2004 SUMMER ASSESSMENT

Reliability of the Bulk Electricity Supply in North America

North American Electric Reliability Council

May 2004

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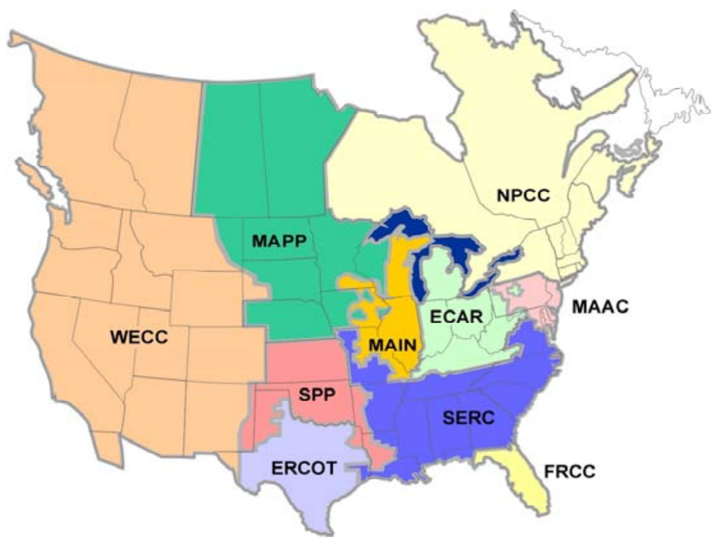
Introduction

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 self-regulatory organization, relying on reciprocity, peer pressure, and the mutual self-interest of all those involved. Through this approach, NERC has helped to make the North American bulk electric system the most reliable in the world.

The 2004 Summer Assessment provides an independent assessment of the reliability of the bulk electricity supply and demand in North America for the period June through September 2004. The Reliability Assessment Subcommittee (RAS) of the NERC Planning Committee prepared this report based upon data submitted by the ten NERC regional reliability councils[1] as of April 30, 2004. This report does not make projections or draw conclusions regarding expected electricity prices for the summer.

Figure 1: NERC Regional Reliability Councils



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

[1] Based on their member systems' projections

Assessment Summary

Generating and transmitting resources are expected to be adequate to meet projected demand for electricity in North America this summer. If all entities comply with NERC reliability standards, there should be no uncontrolled blackouts. Even in areas where resources are expected to be adequate to serve all customer demand, unanticipated equipment problems and extremely hot weather can combine to produce situations in which demands temporarily exceed available generation and transmission capacity. In some local areas noted in the report, system operators may need to implement controlled demand reductions (interruptible demands, voltage reductions, public appeals, and even disconnecting firm customers) to maintain the constant balance between supply and demand needed to ensure overall bulk electric system reliability.[1]

Demand Projections

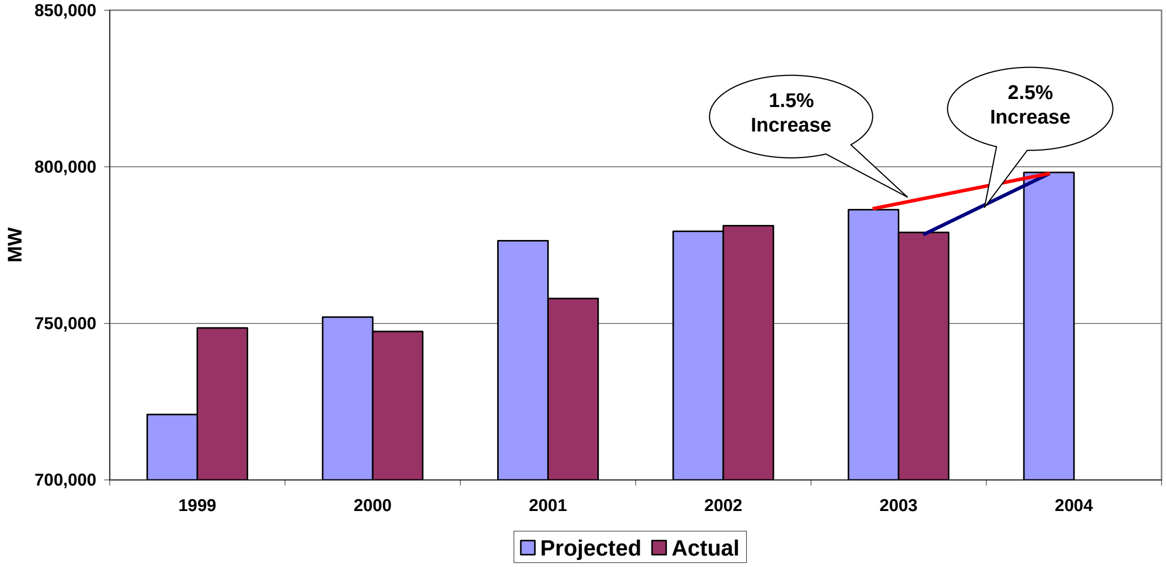
The 2004 peak demand for electricity in North America is projected to increase 2.5% compared to the actual 2003 noncoincident[2] summer peak. To put this growth rate in perspective, the historical average annual peak demand growth for the last ten years has been about 2.44%. It is more meaningful to compare the projected 2004 and projected 2003 demands because actual demands reflect weather effects while projections are based on average historical weather conditions. On that basis, the projected 2004 summer peak demand increases 1.5% as compared to the projected peak demand for summer 2003. Demand growth varies widely among the regions; some expect significant increases in their peak demand for the summer while others project declines.

Table 1: Summer Peak Demand Comparisons for 2003 and 2004

Region [3]	Summer 2004 Projection [4] (MW)	Change from Summer 2003 Actual (%)	Change from Summer 2003 Projection (%)
ECAR	102,554	4.2	1.8
ERCOT	61,432	2.4	6.6
FRCC	42,705	5.7	2.6
MAAC	56,886	6.2	1.1
MAIN	57,662	0.8	0.6
MAPP	34,965	1.5	(0.6)
NPCC	105,263	1.6	1.7
SERC	157,214	3.9	(0.1)
SPP[5]	39,740	(1.2)	(1.0)
WECC	139,798	(0.1)	2.4
NERC	798,219	2.5	1.5

[1] Additional detail is available in the regional sections of this report.
[2] Noncoincident peak demand is the sum of the peak demands of the member utilities within a region, which may not occur at the same hour, day, or month.
[3] Regions are not expected to reach their peak demand simultaneously.
[4] Demand values listed are the projected total internal demand and are weather-normalized; actuals are not. Some interruptible demand or direct control load management may have been activated at the time of the actual summer peak demand.
[5] A portion of the SPP demand was moved to SERC, causing an apparent decrease in the SPP demand.

Figure 2: Actual and Projected Demand Growth



Supply Adequacy

Generating resources are projected to be adequate in all NERC Regions. Capacity margins used to judge reliability in this report only include capacity committed to serve demand (i.e., resources that are owned or purchased by load-serving entities) for most regions. Those capacity values do not necessarily reflect all of the generation located (i.e., uncommitted capacity) within each region. Most units planned to be in service this summer are still on schedule and are expected to be available to serve peak demand.

Although some portions of the continent are continuing to experience drought or below average rainfall conditions, those conditions are not expected to lead to capacity or electric energy shortages this summer. The respective reservoirs are designed for multi-year storage of water resources.

Generation Resource Changes — Table 2 shows the projected change in reported generation capacity by region for non-coincident projected peak demand month.

Table 2: Regional Summer Total Available Resource [1] Projection Comparison

Region	Projected Summer 2004 (MW) [2]	Change from 2003 Actual (%)	Change from 2003 Projection (%)	Net Gen. Additions & Retirements [3] March–Sept. 2004 (MW)
ECAR	127,011	(1.3)	1.0	2,032
ERCOT	76,253	(1.7)	(1.7)	2,262
FRCC	48,297	6.1	4.0	74
MAAC	68,666	4.6	5.1	2,688
MAIN	70,636	0.9	11.9	685
MAPP	42,277	1.7	1.0	219
NPCC	129,684	(3.9)	0.8	2,417
SERC	182,430 [4]	5.1	2.8	1,906
SPP	49,112 [4]	6.9	3.2	0
WECC	181,647	0.2	2.4	2,316

Uncommitted resources are resources within the region or subregion that are not committed to serve load as of the data reporting date. In the past, some regions included uncommitted in the calculation of their margins and some did not. For first time this year, NERC is including and highlighting the influence of uncommitted resources on capacity and reserve margins, as shown in Tables 3a – 3b. Included in the category of uncommitted resources are Liquidated Damages (LD) contracts. LD contracts mean that the supplier has the option of paying the customer in lieu of providing electric supply.

Transmission Adequacy

Regional and interregional transfer capability study results indicate that the North American transmission system is adequate to serve firm customer demand this summer. However, experience shows that at times, volatile and unpredictable flow patterns can pose significant challenges for transmission system operators. The increasing volume of physical transactions adds to the unpredictability of the flow patterns in certain areas. When transmission congestion occurs, congestion management procedures must be implemented to avoid violating system operating security limits.

Existing transmission lines are expected to be adequate for the summer, although new transmission line additions continue at a slow pace. The RAS will include a more comprehensive review of transmission margins during its next long-term assessment.

[1] It is not possible to obtain the projected available resources for 2004 summer by simply adding the available resources for 2003 summer to the net generating changes listed in Table 1. Available resources include the varying impacts of purchases and sales, unit maintenance outages, unit uprates/derates, etc. Also, regional peaks do not occur simultaneously.

[2] Resources listed reflect projected availability for each region's projected peak demand month, **including** uncommitted resources, except for SERC and SPP as described below.

[3] The generation changes listed are only those planned for service during the summer months, as reported by the regions in Appendix 1. Other new generation has been added since last summer, and is already included in capacity resources figure.

[4] SERC & SPP resource projections for 2004 **do not include** uncommitted resources.

Fuel Supply

The regions have reported that fuel supplies, inventories, and deliveries are expected to be adequate this summer. The relative fuel mix of reported generation capacity is shown in the regional section of this report.

Physical and Cyber Security

In light of recent world events, heightened security is in place throughout the electric industry. NERC, as the Information Sharing and Analysis Center (ISAC) for the electricity sector, works with federal, state, provincial and local government organizations, and the industry to monitor the activities under way to protect the physical and cyber elements of the North American electricity system. When conditions warrant, NERC coordinates security alerts throughout the industry to protect the electric system infrastructure.

Regional Areas of Interest

ECAR — Because of ECAR's location and prevailing weather conditions, this region typically experiences widely varying power flows from electricity transactions between different parts of the Eastern Interconnection. As a result, the ECAR transmission system could become constrained during peak periods as a result of generating unit unavailability, or unplanned transmission outages. Should these conditions occur, local operating procedures, as well as the NERC Transmission Loading Relief (TLR) procedure that is used in the Eastern Interconnection, will be required to maintain adequate transmission system reliability. As long as system operators and reliability coordinators recognize transmission limitations in 'real-time' and implement operating procedures in a timely manner, no cascading events are anticipated. The Davis-Besse 883 MW nuclear unit returned to service during March 2004, providing generation and voltage support to the northern Ohio area.

ERCOT — More than 800 MW of wind generation capacity is operating to the south of Odessa in western Texas in a weak transmission area with only about 400 MW of export capability. This has caused local constraints on an almost daily basis in the McCamey area requiring reduction of wind generation. Several transmission projects are currently under way to improve the generation export from this area, but the export limitations, although not a reliability concern, will remain an issue for the summer.

MAAC — PJM and MISO have signed a Joint Operating Agreement (JOA) that governs the power flows between the two market areas. The JOA is designed to facilitate the congestion management process and reduce the number of transaction curtailments that might otherwise occur this summer.

Due to both the retirements of generation and the derating of transmission interfaces in eastern PJM, significant actions were required to maintain the Loss of Load Event criteria of one occurrence in ten years. To achieve this, some transmission owners installed an additional transformer, reactor, and special protection system. PJM led the analysis and will provide operational support necessary due to the retirements and deratings.

MAIN — MAIN's reserve margin, which is based on committed resources, is below its recommended 14% for the upcoming summer. However, when potentially available uncommitted resources are considered, MAIN expects that there will be capacity available to serve all firm load in the region.

The projected internal demand includes 4,166 MW of load within MAIN not supplied with firm capacity contracts but rather by LD contracts, which might not be supported by firm capacity contracts. However, the load being served by LD contracts is less than 40% of uncommitted resources within the region. The RAS does not view this situation as a serious reliability concern for this summer, but recommends that MAIN monitor the performance of the uncommitted generation in serving LD loads during the summer.

The NERC standing committees recently approved the short-term recommendations of the Alliant West TLR Task Force.[1] The recommendations provide for specific variations in the NERC TLR procedure for four flowgates in central and eastern Iowa for this summer. NERC will evaluate the results of implementing the short-term

[1] Recommendations are posted at: http://www.nerc.com/~filez/awttf.html.

recommendations during a four-month pilot project to determine whether the practices and procedures would be applicable across the entire Eastern Interconnection.

NPCC — Under conditions of high demand caused by extreme weather, high unit unavailability and multiple contingencies, the areas of southwestern Connecticut, New York City, and Long Island might be susceptible to reliability problems. Since the summer of 2003, more than 2,000 MW of nuclear capacity has been returned to service to support customer demand in Ontario.

SERC — SERC has seen significant merchant generation development for the past few years. Much of this merchant generation has not been contracted to serve load within the SERC Region and its deliverability within SERC or out of SERC to other parts of the Interconnection 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. Total connected generation is expected to exceed forecast summer peak demand by 63,551 MW or 40.4%.

Heavy loading on the Bull Run-Volunteer-Phipps Bend 500 kV corridor continues to limit transfers to the north and east of TVA. Operating procedures are in place where needed to maintain reliability for outages of key transmission facilities.

SPP — The Federal Energy Regulatory Commission (FERC) has granted SPP conditional approval to operate as a RTO. SPP is the first regional reliability organization to become an RTO

WECC — The California Independent System Operator (CAISO) control area, in its 2004 Summer Assessment, has stated that this WECC subregion expects to have adequate resources to meet base peak demand, but that narrow operating margins exist and there might be problems if adverse conditions affecting supply arise during the summer. The CAISO has acknowledged that its operating reserves might not be sufficient to avoid emergency alerts if peak demand is higher than anticipated, or if supplies tighten for other reasons. These alerts occur when operating reserves fall below certain threshold levels.

With an expected peak demand increase of 1,733 MW over 2003 and a net resource decrease of about 67 MW, the California ISO control area's reliance on external resources to cover possible unexpected peak demand or unit forced outage has increased about 1,800 MW as compared to last summer.

Due to maintenance, the transfer capability of the Pacific DC Intertie (PDCI) will be reduced from 3,100 MW to 2,000 MW until September. Thereafter, the PDCI will be removed from service until the end of the year. The reduced PDCI transfer capability may result in increased energy flows on other transmission paths, including the Path 26 transmission tie between northern and southern California.

August 14th Blackout Response

On February 10, 2004, the NERC Board of Trustees approved 14 recommendations designed to improve reliability in the electric system and increase public confidence in that system in the wake of the August 14, 2003, blackout.[1] In April, the U.S.-Canada Power System Outage Task Force issued its final report on the August 14 Blackout.[2] The task force found that the single most important step that can be taken to improve reliability is for the United States Congress to enact pending reliability legislation. The report also recognized and built upon NERC's blackout recommendations.

NERC has implemented a number of key initiatives to ensure reliability going into the summer 2004 season. Most importantly, NERC is targeting the direct causes of the blackout identified by both NERC and the U.S.-Canada task force and ensuring that they are corrected prior to this summer. NERC has reviewed and approved detailed remediation plans from FirstEnergy, the Midwest ISO, and PJM. Each company must demonstrate to NERC that it has successfully implemented those plans prior to June 30.

NERC is conducting reliability readiness audits for all control areas and reliability coordinators in North America. Audits of twenty of the largest control areas will be completed by June 30. NERC also approved revisions to NERC operating policies to clarify reliability coordinator and control area functions, responsibilities, and authorities.

NERC adopted a set of 38 compliance templates for immediate use by its Compliance Enforcement Program. These templates, which have been edited to more clearly define their measurement and compliance criteria, will be used to measure compliance with NERC reliability rules. The templates will be incorporated into a set of new reliability standards that will translate existing NERC operating policies and planning standards into an integrated and comprehensive set of measurable standards by the end of 2004.

NERC has developed a vegetation management compliance template that requires all transmission owners in North America to report all vegetation-related outages to the Regional Reliability Councils, who in turn will report to NERC. NERC is also working with the industry to develop standards on vegetation management.

Finally, NERC is participating in the May 14, 2004 U.S.–Canada Task Force workshop to discuss the improvement of North American electric reliability standards and other recommendations included in the task force's final report. The U.S. Department of Energy, Natural Resources Canada, Ontario Ministry of Energy, NERC, and related industry representatives will participate with FERC commissioners in addressing the immediate and long-term measures that should be taken to ensure a reliable electric system.

