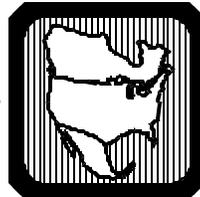


Reliability Assessment

2002–2011

Final Draft for BOT Approval

*The Reliability of
Bulk Electric Systems
in North America*



North American Electric Reliability Council

October 2002

CONTENTS

Foreword	3
About This Report	3
Assessment Time Frame	3
About NERC	3
Executive Summary	5
Resource Adequacy	5
Transmission Adequacy	5
Fuel Supply Adequacy	6
Issues	6
Assessment of Reliability	7
Definition of Reliability	7
Demands and Resources	7
Resource Adequacy Assessment	9
Regional Highlights	19
Transmission Adequacy and Security Assessment	19
Reliability Issues	22
Electricity/Natural Gas Interdependency	22
Planning Issues	26
Environmental Issues	29
Regional Assessments	33
ECAR — East Central Area Reliability Coordination Agreement	33
ERCOT — Electric Reliability Council of Texas	36
FRCC — Florida Reliability Coordinating Council	39
MAAC — Mid-Atlantic Area Council	41
MAIN — Mid-America Interconnected Network	44
MAPP — Mid-Continent Area Power Pool	47
NPCC — Northeast Power Coordinating Council	50
SERC — Southeastern Electric Reliability Council	58
SPP — Southwest Power Pool	63
WECC — Western Electricity Coordinating Council	66
Reliability Assessment Subcommittee	74

About This Report

The North American Electric Reliability Council's (NERC) Reliability Assessment Subcommittee (RAS) annually reviews the overall reliability of existing and planned electric generation and transmission systems of the ten NERC Regional Reliability Councils (Regions).

This *Reliability Assessment 2002–2011* report presents:

- an assessment of electric generation and transmission reliability through 2011,
- a discussion of key issues affecting reliability of future electric supply, and
- Regional assessments of electric supply reliability, including issues of specific Regional concern.

In preparing this report, RAS:

- reviewed summaries of Regional self assessments, including forecasts of peak demand, energy requirements, and planned resources,
- appraised Regional plans for new electric generation resources and transmission facilities, and
- assessed the potential effects of changes in technology, market forces, legislation, regulations, and governmental policies on the reliability of future electric supply.

The data in this report reflects conditions that were projected as of June 20, 2002. Detailed background data is available in NERC's *Electricity Supply & Demand* (ES&D) database, 2002 edition (<http://www.nerc.com/~esd/>).

The majority of new generation additions over the next few years is expected to be constructed by the merchant generation industry. NERC collaborates with the Electric Power Supply Association (EPSA) to capture as much information regarding merchant plant additions as possible. In addition, NERC has contracted with Energy Ventures Analysis, Inc. (www.evainc.com) to monitor proposed new power plant projects and track their status. In some cases, data available from EPSA and EVA are used in this report to supplement data submitted by the Regions.

Assessment Time Frame

RAS views this ten-year assessment in two time frames: the near term, consisting of the first five years and the long term, the balance of the ten-year period. Although the near term represents a fairly accurate forecast of future conditions, the longer-term assessment is more an indication of future trends than an absolute determination. Assessing reliability beyond the near term is extremely difficult because of the level of uncertainty and the quality of information provided for modeling and analysis. The uncertainty in the data is due primarily to the reluctance of some industry participants to establish long-term firm energy commitments in light of an uncertain future or to reveal future plans for competitive reasons. Similarly, transmission plans projected more than five years into the future are considered tentative because justification studies usually have not been completed and regulatory approvals have not been received.

About NERC

On November 9, 1965, a blackout left 30 million people across the Northeastern United States and Ontario, Canada in the dark. In an effort to prevent this type of blackout from ever happening again, electric utilities formed NERC in 1968 to promote the reliability of the electricity supply for North America. This mission is accomplished by working with all segments of the electric industry as well as customers. NERC reviews the past for lessons learned, monitors the present for compliance with reliability standards, and assesses the future reliability of the bulk electric systems. NERC has conducted reliability assessments of the bulk electric systems of North America since 1970.

FOREWORD

NERC's members are ten Regional Reliability Councils that encompass virtually all of the electric systems in the continental United States, Canada, and the northern portion of Baja California Norte, Mexico. The members of these Regional Councils come from all segments of the electric industry — investor-owned, federal, rural electric cooperatives, state/municipal and provincial utilities, independent power producers, and power marketers.

Since 1968, NERC has relied on voluntary efforts and “peer pressure” to ensure compliance with its standards. This voluntary arrangement is no longer adequate. The users and operators of the electric systems who used to cooperate voluntarily on reliability matters are now competitors without the same incentives to cooperate with each other or comply with voluntary reliability standards. Little or no effective recourse exists today under the current voluntary model to correct such behavior — not a single bulk electric system reliability standard can be enforced effectively today by NERC or the Federal Energy Regulatory Commission (FERC).

To ensure the continued reliability of the interconnected bulk electric systems throughout North America in the face of these changes, reliability standards must be made mandatory and enforceable, and fairly applied to all participants in the electricity market. To meet this need, NERC and a broad coalition of industry organizations have proposed legislation that would authorize the creation of a single, industry-based self-regulatory reliability organization (SRO) to develop and enforce reliability standards with FERC oversight in the United States to ensure that the SRO operates effectively and fairly. The proposal follows the model of the Securities and Exchange Commission in its oversight of the securities industry self-regulatory organizations (the stock exchanges and the National Association of Securities Dealers). As the electric industry evolves toward full competition, the SRO will examine traditional reliability planning practices and policies to ensure that they are still applicable and that they continue to result in reliable electric systems. Legislation that would authorize an SRO is currently pending in the U.S. Congress.

Resource Adequacy

Near-term (2002–2006) generation adequacy is deemed satisfactory throughout North America, provided new generating facilities are constructed as anticipated. Projected near-term, NERC-wide capacity margins continue to show increases over projections from previous years, peaking at more than 24% in 2005. Although electricity demand is expected to grow by about 71,000 MW in the near term, new resource additions totaling between 159,000 and 263,000 MW are projected over the same period, depending upon the number of merchant plants assumed placed in service. Even though North American aggregate capacity margins appear adequate, the Resource Adequacy section of this report (page 9) shows that generation additions and resulting capacity margins are not evenly distributed across the continent.

Long-term (2007–2011) generation adequacy is more difficult to assess than the near term, but if current trends continue, long-term adequacy also will be satisfactory. Long-term adequacy depends on the response of merchant plant developers to market signals to construct new generating facilities (and their ability to obtain the necessary financing, siting, and environmental approvals) in areas experiencing declining capacity margins. The timing of new capacity additions is critical. Because new generating capacity additions are being driven by market signals and not target resource adequacy criteria, capacity margins will likely fluctuate, similar to normal business cycles experienced in other industries.

For the first time in several years, starting in fall 2001, the magnitude of new generation projects being announced each day was exceeded by the amount being delayed or canceled. The majority of the project delays and cancellations are for projects identified for initial service in 2003 and 2004. Significant amounts of new capacity are still projected for 2005 and beyond.

Uncertainty surrounds future capacity additions, including the ability to obtain suitable transmission arrangements, the ability to obtain necessary siting and environmental permits, the ability to obtain financial backing, and fuel prices and supply. In addition, political and regulatory actions could influence the amount of new generation built over the next ten years. The Federal Energy Regulatory Commission's (FERC) institution of wholesale electricity price caps in the western United States, reserve requirements proposed in FERC's Standard Market Design Notice of Proposed Rulemaking (SMD NOPR), and state-mandated moratoriums on the construction of new generating facilities within their borders are recent examples.

Transmission Adequacy

North American transmission systems are expected to perform reliably in the near term. Efforts to mitigate potential reliability impacts appear to be working effectively. However, in some areas of North America, transmission systems are reaching their limits as the systems are subjected to new loading patterns resulting from increased electricity transfers and customer demand increases. Even though transmission systems are expected to operate reliably, some areas of the grid are not adequate to transmit the full output of all new generating units to their desired markets. Although some transmission constraints are recurring and well known, new constraints are appearing as electricity flow patterns change. In cases where redispatch options have been exhausted or are ineffective, the only way to remove these constraints is to increase the capability of the transmission system or build new generation close to the demand centers, removing the need for the electricity transfers in the first place.

A reported 7,088 miles of new transmission operated at 230 kV and higher are proposed to be added in the near term, and a total of about 10,100 miles is proposed to be added during the 2002–2011 time frame. This increase represents a 5% increase in the total amount of installed transmission (230 kV and higher) in North America over the next ten years. As discussed in the Planning Issues section of this report (page 26), new transmission line construction is not the only means of ensuring transmission adequacy.

In the long term, reliable transmission will depend upon the close coordination of generation and transmission planning and construction. Transmission planning must now be accomplished through different means than in the

EXECUTIVE SUMMARY

past and involves coordination among many different market participants. Market signals and regulatory decisions will dictate the location and timing of generating capacity additions, and will influence the construction of new transmission facilities.

Fuel Supply Adequacy

The Regions do not currently anticipate any problems with fuel supplies during the next ten years. Hydroelectric resources will be impacted by the amount of precipitation each year, but it cannot be accurately predicted very far into the future. The industry's growing dependence upon natural gas as a primary fuel for new electric generating facilities is addressed in the Reliability Issues section of this report. Environmental regulations are still under discussion and their impact upon fossil fuels will not be known until they are finalized. Environmental issues are also included in the Reliability Issues section of this report.

Issues

A number of issues are discussed in the report to alert readers to their potential impacts upon reliability. These include:

Electricity/Natural Gas Interdependency — With a majority of the new generation fueled by natural gas, the question of the near-term and long-term adequacy of both the availability of natural gas and the infrastructure to move it to the generating stations is coming under increased scrutiny. This section investigates the manner in which gas pipelines are planned and operated versus how the electric systems are planned and operated, and the impact gas supply may have on electric system reliability.

Planning Issues — As the electric industry continues to restructure, identifying those responsible for maintaining adequate electricity supplies is becoming more difficult. Indeed, the very definition of what constitutes an adequate electric supply may change in the future. Transmission expansion as measured by new circuit miles continues to lag the growth of both the demand for electricity and the addition of new generating plants. However, alternatives to new transmission lines exist to maintain the reliability of the system.

Environmental Regulations — The potential reliability impacts associated with U.S. environmental policy and regulatory actions depend largely on the details of their implementation, which have not been fully developed. Important factors in assessing potential reliability impacts include the stringency of the requirements, the time permitted for compliance, the scope of geographic applicability, coincidence with other regulatory requirements, the amount of generation needing modification, and its retrofit outage duration.

Definition of Reliability

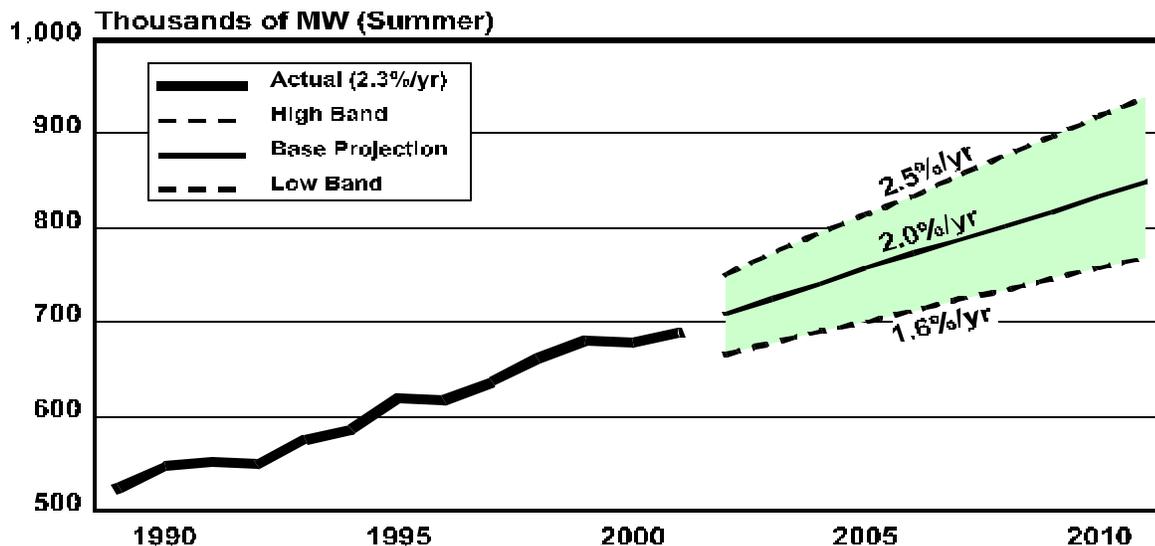
NERC defines the reliability of the interconnected bulk electric systems in terms of two basic functional aspects:

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

Demands and Resources

The average annual U.S. peak demand growth over the next ten years is projected to be 2%. The demand projections in Figures 1 and 2 represent an aggregate of weather-normalized Regional member projections assembled by NERC's Load Forecasting Working Group (LFWG). The LFWG develops bandwidths around the aggregate Canadian and U.S. demand projections to account for uncertainties inherent in demand forecasting. NERC does not prepare its own independent demand forecast because local entities are best suited to make appropriate assumptions concerning diversity, weather, and economic conditions, which are key drivers of the demand forecast.

Figure 1 United States Peak Demand
2002-2011 Projection

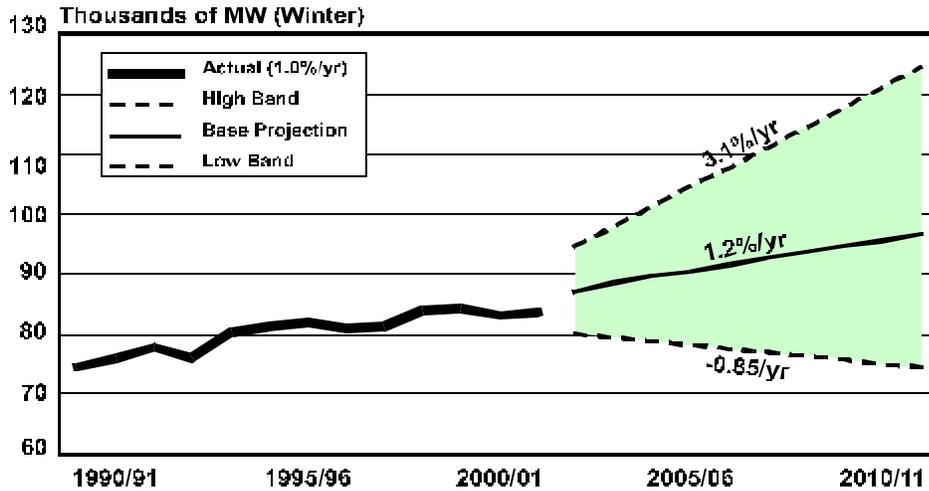


In recent years, an apparent divergence occurred between actual demand growth and future aggregate projections for the United States. The LFWG conducted an examination of this divergence and determined it was primarily due to the assumptions made regarding the expected future economic growth in the country. The LFWG report is available on the NERC web site at www.nerc.com/~filez/lfwg.html. Although the average historical demand growth rate for the last ten years is 2.3%, this growth rate is not expected to continue into the future. The United States experienced unprecedented economic growth in the 1990s; this economic growth has slowed and is reflected in the current projections. It is important to note that the demand growth rate projections are a ten-year average and that individual years may experience greater or lesser rates.

ASSESSMENT OF RELIABILITY

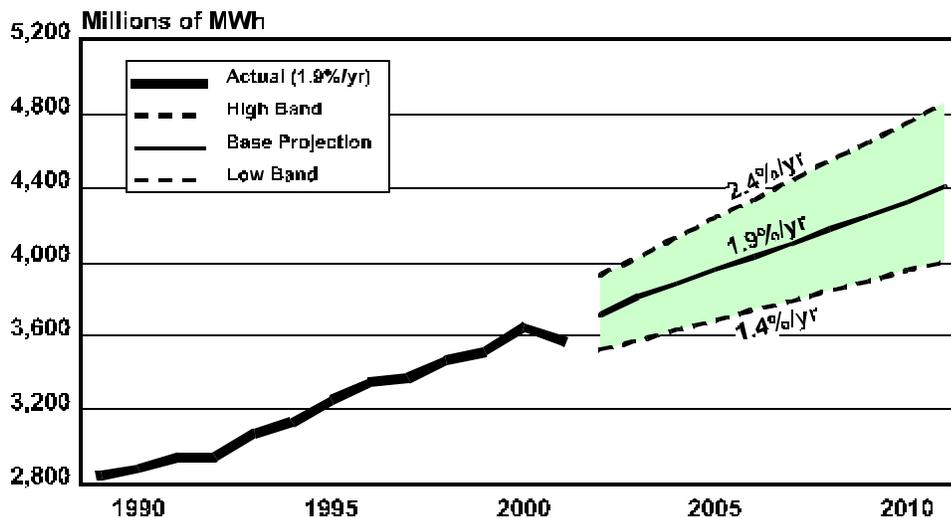
The projected ten-year peak demand growth rate in Canada is 1.2%, down slightly from the 1.4% growth rate projected last year. As with the U.S. projections, forecast uncertainty is shown by the bandwidths around the base aggregate projections in Figure 2.

Figure 2 Canada Peak Demand 2002/03-2011/12 Projection



Figures 3 and 4 include ten-year projections of U.S. and Canadian net energy for load.

Figure 3 United States Net Energy for Load 2002-2011 Projection



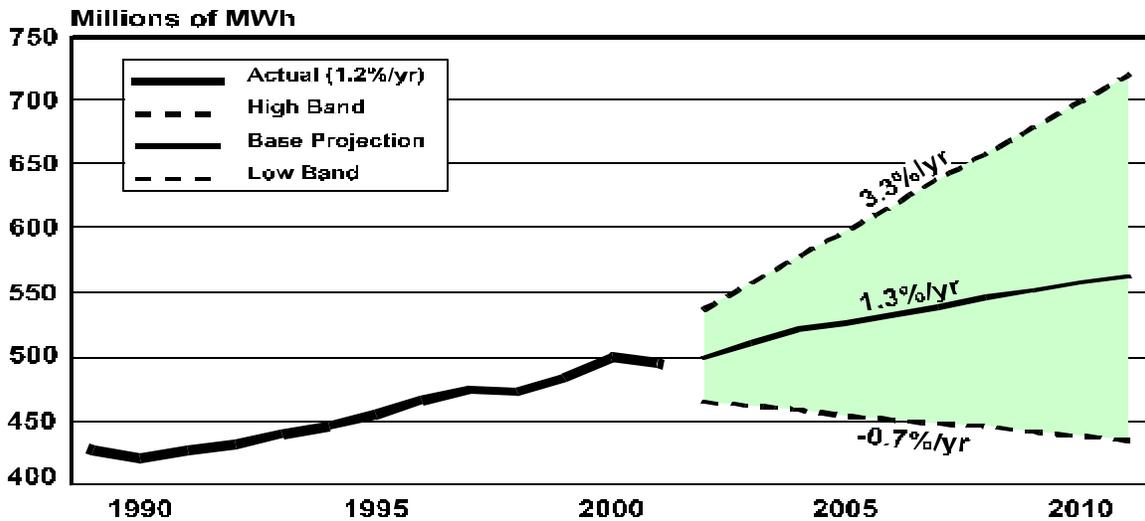
Forecast Bandwidths

Forecasts cannot precisely predict the future. Instead, many forecasts attach probabilities to the range of possible future outcomes. Each base demand projection, for example, represents the midpoint of possible future outcomes. The future year's actual demand has a 50% chance of being higher and a 50% chance of being lower than the projected value. Capacity resources historically have been planned for the 50% demand projections.

For planning purposes, it is useful to have an estimate not only of the midpoint of possible future outcomes, but also of the distribution of probabilities on both sides of that midpoint. Accordingly, NERC's Load Forecasting Working Group develops upper and lower 80% confidence bands around the NERC-aggregated demand projections. Therefore, there is an 80% chance of future demand occurring within these bands, a 10% chance of future demand occurring below the lower band, and an equal 10% chance of future demand occurring above the upper band.

Figure 4

**Canada Net Energy for Load
2002-2011 Projection**



Resource Adequacy Assessment

Capacity adequacy in North America over the next ten years will continue to depend upon the timely construction of new generating facilities by merchant power plant developers. Merchant developers announced plans for more than 286,000 MW¹ of new capacity during the ten-year period, a potential increase of 30.6% compared to the 934,370 MW currently installed in North America. NERC’s Regions report all capacity committed to serve demand within their borders, but capacity that is not committed to serve a specific demand may not be reported to NERC through its traditional data collection process. To better capture the potential impacts of these new generators, RAS has enlisted the services of Energy Ventures Analysis, Inc. (EVA) and the Electric Power Supply Association (EPSA). The extent of this reporting difference is highlighted in Figure 7 on page 12.

In the past, vertically integrated electric utilities, operating under a state or provincial obligation to serve, planned and constructed new generating units to meet fixed resource adequacy criteria targets, such as a certain percent reserve margin or a specified loss-of-load probability. Today, most new generating facilities in North America are merchant projects. Where this is the case, generation planning is now primarily being conducted by developers who examine areas of the continent that offer the greatest business opportunities. These opportunities may include areas with declining capacity margins, access to fuel supplies, access to the transmission system, and ease of permitting.

Figure 5 compares the projected ten-year U.S. capacity margins for the last four years as reported to NERC by the Regions. After several years of decline, 2000 was the first year in which the projected U.S. capacity margins increased, rising sharply over the first five years of the report horizon as numerous new merchant plants were announced. This trend continues in the current ten-year projections, with capacity margins exceeding 24% in 2005. The margin erodes during the latter half of the ten-year period to about 18%, as demand continues to grow while the number of proposed new generating units declines. Projected capacity margins for Canada in Figure 6 exhibit similar trends, peaking at just under 19% in 2005. Shifting incentives, coupled with short lead times to construct

¹ As reported by EPSA as of June 20, 2002. Alternative merchant capacity announcements may have been made since that time.

ASSESSMENT OF RELIABILITY

new natural gas-fired generating facilities, make the increases in near-term projected capacity margins more understandable. The fact that fewer capacity additions are projected beyond 2006 does not mean that additions will not occur, but rather that these decisions have not yet been made or have not been publicly disclosed. Figures 5 and 6 are based upon Regional data submittals; inclusion of supplemental new merchant generator data from EPSA and EVA would serve to increase the margins further.

Figure 5

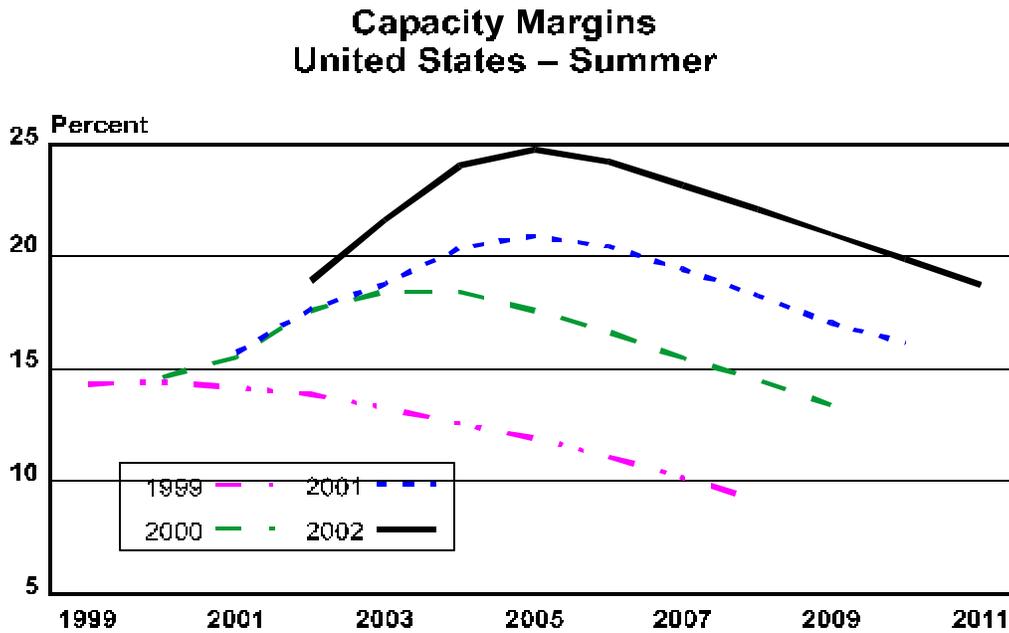
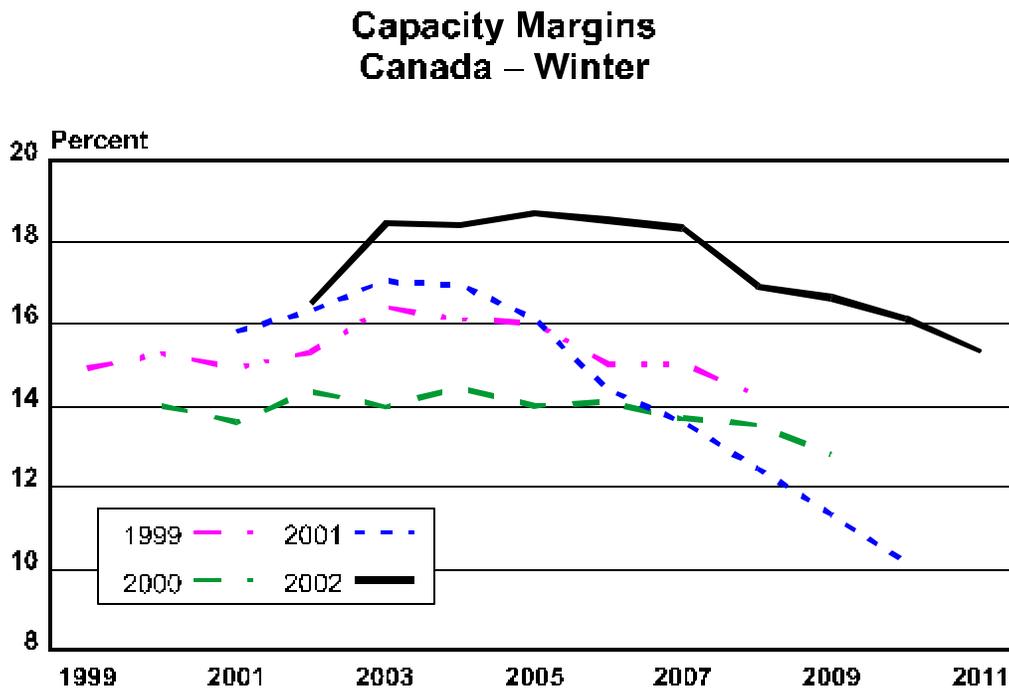


Figure 6



As industry restructuring progresses, capacity margins are beginning to exhibit the characteristics of business cycles found in other industries, i.e., periods of advances and declines. For the past three to four years, the electric industry has experienced a boom of new generation, as the economy continued to grow, fuel prices appeared stable, and forward electricity prices justified investment in new generating facilities. As a result of changing business conditions, starting in November 2001, proposed new generating projects began to slow, and for the first time, the amount of new generator projects being delayed or canceled exceeded the amount of new announcements for proposed generators. Table 1 illustrates the effects of the recent new power plant delays and cancellations.

