Reliability Assessment

1998–2007

The Reliability of

Bulk Electric Systems

in North America

North American Electric Reliability Council

September 1998

CONTENTS

About This Report

The North American Electric Reliability Council (NERC) Board of Trustees formed the Reliability Assessment Subcommittee (RAS) in 1970 to annually review the overall reliability of existing and planned electric generation and transmission systems of the Regional Councils.

This *Reliability Assessment 1998–2007* report presents:

- an assessment of electric generation and transmission reliability through 2007,
- an assessment of the generation adequacy of each Interconnection in North America,
- a discussion of key issues affecting reliability of future electric supply, and
- Regional assessments of electric supply reliability, including issues of specific Regional concern.

This report reflects the expertise, judgment, and interpretations of the RAS members. In preparing this report, RAS:

- interviewed representatives of each Region,
- 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 reflect conditions projected as of January 1, 1998. Detailed background data are available in NERC's *Electricity Supply & Demand* (ES&D) database, 1998 edition.

In response to evolving, market-driven changes in utility practices in planning and operations, major disturbances in the Western Interconnection in 1996, and feedback on the usefulness of previous RAS assessment reports, RAS recognized the need for a major review of the Regional assessment process. RAS developed and is implementing a three-phase approach toward achieving a compliance-based process for the Regional assessments.

For Phase 1, RAS conducted interviews of the Regions in 1997 that described to the Regions what the future assessment process may be, established the potential elements to be assessed, and set up a forum for discussing Regional issues related to reliability. The 1998 interviews (Phase 2) incorporated a review of the Regional plans for conformance to the NERC Planning Standards approved by the NERC Board of Trustees in September 1997. The interviews also expanded the forum for the Regions to discuss reliability issues and assessment methods in the changing electric utility industry. Phase 3 will include mandatory compliance and corrective measures, subject to the enforcement terms to be developed by NERC and the Regions.

New Interconnection Analysis

This year's report includes new generation resource adequacy analyses of the electric systems in North America on an Interconnection basis. For purposes of this report, an Interconnection is defined as any one of the four major electric system networks in North America that operate synchronously and are tied together by direct current ties. These include the Eastern, Western, ERCOT, and Québec Interconnections.

FOREWORD

Note: At its July 1998 meeting, the NERC Operating Committee agreed that Hydro-Québec be considered part of the Eastern Interconnection. However, for this report, Hydro-Québec was analyzed as a separate Interconnection.

Assessment Timeframe

The RAS views this assessment in two timeframes: the near term, consisting of the next three to five years and the long term, which is the balance of the ten-year assessment period. Assessing reliability beyond the near term is extremely difficult because of the level of uncertainty and 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 commitments or to reveal future plans. The current methods of reporting data on purchases and sales are resulting in some double counting of generation resources, degrading the quality of the data.

Similarly, transmission plans projected more than five years are speculative because justification studies are usually incomplete and regulatory approvals have not been received.

RAS will continue to evaluate the usefulness of collecting data and developing an assessment for a ten-year timeframe. Part of that continued evaluation will include discussions with the Department of Energy (DOE) and others on the advisability of reducing the annual data reporting requirements to include the current year and five (instead of ten) future years.

About NERC

Electric utilities formed NERC in 1968 to coordinate, promote, and communicate about the ***reliability*** of their generation and transmission systems. In short, NERC helps its members work together to reduce the likelihood of blackouts.

NERC's members are ten Regional Councils encompassing virtually all of the electric systems in the continental United States, Canada, and a portion of Baja California Norte, Mexico. The members of the Regional Councils are electric systems from all ownership segments of the industry — investor-owned, federal, provincial, municipal, state, rural electric cooperative, independent power producers, and power marketers.

NERC in Transition

NERC is currently in the process of transforming itself from a once voluntary organization into a self-regulating reliability organization with compliance enforcement powers. This change is needed to ensure the continued reliability of North America's interconnected bulk electric systems in a competitive and restructured industry.

In 1997, NERC assembled an independent panel of experts, facilitated by an independent consultant, to recommend the best ways to set, oversee, and implement policies and standards that would ensure continued reliability. In its report, the Electric Reliability Panel stated its belief that the introduction of competition within the electric industry and open access to transmission systems would require a new organization that has the technical competence, unquestioned impartiality, authority, and the respect of electricity market participants necessary to enforce compliance with reliability standards. Thus, the concept of the North American Electric Reliability Organization (NAERO) was born.

At its January 1998 meeting, NERC's Board of Trustees adopted an action plan to encourage discussion of the panel's report and recommendations. A Future NERC Review Team was formed to develop detailed policy recommendations and an implementation plan for the Board's consideration. Subsequently, a public comment period was opened and a number of public workshops were held to provide input on the implementation plan. At a special meeting in July 1998, the NERC Board of Trustees voted to proceed with the NAERO implementation plan and to transform NERC into NAERO.

Similar discussions were taking place concurrently in the DOE Reliability Task Force. Both NERC and DOE groups reached similar conclusions on the need for a self-regulating reliability organization (SRRO). Currently, legislation is being prepared by DOE to clarify the authority of the Federal Energy Regulatory Commission (FERC) in the area of reliability, including the approval of an international SRRO.

The following were among the recommendations approved by the Board in July:

- Basic elements of a new statement of Mission and Purpose for NAERO.
- Election in January 1999 of nine independent members to the NERC Board who will succeed the current Board after reliability legislation is enacted in the United States and Canada.
- Key elements that will serve as the foundation for binding agreements between NAERO and affiliated Regional reliability organizations.
- Membership of NAERO and membership and voting procedures for the three Standing Committees of NAERO — Security, Adequacy, and Market Interface.
- Formation of an "Interim" Market Interface Committee to review NERC reliability policies and standards for impacts on commercial markets prior to the formation of the new Market Interface Committee.

The NERC Board also discussed draft reliability legislation prepared by NERC's legal counsel and agreed to solicit public comments on this draft and develop consensus draft legislation for review by the Board.

EXECUTIVE SUMMARY

Near Term

Electricity supply and transmission systems in the United States and Canada are adequate for the next three to five years. Even when projections and assessments predict adequate resources, unanticipated equipment problems and extreme weather can combine to create supply problems.

Some near-term supply shortfalls could occur. Low margins in the ERCOT Interconnection are possible if proposed capacity from the supply market does not materialize and retirements occur as announced. Unavailability of some nuclear generating units could cause capacity shortages in the MAIN Region during peak demand periods. Temporary supply shortfalls could also occur in Alberta because development of market-driven resources is lagging the growth in customer demand.

The proposed regulations on nitrous oxide (NO_x) emissions are capable of creating future reliability concerns. If the final NO_x legislation adopts the currently proposed compliance deadline of May 1, 2003, outages of significant amounts of fossil-fuel generation will be necessary to install the required NO_x control devices. The scope of this concern requires data collection from the Regions and time for analysis, neither of which can be done in time for the publication of this report. These concerns will be investigated and assessed by RAS in the coming year.

Transmission systems increasingly challenged to accommodate demands of evolving competitive electricity markets. Market-driven changes in transmission usage patterns, the number and complexity of transactions, and the need to deliver replacement power to capacity-deficient areas are causing new transmission limitations to appear in different and unexpected locations.

Transition to the Year 2000 (Y2k) will be a critical challenge to electric industry. Certain computer software and embedded chips used in electric utility equipment and systems may misinterpret the change from the year 1999 to 2000 as they process data. At the request of the U.S. Department of Energy, NERC is coordinating the electric industry's response to this challenge and has assumed a leadership role in preparing electricity production and delivery systems throughout North America for the Y2k transition. NERC's Y2k program focuses on activities in three principal areas:

1. sharing of Y2k solutions,
2. identifying potential weaknesses in interconnected system security, and
3. operational preparedness.

Long Term

Electric supply adequacy could deteriorate in the long term if development of additional generating and transmission capacity does not keep pace with growing customer demand. NERC reports and assesses resource data in its role to ensure reliability. Ultimately, the individual systems and the open market are responsible for providing adequate resources to meet the demands of electric consumers.

Capacity margins eroding to dangerously low levels. Lower capacity margins can diminish the ability of the bulk electric supply systems in North America to respond to higher-than-projected customer demand caused by extreme weather and unexpected equipment shutdowns or outages.

Demand is continuing to grow:

- **Actual growth higher than projections** — Actual experienced growth rates over the last few years are 70% higher than current projections.
- **Strong economy driving growth** — A strong economy in North America is continuing to drive demand and energy to grow faster than projected.

- **Margins could fall below 10% —** Margins in the ERCOT Interconnection are projected to fall below 10% by 2003 unless proposed capacity additions are constructed. If demand growth continues at the rate experienced over the last few years, margins could fall below 10% in the Eastern Interconnection by 2004 and in the Western Interconnection by 2007.

Generating capacity additions not keeping pace. About 24,400 MW of generation additions are planned (not already committed or under construction) before the summer of 2002. During that same period, demand is projected to grow by about 36,000 MW.

Increasing reliance on capacity purchases from undisclosed sources. This trend puts increased dependence on the capacity margins of others and on the demand diversity within each Interconnection. Delivering those resources to deficient areas may become more and more difficult as the transmission system continues to become increasingly constrained. Although uncertainties and assumptions have always been part of long-term transmission studies, the level of uncertainty has increased tremendously. Purchases from undisclosed resources and the reluctance of generation developers to disclose plans for future capacity additions are making modeling for long-term transmission analysis virtually impossible.

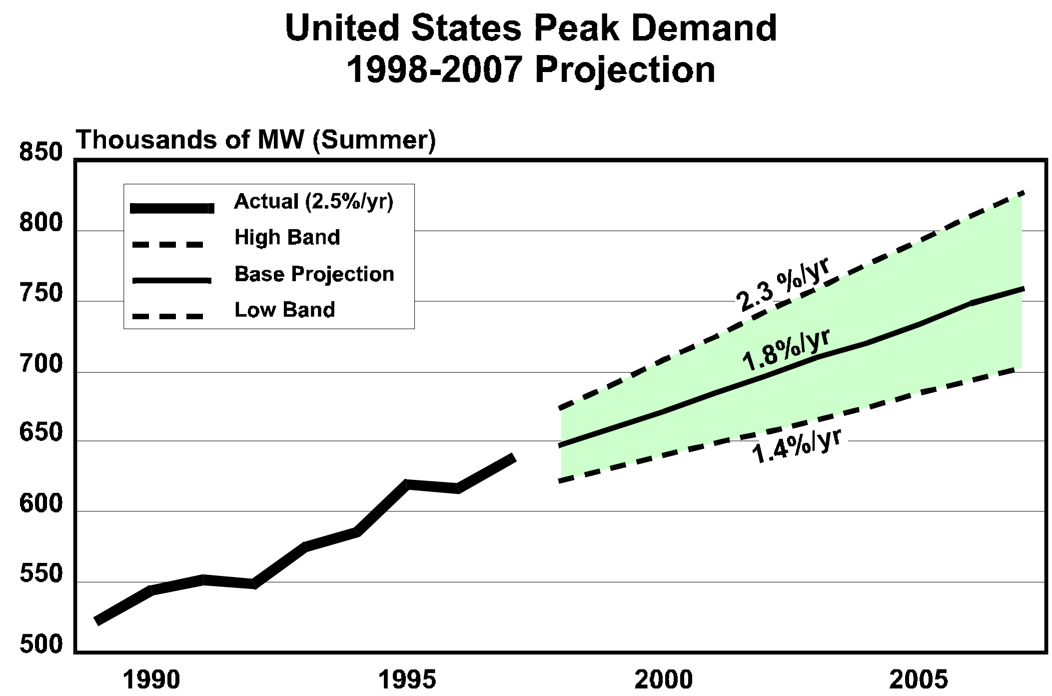
Very few bulk transmission additions planned. Only 6,588 miles of new transmission (230 kV and above) are planned throughout North America over the next ten years. This is significantly lower than the additions that had been planned five years ago. The majority of the proposed transmission projects are for local system support. As the demand on the transmission system continues to rise, the ability to deliver remote resources to load centers will deteriorate. New transmission limitations will appear in different and unexpected locations as the generation patterns shift to accommodate market-driven energy transactions and new independent generators. Delivering energy to deficient areas may become more difficult.

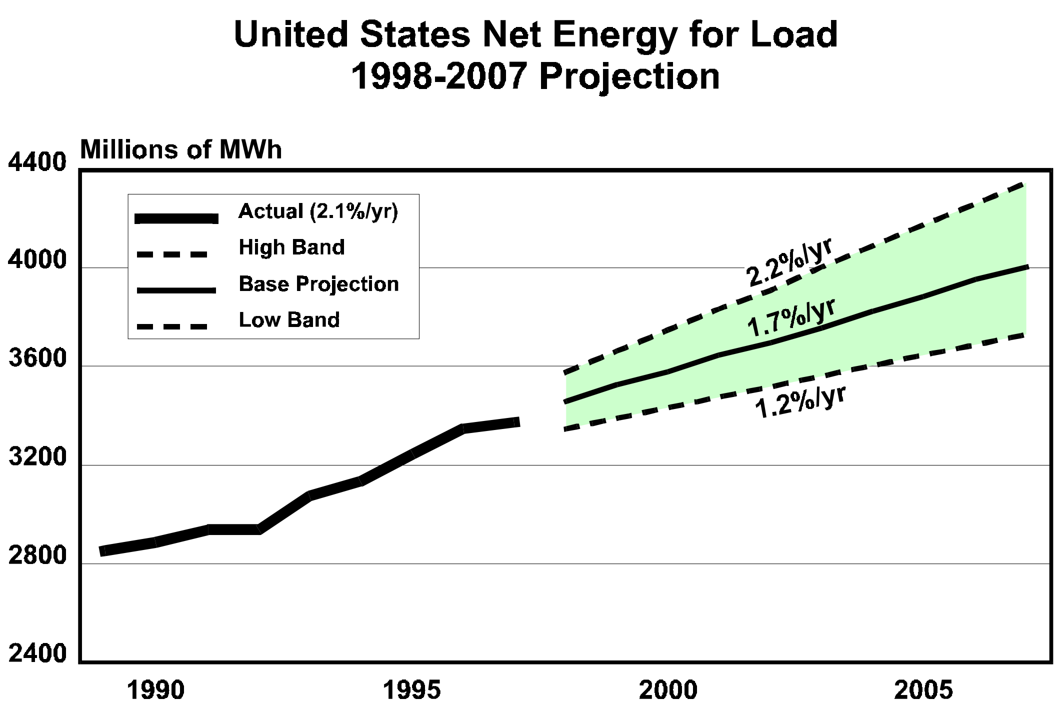
Less coordination of generation and transmission plans. The close coordination of generation and transmission planning is diminishing as vertically integrated utilities divest their generation assets and most new generation is being proposed and developed by independent power producers. Once new generation is announced, the necessary transmission additions to support it must still be designed, coordinated with other generation and transmission additions, and constructed. Since these activities are no longer carried out within a single organization, more time will need to be allowed to coordinate and perform these tasks to properly integrate the new generation to ensure reliability before it can come into service.

Demands and Resources

The average annual peak demand growth over the next ten years is projected to be a relatively modest 1.8% for demand and 1.7% for energy use in the United States (see Figure 1). These increases are similar to the projections of the last several years. High and low bands around the base forecast reflect a range of forecast uncertainty.

Figure 1

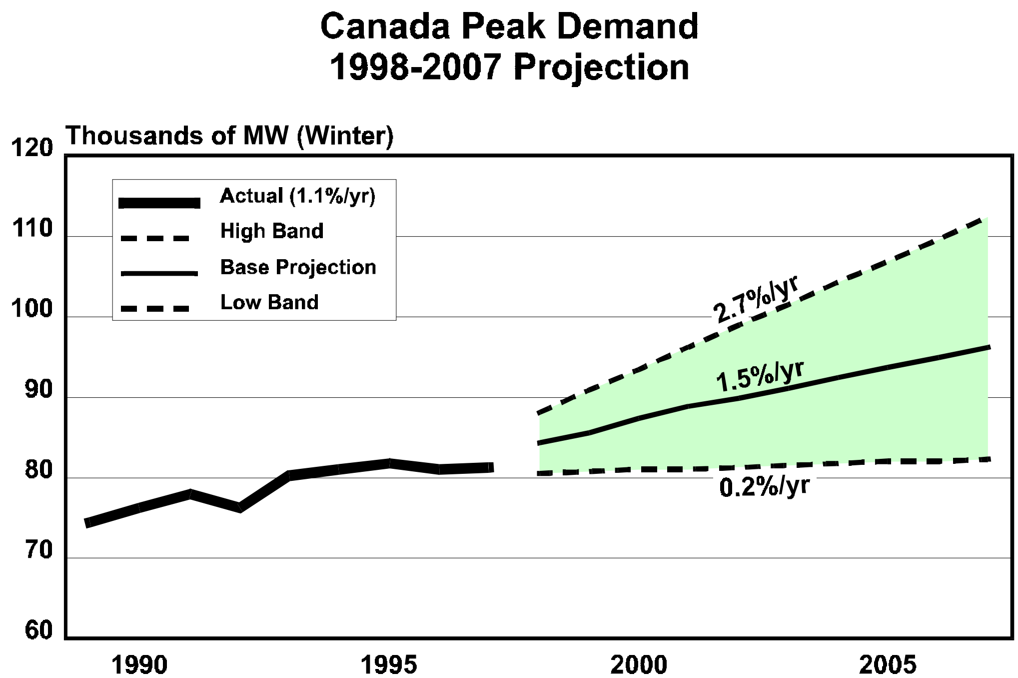


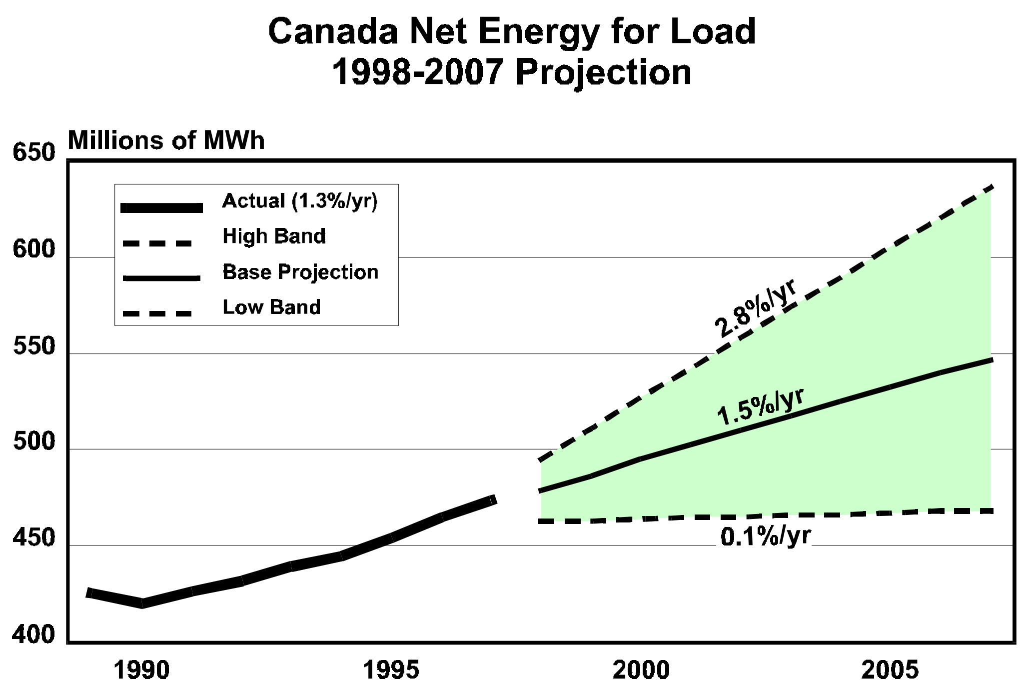


Assessment

The ten-year growth rates in Canada for both peak demand and energy use are 1.5% (see Figure 2). Demand and energy growth experienced in Canada has been somewhat less over the last nine years. Forecast uncertainty is shown by the bandwidths around the base forecasts in Figure 2.

Figure 2





Actual demand and energy growth experienced in the United States over the last nine years is about 70% above the current projections. Actual growth rates have been closer to the rate calculated as the high band for both demand and energy.

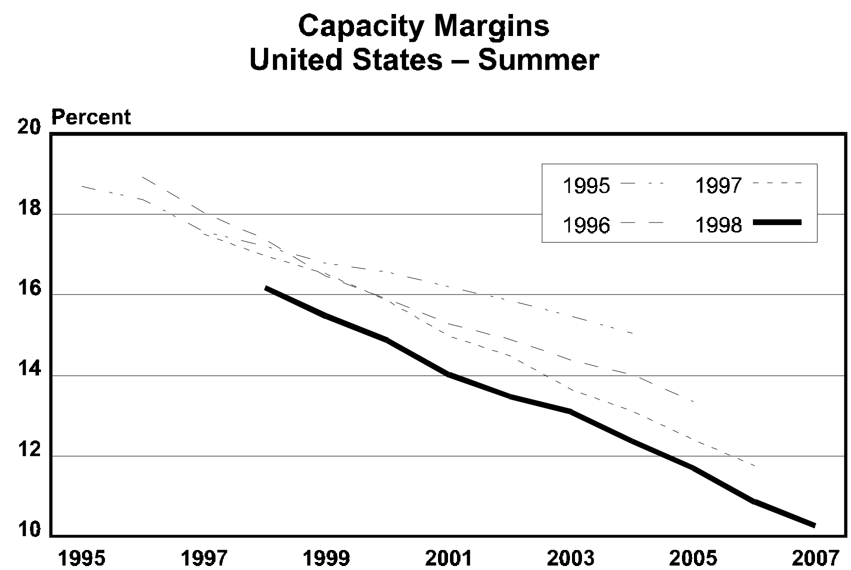
Should demand growth continue at the historical rate, capacity margins could fall below 10% in the Eastern Interconnection by 2004 and in the Western Interconnection by 2007. Margins in the ERCOT Interconnection are projected to fall below 10% by 2003 with the projected demand growth. Interconnection margins are explored further in the Interconnection Analysis section of this report. The evolution to a market-based electricity supply will present significant challenges to accurately forecast demand. As the industry moves to "just-in-time" resource additions, demand and energy projections will become critical to ensuring continued resource adequacy. Given the critical nature of the projections, the process for developing and reporting them will warrant close scrutiny in the next few years.

