Reliability Assessment

2003–2012

The Reliability of
Bulk Electric Systems
in North America

North American Electric Reliability Council
December 2003

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Executive Summary

Introduction

The North American Electric Reliability Council's (NERC) Reliability Assessment Subcommittee (RAS) prepared this independent report, which includes:

- an assessment of the long-term electric supply and demand and transmission reliability through 2012,
- a discussion of key issues affecting reliability of future electric supply and transmission, and
- regional assessments of electric supply reliability, including issues of specific regional concern.

Although the assessment represents a fairly accurate forecast of future conditions for the first several years, the longer-term assessment must be considered more an indication of future trends rather than an absolute evaluation.

In preparing this report, RAS:

- reviewed summaries of regional self-assessments, including forecasts of electric peak demand, electric 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 electricity supplies.

August 14th Blackout

The largest blackout in North America's history occurred on August 14, 2003. In its interim report, the U.S./ Canada Power System Outage Task Force investigating the blackout concluded, and NERC concurred, that certain control areas and reliability coordinators failed to fully comply with existing NERC reliability standards, and that this failure contributed to the blackout.

NERC believes that actions must be taken immediately to ensure that the reliability of the bulk power system in North America is not compromised by deficiencies in the procedures, processes, personnel, tools, and training of control areas and reliability coordinators, or by their failure to comply with NERC and regional reliability standards.

As a first step, NERC sent a letter to each entity in North America that operates a control area and each NERC reliability coordinator asking them to certify that their organizations are operating within NERC and Regional Reliability Council standards and established good utility practices. Further details regarding the letter can be found on page 12 of this report.

NERC is developing a comprehensive program to address the deficiencies identified in the interim report. The task force expects to issue a final report and recommendations in January 2004. NERC will take additional steps to address the findings of the investigation at that time.

Resource Adequacy Satisfactory in Near Term

Resource adequacy will be satisfactory in the near term (2003–2007) throughout North America, provided new generating facilities are constructed as anticipated. In spite of this favorable outlook, there is always the chance that an excessive number of equipment problems, coupled with high demands caused by extreme weather, could create supply problems.

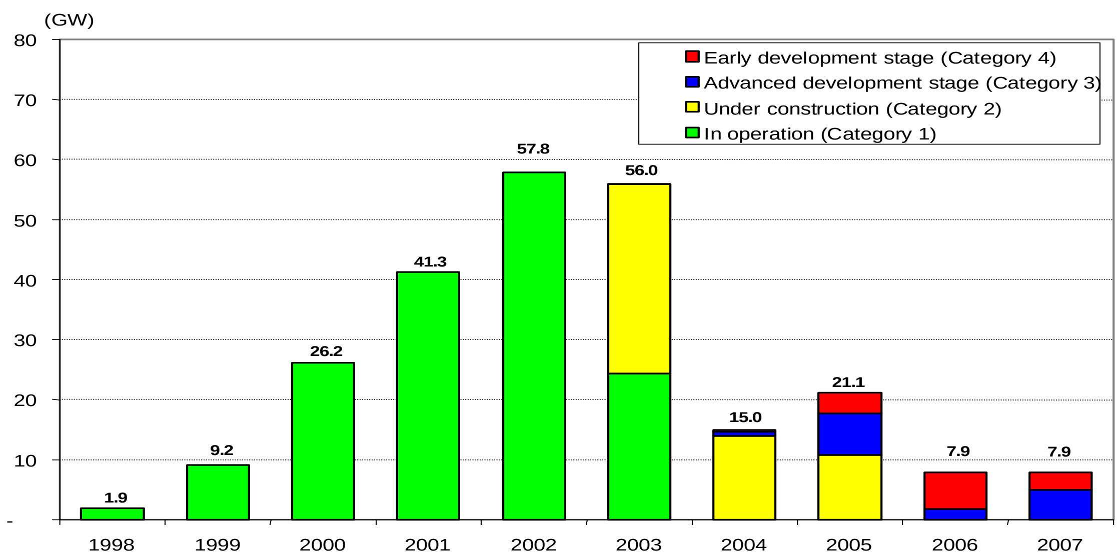
Electricity demand is expected to grow by about 67,000 MW in the near term. Projected resource additions over this same period total about 89,000 MW, depending upon the number of merchant plants assumed to be in service. Even though overall resources appear adequate, generation additions and resulting capacity margins are not evenly distributed across North America, as shown in the *Resource Adequacy* section of this report.

Resource adequacy in the long term (2008–2012) is more uncertain. However, if current trends continue, long-term resource adequacy should be satisfactory. Among the factors that will influence long-term adequacy are: timely completion of planned capacity additions, including the ability to construct the required associated transmission facilities; ability to obtain necessary siting and environmental permits; ability to obtain financial backing; prices and supply of fuel; and political and regulatory actions.

In areas with deregulated electric service, new generating capacity additions will depend on the response of power plant developers to market signals. In these areas, capacity margins will likely fluctuate, similar to normal business cycles experienced in other industries. In other areas, new capacity will primarily be constructed in response to resource adequacy criteria established by utility groups, individual utilities, or their regulators.

Generation projects previously announced continue to be delayed or canceled. However, as shown in Figure 1, new capacity is still being planned for 2004 and beyond, most of which is gas fired.

FIGURE 1: GAS-FIRED TURBINE-BASED CAPACITY BY YEAR AND DEVELOPMENT STATUS



Source: EVA

Transmission Systems Expected to Perform Reliably

The North American transmission systems are expected to perform reliably in the near term. As customer demand increases and transmission systems experience increased power transfers, portions of these systems are reaching their reliability limits. Coincident failures of critical equipment, while highly improbable, can degrade bulk electric system reliability. Emergency action plans and procedures to safeguard the system under such emergency conditions should minimize this possibility by defining the actions system operators should take to arrest disturbances and prevent cascading events.

Even though the transmission systems are expected to operate reliably, some portions of the grid will not be able to transmit the output of all new generating units to their targeted markets. Some well-known transmission constraints are recurring, while new constraints are appearing as electricity flow patterns change. Reliability coordinators, transmission planners, and system operators need to regularly communicate and coordinate their actions to preserve the reliability of the bulk electric transmission system.

Transmission system reliability will be maintained if identified transmission limits are adhered to and operating procedures are implemented as required. In cases where generation redispatch options have been exhausted or are ineffective, the only way to remove these constraints is to build new generation close to the demand centers to eliminate the need for the electricity transfers, or increase the capability of the transmission system.

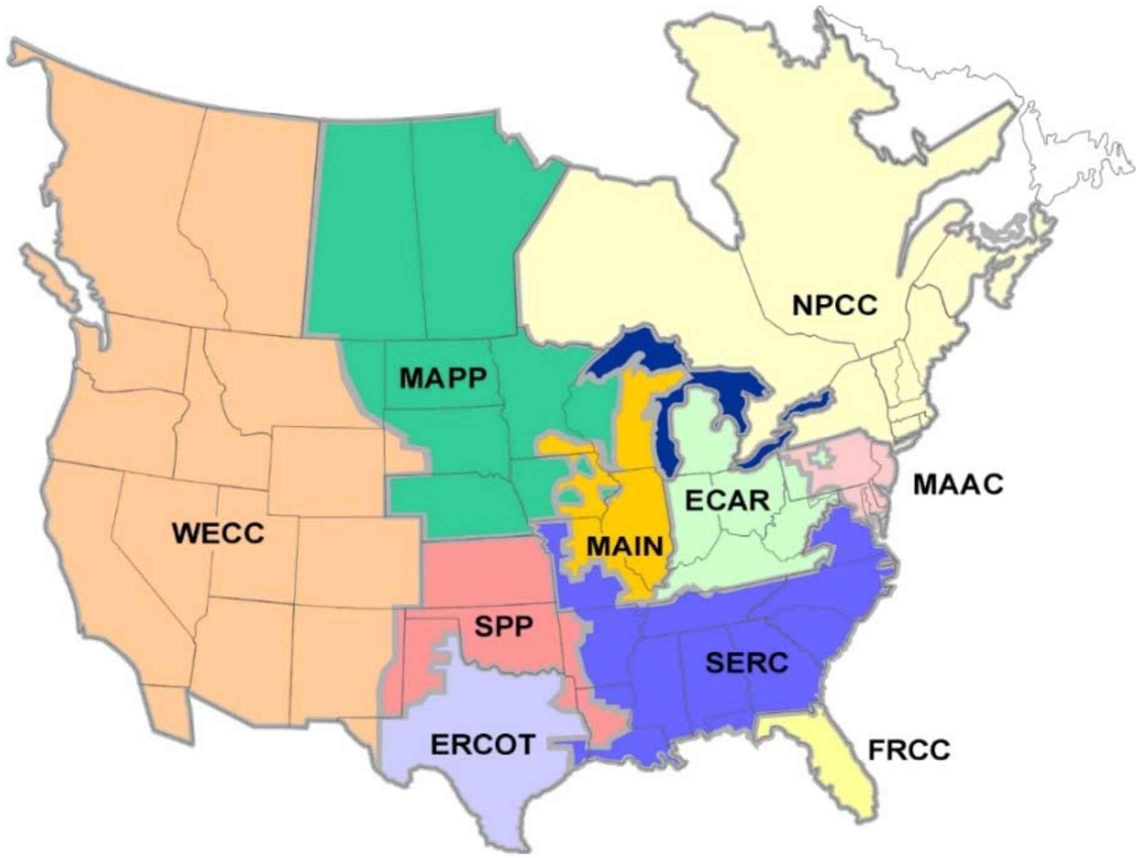
More than 7,400 miles of new transmission (230 kV and above) are proposed to be added through 2007, with a total of about 11,600 miles added over the 2003–2012 timeframe. The 11,600-mile increase represents a 5.6% increase in the total amount of installed transmission in North America over the assessment period. New transmission line construction is not the only means of ensuring transmission adequacy, as discussed in the *Transmission Adequacy* section of this report.

In the long term, reliable transmission will depend upon the close coordination of generation and transmission planning and construction. This coordination activity must now be accomplished through different means than in the past and involves coordination among many different market participants. Market signals and regulatory decisions will dictate the location and timing of generating capacity additions, and also will influence the construction of new transmission facilities.

Fuel Supply Adequate in Most Regions

Most regions do not anticipate any problems with fuel supplies for the assessment period. Hydroelectric resources will be impacted by the amount of precipitation each year, which cannot be accurately predicted very far into the future. The industry's growing dependence upon natural gas as a primary fuel for new power plants is addressed in the *Resource Issues* section of this report. Figure 2 on the next page provides a geographical representation of the NERC Reliability Councils.

Figure 2: NERC Regional Reliability Councils



ECAR
East Central Area Reliability Coordination Agreement

ERCOT
Electric Reliability Council of Texas

FRCC
Florida Reliability Coordinating Council

MAAC
Mid-Atlantic Area Council

MAIN
Mid-America Interconnected Network, Inc.

MAPP
Mid-Continent Area Power Pool

NPCC
Northeast Power Coordinating Council

SERC
Southeastern Electric Reliability Council

SPP
Southwest Power Pool

WECC
Western Electricity Coordinating Council

Regional Areas of Interest

ECAR

ECAR's membership will continue to strive to meet the challenge of maintaining the adequacy and operating reliability of its bulk electric systems as the governance and structure of the utility operations within the region evolve. ECAR will remain focused on its operational preparedness, reliability assessment process, operating guides, and technical documents, to ensure that reliability is maintained through the changing environment and that ECAR and it members are in compliance with NERC and ECAR policies and standards.

The bulk electric systems in ECAR are expected 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. After 2007, additional capacity beyond year-end 2003 levels will be needed to maintain resource adequacy.

ERCOT

In ERCOT, there is growing concern about the future adequacy of natural gas supply, given the fact that over 60% of existing and projected total generating capacity in ERCOT is fueled solely by natural gas. In late February 2003, widespread gas curtailments to electric generators throughout the region during several days of cold weather affected available generating capacity. Concern about this reoccurring in the future has led ERCOT to raise the issue of creating economic incentives for dual fuel (gas/oil) capability and the need for reconsidering the gas supply curtailment priority of electric generation.

MAIN

MAIN expects its transmission system to perform adequately during the planning horizon of this report, assuming that the proposed reinforcements are completed on schedule. However, operational challenges exist on the MAPP-to-MAIN interface because of delays in the completion of the Arrowhead-Weston 345 kV reinforcement project. These delays could impact future reliability and may require implementation of other alternatives including special operating procedures.

MAPP

Projected capacity reported in the MAPP-U.S. region is below MAPP reserve capacity obligations requirements for the period 2006–2012. However, MAPP believes that no capacity deficit will occur during the assessment period because MAPP has requirements for reserve capacity obligation with financial penalties for non-compliance and continually monitors its members' reserve margins. These measures should be sufficient to ensure that enough new capacity will be added to avoid deficits in future years.

NPCC

ISO New England anticipates that New England will meet the NPCC resource adequacy criterion of one-day-in-ten-years loss-of-load expectation through 2012. However, if transmission constraints are not relieved in southwestern Connecticut, operational problems may develop in the near-term within that area under higher than anticipated demand or lower than anticipated capacity, and worsen over the study period. The southwestern Connecticut region will require significant bulk power transmission system reinforcements to address current and future reliability issues.

The Maine and southeastern Massachusetts/Rhode Island (SEMARI) area interfaces within NPCC are currently transmission constrained, resulting in significant locked-in generation within these regions. Short-term upgrades aimed at improving the import capability in the Northeastern Massachusetts (NEMA) sub-area were completed during the summer of 2003. Future transmission expansion into and within the NEMA area will likely be required to enable continued reliability.

New York City may not meet locational capacity requirements beyond 2003 unless additional new resources are added. A local requirement shortage will occur if a proposed 250 MW generating unit currently under construction is not completed prior to the summer of 2004. Through 2012, over 1,000 MW of new resources must be added to meet the projected locational requirement. To date, 3,600 MW of new locational resources are planned through 2012.

Significant transmission reinforcement is required in the Greater Toronto Area (GTA) in order to maintain an acceptable level of supply reliability over the ten-year period. The need for transmission reinforcement is due to forecast customer demand growth both in downtown Toronto and in the municipalities north, west, and southwest of Toronto, as well as the removal from service of Lakeview generating station in 2005. Additional reactive supply capability will also be required before the Lakeview shutdown takes place to maintain an acceptable level of system reliability in the GTA. Transmission reinforcement is also required in various areas in southwestern Ontario to maintain an acceptable level of supply reliability. Plans are in various stages of development and implementation, as required to address the needs for transmission reinforcement or additional supply identified by the IMO in its 10-Year Outlooks published in 2002 and 2003.

SERC

SERC has seen significant merchant generation development during the past few years, especially in the Southern and Entergy subregions. Much of this merchant generation has not been contracted to serve customer demand within SERC. Because deliverability of this generation has not been assured, it is not included in reported capacity margins. Similarly, this generation would only be included in the calculation of capacity margins for other regions if it were to have contracts for firm delivery to those regions.

As of December 31, 2002, total generation connected to the transmission system in SERC was 200,744 MW, including uncommitted merchant generation. An additional 22,216 MW of generation was expected to be connected to the transmission system by July 1, 2003, bringing the total to 222,960 MW. This connected generation exceeds the 2003 forecast peak demand by approximately 70,000 MW or 45%. As much as 46,000 MW of this connected generation may be in excess of that needed for reliability in the region.

WECC

WECC as a region expects to be able to reliably meet electric demand and energy requirements over the assessment period. However, generation adequacy in California becomes less certain by 2007 due to the decrease in proposed new generating projects. WECC has seen a dramatic reduction in the amount of new generation proposed to be constructed and placed in operation in the region from the level reported in the *2002–2011 Reliability Assessment*. In other portions of the region, generation adequacy will be dependent on northwest hydro conditions as well as the pace of construction of new non-hydro generating facilities.

Transmission constraints will continue to limit the deliverability of generation to customer demand and are factored into the generation adequacy uncertainty in WECC. The significant increase in the amount of major new transmission facilities already planned to be added in the WECC Region during the period covered by this report would only partially alleviate the constraints.

Reliability Issues

A number of issues are discussed in this report regarding their potential impacts upon reliability. These issues include:

Electricity Resources

Historically, generation capacity additions were primarily driven by the obligation to serve customer demand. The adequate supply of electric resources has become dependent on numerous interdependent variables such as the necessary financial incentives to promote investment in generating facilities by those who do not have an obligation to serve, the availability and price of fuel, future expectations of electricity prices, availability of transmission to deliver the output of generation, and regulatory and legislative uncertainties.

Transmission

The pace of transmission investment has lagged behind the rate of load growth and generating capacity additions. Many factors have led to this condition including the way in which the grid was developed, viable alternatives to the construction of new transmission lines, and public, regulatory and financial obstacles to the construction of new transmission facilities. In light of these factors, it is likely that transmission owners will increasingly rely on system upgrades rather than new transmission lines for increased transmission capacity.

System Technical Issues

Politically charged issues in the headlines have tended to obscure many technical issues. These technical issues include: the need to coordinate the development of new generation and transmission facilities, increases in system short circuit currents and frequency excursions, and increasingly stringent environmental regulations. The solutions to these technical problems are essential parts of the maintenance of a reliable bulk power system.

Natural Gas Interdependency

With a majority of the new generation relying on natural gas as a fuel source, the question of near-term and long-term adequacy of both the availability of natural gas and the infrastructure to move it to the generating stations is coming under increased scrutiny. The *Resource Issues* section of this report investigates the manner in which gas pipelines are planned and operated in comparison to the electric grid, and the relationship and impact that the gas supply and deliverability might have on electric system reliability.

Transmission Planning Issues

As the industry continues to restructure, it is becoming more difficult to identify those responsible for maintaining adequate electricity supplies and reliable transmission systems. Indeed, the very definition of what constitutes an adequate supply may change in the future. Transmission expansion as measured by new circuit miles continues to lag the growth in both demand for electricity and the addition of new generation. However, alternatives to new transmission lines are being employed to maintain the reliability of the system as discussed in the *Transmission Issues* section of this report.

Definition of Reliability

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

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

About the Data Used in this Report

Detailed background data used in the preparation of this report is available in NERC's *Electricity Supply & Demand* (ES&D) database, 2003 edition (http://www.nerc.com/~esd/).

Most of the new generation additions will be constructed over the next few years by the merchant generation industry. NERC is collaborating with the Electric Power Supply Association (EPSA) to capture as much information regarding merchant plant additions as possible. In addition, NERC has contracted with Energy Ventures Analysis, Inc. (EVA) (http://www.evainc.com/) to monitor and track the status of proposed new power plant projects as well as plant cancellations, delays, and retirements. In some cases, data available from EPSA and EVA are used in this report to supplement data submitted by the regions.

About NERC

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

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

August 14, 2003 Blackout

On August 14, 2003, the northeast portion of the Eastern Interconnection experienced a widespread, cascading blackout affecting up to 50 million people. NERC is participating in the ongoing investigation being conducted by the U.S./Canada Power System Outage Task Force. A report describing the sequence of events and other related information can be found on the NERC website[1] at: Blackout Investigation.

On October 15, 2003, NERC issued a letter requesting that each entity in North America that operates a control area and each NERC reliability coordinator review the following list of reliability practices to ensure their organizations are operating within NERC and Regional Reliability Council standards and established good utility practices. The list includes:

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

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

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

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

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

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

Details of the request can be found on the NERC website at: Quick Action Request.

On November 19, 2003, the U.S.-Canada Power System Outage Task Force issued its report (ftp://www.nerc.com/pub/sys/all_updl/docs/blackout/814BlackoutReport.pdf) that described the major events leading up to the August 14 blackout, and identified the causes of the blackout.

NERC will continue to support the work of the U.S.-Canada Power System Outage Task Force as it conducts the next phase of the investigation to fully understand and model the cascade phase of the blackout. NERC will continue to evaluate the root causes of the blackout and related system and operational deficiencies, and develop actions and recommendations to resolve them.

[1] NERC website: (www.nerc.com)

Adequacy Assessment

Overview

The average annual peak demand growth over the assessment period is projected to be 1.9% for the United States and 1.1% for Canada. The average annual peak demand growth rate for the last ten years has been 2.4% for the U.S. (summer), and 1.4% for Canada (winter). It is important to note that the demand growth rate projections are a ten-year average and that individual years may experience greater or lesser rates due to variations in economic conditions and weather.

In *Figures 3* and *4* (on the next page), the demand projections represent an aggregate of weather-normalized regional member forecasts assembled by NERC's Load Forecasting Working Group (LFWG). LFWG develops bandwidths around the aggregate U.S. and Canadian demand projections to account for uncertainties inherent in demand forecasting. NERC does not prepare its own independent demand forecast because local entities are best suited to make appropriate assumptions concerning diversity, weather, and economic conditions, which are key drivers of the demand forecast.

Figures 3 and *4* also show overlays of the projected capacity resources on the projected demand bandwidths. NERC's Regions report all capacity committed to serve demand within their borders, but capacity that is not committed to serve a specific demand might not be reported to NERC through its traditional data collection process. To supplement these traditional data sources in order to better understand the potential impacts of new generators, RAS has enlisted the services of Energy Ventures Analysis, Inc. (EVA) and the Electric Power Supply Association (EPSA). It is difficult to accurately predict the exact number and in-service dates of future capacity additions merchant developers will actually construct. Using detailed project information from EVA and EPSA to supplement information supplied by the regions, *Figures 3* and *4* show a range of capacity margins for the assessment period.

Four resource curves are shown: the first is based on NERC regional projections; the second is projected capacity resources without the inclusion of any generators that are not currently operational or under construction (Existing plus Under Construction); the third is the subcommittee's best estimate of future capacity resources (Existing plus EVA [2]); and the fourth curve indicates the future resource situation if all announced merchant generation is constructed and brought on line (Existing plus EPSA). *Figure* 3 shows that for even the lowest projection of new resource additions, U.S. projected electricity supplies should exceed baseline demand projections throughout the assessment period. Even so, regional reliability authorities will need to watch the pace of resource additions to see whether required capacity margins are achieved.

[2] EVA maintains a database of all proposed new power plants in the United States and tracks various milestones associated with the completion of the projects, including applications for environmental permits, siting, acquisition of equipment, financing, and contractual arrangements to sell the output of the facilities. Using this key information, announced new merchant plants were screened to establish those most likely to be built.

FIGURE 3: U.S. SUMMER CAPACITY VS DEMAND GROWTH

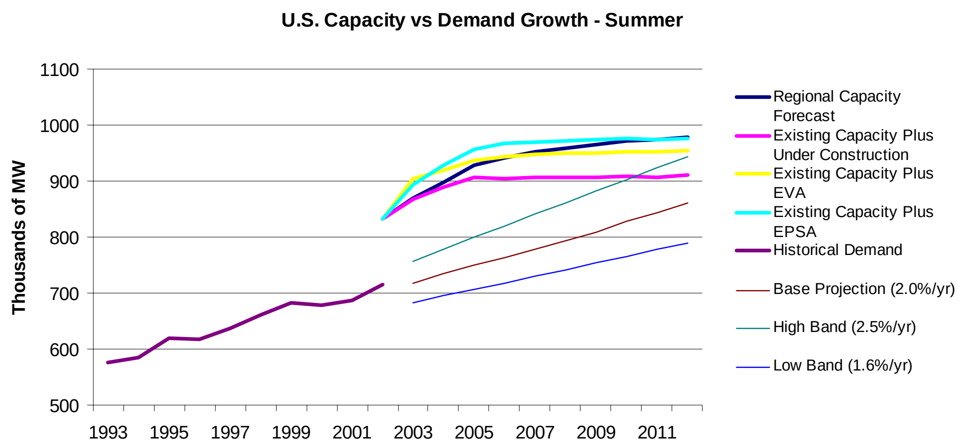


FIGURE 4: CANADIAN WINTER CAPACITY VS DEMAND GROWTH

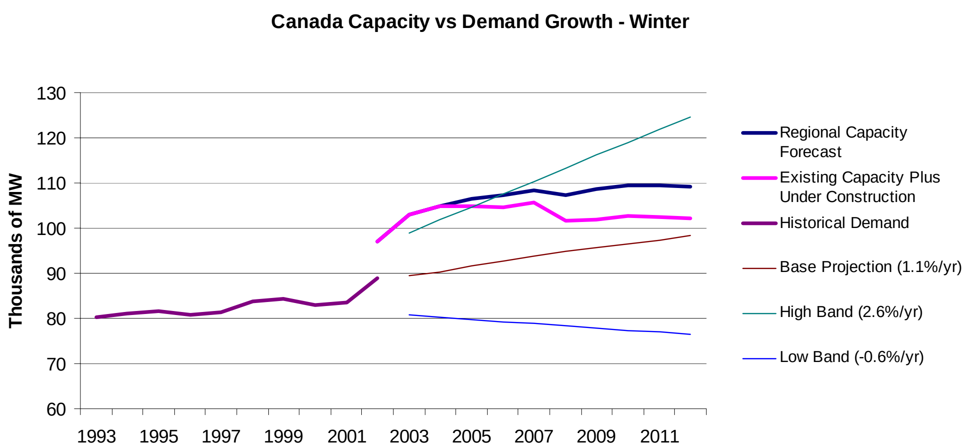


Figure 4 shows a projected bandwidth of Canada's capacity resources for the assessment period, with the lower curve incorporating only existing power plants and those currently under construction. The upper curve includes all proposed new capacity resources reported by the NERC Regions. Information regarding proposed new Canadian capacity additions beyond that reported by the regions is not currently available.

Note: U.S. and Canadian net energy for load (NEL) ten-year growth projections are contained in *Appendix A*.

Regional Details — Detailed descriptions of each of the NERC Regions can be found in their respective sections later in this report.

Forecast Bandwidths

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

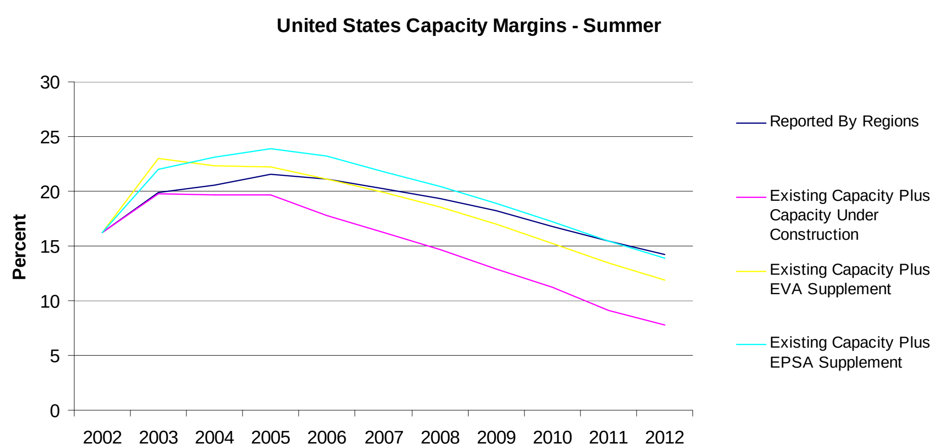
For planning purposes, it is useful to have an estimate not only of the midpoint of possible future outcomes, but also of the distribution of probabilities on both sides of that midpoint. Accordingly, NERC's Load Forecasting Working Group develops upper and lower 80% confidence bands around the NERC-aggregated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

Resource Adequacy

Capacity adequacy in North America over the assessment period will continue to be dependent upon the timely construction of new generating facilities by merchant power plant developers. Investor-owned utilities, public power entities, rural electric cooperatives, and developers announced plans for more than 117,000 MW of new capacity for the U.S. during the course of the ten-year period, potentially a 14% increase over that existing in 2002.[3]

To better capture the potential impacts of these new generators, RAS has enlisted the services of EVA and EPSA. The extent of this reporting difference is highlighted in *Figure 5*.