Summer 2004 Resources

Tables 3a through 3d on the following four pages show the projected capacity margins by region and subregion for each of the four 2004 summer months, with and without uncommitted capacity.

[1] *August 14, 2003 Blackout: NERC Actions to Prevent and Mitigate the Impacts of Future Cascading Blackout*, North American Electric Reliability Council. ftp://www.nerc.com/pub/sys/all_updl/docs/blackout/BOARD_APPROVED_BLACKOUT_RECOMMENDATIONS_021004.pdf

[2] *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, U.S.-Canada Power System Outage Task Force, April 5, 2004.

Table 3a: Estimated June 2004 Summer Resources, Demands, and Margins

June 2004					Without Uncommitted Resources		With Uncommitted Resources	
	Net Internal Demand [1] (MW)	Available Committed Resources [2] (MW)	Uncom-mitted Resources [3] (MW)	Total Available Resources [4] (MW)	Available Capacity Margin [5] (%)	Available Reserve Margin [6] (%)	Available Capacity Margin [7] (%)	Available Reserve Margin [8] (%)
United States								
ECAR [9]	93,973	125,984	—	125,984	25.4	34.1	25.4	34.1
ERCOT	54,488	76,253	—	76,253	28.5	39.9	28.5	39.9
FRCC	38,519	48,297	—	48,297	20.2	25.4	20.2	25.4
MAAC	52,964	68,666	—	68,666	22.9	29.6	22.9	29.6
MAIN	48,975	58,181	11,697	69,878	15.8	18.8	29.9	42.7
MAPP	27,893	34,644	748	35,392	19.5	24.2	21.2	26.9
NPCC	52,281	65,071	1,434	66,505	19.7	24.5	21.4	27.2
NYISO	29,713	34,099	1,434	35,533	12.9	14.8	16.4	19.6
ISO NE	22,568	30,972	—	30,972	27.1	37.2	27.1	37.2
SERC [10]	142,845	181,182	38,335	219,517	21.2	26.8	34.9	53.7
Entergy	24,180	29,114	15,525	44,639	16.9	20.4	45.8	84.6
Southern	40,852	54,087	9,000	63,087	24.5	32.4	35.2	54.4
TVA	26,522	31,609	9,326	40,935	16.1	19.2	35.2	54.3
VACAR	51,291	67,238	4,484	71,722	23.7	31.1	28.5	39.8
SPP	35,907	49,112	8,000	57,112	26.9	36.8	37.1	59.1
WECC [11]	112,990	156,614	—	156,614	27.9	38.6	27.9	38.6
NWPP [11]	32,054	51,842	—	51,842	38.2	61.7	38.2	61.7
RMPA	9,095	12,352	—	12,352	26.4	35.8	26.4	35.8
AZ-NM-S. NV	24,583	32,658	—	32,658	24.7	32.8	24.7	32.8
CA-Mexico [12]	47,258	59,762	—	59,762	20.9	26.5	20.9	26.5
Total — US	**660,835**	**864,004**	**60,214**	**924,218**	**23.5**	**30.7**	**28.5**	**39.9**
Canada								
MAPP	5,213	7,255	—	7,255	28.1	39.2	28.1	39.2
NPCC	45,789	60,062	—	60,062	23.8	31.2	23.8	31.2
Maritimes	3,167	4,301	—	4,301	26.4	35.8	26.4	35.8
IMO	23,083	28,305	—	28,305	18.4	22.6	18.4	22.6
TransÉnergie	19,539	27,456	—	27,456	28.8	40.5	28.8	40.5
WECC	15,414	20,942	—	20,942	26.4	35.9	26.4	35.9
Total — Can.	**66,416**	**88,258**	**0**	**88,258**	**24.7**	**32.9**	**24.7**	**32.9**
Mexico								
WECC-Mexico [12]	1,661	2,386	—	2,386	30.4	43.6	30.4	43.6
Total — NERC	**728,911**	**954,648**	**60,214**	**1,014,862**	**23.6**	**31.0**	**28.2**	**39.2**

Table 3b: Estimated July 2004 Summer Resources, Demands, and Margins

July 2004					Without Uncommitted Resources		With Uncommitted Resources	
	Net Internal Demand [1] (MW)	Available Committed Resources [2] (MW)	Uncom-mitted Resources [3] (MW)	Total Available Resources [4] (MW)	Available Capacity Margin [5] (%)	Available Reserve Margin [6] (%)	Available Capacity Margin [7] (%)	Available Reserve Margin [8] (%)
United States								
ECAR [9]	99,911	127,011	—	127,011	21.3	27.1	21.3	27.1
ERCOT	58,628	76,253	—	76,253	23.1	30.1	23.1	30.1
FRCC	39,583	48,297	—	48,297	18.0	22.0	18.0	22.0
MAAC	55,804	68,666	—	68,666	18.7	23.0	18.7	23.0
MAIN	54,471	59,224	11,412	70,636	8.0	8.7	22.9	29.7
MAPP	29,255	34,571	745	35,316	15.4	18.2	17.2	20.7
NPCC	57,053	65,830	1,481	67,311	13.3	15.4	15.2	18.0
NYISO	31,800	34,149	1,481	35,630	6.9	7.4	10.7	12.0
ISO NE	25,253	31,681	—	31,681	20.3	25.5	20.3	25.5
SERC [10]	151,433	182,430	38,335	220,765	17.0	20.5	31.4	45.8
Entergy	24,897	29,114	15,525	44,639	14.5	16.9	44.2	79.3
Southern	44,118	54,774	9,000	63,774	19.5	24.2	30.8	44.6
TVA	27,913	31,631	9,326	40,957	11.8	13.3	31.8	46.7
VACAR	54,505	67,777	4,484	72,261	19.6	24.4	24.6	32.6
SPP	38,661	49,112	8,000	57,112	21.3	27.0	32.3	47.7
WECC [11]	119,268	158,190	—	158,190	24.6	32.6	24.6	32.6
NWPP [11]	33,406	52,644	—	52,644	36.5	57.6	36.5	57.6
RMPA	10,077	12,342	—	12,342	18.4	22.5	18.4	22.5
AZ-NM-S. NV	25,931	32,004	—	32,004	19.0	23.4	19.0	23.4
CA-Mexico [12]	49,854	61,200	—	61,200	18.5	22.8	18.5	22.8
Total — US	**704,067**	**869,584**	**59,973**	**929,557**	**19.0**	**23.5**	**24.3**	**32.0**
Canada								
MAPP	5,167	6,961	—	6,961	25.8	34.7	25.8	34.7
NPCC	46,095	62,373	—	62,373	26.1	35.3	26.1	35.3
Maritimes	3,078	4,882	—	4,882	36.9	58.6	36.9	58.6
IMO	23,368	28,827	—	28,827	18.9	23.4	18.9	23.4
TransÉnergie	19,649	28,664	—	28,664	31.5	45.9	31.5	45.9
WECC	15,685	21,699	—	21,699	27.7	38.3	27.7	38.3
Total — Can.	**66,947**	**91,032**	**0**	**91,032**	**26.5**	**36.0**	**26.5**	**36.0**
Mexico								
WECC-Mexico [12]	1,750	2,634	—	2,634	33.6	50.5	33.6	50.5
Total — NERC	**772,764**	**963,251**	**59,973**	**1,023,224**	**19.8**	**24.7**	**24.5**	**32.4**

Table 3c: Estimated August 2004 Summer Resources, Demands, and Margins

August 2004					Without Uncommitted Resources		With Uncommitted Resources	
	Net Internal Demand [1] (MW)	Available Committed Resources [2] (MW)	Uncom-mitted Resources [3] (MW)	Total Available Resources [4] (MW)	Available Capacity Margin [5] (%)	Available Reserve Margin [6] (%)	Available Capacity Margin [7] (%)	Available Reserve Margin [8] (%)
United States								
ECAR [9]	99,431	127,128	—	127,128	21.8	27.9	21.8	27.9
ERCOT	60,540	76,253	—	76,253	20.6	26.0	20.6	26.0
FRCC	39,883	48,297	—	48,297	17.4	21.1	17.4	21.1
MAAC	54,482	68,666	—	68,666	20.7	26.0	20.7	26.0
MAIN	53,896	59,181	11,500	70,681	8.9	9.8	23.7	31.1
MAPP	29,016	34,560	744	35,304	16.0	19.1	17.8	21.7
NPCC	57,053	65,833	1,481	67,314	13.3	15.4	15.2	18.0
NYISO	31,800	34,161	1,481	35,642	6.9	7.4	10.8	12.1
ISO NE	25,253	31,672	—	31,672	20.3	25.4	20.3	25.4
SERC [10]	150,979	182,232	38,335	220,567	17.2	20.7	31.5	46.1
Entergy	25,284	29,114	15,525	44,639	13.2	15.1	43.4	76.6
Southern	44,425	54,629	9,000	63,629	18.7	23.0	30.2	43.2
TVA	27,687	31,624	9,326	40,950	12.4	14.2	32.4	47.9
VACAR	53,583	67,731	4,484	72,215	20.9	26.4	25.8	34.8
SPP	38,750	49,112	8,000	57,112	21.1	26.7	32.2	47.4
WECC [11]	120,056	157,340		157,340	23.7	31.1	23.7	31.1
NWPP [11]	33,299	51,986	—	51,986	35.9	56.1	35.9	56.1
RMPA	9,698	12,343	—	12,343	21.4	27.3	21.4	27.3
AZ-NM-S. NV	25,698	31,596	—	31,596	18.7	23.0	18.7	23.0
CA-Mexico [12]	51,361	61,415	—	61,415	16.4	19.6	16.4	19.6
Total — US	**704,086**	**868,602**	**60,060**	**928,662**	**18.9**	**23.4**	**24.2**	**31.9**
Canada								
MAPP	5,326	7,235	—	7,235	26.4	35.8	26.4	35.8
NPCC	45,923	61,228	—	61,558	25.0	33.3	25.4	34.0
Maritimes	3,089	4,965	—	4,965	37.8	60.7	37.8	60.7
IMO	22,971	28,429	—	28,429	19.2	23.8	19.2	23.8
TransÉnergie	19,863	27,834	—	28,164	28.6	40.1	29.5	41.8
WECC	15,421	21,673	—	21,673	28.8	40.5	28.8	40.5
Total — Can.	**66,670**	**90,136**	**330**	**90,466**	**26.0**	**35.2**	**26.3**	**35.7**
Mexico								
WECC-Mexico [12]	1,760	2,634	—	2,634	33.2	49.7	33.2	49.7
Total — NERC	**772,517**	**961,372**	**60,390**	**1,021,762**	**19.6**	**24.4**	**24.4**	**32.3**

Table 3d: Estimated September 2004 Summer Resources, Demands, and Margins

September 2004					Without Uncommitted Resources		With Uncommitted Resources	
	Net Internal Demand [1] (MW)	Available Committed Resources [2] (MW)	Uncom-mitted Resources [3] (MW)	Total Available Resources [4] (MW)	Available Capacity Margin [5] (%)	Available Reserve Margin [6] (%)	Available Capacity Margin [7] (%)	Available Reserve Margin [8] (%)
United States								
ECAR [9]	88,880	126,042	—	126,042	29.5	41.8	29.5	41.8
ERCOT	54,924	76,253	—	76,253	28.0	38.8	28.0	38.8
FRCC	38,321	48,297	—	48,297	20.7	26.0	20.7	26.0
MAAC	47,999	68,666	—	68,666	30.1	43.1	30.1	43.1
MAIN	45,566	58,753	11,527	70,280	22.4	28.9	35.2	54.2
MAPP	26,808	34,423	756	35,178	22.1	28.4	23.8	31.2
NPCC	48,858	62,854	1,481	64,335	22.3	28.6	24.1	31.7
NYISO	27,965	32,383	1,481	33,864	13.6	15.8	17.4	21.1
ISO NE	20,893	30,471	—	30,471	31.4	45.8	31.4	45.8
SERC [10]	139,499	186,624	38,335	224,959	25.3	33.8	38.0	61.3
Entergy	23,285	29,114	15,525	44,639	20.0	25.0	47.8	91.7
Southern	40,171	53,460	9,000	62,460	24.9	33.1	35.7	55.5
TVA	26,685	31,510	9,326	40,836	15.3	18.1	34.7	53.0
VACAR	49,358	73,406	4,484	77,890	32.8	48.7	36.6	57.8
SPP	34,389	49,112	8,000	57,112	30.0	42.8	39.8	66.1
WECC [11]	110,686	152,721	—	152,721	27.5	38.0	27.5	38.0
NWPP [11]	30,728	51,185	—	51,185	40.0	66.6	40.0	66.6
RMPA	8,744	12,162	—	12,162	28.1	39.1	28.1	39.1
AZ-NM-S. NV	23,940	31,056	—	31,056	22.9	29.7	22.9	29.7
CA-Mexico [12]	47,274	58,318	—	58,318	18.9	23.4	18.9	23.4
Total — US	**635,930**	**863,745**	**60,099**	**923,843**	**26.4**	**35.8**	**31.2**	**45.3**
Canada								
MAPP	5,067	7,206	—	7,206	29.7	42.2	29.7	42.2
NPCC	44,052	57,610	—	57,710	23.5	30.8	23.7	31.0
Maritimes	3,161	4,975	—	4,975	36.5	57.4	36.5	57.4
IMO	20,807	25,904	—	25,904	19.7	24.5	19.7	24.5
TransÉnergie	20,084	26,731	—	26,831	24.9	33.1	25.1	33.6
WECC	15,197	21,544	—	21,544	29.5	41.8	29.5	41.8
Total — Can.	**64,316**	**86,360**	**100**	**86,460**	**25.5**	**34.3**	**25.6**	**34.4**
Mexico								
WECC-Mexico [12]	1,754	2,533	—	2,533	30.8	44.4	30.8	44.4
Total — NERC	**702,000**	**952,637**	**60,199**	**1,012,836**	**26.3**	**35.7**	**30.7**	**44.3**

Notes to Tables 3a–3d

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

[2] Existing available generating capacity committed to serving load, plus new units scheduled for service by the given month, plus the net of firm capacity purchases and sales.

[3] Resources within the region or subregion that are not committed to serve load as of the data reporting date.

[4] Total available resources (both committed and uncommitted) within the region or subregion, plus the net of firm capacity purchases and sales.

[5] The difference between available committed resources and net internal demand, expressed as a percentage of available committed 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.

[6] The difference between available committed 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.

[7] The difference between total available resources and net internal demand, expressed as a percentage of total 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.

[8] The difference between total 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.

[9] This is the aggregate noncoincident peak demand projection, adjusted for the historical diversity of the ECAR Region.

[10] The sum of the subregions' resources does not equal the regional total. The capacity of non-reporting entities located geographically in SERC is included via known purchases/sales, not as operable capacity. Due to this inclusion of purchases/sales with no equal and opposite transaction, the subregion capacity totals cannot be summed to arrive at the region total.

[11] The hydro capability for the Oregon-Washington area of NWPP is derated by about 1,800 MW from its generation capability to meet biological opinion requirements resulting from the Endangered Species Act. For additional detail on the constraints applied, see the NWPP area narrative in the WECC Region in this report. A 2,500 MW hydro limitation is used for the CAISO for this summer based on hydro capacity experience with runoff conditions and irrigations requirements. Hydro capability for other WECC areas is the generating capability under median hydro conditions.