Table 1 — New Gas-Fired Power Projects Under Development

Year	As reported June-02 (GW)	As reported December-01 (GW)	Difference (GW)
2002	69.2	69.3	(0.1)
2003	76.1	91.3	(15.2)
2004	63.6	95.8	(32.2)
2005	31.9	24.5	7.4
2006	7.8	1.1	6.7
2007	7.6	1.7	5.9
Total	256.2	283.7	(27.5)

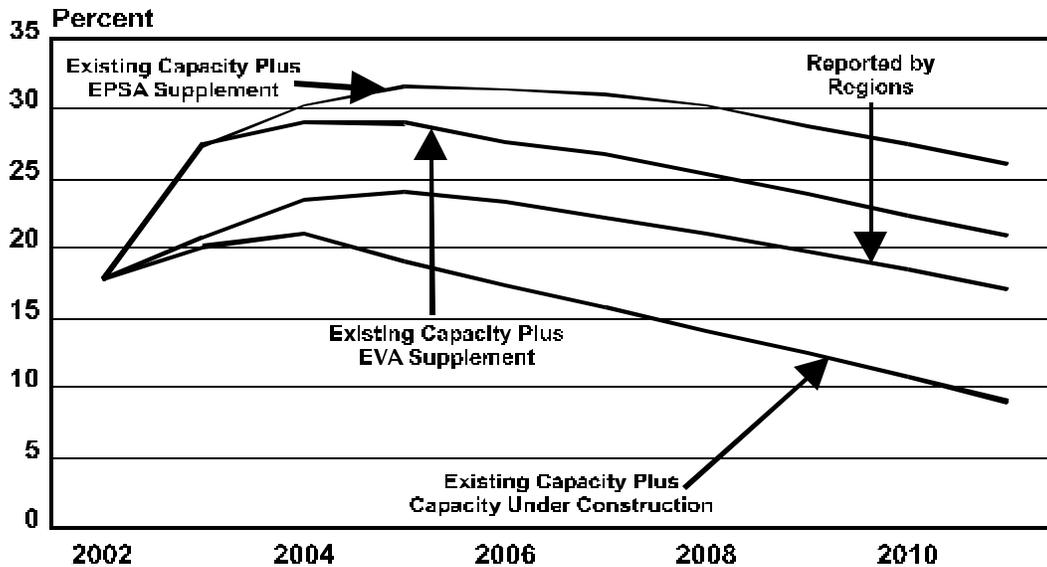
Source: Energy Ventures Analysis, Inc.

Figures 7–10 illustrate the possible range of projected capacity margins for the United States and Canada over the next ten years. Because it is difficult to accurately predict the number and in-service dates of future capacity additions that will actually be constructed, this report provides a range of potential values. The announcement of a new merchant generating facility does not necessarily guarantee its construction for a variety of reasons, including future market prices, the ability to obtain suitable interconnection and transmission access agreements, and the ability to obtain financial backing and other business-related factors. In some cases, a single developer may announce several alternative projects, even though only one will be built. Such announcements are made because developers cannot be assured of obtaining all the necessary permits to build a power plant at one location, forcing them to consider alternate locations as a contingency plan. In other cases, economic or political conditions may change, making a project unprofitable, leading to its cancellation. For example, volatility in natural gas prices may cause developers to review previously announced plans to construct new gas-fired generating units. Similarly, the institution of price caps for wholesale electricity sales also may lead to project cancellations. Finally, some states have issued moratoriums on new power plant construction because the capacity of the proposed facilities exceeds the projected future demand for electricity in the state or out of concern about the environmental consequences of hosting generating facilities whose output could be sold out of state.

ASSESSMENT OF RELIABILITY

Figure 7

United States Capacity Margins – Summer

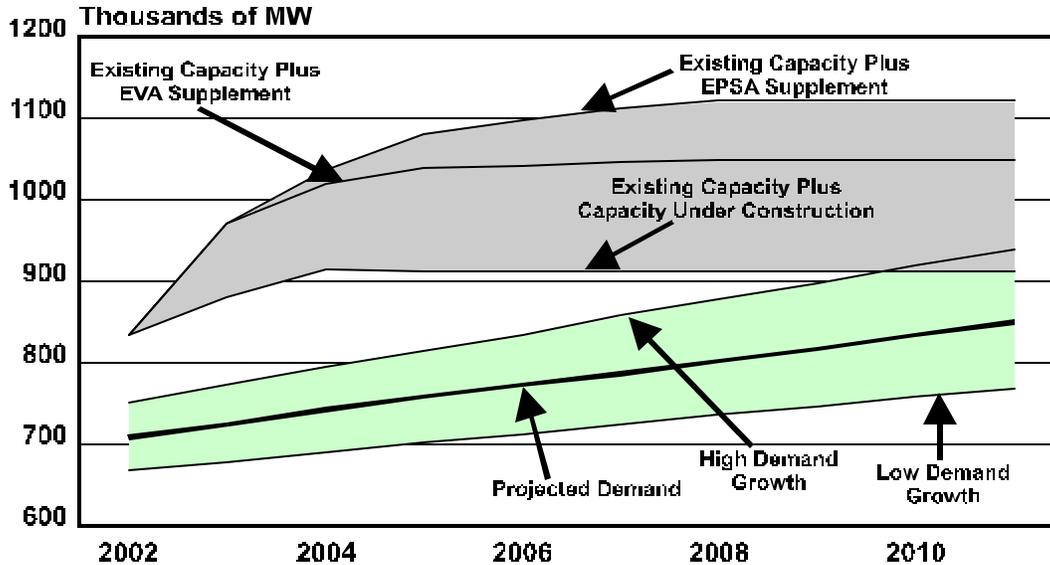


Using detailed project information from EVA to supplement information supplied by the Regions, Figure 7 shows a range of U.S. capacity margins for the next ten years. EVA maintains a database of all proposed new power plants in the United States and tracks various milestones associated with the completion of the projects, including applications for environmental permits, siting, acquisition of equipment, financing, and contractual arrangements to sell the output of the facilities. Using this key information, announced new merchant plants were screened to identify those most likely to be built. Four separate capacity margin projections are shown in Figure 7: the lower bound includes only those generating resources currently in operation or under construction; the upper bound (“Existing Capacity Plus EPSA Supplement”) is the projected margin if all announced new merchant power plants are constructed. Neither of these two cases is deemed likely; they are included for perspective. The line labeled “Reported by Region” reflects the capacity margins as reported by NERC’s Regions. The line labeled “Existing Capacity Plus EVA Supplement” reflects the projected capacity margins after supplementing Regional data with data received from EVA. RAS believes that this line represents the most likely scenario going forward.

Figure 8 overlays the projected U.S. capacity resources for the next ten years on NERC’s projected demand and associated bandwidths. Three resource lines are shown: the first is projected capacity resources without the inclusion of any generators that are not currently operational or under construction (“Existing Capacity Plus Capacity Under Construction”); the second is RAS’ best estimate of future capacity resources (“Existing Capacity Plus EVA Supplement”); and the last line projects the future resource situation if all announced merchant generation is constructed and brought on line (“Existing Capacity Plus EPSA Supplement”). Though it is highly unlikely the highest or lowest capacity resource lines will materialize, they are included to provide perspective. Figure 8 shows that even absent any new resource additions, U.S. projected electricity supplies should exceed base-line demand projections throughout the ten-year period.

Figure 8

United States
Capacity vs Demand – Summer



Canada’s capacity margins for the next ten years are shown in Figures 9 and 10. Figure 9 illustrates a range of capacity margins, with the lower line showing projected capacity margins incorporating only existing power plants and those currently under construction. The upper line includes all proposed new capacity reported by the Regions. Information regarding proposed new Canadian capacity additions beyond that reported by the Regions is not currently available; hence only two capacity margin lines are shown on Figures 9 and 10, as opposed to the multiple projections for the United States. Figure 10 superimposes the projected capacity resources for the next ten years on the projected NERC demand bandwidths for the same time period. Figure 10 shows that even absent any new resource additions, Canadian projected electricity supplies should exceed base-line demand projections throughout the ten-year period.

ASSESSMENT OF RELIABILITY

Figure 9

Canada Capacity Margins – Winter

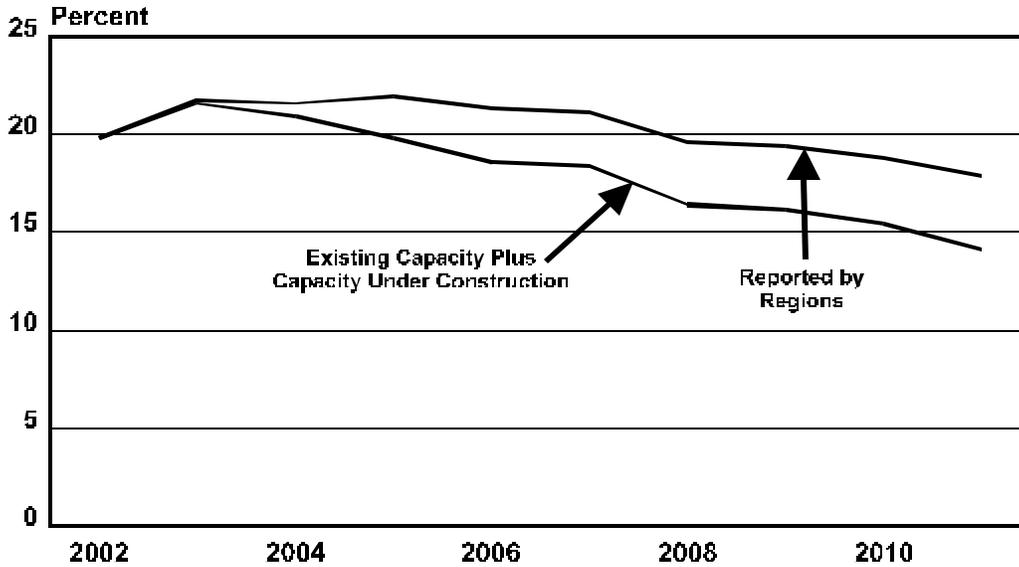
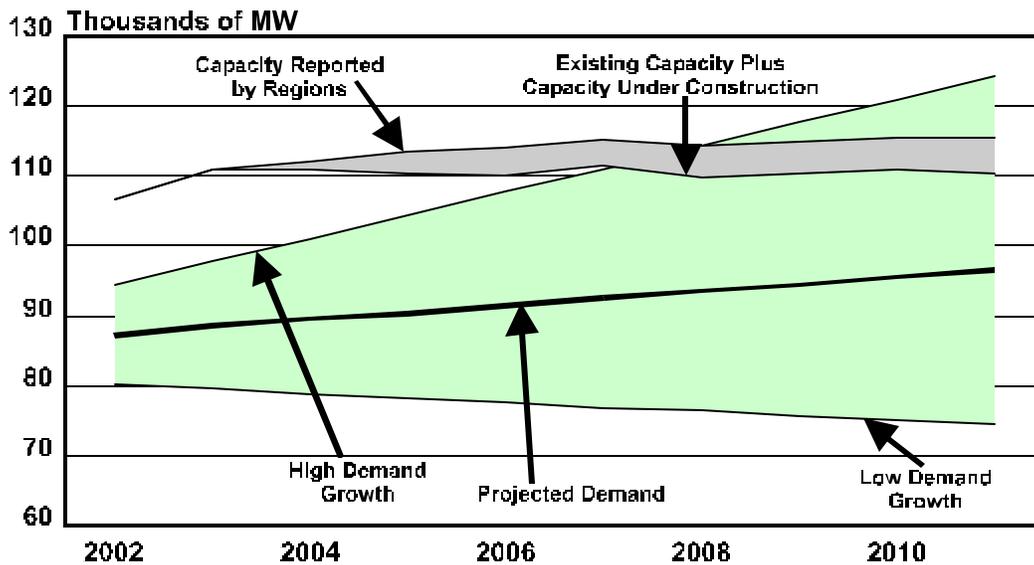


Figure 10

Canada Capacity vs Demand – Winter



All of the preceding capacity margin projections include the effects of currently planned generating unit retirements. They do not, however, include unit retirements that may occur due to environmental restrictions or those that may occur as newer, more efficient plants come on line and older assets are deemed uneconomic. These

ASSESSMENT OF RELIABILITY

retirements are difficult to project and are yet another uncertainty associated with developing long-term resource adequacy projections.

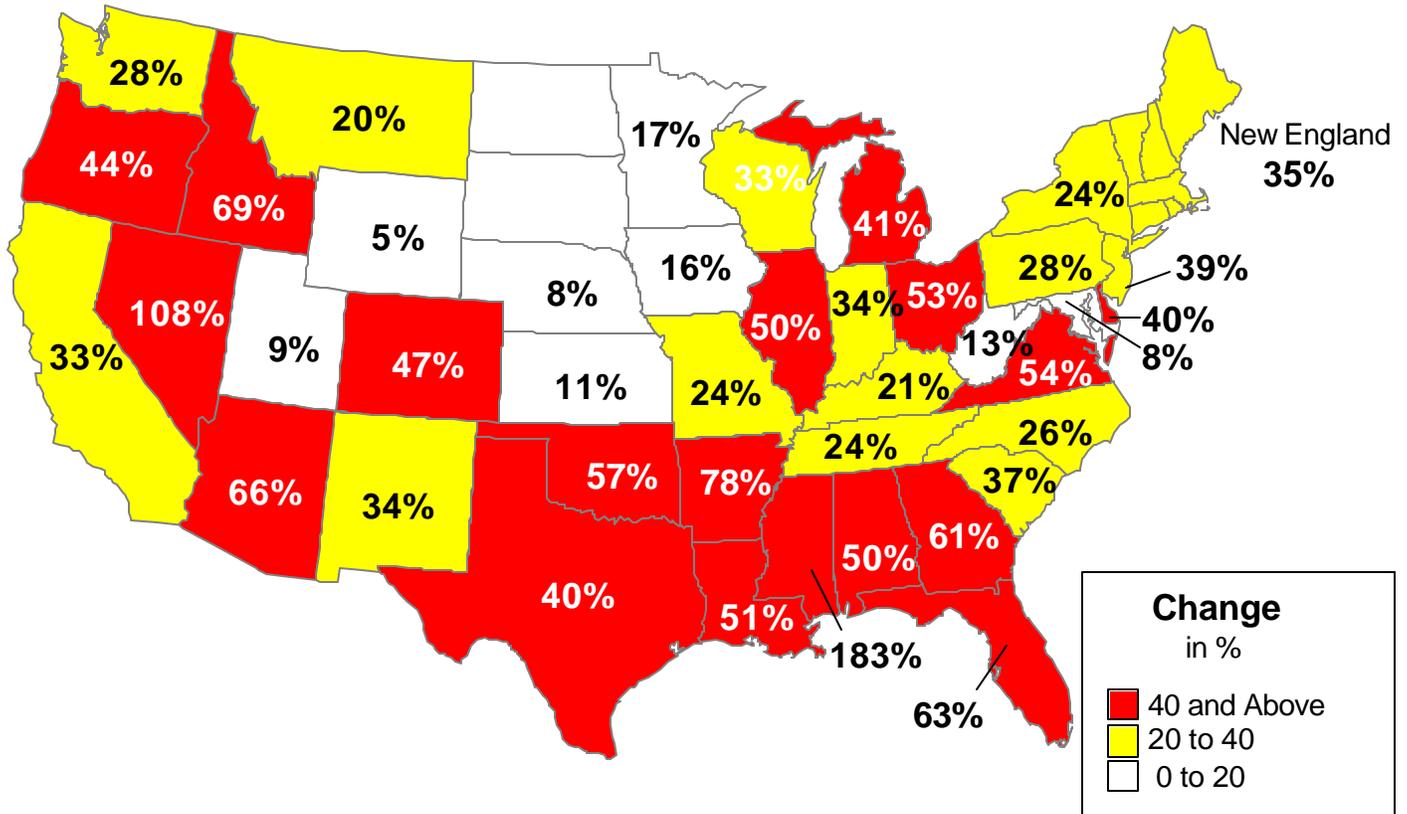
Although the overall capacity is expected to be adequate to serve projected demands, areas of North America may experience deficiencies even as new generating resources are added elsewhere or if transmission limitations limit the delivery of energy to demand centers. As can be seen in Figure 11, the locations being selected for the installation of new generators are not always ideal from a demand and transmission system perspective. For example, an examination of Mississippi shows that if current projections hold, capacity additions within the state through 2007 will be nearly twice what existed in 1998. This capacity exceeds what is needed to serve local demand, and the existing transmission system is not capable of moving this electricity to other areas.

Table 2 shows projected capacity margins for 2002 and 2006 (both summer and winter) by NERC Region. The information in the table was taken directly from submittals made by the NERC Regions. The information in Table 2 is also reflected in Figures 5 and 6.

ASSESSMENT OF RELIABILITY

Figure 11

Percentage of Projected New Generator Additions 1998–2007 as a Percentage of 1998 Total Installed Generation (source: Energy Ventures Analysis, Inc.)



ASSESSMENT OF RELIABILITY

Table 2: Demand and Capacity as Reported by the NERC Regions

Region	Total Internal Demand (MW)	Net Internal Demand (MW)	Planned Capacity Resources (MW)	Reserve Margins (% of Net Internal Demand)	Capacity Margins (% of Capacity Resources)
Summer — 2002					
ECAR	99,346	96,328	122,995	27.7	21.7
FRCC	40,145	37,400	44,735	19.6	16.4
MAAC	54,188	52,569	64,003	21.8	17.9
MAIN	56,888	53,352	70,842	32.8	24.7
MAPP–U.S.	28,191	26,490	32,967	24.5	19.6
MAPP–Canada	5,478	5,283	6,948	31.5	24.0
NPCC–U.S.	54,675	54,617	67,992	24.5	19.7
NPCC–Canada	47,401	46,532	65,468	40.7	28.9
SERC	158,928	152,833	176,168	15.3	13.2
SPP	41,483	39,942	47,591	19.2	16.1
Eastern Interconnection	586,723	565,346	699,709	23.8	19.2
WECC–U.S.	116,852	115,132	142,880	24.1	19.4
WECC–Canada	14,766	14,766	21,129	43.1	30.1
WECC–Mexico	1,697	1,697	2,390	40.8	29.0
Western Interconnection	133,228	131,508	166,902	26.9	21.2
ERCOT Interconnection	57,898	57,736	76,482	32.5	24.5
United States	708,594	686,399	834,770	21.6	17.8
Canada	67,645	66,581	93,545	40.5	28.8
Mexico	1,697	1,697	2,390	40.8	29.0
NERC	777,936	754,677	934,370	23.8	19.2
Summer — 2006					
ECAR	109,113	106,012	155,274	46.5	31.7
FRCC	44,274	41,561	50,395	21.3	17.5
MAAC	57,809	56,190	72,971	29.9	23.0
MAIN	60,799	57,503	76,930	33.8	25.3
MAPP–U.S.	31,257	29,876	32,372	8.4	7.7
MAPP–Canada	5,832	5,562	7,973	43.3	30.2
NPCC–U.S.	57,903	57,842	77,540	34.1	25.4
NPCC–Canada	50,161	49,259	72,472	47.1	32.0
SERC	174,795	169,103	191,820	13.4	11.8
SPP	45,197	43,428	49,458	13.9	12.2
Eastern Interconnection	637,140	616,336	787,205	27.7	21.7
WECC–U.S.	126,886	125,133	204,966	63.8	38.9
WECC–Canada	15,723	15,723	25,863	64.5	39.2
WECC–Mexico	2,374	2,374	4,837	103.7	50.9
Western Interconnection	144,888	143,135	236,235	65.0	39.4
ERCOT Interconnection	66,857	66,695	81,847	22.7	18.5
United States	774,890	753,343	982,844	30.5	23.4
Canada	71,716	70,544	106,308	50.7	33.6
Mexico	2,374	2,374	4,837	103.7	50.9
NERC	848,980	826,261	1,093,800	32.4	24.5

ASSESSMENT OF RELIABILITY

Table 2: Demand and Capacity as Reported by the NERC Regions (continued)

Region	Total Internal Demand (MW)	Net Internal Demand (MW)	Planned Capacity Resources (MW)	Reserve Margins (% of Net Internal Demand)	Capacity Margins (% of Capacity Resources)
Winter — 2002/03					
ECAR	87,133	84,474	125,251	48.3	32.6
FRCC	43,199	39,565	49,165	24.3	19.5
MAAC	44,747	44,048	65,871	49.5	33.1
MAIN	43,028	40,628	67,780	66.8	40.1
MAPP–U.S.	23,234	22,689	31,878	40.5	28.8
MAPP–Canada	6,429	6,234	8,219	31.8	24.2
NPCC–U.S.	45,308	45,194	73,071	61.7	38.2
NPCC–Canada	62,350	60,776	71,157	17.1	14.6
SERC	139,745	134,832	176,365	30.8	23.5
SPP	30,382	29,441	47,267	60.5	37.7
Eastern Interconnection	525,555	507,881	716,024	41.0	29.1
WECC–U.S.	103,314	101,865	144,664	42.0	29.6
WECC–Canada	18,380	18,380	22,872	24.4	19.6
WECC–Mexico	1,308	1,308	2,217	69.5	41.0
Western Interconnection	122,121	120,672	169,547	40.5	28.8
ERCOT Interconnection	45,818	45,656	80,426	76.2	43.2
United States	605,908	588,392	855,277	45.4	31.2
Canada	87,159	85,390	106,515	24.7	19.8
Mexico	1,308	1,308	2,217	69.5	41.0
NERC	694,375	675,090	969,355	43.6	30.4
Winter — 2006/07					
ECAR	94,404	91,930	157,912	71.8	41.8
FRCC	47,215	43,548	53,701	23.3	18.9
MAAC	47,288	46,589	74,898	60.8	37.8
MAIN	45,264	43,604	74,976	71.9	41.8
MAPP–U.S.	25,167	24,604	32,352	31.5	23.9
MAPP–Canada	6,871	6,601	9,344	41.6	29.4
NPCC–U.S.	47,489	47,305	81,678	72.7	42.1
NPCC–Canada	64,952	63,359	74,439	17.5	14.9
SERC	151,445	146,472	188,101	28.4	22.1
SPP	32,732	31,588	49,206	55.8	35.8
Eastern Interconnection	562,827	545,600	796,607	46.0	31.5
WECC–U.S.	112,384	110,908	201,622	81.8	45.0
WECC–Canada	19,776	19,776	26,395	33.5	25.1
WECC–Mexico	1,955	1,955	4,397	124.9	55.5
Western Interconnection	133,161	131,685	232,246	76.4	43.3
ERCOT Interconnection	52,193	52,031	83,525	60.5	37.7
United States	655,581	638,579	992,552	55.4	35.7
Canada	91,599	89,736	114,052	27.1	21.3
Mexico	1,955	1,955	4,397	124.9	55.5
NERC	749,135	730,270	1,115,082	52.7	34.5

Regional Highlights

Regions of particular interest are highlighted below. The Regional assessments that appear later in this report contain further details about these areas.

NPCC — New York

Current projections indicate that New York State will not meet its 18% installed reserve margin requirement beyond 2004. However, currently about 4,200 MW of new capacity have approved applications under the New York State Article X process that have not been included in the projected reserve margins. The completion of these resources would result in New York meeting or exceeding its 18% requirement. Additionally, part of the New York installed capacity market design allows “special case resources” (for example, distributed generation and interruptible load customers) to participate in the installed capacity market.