FIGURE 5: U.S. SUMMER CAPACITY MARGINS IN PERCENT



Using detailed project information from EVA to supplement information supplied by the Regions, *Figure 5* shows a range of U.S. capacity margins for the assessment period. Because it is difficult to accurately predict the exact number and in-service dates of future capacity additions merchant developers will actually construct, this report provides a range of potential values. EVA does not monitor merchant developer activity in Canada.

Four separate capacity margin projections are shown in *Figure 5*: the lower bound is the projected margin including only capacity resources currently in operation or under construction, the upper bound is the projected margin if all announced new merchant power plants are constructed. Neither of these two cases is deemed likely;

[3] Source: EVA

they are included for perspective. The line labeled "Reported by Region" reflects the capacity margins as reported by NERC Regions. The line labeled "EVA Supplement" reflects the projected capacity margins after supplementing regional data with data received from EVA. The subcommittee believes that this line is the most likely scenario going forward.

All of the preceding capacity margin projections include the effects of currently planned generating unit retirements. They do not, however, include unit retirements that may occur due to environmental restrictions or as newer, more efficient plants come on line and older assets are deemed uneconomic. These retirements are difficult to project and are yet another uncertainty associated with developing long-term resource adequacy projections.

As industry restructuring progresses, capacity margins may exhibit the characteristics of normal business cycles found in other industries, i.e., periods of advances and declines. Until recently, the industry has experienced a boom of new generation, as the economy continued to grow, fuel prices appeared stable, and forward electricity prices justified investment in new generating facilities. However, as a result of changing business conditions, starting in November 2001, proposed new generating projects began to slow, were delayed, or canceled.

Table 1 illustrates the effects of the recent new power plant delays and cancellations.

TABLE 1: NEW GAS-FIRED POWER PROJECTS UNDER DEVELOPMENT

Year	As Reported June 2003 (GW)	As Reported December 2001 (GW)	Difference (GW)
2002	57.7	69.3	-11.6
2003	55.4	91.3	-35.9
2004	21.0	95.8	-74.8
2005	29.7	24.5	5.2
2006	12.8	1.1	11.7
2007	7.1	1.7	5.4
Total	**183.9**	**283.7**	**-99.8**

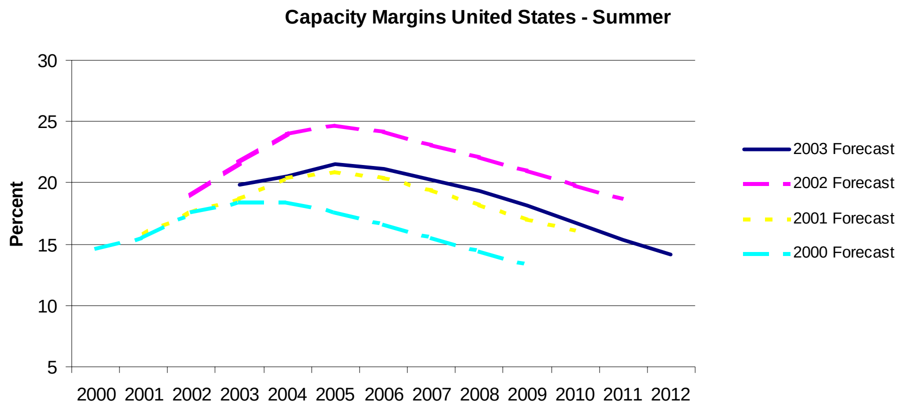
Source: EVA

Changing Capacity Margin Projections

Capacity margin projections continue to change as major portions of the electric industry evolve from the traditional vertically integrated utility model to more of a market-based, unbundled market model. *Figure 6* compares the projected ten-year U.S. capacity margins for the last four ten-year projections as reported to NERC by the regions. After several years of decline, 2000 was the first year in which the U.S. capacity margins increased, rising sharply over the first five years of the report horizon as numerous new merchant power plants were announced in response to market signals.

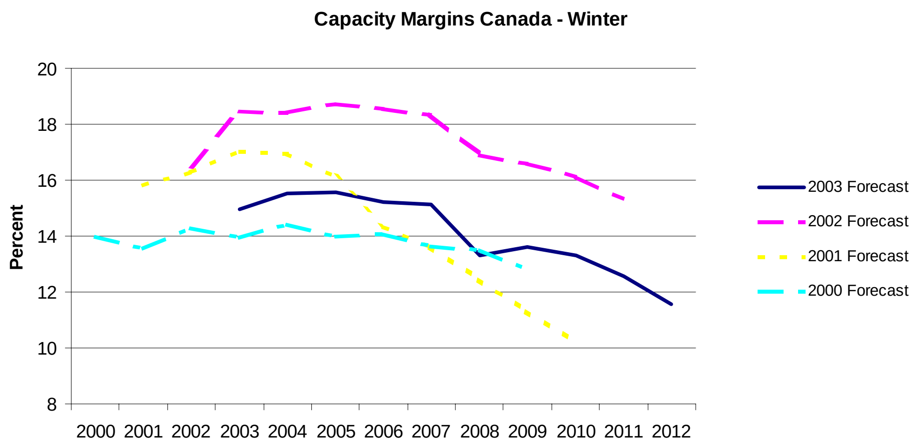
Using detailed projected information from EVA to supplement information supplied by the Regions, *Figure 6* shows the change since the year 2000 in the range of U.S. capacity margins for the next ten years. EVA maintains a database of all proposed new power plants in the United States and tracks various milestones associated with the completion of the projects, including applications for environmental permits, siting, acquisition of equipment, financing, and contractual arrangements to sell the output of the facilities. Using this key information, announced new merchant plants were screened to establish those most likely to be built.

FIGURE 6: U.S. SUMMER CAPACITY MARGIN PROJECTIONS



However, recent cancellations and postponements of merchant plant development are reflected in the lower margin projections this year. Projected 2005 U.S. capacity margins are about 12.7% lower this year than last year's projection for 2005. The projected margin continues to decline during the latter half of the ten-year period to about 14.1%, as projected demand continues to grow while the number of proposed and/or announced new generating units decline. Deliverability of this new capacity is addressed in the Transmission Issues section.

FIGURE 7: CANADA WINTER CAPACITY MARGIN PROJECTION



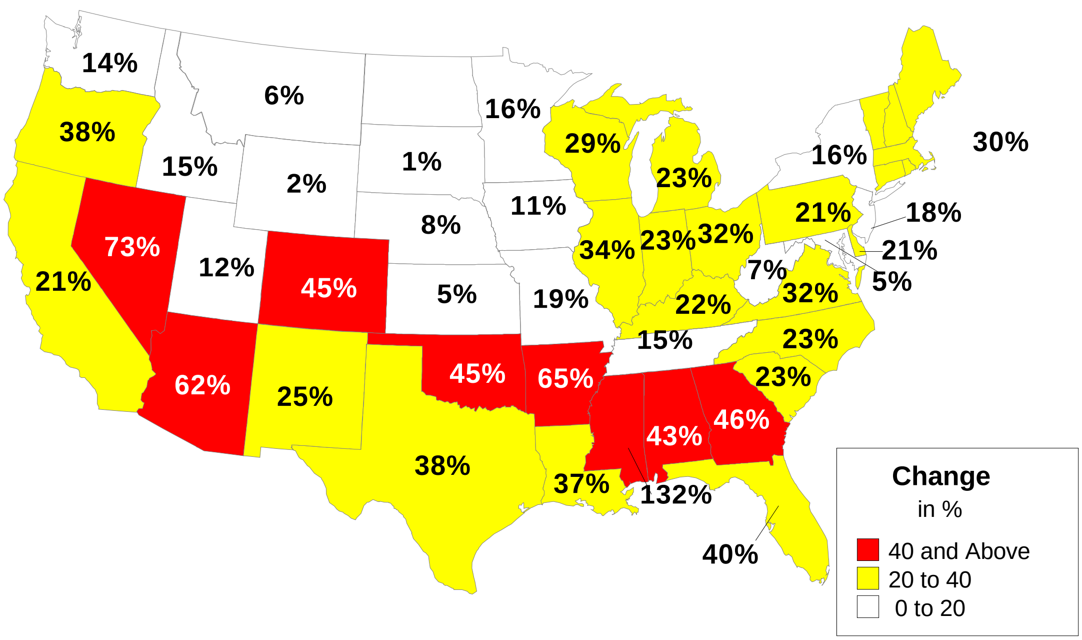
Canadian projected capacity margins in *Figure 7* exhibit similar behavior, peaking at just under 16% in 2005. Shifting incentives, coupled with short lead times to construct new generating facilities, make the increases in near-term projected capacity margins more understandable. The fact that fewer capacity additions are projected beyond 2007 does not mean that additions will not occur, but rather that these decisions have not yet been made or are being held confidential for competitive reasons. The lower capacity margins projected in the later years of the U.S. and Canadian forecasts may reflect that new capacity additions for that time period have not been announced or reported.

Figures 6 and *7* are based purely upon regional data submittals; inclusion of supplemental new merchant generator data from EPSA or EVA would serve to increase the margins further.

Although the overall capacity is expected to be adequate to serve projected demands, pockets of North America may experience deficiencies even as new generating resources are added elsewhere or if transmission limitations limit the delivery of energy to demand centers.

As seen in *Figure 8*, the locations being selected for the installation of new generators are not always ideal from a demand and transmission system planning perspective. For example, an examination of Mississippi shows that if current projections hold, capacity additions within the state through 2007 will be more than twice what existed in 1998. This capacity exceeds what is needed to serve local demand, and the transmission system is not currently capable of moving this electricity to other areas.

FIGURE 8: PERCENTAGE OF PROJECTED NEW GENERATOR ADDITIONS 1998–2007 AS A PERCENTAGE OF 1998 Total Installed Generation



Source: EVA

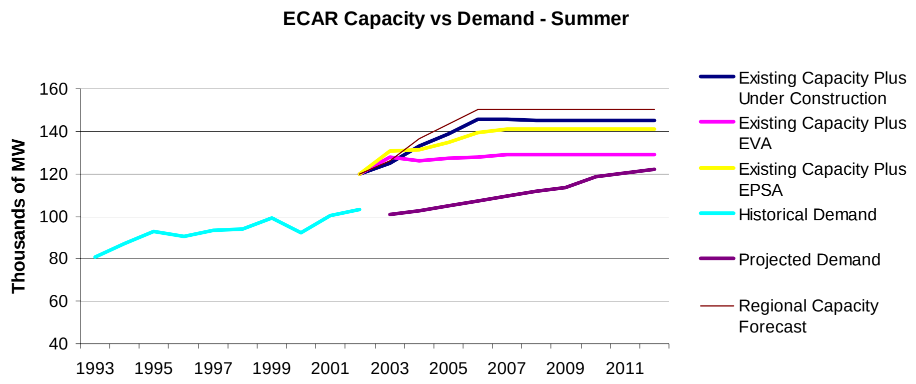
Regional Analysis

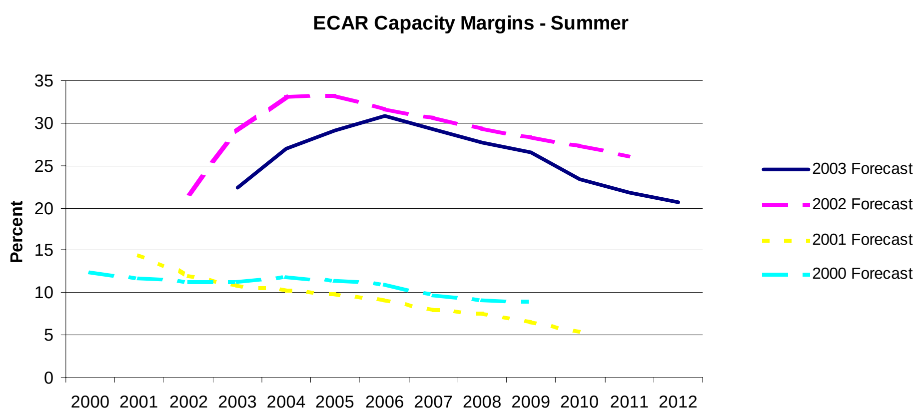
The figures on the following page show the regional and subregional historical demand, forecasted demand growth, capacity margin projections, and generation expansion projections reported by the regions. These data are augmented by generation expansion data from EPSA and EVA.

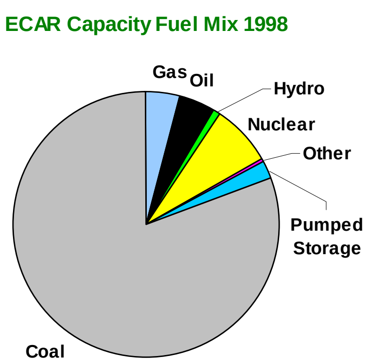
Also included are pie charts comparing the projected change in the composition of capacity resources by fuel type from 1998 to 2008.

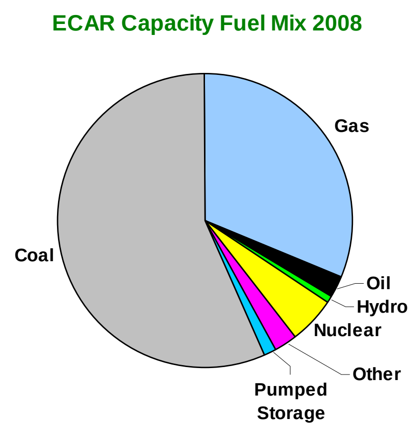
Table 2 on page 31 contains projected capacity margins for 2004 and 2008 (both summer and winter) by NERC Region. The information in the table was taken directly from submittals made by the NERC Regions.

ECAR Capacity and Demand

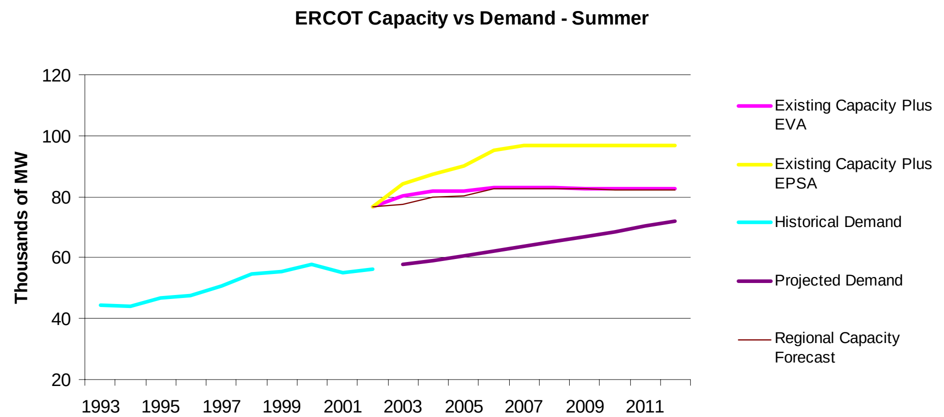


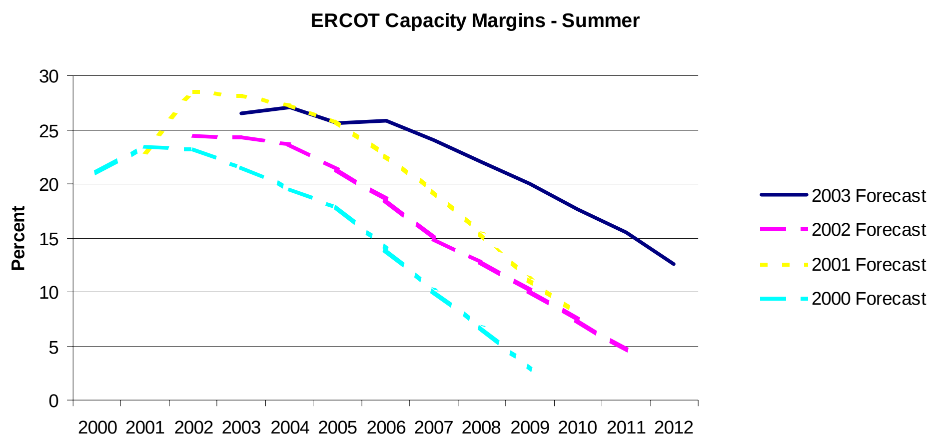


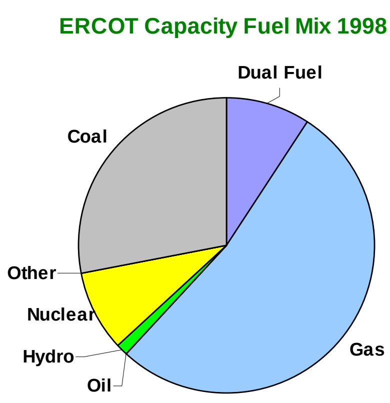


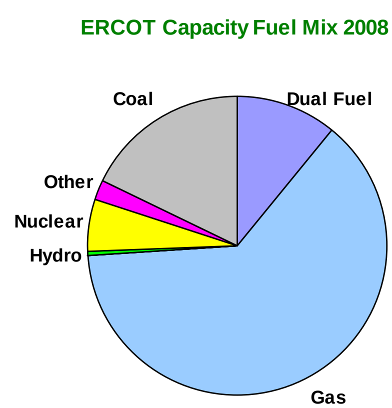


ERCOT Capacity and Demand

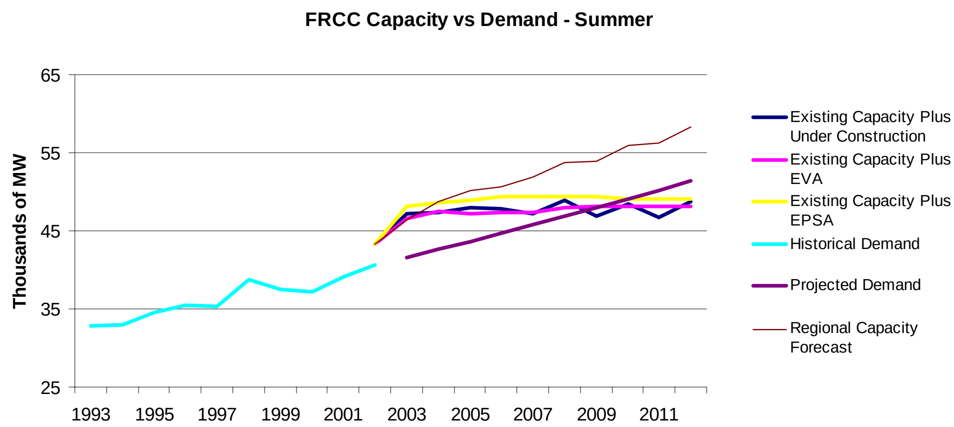


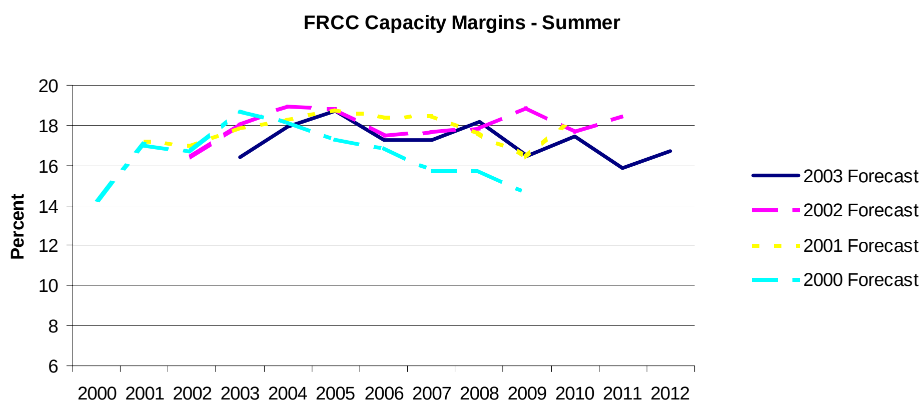


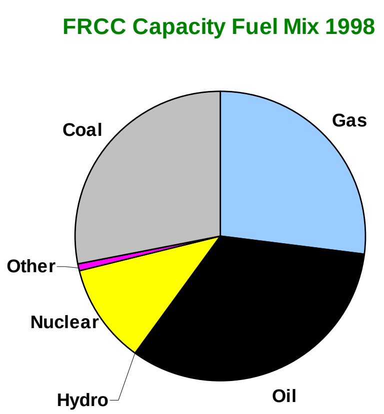


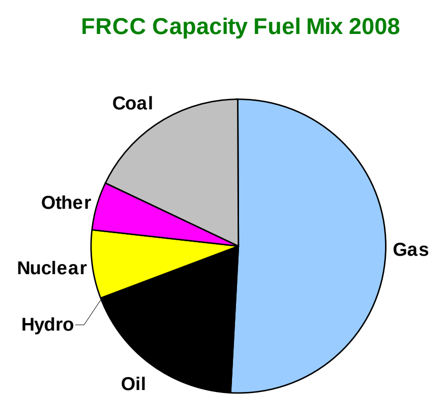


FRCC Capacity and Demand

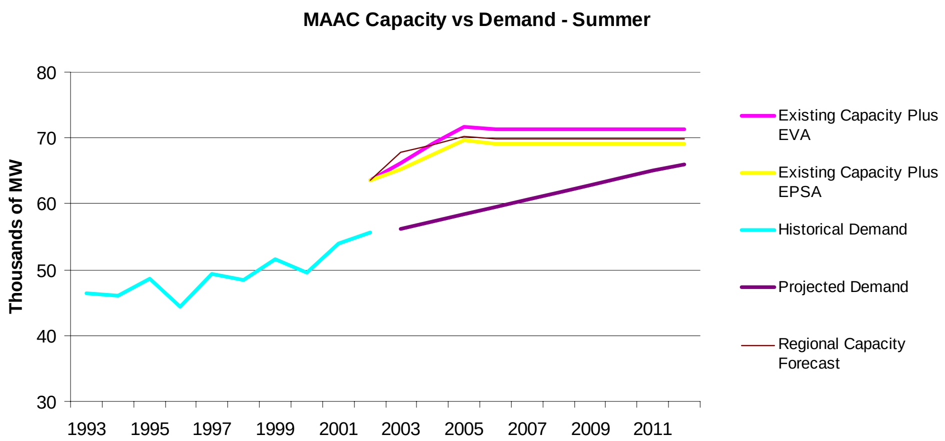




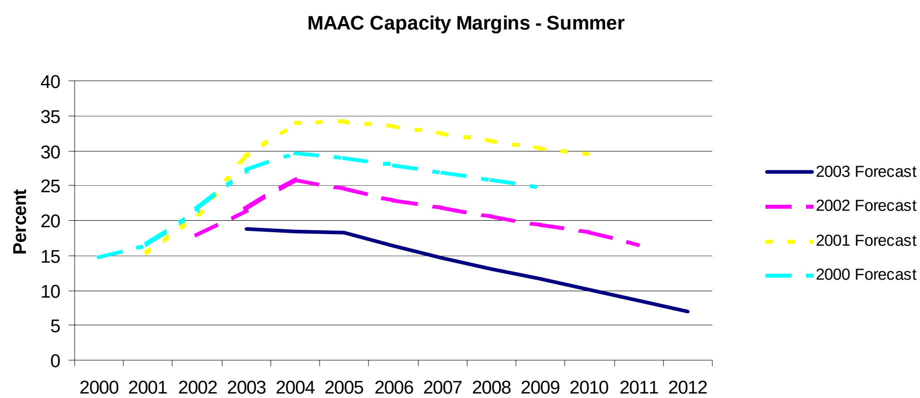


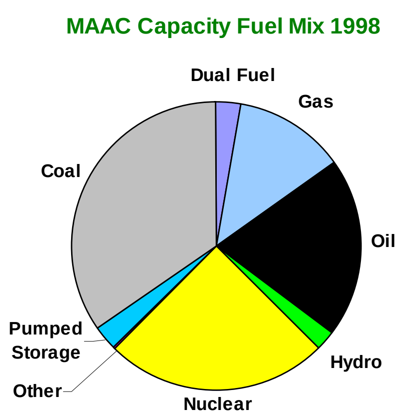


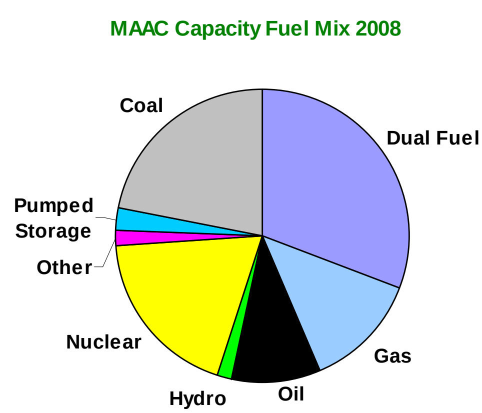
MAAC Capacity and Demand



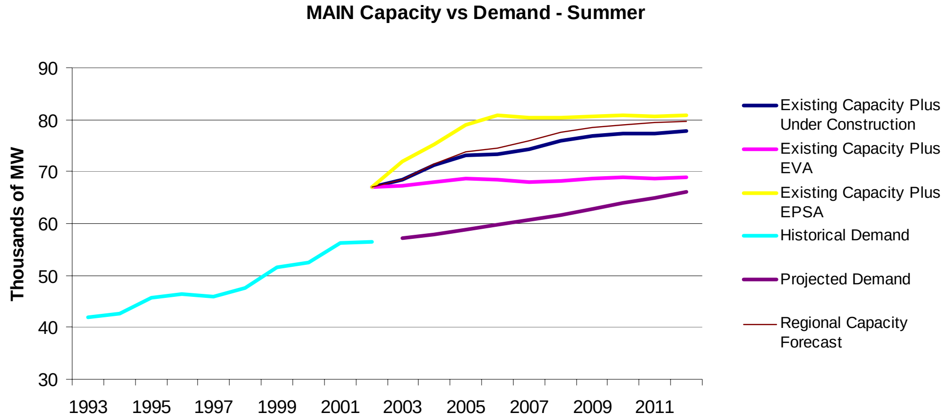
Note: There are no planned units under construction in MAAC.