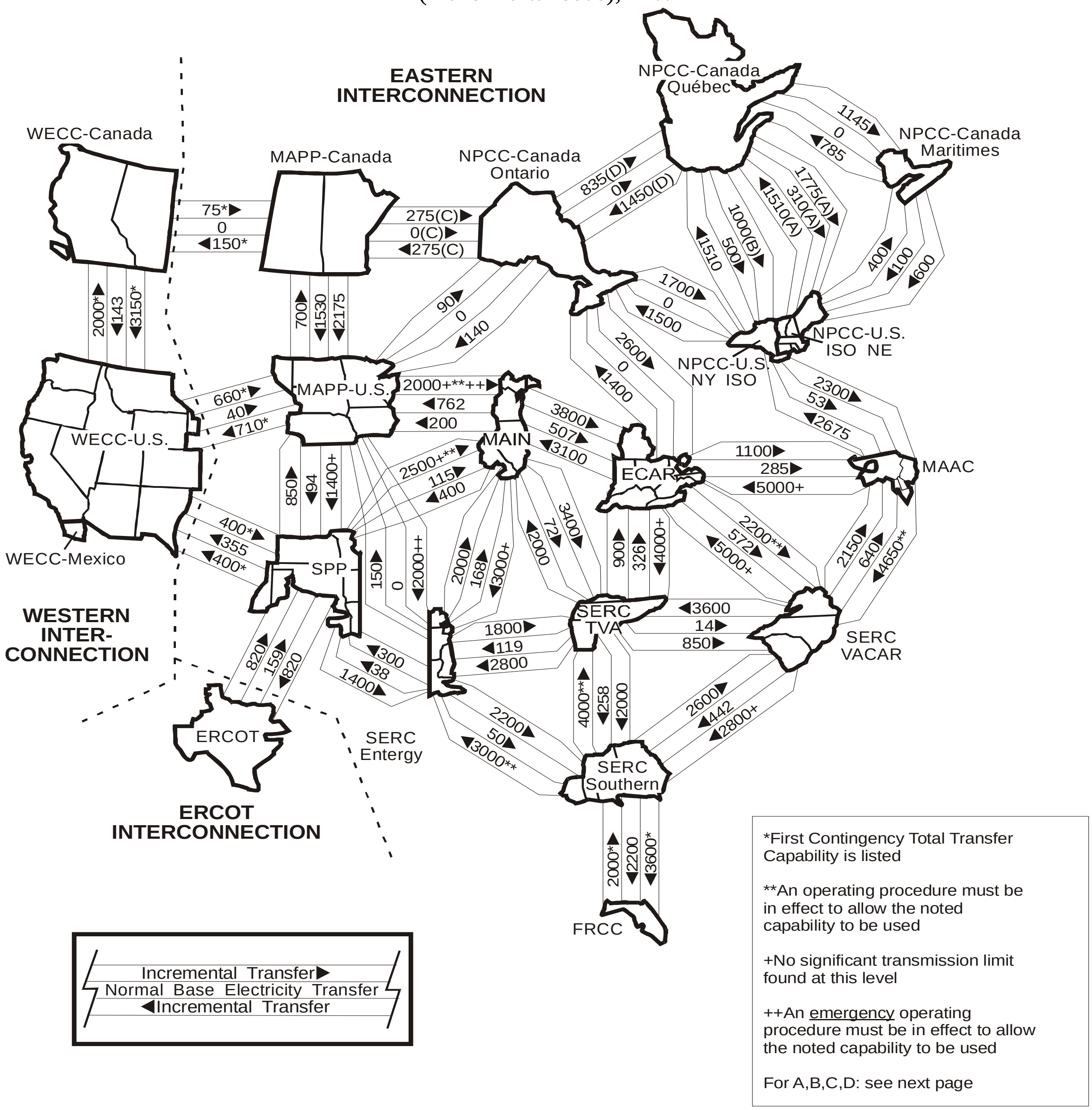
[12] Only the northern portion of the Baja California Norté, Mexico electric system is interconnected with the United States electric system.

First Contingency Incremental Transfer Capability

The nonsimultaneous transfer capabilities shown below 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 numbers given in this diagram should be considered as representative, rather than definitive. For more information, refer to the interregional studies for this peak demand season.

Figure 3: Normal Base Electricity Transfers and First Contingency Incremental Transfer Capabilities

(Nonsimultaneous), MW



Definitions and Notes to Figure 3

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 within emergency limits.

Specific Diagram Notes

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 central east New York 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; synchronous AC ties or HVDC interconnections are not found between the two systems. These total transfer capabilities include 200 MW through Brascan system.

Regional Self-Assessments

Summary tables are provided in each regional assessment to provide a quick reference of projected demand and resources for the coming summer. The following definitions are used in the tables:

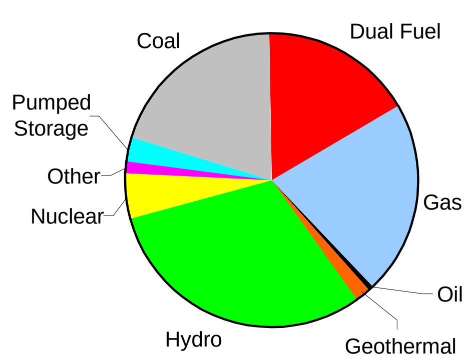
Projected Internal Demand	Internal demand plus standby demand (monthly coincident)
Interruptible Demand & DSM	Interruptible demand and direct-control demand-side management
Projected Net Internal Demand	Projected internal demand less interruptible demand and direct control load management (monthly coincident)
Last Summer's Peak Demand	Last summer's actual peak demand
% Change	Change in projected internal demand compared to last summer's actual peak demand
All-time Summer Peak Demand	All-time summer 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)
Adjustment to Purchases and Sales	Adjustment for transfers of capacity associated with remotely located, totally owned or jointly owned, generating units are included in capacity purchases or sales
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 for the season. Historical demands may be either seasonal or monthly noncoincident values.

Capacity Fuel Mix

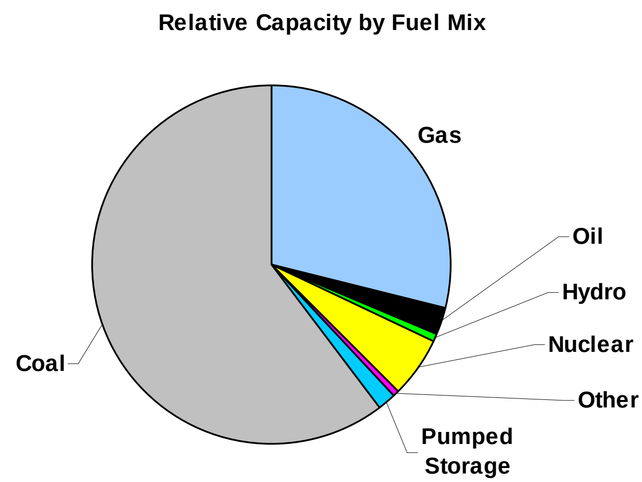
The regional capacity fuel mix charts, shown as a comparative percent of regional generating unit capacity, illustrate each region's relative dependence on various fuels for their reported generation capacity. The charts for each region on the following pages are based on the most recent data available in NERC's *Electricity Supply and Demand* database.

Sample: Relative Capacity by Fuel Mix



ECAR

Projected Internal Demand	102,554	MW
Interruptible Demand & DSM	2,643	MW
Projected Net Internal Demand	99,911	MW
Last Summer's Peak Demand	98,400	MW
Change	4.2	%
All-Time Summer Peak Demand	101,346	MW
Net Operable Capacity	125,309	MW
Projected Purchases	2,902	MW
Projected Sales	1,200	MW
Adj. To Purchases & Sales	—	MW
Net Capacity Resources	127,011	MW
Capacity Margin	21.3	%
Reserve Margin	27.1	%
With Uncommitted Resources		
Uncommitted Resources	—	MW
Total Net Capacity Resources	127,011	MW
Capacity Margin	21.3	%
Reserve Margin	27.1	%



Demand

East Central Area Reliability Coordination Agreement's (ECAR) total internal summer demand forecast is 102,554 MW. This is 1,208 MW (1.2%) higher than the 2001 record peak demand of 101,346 MW and 1,840 MW higher than that projected for 2003. Total connected capacity to serve demand within ECAR is projected to be 127,011 MW (net seasonal capability), which is 917 MW higher than in last summer's assessment. ECAR's capacity margin is projected to be 21.3%, compared to 23.8% expected last summer.

Resources

Based on the projections of connected demand, generation, and interchange power contracts, a low probability of exceeding the margin available for contingencies (capacity resources minus the sum of peak demand, known maintenance, and operating reserve requirements) exists for this summer. ECAR projects a 6% likelihood that it will rely on supplemental capacity resources at the time of the summer peak demand. Supplemental capacity resources may include curtailment of contractually interruptible loads, curtailment of demand-side management (DSM) loads, and additional purchased power.

ECAR does not anticipate any reliance on supplemental resources for average daily conditions this summer. ECAR members recognize that if scheduled capacity additions are delayed, abnormally hot, humid weather and unexpected low generator availability, coupled with an inability to purchase additional power, could make it necessary to curtail demand beyond contractually interruptible loads and demand-side management. However, these adverse conditions are not expected.

The Davis-Besse 883 MW nuclear unit returned to service during March 2004, providing generation and voltage support to the northern Ohio area.

Additional details on the demand and capacity assessment, ECAR report 04-GRP-33, is available on the ECAR website (http://www.ecar.org/).

Transmission

Transmission operators and reliability coordinators must remain diligent to monitor, communicate, and coordinate their actions to preserve the reliability of the ECAR transmission system for the summer 2004 period.

Historically, ECAR has experienced widely varying power flows due to transactions and prevailing weather conditions across the Midwest. As a result, the ECAR transmission system could become constrained during peak periods as a result of unit unavailability and unplanned transmission outages concurrent to large power transactions. Should these conditions occur, local operating procedures, as well as the NERC TLR procedure, will be required to maintain adequate transmission system reliability. As long as transmission limitations are recognized in 'real-time' operations by the reliability coordinators and transmission operators so that operating procedures may be implemented in a timely manner, no cascading events are anticipated.

No significant transmission facility additions have been placed in service prior to this summer peak load period since last summer. However, certain critical flowgates that have experienced TLRs in previous summers continue to be identified as heavily loaded in various reliability assessments and might require operator intervention to ensure adequate reliability levels are maintained.

To prepare for this summer, ECAR has added more than 100 study scenarios and about two dozen voltage analyses to its transmission seasonal assessment process. These additional voltage analyses include the most critical contingencies from each ECAR transmission member. In addition, the assessment includes a ranking of circuits that frequently appear as a constraint, a tabulation of reactive resources within the ECAR Region, and additional results of voltage performance for identified contingencies

To ensure that sufficient transmission analyses have been conducted by ECAR's transmission owners to complement the regional efforts, ECAR has reinstated peer reviews of member transmission assessments for both seasonal and long-term time frames. The seasonal assessments will include both thermal and voltage analyses for a base case and for stressed conditions with single, double, and if warranted, extreme contingencies. Sub-areas such as large metropolitan areas will be assessed. The results of these assessments are communicated to ECAR's reliability coordinators and transmission operators.

In addition to the expanded regional assessment efforts, ECAR fully expects that FirstEnergy will complete the FERC-ordered voltage/reactive analysis of its system, as well as other assessments and take appropriate remedial actions in preparation for the summer peak period.

Detailed information on the ECAR summer transmission assessment, report 04-TSPP-3, is available by contacting the ECAR office.

Operations

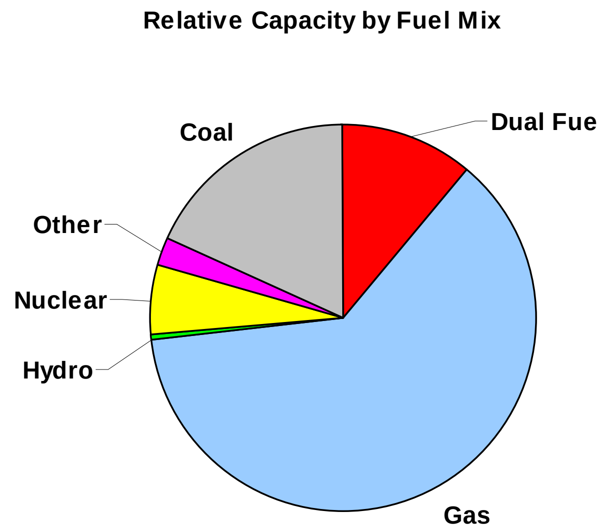
As a result of the August 14, 2003, blackout, ECAR is continuing work to address operations concerns stated in both the NERC and ECAR recommendations. In conjunction with NERC, by summer 2004, ECAR will have completed operations readiness audits on five of its largest control areas (AEP, FirstEnergy, Cinergy, LG&E Energy, and MECS/ITC/METC).

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 that 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.

ERCOT

Projected Internal Demand	61,432	MW
Interruptible Demand & DSM	892	MW
Projected Net Internal Demand	60,540	MW
Last Summer's Peak Demand	59,996	MW
Change	2.4	%
All-Time Summer Peak Demand	59,996	MW
Net Operable Capacity	76,331	MW
Projected Purchases	111	MW
Projected Sales	189	MW
Adj. to Purchases & Sales	—	MW
Net Capacity Resources	76,253	MW
Capacity Margin	20.6	%
Reserve Margin	26.0	%
With Uncommitted Resources		
Uncommitted Resources	—	MW
Total Net Capacity Resources	76,253	MW
Capacity Margin	20.6	%
Reserve Margin	26.0	%



Demand

The Electric Reliability Council of Texas (ERCOT) actual peak demand for 2003 was 59,996 MW, a new all-time peak. The 2003 peak exceeded the previous all-time peak demand of 57,909 MW in 2000 by 4.1% and exceeded the 2002 peak demand by 6.7%. Although the summer of 2003 was cooler than normal overall for the region, the peak was set on an unusually hot day (August 7) with temperatures throughout the region over 100°F.

The 2004 summer peak demand forecast of 61,432 MW was made using weather-normalized, historic growth rates and reflects an increase of 2.4% from 2003 actual. The forecast demand includes approximately 892 MW of demand that could be interrupted if necessary.

Resources

The projected capacity margin for summer 2004 at peak is 20.6%, which remains significantly above the regional requirement of 11%. The actual capacity margin at peak for 2003 was 22.6%.

Approximately 2,200 MW of new generation capacity is expected to commence commercial operation before the summer of 2004. However, there will be a net decrease in available capacity of at least 1,310 MW in ERCOT from the summer of 2003 due to additional generation that has been mothballed in the past year, mainly for economic reasons. On March 29, 2004, a proposal was made to mothball an additional 1,488 MW at several plants in northern and western Texas. ERCOT is currently evaluating if any of that capacity should remain available for reliability must-run purposes. Even if all of this capacity were to be mothballed, ERCOT's projected capacity margin for the summer 2004 would be 19.0%

Entities in ERCOT have contracts that enable them to purchase 111 MW from SPP via DC ties; however, these purchases are not necessary to meet the demand requirements. ERCOT has 189 MW of capacity that can be called on by entities in SPP. In addition, 3,000 MW of generation capacity usually connected to ERCOT has the physical capability of switching to SPP and SERC.

No fuel supply problems are anticipated for summer 2004.

Transmission

The most frequently encountered transmission constraints expected this summer are:

- Southern Texas to Northern Texas and Western Texas to Northern Texas.
- South Texas to Houston
- McCamey Area
- Dallas-Fort Worth (DFW) Area Import
- Lower Rio Grande Valley Area
- Laredo Area Import
- Morgan Plant to the East

Prior to the summer, two additional 345/138 kV autotransformers are going in service in the Dallas-Ft. Worth area (Sargent Road and Everman Switch), along with the Watermill to Sargent Road to West Levee 345 kV line. This new line will be installed on the existing Watermill to West Levee 345 kV line towers. These additions should help reduce local transmission constraint management in the area.

More than 800 MW of wind generation capacity is operating to the south of Odessa in western Texas in a weak transmission area with only about 400 MW of export capability. This has caused local constraints on an almost daily basis in the McCamey area requiring reduction of wind generation. Several transmission projects are currently under way to improve the generation export from this area, but the export limitations, although not a reliability concern, will remain an issue for the summer.

Interregional transfer capability is limited to two DC ties with SPP with a total capacity of 820 MW. ERCOT also has one DC tie with Mexico rated at 36 MW. Transfers over the ties are not necessary to maintain reliability and adequacy of the ERCOT system this summer.

Operations

No significant transmission facilities are scheduled for outages this summer.

ERCOT has reliability must-run contracts with several critical generating units that would have otherwise been unavailable but are needed to maintain local reliability requirements in Corpus Christi, western Texas and the Rio Grande Valley. These units will be used by ERCOT this summer as needed for that purpose.

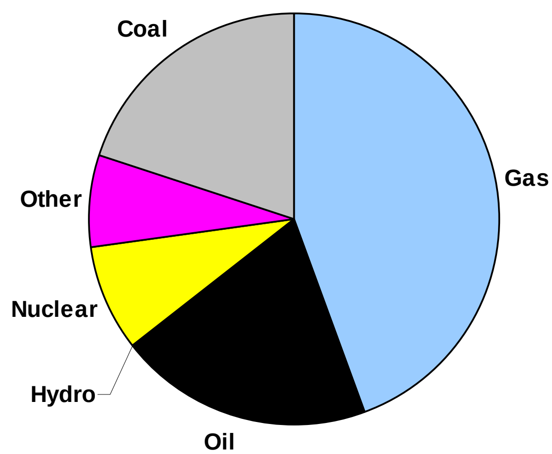
During summer 2004, no regulatory, environmental, or fuel restrictions are anticipated that would adversely affect operations.

FRCC

Projected Internal Demand	42,705	MW
Interruptible Demand & DSM	2,822	MW
Projected Net Internal Demand	39,883	MW
Last Summer's Peak Demand	40,387	MW
Change	5.7	%
All-Time Summer Peak Demand	40,387	MW
Net Operable Capacity	46,705	MW
Projected Purchases	1,592	MW
Projected Sales	—	MW
Adj. to Purchases & Sales	—	MW
Net Capacity Resources	48,297	MW
Capacity Margin	17.4	%
Reserve Margin [1]	21.1	%
With Uncommitted Resources		
Uncommitted Resources	—	MW
Total Net Capacity Resources	48,297	MW
Capacity Margin	17.4	%
Reserve Margin [1]	21.1	%

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

Relative Capacity by Fuel Mix



Demand

The Florida Reliability Coordinating Council (FRCC) is forecasted to reach its 2004 summer firm peak demand of 39,883 MW in August, which represents a projected demand decrease of 1.3% over last years actual summer peak demand of 40,389 MW. This projection is consistent with historical, weather-normalized FRCC demand growth, and is 2.7% more than last year's summer forecast of 38,823 MW. Loads in Florida are typically at a constant level through the summer period. This estimate includes demand reductions due to the use of load management and interruptible demand capabilities estimated to be 2,822 MW.