Capacity margins in the United States continue to decline from projections of the last few years (see Figure 3). For the first time, projected margins in the United States are as low as 10% by the end of the assessment period. Because of the uncertainty in the marketplace, a number of Regions and subregions have discontinued reporting even uncommitted resource additions needed to satisfy Regional criteria in the latter years of the ten-year review period, contributing to the significant decline in the margins.

The profile of the Canadian capacity margins has changed substantially this year, caused by the "lay-up" of 4,300 MW of nuclear capacity by Ontario Hydro in 1998. Projected return-to-service dates of those generators in 2003 bring the Canadian margins back to the level projected in 1997.

RAS expects that more than just the currently committed generating capacity additions will be built over the next ten years. However, the trend of declining margins must be monitored and reported to encourage market participants to plan and construct adequate capacity in a timely fashion to keep up with the trends in demand growth.

Figure 3



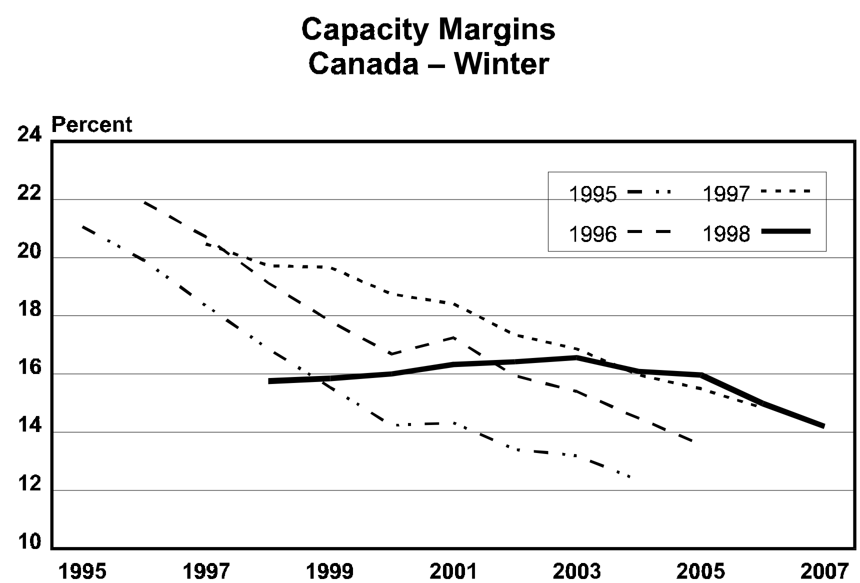


Table 1

Region	Annual Net Energy for Load (Thousands of MWh)	Total Internal Demand (MW)	Net Capacity Resources (MW)	Capacity Margins (% of Capacity Resources)	Transmission 230 kV & Above (Circuit Miles)
			1998		
ECAR	541,787	94,725	105,106	13.3	15,962
ERCOT	255,673	50,944	55,771	14.4	7,032
FRCC*	182,267	35,633	39,613	17.0	6,566
MAAC	250,401	48,846	56,155	17.1	6,931
MAIN	236,252	47,522	52,160	13.4	5,592
MAPP-U.S.	155,446	30,407	34,027	17.1	14,106
MAPP-Canada (winter)	36,608	6,573	7,845	19.4	5,853
NPCC-U.S.	268,289	50,240	60,729	17.3	6,456
NPCC-Canada (winter)	333,612	60,042	69,582	17.9	28,562
SERC	754,105	143,280	155,016	12.9	27,925
SPP	178,371	38,636	43,591	15.1	6,515
WSCC-U.S.	636,756	108,461	135,687	23.0	56,381
WSCC-Canada (winter)	108,359	17,594	18,807	6.4	10,543
U.S.	3,459,347	648,694	737,855	16.2	150,225
CANADA (winter)	478,579	84,209	96,234	15.8	44,958
MEXICO (summer)	7,463	1,432	1,698	15.7	425
			2007		
ECAR	624,683	109,951	120,314	11.8	16,227
ERCOT	285,423	62,127	61,911	6.0	7,782
FRCC*	226,090	42,885	47,078	16.1	6,858
MAAC	287,429	55,387	56,465	5.1	7,023
MAIN	271,042	54,690	61,279	15.0	5,689
MAPP-U.S.	175,106	34,072	33,896	7.6	14,136
MAPP-Canada (winter)	40,443	6,996	8,309	18.4	6,474
NPCC-U.S.	304,513	56,875	59,851	5.0	6,658
NPCC-Canada (winter)	377,351	68,495	76,621	15.1	28,820
SERC	873,847	170,558	179,254	9.8	28,917
SPP	214,342	45,643	48,874	11.0	7,195
WSCC-U.S.	747,936	128,079	140,902	12.1	58,734
WSCC-Canada (winter)	128,543	20,627	22,859	9.8	10,560
U.S.	4,010,411	760,267	809,824	10.3	155,811
CANADA (winter)	546,337	96,118	107,789	14.2	45,854
MEXICO (summer)	13,112	2,526	2,883	12.4	530

* FRCC uses Reserve Margin, not Capacity Margin, as one of its guidelines in assessing adequacy.

Interconnection Analysis

The following section of the assessment examines the resource adequacy of the four Interconnections in North America. Trends are examined in projections of demand, capacity resources, the growing reliance on purchases from others, and generating capacity not yet under construction. The following legend is applicable to all of the Interconnection tables listed in the section. NERC reports and assesses resource data in its role to ensure reliability. Ultimately, the individual systems and the open market are responsible for providing adequate resources to meet the demands of electric consumers.

Legend

Projected Interconnection Internal Demand	Sum of Internal Demand plus Standby Demand (monthly coincident) for the Interconnection
Interconnection Interruptible Demand & DCLM	Sum of Interruptible Demand and Direct Control Load Management (DCLM) for the Interconnection
Projected Interconnection Net Internal Demand	Projected Interconnection Internal Demand less Interconnection Interruptible Demand and DCLM
Projected Interconnection Generating Capacity	Sum of Projected Utility Generating Capacity plus Projected IPP Generation Capacity for the Interconnection
Interconnection Tie Capability	Import Capability of the Interconnection's HVDC ties to other Interconnections
Net Interconnection Capacity Resources	Projected Interconnection Generation plus Interconnection Tie Capability
Interconnection Margin	Net Interconnection Capacity Resources less Projected Interconnection Net Internal Demand
Interconnection Capacity Margin (%)	Interconnection Margin divided by Net Interconnection Capacity Resources, expressed as a percentage
Net Interconnection Capacity Resources Less Capacity Not Under Construction	Existing Capacity, less Planned Capacity Retirements, plus Planned Capacity Reactivations, plus Capacity Under Construction, plus Interconnection Tie Capability
Projected Capacity Additions	Projected Capacity Additions (cumulative, not under construction) for the Interconnection
Projected Capacity Additions as % of Projected Internal Demand	Projected Capacity Additions as a percentage of Projected Internal Demand
Projected Capacity Additions as % of Capacity Margin	Projected Capacity Additions as a percentage of MW Margin

For purposes of this report, an Interconnection is defined as any one of the four major electric system networks in North America that operate synchronously and are tied together by direct current ties. These include the Eastern, Western, ERCOT, and Québec Interconnections. At its July 1998 meeting, the NERC Operating Committee agreed that Hydro-Québec be considered part of the Eastern Interconnection. However, for this report, Hydro-Québec is considered as a separate Interconnection.

Interconnection Capacity Margin and Net Interconnection Capacity Resources are newly defined terms for the Interconnection analysis. These terms are used to quantify the generation within an Interconnection and the ability of the Interconnection to import resources from neighboring Interconnections. Net purchases and sales are not included in this calculation because all purchases and sales are limited to the resources within the Interconnection or by the tie capability. No plans to increase the Interconnection tie capability were reported. Therefore, the tie capability of all Interconnections was assumed to be constant throughout the assessment period.

Demand diversity within an Interconnection may vary greatly due to demographics and the size and nature of the demand within the Interconnection. However, the impact of demand diversity on capacity margins can be counteracted and sometimes outweighed by forced outages of generation caused by equipment failures. It should be noted that the 1994–1996 average equivalent forced outage rate of generation in North America was 9.9% based on all units reporting to the NERC Generating Availability Data System (GADS). To adequately address this interaction, probabilistic analysis would be required. Therefore, both demand diversity and generation availability were excluded from the calculation of the Interconnection capacity margins.

Eastern Interconnection

Demand in the Eastern Interconnection is projected to grow at 1.7% per year, which is below the 2.4% growth experienced over the last nine years (see Figure 4). The upper band for the demand projection is only 2.3%. Should the historical growth trend continue, the capacity margin for the Interconnection could fall below 10% by 2004. Projected capacity margins continue to decline compared to margins projected in the last several years (see Figure 5). Some Regions have discontinued reporting uncommitted resources in the latter years of the review period causing a portion of this decline.

Figure 4

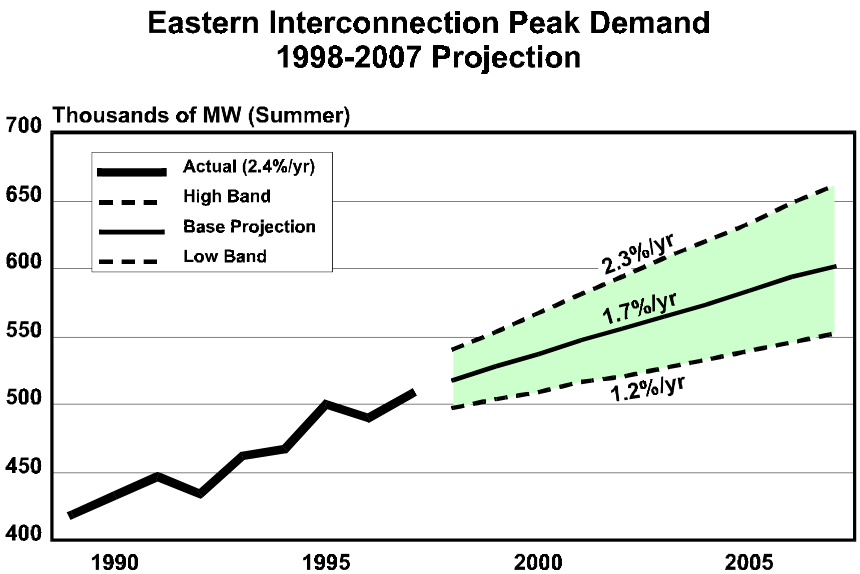
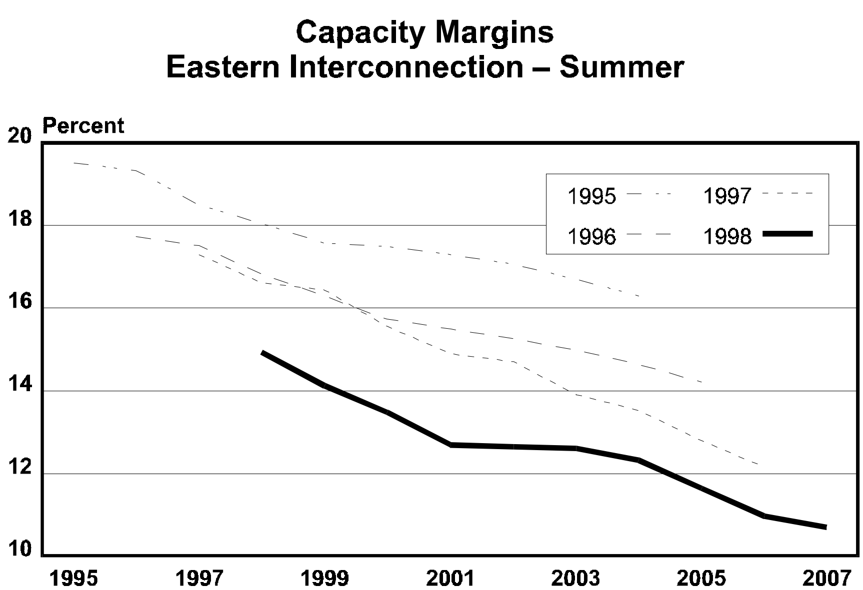


Figure 5



There is a growing trend in the Eastern Interconnection to rely on purchases from undisclosed sources. Such purchases are a reliance on the capacity margin and demand diversity within the Interconnection and the tie capacity of the Interconnection. However, reliance on the demand diversity may be problematic due to transmission system limitations that may arise in delivering those resources to deficient areas. Forced outages of generation during the summer of 1998 demonstrated the potential for deliverability problems of remote capacity resources.

Similarly, there are a number of "as-yet" uncommitted generator capacity additions reported as planned within the Interconnection. Some of these generators are proxies for a recognized need for additional capacity, while others are actual planned unit additions. This shows a continued reliance on short-lead-time generator capacity additions.

Figure 6 shows that if demand were to grow at the high end of the projected bandwidth (2.3%), the generation existing and under construction would be less than the net summer peak demand (all direct control load management exercised and interruptible demands curtailed) by the summer of 2002. The Interconnection's ability to serve that demand would be reliant on demand diversity within the Interconnection and its ability to import resources through its ties. Although the benefit of demand diversity could be great within the Eastern Interconnection, it would be at least partially offset by unplanned generation outages. Also, the ability to take advantage of the diversity within the Interconnection would be subject to transmission limitations. For instance, existing transmission limitations into and out of New England make it impossible to take full advantage of demand diversity between New England and Florida.

Reported generation additions in the Eastern Interconnection are not keeping pace with projected demand growth. Within the Interconnection, there are only about 24,400 MW of planned generation additions (not already committed or under construction) that have been reported to be constructed before the summer of 2002. During that same period, demand is projected to grow by about 36,000 MW. If demand growth materializes at the higher end of the demand growth bandwidth (2.3% per year), demand would grow by about 47,000 MW by 2002, decreasing the Interconnection capacity margin to about 11%. Similarly, if extreme weather caused widespread, abnormally high demand (even 5% above projections), capacity margins would fall below 10% by 1999, and the operable generation may not be able to sustain the demand during peak periods.

This continued imbalance between the projected demand increases and planned generation resources is indicative of erosion in the ability of the Eastern Interconnection to serve higher-than-projected demands or sustain unexpected generation outages. It is clear that additional generating capacity, above what has been reported, will be needed in the Interconnection to maintain adequate operating margins, or significant amounts of new interruptible demand and direct-control load management will be needed to offset the potential shortfalls. Hopefully, many of the merchant generation projects being announced in the electric industry trade press will also be constructed.

Figure 6

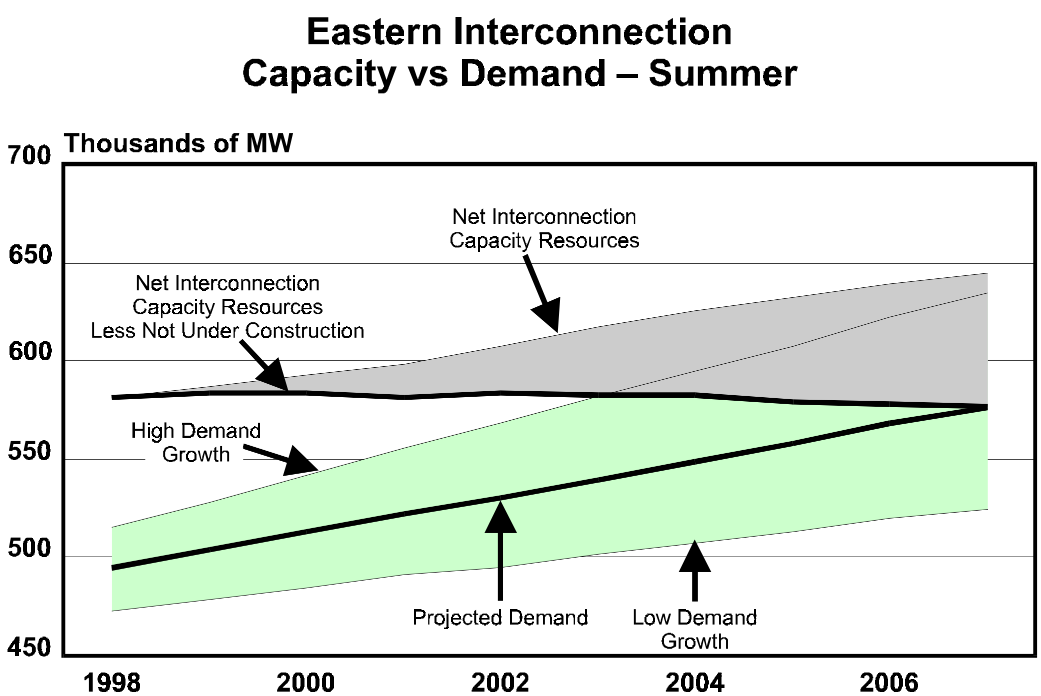


Table 2 shows that more than half of the Interconnection margin of the Eastern Interconnection will consist of capacity not yet under construction by the summer of 2004. Almost its entire Interconnection margin planned for 2007 is not yet under construction.

Table 2 — Eastern Interconnection – Summer

	1998	1999	2000	2001	2002
Projected Interconnection Internal Demand	518,763	528,519	537,834	547,624	556,124
Interconnection Interruptible Demand & DCLM	24,230	24,751	25,078	25,230	25,558
Projected Interconnection Net Internal Demand	494,533	503,768	512,756	522,394	530,566
Projected Interconnection Generating Capacity	574,409	579,728	585,716	591,314	600,468
Interconnection Tie Capability *	6,900	6,900	6,900	6,900	6,900
Net Interconnection Capacity Resources	581,309	586,628	592,616	598,214	607,368
Interconnection Margin	86,776	82,860	79,860	75,820	76,802
Interconnection Capacity Margin (%)	14.9	14.1	13.5	12.7	12.6
Net Interconnection Capacity Resources Less Capacity Not Under Construction	580,715	583,970	583,505	581,050	583,001
Projected Capacity Additions	594	2,658	9,111	17,164	24,367
Projected Capacity Additions as % of Projected Internal Demand	0.1	0.5	1.8	3.3	4.6
Projected Capacity Additions as % of Capacity Margin	0.7	3.2	11.4	22.6	31.7

	2003	2004	2005	2006	2007
Projected Interconnection Internal Demand	565,558	574,108	584,313	594,659	602,360
Interconnection Interruptible Demand & DCLM	25,784	26,055	26,171	26,202	26,504
Projected Interconnection Net Internal Demand	539,774	548,053	558,142	568,457	575,856
Projected Interconnection Generating Capacity	610,685	618,175	624,720	631,575	637,819
Interconnection Tie Capability *	6,900	6,900	6,900	6,900	6,900
Net Interconnection Capacity Resources	617,585	625,075	631,620	638,475	644,719
Interconnection Margin	77,811	77,022	73,478	70,018	68,863
Interconnection Capacity Margin (%)	12.6	12.3	11.6	11.0	10.7
Net Interconnection Capacity Resources Less Capacity Not Under Construction	582,427	582,080	579,379	578,291	576,936
Projected Capacity Additions	35,158	42,995	52,241	60,184	67,783
Projected Capacity Additions as % of Projected Internal Demand	6.5	7.8	9.4	10.6	11.8
Projected Capacity Additions as % of Capacity Margin	45.2	55.8	71.1	86.0	98.4

* Eastern Interconnection tie capabilities include all HVDC tie import capabilities. However, HVDC tie import capability from the Québec Interconnection into New York Power Pool is the maximum approved limit, dependant on internal New York schedules and flow across key interfaces.

Western Interconnection

Demand in the Western Interconnection is projected to grow at 1.9% per year compared with the 2.5% average growth experienced in the West over the last nine years (see Figure 7). Should the historical growth trend continue, the Interconnection capacity margin would fall below 10% by 2007. The Interconnection margin continues to show a decline over the assessment period, consistent with projections made in recent years (see Figure 8).

Figure 7

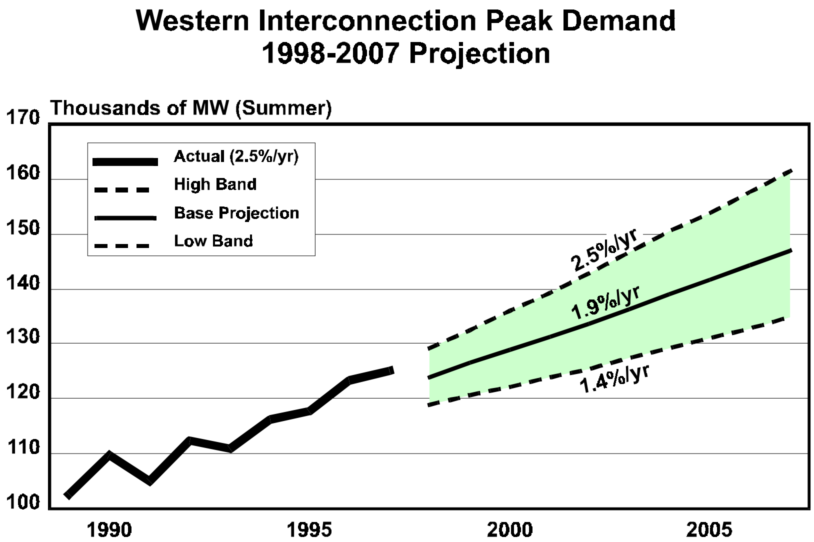
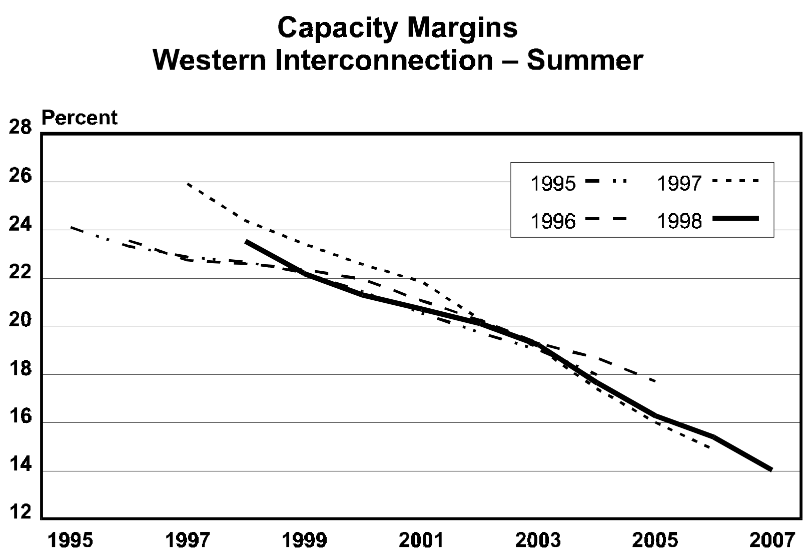


Figure 8



The reported generation capacity expansion plans show that only 35.9% of the Western Interconnection's 2007 margin consists of planned, but not-yet-under-construction generation (see Table 3). This is the lowest reliance on uncommitted generation of all four Interconnections. The Western Interconnection's existing generating capacity is more capable of supporting higher-than-projected peak demands. Net internal demand could grow by a total of 20% from 1998 projected demand before the Interconnection's capacity margin would fall below 10%.