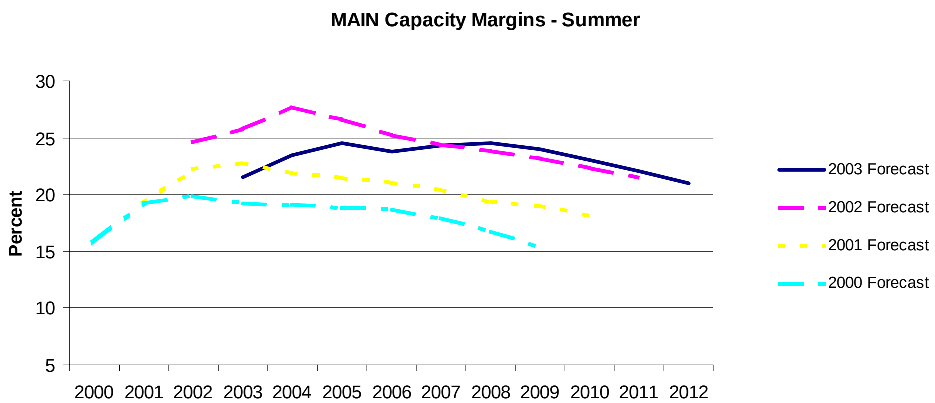


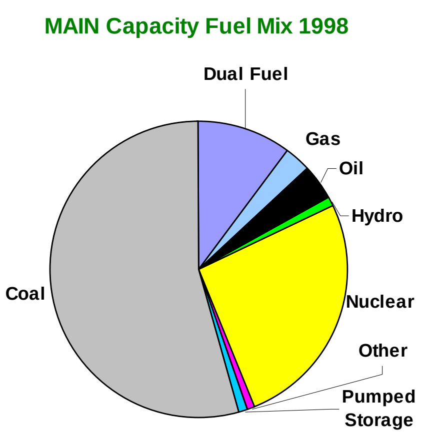


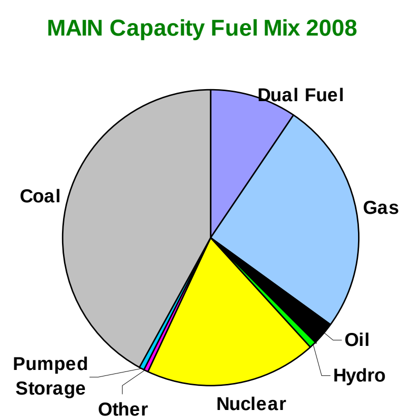


MAIN Capacity and Demand

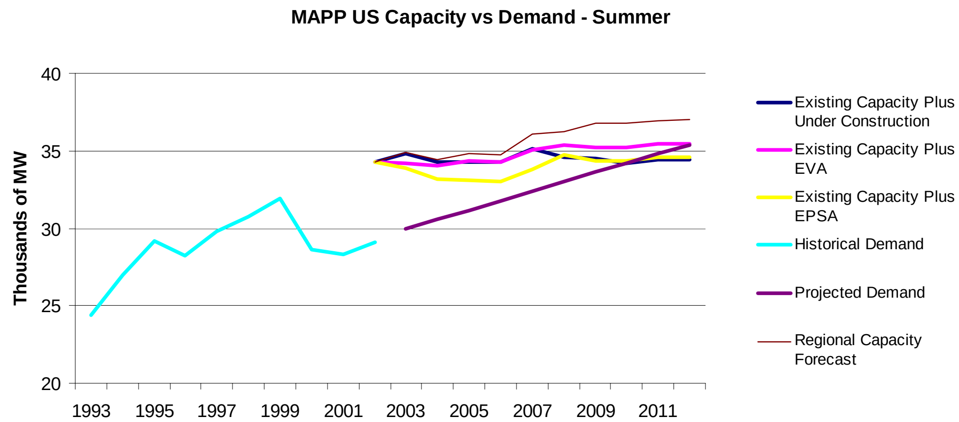


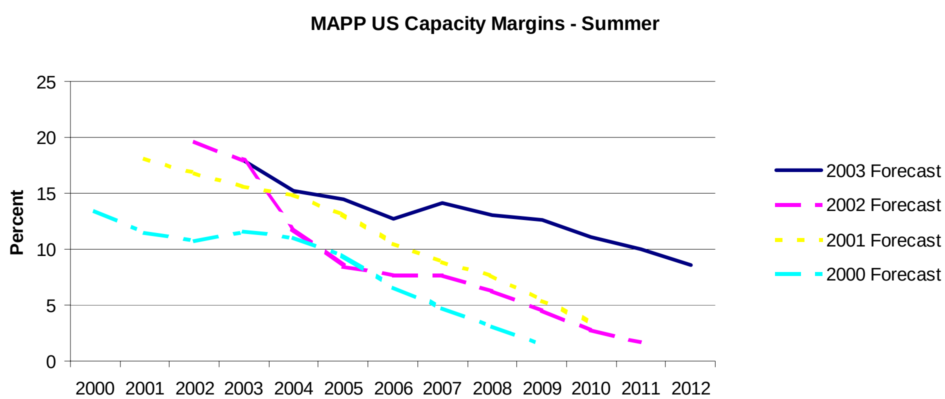


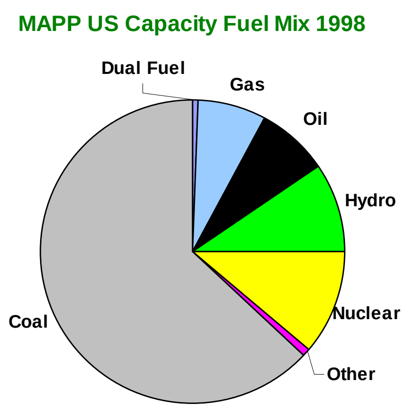


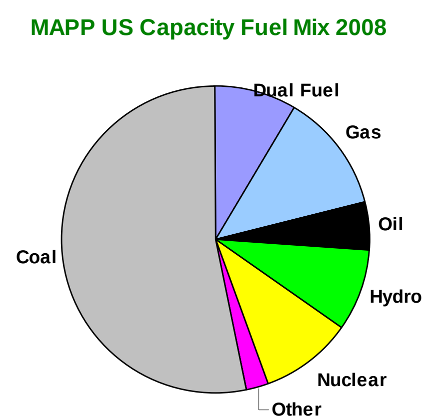


MAPP-U.S. Capacity and Demand

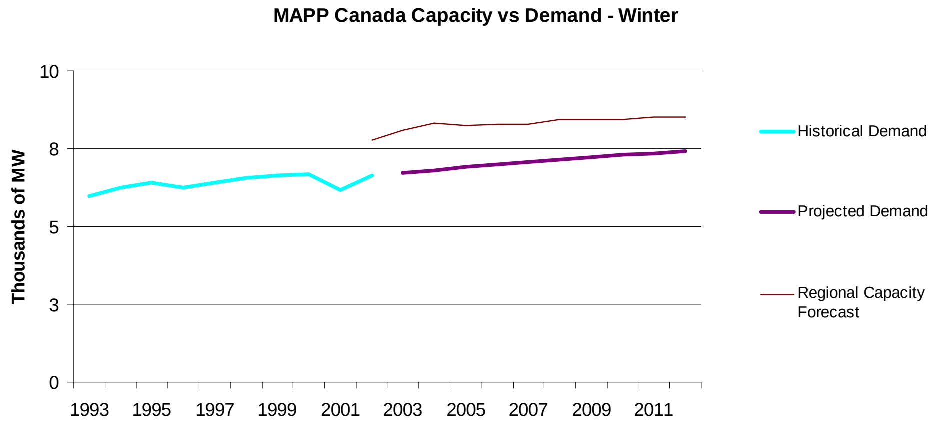




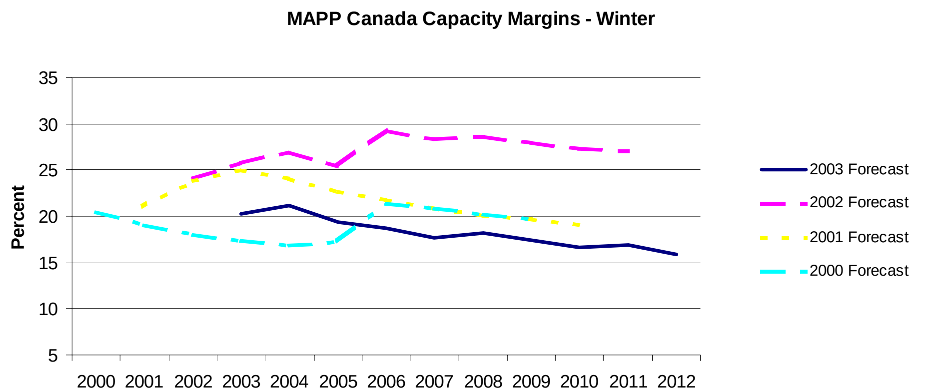


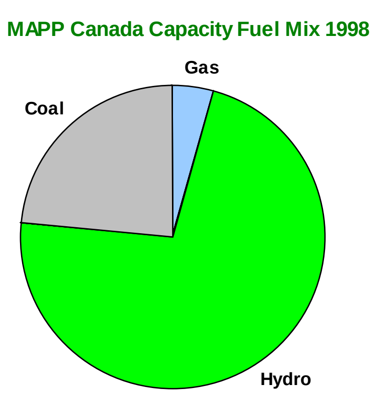


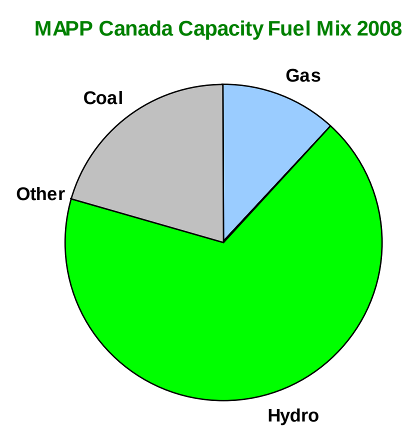
MAPP-CANADA Capacity and Demand



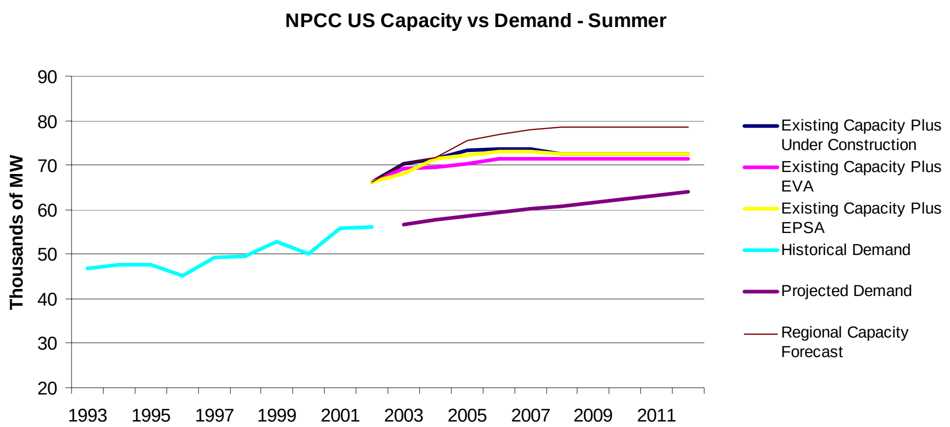
Note: There are no planned units under construction in MAPP Canada.