Resources

The net capacity resources within the FRCC, which includes 1,592 MW of external, long-term firm non-recallable purchases, are expected to adequately meet the forecasted firm peak demand with a 21.1% reserve margin.

Since January 1, 2004, an additional 1,016 MW of net generation will have been added prior to the 2004 summer peak. The majority of this new net generation is due to the re-powering of existing units. Merchant plant capacity that has been placed under firm contract has been included in capacity resources.

Although the FRCC Region has an adequate reserve margin, one control area within the region is projecting very tight resources in the early summer time period. A recent forced outage damaged a turbine and the repairs are taking longer than expected and may extend into June. The control area is taking appropriate measures to mitigate the reliability risk, and FRCC is working closely with this control area to understand and anticipate any potential problems to ensure that any resource adequacy problems are properly addressed.

Transmission

The FRCC bulk transmission system is expected to perform adequately over various system operating conditions. The results of the FRCC "*2004 Summer Transmission Study*," which evaluated different operating scenarios, indicates that any thermal overloads or voltage violations can be managed successfully by operator intervention.

Such interventions include generation redispatch, system sectionalizing, reactive device control, and transformer tap adjustments.

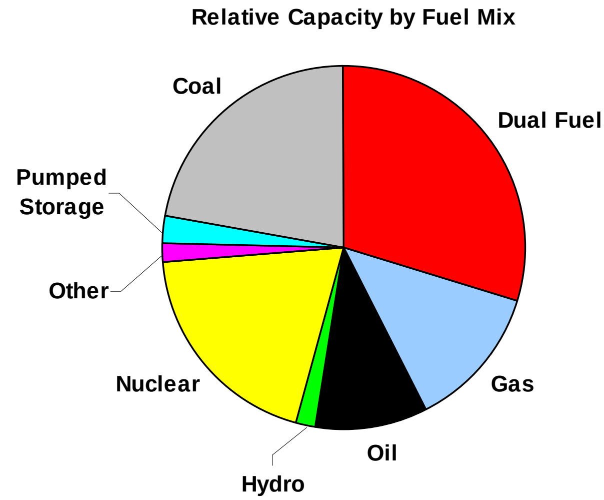
An interregional transfer study is performed annually to evaluate the transfer capability between FRCC and the Southern subregion of SERC for the upcoming summer and winter season. Joint studies of the Florida/Southern transmission interface indicate an import capability of 3,600 MW into the FRCC Region, and export capability of 2,000 MW. Any transfer-related contingencies resulting in transmission overloads or voltage violations can be resolved by operator procedures.

Operations

FRCC does not foresee any reliability issues for 2004 summer. FRCC has examined the fuel supply and found that it continues to be adequate for the region. No scheduled maintenance outages of any significance are planned for the summer.

MAAC

Projected Internal Demand	56,886	MW
Interruptible Demand & DSM	1,082	MW
Projected Net Internal Demand	55,804	MW
Last Summer's Peak Demand	53,566	MW
Change	6.2	%
All-Time Summer Peak Demand	55,569	MW
Net Operable Capacity	68,178	MW
Projected Purchases	488	MW
Projected Sales	—	MW
Adj. to Purchases & Sales	—	MW
Net Capacity Resources	68,666	MW
Capacity Margin	18.7	%
Reserve Margin	23.0	%
With Uncommitted Resources		
Uncommitted Resources	—	MW
Total Net Capacity Resources	68,666	MW
Capacity Margin	18.7	%
Reserve Margin	23.0	%



Demand

The Mid-Atlantic Area Council (MAAC) 2004 summer forecast net peak demand is 55,804 MW. This forecast includes the effects of interruptible demand and load management capabilities, which are estimated to be 1,082 MW. The forecast peak assumes normal summer weather conditions. This forecast is 235 MW higher than the actual MAAC all-time summer peak of 55,569 MW that occurred on August 14, 2002.

Resources

Between June 1, 2003, and mid-July 2004, MAAC's summer generating capacity is expected to increase by a net of 4,294 MW to 68,918 MW. 790 MW of the expected increase is already in service. All nuclear units should be in service and at full capacity (13,320 MW) at the time of the peak. MAAC also has 488 MW of external capacity resources under contract through the summer peak period. With the planned new generation, existing internal generation, and external capacity resources included, the MAAC capacity margin is forecasted to be 18.7% at the time of the forecasted peak. The MAAC reserve margin is expected to be 23.0% at the time of the forecasted peak.

Transmission

In addition to the required level of capacity reserves, MAAC requires that the capacity resources be able to be delivered to the load. With the announced retirements of generation in eastern MAAC and the de-rating of the Branchburg transformers, the 2004 eastern MAAC resources and local transmission import capability has been reduced. However, the overall MAAC generation and transmission combined Loss of Load Event probability remains above the MAAC adequacy requirement of one occurrence in ten years.

Operations

MAAC expects to have sufficient generating capacity to serve the 2004 forecast summer peak demand. When MAAC served its all-time summer peak on August 14, 2002, no emergency procedures were implemented.

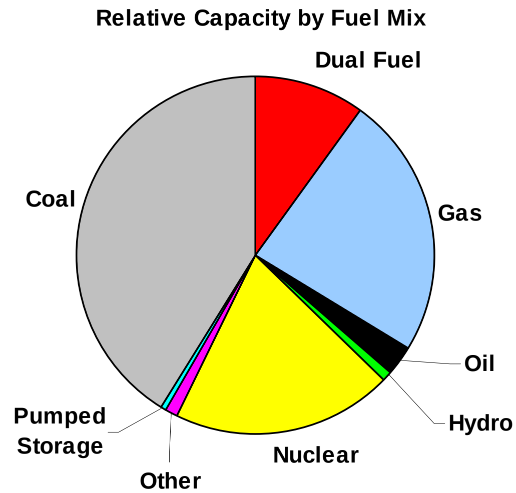
MAAC has a net of 1,979 MW of long-term firm transmission service in place for energy sales out of MAAC through the summer peak period. Presently, these transactions are not capacity backed and therefore can be curtailed in the event of a PJM capacity emergency. Historically, approximately 1,200 MW of internal capacity has been transferred out of MAAC on peak summer days.

The bulk transmission system is expected to perform adequately over a wide range of system conditions. PJM, the Regional Transmission Organization (RTO) for the MAAC Region, is well prepared for operating emergencies. Practice drills are being regularly conducted in preparation should there be an extremely hot summer.

MAIN

Projected Internal Demand	57,662	MW
Interruptible Demand & DSM	3,191	MW
Projected Net Internal Demand	54,471	MW
Last Summer's Peak Demand	57,229	MW
Change	0.8	%
All-Time Summer Peak Demand	57,229	MW
Net Operable Capacity	58,910	MW
Projected Purchases	1,589	MW
Projected Sales	1,275	MW
Adj. to Purchases & Sales	—	MW
Net Capacity Resources	59,224	MW
Capacity Margin	8.0	%
Reserve Margin [1]	8.7	%
With Uncommitted Resources		
Uncommitted Resources	11,412	MW
Total Net Capacity Resources	70,636	MW
Capacity Margin	22.9	%
Reserve Margin [1]	29.7	%

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



Demand

Mid-America Interconnected Network, Inc. (MAIN) total internal non-coincident peak demand forecast for summer 2004 is 57,662 MW, including 3,191 MW of interruptible and DSM load, assuming normal weather conditions. The projected summer peak load is 433 MW (0.76%) higher than last summer's peak demand. For the 2004 summer, the region is expected to be a net firm importer of 314 MW.

Resources

If only capacity that is planned and committed to serving firm load within MAIN is considered, the reserve margin would be 8.7%, which is below MAIN's recommended 14.12% reserve margin. However, MAIN also has 11,412 MW of operable uncommitted generation potentially available to serve load this summer. It is uncertain how much of this uncommitted generation will be available to serve MAIN load this summer. The reserve margin considering all operable generation in MAIN (committed within MAIN plus uncommitted) is forecasted to be 29.7%, which is above MAIN's 14.12% reserve margin recommendation for the upcoming summer.

The projected internal demand includes 4,166 MW of load within MAIN not supplied with firm capacity contracts but rather by liquidated damages (LD) contracts, which to MAIN's knowledge are not supported by firm capacity contracts. Although a requirement is not in place that uncommitted generation within MAIN be available during the summer to serve this load, the load being served by LD contracts is less than 40% of these uncommitted resources.

Based on committed and potentially available uncommitted resources, MAIN expects, but cannot ensure, that there will be capacity available to serve all firm load in MAIN. MAIN will continue to monitor the load and capacity situation as the summer season approaches.

The 70,636 MW of net capacity resources includes about 1,500 MW of generation expected to come on-line in 2004 before or during the summer period. This 1,500 MW figure is net of 130 MW that was retired, mothballed, or temporarily removed from service in 2003. Capacity maintenance is not scheduled for July or August, and only 874 MW and 743 MW of capacity maintenance is scheduled for June and September, respectively.

Neither fuel problems nor limitations of hydro resources are 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 operating conditions. On the whole, import capabilities into MAIN from surrounding regions are considered adequate.

The table below compares MAIN's Import First Contingency Total Transfer Capabilities (FCTTCs) for the summers of 2003 and 2004. The FCTTC values in the table below were developed to help assess MAIN's resource supply reliability (these values are not the same as the Available Transfer Capabilities (ATCs) posted on an OASIS node). The notes associated with Figure 3 of this Summer Assessment are also applicable to the table below.

Table 4: MAIN Import First Contingency Total Transfer Capabilities (FCTTC) (MW)

	2004	2003
ECAR	2,600	2,500
TVA	1,900	2,400
SERC West	2,200	900
SPP*	2.600	2,100
MAPP*	1,200	1,200

* Operating guides used as required

Based on results of the 2003 MAIN Summer Assessment, Alliant West, American Transmission Company, and Dairyland Power Cooperative agreed to the installation of a temporary transformer near Galena, Illinois. This 44 MVA 161/69 kV portable transformer is planned to remain in service for the duration of the upcoming summer to address south-to-north transfers within MAIN and was included in the base model used for the 2004 Summer Assessment.

Based on MAIN's 2004 summer transmission study, these transfer capabilities are expected to be limited by contingency loading on a single facility, the Salem 345/161 kV transformer:

- Import capability into Wisconsin and Upper Michigan (WUMS) from northern Illinois
- Import capability into Alliant West from several directions
- Import capability into northern Illinois from Wisconsin and Upper Michigan
- Import capability into northern Illinois from Iowa is limited by the contingency loading of the Emery-Lime Creek 161 kV line in ALTW. The loading of the Emery-Lime Creek 161 kV line is influenced by generation additions in the area.

These limitations are being managed by their respective transmission system operators, and are not expected to pose a reliability concern for the upcoming summer.

A complete listing of all transmission improvements since summer 2003 and transfer capabilities are available in the *2004 MAIN Summer Transmission Assessment Study* report. (See MAIN website at http://www.maininc.org/)

In response to NERC's February 10, 2004, blackout recommendations, MAIN is making simultaneous transfer capabilities assessments and the impact of the loss of reactive power supply on transfer capabilities.

Operations

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

The following facilities will also require continued monitoring and management by the appropriate reliability coordinators and transmission system operators:

- Historically constrained MAPP to MAIN interface, which will be managed as necessary using special protection schemes (SPS) to maintain reliable operation for the upcoming summer.
- Bland-Franks 345 kV line in southern MAIN, which experienced heavy power flows during 2003 and required implementation of TLR.

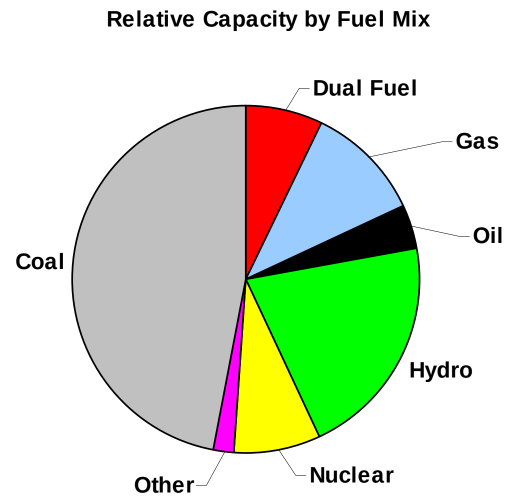
These limitations are being managed by their respective transmission system operators, and are not expected to pose a reliability concern for the upcoming summer.

The NERC standing committees recently approved the short-term recommendations of Alliant West TLR Task Force. The recommendations[1] are intended to address the higher levels of TLRs in the Alliant West area in central and eastern Iowa expected for this summer. The results of implementing the short-term recommendations during the four-month pilot project will be evaluated to determine whether the practices and procedures would be applicable across the entire interconnection.

[1] See NERC website at http://www.nerc.com/~filez/awttf.html

MAPP

Projected Internal Demand	34,965	MW
Interruptible Demand & DSM	544	MW
Projected Net Internal Demand	34,422	MW
Last Summer's Peak Demand	34,434	MW
Change	1.5	%
All-Time Summer Peak Demand	34,896	MW
Net Operable Capacity	40,884	MW
Projected Purchases	5,692	MW
Projected Sales	5,044	MW
Adj. to Purchases & Sales	—	MW
Net Capacity Resources	41,532	MW
Capacity Margin	17.1	%
Reserve Margin	20.7	%
With Uncommitted Resources		
Uncommitted Resources	745	MW
Total Net Capacity Resources	42,277	MW
Capacity Margin	18.6	%
Reserve Margin	22.8	%



Demand

The Mid-Continent Area Power Pool (MAPP) expected July non-coincident peak demand in combined MAPP-US and MAPP-Canada is 34,965 MW. That is 4.1% above last July's peak forecast of 33,572 MW and 6.1% above last July's actual peak demand of 32,947 MW. The load forecast assumes average weather conditions.

Resources

The projected MAPP capacity margin for July is 17.1%. The MAPP Reserve Capacity Obligation requirement is 15%, which is equivalent to a 13.04% capacity margin requirement. This also compares to the July 2003 capacity margin of 18.2%. Capacity additions for Summer 2004 are 206 MW consisting of gas turbines and internal combustion turbines.

There is a projected net capacity import into MAPP from the other regions. There are 755 MW of purchases planned from out of MAPP. There are 537 MW of sales planned out of the MAPP Region.

There are no known fuel limitations anticipated in the region for summer 2004.

Transmission

The MAPP transmission system is judged to be adequate to meet the firm obligations of the member systems for this coming season. The reliability of the transmission system is currently measured by determining the thermal, voltage, and dynamic stability limitations and studying transmission system historical performance. MAPP conducts several steady-state studies annually, which provide an indication of transmission system strength and the necessary data to facilitate analyses of the MAPP network.

MAPP continues to monitor the 18 constrained flowgates (detailed descriptions of the constraints can be found on the MAPP OASIS node) within the region. These constraints can limit MAPP imports and exports under various conditions, and require continuous monitoring. Reliability problems are not expected as long as limits are identified in real time and respected.

The following is based on the MAPP-MAIN-SPP (MMS) 2004 summer study.

- The MAPP 2004 summer import FCITC from MAIN is 200 MW, limited by the Salem 345/161 kV transformer.
- The MAPP 2004 summer import FCITC from SPP is 850 MW limited by the Salem 345/161 kV transformer.

This transformer is sensitive to south-to-north and east-to-west transfers. The base case flow on this transformer has increased 11% since the 2003 summer study. This is primarily due to an increased south-to-north bias. Updates to local line impedances and an increased ALTW load since the 2003 summer study also contributed to the increase. A Salem Operating Guide (ALTW) has been developed, but it is not expected to be needed for the 2004 summer season.

Operations

During the summer of 2003 peak-loading periods for the Nebraska subregion, the Cooper South (COOPER_S) Interface and the western Nebraska to western Kansas (WNE_WKS) Interface were monitored closely. With lower water levels in the Dakotas during summer 2003, COOPER_S did not experience the heavy north-to-south flows that it has in previous years. During peak load periods with heavy exports to the south, NERC TLR procedure was frequently implemented during late night/early morning hours to limit the flows on the Gerald Gentlemen Station-Red Willow 345 kV line to address operating security limits associated with the WNE_WKS Interface. A NERC TLR Level 5 was implemented on June 11, 2003, due to excessive power flow south on the WNE_WKS Interface.

The following is based on studies and information from the Transmission Operations Subcommittee and its working groups.