New York City and Long Island have stringent locational capacity requirements, due to their geography and demand concentration. Based on projected demand growth, New York City will not meet these locational capacity requirements beyond 2002 unless additional new resources within the city become available. Through 2011, over 850 MW of new resources need to be built to meet projected demand growth. However, if the proposed projects for New York City are built, these additions, together with demand-side management programs, will result in New York City meeting its locational capacity requirements.

Ten LM-6000 gas turbines recently have been installed on Long Island, which when coupled with the TransÉnergie 330 MW HVDC cable (currently under test) are projected to satisfy Long Island’s locational capacity requirement through 2008. Projected demand growth after 2008 will require the addition of about 250 MW by 2011.

Southwest Connecticut — New England

New England will meet the NPCC resource adequacy criterion through 2011 assuming normal forecast demand, the proposed transmission upgrades in southwest Connecticut are built and expected generating resource additions are made and integrated into the New England transmission system. However, ISO New England has identified severe reliability problems in southwestern Connecticut due to the inadequate capability to import electricity into the southwestern Connecticut area and the inability to move electricity within that area. The Connecticut state government recently placed a moratorium on all new transmission and generation projects in the state so that the state can formulate a comprehensive energy plan. Once this effort is completed, it is hoped that the moratorium will be lifted so that sorely needed transmission improvements can be made.

ASSESSMENT OF RELIABILITY

Transmission Adequacy and Security Assessment

North American transmission systems are expected to perform reliably in the near term. Procedures and processes to mitigate potential reliability impacts appear to be working effectively. However, portions of the transmission systems are reaching their limits as customer demand increases and the systems are subjected to new loading patterns resulting from increased electricity transfers. Although the transmission systems are expected to perform reliably, some areas of the transmission systems are not adequate to transmit the output of all new generating units to their desired markets.

Many electricity transfers are influenced by weather diversity across the continent that frees up resources in one area to serve demand in another. Because weather patterns are unpredictable in the long term, transmission constraints and congestion have the potential to shift from season to season and year to year. Although some transmission constraints are recurring and well known, new constraints are appearing as electricity flow patterns change. In cases where redispatch options have been exhausted or are ineffective, the only way to remove the constraints is to increase the capability of the transmission system or build new generation close to the demand centers, removing the need for the electricity transfers in the first place.

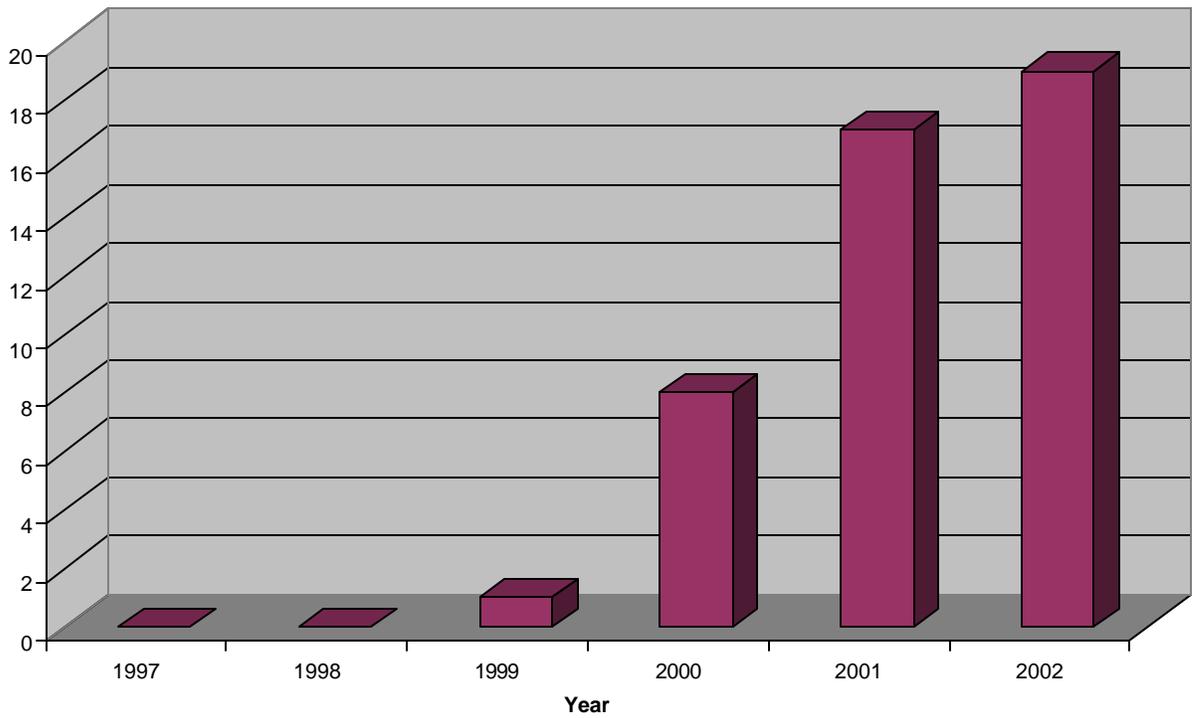
The transmission systems are being subjected to flows in magnitudes and directions that were not contemplated when they were designed and for which there is minimal operating experience. New flow patterns result in an increasing number of facilities being identified as limits to transfers, and transmission loading relief (TLR) procedures were required in areas not previously subject to overloads to maintain the transmission facilities within operating limits. Reliability coordinators call for NERC TLRs to manage transactions within transmission security constraints, which causes a generation redispatch by restricting scheduled transfers.

Operating transmission facilities at levels near security limits does not necessarily translate into an unreliable or insecure transmission system; these conditions may instead be an indication that the transmission system is congested and will not support any further economic transfers of energy. For example, 2000 saw a significant increase in the number of TLRs as heavy north-to-south electricity transfers occurred in the central United States, spurred on by extended temperature diversity (cool in the north, hot in the south), which freed up resources for export. In general, TLRs are an indication that steps must be taken to manage transmission system loading to avoid placing the system in an insecure state. Several steps or classifications of NERC TLR exist, ranging from Level 0 to 6.² Only at TLR levels 5 and higher are firm transactions curtailed. Although few TLRs 5 and higher have been called since the TLR procedure was instituted, the number has increased each year. The 2002 TLRs listed represent those called through July 2002.

² For more information regarding NERC TLR and its levels, please visit <http://hhr.nerc.com>.

Figure 12

Number of Level Five and Higher TLRs per Year



ASSESSMENT OF RELIABILITY

Table 3 — Planned Transmission

	Transmission Circuit Miles 230 kV and Above*			
	2002 Existing	2002–2006 Additions	2007–2011 Additions	2011 Total Installed
ECAR	16,207	155	0	16,362
FRCC	6,822	325	214	7,361
MAAC	7,031	68	0	7,099
MAIN	6,177	241	50	6,468
MAPP–U.S.	14,177	114	0	14,291
MAPP–Canada	5,846	140	14	6,000
NPCC–U.S.	6,463	340	77	6,880
NPCC–Canada	28,780	237	101	29,118
SERC	28,539	1,339	1,280	31,158
SPP	7,618	594	128	8,340
Eastern Interconnection	127,660	3,553	1,864	133,077
WECC–U.S.	56,838	2,716	897	60,451
WECC–Canada	10,857	24	93	10,974
WECC–Mexico	431	136	0	567
Western Interconnection	68,126	2,876	990	71,992
ERCOT Interconnection	7,373	659	170	8,202
United States	157,245	6,551	2,816	166,612
Canada	45,483	401	208	46,092
Mexico	431	136	0	567
NERC Total	203,159	7,088	3,024	213,271

*Note: Circuit miles of transmission are not an absolute indicator of the reliability of the transmission systems or their ability to transfer electricity.

About 10,100 new circuit miles of transmission facilities (230 kV and higher) are planned for construction throughout North America over the next ten years; the majority of these additions are planned for the first five years, reflecting uncertainty in long-term planning. This amount represents a 5% increase in total installed circuit miles (230 kV and higher) over the ten-year period; most of these additions are intended to address local transmission concerns or to connect proposed new generators to the transmission grid and will not have a significant impact on its capability to transfer electricity over long distances. This table does not include circuit upgrades or reconductoring of existing lines. Alternatives to construction of new transmission facilities are presented in the Planning Issues section of this report.

Recently, merchant transmission developers have entered the business of constructing new transmission facilities. Several new transmission lines are being planned by merchant developers. The entry of these new players may result in construction of new transmission beyond that currently planned; however, these new players will face the same hurdles to new construction: public opposition to siting the facility, uncertainty as to how to allocate the costs and benefits of the new facilities, and other regulatory uncertainties. A number of the proposed merchant transmission lines are submarine DC cables, which may enable them to circumvent many siting issues. Additionally, the flow of electricity on DC lines is controllable and predictable, and the benefits of such facilities are easily identified and assignable. Other novel approaches to financing and constructing new transmission are being pursued, such as the planned upgrade to the 500 kV transmission Path 15 in California.

Electricity/Natural Gas Interdependency

With a majority of new generation relying on natural gas as its primary fuel, the near- and long-term adequacy of both the availability of natural gas and the infrastructure to move it to the generating stations are coming under increased scrutiny. This section presents the manner in which gas pipelines are planned and operated compared to the electric transmission facilities, and the impact and relationship the gas supply may have on future electric system reliability.

Government publications forecast the ready availability of adequate quantities of natural gas at market prices. However, the adequacy of the existing gas pipeline infrastructure to deliver the fuel to gas-fired generating units depends largely on the specific location of the generators and the manner in which it is bid into the market (peaking, intermediate, or base load). Reliability standards for the interconnected electrical transmission systems dictate that they are planned to reliably operate through first contingency electrical failures. RAS' investigation reveals that the gas industry does not have similar standards. The lack of similar standards makes it difficult to assess the adequacy of the pipeline infrastructure under single pipeline contingencies. In some areas of North America, a single gas system disturbance may result in the eventual loss of more electrical generation than traditional analysis would indicate for a similar electrical disturbance. Additionally, upon the sudden loss of electrical generating units, gas delivery limitations may prohibit gas-fired generators that remain on line from fully responding to the sudden loss unless adequate measures are taken prior to the occurrence. Unlike the electric system, the gas system has significant storage capability with adequate line packing. This characteristic can allow an electric generating station to operate for enough time that system operators can take action even if interruptions occur elsewhere on the gas delivery system.

Operations

Although interconnections exist among the natural gas pipelines, the pipelines generally operate independently of one another, which may place long-term fuel supplies in jeopardy due to single component failures in the gas delivery infrastructure. Also, the pipeline owners are under no legal obligation to assist one another in emergency situations, unless a contractual arrangement to do so has been previously negotiated, but in fact have cooperated in the past and are expected to continue to do so because they are aware of their mutual dependencies.

As with electrical curtailments, the security of the gas delivery system can be maintained through the use of gas curtailments. Although FERC set customer curtailment priorities for the pipelines in the 1970s, the procedures have not been rigorously tested because they are rarely implemented. If and when gas curtailments are necessary, electric generators will have their service cut in accordance with the order of firmness that they contracted. If customers contracted for non-firm service, they will be the first curtailed after a predetermined notice period (typically several hours). Well-defined procedures exist in all operations centers to deal with "limited fuel" units. In addition, electric generators (especially new combustion turbines and combined cycle plants) depend upon high gas pressure at their delivery point and are susceptible to pressure drops depending on their specific design.

Gas Transients

The interconnected electric transmission systems are designed and operated to be secure against the sudden loss of any single circuit, transformer, or generating unit without loss of firm customer demand. Such losses result in electrical transients that are often instantaneous and large in magnitude, requiring that the electrical system be pre-configured to handle the contingency. The amount of spinning reserve within an area is sized to reliably accommodate a reduction of import capability or loss of the local generation. With more generating stations being supplied by natural gas, interactions between the gas supply and the generating units are

How are gas pipelines planned?

If enough prospective customers sign non-binding bids during "open season" to make a project financially attractive, binding bids will be solicited for inclusion in a request to FERC, which has authority over the siting of new interstate pipelines or expansion of existing ones. The entire permitting and construction process can be accomplished in 18–24 months.

RELIABILITY ISSUES

increasingly becoming an electrical security issue. Transients in the operation of a gas pipeline may have a significant impact on the continuity of service of gas-fired generation being served by that pipeline.

The following two scenarios illustrate potential reliability interactions:

1. The sudden loss of a generating facility (independent of fuel supply) that results in a step change in output on other gas-fired generating stations, or
2. The sudden loss of a common gas supply that results in the loss of several generators beyond that which is normally considered under traditional reliability planning standards.

In both of these scenarios, the amount of gas pipeline packing will determine the initial response, while the action of local gas compressor stations and valves will determine the intermediate response.

Line packing relates to the amount of additional gas that is contained in a pipe as a result of maintaining above-normal pressure in the pipe. Line packing is critical for a pipeline to be able to handle the pressure drawn down that results from large swings in demand, such as during the morning ramp-up of gas-fired generation or the reaction to transients as described above. The ramp rate of generators fed from a particular gas pipeline is limited by the initial pressure of the line, the allowable rate of change of pressure in the line, and the minimum allowable pressure of the line. The inability to pack a line or the failure to line pack prior to a large, unanticipated swing in electrical demand can result in the inability of electric generators to serve demand.

Unlike the delivery of energy over the electric systems, the transportation of natural gas via pipelines happens over much longer time frames, enhancing the operating security of the supply network. On average, natural gas travels between 40–60 miles per hour through the pipelines. Therefore, problems with supply at the wellhead are known hours or even days before they will affect gas delivery to customers, allowing measures to be taken to mitigate potential problems. These measures may include redirection of gas to elsewhere in the system, implementing a change in pipeline pressure, or making use of stored natural gas supplies. Although these measures will generally be sufficient to maintain uninterrupted service to the majority of natural gas customers, it is unclear if they will do the same for electric generators dependent upon high-pressure deliveries. Therefore, coordination and cooperation between the gas and electric operating centers will be necessary to maintain reliable service.

The interaction between the electric industry and gas pipelines is also an issue with the standing American Gas Association (AGA)/FERC Committee. A task group published study, “Impact of Power Generation Gas Demand on Natural Gas Local Distribution Companies” (October 2001), contains recommendations on changes to the criteria used by FERC to approve gas connections to electric generating plants. The paper also identifies the need for more formal coordination between the operations center for the pipelines and the respective operations centers of the electric system.

Planning

Gas adequacy has two components, supply (i.e., availability) and the infrastructure to move it. Natural gas deposits in Canada, the Rocky Mountains, and deepwater sites in the Gulf of Mexico are expected to provide adequate supplies into the future. In some cases, the location of the gas reserves may require either new technology or significant expenditures to extract the gas. In the last two years, 12.3 billion cubic feet per day of new pipeline capacity was installed via 65 projects.¹ Pipeline extensions and laterals make up more than 70% of new expansions.

¹ Tobin, James. *Natural Gas Transportation – Infrastructure Issues and Operational Trends*. EIA/Natural Gas Division, October 2001.

Much of the growth in natural gas consumption has been met with new pipelines or extensions from new supply areas rather than expanding infrastructure in existing areas. Additional capacity also is being developed by increasing compression on the existing system and by looping (integrating a parallel pipeline). Over the last decade, pipeline capacity from Canada to the United States has increased by 123%.

It is important to note that natural gas pipelines are not centrally planned, although plans for new pipelines and expansion of existing pipelines are centrally reviewed and approved by FERC. Pipeline owners are not required to develop common computer model formats of their systems or to submit such models to FERC, as electric utilities are required to do with their transmission systems. Thus, there appears to be no independent review of the reliability of the natural gas pipeline infrastructure or of its ability to deliver natural gas at the pressures needed to maintain new electric generation.

Pipeline owners are not required by FERC to allow third-party access to their pipelines nor are they required to build at a new customer's request if there is not sufficient interest from others to warrant the construction. New gas pipelines cannot be built on speculation; pipeline owners must demonstrate a need for new construction before they can obtain FERC approval. Typically, this demonstration consists of firm customer contracts for 35% of the new pipeline's capacity.

Little redundancy exists in gas pipelines, and in many cases, where redundancy does exist, it is in common rights-of-way leading to susceptibility of common mode failures. In the case of the pipeline explosion in New Mexico in 2000, three pipelines were buried in the same right-of-way at varying depths and all three were interrupted when the explosion occurred.

When electric generators express an interest to connect to a gas pipeline, the pipeline owner typically makes no guarantees that they can maintain constant delivery at the pressures required for new generators to maintain operations. From the pipeline owner's perspective, the addition of a high pressure, low-capacity factor, interruptible customer may not provide sufficient revenues to justify an investment in new infrastructure. Instead, the pipeline owner may make minor expansion provisions with the understanding that uninterrupted deliveries to the generator are not guaranteed under all conditions. In severe weather situations, electric and gas demands may both peak; if future electric capacity additions continue to be dominated by natural gas-fired generators, it becomes more likely that electric reliability problems may occur at peak demands.

Brief Discussion of Regions²

Northeast

In the Northeast, natural gas pipeline capacity has grown in response to the displacement of fuel oil by natural gas as the region's primary heating fuel and the need to supply new electric generating stations. Today, the region's interstate capacity is being utilized at high levels during peak months. Despite the growth in pipeline capacity, increased demand has placed a burden on currently constrained pipeline infrastructure. New pipelines proposed for this region include: Cross Bay, Islander East, Connecticut-Long Island, and Iroquois Eastern Long Island.

Midwest

Pipeline capacity usage in the Midwest has reached 90% on pipelines importing Canadian supplies. Several projects have been approved or are awaiting approval, including: Horizon, Guardian, and ANR Wisconsin Loop.

Southeast

Pipeline capacity in the Southeast grew by 10% over the last decade. Much of the volume flowing through the region is for markets in the Northeast and Midwest. Recently completed pipeline expansion projects have

² Tobin, James. *Natural Gas Transportation – Infrastructure Issues and Operational Trends*. EIA/Natural Gas Division, October 2001.

RELIABILITY ISSUES

improved deliverability. Like the northeast, use of this region's interstate pipelines is high during peak demand months (winter months, except in Florida). Additional pipeline capacity is expected to be installed to prevent possible shortfalls.

West

During the past two years, western pipeline capacity grew by only 1%, but demand by gas-fired electric generating stations has still been accommodated. However, a tight market was created by increased demand resulting from heavy dependence upon gas-fired generating plants between late 2000 and mid-2001 because of decreased availability of hydro resources. New projects have been proposed to increase pipeline capacity into California. Oregon and Washington also have proposals for new pipelines to supply growing gas markets. New gas-fired electric generators proposed for Arizona and Nevada are prompting pipeline expansion in these states, as well.

What Does All This Mean for the Electric Industry?

Natural gas is a clean-burning and highly efficient fuel, especially when used in combined-cycle plants. These features, coupled with the short lead times and pay-back periods associated with the low capital cost technology to generate electricity using natural gas as a primary fuel, has resulted in over 90% of all proposed new electric generators for the next ten years to be gas fired. Although ample supplies of natural gas exist, the cursory review conducted by RAS indicates that additional coordination between the planning and operation of electrical generation and natural gas infrastructure is necessary to ensure future deliveries of natural gas to the generators. Further cooperation and coordination between electric generators and natural gas supplies and delivery are warranted.

Due to the proliferation of new gas-fired generators fed from common supply pipelines, some areas of the continent may experience a gas system disturbance whose impact is more severe than the loss of a single generator, transmission line, or transformer. A single gas contingency, such as the interruption or pressure loss of a single gas pipeline, may result in the loss of multiple electric generators. With proper site planning and unit design, the impacts of gas pipeline contingencies can be mitigated. Although many natural gas-fired electric generators have dual-fuel capabilities (i.e., burn fuel oil as a backup), questions surround the ability of this capability to fully mitigate a widespread loss of natural gas deliveries. Some generators must be taken off line to switch out burners; others may not have oil supplies available when the emergency occurs because they may have burned stored oil as a hedge against gas price spikes. Still others may not be able to switch when called upon due to environmental limitations and finally, in most cases, there is not enough on-site oil in storage to ride through an extended interruption of natural gas supplies.

What can weather do?

Under severe weather conditions, natural gas wellheads can freeze, limiting the amount of natural gas available to be packed into pipelines. The southwestern U.S. gas-producing region experienced such a freeze for a week in 1989, losing 25–30% of their production capability.

In 1992, Hurricane Andrew damaged hundreds of gulf coast platforms and pipelines, reducing output by as much as 70% at times (almost 20% of total U.S. production).

Planning Issues

Adequacy of Supply

The role of ensuring adequacy of electricity supply to electric customers does not always reside with vertically integrated utilities. In many instances, the entities now responsible for this function manage their power supply obligations through a portfolio of owned generators and power purchase contracts with other generators. Each of these entities must evaluate the reliability and firmness (i.e., adequacy) of the resources in its supply portfolio. They may be helped in their evaluation by standards such as reserve margins imposed by state regulators, RTOs/ISOs, or by their NERC Regions.

Prior to industry restructuring, vertically integrated electric utilities were responsible for ensuring that adequate generation was built. With readily identifiable owners of current generation and builders of future generators (those vertically integrated utilities), the Regions were able to monitor projected reserve margins and encourage the development of sufficient capacity. Now, however, due to federal, state, and provincial initiatives, the North American electric industry is being transformed. A multitude of non-utility generation developers have stepped up to construct new plants. The new plants constructed by these developers are based on different economic models than those models used by vertically integrated utilities and, as a result, the new plants must be treated differently in today's reliability assessments.

Merchant power plants have become the dominant source of new power generation in most parts of the United States, representing more than 90% of the capacity additions that have been made since 1997. Non-utility installed capacity has increased almost fourfold in less than five years, rising from 70.3 Gigawatts (GW) in 1997 to 319.5 GW in 2001. During 1997–2001, the amount of non-utility generation has grown from 8.5% of total U.S. capacity in 1997 to 35.6% of the total in 2001.

Responding to revised financial expectations and temporary downgrades from credit agencies, a number of developers have sold or canceled plants to improve their cash positions and lower their debt/equity ratios. This slowdown, along with a general economic downturn in many regions of the country, has resulted in the suspension of many generation projects under development and/or projected to come on line in the middle of the decade. Most projects scheduled to come on line in the next two years appear to be on schedule, which will improve the near-term adequacy of supply, but longer-term projects are being canceled. Because reliability is increasingly dependent upon the relationship between load-serving entities and market forces, long-term reliability will be driven by future market conditions.

One outcome of the new market environment is that it is difficult to draw reliability conclusions from reported or calculated generation capacity or reserve margins, particularly on a Regional basis. In some Regions, the data reported may be incomplete, developers may be reluctant to announce new projects, announced units may not be under contract, existing generators may not provide information concerning unit upgrades/retirements, etc. Regions must use their best judgment to decide whether to include generators in their adequacy assessments in cases where the generator has not committed to serve demand within the Region.

New generating plants sited in areas where the transmission system was not planned or built to support them will also distort the reliability picture in some Regions. The Department of Energy's (DOE) EIA-411 report used by the electric industry as the basis for demand and capacity evaluations fails to take into consideration whether or not generators are stranded and unable to reach desired markets.

Transmission Planning

Although the North American transmission systems are expected to perform reliably, in some areas the transmission grid is not adequate to transmit the output of all new generating units to their desired markets. 10,300 miles of transmission lines, 230 kV and higher are planned to be added, while an estimated 159,000–286,000 MW of

RELIABILITY ISSUES

new generation may be added by 2011. The planned additions represent an increase of about 30% in generating capacity over currently installed levels compared to a 5% increase in transmission. This mismatch of additions of new transmission lines and new generators may be attributed to a number of factors. First, because of the cost and siting requirements associated with transmission line construction, transmission is not built on a speculative basis; transmission owners will build transmission sufficient to serve their customer demands only when they can demonstrate a clear need to regulators and the public. Second, little planned transmission line construction is likely to occur to accommodate economic transfers, even if such additions may benefit large numbers of customers. This reluctance to construct new transmission facilities is similar to the *tragedy of the commons* in which costs and other negative impacts are concentrated on a limited number of parties, although the benefits are distributed to all parties. With industry restructuring and the development of regional wholesale markets, new transmission lines may be economically beneficial to all parties, including the consumers of electricity, but their costs are incurred by only one or several entities. As a result, those entities may be reluctant to build the needed transmission facilities.

Impact of Generation Siting

The siting of new generators, whether utility or merchant built, can clearly have an impact on the reliability of the interconnected electric systems. For example, locating new generators electrically close to demand centers will cause less of a burden on the transmission systems than generators built in remote locations. In some instances, constructing new generators near demand centers may actually reduce transmission system loadings.

The availability of adequate transmission facilities and the cost of building new facilities to integrate new generators into the system are factors that help determine where new generation will be located. However, factors such as the availability and cost of fuel, cooling water and land costs often override transmission adequacy when plant developers select the location for their new generators. For example, wind generation is being encouraged through various programs for its environmentally friendly and renewable resource characteristics. However, the areas most suitable for wind generation — areas that have high average wind speeds and land availability — are usually far away from demand centers and high-voltage transmission facilities. An example is the proliferation of wind generation in western Texas, which has resulted in transmission overloads and curtailments of generation in the area.