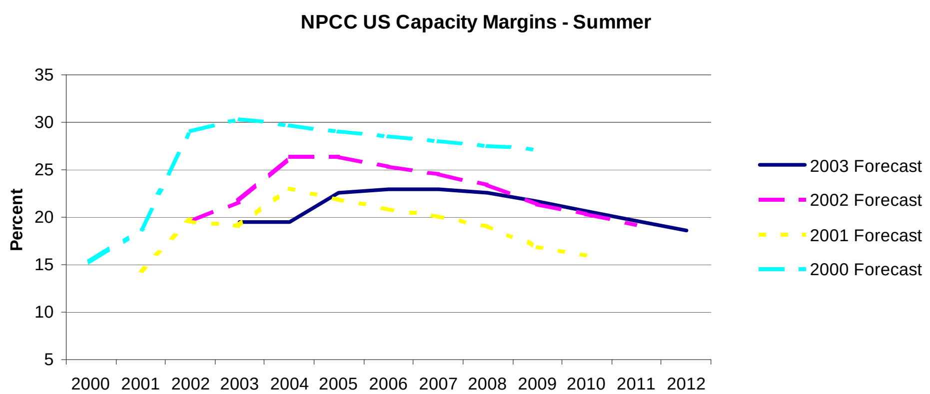


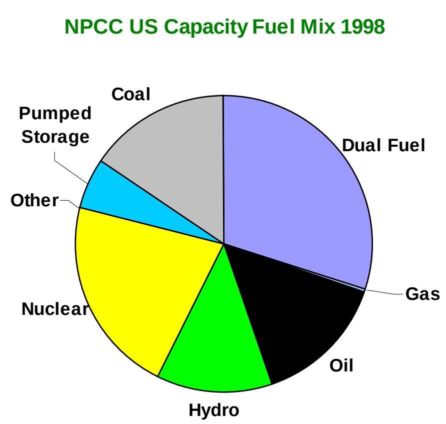


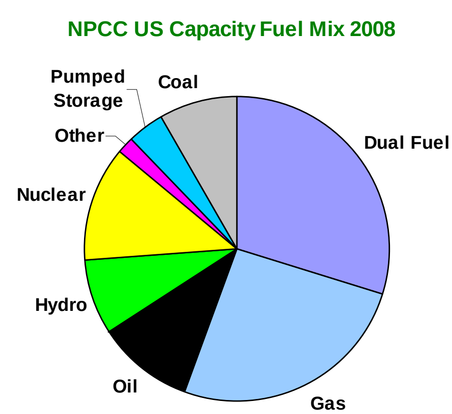


NPCC-U.S. Capacity and Demand

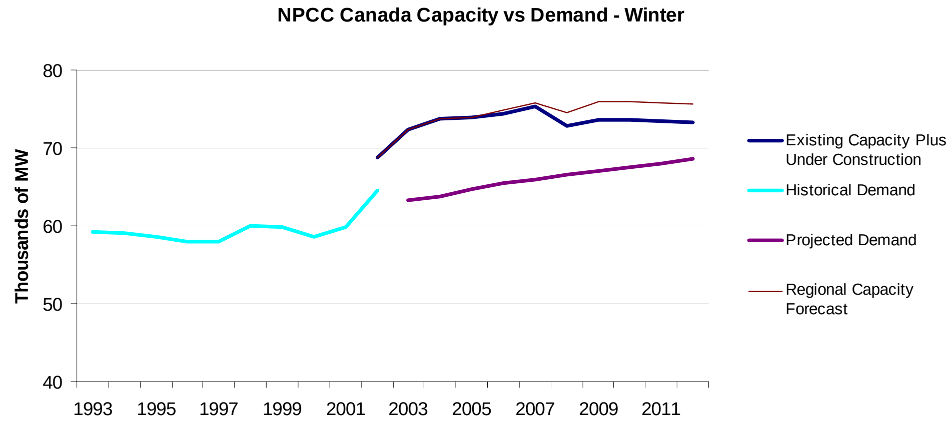


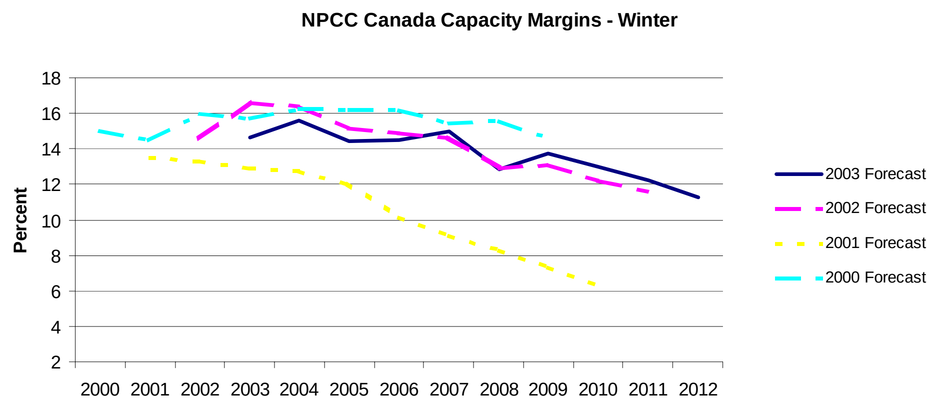


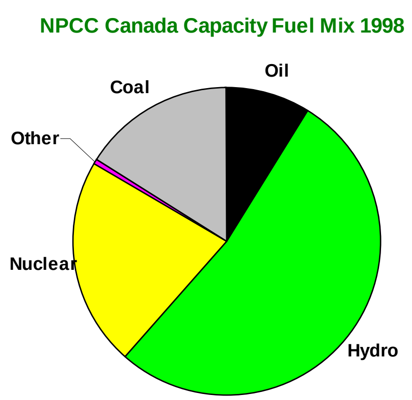


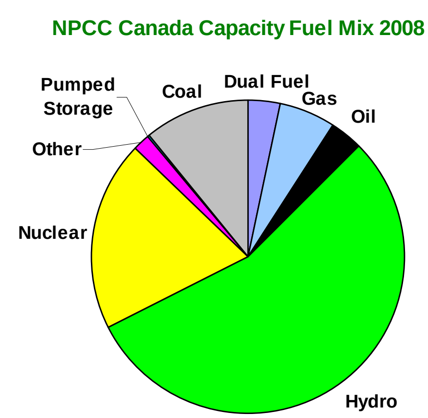


NPCC-Canada Capacity and Demand

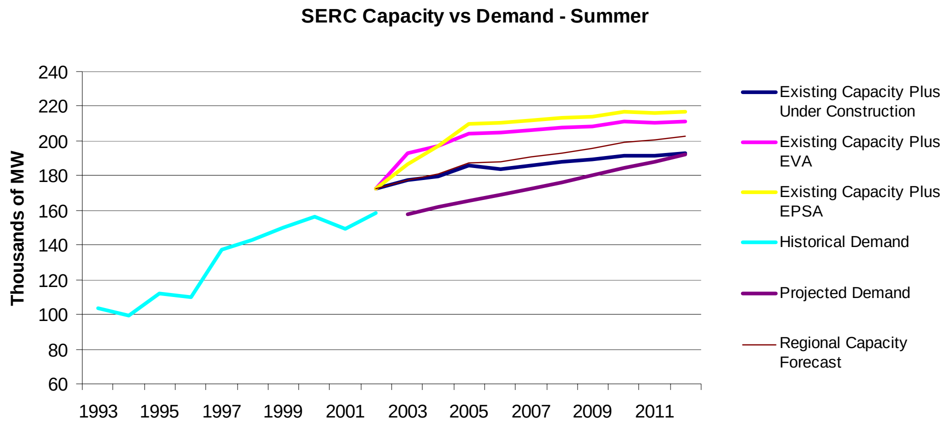


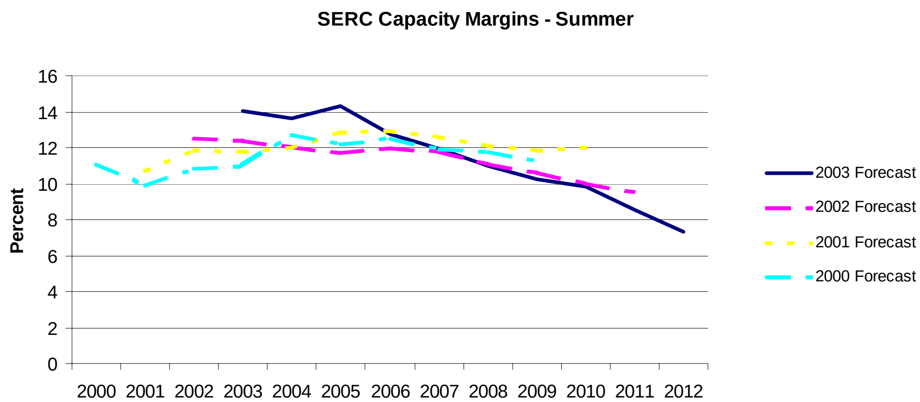


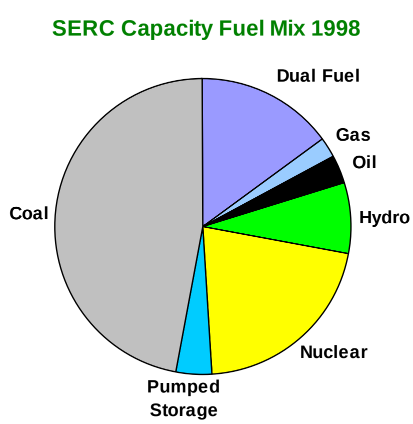


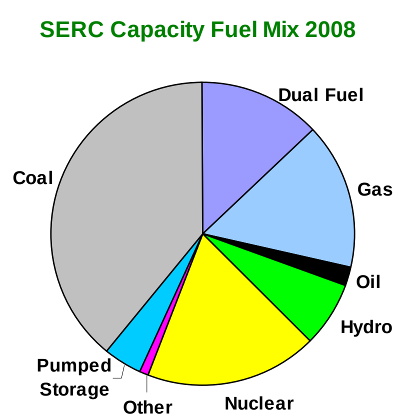


SERC Capacity and Demand

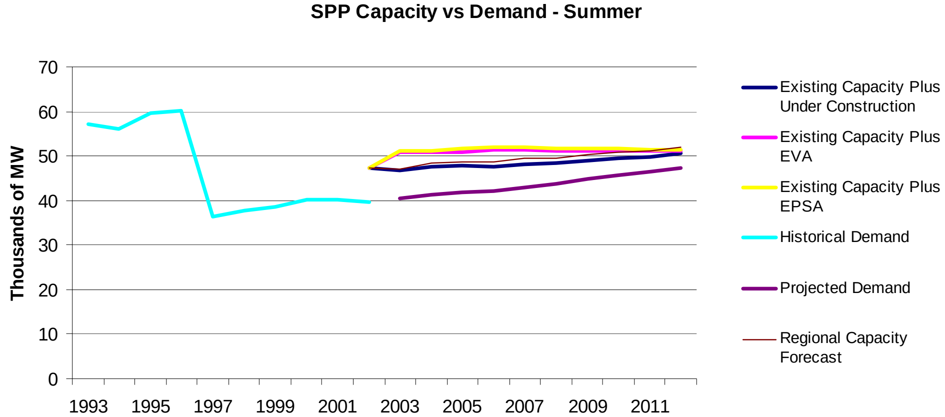


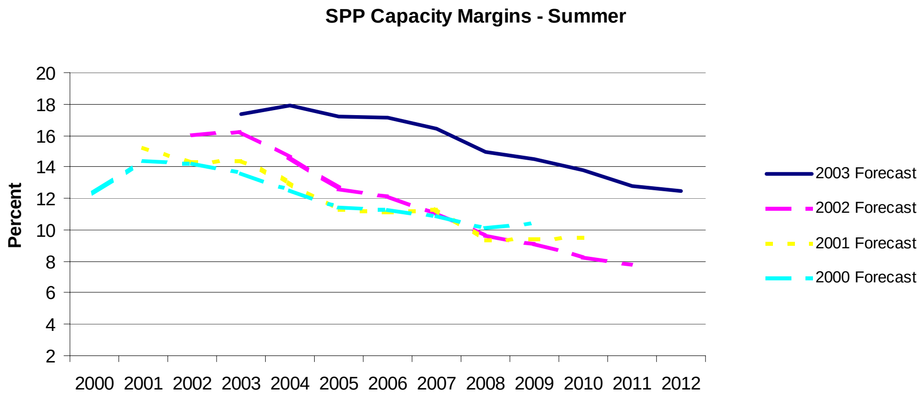


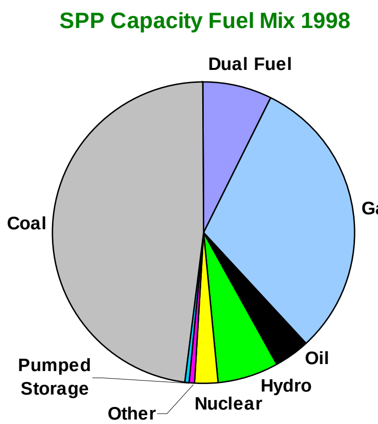


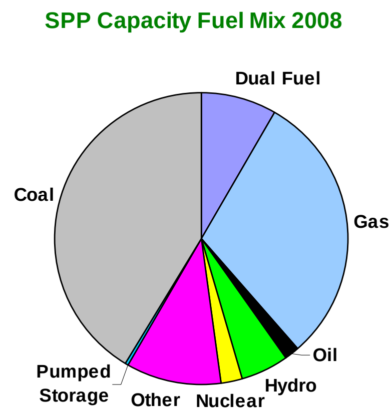


SPP Capacity and Demand

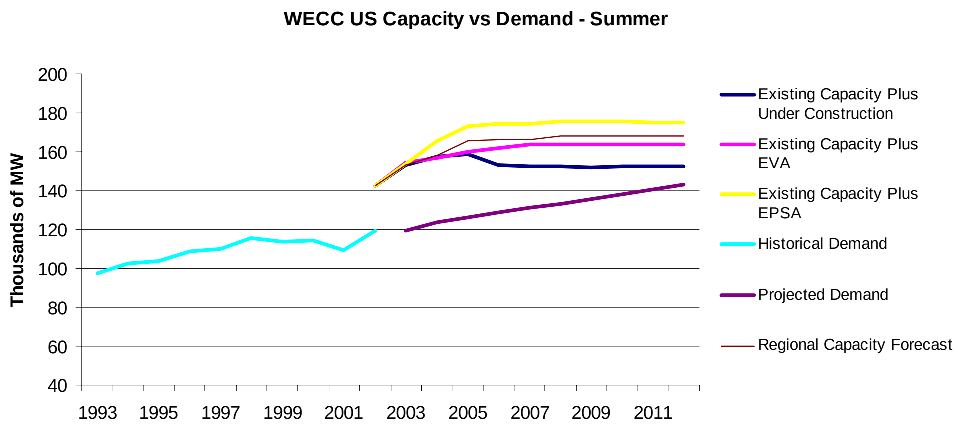


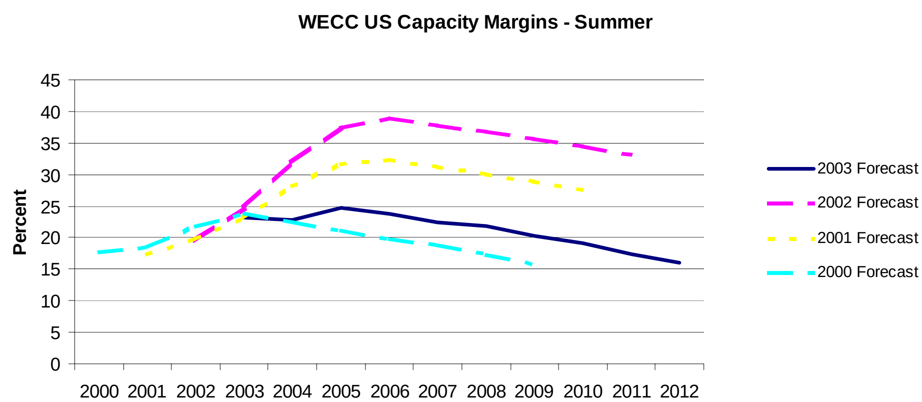


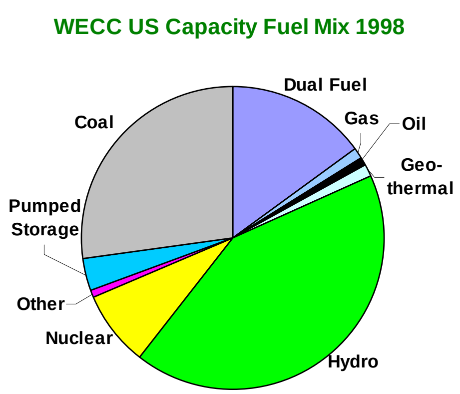


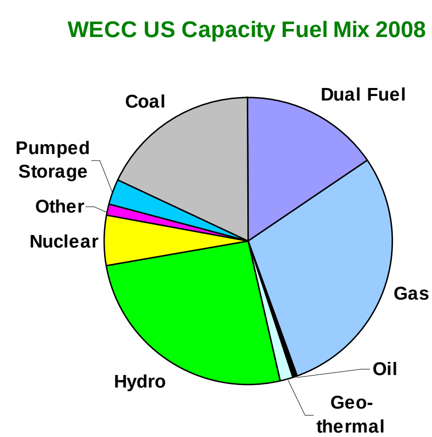


WECC-U.S. Capacity and Demand

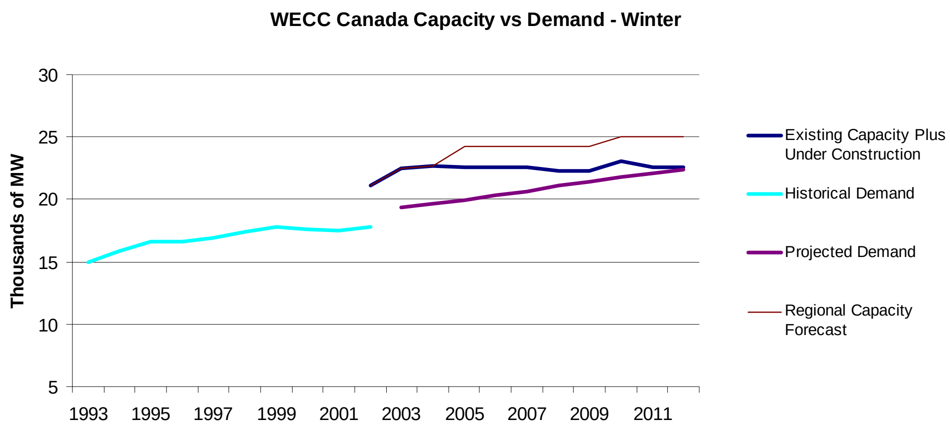


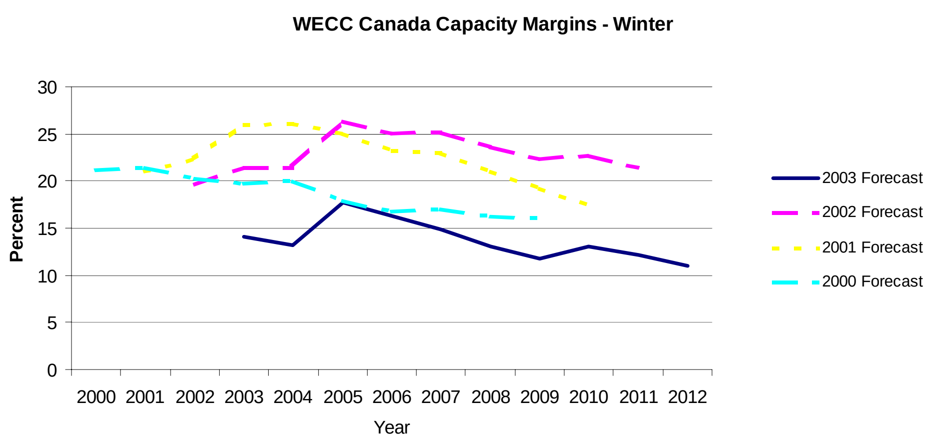


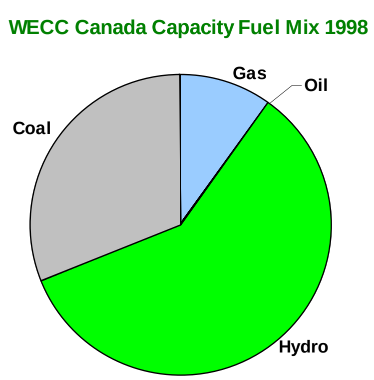




WECC-Canada Capacity and Demand







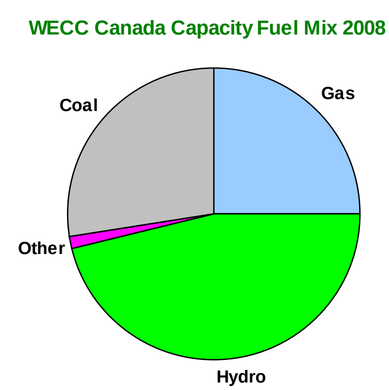


TABLE 2: DEMAND AND CAPACITY AS REPORTED BY THE NERC REGIONS

Region	Total Internal Demand (MW)	Net Internal Demand (MW)	Planned Capacity Resources (MW)	Reserve Margins (% of Net Internal Demand)	Capacity Margins (% of Capacity Resources)
		Summer – 2004			
ECAR	102,737	99,675	136,407	36.9	26.9
FRCC	42,668	39,824	48,722	22.3	18.3
MAAC	57,330	56,211	68,948	22.7	18.5
MAIN	57,802	54,678	71,386	30.6	23.4
MAPP-U.S.	30,555	29,207	34,459	18.0	15.2
MAPP-Canada	5,615	5,347	7,283	36.2	26.6
NPCC-U.S.	57,770	57,760	71,762	24.2	19.5
NPCC-Canada	49,531	48,669	64,440	32.4	24.5
SERC	161,650	156,082	180,915	15.9	13.7
SPP	41,345	39,922	48,323	21.0	17.4
Eastern Interconnection	607,003	587,375	732,645	24.7	19.8
WECC-U.S.	123,942	122,107	158,028	29.4	22.7
WECC-Canada	15,849	15,849	22,157	39.8	28.5
WECC-Mexico	1,907	1,907	2,634	38.1	27.6
Western Interconnection (a)	141,698	139,863	182,819	30.7	23.5
ERCOT Interconnection	59,080	58,364	80,021	37.1	27.1
U.S.	734,879	713,830	898,971	25.9	20.6
Canada	70,995	69,865	93,880	34.4	25.6
Mexico	1,907	1,907	2,634	38.1	27.6
NERC	807,781	785,602	995,485	26.7	21.1
		Summer – 2008			
ECAR	111,884	108,783	150,413	38.3	27.7
FRCC	46,840	44,024	53,786	22.2	18.1
MAAC	61,746	60,627	69,783	15.1	13.1
MAIN	61,746	58,594	77,684	32.6	24.6
MAPP-U.S.	33,022	31,554	36,261	14.9	13.0
MAPP-Canada	5,947	5,947	7,501	26.1	20.7
NPCC-U.S.	60,795	60,791	78,514	29.2	22.6
NPCC-Canada	52,131	51,249	64,883	26.6	21.0
SERC	176,350	171,300	192,838	12.6	11.2
SPP	43,855	42,429	49,467	16.6	14.2
Eastern Interconnection	654,316	635,298	781,130	23.0	18.7
WECC-U.S.	133,055	131,220	167,835	27.9	21.8
WECC-Canada	17,052	17,052	23,853	39.9	28.5
WECC-Mexico	2,477	2,477	3,288	32.7	24.7
Western Interconnection (a)	152,584	150,749	194,976	29.3	22.7
ERCOT Interconnection	65,213	64,497	82,770	28.3	22.1
U.S.	794,506	773,819	959,351	24.0	19.3
Canada	75,130	74,248	96,237	29.6	22.8
Mexico	2,477	2,477	3,288	32.7	24.7
NERC	872,113	850,544	1,058,876	24.5	19.7

Region	Total Internal Demand (MW)	Net Internal Demand (MW)	Planned Capacity Resources (MW)	Reserve Margins (% of Net Internal Demand)	Capacity Margins (% of Capacity Resources)
		Winter – 2004/2005			
ECAR	87,556	85,111	142,718	67.7	40.4
FRCC	45,301	41,834	51,017	22.0	18.0
MAAC	45,522	45,164	72,658	60.9	37.8
MAIN	42,755	40,696	69,913	71.8	41.8
MAPP-U.S.	24,541	23,964	34,161	42.6	29.8
MAPP-Canada	6,812	6,544	8,305	26.9	21.2
NPCC-U.S.	47,636	47,619	75,438	58.4	36.9
NPCC-Canada	63,789	62,314	73,813	18.5	15.6
SERC	141,511	136,796	184,894	35.2	26.0
SPP	30,555	29,516	48,003	62.6	38.5
Eastern Interconnection	535,978	519,558	760,920	46.5	31.7
WECC-U.S.	107,868	107,374	151,819	41.4	29.3
WECC-Canada	19,668	19,668	22,663	15.2	13.2
WECC-Mexico	1,418	1,418	2,329	64.2	39.1
Western Interconnection (a)	128,054	127,560	177,006	38.8	27.9
ERCOT Interconnection	47,702	46,986	82,972	76.6	43.4
U.S.	620,947	605,060	913,593	51.0	33.8
Canada	90,269	88,526	104,781	18.4	15.5
Mexico	1,418	1,418	2,329	64.2	39.1
NERC	712,634	695,004	1,020,703	46.9	31.9
		Winter – 2008/2009			
ECAR	95,042	92,677	154,891	67.1	40.2
FRCC	49,814	46,342	57,851	24.8	19.9
MAAC	48,338	47,980	72,307	50.7	33.6
MAIN	45,628	43,564	75,718	73.8	42.5
MAPP-U.S.	26,167	25,627	35,661	39.2	28.1
MAPP-Canada	7,158	6,890	8,426	22.3	18.2
NPCC-U.S.	50,075	50,066	82,389	64.6	39.2
NPCC-Canada	66,507	65,016	74,590	14.7	12.8
SERC	153,297	148,936	191,802	28.8	22.3
SPP	32,663	31,625	49,535	56.6	36.2
Eastern Interconnection	574,689	558,723	803,170	43.8	30.4
WECC-U.S.	116,071	115,567	158,014	36.7	26.9
WECC-Canada	21,102	21,102	24,262	15.0	13.0
WECC-Mexico	1,890	1,890	2,349	24.3	19.5
Western Interconnection (a)	138,021	137,517	184,853	34.4	25.6
ERCOT Interconnection	52,654	51,938	85,856	65.3	39.5
U.S.	669,749	654,322	964,024	47.3	32.1
Canada	94,767	93,008	107,278	15.3	13.3
Mexico	1,890	1,890	2,349	24.3	19.5
NERC	766,406	749,220	1,073,651	43.3	30.2

(a) The sum of WECC-U.S., Canada, and Mexico peak hour demands or planned capacity resources do not necessarily equal the coincident Western Interconnection total because of subregional and country peak load diversity.

Transmission Adequacy

The North American transmission systems are expected to perform reliably. However, in some areas the transmission grid is not adequate to transmit the output of all new generating units to their targeted markets, limiting some economy energy transactions but not adversely impacting reliability.

Portions of the transmission systems are reaching their limits as customer demand increases and the systems are subjected to new loading patterns resulting from increased power transfers caused by market conditions and weather patterns. Operating procedures, market-based congestion management procedures, and transmission loading relief procedures (TLRs) are used to control the flow on the system within operating reliability limits.

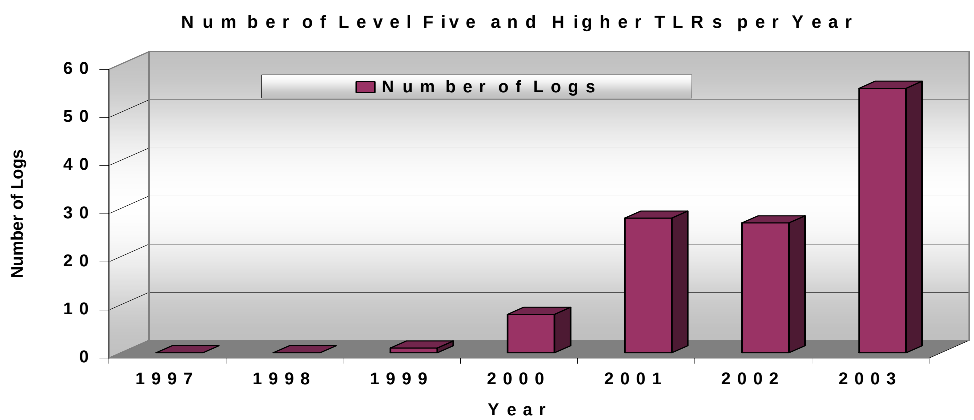
Although some well-known transmission constraints are recurring and new constraints are appearing as electricity flow patterns change as new generation is installed. As a result, the transmission system is being subjected to flows in magnitudes and directions that were not contemplated when it was designed or for which there is minimal operating experience.

> Weather diversity across the continent often frees up generation resources in one area prompting transfers to serve demand in another. For example, 2000 saw a significant increase in the number of TLRs as heavy north-to-south power transfers occurred in the central United States, spurred on by extended temperature diversity (cool in the north, hot in the south), which freed up resources for export. Because weather patterns are unpredictable, transmission constraints and congestion have the potential to shift from day to day, season to season, and year to year.

New flow patterns result in an increasing number of facilities being identified as limits to transfers, and market-based congestion management procedures and TLR procedures are required in areas not previously subject to overloads to maintain the transmission facilities within operating limits.

In some areas, market operators employ locational marginal pricing (LMP) to effect a generation redispatch through economic incentives. In other areas of the Eastern Interconnection, reliability coordinators invoke NERC TLRs to maintain reliability by managing transactions within transmission operating reliability constraints. In effect, TLRs cause generation redispatch by restricting or curtailing scheduled transfers.

Figure 9: Number of Level Five and Higher TLRs per Year



Note: Year 2003 through November 14, 2003

Transmission facility operation at levels near reliability limits do not necessarily translate into an unreliable transmission system; these conditions may instead be a sign that the transmission system is congested and will not support any further economic transfers of energy. TLRs, in general, are an indication that steps must be taken to manage transmission system loading to avoid placing the system in an unreliable state. Several steps or classifications of NERC TLR exist, ranging from level 0 to 6.[4]

It is only at TLR levels 5 and higher that firm transactions are curtailed. Although TLR 5 and higher are a relatively small portion of the TLRs that have been called since the procedure was instituted, the large increase in their number in 2000 and 2001 signaled a troubling trend. While the number of level 5 TLRs and above decreased in 2002, the year 2003 to date shows a further increase. *Figure 9* shows the number of TLRs level 5 and higher since the procedure was begun in 1997. The TLRs listed for 2003 are the actual number through November 14, 2003.

Over the long term, where redispatch options have been exhausted or are ineffective, the only way to relieve transmission constraints is to:

- locate new generation close to the demand centers, or
- increase the capability of the transmission system, or
- rely on demand-side management procedures.

Currently, several new transmission facilities are being planned by merchant developers. The entry of these new players into the transmission area may result in construction of new transmission beyond that currently planned; however, these new players will face the same hurdles to new construction:

- public opposition to siting the facility,
- uncertainty as to who 'gets paid' for the benefit of the new facilities or how to allocate the costs, and
- regulatory uncertainty.

A number of the new merchant transmission lines are submarine direct current (DC) cables, thereby circumventing the benefit allocation and assignment of payments. However, even those projects can encounter regulatory and siting delays. The New Haven Harbor, Connecticut, to Shoreham, New York (Long Island), HVDC merchant transmission facility completed in 2002, continues to be hampered by regulatory issues that are delaying its commercial operation.

In ERCOT, where regional transmission planning is in place and state regulations govern cost allocation, a number of transmission expansion projects are being constructed.

The Midwest Independent System Operator (MISO) has also announced recent regional transmission expansion plans. However, those plans cross a number of jurisdictional boundaries, and it is currently unclear how state regulators will view the proposed projects.

Other key projects receiving additional regulatory scrutiny include:

- American Transmission Company has proposed a 345 kV line between Minnesota and Wisconsin for completion by summer 2007 that will help to relieve constraints associated with imports into Wisconsin, and MAIN imports from MAPP. This proposal is under re-examination by Wisconsin regulators.
- PG&E and Western Area Power Administration are in the process of reinforcing Path 15 between northern (PG&E's Los Banos substation) and southern (PG&E's Gates substation) California. The upgrade will be operational by fall of 2004. Path 15 limited south-to-north transfers to northern California during the California energy crisis in the winter of 2000–2001.

[4] See NERC Policy 9 "Reliability Coordinator Procedures," Appendix 9C1 "Transmission Loading Relief Procedure" for additional details on the various TLR levels.

Table 3 below provides a projection of planned increases in transmission circuit miles for 230 kV and above.

TABLE 3: PLANNED TRANSMISSION
TRANSMISSION CIRCUIT MILES — 230 KV AND ABOVE*

	2002 Existing	2003–2007 Additions	2008–2012 Additions	2012 Total Installed
ECAR	16,422	122	0	16,544
FRCC	6,769	393	108	7,270
MAAC	7,031	70	0	7,101
MAIN	6,178	438	75	6,691
MAPP-U.S.	14,356	114	0	14,470
MAPP-Canada	6,656	57	242	6,955
NPCC-U.S.	6,351	589	37	6,977
NPCC-Canada	28,780	235	87	29,102
SERC	28,880	1,326	966	31,179
SPP	7,639	637	245	8,521
Eastern Interconnection	129,062	3,981	1,760	134,803
WECC-U.S.	57,678	2,351	1,827	61,856
WECC-Canada	10,751	24	93	10,868
WECC-Mexico	563	24	0	587
Western Interconnection	68,992	2,399	1,920	73,311
ERCOT Interconnection	7,301	1,049	0	8,350
U.S.	158,605	7,089	3,258	168,952
Canada	46,187	316	422	46,925
Mexico	563	24	0	587
NERC	205,355	7,429	3,680	216,464

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

Resource Issues

Economics

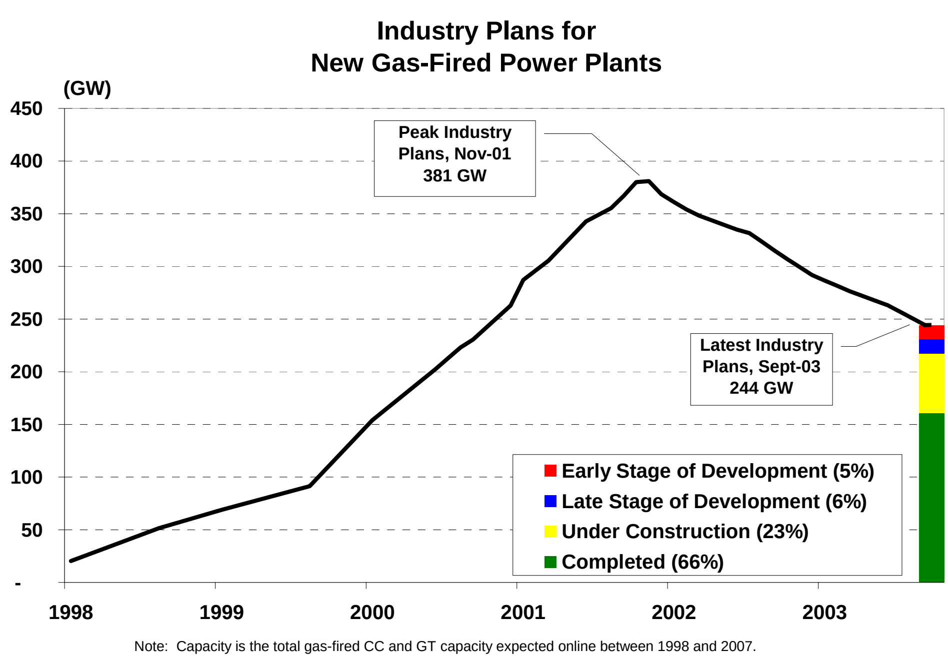
Historically, the expansion of resources was driven primarily by the obligation to serve native load. The adequate supply of reliable electric resources has become dependent on several evolving interdependent variables, including:

- the necessary financial incentives to promote investment in generating facilities and a supporting economy,
- readily available fuel at a stable price,
- transmission to transport the electric energy from the source to the customer, and
- regulatory and legislative uncertainties.

Since 1997, RAS has been exploring the relationship between future resource availability and the economics of the evolving electric supply marketplace. The impetus for development of new generation capacity has been evolving from that of regulated capacity adequacy requirements toward a response to market signals. Without appropriate market signals, new capacity may not be placed in service when needed, leading to periods of reduced resource adequacy until needed capacity can be installed. Open markets for generation development have evolved inconsistently across the continent, creating generation surpluses in some areas and minimal new development in others.

The restructured electric industry has experienced a period of weakening economic activity, resulting in less capital available for investment in future generating capacity. Volatility in fuel prices, reduced energy demand (caused by the current economic cycle and mild weather) and surpluses of generating capacity have resulted in reduced earnings for many generators in the wholesale market. In some cases, this has led to bankruptcy, plant cancellations or delays, and plant shutdowns.

FIGURE 10: INDUSTRY PLANS FOR NEW GAS-FIRED POWER PLANTS



Source: EVA

Figure 10 shows the slowing merchant plant development activity, indicating the beginnings of a typical supply and demand market cycle. Despite this slowdown in development, the projected regional capacity margins remain adequate in the near term.

Economic Impacts — Long-term assessments of reliability are, in part, based on expectations of the availability of adequate amounts of generation resources. However, recent downgrades in the securities of various power companies may affect their ability to complete development and construction of announced power plants, and/or to continue the operation and proper maintenance of existing facilities.

The financial situation of some generation owners may make it difficult to obtain from capital markets the financing for these activities. Unfortunately, these concerns may tend to be self-reinforcing, and rating agency downgrades may trigger loan covenants, which may further reduce financial strength, which may lead to further downgrades, etc.

Effects of Financing on Generation Development and Operation — Financial problems currently being experienced by generation developers could present problems in the long-term resource picture. Financial institutions might be less inclined to provide capital for speculative development. Reduced financial support may make it difficult to make plant equipment purchase commitments and negotiate fuel supply contracts, and increase the hesitancy of potential partners to participate in development projects.

Coupled with the lead time necessary to bring a project on line, the financial issues could result in a lag in development of necessary generation resources in the future. Although reduced levels of development efforts may not be immediately reflected in resource adequacy, in the long run, the ability to meet customer demand may be affected.

When a generation project goes into the construction phase, sufficient financial support becomes a critical factor for achieving successful completion. If there are fewer dollars available for construction as a result of credit challenges, there may be difficulty in obtaining engineering, procurement, and construction contracts, an inability to meet turbine and balance of plant equipment payment schedules, and difficulty in accommodating change orders.

In some instances, plants beneficial to local system reliability may be marginally economic, and could be cancelled or postponed.

Providing credit support for negotiating long-term maintenance and operating agreements could be problematic as well. Obtaining insurance, which would be required for placing permanent financing, and paying for transmission interconnection/upgrades might be a challenge.

Financially challenged generation operators may have deferred maintenance, insufficient spare-part inventories, and problems in long-term fuel acquisition. Although these may not have readily apparent near-term effects on the operation and availability of the facilities, the cumulative effects could impact the long-term availability and reliability of the generation. A more immediate problem may be inadequate funding for fuel purchases and continued operation of generators having more severe credit ratings problems.

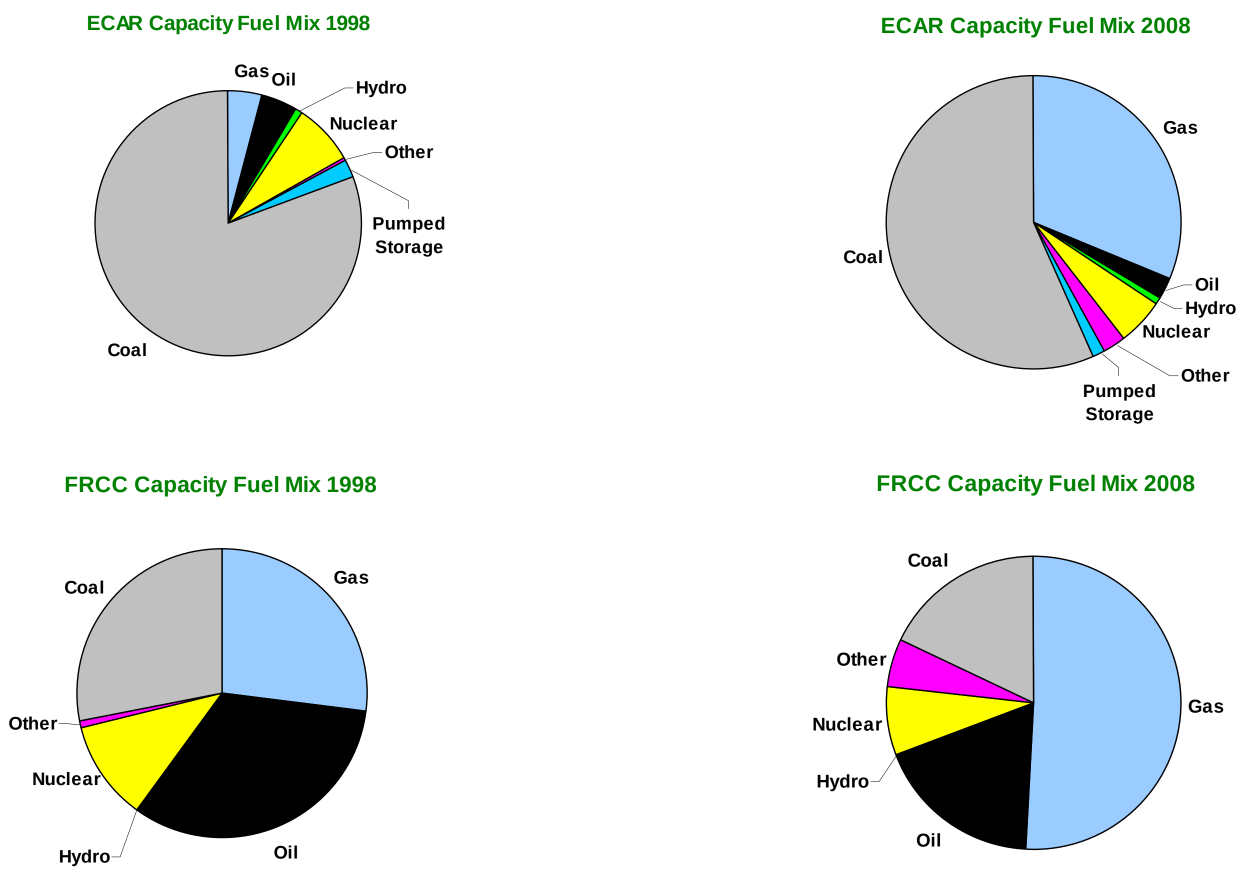
Increasing Reliance on Natural Gas

Natural gas is currently the fuel of choice for most planned generation additions, recognizing its qualities as clean burning, efficient, and widely available fuel. The following have been identified as issues that could impact reliability:

1. Fuel Diversity
2. Fuel Deliverability
3. Fuel Availability

Fuel diversity is a concern relative to the impact on the overall generating capacity for disruptions in the supply of different types of fuel. If there are a number of fuels that are used for generation, a disruption in any one of those fuel chains will not have an overwhelming impact on generation capacity (all of the "eggs" are not in one basket). As shown in *Figure 11*, in some regions the increase in natural gas usage increases the diversity of fuel types (e.g., ECAR), while in other regions, it decreases the diversity of fuel types (e.g., FRCC). In general, an increase in fuel diversity increases the overall probability of having adequate fuel for generating capacity.

Figure 11: Samples of Regional Pie Charts – ECAR and FRCC



Please refer to Generation by Fuel Type pie charts in the Adequacy Assessment section for further illustrations of this issue for the other NERC Regions.

Fuel deliverability is a concern relative to the operating reliability of the infrastructure that delivers natural gas to the generating stations. In some areas, deliverability to the generation is limited. A cursory review of any of the

North American maps for gas pipelines would show that some regions of the country are only served by a few, and in some areas, one pipeline. As such, the operating reliability of the gas infrastructure needs to be factored into the overall operational and planning reliability.

Unlike electric systems, gas pipelines have characteristics that allow some level of gas to be delivered for some time after there is a disruption in the pipelines. These technical issues were identified in last year's Long-Term Reliability Assessment. As a result of identifying the issues, NERC established a Gas/Electricity Interdependency Task Force (GEITF) to identify the magnitude of the problem and recommend a course of action. In parallel with the NERC task force, a consortium of northeast RTOs/IMOs and NERC commissioned a hydraulic analysis of the gas system in the northeast. The results from that analysis are not yet available. The output from both activities is expected to scope the magnitude of the reliability issue.

The GEITF has been evaluating the interdependency between gas pipeline operation and planning, and electric system operation and planning reliability over the next ten years. If negative reliability impacts are found, it is anticipated that additional industry effort will be established to perform detailed analyses or studies to determine mitigation measures.

The review will identify and recommend possible measures to mitigate any negative reliability impacts. Some of the areas the GEITF are considering include:

- developing guidelines for coordinating maintenance between gas pipelines and electricity providers,
- developing a standard on criteria that gas-fired generation must meet to qualify for inclusion in reserve margin calculations,
- establishing guidelines for communications protocols between electric reliability coordinators and gas pipeline control centers,
- conducting regional analysis of gas pipeline capacity,
- establishing a monitoring system to report all gas events that threaten or cause electrical reliability problems,
- reviewing the need for emergency gas pipeline interconnections and subsequent emergency tariffs, and
- developing a NERC standard to include gas pipeline contingencies.

Fuel availability is a concern relative to the ability to obtain enough gas for generation. With the projected increase in natural gas usage for electricity generation in the United States, coupled with its traditional role as a home-heating fuel and industrial fuel, total gas consumption by 2012 is expected to increase by 26% over that of 2002. Current NERC projections show that capacity fired by natural gas will represent over 38% as a percentage of the total electric generating capacity for the summer of 2008. In contrast, capacity fired by natural gas was 23% of the total electric generation capacity as recently as 1998. With this continuing growth in gas usage by the electricity sector, the adequacy and operating reliability of the natural gas supply and its infrastructure will become ever more critical to the reliability of electric supply.

