interruption. In previous years, various programs provided up to 2,800 MW of interruptible demand. However, the same programs provided only 1,600 MW in 2001, and 1,409 MW in 2002. For this winter, customer commitment for voluntary load reduction is estimated to be 1,304 MW. There are restrictions on utilizing the voluntary demand reductions, including limitations on the number of activations per day (generally one) and the number of activations per year. Customers participating in the interruptible demand programs are limited to commercial, industrial, agricultural, and air conditioning loads. The CISO also has approximately 891 MW of non-spinning reserves that can be converted to energy, giving a total of 2,195 MW of emergency mitigation measures that can be implemented prior to curtailing firm peak demand.

Resource Assessment — Barring major generation or transmission outages, the CISO anticipates sufficient capacity margins throughout the winter season to serve forecast peak demand and meet minimum operating reserve requirements.

Environmental Issues — 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 adverse impacts on resource adequacy within the CISO control area.

Transmission System Assessment — With the addition of a 1,120 MVA transformer bank at the Imperial Valley substation, the maximum import capability from northern Baja California, Mexico has been increased from 800 MW to 1,100 MW. However, actual transfer capability may be as low as 500 MW, due to several local area constraints.

Operating procedures may have to be implemented during both high and low demand periods to limit flows on critical facilities and/or maintain adequate voltage levels and system frequency.

Other California Control Areas

Adequate resources are expected in the Comision Federal de Electricidad (CFE), Los Angeles Department of Water and Power (LADWP), and Sacramento Municipal Utility District (SMUD) control areas. The areas have adequate internal transmission and transmission interconnection capability and fuel availability is expected to be adequate. The areas have no concerns with maintaining adequate reactive reserves. Both CFE and LADWP areas expect to have excess resources available for capacity and energy sales to other control areas. The SMUD control area is highly dependent on imports to meet its peak demand and energy load requirements. Capacity resources have been acquired to meet the forecast peak demand and

reactive reserve margins are expected to be adequate. Under extreme conditions, transmission constraints will be relieved by generation re-dispatch or other measures.

Rocky Mountain Power Area

The Rocky Mountain Power Area's peak demand may occur in either summer or winter. The 2003/2004 winter peak demand forecast of 9,153 MW is 8.3% above last winter's actual peak demand of 8,453 MW. Last winter's peak demand was lower than expected due to mild weather conditions. The forecast peak demand includes 18 MW of interruptible demand capability. The projected capacity margin for the peak month is 23.0%.

For the past four years, water inflows into the hydro system have been below average, resulting in below average reservoir storage conditions. Consequently, most reservoir releases will be at the minimum allowable downstream flow levels. Entities within the area have arranged for seasonal purchases of firm capacity and energy to offset the hydroelectric generation shortages during the winter period. 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 the plant will be able to respond to short-term emergency conditions.

The transmission system is expected to be adequate for all firm transfers and most economy energy transfers. However, the transmission path between southeastern Wyoming and Colorado often becomes heavily loaded, as do the transmission interconnections to Utah and New Mexico. Consequently, the WECC Unscheduled Flow Mitigation Procedure may be invoked on occasion this winter to provide line loading relief for these paths.

Reactive reserve margins are expected to be adequate for all peak load conditions. The Big Horn basin in northwestern Wyoming expects very low hydro conditions, which translates into limited voltage support from the plants in the area. Close attention to maintaining appropriate voltage levels is expected to prevent voltage problems.

Arizona-New Mexico-Southern Nevada Power Area

This is a summer peaking area. Due largely to last winter's above average temperatures, the 2003/2004 winter peak demand forecast of 17,352 MW is 12.2% above last winter's actual peak demand of 15,466 MW. The forecast for the area includes 255 MW of load management and interruptible demand capability. The projected capacity margin for the peak month is 42.7%.

Based on inter- and intra-area studies, the transmission system is considered adequate for projected firm and a significant amount of economy electricity transfers. If necessary, phase-shifting transformers in the southern Utah-Colorado-Nevada transmission system will be used to help control unscheduled flows. Reactive reserve margins have been studied and are expected to be adequate throughout the area.

Fuel supplies are expected to be adequate to meet winter peak demand conditions. The area has experienced drought conditions and reduced water flows on many Colorado River and other tributaries. However, due to reservoir storage capability, it is expected that the below-normal precipitation will not adversely affect hydroelectric generation.