Existing generation in the Western Interconnection is capable of sustaining projected demand growth, even if at the high side of the bandwidth (see Figure 9).

Figure 9

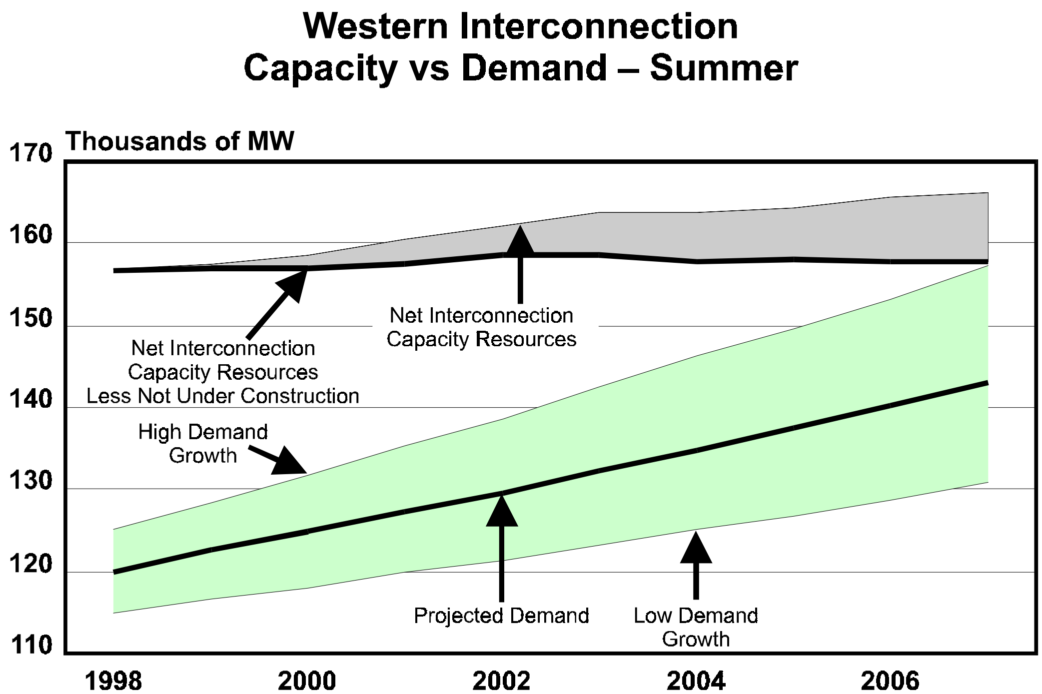


Table 3 — Western Interconnection – Summer

	1998	1999	2000	2001	2002
Projected Interconnection Internal Demand	123,969	126,613	128,935	131,388	133,648
Interconnection Interruptible Demand & DCLM	3,975	4,000	4,131	4,147	4,157
Projected Interconnection Net Internal Demand	119,994	122,613	124,804	127,241	129,491
Projected Interconnection Generating Capacity	155,830	156,510	157,531	159,438	160,997
Interconnection Tie Capability	1,080	1,080	1,080	1,080	1,080
Net Interconnection Capacity Resources	156,910	157,590	158,611	160,518	162,077
Interconnection Margin	36,916	34,977	33,807	33,277	32,586
Interconnection Capacity Margin (%)	23.5	22.2	21.3	20.7	20.1
Net Interconnection Capacity Resources Less Capacity Not Under Construction	156,850	157,062	156,928	157,427	158,534
Projected Capacity Additions	105	528	1,683	3,091	3,543
Projected Capacity Additions as % of Projected Internal Demand	0.1	0.4	1.3	2.4	2.7
Projected Capacity Additions as % of Capacity Margin	0.3	1.5	5.0	9.3	10.9

Table 3 — Western Interconnection – Summer (continued)

	2003	2004	2005	2006	2007
Projected Interconnection Internal Demand	136,445	138,986	141,744	144,374	147,128
Interconnection Interruptible Demand & DCLM	4,170	4,181	4,193	4,200	4,200
Projected Interconnection Net Internal Demand	132,275	134,805	137,551	140,174	142,928
Projected Interconnection Generating Capacity	162,644	162,597	163,234	164,573	165,139
Interconnection Tie Capability	1,080	1,080	1,080	1,080	1,080
Net Interconnection Capacity Resources	163,724	163,677	164,314	165,653	166,219
Interconnection Margin	31,449	28,872	26,763	25,479	23,291
Interconnection Capacity Margin (%)	19.2	17.6	16.3	15.4	14.0
Net Interconnection Capacity Resources Less Capacity Not Under Construction	158,535	157,916	157,919	157,869	157,868
Projected Capacity Additions	5,189	5,761	6,395	7,784	8,351
Projected Capacity Additions as % of Projected Internal Demand	3.9	4.3	4.6	5.6	5.8
Projected Capacity Additions as % of Capacity Margin	16.5	20.0	23.9	30.6	35.9

ERCOT Interconnection

Demand growth in the ERCOT Interconnection is projected to grow at 2.2% per year, compared with the 2.8% average growth experienced in ERCOT over the last nine years (Figure 10). The projected high-band growth rate is equivalent to the historical growth rate.

ERCOT's future resource adequacy is heavily dependent on the capacity supply market. Approximately 10,000 MW of new generating capacity proposals have been submitted to the ERCOT ISO for Interconnection study. While this proposed capacity is not reported as "under construction," it reflects the desire of generating entities to build new capacity. Also, utilities in ERCOT have announced the retirement of 3,200 MW of existing capacity. Whether or not these retirements will occur as announced will depend on the need for the capacity at the time of the planned retirement.

ERCOT's dependence on proposed capacity additions is reflected in the reliance on significant purchases from unspecified resources. Since the import capability of the Interconnection's two HVDC ties is 940 MW, it is obvious that most of those purchases are surrogates for expected new capacity sources within ERCOT.

If none of the proposed capacity is built and the generating unit retirements occur as announced, the ERCOT Interconnection capacity margin would fall below 10% by 2003 and to negative 1.3% by 2007 (Figure 11) at the projected 2.2% demand growth rate. Should the historical growth rate trend continue, the capacity margin for the Interconnection would fall below 10% by 2002 and to negative 6.5% by 2007.

Figure 10

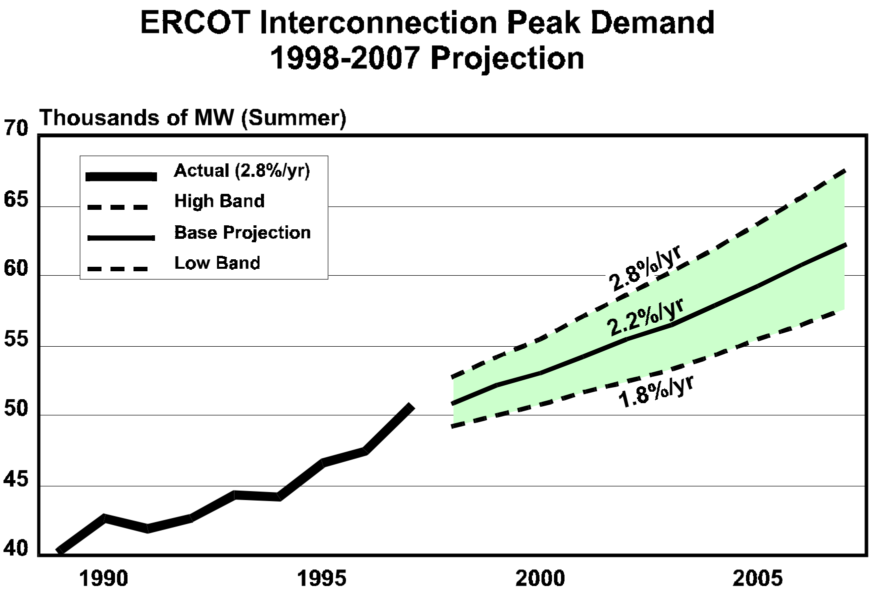
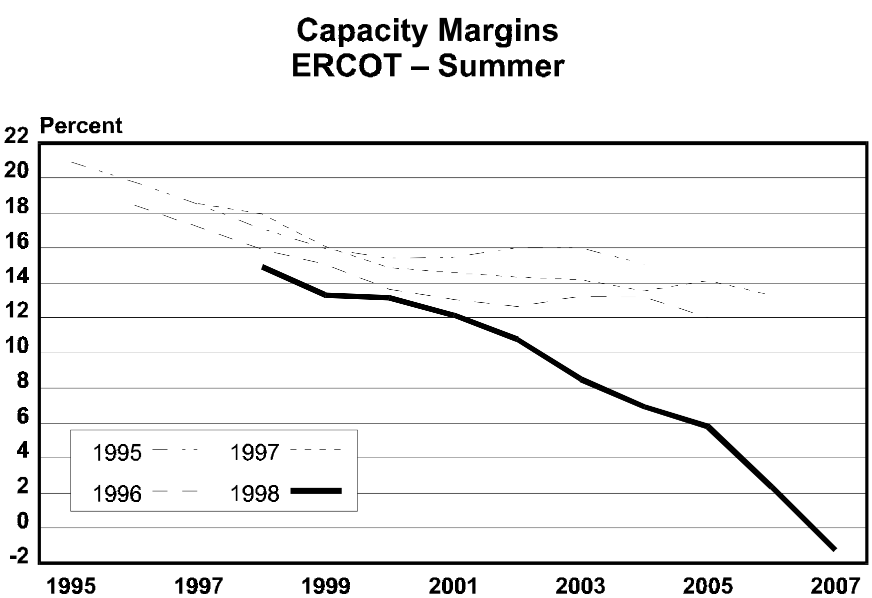


Figure 11



A significant amount of additional generation is needed in ERCOT as soon as possible. Events of the 1997 and 1998 summers indicate that demand spikes of 5% above forecast can occur in the Interconnection during extreme weather conditions. Prolonged extreme weather during the summer of 1998 caused a demand spike of 53,600 MW in early August (although about 3,000 MW of interruptible demand was being served) — a demand level not projected until after 2003. As seen in Figure 12, that level of demand almost exceeded ERCOT's existing generating capacity.

Figure 12

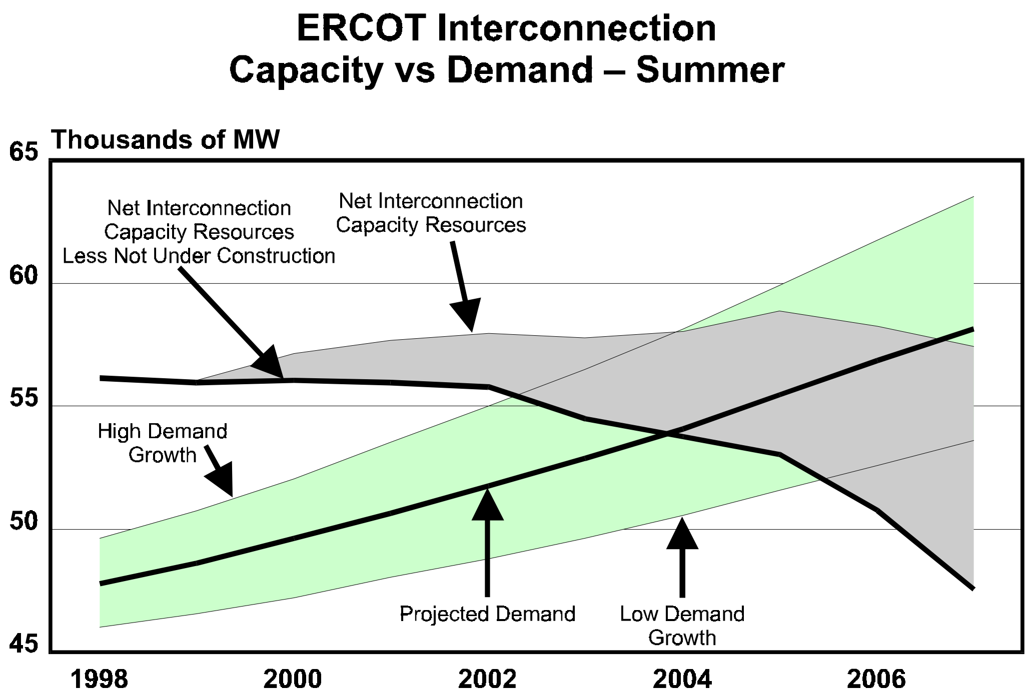


Table 4 — ERCOT Interconnection – Summer

	1998	1999	2000	2001	2002
Projected Interconnection Internal Demand	50,944	52,055	53,076	54,195	55,373
Interconnection Interruptible Demand & DCLM	3,198	3,419	3,469	3,547	3,621
Projected Interconnection Net Internal Demand	47,746	48,636	49,607	50,648	51,752
Projected Interconnection Generating Capacity	55,196	55,148	56,199	56,723	57,070
Interconnection Tie Capability	940	940	940	940	940
Net Interconnection Capacity Resources	56,136	56,088	57,139	57,663	58,010
Interconnection Margin	8,390	7,452	7,532	7,015	6,258
Interconnection Capacity Margin (%)	14.9	13.3	13.2	12.2	10.8
Net Interconnection Capacity Resources Less Capacity Not Under Construction	56,136	55,994	56,037	56,001	55,774
Projected Capacity Additions	0	94	1,102	1,662	2,236
Projected Capacity Additions as % of Projected Internal Demand	0.0	0.2	2.2	3.3	4.3
Projected Capacity Additions as % of Capacity Margin	0.0	1.3	14.6	23.7	35.7

	2003	2004	2005	2006	2007
Projected Interconnection Internal Demand	56,532	57,808	59,307	60,759	62,127
Interconnection Interruptible Demand & DCLM	3,689	3,754	3,821	3,882	3,944
Projected Interconnection Net Internal Demand	52,843	54,054	55,486	56,877	58,183
Projected Interconnection Generating Capacity	56,816	57,143	57,954	57,292	56,515
Interconnection Tie Capability	940	940	940	940	940
Net Interconnection Capacity Resources	57,756	58,083	58,894	58,232	57,455
Interconnection Margin	4,913	4,029	3,408	1,355	(728)
Interconnection Capacity Margin (%)	8.5	6.9	5.8	2.3	(1.3)
Net Interconnection Capacity Resources Less Capacity Not Under Construction	54,479	53,750	53,022	50,717	47,539
Projected Capacity Additions	3,277	4,333	5,872	7,515	9,916
Projected Capacity Additions as % of Projected Internal Demand	6.2	8.0	10.6	13.2	17.0
Projected Capacity Additions as % of Capacity Margin	66.7	107.5	172.3	554.6	NA

Québec Interconnection

At its July 1998 meeting, the NERC Operating Committee concluded that Hydro-Québec should be considered part of the Eastern Interconnection. The definition of "Interconnection" is to be revised accordingly in the *NERC Operating Manual*. Those actions are not reflected in this report.

Figure 13

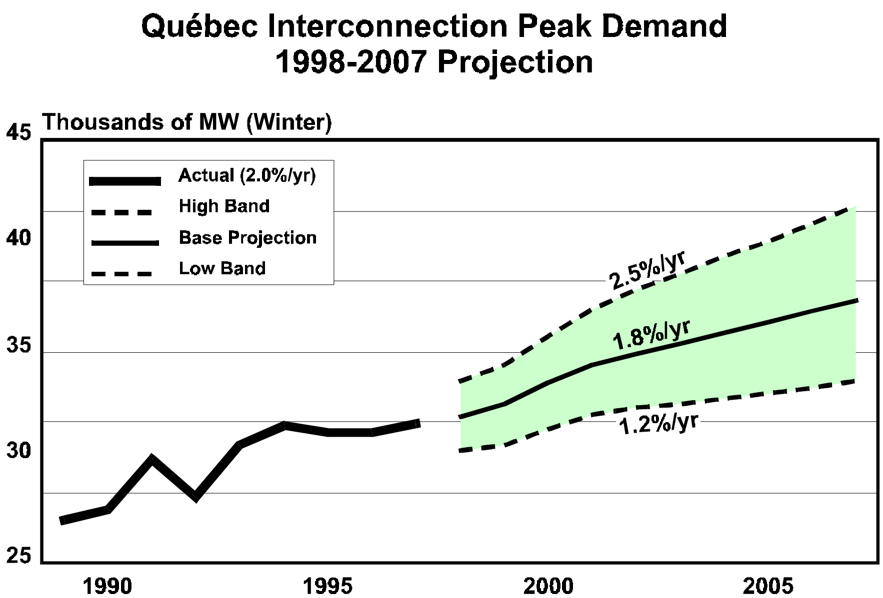
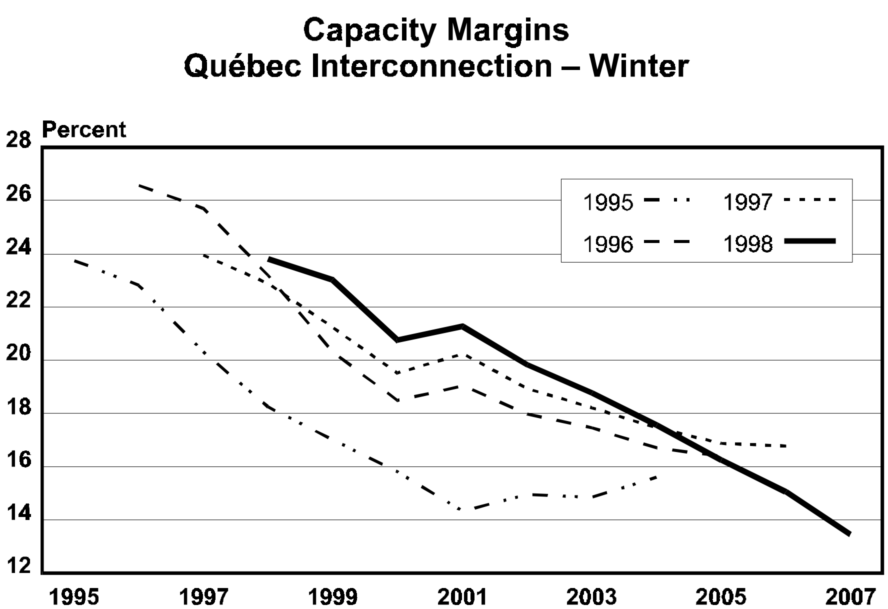


Figure 14



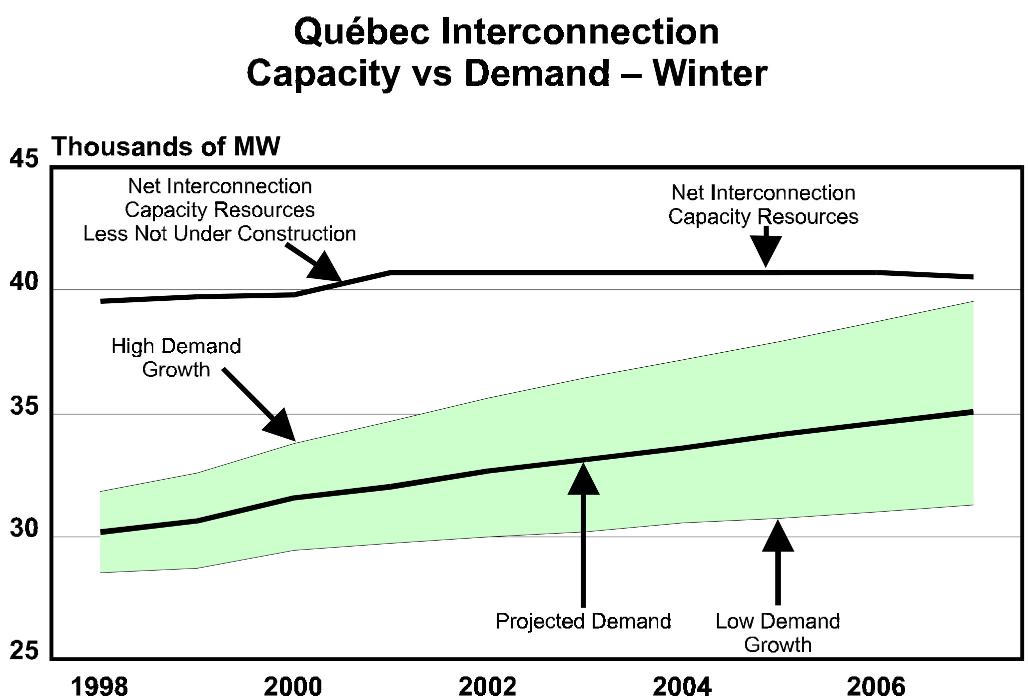
Demand growth in the Québec Interconnection is projected to be 1.8%, just below the historical 2.0% growth rate over the last nine years (see Figure 13). The winter Interconnection capacity margin for the Québec Interconnection, which is winter peaking, is the most robust of any of the Interconnections in North America for the assessment period. If demand grows at the upper band growth rate of 2.5% per year, the Interconnection's capacity margin falls below 10% in the winter of 2006/07 and to 7.2% by the winter of 2007/08.