Outlook for Nuclear Generation

Nuclear generation in North America is an important part of a diversified fuel mix. The U.S. Energy Information Administration (EIA) reports that 2002 established a record for calendar-year output of electric energy generated by the 103 nuclear reactors in the United States. The production for 2002 was 780.2 billion kWh, compared with the previous 2001 record of 768.8 billion kWh. Further, nuclear facilities scheduled for relicensing have thus far done so successfully; most recently the North Anna and Surry plants in Virginia received renewals from the U.S. Nuclear Regulatory Commission to operate for an additional twenty years.
The lack of resolution on long-term spent fuel storage continues to be the most contentious issue related to nuclear generation.

Renewable Resources

Renewable resources today are provided primarily by hydroelectric energy, but it appears that renewable resources will be increasingly derived from wind energy.

An alternative to the expanding consumption of natural gas over the next ten years may come from local initiatives to pursue renewable electric energy resources. Several states in the United States have established standards requiring that a minimum percentage of energy consumed be derived from renewable resources. The New York Public Service Commission is now finalizing a renewable energy portfolio standard, which will ensure that, within ten years, at least 25% of the electric power purchased within New York state must be supplied by renewable resources. In California, legislation has been passed requiring utilities within the state to increase their purchases of electricity derived from renewable energy resources by 1% per year through the year 2017, or until at least 20% of energy purchased is derived from renewable resources. In Texas, legislation mandates retail electric providers to obtain a total of at least 2,000 MW from renewable resources by 2009.

The Ontario government recently announced a Green Power Standard that would require Ontario's electricity system to secure an additional 1% of its current electricity needs from renewable resources in each of eight years, starting in 2006. During its eight-year lifespan, the program will add 3,000 MW of renewable energy to the Ontario system. At the end of the program, approximately one-third of Ontario's electricity will come from renewable sources, since about 25% of Ontario's current installed capacity, largely hydroelectric power plants, is considered renewable energy.

Wind Energy

Wind represents an area of rapidly growing generation development investment. However, the capacity additions should not be counted fully toward capacity requirements due to the intermittent nature of wind generation.

Wind driven capacity totaling 6,868 MW was installed worldwide in 2002, bringing the total installed wind capacity for all nations to more than 31,000 MW, an increase of 28%. 90% of this capacity is situated in Europe and the United States. 10% of the growth for 2002 occurred in the United States. Several major sites, considered particularly amenable for the siting of wind farms, are actively being considered.

Wind power shows promise for several reasons:

- Wind as a fuel source represents a diverse and renewable fuel.
- The construction time of the facilities is relatively short, permitting more rapid deployment of the resource together with a shorter recovery period for the capital investment.
- The licensing of a wind generating facility is, to date, a more simple and quicker process than fossil-based systems.

However, the industry faces challenges in successfully integrating wind resources. Two technical problems presented by the wind turbine are:

1. limited ability to provide voltage support to the network, and
2. intermittent nature of the resource.

The intermittent nature precludes scheduling a wind resource for the time of system peak demand, when resources are typically most needed by the power system. Additionally:

- The intermittent nature of the wind resource also makes it 1) difficult to bid wind-generated energy into the typical day ahead hourly market without special tariff accommodations, and 2) complicates control area regulation requirements.

- A further complication in fully utilizing the potential of wind generation is the large physical size of the average turbine and resulting wind farm. The visual impact of the turbine is beginning to generate the kinds of “Not In My Backyard” objections and interventions associated with other electric facilities.
- The physical dimensions of wind farms often require the facilities to be located in remote, rural locations away from load centers, which are often inaccessible to the bulk transmission network. The remote location could strain the underlying transmission system and require reinforcement of the transmission system to deliver the wind energy to customers.

Transmission Issues

Development of the Transmission Grid

The construction of the interconnected network of extra high voltage (EHV) transmission lines in place today occurred primarily from the 1960s through the 1980s. Prior to 1950, maximum transmission voltages were typically 138 kV. From the mid-1950s through the 1960s, 345 and 500 kV systems were developed. By the early 1970s, transmission networks of voltages as high as 765 kV were built. This construction resulted in a transmission system with sufficient capacity such that, in many regions, additions to the high voltage transmission systems would not be required for many years. This surge in transmission capacity is often referred to as the "lumpy" stair-step nature of transmission construction. The term lumpy indicates that in a growing market, the economies associated with large capital investments dictate that more capacity be installed than is needed in the early years so that the capacity of the investment is sized properly to be useful throughout its life. This additional capacity, combined with the drop off in demand growth rates beginning in the 1970s, enabled the industry to reduce investments in transmission throughout much of the 1990s.

In addition to the construction of the EHV transmission network, more efficient operations enabled by advanced operating tools, such as state estimation and operating reliability analysis, have reduced the need for "on the ground" asset expansion. A more efficient use of existing rights-of-way, including reconductoring of lines with larger capacity conductors, increasing the operating voltage (e.g., converting a 138 kV circuit to 230 kV operation) and the use of flexible AC transmission systems (FACTS) devices and other advanced technologies, that significantly increase the throughput of existing transmission paths, have all reduced the need for new transmission investments.

Reduced Transmission Construction

Historically, expenditures for new transmission construction have reasonably tracked the increases in network customer demand and the corresponding generation capacity additions. In recent years, however, there has been a reduced level of transmission investment as compared to the rate of customer demand growth and generation construction. For example, it was estimated that in 1972 approximately 30 GW of generation was added and $6 billion expended on transmission investments (in year 2000 dollars). In 2001, 41.8 GW of generation was added while transmission investment was only $3.9 billion. In 2002, 57.7 GW of generation was added while transmission investment was only $3.5 billion. In 2003, 53.8 GW of generation is expected to be added along with $3.8 billion of transmission investment.

Some have suggested that this reduced level of investment in transmission is the result of the transmission owner's unwillingness to make necessary investments in transmission. However, false conclusions may be drawn concerning the "expansion rate" of the transmission system by such a comparison. To address the issue of the apparent decline in transmission construction, it is necessary to examine the social, political, and economic forces that impact grid expansion.

Obstacles to New Transmission Construction

Transmission owners have also faced significant obstacles when they seek to construct new transmission facilities, particularly new EHV facilities. These obstacles include regulatory, public, and financial concerns.

Regulatory Concerns

A key to successful implementation of a transmission project is regulatory approval. Alignment at all federal, state, and local regulatory levels is also important. An example of good regulatory alignment is a project to construct new 500 kV transmission facilities in central Arizona to connect areas with relatively high customer demand growth to new in-state and out-of-state utility and merchant generation. This project has benefited from regulatory support at all levels allowing both publicly and privately held project participants. In ERCOT, where regional transmission planning is in place and a state regulatory agreement has been reached on cost allocation, a number of transmission expansion projects are being constructed. In many other cases, however, regulatory agencies are not in alignment, resulting in project delays and uncertainty.

Public Concerns

While siting of new transmission lines has never been easy, it is becoming increasingly more difficult today than in the past. As the population has grown and more previously rural areas are developed, available corridors for new transmission are shrinking.

Public opposition is often exacerbated by the fact that transmission lines are very visible and extend over significant distances. In addition to traditional arguments against construction of new lines, opponents frequently advocate the investigation of alternatives to transmission through more aggressive integrated resource planning processes involving construction of new large-scale generation projects, pervasive implementation of distributed generation, or significantly expanded energy conservation measures. In one recent case, a 500 kV line was denied a permit by the state siting agency after intense local opposition, in spite of the fact that the sponsors and the involved independent system operator concluded that the new line was necessary to reduce overall energy costs and improve reliability.

Also affecting the ability to construct new transmission lines are the varying levels of benefits assigned by different entities. Where communities have developed policies that would limit commercial and residential growth, new or expanded transmission is viewed as contrary to this policy. Such policies can adversely impact the ability of a neighboring community’s desire to encourage growth or a broader desire to achieve regional benefits from expanded transmission.

Another factor affecting construction of new projects is the balance between the benefits and impact of the project. Many communities are supportive of new transmission facilities when those facilities are consistent with or support their own objectives; the community benefiting from the project is also the community being impacted. However, any impacted community or region may oppose projects that benefit another community or region.

Financial Considerations

Investment in transmission in the near term needs to be considered in the context of the overall financial health of the electric industry. The financial community is looking differently at the industry in light of the mixed results with industry restructuring, the rapid expansion, and then contraction of the energy trading business and difficulties in the merchant generation business sector. Even firms whose business plans have focused on maintaining vertically integrated utilities in markets that did not undergo significant restructuring have been impacted by the developments in the industry elsewhere.

The Federal Energy Regulatory Commission (FERC) is currently engaged in examining the effects of instituting various forms of financial incentives for investment in transmission. FERC has received a wide variety of comments on this issue. These comments range from strong support that incentives will significantly improve the investment outlook to opposition that the incentives will only serve to increase the cost of transmission that would have been built anyway.

One other financial consideration impacting new transmission is the cost of environmental mitigation. In many regions, mitigation associated with new lines is getting more and more costly due to additional wildlife protections or the requirement to place new lines underground to avoid visual or other environmental impacts. The high cost of these mitigations can be a deterrent to new construction.

Prospects for Future Transmission Construction

Merchant transmission projects have emerged in recent years and are thought by some to be an alternative to traditional utility construction. The entry of these new players into the transmission area may result in construction of new transmission beyond that currently planned. The California ISO has approved the addition of a third 500 kV transmission line to reinforce Path 15 (central to northern California), which will be primarily funded by merchant participants. That transmission path limited south-to-north transfers to northern California during the California energy crisis in the winter 2000–2001.

However, these new players can face the same hurdles to new construction: public opposition to siting the facility, uncertainty as to how the costs and benefits of the new facilities are allocated, and regulatory uncertainty.

A number of the new merchant transmission lines are DC connections. In general, the electrical characteristics of DC transmission facilities allow for more precise control of the direction and amount of power flows, thereby avoiding many of the problems of benefit allocation and assignment of payments associated with alternating current (AC) transmission lines.

As demand continues to grow and wholesale market requirements expand, transmission owners will encounter increasing pressure to add transmission capacity. Some new high voltage transmission lines will have to be built if reliability and economic efficiency are to be maintained. However, new transmission line projects will continue to face the many obstacles listed above. Projects that can demonstrate a clear communal benefit for the local area will be more likely to gain public acceptance. Even then, the permitting and siting process will be long and difficult.

It may be unrealistic to expect local communities to be in favor of the construction of new high voltage transmission lines that would facilitate market transactions that benefit customers elsewhere. In light of these many obstacles, it is likely that transmission owners will rely increasingly on upgrades to the existing transmission system for increased transmission capacity. These methods can result in additional transmission capacity with minimal additional right-of-way acquisition. Their applications may delay or even do away with the need for many new transmission line projects that would otherwise be required.

System Concerns & Observations

This section discusses the issues and trends that could impact the overall reliability of the North American electric bulk power system.

Coordination of Generation and Transmission Planning

A number of approaches are being implemented cross North America at this time to assure that there is adequate generation and transmission to serve demand. They range from the traditional approach taken by vertically integrated utilities, reliance on market forces, to heavily rule-based approaches, which impose strict adequacy requirements on load-serving entities and then allow competitive suppliers to respond to market-driven price signals. Regardless of the approach taken, these coordination efforts are intended to ensure the reliable operation of the bulk electric system.

Up to and into the 1990s, transmission and generation resources were generally planned, built, and operated on a fully integrated basis within defined service territories. Vertically integrated utilities built generating resources as required by the regulatory compact to meet the electric demand of the customers within their respective franchise service territories. Transmission-dependent utilities contracted for their capacity or built generating resources to meet their demand. Some entities, such as PJM, the New York Power Pool, and the New England Power Pool, coordinated resource planning on a regional basis.

As a result of industry restructuring, the integrated planning and construction of generation and transmission by vertically integrated utilities have been supplanted by merchant generation designed to operate as part of the competitive wholesale generation marketplace. New generation is not necessarily matched to a specific “obligation to serve” demand, but may be constructed in anticipation of selling capacity, energy, and ancillary services in the competitive wholesale electricity market. In such cases, the generation interconnection process is not directly linked to the obligation to serve demand, which might impact the ability to perform long-range planning.

The usefulness of transmission expansion planning is heavily dependent on accurate customer demand forecasts and generation resource expansion plans. Because the generator interconnection process is not directly linked to a specific demand, the level of complexity has increased in developing a reasonable base case upon which transmission expansion plans can be based. This situation is problematic in several respects. Interconnection studies and transmission services studies for the same generator may be performed independently, might not be concurrent, and could be separated in time by months or perhaps years. Generators currently in the queue may ultimately not be built, thereby complicating transmission service studies as well as other generation connection studies. Load-serving entities could increase the uncertainty of the base case by deferring commitments regarding the long-term designation of specific generation resources, or merchant plant developers may hold several generation interconnection queue positions, but intend to only develop the most favorable site.

In areas where the installation of generation is not tied to specific demand, the transmission customers must often initiate the evaluation of the ability of the transmission system to deliver electric power from the new generation. In this case, transmission investment cannot always advance in lockstep with generation additions, and transmission expansion will tend to lag generation construction, which may result in mismatches in the amount of generation and the amount of transmission necessary to deliver new generation to customers.

Where markets for energy, capacity, and ancillary services are integrated with a regional transmission expansion process, the adequacy and deliverability of generation resources are more likely to be ensured. Regional transmission organizations (RTO) or independent system operators (ISO) having resource adequacy requirements would be able to perform the functional equivalent of coordinated generation and transmission planning.

Short-Circuit Current Issues

The recent proliferation of generators connecting to the transmission system has caused a significant increase in the level of short-circuit currents (also known as fault currents) during system disturbances. Whenever a generator is added to the system, the transmission system must be analyzed to ensure that the resultant increase in fault current does not exceed the ability of existing circuit breakers to interrupt fault currents. If the interrupting capability of the circuit breakers is exceeded, the equipment must be replaced with higher interrupting capability equipment. Some systems have calculated that the short-circuit currents at EHV stations are approaching 80 to 100 kA in some instances. This fact is important because:

- the number of vendors who can supply equipment rated to interrupt fault currents higher than 63 kA at 115 kV and 230 kV is limited,
- equipment capable of interrupting fault currents greater than 63 kA at voltages of 500 kV or above is not available, and
- equipment that can interrupt currents in excess of 80 kA for any voltage class is not available.

In some instances, substation configurations may have to be redesigned to limit the fault current that any single system component may have to interrupt. The reconfiguration is usually accomplished by physically splitting the substation bus into separate sections to isolate the transmission lines entering the station. These reconfigurations not only change the short-circuit current in the station, but often change the behavior of the overall transmission system behavior during a fault.

These high short-circuit currents affect not only the choice of equipment ratings, substation bus bar and grounding design, but also personnel protective equipment (PPE) used for maintenance personnel to safely work on equipment. The PPE is important to the safety of personnel during line and equipment maintenance. The PPE includes temporary protective grounds (TPGs) and fire retardant protective (FRP) clothing. It appears that TPGs have been tested up to 63 kA and as such can be used to perform maintenance in systems that have short circuit currents up to that level. FRP clothing requirements for fault currents less than 63 kA also appear to be well documented and accepted in the industry. While some testing has been conducted to define the TPG requirements for handling short circuit currents in excess of 63 kA, there is no industry-wide consensus on the standards or procedures to follow when fault currents exceed that level.

The following list of safety issues have to be considered for transmission systems with fault currents exceeding 63 kA as they impact reliable operation of the system:

- Specific hardware (cables, clamps, attachment points) and work configurations must be used to handle currents above 63 kA.
- Very specific (layered) fire retardant clothing and work distances are required above 63 kA.
- Many existing substation buses and grounding systems would require significant rebuild that would be very difficult and, in some cases, impossible to accomplish within the existing substation.

Frequency Excursions

For the past ten years, those who monitor the frequency response of the Eastern and Western Interconnections have recorded that the interconnections are becoming more sensitive to loss of generation based on actual measurements. Measurements are made to determine how large a disturbance, measured in MW, it takes to change the bulk system frequency by 0.1 Hertz. Over the last ten years, the loss of generation required to produce a 0.1 Hz change has decreased by 70 MW/year.

Both the Eastern and Western Interconnections grew in installed generation and load, and, all other conditions being equal, a larger disturbance should be required to produce the 0.1 Hz deviation in frequency than it has in the past. The exact cause of the increased swings in frequency is unknown at this time; however, some postulated contributing factors have been identified.

A review of present inertia constants of new combined-cycle plants indicates that their inertia constants are about the same to slightly larger than those of similarly sized existing fossil units. However, due to the modular nature of the new plants, the number of units on line at any time will be fewer today than in the past. Simply put, at lower loads, the larger conventional units had to be run at less than full output. Today, combined-cycle facilities will shut down some of the smaller generators in order to be able to run the remaining units more efficiently at or near full load. Therefore, fewer units and consequently less inertia are connected at time of peak demand.

The characteristics of the load have changed as the demographics and the nature of the North American economy has changed. The amount of heavy manufacturing, aluminum smelting, steel and rolling mills have decreased, reducing the inertia of the load connected to the grid. Also, the nature of the loads has changed with the increase in variable speed drives instead of large motors. This change reduces the inertia of the load by making it look like a rectifier with little or no feedback. The nature of the major transmission systems has also changed in that there are more static VAR systems and more large high voltage DC system in the Eastern Interconnection.

One unintended consequence of the proliferation of environmental controls on generating units is that the traditional governor action allowing the unit to closely follow frequency has been essentially eliminated. The governor is active but does not significantly change the unit output unless there is a major system deviation. Units that do not readily respond to frequency change have an overall detrimental effect on the frequency response of the system.

Some observers have indicated that this trend is not important. In Europe, the normal frequency range has been + or -0.5 Hz for many years without any detrimental impact on the operation of the system. The NERC Frequency Excursion Task Force came to the same conclusion in their 2002 presentation to the Operating Committee. However, reports of various generation torsional frequency issues and the development of what appears to be very large HVDC systems, warrants additional review and continuous observation to ensure that frequency swings on the interconnections do not become a problem.

Environmental Issues

If new environmental regulations allow adequate time for equipment installation and fuel conversions, and commercial technologies are available to comply with the requirements, any reliability impacts should be minimal. However, if any of these constraints are compromised, reliability might suffer when units are taken out of service due to retrofits or reduced fuel diversity, or if mass retirements of fossil fuel generation occur. The resulting replacement of existing fossil-fueled generation and concomitant changes to the transmission infrastructure might be difficult to site, finance and construct, and could further stress the ability of the natural gas infrastructure to deliver gas where it is needed by gas-fired generating facilities.

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

- Need to develop new control technology to meet requirements;
- Time needed to permit, design, procure, and install the control technology;
- Changes to unit/plant operation;
- Changes to the availability and type of fuel used; and
- Likelihood of retirement of generation.

Environmental compliance with either continued rulemakings under the Clean Air Act or under proposed multi-pollutant environmental legislation would require significant retrofits to existing coal-fired capacity. As previously mentioned, the overall impact of these environmental requirements on reliability will depend on providing sufficient time to make the necessary modifications and the commercial availability of control technologies. The most significant retrofits would be to reduce sulfur dioxides (SO_2), nitrogen oxides (NO_x), mercury, and, possibly, carbon dioxide.

Regional Self Assessments

ECAR

The bulk electric systems in ECAR are expected 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. Construction will soon begin on American Electric Power's (AEP) 765 kV project in southeastern ECAR, which is needed to guard against potential widespread interruptions.

The region's criteria for resource adequacy will be satisfied through at least 2007. This assumes that capacity resources are available outside ECAR when needed, and that the average annual generating unit availability is maintained at or above levels experienced in recent years. After 2007, additional capacity beyond year-end 2003 levels will be needed to maintain resource adequacy. The actual amount of announced generation that is built will determine the adequacy of the generation resources beyond 2007.

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

Demand

Throughout the assessment period, the peak total internal demand in ECAR is expected to continue to occur during the summer. These projected peak demands include demand that is connected to member transmission systems, even though the demand may be supplied by non-member resources. A 1.9% average annual growth rate is expected over the 2003–2012 period, with a higher average annual growth rate of 2.24% during the first five years. This peak demand growth is based on forecast economic factors and average summer weather conditions, and as such, actual peak demands may vary significantly from year to year. Current resource plans developed by ECAR members indicate that direct-controlled and interruptible load management programs will provide 2,900–3,200 MW of supplemental resources via demand reduction during the years 2003–2012. With interruptible loads and loads under demand-side management removed, ECAR's net internal demand is projected to be around 116,000 MW in 2012.

Capacity

ECAR members develop ten-year capacity plans that reflect the capacity resources necessary to reliably serve demand and energy for their companies. In addition, a significant number of generation projects have been announced in the region by members and non-members alike. Since most of these projects have been announced by non-members, they are not included in members' capacity projections. When the announced capacity projects and member plans are combined, the net demonstrated generating capacity is projected to increase more than 7,000 MW during 2003. The total announced increase in generating capacity is more than 21,000 MW by 2012. Approximately 18,000 MW of this potential capacity increase from 2003 through 2012 is in the form of combustion turbines and combined cycle plants projected to operate on natural gas.

Resources

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.

The construction status of many near-term capacity projects is not known until nearly in service, and later projects are not yet under construction. This makes for uncertainty regarding the timing and amount of new capacity additions, and consequently, the expected ECAR capacity margins. Capacity margins in ECAR, that include the announced additions after 2003, would range from 21% in 2003 to a high of 25% in 2006, declining to 16% in 2012. Capacity margins, without including announced additions after 2003, would decline over the next ten years from 21% in 2002 to a low of 7% in 2012.[5]

The magnitude of the variation in expected capacity margins illustrates the uncertainty faced by the region in depending on the market to supply new generation resources, since some but not all of the announced additions are likely to be built. The analysis carried out in the ECAR 2003 assessment does not include the announced capacity after 2003, but instead indicates the amount of such capacity that might be needed to achieve an acceptable level of reliability.

The ECAR 2003 assessment indicates that through 2007, there will be no additional need to supplement the capacity presently in service or under construction. This assumes that capacity resources are available outside ECAR when needed, and that the average annual generating unit availability is maintained at or above levels experienced in recent years. ECAR has not explicitly analyzed the amount of capacity, beyond 2007, needed to meet the ECAR reliability criteria.

By the year 2012, about 68% of the capacity in ECAR in service at year-end 2003 will be 30 or more years old, and about 38% will be 40 or more years old. ECAR believes that the aging of generating capacity will necessitate increased maintenance and lengthened outages. ECAR members recognize the challenges in maintaining the high levels of generation availability experienced in recent years.

Coal is the predominant fuel used within ECAR, fueling 67% of the generating capacity in 2003. Many ECAR member companies are retrofitting selective catalytic reduction equipment (SCR) to meet NO_x compliance by 2004. ECAR anticipates that all members will fully comply with the NO_x requirements by the target date.

Transmission

The bulk electric systems in ECAR are expected 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.

The Michigan systems are in the process of completing the installation of phase angle regulators (PAR) in the interconnections between the International Transmission Co. (now ITC, formerly part of Detroit Edison) and Ontario systems, but the PARs are not expected to be in service until after the 2003/04 winter season. With the PAR addition, the power flows circulating around Lake Erie, which have often limited the ability of the Michigan systems to receive firm purchases from Ontario, can be controlled to improve the transfer capability between ECAR and NPCC (Ontario).

Current plans call for the addition of about 123 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 AEP’s 765 kV project, originally scheduled for service in May 1998. The Wyoming-to-Jacksons Ferry 765 kV line portion of this project is now expected to be completed by June 2006. A tri-regional assessment of the reliability impacts of this project concluded that a reliability risk in the southeastern portion of AEP’s service territory exists due to its delay. Although operating procedures can minimize the risk of interruptions in that area, the likelihood of such power outages will increase until the project is completed. As noted above, significant amounts of new generation have been proposed in ECAR over the next ten years.

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[5] Internal ECAR reports typically use Total Internal Demand, which would differ from the numbers shown in this report that are based on Net Internal Demand.

Depending on specific dispatch patterns of this new and existing generation, the full output of this new generation will not be attainable without exceeding transmission limitations.

Operations

As of spring 2003, the ECAR MET reliability coordinator, the ECAR East reliability coordinator, and the ECAR North reliability coordinator no longer exist. The Midwest ISO, PJM, and TVA are now performing the reliability coordinator functions for all of the ECAR control areas.

In the future, two major transmission additions are planned that will improve the reliability of the ECAR transmission system. The first, which is scheduled to be in service during the 2004 spring season, is the installation of PARs in the interconnections between International Transmission Co. in Michigan, and the Independent Market Operator in Ontario. The other addition is AEP's 765 kV transmission line project. This new line from the Wyoming substation to the Jacksons Ferry substation is scheduled to be in service by June 2006. These two projects are also discussed under the Transmission Assessment.

Assessment Process

Each individual company does planning for facility additions. Regional reliability assessments are performed to determine the adequacy of the existing and future bulk power system to serve projected load, given the proposed changes or additions to generation capacity and transmission facilities. The ECAR Generation Resources Panel and Transmission System Performance Panel perform assessments under direction of the ECAR Coordination Review Committee.

ECAR assessment procedures are applied to all generation and transmission facilities that might significantly impact bulk electric system reliability. These assessments consider ECAR as a single integrated system. The operating reliability impact of interactions with neighboring Regions is assessed by participation in several interregional groups such as MAAC-ECAR-NPCC (MEN), VACAR-ECAR- MAAC (VEM), and MAIN-ECAR-TVA (MET). Generation resource assessments of the ECAR systems on a region-wide basis are performed annually for a planning horizon up to ten years, and semiannual assessments are made for the upcoming summer and winter peak demand seasons. Transmission assessments are performed regularly for selected future years out to the planning horizon and semiannually for the summer and winter peak demand seasons. If transmission deficiencies are discovered during this process, the member system with the deficiency will determine the action to be taken.

ECAR's membership currently consists of 21 full members and 22 associate members serving more than 38 million people in a 194,000 square mile region covering all or part of the states of Michigan, Indiana, Kentucky, Ohio, Virginia, West Virginia, Pennsylvania, Maryland, and Tennessee. www.ecar.org

ERCOT

The Electric Reliability Council of Texas (ERCOT) is operated as a single control area electric interconnection that enables a competitive wholesale electricity market and the ability of retail customers to choose their electric supplier. Market mechanisms are used to the greatest extent possible to address reliability issues of generation adequacy, system operating reliability and transmission congestion. ERCOT has been successful in maintaining a reliable electric system utilizing these market mechanisms with occasional "command and control" tools when market mechanisms are not fully effective.

Due to competitive forces, merchant plant developers are less likely to share plans for generation additions exceeding a three-year horizon. Despite this, it is expected that capacity margins for the assessment period will be kept above the regional minimum requirement of 11% without any publicly announced generation additions after 2006. However, there is growing concern about the future availability of natural gas supply given recent operating experience and the large amount of new and existing generation capacity solely dependent on that fuel.

A number of major transmission projects will be completed during the assessment period. These projects will help relieve problems that constrain operation of generation in ERCOT. These constraints limit imports into the Dallas-Fort Worth and Houston load centers and have required ERCOT to contract with Reliability Must Run (RMR) generation that would otherwise not be operated in other parts of the region to maintain area operating reliability. The long lead times and difficulty in building new transmission facilities will likely require implementation of ERCOT Congestion Management Procedures on an ongoing basis during the period.

Demand

In 2002, ERCOT had a peak demand of 56,233 MW, a 1.9% increase from 2001. The 55,201 MW peak in 2001 was a 4.2% decrease from the summer peak demand of 57,606 MW in 2000 due to cooler weather and a slowing economy. The projected peak for 2003 was 57,639 MW, a 2.5% increase from 2002 and equivalent to the 2000 peak. The actual summer peak occurring on August 7, 2003 was 59,992 MW, on a day with record high temperatures throughout the region. For the period 1991 to 2000, demand had been increasing an average of 4.3% per year.