Subregions

Northern MAPP

No significant operational issues are expected this summer for northern MAPP subregion. The existing standing guides, and temporary operating guides that are developed as needed, have proven to effectively deal with the system conditions throughout the year. The Manitoba-United States configuration was enhanced so that the scheduling limits were increased by 200 MW system-intact prior to last winter. Increased southward transfer flows from Manitoba may be experienced this summer, but they have not occurred yet.

Reservoir water levels continue to remain low throughout the subregion, 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 MAPP. A number of bulk transmission outages are scheduled in the subregion for maintenance; however, no operating problems are expected. Temporary operating guides will be developed as necessary. No major transmission or generation additions to the subregion area are expected this summer.

Iowa

Phase-1 of the Greater Des Moines Energy Center (GDMEC) project (which was completed in 2003) added the GDMEC 345 kV substation and two combustion turbine units, each having an output of 210 MW. Phase-2, which will be completed prior to summer 2004, consists of a heat recovery steam generator and steam turbine with an output capability of 190 MW. This third generator will improve operational control of heavy east-to-west power transfers across Iowa.

Alliant Energy's 600 MW Power Iowa Combustion Turbine located at Emery substation is scheduled to be online by the summer of 2004. This unit should aid in operational control of heavy south-to-north power transfers across Iowa.

MEC will continue to have two MAPP 345 kV constrained interfaces (Quad Cities West and Montezuma West). Standing operating guides are in place for both interfaces.

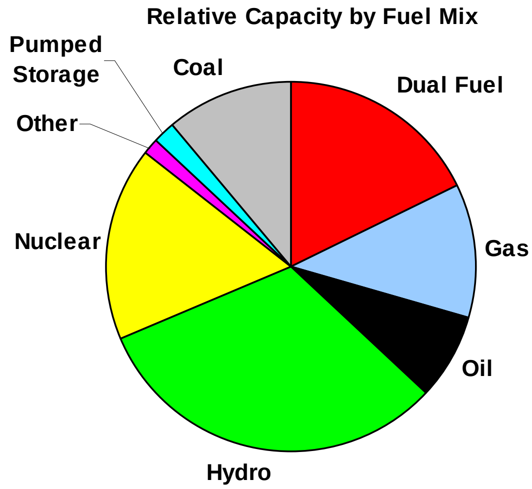
Nebraska

No significant operational issues are expected in Nebraska during summer 2004. Nebraska Public Power District (NPPD) and Omaha Public Power District (OPPD) currently post six constrained paths on the MAPP OASIS, which are located within or adjacent to the NPPD and OPPD control areas. All of these interfaces have approved operating guides that have proven effective in dealing with system conditions throughout the year.

Lincoln Electric System (LES) experienced a bulk transmission transformer failure on January 27, 2004. This transformer is a critical interconnection to the bulk transmission system. The transformer repair/replacement is estimated to take 12–18 months. LES and NPPD are developing operating procedures necessary to maintain system reliability in the Lincoln area.

NPCC

Projected Internal Demand	105,263	MW
Interruptible Demand & DSM	2,115	MW
Projected Net Internal Demand	103,148	MW
Last Summer's Peak Demand	103,646	MW
Change	1.6	%
All-Time Summer Peak Demand	120,640	MW
Net Operable Capacity	128,444	MW
Projected Purchases	1,469	MW
Projected Sales	1,710	MW
Adj. to Purchases & Sales	—	MW
Net Capacity Resources	128,203	MW
Capacity Margin	19.5	%
Reserve Margin	24.3	%
With Uncommitted Resources		
Uncommitted Resources	1,481	MW
Total Net Capacity Resources	129,684	MW
Capacity Margin	20.5	%
Reserve Margin	25.7	%



In the Northeast Power Coordinating Council (NPCC), ISO New England (ISO NE), the New York Independent System Operator (NYISO) and the Ontario Independent Electricity Market Operator (IMO) expect sufficient resources to be available to meet projected demands during 2004 summer. When compared to the summer of 2003, the return to service of previously deactivated units and the addition of new generation will improve the overall resource picture in NPCC for the summer of 2004.

More than 2,000 MW of previously deactivated nuclear capacity has been returned to service within Ontario since the summer peak of 2003; another 708 MW of new generating capacity has been added as well.

The NYISO expects to add 1,481 MW of new capacity, of which 187 MW is to be located within Long Island and 221 MW within New York City, ensuring that these critical load zones meet their more stringent internal capacity requirements.

New England projects about 275 MW of generation additions since the summer peak of 2003. Because necessary transmission upgrades have not been made to southwest Connecticut, potential reliability problems remain for the area. However, 125 MW of emergency energy resources have been secured for the summer of 2004 to maintain reliable electric supplies in southwest Connecticut during periods of high electricity use this summer.

The remaining NPCC Canadian subregions, Québec, and the Maritimes (the provinces of New Brunswick, Nova Scotia, and Prince Edward Island), are predominately winter-peaking control areas, and thus adequate resources are expected to be available to serve the forecast summer peak demand and meet operating reserve requirements.

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

Subregions

Maritimes

Demand — Based on the Maritimes area 2004 demand forecast, the peak demand of 3,633 MW is predicted to occur for the summer period, June through August, beginning May 30, 2004. The actual peak for summer 2003 was 3,441 MW, which occurred August 16, 2002 (coincident). Since the Maritimes is a winter-peaking area, forecasted peaks for the shoulder months of May and September are normally higher than the summer period. For the week beginning May 2, 2004, the predicted peak is 3,922 MW, and for the week beginning September 26, 2004, the predicted peak is 3,640 MW.

The 2003 coincident peak load experienced by the Maritimes area during the May through September was 3,902 MW, which was approximately 182 MW (4.9%) higher than last year's forecast of 3,720 MW. This is due to the peak occurring in May while experiencing below normal temperatures. This resulted in a greater electric heating load than would normally be the case.

Resources — The Maritimes area is projecting more than adequate capacity margins for the summer 2004 assessment period. Net margins are comparable to summer 2003 and meet the regional requirement of 20% of forecasted demand.

The Maritimes area is forecasting normal hydro conditions for the summer 2004 assessment period. The area is not anticipating any fuel supply problems impacting generation. The Maritimes did not anticipate, nor did it experience, any capacity shortages during the summer of 2003. Further, planned additions to merchant capacity are not anticipated this summer.

Transmission —No major additions were made to the Maritimes bulk transmission system. Interconnection capability remains unchanged and is able to deliver up to 700 MW to New England and up to 700 MW to Québec.

Operations — 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 summer 2004 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, and pose no reliability problems.

ISO New England

Demand — The New England control area's forecasted summer 2004 peak demand is 25,735 MW, an increase of 615 MW (2.4%) as compared with the forecast for summer 2003 of 25,120 MW and 4.2% higher than the actual peak demand of 24,685 MW realized during the summer of 2003.

At these forecasted load levels, a one-degree increase in the Temperature Humidity Index (THI) will result in approximately 800 MW of additional load. The amount of additional load depends on the total deviation from the "normal weather" approximation.

Resources — Net operable capacity resources of 30,789 MW (August) within ISO NE include approximately 100 MW of generation out of service on maintenance as well as 300 MW from new generation, which are expected to be in service by August. The total amount of external capacity purchases from control areas outside of New England is approximately 900 MW. Total interruptible demand resources projected to be available for the summer of 2004 is approximately 500 MW. These include demand that is interrupted based on the price of energy and demand interrupted in times of operable capacity shortages. Including capacity purchases and interruptible demand, New England is forecasted to have an available capacity margin of approximately 6,400 MW (August).

Transmission — Although it is projected that operable capacity is surplus for the ISO NE control area, the southwestern Connecticut region may face reliability problems due to transmission constraints into and within that region. Pursuant to planning studies conducted for the 2003 and 2004 Regional Transmission Expansion Plans, ISO NE has identified concerns regarding electric transmission reliability in southwestern Connecticut. Under certain contingencies and demand conditions, the electric load in the southwestern Connecticut region could exceed the combined ability of the electric generating resources in the subregion and the available transmission capacity to import electric energy into the subregion. Under these conditions, the generation and transmission systems within the subregion may not be able to supply the electric load without overloading lines or causing low voltage. In order to address this reliability concern, ISO NE has signed a Request For Proposal (RFP) for up to 125 MW of quick-start resources.

ISO NE projects that there may be instances when NEPOOL will not have sufficient operable capacity within the control area under periods of higher than anticipated peak demands and/or higher than anticipated generating unit forced outages. Consequently, ISO NE expects to invoke operating procedures to mitigate any short-term operable capacity deficiency. ISO NE has in place Operating Procedure No. 4 (OP-4) *Action During a Capacity Deficiency*, which includes: purchasing emergency energy from the interconnected grid, interrupting interruptible load customers, and implementing voltage reductions in the event of a capacity shortage. This procedure provides load or capacity relief varying between 3,000 to 4,000 MW, depending on system conditions at the time. OP-4 is used by system operators as part of "normal" operations to mitigate capacity shortages. Load relief from operating procedures is also considered as resources for meeting the NEPOOL Resource Planning Reliability Criterion of one day in ten years disconnection of non-interruptible customers. The total estimated load relief obtainable from OP-4 has not been reflected in the available resources reported above. ISO NE does not expect to implement Operating Procedure No. 7 (OP-7) *Action in an Emergency*, which are procedures to be followed in the event of an operating emergency involving unusually low frequency, equipment overload or unacceptable voltage levels in an isolated or widespread area of New England.

During summer 2004, the following transmission upgrades are on schedule to be energized by the summer peak:

- The Sandbar Phase Angle Regulator (PAR) located in Vermont, the addition of a second Scobie 345-115 kV (400 MVA) transformer in New Hampshire, and the Glenbrook STATCOM project that includes the tapping of the Darien-Southend 115 kV (circuit 1977) line located in Connecticut.
- The installation of the Sandbar PAR, which is part of the Northwest Vermont Reliability Project, expedited due to last year's failure of the Plattsburgh PAR. The new Sandbar PAR will be used to regulate the flow on the Plattsburgh-Sandbar 115 kV (circuit PV20) tie line between New York and Vermont, in place of the old Plattsburgh PAR.

The second Scobie autotransformer improves reliability in the Manchester-Nashua area of New Hampshire. Due to area load growth, the existing autotransformer has recently experienced heavy loadings. The Glenbrook STATCOM project and the tapping of the 1977 line into the Glenbrook Substation improve dynamic voltage and thermal response to contingencies in the Norwalk-Stamford area.

New York ISO

Demand — The forecast peak for the NYISO is 31,800 MW, which is 370 MW higher than last year's forecast and 1,467 MW higher than last years actual 2003 NYISO peak load of 30,333 MW, which occurred on June 26. This forecast is 2.6% higher than the all-time peak of 30,983 MW that occurred on August 9, 2001. The forecast is based on the forecasts for the transmission districts by the transmission owners and municipal agencies. For peak load normalization, the NYISO uses a THI value of 81.31^0 F. At forecast load levels, a one-degree increase in the THI will result in approximately 500 MW additional load. Under extreme conditions, the peak load could reach 33,000 MW.

Resources — The NYISO conducts semi-annual and monthly Installed Capacity (ICAP) auctions. Based on the forecast load for 2004, the ICAP requirement is 37,524 MW based on the 18% installed reserve margin requirement. When allowances are taken for unplanned outages (based on historical performance of 9.7% unavailable capacity), the net available resources will be 33,877 MW, which will be sufficient to meet the NYISO load and 1,800 MW ten-minute and 30-minute operating reserve requirements during the peak load hours, with a surplus of approximately 265 MW expected at peak conditions. Currently, 37,254 MW are available from in-state plants, but the NYISO expects new generation, out-of-state supplies and capacity from demand-response programs to raise the total to 41,350 MW if needed. New generation will come from a variety of sources, including a new 221 MW combined-cycle plant brought on line in New York City and the 1,073 MW Athens, New York plant.

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

Despite the positive forecast, the NYISO President, William Museler, warned that an extended heat wave could force an over-reliance on out-of-state reserves, which may not be readily available. He said the state must take steps to encourage the development of new generation in New York State. Generation resources that are external to the NYCA that provide ICAP to the New York market are included in the ICAP total of the New York load and capacity assessment. Resources within the NYCA that provide firm capacity to an entity external to the NYCA are not included in the ICAP total (i.e., this generation cannot participate in the ICAP market).

NYISO expects approximately 1,100 MW of load relief from emergency operating procedures that include internal load curtailment by the transmission owners, public appeals and 5% system wide voltage reductions. Participation in the Emergency Demand Response Program and Special Case Resources programs represents an additional 700 MW available through the market.

A total of 1,481 MW in resource additions are expected to be available for service prior to the summer peak. Of this amount, 1,073 MW is provided by a new natural gas fired combined-cycle merchant plant located near Athens, New York; and 221 MW is provided by a new natural gas fired, combined-cycle merchant plant located in New York City; the remaining 187 MW is provided by simple-cycle combustion turbines in the Long Island zone. All of these facilities are expected to be in service prior to July 1.

Transmission —Major transmission facility additions to the New York bulk power system are not planned for the summer 2004 period.

After August 14, 2003, the Long Island Power Authority obtained an emergency order from the U.S. Department of Energy to operate the Cross-Sound Cable HVDC tie line between New Haven Harbor (ISO NE) and Shoreham (NYISO). This line continues to be available to operate only under emergency conditions.

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

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

Operations — The NYISO is developing wide-area view displays for use by the control room system operators. These displays will present inter-area, real-time data obtained via the ICCP and present a geographical overview of EHV transmission conditions of the Lake Erie transmission path and critical inter-area interconnections. These displays were scheduled to be available during May.

New York City and Long Island

As part of its peak period capacity assessment, the NYISO determines the locational capacity requirements for the New York City and Long Island load zones in addition to the statewide capacity requirement. For the summer 2004, new capacity additions prior to the summer will satisfy the statewide and locational requirements.

Ravenswood 4 will have a real power output of 221 MW and will connect to the 138 kV system in New York City. Two natural gas fired combustion turbines, with a combined capability of 91 MW, are being installed at Freeport in the Long Island zone, and the Long Island Power Authority (LIPA) is installing two 48 MW blocks of emergency generation at the Holtsville and Shoreham stations.

Ontario IMO

Demand — Ontario's forecast summer peak demand is 23,668 MW based on normal weather. This is 2.1% higher than the 2003 normalized summer peak demand of 23,164 MW, and is less than the all-time record summer peak demand of 25,414 MW, which occurred on August 13, 2002. Firm sales are not projected for the 2004 summer period.

Resources — Resources are forecast to be adequate during the upcoming summer period. One Pickering A nuclear unit, shut down since 1996, and two Bruce A nuclear units, shut down since 1998, have returned to service. Also, 708 MW of new generating capacity is expected to come in service either before or during the summer period. A capacity margin of 18.9% is projected for the month of July. However, 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, outage cancellations, or outage recalls by the IMO.

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 and other influencing factors. The Ontario fuel supply infrastructure is judged to be adequate during the summer peak demand, and fuel delivery problems are not anticipated for this summer.

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

The ability to have total control over the flows across the Michigan-Ontario interface using the four phase-angle regulators continues to be delayed by equipment failures and will not be available for summer 2004. In the meantime, operating guides are in place to ensure that the interface is operated reliably.

The Scott-Bunce Creek 230 kV interconnection (circuit B3N) between Ontario and Michigan is currently forced out of service. The scheduled date for its return-to-service is September 30, 2004, but further delay could occur. This outage increases the upper import limit capability of Michigan-Ontario transfers by 200 MW in the summer and by 300 MW in the winter; the Ontario-Michigan export limit decreases by approximately 500 MW in the summer and in the winter.

Operations —Unusual operating conditions, environmental, or regulatory restrictions that would affect capacity availability are not anticipated for this summer. All known planned generator outages have been included in the IMO's adequacy assessment.

Hydro-Québec

Demand — Hydro-Québec's internal peak demand for summer 2004 is expected to be 22,511 MW in May 2004. The actual peak demand for summer 2003 was 21,813 MW and it occurred on May 2. The winter peaking nature of the Hydro-Québec system is demonstrated by comparing these demands with the all-time winter peak demand of 36,268 MW, which occurred on January 15, 2004, at 5:30 p.m.

Resources — Net capacity resources are expected to be more than sufficient to meet expected internal demand, contractual obligations and reserve requirements during the summer. The available capacity margin is expected to be more than 6,740 MW throughout the summer and more than 9,000 MW in July.

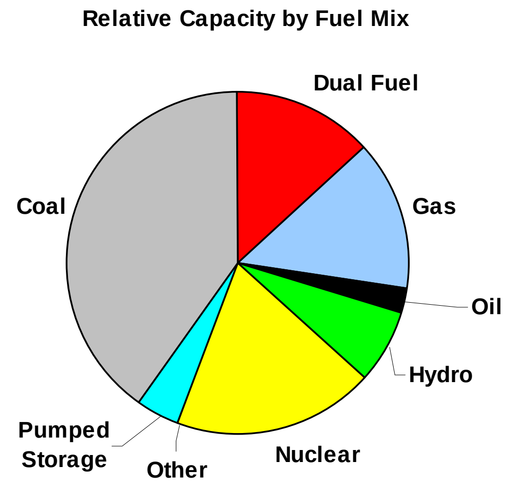
Based on the level of current water reserves in Hydro-Québec's reservoirs and the availability of other non-hydraulic resources, Hydro-Québec's generation availability meets the energy reliability criterion.