APPENDIX 1: GENERATING UNIT ADDITIONS SCHEDULED FOR INITIAL SERVICE, RETIREMENT OR RERATING OCTOBER 2003 THROUGH FEBRUARY 2004

Region/ Subregion	Unit	MW Change	Unit Type	Fuel Type	Change to Unit	Projected Operating Date
ECAR	Lawrenceburg 1–6	1150	Combined Cycle	Gas	New	December
ERCOT	Deer Park Energy Center 3	185	Combined Cycle	Natural Gas	New	February
	Deer Park Energy Center 4	185	Combined Cycle	Natural Gas	New	February
	Deer Park Energy Center 5	275	Combined Cycle	Natural Gas	New	February
	Wise County Power Plant	720	Combined Cycle	Natural Gas	New	January
	Texas City Cogen	460	Combustion Turbine	Natural Gas	New	February
	Brazos Wind Ranch	160	Wind Turbine	Wind	New	December
	Sweetwater	200	Wind Turbine	Wind	New	November
	Mission Road 3	-100	Steam Turbine	Natural Gas	Retire	December
FRCC	Stanton A	647	Combined Cycle	Natural Gas	New	October
	Hines 2	582	Combined Cycle	Natural Gas	New	November
	Bayside 2	1022	Combined Cycle	Natural Gas	New	January
	Gannon 6	-372	Steam Turbine	BIT	Retire	January
	Sanford 5	11	Combined Cycle	Natural Gas	Uprate	January
	Lauderdale 4	2	Combined Cycle	Natural Gas	Uprate	January
	Martin 1	17	Steam Turbine	Natural Gas	Uprate	January
	Martin 2	15	Steam Turbine	Natural Gas	Uprate	January
	Crystal River 3	7	Steam Turbine	NUC	Uprate	January
	Port Everglades 4	26	Steam Turbine	RFO	Uprate	January
	Riviera 3	1	Steam Turbine	RFO	Uprate	January
MAAC	H13 Dolfield 33 kV	9	Internal Combustion	Kerosene	New	December
	A12 Martins Creek	600	Combined Cycle	Natural Gas	New	mid-February
	G22 Merck	38	Combustion Turbine	Natural Gas	New	December
	H20 Oak Grove	3.5	Combustion Turbine	Natural Gas	New	December
	J05 Huron	8	Combustion Turbine	Natural Gas	New	December
	I01 Ontario	7.5	Wind Turbine	Wind	New	December
	J06 Bear Creek	34	Wind Turbine	Wind	New	December
	G46 Peach Bottom	70	Nuclear	Uranium	Uprate	December
	G44 Dupont Seaford	10	Steam Turbine	Waste Heat	Uprate	December
MAIN	None					
MAPP–Can	None					
MAPP–US	Glencoe Lite & Pwr	3.2	Internal Combustion	LFG	New	January
	Salt Valley	27	GT	Natural Gas	New	January
	Burdick	40	GT	Natural Gas	New	November
	Burdick	40	GT	Natural Gas	New	November
	Grand Marais	-0.6	Internal Combustion	DFO	Retire	December
	Grand Marais	-1.1	Internal Combustion	DFO	Retire	December
	Grand Marais	-1	Internal Combustion	DFO	Retire	December
	Salt Valley	9	Combustion Turbine	Natural Gas	Uprate	January
	Salt Valley	9	Combustion Turbine	Natural Gas	Uprate	January
	Salt Valley	9	GT	Natural Gas	Uprate	January
	Fort Calhoun	108	Steam Turbine	NUC	Uprate	November

APPENDIX 1 (CONT.): GENERATING UNIT ADDITIONS SCHEDULED FOR INITIAL SERVICE, RETIREMENT OR RERATING OCTOBER 2003 THROUGH FEBRUARY 2004