Natural gas-fired generators continue to proliferate near the fuel supply, with little consideration given to the location of the possible demand for the output of the plants. In some areas of the continent, installed capacity will soon outnumber accessible demand by a ratio of 2:1. Many developers request only an interconnection to the transmission system (the minimum transmission investment) with the intent of operating only in the hourly spot market and do not request firm transmission service to deliver the output of their plants to customers because this could trigger costly transmission infrastructure reinforcements. Although large amounts of new generating capacity will be installed in the next few years, RAS questions its contribution to NERC-wide adequacy in cases where capacity will be isolated due to transmission system constraints (see map on page 16).

Remote locations that have many desirable traits for a new generator do not typically have sufficient transmission facilities available to fully integrate that generation into the system when it commences operation. Even if the transmission planner is aware of a coming new generation project, enough time may not be available to complete any major needed transmission improvements before the generation project is completed. For example, once a commitment is made, a natural gas-fueled plant can be completed in one and a half to two years. Wind generation can be constructed in six to twelve months. Although modest upgrades of existing transmission lines are possible in that time frame in some cases, any planning and construction of significant new transmission needed to reliably integrate these resources into the grid will take three to five years or longer.

When generators located a significant distance from demand centers commence operation without all needed transmission facilities in service, the transmission systems can be affected in several ways. First, local

transmission facilities may experience thermal overloading because they were sized only to handle relatively light local demands. If thermal overloading is not controlled, it can lead to line damage and outages, possibly cascading over a wide area. Second, if large amounts of new generation are located a long distance from demand centers and other generation resources without adequate connecting transmission, stability problems may occur. These problems might lead to system separation or voltage collapse.

These potential threats to reliability can often be addressed by system operator action until adequate transmission is built to fully integrate remote generation. However, the action most likely to be taken by the operator is to limit output from remote generation. Limiting the output of those resources due to transmission constraints can effectively make needed generating capacity unavailable to meet system demand requirements under conditions when it may be needed most.

Alternatives to New Transmission Lines

Building new transmission lines is not the only way to alleviate transmission constraints and to increase the capacity of the transmission systems. With continued public resistance to the siting and construction of new transmission facilities, other methods for increasing transmission capacity must be found. Better utilization of the existing transmission facilities is one way to accomplish this. Some of these methods to increase transmission system capacity include (1) re-conductoring existing lines with a larger wire size, if tower design permits; (2) utilizing empty tower positions on multiple circuit tower lines; (3) providing voltage support by adding capacitor banks or static var compensators in existing substations; (4) utilizing new flexible AC transmission (FACTS) devices; (5) replacing transmission transformers with larger capacity ones or by adding additional transformers at existing locations; and (6) upgrading limiting circuit components within substations. All of these methods can result in additional transmission capacity but require no additional right-of-way acquisition that may drastically delay or even derail a new transmission line project.

Demand responsiveness programs targeting transmission limitations could also delay the need for new transmission construction. For this approach to work, the demand responsiveness program must be properly designed to target load curtailments to alleviate transmission loading. Residential and small commercial load reduction must be of significant magnitude to have any noticeable effect upon the transmission system. Large industrial customers, such as arc-furnace operators, may have a significant impact on reducing load and subsequently relieving the burden on the transmission system.

Non-wire enhancements to maintain transmission adequacy are becoming more important as alternatives to transmission construction as the transmission system becomes increasingly stressed. Transmission owners are using techniques, such as real-time operation using state estimation, security analysis, and dynamic ratings, to get “more bang for the buck” out of transmission facilities.

Transmission planners are more closely analyzing the system to utilize Special Protection Systems (SPS) or Remedial Action Schemes (RAS) in lieu of building new transmission lines and substations. A SPS or RAS is designed to detect abnormal system conditions and take pre-planned, corrective action (in addition to the isolation of faulted elements) to provide acceptable system performance. SPS and RAS actions include, among others, changes in demand (e.g., load shedding), generation, or system configuration to maintain system stability, acceptable voltages, or acceptable facility loadings. As the number of SPSs and RASs employed increases, so does the complexity of operating the system.

State estimation uses real-time detailed system parameters and modeling to analyze present system conditions. This technique allows the operator/engineer doing the analysis to know exactly what is happening on the system and to determine what options are available at the time to keep it secure.

RELIABILITY ISSUES

Finally, transmission planners and operators can use dynamic ratings for equipment to fully utilize the transmission system in some cases. For example, operators will allow lines to carry more electricity during lower ambient temperatures, as line ratings are higher during colder temperatures in winter than in summer. Transformers also may be loaded to higher levels during cold weather depending upon loss-of-life criteria.

Environmental Issues

The U.S. electric power industry faces increasingly stringent environmental regulation. At least a dozen regulatory initiatives are mandated by current environmental law, as well as significant legislative activity at both federal and state levels, which increase the stringency of existing laws. Current regulatory initiatives and potential new legislation could impact reliability in regions that rely on fossil-fired generating capacity. Today's reliability concerns are similar to those raised regarding the NO_x State Implementation Plan (SIP) call, which were driven by the amount of plant retrofits required within a relatively brief regulatory compliance timeframe.

If new environmental regulations allow adequate time for equipment installation and fuel conversions to take place and commercial technologies are available to comply with requirements, any reliability impacts should be minimal. However, if any of these constraints are compromised, reliability may suffer when units are taken out of service for retrofits, through reduced fuel diversity, or through mass retirement of fossil-fuel generation. The replacement of existing fossil-fuel capacity and concomitant changes to the transmission infrastructure might be difficult to site, finance and construct, and could further stress the natural gas delivery infrastructure.

New environmental requirements may lead to retirement of older units needed for local area power support in non-attainment areas, resulting in the need for transmission reinforcement. The control strategy requirements that states will adopt after the Environmental Protection Agency (EPA) designates areas not meeting revised ozone and fine particle standards may target some generators for controls over the next decade in addition to those already on the books.

Currently, the U.S. electric utility industry continues to implement requirements of the federal acid rain program; state implementation plans (SIPs) for compliance with ambient air quality standards (especially the one-hour ozone standard); and, in many eastern states, the Regional NO_x SIP call. The ozone standards and NO_x SIP Call compliance dates in 2003 and 2004 will require the installation of NO_x control equipment on well over 100,000 MW of generation in 21 eastern states. About 61,000 MW of generation have been or are in the process of being modified to be in compliance as of today¹. This progress translates to 75 to 90% compliance achievement ahead of schedule.

The additional environmental regulatory initiatives in various stages of development that would affect the electric utility industry include:

- implementation of the more stringent ambient air quality standards adopted in 1997 for ozone and particulates;
- the regional haze program including application of the Best Available Retrofit Technology (BART);

The NO_x SIP Call

In September 1998, the U.S. Environmental Protection Agency (EPA) issued a final rule establishing more stringent emissions limits for nitrogen oxides (NO_x) in 22 eastern states and the District of Columbia (the SIP call). The emission reductions are intended to control the regional transport of ozone from the midwest and southeast to several northeastern states during the summer season.

The new emission limits caused affected states to revise their state implementation plans (SIPs), which detail their strategies for meeting regulatory requirements under the Clean Air Act.

NERC RAS conducted an analysis of the potential impacts of the NO_x SIP call in February 2000. The final report may be viewed at: ftp://www.nerc.com/pub/sys/all_updl/docs/pubs/NOxStudy.pdf

¹ As reported by NESCAUM—Northeast States for Coordinated Air Use Management

- rules for hazardous air pollutant (HAPs) emissions, including mercury, from fossil-fired electric utilities;
- resolution of pending enforcement litigation for alleged violation of EPA new source review requirements, and finalization of announced changes in these requirements, both of which could impact maintenance and improvements to existing plants; and
- more stringent requirements on the use of water, water intake structures, and discharge of pollutants.

The current patchwork of environmental regulation provides a disincentive to developing capital-intensive fossil-fired generation because developers cannot anticipate the level of future environmental regulations. In addition, because many of the control technologies affect the operation of one another and the ultimate removal of pollutants, more cost-effective strategies could be developed if all of the environmental regulations that these units would ultimately face were known at the outset. With this in mind, some are seeking to develop multi-pollutant legislation that will provide electric generating plant developers with a greater certainty regarding the level of emissions that generating plants will have to meet in the foreseeable future.

In 2001, Senator Jeffords introduced the Clean Power Act of 2001 (S.556). President Bush's Clear Skies Initiative, announced in February 2002, was subsequently introduced in both houses of Congress as the Clear Skies Act of 2002 (S. 2815, H.R. 5266). Both bills establish cap and trade programs that significantly reduce the emissions of SO₂, NO_x, and mercury. The President's initiative would also replace a number of existing provisions of the Clean Air Act. In addition, the Clean Power Act of 2001 limits emissions of carbon dioxide from the electric power sector, while the Clear Skies Initiative addresses carbon dioxide by enhancing the existing national registry of greenhouse gas emissions and reductions, and setting a goal of reducing the nation's greenhouse gas intensity through tax incentives, and increasing federal research and development on clean fuel and improved energy efficiency.

A number of factors should be considered in assessing the impact that such legislation would have on the reliability of the electric industry. These factors include:

- the need to develop new control technology to meet requirements;
- the time needed to permit, design, procure, and install the control technology;
- the changes to unit/plant operation;
- the changes to the availability and type of fuel used; and
- the likelihood of retirement of generation.

Environmental compliance with either continued regulatory activity under the Clean Air Act, or under proposed multi-pollutant environmental legislation, would require significant retrofits to existing coal-fired capacity. As previously mentioned, the overall impact of these environmental requirements on reliability will depend both on providing sufficient time to make the necessary modifications and the commercial availability of control technologies. The most significant retrofits expected will be performed to reduce sulfur dioxides (SO₂), nitrogen oxides (NO_x), mercury, and possible carbon dioxide (CO₂).

1. **Sulfur Dioxides (SO₂)** — Scrubbers (flue-gas desulfurization — FGD) will be required to reduce emissions of sulfur dioxides under multi-pollutant proposals currently under consideration. The EPA estimates that an additional 114,582 MW of scrubber capacity will be required by 2020 to meet proposed Clear Skies Initiative. The Energy Information Administration (EIA), in an analysis of the Clear Skies

RELIABILITY ISSUES

Initiative, projected the need to add 129,617 MW of scrubbers by 2020. The electric industry has had significant experience with scrubber installations.

2. **Nitrogen Oxides (NO_x)** — NO_x, a precursor to the formation of ozone is believed to be a secondary factor in the formation of PM_{2.5}. NO_x emissions in the eastern United States are required to be reduced by the recent NO_x SIP Call. Efforts to reduce regional haze in the West, and to achieve attainment of both the revised ozone and particulate standards in the East will require further reductions in NO_x emissions. NO_x emission limits are capped in both multi-pollutant proposals mentioned above. In either case, coal-fired generating plants will likely retrofit selective catalytic reduction (SCR) technology. The EPA estimates that 210,628 MW of capacity will be retrofit by 2020 to meet proposed requirements under the Clear Skies Initiative. EIA's analysis of the Clear Skies Initiative projects 214,781 MW of SCR and selective non-catalytic reduction (SNCR) technology will be added by 2020. Worldwide, the electric industry has some experience with the addition of SCR. However, North American operators only recently have begun to gain experience operating SCR equipment, especially in conjunction with FGD.
 3. **Mercury** — Mercury contained in coal is released into the atmosphere when coal is burned to produce electricity. In 2000, EPA listed coal-fired power plants, primarily on the basis of mercury emissions, under the hazardous air pollutant provisions of the CAA, requiring EPA to set Maximum Achievable Control Technology (MACT) emissions levels. Although EPA is expected to propose these levels by 2003, the approaches selected in any subcategorization of coal units could determine if individual plants are forced to close or could comply by adding control devices. These devices include fabric filters and sorbent-based technologies such as activated carbon injection, which has been used successfully in smaller municipal and medical waste combustors, but is only now being demonstrated on the lower-concentration, high-volume exit gas of fossil-fired generating plants. Multi-pollutant legislative proposals that cap mercury emissions could provide some power plants with additional flexibility over MACT and permit continued operation. Current U.S. mercury emissions from coal-fired power plants total 48 tons. Multi-pollutant legislative proposals under consideration would require reductions to between 5.5 and 15 tons.
 4. **Carbon Dioxide (CO₂)** — No existing legislation requires reductions in carbon dioxide emissions from generating plants. However, since the United States signed the Framework Convention on Climate Change, numerous proposals have been made for the requirement for the reduction in greenhouse gas emissions, especially carbon dioxide emissions in the electric power sector. Currently, the electric power sector accounts for about one-third of all U.S. greenhouse gas emissions. Proposals to significantly reduce electric power sector greenhouse gas emissions would require a significant movement to less-carbon intensive technologies, such as renewables, nuclear power, and natural gas, and/or a reduction in electricity demand. Although research and development to sequester carbon is currently under way, a near-term technology breakthrough is unlikely. A requirement for the reduction in carbon emissions from the electric sector would likely require an unparalleled investment and is the greatest potential reliability risk of all of the environmental requirements mentioned here.
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ECAR

The bulk electric systems in the East Central Area Reliability Coordination Agreement (ECAR) will continue to perform well in meeting forecast demand obligations over a wide range of anticipated system conditions as long as established operating limits and procedures are followed and proposed projects are completed in a timely manner. Particular concern remains regarding the delay of the American Electric Power (AEP) 765 kV project in southeastern ECAR, which is needed to guard against potential widespread interruptions. The Region's criteria for resource adequacy will be satisfied through at least 2006. This assumes that capacity resources are available outside ECAR when needed, and that the average annual generating unit availability is maintained at or above levels experienced in recent years. After 2006, additional capacity beyond year-end 2002 levels will be needed to maintain resource adequacy. The actual amount of announced generation that is built will determine the adequacy of the generation resources beyond 2006.

As the industry moves toward increased competition, ECAR's membership is striving to meet the challenge of maintaining the adequacy and security of its bulk electric systems. ECAR continues to review and update its organizational structure, governance provisions, reliability assessment process, and technical documents and guides to ensure that reliability is maintained in the changing environment and that ECAR is in compliance with NERC Policies and Standards.

ECAR Assessment Process

Facility additions are planned by individual companies in ECAR. Regional reliability assessments are performed to determine the adequacy of the existing and future bulk power system to serve projected demand, given the proposed changes or additions to generation capacity and transmission facilities. The ECAR Generation Resources Panel and Transmission System Performance Panel perform assessments under direction of the ECAR Coordination Review Committee.

ECAR assessment procedures are applied to all generation and transmission facilities that might significantly impact bulk electric system reliability. These assessments consider ECAR as a single integrated system. The security impact of interactions with neighboring Regions is assessed by participation in several interregional groups such as MAAC-ECAR-NPCC (MEN), VACAR-ECAR- MAAC (VEM), and MAIN-ECAR-TVA (MET). Generation resource assessments of the ECAR systems on a Region-wide basis are performed annually for a planning horizon of up to ten years, and semiannual as-

sessments are made for the up-coming summer and winter peak demand seasons. Transmission assessments are performed regularly for selected future years out to the planning horizon and semiannually for the summer and winter peak demand seasons. If transmission deficiencies are discovered during this process, the member system with the deficiency is asked to explain what remedial action will be taken.

Demand

Throughout the assessment period, the peak total internal demand in ECAR is expected to continue to occur during the summer. These projected peak demands include demand that is connected to member transmission systems, even though non-member resources may supply the demand. A 1.9% average annual growth rate is expected during 2002– 2011, with a higher average annual growth rate of 2.4% during the first five years. This peak demand growth is based on forecast economic factors and average summer weather conditions, and as such, actual peak demands may vary significantly from year to year. Current resource plans developed by ECAR members project a reliance on direct-controlled and interruptible load management programs of about 2,800 MW by 2011. With interruptible loads and loads under demand-side management removed, ECAR's net internal demand is projected to reach 114,828 MW in 2011.

Capacity

ECAR's members develop ten-year capacity plans that reflect the capacity resources necessary to reliably serve demand and energy for their companies. In addition, a significant number of generation pro-

REGIONAL ASSESSMENTS

jects have been announced in the Region, by members and non-members alike. Since most of these projects are announced by non-members, they are not included in the members' capacity projections. When the announced capacity projects and member plans are combined, the net demonstrated generating capacity is projected to increase by nearly 8,000 MW during 2002. The total announced increase in generating capacity is more than 42,000 MW by 2011. Approximately 35,000 MW of this potential capacity increase from 2002 through 2011 is in the form of combustion turbines and combined-cycle plants projected to operate on natural gas.

Resource Assessment

ECAR annually conducts an extensive probabilistic assessment of long-term capacity margin adequacy. It considers the Regional peak demand profile and the generation availability of ECAR members to assess ECAR-wide reliability against a criterion of one-to-ten days per year of dependence on supplemental capacity resources. Supplemental capacity resources may include assistance from neighboring Regions, contractually interruptible demands, and direct control load management.

The construction status of many near-term capacity projects is not known until they are nearly in service, and later projects are not yet under construction. This makes for uncertainty regarding the timing and amount of new capacity additions, and consequently, the expected ECAR capacity margins. Capacity margins in ECAR that include the announced additions after 2002 would range from a low of 20% in 2002 to a high of 32% in 2006, declining to 26% in 2011 based on net internal demand. Capacity margins exclusive of announced additions after 2002 decline over the next ten years from a high of 20% in 2002 to a low of 5% in 2011, based on net internal demand.

The magnitude of the variation in expected capacity margins illustrates the uncertainty faced by ECAR in assessing the ability of the market to supply new generation resources, since some but not all of the announced additions are likely to be built. The analysis carried out in the ECAR assessment does not include announced capacity after 2002, but instead indicates what amount of such capacity might

be needed to achieve an acceptable level of reliability.

The ECAR assessment indicates that through 2006, there will be no additional need to supplement the capacity presently in service or under construction. This assumes that capacity resources are available outside ECAR when needed and that the average annual generating unit availability is maintained at or above levels experienced in recent years. ECAR has not explicitly analyzed the amount of capacity needed to meet the ECAR reliability criteria beyond 2006.

ECAR believes that aging generating capacity will necessitate increased maintenance and lengthened outages. By the year 2011, about 74% of the capacity in ECAR in service at year-end 2002 will be 30 or more years old, and about 39% will be 40 or more years old. ECAR members recognize the challenges in maintaining the high levels of generation availability experienced in recent years.

Coal is the predominant fuel used within ECAR, fueling 68% of the generating capacity in 2002. Many ECAR members are in the process of retrofitting selective catalytic reduction equipment to meet NO_x compliance requirements. The potential need for extended spring and fall planned outages between now and 2004 to accommodate these retrofits may present an additional reliability challenge for the Region. However, ECAR anticipates that all members will fully comply with the NO_x requirements by the target date.

Transmission Assessment

The transmission networks in ECAR are expected to meet adequacy and security criteria over a wide range of anticipated system conditions as long as established operating procedures are followed, limitations are observed, and critical facilities are placed in service when required. The Michigan systems are in the process of completing the installation of phase angle regulators (PAR) in the interconnections between the Detroit Edison and Ontario systems, but the PARs are not expected to be fully operational until winter 2002/03. With the PAR addition, the power flows circulating around Lake Erie that have often limited the ability of the Michigan systems to receive firm purchases from Ontario can be con-

trolled to improve the transfer capability across the NPCC-ECAR interface. Throughout ECAR, local transmission overloads are possible during some generation and transmission contingencies. However, ECAR members use operating procedures to effectively mitigate such overloads. Current plans call for the addition of about 155 miles of extra high voltage (EHV) transmission lines (230 kV and above) that are expected to enhance and strengthen the bulk transmission network. Included in these planned additions is the American Electric Power (AEP) 765 kV project, originally scheduled for service in May 1998. The Wyoming-to-Jacksons Ferry 765 kV line portion of this project is now expected to be completed by June 2006. A tri-regional assessment of the reliability impacts of this project concluded that a reliability risk exists due to its delay. Although operating procedures can minimize the risk of widespread interruptions, the likelihood of such power outages will increase until the project is completed. As noted above, significant amounts of new generation have been proposed in ECAR over the next ten years. Depending on specific dispatch patterns of this new and existing generation, the full output of this new generation will not be attainable without exceeding transmission limitations.

Operations Assessment

ECAR is in the process of transitioning from the existing reliability coordinators (previously called security coordinators) to new reliability coordinators and has taken actions to insure that the reliability of the transmission systems in the Region is maintained during this transition. Previously, the ECAR MET reliability coordinator monitored power flows in the southern, central, and western areas of ECAR. The Midwest ISO now monitors some of the control areas that were monitored by the ECAR MET reliability coordinator; some are now monitored by TVA; and some continue to be monitored by the ECAR MET reliability coordinator. Previously, the ECAR East reliability coordinator monitored power flows in the eastern area of ECAR. One control area that was previously monitored by the ECAR East reliability coordinator is now monitored by PJM. Effective May 1, 2002, the other two control areas will be monitored by the ECAR MET reliability coordinator and the ECAR East reliability coordinator will cease to exist. Previously, the ECAR North reliability coordinator monitored power flows in the north-

ern portion of ECAR. The Midwest ISO now monitors the power flows within the northern portion of ECAR and the ECAR North reliability coordinator ceased operating. At the end of the transition period, the ECAR MET reliability coordinator will also cease to exist and the RTO/ISOs or other entities will perform the reliability coordinator functions for all of the ECAR control areas.

ECAR membership currently consists of 18 full members and 30 associate members serving more than 38 million people in a 194,000 square mile region covering all or part of the states of Michigan, Indiana, Kentucky, Ohio, Virginia, West Virginia, Pennsylvania, Maryland, and Tennessee.

REGIONAL ASSESSMENTS

ERCOT

In 2002, the Electric Reliability Council of Texas (ERCOT) will complete its first full year of operation as a single control area Region and Interconnection, continuing open access to the transmission system for wholesale transactions and enabling retail customers to choose their electric suppliers. Although there have been challenges in operating new control systems under a unique market design, ERCOT has been successful in maintaining a secure and adequate electric system.

After a reduction in summer peak demand from 2000 to 2001 due to milder weather and a slow down in the economy, it is expected that 2002 demand will rebound to the level experienced in 2000. Demand is projected to increase around 4% each year in the near term and drop back to a 2.5–3% growth in the long term of the 2002–2011 assessment period.

Approximately 6,000 MW of new generating capacity began operating in 2001. Of this new capacity, 915 MW was wind powered, with the balance being natural gas fueled. The ERCOT market continues to attract new generation projects with an additional 7,200 MW of new generation planned to start operation in 2002. Summer capacity margins for 2002 are expected to be 23.6%. Although announced additional capacity declines after 2004, short lead times for new generation should enable new capacity needed by the market to be built in this assessment period to maintain adequate margins. In addition, ERCOT is implementing capabilities in its systems that will allow loads to respond to the market and act as resources by reducing their demand.

A number of major transmission projects will be completed during this assessment period. These projects will help relieve problems that prohibit unconstrained operation of generation in ERCOT. These constraints limit imports into the Dallas-Fort Worth and Houston demand centers from the south and west. The long lead times and difficulty in building new transmission facilities will likely require implementation of ERCOT Congestion Management Procedures on an ongoing basis during the period.

Demand and Energy

In 2001, ERCOT experienced a summer with milder weather than the previous year in conjunction with an economic downturn. As a result, ERCOT summer peak demand decreased from 57,606 MW in 2000 to 55,201 MW in 2001, a 4.2% decrease. For the period 1991 to 2000, demand had been increasing an average of 4.3% per year.

Between 2000 and 2001, the actual ERCOT energy consumption dropped from 288,713 GWh to 278,226 GWh, a 3.6% decrease. For the period 1991 to 2000, the compound annual growth rate had been 3.5%.

ERCOT forecasts are compiled from members' forecasts that are based on 30-year historical average temperatures. The average annual growth rate in ERCOT's summer peak demand is projected to be 3.4% during 2002–2011. The projected annual growth for energy is 3.2%. In last year's

assessment, the average annual growth rate for both demand and energy was expected to be 2.7%. The increase is due to the expected recovery from the economic downturn. The downturn was not factored into last year's 2001–2010 forecasts.

ERCOT has two DC ties to the Eastern Interconnection and one to Mexico with a total capacity of approximately 856 MW. About 190 MW may be used to transfer output of a power plant in ERCOT partially owned by utilities in the SPP Region to those utilities. There are two entities in ERCOT that are forecasting purchasing approximately 115 MW over the ties for the assessment period. The usage trend of the ties appears to be due to increasing purchases from outside ERCOT for economy energy rather than to meet capacity needs.

Resource Assessment

ERCOT has historically had a planning reserve margin requirement of 15%, which equates to a capacity

margin of 13%. A recently completed reliability study indicates that level of margin should provide about a one-day-in-ten-year loss of load expectation, which is a generally used industry standard. ERCOT, in conjunction with the Public Utility Commission of Texas, is determining what mechanisms may be needed to maintain adequate margins going forward in the new deregulated market environment.

Due to the short lead time required to construct new generating plants, ERCOT does not maintain a new generation forecast beyond 2007. Assuming a conservative outlook, counting only new generation capacity that has actually executed an interconnection agreement with a transmission provider and excluding DC tie imports (856 MW) and capacity that can be switched out of ERCOT (1,726 MW), capacity margins in ERCOT are expected to be 23.6% in 2002 and decrease to 14.7% in 2006, still above the 13% level. If the DC tie import capability and the switchable capacity is included, 2006 capacity margins would be 17.4%. Based on this assessment, ERCOT expects to have adequate resources through 2006 with ample opportunity for the market to do what is necessary to maintain that adequacy through 2011.