The Québec Interconnection has more than adequate capacity margins for summer, remaining above 55% throughout the assessment period.

Only 900 MW of new generating capacity is reported as under construction by Hydro-Québec, scheduled for operation in 2001. No other planned capacity additions were reported. This lack of planned generation additions has a marked impact on the Interconnection capacity margin decline after 2001 (see Figure 14).

Winter capacity resources in the Québec Interconnection are expected to be adequate throughout the assessment period even if customer demand growth is at the high end of the bandwidth (Figure 15). During the summer, the Interconnection has significant resources available for export. There are no planned capacity additions for the Québec Interconnection during the assessment period.

Figure 15



Note: Québec's Interconnection Capacity resources include 5,050 MW capacity purchased from Churchill Falls throughout the assessment period.

Table 5 — Québec Interconnection – Winter

	1998/1999	1999/2000	2000/2001	2001/2002	2002/2003
Projected Interconnection Internal Demand	31,900	32,480	33,470	34,360	34,930
Interconnection Interruptible Demand & DCLM	1,780	1,870	1,910	2,310	2,300
Projected Interconnection Net Internal Demand	30,120	30,610	31,560	32,050	32,630
Projected Interconnection Generating Capacity*	36,031	36,259	36,322	37,204	37,204
Interconnection Tie Capability	3,500	3,500	3,500	3,500	3,500
Net Interconnection Capacity Resources	39,531	39,759	39,822	40,704	40,704
Interconnection Margin	9,411	9,149	8,262	8,654	8,074
Interconnection Capacity Margin (%)	23.8	23.0	20.7	21.3	19.8
Net Interconnection Capacity Resources Less Capacity Not Under Construction	39,531	39,759	39,822	40,704	40,704
Projected Capacity Additions	0	0	0	0	0
Projected Capacity Additions as % of Projected Internal Demand	0.0	0.0	0.0	0.0	0.0
Projected Capacity Additions as % of Capacity Margin	0.0	0.0	0.0	0.0	0.0

	2003/2004	2004/2005	2005/2006	2006/2007	2007/2008
Projected Interconnection Internal Demand	35,370	35,860	36,380	36,870	37,390
Interconnection Interruptible Demand & DCLM	2,300	2,300	2,300	2,300	2,300
Projected Interconnection Net Internal Demand	33,070	33,560	34,080	34,570	35,090
Projected Interconnection Generating Capacity*	37,204	37,204	37,204	37,204	37,042
Interconnection Tie Capability	3,500	3,500	3,500	3,500	3,500
Net Interconnection Capacity Resources	40,704	40,704	40,704	40,704	40,542
Interconnection Margin	7,634	7,144	6,624	6,134	5,452
Interconnection Capacity Margin (%)	18.8	17.6	16.3	15.1	13.4
Net Interconnection Capacity Resources Less Capacity Not Under Construction	40,704	40,704	40,704	40,704	40,542
Projected Capacity Additions	0	0	0	0	0
Projected Capacity Additions as % of Projected Internal Demand	0.0	0.0	0.0	0.0	0.0
Projected Capacity Additions as % of Capacity Margin	0.0	0.0	0.0	0.0	0.0

* Includes 5,050 MW of generating capacity purchased from Churchill Falls throughout the assessment period.

Transmission Adequacy and Security Assessment

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

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

Recently, the adequacy of the bulk transmission system has been challenged to support the movement of power in unprecedented amounts and in unexpected directions. Generating resource adequacy problems caused by unplanned generation outages and the evolution of the electric industry under open access are the direct cause. These changes in the use of the transmission system have called into question the adequacy of the transmission system. Also, these changes will test the electric industry's ability to maintain system security in operating the transmission system under conditions for which it was not planned or designed.

The transmission system of North America is expected to perform reliably at least in the near term. Even though loadings on the transmission system are increasing in some areas and the number of transactions is rising rapidly, the procedures and processes to mitigate potential reliability impacts appear to be working effectively for now. Recent experience of the summer of 1998 indicates that although the transmission system was particularly stressed in some areas, the system performed reliably and firm demand was not interrupted due to transmission transfer limitations.

The prospect for reliability of the system in the longer term is open to question. A number of signs exist that individually may not be of concern, but collectively could impact reliability in the future. Business is increasing on the transmission system, but very little is being done to increase the load serving and transfer capability of the bulk transmission system. Most of the transmission projects planned over the next ten years are intended to reinforce parts of the system to alleviate local problems.

Table 6 — Planned Transmission

	Transmission Miles		
	1998 Existing	Planned Additions	2007 Total Installed
United States			
AC	147,799	5,587	153,386
HVDC	2,426	—	2,426
Subtotal	150,225	5,587	155,812
Canada			
AC	42,080	896	42,976
HVDC	2,878	—	2,878
Subtotal	44,958	896	45,854
Mexico			
AC	425	105	530
HVDC	—	—	—
Subtotal	425	105	530
NERC Total			
AC	190,304	6,588	196,892
HVDC	5,304	—	5,304
Total	195,608	6,588	202,196

The transmission system is being subjected to flows in magnitudes and directions that have not been studied or for which there is minimal operating experience. For example, the typical west-to-east sales of power from MAIN to ECAR to MAAC have been frequently reversed this summer due to capacity shortages and the associated changes in market economics in the Midwest. Such reversals have resulted in new facilities being identified as limits to transfers and transmission loading relief (TLR) procedures have been required in areas not previously subject to TLR to maintain the transmission facilities within operating limits.

Another indication of the increased use of the system is the increased use of TLR to prevent facility or interface overloads. From January 1, 1998 through September 1, 1998, NERC TLR has been invoked 250 times. Numerous other localized TLR procedures have also been invoked in that same time period. Because of the unpredictable nature of financial opportunities driving the energy market, variations in transfer patterns will result in changeable flow patterns and the locations where TLR must be invoked. There are few planned additions to the transmission system that hold any promise of reversing this trend.

Regardless of the causes, the trends in variable flow patterns and increased TLR use is causing increased administrative burdens for system operators at times when the workload is already heavy. The people and systems cannot sustain these trends without new tools to adapt to the increased workload and technical complexity. If the continuing adaptation to changing operating conditions can be maintained, the security of the system can be preserved. However, if the adaptation does not keep pace with the changes, reliability in the longer term will be jeopardized.

Additional issues affecting the reliability of the North American transmission system are explored in the Transmission Issues section of this report.

1998 REVIEW PROCESS

As part of its 1998 reliability assessment process, RAS conducted interviews with each Region to better understand their respective Regional reliability assessment processes. The general observations of the RAS from those interviews follow. There are a number of Regional and NERC initiatives already under way to address many of the issues cited.

Regional Interview Observations

Operations

- Operator training is receiving high priority as system operation is becoming more complex.
- Additional emphasis has been placed on operational planning and analysis.
- Security coordinators are operational in all Regions.

Resource Adequacy

- Wide variations in loss-of-load-expectation (LOLE) calculation methodologies exist among Regions.
- Concern is growing that single-area LOLE analyses may overstate reliability in some cases when external assistance is assumed to be available and deliverable.
- Purchases from "unknown" or undisclosed sources are inconsistently modeled in LOLE analyses.
- Reliance on demand-side management may become more prevalent as customers begin choosing their suppliers or a lesser level of reliability.
- Some Regions have a legislated obligation to carry a specific level of planned resource margin, others have Regional margin obligations, and some have no planned resource margin requirements.

Reserve Sharing

- Reserve sharing is becoming more widespread in the Regions, even though the methods vary.
- Most Regions or subregions have procedures in place to provide for spinning reserve and ten-minute operating reserve requirements.
- Demand-side management is becoming more prevalent as a component of operating reserves.
- Auditing and testing of ten-minute reserves (both supply and demand side) are not prevalent. Both need to be improved to ensure reserves will be available when called upon.

Merchant Plant Activity

- Merchant plant owners are not disclosing the location, in-service dates, or capabilities of new generating plants until absolutely necessary for permitting. This leaves very little time to adequately analyze impacts of the planned generation on the bulk transmission system.
- Merchant activity is more prevalent in some areas, typically where economic incentives or need for additional generating capacity indicate the potential for success.

Reactive Capability

- Reactive needs of the system are changing as number, direction, distance, and size of transfers are changing.
- Many systems are installing shunt capacitors in lieu of other transmission system additions.
- More voltage collapse analyses are being performed.
- More systems are evaluating the use of undervoltage load shedding as a remedial action to prevent system collapse.
- Although continuing to pursue and review testing of generator reactive capabilities, no Region has completed the testing of all generators.

Year 2000 (Y2k) Problems

- Regional coordination of Y2k activities has only just begun.
- Lack of knowledge of Y2k activities is heightening anxiety over results.
- It is not clear how many of the potential Y2k problems have been investigated and corrected so far.

NERC Planning Standards Compliance

- The compliance program appears to be on track and the Regions do not seriously question the need to comply. There are understandable concerns about cost.
- The need for generator testing is not well understood. The costs and resources associated with this particular requirement are considerable.

Available Transfer Capability

- The results of problems in calculation of ATC and administration of energy schedules are being reflected in the operating arena. Overloads caused by the over-subscription of transmission capability and the dichotomy of “contract path” versus the resultant flows on the transmission systems are being resolved through the use of TLR. Transmission providers’ use of TLR is an effective reliability tool to deal with overloads on the transmission system. However, from a market customer satisfaction perspective, ATC and TLR are very problematic.
- ATCs provided by systems on each side of an interface are often different due to lack of coordination. Inter- and intraregional coordination has been the focus of significant effort by the NERC Available Transfer Capability Working Group (ATCWG) since the RAS interviews.
- Use and calculation of Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) vary substantially among transmission providers. These differences have an impact on the coordination of ATCs for transmission interfaces between providers.
- Calculations of ATC sometime result in negative values. Some reasons for this are the relative timing of multiple transmission reservations, updating of base system condition assumptions, and reliability criteria not being met in the underlying transfer capability analysis.

RELIABILITY ISSUES

Throughout the history of the electric industry in North America, challenges to the reliability of the bulk generation and transmission systems have existed. High demand growth rates in the 1960s found utilities struggling to maintain adequate generation capacity margins. Rapid expansion of the transmission systems and stronger interconnections between utilities offered the promise of shared risk for generation outages, but found the industry struggling to understand how the systems would interact.

The oil embargo during the mid-1970s caused a marked decrease in demand growth rates at a time when the industry was in a headlong expansion. Shutting down that expansion and coping with the lower growth rates left many utilities with large capacity margins and unwieldy debt for cancelled or delayed generation facilities. In the 1990s, load growth and a slower pace of resource additions have decreased the previously large capacity margins. Furthermore, transmission utilization has dramatically increased with few substantial additions to the transmission system. These factors, coupled with the implementation of open access, characterize the state of the industry as we approach this assessment of the bulk generation and transmission system.

As the electric industry in North America continues its transition to an open marketplace, a number of new reliability issues are facing the industry.

Year 2000 Transition

An urgent challenge to electric reliability throughout the world is the transition to the Year 2000 (Y2k). This transition effort is necessary because certain software and hardware in use in the electric and other industries use a two-digit code to represent the last two digits of the year. As a result, these software and hardware may misinterpret the change from 1999 to 2000 as they process data. Additionally, there are a number of other key dates such as August 22, 1999 and September 9, 1999, that may be misinterpreted by computer programs and hardware.

In the electric industry, the extensive computer and control systems that operate power plants, the relays and circuit breakers that protect the system during short circuits, the communications systems that allow operators to control system elements at remote sites, and the energy management system computers that control the flow of electricity across the grid are all susceptible. Software and electronic hardware glitches could cause any of those systems to malfunction resulting in the unexpected opening of transmission lines, outages of generation, or loss of system control elements. Obviously, the implications of Y2k to the reliability of the interconnected bulk electric systems are serious.

NERC's Y2k Action Plan

The U.S. Department of Energy (DOE) has asked NERC to assume a leadership role in preparing the electricity production and delivery systems of the United States for Y2k. DOE's request is part of a broad initiative by the President of the United States to ensure that infrastructure essential to the nation's security and well being remains operational during critical Y2k transition periods.

The President of the United States has submitted to Congress proposed "Good Samaritan" Legislation to promote a more open sharing of Y2k-related information by protecting those who share information on Y2k solutions or whether a product or service is Y2k compliant from liability claims arising from sharing of that information. Also, the U.S. Department of Justice has taken the position that organizations collaborating on Y2k issues are not subject to antitrust actions.

Nearly all of the detailed problem identification and resolution in the electric industry to date have been performed by individual utilities. Those electric utilities that have attacked the problem aggressively are to be commended. However, NERC's concern is that all electric utilities with a direct reliability impact on North American electrical Interconnections must address the Y2k problem in a coordinated manner. This concern is due to the high degree of interdependence of electric systems within an electrical Interconnection. One unprepared system has the potential to adversely impact the operation of the rest of the Interconnection.

In response to DOE's request, the NERC Y2k program focuses activities in three principal areas: a) sharing of Y2k solutions, b) identifying potential weaknesses in interconnected system security, and c) operational preparedness. DOE's request provides NERC with an opportunity and a challenge to coordinate the efforts of individual Regions and electricity providers across North America toward a collective goal of maintaining secure operation of the electric systems through critical Y2k transition periods.

Nature of the Y2k Problem in Electricity Production and Delivery

Maintaining a reliable supply of electricity during the Y2k transition is being diligently pursued. There are four critical areas that pose the greatest direct threat to power production and delivery:

- **Power production —** Generating units must be able to operate through critical Y2k periods without inadvertently being forced out of service. The threat is most severe in power plants with digital control systems (DCSs). Numerous control and protection systems within these DCSs use time-dependent algorithms that may result in unit trips. Older plants operating with analog controls will be less problematic. Digital controllers built into station equipment, protection relays, and communications also may pose a threat. NERC's power production Y2k readiness assessment involves non-nuclear facilities.
- **Nuclear generation —** Since the second half of 1996, U.S. electric utilities with nuclear generating facilities have been working with the Nuclear Energy Institute (NEI), the Nuclear Utility Software Management Group, and the Nuclear Regulatory Commission to develop a Y2k readiness program. To avoid duplication of effort and the need for these utilities to respond to different surveys of nuclear Y2k readiness assessment, NERC and NEI agreed that NERC would incorporate in its report to DOE information on the preparedness of nuclear facilities developed by NEI.
- **Energy management systems —** Control computer systems within the electric control centers across North America use complex algorithms to operate transmission facilities and control generating units. Many of these control center software applications contain built-in time clocks used to run various power system monitoring, dispatch, and control functions. Many energy management systems are dependent on time signal emissions from Global Positioning Satellites, which reference the number of weeks and seconds since 00:00:00 UTC January 6, 1980. In addition to resolving Y2k problems within utility energy management systems, these supporting satellite systems, which are operated by the U.S. government, must be Y2k compliant.
- **Telecommunications —** Electric supply and delivery systems are highly dependent on microwave, telephone, and VHF radio communications. The dependency of the electric supply on facilities leased from telephone companies and commercial communications network service providers is a crucial factor. With telecommunications systems being the nerve center of the electric networks, it is important to address the dependencies of electric utility systems on the telecommunications industry during critical Y2k transition periods.
- **Protection systems —** Although many relay protection devices in use today are electromagnetic, newer systems are digital. The greatest threat here is a common mode failure in which all the relays of a certain model fail simultaneously, resulting in a large number of coincident transmission facility outages.
- **Distribution systems —** NERC's expertise and activities since its inception have always been limited to the bulk electric systems of North America. Therefore, NERC turned to the American Public Power Association, the Edison Electric Institute (EEI), and the National Rural Electric Cooperative Association, which have the necessary expertise, to prepare joint regular quarterly assessments of the distribution systems in the United States. This joint distribution assessment will be incorporated into NERC's Y2k reports to DOE.
- **Utility business information systems —** NERC also will incorporate into its Y2k assessment reports information on utility business information systems. These systems cover such areas as call centers, financial and cost management, accounts payable/purchasing/inventory, and security. This information will be reported by organizations responding to NERC's Y2k readiness assessment survey and will be summarized quarterly by EEI.

Y2k Defense in Depth

The second key element of NERC's plan is operational security through a "defense-in-depth" concept, which has been well developed in the design and operation of nuclear facilities. The defense-in-depth concept assumes that although an entity has taken all reasonable and necessary preventive steps, there can never be 100% assurance that major system failures cannot cause a catastrophic outcome. Alternatively, multiple defense barriers are established to reduce the risk of catastrophic results to extremely small probability levels and to mitigate the severity of any such events.

It is certain that not all Y2k problems have been or will be identified, fixed, and tested in the time remaining. Also, it would not be prudent to expend unlimited resources on potential problems in search of 100% avoidance of component failures. The cornerstone of the NERC Y2k plan, therefore, is to coordinate industry actions in implementing the following defense-in-depth strategy:

Identify and fix known Y2k problems — NERC is providing a vehicle for sharing of information on known and suspected Y2k problem areas and solutions associated with the operation, control, and protection of bulk electric generation and transmission facilities. From this information exchange, a master list of critical Y2k problem areas and solutions will be developed and made widely available. NERC will initiate a reporting process for key entities to report progress against specific criteria designed to address a known list of Y2k problem areas. Through its Regional Reliability Councils, NERC will review the progress of these entities to verify that all responsible parties are taking appropriate measures. This identification of problem areas, solutions, and testing of the solution is a process that will continue into the next millenium.

Identify worst-case conditions — NERC will coordinate the conduct of Regional and individual system simulations to identify moderate and worst-case scenarios in response to various classes of Y2k failures. Specific classes of failures that result in the worst conditions will be examined further to determine possible fixes and preventive or mitigation measures.

Prepare for the worst — NERC will coordinate efforts to prepare for safe operation of the electric systems under potential worst-case conditions. Preparations will include development of special operating procedures and conducting training and system-wide drills.

Operate systems in a precautionary posture during critical Y2k transition periods — NERC will coordinate efforts to operate transmission and generation facilities in precautionary configurations and loadings during critical Y2k periods. Examples of precautionary measures may include reducing the level of planned electricity transfers between utilities, placing all available transmission facilities into service, bringing additional generating units on-line, and rearranging the generation mix to include older units with analog controls. Another example is increased staffing at control centers, substations, and generating stations during critical periods. Fortunately, from an electric reliability perspective, New Year's Eve falls on Friday, December 31, 1999, and January 1 is a Saturday. Therefore, electric system conditions are likely to be more favorable than during peak demand periods. The level of electricity transfers should be at lighter levels and extra generating capacity should be available during the most critical transition period.

Three-phase Work Plan

The NERC Y2k program work plan is organized into three phases: 1) information sharing and status review, 2) coordination of preparedness plans and scenario analysis, and 3) coordination of precautionary operations during the Y2k transition.

Phase 1 (May–September 1998) — NERC will mobilize coordination and information sharing efforts and perform a preliminary review of Y2k readiness of electricity power production and delivery systems. Detailed plans for Phases 2 and 3 will be developed. Phase 1 will culminate with an initial report to the NERC Board of Trustees (Board) and to DOE covering the preliminary situation report and a detailed work plan for Phase 2 and Phase 3.

Phase 2 (September 1998–July 1999) — NERC will facilitate efforts by the Regional Reliability Councils and responsible operating entities to resolve the known Y2k technical problems. A process will be established for periodic progress reports using an established list of reporting criteria. System simulations and engineering studies will be conducted during this phase to understand likely and worst-case scenarios. This phase will culminate in July 1999 with a report to the NERC Board and to DOE on measures being taken to prepare electric power production and delivery systems for operation during the Y2k transition.

Phase 3 (July 1999–January 2000) — During this period, NERC will review the preparation of contingency plans and operating procedures. NERC will assist Regions in the conduct of drills and final arrangements to prepare for critical Y2k periods. Although the most critical period is expected to be on the dates of December 31, 1999 and January 1, 2000, configuring systems in a precautionary posture and then restoring normal conditions afterward are expected to require several weeks.

Regulatory and Organizational Changes

Regulatory and organizational issues that will impact the electricity market may also impact electric system reliability. The reliability issue is the need to guard against new rules and practices that would remove the "reliability safety net" that ensures continued reliability. NERC (the evolving NAERO), the Regional Councils, security coordinators, individual utilities, and others continue to develop the processes and systems needed to protect the reliability of the bulk electric system while supporting the desired market activities to the greatest extent possible. However, new regulatory structures and incentive systems must be developed to align the planning functions with the new industry structure. Any changes should be designed to move the industry at a pace that can be reliably maintained. The involvement of many new participants in the electricity business, at a time of rapid change that challenges even the traditional utilities, brings the need for continued education of all participants.

Jurisdictional Issues

Various federal, provincial, and state and local regulatory systems are in place to promote economic development as well as protect the interests of people and businesses. Although these systems strive to work in concert for the common good, compromises must sometimes be made. For example, siting new electric transmission lines may be needed to provide a mandated transmission service, but approvals for such siting must consider environmental and local concerns, which may conflict with the transmission objective. Siting problems can significantly contribute to the "difficulty to build" new transmission and delay the completion of new transmission facilities. It is difficult for a siting authority to grant approvals with compromised requirements when the siting authority does not perceive benefits for its constituency. Coordination of these jurisdictional issues must be considered as industry restructuring continues.

An improper balance of the interests could result in:

- transmission investments that lack long-term benefits,
- inappropriate attention to environmental impacts (too little or too much), and
- substantially higher risks to electric system reliability in some areas.

American Electric Power's Wyoming-to-Cloverdale 765 kV transmission project is an example of the regulatory difficulties the industry faces when trying to expand transmission system capabilities across multiple state jurisdictions. This project, originally scheduled for service in May 1998, continues to be delayed and is now scheduled for service in December 2002. This delay increases the potential for widespread interruptions. Although operating procedures can reduce the risk of interruptions, the likelihood of such power outages will increase until a system expansion can be completed.