Between 2001 and 2002, the actual ERCOT energy consumption increased slightly from 278,226 to 280,269 GWh, a 0.7% increase. The 2002 energy consumption was still less than the record of 288,713 GWh in 2000. Energy consumption in 2003 is expected to increase to 287,333 GWh, a 2.5% increase from 2002. For the period 1991 to 2000, the compound annual growth rate in energy consumption had been 3.5%.

The average annual growth rate in ERCOT's summer peak demand is projected to be 2.5% for the 2003 through 2012 period. The projected annual growth for energy is 2.7%. These growth rates are based on long-term historical trends and thus assume a continued recovery from the recent economic downturn to average growth and historical average weather.

ERCOT has two DC ties to the Southwest Power Pool (SPP) and one to Mexico with a total capacity of approximately 856 MW. About 190 MW may be used to transfer output of a power plant in ERCOT partially owned by utilities in the SPP to those utilities. Two entities in ERCOT are forecasting purchasing approximately 115 MW over the ties to the SPP for the assessment period. The use of the ties has generally been for purchases from outside ERCOT for economy energy reasons.

Resources

In 2002, ERCOT established a minimum planning reserve margin requirement of 12.5%, which equates to a capacity margin of 11%. This requirement was based on a reliability study that indicates with reasonable assumptions that level of margin should provide about a one-day-in-ten-year loss-of-load expectation (LOLE), which is a commonly used industry standard. ERCOT, in conjunction with the Public Utility Commission of

Texas, is determining what mechanisms may be needed to maintain adequate margins going forward whenever projected margins fall to the minimum level.

Due to the short time required to construct new generating plants, ERCOT does not maintain a new generation forecast beyond 2008. Counting only new generation capacity that has actually executed an interconnection agreement with a transmission provider and including DC tie imports and capacity that can be switched between ERCOT and SPP and SERC, capacity margins in ERCOT are expected to be no lower than 25% through 2008. Based on this assessment, ERCOT expects to have adequate resources through 2008 with ample opportunity for the market to do what is necessary to maintain that adequacy through 2012.

In addition, ERCOT has put structures and systems in place that will allow load to act as a resource (by voluntary interruption) and participate in the market. The current amount of load acting as a resource is 1,150 MW and it is expected to grow in the coming years as this market develops.

Between 2003 and 2006, over 9,200 MW of new generating capacity has been announced in ERCOT. Wind turbines will account for 375 MW of this capability with the balance being natural gas-fueled generation.

A concern is growing about the availability of natural gas during the winter peak given the fact that over 60% of existing and projected total generating capacity in ERCOT is fueled solely by natural gas. In late February 2003, widespread gas curtailments to electric generators throughout the region during several days of cold weather affected available capacity. On February 25, 2003, ERCOT implemented the first step of the Emergency Electric Curtailment Plan (EECP) to address a shortage of electricity due to the natural gas curtailments. Fortunately, the market was able to increase generation to avoid further steps of the EECP and no interruptible or firm load shedding was necessary. Concern about this reoccurring in the future has led ERCOT to raise the issue of creating economic incentives for dual fuel (gas/oil) capability and the need for reconsidering the order of electric generation in gas supplier curtailment priorities.

Transmission

The major transmission constraints in ERCOT continue to be related to the transfer of energy into the Dallas-Fort Worth and Houston load centers. Almost all of the 16,000 MW of new generation coming on line in the past three years has been located outside these areas due to environmental and economic considerations. The much longer lead time in building transmission compared to building new generation or shutting down old generation is the root cause of these constraints. ERCOT manages these constraints operationally by a market-based generation redispatch when possible and direct redispatch instructions or RMR contracts when necessary.

Local constraints in smaller load centers in west and south Texas are also dependent on local generation for both voltage support and keeping within transmission loading limits. Some of this local generation consists of older plants that are not economical to run in a competitive market. To keep this generation available to maintain system operating reliability, ERCOT has executed RMR contracts with generation owners. In addition, more than 1,000 nameplate MW of wind generation has been built in west Texas in the last three years and the relatively weak existing transmission system in the area has required almost daily limitation of the output of this renewable generation resource.

ERCOT directs and supports three regional planning groups of transmission providers that have studied these and other transmission issues and proposed solutions. These solutions include new facility construction and special protection systems, if necessary, that activate when contingencies occur until new facilities can be constructed. Capital-intensive transmission projects to serve remote locations in Texas are also being evaluated against other economic means to meet the NERC and ERCOT reliability criteria. Continued congestion management through RMR services and market protocols (including demand participation) may prove cost effective in these areas.

A number of 345 and 138 kV lines have been completed and are under construction in west and south Texas that will provide relief for existing constraints. In 2003, the Morgan Creek-Red Creek-Comanche 345 kV line in west

Texas and the San Miguel-Pawnee-Coleto Creek 345 kV line in south Texas were or will be completed. A total of almost 1,000 miles of new 345 kV line construction is planned to be in service between 2003 and 2008. Numerous other projects are in the planning stage or under way that will address localized congestion issues. Construction plans for 345 and 138 kV lines have been approved to relieve the existing and future constraints on wind generation in west Texas. However, long transmission construction lead times will likely require continued active congestion management by ERCOT throughout the assessment period.

Operations

Operational challenges during the assessment period are anticipated to continue to center around transmission congestion management. A market "redesign" initiative just beginning in ERCOT may change current congestion management procedures from a zonal to a more nodal-based system. This transition may present some operational challenges, but may also improve the efficiency of transmission congestion management.

As previously discussed, there are operational issues connected with potential reduction of available capacity due to natural gas curtailments. Emergency operating procedures may need to be modified if such curtailments become more frequent.

ERCOT has 135 members that represent independent retail electric providers, generators, and power marketers and investor owned, municipal, and cooperative utilities and retail consumers. It is a summer-peaking region responsible for about 85% of the electric load in the state of Texas. ERCOT serves a population of over 15 million in a geographic area of about 200,000 square miles with over 78,000 MW of generating capacity and 37,000 miles of transmission lines. www.ercot.com

FRCC

The Florida Reliability Coordinating Council (FRCC) expects to have adequate generating capacity reserves and transmission system capability to meet the regional reserve margin standard throughout the 2003–2012 assessment period.

Demand

FRCC members use historical weather databases consisting of as many as 54 years of data for the weather assumptions they use in their forecasting models. FRCC is historically a winter-peaking region. However, because the region is geographically a subtropical area, a greater number of high-demand days normally occur in the summer. Therefore, it is possible for the annual peak to occur in the summer.

The 2003 ten-year demand forecast for FRCC is slightly higher than 2002. Projected annual net peak demand and the energy growth rates for FRCC for the next ten years are both 2.6%. This is about the same as last year.

Resources

FRCC reserve margins over the winter and summer peaks for the next ten years are 20% or greater except for one winter peak, which is projected to be 19.5%. These reserve margins do not reflect any merchant generating capacity that has not been firmly contracted for by load-serving entities. FRCC members are projecting the net addition (i.e., additions less removals) of 16,013 MW of new capacity over the next ten years. Of this, 13,160 MW are projected to be natural gas-fired combined cycle units.

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

FRCC formed a Natural Gas/Electricity Interdependency Task Force in 2003 to assess and monitor the risks associated with having an ever-increasing percentage of generating units fueled by natural gas. The task force is focusing on pipeline transportation adequacy and reliability as it affects electric generator operation and reliability in FRCC. Membership includes representatives from the electric industry, natural gas pipeline companies serving the FRCC, and natural gas local distribution companies.

More than 4,087 MW of merchant plant capability exists in FRCC, of which over 2,984 MW is under firm contract. An additional 646 MW is scheduled to become commercial by summer 2004. In the past year, the construction of a number of merchant generators has been put on hold. The amount of merchant generation that may come on line in the next ten years is dependent on a number of factors that are not capable of being projected at this time. These include the results of contractual negotiations for the sale of announced capacity, transmission interconnections and/or service requests and associated queuing issues, and federal, state, and local siting requirements.

Transmission

Transmission studies were performed by FRCC for the 2003 summer period and for the 2003–2012 ten-year period. The studies showed that operational procedures such as generation re-dispatch, sectionalizing, planned load shedding, reactive device control and transformer tap adjustments successfully mitigate all the reportable load and voltage violations appearing in the first five years. In the long term, violations of criteria can be resolved by planned transmission projects where there is adequate time to monitor trends and construct required network upgrades. None of the problems are considered significant to the reliability of the system. No transmission line load relief events have occurred in FRCC since 1999. Individual members plan to construct 501 miles of 230 kV transmission lines during the 2003–2012 assessment period.

Interregional transmission studies are performed each year to evaluate the transfer capability between the southern Subregion of SERC and FRCC for the upcoming summer and winter seasons. Joint studies of the Florida/Southern transmission interface demonstrate there is adequate capability for additional power imports into the FRCC Region over and above the owned and contracted 2,448 MW currently being imported on a firm basis.

Operations

FRCC has Reliability Coordinator Agents who monitor real time system conditions and evaluate near-term operating conditions. FRCC has a detailed operating reliability process that gives the Reliability Coordinator Agents the responsibility and authority to direct actions to ensure the operating reliability of the bulk electric system in the region.

The Reliability Coordinator Agents use a region-wide Contingency Analysis Program and a “Look-Ahead” Program to evaluate current system conditions. These programs are updated with data from operating members on an as-needed basis throughout the day. The procedures in the operating reliability process are periodically evaluated and updated to ensure regional reliability, conformance to FRCC procedures, and adherence to NERC standards and policies.

FRCC foresees no operational issues that would impact reliability during the ten-year assessment period.

Assessment Process

FRCC members plan for facility additions on an individual basis. However, they exchange information to maintain the reliability of the bulk electric system, and provide data to FRCC for regional databases as well. FRCC follows a formal reliability assessment process by which a committee and working group structure is utilized to annually review and assess reliability issues that either exist or have potential for developing. This process determines which areas deserve closer scrutiny in the planning and operating studies that will be performed during the year. The results of these studies are utilized to ensure that FRCC remains ready to meet the reliability needs of the future.

The FRCC membership is comprised of 29 members, of which 11 operate control areas in the Florida Peninsula. FRCC membership includes investor-owned utilities, cooperative systems, municipals, power marketers, and independent power producers. The region covers about 50,000 square miles. www.frcc.com

MAAC

Generation resources are expected to be adequate in the Mid-Atlantic Area Council (MAAC) over the next ten years. Consistent with the MAAC Reliability Principles and Standards and in accordance with the PJM Open Access Tariff, PJM is currently evaluating generator interconnection requests for over 18,000 MW of new generating capacity expected by 2010. MAAC believes that sufficient capacity will be added to meet the MAAC adequacy objective that the probability of load exceeding available resources will be no greater, on the average, than one day in ten years.

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

Demand

MAAC is a summer-peaking region. The 2003 net peak demand and energy forecasts over the next ten years have increased in comparison to the 2002 forecasts. The 2003 net peak demand growth rate has grown to 1.8%, up from 2002's 1.6% growth rate. Geographic zone growth rates vary from 0.9 to 2.5%. The energy growth rate expands this year to 1.6% from last year's 1.5%.

Resources

Generation resources are expected to be adequate in the MAAC Region over the next ten years. Consistent with the MAAC Reliability Principles and Standards and in accordance with the PJM Open Access Tariff, PJM is currently evaluating generator interconnection requests for over 18,000 MW of new generating capacity through 2010. While it is difficult to predict how many generation projects will actually make it on line, MAAC anticipates that sufficient capacity will be added to meet the MAAC resource adequacy requirement. This requirement ensures that the probability of load exceeding available resources will be no greater, on the average, than one day in ten years.

Transmission

Based on identified system enhancements, transmission capability over the next five years is expected to meet MAAC criteria requirements. In addition to the direct connect transmission facilities of $359 million associated with new generating capacity, several transmission reinforcement projects are expected to be in service by 2007:

- Baseline additions by transmission owners of $220 million
- Reinforcements by developers to ensure deliverability of $316 million

This data is periodically updated by the Regional Transmission Expansion Planning Process. The full plan and project details can be found at: http://www.pjm.com/services/trans/downloads/regionalplan_4_0.chm.

These projects are currently being evaluated by PJM through the PJM Regional Transmission Expansion Planning Process. PJM also evaluates all proposed independent transmission enhancements under this process in order to ensure that sufficient transmission will be added to meet MAAC criteria.

MAAC members also rely on PJM to prepare a plan for the enhancement and expansion of transmission facilities to meet requests for firm transmission service. Based on data from the transmission owners and input from the Transmission Expansion Advisory Committee, PJM has the responsibility to prepare a Regional Transmission Expansion Plan that consolidates the transmission needs of the entire region into a single plan for maintaining reliability. The plan is subject to approval by the PJM Board of Managers. MAAC staff also conducts many specialized planning studies as needed within the region and with surrounding systems.

Operations

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

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

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

The PJM RTO is the reliability coordinator for PJM, which includes Allegheny Power. Additionally, PJM RTO is the reliability coordinator for Duquesne Light Company, American Electric Power, Commonwealth Edison and Dayton Power & Light. Allegheny Power, the energy delivery business unit of Allegheny Energy, Inc., joined PJM on April 1, 2002. The inclusion of Allegheny Power expands the PJM energy market but not the MAAC Region. Allegheny Power remains part of the ECAR Region.

Assessment Process

Reliability assessments are performed regularly for selected future years over a ten-year planning horizon, and semiannually for the pre-seasonal horizon. If deficiencies are discovered during this process, the member with the deficiency is required to put in place plans to resolve the problem. The necessary reserves to remain at a LOLP of one-day-in-ten-years are calculated annually for the entire ten-year planning horizon. A reserve requirement is then set for a planning period two years into the future.

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

PJM has established a FERC-approved Regional Transmission Expansion Planning Process that ensures that PJM and the MAAC bulk power system will be enhanced as required to comply with MAAC and NERC reliability standards.

MAAC serves over 22 million people in a nearly 50,000 square mile area in the Mid-Atlantic region. The region includes all of Delaware and the District of Columbia, major portions of Pennsylvania, New Jersey, and Maryland, and a small part of Virginia. MAAC comprises less than 2% of the land area of the contiguous United States but serves 8% of the electrical load. The MAAC Region is comprised of more than 200 members. MAAC operates under an agreement that became effective January 1, 2001 and is available for review on the MAAC website at www.maac-rc.org.

MAIN

Within the Mid-America Interconnected Network (MAIN), generation resources are expected to be adequate over the next ten years based on current load forecasts. Planning for the integration of new generation into the transmission grid and transmission service reservations, particularly in regard to rollover rights, continues to be a major challenge.
For the planning horizon, MAIN expects its transmission system to perform adequately with the proposed reinforcements completed on schedule. However, operational challenges exist on the MAPP-to-MAIN interface because of delays in the completion of the Arrowhead-Weston reinforcement project.

Demand

MAIN projects its summer peak MW demand for 2003–2012 to increase at an average annual rate of about 1.7%. This projection assumes average weather conditions and economic growth. The actual 2002 peak demand in MAIN was 55,977 MW.

MAIN's projected annual growth rate of electrical energy usage for 2003–2012 is about 1.5%. Actual energy use in MAIN for 2002 was 279,320 GWh. The forecast peak demand for 2012 is approximately 66,300 MW, with a projected energy requirement of 318,000 GWh.

Resources

Approximately 11,500 MW of net new capacity resources are scheduled to be in service within the MAIN Region by 2012. This takes into account expected additions, upgrades, suspended operations, and retirements. Given this increase in capacity, long-term planning reserve margins for MAIN as a whole are expected to be above the MAIN minimum required reserve margin of 17% (14.5% capacity margin).

MAIN is expected to have adequate installed generation capacity to meet its criterion of one-day-in-ten-years LOLE for the next ten years. This is based on the projected reserve margins for MAIN, and the assumption that adjacent regions carry the same average level of reserves and that MAIN has access to these reserves.
MAIN's present capacity is 67,837 MW with a mix of 43% coal, 21% nuclear, 31% gas, 3% oil, and 2% other. MAIN's capacity in 2012 is projected to be 79,312 MW, with 56% or 6,473 MW of the new generation being natural gas-fired simple and combined cycle. The resulting capacity mix for 2012 is projected to be 43% coal, 18% nuclear, 35% gas, 2% oil, and 2% other.

Transmission

For the ten-year planning horizon, MAIN expects its transmission system to perform adequately if planned reinforcements or some equivalent of these plans are installed. This assessment is based on historic and current analyses used to judge compliance with NERC Planning Standards I.A.S1 through I.A.S4.

All MAIN transmission owners provided assessments for their systems. Specifically, for Standards S1 and S2, MAIN transmission owners assessed 2004 summer, 2004/5 winter, and 2009 summer conditions as requested by MAIN; some owners also included assessments of other time periods and in-house studies.

For standards S3 and S4, MAIN made its assessment using the following studies:

1. The MAIN 2007 Summer Future System Study Group (FSSG) steady-state analysis of double circuit tower line contingencies.
2. The MAIN FSSG stability study of select M3 and M4 contingencies for 2009 summer conditions.
3. The MAIN FSSG studies done in previous years.
4. Assessments from in-house studies provided by MAIN transmission owners.

For all four standards, the assessment was more specific for the near-term period than for the longer-term period, as there are more uncertainties involved in longer-term simulations. However, MAIN members expect regional reliability organization (RRO) and regional transmission organization (RTO) coordinated planning activities will provide enhanced assessments of the long-term planning horizon.

Mitigation plans related to planning standards compliance and for other reasons (aging facilities, in-house criteria, load growth, IPP connections, parallel path flow concerns), including major reinforcements that may impact the adequacy of MAIN's transmission system for the first five years (2003–2007) of the planning horizon, include the following:

- Capacitor bank additions for local area voltage support, installation of new and/or upgrade of 69, 115, 138, 161, and 230 kV lines, and installation of transformers to alleviate local loading concerns, or to improve transfer capabilities, throughout MAIN.
- Second Rush Island-St. Francois 345 kV, and Callaway-Franks 345 kV lines, and Loose Creek-Jefferson City 345 kV, Cahokia-Dupo 345 kV and Palmyra-S. Quincy 345 kV supply lines to related new 345/138 and/or 345/161 kV substations in south MAIN.
- Weston-Stone Lake-Arrowhead 345 kV project, Morgan-Werner West 345 kV line, and Oak Creek-Bluemound 345 kV line in WUMS.
- Second Burnham-Taylor 345 kV line in northern Illinois.

Some MAIN transmission owners have been experiencing delays in getting regulatory approval and permits, and in acquiring rights-of-ways. These delays could impact future system operations and may require implementation of other alternatives, including operating measures, to ensure reliable operation of the system.

Parallel path flows have frequently restricted transfer capabilities into and within Wisconsin. Additionally, certain EHV facilities in southern MAIN have experienced heavy loadings resulting in transmission loading relief (TLR) requests in the past. These heavy loadings were in part due to parallel path flows occurring during large north-to-south power transfers from and across MAIN. Similar power transfer conditions require close monitoring of system facilities and close coordination among all parties on a continued basis.

The impact of merchant generation is studied on a continuing basis. Uncertainties regarding these installations, their impact on the overall planning process, and coordination of transmission service rollover rights offer further challenges. The lack of coordination of these factors, including seams issues between RTOs, would adversely affect future reliability assessments.

As part of MAIN's 2002 Compliance Program, MAIN conducted on-site audits for certain NERC planning measurements. Audits were made of all transmission-owning companies in MAIN. The reviews included planning measurements I.A.M1, I.A.M2, I.A.M3, and I.A.M4. The companies were required to present evidence that requirements contained in the measurements were being followed. The evidence was checked for loading and voltage concerns as well as for near and longer term planning periods. Evidence was required to demonstrate that contingencies listed in Section I.A Table 1 were addressed. Evidence was checked for simulation date and applicability to meet annual requirements.

Operations

MAIN is a Reserve Sharing Group (RSG) and all control areas within the region share reserves in order for the RSG to comply with the NERC Disturbance Control Standard. The MAIN Callable Reserve System continues to be an accurate and reliable tool for implementing the RSG process.

Most MAIN generation owners have modified their units to comply with new NO_x emission regulations. These new NO_x regulations may cause energy restrictions on certain units. The added emissions control equipment may cause unit deratings and increased forced outage rates. It is expected that the addition of new gas generation into the regional mix will reduce the impact of any decrease in coal unit availability. However, the growing reliance on the natural gas supply network for a large portion of generation within MAIN is also a reliability concern.

The MAIN Operating Reliability Measures Working Group has been formed to coordinate operating reliability activities for MAIN members. These activities include gathering and disseminating operating reliability related information, identifying the requirements for equipment spares and replacement alternatives, and developing strategies for recovery and operation under extended contingency conditions. Procedures for the efficient engagement of emergency management groups during operating reliability emergencies have also been developed.

Assessment Process

The MAIN Planning Committee is responsible for preparation of this assessment with input from its subcommittees and working groups.

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

The MAIN Guide 6 Working Group reviews long-term regional capacity and reserve requirements annually. The MAIN Operating Reserve Subcommittee continually reviews operating reserve requirements and procedures.

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

The 37 members and 7 associate members of the Mid-America Interconnected Network (MAIN) include 16 control areas and other organizations. MAIN is a summer peaking region serving a population of approximately 20 million in a geographic area of about 150,000 square miles. MAIN encompasses portions of Iowa, most of Illinois, the eastern third of Missouri, the eastern two-thirds of Wisconsin, and most of the Upper Peninsula of Michigan. www.maininc.org

MAPP

For the period 2006–2012, currently projected capacity reported in the Mid-Continent Area Power Pool (MAPP) U.S. region is below MAPP requirements for reserve capacity obligations, but MAPP does not expect any capacity deficits to occur during the next ten years. MAPP-U.S. utilities have committed to provide an additional 2,700 MW of new generation during this period. Most utilities in the region propose to install natural gas-fired combustion turbines with short construction lead time to meet capacity obligations.

The MAPP transmission systems are adequate to meet the committed needs of the member systems and will continue to meet reliability criteria throughout the period. The system is expected to be highly utilized due to continuing power marketing activity, and is expected to be managed within its secure limits, which may not meet all market needs.

Demand

The MAPP-U.S. and MAPP-Canada combined 2002 summer non-coincident peak demand was 34,632 MW, a 5.2% increase over 2001 (32,912 MW), and 4.0% above the 2002 forecast (33,285 MW).

MAPP-Canada was 8.2% above the 2001 actual demand and 2.9% above the 2002 forecast.

MAPP-U.S. was 4.7% above 2001 actual demand and 4.3% above the 2002 forecast. The MAPP-U.S. summer peak demand is expected to increase at an average rate of 1.8% per year during the 2003–2012 period, as compared to 1.9% predicted last year for the 2002–2011 period. The MAPP-U.S. 2011 non-coincident summer peak demand is projected to be 34,811 MW. This projection is 5.4% above the 2011 non-coincident summer peak demand predicted last year.

Annual electric energy usage for MAPP-U.S. in 2002 (150,058 GWh) was 3.6% above 2001 consumption and 1.7% above the 2002 forecast.

Resources

Generating resources for MAPP-Canada are forecast to be adequate over the ten-year period. Current planned capacity reported in the MAPP-U.S. region is below MAPP requirements for reserve capacity obligation during 2006–2012. The MAPP Restated Agreement obligates the member systems to maintain reserve margins at or above 15%, which is equivalent to a 13.04% minimum capacity margin requirement. The summer capacity reserve margin is forecast to decline from a high of 17.9% in 2003 to 12.7% in 2006 and 8.5% in 2012. MAPP-U.S. will provide an additional 2,700 MW of new generation for the period of 2003–2012 as reported in the EIA-411.

However, the *MAPP Regional Plan* has reported over 6,600 MW of new generation for the period of 2002–2011, 3,900 MW above that reported to NERC in the EIA-411.[6] This discrepancy between the *MAPP Regional Plan* and the EIA-411 data may be due to the fact that members may not have reported merchant or other generation not yet sited through the data collection process used to prepare the NERC assessment report. Therefore, for the next ten-year period, the MAPP capacity margins are likely to be higher than those shown above.

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

[6] The *MAPP Regional Plan* is updated biennially.

Transmission

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

MAPP members continue to plan for a reliable transmission system. Coordination of expansion plans in the region takes place through joint model development and study by the Regional Transmission Committee. This committee includes transmission owning members, transmission using members, power marketers, and state regulatory bodies. The Transmission Planning Subcommittee, in cooperation with the subregional planning groups, has prepared the *MAPP Regional Plan* 2002 to 2011, to address the needs of all stakeholders. In addition to the transmission planning process conducted through the MAPP Regional Transmission Committee, MAPP members are participating in the MISO transmission expansion planning process.

In general, the MAPP transmission system is judged to be adequate to meet firm obligations of the member systems provided that the local facility improvements identified in the ten-year transmission plan are implemented. MAPP continues to monitor the 19 flow gates within the region to maintain reliability during MAPP exports.

Import restrictions for nonfirm energy in eastern Iowa are due to thermal limitations that include both MAPP and non-MAPP facilities. Proposed upgrades to the Poweshiek-Reasnor 161 kV line have been identified as one reinforcement that would reduce the import restrictions. Outages of 345 kV tie lines connecting the Twin Cities metropolitan area of Minneapolis-St. Paul to the Iowa and Wisconsin regions are continuing to result in system stability restrictions that limit energy transfers from the Twin Cities to Iowa and Wisconsin. The Arrowhead-Weston 345 kV transmission line has been identified as a significant reinforcement to improve the overall performance of this interface. The proposed line is expected to be in service in 2008.

At times, high levels of power marketing activity are expected to fully utilize the available capacity within the existing transmission system. Consequently, MAPP members continue to take a proactive role in the planning and operation of the system in a secure and reliable manner.

Operations

The MISO as MAPP's reliability coordinator is fully operational, with the implementation of real-time system monitoring of key flow gates, data collection at five-minute intervals, and near real-time pre-contingency analyses of system conditions. MAPP member systems jointly perform interregional and intraregional seasonal operating studies under the direction of the Transmission Operations Subcommittee to coordinate real-time operations. Subregional operating review working groups have been formed to deal with day-to-day operational issues such as unit outages and schedule transmission system maintenance. The MAPP Reserve Sharing Pool continues to provide a benefit to the region through the sharing of generation reserves during system emergencies.

Assessment Process

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

MAPP membership includes 108 utility and non-utility systems. MAPP 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.
www.mapp.org

NPCC

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

Demand

Among the five NPCC control areas, the Maritimes area and Québec are predominantly winter-peaking systems. The Ontario area has historically experienced its annual peak demand in the winter, but, in four of the last five years, Ontario's annual peak demand has occurred during the summer due to extreme weather conditions. However, even assuming normal weather conditions, Ontario is now forecast to become a summer-peaking area by the year 2005; the New York and New England areas continue to be summer-peaking systems as well. The expected growth, together with an assessment of the projected transmission and resources, follows individually for the Maritimes area, New England, New York, Ontario and Québec.

Transmission

The existing interconnected bulk electric transmission systems in New England, New York, Ontario, New Brunswick, and Nova Scotia meet NPCC criteria and are expected to continue to do so throughout the forecast period. For the ten-year period through 2010, currently planned transmission within NPCC includes 25 circuit-miles at the 230 kV voltage level, 60 circuit-miles at the 345 kV voltage level, and 362 circuit-miles of HVDC construction.

Operations

Reliable operations within NPCC are achieved through a hierarchical structure. Criteria, guides, procedures, and reference documents developed at the NPCC level are expanded and implemented at the area level by the three Canadian control areas, the New York ISO, and the ISO New England Inc. The criteria establish the fundamental principles of interconnected operations among the areas. Specific operating guidelines and procedures provide system operators with detailed instructions for dealing with system anomalies.