In addition, ERCOT is putting structures and systems in place that will allow demand to act as a resource (by voluntary interruption) and participate in the market. Demands acting as resources can currently provide certain ancillary services in ERCOT and programs that will allow and encourage loads to respond to market prices are being developed. The exact amount of demand that will participate is not known at this time, but it is expected to grow in the coming years as the ERCOT market develops.

Between 2002 and 2004, over 14,000 MW of new generating capacity is expected in ERCOT. Wind turbines will account for 485 MW of this capability with the balance being natural gas-fueled generation. No natural gas-fuel supply or deliverability problems are anticipated in ERCOT that will significantly impact operation of the new or existing natural gas-fueled generation.

Transmission Assessment

The major transmission constraints in ERCOT deal with transferring energy into the Dallas-Fort Worth

and Houston demand centers. Most new and relatively economical generation coming on line in the past years has been located outside these areas due to environmental and economic considerations. The long lead time to build transmission compared to generation has resulted in constrained transfers into these areas on the existing system. There are also local constraints in west Texas mainly due to the large amount of wind generation added in the area in the last two years and the relatively weak existing transmission system in the area. ERCOT manages this congestion by a market-based generation redispatch when possible and direct redispatch instructions when necessary.

ERCOT directs and supports several regional planning groups that have looked at these and other transmission issues and have proposed solutions. These solutions include new facility construction and special protection systems, that, if necessary, activate when contingencies occur until new facilities can be constructed. Major 345 kV lines are under construction in west and south Texas that will address existing problems. These include the Morgan Creek-Red Creek-Comanche line in west Texas and the San Miguel-Pawnee-Coleto Creek line in south Texas. Numerous other projects are in the planning stage or under way that will address localized congestion issues. However, the problem of long transmission construction lead times will likely require a significant level of continued active congestion management by ERCOT throughout the assessment period.

Operations Assessment

ERCOT implemented a historic change in its operating structure on July 31, 2001 when it converted from ten traditional control areas within the interconnection to a single control area interconnection operating under a unique market structure. That transition was successful and the security of the ERCOT system was maintained.

Operational challenges during the assessment period are anticipated to center around transmission congestion management until additions to the transmission system can catch up with system needs. Congestion management could be complicated if significant amounts of generation located in ozone non-attainment areas, which are also demand centers, must be limited or shut down by 2005 due to NO_x

REGIONAL ASSESSMENTS

emission standards. The Dallas-Fort Worth area is particularly affected by these standards and is one of the most import-constrained areas in ERCOT.

ERCOT has 138 members and two adjunct members that represent independent retail providers, generators and power marketers and investor-owned, municipal and cooperative utilities, and retail consumers. It is a summer-peaking Region responsible for about 85% of the electric demand in the state of Texas. ERCOT serves a population of over 14 million in a geographic area of about 200,000 square miles with over 70,000 MW of generating capacity and 37,000 miles of transmission lines.

FRCC

The Florida Reliability Coordinating Council (FRCC) expects to have adequate generating capacity reserves and transmission system capability to meet the Regional reserve margin standard throughout the 2002–2011 assessment period.

FRCC members continue to operate and exchange information in an effort to maintain the reliability of the bulk electric system. As a Region of NERC, FRCC has developed a formal reliability assessment process by which a committee and working group structure is utilized to annually review and assess reliability issues that either exist or have potential for developing. This process determines what planning and operating studies will be performed during the year to address those issues. The results of these studies are utilized so that FRCC remains ready to meet the reliability needs of today's changing environment.

Assessment Process

FRCC members plan for facility additions on an individual basis. However, in addition to their own databases, they use data developed as a group under FRCC to assess the impact of neighboring systems and to adjust their plans accordingly. FRCC maintains powerflow, stability, and short-circuit databases for the use of FRCC and its members.

Annually, the existing and expected conditions within the Region are reviewed, both short and long term. Recommendations are made to the FRCC Engineering and Operating Committees regarding the studies that should be conducted by the working groups for the next year. These reliability studies encompass Regional generation and transmission adequacy and security including import/export capabilities.

Upon completion of the reliability studies, reports including results, conclusions, and recommendations are published. Then, actions taken to meet reliability criteria as a result of all study report recommendations are monitored.

FRCC has also developed a compliance program to ensure member and Regional compliance with FRCC and NERC Planning Standards and Operating Policies.

Demand and Energy

FRCC members use historical weather databases consisting of as much as 53 years of data for the weather assumptions they use in their forecasting models. FRCC is historically a winter-peaking

Region. However, because the Region is geographically a subtropical area, a greater number of high-demand days normally occur in the summer. Therefore, it is possible for the annual peak to occur in the summer.

The projected annual net peak demand and the energy growth rates for FRCC for the next ten years are 2.4% and 2.7% respectively. This represents a slight increase from last year. Demand growth projections have increased as a result of higher population growth estimates.

Resource Assessment

Reserve margins for the ten-year assessment period (2002–2011) are about the same as the FRCC reserve margins reported in last year's assessment report. Almost 80% of the demand in FRCC is served by IOUs that are required to plan a 20% reserve margin. FRCC, as part of its overall assessment of resource adequacy, determines reserve margin for both summer and winter, based on system conditions at the time of the system seasonal peaks. These system peaks are assumed to be in January and August for planning and assessment purposes. The reserve margin is determined by utilizing the net of the total peak demand (which includes the projected effects of conservation) minus the effects of exercising load management and interruptible loads during the peak demand periods. FRCC members are projecting the net addition (i.e., additions less removals) of 17,391 MW of new capacity over the next ten years. Of this, 14,895 MW are projected to be natural gas-fired combined cycle.

REGIONAL ASSESSMENTS

The increased reliance on generation that requires a short build time, such as combined-cycle and combustion turbine units that burn natural gas, is evident in the assessment. This technology gives the demand serving entities considerable flexibility in reacting to a dynamic marketplace in today's changing and competitive environment. This changing environment will continue to place more emphasis on increased efficiency of existing units. A number of the older existing units are being re-powered in combined cycle configuration burning natural gas with increased capability. Fuel contracts are in place to meet the requirements of all existing and near-term planned generation. Contracts for long-term planned generation will be in place before the units become commercial. FRCC does not foresee any problems with fuel supply adequacy during peak periods.

More than 1,796 MW of existing merchant plant capability exists in the Region, with an additional 2,310 MW scheduled to come in service by January 2003. However, the amount that may come on line in the next ten years is dependent on a number of factors that are not capable of being forecasted at this time. These include the results of contractual negotiations for the sale of the announced capacity, transmission interconnections and/or service requests and associated queuing issues, merchant plants, and federal, state and local siting requirements.

Transmission Assessment

FRCC has completed a Transmission Protection Adequacy Review Study. The study concluded that the interconnected transmission systems in the Region meet the performance requirements for all contingencies studied.

Transmission studies were performed by FRCC for the 2002 summer period and for 2002–2011. The studies showed that operational procedures such as generation re-dispatch, sectionalizing, planned load shedding, reactive device control and transformer tap adjustments successfully mitigate all the reportable demand and voltage violations appearing in the first five years. In the long term, violations of criteria can be resolved by planned transmission projects where there is adequate time to monitor trends and construct required network upgrades. None of the

problems are considered significant to the reliability of the system. Individual members plan to construct 503 miles of 230 kV and 36 miles of 500 kV transmission lines during the 2002–2011 assessment period.

Interregional transmission studies are performed to evaluate the transfer capability between the Southern subregion of SERC and FRCC. Joint studies of the Florida/Southern transmission interface demonstrate there is adequate capability for additional power imports into FRCC over and above the 1,623 MW currently being imported on a firm basis.

As regional transmission organizations are formed, FRCC will update processes and procedures to ensure complete transmission system assessment. In fact, FRCC and GridFlorida are already working together to insure a smooth transition to the new structures.

Operations Assessment

FRCC has reliability coordinator agents who monitor real-time system conditions and evaluate near-term operating conditions. FRCC has a detailed security process that gives the reliability coordinator agents the responsibility and authority to direct actions to ensure the security of the Region's bulk electric system.

The reliability coordinator agents use a Region-wide security analysis program and a "Look-Ahead" program to evaluate current system conditions. These programs use databases that are updated with data from operating members on an as-needed basis throughout the day. The procedures in the security process are periodically evaluated and updated to ensure Regional reliability, conformance to FRCC procedures and standards, and adherence to NERC Standards and Policies.

FRCC membership includes 32 members of which 12 operate control areas in the Florida Peninsula. FRCC membership includes investor-owned utilities, cooperative systems, municipals, power marketers, and independent power producers. The Region covers about 50,000 square miles.

MAAC

Generation resources are expected to be adequate in the Mid-Atlantic Area Council (MAAC) during the next ten years. Consistent with the MAAC Reliability Principles and Standards and in accordance with the PJM Open Access Tariff, PJM is currently evaluating generator interconnection requests for over 50,000 MW of new generating capacity expected by 2007. MAAC believes that sufficient capacity will be added to meet the MAAC adequacy objective that the probability of demand exceeding available resources will be no greater, on the average, than one day in ten years.

Based on identified system enhancements, the bulk transmission capability over the next five years is expected to meet MAAC criteria requirements. In addition to the direct connect transmission facilities associated with new generating capacity, several transmission reinforcement projects are expected to be in service by 2005. Other transmission projects are also being evaluated by PJM through the PJM Regional Transmission Expansion Planning Process. It is reasonable to expect sufficient transmission will be added to meet MAAC criteria.

MAAC and the PJM ISO

MAAC is unusual among reliability councils in that it encompasses only one control area — the PJM Interconnection, L.L.C. (PJM). PJM operates the transmission system in all or part of Pennsylvania, New Jersey, Maryland, Delaware, Virginia, and the District of Columbia and is subject to the jurisdiction of the FERC.

PJM is the second largest centrally dispatched electric control area in North America and the fourth largest in the world. PJM became the first operational ISO in the United States on January 1, 1998, administering the PJM Open Access Transmission Tariff and managing the PJM Energy Market. The Operating Agreement established PJM as an ISO, governed by an independent Board of Managers.

PJM and PJM West

On April 1, 2002, Allegheny Power, the energy delivery business of Allegheny Energy, Inc., joined PJM thus expanding PJM's geographical boundaries and market through the creation of PJM West. This agreement fostered the development of a more robust regional power market. PJM will provide transmission service to all market participants in accordance with the requirements of FERC Order 2000, while simultaneously expanding the PJM market. The arrangement will, for the first time, expand the PJM power system management concepts beyond a single control area to create a significantly larger energy market, the PJM RTO.

Allegheny Power delivers energy to three million people in parts of Maryland, Ohio, Pennsylvania, Virginia, and West Virginia.

Development of PJM West expands the Mid-Atlantic energy market but not the MAAC Region. PJM West remains part of ECAR. PJM's expanded scope demonstrates the ability of its energy market and congestion management systems to function over multiple control areas and under multiple Regional Reliability Council reliability standards. The PJM West arrangement is open to, and structured to accommodate, additional energy delivery participants. Duquesne Light Company, American Electric Power, Commonwealth Edison, Illinois Power, and Dayton Power & Light have also made their intentions public to join PJM West in the near future. Dominion Virginia Power will also join as PJM South.

MAAC Agreement and Membership

MAAC operates under an agreement that became effective January 1, 2001 and is available for review on the MAAC web site at www.maac-rc.org. Major changes from the previous MAAC Agreement include:

- All PJM Operating Agreement signatories (200) are now automatically members of MAAC, which provides a more direct link of the MAAC and NERC reliability standards to all entities involved in PJM.

REGIONAL ASSESSMENTS

- The Administrative Board replaces the MAAC Executive Board and a MAAC Members Committee has been formed.
- An independent Compliance Monitoring and Enforcement Unit has been formed to handle NERC Standards compliance.

Market Structure

Implementation of the PJM Open Access Transmission Tariff on April 1, 1997, facilitated the emergence of PJM's Regional, bid-based energy market, the nation's first. PJM has become one of the most liquid and active energy markets in the country. PJM enables participants to buy and sell energy, schedule bilateral transactions, reserve transmission service, secure fixed transmission rights (FTR), schedule ancillary services, and participate in the installed capacity markets, the regional transmission expansion planning process and OASIS. PJM provides market settlement and billing services for all of these functions.

MAAC Assessment Process

Transmission assessments are performed regularly for selected future years over a ten-year planning horizon, and semiannually for the pre-seasonal horizon. If deficiencies are discovered during this process, the member with the deficiency is required to describe how the problem will be resolved. The necessary reserves to remain at a loss-of-load probability of one day in ten years are calculated annually for the entire ten-year planning horizon. A reserve requirement is then set for a planning period two years into the future.

The security impact of interactions with neighboring Regions is assessed by participation in MAAC-ECAR-NPCC (MEN) and VACAR-ECAR-MAAC (VEM) interregional reliability assessments.

PJM has an established, FERC-approved, regional transmission expansion planning process which ensures that the PJM, and hence, the MAAC bulk power system will be enhanced if MAAC reliability assessments or compliance to NERC Standards deem that system expansion is necessary.

Demand and Energy

MAAC is a summer peaking Region. The 2002 net peak demand and energy forecasts over the next ten years have increased in comparison to the 2001 forecasts. The 2002 net peak demand growth rate has grown to 1.6%, up from 2001's 1.5% growth rate. Geographic zone growth rates vary from 1.0 to 2.5%. The energy growth rate remains the same as last year at 1.5%.

Installed Generating Capacity Requirements

Generation resources are expected to be adequate in MAAC throughout the next ten years. Consistent with the MAAC Reliability Principles and Standards and in accordance with the PJM Open Access Tariff, PJM is currently evaluating generator interconnection requests for over 50,000 MW of new generating capacity expected by 2007. Although it is difficult to predict how many generation projects will actually make it on line, MAAC anticipates that sufficient capacity will be added to meet the MAAC adequacy objective. This objective insures that the probability of load exceeding available resources will be no greater, on the average, than one-day-in-ten-years.

One concern is the possible effects of EPA regulations requiring abatement of NO_x by 2003 in all states within MAAC. The extent to which meeting these regulations results in retirement of existing generating units or long outages of existing units for capital modifications will be closely monitored and evaluated over the next year.

Transmission Adequacy and Security Requirements

Based on identified system enhancements, transmission capability over the next five years is expected to meet MAAC criteria requirements. In addition to the direct connect transmission facilities associated with new generating capacity, several transmission reinforcement projects are expected to be in service by 2005. These projects are currently being evaluated through the PJM regional transmission expansion planning process. PJM evaluates all proposed transmission enhancements under this process in order to ensure that sufficient transmission will be added to meet MAAC criteria.

Capacity Additions and Transmission Planning

All developers who plan to install new generation or increase the capacity of existing capacity within PJM must request interconnection with the PJM transmission system and pay for any attachment facilities, local upgrades, and network upgrades necessary to accommodate the requested interconnection. Requests for interconnection are evaluated in the order in which they are received. Multiple milestones in the evaluation process allow a developer to decide whether or not to continue. If more than one generation addition causes the need to expand common equipment, the cost burden is shared.

MAAC members also rely on PJM to prepare a plan for the enhancement and expansion of transmission facilities to meet requests for firm transmission service. Based on data from the transmission owners and input from an advisory committee, PJM has the responsibility to prepare a Regional Transmission Expansion Plan that consolidates the transmission needs of the entire Region into a single plan for maintaining reliability. The plan is subject to approval by the PJM Board of Managers.

The MAAC staff coordinates the planning of generation to meet the PJM control area peak demand. They coordinate planning of the interconnected bulk power transmission system to deliver energy reliably and economically to customers. MAAC staff also conducts many specialized planning studies as needed within the pool and with surrounding systems.

Operations Responsibilities

The PJM staff forecasts, schedules and coordinates the operation of generating units, bilateral transactions, and administers the spot energy market to meet load and reserve requirements. To maintain a reliable and secure electric system, PJM monitors, evaluates, and coordinates the operation of over 8,000 miles of high-voltage transmission lines. The PJM OASIS is used to reserve transmission service. Operations are closely coordinated with neighboring control areas, and information is exchanged to enable real-time security assessments of the transmission grid.

PJM remains dedicated to meeting the reliability criteria and standards of the NERC and MAAC.

PJM provides market settlement services for energy, ancillary services, transmission services, fixed transmission rights, and capacity reserve obligations.

Economy in the operation of a system, composed of numerous generators, requires that the units be dispatched in order of increasing marginal bid price regardless of their ownership or location relative to system demand.

MAAC serves over 22 million people in a nearly 50,000 square mile area in the Mid-Atlantic Region. The Region includes all of Delaware and the District of Columbia, major portions of Pennsylvania, New Jersey, and Maryland, and a small part of Virginia. MAAC comprises less than 2% of the land area of the contiguous United States but serves 8% of the electrical demand. There are 200 members of MAAC.

REGIONAL ASSESSMENTS

MAIN

Within the Mid-America Interconnected Network (MAIN) generation resources are expected to be adequate over the next ten years based on current demand forecasts. Planning for the integration of new generation into the transmission grid and transmission reservations, particularly in regard to roll over rights, continues to be a major challenge.

For the planning horizon, MAIN expects its transmission system to perform adequately with the proposed reinforcements completed on schedule.

MAIN continues to be a reliability coordinator and an OASIS node, performing real-time monitoring to ensure reliability.

Assessment Process

The MAIN Planning Committee, its subcommittees, and working groups play key roles in the assessment process.

The MAIN TTFSC (Transmission Task Force Steering Committee) directs model development efforts and conducts near-term and long-term transmission assessment studies as directed by the MAIN Planning Committee. The neighboring Regions ECAR, MAPP, SPP, SERC West and TVA — participate in these studies to assess MET (MAIN-ECAR-TVA), MMS (MAIN-MAPP-SPP), and MAIN-SERC West interfaces. The TTFSC also prepares Regional transmission assessments for the upcoming peak periods based on these studies and assessments for the ten-year planning horizon as well as assessments provided by transmission owners to MAIN as a part of compliance requirements for the NERC Planning Standards.

The MAIN Guide 6 Working Group reviews long-term Regional capacity and reserve requirements annually with input from the MAIN Load Forecasting Working Group. The MAIN Operating Reserve Subcommittee continually reviews operating reserve requirements and procedures.

During each spring, independent review teams audit MAIN members who serve native load in the Region. This audit is conducted in order to determine the adequacy of power supply resources for meeting the upcoming summer peak demand and reserve requirements.

Demand and Energy

MAIN projects its summer peak demand for 2002–2011 to increase at an average peak annual rate of about 1.7%, the same forecast rate as last year. This projection assumes average weather conditions and economic growth. The actual 2001 peak demand in MAIN was 55,675 MW.

MAIN's projected annual growth rate of electrical energy usage for 2002–2011 is about 1.4%, the same forecast rate as last year. Actual energy use in MAIN for 2001 was 271,053 GW. The forecast peak demand for 2011 is 66,065 MW, with a projected energy requirement of 306,680 GW.

Resource Assessment

More than 4,900 MW of new capacity resources are scheduled to be in service within MAIN during the first half of 2002. Given this large increase in capacity, long-term reserve margins for MAIN as a whole are expected to be well within the MAIN requirement of 17 to 20% (14.5 to 16.7% capacity margin). The majority of planned capacity additions in MAIN are short lead-time gas-fired combustion turbine peaking units owned by IPPs, and much of their output is sold on a short-term basis.

MAIN is expected to have adequate installed generation capacity to meet its criterion of one-day-in-ten-years loss-of-load-expectation for the next ten years. This is based on the projected reserve margins for MAIN, the assumption that adjacent Regions carry the same average level of reserves, and that MAIN has access to these reserves.

MAIN's present capacity is 61,617 MW with a mix of 47% coal, 22% nuclear, 25% gas, 3% oil, and 3% other. MAIN's capacity in 2011 is projected to be 77,091 MW, with 83% or 12,876 MW of the new generation being natural gas-fired simple and combined cycle. The resulting capacity mix for 2011 is projected to be 40% coal, 18% nuclear, 37% gas, 2% oil, and 3% other.

Transmission Assessment

For 2002 summer, MAIN expects import capabilities from surrounding Regions to be adequate, except for certain imports into Wisconsin and Iowa, which are judged to be marginally adequate. The MAIN bulk electric transmission system generally appears to have no major limitations and is expected to perform adequately over a wide range of system conditions. However, parallel path flows have frequently restricted transfer capabilities into and within Wisconsin. Additionally, certain EHV facilities in southern MAIN experienced heavy loadings resulting in transmission loading relief (TLR) requests in the past. These heavy loadings were in part due to parallel path flows occurring during large north-to-south power transfers from and across MAIN. Consequently, MAIN members will continue to closely monitor these EHV lines in southern MAIN and the historically constrained MAPP-to-MAIN interface.

For the planning horizon, MAIN expects its transmission system to perform adequately if planned reinforcements or some equivalent of these plans are installed. This assessment is based on historic and current analyses used to judge compliance with NERC Planning Standards I.A.S1 through I.A.S4. All MAIN transmission owners provided assessments for their systems. Specifically, for Standards S1 and S2, MAIN transmission owners assessed 2003 summer and 2007 summer conditions as requested by MAIN; some owners also included assessments of other time periods and in-house studies. For Standards S3 and S4, MAIN made its assessment using the MAIN Future System Study for 2004 summer conditions, the MAIN Extreme Disturbance Study for 2002 summer conditions, a Regional study for December 31, 1999, and assessments from in-house studies provided by MAIN transmission owners.

For all four standards, the assessment was more specific for the near-term period than for the longer-term period. The less specific long-term assessment is appropriate due to the increased uncertainty involved. It is anticipated that RROs and RTOs will reduce the level of uncertainty by further coordinating planning activities.

The MAIN Future System Study Group has performed a 2007 summer interchange capability study.

System enhancement plans related to planning standards compliance and for other reasons (aging facilities, in-house criteria, demand growth, IPP connections, parallel path flow concerns), including major reinforcements that may impact the adequacy of MAIN's transmission system in the planning horizon, include the following:

- Capacitor bank additions for local area voltage support, installation of new and/or upgrade of 69, 115, 138, 161, and 230 kV lines, and installation of transformers to alleviate local loading concerns, or to improve transfer capabilities.
- Second Rush Island-St. Francois 345 kV line (2003)
- Callaway-Franks 345 kV line (2004)
- Loose Creek-Jefferson City 345 kV line (2005)
- Weston (MAIN)-Arrowhead (MAPP) 345 kV Project (2005)
- Morgan-Werner West 345 kV line (2007)
- Second Burnham-Taylor 345 kV line (2004)
- Second Pleasant Valley-Silver Lake 345 kV line (2004)
- Cahokia-Dupo 345 kV line (2004)
- Oak Creek-Brookdale 345 kV line (2007)
- Brookdale-Granville 345 kV line (2007)

REGIONAL ASSESSMENTS

- Pleasant Prairie-Libertyville 345 kV line (2011)

Some MAIN transmission owners have been experiencing delays in obtaining regulatory approval and permits, and rights-of-ways for expansion of the transmission grid. These delays could impact the assessment provided at this time and may require implementation of other reinforcement alternatives including operating measures.

The impact of new merchant generation within MAIN is studied on a continuing basis by the respective transmission provider pursuant to the applicable open-access transmission tariff. Uncertainties regarding these generator installations, the formation of new RTOs and their impact on the overall planning process, and coordination of transmission service roll-over-rights offer further challenges. Furthermore, long-term planning assessments are somewhat dependent on the market's reaction to the formation of new congestion management techniques and market designs within the burgeoning RTO structure. A lack of coordination of these factors would greatly affect this assessment.

Operations Assessment

During 2001, MAIN certified three new control areas and is now in the process of re-certifying existing control areas.

MAIN is a reserve sharing group (RSG) and all control areas within the Region share reserves in order for the RSG to comply with the NERC Disturbance Control Standard. The MAIN Reserve Sharing System (RSS), which was developed in-house, continues to be an accurate and reliable tool for implementing the RSG process.

MAIN continues to be a reliability coordinator and an OASIS node for its members who have not joined an RTO. MAIN conducts real-time monitoring of flowgates, bus voltages, and system frequency to ensure reliability. MAIN continues to provide congestion management through the NERC TLR process in accordance with the NERC Operating Policies.

On a daily basis during the peak summer months, the MAIN center conducts a morning security

conference call that enables entities from across the Eastern Interconnection to communicate current and anticipated operating conditions.

Most MAIN coal-fired generation owners are modifying their generating units to comply with NO_x regulations. This poses several concerns that include the simultaneous outages of units to allow for installation of the NO_x control devices, potential unit deratings during operation of these devices, and higher forced outage rates caused by the NO_x retrofits. It is expected that the addition of new gas generation into the Regional mix will reduce the impact of any simultaneous outages or deratings resulting from restrictions. New regulations involving multi-pollutant control strategies for SO₂, NO_x, and mercury may have an additional impact on the operation of coal-fired generators.

The 38 members and seven associate members of MAIN include 17 control areas and other organizations involved in Regional energy markets. MAIN is a summer-peaking Region serving a population of approximately 20 million in a geographic area of about 150,000 square miles. MAIN encompasses portions of Iowa, most of Illinois, the eastern third of Missouri, the eastern two-thirds of Wisconsin, and most of the Upper Peninsula of Michigan.