Another issue is how alternative plans to line construction will be evaluated. For example, distributed generation could be an alternative to transmission expansions in some cases, but different entities may be responsible for each. How will a state board assure itself that all reasonable alternatives to any given project are considered, properly supported, and compared?

Despite the lack of U.S. federal legislation for retail competition, many states are moving ahead with retail access initiatives. Meanwhile, enforcement of compliance with established reliability standards remains tenuous. As long as everyone can agree, the standards are not likely to be challenged. But when agreement can't be reached, the standard will be challenged and there is no consensus on who has jurisdiction or the necessary authority to resolve the disagreement. The Federal Energy Regulatory Commission (FERC) is now considering whether it could assert that it has the necessary authority over reliability. Even so, it may decide it will have to approve the standards first, which could be a time-consuming process. Some claim the NERC Standards are invalid because they were approved by a governance structure that didn't provide "due process." Until federal legislation is passed that establishes and delegates explicit authority to a self-regulating organization such as the proposed NAERO, FERC may not have the necessary authority to compel compliance with established rules. Also, international issues (Canada and Mexico) must be addressed in the preparation, approval, and interpretation of NERC Standards.

Incentive Systems

Transmission providers (TPs) may find it difficult to justify investment in new or upgraded transmission facilities without proper incentives. TPs are subject to requirements to connect new generation at any location and provide transmission service, but may not be allowed full cost recovery by some state commissions. Transmission congestion pricing could provide price signals to encourage efficient generation siting and transmission expansion. However, until sufficient incentives are put in place, the growth in transmission capacity is not likely to keep pace with the business or reliability needs of the system.

Data Sharing

Historically, data have been reported and voluntarily shared among utilities. The basis for such data sharing is undergoing significant review and change due to market-induced concerns with confidentiality and proprietary interests. Some industry participants have indicated their reluctance to share data and in some cases have refused to provide information that historically has been available and used for operational control and planning. NERC and DOE/EIA continue to refine the data collection process, balance reliability assessment needs with market needs, explore confidentiality issues, and improve the efficiency of the process. NERC has established a new scope for a Data Coordination Working Group to work with DOE to "eliminate duplication and inefficiency in electric system data reporting processes and improve overall data accuracy and consistency." Since the planning horizon has been shortened by the advent of short lead-time generation resources, NERC and DOE are considering modifying the data collection and assessment process for the five- to ten-year horizon.

Considering the number and variety of participants in the evolving electricity business, the reliability challenge is to maintain accurate and consistent data to support the operational control, planning, and assessment processes. Legislative changes may be needed to ensure availability of these data so operational readiness can be maintained.

Resource Adequacy

As the competitive electric industry evolves, the marketplace must meet the future adequacy needs in a timely manner. Therefore, the proper marketplace signals defining financial incentive, investment risk, and potential returns must be developed. In assessing the ten-year planning horizon, the response to date is seen to be disparate across North America. As indicated in the individual Regional assessments in this report, plans are in place for sufficient amounts of generating capacity in some Regions. Yet, in other Regions, clearly demonstrated needs for future resource growth are accompanied by few "committed" generating unit additions. The response to price signals within the marketplace is evolving. At present, the translation of price signals leading to actual generation investment is inconsistent across North America.

To ensure continuing resource adequacy, the risk of failing to serve the customer must be recognized and incorporated in price structures. In the unbundled industry, each market participant assumes only a portion of the financial risk. Furthermore, the risk that customer demand will exceed the level expected in the forecast should be considered. Response in the market to this possible situation will determine whether resource adequacy is maintained.

The proposed regulations on nitrous oxide (NO_x) emissions are capable of creating future reliability concerns. If the final legislation adopts the currently proposed compliance deadline of May 1, 2003, outages of significant amounts of fossil-fuel generation will be necessary to install the required NO_x control devices. The scope for this concern requires data collection from the Regions and time for analyses, neither of which can be done in time for the publication of this report. These concerns will be investigated and assessed by RAS in the coming year.

Alberta Case Study
Market forces alone now drive resource additions in Alberta, rather than being driven by utility planning analysis. This was brought about by legislation that created the Power Pool of Alberta several years ago. Pool prices rise sharply as generation supply is exhausted and more costly generation is dispatched. These prices are monitored by customers and serve as a signal to voluntarily disconnect their load when the price gets too high.

Consistently higher pool prices experienced in Alberta during the summer of 1997 provided the economic signal required to stimulate resource additions. New generation, totaling several hundred megawatts, is proposed to come on line over the next few years. However, if not enough customers choose to disconnect their loads from the Alberta system, a resource deficiency can result. During the summer of 1998, the Transmission Administration of Alberta shed firm customer demand on two separate occasions to maintain adequate regulating margin. This is indicative of a potential reliability problem inherent in a purely market-driven system — development of capacity resources lagging the growth in demand.

New England Case Study
Another interesting example of market-driven generation resource development is in New England. When the three Millstone and the Connecticut Yankee nuclear units were out of service during the summer of 1996, New England was faced with a capacity shortfall under peak demand conditions. When that situation continued into the summer of 1997, there was a clear need for additional generating capacity from a reliability perspective. Plans were soon announced to construct a plant at United Illuminating's Bridgeport Harbor generating station. Subsequently, when the retirement of Connecticut Yankee (560 MW) and Maine Yankee (870 MW) nuclear units was announced in 1997, the market was given a clear signal that not only was there a need for new capacity, but that need would be sustainable as replacement for the retiring units. Now, about 30,000 MW of merchant generation is being proposed in New England, although very little of that capacity has been reported in New England's capacity expansion plan.

Eastern Interconnection Experience
On June 25 and 26, 1998, the Eastern Interconnection experienced unprecedented high prices for wholesale energy during a severe capacity shortfall in the Midwest. The exact causes of the price spike are under investigation by FERC and others. However, one significant reliability aspect of that capacity crisis was the convergence of a heavy reliance on capacity purchases with extremely low operating reserves in the Midwest. If capacity margins continue to decline as currently projected, this may prove to be a harbinger of future operating challenges.

During that period, an early heat wave drove demand throughout the Midwest toward projected summer peak levels. Operating capacity margins in MAIN and ECAR were low due to ongoing maintenance and forced outages of major generating units, including ongoing outages of several nuclear units. Severe thunderstorms and tornadoes the night of June 24 damaged transmission circuits critical to imports into MAIN and Michigan. The stage was set for a true test of the bulk electric systems in the Eastern Interconnection.

Many utilities in MAIN and ECAR had secured capacity and energy for the summer through various types of purchase contracts. Because of the unusually large amount of generation out of service in the Midwest, more purchases than planned were necessary to serve the unexpectedly high customer demand. Fortunately, the many participants in today's electricity marketplace were able to locate sufficient generation resources, including some capacity that may not have been made available in the past. However, deliverability of those resources was crucial. Some deliveries were hampered by the physical limitations of the transmission system, which had been worsened by storm damage. In another instance, some planned-on purchases over firm transmission reservations were cut because the energy backing the purchase was nonfirm. Still other purchases relied on "financially firm" supply contracts, which require the supplying party to deliver energy or pay the receiving party's replacement energy costs. During the peak hours of June 25 and 26, at least one supplier defaulted on physical deliveries of power.

As planned capacity margins dwindle, the flexibility of the bulk electric system to deliver electricity to all customers under unusually severe conditions, as were experienced in late June, will likewise diminish. The risks as well as the opportunities presented by the innovative supply strategies of the evolving competitive supply market should be recognized by the load serving entities. Resource adequacy analysis techniques must evolve to keep pace with the evolving marketplace to avoid double-counting of generating resources or over-reliance on demand diversity, even in a system as large as the Eastern Interconnection.

New Potential for Interruptible Demand

The high wholesale price signals experienced at the end of June may be indicative of the potential for an increase in "financially interruptible" demand. As the marketplace moves toward retail open access to resources, sharing of real-time pricing signals with the ultimate consumers may create more robust levels of interruptible demand. If sufficient interruptible demand is created by financial signals, it could slow the pace of "real" demand growth that would necessitate construction of new generating capacity.

In Alberta, customers are given a real-time price signal and may choose to interrupt their own demand when the price gets too high. If insufficient customer demand is interrupted due to economics, the Transmission Administrator is authorized to order shedding of firm customer demand by the distribution companies to maintain required operating reserves.

Customers are assuming the risks of supply adequacy in making their marketplace decisions. Although the relative prices of various energy service providers are clearly known, the risk of supply interruptions is rarely factored into the decision. Also, few, if any, customers understand the implications of contracting for other than firm power supplies and firm transmission services. Customers in North America have enjoyed ample capacity margins, creating an expectation of a continuing adequate and reliable electric supply. Declining capacity margins, coupled with a movement toward a market-driven supply, could create capacity shortages when new capacity is not available in time to meet increased customer demand.

Demand Forecasting

Reasonably accurate demand forecasts are needed to assess the reliability of the bulk electric system. The aggregated area demand is needed in the assessment of resource adequacy (taking into account the import capability) and individual bus demands are needed to assess transmission reliability. In the past, vertically integrated utilities produced these forecasts to fill these needs. In the evolving industry structure, suppliers will be forecasting the market, load aggregators will make separate forecasts for their acquisition requirements, and the "wires" organization will need a forecast of all the demands to be connected to the system.

Some changes are needed in the reporting requirements to ensure the total demand is accounted for, without double or under counting of demand. Data confidentiality concerns will require these data be made available only to those entities responsible for reliability and appropriate government agencies.

Even with a process for reporting forecast demand, reliability assessments need to consider the impact of uncertainties. “Under” forecasting, which has been observed frequently in the past, can result in lower than expected reserves as well as shortage of reactive power capability needed to support the system voltage.

Other Capacity-related Issues

Recent experience with nuclear unit availability in the Midwest and New England raises an additional concern. Without evidence of improved and sustained reliable operation of nuclear units, it seems prudent to assume that operational capacity resource adequacy will continue to be impacted. Also, relicensing or economic issues could possibly cause additional nuclear unit retirements in light of increasing competition in the generation sector. In the past two years, Connecticut and Maine Yankee nuclear units in New England (totaling 1,430 MW) and the Zion nuclear plant (two units totaling 2,080 MW) were retired before the end of their planned commercial life. Recently, plans to retire the Millstone 1 nuclear unit (641 MW) in Connecticut also was announced.

A further concern is the growing inability to assess future resource adequacy with confidence in the six to ten-year time period. The competitive desire for confidentiality in releasing firm plans, together with shorter lead times for the typically smaller gas-fired generation being built, are leading to an unwillingness to commit to construction of resources beyond the five-year horizon. These pressures contribute to an inability to clearly identify sites for future resources, which will make it more difficult in the future to assess either the long-term resource adequacy of the bulk electric supply or the reliability of the transmission system. It also is essential that there be in place safeguards to ensure that resource capacity assessments measure only verifiable capacity supply. Again, the inability to confirm a future site for a merchant plant may inadvertently lead to the counting of multiple sites and, consequently, the overstating of future resource supplies.

In the shorter timeframe, there also will be economic pressure on the owners of existing, inoperable generating units to include them in their reserve projections. Accreditation methods must be in place to ensure that stated reserves can be achieved and demonstrated.

Reliability of secure and uninterrupted fuel supply is important to ensuring resource adequacy. There is an increasing dependency on natural gas as the fuel source for the bulk electric supply systems of North America. New generation resources being sited today are predominantly gas-fired; over the ten-year assessment period the utilization of gas supply in the United States and Canada is projected to increase by 89%. Nevertheless, current projections for the year 2007 assume that electricity production by gas will only amount to 12% of the total MWh generated, while two-thirds of electric energy is projected to be supplied by existing coal-fired and nuclear capacity. There is growing uncertainty over the economic viability of some of these older plants in ten years. If coal and nuclear plants cannot continue to operate competitively, gas will be the fuel replacing coal and nuclear.

Such growing dependence on a single fuel source places increasing pressure on both the raw supply of gas as well as the deliverability and vulnerability of the infrastructure. The uninterrupted supply of fuel will become dependent on the pipeline system and its exposure to either natural interruptions or sabotage. In many areas of North America, this concern is further heightened by the competing use of natural gas as a primary heating fuel. Particularly during periods of extreme cold, the demands on gas supply are at their maximum by both the electric industry and heating industry simultaneously. The impact of new environmental restrictions was not analyzed in this assessment, however, if more stringent legislation is established, the likely result will be to place even greater reliance on natural gas for future generating capacity.

Operational Issues

Transaction Management

Open access has dramatically increased the number of multiregional energy transactions taking place with larger numbers of intermediary parties involved. To assist system operators and security coordinators in managing such transactions and to enable them to perform transmission congestion management (TCM) when necessary, NERC has instituted transaction tagging and TLR procedures.

As the number of transactions and their complexity increases, administration of transmission congestion management and line loading relief become more and more difficult. Reliability can be adversely impacted if TCM and TLR cannot be performed in a timely manner, and could necessitate the use of lower transmission limits (or larger transmission reliability margins) to provide adequate safety margins for reliability.

Therefore, all control area operators and marketing entities must follow strict energy scheduling rules to keep all schedules identified and prioritized properly so that they may be curtailed in a timely manner if the need arises. To facilitate and improve the exchange of transaction and scheduling information between operating entities and market participants, NERC has initiated a project called the Transaction Management System (TMS). The TMS is envisioned as a seamless, reliable, and secure integration of electronic reservation and energy scheduling systems for streamlining and automating:

- Transmission reservations
- Ancillary services procurement
- Energy scheduling processes
- Transaction Tagging

Such enhancements are essential to operating reliability and security processes, including transmission congestion management.

The streamlining and automation also will support the next-hour energy market by facilitating the rapid exchange of transaction and scheduling data among Regions, operating entities, and market participants. Exchange of such information between the market participants and the operating entities that are responsible for system operation and security is essential in the "just-in-time" open market. Retail open access will further drive the need for fast, automated systems for tracking and controlling the increasingly complicated movement of electricity across the bulk transmission system.

Responsibility for Coordination of Operations Between Generating Plants and the Transmission System

The responsibility for coordinating operations between generating plants and transmission systems traditionally has been assigned to the utility transmission system operators and system planners. Administrative separation of the generation and transmission assets by the traditional utilities, as well as the growing number of large merchant plant participants (including self-serve generation plants), demands a more standardized and formal understanding of the bulk electric grid control and reliability criteria by all (voltage schedules, reactive support, control area roles). Interconnection and operating arrangements between all generation entities and their interconnected transmission providers must include a commitment by all parties to operate in compliance with NERC Operating Policies and Planning Standards. Similar requirements must apply to Regional operating policies and planning standards.

All participants must recognize the need to operate in a manner that will ensure reliability in interconnected operations while facilitating the transmission open access and comparability rules brought about by FERC Order Nos. 888 and 889. Compliance must be ensured through Regional and NERC monitoring groups and reporting processes. Formal contracts must be written that are explicit on Interconnection operation obligations, control authority, and compliance consequences. Dispute resolutions must be facilitated outside the real-time operating environment using formal and well-understood resolution mechanisms. The NERC compliance process will continue to evolve with relevant penalties assessed for failure to meet the approved interconnected operating reliability policies and standards.

Reluctance to Share Real-time and Operational Planning Data

To reliably operate the bulk electric system, operators must know all pertinent operational information. Unfortunately, recent developments in the electricity marketplace are impeding the necessary information exchange. The requirement for compliance, along with the Code of Conduct provisions required by FERC Order No. 889, have created reluctance on the part of market participants to share operational real-time and operational planning data with TPs. Even with the Code of Conduct provision, suspicion remains that transmission operators could be providing an advantage to their affiliated marketing groups.

The number and size of TPs not subject to the Code of Conduct because they are not under FERC's jurisdiction is a related issue. Other market participants are reluctant to share any information with those entities because they are not restricted from passing such information to their wholesale merchant affiliates. Resolution of jurisdictional issues for and by FERC is necessary to provide for comparable treatment of all market participants.

Transmission Issues

The increased use of the transmission system in North America brings additional challenges to transmission planning. These challenges include such reliability issues as planning for reactive power and the planning processes themselves, which need to evolve to reflect the new market realities. Other challenges include alleviating problems with ATC calculation inconsistencies and incorporation of new metrics of system use in the planning process such as TLR statistics and ATC performance indices.

The increased line loading due to load growth, the increasing number and distance of transactions, scarcity of major transmission construction projects, and a wider variation in generation dispatch patterns result in a dramatic increase in reactive support requirements. In the short term, these are satisfied by significant installation of transmission capacitor banks, but, in the long term, dynamic reactive planning reserve requirements must be developed and used based on sound planning and operating standards. The geographical "zones" for these requirements will be based on cohesive electrical behavior of the system rather than on traditional service boundaries. Such zones may be much more numerous than the number of control areas currently in North America. If these issues are not properly addressed, voltage collapse may occur more often in the future.

The time frame necessary to plan, approve, and construct major transmission projects has eclipsed the time frame necessary to plan, site, approve, and construct some types of generation. This extended time frame for transmission additions may result in local supply deficiency problems that cannot be mitigated by importing power. An alternative may be placement of generation at sites in the deficient areas that requires no additional transmission facilities, providing no other siting limitations exist.

Although uncertainties and assumptions have always been a part of long-term transmission studies, the level of uncertainty has increased tremendously. Generation developers are reluctant to disclose their plans for future capacity additions. Similarly, utilities intending to purchase from others are reluctant to speculate on whom or where their suppliers might be, making modeling of such transactions for transmission analysis virtually impossible.

The new realities of the marketplace reflect a need to revise planning processes. Processes and parties involved with generation and transmission planning are no longer closely linked and proceed on differing time schedules. If it only takes 18 months (after initial public announcement) to site and construct significant generation additions, the total transmission planning process for all parties should be substantially shorter than a year to ensure reliable connection and incorporation of that generation into the transmission system. Requests from entities contemplating construction of generation now are being received with little forewarning. The transmission planning process must strive to keep pace. Current Regional planning coordination processes need to be streamlined and staffed so that the Regional and local transmission providers' requirements can be satisfied within a much quicker response time.

Even with revised processes, it is likely that transmission facilities to connect the generation and reinforce the bulk electric system will not be available when required due to longer lead times for transmission projects. Resource developers need to coordinate their plans and expectations with the transmission owners at the earliest opportunity rather than waiting until the last possible moment. Furthermore, interim operating procedures may be needed until transmission reinforcements are completed.

An example of the changing marketplace is how TLR information is fed back into the planning process. Because much of the TLR activity deals with nonfirm use of transmission, it is unlikely that transmission would be planned based on this use of the system. A paradigm shift may be required so that transmission can be built to respond to demands from the transmission service marketplace, as opposed to the current process of building transmission to satisfy the need to serve local demand requirements.

A practical limit may exist on how often and how many schedule interruptions/events can be handled in a TLR process before the system begins to break down, potentially resulting in damage to transmission equipment or shedding of load. Although ATC calculation is not a direct reliability issue, its inconsistent calculation can increase the use of TLR and other operational complexities, which has the potential to cause reliability problems.

The increasing lack of long-term commitments between customers and suppliers and decreasing resource margins require that a much greater number of generation patterns be studied over a wider area. Owners of generation will try to maximize income, which may result in different generation patterns than experienced or planned for in the past. Significant merchant plant construction of low-cost generation will further compound the problem due to the need for load following and regulation capability.

To address these realities, significant additional analysis will have to be performed on an interregional basis. To do so will require "multiregional" transmission performance analysis to examine wider areas than can be examined by the current Regional and interregional transmission studies. Multiregional study assumptions and methodologies must be developed to augment the current Regional and interregional procedures. Such multiregional analyses will require an additional commitment by the transmission providers to provide the necessary technical expertise to perform the studies.

The bulk electric systems in ECAR will continue to perform well in meeting the 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. A particular concern is the certification difficulties of American Electric Power's Wyoming-Cloverdale 765 kV line, which is needed to guard against the potential for widespread interruptions. Currently planned capacity resources will satisfy the Region's criterion for reliability adequacy throughout the assessment period provided the average annual generating unit availability is maintained at or above levels experienced in recent years.

ECAR

As the industry moves toward increased competition, ECAR's membership is striving to meet the challenge of maintaining the adequacy and security of the bulk electric systems. ECAR continues to review 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. To facilitate achieving its reliability goals, ECAR members have opened full membership to its associate members while implementing changes to its funding and voting provisions; engaged in the process to transform NERC into a self-regulated reliability organization; and, provided leadership and support to the technical activities being coordinated by NERC's Security Process Support System Task Force. The ECAR members also have enhanced their Open Access Same-time Information System (OASIS) to improve its maintainability and availability.

ECAR Assessment Process

In ECAR, planning for facility additions is done by individual member utilities. Regional assessments are performed to ensure that members' plans are well coordinated and comply with Regional reliability criteria. Assessments are performed by ECAR's Generation Resources Panel (GRP) and Transmission System Performance Panel (TSPP) under direction of the Coordination Review Committee. ECAR's assessment procedures are applied to all generation and transmission facilities that significantly affect 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 ten-year or longer planning horizon, and semiannual seasonal assessments are made for the upcoming peak demand seasons. Transmission assessments are performed regularly for selected future years out to the planning horizon and semiannually for the near term. If deficiencies are discovered during this process, the member system with the deficiency is asked to explain what remedial action will be taken. The assessment procedures for both transmission and generation resources were recently modified to continue their relevance in today's competitive environment.

Demand and Energy

Throughout the assessment period, the total internal peak demand of ECAR members is expected to continue to occur during the summer with a 1.7% average annual growth rate, up from 1.6% forecast last year. ECAR is reviewing demand-reporting issues to ensure meaningful reliability assessments in the open access environment. Current resource plans developed by ECAR members project a reliance on direct-controlled and interruptible load management programs of about 3,800 MW by 2007 — plans also include about 400 MW of new passive demand-side management programs not controlled by system operators. With interruptible loads and loads under demand-side management removed, ECAR's net internal demand is projected to grow at an annual average growth rate of 1.7%, reaching about 105,265 MW in 2007.