TransÉnergie, the New York ISO, the Independent Electricity Market Operator (Ontario), and the ISO New England Inc. serve as the operating reliability coordination centers for NPCC. As such, entities exchange operating reliability data through the Interregional Security Network (ISN). NPCC conducts weekly operational planning calls between control area operators to coordinate short-term system operations.

NPCC provides a mechanism that augments the regular conference call process to enable operational reliability entities in NPCC and neighboring regions to communicate current operating conditions and, if appropriate, facilitate the procurement of assistance under emergency conditions. These calls may be initiated upon the request of any NPCC control area system operator and are coordinated by NPCC staff, and establish communications among the area operations managers in NPCC in the event of a physical threat to the operating reliability of the interconnected bulk power supply system of the Northeast Power Coordinating Council.

Ontario and New York, together with other Lake Erie companies, have developed the Lake Erie Emergency Redispatch (LEER) procedure to facilitate emergency redispatch among participants within the Lake Erie control areas to relieve transmission constraints.

Assessment Process

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

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

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

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

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

Interregional

To further the coordination of interregional transmission assessment, NPCC is a party to interarea coordination study agreements with MAAC and ECAR. Through these and a similar agreement among MAAC, ECAR, and the Virginia-Carolinas (VACAR) subregion of SERC, studies are regularly conducted among MAAC, ECAR, and NPCC (MEN) and VACAR, ECAR, and MAAC (VEM). All are performed under the auspices of the Joint Interregional Review Committee, composed of representatives from ECAR, MAAC, NPCC, and VACAR. The ISO-NE, the NYISO, the IMO, and PJM also pursue enhanced interregional coordination and system planning.

Subregions

New England — Under expected weather conditions (50/50 probability forecast), the New England peak demand (summer peaking) is projected to be 25,120 MW for 2003 and 28,710 MW for 2012. This forecast represents a compound annual growth rate of 1.5%. The forecasted peak demands have a 50% probability of being exceeded under expected weather conditions.

Under extreme weather (90/10 probability forecast), New England peak demand (summer) is projected to be 26,630 MW for 2003 and 30,470 MW for 2012. This forecast represents a compound annual growth rate of 1.5% as well, and represents an increase of about 6% over expected weather conditions. The forecasted peak demands have a 10% chance of being exceeded under extreme weather conditions.

New England's all-time peak demand of 25,348 MW was experienced on August 14, 2002 during a hot and humid period.

Installed capacity margins are expected to be sufficient to satisfy the New England demand throughout the study period. They are at the greatest in 2003 with a margin of 27.7% and slowly decline to the minimum of 18% for the study period in 2012. The margins include firm capacity purchases of approximately 890 MW per year. The study period assumed no retirements, and new generation totaling 6,053 MW is expected to be on line by 2008.

Last year, projected capacity margins ranged from 16% in 2002 to 25% in 2011. The primary factors associated with the change from last year's forecast are the updated load forecast coupled with the updated new generation forecasts.

ISO New England anticipates that New England will meet the NPCC resource adequacy criterion of one-day-in-ten-years loss-of-load expectation through 2012. However, if transmission constraints are not relieved in southwestern Connecticut, operational problems may develop in the near term within that area under higher than anticipated demand and/or lower than anticipated capacity, and worsen over the study period. The southwestern Connecticut region will require significant bulk power system reinforcements to address current and future reliability issues.

To meet critical electric system reliability needs in southwestern Connecticut (SWCT) for the summer of 2003, the Connecticut Light and Power Company, a wholly owned subsidiary of Northeast Utilities, implemented an emergency plan that included:

- Issuing a Request for Proposal (RFP) for installation up to 80 MW of temporary generation to address reliability needs and other power emergencies this summer;
- Aggressive support for and participation in ISO New England-administered demand-side management (DSM) programs that could potentially reduce this summer's peak load by up to 20 MW.

Similar actions will be necessary in future years if transmission constraints are not relieved.

Nearly 100% of the 6,053 MW of proposed new generation will be fired by natural gas. It is still anticipated that the natural gas pipeline infrastructure will be sufficient to deliver the gas to those customers with firm gas contracts. However, for generators without firm gas transportation contracts, it is possible that, at times (particularly during the winter peak heating months), they will be unable to receive the fuel deliveries due to gas delivery constraints. Under these circumstances, those generators without dual fuel capability will be forced to curtail generation. ISO New England anticipates that it will have an acceptable amount of diversity among fuels used to power the generation within New England.

An important aspect of regional system planning for reliability is the degree of diversity and dependency on specific fuels for energy supply. The ISO New England has conducted various assessments regarding fuel dependency. Given the fact that New England is becoming more and more dependent on natural gas as an electrical energy fuel source, the assessments have particularly focused on issues relating to the ability of the gas pipeline infrastructure to supply the energy needs of New England. Results of these assessments have been published in reports and are available from the ISO New England upon request. Based on these study results, the ISO New England anticipates that it will have an acceptable amount of diversity among fuels used to power the generation within New England during the summer peak demand months. The most recent ISO New England fuel diversity assessment was conducted as a part of the 2003 Regional Transmission Expansion Plan. As noted in the Draft 2003 Regional Transmission Expansion Plan Executive Summary:

> "Studies indicate that New England's projected reliance upon natural gas-fired generating units has potentially negative system-wide impacts. The advent of several thousand megawatts of new gas-fired combined cycle units in New England could have serious reliability impacts on the system should gas pipeline interruptions or extremely cold weather occur. ISO New England has formed a Fuel Diversity Working Group to examine the problem. The effort will focus on understanding the dynamic relationships between the electric and natural gas infrastructure in New England, and how electric reliability could be impacted."

In summary, ISO New England is concerned with issues relating to fuel supply and is actively reviewing associated reliability impacts on the bulk power system to ensure that system reliability would not be compromised due to fuel supply issues.

Numerous transmission enhancements are scheduled to be available by the end of 2003. In the Boston area, enhancements will have included the interconnection of 1,600 MW of additional generation through the installation of a new 345 kV line, the reconductoring of the two 115 kV circuits and the replacement of the Mystic autotransformer. Further, the import limits into Boston will have been increased by approximately 200 MW.

The Maine and southeastern Massachusetts/Rhode Island (SEMARI) area interfaces are currently transmission constrained, resulting in significant locked-in generation within these regions. Circuit breaker upgrades in the SEMARI area will increase the export capability in this sub-area in 2003. Even with improvements in SEMARI, there will still be significant capacity locked in this sub-area due to the lack of adequate transmission capability. Short-term upgrades aimed at improving the import capability in the northeast Massachusetts (NEMA) sub-area were completed for the summer of 2003. Future transmission expansion into and within the NEMA area will likely be required to enable continued reliable service to its load.

The transmission system in northwestern Vermont will need to be enhanced to address current and future system needs. In northwest Vermont, a comprehensive set of upgrades is planned to provide a reliable supply to northwest Vermont both with and without the Highgate HVDC tie in service and with minimal reliance on local unreliable generation.

The most transmission constrained sub-area of New England affecting reliability is southwestern Connecticut. To alleviate projected southwestern Connecticut transmission constraints, plans are being developed to help solve the twin problems of congestion cost and inadequate infrastructure by expanding the transmission system to connect customers in southwestern Connecticut to the 345 kV grid. The first phase of the proposed upgrades, to be implemented in 2005, is expected to increase import limits into southwestern Connecticut by up to 300 MW. The second phase, to be implemented in 2007, is expected to increase import limits in southwestern Connecticut by another 800 MW.

Projects planned over the next ten years that will provide incremental enhancements in southwest and northwest Connecticut include:

- installations in southwestern Connecticut to increase voltage limited import capability,
- an increase in the southeastern Massachusetts/Rhode Island export capability,
- an improvement in the reliability of supply to northwestern Vermont,
- an increase in northwest Connecticut import capability, and
- voltage support in southwestern Connecticut and New Hampshire.

Also under consideration is the resolution of the Cross Sound 330 kV HVDC interconnection between the East Shore substation in New Haven, Connecticut, and the Shoreham substation on Long Island in New York state.

New York — The New York State Reliability Council (NYSRC) has determined that an 18% installed reserve margin for the New York control area is required to meet the NPCC and more stringent NYSRC resource adequacy criterion. Existing resources within the New York control area provide sufficient capacity to meet the current 18% installed reserve margin. Given current demand projections, the New York control area will meet the NPCC resource adequacy criterion of one-day-in-ten-years LOLE through 2012 with the addition of approximately 4,000 MW of new resources.

It is anticipated that the resources necessary to meet future requirements would be procured through the installed capacity market of the NYISO. Currently, there are approximately 5,400 MW of new capacity with certification under the New York State Article X process. Additionally, part of the New York installed capacity market design allows Special Case Resources (for example, distributed generation and interruptible load customers that are not visible to the NYISO Market Information System) to participate in the installed capacity (ICAP) market. As much as 2,500 MW of external ICAP can participate in the installed capacity market.

In addition to the above statewide requirement, the New York ISO imposes locational capacity requirements on those load-serving entities located within New York City and Long Island due to their geography, as described in the "*Locational Installed Capacity Requirements Study*," published by the NYISO on February 12, 2003. The load-serving entities within these localities must procure a percentage of their capacity requirement from resources located within the locality. The New York City locational capacity requirement is 80% of the demand level, and the locational capacity requirement is 95% of the demand level within the Long Island locality.

Long Island continues to meet its projected demand growth with the addition of gas turbines. In addition to the ten gas turbines that were added in 2002, there will be at least 100 MW of gas turbines being connected in 2003. These additions, along with projections for load relief measures, are expected to meet Long Island's locational requirement through 2008. Projected load growth after then will require the addition of approximately 250 MW by 2012.

New York City may not meet locational capacity requirements beyond 2003 unless additional new resources within this locality become available or interconnection capacities improve. A shortage will most likely occur in 2004 before planned projects begin to materialize in 2005. Through 2012, over 1,000 MW of new resources must be added to meet the projected locational requirement.

Details of the above projects are available on the website of the NYISO at: *http://www.nyiso.com/services/documents/planning/pdf/ny_interconnections_list_050703.pdf* or go to www.nyiso.com, then click on Services, then Planning, then Transmission Expansion and Interconnection.

Ontario — Ontario's ten-year demand forecast was derived using an econometric forecasting model. Under the median economic growth scenario, energy consumption is forecast to grow at an average annual growth rate of 1.0%, as compared to last year's forecast growth rate of 0.9%. In four of the last five years, Ontario's annual peak demand occurred during the summer due to extreme weather conditions.

New generators and nuclear generators returning from long-term outages will improve the reliability of the Ontario power system. Since last year, a 500 MW cogeneration facility was placed in service in southwestern Ontario. However, additional Ontario electricity supply and demand response will be required to maintain adequacy throughout the decade and reduce Ontario's dependency on supply from other jurisdictions.

To date, the IMO has received proposals for generating facilities totaling more than 8,000 MW of additional supply. Construction has begun on four of the proposed facilities comprising 2,216 MW. This assessment does not include projects that are not yet under construction. It also does not include the Lakeview thermal station after the end of April 2005, when it is required to cease generating electricity in compliance with regulatory requirements. If new generators currently under construction and nuclear generators returning from long-term outages are placed in service on schedule, and if no other generators are retired or taken out of service on a long-term basis beyond those that have currently been identified to the IMO, additional generation could be needed by the end of the decade. However, if the generation additions do not take place, or if additional generation is taken out of service, the need for additional generation could be advanced significantly.

The IMO continues to investigate the impacts and potential problems associated with natural gas becoming an increasing part of the new generation fuel mix in Ontario and throughout northeastern North America. To date, no major issues regarding fuel supply have been identified for Ontario.

Significant transmission reinforcement is required in the Greater Toronto Area (GTA) in order to maintain an acceptable level of supply reliability over the ten-year period. The need for transmission reinforcement, or suitably located additional supply, is due to forecast load growth both in downtown Toronto and in the municipalities north, west, and southwest of Toronto, as well as the removal from service of Lakeview Thermal Generating Station in 2005. Additional reactive supply capability will also be required before the Lakeview shutdown takes place in order to maintain an acceptable level of system reliability in the GTA. Transmission reinforcement is also required in various areas in southwestern Ontario in order to maintain an acceptable level of supply reliability. In order to increase the Ontario import and export capabilities, major transmission interconnection projects have been proposed and are in various development stages, including:

- a new 230 kV, 845 MVA phase angle regulator (PAR) on the Ontario-Michigan interconnection circuit L4D. The expected in-service date is late spring 2004, and
- a new 1,250 MW interconnection between Ontario and Québec consisting of a 230 kV two-circuit line starting at the Hawthorne transformer station and ending at a new Outaouais HVDC converter station in Québec. Depending on regulatory approvals, the estimated in-service date is the third quarter of 2005.

The increasing age of Ontario generation is emerging as a potential issue toward the end of, and beyond, the ten-year period as much of the existing generation infrastructure reaches or exceeds its nominal life. Up to 20% of the existing resource base can be expected to be retired from service or require substantial refurbishment over the next ten years, with another 20% in the subsequent five years. New environmental regulations, particularly with respect to air emissions, could also drive the need for replacement of existing supply with cleaner alternatives.

Québec — The actual peak demand for summer (May through September) 2002 was 22,522 MW, which occurred on May 14th at 6:30 p.m., was the all-time internal summer peak demand. The conditions at the time of peak were abnormally cold for that time of the year. Temperatures approached freezing in the southern part of Québec, where a large part of the load is located, resulting in strong heating demand.

For the winter (November through March) 2002–03, the internal peak load reached 34,989 MW on January 22, 2003, at 5:30 p.m., an all-time winter peak demand and about 1,800 MW higher than the peak load forecasted. This all-time peak is attributed to a long period of cold weather and stronger economic activity in Québec. At that peak time, the system supported deliveries of 381 MW to neighboring networks and imported over 1,000 MW.

The internal peak load forecasted for the winter of 2003–04 is 33,878 MW and is expected to grow at an annual average rate of 1% to reach 37,160 MW for the winter of 2012–13. In addition, Hydro-Québec has a firm commitment to export 376 MW to neighboring networks for the whole period. The winter peak load forecast (made in October 2002) is only slightly changed from that projected in October 2001 for the 2003–04 to 2011–12 period.

Hydro-Québec energy is largely produced by hydro generating stations, located on different river systems geographically distributed, the major ones with multi-annual storage capability. For the planning and the day-to-day operation of the Hydro-Québec system, HQ can rely on those multi-annual reservoirs (water reserves) and on some other non-hydraulic means, allowing Hydro-Québec to cope with negative inflow variations. Those means include, among other things, fossil generation.

With respect to water inflows, the HQ energy reliability criterion (publicly available) states that the Hydro-Québec system should be able to survive a sequence of low inflows having a 2% probability of occurrence, which is equivalent to the worst two consecutive low inflow years registered since 1943. Based on the present level of water reserves in our reservoirs and the availability of other non-hydraulic means, no generation shortage is expected for the short and medium term.

For the thermal units, each one has on-site fuel reservoirs which can be refueled by truck delivery or by barge for the racy units (at this location, the St-Lawrence Seaway is open throughout the year). As these units represent only 5% of the Hydro-Québec power capacity, fuel and delivery capacity to these units is not a major concern.

Over the period 2003 to 2013, Hydro-Québec will have available 625 MW of industrial interruptible load during the winter season, reduced by 375 MW now included under firm purchase contract with a neighboring network in Québec.

In 2002, internal electrical energy usage in Québec totaled 176.2 TWh, an increase of more than 3% over 2001. For 2003, the internal electrical energy usage is forecasted to increase by 2.7% over the 2002 reported figure to reach 181 TWh. Between 2004 and 2012, the internal electrical energy usage is forecasted to grow at an average rate of 1.2% from 182.1 to 200.4 TWh in 2012. Last year, the annual average rate of growth from 2004 to 2011 was a bit lower at 0.91%. Compared to last year's forecast, the large industrial consumer's rate of growth of demand is higher, while the rate of growth for the residential consumers is lower. The large industrial consumer demonstrates a greater load factor than the residential consumer, resulting in the higher level of energy demand in the current forecast.

At the July 2002 peak, the observed summer resources for the Québec area were 32,024 MW of generating capacity and 5,005 MW of firm purchases, for a total resource of 37,029 MW. These summer resources will increase to 39,452 MW by July 2012, with 35,584 MW of generating capacity and 3,868 MW of firm purchases. As summer inoperable capacity will vary from 7,619 MW in July 2003 to 8,201 MW in July 2012, the net summer capacity resources will vary from 27,573 MW in the 2003 summer to 30,874 MW in the 2012 summer.

At the winter peak of 2002–03, the observed winter resources for the Québec area were 32,035 MW of generating capacity and 7,271 MW of firm purchases, totaling resources of 39,306 MW. These winter resources will increase to 42,054 MW by the winter 2012–13 with 35,584 MW of generating capacity and 6,470 MW of firm purchases. As winter inoperable capacity will vary from 1,280 MW for the next winter peak to 1,260 MW for the 2012–2013 winter peak, the net winter capacity resources will vary from 37,434 MW for the next winter peak to 40,418 MW for the 2012–13 winter peak.

The increase of capacity from 2002 to 2012 will be 3,560 MW: 2,260 MW of hydro generation and 1,300 MW of gas combined cycle, including a 507 MW merchant plant scheduled for Québec in 2007. The overhaul of the nuclear station Gentilly 2 is planned for April 2008 to September 2009. However, postponing this overhaul to a later date is being reviewed.

In its last Triennial Review of Resource Adequacy in October 2002, Hydro-Québec demonstrated that the resource requirements had to be 10–11% over the annual peak load to comply with the Québec adequacy criterion. The forecasted ratio over the period from 2002–03 to 2012–13 is over 11%, except for the winter 2012–2013. Hydro-Québec Distribution, responsible for sales and services to Québec customers, will issue calls for tenders for the purchase of long-term contracts to provide resources to maintain the Québec resource reliability well inside the required resource adequacy criterion.

As the result of the 1998 ice storm, a 735 kV transmission project will be completed in 2003 to increase the operating reliability of the system. Numerous transmission projects are planned for the integration of the additional resources including:

- the installation of semi-conductor devices at the Lévis and Boucherville 735 kV substations, planned respectively for 2006 and 2007, which will be operated as dynamic shunt compensators on a steady-state basis. In case of severe icing conditions, these devices will be transformed to sequentially allow the injection of high DC current in 735 kV and 315 kV lines to melt the accumulated ice on conductors.
- a 1,250 MW interconnection between Québec and Ontario, subject to a final agreement between the parties and regulatory approvals.
- a 1,000 MW interconnection for the third quarter of 2003 between Québec and New York consisting of a variable frequency transformer isolating the AC and HVDC electric systems.

Maritime Area (New Brunswick, Nova Scotia, and Prince Edward Island) — In response to global changes in the electricity market, the New Brunswick provincial government recently introduced and subsequently passed a new Electricity Act opening the wholesale and large industrial electricity markets to competition. A final implementation date has yet to be set.

The current New Brunswick Power ten-year demand and energy forecast has increased compared to the forecast reported last year. In developing its demand and energy forecasts, NB Power assumes the weather will be "normal" as measured by heating degree-days.

The Nova Scotia Power, Inc. peak demand (including firm sales) is projected to be approximately 2,045 MW in 2003, increasing to approximately 2,280 MW by 2012. Approximately 400 MW of this peak demand is non-firm. The total installed generating capacity plus firm purchases remain constant at approximately 2,260 MW over the ten-year period.

The Maritime Electric Company, Ltd. demand and energy are expected to grow at 1 and 1.7% respectively, during 2003 and are forecasted to grow at between 2.2 and 2.4% per year thereafter. The changes from last year are insignificant and represent typical demand and energy growth in the PEI area. Weather assumptions are not used for energy forecasts.

The Maritimes Area has a diversified mix of resources such that the reliance on any one type or source of fuel is reduced. In addition, fuel storage facilities located at each plant are sufficient to permit continued operation of the plants during short duration interruptions to the fuel supply. During longer-term interruptions, this fuel storage capability affords the opportunity to secure other sources of supply or, at some plants, to switch to a different fuel. A mix of new generation and purchases will be used to continue to meet the 20% criterion within the Maritimes Area.

No transmission constraints were identified within the Maritimes Area. Additional major transmission facilities include:

- In New Brunswick, construction of a 345/138 kV tie at the Memramcook Terminal to strengthen intra-area interconnections and to improve the load-serving capability in the area which started in the fall of 2002. The tie transformer will be in service in the fall of 2003, and
- The proposed new International Power Line between New Brunswick and Maine which has undergone National Energy Board hearings with a decision expected by late spring or early summer 2003. Following NEB approval, NB Power will seek partners to construct the Maine portion of the line. The planned in-service date for this project is the autumn of 2006.

The Kyoto Protocol, ratified by the Government of Canada, calls for a 6% reduction in the 1990 levels of greenhouse gases emissions to be achieved between 2008 and 2012. These reductions could be achieved through a combination of initiatives including the proposed refurbishment of the Point Lepreau Nuclear Generating Station, demand-side management programs, renewable projects, reduced exports and the advancement of the installation of new generating facilities within the Maritimes Area. The NB Power's Coleson Cove generating plant has been modified to burn orimulsion to meet the anticipated emission standards for SO_2, NO_x, and particulates.

NPCC is a voluntary, non-profit organization. Its current members, of which there are 35, represent transmission providers, transmission customers and ISOs serving the northeastern United States and central and eastern Canada. Also included are five non-voting public interest memberships extended to regulatory agencies with jurisdiction over participants in the electricity market in northeastern North America as well as public-interest organizations expressing interest in the reliability of electric service in the region. The geographic area covered by NPCC, approximately one million square miles, includes the state of New York, the six New England states, and the provinces of Ontario, Québec, New Brunswick, and Nova Scotia. www.npcc.org

SERC

Generating capacity in the region is expected to be adequate to reliably supply the forecast firm peak demand and energy requirements throughout the assessment period. Merchant generation additions have resulted in thousands of MW of excess generating capacity in the region. Coordinated planning studies are conducted within the Southeastern Electric Reliability Council (SERC) and with adjacent NERC Regions. Transmission capacity is expected to be adequate to supply firm customer demand and firm transmission reservations. Planned transmission additions include 1,766 miles of 230 kV lines and, 526 miles of 500 kV lines. SERC members invested over $1 billion in new transmission lines and system upgrades in 2002, and they are planning transmission capital expenditures of more than $6 billion over the next five years.

Demand

The 2004 summer peak demand forecast is 155,756 MW and the forecast for 2012 is 187,417 MW. The average annual growth rate is 2.3%. This is slightly higher than last year's forecast growth rate of 2.25%. The growth rate over the last ten years averaged 2.9%. The forecast growth rate in energy usage is 2.1%, up slightly from last year's forecast of 2.0%. The historical growth rate for the last ten years was 2.8%. These forecasts are based on average historical weather conditions. Temperatures higher or lower than normal and the utilization of interruptible demand and demand-side management can significantly impact the actual peak demand and energy for the region.

The amount of interruptible demand and load management is expected to decline over the forecast period from 5,568 MW in 2004 to 4,759 MW in 2012.

Resources

The projected 2004 capacity mix for SERC is about 48% steam, 18% nuclear, 10% hydro/pumped storage, 18% gas/oil, and 6% of purchases and miscellaneous other capacity. The majority of planned capacity additions are gas/oil fueled combustion turbine or combined cycle units.

SERC believes that capacity resources will be sufficient to provide adequate and reliable service for forecast demands. The projected capacity resource margin for 2004 is 13.8% and ranges from 14.5 to 7.0% over the assessment period. These capacity margins assume the use of load management and interruptible contracts at the time of the annual peak.

Merchant Generation

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

To understand the extent of generation development in the region, it is instructive to examine how much generation is connected or has requested connection to the transmission system. A summary of generation interconnection requests is shown in *Table SERC 1: Generation Development 2003–2012*. This table includes both utility and merchant plants. The majority of development was reported for the first five years and totals over 71,000 MW. Those requests reported as "signed/filed" are believed to have a somewhat higher probability of being built than those listed as "requested."

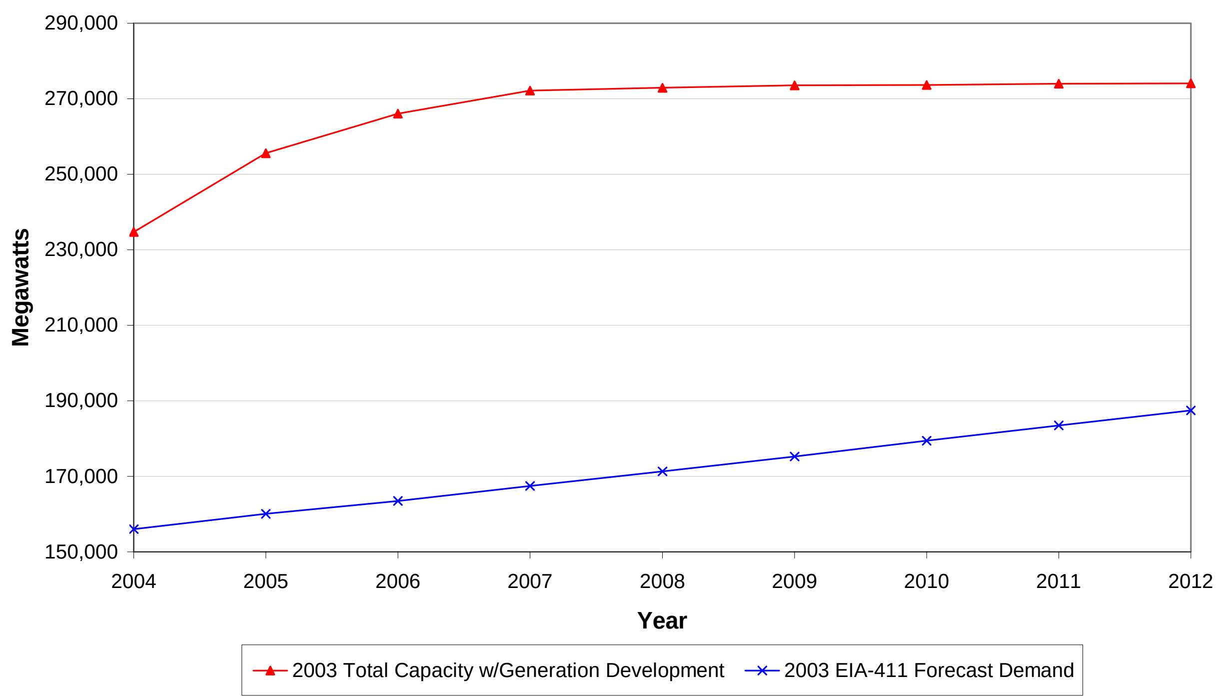
TABLE SERC 1: GENERATION DEVELOPMENT 2003–2012

Current Status of Generation Plant Development	*In-Service Year of Added Generation (MW)									
	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Interconnection Service Requested Only	1,993	4,741	12,447	9,351	4,514	675	695	100	270	100
Interconnection Agreement Signed/Filed	20,223	7,002	8,372	1,184	1,600	0	0	0	0	0
Annual Total	22,216	11,743	20,819	10,535	6,114	675	695	100	270	100
Cumulative Total	22,216	33,959	54,778	65,313	71,427	72,102	72,797	72,897	73,167	73,267

*Source: SERC Reliability Review Subcommittee 2003 report to the SERC Engineering Committee

As seen in *Figure SERC 3* below, if all of the reported capacity is built, installed capacity in the region will significantly exceed demand in the region. As of December 31, 2002, total generation connected to the transmission system in SERC was 200,744 MW. An additional 22,216 MW of generation was planned to be connected to the transmission system by July 1, 2003, bringing the total to 222,960 MW. If all of this capacity is built, installed generation could exceed forecast peak demand by 69,585 MW or 45%. As much as 46,000 MW of this connected generation may be excess to what is needed for reliability in the region.