MAPP

For the period 2004–2011, currently projected capacity reported in the Mid-Continent Area Power Pool (MAPP) U.S. region is below MAPP requirements for reserve capacity obligations, but MAPP does not expect any capacity deficits to occur during the next ten years. If demand forecast uncertainty is taken into account, the Region may be below its reserve requirement by 2004 summer and 4,626 MW below the requirement by 2011 summer. MAPP-U.S. utilities have committed to provide an additional 2,800 MW of new generation during this period. Most utilities in the Region propose to install natural gas-fired combustion turbines with short construction lead time to meet capacity obligations.

The MAPP transmission systems are adequate to meet the committed needs of the member systems and will continue to meet reliability criteria throughout the period. The system is expected to be highly utilized due to continuing power marketing activity, and is expected to be managed within its secure limits, which may not meet all market needs. Current MAPP studies identified the need to monitor additional facilities and define new flow gates. Potential restrictions to energy transfers have emerged as bi-directional between Iowa and Illinois as well as the previously realized limitations from the Twin Cities (Minneapolis-St. Paul) area to Iowa and Wisconsin.

MAPP Assessment Process

The MAPP Reliability Council, Regional Reliability Committee, and the Regional Transmission Committee direct the annual assessment of adequacy and security through working groups. The Transmission Reliability Assessment and Composite System Reliability Working Groups jointly prepare the MAPP ten-year Regional Reliability Assessment. The Reliability Studies, Design Review, Transmission Operations and Planning Subcommittees are committed to reviewing MAPP reliability from near-term and long-term perspectives to ensure the MAPP system can meet the needs of its members.

Demand and Energy

The MAPP-U.S. and MAPP-Canada combined 2001 summer non-coincident peak demand was 33,690 MW, a 3.9% increase over 2000, and 2.4% above the 2001 forecast (32,906 MW).

MAPP-Canada was 0% above the 2000 actual demand and 0.6% below the 2001 forecast.

MAPP-U.S. was 3.7% above 2000 actual demand and 3.6% below the 2001 forecast. The MAPP-U.S. summer peak demand is expected to increase at an average rate of 1.9% per year during the 2002–2011 period, as compared to 1.9% predicted last year for the 2001–2010 period. The MAPP-U.S. 2011 non-coincident summer peak demand is projected to be

33,734 MW. This projection is 1.3% above the 2010 non-coincident summer peak demand predicted last year.

Annual electric energy usage for MAPP-U.S. in 2001 (144,893 GWh) was 0.7% below 2000 consumption and 2.7% below the 2001 forecast.

Resource Assessment

Generating resources for MAPP-Canada are forecast to be adequate over the ten-year period. In addition, when a 3% demand forecast uncertainty is taken into account, the MAPP-Canada area may have capacity surplus of as much as 2,074 MW by 2011 summer. MAPP-Canada will provide an additional 915 MW of new generation for the period of 2002–2011.

Current planned capacity reported in the MAPP-U.S. region is below MAPP requirements for reserve capacity obligations during 2004–2011. The MAPP Agreement obligates the member systems to maintain reserve margins at or above 15%, which is equivalent to a 13.04% minimum capacity margin requirement. The summer reserve margin is forecast to decline from a high of 22.8% in 2002 to 13.3% in 2004 and 3.5% in 2011. In addition, when a 3% demand forecast uncertainty is taken into account, the MAPP-U.S. area may be capacity deficient by 2004 summer and nearly 4,626 MW deficient by 2011 summer. MAPP-U.S. will provide an

REGIONAL ASSESSMENTS

additional 2,800 MW of new generation for the period of 2002–2011.

MAPP's Regional Plan has reported over 7,000 MW of new generation planned for construction during 2001–2010. This discrepancy between the MAPP Regional Plan and the data used in this report may be due to the fact that members may not have reported merchant or other generation not yet sited through the data collection process used to prepare the NERC assessment report. Therefore, for the next ten-year period, the MAPP capacity margins will likely be higher than those shown above.

Although planned capacity reported in the MAPP U.S. region is below MAPP requirements for reserve capacity obligations, MAPP believes that no capacity deficit will occur during the ten-year period. MAPP has requirements for reserve capacity obligations with financial penalties and continually monitors member reserve margins. This mechanism ensures that members plan for adequate capacity to meet their expected demand.

Transmission Assessment

The existing transmission system within MAPP-U.S. is comprised of 7,240 miles of 230 kV, 5,742 miles of 345 kV, and 343 miles of 500 kV transmission lines. MAPP-U.S. members plan to add 690 miles of 345 kV and 283 miles of 230 kV transmission in the 2002–2011 time frame. The MAPP-Canada existing transmission system is comprised of 4,578 miles of 230 kV and 130 miles of 500 kV transmission lines. MAPP-Canada is planning for an additional 267 miles of 230 kV during 2002–2011. MAPP U.S. and Canada have a total of 2,030 miles of HVDC lines.

MAPP members continue to plan for a reliable transmission system. Coordination of expansion plans in the Region takes place through joint model development and study by the Regional Transmission Committee. This committee includes transmission owners, transmission users, power marketers, and state regulatory bodies. The Transmission Planning Subcommittee, in cooperation with the five subregional planning groups, prepared the MAPP Regional Plan, 2000 to 2009, to address the needs of all stakeholders. A 2001 update to the plan was also prepared.

In general, the MAPP transmission systems are judged to be adequate to meet firm obligations of the member systems provided that the local facility improvements identified in the MAPP Regional Plan are implemented. MAPP continues to monitor the 19 flow gates within the Region that limit MAPP exports, and monitors four flow gates that maintain reliability levels for importing from the east.

Current studies of MAPP have identified potential restrictions on the transmission system for outages of certain 345 kV tie lines connecting the Twin Cities metropolitan area of Minneapolis–St. Paul to Iowa and Wisconsin areas, such as Prairie Island–Byron or King-Eau Claire. These outages may result in system stability restrictions that continue to limit energy transfers from the Twin Cities to Iowa and Wisconsin. The import restrictions due to facility loadings in eastern Iowa are thermal limitations.

A transmission system limitation has been identified in the eastern North Dakota–northern Minnesota area that will limit the ability to meet firm obligations in and through the area during winter peak conditions. A study is currently being conducted that will identify and recommend transmission system alternatives.

MAPP has seen a tremendous increase in power marketing activity resulting from open access and available low cost energy in the Region. This high level of activity has resulted in a higher utilization of the existing transmission system near its reliability limits to take advantage of market opportunities. MAPP members will continue to take a proactive role in the planning and operation of the system in a secure and reliable manner.

Operations Assessment

The MISO reliability coordinator is now fully operational with the implementation of real-time system monitoring of key flow gates, data collection at five-minute intervals, and near real-time pre-contingency analyses of system conditions. MAPP member systems jointly perform interregional and intraregional seasonal operating studies under the direction of the Transmission Operations Subcommittee to coordinate real-time operations. Subregional operating review working groups have been formed to deal with day-to-day operational issues such as

unit outages and schedule transmission system maintenance. The MAPP Reserve Sharing Pool continues to provide a benefit to the Region through the sharing of generation reserves during system emergencies.

MAPP membership includes 108 utility and non-utility systems. The MAPP Region covers all or portions of Iowa, Illinois, Minnesota, Nebraska, North and South Dakota, Michigan, Montana, Wisconsin, and the provinces of Manitoba and Saskatchewan. The total geographic area is 900,000 square miles with a population of 18 million.

NPCC

The continuing challenge to the Northeast Power Coordinating Council (NPCC) is the assimilation of new merchant generating capacity to ensure resource adequacy. These plants must be brought on line in a timely manner, and the transmission network must be sufficient to fully integrate this new generation.

Resource Assessment Process

NPCC has a comprehensive resource assessment program directed through NPCC Document B-08, “Guidelines for Area Review of Resource Adequacy.” This document charges the NPCC Task Force on Coordination of Planning (TFCP) to conduct periodic reviews of resource adequacy for the five NPCC control areas: the Maritimes area (New Brunswick Power and Nova Scotia Power, Inc.), New England (ISO New England Inc.), New York (New York ISO), Ontario (Independent Electricity Market Operator), and Québec (TransÉnergie). In undertaking each review, the TFCP will ensure that the proposed resources of each NPCC area will comply with NPCC Document A-02, “Basic Criteria for Design and Operation of Interconnected Power Systems.” The area must successfully demonstrate:

- its resource adequacy criterion and how it is applied
- resource requirements to meet the criteria for the time period under consideration
- interconnection assistance considered in determining its requirement
- how its resource criteria meet the NPCC criterion as follows:

“Each Area’s resources will be planned in such a manner that, after due allowance for scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring areas and Regions, and capacity and/or load relief from available operating procedures, the probability of disconnecting non-interruptible customers due to resource deficiencies, on the average, will be no more than once in ten years.”

To focus on the timely installation of capacity requirements, each area conducts an interim assessment of resource adequacy on an annual basis. A more comprehensive resource review is conducted on at least a triennial basis, and it is conducted more frequently as changing conditions may dictate.

The primary objective of the NPCC area resource reviews is to identify those instances in which a failure to comply with the NPCC “Basic Criteria for Design and Operation of Interconnected Power Systems” or other NPCC criteria could result in adverse consequences to another NPCC area or areas. If such problems are determined, NPCC informs the affected systems and areas, works with them to develop mechanisms to mitigate potential reliability impacts and monitors the resolution of the concern.

Area Resource Assessment

New England

New England will meet the NPCC resource adequacy criterion of one-day-in-ten-years loss-of-load expectation (LOLE) through 2011 assuming normal demand, the proposed transmission upgrades in southwest Connecticut are in service, and generating resource additions are integrated into the New England transmission system. However, at this time the moratorium placed upon all new transmission and generation projects in Connecticut by the state government has the potential to seriously impact future reliability in the state.

New England system (summer) peak demand is projected to be approximately 24,200 MW for 2002 and 27,750 MW for 2011, while installed generating capacity is projected to be approximately 28,000 MW for 2002 and 34,600 MW for 2011. The corresponding generation installed reserves range from approximately 16% in 2002 to 25% in 2011. The projected installed capability accounts for more than 5,500 MW of new generating units that have obtained interconnection approval and are under construction. However, it does not reflect any

generation retirements that may occur under a competitive market environment. The expected installed reserve values are more than adequate to meet the required reserve levels, projected to be less than 18%, during the 2002 through 2011 period.

The 2001 and 2002 ISO New England Regional transmission expansion studies have identified that there are severe reliability problems in southwestern Connecticut due to the inadequate capability to import power into southwestern Connecticut and the inability to move power around within that area. The peak demand in southwest Connecticut is forecast to be about 1.5 times the amount of total local generation throughout the 2002–2011 period. While the area continued to experience strong demand growth during the past decade, few transmission upgrades have been brought into service. Currently, there is minimal operating flexibility, especially when generating unit and transmission line outages occur in this area, or even for planned maintenance coordination. As a result, this region of Connecticut is highly dependent on power imports over the 115 kV transmission system and a 138 kV interconnection with Long Island, both of which are limited. Recognizing the transmission import limit into southwest Connecticut coupled with the type and age of the local generating units (average age is 30 years), there is a concern that demand would not be met under certain peak load, generation availability, and transmission constraint conditions.

To mitigate these problems, Northeast Utilities has proposed transmission upgrades to increase transmission import capability into southwest Connecticut. In addition to two new circuit breakers that were installed at the Long Mountain substation in late 2001, and the installation of capacitors at the Rocky River and Stony Hill substations this summer, a static VAR compensator will be installed at the Glenbrook substation in 2004, and other local transmission enhancements are planned. Also proposed are transmission improvements aimed at increasing transfer capability into the area. These improvements will be implemented in two phases. Phase I will include a new 345 kV transmission line linking the Plumtree and Norwalk substations, scheduled for late 2004; phase II will link the Besseck to Norwalk 345 kV circuit through the Devon and Pequonnock substations, scheduled for early

2006. The completion of these transmission upgrades will alleviate the projected reliability problems in southwestern Connecticut through an increase of over 1,100 MW of transmission import capability into the area (as compared with the current planning import limit of 1,850 MW).

Concerned with serving demand in southwest Connecticut during the summer of 2002, NEPOOL implemented an Emergency Capability Supplemental Program to augment the supply in that area. The Emergency Capability Supplement Program solicited 80 MW of demand side load reduction and/or supply-side temporary generation to be located in southwestern Connecticut towns. As a result, about 84 MW of demand reduction, new temporary peaking generation, and existing emergency generators were contracted for operation during summer 2002.

New York

The New York State Reliability Council (NYSRC) establishes the installed reserve margin for the New York control area. Currently, the NYSRC has determined that an 18% installed reserve margin is required to meet the NPCC and more stringent NYSRC resource adequacy criterion. Given current demand and capacity projections, New York will meet the NPCC resource adequacy criterion of one-day-in-ten-years LOLE through 2011 with the expected installation of approximately 1,100 MW of new generating capacity.

Existing capacity within New York and known purchases and sales with neighboring control areas are sufficient to meet the 18% installed reserve margin through the year 2004. Beyond the year 2004, New York is showing a deficiency in reported capacity to meet the 18% installed reserve margin. It is anticipated that the resources necessary to meet the required installed reserve margin will be procured through the installed capacity market of the NYISO. Currently, there are about 4,200 MW of new capacity with certification under the New York State Article X process. Additionally, part of the New York installed capacity market design allows “special case resources” (for example, distributed generation and interruptible load customers that are not visible to the NYISO Market Information System) to participate in the installed capacity market. These

REGIONAL ASSESSMENTS

customers thus become another source of capacity for the load-serving entities.

In addition to the statewide requirement, the NYISO imposes locational capacity requirements on load-serving entities located within New York City (NYC) and Long Island (LI) due to their geography, as described in the “Locational Installed Capacity Requirements Study,” NYISO, February 28, 2002. The load-serving entities within these localities must procure a percentage of their capacity requirement from resources located within the locality. The NYC locational capacity requirement is 80% of the demand level, and the locational capacity requirement is 93% of the demand level within the LI locality.

Ten LM-6000 gas turbines have recently been installed on Long Island, which coupled with the TransÉnergie 330 MW HVDC cable (currently under test), are projected to meet the LI locational requirement through 2008. Projected demand growth after then will require the addition of approximately 250 MW by 2011.

NYC may not meet locational capacity requirements beyond 2002 unless additional new resources within this locality become available. Through 2011, over 850 MW of new resources need to be established to meet the locational requirement portion of projected growth.

The following tables are excerpts from “List of Proposed Interconnections in the New York Control Area” updated August 21, 2002, posted on NYSIO’s web site ([nyiso.com-Services/Planning/Transmission Expansion and Interconnection/](http://nyiso.com-Services/Planning/TransmissionExpansionandInterconnection/)) and show those NYC and Long Island projects that list in-service dates.

Titan Smith Street	79.9	2003/S
Bay Energy Project	79.9	2003/S
Ramapo Energy	1100	2003/S
Astoria Energy	1000	2003/S
Gotham Power - Bronx I	79.9	2003/S
Berrians GT Replacement	79.9	2003/S
Fortistar VP	79.9	2003/Q2
Fortistar VAN	79.9	2003/Q2
KeySpan Ravenswood	270	2003/12
Maspeth	79.9	2003
Poletti Expansion	500	2004/Sp
Millennium 1	160	2004/S
Millennium 2	320	2004/S
East River Repowering	288	2004/09
Cross Hudson Project	550	2004
Liberty Gen Co, LLC	600	2005/05
Ravenswood Repowering Ph I	440	2005
Liberty Generation	400	2005
TransGas Energy	1100	2006
Astoria Repowering-Phase 1	499	2007
Astoria Repowering-Phase 2	800	2007

Project Name	Size (MW)	Proposed In-Service
NYC Energy LLC	79.9	2002/Q4
East Coast Power-Linden	70	2002-3
Redhook Energy	79.9	2003/Sp
CPN 3rd Turbine, Inc. (JFK)	45	2003/05

Table 2 — Proposed NYC Tie-line Projects

Project Name	Size (MW)	Proposed In-Service
Project Neptune DC PJM-NYC	600	2003
Linden VFT Inter-Tie Project	300	2004/06
Project Neptune DC NB-NYC	1200	2004
GenPower DC Tie-line	800	2004
Project Neptune DC PJM-NYC	600	2004
Jupiter PJM-NYC Cable	1200	2004
PJM-New York City HVDC	990	2005
PJM-Rainey HVDC	660	2005/12

Table 3 — Proposed Long Island Generation Projects

Project Name	Size (MW)	Proposed In-Service
PPL Kings Park	300	2003/Q4
Brookhaven Energy	580	2003/11
Spagnoli Road CC Unit	250	2004/S
Suffolk Power-Yaphank	255	2005/11
Wading River Gen Ext.	150	2005
Oceanside Energy Center	330	2005
SE Long Island	575	2005

Table 4 – Proposed Long Island Tie-line Projects

Project Name	Size (MW)	Proposed In-Service
CT-LI DC Tie-line	330	2002/10
Project Neptune DC PJM-LI	750	2003/S
NU CT-LI HVDC Cable	660	2004

Table 4 — Proposed Long Island Tie-line Projects

CT-Ruland, LI DC Tie	300	2006
CT-Pilgrim, LI DC Tie	300	2006

Ontario

Based on existing and proposed facilities, Ontario is expected to have a reliable supply of electricity during 2002–2011 under a wide variety of conditions. Opportunities also exist for additional transmission enhancements to improve the efficiency of the Ontario electricity market. Ontario expects to be in compliance with the NPCC reliability standard, based on a LOLE of one day in ten years, throughout the period.

Ontario's ten-year demand forecast was derived using an econometric forecasting model. The current forecast has an average annual growth rate of 0.9% over the forecast period compared with last year's forecast growth rate of 1.2%. Ontario has typically experienced its annual peak demand in the winter. However, in three of the last five years Ontario experienced its annual peak during the summer due to extreme weather conditions. Based on normal weather constructed from 30 years of historical weather data, the latest ten-year demand forecast suggests that Ontario will become a summer peaking area in 2008.

No long-term firm sales have been identified to the IMO for the next ten-year period.

Additional resources within Ontario are forecast to be required for reliability purposes beginning in about 2009. The aggregate amount of new merchant capacity proposed to come on line in the next ten years is about 6,200 MW.

No fuel supply issues have been identified for Ontario.

No significant transmission constraints are expected to persist for the ten-year period.

Major transmission proposals include:

REGIONAL ASSESSMENTS

- a new 230 kV, 845 MVA phase shifter on the Ontario-Michigan interconnection circuit L4D. The expected in-service date is January 2003.
- a new 1,250 MW interconnection between Ontario and Québec consisting of a 230 kV two-circuit line starting at the Hawthorne transformer station and ending at a new Outaouais converter station in Québec. Depending on regulatory approvals, the probable in-service date will be the third quarter of 2004.
- new merchant transmission marine cables between Ontario and a location to be determined in Pennsylvania or Ohio (or both), having a capability of up to 1,000 MW. The expected in-service date is the second quarter of 2004.

Interregional transmission transfer capability studies have been conducted, and there are no concerns with the level of imports required.

No major unit outages, transmission additions or temporary operating measures are expected in Ontario that may impact the ability of Ontario to meet NPCC reliability requirements for any extended periods over the next ten years. A number of generator outages are expected to be performed to incorporate modifications associated with various environmental requirements. These outages are generally reflected in the reliability models. No specific studies have been conducted to isolate the specific impact of local environmental or regulatory restrictions.

Québec

The new regulatory environment in North America has obligated most vertically integrated electricity companies to restructure their activities along basic operating segments: generation, transmission, and distribution. In keeping with this trend, Hydro-Québec has created four business divisions covering its core activities: Hydro-Québec Distribution, Hydro-Québec Production, Hydro-Québec TransÉnergie (in 1997), and Hydro-Québec Engineering.

For the near term, Québec projects adequate reserves to comply with the NPCC Resource Adequacy

Criterion of one-day-in-ten-years LOLE. From 2003 to 2008 more than 2,000 MW of generation capacity will be committed. Beyond 2006, uncommitted generation capacity continues to be studied, and proposals are being put forward.

Maritime Area (New Brunswick, Nova Scotia, and Prince Edward Island)

New Brunswick Power has sufficient capacity to meet its forecast demand and reserve requirements except for the winter 2006/07 period during the proposed Point Lepreau refurbishment. Sufficient capacity will be purchased to meet the requirements during this period.

The reserve criterion for the Maritimes area is 20%, and adherence to this criterion is demonstrated to comply with NPCC reliability criterion. As a result of the Sable gas fields, the Maritimes area now projects increasing use of natural gas for electricity generation throughout the study period, and, in some years, actually reducing projected electric consumption as heating load transfers to natural gas.

The required reserve for peak electrical capability is equal to the greater of the largest generating unit utilized on the NB Power system or 20% of the firm in-province peak demand. This required reserve is added to the peak forecast demand (which includes any firm system sales) to determine the total demand that must be met. The total demand is then compared with the sum of the committed supplies available from hydro, nuclear, fossil units, IPPs, and firm purchases to determine the surplus or deficit.

The latest NB Power demand forecast assumes that, beginning midway through 2005/06, natural gas will impact industrial electricity sales through customer self-generation projects. Although this will decrease peak demand, NB Power will be required to provide firm backup for this 150 MW. Although in this instance it is not included in the reported Net Internal Demand, NB Power will be required to carry reserve on the 150 MW; it is therefore added to the Net Internal Demand when calculating reserve requirement.

As discussed below, NB Power is currently considering two major development projects intended for completion within the ten year planning horizon.

All projects are subject to regulatory and environmental approval.

Coleson Cove Orimulsion(r) Conversion

This project consists of the conversion of the three 335 MW oil-fired units at the Coleson Cove Generating Station to use Orimulsion(r) as their primary fuel, as well as the addition of new environmental controls, including wet flue gas scrubbers. The key drivers for the project are the desire to meet the anticipated emission standards for SO₂ and NO_x and the low and stable cost of Orimulsion(r) fuel. Construction is expected to begin in the fall 2002, with an anticipated in-service date of November 1, 2004. It is anticipated that during most of the conversion, only one unit will be out of service at a time except possibly for the short period of time at the end of the project when the units and scrubbers will be tied together. The units will continue to burn oil until the scrubbers are in service. NB Power has submitted an application to the New Brunswick Public Utilities Board (PUB) for this refurbishment project, and the PUB has recommended that NB Power proceed. The proposed project is currently going through an Environmental Impact Assessment, and a final decision is expected shortly.

Point Lepreau Refurbishment

This project proposes to re-tube the nuclear reactor and refurbish other components as necessary to extend the life of the Point Lepreau Nuclear Generating Station to 2032. The project would require eighteen months to complete, with the unit out of service from April 1, 2006 to Oct 31, 2007. An application is presently pending before the PUB for this refurbishment project.

Second New England 345kV Interconnection

NB Power is proposing to construct, operate, and maintain a second 345 kV interconnection with the state of Maine. The proposed 60-mile line will connect the Point Lepreau Peninsula on the Bay of Fundy in New Brunswick to a point on the international border between Canada and the United States near Woodland, Maine. The proposal is presently going through the National Energy Board's regulatory process.

In addition to the above projects, existing generation within the NB Power service region was upgraded at NB Power's Courtenay Bay generating station, in October 2001. The 100 MW oil-fired unit number 3 was repowered with the addition of a 174 MW combustion turbine and now operates as a 263 MW natural gas-fired combined-cycle plant.

Transmission Assessment

The existing interconnected bulk electric transmission systems in New England, New York, Ontario, New Brunswick, and Nova Scotia meet NPCC criteria and are expected to continue to do so throughout the forecast period. For the ten-year period, currently planned transmission within NPCC includes 25 circuit-miles at the 230 kV voltage level, 60 circuit-miles at the 345 kV voltage level, and 362 circuit-miles of HVDC construction.

A summary of the major transmission projects currently being proposed within NPCC include:

- the reinforcement of the NPCC-ECAR interface with the addition of phase-angle regulating (PAR) transformers to the Scott-Bunce 120 kV circuit and the two Lambton-St. Clair 345 kV circuits. The Presidential Permit granting permission for the operation of the Ontario-Michigan phase-angle regulators was granted on April 19, 2001, but continuing failures of the PARs in circuits L4D and L51D have delayed operation; it is anticipated that the PARs will not be in service earlier than January of 2003.
- the Harbor Cable project, two bundled HVDC underwater cables, each with a 330 MW capability, for a total of 660 MW of transfer capability between Linden, New Jersey, in PJM and New York City. The TransÉnergie merchant transmission project is scheduled for energization in May of 2005.
- a new 1,250 MW interconnection between Ontario and Québec consisting of a 230 kV two-circuit line connecting the Hawthorne transformer station to a new Outaouais converter station in Québec. Depending on

REGIONAL ASSESSMENTS

regulatory approvals, the in-service date is expected to be the third quarter of 2004.