Transmission — No significant upgrade by Hydro-Québec TransÉnergie of transmission system is planned for summer 2004. A certain number of outages due to the summer maintenance schedule affect the transfer capabilities on different parts of the transmission system but transmission margins are still adequate. Hydro-Québec's system is a strong winter peaking system and, moreover, maintenance schedules are set up to maximize capacity margins with regards to internal demand and firm capacity sales.

Operations —Hydro-Québec does not anticipate any operating issues this summer.

SERC

Projected Internal Demand	157,214	MW
Interruptible Demand & DSM	5,781	MW
Projected Net Internal Demand	151,433	MW
Last Summer's Peak Demand	151,252	MW
Change	3.9	%
All-Time Summer Peak Demand	157,333	MW
Net Operable Capacity	173,930	MW
Projected Purchases	13,264	MW
Projected Sales	4,593	MW
Adj. to Purchases & Sales	(171)	MW
Net Capacity Resources	182,430	MW
Capacity Margin	17.0	%
Reserve Margin	20.5	%
With Uncommitted Resources		
Uncommitted Resources	38,335	MW
Total Net Capacity Resources	220,765	MW
Capacity Margin	31.4	%
Reserve Margin	45.8	%



Demand

Southeastern Electric Reliability Council (SERC) projects the total internal demand for the 2004 summer season to be 157,214 MW. This projection is based on average historical summer weather. The forecast 2004 summer peak is 157 MW (0.1%) lower than the forecast 2003 summer peak and is 5,962 MW (3.9%) higher than the actual 2003 summer peak. This significantly higher 2004 forecast, as compared to the actual 2003 loadings, is due in part to milder weather conditions experienced last summer.

SERC has significant demand response programs. These programs allow demand to be reduced or curtailed when needed to maintain reliability. Interruptible demand and demand-side management capabilities increased to 5,781 MW from the 5,560 MW reported last summer.

Temperatures that are higher or lower than normal and the utilization of interruptible demand and demand-side management can significantly impact the actual peak demand for the region.

Resources

Capacity resources in SERC are expected to be adequate to supply the projected firm summer demand. The projected 2004 summer capacity margin for SERC is 17.0%. This is higher than last year's projected capacity margin of 14.4%. Planned transactions across the SERC electrical borders include 714 MW of purchases coming into the region and 2,383 MW of sales leaving the region. These transactions, plus a net of 10,340 MW of firm purchases from non-SERC members located internal to SERC, have been included in the capacity margin for the region.

Merchant Generation

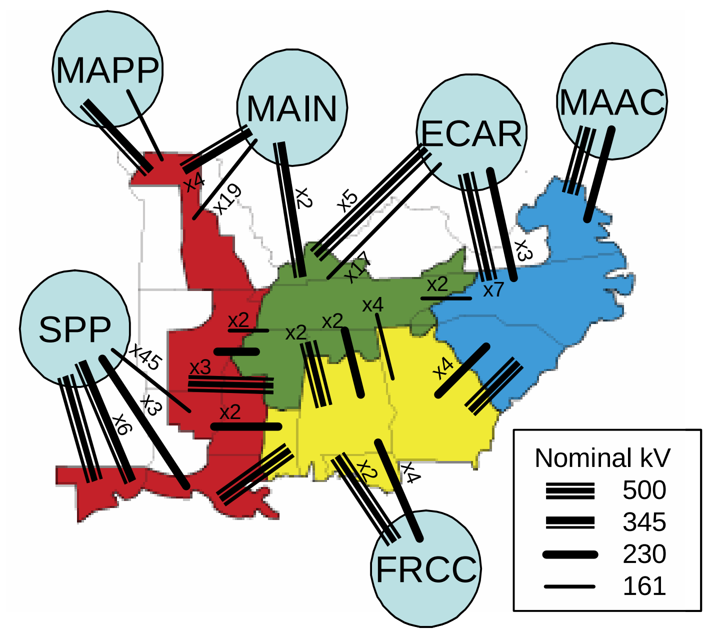
SERC has seen significant merchant generation development for the past few years. Much of this generation has not been contracted to serve load within SERC and its deliverability within SERC or out of SERC to other parts of the interconnection is not ensured. For these reasons, only merchant generation contracted to serve SERC load is included in the capacity margins reported for SERC.

To understand the extent of generation development in the region, it is instructive to examine how much generation is connected to the transmission system. Total connected generation is expected to exceed forecast summer peak demand by 63,551 MW or 40.4%. As of December 31, 2003, total generation connected to the transmission system in SERC, including uncommitted merchant generation was 223,564 MW according to an annual survey of all transmission providers in the region. SERC expects approximately 5,116 MW of additional generation to connect to the transmission system by December 31, 2004, bringing total connected generation to 228,680 MW.

Transmission

SERC has extensive transmission interconnections between its subregions. SERC also has extensive interconnections to ECAR, FRCC, MAAC, MAIN, MAPP and SPP. For interconnections of 161 kV and above, the voltage and number of interconnections at that voltage are shown in Figure 4. 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 4: Number of Interconnections by SERC Subregion
(the number after "X" refers to the number of interconnections)



Approximately 181 miles of new 230 kV, 345 kV, and 500 kV transmission lines were built in 2003 and an additional 88 miles are planned for completion in 2004. SERC members invested more than $1 billion in new transmission lines and system upgrades in 2003 (100 kV and above).

Coordinated interregional transmission reliability and transfer capability studies for the 2004 summer season were conducted among all the SERC subregions and with the neighboring regions. These studies indicate that the bulk transmission systems within SERC and between adjoining regions can be expected to provide adequate and reliable service over a range of system operating conditions.

Operations

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 flows are anticipated within SERC. These flows are largely driven by increased short-term transactions and prevailing weather conditions across the Eastern Interconnection. 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

For the Entergy subregion, the projected total internal demand for the 2004 summer season is 26,239 MW based on normal weather for peaking conditions. This is 237 MW (0.9%) higher than the forecast 2003 summer peak and is 625 MW (2.4%) higher than the actual 2003 summer peak. The projected capacity margin in the subregion for 2004 summer is 13.2%. Capacity in the subregion should be adequate to supply forecast demand.

No reliability problems are anticipated on the Entergy transmission system this summer. Entergy expects to meet its peak load demand for the 2004 summer through a combination of internal generation and market power purchases. Based on the results of the VAST 2004 Summer Reliability Study, Entergy anticipates being able to reliably import adequate levels of power from neighboring SERC utilities to meet its own direct connect customer demands and to serve some additional transmission service requests.

No significant issues affecting the reliability of the Entergy transmission system were identified in the study. No significant resource issues were identified in the study. Import and export capability for all neighboring SERC utilities were determined to be satisfactory for the summer 2004 operating period. Entergy’s simultaneous import capability for the 2004 summer operating period is expected to range from approximately 1,000 MW to 2,500 MW.

Southern

For the Southern subregion, the projected total internal demand for the 2004 summer season is 44,695 MW based on normal weather for peaking conditions. This is 683 MW (1.5%) lower than the forecast 2003 summer peak and is 3,678 MW (9.0%) higher than the actual 2003 summer peak. The projected capacity margin in the subregion for 2004 summer is 18.7%. Capacity in the subregion should be adequate to supply forecast demand.

Because of the large amount of generation within the Southern control area that is uncommitted and without firm transmission service, flow patterns are sensitive to weather conditions. Exports out of the area are high when weather is mild in the subregion and hot elsewhere. The ability of the FRCC to export power can also result in volatile flow patterns. However, these flows are not a reliability concern and can be managed through real-time security analysis.

During the 2003 summer, the Southern control area experienced very significant, unpredictable loop flows on the VACAR-SOCO interface. High, unpredictable loop flows are also expected to continue on the TVA-SOCO interface. Additionally, uncommitted generation located on the TVA-SOCO interface and new generation located on the VACAR-SOCO interface may also impact the bulk power flows within the Southern control area for the 2004 summer. Transmission constraints are expected to appear during periods of high loop flows for multiple contingency conditions on the 230 kV system around Atlanta and also for the contingency loss of the Norcross-Oconee 500 kV line. In the short-term, constraints can be managed through local procedures and the TLR process and are therefore not a reliability concern to the Southern subregion.

TVA

For the TVA subregion, the projected total internal demand for the 2004 summer season is 30,123 MW based on normal weather for peaking conditions. This is 214 MW (0.7%) higher than the forecast 2003 summer peak and is 1,488 MW (5.2%) higher than the actual 2003 summer peak. The projected capacity margin in the subregion for 2004 summer is 11.7%. Capacity in the subregion should be adequate to supply forecast demand.

The TVA transmission system is expected to continue to experience large and volatile flows as in recent years. Critical facilities will be monitored and appropriate actions taken to maintain reliability in the event of excessive flows. These flows are driven by the uncommitted generation to the south of the subregion and weather conditions to the north of the subregion. Coordinated studies with ECAR, MAIN, and the other SERC subregions indicate that there will be adequate transmission transfer capability on all interfaces this summer. Operating procedures are in place where needed to maintain reliability for outages of key transmission facilities. No internal constraints were identified that would present a reliability concern.

VACAR

For the VACAR subregion, the projected total internal demand for the 2004 summer season is 56,851 MW based on normal weather for peaking conditions. This is 116 MW (0.2%) higher than the forecast 2003 summer peak and is 865 MW (1.6%) higher than the actual 2003 summer peak. The projected capacity margin in the subregion for 2004 summer is 18.1%. Capacity in the subregion should be adequate to supply forecast demand.

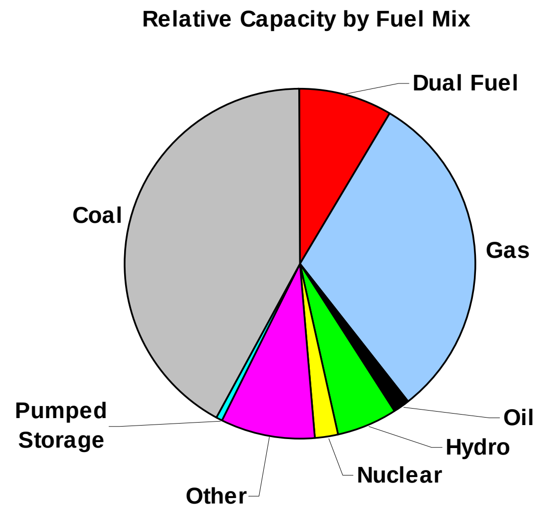
No reliability problems are anticipated on the VACAR transmission systems this summer. Coordinated studies for the 2004 summer season performed with ECAR, MAAC, and the other SERC subregions indicate that there will be adequate transmission transfer capability on all interfaces this summer to support reliable operations.

The limiting transmission facility for most VACAR imports from the other SERC subregions is the Big Shanty-Bull Sluice 500 kV circuit for the loss of the Klondike-Norcross 500 kV line. Higher base flows on the Big Shanty-Bull Sluice circuit have reduced the VACAR import capability on several interfaces as compared to last summer; however, adequate capability still exists to maintain reliability. These higher base flows are the result of a network modification at South Hall, which increases west-to-east flows on the Big Shanty-Bull Sluice circuit, as well as generation and load changes in the area. The Big Shanty-Bull Sluice circuit is scheduled to be uprated prior to the 2005 summer period. Last summer, the Bull Run-Volunteer 500 kV circuit limited most VACAR imports from other SERC subregions. That facility has been uprated since last summer.

VACAR imports from ECAR continue to be voltage and thermally limited this summer by facilities along the VACAR-ECAR-MAAC interface, at levels lower than last summer. Base case loading on these facilities is higher due to changes in modeled PJM generation dispatch. Higher transfers are modeled from PJM West (Allegheny Power) to traditional PJM, as well as an additional 500 MW base transfer modeled from Commonwealth Edison, which is scheduled for implementation into the PJM market by this summer. These studies indicate that there will be adequate transmission transfer capability on all interfaces this summer to support reliable operations.

SPP

Projected Internal Demand	39,740	MW
Interruptible Demand & DSM	990	MW
Projected Net Internal Demand	38,750	MW
Last Summer's Peak Demand	40,214	MW
Change	(1.2)	%
All-Time Summer Peak Demand	40,214	MW
Net Operable Capacity	46,241	MW
Projected Purchases	7,051	MW
Projected Sales	4,066	MW
Adj. to Purchases & Sales	(114)	MW
Net Capacity Resources	49,112	MW
Capacity Margin	21.1	%
Reserve Margin	26.7	%
With Uncommitted Resources		
Uncommitted Resources	8,000	MW
Total Net Capacity Resources	57,112	MW
Capacity Margin	32.2	%
Reserve Margin	47.4	%



Demand

The Southwest Power Pool (SPP) noncoincident total internal demand forecast for the upcoming summer peak month of August is 39,740 MW, which is 1.2% lower than the adjusted 2003 actual summer peak monthly total internal noncoincident demand of 40,214 MW. Actual peak demand for summer 2003 was close to what was projected. Actual peak demand has grown at 1.7% per year from 1999 to 2004.

Resources

SPP has added 194.25 MW of generating capacity based on nameplates to the region since last summer. However, these capacity resources are attributed to two new wind farms that came on line at the end of 2003, of which a fraction will be counted in net accredited capability during summer peak load conditions. SPP expects to be a net importer of 45 MW during the 2004 summer peak period. The forecasted regional capacity margin for the peak month of July is 21.1%, which exceeds the SPP criteria minimum requirement of 12%.

Fuel supply for SPP generating units is expected to be adequate for the summer months. SPP reservoirs have improved to above normal for this time of year. Normal hydro capacity is expected for the summer conditions. The energy output from hydro is not expected to have regional impact since only a small percentage of SPP capacity is hydro based. Environmental and/or regulatory restrictions are not expected to impede reliability during the summer months.

Because of changes being considered in the Missouri River Master Water Control Manual (1979), SPP has conducted studies relating to the impact of cooling water restrictions on local generation and transmission during the 2004 summer load season. If the proposed changes are implemented, generating units located along the Missouri River could be derated. To ensure reliability, SPP staff has evaluated potential derates and the ability of the system to replace lost capacity. No major regional problems are expected to occur within SPP should the derates occur during summer peak load conditions.

Transmission

Based on the most recent analysis of the SPP, MAIN, MAPP, and SERC interfaces, completed by the MAIN Transmission Assessment Study Group, all SPP regional import interfaces are found to be limited by the Fort

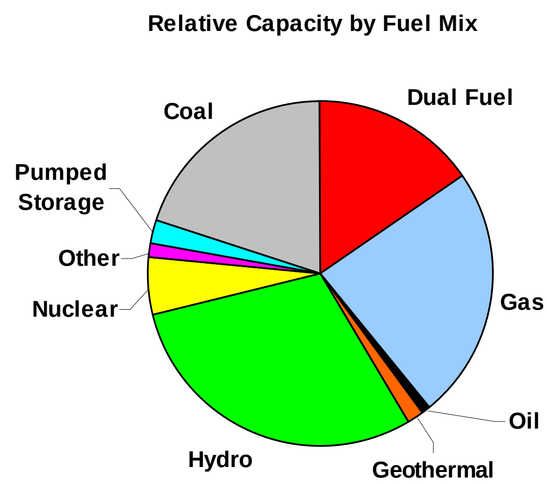
Smith 500/161 kV transformer (OKGE) for the outage of Fort Smith 345/161 kV transformer (OKGE). The limitation affects imports into SPP from MAIN, SERC-West, and TVA as well as subregional imports into SPP-South from AMRN. Linear analysis results showed SPP imports to be in the range of 300–400 MW FCITC. Further AC analysis on the limit confirmed even lower import FCITC, possibly in the range of 0 MW FCITC.

The Fort Smith transformer has been a limiting constraint to transfers in previous assessments. The loading on the transformer is expected to increase further this summer due to dispatch changes in the surrounding area. OKGE planned to install a second Fort Smith 500/161 kV transformer to address the limitation. However, the planned upgrade will only be completed by November of this year. An operating directive is being proposed to alleviate the overload on the Fort Smith transformer. If loading problems still persist, OKGE will then need to provide load relief for the station that may be accomplished by shifting dispatch among the various OKGE units or by load switching.

Absent this local area problem, which is aggravated by interregional transfers, the transmission system within SPP is expected to perform reliably over the 2004 summer load season.