NPCC–Hydro Québec	Outardes 3	64	Hydroelectric	Water	Uprate	December
	Sainte-Marguerite 3	280	Hydroelectric	Water	New	December
NPCC–ISONE	None					
NPCC–Maritimes	None					
NPCC–NYISO	Ravenswood #4	250	Combined Cycle	Natural Gas	New	January
NPCC–Ontario IMO	Bruce A Unit G4	770	Nuclear	Uranium	Reactivate	November
NPCC–Ontario IMO	Bruce A Unit G3	770	Nuclear	Uranium	Reactivate	November
SERC–Southern	Atkinson 5A	32	Combustion Turbine	Oil	Environmental	November
	Atkinson 5B	32	Combustion Turbine	Oil	Environmental	November
	Bowen 6	32	Combustion Turbine	Oil	Environmental	November
	McDonough 3A	32	Combustion Turbine	Oil	Environmental	November
	McDonough 3B	23	Combustion Turbine	Oil	Environmental	November
	Wansley 5A	49	Combustion Turbine	Oil	Environmental	November
	Scherer 1	3	Steam Turbine	BIT	Fuel Conversion to SUB	January
	Scherer 2	3	Steam Turbine	BIT	Fuel Conversion to SUB	January
	Hatch 1	13	Nuclear	Uranium	Uprate	November
	Hatch 2	13	Nuclear	Uranium	Uprate	November
SERC–TVA	Paradise 1	20	Fossil	Coal	Uprate	December
	Fort Loudoun 3	1.8	Hydraulic Turbine	Water	Uprate	November
SERC–VACAR	Urquhart CT5	-2	Combustion Turbine	Natural Gas	Derate	November
	Urquhart CT6	-2	Combustion Turbine	Natural Gas	Derate	November
	Urquhart No. 1	-1	CA	Waste Heat	Derate	November
	Urquhart No. 2	-1	CA	Waste Heat	Derate	November
	John S. Rainey CT3	100	Combustion Turbine	Natural Gas	New	January
	John S. Rainey CT4	100	Combustion Turbine	Natural Gas	New	January
	John S. Rainey CT5	100	Combustion Turbine	Natural Gas	New	January
	Coit GT No. 1	4	GT	Natural Gas	Uprate	November
WECC–AZ–NM–SNV	Harquahala CC 2	500	Combined Cycle	Natural Gas	New	October
	Bighorn CC 1	550	Combined Cycle	Natural Gas	New	December
	Mesquite CC 2	625	Combined Cycle	Natural Gas	New	February
	SGS Solar	1	Solar	Sun	New	January
	Stone Forest	3	Steam Turbine	Wood	New	November
	Palo Verde 2	92	Nuclear	Uranium	Uprate	December

APPENDIX 1 (CONT.): GENERATING UNIT ADDITIONS SCHEDULED FOR INITIAL SERVICE, RETIREMENT OR RERATING OCTOBER 2003 THROUGH FEBRUARY 2004

WECC–CA–MX	Fresno Cogen	50	Combustion Turbine	Natural Gas	Expansion	November
	Glenarm 3	49	Combustion Turbine	Natural Gas	New	November
	Glenarm 4	49	Combustion Turbine	Natural Gas	New	November
	El Dorado 1–2	20	Hydroelectric	Water	New	October
	Etiwanda 5	-120	Combustion Turbine	Natural Gas	Retire	December
	Magnolia 5	-22	Combustion Turbine	Natural Gas	Retire	December
	Olive 3–4	-55	Combustion Turbine	Natural Gas	Retire	December
	Pittsburg 1–4	-625	Steam Turbine	Natural Gas	Retire	October
WECC–NWPP	Chehalis CC	520	Combined Cycle	Natural Gas	New	October
	Scotford CC	180	Combined Cycle	Natural Gas	New	October
	MacKay River	165	Combustion Turbine	Natural Gas	New	November
	Medicine Hat 13	42	Combustion Turbine	Natural Gas	New	October
	Elmworth 3	6	Internal Combustion	Natural Gas	New	December
	McBride Lake	75	Wind Turbine	Wind	New	October
	Kettles Hill	63	Wind Turbine	Wind	New	December
	Oldman Flats	60	Wind Turbine	Wind	New	December
	Combine Hills	12	Wind Turbine	Wind	New	December
	Thompson River	12	Steam Turbine	Wood Waste	New	December
	Waneta 2	25	Hydroelectric	Water	Uprate	November
WECC–RMPA	Colorado Green	40	Wind Turbine	Wind	New	December

APPENDIX 2: TRANSMISSION SYSTEM ADDITIONS AND UPGRADES (230 KV AND ABOVE)
October 2003 through February 2004