- new merchant transmission marine cables between Ontario and a location to be determined in Pennsylvania or Ohio (or both), having a capability of up to 1,000 MW. The expected in-service date is the second quarter of 2004.
- the Neptune Project, a merchant electricity transmission project proposed by the Neptune Regional Transmission System, designed to bring power from Canada and MAAC to New England and New York. FERC granted conditional approval of the project in July 2001. The Neptune project, to be developed in four stages, would link 1,200 MW interconnections in New Jersey and Maine with interconnections in Boston, New York City, Long Island, and Connecticut. Ultimately, the project would allow the transmission of 3,600 MW of power from Maine and Canada to the northeast as well as another 1,200 MW of power from PJM to New England and New York.
- a second 345 kV interconnection between the province of New Brunswick and the state of Maine. The proposed line will be approximately 95 km in length and connect the Point Lepreau Peninsula on the Bay of Fundy in New Brunswick to a point on the international border between Canada and the United States near Woodland, Maine.
- a new 345 kV transmission line linking the Plumtree and Norwalk substations in New England, scheduled for late 2004, and the connection of the Beseck to Norwalk 345 kV circuit through the Devon and Pequonnock substations, scheduled for early 2006.
- the holding of an open season by TransÉnergie for the proposed Cross Hudson cable project, a 660 MW, 345 kV HVDC marine interconnection linking the Linden, New Jersey, generating plant and a substation to be determined of the Consolidated Edison Company of New York, Inc. (ConEd).

- the holding of an open season by TransÉnergie for the proposed Harbor Cable project, a 660 MW, 345 kV HVDC marine interconnection linking the Linden, New Jersey, generating plant and a Consolidated Edison Company of New York, Inc. substation.
- the proposal for the Cross Hudson 1,200 MW, 345 kV HVDC marine interconnection from the Ridgefield, New Jersey, generating plant and ConEd's 49th substation.

Interregional Assessments

To further the coordination of interregional transmission assessment, NPCC is a party to Inter-Area Coordination Agreements with MAAC and ECAR. Through these and a similar agreement among MAAC, ECAR, and the Virginia-Carolinas (VACAR) subregion of SERC, studies are regularly conducted among MAAC, ECAR and NPCC (MEN) and VACAR, ECAR and MAAC (VEM). All are performed under the auspices of the Joint Interregional Review Committee, composed of representatives from ECAR, MAAC, NPCC, and VACAR.

The ISO-NE, the NY ISO, the IMO, and PJM also take part in the ISO Memorandum of Understanding to pursue enhanced interregional coordination and system planning.

Operations Assessment

Reliable operations within NPCC are achieved through a hierarchical system. Criteria, guides, procedures, and reference documents developed at the NPCC level are expanded and implemented at the area level by the three Canadian control areas, NYISO, and ISO-NE. The criteria establish the fundamental principles of interconnected operations among the areas. Specific operating guidelines and procedures provide the system operator with detailed instructions to deal with such situations as depletion of operating reserve, capacity shortfalls, line loading relief, declining voltage, light load conditions, the consequences of a solar magnetic disturbance, measures to contain the spread of an emergency and restoration of the system following its loss.

Coordination in the daily operation of the bulk electric system is achieved through recognized principles of good electric system operation,

communications, and mutual assistance during an emergency. TransÉnergie, ISONY, the IMO, and ISO-NE serve as the security coordination centers for NPCC. As such, each exchanges necessary security data through the interregional security network. Further, NPCC routinely conducts weekly operational planning calls between control area operators to coordinate short-term system operations. NPCC establishes procedures for the exchange of security information discussed in these regularly scheduled, prearranged conference calls. The “NPCC Emergency Preparedness Conference Call Procedures” provide a mechanism that augments the regular conference call process to enable operational security entities in NPCC and neighboring Regions to communicate current operating conditions and, if appropriate, facilitate the procurement of assistance under emergency conditions. These calls may be initiated upon the request of any NPCC control area system operator and are coordinated by NPCC staff.

The NPCC security conference call establishes communications among the area operations managers in NPCC in the event of a physical threat to the security of the interconnected bulk power supply system of the Region. The NPCC System Operations Managers Working Group (CO-8) has established this conference call process to permit a timely assessment of the overall system conditions in each area and to facilitate a common posture for each area during such a threat. During the course of the security threat, the area operations managers will conduct the security conference call as frequently as deemed necessary to assess and monitor the crisis. Upon the conclusion of the threat, the security conference call will be used to coordinate the stand down of each NPCC area.

Ontario and New York, together with other Lake Erie companies, participate in the Lake Erie Emergency Redispatch (LEER) procedure. The objective of this procedure is to facilitate emergency redispatch among participants within the Lake Erie control areas to relieve transmission constraints that could otherwise result in the requirement of another Lake Erie company to shed firm load. It is implemented only when firm load curtailment is imminent. The LEER procedure was originally approved by FERC on May 12, 1999, and the Lake Erie Security Process Working Group has continued to refine

the security tools used to activate the LEER procedure to ensure they continue to meet the needs of the Lake Erie system operators. An amended LEER Agreement was filed with FERC in August of 2002, reflecting current changes in the industry. These include:

- a description of the LEER settlement procedure;
- a description of how the LEER process handles constraints that may develop during the process of restoring the system to normal (unwinding a LEER transaction);
- the recognition that Phase Angle Regulator adjustments are not limited to only those under the control of the constrained system;
- the replacement of the term “security coordinator” with “reliability coordinator” to ensure consistency with recent NERC terminology changes; and
- the modification of the LEER participant list to include the Midwest ISO and reflect other organizational changes of several existing LEER participants.

NPCC is a voluntary, non-profit organization. Its 36 members represent transmission providers, transmission customers, and ISOs serving the northeastern United States and central and eastern Canada. Also included are five non-voting memberships extended to regulatory agencies with jurisdiction over participants in the electricity market in northeastern North America as well as public-interest organizations expressing interest in the reliability of electric service in the Region. The geographic area covered by NPCC, approximately one million square miles, includes the state of New York, the six New England states, and the provinces of Ontario, Québec, New Brunswick, and Nova Scotia.

SERC

The Southeastern Electric Reliability Council (SERC) is expected to have adequate generating and transmission capacity to supply the forecast peak demand and energy requirements throughout the ten-year assessment period. Projected capacity margins for the Region range from 9.9 to 12.7%. Member systems are planning to add nearly 33,000 MW of new generating capacity over the next ten years. Approximately 6,400 MW or 19.5% of this planned generation is identified as natural gas-fueled simple-cycle or combined-cycle combustion turbine; the remainder is mainly unspecified capacity or purchases. A survey of transmission providers indicates that over 243,000 MW of generation is proposed or under development in the Region. Planned transmission additions include over 2,600 miles of new 230 kV and 500 kV transmission lines. SERC members are planning to invest nearly \$7 billion over the next five years in new and upgraded transmission facilities.

Demand and Energy

SERC members use historical weather patterns and assume normal weather conditions to develop their forecasts of peak demand and energy. SERC is historically a summer peaking Region. Current forecasts indicate that SERC will remain summer peaking. The 2002 summer peak demand forecast is 154,337 MW and the forecast for 2011 is 188,630 MW. The average annual growth in forecast summer peak demand is 2.25%. This is slightly higher than last year's forecast growth rate of 2.21%. The growth rate over the last ten years averaged 2.59%. The amount of interruptible demand and load management is expected to decline over the forecast period from 6,095 MW in 2002 to 5,726 MW in 2011.

The forecast growth rate in energy usage is 2.00%, down slightly from last year's forecast of 2.09%. The historical growth rate for the last ten years was 2.80%.

Resource Assessment

The existing generating capacity within SERC consists of 87,110 MW steam, 31,936 MW nuclear, 18,371 MW hydro/pumped storage, 10,150 MW combined cycle, 17,827 MW combustion turbine, and 11,157 MW of purchases and miscellaneous other capacity. SERC members have reported approximately 32,800 MW of planned generation additions within SERC for the ten-year period. These additions include 1,854 MW of simple cycle combustion turbines, 4,545 MW of combined cycle, 951 MW of steam, 554 MW nuclear, 799 MW hydro/pumped storage, 11,606 MW of uncommitted-planned capacity, and 6,406 MW of various other generation.

Based on the forecast peak demand and capacity resources reported by SERC members, the capacity resource margin during the ten-year period ranges from 9.9 to 12.7%. These capacity margins assume the use of load management and interruptible contracts at the time of the annual peak. These margins are generally higher than last year's reported margins. Not included in these capacity margins is much of the merchant generation that has been built or is planned to be built in SERC. Merchant generation that has been purchased by SERC members to serve their customers is usually reported to SERC and included in the SERC capacity margin. However, the majority of merchant generation is not included because the merchant plant developers do not report their generation capacity to SERC. The above capacity margins therefore tend to understate the amount of capacity likely to be installed in the Region. SERC believes that capacity resources will be sufficient to provide adequate and reliable service for forecast demands.

Fuel supplies generally appear to be adequate over the forecast period. However, the planned increase in gas-fueled generation will require significant increases in both gas supply and pipeline capacity.

For the past four years, SERC has conducted an annual survey of transmission owners in order to identify the amount of generation that is under development in the Region. The 2002 survey asked for all generation development within SERC to be reported, whether it was a merchant plant or a utility-owned plant. Respondents were asked to report projects according to their stage of development. The amount of generation designated as a network

resource was also requested. The subregions coordinated responses to avoid double counting.

A summary of the survey responses is contained in the following table:

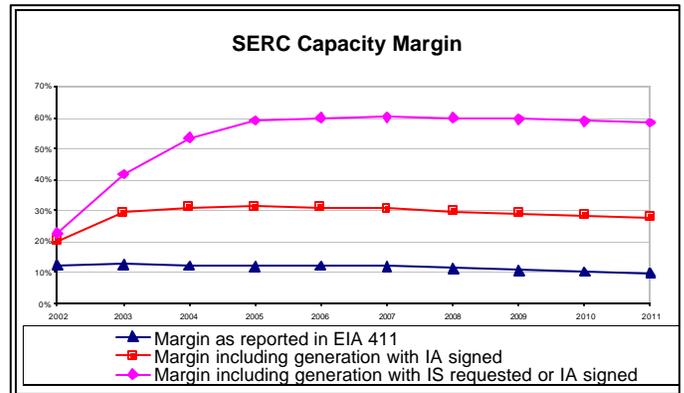
Table 1: SERC Generation Development 2002–2011

Current Status of Generation Plant Development	*In-Service Year of Added Generation (MW)									
	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Interconnection Service Requested Only	6,046	42,328	64,876	51,195	12,858	9,616	4,080	85	0	0
Designated as Network Resource	1,166	2,917	3,662	18,550	5,083	7,941	705	85	0	0
Interconnection Agreement Signed/Filed	17,053	25,667	7,805	2,090	75	580	0	0	0	0
Designated as Network Resource	5,536	5,929	216	0	75	580	0	0	0	0

Source: SERC Reliability Review Subcommittee 2002 report to the SERC Engineering Committee

The survey indicates a total of 23,099 MW of generating capacity is under various stages of development in SERC for the current year. The total for each of the next three years exceeds 70,000 MW. The majority of development was reported for the first five years and totals approximately 230,000 MW. The ten-year total is almost 243,700 MW. The potential impact on SERC capacity margins is shown in the figure in the next column. The survey shows that there is significantly more generation under development in the Region than is being reported to SERC through traditional data collection channels. The amount of generation in the survey greatly exceeds the amount of capacity needed to supply the forecast demand growth in SERC. Therefore, much of this capacity may be intended to serve demands outside the Region. However, the transmission systems in SERC are capable of exporting only a small percentage of this generation. If this generation is fully developed, there is a strong possibility that much of it will become stranded. Of course, the amount of generation that will actually be built is highly dependent on factors such as market prices, the ability to arrange suitable interconnection and transmission access agreements, the number of other merchant plants that are being

constructed, the ability of the company to obtain financial backing, and other typical business factors.



Source: SERC Reliability Review Subcommittee 2002 report to the SERC Engineering Committee

Transmission Assessment

The existing bulk transmission system within SERC is comprised of 19,372 miles of 230 kV, 758 miles of 345 kV transmission lines, and 8,468 miles of 500 kV transmission lines. Planned transmission additions include 2,181 miles of 230 kV and 438 miles of 500 kV lines over the next ten years.

SERC is directly interconnected with the transmission systems in ECAR, FRCC, MAAC, MAIN, and SPP. Transmission studies in the Region are coordinated through joint interregional reliability study groups. The results of individual system, Regional, and interregional studies demonstrate that the SERC transmission systems meet NERC and SERC reliability criteria and should have adequate delivery capacity to support forecast demand and energy requirements under normal and contingency conditions. It is becoming increasingly difficult to maintain sufficient transfer capability above contractually committed uses to provide for unexpected conditions. This is a reliability concern because it impacts the geographic diversity of external resources that can be called upon during emergency import scenarios that may result from large unit outages.

Generation interconnection studies have identified several areas with potential stability concerns. In some cases, these areas extend over multiple control areas and affect large geographic areas. To address these stability concerns, major transmission system additions are likely to be required. A number of

REGIONAL ASSESSMENTS

studies are currently under way to address these concerns and to identify the required system improvements.

As part of its annual reliability assessment this year, SERC conducted a survey of transmission owners to determine the planned expenditures for transmission system construction over the next five years. The results of this survey are shown in the table below. As can be seen, SERC members are planning capital expenditures of nearly \$7 billion over the next five years. The survey results demonstrate that SERC members are committed to making the transmission investments needed to assure an adequate and reliable transmission system.

Table 2 — SERC Survey of Transmission Development

SERC Total				
Total Transmission Expenditure, in Dollars, per Year				
2002	2003	2004	2005	2006
\$1,344,411,424	\$1,215,615,350	\$1,366,466,301	\$1,493,317,250	\$1,512,657,000

Source: SERC Reliability Review Subcommittee 2002 report to the SERC Engineering Committee

Operations Assessment

Large and variable loop flows are expected to impact transfer capabilities on a number of interfaces within SERC and between SERC and other Regions. The projected significant increases in merchant plant capacity over the next few years lead to increasing uncertainty in flow patterns on the transmission system. Unexpected flow patterns can also significantly impact transfer capability.

Subregional Assessments

Entergy Subregion

The forecast 2002 summer peak demand for the Entergy subregion is 25,404 MW. The summer peak demand is forecast to increase to 29,325 MW in 2011. The average annual demand growth rate is 1.61% for the Entergy subregion in the next ten years. This is slightly lower than the 1.71% projected last year and lower than the 2.75% historical peak demand growth rate.

The subregion projects approximately 2,970 MW of new capacity resource additions in the next ten years. Approximately 1,479 MW of the capacity

increase is projected to be combined-cycle additions, and 80 MW is projected to be combustion turbines. The remainder is projected to be derived mostly from increases in steam plant additions and in net purchases.

Reported capacity margins in the Entergy subregion are above 10% for the majority of the ten-year period. In addition, the Entergy subregion continues to sign interconnection agreements with independent power producers who are locating within the subregion. Over 21,000 MW of IPP generation has signed interconnection agreements with Entergy Corporation, alone. More than a quarter of that amount is already in service. This merchant generation is not reported in the subregional totals included in this report.

Existing bulk transmission in the Entergy subregion is comprised of approximately 2,100 miles of 230 kV, 750 miles of 345 kV, and 2,100 miles of 500 kV transmission. Planned transmission additions include 303 miles of 230 kV and 14 miles of 500 kV over the next ten years.

Transmission interfaces to the north are expected to continue to be impacted by loop flows for the 2002 summer. NERC flowgates in the southeast quadrant of the Entergy subregion continue to be heavily loaded, and are expected to limit interregional transfers for several systems. Loop flow from recent generation additions in the southwest quadrant of the Southern subregion is expected to exacerbate these conditions. Joint studies with neighboring control areas and Regions continue to investigate possible solutions and operational restrictions to preserve system reliability under such conditions.

Southern Subregion

The 2002 summer peak demand forecast is 45,837 MW and the forecast summer peak demand for 2011 is 58,624 MW. This represents an average annual growth rate of 2.77%. This rate of growth is slightly lower than the 3.1% for the historical peak demand and slightly lower than the 2.93% projected last year.

The Southern subregion projects a resource capacity increase of over 15,000 MW from 2002 to 2011. These values reflect unit retirements, changes in

capacity purchases and sales, as well as new resource additions. The majority of capacity additions during the reporting period are: net purchases at 12,113 MW, combined-cycle units at 1,110 MW, and combustion turbines at 927 MW. Reported capacity margins in the Southern sub-region range from approximately 11.5 to 13.3%.

The existing Southern subregion bulk transmission system is comprised of 7,110 miles of 230 kV and 1,980 miles of 500 kV transmission lines. During the next ten years, an additional 1,198 miles of 230 kV and 339 miles of 500 kV transmission are planned.

TVA Subregion

The forecast 2002 summer peak demand is 27,729 MW and the forecast peak demand for 2011 is 34,020 MW. This represents an average annual summer peak demand growth rate, including load management, of 2.3 percent over the next ten years. This growth rate is higher than the 1.79% forecast last year and slightly higher than the historical growth rate of 2.1%. The amount of contractual interruptible demand forecast for the subregion ranges from 1,987 MW in 2002 summer to 2,095 MW in 2011 summer.

Generation resources within the TVA subregion include a diverse mixture of hydroelectric, coal, nuclear, pumped storage, and gas turbine units. The summer net installed operable capacity in the subregion for 2002 is 32,390 MW. In addition, approximately 6,890 MW of merchant capacity will be operational in the subregion as of June 1, 2002. Although the output of these merchant plants may at times be utilized to help meet the demand in the subregion, the long-term contractual status for the output of these plants was unknown at the time of this report.

Generation with coal and nuclear fuels continues to be the primary energy supply for the subregion, accounting for 66% of the reported capacity in 2002. For 2002 summer, the Tennessee Valley Authority reported the planned addition of 616 MW of natural gas-fired peaking capacity, the long-term purchase of 440 MW from an IPP within the subregion, and various unit upgrades totaling 77 MW. A net total of 5,870 MW of additional capacity is projected over

the 2002–2011 period to meet peak demand growth in the TVA subregion.

The 2002 capacity resource margin projection averages 12.5% over the ten-year period and remains above 11% for the entire period. It should be noted that non-utility merchant capacity additions are not reflected in these margins.

The existing TVA subregion bulk transmission network consists of transmission lines operated at 115 to 500 kV. The majority of the network consists of about 10,600 miles of 161 kV and about 2,400 miles of 500 kV facilities that transmit power from generation sites to demand centers within the subregion. There are 31 miles of 230 kV and above transmission line additions planned for the TVA sub-region during the next ten years. Many 161 kV improvements are also planned during this period. TVA and Southern are constructing a new 230 kV tie that should be operational in late summer 2002.

Transmission assessment studies indicate that a heavy dependence on “market purchases” from resources physically located outside the subregion will bear a degree of risk based on transmission constraints. Recent operating experience and planning studies have increased awareness of the impacts on the TVA bulk transmission system that result from large-scale imports by the SERC Region. The impact of increasing merchant plant capacity interconnecting in SERC, tilting the supply/demand balance, will provide significant challenges to modeling and analysis of transmission system performance.

VACAR Subregion

The forecast 2002 summer peak demand is 55,367 MW and the forecast 2011 summer peak demand is 66,661 MW. This represents an average annual growth rate of 2.08%. This is slightly higher than the 2001 forecast annual growth rate in summer peak of 2.07%. The actual growth in summer peak demand since 1992 has been 2.40%. Demands in demand side management programs may or may not have been activated during the actual peak demand periods. This could lead to larger variations in the actual demands reported. The projected amount of interruptible demand and load management in 2002 is 2,555 MW and is projected to decrease to 2,512 MW in 2011.

REGIONAL ASSESSMENTS

For the 2001 summer period, the VACAR subregion had installed generating capability of 61,183 MW. Projected installed generating capability for the 2002 summer period is 63,375 MW. This represents an anticipated increase of 2,192 MW above the 2001 summer peak season. These figures do not include projected resource purchases.

During the period of 2002–2011, 8,709 MW of capacity is projected to be added within the VACAR subregion. The majority of this capacity, 6,596 MW (76%), is designated as uncommitted. Over 2,800 MW of combined cycle or combustion turbine is projected to be added. Capacity purchases for the period 2002–2011 are projected to be 6,718 MW in 2002 and 4,531 MW in 2011. These values also represent the maximum and minimum projected purchases for the ten-year reporting period.

Capacity margin calculations are based on forecast demands with load management in effect. The projected capacity margins of 12% or above for the first six years of the 2002–2011 period are similar to the 2001 forecast. Starting in 2005, there is a reported gradual decrease in capacity margin through the remaining reporting period with the projected 2011 VACAR capacity margin reported at just below 8%.

As of the end of 2001, the VACAR subregion had a total of 2,002 circuit miles of 500 kV and 10,063 circuit miles of 230 kV transmission in service. Throughout 2002–2011, VACAR presently plans to construct 85 miles of 500 kV transmission lines and 666 miles of 230 kV transmission lines.

SERC membership includes 37 members and 27 associate members. The SERC Region includes portions of 13 states in the southeastern United States, and covers an area of approximately 464,000 square miles. SERC is divided geographically into four diverse sub-regions that are identified as Entergy, Southern, Tennessee Valley Authority (TVA), and the Virginia-Carolinas Area (VACAR).

SPP

The Southwest Power Pool (SPP) anticipates consistent growth in demand and energy consumption over the next ten years. Adequate generation capacity will be available over the short term to meet native network load needs with committed generation resources meeting minimum capacity margins. Beyond the short term, adequate capacity margins will be highly dependant on the availability of the market to provide the necessary generation resources.

The SPP bulk transmission system will reliably serve native network demand for the short term while incremental system flows from commercial transmission reservations will most likely utilize any remaining transmission capacity. Several transmission upgrades have been identified either to accommodate transmission service under the SPP Open Access Transmission Tariff (SPP-OATT) or to meet specific transmission owner import/export needs. Future network analysis becomes less exact and more difficult due to the large number of proposed merchant plant additions without firm commitments for transmission service. From the time of a commitment made by a generator to SPP for transmission service, the remaining time required for completion of the generation project is often less than the lead time required for the construction upgrades necessary to provide transmission service; in some cases, much less.

SPP-MISO Merger Update

The merger between SPP and the Midwest Independent Transmission System Operator, Inc. (MISO) moved closer to completion when FERC approved the consolidation of the companies' open access transmission tariffs effective with the merger closing. The merger is on schedule to close during the fourth quarter of 2002. The FERC order was the first in a series of federal and state level regulatory approvals required to complete the merger.

When finalized, the combined organization will operate an interconnected transmission system encompassing more than 150,000 MW of generation capacity in 20 U.S. states and one Canadian province.

Demand and Energy

SPP is a summer-peaking Region with projected annual peak demand and energy growth rates of 2.4 and 2.2%, respectively, over the next ten years. Members continue to forecast similar future peak demand and energy requirements growth as in previous years. These demand growth rates are consistent with the ten-year historical growth rates of SPP.

Members are focusing more on the short term (two to five years), thereby shortening the planning horizon. This reduces the long-term (six to ten years)

forecast accuracy. The projected growth rates for peak demand and energy over the next five years are 2.3% and 1.9%, respectively. The actual growth rates for peak demand and energy over the last five years were 2.5% and 2.5%, respectively. The SPP actual peak demand and energy used in 2001 was 40,273 MW and 193,590 GW.

Resource Assessment

SPP's present capacity is 44,259 MW, with a mix of 46% coal, 34% gas, 2% oil, and 18% other. SPP's reported capacity in 2011 is projected to be 46,023 MW, with a mix of 46% coal, 35% gas, 2% oil, and 17% other.

SPP criteria require that members maintain a capacity margin of 12%, which is reduced to 9% for members with primarily hydro-powered generation. Expected capacity margins for SPP are 16.2% in 2003, 14.6% in 2004 and 12.6% in 2005. The reported capacity margin for 2006 is 12.2% and is projected to decline to roughly 9% in 2009–2010.

Regarding capacity margins beyond 2005, SPP members are largely assuming that the market will provide needed resources, or that new, presently uncommitted capacity sources could be made available to those members within a two- or three-year time period.

REGIONAL ASSESSMENTS

The capacity reported for SPP included in this report does not reflect some 10,000 MW of merchant plant additions, which are expected to come on line during the 2002–2006 time period. The above capacity margins would increase about 1.7 percentage points for each 1,000 MW of merchant plant capacity that is added.

Transmission Assessment

There are a limited number of bulk transmission upgrades within SPP designed to increase transfer capability. One reason for minimal system upgrades is the unanswered questions surrounding cost recovery to accommodate requested transmission service. Most transmission projects specifically associated with contracted transmission service consist of terminal equipment upgrades and transmission circuit reconductorings. Other network upgrades of significance are a result of individual transmission owner export/import needs. The planned transmission facilities of Regional significance include:

- 210 MW Finney-Lamar HVDC interconnection between SPP and WECC in 2004
- Potter-Northwest 345 kV tie line proposed in 2006

To determine available transfer capability (ATC), transfer capability studies are performed monthly on the bulk transmission system based on a sliding 16-month window. These calculations account for the most restricting credible contingencies as recognized by each member company and/or the regional transmission provider.

The bulk transmission system is shown to meet applicable NERC and Regional planning standards for this sliding study window. In addition to the 16-month sliding ATC studies, SPP has evaluated the general reliability of the power transmission network in accordance with NERC requirements. Measures 1 and 2 of the NERC compliance standards have been completed for the one to five year time frames. SPP transmission owners have provided mitigation plans where examination of the power transmission network has identified base case and/or (n-1) conditions producing Regional violations of reliability criteria. A similar six to ten year reliability assessment will be completed later this year.