WECC

Projected Internal Demand	139,798	MW
Interruptible Demand & DSM	2,561	MW
Projected Net Internal Demand	137,237	MW
Last Summer's Peak Demand	139,914	MW
Change	(0.1)	%
All-Time Summer Peak Demand	139,914	MW
Net Operable Capacity	181,464	MW
Projected Purchases	286	MW
Projected Sales	103	MW
Adj. to Purchases & Sales	—	MW
Net Capacity Resources	181,647	MW
Capacity Margin	24.4	%
Reserve Margin	32.4	%
With Uncommitted Resources		
Uncommitted Resources	—	MW
Total Net Capacity Resources	181,647	MW
Capacity Margin	24.4	%
Reserve Margin	32.4	%



Demand

The aggregate 2004 Western Electricity Coordinating Council (WECC) summer total internal demand is forecast to be 139,798 MW (U.S. systems 122,507 MW, Canadian systems 15,531 MW, and Mexican system 1,760 MW). The forecast is based on average weather conditions and is 0.1% below last summer's actual peak demand of 139,914 MW, which was established under generally normal to above normal temperatures in the Northwest and Rocky Mountain areas.

Resources

WECC resources are expected to increase by about 5,100 MW from August 2003 through August 2004, while peak demands are expected to decrease by about 116 MW. Consequently, expected capacity margins have increased compared to last summer. For the peak summer month of August, WECC's capacity margin is expected to be 24.4%. 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.

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. However, operating procedures may have to be implemented during high-demand periods to limit flows on critical facilities. Generally, dry conditions in the West can result in wildfires that can affect transmission lines. Operating procedures may be required to limit the impact of wildfires on overall transmission system reliability.

Subregions

California-Mexico Power Area

This is a summer-peaking area. The 2004 summer peak demand forecast of 54,881 MW is 3.4% above last summer's actual peak demand of 53,071 MW, which was established under slightly milder than normal temperatures in the area. Area resources are expected to decrease by about 100 MW since last year's peak in July

2003 through August 2004. The forecast peak demand includes 1,693 MW of interruptible demand capability and 67 MW of load management. The projected capacity margin for the peak month is 17.1%.

California ISO Control Area (CAISO)

Demand — The CAISO summer peak demand forecast for normal weather conditions is 44,422 MW, which is 4.1% greater than the 2003 summer peak demand of 42,689 MW. The 2003 actual summer peak demand was 205 MW less than forecast, partially due to slightly milder than normal temperatures. The relatively higher load forecast is attributed to adjusting for normal temperatures and improving economic conditions in much of the area.

A portion of the peak demand forecast represents customer demand that is subject to voluntary interruption. Prior to 2001, various programs provided up to 2,800 MW of interruptible demand. However, the same programs provided only 1,600 MW in 2001, 1,409 MW in 2002, and 1,321 MW in 2003. For this summer, customer commitment for voluntary load reduction is estimated to be 1,435 MW. Restrictions on utilizing the voluntary demand reductions include 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. CAISO also has approximately 1,376 MW of non-spinning reserves that can be converted to energy, giving a total of 2,811 MW of emergency mitigation measures that can be implemented prior to curtailing firm peak demand.

Resources — Barring major generation or transmission outages, CAISO anticipates sufficient capacity margins throughout the summer season to serve forecast peak demand and meet operating reserve requirements of 2,750 MW (6%). From the 2003 summer peak through December, 1,955 MW of new generation was added and 880 MW of existing generation was retired; 1,175 MW was mothballed for the summer for a net decrease of 100 MW. Only 33 MW of net additional generation is planned through August 2004. With an expected peak demand increase of 1,733 MW over 2003 and a net resource decrease of about 67 MW, the California ISO control area's reliance on external resources to cover possible unexpected peak demand or unit forced outage has increased about 1,800 MW as compared to last summer.

The CAISO, in its 2004 Summer Assessment, has noted that these relatively narrow operating margins might lead to emergency alerts if adverse conditions affecting supply arise during the summer. Specifically, the CAISO has acknowledged that its operating reserves might not be sufficient to avoid these alerts if peak demand is higher than anticipated, or if supplies tighten for other reasons such as limited import capability, transmission outages, limitations on generation dispatch, etc. The three stages of emergency alerts occur when operating reserves fall below certain threshold levels.

Specifically, a Stage 1 emergency is declared when the CAISO determines there will be an operating reserve shortfall within the next two hours, whereby reserve levels fall to between 6% and 7%. Stage 1 does not require interruption of service to customers. A Stage 2 emergency is declared anytime there will be a serious operating reserve shortfall (less than 5%) within the next two hours. At this stage, interruption of service to some or all of selected customers is required, e.g., those who participate in voluntary load reduction programs. A Stage 3 emergency is declared anytime actual or anticipated operating reserves are less than or equal to 1.5% within the next two hours. Stage 3 requires significant ISO intervention to keep the system operating. Involuntary curtailment of service to consumers (i.e., rolling blackouts) is required to maintain operating reserve above 1.5%. Only one emergency alert, a Stage 1, has been called in 2004 and that occurred on March 29.

Environmental — All power plants in California are required to operate in accordance with strict air quality environmental regulations. Some plant owners have upgraded emission control equipment to remain in compliance with increasing emission limitations while other owners have chosen to discontinue operating some plants. However, the effects of owners' responses to environmental regulations have been accounted for in the area's resource data and it is not expected that environmental issues will have additional adverse impacts on resource adequacy within the CAISO control area.

Transmission — The transfer capability of the Pacific DC Intertie (PDCI) will be reduced from 3,100 MW to 2,000 MW until September. Thereafter, the PDCI will be removed from service until the end of the year. The PDCI transfer limitation may reduce Oregon-to-southern California imports by up to 750 MW compared to historical import levels. The reduced PDCI transfer capability may result in increased energy flows on other transmission paths, including the Path 26 transmission tie between northern California and southern California. It is expected that a special protection scheme change on Path 26 will allow a north-to-south transfer capability increase of 400 MW.

An estimated 770 MW of southern California generation may be constrained by internal transmission limitations. This constrained generation is not included in the capacity margin calculations for this area. The most notable limitations are the South of Lugo transmission path, which serves the eastern Southern California Edison area, and the Miguel substation in the San Diego area of California. The South of Lugo limitation has been reduced by recent upgrades and will be further reduced by adding additional transformer capacity at the Mira Loma substation prior to the summer peak period. However, a South of Lugo limitation may still occur under heavy load conditions. Additional transformer capability being installed to address the Miguel constraint will not be in service this summer so previously established mitigation measures will remain in effect. The southern California area constraints are not expected to adversely affect reliability.

Studies of local area conditions have identified several areas that may experience thermal overloads or voltage instability under certain conditions, including higher than forecast peak demands. Operating procedures have been or are being developed to address adverse local area conditions.

Comision Federal de Electricidad Control Area (CFE)
Adequate resources are expected in the CFE control area for summer 2004. The area has adequate internal transmission and transmission interconnection capability and fuel availability is expected to be adequate. The area reports having no concerns with maintaining adequate reactive reserves and expects to have excess resources available for capacity and energy sales to other control areas.

Los Angeles Department of Water and Power Control Area (LDWP)
The LDWP control area anticipates adequate resources for the 2004 summer period. The area expects adequate fuel availability and has adequate internal transmission and transmission interconnection capability. The area reports having no concerns with maintaining adequate reactive reserves and expects to have excess resources available for capacity and energy sales to other control areas.

Sacramento Municipal Utility District Control Area (SMUD)
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. Transmission constraints are not expected during the summer period under typical operating conditions. Under extreme conditions, transmission constraints will be relieved by generation re-dispatch or other measures.

Arizona-New Mexico-Southern Nevada Power Area
This is a summer peaking area. The 2004 summer peak demand forecast of 26,183 MW is 2.5% above last summer's actual peak demand of 25,547 MW. Area resources are expected to increase by about 3,100 MW over last summer. The forecast for the area includes 252 MW of load management and interruptible demand capability. The projected capacity margin for the peak month is 19.0%.

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 summer peak demand conditions. The area is experiencing drought conditions and reduced water flows are anticipated 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.

Rocky Mountain Power Area

The Rocky Mountain Power area's peak demand may occur in either summer or winter. The 2004 summer peak demand forecast of 10,268 MW is 2.1% below last summer's actual peak demand of 10,489 MW, which was established under higher than normal temperatures in the area. Resources are expected to increase by about 700 MW over last summer. The forecast peak demand includes 191 MW of interruptible demand capability. The projected capacity margin for the peak month is 18.4%.

Water inflows into the hydro system are expected to be significantly below average this year. However, since much of the area's hydro system is designed for multiple dry years, the current below average storage conditions are not expected to affect adequacy of supply. 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 summer to provide line loading relief for these paths.

Reactive reserve margins are expected to be adequate for all peak load conditions.

Northwest Power Pool (NWPP) Area

NWPP is a winter peaking area. Due partially to last summer's above-average temperatures in portions of the area, the 2004 summer peak demand forecast of 49,460 MW for the combined northwestern United States and Canadian areas is 2.7% below last summer's actual peak demand of 50,838 MW. Area resources are expected to increase by about 1,400 MW over last summer. The summer peak demand forecast includes 369 MW of load management and interruptible demand. The projected capacity margin for the peak month is 34.0%.

NWPP comprises all or major portions of the states of Idaho, Montana, Nevada, Oregon, Utah, Washington, Wyoming, a small portion of northern California and, the Canadian provinces of Alberta and British Columbia. Barring degradation in hydro conditions from current forecasts, the extended loss of a major thermal unit, or load significantly in excess of the forecast peak demand or energy requirement, the region is expected to be able to meet firm loads and maintain required reserves for the 2004 summer period under normal temperature conditions.

The 2004 April forecast for the January through July volume runoff (Columbia River flows) at The Dalles, Oregon, is 77% of average. Under normal weather conditions, NWPP does not anticipate depending on imports from external areas during summer peak demand periods. However, if the lower than normal precipitation continues, the area may import electric power to reduce reservoir drafts.

The water flow associated with hydroelectric resources must balance several competing purposes, including but not limited to current electric power generation, future electric power generation, flood control, biological opinion requirements resulting from the Endangered Species Act, as well as special river operations for recreation, irrigation, navigation, and the refilling of the reservoirs each year. Any time precipitation levels are below normal, balancing these interests becomes difficult.

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.

Appendix 1: Generating Unit Additions Scheduled for Initial Service, Retirement or Rerating
March through September 2004

Region/ Subregion	Unit	MW Change	Unit Type	Fuel Type	Action	Scheduled Operating Date
ECAR	Covert	1104	Combined Cycle	Gas	New	March
	Trimble County 7, 8	348	Combustion Turbine	Gas	New	April
	Trimble County 9, 10	348	Combustion Turbine	Gas	New	June
	Anderson	90	Combustion Turbine	Gas	New	May
	Mitchell	17	Combustion Turbine	Gas	Reactivate	September
	Mitchell	125	Steam	Gas	Reactivate	September
ERCOT	Deer Park Energy Center 3	186	Combined Cycle	Natural Gas	New	June
	Deer Park Energy Center 4	186	Combined Cycle	Natural Gas	New	June
	Deer Park Energy Center 5	276	Combined Cycle	Natural Gas	New	June
	Sand Hill 5A	160	Combined Cycle	Natural Gas	New	March
	Sand Hill 5C	140	Combined Cycle	Natural Gas	New	March
	Wise County Power Plant 1	212	Combined Cycle	Natural Gas	New	March
	Wise County Power Plant 2	212	Combined Cycle	Natural Gas	New	March
	Wise County Power Plant 3	241	Combined Cycle	Natural Gas	New	March
	Leon Creek Peaking 1	46.2	Combustion Turbine	Natural Gas	New	June
	Leon Creek Peaking 2	46.2	Combustion Turbine	Natural Gas	New	June
	Leon Creek Peaking 3	46.2	Combustion Turbine	Natural Gas	New	June
	Leon Creek Peaking 4	46.2	Combustion Turbine	Natural Gas	New	June
	Texas City Cogen 1	116	Combustion Turbine	Natural Gas	New	March
	Texas City Cogen 2	116	Combustion Turbine	Natural Gas	New	March
	Texas City Cogen 3	116	Combustion Turbine	Natural Gas	New	March
	Texas City Cogen 4	116	Combustion Turbine	Natural Gas	New	March
FRCC	Lauderdale 4	-3	Combined Cycle	Natural Gas	Derate	June
	Martin 3	6	Combined Cycle	Natural Gas	Uprate	June
	Martin 4	6	Combined Cycle	Natural Gas	Uprate	June
	Sanford 4	13	Combined Cycle	Natural Gas	Uprate	June
	Sanford 5	13	Combined Cycle	Natural Gas	Uprate	June
	Ft. Myers 2	46	Combined Cycle	Natural Gas	Uprate	June
	Ft. Myers Ct 3	6	Combustion Turbine	Natural Gas	Uprate	June
	Martin 8	8	Combustion Turbine	Natural Gas	Uprate	June
	Ft. Myers 1-12	-12	Combustion Turbine-Gas	Distillate Fuel Oil	Derate	June
	Martin 2	-4	Steam	Natural Gas	Derate	June
	Cape Canaveral 1	-4	Steam	Residual Fuel Oil	Derate	June
	Cape Canaveral 2	-4	Steam	Residual Fuel Oil	Derate	June
	Turkey Point 1	-4	Steam	Residual Fuel Oil	Derate	June
	Martin 1	4	Steam	Natural Gas	Uprate	June
	Port Everglades 4	2	Steam	Residual Fuel Oil	Uprate	June
	Riviera 3	1	Steam	Residual Fuel Oil	Uprate	June

Appendix 1: Generating Unit Additions Scheduled for Initial Service, Retirement or Rerating March through September 2004

Region/ Subregion	Unit	MW Change	Unit Type	Fuel Type	Action	Scheduled Operating Date
MAAC	A59 Emilie	600	Combined Cycle	Natural Gas	New	April
	A12 Martins Creek	600	Combined Cycle	Natural Gas	New	June
	B19 Melrose	20	Combined Cycle	Natural Gas	New	June
	A21 Chichester	757	Combined Cycle	Natural Gas	New	May
	B30 Emilie	600	Combined Cycle	Natural Gas	New	May
	D25 Hay Road	39	Combined Cycle	Natural Gas	Uprate	June
	G19 Linden	12	Combined Cycle	Natural Gas	Uprate	June
	D11 DEMEC	50	Combustion Turbine	Natural Gas	New	June
	G22 Merck	38	Combustion Turbine	Natural Gas	New	June
	H20 Oak Grove	3.5	Combustion Turbine	Natural Gas	New	June
	J05 Huron	8	Combustion Turbine	Natural Gas	New	June
	Burlington 101	-53	Combustion Turbine	Natural Gas	Retire	April
	Burlington 102	-52	Combustion Turbine	Natural Gas	Retire	April
	Burlington 103	-52	Combustion Turbine	Natural Gas	Retire	April
	Burlington 104	-52	Combustion Turbine	Natural Gas	Retire	April
	Burlington 105	-52	Combustion Turbine	Natural Gas	Retire	April
	F07 Dickerson H	16	Combustion Turbine	Natural Gas	Uprate	June
	G18 Linden	12	Combustion Turbine	Natural Gas	Uprate	June
	G20 Essex	6	Combustion Turbine	Natural Gas	Uprate	June
	H13 Dolfield 33 kV	9	Internal Combustion	Kerosene	New	June
	C15 Friedensburg	5	Internal Combustion	Landfill Gas	New	June
	D01 Sight and Sound	1.6	Internal Combustion	Landfill Gas	New	June
	H27 Marion	1.9	Internal Combustion	Landfill Gas	New	June
	H17 Salem 2	65	Nuclear	Uranium	Uprate	April
	A54 TMI	45	Nuclear	Uranium	Uprate	June
	H18 Hope Creek	37	Nuclear	Uranium	Uprate	June
	B34 Seward	304	Steam	Waste Coal	New	May
	Sayreville 4	-114	Steam	Natural Gas	Retire	March
	Sayreville 5	-115	Steam	Natural Gas	Retire	March
	Delaware 7	-126	Steam	Oil	Retire	March
	Delaware 8	-124	Steam	Oil	Retire	March
	F08 Chalk Point	6	Steam	Coal	Uprate	June
	G04 Brunner Island	14	Steam	Coal	Uprate	June
	G05 Brunner Island #1	14	Steam	Coal	Uprate	June
	G08 Kearny	7	Steam	Oil	Uprate	June
	G44 Dupont Seaford	10	Steam	Waste Heat	Uprate	June
	I13 Hooversville	30	Wind	Wind	New	April

Appendix 1: Generating Unit Additions Scheduled for Initial Service, Retirement or Rerating March through September 2004