Region/ Subregion	Facility	Length in Miles	Capacity MVA	Voltage kV	Type of Change	Projected Operating Date
ECAR	Dale Summit / Milesburg - Singletown	0	no change	230	loop into station	December
ERCOT	Norwood 345/138 autoransformer		600	345	New	December
	Morgan Creek tertiary reactors			345	New	December
	Odessa EHV tertiary reactors			345	New	December
	Royse autotransformer		600	345	Replacement	December
	Gibbons Creek-Obrien ckt 99			345	Upgrade	December
FRCC	Cedar - Lauderdale	1	514	230	New	October
	Coast - Peachland	7	596	230	New	November
	Collier - Orange River	9	759	230	New	November
	Juneau - Ohio-Sheldon	5	800	230	New	December
MAAC	None					
MAIN	None					
MAPP–Canada	None					
MAPP–US	19th & Alvo to NW 12th & Arbor	3.5	373	115	New	November
NPCC–Hydro Québec	Hertel-Monterigie (7049)	70.3		735	New	December
	Des Cantons-Monterigie (7048)	70.4		735	New	December
	Bergeronne Compensation Serie increased			735	Upgrade	November
NPCC–ISO-NE	West Rutland Transformers #2	-	250	345 / 115	New	November
	Canal Transformer - #3	-	550	345 / 115	New	November
	Canal - Bourne	2.5	450	115	New	November
	Canal Breakers - 4	-	-	345	New	October
	Sherman Road Breaker - 1	-	-	345	New	December
	Amherst Transformer	-	190	345 / 34.5	New	November
	Amherst Breakers - 2	-	-	345	New	November
NPCC–Maritimes	None					
NPCC–NYISO	None					
NPCC– Ontario IMO	None					
SERC–Entergy	Horn Lake - Freeport (Duke Southhaven)	3.81	392	230	New	October
	Mayflower 500/115 kV Autotransformer	N/A	420	500/115	New	October
	Choctaw (Dow Meter Point) - Addis	4.35	685	230	New	October
	Choctaw (Dow Meter Point) - Dow	1.7	685	230	New	October
	Choctaw (Dow Meter Point) - Dow	1.7	685	230	New	November
SERC–Southern	Old Alabama 230/115-kV Substation	N/A	157	230	230/115-kv Tfm.Removal	November
	Clermont Jct. - Middlefork 230-kV Line	19	602	230	115 to 230-kV Conversion	January
	Clermont Jct. 230/115-kV Substation	N/A	300	230/115	230-kV Bus & Tfm. Add'n	January

APPENDIX 2 (CONT.): TRANSMISSION SYSTEM ADDITIONS AND UPGRADES (230 KV AND ABOVE)
October 2003 through February 2004

Region/ Subregion	Facility	Length in Miles	Capacity MVA	Voltage kV	Type of Change	Projected Operating Date
	Vogtle 500/230-kV Substation	N/A	2-90Mvar	230	2-90Mvar Capacitor Add'n	November
	Montgy.S.S.-Snowdoun to Hyundai	1.5	807	230	New	December
	Eatonton - Porterdale 230-kV Line	42	497	230	Uprate	February
	Thalmann - W.Brunswick 230-kV (White)	7.7	509	230	Uprate	October
	Thalmann - W.Brunswick 230-kV (Black)	7.7	509	230	Uprate	November
	O'hara-Wansley 500-kV Line	50.9	3429	500	Uprate	November
	Ropers Corner 230/115-kV Substation	N/A	300	230/115	Transformer Addition	December
SERC–VACAR	Yemassee - Jasper County #2	37	960	230	New	January
	Yemassee (SCE&G) - Yemassee (SCPSA)	3	960	230	New	January
WECC–AZ–NM–SNV	Beltway transformer bank	—	300	230 / 138	New	November
	Harry Allen-Silverhawk	6	900	500	New	October
	Shiprock – Four Corners	8	1200	345	New	February
	Crystal phase shifters	—	1300	500	New	February
	Shiprock – Four Corners	-8	300	230	Replacement	February
WECC–CA–MX	Los Banos series capacitor	—	3500	500	New	December
WECC–NWPP	Anderson transformer bank	—	168	230	New	December
	Pearl transformer bank	—	1300	500 / 230	New	October
	Snoking Transformer	—	1300	500 / 230	New	November
	Schultz-Raver series capacitor	—	3600	500	New	November
	Schultz-Echo Lake series capacitor	—	3600	500	New	November
	Kangley - Echo Lake	9	4000	500	New	December
	Brilliant – K. Canal	12	339	230	New	February
WECC–RMPA	San Luis Valley Autotransformer #1	—	150	230 / 115	New	December
	San Luis Valley Autotransformer #2	—	150	230 / 115	New	December
	Colorado Green transformer bank	—	170	230	New	December
	Rapid City DC Tie	—	200	230	New	October
	Hesperus # 2 transformer bank	—	250	345 / 115	New	December
	Lamar-Colorado Green	44	376	230	New	December
	San Luis Valley Autotransformer	—	112	230 / 115	To be replaced	December