SPP has recently reviewed the overall long-term adequacy of the SPP interconnected bulk electric transmission system in a joint study with MAIN, MAPP and SERC. This study shows that the SPP power transmission network has adequate export ability to all neighboring Regions under 2007 summer peak demand conditions. The study also judges all imports to be adequate with the exception of the SPP Regional and subregional imports from SERC West and Entergy, respectively. Entergy, in coordination with its neighboring utilities, is pursuing options to alleviate the projected high base and contingency loadings on its 500 kV system resulting from the increase in east-to-west flow bias across the SERC west subregion. Adequate lead times are expected to allow implementation of necessary solutions to address these and other projected EHV constraints. Within SPP, the Ft. Smith 500/161 kV transformer, LaCygne-Stilwell 345 kV line, St Joe-Midway 161kV line, and HTI Jct.-Circleville 115 kV line have been identified as limiting elements for some transfers.

SPP generation interconnection procedures accommodate the needs of the merchant developers regarding studies to determine the transmission additions necessary to integrate their planned capacity additions into the bulk transmission system. In some cases where extreme amounts of transmission additions are required to serve the total planned capacity of new generation, other alternatives may be needed to meet the needs of both the transmission provider and the merchant developer.

Operations Assessment

SPP has operated a security center since 1997 and is the reliability coordinator for the SPP Region. The security center, located in the SPP offices, provides the exchange of near real-time operating information and around-the-clock security coordination.

SPP implements security procedures required of a NERC reliability coordinator under NERC Operating Policies. SPP coordinates maintenance outage schedules of the generation and transmission facilities within the Region. Security analysis is performed daily to help members recognize heavy line loading that is expected to occur. When heavy line loading occurs in real time or is expected to occur in near real time, NERC TLR procedures are invoked

to relieve facility loading. A major tenet of these procedures is to ensure that TLR is achieved by real changes in generation patterns, not a mere shuffling of interchange schedules. These procedures have provided for TLR in SPP and surrounding Regions. SPP has experienced TLR curtailments on its transmission facilities in recent years and expects that this will continue in the future. Although SPP has adequate transmission to reliably serve native load, it expects heavy use of the transmission system for economy transactions to continue into the future.

SPP operates an automatic reserve-sharing program as a sub-function of the Regional operating reserve criteria and requirements in which Regional participation ensures necessary capacity reserves are available on a daily basis for unexpected loss of generation. The automatic reserve-sharing program meets NERC operating policy requirements.

SPP, currently consisting of 52 members, serves more than 4 million customers, and covers a geographic area of 400,000 square miles containing a population of over 18 million people. In covering a wide political, philosophical, and operational spectrum, SPP's current membership consists of 14 investor-owned utilities, seven municipal systems, eight generation and transmission cooperatives, three state authorities and one federal government agency, one wholesale generator, and 18 power marketers. SPP has more than 350 electric industry employees on various organizational groups that bring together unmatched expertise to deal with tough reliability and equity issues. An administrative and technical staff of approximately 100 persons facilitates the organization's activities and services. Primary offices are located in Little Rock, Arkansas and a branch office is located in Hilliard, Ohio.

REGIONAL ASSESSMENTS

WECC

The utility environment is changing. A number of important issues within the Western Electric Coordinating Council (WECC) that must be responsibly managed to maintain Regional system reliability.

WECC anticipates addressing these issues in large part by continuing its tradition of being proactive, and positioning itself as an organization to effectively accommodate change and meet the challenges that lie ahead.

Introduction

WECC's outlook regarding the reliability of the interconnected electric system in the west is presented below for each of the four subregions that comprise the Western Interconnection–Northwest Power Pool area, Rocky Mountain Power area, Arizona-New Mexico-Southern Nevada Power area, and California-Mexico Power area.

Projected capacity margins and fuel supplies are anticipated to be adequate to ensure reliable operation in all areas of the Region during 2002–2011. However, in summer 2002, the Arizona-New Mexico-Southern Nevada Power area's 10.7% projected capacity margin is tight. Expected capacity adequacy for summer 2002 is thoroughly addressed in the WECC 2002 Summer Assessment report. The report is available on the WECC web site (www.wecc.biz). Capacity margins in the Arizona-New Mexico-Southern Nevada subregion improve beyond 2002.

The determination of capacity margin adequacy over the next ten years assumes the timely construction of approximately 81,055 MW of net new generation, which is up dramatically from the 56,849 MW reported last year. The capacity margin adequacy also assumes average weather conditions. If multiple areas peak simultaneously, portions of the Region may need to issue public appeals for customers to reduce their electricity consumption, and other measures may be instituted as necessary to ensure that adequate operating reserves are maintained. The transmission system is considered adequate for firm and most economy energy transfers.

Under WECC's reliability plan, three reliability centers have been established for the Region. The reliability center coordinators are charged with ac-

tively monitoring, on a real-time basis, interconnected system conditions to anticipate and mitigate potential reliability problems and to coordinate system restoration should an outage occur. Through active participation in WECC, individual member participants will be able to manage these issues and maintain a balance between reliability and the economic pressures of competition. WECC provides an open forum for all entities that have a stake in the planning and operation of the interconnected electric system in western North America, enabling them to actively share in the responsibility of maintaining this essential balance.

WECC Assessment Process

The evaluation of reliability within WECC is performed using a comprehensive annual assessment process based on the following established reliability criteria:

- Power Supply Assessment Policy,
- Minimum Operating Reliability criteria, and
- NERC/WECC Planning Standards.

Adherence to these criteria provides an objective and deterministic evaluation of the adequacy of the western interconnected power system.

Resource Assessment

The WECC resource assessment process has been in place for many years and is prepared for the four subregions of WECC. A resource assessment on a Region-wide basis is not appropriate because of transmission constraints.

Resource adequacy is assessed by comparing the sum of the individual member reserve requirements

(determined by criteria) for a subregion with the projected reserve capacity. WECC is currently refining its resource adequacy assessment practice in light of the changing electric industry. WECC's enhanced assessment methodology places additional emphasis on transmission limitations between assessment areas within WECC.

At present, the projected reserve capacity (margin) is determined by subtracting the firm peak demand, exclusive of interruptible and controllable load management peak demand, from the net generation and firm transfers. Net generation and firm transfers are determined exclusive of inoperable capacity. If the projected reserve capacity exceeds the reserve requirement, it is expected that projected resources are adequate for the subregion. On this basis, projected reserve capacity is expected to be adequate throughout WECC for the 2002 through 2011 ten-year period. The assessment assumes that approximately 81,100 MW of net new generation will be built when and where needed.

Transmission Assessment

The member systems' transmission facilities are planned in accordance with the "NERC/WECC Planning Standards," which establish performance levels intended to limit the adverse effects of each member's system operation on others and recommends that each member system provide sufficient transmission capability to serve its customers, to accommodate planned interarea power transfers, and to meet its transmission obligations to others.

Each year WECC prepares a transmission study report that provides an ongoing reliability-security assessment of the WECC interconnected system in its existing state and for system configurations planned through the next ten years. The disturbance simulation study results are examined relative to the "NERC/WECC Planning Standards." If study results do not meet the expected performance level established in the criteria, the responsible organizations are obligated to provide a written response that specifies how and when they expect to achieve compliance with the criteria. Other measures that have been implemented to reduce the likelihood of widespread system disturbances include: a southern island load tripping plan, a coordinated off-nominal frequency load shedding and restoration plan, meas-

ures to maintain voltage stability, a comprehensive generator testing program, enhancements to the processes for conducting system studies, and a reliability management system (described in more detail below).

WECC has established a process that is used to verify compliance with established criteria. The process is summarized below with the key components to be monitored in this process:

Compliance Monitoring

WECC conducts a voluntary peer review process through which every operating member is reviewed at regular intervals to assess compliance with WECC and NERC operating criteria. Control areas are reviewed once every three years.

Annual Study Report

In accordance with WECC policy, the system will not be operated under system conditions that are more critical than the most critical conditions studied.

Security assessment shall be an integral part of planning, rating, and transfer capability studies.

Project Review and Rating Process

Study groups are formed to ensure project path ratings comply with all established reliability criteria.

Operating Transfer Capability Policy Group Process

Operating studies are reviewed to ensure that simultaneous transfer limitations of critical transmission paths are identified and managed through nomograms and operating procedures. Four subregional study groups prepare seasonal transfer capability studies for all major paths in a coordinated subregional approach for submission to WECC's Operating Transfer Capability Policy Group.

Reliability Management System

WECC officially implemented Phase 1 of its Reliability Management System (RMS) on September 1, 1999, after a 19-month evaluation period. WECC's

REGIONAL ASSESSMENTS

RMS program is a first-of-a-kind sanction-based program to maintain reliability, and represents a significant milestone for WECC members and the electric industry.

The program developed voluntarily through an open public process involving the WECC membership, the regulatory community, and other interested stakeholders provides for the enforcement of reliability criteria (planning and operating) by imposing sanctions for noncompliance through contracts that are signed by WECC and each RMS participant. WECC was granted a Declaratory Order by FERC and received a Business Review Letter from the Department of Justice enabling WECC to proceed with RMS implementation in early 1999. FERC issued an order on July 29, 1999, accepting the RMS contracts. Thirty-three WECC members, representing a substantial number of the WECC control areas have signed the RMS agreements.

Phase 1 of the RMS requires compliance with the following criteria:

- control performance,
- operating reserve,
- operating transfer capability,
- disturbance control, and
- generating unit automatic voltage regulators and power system stabilizers.

The control performance standards, operating reserve, and operating transfer capability requirements are assessed monthly. The disturbance control standard, and requirements for power system stabilizers and automatic voltage regulators are assessed quarterly.

Phase 2 of the RMS was officially implemented on November 1, 2000 after a 25-month evaluation period. Phase 2 includes requirements for:

- availability of major transmission path operating limits to system operators,
- protective relay and remedial action scheme application certification, and

- protective relay and remedial action scheme misoperation analysis and corrective action.

Phase 3 of the RMS system is presently under evaluation and development. Phase 3 includes requirements for:

- interchange schedule tagging,
- operator certification,
- qualified path unscheduled flow relief-contributing schedule curtailment compliance standard, and
- transmission maintenance standards.

On the basis of these ongoing activities, transmission system reliability of the Western Interconnection is projected to be adequate throughout the ten-year period.

NORTHWEST POWER POOL AREA

The Northwest Power Pool (NWPP) area is comprised of all or major portions of the states of Idaho, Montana, Nevada, Oregon, Utah, Washington, and Wyoming; a small portion of northern California; and the Canadian provinces of British Columbia and Alberta. For the period from 2001 through 2011, peak demand and annual energy requirements are projected to grow at respective annual compound rates of 2.5 and 1.9%. With a significant percentage of hydro generation in the Region, the ability to meet peak demand is expected to be adequate for the next ten years. The ability to meet sustained seasonal energy requirements over the ten-year period is dependent on new generation additions. Resource capacity margins for this winter peaking area range between 26.6 and 32.0% of firm peak demand for the next ten years.

Northwest power planning is done by sub-area. Idaho, Nevada, Wyoming, Utah, British Columbia, and Alberta individually optimize their resources to their demand. The Coordinated System (Oregon, Washington, and western Montana) coordinates the operation of its hydro resources to serve its demand. The Coordinated System hydro operation is based on critical water planning assumptions (currently the 1936–1937 water year). Critical water in the Coordinated System equates to approximately 11,000

average MW of firm energy load carrying capability. Under average water year conditions, the additional non-firm energy available is approximately 3,000 average MW. The 2002 projected January through July volume runoff (Columbia River flows) at The Dalles, Oregon is 100 million acre-feet (Maf), or 93% of the 30-year average. The 2001 runoff was the second lowest water year the Northwest has experienced since record keeping began and Coordinated System hydro reservoirs refilled to the lowest levels seen in almost a decade.

The water flow associated with hydro-powered 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 even more difficult.

Agreement was reached in 2000 among U.S. Federal parties involved in operation of the Columbia River Basin concerning river operations for a period of ten years. This agreement is embodied in the Biological Opinion of 2000. However this agreement is subject to three, five, and eight-year performance checks and reopening by the parties. These include the National Marine Fisheries Service, the U.S. Fish and Wildlife Service, the U.S. Bureau of Reclamation, the U.S. Army Corps of Engineers, and the Bonneville Power Administration (BPA). The net impact of the present agreement is a reduction in generating capability as a result of hydro generation spill policies designed to favor migration of anadromous fish. The agreement includes provision for negotiating changes in the plan under emergency conditions as was done in 2001.

With respect to non-hydro generation in the area, generation interconnection study requests totaling substantial capacity have been received by BPA and other transmission providers and are being processed. However, fewer study requests remain active this year compared to last year. The adequacy of the generation supply over the next ten years in the NWPP will depend on how many of these and other proposed plants are actually built. Generally, these

generation facilities will have a relatively short time to completion once the decision is made to proceed with construction. These factors combine to make it difficult to forecast generation adequacy with any certainty for an extended period of time.

In view of the longer time required for transmission permitting and construction, it is recognized that network planning should focus on establishing a flexible grid infrastructure. This is being done with the goals of allowing anticipated transfers among NWPP systems, addressing several areas of constraint within Washington, Oregon, Montana, and other areas within the Region, and integrating new generation. Projects at various stages of planning and implementation include approximately 300 miles of 500 kV transmission as well as modernization of the Celilo terminal of the Celilo-Sylmar high voltage DC line.

Maintaining the capability to import power into the Pacific Northwest during infrequent extreme cold weather periods continues to be an important component of transmission grid operation. In order to support maximum import transfer capabilities the Northwest depends on tripping of direct service industry (DSI) demand as a remedial action for loss of the Pacific Interties. If these transfer capabilities are to be supported this winter, it would have to be through the tripping of firm demands, since the DSI demand has been depleted by buy downs. Reduction of DSI demands through buy downs also affects transfer capabilities from Montana into Washington. If drought conditions occur, it may be advantageous to maximize transfer capabilities to reduce reservoir drafts and aid reservoir filling.

Generation in the province of Alberta, Canada operates in a fully deregulated market and resource additions are market driven. In 2001, 500 MW of generation was built in the area and it is expected that an additional 1,300 MW of generation will be added in 2002. A further 5,000 MW of generation additions are projected into the 2006 time frame. The generation additions are expected to result in transmission constraints in a number of areas on the system. Plans to alleviate the constraints include the development of a 500 kV network overlaying an existing 240 kV network. It is anticipated that the transmission system additions will be needed by 2009.

REGIONAL ASSESSMENTS

The Canadian province of British Columbia relies on hydroelectric generation for 90% of its resources. To a large extent, water levels at reservoirs across the province have recovered from the low levels of last year but still remain below normal levels in some cases. It is not expected that this condition will adversely affect the province's resource adequacy.

There are constraints in several areas of the transmission system. British Columbia Hydro and Power Authority has prepared a system impact study that addresses constraints between remote hydro plants and lower mainland and Vancouver Island demand centers. The Guichon series capacitor station on the Kelly Lake-Nicola 500 kV line will increase transfer capability from major hydro resources to the Canada-U.S. border by 500 MW. Another recently completed study addresses the transmission constraint between the Selkirk and Nicola substations. Suggested upgrades include series compensation on the 500 kV lines between these substations. The mainland-to-Vancouver Island constraint is being relieved by the construction of additional generation on the island.

ROCKY MOUNTAIN POWER AREA

The Rocky Mountain Power area (RMPA) consists of Colorado, eastern Wyoming, and portions of western Nebraska and South Dakota. The RMPA may experience its annual peak demand in either the summer or winter season due to variations in weather. Over the period from 2001 through 2011, peak demand and annual energy requirements are projected to grow at an annual compound rate of 2.3%. Resource capacity margins range between 12.9 and 21.8% of firm peak demand for the next ten years.

Significant amounts of generation continue to be installed in the RMPA. Public Service Company of Colorado (PSC) added over 500 MW of generation to its system in 2001. Front Range Power, a 460 MW gas-fired plant, is under construction in the Colorado Springs area and will be operational by spring 2003. PSC is also purchasing or constructing about 340 MW of resources that will be on line by June 2002. In addition, PSC plans to add over 700 MW in 2003 (240 MW will be purchased from Front Range Power), and 585 MW in 2004. Most of this

generation is planned as gas-fired turbines, but around 200 MW is from wind generation. PSC intends to have a 210 MW back-to-back DC tie in service near Lamar, Colorado in 2004. Platte River Power Authority is adding three 80 MW gas-fired generation units in 2002, for a total of 240 MW. The new generation project includes a Rawhide-Timberline 230 kV line and upgrades to some existing 115 kV lines in the Loveland/Fort Collins area to meet projected peak demand. Black Hills Power has installed a second 40 MW gas-fired turbine generator at the existing Wyodak generation complex. Also, a 40 MW gas-fired turbine generator was installed at the Lange substation in Rapid City, South Dakota. Both generators will provide for local area voltage support as well as for future demand growth. Wygen, an 80 MW coal-fired plant, is under construction and is scheduled to be on line in early 2003. A 200 MW back-to-back DC tie, located at Rapid City, South Dakota, is scheduled for completion in late 2003. Two Elk Power Partners is planning to add a 250 MW waste coal-fired plant in east central Wyoming by 2005.

Hydroelectric generation is expected to be slightly below normal in the northern and central Rocky Mountains in 2002. Water inflows into the South Platte, North Platte, Colorado, Big Thompson and Green Rivers are expected to be considerably below normal in 2002 as snowpack is between 60 and 70% of normal in these river basins. Water inflows into the Missouri River are expected to be approximately 70% of normal this year. Reservoir storage is below normal and hydroelectric generation is expected to be below the long-term average. The Glen Canyon power plant is operating under environmental constraints, with no seasonal steady flow test expected this summer. The associated release limitations reduce peaking capability, but the plant will be able to respond to short-term emergency conditions.

Tri-State Generation and Transmission Association, Inc. is constructing a major 230 kV line from Walsenburg, Colorado to Gladstone substation in northeast New Mexico. The planned in-service date is 2004. PSC plans on constructing a new Midway-Smoky Hill 345 kV line by 2005. Several minor improvements have allowed an increase in transfer capability from southeast Wyoming to northeast Colorado, from 1,588 to 1,605 MW. This transmis-

sion path is known as Path 36 or TOT3. In June 2001, PSC finished construction of a major 230 kV line from Fort St. Vrain to Green Valley substation northeast of Denver. The line increases the import capability to the Denver area. WestPlains Energy is installing a 100 MVA 230/115 kV transformer near Canon City, Colorado. The transformer, which is expected to be in service in the summer of 2003, will provide backup and increased voltage support for the Canon City area.

ARIZONA-NEW MEXICO-SOUTHERN NEVADA POWER AREA

The Arizona-New Mexico-Southern Nevada Power area consists of Arizona, most of New Mexico, the westernmost part of Texas, southern Nevada, and a portion of southeastern California. Over the period from 2001 through 2011, peak demand and annual energy requirements are projected to grow at respective annual compound rates of 3.1 and 2.9%. Resource capacity margins for this summer peaking area range between 10.7 and 31.3% of firm peak demand for the next ten years. The ability to meet sustained seasonal energy requirements over the ten-year period is dependent on new generation additions.

Several transmission projects have been reported for the subregion that will increase transfer capability and improve reliability. These projects include a 113 mile 230 kV interconnection from Walsenburg substation in southeastern Colorado to a new 230/115 kV substation at Gladstone, New Mexico. This line is scheduled to enter service in 2003. An additional line from the Palo Verde 500 kV switchyard to the Estrella switchyard in the Phoenix area, the Palo Verde-Southwest Valley 500 kV line, is scheduled for completion in 2003. In Nevada, the Faulkner-Tolson and Tolson-Arden 230 kV lines will increase import capability in 2003 to accommodate near-term demand growth. New 500 kV lines are planned for 2003 in southern Nevada to deliver the output of new generating plants proposed for the area. In 2004, a 216 mile 345 kV line is planned between Palo Verde and Nogales, near the Arizona border with Mexico. Transmission projects scheduled to enter service in 2005 include a 395 mile 500 kV line from Shiprock, New Mexico to Marketplace, Nevada. An additional 345 kV connection between generating facilities in northern New Mexico and a

substation in central New Mexico is under investigation, with a possible in-service date of 2006. Also planned for an in-service date of 2006 is a 125 mile 500 kV line from Palo Verde to the Phoenix area.

As with other areas within WECC, the future adequacy of the generation supply over the next ten years in the Arizona-New Mexico-Southern Nevada region will depend on how many among these and future proposals are actually built. Generally, these generation facilities will have a relatively short time to completion once the decision is made to proceed. These factors combine to make it difficult to forecast generation adequacy with any certainty for an extended period of time.

In association with these Arizona generation proposals, several Arizona utilities embarked upon a regional EHV transmission study to evaluate developing transmission alternatives in the Central Arizona area. The study is called the central Arizona Transmission System (CATS) study and encompasses an area bounded by environs between the Phoenix and Tucson metropolitan areas and the Palo Verde Nuclear Generating Station. The purpose of the study is to evaluate what high voltage transmission facilities are needed in the long term to, among other things, improve the use of the existing transmission system for future demand growth in the Phoenix and southern Arizona areas, increase the power transfer capability between the Phoenix and Tucson areas, facilitate future generation additions south of Phoenix and north of Tucson, and provide additional transmission capacity to and from the Palo Verde energy trading and marketing hub. The CATS study has provided a framework for the participating utilities to plan and coordinate transmission lines and receiving stations in the area. The study has also identified how the timing and phasing of projects can be done in a coordinated manner.

CALIFORNIA-MEXICO POWER AREA

The California-Mexico Power Area encompasses most of California and the northern portion of Baja California, Mexico. Restructuring of the electric industry in California has added much uncertainty to future adequacy projections of generating capacity, energy production by merchant power producers, and effects of customer energy efficiency and demand-side management programs. Recognizing that

REGIONAL ASSESSMENTS

future forecast uncertainty exists, peak demands and annual energy requirements are currently projected to grow at respective annual compound rates of 2.4 and 1.3% from 2001 through 2011. Projected resource capacity margins range between 13.9 and 44.8% of firm peak demand for the next ten years.

California experienced load curtailments in 2000. Non-firm peak demand curtailments during the last week of June occurred during a period when portions of the Northwest experienced hot to record-high temperatures and portions of the Southwest were also hot. The high temperatures and Northwest generator outages limited the ability of these areas to export to California. This experience demonstrates that even with the assumptions of future generation and transmission expansion projects, statewide and local reliability problems can exist in the short term.

Due to mild temperatures, conservation, increased electric rates, and weak economic conditions, the 2001 summer peak demand of 48,351 MW was 5.6% less than the 2000 summer peak demand of 51,213 MW. The reduced peak demand over the summer, coupled with increased resources, allowed uninterrupted service to California customers for the first time in three years. Although customer demand is expected to increase to 52,255 MW for the summer of 2002, resource additions during the past year exceed the expected demand growth so it is expected that California will not experience firm customer demand curtailments during the 2002 summer period.

Over 60 generation projects totaling more than 4,500 MW have been canceled in the last 18 months due to the financial situation of several developers and uncertainty in the energy markets. Remaining projects, however, still total over 40,000 MW. The actual level of new net generation is still uncertain but resource adequacy is expected to be sufficient at least in the near term.

The CISO administers a coordinated planning process that forms the basis for planning future changes and additions to the transmission system. The process calls for stakeholder participation in the planning process with the intent to facilitate the development of projects that best meet the needs of all users while maximizing the potential benefits to California.

The resource uncertainty mentioned above significantly complicates associated transmission planning. However, transmission addition work is proceeding for the area. During 2000 and 2001, the transmission between southern and northern California was often congested. Based on analysis performed by the CISO, it was determined that a 1,500 MW upgrade to the transmission was economically justified based on its ability to mitigate the constraint. The upgrade is to include 84 miles of additional 500 kV transmission and other related 500 kV and 230 kV system reinforcements. The project is currently scheduled for completion by late 2004. The CISO has also identified a need for additional transmission to address reliability concerns in the San Diego and southern Orange County area beginning in 2005. To reliably meet projected demand growth, San Diego Gas and Electric has proposed a 500 kV interconnection with Southern California Edison in 2005 called the Valley-Rainbow project. This project would also foster increased competition in the regional electricity market. However, licensing delays may delay the project's in-service date and expose the San Diego area to reduced levels of reliability.

California Senate Bill 28X may affect requirements for pollution reduction retrofits on generating units within the state. As plans regarding implementation of the bill are not completed, its impact on reliability cannot be assessed at this time. Also, several hundred megawatts of generation capacity may be retired at the end of 2002 due to environmental limitations and/or decisions by the owners not to install retrofit equipment on the plants.

WECC has 145 members and encompasses about 1.8 million square miles in 14 western states, two Canadian provinces, and a portion of Baja California Norte, Mexico. Extremes in population and demand densities, in addition to long distances between demand centers and electric generation sources, characterize the Region. The Region is subdivided into four areas: the Northwest Power Pool Area, which is winter peaking and heavily dependent on hydroelectric generation (62% of installed capacity); the Rocky Mountain Power Area, which can be either summer or winter peaking with a 13% hydroelectric and 60% coal-fired generating

capacity mix; the Arizona-New Mexico-Southern Nevada Power Area, which is summer peaking with a 14% nuclear and 36% coal-fired generating capacity mix; and the California-Mexico Power Area, which is summer peaking and heavily dependent on gas-fired generating units (52% of installed capacity).

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