Resource Assessment

ECAR members are projecting to add or contract for about 16,200 MW of new capacity, including about 4,000 MW of nonutility generation added during the ten-year period. Less than 3% of the projected generation additions are reported to be under construction or under contract. Of the new capacity, about 10,000 MW are projected to be short lead-time combustion turbines, with most of the new capacity projected to be gas-fired. Capacity margins in ECAR, based on net internal demand, are expected to decline to a minimum of 6.5% in 2002. If capacity reported as planned is excluded, capacity margins will become negative in 2006. As these resource projections evolve, the mix of demand-side programs, nonutility generation, and utility-owned capacity used to meet demand growth may change.

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 (DSCR). Supplemental Capacity Resources include assistance from neighboring Regions, contractually interruptible demands, and direct-control load management.

One of the most critical parameters affecting the adequacy of bulk electric supply in ECAR is generation availability. The 1998 capacity margin assessment determined that the annual generation availability must remain at or above 81% to meet the DSCR criterion throughout the assessment period. For perspective, average annual generation availability in ECAR has been 81.3% over the last nine years and was 84.7% during 1997.

ECAR believes that the aging of generating capacity will necessitate increased maintenance and lengthened outages. By the year 2007, about 61% of the capacity in ECAR will be 30 or more years old, and about 23% will be 40 or more years old. ECAR members recognize the challenges in maintaining high levels of generation availability experienced in recent years but expects to meet them. As margins continue to decline, coordination of maintenance schedules will become more important and difficult.

Coal, the predominant fuel used within the ECAR Region, is expected to supply about 83% of the total electrical energy requirements in the year 2007. Although compliance plans to meet Phase 1 of the Clean Air Act Amendments of 1990 (CAAA) have been implemented, some uncertainty still remains in NO_x regulation compliance. The SO_2 emissions cap provisions of the CAAA may lead to some generating units becoming energy limited. A utility at or approaching its annual emissions limit may be unable to provide emergency assistance to neighboring utilities.

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.

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 385 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) Wyoming-to-Cloverdale 765 kV transmission project. This project, originally scheduled for service in May 1998, continues to encounter certification difficulties, although some progress has been made during the past year. The earliest date that this project can be completed is December 2002, increasing the potential for widespread interruptions in southeastern ECAR. Last year, a triregional assessment of the reliability impacts of this project concluded that a reliability risk exists due to the delay of this project. Although operating procedures can minimize the risk of widespread interruptions, the likelihood of such power outages will increase until the project can be completed.

Operations Assessment

Three security coordinators maintain reliability of the transmission system in the ECAR Region. AEP is the security coordinator that monitors power flows between ECAR and Regions to the West and Southwest. Allegheny Power is the security coordinator that monitors power flows between ECAR and the Regions to the East and Southeast. The Michigan Electric Coordinated Systems (MECS) is the security coordinator that monitors power flows circulating around Lake Erie. Each of these security coordinators works with security coordinators from surrounding Regions and use the Transmission Loading Relief (TLR) procedure to maintain the reliability of the interconnected transmission network. Critical transmission interface loadings within ECAR are also monitored and controlled by ECAR members.

In addition to the NERC TLR, the Reliability Coordination Plan (RCP) may be used by systems in eastern ECAR, MAAC, and the VACAR Subregion of SERC to curtail or limit west-to-east transfers to ensure adequate reliability in that part of the system.

The East Central Area Reliability Coordination Agreement (ECAR) membership currently consists of 28 full members and 34 associate members serving either all or parts of the states of Michigan, Indiana, Kentucky, Ohio, Virginia, West Virginia, Pennsylvania, Maryland, and Tennessee.

The near-term generation resource requirements can be met from the existing reserves of generation capacity of the utilities and qualified facility cogeneration plants. In addition, new generation capacity planned or under construction will add approximately 600 MW by 1999. Beyond the year 2000, many new proposals for generation resources from independent power producers have been made and, if built, will maintain planning reserves at a reliable level. The new resources are gas-fired, high efficiency gas turbine-combined cycle plants.

The transmission system required to move energy from the generation to the load centers is adequate for the near term. Future transmission will be reliable only if sufficient time exists to acquire regulatory approval, acquire right of way, and build facilities in the time period between the results of the RFP process and the completion of the new generation facility.

ERCOT

ERCOT Assessment Process

The Engineering Subcommittee produces and performs the power flows required for the members to assess the reliability of their transmission systems. An annual report is made to report transfer capabilities and the results of selected contingencies. The studies indicate if the planned interchange and associated contingency evaluation will meet the ERCOT Planning Criteria. The study work done by the subcommittee is not intended to be an exhaustive study of all the contingencies that would be necessary to test the system and prove the reliability criteria. Rather, it is the responsibility of each member to test its systems and report to the subcommittee those issues that might pose a future reliability concern.

The Engineering Subcommittee has completed the restructuring of its task forces and responsibilities. The subcommittees are very involved with the conversion of the existing Guides and Criteria to be consistent with the NERC Planning Standards and Guides.

Demand and Energy

The actual 1997 ERCOT summer demand grew to 50,150 MW from 47,683 MW in 1996, a 5.2% increase. This demand includes serving interruptible loads. For the period 1989–1997, the average annual compound growth rate has been 2.8%.

The actual ERCOT energy consumption grew from 246,388 GWh in 1996 to 249,169 GWh in 1997, a 1.2% increase. For the period 1989–1997, the compound annual energy growth rate has been 2.5%.

The average annual growth rate in ERCOT's summer peak demand is projected to be 2.2% for the 1998–2007 period, and the expected winter peak demand is projected to grow at 2.4%. The projected annual growth for energy is 1.22%.

ERCOT is within its 15% reserve margin when interruptible loads are removed. Peak demands, however, appear to be increasing above the currently projected annual growth rate of 2.2% indicating that ERCOT's reserve margin will fall below 15%.

Resource Assessment

Using the utilities' actual hourly loads, projected hourly loads, and generator outage data, loss-of-load probability (LOLP) and loss-of-load hours (LOLH) reliability studies were produced for the 1997–2000 time period. The results indicate that ERCOT will continue to meet a one-day-in-ten-year LOLP. The studies may be viewed as conservative because the generation represented in the studies does not model approximately 2,000 MW of qualified facilities that sell to the utilities on a nonfirm basis. The ability to continue making these types of calculations in the future may be compromised by the lack of data concerning performance and forced outage rates and the inability to identify future generating unit additions.

The future resources that have been specified in the Capacity-Demand-Reserve Working Paper as unspecified have brought many new proposals for new generation sources and interconnections. In the period since January 1, 1998, over 10,000 MW of new capacity have been proposed. While it is unlikely that all of the proposed generation will be built, the forecast for new generation looks much better than last year.

ERCOT should continue to have adequate resource reliability as long as the entities responsible for securing capacity resources allow sufficient lead time in their acquisition process to ensure the capacity and associated transmission support is available when required.

Transmission Assessment

The transmission system is experiencing constraints during high load periods. ERCOT has adopted a new planning process suitable for the open access environment and will be adopting projects to address these constraints and strengthen the bulk transmission system to accommodate new generation and increased loads. The timing of these new facilities will be very important to reliability. ERCOT is currently experiencing much higher than anticipated load growth. New generation is needed and is being proposed by the generation entities, however, timing again is critical. The ERCOT Independent System Operator continues to monitor planned transmission service requests and generation interconnection requests to determine reserve levels. Preliminary studies are being conducted at the request of the Texas Legislature to explore synchronous connections of the ERCOT system to neighboring Reliability Councils.

Operations Assessment

The ERCOT-ISO that went into operation in January 1997 continues to schedule and approve all transactions and to make daily assessments of transfer capability and security based on load flow simulations of the system that include expected outage conditions.

The Electric Reliability Council of Texas (ERCOT) is comprised of six municipal G & Ts, seven cooperative G & Ts and river authorities, four investor-owned utilities, nine independent power producers, 39 power marketers, 14 transmission-dependent utilities, one power broker, and one associate of ERCOT. ERCOT members serve over 12 million customers (and about 200,000 square miles or 73% of Texas) and account for 56,000 MW of generating capacity and 32,000 miles of transmission lines.

The Florida Reliability Coordinating Council (FRCC) expects to have adequate generating capacity reserves and transmission system capability to meet Region reference reserve margins throughout the 1998–2007 assessment period.

FRCC was created in October 1996 to ensure bulk electric system reliability in Florida. FRCC members regularly exchange information in both planning and operating areas related to 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. The Reliability Assessment Group (RAG) administers this process and determines what planning and operating studies will be performed during the year to address those issues.

RAG is also the mechanism for collecting, assembling, and assessing the Regional EIA-411 Report, and the FRCC Load and Resource Plan, which is submitted annually to the Florida Public Service Commission.

FRCC

Assessment Process

Within the FRCC Region, the 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 load flow, stability, and short-circuit databases for the use of FRCC and its members.

Annually, RAG reviews existing and expected conditions within the Region; both short and long term. RAG, which includes planning, marketing, and operating members, makes recommendations to the Engineering and Operating Committees on 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 that include results, conclusions, and recommendations are published. RAG monitors actions taken to meet reliability criteria as a result of all study report recommendations.

Demand and Energy

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 Florida for the next ten years are 2.2% and 2.4%, respectively. These growth rates are lower than the ten-year historical average growth rate of 3.2% and 3.3%, due to new key assumptions. These new assumptions embody state population forecast trends to examine electricity demand and energy trends. The University of Florida projections of population growth, which are used by FRCC, show a moderation in population growth in the FRCC Region over the assessment period versus the previous ten years.

Resource Assessment

FRCC judges the reserve margins for the ten-year assessment period (1998–2007) to be above the reference reserve margin standard of 15%. The Resource Working Group (RWG), 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 the months of January and August for planning and assessment purposes. The reserve margin is determined by utilizing the net of the total peak demand minus the effects of exercising load management and interruptible loads during the peak demand periods. FRCC members are projecting the addition of over 8,000 MW of new capacity over the next ten years. Of this, more than 5,000 MW are projected to be natural gas-fired combined cycle units and over 1,500 MW is committed.

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.

Supply assumptions for natural gas reliance in the assessment process was a concern. Because of this concern, a ten-year annual projection of natural gas requirements for electric generation was required of each generating entity for both existing and future generating units. Once the projected natural gas requirements were developed, RWG worked with the Florida Gas Transmission (FGT) to develop a reasonable timeframe for expansion of the natural gas transmission facilities. FGT estimates 18 to 36 months to obtain all permits, plus environmental and regulatory approvals to complete construction of any pipeline and compression facilities required for natural gas generation developments identified throughout the study period.

Transmission Assessment

The Stability Working Group (SWG) has completed studies of single and multiple outage performance for the 1999 system with Florida at import limit conditions and oscillatory stability studies with Florida at export limit conditions. SWG has made recommendations that either have been or are in the process of being implemented by FRCC members. These include completed installations of power system stabilizers on the Turkey Point 3 and 4 generators and the in-progress installation of a power system stabilizer on the Crystal River 3 generator.

The Transmission Working Group will be assuming the intraregional seasonal and ten-year analyses this study year to meet NERC and FRCC reliability criteria. This effort historically has been performed by the member systems and has to date resulted in plans to construct 142 miles of 230 kV and 150 miles of 500 kV transmission during the 1998–2007 assessment period. This study effort is complemented by the Florida/Southern Planning Task Force, which evaluates the transfer capability between the Southern Subregion of SERC and FRCC.

Operations Assessment

FRCC has both a security coordinator and an operations planning coordinator who monitor system conditions and evaluate near-term operating conditions. FRCC has a detailed Security Process that gives the security coordinator the authority to direct actions to ensure the real-time security of the bulk electric system in the Region.

The security coordinator uses a Region-wide Security Analysis Program and a "Look-Ahead" Program to evaluate current system conditions. These programs use databases that are updated with real-time data from operating members on an as-needed basis throughout the day.

The procedures in the Security Process are being evaluated and updated on an ongoing basis to ensure Regional reliability, conformance to FRCC procedures, and adherence to NERC Standards and Policies. The Transmission Loading Relief procedures contained in the Security Process are continually being revised to better address the needs of the current operating environment.

The Florida Reliability Coordinating Council (FRCC) membership includes 37 members of which 12 operate control areas in the Peninsula Florida. FRCC membership includes investor-owned utilities, cooperative systems, municipals, and power marketers. The Region covers about 50,000 square miles.

Adequate generating capacity is planned through the 1999 (June 1, 1999 to May 31, 2000) planning period. As of June 1, 1997, planned capacity for the 2000 planning period and beyond is not adequate to meet MAAC's maximum loss of load requirement of one day in ten years. Some recently announced capacity additions may alleviate problems in the near term, but there are few longer-term facility additions planned.

The planned bulk transmission system in the MAAC Region, with its numerous ties to the Eastern Interconnection, meets transmission adequacy and security requirements through the 2003 planning period.

MAAC

Maintaining Reliability in the Changing Environment

As the industry moves rapidly toward retail customer choice, the Mid-Atlantic Area Council (MAAC) is addressing the challenge of maintaining the adequacy and security of the bulk electric systems. Historically, firm load was tied to long-term capacity supply. With wholesale open access, some Regional load is supplied under contracts that have no commitments beyond the contract duration. During the transition to retail access, there could be a dramatic increase in the number of these capacity contracts and a decrease in the duration of these contracts. For example, at the beginning of 2000, retail customer choice will be available to all customers in Pennsylvania. Similar regulations have been passed in New Jersey, Delaware, and Maryland. Long-term reliability assessments must be performed to manage the increased uncertainty due to a rapidly increasing number of shorter capacity commitments. The future challenge will be to develop a process to provide adequate capacity resources recognizing that a large amount of load can switch suppliers on a billing cycle basis. MAAC continues reviewing its organizational structure, its governance provisions, its reliability assessment process, and its technical documents and guides to ensure that reliability will be maintained in the changing environment, and that MAAC will be in full compliance with the NERC Planning Standards and Operating Policies.

MAAC Assessment Process

Transmission assessments are performed regularly for selected future years out to the planning horizon, and semiannually for the near-term system. In addition, each member periodically makes assessments of its planned system for a selected future year. If deficiencies are discovered during this process, the member with the deficiency is required to explain what remedial action will be taken. MAAC's summer peak load generation resource assessment procedures are being revised but will be performed annually for a ten-year or longer planning horizon. An annual generation resource assessment is also performed for the next winter's peak load period.

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

Demand and Energy

Net peak demand and energy forecasts for 1998 are similar to the 1997 forecasts. The net peak demand growth rate grows to 1.4% from last year's 1.3%. Company growth rates vary from 0.6% to 2.4%. The energy growth rate returns to 1.5% from 1.4%.

Overall Reliability Assessment

The MAAC system, as planned for the 1999 *(June 1, 1999 to May 31, 2000)* planning period, was found to be in compliance with the MAAC Criteria. However, several areas were identified, for the periods beyond the 1999 planning period, that are not adequate to meet MAAC requirements. These areas are described below.

Resource Adequacy

Adequate generating capacity is planned for the 1999 planning period. However, based on load and capacity plans submitted to MAAC as of June 1, 1997, planned capacity for the 2000 planning period and beyond are not adequate to meet MAAC Criteria. Possible noncompliance as it relates to generating capacity adequacy could be alleviated based on recently announced plans by several “non-load-serving entities” to build new generating capacity in the MAAC Region.

The evolution of the electric supply industry from a regulated environment to an open access competitive environment has created considerable uncertainty that makes the assessment of generating capacity supply adequacy difficult, particularly beyond a two-year horizon. Factors contributing to this uncertainty regarding the commitment of future resources include:

- Load-serving entities appear to be reluctant to commit to resources more than one or two years in advance of their need, and many are not reporting plans for unspecified or undetermined resources to meet future capacity obligations.
- Generating entities generally do not commit to building new plants more than two or three years in advance of the planned in-service date. This time horizon represents roughly the design and construction lead time for the types of plants being considered today.
- There is some exposure to accelerated retirements of existing generating units as generation owners consider the economics of continuing operation of each unit in the new competitive energy marketplace.
- While only a small portion of the increase is currently shown as fueled by natural gas, expectations are that a major portion of this new capacity will be gas fired as the capacity is committed.
- There is considerable uncertainty about how retail competition will affect the availability of Active Load Management programs in the MAAC Region. The effect of retail access across the MAAC Region on the availability of Active Load Management will have to be monitored closely.
- In recent years, the trend for outage rates in MAAC has been down despite an increasing average age of generating units. This reflects improved maintenance practices and should prevent the increasing age of generators from becoming a reliability problem.

Transmission Adequacy and Security and Network Transfer Capability

The planned bulk transmission system in the MAAC Region, with its ties to the Eastern Interconnection, is in compliance with the MAAC Principles and Standards through the 2003 planning period. Both steady-state power flow and dynamic analyses were used to test the system under summer and winter peak conditions for the 1999 and 2003 planning periods. The system was not analyzed for the planning periods beyond 2003 due to the uncertainty associated with the generation capacity plans and the impact and treatment of Active Load Management.

Sufficient generating resources are expected to be available through the 2003 planning period to enable the MAAC system to be readjusted after the loss of any one of a list of identified critical 500 kV lines. The subsequent loss of any 500 kV line or critical 230 kV line would not cause any facility to be loaded beyond its short-term thermal rating. It should be noted that import capability following the outage of any one of these lines would be reduced significantly.

The MAAC system as planned through the 2003 planning period has, with one exception, sufficient reactive capacity with adequate controls distributed across the system to maintain acceptable emergency voltage profiles for the conditions specified in the MAAC Criteria. Additional reactive capacity may be required in the Jersey Central Area after the proposed retirement of Sayreville and Oyster Creek generation in January 2000 and October 2000, respectively. System expansion studies for this Area have been initiated.

Voltage constraints will continue to be a limiting condition for energy transfers into and throughout the MAAC system. However, import capabilities are adequate for reliable system operation.

As with capacity adequacy, the evolution of the electric industry introduces uncertainties with respect to the long-term adequacy of the interconnected transmission system.

- Transmission adequacy in the long term may be at risk as a result of the lack of long-term plans for capacity resources. The timeframe to plan, design, obtain rights-of-way and siting approvals, and construct transmission can be substantially longer than the two- to three-year lead time required for new generation and even shorter lead times to arrange capacity purchases.
- Although the capacity resources may be available, transmission capacity may not be adequate to deliver the generating capacity where it is needed if plans cannot be developed more than five years in advance. The challenge will be to identify areas of the system where transmission may not be adequate and where the siting of generating facilities would not require transmission enhancement.

Dynamics testing shows that the MAAC system meets all MAAC stability requirements for more probable contingencies for the planning periods 1997 through 2003. More than 1,500 dynamic simulations were performed to evaluate the stability of the MAAC system.

Operations Assessment

MAAC recognizes that increasing competition in the electricity market has increased both the number of market participants and the number of transactions. To meet the operational needs of this expanded market, the Region is developing additional rules and procedures for communications and data reporting necessary to ensure reliable operation of the bulk electric system. The MAAC Regional transmission system is adequate for reliable operation under non-simultaneous emergency assistance transfer conditions. It also is likely that there is enough operating flexibility in the electric system to maintain reliability even during simultaneous emergency electricity transfers.

PJM Restructuring Filings

A series of FERC filings throughout 1997 offered various proposals to restructure the PJM Pool. Despite differences in their approaches to transmission pricing, governance, and some generation aspects of a restructured pool, the proposals submitted all favored establishing an independent system operator (ISO) that implements a Regional transmission tariff modeled closely on FERC's pro-forma tariff.

In a November 25, 1997 Order, FERC accepted a PJM restructuring proposal that was implemented on January 1, 1998. Major aspects of the Order included:

- Locational Marginal Pricing (LMP) — prices congestion as the difference in energy costs between sending and receiving buses.
- Fixed Transmission Rights (FTR) — protects FTR holders from congestion costs.
- Zonal Transmission Rates — allows transmission rates to be based on the revenue requirement of the zone in which the load is located.
- PJM Operations — the PJM-ISO operates the bulk electric transmission system and administers the PJM power exchange.
- Governance — PJM's governance encompasses a two-tier system based on an independent board and a broad stakeholder-based members committee.
- Market Monitoring — PJM is to file a plan to monitor and report on issues related to the determination of congestion costs and the potential to exercise market power within PJM.

Because of a number of infrastructure changes, PJM deferred the implementation of Locational Marginal Pricing until April 1, 1998. All other aspects of the restructuring Order became effective January 1, 1998.

The Mid-Atlantic Area Council (MAAC) Region consists of 15 full members and 31 associate members serving over 22 million people in a 48,700 square-mile area. 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.

Although the unusual outage of several nuclear generating units caused an increased risk to reliability in 1998, MAIN expects to have adequate generating capacity and transmission import capability to meet its reliability criteria throughout the 1998–2007 period.

MAIN

Demand and Energy

Summer peak demand for the 1998–2007 period is forecast to increase at an average annual rate of about 1.5 %, about the same as last year's projected rate. The actual Mid-America Interconnected Network (MAIN) 1997 demand of 45,887 MW was about 3% lower than last year's forecast.

The projected average annual growth rate of electrical energy for 1998–2007 is 1.5%, about the same as last year's forecast rate. Actual energy use in MAIN in 1997 was 236,143 GWh, which was slightly lower than was forecasted.

Resource Assessment

MAIN utilities expect to add more than 6,000 MW of net production capacity resources during the next ten years. Reserve margins for MAIN as a whole are projected to remain near the recommended range of 17% to 20% (14.5% to 16.7% capacity margin). Most of the planned capacity additions in MAIN are short lead-time combustion turbine peaking units for which no firm commitments have been made as to siting, permitting, or financing.

Supply adequacy in MAIN is assessed using loss of load probability (LOLP) analysis. Considering load forecast uncertainty due to all factors, including weather and diversity among NERC Regions, MAIN will have adequate installed generating capacity to meet its one-day-in-ten-years criterion (0.1 day or less per year LOLP) throughout the entire study period, based on the projected yearly reserve margins for MAIN and an assumed adequate import capability.