Definitions, Assumptions, and Abbreviations

How NERC Defines Reliability

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

- Adequacy — The ability of the electric 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 electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

Assumptions

In preparing its independent assessment, the Reliability Assessment Subcommittee (RAS) of the Planning Committee reviewed the individual Regional self-assessments. Summaries of supporting data are contained in Tables 1 and 2 and 3, and in Figure 2. The RAS did not independently verify the information contained in the individual Regional assessments in all cases. Additional supporting documentation is available through the Regional offices.

This assessment contains electricity supply and demand projections submitted by electric utilities through their regional councils for December 2003 through February 2004 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 would be effective, if and when they are needed.
- Electricity transfers will occur as projected.

Abbreviations Used in This Report

AC	Alternating Current
AEP	American Electric Power
AP	Allegheny Power
AZ-NM-SNV	Arizona-New Mexico-Southern Nevada Subregion of WECC
CA-MX	California-Mexico Power Area Subregion of WECC
CISO	California Independent System Operator
COI	California-Oregon Intertie
CP&L	Carolina Power & Light Company
DOE	Department of Energy (United States)
DSM	Demand-Side Management
ECAR	East Central Area Reliability Coordination Agreement
EHV	Extra High Voltage
ERCOT	Electric Reliability Council of Texas

FCITC	First Contingency Incremental Transfer Capability
FCTTC	First Contingency Total Transfer Capability
FRCC	Florida Reliability Coordinating Council
HQ	Hydro-Québec
HVDC	High Voltage Direct Current
iIDC	interim Interchange Distribution Calculator
IDC	Interchange Distribution Calculator
IIPA	Integrated Independent Performance Assessment
IMO	Independent Electricity Market Operator (formerly Ontario Hydro)
IPP	Independent Power Producer
ISN	Interregional Security Network
ISO	Independent System Operator
ISO-NE	Independent System Operator New England
kV	kilovolts (thousands of volts)
MAAC	Mid-Atlantic Area Council
MAIN	Mid-America Interconnected Network, Inc.
MAPP	Mid-Continent Area Power Pool
MEN	MAAC-ECAR-NPCC
MET	MAIN-ECAR-TVA
MVA	Megavoltamperes
MVAr	Megavars
MW	Megawatts (millions of watts)
NEL	Net Energy for Load
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Council
NPCC	Northeast Power Coordinating Council
NRC	Nuclear Regulatory Commission (United States)
NU	Northeast Utilities
NUG	Non-Utility Generator
NWPP	Northwest Power Pool Area Subregion of WECC
NYISO	New York Independent System Operator
NYPP	New York Power Pool
OCSG	Operating Capability Study Group
OH	Ontario Hydro
OP 4	NEPOOL Operating Procedure 4 (Action During a Capacity Deficiency)
OPF	Optimal Power Flow
OTC	Operating Transfer Capability
PDCI	Pacific Direct Current Intertie
PJM	Pennsylvania-New Jersey-Maryland
RAS	Reliability Assessment Subcommittee
RCP	Reliability Coordination Plan

RMPA	Rocky Mountain Power Area Subregion of WECC
RMS	Reliability Management System
SERC	Southeastern Electric Reliability Council
SMAIN	Southern MAIN
SPP	Southwest Power Pool
TIS	Transaction Information System
TLR	Transmission Loading Relief
TVA	Tennessee Valley Authority
TWh	Terawatthours (trillions of watt hours)
VACAR	Virginia and Carolinas Subregion of SERC
VAST	Virginia-AEP-Southern-TVA
VEM	VACAR-ECAR-MAAC
VP	Virginia Power
WECC	Western Electricity Coordinating Council
WUMS	Wisconsin-Upper Michigan Subregion of MAIN

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