FIGURE SERC 3: GENERATION DEVELOPMENT IN SERC



Transmission

The existing bulk transmission system within SERC is comprised of 19,578 miles of 230 kV, 758 miles of 345 kV, and 8,548 miles of 500 kV transmission lines. Planned transmission additions include 1,766 miles of 230 kV and 526 miles of 500 kV transmission lines. SERC members invested over $1 billion in new transmission lines and system upgrades in 2002, and they are planning transmission capital expenditures of more than $6 billion over the next five years.

SERC member transmission systems are directly interconnected with the transmission systems in ECAR, FRCC, MAAC, MAIN, MAPP, and SPP. Transmission studies are coordinated through joint interregional reliability study groups. The results of individual system, regional, and interregional studies are used to demonstrate that the SERC transmission systems meet NERC and SERC reliability criteria. The transmission systems in SERC are expected to have adequate delivery capacity to support forecast demand and energy requirements and firm transmission reservations under normal and contingency conditions. SERC members seek to maintain sufficient reliability margins to provide for unexpected conditions. This is an important element of reliable transmission system planning.

Operations

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

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

Subregions

Entergy — The forecast 2004 summer peak demand for the subregion is 26,057 MW. The summer peak demand is forecast to increase to 29,642 MW in 2012. The average annual demand growth rate is 1.8%. This is slightly higher than the 1.6% projected last year and lower than the 2.4% historical peak demand growth rate.

The projected capacity margin is 12.6% for the 2004 summer, and ranges from 13.7 to 10.4% over the planning period.

Planned transmission additions include 157 miles of 230 kV and 23 miles of 500 kV transmission lines.

Southern — The forecast 2004 summer peak demand for the subregion is 46,570 MW. The summer peak demand is forecast to increase to 56,804 MW in 2012. The average annual demand growth rate is 2.6%. This is slightly lower than the 2.8% projected last year and lower than the 3.6% historical peak demand growth rate.

The projected capacity margin is 12.7% for the 2004 summer, and ranges from 14.3 to 4.2% over the planning period. Capacity margins decline in the later years of the planning horizon. Consequently, capacity in addition to that currently planned will be needed to maintain reliability. The subregion has large amounts of merchant generation that could provide the needed capacity and there is adequate time to build new capacity if necessary, therefore the low capacity margins in the later years are not a reliability concern at this time.

Planned transmission additions include 985 miles of 230 kV and 382 miles of 500 kV transmission lines.

TVA — The forecast 2004 summer peak demand for the subregion is 28,439 MW. The summer peak demand is forecast to increase to 35,676 MW in 2012. The average annual demand growth rate is 2.8%. This is slightly higher than the 2.3% projected last year and comparable to the 2.8% historical peak demand growth rate.

The projected capacity margin is 10.1% for the 2004 summer, and ranges from 12.6 to 10.9% over the remainder of the planning period. Capacity margins decline in the later years of the planning horizon. Capacity in addition to that currently planned will be needed to maintain reliability. Merchant generation in the subregion could provide some of the needed capacity and there is adequate time to build new capacity if necessary, therefore the lower capacity margins in the later years are not a reliability concern at this time.

Planned transmission additions include 33 miles of 230 kV and 36 miles of 500 kV transmission lines.

VACAR — The forecast 2004 summer peak demand for the subregion is 55,310 MW. The summer peak demand is forecast to increase to 65,295 MW in 2012. The average annual demand growth rate is 2.0%. This is slightly lower than the 2.1% projected last year and lower than the 2.9% historical peak demand growth rate.

The projected capacity margin is 16.0% for the 2004 summer, and ranges from 15.4 to 6.4% over the remainder of the planning period. Capacity margins decline in the later years of the planning horizon. Capacity in addition to that currently planned will be needed to maintain reliability. Merchant generation currently proposed in the subregion could provide the needed capacity and there is adequate time to build new capacity if necessary, therefore the low capacity margins in the later years are not a reliability concern at this time.

Planned transmission additions include 591 miles of 230 kV and 85 miles of 500 kV transmission lines.

SERC membership includes 38 members and 26 associate members. SERC includes portions of 13 states in the southeastern United States, and covers an area of approximately 464,000 square miles. SERC is divided geographically into four diverse subregions that are identified as Entergy, Southern, Tennessee Valley Authority (TVA), and the Virginia-Carolinas area (VACAR). www.serc1.org

SPP

The Southwest Power Pool (SPP) anticipates consistent growth in demand and energy consumption over the next ten years. Adequate generation capacity will be available over the planning horizon to meet native network load needs with committed generation resources meeting minimum capacity margins.

The SPP bulk transmission system will reliably serve native network load for the short term while incremental system flows from commercial transmission reservations will most likely utilize any remaining transmission capacity. Several transmission upgrades have been identified either to accommodate transmission service under the SPP Open Access Transmission Tariff (SPP-OATT) or to meet specific transmission owner import/export needs. Future network analysis becomes less exact and more difficult due to the large number of proposed merchant plant additions without firm commitments to transmission service.

Demand

SPP is a summer-peaking region with projected annual peak demand and energy average growth rates of 1.6 and 1.5%, 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 consistent with historical growth rates of SPP.

Members are focusing more on the short term (two to five years), thereby shortening the planning horizon. This reduces the long-term (six to ten years) forecast accuracy. The projected growth rates for peak demand and energy over the next five years are 1.2 and 1.1%, respectively. The actual growth rates for peak demand and energy over the last five years were 1.3 and 1.5%, respectively. The SPP actual peak demand and energy used in 2002 was 39,571 MW and 194,876 GWh.

Resources

SPP's present capacity is 44,110 MW with a mix of 46% coal, 32% gas, 2% oil, and 20% other. SPP's reported capacity in 2012 is projected to be 46,306 MW, with a mix of 46% coal, 33% gas, 2% oil, and 19% other.

SPP criteria requires that members maintain a 12% capacity margin. Expected capacity margins reflected in EIA-411 data are 17.9% in 2004, 17.2% in 2005, and 17.1% in 2006. The capacity margins decline over time but exceed 12% through 2012. The capacity reported for SPP based on the EIA-411 information does not reflect some 8,300 MW of merchant plant additions, which are expected to come on line during the 2003 to 2005 time period. As a result, the expected capacity margins within SPP should be more than adequate over the planning horizon even if only a portion of these uncommitted resources are deliverable to meet native load requirements.

Transmission

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

- 210 MW Lamar HVDC and the associated 100 mile 345 kV circuit between Finney and Lamar for interconnection between SPP and WECC in late 2004, and
- Potter-Northwest 345 kV tie line being evaluated as an option beyond 2007.

SPP recently eliminated one of the most prominent transmission bottlenecks within the region using a unique approach. The LaCygne-Stilwell 345 kV line is a critical outlet for large baseload generating units owned by Westar Energy and Kansas City Power & Light Company. Loadings on this line have been heavily impacted by merchant activity in SPP, as well as in SERC and MAPP. The 30 mile transmission line, located south-southwest of Kansas City, was rebuilt using new technology that allows the use of existing structures and for the work to be done while the line is energized, resulting in minimal disruption to the transmission line operation and the market. KCP&L was responsible for upgrading this critical 345 kV line and completed the project prior to summer 2003. As a result, the LaCygne-Stilwell line capacity increased from 1,251 MVA to 1,972 MVA. The funding for this project resulted from an agreement among the SPP Transmission Owners.

SPP has evaluated the general reliability of the transmission network for the one-to-five-year timeframe in accordance with NERC Planning Standards I.A.S1 and I.A.S2. The SPP transmission owners have provided mitigation plans where examination of the power transmission network has identified base case and/or (n-1) conditions producing regional violations of reliability criteria. A preliminary six-to-ten-year reliability assessment indicates that a majority of the SPP members have mitigation plans, which are effective in addressing expected reliability criteria violations. SPP is working with those remaining members to identify mitigation plans, which can be implemented in a timely manner.

SPP is developing a formal regional transmission expansion planning process. This process will be an open and collaborative effort with all affected stakeholders. SPP staff and members actively supported the development and analysis for the MISO Transmission Expansion Plan (MTEP) until the MISO-SPP merger terminated in early 2003. MISO staff independently proposed a SPP 345 kV plan that has been included in the final MTEP draft report. SPP is evaluating an alternative EHV expansion plan within the region. A preliminary analysis of the alternative EHV expansion plan is promising, but the recommended plan and its benefits need additional review that will be presented in the SPP regional transmission expansion plan.

SPP generation interconnection procedures accommodate the needs of the merchant developers regarding studies to determine the transmission additions necessary to integrate their planned capacity additions into the bulk transmission system.

Operations

SPP has operated an operating reliability center since 1997 and is the reliability coordinator for the SPP region. The operating reliability center provides the exchange of near real time operating information and around-the-clock operating reliability coordination.

SPP implements operating reliability procedures required of a NERC reliability coordinator under NERC Operating Policies. SPP coordinates maintenance outage schedules of the generation and transmission facilities within the region. Operating reliability analysis is performed daily to help members recognize heavy line loading that is expected to occur. When heavy line loading occurs in real time or is expected to occur in near real time, NERC Transmission Loading Relief (TLR) procedures are invoked to relieve facility loading. A major tenet of these procedures is to ensure that TLR is achieved by real changes in generation patterns, not a mere shuffling of interchange schedules. These procedures have provided for TLR in the SPP Region and surrounding regions. SPP has experienced TLR curtailments on its transmission facilities in recent years and expects that this will continue in the future. Although SPP has adequate transmission to reliably serve native load, it expects heavy use of the transmission system for economy transactions to continue into the future.

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

SPP currently consisting of 50 members, serves more than 4 million customers, and covers a geographic area of 400,000 square miles containing a population of over 18 million people. In covering a wide political, philosophical, and operational spectrum, SPP's current membership consists of 14 investor-owned utilities, six municipal systems, eight generation and transmission cooperatives, three state authorities and one federal *government agency, one independent power producer, and 17 power marketers. SPP has more than 350 electric industry employees on various organizational groups that bring together unmatched expertise to deal with tough reliability and equity issues. An administrative and technical staff of about 100 persons facilitates the organization's activities and services.* www.spp.org

WECC

Despite a dramatic decrease in proposed new generation during the past year, generating capacity in the Western Electricity Coordinating Council (WECC) is expected to be adequate to reliably supply the forecast firm peak demand and energy requirements throughout the assessment period. Transmission capacity is expected to be adequate to supply firm customer demand and firm transmission transactions. Plans have been announced for the construction of 4,319 miles of 230 kV, 345 kV, and 500 kV transmission lines during the 2003–2012 period.

Overview

WECC is spread over a wide geographic area with significant distances between load and generation areas, making transmission constraints a significant factor when considering reliability in the region. For these reasons, reliability in WECC is best examined at a subregional level. The capacity margins discussed in the subregional assessments that follow assume the planned construction of 32,323 MW of net new generation, which is dramatically less than the net planned capacity additions of 81,055 MW reported last year for the 2002–2011 time period. The 60% reduction in net capacity additions is largely due to the deteriorated financial condition of several major merchant plant developers and the fact that more new plant capacity was proposed than was needed. Approximately 8,000 MW of the 81,055 MW of planned net capacity additions went into operation during 2002.

The capacity margin adequacy also assumes average weather conditions. WECC is spread over a wide geographic area with considerable weather diversity in loads and resource availability. If multiple areas peak simultaneously, portions of the region may need to take actions to ensure that adequate operating reserves are maintained.

Transmission facility additions reported for the 2003–2012 ten-year period include 1,572 miles of 230 kV, 824 miles of 345 kV, 1,923 miles of 500 kV transmission lines, two 200 MW DC ties to the Eastern Interconnection, and a 1,000 MW DC tie to Mexico. The transmission system is considered adequate for firm and most economy energy transfers.

Demand

Due to warmer than normal temperatures throughout portions of the region in 2002, peak demands are expected to increase by only 0.4% from 2002 to 2003. However, due to an expected economic recovery peak demands are expected to jump by 3.7% from 2003 to 2004. Thereafter, peak demands are expected to increase by about 1.9% per year. It should be noted that resource adequacy is measured against firm peak demand, not total peak demand. Non-firm demands within WECC are about 1,850 MW. About 1,300 MW of the 1,850 MW is in California.

Resources

Projected reserves are expected to be adequate throughout the WECC Region for the 2003–2012 ten-year period. This assessment assumes that approximately 32,300 MW of planned net new generation will be built when needed and that up to 6,000 MW of Pacific Northwest and Arizona-New Mexico capability will be available during summer periods to serve California and Rocky Mountain area peak demands. A drought may dramatically reduce Pacific Northwest capacity available for export. Therefore, capacity adequacy after about 2008 becomes highly dependent on northwest hydroelectric conditions.

The net resource addition of 32,323 MW used in this assessment is composed of 12,294 MW of committed net resource additions (18,166 MW of plants under construction less 5,872 MW of planned retirements) and 20,029 MW of uncommitted resource additions. If the planned retirements occur as scheduled and if no plants are built beyond those already under construction, WECC's capacity margin would drop below 13% by the summer of 2010. Almost one fourth of the uncommitted resources are in California and capacity margins in the California-Mexico area decrease to near minimum operating requirements by the summer of 2008. It should be noted, however, that a significant portion of the planned retirements may be deferred if resource additions continue to decline significantly.

WECC's Reliability Assessment Subcommittee has studied resource adequacy scenarios that include transfer capability restrictions and capability derate assumptions. A scenario that assumed no capability increase from uncommitted additions, a 1,388 MW northwest hydro sustained peaking capability limitation, and non-hydro forced outages of 5% (8% for California resources) resulted in capacity margins dropping to 10.7% by 2008.

Transmission

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

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

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

- Compliance Monitoring
  A voluntary peer review process through which every operating member is reviewed at regular intervals to assess compliance with WECC and NERC operating criteria. Control areas are reviewed once every three years.
- Annual Study Report
  In accordance with WECC policy, the system will not be operated under system conditions that are more critical than the most critical conditions studied.
  Operating reliability assessment shall be an integral part of planning, rating, and transfer capability studies.
- Project Review and Rating Process
  Study groups are formed to ensure project path ratings comply with all established reliability criteria.
- Operating Transfer Capability Policy Committee Process

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

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

Operations

Under WECC's Regional Reliability Plan, three reliability centers have been established for the region. The reliability center coordinators are charged with actively monitoring, on a real-time basis, interconnected system conditions to anticipate and mitigate potential reliability problems and to coordinate system restoration should an outage occur.

Subregions

Northwest Power Pool Area — The Northwest Power Pool (NWPP) area is comprised of all or major portions of the states of Idaho, Montana, Nevada, Oregon, Utah, Washington, and Wyoming; a small portion of northern California; and the Canadian provinces of British Columbia and Alberta. For the period from 2003 through 2012, peak demand and annual energy requirements are projected to grow at annual compound rates of 1.6 and 1.7%, respectively. With a significant percentage of hydro generation in the region, the ability to meet peak demand is expected to be adequate for the next ten years. Capacity margins for this winter-peaking area range between 23.4 and 29.6% for the next ten years.

Northwest power planning is done by sub-area. Idaho, Nevada, Wyoming, Utah, British Columbia, and Alberta individually optimize their resources to their demand. The Coordinated System (Oregon, Washington, and western Montana) coordinates the operation of its hydro resources to serve its demand. The 2003 projected January through July Columbia River flow at The Dalles, Oregon is expected to be 89.3 million acre-feet (Maf), or 83% of the thirty-year average. The 2001 runoff was the second lowest water year the northwest has experienced since record keeping began and Coordinated System hydro reservoirs refilled to the lowest levels seen in almost a decade. In 2002, the reservoirs refilled to approximately 92% of capacity by July 31.

The water flow associated with hydroelectric resources must be balanced among several competing uses. These uses include current electric power generation, future electric power generation, flood control, biological opinion requirements resulting from the Endangered Species Act, and special river operations for recreation, irrigation, navigation, and the refilling of the reservoirs each year. Any time precipitation levels are below normal, balancing these interests becomes even more difficult.

A ten-year agreement was reached in 2000 among U.S. Federal parties (National Marine Fisheries Service, the U.S. Fish and Wildlife Service, the U.S. Bureau of Reclamation, the U.S. Army Corps of Engineers, and the Bonneville Power Administration) involved in the operation of the Columbia River Basin concerning river operations. However, this agreement is subject to three, five, and eight-year performance checks and reopening by the parties. The net impact of the agreement is a reduction in generating capability as a result of hydro generation spill policies designed to favor fish migration. The capability reduction, which varies depending on water flows and other factors, is reflected in the margin calculations presented in this report. The agreement includes a provision for negotiating changes in the plan under emergency conditions as was done in 2001.

In view of the longer time required for transmission permitting and construction, it is recognized that network planning should focus on establishing a flexible grid infrastructure. This is being done with the goals of allowing anticipated transfers among NWPP systems, addressing several areas of constraint within Washington, Oregon, Montana, and other areas within the region, and integrating new generation. Projects at various stages of planning and implementation include approximately 800 miles of 500 kV transmission lines as well as modernization of the Celilo terminal of the Celilo-Sylmar high-voltage DC line.

Maintaining the capability to import power into the Pacific Northwest during infrequent extreme cold weather periods continues to be an important component of transmission grid operation. In order to support maximum import transfer capabilities, the northwest depends on tripping of large industrial customer demand as a remedial action for loss of the Pacific Interties. If drought conditions occur, it may be advantageous to maximize transfer capabilities to reduce reservoir drafts and aid reservoir filling.

Generation in the province of Alberta, Canada operates in a fully deregulated market and resource additions are market driven. Generation additions are expected to result in transmission constraints in a number of areas on the system. Plans to alleviate the constraints include the development of a 500 kV network overlaying an existing 240 kV network. It is anticipated that the transmission system additions will be needed by 2009.

The Canadian province of British Columbia relies on hydroelectric generation for 90% of its resources. British Columbia Hydro and Power Authority is addressing constraints between remote hydro plants and lower mainland

and Vancouver Island load centers. The Guichon series capacitor station on the Kelly Lake-Nicola 500 kV line and additional series compensation on the Selkirk-Nicola 500 kV line will increase transfer capability from major hydro resources to the major load centers and the Canada-U.S. border. The increasing mainland to Vancouver Island transmission constraint will be relieved by the construction of additional generation on the island in 2005.

Rocky Mountain Power Area — The Rocky Mountain Power Area (RMPA) consists of Colorado, eastern Wyoming, and portions of western Nebraska and South Dakota. The RMPA may experience its annual peak demand in either the summer or winter season due to variations in weather. Over the period from 2003 through 2012, peak demand and annual energy requirements are projected to grow at annual compound rates of 1.7 and 1.2%, respectively. Capacity margins range between 12.0 and 16.4% for the next ten years.

Significant planned transmission upgrades include:

Proposed RMPA Projects	Planned Date
Rapid City, South Dakota 200 MW DC Tie to MAPP	Late 2003
Lamar, Colorado 200 MW DC Tie to SPP	Early 2005
Walsenburg, Colorado to Gladstone, New Mexico 230 kV line	2005
Midway-Denver 345 kV line (initially operated at 230 kV)	2005
Green Valley Spruce 230 kV line (built for 345 kV operation)	2005
Upgrades to Path 36 (TOT3) between southeast Wyoming and northeast Colorado	2003 and 2005
San Luis Valley transformer upgrade	Late 2003

Arizona-New Mexico-Southern Nevada Power Area — The Arizona-New Mexico-Southern Nevada Power Area consists of Arizona, most of New Mexico, the westernmost part of Texas, southern Nevada, and a portion of southeastern California. Over the period from 2003 through 2012, peak demand and annual energy requirements are projected to grow at annual compound rates of 2.8 and 2.9%, respectively. Capacity margins for this summer peaking area range between 12.6 and 24.2% for the next ten years.

As with other areas within WECC, the future adequacy of the generation supply over the next ten years in the Arizona-New Mexico-Southern Nevada area will depend on how much new capacity is actually constructed. Generally, the proposed plants have relatively short construction times once the decision is made to proceed. These factors combine to make generation adequacy forecasting problematic for an extended period of time.

Several Arizona utilities have participated in a regional EHV transmission study to evaluate developing transmission alternatives in the Central Arizona area. The study is called the Central Arizona Transmission System (CATS) study and encompasses an area bounded by environs between the Phoenix and Tucson metropolitan areas and the Palo Verde Nuclear Generating Station. The purpose of the study is to evaluate long-term high-voltage transmission facility requirements to serve future load growth in the Phoenix and southern Arizona areas, to increase the power transfer capability between the Phoenix and Tucson areas, to facilitate future generation additions south of Phoenix and north of Tucson, and to provide additional transmission capacity to and from the Palo Verde energy trading and marketing hub. The CATS study has provided a framework for the participating utilities to plan and coordinate transmission lines and receiving stations in the area. The study has also identified how the timing and phasing of projects can be done in a coordinated manner.

Significant planned transmission upgrades are tabulated below.

Proposed AZ/NM/SNV Projects	Planned Date
Palo Verde to Rudd 500 kV line	2003
Falkner-Tolson and Northwest-Arden 230 kV lines	2003
Southern Nevada 500 kV generation outlet lines	2003
Nogales, Arizona to Tucson 345 kV lines	2005
Palo Verde to Nogales 345 kV lines	2006
Palo Verde to Phoenix 500 kV lines	2007
Northern to central New Mexico 345 kV generation outlet lines	2007
Shiprock, New Mexico to Marketplace, Nevada 500 kV line	2008
Palo Verde to West and North Phoenix 500 kV lines	2008 and 2010
Yuma, Arizona to Gila Bend, Arizona 230 kV line	2010

California-Mexico Power Area — The California-Mexico Power Area encompasses most of California and the northern portion of Baja California, Mexico. Peak demands and annual energy requirements are currently projected to grow at annual compound rates of 2.2 and 2.0%, respectively, from 2003 through 2012. Projected capacity margins range between 11.8 and 19.9% for the next ten years.

Restructuring of the electric industry in California has added much uncertainty to future adequacy projections of generating capacity, energy production by independent power producers, and effects of customer energy efficiency/demand-side management programs. For example, last year's adequacy assessment reported over 45,000 MW of planned resource additions for the area for the 2002 through 2011 ten-year period. This assessment reflects planned additions of only 7,100 MW over the 2003–2012 period. Of the 7,100 MW of planned additions, 5,900 MW are planned for 2003 through 2007, resulting in capacity margins in excess of 13%. The remaining 1,200 MW of planned additions reported for 2008 through 2012 results in a capacity margin of 7.7%, assuming no increase in imports from other areas. It is assumed that localized transmission constraints are addressed as generation is added. If internal constraints are not addressed, additional generation and/or transmission additions will be needed prior to 2007.

The three major investor-owned utilities in California have developed short-term resource plans for 2003 and 2004 and a long-term resource plan is being reviewed by the California Public Utilities Commission. In addition, the California Energy Commission is reviewing the resource adequacy for all utilities in California, including municipal utilities and irrigation districts, as part of its Integrated Energy Policy Report proceeding.

The California Independent System Operator (CAISO), which serves the majority of the load in the area, administers a coordinated planning process that forms the basis for planning future changes and additions to the transmission system. The process calls for stakeholder participation in the planning process with the intent to facilitate the development of projects that best meet the needs of all users while maximizing the potential benefits to California.

The resource uncertainty mentioned above significantly complicates associated transmission planning. However, the CAISO is preparing a long-term transmission expansion plan that will be coordinated with the state agency resource adequacy proceedings to ensure that transmission and generation planning are coordinated.

Significant transmission upgrade projects during the 2003 through 2012 period include a 1,500 MW upgrade to Path 15 in central California, scheduled for late 2004, and 500/230 kV transformer additions at key locations around the state in 2003 and 2004.

Due to the addition of several generating plants in Arizona, southern Nevada, and Mexico, the bulk transmission system in the southwest is becoming increasingly congested. Special protection schemes have been implemented for new generation connected to the Imperial Valley substation in order to relieve some of the congestion and an operating nomogram is used to limit the simultaneous operation of generating plants connected to the Imperial Valley substation and imports from CFE and Arizona. The CAISO anticipates that the 500 kV interconnection between Arizona and California that connects to the Imperial Valley substation will be constrained most of the time due to increased imports for new southwest generation. The CAISO utilities in southern California and Arizona, and other interested parties, are participating in an effort to identify and construct facilities necessary to address these constraints in the longer term. The CAISO has also identified a need for additional transmission to address reliability concerns in the San Diego and southern Orange County area beginning in 2005.

WECC, with 158 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 (59% of installed capacity);*
- *the Rocky Mountain Power Area, which can be either summer or winter peaking with a 12% hydroelectric and 56% coal-fired generating capacity mix;*
- *the Arizona-New Mexico-Southern Nevada Power Area, which is summer peaking with a 12% nuclear and 33% coal-fired generating capacity mix; and*
- *the California-Mexico Power Area, which is summer peaking and heavily dependent on gas-fired generating units (55% of installed capacity).*

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Energy Projections

FIGURE A1: UNITED STATES NET ENERGY FOR LOAD 2003–2012

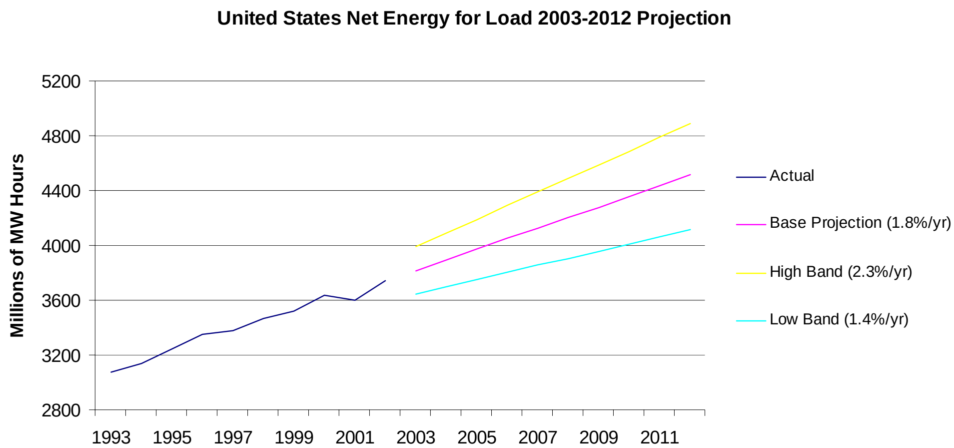
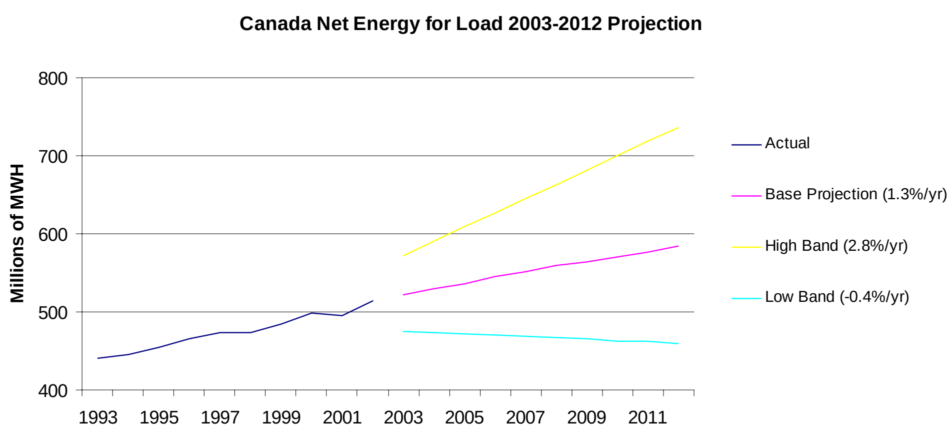


FIGURE A2: CANADIAN NET ENERGY FOR LOAD 2003–2012



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