The expected outage of 3,026 MW of nuclear generation in the MAIN Region increased the risk for loss of load during the 1998 peak period. The situation in which a large number of nuclear units are unavailable, prior to entering the peak period, is unusual and is the result of a combination of physical plant, operator, and regulatory issues. The owners of the unavailable nuclear generating units in MAIN are continuing their efforts to restart these units and expect that these units will be available in future years. Utilities in MAIN who are affected by the loss of the nuclear capacity have contracted for supplemental capacity with firm transmission service for the summer of 1998 to minimize the effect of the loss. They will continue to purchase supplemental capacity in future years if the nuclear capacity continues to be unavailable.

Transmission Assessment

For the summer of 1998, MAIN has judged that interregional import transfer capability from MAPP to be adequate, from ECAR marginally adequate, and from SPP and TVA to be inadequate. In addition, MAIN import capabilities from surrounding Regions decreased in the three projected scenarios of generation deficiency studied for 1998 summer. Two new emergency transmission-operating procedures were developed for 1998 summer to increase transfer capability. Details of the MAIN assessment are contained in the NERC *1998 Summer Assessment* report. Because the generation deficiency scenarios projected for the 1998 summer are not expected to reoccur, the inadequate transmission capability assessments for 1998 will not be applicable to the future.

While the long-term analysis of transmission in MAIN indicates that the overall MAIN transmission system should be adequate to support reliable operations, concern exists that certain key interfaces will be inadequate in the future. The Northern Illinois import capability from ECAR and the Eastern Missouri import capability from Kansas are judged inadequate in the future year study and will require further investigation. Some of the transmission limitations identified have been upgraded to provide improved import transfer capability.

In addition to MAIN's Future System Study Group, two new long-term study groups have been formed. One group is studying the South Central Illinois Subregion and the other is studying the Wisconsin Upper Michigan Subregion of MAIN. Both groups are concentrating on developing transmission solutions for higher import capability. The Illinois group also is specifically investigating export capability out of or across central Illinois.

The Northeast Macomb-Niota 138 kV line is expected to be complete by end of summer 1998, which will complete a 138/161 kV interconnection between IES in the MAPP Region and Ameren. The Ameren Sioux-Roxford 345 kV line is expected to be complete by summer 1999. ComEd will be seeking certification for two additional 345 kV lines from Lockport to Lombard with an anticipated service date of summer 2001.

Operations Assessment

The summer of 1997 was mild compared to previous years. However, MAIN still dealt with numerous transmission loading relief requests and control area emergencies. MAIN recently has begun using the NERC Transmission Loading Relief (TLR) procedure as its primary line loading relief tool instead of MAIN Guide 1C. Guide 1C is still available, however, if adequate relief cannot be achieved otherwise.

MAIN has automated the collection and uploading of energy tags and hourly schedules to the interim Interchange Distribution Calculator (iIDC). This tool is an integral part of the NERC TLR procedure and is used to determine curtailments. The iIDC utilizes an existing inter-utility communications system that provides an efficient mechanism to exchange critical operating information with other Regions, required for security activities.

MAIN is now the security coordinator for its member systems. To assist with this function, an Interregional Security Network (ISN) is being developed that will enable MAIN to gather and exchange "real-time" data at the center utilizing the Inter-control Center Communication Protocol (ICCP). MAIN will be an ISN node.

The MAIN Coordination Center continues to expand to meet the needs of its members. Included in this expansion is the addition of Entergy and Associated Electric Cooperative to the MAIN-OASIS node. In addition, work has begun on the development of a new MAIN communication system. This internal Regional network will provide increased functions and flexibility in order to meet growing needs within the Region.

MAIN has completed the installation of the callable reserve project. This automated system now allows member utilities to react more quickly to generation unit outages to comply with the NERC Disturbance Control Standards.

MAIN Assessment Process

MAIN's individual member utilities plan their own facility additions. MAIN performs Regional assessments, under the direction of the MAIN Engineering Committee (EC), to ensure that members' plans are coordinated to provide a reliable system. The EC's Transmission Task Force performs short-term and long-term studies of the adequacy of MAIN's transmission system. The EC's MAIN Guide 6 study group analyzes the reliability of MAIN's generation system. MAIN works with its neighboring Regions to analyze interregional reliability through its participation in the MAIN-ECAR-TVA (MET) and MAIN-MAPP-SPP (MMS) groups.

The 45 members of the Mid-America Interconnected Network (MAIN) include 14 electric utilities and more than 30 other organizations involved in Regional energy markets. MAIN is a summer-peaking Region serving a population of 19 million in a geographic area of 120,000 square miles encompassing most of Illinois, the eastern third of Missouri, the eastern two-thirds of Wisconsin, and most of the Upper Peninsula of Michigan.

MAPP

Planned resources in the MAPP-U.S. area are judged to be inadequate to supply the forecast annual summer peak demand growth through the next ten years. The Region will be capacity deficit by 2000 summer and nearly 4,500 MW deficit by 2006 summer. MAPP-U.S. utilities have committed to install approximately 375 MW during this period. Most utilities in the Region propose to install natural gas turbines with short construction lead-time to meet capacity obligations.

The MAPP transmission system is adequate to meet the needs of the member systems and will continue to meet reliability criteria through the planning period. Increased loading on the key Minnesota-Wisconsin interface resulting from the capacity shortage in MAIN may restrict market opportunities in the southern and central parts of the Region. Several new transmission projects are being proposed to relieve these constraints, but the system is expected to continue to operate near its secure limit.

The Mid-Continent Area Power Pool (MAPP) Region has significantly increased its membership with the addition of three transmission owning members in Kansas, two in Missouri, and three in Wisconsin. These members have joined the MAPP Reliability Council (MRC), Region Transmission Council (RTC), Power and Energy Market (PEM), or all three. In addition, 23 new transmission-dependent companies have joined the MAPP Power and Energy Market, the Regional Transmission Council, or both. MAPP membership now totals 102 members and includes 20 transmission owning members, 52 transmission using members, 68 Power and Energy Market members, 22 associate members, and eight regulatory participants. As a result of this tremendous growth in membership and power market activity in the MAPP Region, MAPPCOR has increased staff by nearly 45% to support Regional security and reliability activities. The MAPP Security Center has been a major focus of activity and is expected to be fully operational in 1999.

MAPP Assessment Process

The MAPP Reliability Committee and Regional Reliability Council direct the annual assessment of adequacy and security through the Council's working group structure. The Transmission Reliability, Transmission Studies, Reliability Studies, Reserve Requirements, and Model Building Working Groups jointly prepare the MAPP ten-year Regional Reliability Assessment. The Reliability Studies Subcommittee, Design Review Subcommittee, and Operating Review Subcommittee are committed to reviewing MAPP reliability from a near-term and long-term perspective to ensure the MAPP system can meet the needs of its members.

Demand and Energy

The MAPP-U.S. and MAPP-Canada combined 1997 summer noncoincident peak demand was 33,129 MW, a 4.1% increase over 1996 (31,813 MW) and 2.7% over the 1997 forecast (32,259 MW). MAPP-U.S. accounted for 3.3% above 1996 actual demand and 2.8% above the 1997 forecast. MAPP-Canada was 3.2% above 1996 actual demand and 1.9% above the 1997 forecast.

The MAPP-U.S. 1998–2007 forecast of average annual growth in summer peak demand has decreased from last year from 1.7% to 1.2%. The MAPP-U.S. 2006 noncoincident summer peak demand (the last common year of the last two forecasts) is forecast at 32,151 MW. This projection is 1.5% above the 1996 forecast.

Annual electric energy usage for MAPP-U.S. was 4.2% above 1996 consumption and 1.5% above the 1997 forecast.

Resource Assessment

Generating system adequacy for the MAPP-U.S. Region is judged to be inadequate for the ten-year planning period. MAPP-Canada will be adequate over the same period. Net capacity for MAPP-U.S. (committed and proposed generation additions, uprates, and retirements) will provide an additional 375 MW of capacity in the MAPP-U.S. Region for 1998–2007. Committed and proposed capacity additions (new) account for 126 MW, uprates account for 105 MW, proposed units at 146 MW, and retirements at -2 MW. The overall capacity resource margin is below 1997 forecast and declines from a high of 21% in 1998 to 3% in 2006 when committed and proposed generation is considered.

The MAPP Agreement obligates the member systems to maintain reserve margins at or above 15% over the reporting period, however, the Region must carefully watch construction lead times to ensure that enough resources will be available to maintain Regional adequacy. The ability to import power may be severely limited in the near term because of the lack of external resource availability.

Transmission Assessment

The existing transmission system within MAPP-U.S. is comprised of 7,264 miles of 230 kV, 5,599 miles of 345 kV, and 342 miles of 500 kV transmission lines. MAPP-U.S. members plan to add 30 miles of 345 kV transmission in the 1998–2007 timeframe. 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 forecasting an additional 480 miles of 230 kV transmission in the 1998–2007 timeframe.

MAPP member systems 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-owning members, transmission-dependent members, power marketers, and state regulatory bodies. The Transmission Planning Subcommittee, in cooperation with the five sub-Regional planning groups, prepares a ten-year transmission plan to meet the needs of all stakeholders.

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 stretched the existing transmission system to 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

Development of the MAPP Security Center is continuing at a rapid pace with the implementation of real-time system monitoring of key flowgates, data collection at five-minute intervals, and near real-time pre-contingency analyses of system conditions. MAPP member systems jointly perform inter- and intraregional seasonal operating studies under the direction of the Operating Review 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 scheduled transmission system maintenance. The MAPP Reserve Sharing Pool continues to provide a benefit to the Region through the sharing of generation during system emergencies.

The Mid-Continent Area Power Pool (MAPP) membership includes 89 utility and nonutility 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.

The most important issue facing NPCC over the next ten years is how to maintain reliability in this international Region as the electric utility industry is changing from a regulated to a competitive environment. The NPCC Reliability Assessment Program is the cornerstone on which NPCC has built its high level of reliability, and, enhanced to meet the new NERC Standards, it will continue to guide the Council into the future. Two near-term developments bear mentioning:

The security of the NPCC bulk electric supply network has been enhanced through the full compliance of Hydro-Québec with all NPCC Criteria. Hydro-Québec has completed its program to improve the reliability of its transmission system, and as of May 1, 1998, the loss of the Hydro-Québec System is no longer considered a single contingency in planning or operation of Hydro-Québec or other systems.

Within the five-year planning horizon, ISO New England, Inc. is beginning to see the response of the marketplace to anticipated resource needs. Forty-two merchant plants representing over 23,000 MW of generating capacity have filed applications with ISO New England for the necessary system integration studies. The in-service dates for the generation facilities, all of which are proposed as gas fired, range from 1998 to 2002.

NPCC

NPCC Assessment Process

The Northeast Power Coordinating Council (NPCC) Reliability Assessment Program brings together the efforts of the Council, its member systems and Areas in the assessment of the reliability of the bulk electric system. Over the years, NPCC has developed an extensive set of Criteria, Guides, and Procedures (NPCC Documents) that define reliable operation and planning within NPCC, and with which compliance is mandatory on the part of all NPCC members. The Reliability Assessment Program assures that all NPCC Documents are reviewed on a periodic basis to ensure that they remain current and timely in their focus. As part of the Program, the Task Force on Coordination of Planning is charged, on an ongoing basis, with conducting reviews of resource adequacy of each Area of NPCC. In a similar manner, the Task Force on System Studies is charged with conducting periodic reviews of the reliability of the planned bulk electric transmission systems of each Area of NPCC and the transmission Interconnections to other Areas.

The primary objective of the NPCC Area 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 (Document A-2), or other NPCC Criteria, could result in adverse consequences to another NPCC Area or Areas. If, in the course of the study, such problems of an inter-Area nature are determined, NPCC informs the affected systems and Areas and monitors the resolution of the possible threat to reliability.

The NPCC Reliability Assessment Program is currently being enhanced to ensure that NPCC will comply with the new NERC Planning Standards and revised Operating Policies.

Demand and Energy

The average annual growth rate forecast for the summer peak demand for NPCC-U.S. for 1998 through 2007 is 1.4%, as compared with the forecast of 1% in 1997. The projected summer peak demand for NPCC-U.S. for 2006, the last common year of the two most recent ten-year forecasts, is about 2,330 MW higher than last year's forecast. In addition, the projected annual electrical energy growth rate is 1.4% as compared with the projection of 1.1% for 1997.

The average annual growth rate for the winter peak demand for NPCC-Canada is 1.5%, as compared to last year's 1.3% forecast. The projected winter peak demand of NPCC-Canada for 2006/07 is about 420 MW more than last year's forecast. The projected annual electrical energy growth rate is 1.4%, which is unchanged from last year's forecast.

Resource Assessment

In New England, the NEPOOL average annual growth rate for 1998 through 2007 is 1.9% for the summer peak demand and 1.7% for the winter peak demand. These values are higher than last year's corresponding forecasts of about 1% and 1.2%, respectively. Energy growth is projected to be 1.9% as compared to the 1.2%, which was projected last year.

As discussed in the NERC *1998 Summer Assessment*, NEPOOL again will be faced with difficult operating conditions for the third consecutive summer due to the unavailability of at least two of the three Millstone nuclear units in Connecticut. However, within the five-year planning horizon, ISO New England is beginning to see the response of the marketplace to anticipated resource needs, with 42 merchant plants representing more than 23,000 MW of generating capacity having filed applications with the ISO-NE for the necessary system integration studies. The in-service dates for the generation facilities, all of which are proposed as gas fired, range from 1998 to 2002.

In New York, the peak demands that are forecast for the years 1998 through 2007 show an average annual growth rate of 1%, which is a slight decrease compared to last year's forecast of 1.1%. The forecast net energy for the same ten-year period also shows a growth rate of 1%, down somewhat from the 1996 forecast of 1.1%. Capacity changes in New York include the planned reactivation in June 1998 of the 850 MW Oswego 5 oil-fired unit that has been mothballed for about four years. The New York Power Pool reserve margin will be adequate during the 1997 through 2002 period, while recognizing the uncertainties facing the industry as a whole over the last five years of the assessment period. The member systems are considering various options for increasing capacity by 2003.

Ontario Hydro's average annual growth rate for 1998 through 2007 is 1.1% for the winter peak demand, as compared to a rate of 0.9% reported last year. Energy growth is projected at 1.1% for the same period as compared to last year's value of 1.2%. Generating capacity owned by IPPs will increase by 25 MW in 1998 due to previous commitments, but is projected to stay constant at about 1,600 MW throughout the remaining part of the forecast period. Future capital expenditures continue to be reviewed with many previously planned capacity additions indefinitely postponed.

Ontario Hydro is forecasting adequate levels of resources throughout the reporting period, even after having laid-up four Pickering nuclear units on December 31, 1997 and three Bruce A nuclear units on April 1, 1998. Thus, a total of 4,360 MW of nuclear generation have now been removed from the system to enable Ontario Hydro to concentrate work on the remaining 12 nuclear units as per the nuclear recovery program. The decision to return the nuclear capacity to service will be based on economics and market conditions. Pickering units are projected to return to service in the period 2000 to 2002. Bruce A units will be considered for operation starting in the year 2003. In order to provide some compensating capacity, two Lennox fossil-fired units were returned to service from a mothballed state in late 1997 and early 1998 adding 1,100 MW capacity to the Ontario Hydro system.

Hydro-Québec's average annual growth rate for 1998 through 2007 is 1.8% for the winter peak, which is slightly higher than the 1.6% forecasted last year. The demand for energy will increase at an average annual rate of 1.6% between 1998 and 2007, which is unchanged from last year's projection. Industrial interruptible demand will be about 2,300 MW by the end of the forecast period. IPP-owned generating capacity will be about 330 MW in the winter of 1998/99 and is projected to increase to about 370 MW by the winter of 2007/08. Utility-owned generation is projected to increase by about 1,000 MW by the winter of 2007/08, while more than 2,900 MW of previously planned generation, including the initiation of the Great Whale project, still is delayed beyond the forecast period of this assessment.

In the Maritime Area (New Brunswick, Nova Scotia, and Prince Edward Island), the average annual growth in winter peak demand for 1998 through 2007 is 1.4% and the corresponding growth in energy is 1.3%, down from 1.9% in last year's forecast. Planned utility generating unit additions currently total about 195 MW through the forecast period while about 120 MW will be lost due to retirements and re-powerings. Projected IPP generator additions are estimated to total about 190 MW.

As projected last year for the U.S. portion of NPCC, IPP generation in 1997 was the largest source of electricity, followed by coal-fired and nuclear-fueled generation. By the end of the forecast period, gas-fired generation, from both utility and nonutility sources, is projected to supply about 40% of the electrical energy in the U.S. portion of NPCC. Discovery of the Sable gas fields near Nova Scotia has lessened the concern expressed in previous assessments over the ability of gas suppliers to deliver large amounts of gas to the northeastern United States. Also, as a result of the Sable gas fields, this is the first year that the Canadian utilities of NPCC project any use of natural gas for electricity generation during the forecast period. So far, the gas use is confined to the Maritime Area of NPCC-Canada.

The electric utility industry is facing greater changes than ever before, i.e., the changes from a regulated to a competitive industry brought about by FERC Orders 888 and 889. These changes have already had some effect on the assessments discussed here and will have an even greater influence on future assessments. For example, the traditional utilities that used to provide the data for these assessments are breaking up. Several utilities already have sold their generating assets to independent owners or are intending to do so. The impact on reliability of these developments cannot be gauged yet.

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. In the U.S. Areas of NPCC, planned transmission additions for voltage levels 230 kV and above total about 200 miles, all in New England. In the Canadian Areas of NPCC, planned transmission line additions during the ten-year forecast period for voltage levels 230 kV and above total about 450 miles, with construction planned by Hydro-Québec and Ontario Hydro.

Hydro-Québec joined NPCC in 1981 with the understanding that, although its system did not satisfy all of the provisions of the NPCC Criteria, contingencies on its system would not be allowed to have a significant adverse impact on the other NPCC systems. The security of the NPCC bulk electric supply network has now been enhanced through the full compliance of Hydro-Québec with the NPCC Criteria. Hydro-Québec has completed its program to improve the reliability of its transmission system. This represents the culmination of an extensive program incorporating significant capital investments, including the installation of series compensation on the bulk electric supply system as well as revised procedures and methodologies. As of May 1, 1998, the loss of the Hydro-Québec system is no longer considered a single contingency for planning or operation of Hydro-Québec or other systems.

Operations Assessment

Reliable operations within NPCC are achieved through a hierarchical system. Criteria, Guides, and Procedures developed at the NPCC level are expanded and implemented at the Area level by NEPOOL and ISO New England, the New York Power Pool, and the five Canadian member systems. 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.

Hydro-Québec, ISO New England, the New York Power Pool, and Ontario Hydro serve as the security coordination centers for NPCC. As such, each will exchange necessary security data through the Interregional Security Network (ISN). Further, the NPCC Areas conduct conference calls weekly to assess the operating conditions for the coming week, and procedures are in place to initiate emergency conference calls whenever one or more Areas feel it would serve to avoid an emergency.

NPCC also 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-NPCC (MEN) and VACAR-ECAR-MAAC (VEM). All are performed under the auspices of a permanent Joint Interregional Review Committee made up of representatives from ECAR, MAAC, NPCC, and VACAR.

The Northeast Power Coordinating Council (NPCC) is a voluntary, nonprofit organization. Its members and associate members currently represent investor- and publicly-owned utilities serving the northeastern United States and central and eastern Canada, and power marketers. In addition, NPCC is working closely with a number of associated organizations such as power pools, control centers, and NERC.

The area covered by NPCC includes New York, the six New England states, and the provinces of Ontario, Québec, New Brunswick, Nova Scotia, and Prince Edward Island. The total population served is approximately 49 million, encompassing about 20 million electric customers. The area covered is approximately one million square miles.

Planned capacity resources are judged to be adequate to supply the forecast annual summer peak demand growth of 2%. The overall SERC capacity resource margin continues to decline, reflecting the members' reliance on short lead-time resources and market uncertainties. Many systems in SERC are planning to install or purchase peaking-type capacity during this reporting period.

The ability to transfer power above contractually committed uses, both intra- and interregionally, has become marginal on some interfaces under both studied and actual operating conditions. The unknown increase in bulk power marketing activity over the review period is expected to push the operating state of the transmission system beyond that which is planned and must be considered in the overall ability to transfer power.

SERC

Assessment Process

The Reliability Review Subcommittee (RRS) of the Southeastern Electric Reliability Council-Engineering Committee (SERC-EC) annually assesses and reports on the adequacy of reliability studies conducted by SERC's four subregions, the coordination of such studies with other affected subregions or Regions, and the ability of the planned systems to meet SERC and NERC reliability criteria.

RRS evaluates adequacy and security for a ten-year period based on SERC's "Principles and Guides for Reliability in System Planning." Data for this analysis is provided to SERC by the individual member systems.

RRS maintains a listing of reliability studies; recommends new reliability studies deemed necessary; reviews SERC reliability criteria (along with the SERC Planning Standards Working Group); acts as liaison between SERC-EC and other groups within SERC and NERC; and serves as a clearinghouse for the exchange of information.

In June 1998, the RRS completed its 19th annual review of subregional expansion plans and the process of coordination of planning among the SERC subregions and between SERC and adjacent Regions.

Demand and Energy

SERC's 1997 summer peak demand of 137,382 MW was a 3.7% increase from the 1996 summer peak of 132,488 MW. The 1998–2007 forecast of average annual growth in summer peak demand has decreased slightly from last year's 2.3% to 2%. Forecast growth rates have not varied widely.

Resource Assessment

Planned resources are judged to be adequate to meet forecast annual summer peak demand growth for the 1998–2007 period. Net capacity additions within SERC for the 1998–2007 period total 22,497 MW. These additions include combustion turbine units (35%), combined cycle (30%), and unspecified other (33%).