Region/ Subregion	Unit	MW Change	Unit Type	Fuel Type	Action	Scheduled Operating Date
MAAC	F04 Somerset	30	Wind	Wind	New	June
	I04 Somerset-Allegheny	45	Wind	Wind	New	June
	K09 Bear Creek	34	Wind	Wind	New	June
	I01 Ontario	7.5	Wind	Wind	New	June
MAIN	Riverside 1-3	625	Combustion Turbine	Natural Gas	New	June
	Kaukauna Ct	60	Combustion Turbine	Natural Gas	New	May
MAPP-Canada	NA4 1	0.6	Other	Wood/Wood Waste Solids	New	May
MAPP-US	Salt Valley 2	6.4	Combustion Turbine	Natural Gas	Uprate	May
	Salt Valley 4	6.6	Combustion Turbine-Gas	Natural Gas	Uprate	May
	Earl F Wisdom 2	93.5	Combustion Turbine-Gas	Natural Gas	New	May
	Exira Station 1	45	Combustion Turbine-Gas	Natural Gas	New	May
	Exira Station 2	45	Combustion Turbine-Gas	Natural Gas	New	May
	Valley Queen Cheese 1	-0.25	Internal Combustion	Distillate Fuel Oil	Derate	May
	Valley Queen Cheese 2	-0.25	Internal Combustion	Distillate Fuel Oil	Derate	May
	Argyle 4	2.25	Internal Combustion	Distillate Fuel Oil	New	July
	Elroy 6	2.25	Internal Combustion	Distillate Fuel Oil	New	September
	Elroy 7	2.25	Internal Combustion	Distillate Fuel Oil	New	September
	Lanesboro 4	2.25	Internal Combustion	Distillate Fuel Oil	New	June
	Seven Mile Creek LFG 1	3	Internal Combustion	Distillate Fuel Oil	New	May
	Ft. Pierre 5	2	Internal Combustion	Distillate Fuel Oil	New	June
	Ft. Pierre 6	2	Internal Combustion	Distillate Fuel Oil	New	June
	Ft. Pierre 7	2	Internal Combustion	Distillate Fuel Oil	New	June
	Lake Park 1	2	Internal Combustion	Distillate Fuel Oil	New	June
	McNeilus Wind Farm 2	2.25	Wind Turbine	Wind	New	June
NPCC-Hydro Québec	None	—	—	—	—	—
NPCC–ISONE	Milford Power Cc Unit 2	245	Combined Cycle	Natural Gas	New	June
	Millstone Unit 2 Uprate	31	Nuclear	Nuclear	Uprate	June
NPCC–Maritimes	St. George	12.1	Hydro	Water	—	March
NPCC–NYISO	Freeport	47	Combustion Turbine	Natural Gas	New	July
	Freeport	44	Combustion Turbine	Natural Gas	New	June
	Athens	1080	Combined Cycle	Natural Gas	New	June
	Ravenswood 4	250	Combined Cycle	Natural Gas	New	June

Appendix 1: Generating Unit Additions Scheduled for Initial Service, Retirement or Rerating March through September 2004

Region/ Subregion	Unit	MW Change	Unit Type	Fuel Type	Action	Scheduled Operating Date
NPCC–Ontario IMO	ATCO - Brighton Beach - G1	180	Combined Cycle – Gas Turbine	Natural Gas	New	June
	ATCO - Brighton Beach - G2	180	Combined Cycle – Gas Turbine	Natural Gas	New	June
	ATCO - Brighton Beach - G3	218	Combined Cycle – Steam Turbine	Natural Gas	New	June
	Imperial Oil - Sarnia	98	Simple Cycle Gas Turbine	Natural Gas	New	April
	Northland Power - Kirkland Lake - G6	32	Simple Cycle Gas Turbine	Natural Gas	New	August
SERC–Entergy	None	—	—	—	—	—
SERC–Southern	Wansley-9	503	Combined Cycle	Natural Gas	New	June
	Bowen 6	-32	Combustion Turbine	Oil	Environ. Derate [1]	May
	McDonough 3A	-32	Combustion Turbine	Oil	Environ. Derate [1]	May
	McDonough 3b	-32	Combustion Turbine	Oil	Environ. Derate [1]	May
	Wansley 5A	-49	Combustion Turbine	Oil	Environ. Derate [1]	May
	Silver Creek #2	83	Combustion Turbine	Natural Gas	New	June
	Hatch 1	13	Nuclear	Uranium	Uprate	May
SERC–TVA	Bull Run-1	27	Fossil	Coal	Uprate	April
	Paradise-3	30	Fossil	Coal	Uprate	May
	Apalachia-2	2	Hydro	Water	Uprate	June
	Chatuge-1	3	Hydro	Water	Uprate	July
	Watts Bar Hydro-5	1	Hydro	Water	Uprate	August
SERC–VACAR	Jasper-1	875	Combined Cycle	Natural Gas	New	May
	Marsh Run-1	157	Combustion Turbine	Natural Gas	New	June
	Marsh Run-2	157	Combustion Turbine	Natural Gas	New	June
	Marsh Run-3	157	Combustion Turbine	Natural Gas	New	June
SERC–VACAR	Fairfield Pumped Storage-5	8	Pumped Storage	Water	New	June
	Fairfield Pumped Storage-6	8	Pumped Storage	Water	New	June
	Bath County-5	27	Pumped Storage	Water	Uprate	April
SPP	None	—	—	—	—	—
WECC–AZ–NM–SNV	Silverhawk CC	491	Combined Cycle	Natural Gas	New	June
	Eagar Biomass	3	Steam	Wood	New	March

Appendix 1: Generating Unit Additions Scheduled for Initial Service, Retirement or Rerating March through September 2004

Region/ Subregion	Unit	MW Change	Unit Type	Fuel Type	Action	Scheduled Operating Date
WECC–CA–MX	Valley CC	533	Combined Cycle	Natural Gas	New	April
	El Dorado 1-2	20	Hydro	Water	New	June
	Castaic 2	10	Hydro	Water	Uprate	June
	Sycamore Canyon B	3	Internal Combustion	Landfill Gas	New	March
	El Sobrante	3	Internal Combustion	Landfill Gas	New	June
	Simi Valley	3	Internal Combustion	Landfill Gas	New	June
	Sonoma Cnty LFG	2	Internal Combustion	Landfill Gas	New	July
	Lincoln LF	2	Internal Combustion	Landfill Gas	Uprate	June
	Haynes	-222	Steam	Natural Gas	Retirement	September
	Solano Wind	5	Wind	Wind	New	July
WECC–NWPP	Nebo CC	130	Combined Cycle	Natural Gas	New	June
	Goldendale CC	248	Combined Cycle	Natural Gas	New	July
	Syncrude UE	75	Combined Cycle	Natural Gas	New	September
	U Bonnington 5	2	Hydro	Water	New	March
	Irrican 1	7	Hydro	Water	New	April
	Pingston Expansion	15	Hydro	Water	New	August
	Upper Mamquam	25	Hydro	Water	New	August
	U Bonnington 6	2	Hydro	Water	Upgrade	July
	NS Elmworth 4	3	Internal Combustion	Natural Gas	New	May
	Summerview	99	Wind	Wind	New	May
	Ft. Macleod	81	Wind	Wind	New	May
	Magrath	30	Wind	Wind	New	June
	Great Falls	50	Wind	Wind	New	June
	Kettles Hill	63	Wind	Wind	New	September
WECC–RMPA	Rocky Mountain EC	585	Combined Cycle	Natural Gas	New	June
	Rawhide GT 4	48	Combustion Turbine	Natural Gas	New	April

Appendix 2: Transmission System Additions and Upgrades (230 kV and Above)

March through September 2004

Region/ Subregion	Facility	Length in Miles	Capacity MVA	Voltage kV	Action	Scheduled Operating Date
ECAR	South Berwick	—	180 / 210	345 / 69	Install Transformer	June
	Boonboro	—	224 / 253	230 / 138	Install Transformer	May
	Gaines	—	595 / 620	345 / 138	Install Transformer	June
	South Berwick / Fostoria Central - Galion	—	No Change	345	Loop into Sub	June
	Hiple / East Elkhart - Collingwood	—	No Change	345	Loop into Sub	June
	Urbana / Lime Kiln - Montgomery	2	No Change	230	Loop into Sub	September
	Boonsboro / Doubs - Ringgold	3	482 / 576	230	Tap to Sub	May
ERCOT	Watermill - W. Levee 345-Kv Circuit	9	—	345	New	May
	Everman 345 / 138-Kv Autotransformer	—	600	345	New	May
	Sargent Rd 345 / 138-Kv Autotransformer	—	600	345	New	May
	WA Parish - Dow ckt. 99	55.64	—	345	Upgrade	April
	Valley - Anna 345-Kv Line	27	—	345	Upgrade	May
FRCC	Andytown - Pennsuco	2	508	230	New	June
	Brandy Branch - Normandy	14	668	230	New	July
	Broward - Corbett - Rainberry - Yamato	11	759	230	New	June
	Dade - Overtown	11	759	230	New	June
	Whidden - Vandola	27	1067	230	New	June
MAAC	Yorkana-Otter Creek	12	650	230	New	June
MAIN	Burnham - Calumet	7	1356 / 1739	345	New	June
	Calumet - Garfield	7	1356 / 1739	345	New	June
	Wolf Transformer	—	300	345 / 138	New	June
	Garfield - Taylor(Cable)	6	700 / 845	345	New	June
	Crawford Auto Reclosers	—	—	345	New	June
	Calumet Shunt Inductor	—	—	345	New	June
	TSS -120 Second Bus Tie	—	—	345	New	June
	Des Plaines Bus Tie	—	—	345	New	June
	Beleau Tap - Sioux/Montgomery	—	—	345	Reconfigure	June
MAPP–Canada	St. Leon To St.Leon Wind Site (Mheb)	1	251	230	Addition	June
MAPP–US	None	—	—	—	—	—
NPCC–ISONE	Sandbar Phase Angle Regulator	—	350	115	New	June
	2Nd Scobie Transformer	—	400	345 / 115	New	May
	1977 Line Tap (South End-Darien)	—	—	115	New	June
	Glenbrook Statcom	—	—	115	New	May
	Sherman Road Breakers	—	—	345	New	May
NPCC–Maritimes	None	—	—	—	—	—
NPCC–NYISO	None	—	—	—	—	—
NPCC– Ontario IMO	None	—	—	—	—	—

**Appendix 2: Transmission System Additions and Upgrades (230 kV and Above)
March through September 2004**

Region/ Subregion	Facility	Length in Miles	Capacity MVA	Voltage kV	Action	Scheduled Operating Date
NPCC–Hydro Québec	None	—	—	—	—	—
SERC–Entergy	Franklin 500 / 115 Kv Auto	—	560	500 / 115	Addition	August
SERC–Southern	Glaze Road Switching Station	—	0	230	Addition	May
	Suwanee Substation Capacitor Addition	—	120	230	Addition	April
	Scottsdale Substation Capacitor Addition	—	120	230	Addition	May
	West Brunswick Substation	—	300	230 / 115	Addition	April
	Clermont Junction Substation	—	300	230 / 115	Addition	March
	Pike Co TS	—	400	230 / 115	Addition	June
	Mcconnell Road 230/115 Kv	—	400	230	Addition	March
	Pike Co - Snowdoun	0.1	502	230	Addition	May
	Pike Co - Pinckard	0.1	502	230	Addition	May
	Mcfarland	3.8	509	230	Addition	March
	Mcconnell Road - Big Shanty	6.2	602	230	Addition	May
	Yellowdirt - Hickory Level	31.1	866	230	Addition	June
	Thalmann Substation	—	1344	500 / 230	Addition	May
	South Hall Substation	—	2016	500 / 230	Addition	May
	Clermont Junction - Middlefork	19	602	230	Conversion	March
	Holcomb Bridge - Glaze Dr	2.14	602	230	Conversion	May
	East Point - Adamsville - Mcdonough	12.4	485	230	Re-Rating	March
	Butler - Talbot 1 230 Kv Line	24.3	792	230	Re-Rating	June
	Talbot County	—	807	230	Re-Rating	June
	Mcintosh - West Mcintosh #1 & #2	1	1144	230	Re-Rating	April
	Old Alabama Road Substation	—	160	230 / 115	Retirement	May
SERC–TVA	Browns Ferry Np - Trinity	16.56	2598	500	Re-Rating	June
	Bull Run - Volunteer	21.26	2598	500	Re-Rating	June
SERC–VACAR	Line 2063 Clifton-Ox	6.5	470	230	Addition	May
	Pleasant View 500 / 230 Kv Substation	—	840	500 / 230	Addition	May
	Yemassee (SCE&G) - Yemassee(Santee Cooper)	3	960	230	Addition	March
	Yemassee - Jasper County #2	37	960	230	Addition	May
	Anderson Bank 2	—	400	230	Re-Rating	June
	Line # 2018 Greenwch - Elizabath River	10.2	637	230	Re-Rating	May
SPP	None	—	—	—	—	—
WECC–AZ–NM–SNV	Surprise Transformer	—	188	230 / 69	New	June
	Beltway Transformer	—	300	230 / 138	New	June
	Hoover-Mead	5	400	230	New	June
	Winchester - Apache	21	438	230	New	April
	Winchester - Winchester	1	581	345	New	March
	Northwest - Beltway	13	780	230	New	March
	Beltway - Arden	19	780	230	New	March
	Shiprock - Four Corners	8	1200	345	New	March
	Shiprock - Four Corners	-8	300	230	Replacement	March

Appendix 2: Transmission System Additions and Upgrades (230 kV and Above)
March through September 2004

Region/ Subregion	Facility	Length in Miles	Capacity MVA	Voltage kV	Action	Scheduled Operating Date
WECC–CA–MX	Los Banos Transformer	—	400	230/70	New	June
	Brighton Transformer	—	420	230 / 115	New	May
	Lakeville Transformer	—	420	230 / 115	New	May
	Ravenswood Transformer	—	420	230 / 115	New	May
	Ignacio Transformer	—	420	230 / 115	New	June
	Ravenswood Transformer	—	420	230 / 115	New	June
	Mira Loma Transformer	—	1120	500 / 230	New	June
	East Shore Circuit Breaker	—	—	230	New	May
	Lockeford Transformer	—	200	230 / 60	Replacement	May
	Tesla Transformer	—	403	230 / 115	Replacement	May
	Pittsburg Transformer	—	420	230 / 115	Replacement	May
	Wilson Transformer #2	—	420	230 / 115	Replacement	June
WECC–NWPP	Oregon Basin Capacitor Bank	—	20	230	New	March
	Sheridan Capacitor Bank	—	30	230	New	March
	Blacks Fork Capacitor Bank	—	30	230	New	June
	South Trona Capacitor Bank	—	30	230	New	June
	Rock Springs Capacitor Bank	—	60	230	New	June
	Caldwell Capacitor Bank	—	94	230	New	May
	Bridger Capacitor Bank	—	200	230	New	June
	Monument - Caven Creek	18	444	230	New	March
	Caldwell - Middleton	5	546	230	New	May
	Brilliant - K. Canal	12	600	230	New	May
	Dunphy - Ely	173	600	345	New	May
	Battle River - Metiskow	63	617	240	New	August
	Mona - Mona	2	1163	345	New	June
	Garrison Capacitor Bank #1	—	1300	500	New	July
	Garrison Capacitor Bank #2	—	1300	500	New	July
	Ontario - Caldwell	0	478	230	Reconductor	May
WECC–RMPA	Hesperus # 2 Transformer Bank	—	234	345 / 115	New	September
	San Luis Valley Transformer	—	280	230 / 115	New	April
	Wolcott Tap-Steamboat #2	16	495	230	New	September
	Green Valley-Spruce #2	19	800	230	New	May

Definitions, Assumptions, and Abbreviations

How NERC Defines Reliability

NERC defines the reliability of the interconnected bulk electric system in two ways:

- 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, RAS reviewed the individual regional self-assessments, although RAS did not independently verify the information contained in the individual regional assessments in all cases. Summaries of supporting data are contained in Tables 1 and 2 and Figure 3. 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 June 2003 through September 2003 and is based on several assumptions:

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

Abbreviations Used in This Report

AC	Alternating Current
AEP	American Electric Power
AP	Allegheny Power
AMRN	Ameren
AZ–NM–SNV	Arizona-New Mexico-Southern Nevada (Subregion of WECC)
CA–MX	California-Mexico (Subregion of WECC)
CAISO	California Independent System Operator
COI	California-Oregon Intertie
CP&L	Carolina Power & Light Company
DOE	Department of Energy (United States)
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
IDC	Interchange Distribution Calculator
IIPA	Integrated Independent Performance Assessment
IMO	Independent Electricity Market Operator (in Ontario)
IPP	Independent Power Producer
ISN	Interregional Security Network
ISO	Independent System Operator
ISO NE	New England Independent System Operator
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
MISO	Midwest Independent System Operator
MVA	Megavoltamperes
Mvar	Megavars
MW	Megawatts (millions of watts)
NEL	Net Energy for Load
NERC	North American Electric Reliability Council
NPCC	Northeast Power Coordinating Council
NRC	Nuclear Regulatory Commission (United States)
NUG	Non-Utility Generator
NWPP	Northwest Power Pool (Subregion of WECC)
NYISO	New York Independent System Operator
NYPP	New York Power Pool
OCSG	Operating Capability Study Group
OKGE	Oklahoma Gas and Electric
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
RTO	Regional Transmission Organization
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

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