The overall SERC capacity resource margin is down from the 1997 forecast and declines from a high of 12.7% in 1998 to a low of 8.8% in 2007. Although the systems in SERC do plan to maintain capacity margins at or above 9% during the reporting period, about 90% of the planned capacity additions in the next ten years are uncommitted, undefined resources. The committed capacity margin is calculated by removing all resources that are not currently under construction or permitted and computing the resulting capacity margin against projected summer peak demand. The Regional committed capacity margin drops below 10% in 2000 and below 5% in 2003 indicating that the SERC Region has about two years to bring new capacity on line.

Based on its review of the 1998–2007 period, RRS believes that SERC's committed capacity margin lead time of about two years appears marginally adequate for the Region in view of the significant commitment by member systems to short lead-time resources. The Region and its member systems must continue to carefully watch this capacity margin lead time to ensure that proper resource development is pursued to maintain Regional reliability.

Transmission Assessment

The existing bulk transmission system within SERC is comprised of 15,461 miles of 230 kV transmission lines, 753 miles of 345 kV transmission lines, and 8,470 miles of 500 kV transmission lines. SERC systems plan to add 841 miles of 230 kV transmission lines and five miles of 500 kV lines in the 1998–2007 period. No additional 345 kV transmission lines are planned during the period.

SERC member systems continue to plan for a reliable bulk transmission system. Coordination of transmission expansion plans in the Region is maintained by joint modeling efforts among member systems. The ability to transfer power above contractual commitments has become marginal on some interfaces, both in transfer capability studies and under actual operating condition. The problem persists whether the incremental transfers are intra- or interregional in nature. This reduced transfer is a reliability concern because it impacts the geographic diversity of emergency resources that can be imported during large generator unit outages.

The increase in bulk power marketing activity resulting from the transmission open access tariffs will continue to push the operating state of the transmission system into conditions for which it was not originally planned. SERC member systems need to take a proactive role in advocating the continued planning and operation of the system in a manner that meets NERC and SERC reliability criteria.

Operations Assessment

SERC has implemented several measures in the last few years to ensure reliability of the system. There are five security coordinators in SERC — one in each of the Entergy, Southern, and TVA Subregions, and two in the Virginia-Carolinas Subregion. In addition, line loading relief procedures have been implemented since the summer of 1997. The SERC ATC Working Group has continued to refine the SERC ATC procedures to improve the overall process and to comply with NERC requirements.

SERC members' systems jointly perform seasonal operating studies and coordinate operations. The establishment of security coordinators and the sharing of real-time information have provided significant reliability benefits for operating the system.

Southeastern Electric Reliability Council (SERC) membership includes 38 member systems and 32 associate members. The Region, represented by the Council, is located in 13 states in the Southeastern United States, and covers an area of approximately 464,000 square miles. SERC is divided geographically into four diverse subregions that are identified as Southern, Tennessee Valley Authority (TVA), the Virginia-Carolina Area (VACAR), and Entergy.

SPP will have adequate generation capacity over the short term with committed capacity meeting targeted reserve margins. Beyond the short term, meeting the target margins will be highly dependent on the ability of the market to provide the necessary generation resources.

The bulk transmission system is adequate and will continue to meet the SPP criteria for reliability during the short term. Beyond that, the bulk transmission system will be reliable if sufficient lead times exist to add the transmission facilities necessary to accommodate currently unknown generation additions.

SPP

Changes in SPP Membership

Former Southwest Power Pool (SPP) members Associated Electric Cooperative, Inc., Entergy Corporation, and Cajun Electric Power Cooperative are now reporting in the SERC Region. Former SPP member St. Joseph Light and Power Company is now reporting in the MAPP Region. All future and historical statistics stated herein are based on the omission of data for these four companies. The peak demand of SPP has been reduced by approximately 38% as a result of the departure of these former members.

Assessment Process

The SPP Reliability Assessment Working Group (RAWG) reports directly to the SPP Board of Directors in an “auditor” role. RAWG reviews (and summarizes in SPP’s Annual Report) the many detailed studies performed by SPP organization groups throughout the year. RAWG tracks and documents SPP bulk electric system reliability and highlights areas that, if unsuccessfully managed, will threaten service continuity.

RAWG reviews member projections of load demand, capability, and capacity margin. RAWG analyzes how future resource needs are planned to be met such as through committed versus uncommitted new capacity, unknown or undermined capacity, units returned to service, and demand-side management. In addition, RAWG reviews loss-of-load-expectation (LOLE) analyses performed by another SPP working group.

The RAWG reviews the studies performed by the Transmission Assessment Working Group (TAWG). TAWG performs seasonal power flow studies for purposes of determining Available Transfer Capabilities for transmission system interfaces between member systems. In addition, TAWG participates in interregional studies with other Regions.

Demand and Energy

SPP is a summer-peaking Region with projected annual peak demand and energy growth rates of 1.8% and 2%, respectively, over the next ten years. Members continue to forecast similar growth of future demand and energy requirements compared to previous years. These growth rates are considerably lower than the ten-year historical growth rates of 2.4% and 3% for peak demand and energy, respectively.

Members are focusing more on the short term (two to five years), thereby shrinking the planning horizon. This reduces the need for long-term (five to ten years) forecast accuracy. The projected growth rates for peak demand and energy over the next five years are 1.4% and 1.9%, respectively. The actual growth rates for peak demand and energy over the last five years were 2.3% and 2.2%, respectively.

Resource Assessment

SPP Criteria allows members to reduce their minimum capacity margin target from 15.25% to 13%, if studies indicate that their expectation of demand exceeding generation is not greater than one occurrence in ten years. Some members have reduced their capacity margin criteria in this way. The SPP Board of Directors recently approved a new criterion that requires a 12% capacity margin, effective October 1, 1998.

For the most part, SPP members are assuming that the market will provide needed resources, or that new uncommitted capacity sources could be made available by those members in a two- to three-year time period. Capacity margins reflecting only committed additions are expected to be 14% in 1999, 12% in 2000, and 11% in 2001. These capacity margins may be somewhat optimistic because projected growth is considerably lower than historical demand growth.

SPP is caught up in the transition to a fully functioning generation market. These capacity margin levels result from the fact that SPP members are not building new capacity and are depending on the generation market to provide needed capacity. Unless that market begins building capacity very soon, there is a growing risk that capacity margins will be inadequate to maintain the level of reliable service provided in recent years. Based on available information, merchant plant activity in the SPP Region is practically nonexistent.

During its recent reliability review, RAWG uncovered significant inconsistencies in the SPP EIA-411 data that is used to calculate expected capacity margins. RAWG also saw a need to have more specific information on portions of that data in order to understand its implications. The Capacity Margin Task Force, SPP staff, and RAWG worked together to audit the EIA-411 data and solicit revised EIA-411 data and explanatory information from SPP members, recalculated expected capacity margins, and recommended action concerning these margins to the SPP Board. As a result of this effort, there is a heightened awareness of the importance of correct EIA-411 data, especially in light of the very tight reserve situation.

Though SPP has never experienced loss of firm customer demand due to a capacity shortage, lower margins may challenge this trend in the future. It is becoming very difficult to assess generation reliability in the increasingly competitive market place. While economic theory states that the market place will meet demands, system operators had difficulty finding access to resources, regardless of price, in the past three years. This is occurring more frequently.

The LOLE studies performed by SPP show that an adequate capacity margin for SPP is very sensitive to small changes in unit availability. Availability studies do show improvements in unit availability over the past several years, and members are committed to continuing this trend.

An increasingly important factor in the LOLE studies will be the reliance on resources outside the individual members' areas and outside SPP. As capacity margins dwindle and SPP members and those of other Regions rely more and more on the "market" to supply the necessary capacity to serve their customers, the reliability of those outside resources must be studied carefully.

Transmission Assessment

Minimal additions of transmission facilities of Regional significance are planned for the bulk transmission system over the next ten years. The additions being planned primarily benefit local areas and have no significant impact on subregional or Regional transfer capability.

Seasonal transfer capability studies were performed on the current and planned bulk transmission system. Certain assumptions were made as to the size, type, and location of currently unknown generation additions. These calculations account for the most restricting credible operating contingency and are tracked from study to study for variations which may indicate a problem.

The results of these transfer studies indicate that there is, and will continue to be, ample Regional transmission interconnection capability to reliably withstand the loss of internal generating capacity if sufficient lead time exists to add the transmission capacity necessary to accommodate currently unknown generating unit additions.

Operations Assessment

SPP operated without a security center until installation of one in late 1997. The security center, located at the SPP offices, provides the exchange of near real-time operating information and around-the-clock security coordination.

Line loading relief procedures have been developed in accordance with NERC's Operating Policies. These procedures include preemptive screening, performed daily, to help members recognize heavy line loading that is expected to occur. A major tenet of these procedures is to ensure that line loading relief is cured by real changes in generation patterns, not a mere shuffling of interchange schedules.

SPP continues certification of system operators. Certification consists of attending a three-day course and passing a test covering the NERC Operating Policies and SPP Criteria. SPP requires that each control area have at least one certified system operator on duty at all times. All members involved in bulk power operations are encouraged to seek certification.

SPP recently reviewed its Criteria and made modifications to ensure those Criteria provide for a reliable electric system that is in balance with business demands.

SPP continues toward the formation of an independent system operator. The fundamental principles of the ISO formation are:

- Organizational Structure — The ISO should be synonymous with the SPP organization with all reliability, transmission administration, commercial, compliance, and administration functions reporting to a single board of directors.
- Governance — The ISO should be governed by a hybrid board structure with three sectors containing an equal number of representatives: transmission providers, transmission customers, and impartial experts.
- Coordinated Planning — The ISO should actively and openly coordinate Regional planning with transmission providers, rather than centrally perform planning.
- Constraint Identification and Control — The ISO should perform the full security functionality currently approved and being implemented by SPP. In addition, a mechanism to efficiently deal with system congestion is badly needed to enhance security functions.
- Regional Network and Long-term Point-to-Point Transmission Service — The ISO should provide Regional network service tariff and a provision for long-term firm point-to-point service to supplement the short-term service tariff currently in effect.
- Compliance Monitoring — The ISO staff should actively and openly monitor compliance with SPP and NERC criteria and policies with oversight from an SPP organizational group.
- Energy Exchange — The ISO should have no involvement in an energy exchange market.

Southwest Power Pool (SPP) has 56 members serving all or parts of Arkansas, Louisiana, Mississippi, Missouri, Kansas, Oklahoma, Texas, and New Mexico. The Region monitors, coordinates, promotes, and communicates information on the reliability of the electricity supply systems through the dedicated efforts of more than 370 people from member systems. The Board of Directors has responsibility for overall policy direction and an administrative and technical staff located in Little Rock, Arkansas provides day-to-day coordination.

Transmission system reliability is expected to be adequate throughout the ten-year period based on the annual study report and ongoing seasonal operating transfer capability assessments of major interties.

Projected resource capacity is expected to be adequate for the assessment period throughout WSCC.

WSCC

Western Systems Coordinating Council's (WSCC) 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.

The projected capacity margins (considering generation unavailable due to maintenance) and fuel supplies are anticipated to be adequate to ensure reliable operation in all areas of the Region. The transmission system is considered adequate for firm and economy transfers. WSCC's unscheduled flow mitigation plan is in effect, and part of this plan involves the coordinated operation of phase-shifting transformers at key locations to help control unscheduled power flow within the Region.

WSCC has implemented a schedule tracking system for recording all schedules between control areas from the original source to the final destination. This tracking system is designed to improve frequency control and increase system operator effectiveness in responding to transmission system outages.

Under WSCC's Regional Security Plan, security centers have been established in each of the four WSCC subregions. The security center coordinators are charged with actively monitoring system conditions and ensuring that the necessary steps to mitigate potential reliability problems are taken in a timely manner. It is envisioned that this responsibility will be assumed by independent system operators (ISOs), which are currently under development in several of the subregions, when they become fully operational in the future.

In the following text, several issues are mentioned that could pose significant challenges to the preservation of reliability in varying degrees:

- competition and increasing pressures to reduce costs,
- changes in the structure of the electric industry, and
- uncertainty regarding load growth projections and the planning and installation of new generation.

Through active participation in WSCC, individual member participants will be able to manage these issues and maintain a balance between reliability and the economic pressures of competition. WSCC is 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.

WSCC Assessment Process

The WSCC Region follows a comprehensive annual assessment process based on the following established reliability criteria:

- Power Supply Design Criteria,
- Minimum Operating Reliability Criteria, and
- Reliability Criteria for Transmission System Planning.

Adherence to these criteria provides an objective and deterministic evaluation of the reliability (adequacy and security) of the western interconnected system.

Resource Assessment

The resource assessment process in the WSCC Region has been in place for many years and is always completed by the four subregions of WSCC. A resource assessment on a Region-wide basis is not performed 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.

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 scheduled maintenance and inoperable capacity. If the projected reserve capacity margin 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 the WSCC Region for the 1998 through 2007 ten-year period.

Transmission Assessment

The member systems' transmission facilities are planned in accordance with the "WSCC Reliability Criteria for Transmission System Planning," which establishes 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 inter-area power transfers, and to meet its transmission obligation to others.

Each year, WSCC prepares a transmission study report that provides an ongoing reliability assessment of the WSCC 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 "WSCC Reliability Criteria for Transmission System Planning." 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.

The WSCC Region 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 — A voluntary peer review process through which every operating member is reviewed at least once every five years to assess compliance with WSCC and NERC operating criteria.
- Annual Study Report — 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 Capability Study Group Process — Intertie operating transfer capabilities will be limited to conditions studied either in base cases or in sensitivity studies. Double and triple contingency outages and other extreme system contingencies will be analyzed to develop a risk assessment of relay misoperations and unplanned cascading events.

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 the states of Washington, Oregon, Idaho, and Utah; the Canadian provinces of British Columbia and Alberta; and portions of Montana, Wyoming, Nevada, and California. Over the period from 1997 through 2007, peak demand and annual energy requirements are projected to grow at respective annual compound rates of 1.9% and 2%. Resource capacity margins for this winter-peaking area range between 9% and 16% of firm peak demand for the next ten years.

The internal NWPP Area transmission capability is expected to permit anticipated transfers between NWPP systems during 1998. Should a contingency occur, such as very high peak demands during a period of extreme cold weather, the Pacific Northwest may need to rely on the capability to import power. Current studies show that import capability into load centers will be adequate under moderate and extreme weather conditions. Operating procedures and operational indicators to monitor loadings on key facilities have been developed to ensure that, if needed, the Pacific Northwest could import power at safe, reliable levels.

This past winter's 6,900 MW north-to-south operating transfer capability for the California-Oregon Intertie and Pacific DC Intertie combined facilities was 650 MW higher than the prior winter's operating transfer capability of 6,250 MW. The higher operating level is due to several factors, including: installation of 1,000 Mvar of 500 kV and 230 kV capacitors; enhancement of the Fast AC Reactive Insertion Scheme; removal of reactive constraints at McNary and John Day; improved modeling of the Keeler and Maple Valley SVCs; and four seasons of operating experience with new procedures. The spring and summer combined operating transfer capability (OTC) also has been revised upward for 1998 with the spring OTC increasing from 7,200 MW to 7,900 MW and the summer OTC increasing from 6,900 MW to 7,200 MW. Improvements incorporated for the 1998 summer period include addition of unwatering capability at The Dalles (six units) and John Day (four units), and improvements in Pacific DC Intertie controls for depressed voltage conditions.

Pacific Northwest reliability studies have not identified power marketer transactions as significantly impacting transfer capability. However, the growing number of power schedules that are now being transacted, by both utilities and marketers, continues to have a significant adverse effect on power accounting capabilities. Continued difficulties in inadvertent interchange accounting in the Western Interconnection may eventually have a detrimental effect on system reliability.

The June mid-month forecast of Columbia River runoff for the period January through July as measured at The Dalles was 102 million-acre feet, or 96% of the 30-year average. The forecast portends substantially lower runoff for 1998 than the record high runoff of 150% recorded in 1997. The volume forecast in the Canadian Upper Columbia is about 90% of average.

Coordinated system storage energy as of July 31, 1997 reached 99% of allowable refill in the Actual Energy Regulation (AER), establishing first-year Firm Load Carrying Capability for operation in 1997/98. The actual reservoir refill was 95% of full, slightly below the calculated AER — the difference is assumptions used for full content in the AER for several reservoirs that in actual operation are required to be less than full in July. This was the second consecutive year that the system was declared essentially full, after four low refill years in the early 1990s. It is expected that reservoirs will again refill to about 95% of full content by July 31, 1998.

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 1997 through 2007 period, peak demand and annual energy requirements are projected to grow at respective annual compound rates of 2% and 2.3%. Summer resource capacity margins range between 18% and 22% of firm peak demand for the next ten years.

Operation of a new reserve-sharing group, the Rocky Mountain Reserve Group, is expected to start up in 1998. This reserve sharing pool will take the place of the Inland Power Pool and is expected to improve the Region's response to real-time generation deficiencies.

The transmission system within the Colorado and Wyoming Areas has had few additions to allow for increased electric power transfers into or out of the Area. However, transfer limits on the transmission path through the Area are not expected to be of major concern as the path has been stressed on occasion for several years. The path was qualified for the WSCC Unscheduled Flow Reduction Procedure in 1997 and the procedure has been invoked on several occasions. It is expected that the procedure will continue to be invoked in the future.

A new transmission facility was installed by Tri-State, the Comanche-Walsenburg 230 kV line, which will improve reliability and voltage in the southern Colorado Area. Another change affecting the transmission system is the addition of a voting logic scheme for the Northeast-Southeast separation scheme. The voting logic requires the reception of two out of three trip signals at Four Corners before a signal is sent to the circuit breakers to separate the system. This addition will enhance the security of the scheme by preventing false operations. The continual increase in year-round loading on the 345 kV system has caused many of these lines to be worked on hot. The ability to remove these lines has become very limited.

Hydro conditions in the Rocky Mountain Area were good to excellent in 1997 but the 1998 hydro conditions are expected to be below average due to the poor snowpack level. However, reservoir storage levels are adequate because of the favorable conditions in 1997.

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 1997 through 2007 period, peak demand and annual energy requirements are projected to grow at respective annual compound rates of 2.9% and 2.4%. Resource capacity margins for this summer-peaking Area range between 13% and 15% of firm peak demand for the next ten years.

No industry restructuring legislation was passed during the 1998 legislative session in New Mexico. Effective January 1, 1999, the three-appointed member New Mexico Public Utilities Commission will be merged with the New Mexico State Corporation Commission to become a five-member elected Public Regulation Commission. Texas-New Mexico Power Company has received approval from the New Mexico Public Utilities Commission to allow its New Mexico customers to choose their electric supplier in the year 2000. One city in New Mexico has issued bonds to finance the acquisition of its electric distribution system.

The Arizona Corporation Commission has adopted rules regarding competitive electric services in Arizona. Starting January 1, 1999, 20% of the load will have retail access. All remaining load will have retail access by January 1, 2001. A bill passed by the Arizona State Legislature, which became law on May 29, 1998, is intended to ensure that customers of the Salt River Project will be able to participate in open access in a similar manner as the customers of utilities in Arizona, which are under the jurisdiction of the Arizona Corporation Commission. On July 17, 1997, the Nevada State Legislature passed a bill into law opening access for all Nevada customers no later than December 31, 1999.

Significant amounts of shunt capacitors and series compensation have been and are being installed in order to preserve reliability in the Area. Several southwestern utilities are planning to either install combustion turbine generators or make purchases of peaking power from independent power producers (IPPs).

The major generating plant operators in the Area have created a Southwest Reserve Sharing Group. This group will be sharing contingency reserves with a computer-assisted communication system for activating reserves in the form of emergency assistance to recover from group disturbances within the ten-minute recovery criteria.

The restructuring of the electric utility industry has seen the Southwest utilities investigating the feasibility of an independent system operator (ISO) to be called Desert STAR (Desert Southwest Transmission and Reliability Operator). The main goals of Desert STAR are to provide electrical system security and reliability in accordance with NERC and WSCC policies and to provide nondiscriminatory open access to the transmission system. The Desert STAR initial feasibility evaluation was completed in September 1997. A development agreement has been entered into by more than 30 entities, during 1998, to further define the role and responsibilities of the proposed ISO.

California-Mexico Power Area

The California-Mexico Power Area encompasses most of California and the northern portion of Baja California Norte, Mexico. Restructuring of the electric industry in California in 1998 and beyond adds much uncertainty to future adequacy projections of generating capacity, energy production by IPPs, and effects of customer energy efficiency/demand-side management programs. Recognizing that future forecast uncertainty exists, peak demands and annual energy requirements are currently projected to grow at respective annual compound rates of 0.9% and 1.6% from 1997 through 2007. Projected resource capacity margin ranges between 13% and 20% of firm peak demand for the next ten years.

The California Independent System Operator (CISO) assumed operational control of the transmission grid of the three California investor-owned utilities on March 31, 1998. The CISO is responsible for several functions including: providing nondiscriminatory, open access to the transmission grid; controlling dispatch and maintaining reliability of the transmission grid; procuring and providing ancillary services; coordinating day-ahead and hour-ahead power scheduling and real-time power balancing; performing settlement function for unscheduled transactions and ancillary services; administering congestion management protocols; and billing.

A Southern Island Load Tripping Plan is being implemented in the Area. The objective of the load-tripping plan is to drop load as quickly as possible whenever system disturbances result in the separation of the California-Oregon Intertie. The scheme is expected to reduce the magnitude of voltage and frequency deviations and thereby minimize consequences such as additional generator tripping and increased loss of customer load.

Western Systems Coordinating Council (WSCC), with 86 members and 22 affiliate members, 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 (65% of installed capacity); the Rocky Mountain Power Area, which can be either summer or winter peaking with a 24% hydroelectric and 59% coal-fired generating capacity mix; the Arizona-New Mexico-Southern Nevada Power Area, which is summer peaking with a 17% nuclear and 44% coal-fired generating capacity mix; and the California-Mexico Power Area, which is summer peaking and heavily dependent on gas-fired generating units (47% of installed capacity).

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